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Rheological Screening of HPAM for High-Salinity EOR

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ABSTRACT - Hydrolyzed polyacrylamide (HPAM) polymer flooding is a practical chemical enhanced oil recovery method, but polymer performance can deteriorate under high salinity, elevated temperature, and high shear rate. This study presents an integrated laboratory screening workflow for five commercial HPAM polymers under reservoir-representative conditions. Polymer solutions were prepared at 500–5000 ppm and tested at shear rates of 1–1000 s⁻¹, salinities of 3,000–200,000 ppm, and temperatures up to 90°C. Rheological screening was followed by adsorption and core flooding tests for the most suitable candidates, Polymers C and E. These two polymers were carried forward because they achieved the highest composite scores in the technical screening, combining strong viscosity retention with favorable injectivity and salinity/temperature tolerance. All polymers showed shear-thinning behavior, while salinity and temperature reduced apparent viscosity. Polymer A provided the highest bulk viscosity; however, Polymer C gave the best balance among viscosity retention, salinity tolerance, injectivity, adsorption behavior, and recovery performance. Core flooding confirmed that Polymer C at 3000 ppm produced the highest incremental recovery, approximately 10.0% in Core 1 and 8.8% in Core 2. The results show that HPAM selection should be based on integrated rheology, adsorption, and recovery testing rather than viscosity alone. The main contribution of this work to polymer technology is a transferable, six-stage integrated screening protocol that links rheological behavior, salinity and thermal tolerance, adsorption loss, and core-scale recovery response within a single laboratory workflow, providing a practical decision basis for selecting HPAM polymers for high-salinity EOR projects rather than relying on isolated viscosity or adsorption data.

Keywords: HPAM, polymer flooding, rheology, high salinity, core flooding.

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1. Introduction

Enhanced oil recovery (EOR) is commonly applied after primary and secondary recovery to mobilize oil that remains in mature reservoirs. Polymer flooding improves waterflood performance by increasing the viscosity of the injected aqueous phase and reducing the water-oil mobility contrast. Better mobility control can delay water breakthrough, improve sweep efficiency, and increase recovery from waterflooded reservoirs (Green & Willhite 1998; Sorbie 1991; Lake et al., 2014; Gbadamosi et al., 2022; Ambaliya & Bera 2023; Seright & Wang 2023).

HPAM remains one of the most widely used EOR polymers because it is commercially available, relatively inexpensive, and capable of producing high solution viscosity at practical concentrations (Seright & Wang 2023). Its performance, however, is sensitive to salinity, temperature, shear rate, polymer-rock interaction, and injected concentration. Monovalent and divalent ions can shield charged polymer groups, compress polymer coils, and reduce apparent viscosity, whereas temperature and high shear may accelerate viscosity loss or mechanical degradation (Zhang et al., 2022; Navaie et al., 2022; Qi et al., 2023; Perez et al., 2024; Khlaifat et al., 2024).

Recent laboratory studies also show that polymer selection cannot rely on bulk viscosity alone. Static adsorption, retention, in-situ rheology, and injectivity can change the effective polymer concentration reaching the displacement front and may control the final recovery response. High-salinity and high-temperature screening studies have therefore combined rheology with adsorption and core displacement measurements to identify candidates that remain stable in brine while maintaining acceptable porous-media flow behavior (Mousapour et al., 2021; Mousapour et al., 2024; Alajmi et al., 2025; Yarahmadi et al., 2025). For example, Mousapour et al. (2021) reported that polymer ranking based on rheology alone did not match the ranking obtained once static adsorption was included, while Mousapour et al. (2024) showed that in-situ injectivity in sandstone could fall well below bulk-viscosity predictions once retention effects were accounted for. Alajmi et al. (2025) further demonstrated that fracture presence altered adsorption and in-situ rheology relative to intact core plugs, and Yarahmadi et al. (2025) found that synthetic HPAM generally outperformed bio-based polymers in adsorption resistance despite comparable initial viscosities. Together, these studies indicate that rheology, adsorption, and displacement behavior do not always rank polymers consistently, motivating the integrated multi-criteria screening adopted in the present work. Modified or hybrid polymer systems have also been examined to improve salinity tolerance and recovery efficiency under harsher reservoir conditions (Karimov et al., 2025; Khamis et al., 2026).

Nanoparticle-assisted chemical systems are being developed for the same purpose Subagio et al. (2026), for example, stabilised silica nanofluids with an AOS–DLS surfactant pair in formation brine, maintaining dispersion stability for more than three months at 60 °C and obtaining 12.9% OOIP incremental recovery in sandstone core flooding, which underlines that thermal and salinity stability of the injected chemical is a prerequisite for recovery performance. Field-scale experience supports the practical relevance of this laboratory screening approach. In the Daqing oilfield, the world's largest commercial polymer flood, HPAM injection has sustained an average incremental oil recovery of about 11% over waterflooding across the tested blocks, with performance strongly dependent on the polymer grade and injection strategy selected during preliminary screening (Wang & He 2006). Similarly, laboratory-guided polymer selection under high-temperature, high-salinity conditions in the Bohai heavy-oil field improved water-cut reduction and increased per-well production after the target polymer was identified through property screening prior to field deployment (Zhang et al., 2022). These field cases illustrate that the choice of HPAM grade, informed by rheological, adsorption, and displacement screening rather than viscosity alone, directly affects commercial recovery outcomes, reinforcing the motivation for the integrated screening workflow presented here.

Although previous studies have reported HPAM viscosity, adsorption, or injectivity behavior separately, fewer screening studies connect these indicators with recovery response in one compact experimental workflow. The present work therefore ranks five commercial HPAM candidates using the same sequence of rheology, salinity and temperature tolerance, adsorption, and core-flood recovery tests. This integrated comparison reduces the risk of selecting a polymer only because it gives high bulk viscosity under simple laboratory conditions. The objective of this work is to evaluate five HPAM polymers through an integrated experimental workflow and identify the

candidate that provides the best practical balance between rheological strength, injectivity, adsorption loss, and oil recovery. Despite the availability of commercial HPAM products, systematic comparative screening that links rheology, adsorption, and displacement performance under high-salinity conditions in a single compact workflow remains limited in the published literature. This study addresses this gap by presenting an integrated experimental screening protocol for five commercial HPAM polymers under reservoir-representative conditions. The specific objectives are to: (i) characterize the rheological response of each polymer under varying shear rate, salinity, and temperature; (ii) evaluate polymer adsorption in porous media; and (iii) quantify incremental oil recovery through core flooding. The results provide a ranked comparison of candidate polymers and a transferable six-stage screening procedure applicable to high-salinity EOR projects.

2. Methodology

2.1 Polymer materials and solution preparation

Five commercial HPAM polymers, denoted A, B, C, D, and E, were evaluated. Their molecular weights were 10–12, 9–11, 5–7, 4–6, and 3–5 MDa (million g/mol) for Polymers A, B, C, D, and E, respectively, with degrees of hydrolysis in the range of 25% to 35%. Polymer E was supplied as a liquid polymer, whereas the remaining polymers were supplied in powder form. Polymer solutions were prepared at concentrations of 500, 1000, 2000, 3000, 4000, and 5000 ppm. Powder polymers were slowly added to brine or deionized water under controlled vortex mixing at 300 RPM to minimize fish-eye formation and incomplete hydration. The solutions were then mixed under moderate agitation and aged for 24 h at 25 °C before rheological testing. The experimental workflow is summarized in Figure 1 as shown below. The six-stage sequence includes polymer selection, solution preparation and aging, rheological screening (shear rate, salinity, temperature), candidate ranking by technical screening, adsorption and core flooding tests, and final polymer selection based on combined viscosity retention, injectivity, adsorption loss, and recovery response. Each stage of the workflow served a specific screening function and generated the input required for the next stage. In Stage 1 (polymer selection), the five candidates were selected to span a practical range of molecular weight and hydrolysis degree available commercially. In Stage 2 (solution preparation and aging), controlled hydration under vortex mixing minimized fish-eye formation and ensured reproducible baseline viscosity before any stress condition was applied. In Stage 3 (rheological screening), each polymer was tested sequentially across shear rate, salinity, and temperature to isolate the sensitivity of apparent viscosity to each variable individually before combined conditions were imposed. In Stage 4 (technical ranking), the rheological outputs were normalized and scored against four criteria (viscosity retention, salinity tolerance, thermal stability, and injectivity; Table 2, Figure 5) to narrow the five candidates to the two most promising ones, avoiding the cost and time of running full adsorption and core-flood programs on all five polymers. In Stage 5 (adsorption and core flooding), the two shortlisted polymers, C and E, were evaluated under reservoir-representative salinity and temperature in duplicate core plugs to obtain adsorption and incremental recovery data. In Stage 6 (final selection), the outputs of Stages 3–5 were combined to identify the polymer offering the best practical balance of performance criteria, rather than the single criterion of highest bulk viscosity. This staged design allowed early-stage rheological results to guide which polymers advanced to the more resource-intensive adsorption and core-flooding stages.

2.2 Rheological measurements

Rheological measurements were performed using a Brookfield DV-II+ Pro rotational viscometer equipped with an OFITE stainless-steel measurement cup. Apparent viscosity was evaluated over shear rates from 1 to 1000 s⁻¹. The experimental program focused on polymer concentration, salinity, and reservoir-relevant temperature effects up to 90°C. Salinity levels of 3,000, 33,000, 93,000, and 200,000 ppm total dissolved solids (TDS) were used to represent low- to high-salinity brine environments. The 93,000 ppm brine, representative of the target reservoir formation water, was prepared with NaCl (73,000 ppm), CaCl₂ (12,000 ppm), and MgCl₂ (8,000 ppm). All rheological comparisons were made after polymer hydration and using the same concentration, salinity, and temperature sequence to support direct ranking among the tested polymers. Apparent-viscosity readings were recorded after temperature equilibration and stabilization of the instrument response at each condition.

2.3 Oil characterization and core flooding

Crude oil was collected from the target field and dewatered before testing. The measured dead-oil viscosity was 79 cP and the live-oil viscosity was 8 cP, with an API gravity of approximately 30. Cyclohexane was added at approximately 25% v/v to match the target live-oil viscosity of 8 cP. Two sandstone core samples from the target field were used for adsorption and recovery experiments. The core flooding procedure included core cleaning, drying, brine permeability measurement, tracer injection, polymer injection at a constant injection rate of 1 cm³/min, and post-polymer brine injection until pressure stabilization. Additional oil recovery was evaluated by comparing oil production after polymer flooding with the preceding waterflood recovery. Before polymer injection, each core was prepared and waterflooded to establish a reference recovery. Polymer flooding was then applied after waterflooding so that the reported additional recovery reflected incremental performance under comparable porous-media conditions.

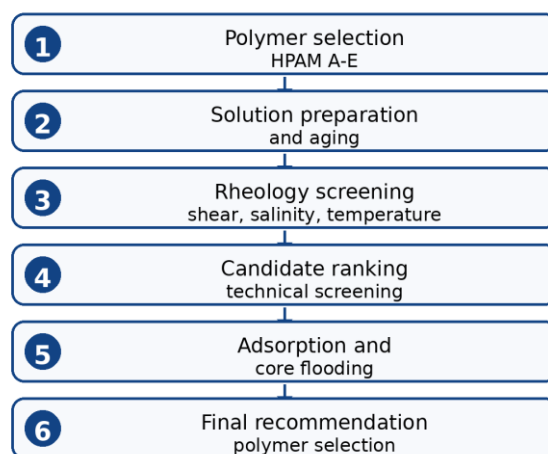


Figure 1.

Experimental workflow for screening HPAM polymers for high-salinity EOR applications.

2.4 Adsorption measurements

Adsorption was evaluated by comparing polymer breakthrough with tracer breakthrough under the same core conditions. The difference between injected and produced polymer concentration was used to estimate the adsorbed polymer mass. Adsorption was reported as milligrams of polymer per gram of rock. The candidate polymers, C and E, were tested at 1800 and 3000 ppm under high-salinity reservoir conditions at a temperature of 60 °C, representing the target reservoir's operating flooding temperature, whereas the bulk rheological screening was extended to 90 °C to establish the polymers' thermal-tolerance envelope beyond the actual field condition. Each measurement was performed in duplicate and the reported values represent the mean; the deviation between duplicates was within 5%. The flooding conditions and parameters are shown below in Table 1.

Table 1.

Core sample properties used in adsorption and recovery experiments.

Parameter	Core 1	Core 2
Rock type	Sandstone	Sandstone
Porosity (%)	23	23
Permeability (mD)	170	250
Pore volume (cm ³)	20.0	19.8
Polymer candidates	C and E	C and E
Polymer concentrations (ppm)	1800 and 3000	1800 and 3000
Flooding temperature (°C)	60	60
Injection rate (cm ³ /min)	1.0	1.0

3. Result and discussion

3.1 Effect of shear rate and concentration

All tested polymers showed shear-thinning non-Newtonian behavior. Viscosity increased with polymer concentration because higher polymer loading increases molecular entanglement and solution network strength. However, viscosity decreased as shear rate increased because polymer chains progressively aligned in the flow direction. Figure 2 below presents the viscosity–shear rate comparison at 5000 ppm polymer concentration, 30°C, and 3000 ppm salinity. Polymers A and C showed the strongest thickening ability at low shear rate, whereas Polymers B and D had lower apparent viscosity but better expected injectivity. Polymer E showed the lowest viscosity response, but it maintained stable flow behavior and therefore remained attractive for pressure-constrained applications. Quantitatively, apparent viscosity at 5000 ppm and 1 s^{-1} ranged from approximately 210 cP for Polymer A to 8 cP for Polymer E, a more than 25-fold spread that highlights the practical significance of polymer selection at the screening stage. Across the tested shear-rate range, all polymers displayed the shear-thinning index characteristic of entangled HPAM solutions, with the steepest viscosity decline occurring between 1 and 100 s^{-1} and a comparatively flat response above 100 s^{-1} ; this behavior is consistent with progressive chain disentanglement and alignment rather than mechanical scission, since viscosity did not show the irreversible step-change typically associated with chain breakage. From an operational standpoint, the narrower viscosity gap between polymers at high shear rate implies that near-wellbore injectivity differences among the candidates should be smaller than the bulk-viscosity contrast alone would suggest, reinforcing the need for the injectivity-weighted screening applied in Section 3.4. At the lower concentrations used in the downstream adsorption and core-flood tests, the bulk apparent viscosity at 10 s^{-1} was approximately 35 cP for Polymer C and 25 cP for Polymer E at 3000 ppm, and approximately 5 cP for Polymer C and 2 cP for Polymer E at 1800 ppm, consistent with the shear-thinning and concentration-dependent behavior characterized in Figure 2.

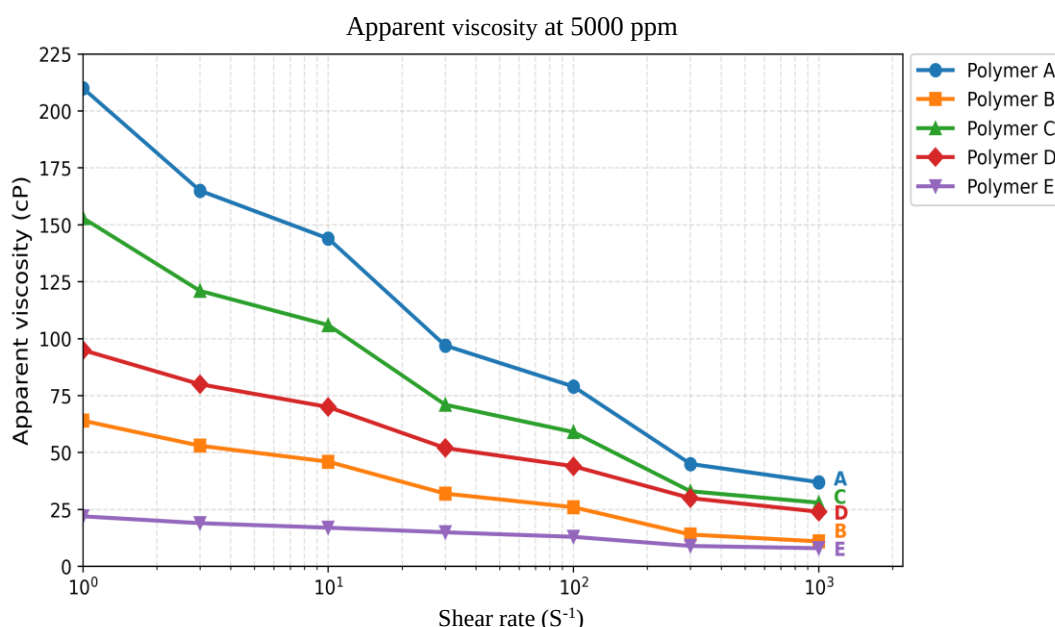


Figure 2.
Apparent viscosity versus shear rate at 5000 ppm polymer concentration for five commercial HPAM polymers (A–E).

2.5 Effect of salinity

Increasing salinity caused a systematic decrease in viscosity for all polymer types. The salinity effect is consistent with the well-established ionic shielding mechanism, in which dissolved ions reduce the electrostatic repulsion along HPAM chains, contract the polymer coil, and weaken intermolecular interactions (Sorbie 1991). Figure 3 summarizes the salinity trend at a fixed shear rate. At low salinity, the differences among polymers remained clear, with Polymers

A and C maintaining the highest viscosity. At elevated salinity, the viscosity contrast between polymer types decreased. At 93,000 ppm, Polymer A and Polymer C retained the highest apparent viscosity, whereas Polymer E remained the lowest-viscosity polymer but maintained favorable flow stability. Increasing salinity from 3,000 to 200,000 ppm reduced apparent viscosity by up to 70% across the tested polymers, but the magnitude of this loss was not uniform: Polymers A and C lost proportionally less of their initial viscosity than Polymers B and D, indicating a higher intrinsic resistance to ionic shielding, consistent with their comparatively higher molecular weight and hydrolysis degree. The viscosity contrast between polymers narrowed at high salinity because divalent cations (Ca^{2+} , Mg^{2+}) preferentially compress the polymer coil regardless of the initial chain conformation, so that the differentiating effect of hydrolysis degree becomes less pronounced once the coils are already contracted. This narrowing has a direct screening implication: viscosity measurements at low salinity alone would have over-stated the practical differences among candidates under the target reservoir's 93,000 ppm formation-water salinity.

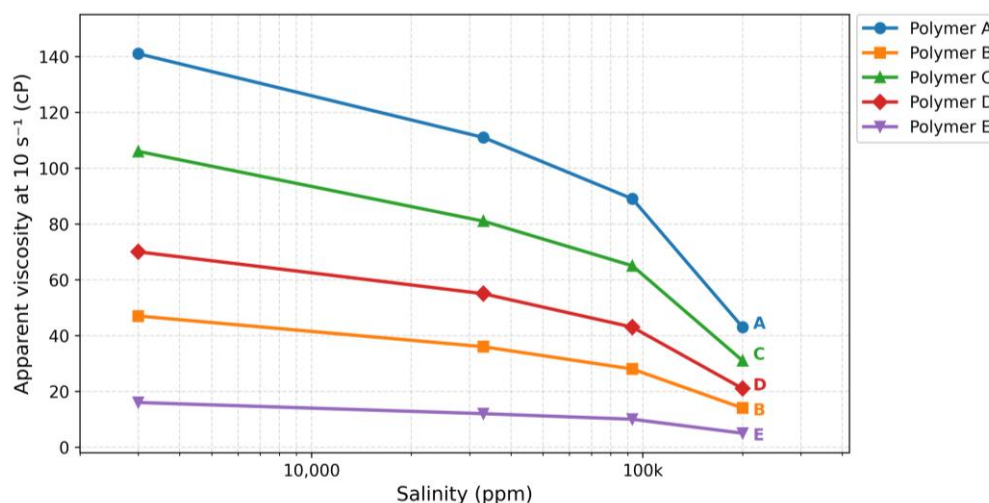


Figure 3.
Effect of salinity on apparent viscosity at a fixed shear rate of 10 s^{-1} and 5000 ppm polymer concentration for five HPAM polymers (A–E).

2.6 Effect of temperature and combined reservoir conditions

Temperature reduced the apparent viscosity of all tested polymer solutions. The reduction became more pronounced as temperature increased from ambient conditions to 90°C , where thermal motion weakened polymer-chain interactions and reduced the viscosity retained under reservoir-representative conditions. Figure 4 shows the viscosity response over the tested temperature range of $30\text{--}90^\circ\text{C}$. Figure 4 shows that Polymers A and C maintained the highest apparent viscosity over the investigated temperature range, whereas Polymer E remained the most injectable low-viscosity candidate. The temperature-induced viscosity loss reached up to 55% between 30 and 90°C , somewhat smaller than the salinity-induced loss, suggesting that under the tested reservoir conditions ionic shielding was the dominant degradation mechanism relative to thermal chain disruption alone. Because the 90°C tests were conducted at the 93,000 ppm reservoir salinity, the combined effect of temperature and salinity was cumulative rather than independent: polymers that already retained less viscosity under high salinity (Polymers B, D, and E) showed a comparatively smaller additional percentage loss from temperature, since much of their salinity-sensitive viscosity had already been lost, whereas Polymers A and C, which retained more viscosity at high salinity, showed a larger absolute (though not necessarily larger relative) drop when temperature was subsequently increased. This combined-condition behavior is the practical basis for testing salinity and temperature together rather than assuming their effects are simply additive.

2.7 Polymer screening and candidate selection

The rheological screening showed that Polymer A achieved the highest viscosity, but very high apparent viscosity can increase injection pressure and reduce operational flexibility. Polymer C provided high viscosity retention with better practical injectivity, whereas Polymer E showed low viscosity but high salinity and temperature stability. Figure 5 compares these three top-ranked candidates using the four rheological screening criteria from Table 2 (viscosity

retention, salinity tolerance, thermal stability, and injectivity); each criterion was normalized to the maximum observed value among the three candidates, so that a score of 1.0 represents the best-performing polymer for that criterion. This comparison uses only data available prior to adsorption and core-flood testing. Based on this rheological comparison, Polymers C and E were selected to proceed to adsorption and core-flood testing because they achieved the highest composite technical-screening scores (Figure 5, Table 2), representing two different design strategies: stronger mobility control for Polymer C and higher injectivity with lower viscosity for Polymer E. Table 2 below shows a summary of the technical screening of the tested HPAM polymers.

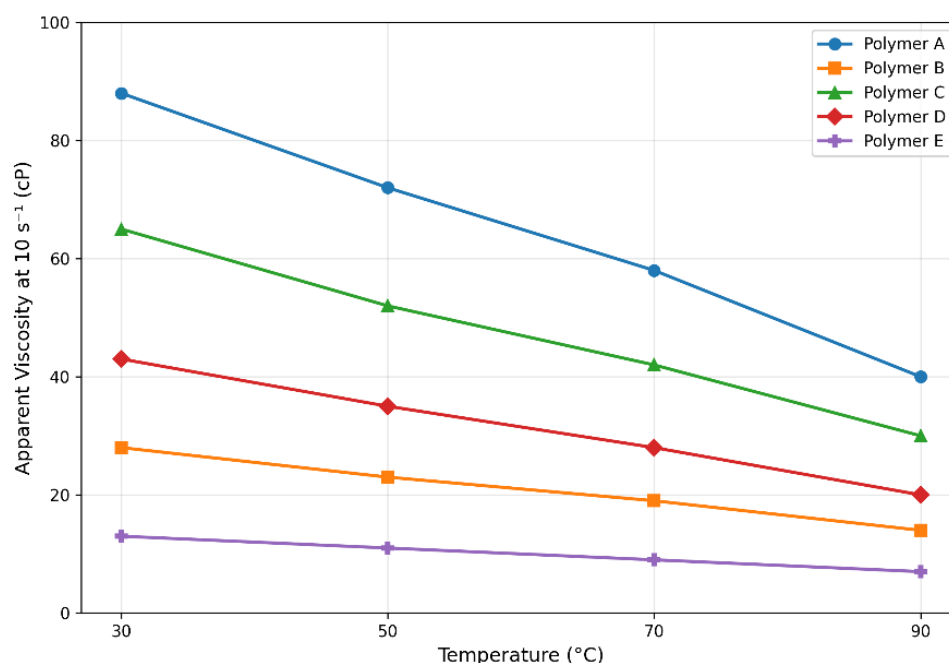


Figure 4.

Effect of temperature on apparent viscosity at 10 s^{-1} shear rate, 93,000 ppm salinity, and 5000 ppm polymer concentration for five HPAM polymers (A–E).

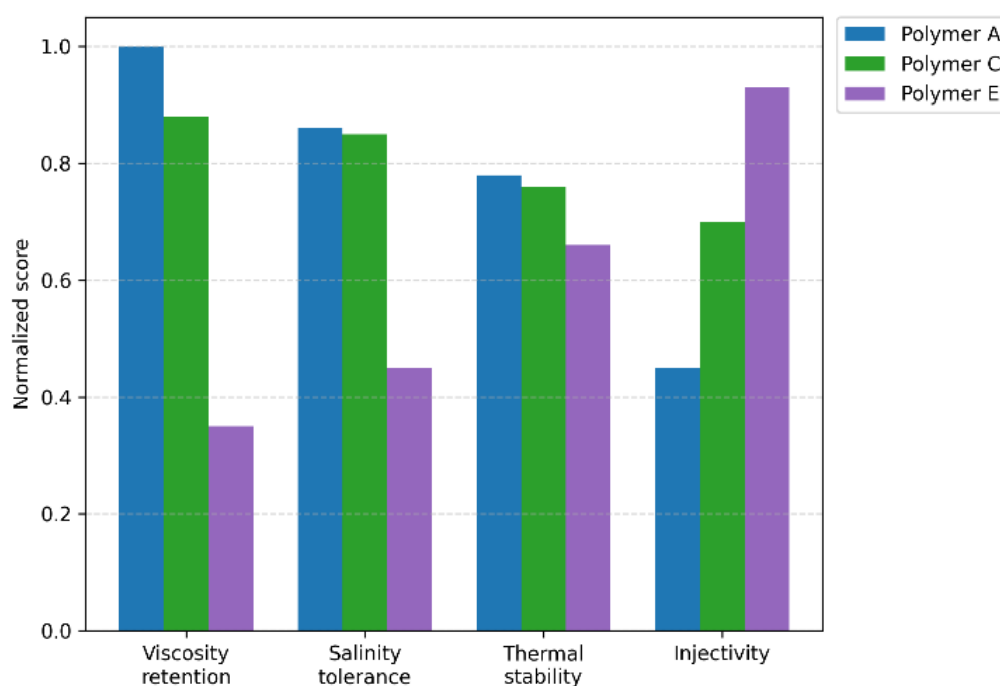


Figure 5.

Normalized rheological screening scores for three top-ranked candidate HPAM polymers (A, C, E) across the four pre-selection criteria used prior to adsorption and core-flood testing: viscosity retention, salinity tolerance, thermal stability, and injectivity.

Table 2.
Technical screening summary of the tested HPAM polymers.

Polymer	Viscosity retention	Thermal stability	Salinity tolerance	Injectivity	Screening interpretation
A	Very high	High	High	Low	High viscosity but less operational flexibility
B	Low-moderate	Moderate	Moderate	Moderate	Not competitive under high salinity
C	Moderate-high	High	High	Moderate	Best overall candidate for core flooding
D	Moderate	Moderate	Moderate	Moderate	Intermediate performance
E	Low	High	High	High	Injectable candidate for pressure-limited cases

2.8 Adsorption behavior in porous media

Adsorption measurements for Polymers C and E showed a rapid increase during the early injected pore volumes, followed by a plateau between approximately 2 and 5 PV, as shown in Figures 6 and 7. Polymer C reached plateau adsorption values of approximately 0.42 mg/g rock in Core 1 and 0.36 mg/g rock in Core 2, while Polymer E showed lower plateau adsorption of 0.28 and 0.24 mg/g rock, respectively. This behavior indicates progressive occupation of active adsorption sites until an equilibrium condition is reached. In the tested cores, Polymer E showed lower bulk viscosity but still displayed notable retention. Polymer C provided the more favorable combination of adsorption behavior and recovery response.

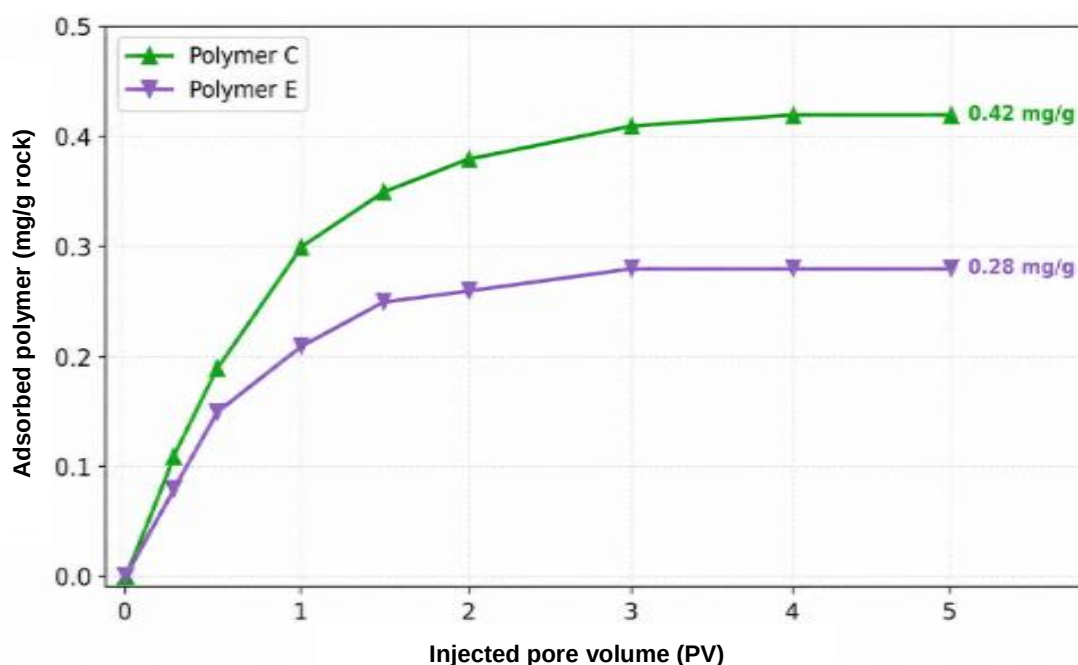


Figure 6.

Adsorption behavior of Polymers C and E expressed as adsorbed polymer mass per gram of rock (mg/g rock) versus injected pore volume (PV) in Core 1.

Figure 7 shows the corresponding adsorption behavior measured in Core 2, which exhibited slightly lower adsorption levels for both polymers compared with Core 1, consistent with the higher permeability of Core 2 (250 mD versus 170 mD).

2.9 Additional oil recovery performance

Polymer injection increased oil recovery in both core samples, as shown in Figures 8 and 9. Approximately 80% of the final additional recovery was achieved within the first 2 PV of polymer injection, after which the recovery curves approached a plateau, indicating that further injection provided diminishing returns. Polymer C consistently

outperformed Polymer E at both tested concentrations, attributable to its higher apparent viscosity generating greater mobility control and improved sweep efficiency within the porous medium. For Core 1, Polymer C at 3000 ppm achieved approximately 10.0% additional recovery, compared with 8.5% for Polymer E at the same concentration. For Core 2, Polymer C at 3000 ppm achieved about 8.8%, whereas Polymer E achieved about 7.4%. At the lower concentration of 1800 ppm, Polymer C and Polymer E produced additional recoveries of 6.0% and 5.0% in Core 1, and 5.2% and 4.4% in Core 2, respectively, consistent with the concentration-dependent viscosity behavior observed during rheological screening (Table 3).

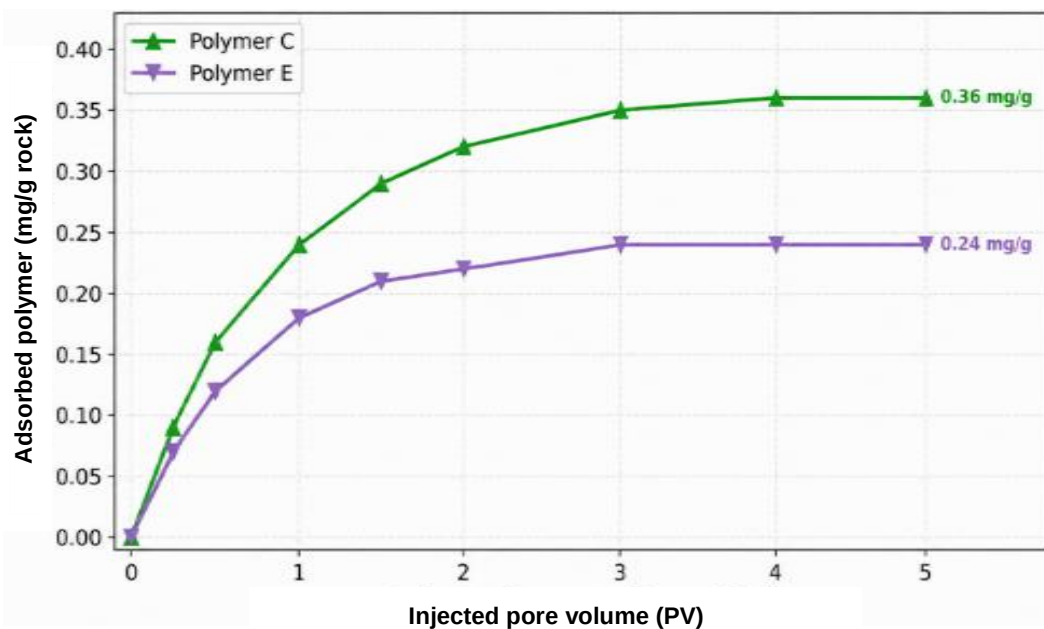


Figure 7.

Adsorption behavior of Polymers C and E expressed as adsorbed polymer mass per gram of rock (mg/g rock) versus injected pore volume (PV) in Core 2.

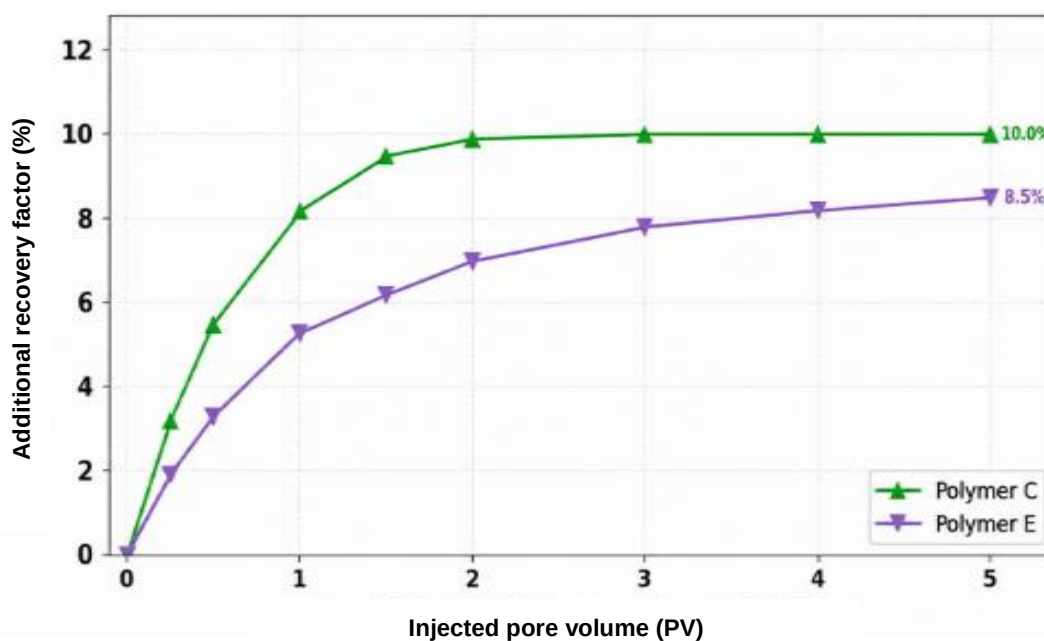


Figure 8.

Additional oil recovery versus injected pore volume (PV) during polymer flooding in Core 1 for Polymers C and E at 3000 ppm concentration.

Figure 9 presents the recovery performance in Core 2. Both polymers produced lower absolute recovery factors in Core 2 compared with Core 1, which is attributed to the higher permeability of Core 2 resulting in a less favorable mobility ratio at the tested concentrations.

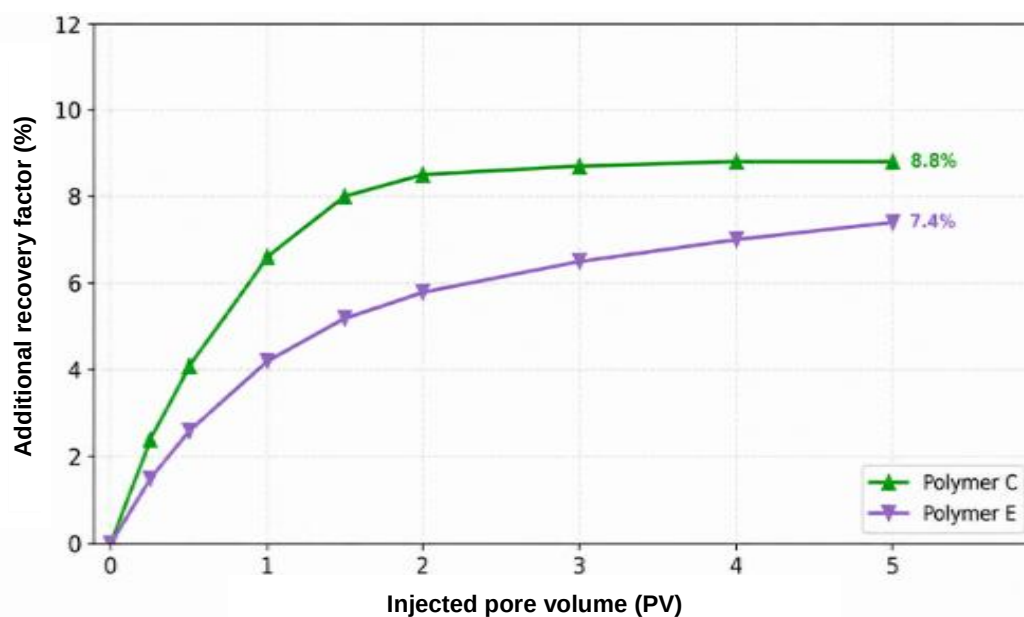


Figure 9.
Additional oil recovery factor versus injected pore volume (PV) during polymer flooding in Core 2 for Polymers C and E at 3000 ppm concentration.

Table 3.
Final additional recovery factor obtained from core flooding experiments.

Core	Polymer	Concentration (ppm)	Additional RF (%)	Core	Polymer	Concentration (ppm)	Additional RF (%)
Core 1	C	3000	10.0	Core 2	C	3000	8.8
Core 1	E	3000	8.5	Core 2	E	3000	7.4
Core 1	C	1800	6.0	Core 2	C	1800	5.2
Core 1	E	1800	5.0	Core 2	E	1800	4.4

2.10 Practical interpretation

The experimental results confirm that the best polymer is not necessarily the polymer with the highest bulk viscosity. Field applicability requires a balance between viscosity generation, injectivity, salinity tolerance, temperature resistance, adsorption loss, and incremental recovery. Polymer C was the best overall candidate because it combined strong rheological performance with favorable adsorption behavior and higher incremental recovery. Polymer E may still be useful in reservoirs with strict pressure limitations because of its higher injectivity and stable flow behavior; however, its lower viscosity reduced its recovery performance relative to Polymer C. Notably, Polymer C showed higher adsorption (0.42 mg/g rock in Core 1 versus 0.28 mg/g for Polymer E), yet it still achieved better incremental recovery, indicating that its viscosity advantage outweighed its higher adsorption loss under the tested conditions. These findings support the use of integrated rheology, adsorption, and core flooding evaluation before field-scale polymer selection.

The present results add an important practical screening implication: the highest bulk viscosity did not produce the best overall candidate. Polymer C gave stronger recovery than Polymer E and better overall suitability than Polymer A because it combined sufficient viscosity retention with acceptable injectivity, adsorption behavior, and displacement response.

The study should be interpreted as a laboratory screening workflow. Before field implementation, the selected polymer should still be assessed for long-term aging, full brine and oil compatibility, mechanical degradation through surface facilities and near-wellbore restrictions, scale-up injectivity, and economic optimization under the target reservoir conditions.

4. Conclusion

All tested HPAM polymers exhibited shear-thinning non-Newtonian behavior. Apparent viscosity at 5000 ppm ranged from approximately 8 cP (Polymer E) to 210 cP (Polymer A) at 1 s^{-1} , and decreased by up to 70% as salinity increased from 3,000 to 200,000 ppm and by up to 55% as temperature increased from 30 to 90 °C. These magnitudes confirm the necessity of screening under reservoir-representative conditions rather than relying on ambient-condition viscosity data alone. Polymer A showed the highest bulk viscosity, but Polymer C provided the best practical balance among viscosity retention, salinity tolerance, injectivity, adsorption behavior, and recovery performance. Polymer E showed lower viscosity but stable flow behavior, making it a possible option for pressure-constrained applications. Core flooding confirmed that Polymer C at 3000 ppm produced the highest additional recovery, approximately 10.0% in Core 1 and 8.8% in Core 2. HPAM polymer selection for high-salinity EOR reservoirs should therefore be based on integrated rheology, adsorption, and displacement testing rather than bulk viscosity alone. The six-stage screening workflow demonstrated here provides a reproducible laboratory basis for ranking polymer candidates prior to field-scale evaluation or pilot design.

5. Acknowledgement

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6. Declarations

The authors declare that this manuscript presents original work, has not been published previously, and is not under consideration for publication elsewhere.

6.1 Author contributions

E. Osama designed the study, performed data analysis, visualized the results, and drafted the manuscript. M. Saafan and A. Salem contributed to reservoir-engineering interpretation and supervision. A. Alsabagh contributed to polymer-chemistry interpretation. O. Elfarouk contributed to data analysis and manuscript review. M. Tantawy contributed to manuscript review and validation. All authors read and approved the final manuscript.

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This research received no external funding from funding agencies in the public, commercial, or not-for-profit sectors.

6.3 Competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

6.4 The use of AI or AI-assisted technologies

During the preparation of this manuscript, the authors used AI-based writing and editing assistance tools to support language refinement, formatting, and reference organization. All scientific content, data interpretation, and conclusions are the sole responsibility of the authors, who reviewed and edited all AI-assisted output and take full responsibility for the content of this publication.

7. Glossary of terms and symbols

Terms & Symbols	Definition	Unit
HPAM	Hydrolyzed polyacrylamide	-
EOR	Enhanced oil recovery	-
ppm	Parts per million	-
cP	Viscosity	centipoise
PV	Injected pore volume	-
mD	Core permeability	millidarcy
RF	Recovery factor	%
API	Oil gravity	°API
qads	Adsorbed polymer mass per rock mass	mg/g rock
s ⁻¹	Shear rate	per second

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