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Best Practices for Accelerated Screening and Deployment of Polymer Flooding: Engineering Workflows and Field Learnings

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Introduction

Global oil production increasingly comes from mature fields where recovery factors remain stubbornly low (typically around 35% of the original oil in place) despite decades of technological progress in petrophysics, reservoir simulation, and seismic imaging (OGA 2018; NPD 2019). At the same time, water production continues to grow: for many assets, 3–7 barrels of water must be handled, treated, and reinjected for every barrel of oil produced. This combination of low ultimate recovery and high water handling erodes project value, stresses surface facilities, and increases energy use and CO_2 emissions. When not addressed early, both recovery opportunities and economic windows for Enhanced Oil Recovery (EOR) are progressively lost.

Polymer flooding is a well-established water-based EOR method for improving macroscopic sweep efficiency by increasing injected-water viscosity and reducing the water–oil mobility ratio. Numerous field applications have demonstrated its ability to delay water breakthrough, recover additional oil, and reduce water–oil ratio (WOR). However, even in reservoirs that are technically well suited for polymer injection, projects are frequently delayed or abandoned. Long decision cycles, fragmented workflows, and slow transitions between concept, laboratory work, design, and field deployment often limit the impact of polymer flooding more than chemistry or physics do.

To fully capture the benefits of polymer flooding, engineers need workflows that are both technically robust and fast to execute. The key challenge is not to reinvent polymer flooding, but to remove unnecessary delays in screening, data acquisition, laboratory evaluation, design, and piloting while still honoring basic reservoir-engineering principles and field constraints. This requires a clear sequence of decisions, early identification of key uncertainties, and a practical methodology that links polymer chemistry, surface facilities, reservoir behavior, and project economics.

The objective of this paper is to summarize best practices and propose an accelerated, field-centric workflow for polymer flooding, from reservoir screening and candidate selection through laboratory design, simulation, pilot implementation, and early decision gates for full-field deployment. The emphasis is on moderate-to-high permeability conventional reservoirs with active or planned waterflooding, where displacement efficiency is limited by heterogeneity and an adverse water–oil mobility ratio. The workflow is not intended to be universal or to cover all reservoir types (e.g., tight formations, heavily fractured systems, or carbonates at ultra-high temperature), but to provide a pragmatic, experience-based framework for rapidly moving technically suitable projects from the idea stage to polymer injection in the field.

Status and Timing of EOR

The timing of polymer flooding has two dimensions: when the process is introduced during the reservoir life, and how quickly engineers can progress from concept to field deployment. Both factors strongly influence injectivity, sweep efficiency, and project economics.

Secondary vs. Tertiary Polymer Flooding

Although polymer flooding is still often labeled a “tertiary” method, field evidence consistently shows superior technical and economic performance when implemented early, contrary to the widespread belief that EOR must be postponed because it is costly. Waterflooding progressively reshapes the saturation field, establishes high-permeability channels, and drives up water-cut and handling costs; once these preferential pathways are entrenched, a late (tertiary) polymer flood must contend with stronger heterogeneity, degraded pressure support, higher water-management expenses, and reduced sweep efficiency, often requiring more polymer for less incremental recovery.

Early (secondary) polymer injection avoids these penalties by applying mobility control when the oil bank is intact, reservoir pressure is higher, and water cuts (and their associated costs) are still low, resulting in cleaner polymer propagation, more stable displacement fronts, faster recovery acceleration, and lower operating costs (Thomas, 2025). When polymer flooding is delayed, technical and economic inefficiencies accumulate: mobility control becomes less effective in a channelized reservoir; earlier polymer breakthrough limits incremental oil; the monetization window narrows; and larger polymer volumes may be needed to overcome heterogeneity. At high water cuts, the energy required for lifting, separating, treating, and reinjecting produced water escalates sharply (Farajzadeh et al., 2021); polymer flooding can mitigate this penalty, but only when initiated before excessive water handling becomes unavoidable. Field evidence reinforces this conclusion: at Milne Point (Alaska), secondary polymer injection delivered higher recovery and more stable injectivity than tertiary application in the same field (Aitkulov et al., 2024); at the Captain Field (UK), polymer injection accelerated recovery by six years and avoided more than 25 million barrels of produced water (Poulsen et al., 2018; Johnson et al., 2023); and in Argentina, early deployment at Grimbeek and Manantiales Behr reversed regional decline trends (Juri et al., 2017; 2020). These examples demonstrate that the effectiveness of polymer flooding (and the economic value it creates) declines with time, and that accelerated decision-making is essential to capture the full potential of mobility control or any recovery method (Parra Sanchez, 2010).

We recognize that a major argument in favor of waterflooding before polymer flooding has been that of the additional reservoir description gained during waterflooding could enhance success of the subsequent polymer flooding. However, if the information gained during waterflooding truly provided decisive insights, we would expect substantially better recovery outcomes. Since polymer injection commonly tests the limits of injectivity for a reservoir, knowledge of indigenous flow directions within a well pattern can be of critical importance to mitigating preferential channeling. Interestingly, well patterns (e.g., five-spots) established during waterflooding have commonly not considered native in-situ stress directions. Consequently, the waterflood well locations are often not optimum for polymer flooding—which would be improved with a line-drive flow configuration that takes advantage of the direction that fractures or fracture-like features naturally follow (Seright and Wang 2023a). Thus, if polymer flooding is contemplated for a particular reservoir, the in-situ stresses should be established before any secondary recovery is attempted (or even before extensive primary production). FMI logs and pressure transient analyses on early-drilled wells and tectonic considerations have often been suitable for this determination.

Field Learnings: Why Polymer Flooding Succeeds or Fails

A review of more than 70 polymer flooding field applications shows that most failures are not caused by polymer chemistry, but by operational and reservoir-execution issues (Standnes & Skjevrak, 2014). These insights directly inform where engineers must focus early in the workflow to avoid delays and de-risk pilots. The typical causes of underperformance summarized by the authors are summarized below (along with additional supporting references).

Low reservoir permeability (<200 mD). Polymer propagation becomes difficult, pressure gradients rise, and injectivity drops. Many discontinued projects occurred in low-permeability zones where the injection system created pressure barriers before the polymer bank was established (Wang et al. 2008; Ghosh et al. 2021; Wang et al. 2022).

Insufficient slug sizes (<20% PV). Failed projects typically injected only ~17% PV; successful floods tended to exceed ~50% PV. When polymer slugs are too small, chase water rapidly fingers through the polymer bank, and the expected mobility control does not develop (Seright 2017; Sagyndikov et al. 2025).

Poor water and polymer quality control. Solids, iron, oxygen, and bacterial contamination caused plugging, instability, and degradation. Emulsion polymers were frequently linked to incomplete inversion and injectivity loss; powders sometimes suffered from inadequate hydration and undissolved residues (Dwyer and Delamaide 2015; Dwarakanath et al. 2016; Jouenne et al. 2016).

Mechanical degradation in surface facilities. High shear through chokes, valves, and sharp pipe geometries can reduce viscosity by 30–45% before the polymer reaches the reservoir. Without a polymer-friendly injection system, lab viscosities are not representative of field conditions. (Wang et al. 2009; Jouenne et al. 2015, 2017a; Lüftenegger et al. 2015; Mehta et al. 2016; Kumar et al. 2016; Husveg et al. 2020; Sagyndikov et al. 2022; Aitkulov et al. 2024).

Late (tertiary) deployment in mature floods. Established high-permeability channels and high-water cuts make mobility control less effective and accelerate polymer breakthrough. (Delamaide 2021; Sagyndikov et al. 2025).

Key Best Practices Derived from Field Evidence

From these observations, several consistent best practices emerge:

- **Inject early whenever practical.** Secondary polymer floods systematically show higher success rates than tertiary cases (Huh and Pope 2008; Delamaide 2021; Aitkulov 2024b).
- **Match polymer molecular weight to reservoir permeability.** Low-permeability zones may require reduced well spacing or tailored injection strategies (Wang et al. 2008; Ghosh et al. 2021).

- **Inject a sufficiently large slug (>50% PV).** Under-designed slugs are a major source of failure (Seright 2017; Seright and Wang 2023a; Sagyndikov et al. 2025)
- **Design polymer-friendly injection systems.** Minimize shear, avoid restrictive chokes, eliminate oxygen and iron, and ensure complete inversion or hydration (Wang et al. 2009; Jouenne et al. 2015, 2017a,b; Lüftenegger et al. 2015; Mehta et al. 2016; Kumar et al. 2016; Gathier et al., 2020; Husveg et al. 2020; Sagyndikov et al. 2022; Gathier et al. 2020,2022 ; Aitkulov et al. 2024a).
- **Ensure high water quality.** Control solids, bacteria, dissolved oxygen, and hardness (Dwyer and Delamaide 2015; Aitkulov et al. 2024a).
- **Shortlist only polymers with clean dissolution and robust viscosity.** Remove candidates exhibiting fisheyes or long maturation times (Aitkulov et al. 2024a).
- **Apply disciplined surveillance.** Track polymer arrival, pressure trends, and polymer concentration to validate propagation and retention (Aitkulov et al. 2024a)

Implications for Fast-Track Project Execution

These learnings demonstrate that the technical risks in polymer flooding are well understood and, in most cases, manageable. Failures frequently come from inadequate reservoir characterization, insufficient polymer quality control, and improperly designed injection systems, not fundamental issues with polymer flooding itself.

Therefore, an accelerated workflow must prioritize:

1. Early reservoir screening, proper reservoir characterization, and careful pilot-zone selection
2. High-discrimination polymer sampling and rapid elimination of weak candidates
3. Representative corefloods at realistic shear rates and saturation states
4. Early surface-facilities assessment to assess necessary upgrades, avoid degradation
5. Clear decision gates linked to polymer arrival and incremental oil response

These principles form the foundation for the screening and ranking methodology described in the following sections.

Screening, Ranking, and KPI Alignment

Selecting where and how to deploy polymer flooding is the most critical step in accelerating project execution. Screening must be fast, technically sound, and directly linked to the project KPIs that determine whether a pilot can justify full-field expansion.

The process proposed here is applicable to moderate-to-high permeability non-fractured reservoirs under active or planned waterflooding. It is not intended as a universal workflow for all reservoir types.

First-Level Screening: Technical Suitability

A reservoir is a strong candidate for polymer injection when three conditions are met:

1. Active or planned waterflooding, ensuring pressure support and established injection infrastructure.
2. Connectivity between injectors and producers, enabling measurable responses.
3. Sweep limitation, caused by heterogeneity or an unfavorable mobility ratio, leading to bypassed oil and early water breakthrough.

These conditions are met in the vast majority of conventional waterfloods, which are inherently heterogeneous and prone to channeling.

We propose **Table 1** outlining which parameters allow for rapid deployment and which ones require more detailed investigation:

Table 1—Rapid Deployment Parameters

Parameter	Range for fast implementation	Range of parameters requiring more investigations
Oil viscosity (live)	Up to10 000 cP (Delamaide 2018; Naukenova, 2019)	Very light oils but where large permeability contrasts exist
Reservoir temperature	Up to 120°C (Seright et al. 2021)	Above 120°C, depending on salinity, spacing
Injection water salinity	Preferably <30,000 mg/L; R^+ <0.1, but with field up to 220 g/L connate water (Braccalenti et al., 2013; Kushekov et al., 2024)	
Permeability	Typically above 200 md, but lower-permeabilities may be considered	Permeability below 200 mD depending on reservoir characteristics, injectivity & well spacing
Recommended minimum PV/year	>0.15 PV/year for fast response and oil bank displacement (NPV) (Wang et al. 2008; Aitkulov et al. 2024b)	<0.15PV/year

These ranges are broad and not prescriptive; they simply reflect where polymer flooding has historically delivered the most reliable results.

Second-Level Ranking: Cost and Feasibility

Among technically viable candidates, the next step is to assess which opportunities can be developed rapidly and economically. These key factors include:

- **Polymer chemistry compatibility** with temperature and brine composition
- **Water-sourcing constraints** (fresh, softened, produced, or mixed water with volumes and evolution perspectives)
- **Operational complexity** (onshore vs. offshore, logistics, space for mixing units (Gathier et al., 2020))
- **Existing facilities** that may require upgrading to support polymer-friendly injection

This level does not eliminate candidates but helps prioritize those that require the least adaptation to reach pilot stage.

Third-Level Ranking: Fast Learning and Quick Response

To accelerate deployment, priority should be given to patterns where polymer performance will be visible within months to a few years. These areas are characterized by:

- **Injectivity ≥0.15 PV/year**, allowing timely reservoir response (Wang et al. 2008; Aitkulov et al. 2024b)
- **Hydraulic confinement** with limited impact from adjacent water injectors, helping avoid ambiguous interpretations of polymer-injection results.
- **Minimal aquifer support,** helping ensure that the produced water response can be clearly linked to injected fluids. These criteria ensure that the pilot provides interpretable results without long waiting times.

KPI Alignment: The Most Critical Step of the Workflow

The choice of Key Performance Indicators (KPIs) fundamentally conditions the selection of the polymer pilot zone and, consequently, the laboratory program, surveillance plan, and the criteria for full-field expansion (Pandey et al. 2012). A pilot can only be representative if the KPIs and the "big picture" development objectives are reconciled early. Otherwise, a mismatch occurs: the zone that best reflects the field behavior (heterogeneity, injectivity, facilities constraints) may not deliver the short-term incremental oil or water-cut reduction required by management to sanction an expansion, while a high-potential zone selected to satisfy corporate KPIs may not be technically representative enough to de-risk a full-scale deployment.

Therefore, the first and most critical step is to align what is expected with what must be demonstrated. Is the objective to confirm injectivity and pressure behavior? Prove acceleration in a secondary polymer-flood context? Deliver a minimum incremental oil volume in a tertiary case? Demonstrate increased oil cut (e.g.,+1%, +5%, +10%)? Because the required KPIs differ between secondary and tertiary polymer flooding, the pilot geometry, displacement volumes, and evaluation windows must be designed accordingly.

Reconciliation of KPIs with the broader field development picture ensures the pilot is both convincing to management and technically meaningful. This alignment dictates the required laboratory workflow (rheology, retention, degradation, core floods), the selection of surveillance tools (PLT, SWCTT, Hall plots, interwell tracers), and the pattern configuration needed to scale results to the full field.

Beyond oil rate and water-cut metrics, a pilot must also achieve additional objectives essential for expansion: validating economics, testing facilities for dissolution and injection, establishing injectivity envelopes, calibrating the simulation model (oil recovery, pressure/rate, produced polymer concentrations), identifying potential operational issues, and building local operational capability

Typical KPIs include:

- **Injectivity confirmation** and acceptable pressure behavior
- **Acceleration of production** (secondary polymer flood)
- **Incremental oil** over a defined window (tertiary cases)
- **Increase in oil cut** (e.g., +1%, +5%, +10%)
- **Economic viability**

A mismatch between KPIs and reservoir reality routinely leads to pilots that are technically representative but commercially unconvincing (or the reverse). The pilot zone must therefore be selected only after KPI expectations are clarified.

The next sections describe how to build the laboratory program and simulation workflow around these screened opportunities.

Laboratory Workflow for Fast and Representative Polymer Evaluation

Laboratory work must be designed to answer a limited number of questions directly relevant to polymer selection, injectivity, and pilot design. To accelerate deployment, the workflow should be representative, discriminating, and sequenced to eliminate weak candidates early. The following workflow applies to moderate-to-high permeability sandstone reservoirs and is not intended for tight, heavily fractured, or ultra-high-temperature systems.

Field-to-Lab Philosophy

The reliability of laboratory results depends on how closely test conditions mimic the actual water, shear, temperature, and flow regimes experienced in the field (Thomas, 2023). The following principles guide all experiments:

- Use representative water (composition, treatment steps, contaminants).
- Calculate and select reservoir-relevant flow velocities and associated shear rates (example: ~7 s^{-1} for vertical wells; <1 s^{-1} for long horizontals).
- Run corefloods at realistic pressure gradients.
- Avoid tests that are known to produce misleading or non-scalable results (e.g., residual resistance factor)

This field-to-lab approach ensures that viscosity, polymer stability, retention, and injectivity expectations remain consistent with field behavior.

Minimum Input Data Before Testing

Only a few parameters are essential to begin meaningful laboratory work:

- **Water composition** (TDS, R^+, solids, iron, oxygen, pH, OIW), volumes and expected evolution of composition
- **Current reservoir temperature**
- **Permeability and heterogeneity** (core data or distributions)
- **Fluid viscosities** (μ_o and μ_w at reservoir temperature)
- **Relative permeabilities, especially the endpoints** (k_{ro}, k_{rw}). These must be based on laboratory measurements (i.e., NOT history matching of field performance). Relative permeabilities based on history matching incorporate and are largely

dominated by assumptions about reservoir heterogeneity (Delaplace et al. 2013). Consequently, mobility ratios based on history matching can exaggerate/over-predict permeabilility endpoints (Berg and Bjorlykke 2014)—causing misleading claims that the optimum polymer/oil mobility ratio for a polymer flood can be substantially (i.e., 10 or more) greater than one (Delamaide 2024,2025). Although there certainly are experimental challenges with laboratory measurement of relative permeabilities (Berg and Bjorlykke 2014), they provide a much more realistic and relevant estimate of the relative permeability characteristics and result in reliable and quantitative selection of polymer viscosities that are consistent with well-established reservoir engineering principles (Seright et al. 2018).

- **Representative reservoir shear rate** Although the commonly used shear rate of 7.34 s^{-1} may be applicable for vertical wells with moderate spacing (e.g., 10-20 ac), this value is much too high for applications using horizontal wells—where shear rates of 1 s^{-1} or less are more appropriate (Dandekar et al. 2021; Seright and Wang 2023a; Azad and Seright 2025).
- **Target mobility ratio** for displacement. For many (perhaps, most) applications, this target should be near one (Seright 2016; Seright and Wang 2023a; Aitkulov et al. 2024a) and must be based on laboratory-measured relative permeabilities (i.e., not from history matching). If sufficient injectivity capacity exists in the application, target polymer/oil mobility ratios below one may be desirable in some heterogeneous reservoirs (Seright 2016, Wang et al. 2022).

These inputs enable first-pass viscosity targets and polymer-chemistry selection.

Step 1: Polymer Sampling and Supplier Qualification

Polymer variability between batches can significantly impact dissolution behavior and viscosity. To avoid relying on unrepresentative lab samples, the recommended practice is:

1. Request 5–10 samples from different batches/suppliers. In parallel, supplier audits (production quality, ISO certifications, ability to scale up) help avoid downstream procurement issues.
2. Perform first-pass discrimination tests:
   - Dissolution time
   - Presence of fisheyes, undissolved residues
   - Viscosity vs. concentration measured at one fixed salinity, temperature, and shear rate

These rapid tests identify polymers with the cleanest dissolution, fastest hydration, and highest viscosifying power at lowest dosage. Typically, only three candidates progress to coreflooding.

Polymer chemistry selection is mainly controlled by reservoir temperature, water composition, and divalent-cation concentration (R^+), as these factors determine the stability limits of HPAM, ATBS-modified polymers, and specialty terpolymers. The ranges provided below (**Table 2**) summarize where stability has been demonstrated through field experience and published thermal-stability studies (Divers et al. 2016; Gaillard et al. 2017; Gaillard et al. 2012; Jouenne et al. 2017; Sandengen et al. 2017,2018; Mittal et al. 2018; Shankar et al. 2022; Shankar and Sharma 2022; Seright et al. 2023; Seright et al., 2025); they should be viewed as practical guidelines rather than strict limits, and some situations may require adjustments or additional testing. These ranges indicate where polymers have been successfully deployed, not rigid boundaries. Water softening can broaden the applicable window for both HPAM and ATBS-based polymers. While vendor-specific additives may further influence stability, they cannot substitute for selecting a polymer chemistry that is fundamentally compatible with the reservoir temperature and salinity. In the following table, the specific parameter R+ is defined as the weight ratio of cationic divalent ions divided by the total of cationic ions as in following equation:

$$R^+ = \Sigma\,(Ca^{2+} + Mg^{2+}) \,/\, \Sigma\,(Na^+ + K^+ + Ca^{2+} + Mg^{2+} + H^+) \quad (1)$$

Table 2—Recommended Polymer Chemistry

Reservoir Temperature	TDS (mg/L) Injection water	R^+ (Ca^{2+}+Mg^{2+} / total cations) Injection water	Recommended Polymer Chemistry
< 60°C	Any	<0.15	Standard HPAM
60–85°C	<60,000	<0.12	Low/medium ATBS (5–30%)
85–90°C	Up to 80,000	<0.10	High ATBS (>35%)
95–120°C	Up to 100,000	≤0.10–0.12	High ATBS (100%); softened water preferred
Any temperature	Any	Any (if softened water available)	HPAM/ATBS combination with proper water conditioning

Polymer chemistry selection is governed by a few key principles (Thomas 2019). Temperature is the dominant factor: above roughly 80–90 °C, hydrolysis accelerates and higher ATBS content becomes essential for long-term stability (Parker et al., 1993; Rashidi et al., 2010; Vermolen et al., 2011; Seright et al. 2021). Divalent cations exert a strong influence through complexation, making the R^+ ratio more diagnostic than absolute salinity, as high divalent levels rapidly reduce viscosity and can trigger precipitation in under-sulfonated polymers. Total salinity also affects viscosifying efficiency, with HPAM losing viscosity sharply as TDS increases, an effect that ATBS can mitigate, though not fully eliminate. Tailored chemistries introduce tradeoffs, as increasing ATBS content enhances thermal and oxidative stability but raises cost and may slightly reduce viscosifying power.

Step 2: Rheology in Relevant Brines

For each shortlisted polymer candidate, viscosity must be characterized at representative shear rates in both the make-up water and the formation brine. At this stage, ambient-temperature measurements are generally sufficient, provided that oxygen is rigorously excluded when working at elevated temperatures (Seright et al. 2010, 2023b). The resulting viscosity–shear curves are then used to determine the polymer concentration required to achieve the target mobility ratio. Although rheometer data are not directly employed in reservoir simulation, they are essential for verifying batch-to-batch consistency and for detecting any abnormal degradation.

Step 3: Propagation and Retention in Analog Cores

The three shortlisted polymers are next evaluated in analog cores at reservoir-representative velocities (or, ideally, at representative pressure gradients) to assess pressure response, propagation behavior (breakthrough pore volume and plateau concentration), and any signs of plugging or abnormal retention. Retention can be measured at 100% water saturation, and only the polymer showing clean propagation, low retention, and no injectivity issues is advanced to reservoir-core testing.

Retention can be determined using single-slug propagation tests following guidance from Wang et al. (2020), Seright & Wang (2022, 2023; Seright 2026). The key outputs are the polymer breakout pore volume, which governs the delay in front propagation, and the initial plateau concentration, which indicates whether the injected concentration must be increased to maintain a near-unity mobility ratio. Double-bank tests designed to quantify inaccessible pore volume should be avoided, as IAPV is generally irrelevant in moderate- to high-permeability reservoirs and often yields misleading results. If inaccessible pore volume is felt to be important (e.g., for applications with less than 200 mD), the method of Dean et al. (2022) should be used (Seright 2026). Retention tests should be run for each polymer candidate.

Step 4: Reservoir-Core Testing (Only One Polymer)

Testing only one polymer on actual reservoir cores is essential to avoid long delays and cost escalation. The final polymer candidate(s) should be evaluated for injectivity and plugging tendency using resistance-factor measurements in cores equipped with internal pressure taps or composite cores with inter-core taps. A suitable polymer should show consistent resistance factors along the core length, indicating stable propagation. Resistance factors should not exceed ~2× the viscosity expected from viscometry at equivalent shear rate (Seright et al. 2011)

Key outputs:

- Stable resistance factor (RF) in at least two representative facies
- Retention under reservoir saturation conditions

- Stability of propagation front
- Consistency of resistance factor along the core length.

Residual resistance factor (RRF) tests should generally be avoided, as they often yield non-representative and non-scalable values in moderate–high permeability reservoirs (Seright 2010, 2016).

Step 5: Thermal, Chemical, and Mechanical Stability

Polymer stability is governed primarily by monomer composition (whether HPAM, ATBS-based copolymers, or terpolymers) and must be assessed as a function of reservoir temperature and brine chemistry, drawing on prior work (Gaillard et al., 2017; Jouenne et al. 2017; Sandengen et al. 2017,2018; Seright et al. 2023). HPAM is generally adequate up to about 60 °C, whereas higher temperatures require increasing ATBS content to ensure long-term resistance to hydrolysis and oxidative degradation. Comparative stability among shortlisted products can be established using short-duration aging tests of roughly 45 days at reservoir temperature, with dissolved oxygen maintained below 10 ppb in formation or softened brine. This step confirms the suitability of the selected chemistry and indicates whether oxygen scavengers or biocides will be required in the field. Routine laboratory tests for mechanical degradation are unnecessary for most applications, as field evidence and studies show that porous-media-induced degradation is minimal (Sagyndikov et al. 2022; Shankar and Sharma 2022; Seright et al., 2025). Mechanical effects across pumps, valves, and filters should instead be evaluated through simple before/after field tests for the specific equipment in use. Laboratory back-pressure regulators should be avoided, when possible, as they can artificially degrade HPAM solutions.

Step 6: Field-Focused Quality Control

Filterability and on-site quality checks should follow guidance from Aitkulov et al. (2024b) and established field practices. Filter tests are valuable only for detecting batch-to-batch variations of delivered polymer and have limited relevance in remote laboratories (Thomas 2023). On-site measurements (viscosity, polymer concentration, filterability) sample only a very small fraction of the injected stream; therefore, combined interpretation (including monitoring pressure drops across sock filters) is essential. Water quality (salinity, hardness, iron, oxygen, particulates, oil) remains critical in preparing and maintaining stable polymer solutions.

Summary of the Accelerated Workflow

The accelerated laboratory workflow minimizes unnecessary experimentation and focuses on **rapid elimination** of unsuitable polymers:

1. With reservoir cores, oil, and representative water samples, determine relative permeability curves (or at least the endpoints) (Seright et al. 2018).
2. Initial sampling (5–10 samples); shortlist to 3 polymers. Eliminate candidates with slow dissolution, fisheyes, or low viscosity efficiency.
3. Rheology in make-up and formation brines
4. Analog-core injectivity and retention to compare the selected polymers; shortlist to 1 polymer
5. Reservoir-core propagation and resistance factor, with internal taps.
6. Stability testing [short term (e.g., 1-2 months) simply to check for unexpected effects from possible vendor chemical additives]
7. Field-oriented quality checks

This workflow provides a solid and efficient way to choose the right polymer, making sure the final selection matches the reservoir conditions, the pilot objectives, and the practical limits of field operations.

Modelling Principles and Workflow for Polymer-Flood Simulation

Many promising polymer projects fail at the simulation stage due to forecasts of uninjectable viscosities exceeding bottom-hole pressure limits, despite field experience showing injectivity issues are rare (Thomas et al. 2019). Effective polymer-flood simulation must be anchored in laboratory-measured porous-media behavior, avoid generic viscosity–concentration tables, and incorporate physical principles that prevent unrealistic injectivity and polymer-bank forecasts. Key principles include: (1) use of core-derived resistance factors, retention, and propagation data; (2) explicit modeling of near-wellbore effects, which control injectivity and degradation; and (3) conservative treatment of chase-water phases, recognizing their inherent instability and the impracticality of field-scale fingering simulations (Thomas, 2023).

Coreflooding data—resistance factor versus velocity, retention, breakthrough PV, plateau concentration, and effective viscosity—are essential. Initial models should assume a residual resistance factor of 1.0 (in zones >500 mD) unless justified by core data, with minimal mechanical degradation and no shear-thickening unless supported by reservoir evidence. Two complementary base models (fixed-rate and fixed-pressure) are recommended, with dynamic grid refinement near the polymer front. Post-pilot, recalibrate using measured injectivity and polymer concentrations.

For vertical cased and perforated wells, conventional simulators often misrepresent polymer injectivity by assuming radial, isotropic flow and artificially enlarged wellbore radii (Tai et al. 2021; Skoreyko and Kumar 2017). This fails to capture directional, dynamic fractures initiated by perforations (Behrmann & Elbel 1991; Hossain et al. 2000), which reduce near-well velocities and enable lower-pressure polymer injection. Models omitting perforation-controlled fracture initiation and growth cannot reliably predict injectivity.

Simplified approaches that ignore fractures and assume pure shear-thinning HPAM behavior (Delamaide 2019, 2024) are motivated by regulatory concerns but overlook the substantial injectivity and sweep improvements from controlled, near-well fractures (Seright and Wang 2023a). Reopening existing fractures requires less pressure than initial creation, often allowing practical injectivity within regulatory limits.

While shear-thinning aids injectivity (Dauben and Menzie 1967; Gogarty 1967; Lake 1989; Green and Willhite 2018), recent models ignore shear-thickening even when relevant. Shear-thickening velocities correlate with polymer molecular weight and permeability-porosity, and are largely independent of concentration, salinity, or hardness (Howe et al. 2015; Seright et al. 2011, 2023, 2025). Field-scale injection rates (Azad and Seright 2025) yield sand face velocities (5–100 ft/d) that overlap the shear-thickening regime for common HPAMs, making its neglect in calculations unjustified.

Field data shows polymer injectivity is generally modestly less than water injection, even though polymer viscosity is much higher (Wang et al. 2008a,b; Seright et al. 2010; Van den Hoek et al. 2009; Manichand et al. 2013; Seright 2017; Thomas et al. 2019; Sagyndikov et al. 2021), and HPAM does not degrade significantly during injection (Sagyndikov et al. 2021). The apparent success of simplified injectivity forecasts (Delamaide 2019, 2024) is due to fracture mechanics, not shear-thinning. Fractures extend as injection pressure and viscosity increase, maintaining a balance between fracture area and fluid viscosity (Gidley et al. 1989; Behrmann & Elbel 1991; Hossain et al. 2000; Wang et al. 2022).

Modeling chase-water phases requires caution due to rapid viscous fingering and polymer-bank bypass (Sagyndikov et al., 2025), which cannot be accurately resolved at field scale. Any simulated improvement during chase water must be validated against field evidence.

All simulation results require rigorous quality control and benchmarking against analogous fields. Unrealistic injectivity losses or polymer-bank collapse often signal modeling artifacts. Uncertainty should be bracketed through sensitivity analyses, varying slug size, retention, resistance factors, permeability, and geometry. Avoid practices such as blind use of rheometer-based viscosity tables, unrealistic shear-thickening models, large residual resistance factors, stable chase-water assumptions, and forced history matches (Thomas 2023). Core and field data often show that similar rheometer behaviors can yield very different resistance factors (Leblanc et al. 2015).

Summary of the Simulation Approach

A robust, accelerated modelling workflow relies on:

- Using lab-derived relative permeability curves
- Applying porous-media resistance factor and retention data at realistic velocities
- Refining near-wellbore grids to capture completion/fracturing effects
- Employing dual rate- and pressure-controlled base models
- Treating chase-water instability conservatively
- Ensuring physical consistency with lab and field data
- Bracketing forecasts with sensitivity analysis

This approach produces realistic injectivity expectations, credible forecasts, and rapid decision gates for pilot design and full-field deployment.

Pilot Design, Execution, and Monitoring

A polymer pilot must demonstrate the key performance indicators (KPIs) required to sanction full-field deployment while minimizing ambiguity in how results are interpreted. Success therefore depends on three pillars: selecting the right pattern, designing a representative but suitably confined test, and implementing disciplined surveillance linked to clear decision gates. The process begins with defining the pilot objectives (before pattern selection or laboratory work is initiated) as failure to align KPIs early is one of the most common reasons why pilots become inconclusive or non-actionable. Typical KPIs include injectivity performance (pressure–rate trends, near-wellbore behavior), polymer propagation (breakthrough timing and arrival concentration), and either incremental oil recovery or production acceleration depending on whether the project is operated in secondary or tertiary mode. Additional KPIs usually include measurable oil-cut/water-cut changes over a defined interval, comparison with simulation forecasts, and demonstration of operational readiness in terms of hydration, mixing, filtration, and field logistics.

Pattern selection is central to pilot interpretability. The pilot should be implemented in a hydraulically confined zone that reflects the heterogeneity and injectivity conditions of the main field while limiting interactions with surrounding injectors and aquifer influx. Preferred characteristics include clear injector–producer connectivity verified by pressure history or tracers, minimal external interference, representative permeability and heterogeneity (avoiding the best or worst extremes), and a pore volume small enough to deliver observable responses within 12–24 months (Pandey et al., 2012). The pattern must also be analogous to planned full-field development so that results scale logically, keeping some flexibility to adapt to varying reservoir conditions.

The polymer injection strategy must align with the project mode and expected breakthrough time. Initial polymer concentration is selected based on target mobility ratio and measured resistance factor values. A controlled viscosity ramp-up period verifies system integrity and avoids abrupt injectivity changes. Slug size must be large enough - typically >0.5 PV - to produce measurable mobility control. A chase-water plan should be defined in advance but interpreted cautiously because of the inherent instability of water displacing a viscous polymer solution. Injection rates should remain as constant as possible, or bottom-hole pressure should be controlled relative to fracture-gradient margins. Prior to ramp-up, polymer-friendly injection conditions must be secured, including low-shear operation, tight control of oxygen and iron, and stable mixing and filtration procedures.

A high-frequency surveillance program is essential for interpreting the pilot and triggering decision points. Table 3 provides a list of parameters with a monitoring frequency:

Table 3: Polymer Injection Monitoring Plan.

Frequency	**Area**	**Monitoring Elements**	**Purpose / Diagnostic Value**
Continuous / Daily	Injection	Injection rate, wellhead pressure (WHP), Hall plots	Track injectivity trends and near-wellbore behavior
	Production	Oil and water production rates	Quantify response and production acceleration
	Operations	Polymer concentration at make-up and wellhead; injected viscosity	Verify mixing, dilution, and mobility control
	Operations	Water quality (salinity, hardness, oxygen, iron, bacteria, solids; filter pressure drop)	Monitor risks to polymer stability
	Operations	Pump performance; pressure losses in lines and filters	Detect mechanical issues, plugging, or restrictions
Daily	Injection	Polymer concentration and viscosity at wellhead	Ensure injected-fluid specification and consistency
	Production	Oil cut (baseline-corrected); water cut (corrected)	Track sweep efficiency and incremental oil
Periodic	Injection	Injection Logging Tool (ILT); Hall plots; Pressure-falloff / step-rate tests	Verify injection profile and diagnose injectivity changes
	Production	Polymer presence and concentration; Breakthrough timing; plateau concentration; Produced-water viscosity (where measurable)	Confirm polymer breakthrough and propagation
Monthly	Reservoir & Facilities	Produced-water chemistry (salinity, hardness, iron, sulfides, bacteria)	Assess long-term reservoir and facility health
	Reservoir & Facilities	Laboratory polymer analysis in produced fluids	Quantify propagation, retention, and degradation

Clear, pre-defined decision gates ensure timely progression and prevent pilots from drifting without actionable conclusions. After polymer ramp-up (Gate 1), the system should demonstrate stable wellhead viscosity, absence of unexpected injectivity losses, and proper mixing and filtration performance. The oil-response window (Gate 2) assesses incremental oil or acceleration, verifies sustained injectivity and facilities performance, and evaluates economics relative to chemical cost. Polymer arrival at the first producer (Gate 3) triggers comparison of breakthrough PV and concentration against simulations, updating retention and resistance factor estimates, and recalibration of the model using real propagation behavior. If KPIs are met, expansion to adjacent patterns can be recommended. At pilot conclusion (Gate 4), the project should have validated the polymer type and dosage, confirmed injectivity envelope, refined slug and chase-water strategy, and established operational readiness. A positive Gate 4 outcome supports preparation of a full-field development plan.

Scaling a pilot to full-field implementation requires applying the same design principles consistently, while allowing for adjustments in injection rates, polymer viscosity, and molecular weight to account for geological variability across the field.

In summary, a well-designed polymer pilot integrates (1) clear and aligned KPIs, (2) a confined and interpretable pattern, (3) an injection strategy tied to mobility control, (4) high-frequency surveillance to track injectivity and propagation, (5) decision gates that eliminate ambiguity, and (6) direct scalability to field development. This structured approach produces strong, interpretable evidence of polymer performance and supports accelerated and confident deployment at field scale.

Conclusions

Polymer flooding remains one of the most reliable and scalable techniques for improving sweep efficiency in waterflooded conventional reservoirs. However, many projects fail to reach pilot or field deployment because of long decision cycles, fragmented workflows, and laboratory programs that do not reflect field conditions. The experience-based workflow presented in this paper aims to accelerate polymer-flood implementation without compromising technical rigor. Field learnings from more than 70 polymer floods show that most underperforming projects result from operational issues (poor water quality, insufficient slug size, inadequate injectivity management, or premature termination) rather than from polymer chemistry. These insights highlight the value of early deployment, disciplined execution, and a strong emphasis on representativity in the laboratory.

This paper introduces several new contributions to the practical deployment of polymer flooding by proposing a unified and accelerated workflow that integrates screening, laboratory testing, simulation, and pilot design into a single coherent process. Central to this approach is a KPI-first methodology, which demonstrates that misaligned technical and commercial KPIs are a major failure mode in polymer pilots and shows how early alignment materially improves pilot interpretability and decision quality. The laboratory workflow is explicitly designed around representativity, eliminating non-value-added tests in favor of rapid polymer elimination, porous-media behavior, and field-relevant performance. The paper also provides a field-grounded critique of current injectivity-modeling practices, emphasizing resistance-factor-based workflows validated by field evidence. Finally, it clarifies the technical rationale for early (secondary) polymer flooding beyond economics, including fracture directionality, mobility-ratio evolution, near-wellbore conditioning, and long-term sweep stability.

Building on these contributions, the paper proposes a three-level screening and ranking framework that rapidly identifies high-potential opportunities based on technical suitability, economic feasibility, and the speed at which a meaningful field response can be observed. Early KPI alignment ensures that pilot objectives remain both technically representative and commercially relevant, preventing the mismatches that often lead to inconclusive pilots. The laboratory program focuses on dissolution testing, viscosity screening, analog-core propagation, and a single reservoir-core study centered on porous-media behavior, with polymer chemistry selected using a practical stability envelope defined by temperature and water composition. The simulation workflow prioritizes porous-media-derived resistance factors and retention, refined near-wellbore representation, and conservative handling of chase-water instability to deliver credible injectivity forecasts. A hydraulically confined and representative pilot design enables early learning from pressure trends, polymer breakthrough, and oil-cut response, with clear decision gates supporting rapid progression from concept to demonstration and, where justified, full-field deployment.

Nomenclature

ATBS = 2-acrylamido-2-methylpropane sulfonic acid
EOR = enhanced oil recovery
FMI = formation micro image log
HPAM = partially hydrolyzed polyacrylamide or acrylamide-acrylate copolymer
IAPV = inaccessible pore volume
ILT = injection logging tool
KPI = key performance indicator
k = permeability, darcies [μm^2]
k_{ro} = relative permeability to oil, darcies [μm^2]
k_{rw} = relative permeability to water, darcies [μm^2]

M_w = polymer molecular weight, g/mol [daltons]
NVP = net present value
OIW = total oil content in water, ppm [mg/L]
PLT = production logging tool
PV = pore volume
R^+ = defined by Eq. 1: $\Sigma\ (Ca^{2+} + Mg^{2+}) / \Sigma\ (Na^{+}+K^{+}+Ca^{2+}+Mg^{2+}+H^{+})$
RF = resistance factor (brine mobility divided by polymer mobility)
RRF = residual resistance factor (brine mobility before polymer divided by brine mobility after polymer)
SWCTT = single-well chemical tracer test (for determining resident oil saturation)
TDS = total dissolved solids, ppm [mg/L]
WHP = wellhead pressure, psi [Pa]
WOR = producing water/oil ratio
μ_o = oil viscosity, cP [mPa-s]
μ_w = water viscosity, cP [mPa-s]
$\varnothing$ = porosity

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