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Integrity-Constrained Laboratory Screening of EOR Methods for Heavy-Oil Carbonate Reservoirs

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ABSTRACT

Enhanced oil recovery (EOR) screening is commonly initiated from reservoir and fluid properties, displacement mechanisms, and expected recovery potential. In technically complex offshore systems, however, a candidate method may be unsuitable for further development if the associated fluids and operating conditions intensify corrosion, inorganic scaling, organic deposition, emulsion persistence, phase instability, or near-wellbore damage. This study develops an integrity-constrained pre-pilot laboratory screening workflow for the integrated Field X-Field Y system. The workflow integrates brine chemistry and water-compatibility calculations, corrosion and inhibitor tests, wax-appearance-temperature (WAT) and viscosity data, emulsion stability, PVT recombination, and filtration compatibility. Untreated corrosion rates reached 11.586 mm/year at the electrical submersible pump outlet and 2.942 mm/year at the wellhead. Field X-Field Y formation-water mixing was compatible at 60 °C, whereas cooling to 30–50 °C increased predicted $BaSO_4$-dominated precipitation, with 18.849 mg/L at 30 °C for the 75/25 mixture; the broader marine-water case reached 58.79 mg/L under the evaluated low-temperature/low-pressure condition. Field Y DST-1 was the most restrictive oil in the organic-deposition screen, with 10.6 wt.% paraffin and WAT evidence spanning 17.4–22.4 °C. Artificial emulsions retained up to 70% water for Field X DST-3 and 80% for Field Y DST-1. For the selected associated-gas analogue, a gas-oil ratio not above 90 m³/t at 18 MPa and 60.5 °C was used as the single-phase recombination boundary. The six-domain matrix was reformulated as an equal-weight ordinal qualification-burden index rather than a recovery-ranking tool; WAG had the highest burden (S=15; R=2.50), and this position remained unchanged under ±25% one-at-a-time criterion-weight perturbations. The framework therefore identifies operational-integrity constraints and the laboratory qualification required before direct displacement corefloods, compositional simulation, and pilot validation; it does not quantify incremental oil recovery.

Keywords: enhanced oil recovery, EOR screening, operational integrity, corrosion, barium sulfate scale, wax appearance temperature, PVT stability.

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Introduction

Mature and technically complex oil fields require recovery strategies that extend productive life and strengthen technical justification before pilot-scale implementation. Traditional EOR screening relies on reservoir temperature, oil viscosity, permeability, depth, pressure, oil composition, and displacement mechanisms [[1], [2], [3], [4], [5], [6], [7], [8]]. These criteria remain necessary, while field-development concepts involving multiple reservoirs, commingled production, alternative injection waters, offshore surface facilities, and high-salinity produced fluids require a broader integrity-based qualification. In such systems, the selected EOR method must be compatible not only with the reservoir rock and oil, but also with produced-water treatment, metallurgy, flow assurance and chemical protection requirements.

The Field X-Field Y system represents a case in which preliminary EOR selection requires a separate operational-integrity gate in addition to conventional reservoir-displacement screening. Water-based methods are affected by sulfate-barium compatibility and corrosion; gas-based methods require phase stability and PVT qualification; chemical methods are constrained by salinity, hardness, emulsification, and reagent compatibility; and WAG couples the aqueous- and gas-phase constraints. Accordingly, the objective of this paper is to construct a pre-pilot laboratory screening workflow that translates the available Field X-Field Y compatibility and flow-assurance evidence into explicit qualification requirements for EOR method groups. The workflow is intended to identify what must be controlled or tested before displacement-efficiency evaluation, not to predict recovery factors or incremental oil production.

The scientific novelty lies in the decision layer applied between conventional EOR screening and method-specific displacement testing. Classical screening, multi-criteria decision-making, and recent data-driven approaches primarily rank EOR alternatives using reservoir/fluid suitability, expert-weighted criteria, sustainability indicators, or analog project databases. The present framework asks a different question: which operational-integrity constraints are directly coupled to each candidate method, and how much laboratory qualification is required before that method advances to coreflood, simulation, or pilot stages? Six independently generated evidence domains corrosion, inorganic scaling, organic deposition, emulsion behavior, PVT/phase stability, and filtration compatibility – are converted into a traceable ordinal coupling matrix. The matrix is deliberately separated from expected recovery, economics, and field-performance prediction, thereby avoiding the interpretation of laboratory compatibility data as a displacement-efficiency result.

Literature review

EOR screening has historically been structured around reservoir and oil-property thresholds. The classical screening approach separates thermal, gas, chemical, and microbial methods using parameters such as oil gravity, viscosity, reservoir temperature, permeability, and remaining oil saturation [[1], [2]]. Broader EOR reviews emphasize that method selection must be updated as field maturity, economics, and technology readiness change [[3], [4], [5]]. Textbook frameworks further show that displacement mechanisms alone do not guarantee field applicability because injectivity, mobility ratio, phase behavior, chemical loss, and facility constraints may dominate practical performance [[6], [7], [8]]. Water-based and chemical EOR methods are particularly sensitive to brine composition. High salinity and hardness can reduce polymer performance, destabilize surfactant systems, and increase the risk of inorganic scale. For low-salinity or engineered-water flooding, the target is not only salinity reduction but also controlled ion composition, clay response, and surface chemistry [[6], [7]]. In carbonate and high-salinity systems, sulfate and barium/strontium interactions become important because injected or mixed waters may cross the saturation threshold for sulfate scales. Oilfield scale literature identifies $BaSO_4$ as one of the most persistent and difficult scales to remove, and its formation is commonly associated with mixing of sulfate-bearing and barium-rich brines under changing temperature and pressure [[9], [10]].

Recent EOR-screening research has expanded beyond fixed property windows. Multi-criteria approaches have used fuzzy AHP/FTOPSIS or hybrid FAHP-goal-programming formulations to combine technical, environmental, economic, and social criteria [[11], [12]]. Statistical and machine-learning frameworks have also ranked EOR classes from global project databases [[13], [14]], while VIKOR coupled with Monte-Carlo analysis has been used to quantify ranking robustness under changing criterion weights [15]. These developments improve method prioritization, but their principal inputs remain reservoir/fluid descriptors, expert preferences, sustainability criteria, or analog-project outcomes. In contrast, the present study uses field-specific laboratory compatibility and flow-assurance evidence as a pre-pilot integrity gate and explicitly does not infer displacement efficiency from that evidence.

Corrosion is another screening barrier. Internal corrosion in oilfield systems is controlled by water chemistry, CO_2/H_2S, oxygen contamination, flow regime, temperature, solids, microbiology, and inhibitor performance [[16], [17], [18], [19]]. An EOR method that increases water circulation, gas-water contact, or sulfate-reducing bacterial activity may change the corrosion regime even if it improves sweep. Therefore, corrosion must be evaluated as part of the EOR decision rather than only as a production-chemistry issue.

Organic deposition and emulsion behavior influence both subsurface and surface performance. Wax and asphaltene deposition are controlled by oil composition, temperature history, pressure depletion, gas liberation, and mixing. The wax appearance temperature (WAT) and viscosity-temperature response are therefore essential for gas injection, cold-water injection, thermal methods, and offshore transport [[20], [21]]. Emulsion stability affects separation, chemical flooding, WAG, and any method that increases water cut or changes interfacial conditions. Stable emulsions increase the load on surface processing, can trap water and solids, and may demand additional demulsification capacity [[22], [23]].

PVT behavior is the bridge between fluid displacement and laboratory representativeness. Gas injection, miscible or near-miscible processes, and coreflood studies require recombined fluids to remain single-phase under test conditions. Single-phase stability preserves the representativeness of measured recovery and pressure response during filtration experiments [[24], [25]]. For this reason, PVT constraints are treated here as an integral screening criterion for gas-based and hybrid EOR methods.

Experimental part

The study integrates an existing laboratory and engineering dataset for the anonymized Field X-Field Y fluid system. The evidence base comprises: (i) formation-water chemistry and water-mixing precipitation calculations; (ii) steel-coupon corrosion measurements for production and wellbore conditions; (iii) corrosion-inhibitor screening; (iv) scale-control screening records; (v) viscosity-temperature and WAT measurements; (vi) recombination of degassed oil with associated-gas analogues; (vii) artificial-emulsion stability and optical-microscopy observations; and (viii) filtration compatibility of a potential injection water with Field X brine and rock. For traceability, study outputs were classified as directly measured, calculated/predicted, or derived screening quantities. Corrosion rate, inhibitor response, viscosity/WAT, emulsion behavior, PVT recombination response, and filtration permeability change are treated as laboratory observations; scale precipitation is explicitly reported as calculated/predicted; and the EOR matrix and weight-sensitivity results are derived screening quantities. This classification prevents calculated scale values and derived scores from being presented as direct experimental measurements. The overall laboratory screening workflow and the equipment configuration are shown in Figures 1 and 2, respectively.

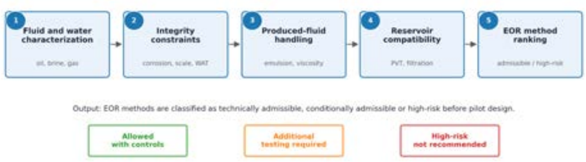

Figure 1 - Laboratory workflow for integrity-constrained EOR screening

Figure 2 - Laboratory equipment schematic used for integrity-constrained EOR screening

Water compatibility was evaluated from ionic composition, total dissolved solids, and calculated precipitation for Field X/Field Y formation-water mixtures at 30, 40, 50, and 60 °C; additional alternative-injection-water and marine-water cases were used to examine sensitivity to sulfate input and lower-temperature/lower-pressure conditions. Corrosion screening used steel coupons and reported corrosion rate in mm/year. Inhibitor protective effect was calculated as IE = (CRblank − CRtreated)/CRblank × 100%, where CR is the corrosion rate. Organic-deposition screening used the available kinematic/dynamic viscosity and WAT evidence, including rheological and acoustic-resonance records. Artificial emulsions were prepared at varying water contents and assessed by retained-water behavior, aggregative stability, and optical microscopy of globule size. PVT recombination was used to identify gas-oil ratios that maintained a homogeneous single-phase fluid at 18 MPa and 60.5 °C; for the selected analogue, the screening boundary was ≤90 m^3/t. Filtration compatibility was expressed as permeability decline after contact between the alternative injection water, Field X brine, and rock, with the supplied archive reporting a maximum decline of 7%. These tests provide compatibility and integrity information; they are not direct EOR displacement experiments.

Methodological traceability and uncertainty

The supplied archive does not contain complete instrument manufacturer/model information, specimen dimensions and preparation records, exposure duration, replicate-level raw observations, calibration certificates or traceable standard identifiers for every legacy laboratory domain. These values were therefore not reconstructed or estimated. Where replicate-level observations are unavailable, Figures 3–9 report the supplied endpoint values without fabricated standard-deviation or confidence-interval error bars. The vertical range shown for WAT in Figure 8 represents the span of method-specific WAT evidence, not statistical uncertainty. Full reproducibility of the legacy tests requires the additional metadata listed in the revision supporting file; the present manuscript reports all methodological conditions that are directly supported by the supplied study archive. The laboratory screening domains, primary indicators, and their roles in EOR decision-making are summarized in Table 1.

Table 1 - Laboratory screening domains and EOR selection role

Domain	Primary indicator	EOR decision role/data type
Corrosion	Corrosion rate, mm/year; inhibitor performance	Infrastructure compatibility and chemical-protection requirement. Directly measured/calculated inhibitor efficiency.
Inorganic scaling	$BaSO_4$/total precipitate, mg/L; water chemistry	Aqueous-phase compatibility and sulfate-control requirement. Water chemistry measured; precipitation calculated/predicted.
Organic deposition	Paraffin content; WAT; viscosity-temperature response	Low-temperature flow-assurance qualification. Laboratory-observed properties.
Emulsion behavior	Maximum retained water; aggregative stability; globule size	Produced-fluid handling and separation qualifications. Laboratory-observed.
PVT stability	Gas-oil ratio; viscosity; single-phase recombination condition	Gas/hybrid fluid preparation and phase-stability qualification. Laboratory-observed.
Filtration compatibility	Permeability decline after fluid-rock interaction	Injectivity / near-wellbore damage qualification. Laboratory-observed endpoint response.

Results and Discussion

Corrosion as an infrastructure-screening barrier

The strongest constraint identified in the screening dataset is corrosion. Untreated rates are strongly aggressive in all tested operating points, with the most severe values at the ESP outlet and wellhead. These rates exceed the range that can be considered acceptable for long-term EOR operation without chemical protection. For EOR selection, this means that methods increasing water circulation, gas-water interaction, or oxygen/SRB exposure should be qualified using both reservoir displacement performance and operational-integrity criteria. The untreated corrosion rates are summarized in Table 2 and illustrated in Figure 3.

Table 2 - Untreated corrosion rates used as EOR screening constraints

Operating point	Corrosion rate, mm/year
General multiphase stream from wells	0.91
General multiphase stream after primary treatment	0.575
Crude oil before separator after hot-oil treatment	1.095
ESP outlet	11.586
Wellhead	2.942

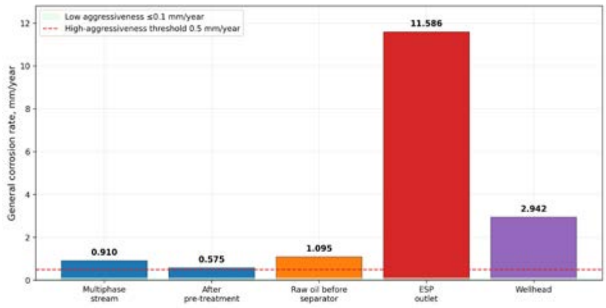

Figure 3 - Untreated corrosion rates in production and wellbore conditions

Inhibitor screening substantially reduced corrosion rates. The best tested treatments reached 0.107-0.112 mm/year under the specified laboratory conditions. This shifts corrosion from a blocking factor into a manageable design constraint if inhibitor selection, dosage optimization, and field validation are incorporated into the EOR design. The corrosion-inhibitor screening results are reported in Table 3 and illustrated in Figure 4.

Table 3 - Corrosion-inhibitor response under Field X conditions

Treatment	Dose, g/t	Corrosion rate, mm/year	Protective effect, %
Blank sample	0	0.575	0
CI-1	50	0.132	77.1
CI-1	70	0.118	79.6
CI-2	50	0.125	78.38
CI-2	70	0.107	81.4
CI-3	50	0.122	78.7
CI-3	70	0.112	80.5
Complex CI-4	90	0.109	81.1

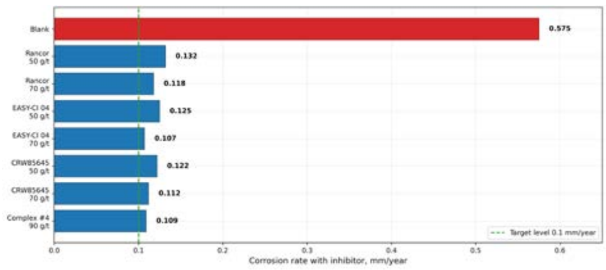

Figure 4 - Corrosion-inhibitor screening response

Water chemistry and sulfate-barium scale risk

The two formation waters differ in total salinity and sulfate-barium balance. Field X water is more saline and barium-rich, whereas Field Y water contains sulfate. This contrast creates a clear scale mechanism: mixing can introduce sulfate into a barium-containing system and cause $BaSO_4$ precipitation. The predicted precipitation depends strongly on temperature. At 60 °C, the waters are compatible in all ratios, but decreasing the temperature to 50, 40, and 30 °C produces a $BaSO_4$-dominated precipitate. The maximum predicted precipitate for Field X-Field Y formation-water mixing is 18.849 mg/L at 30 °C for the 75/25 Field X/Field Y mixture. The formation-water chemistry is presented in Table 4, while the temperature-dependent precipitation results are summarized in Table 5 and Figure 5.

Table 4 - Formation-water chemistry used in the screening calculation

Water type	pH	Density, g/cm^3	TDS, g/L	SO_4, mg/L	Cl, mg/L	Ca, mg/L	Mg, mg/L	Ba, mg/L
Field X formation water	5.9	1.154	225.9	0.0	138069.2	6727.4	1718.9	46.5
Field Y formation water	6.8	1.122	185.1	118.6	113404.2	6800.2	1867.7	17.0

Table 5 - Predicted precipitate during Field X-Field Y formation-water mixing, mg/L

Field X/Field Y ratio, %	30 °C	40 °C	50 °C	60 °C
100/0	16.499	12.022	6.22	0.0
75/25	18.849	13.293	6.7	0.0
50/50	13.639	8.543	2.53	0.0
25/75	3.829	0.072	0.0	0.0
0/100	0.009	0.003	0.0	0.0

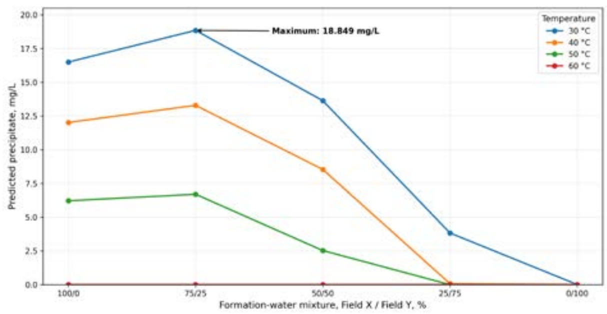

Figure 5 - Temperature-dependent scale potential during Field X-Field Y water mixing

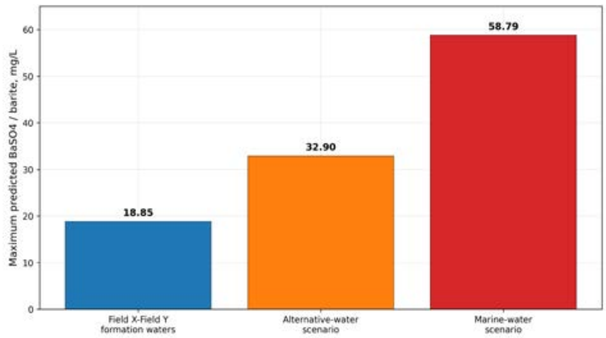

Figure 6 - Maximum predicted barite risk across water-mixing scenarios

The wider screening dataset shows that alternative and marine-water options can introduce a higher scale burden than formation-water mixing alone. Marine-water mixing is the most restrictive case, with a maximum predicted barite concentration of 58.79 mg/L under low-temperature and low-pressure conditions. This result directly affects waterflooding, engineered-water flooding, chemical flooding, and WAG selection because each of these methods requires an aqueous phase to be injected, recycled, or produced. The maximum predicted barite risk across the evaluated water-mixing scenarios is compared in Figure 6.

Organic deposition and low-temperature flow assurance

Organic-deposition screening separates Field X and Field Y oils into different risk groups. Field X DST-3 has moderate paraffin content and a WAT of approximately 9-10 °C, while Field Y DST-1 is the limiting oil with 10.6 wt.% paraffin and a WAT range of 17.4-22.4 °C depending on the method. Field Y DST-2 is less restrictive than DST-1 but still requires consideration during commingled production. For EOR selection, this means that injection methods causing temperature decrease, pressure depletion, gas liberation, or fluid mixing must be evaluated against wax/asphaltene deposition risk. The key organic-deposition indicators are summarized in Table 6; the Field X DST-3 viscosity-temperature relationship and the comparison across the tested oils are shown in Figures 7 and 8, respectively.

Table 6 - Organic-deposition screening indicators

Oil sample	Paraffin, wt.%	Pour point, °C	WAT by rheometer, °C	Additional WAT evidence
Field X DST-3	3.0	-15	9.0	below 10 by viscosity curve
Field Y DST-1	10.6	10.0	17.4	22 by ARS; 22.4 by viscosity curve
Field Y DST-2	7.3	-3.0	5.8	12.7 by viscosity curve

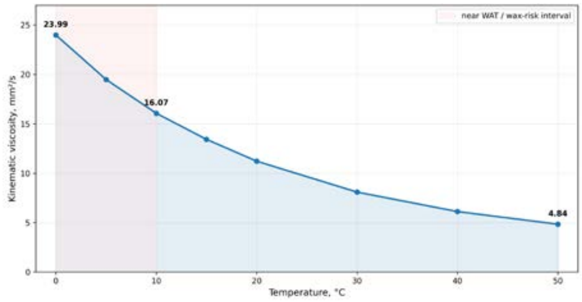

Figure 7 - Field X DST-3 viscosity-temperature relationship

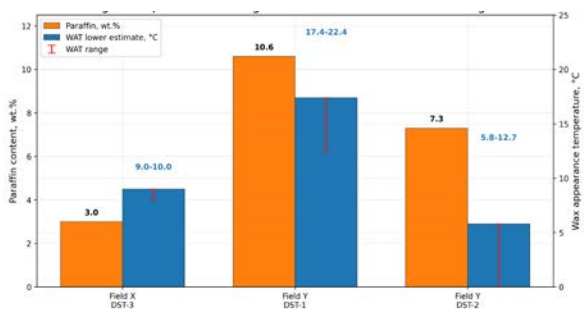

Figure 8 - Organic-deposition constraints across tested oils

Emulsion stability as a produced-fluid handling constraint

Emulsion behavior is a key produced-fluid handling control factor for water-based, chemical, and hybrid EOR methods. Field X artificial emulsions retain up to 70% water, and Field Y DST-1 emulsions retain up to 80% water. Field Y DST-2 behaves differently: a stable emulsion does not form at 60-90% water, indicating a less persistent emulsion structure at high water content. The microscopy results also show different globule-size ranges, with Field Y DST-1 having the broadest range. This result is important because increased water cut, surfactant use, WAG cycling, or produced-water recycling increases separation requirements even when subsurface displacement is favorable. The emulsion-screening results are summarized in Table 7 and Figure 9.

Table 7 - Emulsion-screening results

Oil sample	Maximum retained water, %	Aggregative stability behavior	Globule-size range, μm
Field X DST-3	70	highest stability at 30-50% water; relative decline at 60-70%	19.6-31.7
Field Y DST-1	80	100% aggregative stability at all water contents; maximum stability at 50-70%	17.7-73.9
Field Y DST-2	50	stable emulsion absents at 60-90% water; high stability preserved at 30%	18.0-29.2

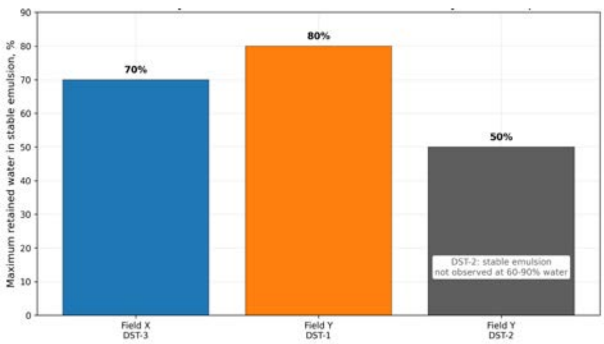

Figure 9 - Maximum retained water in stable artificial emulsions

PVT recombination constraints for gas-based and hybrid EOR

PVT recombination controls the validity of gas-EOR and hybrid-EOR laboratory tests. For Field X, associated gas analogues were used to reconstruct a representative reservoir fluid at 18 MPa and 60.5 °C. The recommended gas-oil ratio for the coreflood-ready recombined fluid is not above 90 m^3/t for the selected analogue, corresponding to a representative viscosity of approximately 1.2 cP. This condition is used as a laboratory boundary to avoid gas breakout during filtration experiments and to ensure that gas-based screening reflects the intended reservoir fluid rather than an unstable experimental mixture. The corresponding PVT recombination constraints are summarized in Table 8.

Table 8 - PVT recombination constraints for gas-EOR screening

Gas analogue	Gas-oil ratio range, m^3/t	Viscosity range, cP	Recommended gas-oil ratio, m^3/t	Decision note
Associated gas analogue A	70-95	1.00-2.11	≤90	Selected for recombined fluid coreflood preparation
Associated gas analogue B	70–95/98	1.05-1.50	95 and below	Recommended due to operationally convenient sampling pressure

Filtration compatibility and injectivity risk

Filtration compatibility provides a link between fluid chemistry and near-wellbore injectivity risk, but it does not constitute an EOR displacement-efficiency test. The tested alternative injection water produced up to 7% permeability decline after interaction with Field X brine and rock. Within the supplied dataset, this endpoint is used only to indicate that no larger permeability loss was observed in the reported compatibility test; qualification of water-based or hybrid EOR still requires method-specific coreflood/injectivity testing under representative saturation, rate, and stress conditions. The filtration-compatibility endpoint and its screening interpretation are summarized in Table 9.

Table 9 - Filtration compatibility indicator

Test system	Permeability response	Screening interpretation
Alternative injection water with Field X brine and rock	up to 7% permeability reduction	compatible/acceptable for further screening

EOR method screening matrix

The laboratory results were integrated into an ordinal integrity-qualification matrix across six domains: corrosion, scale, organic deposition, emulsion, PVT/phase behavior and filtration compatibility. For method j and domain i, a coupling score sij of 1, 2, or 3 was assigned: 1 = low direct dependence on the domain within the available evidence and routine verification only; 2 = moderate or method-specific dependence requiring dedicated qualification before a pilot; and 3 = strong/direct dependence for which mitigation or validation is mandatory before the method advances. Thus, the score represents qualification burden, not predicted recovery, economics, technical success probability or incremental oil. Equal default weights (wi = 1/6) were used because the supplied dataset provides no defensible basis for preferential criterion weighting. The raw score is Sj = Σsij (range 6–18) and the normalized index is $R_j = \Sigma w_i \cdot s_{ij} = S_j/6$ (range 1–3). Scores of 6–9 are interpreted as lower qualification burden, 10–12 as moderate burden, and 13–18 as high burden. These bands are decision-support categories only and are not field-admissibility thresholds. The resulting integrity-qualification score matrix is presented in Table 10, while the interpretation of the qualification burden and the required next-stage evidence are summarized in Table 11.

A one-at-a-time weight-sensitivity analysis was added to test whether the ranking is an artifact of equal weighting. Each criterion weight was independently increased and decreased by 25%, with all six weights renormalized to sum to unity, giving 12 perturbed weighting cases. WAG retained the highest normalized qualification-burden index in every case (R = 2.44–2.57), and gas injection remained second (R = 1.96–2.04). The other method groups remained within R = 1.61–1.88. This analysis demonstrates the robustness of the burden ordering to moderate weight perturbation; it does not validate EOR recovery performance. The corresponding criterion-weight sensitivity results are shown in Figure 10.

Table 10 - Integrity-constrained EOR screening score matrix for Field X-Field Y

EOR method group	Corrosion	Scale	Organic	Emulsion	PVT	Filtration	Total score
Conventional/modified waterflooding	3	3	1	1	1	1	10
Low-salinity or engineered-water flooding	3	3	1	2	1	1	11
Polymer flooding	2	3	1	2	1	1	10
Surfactant/alkali-surfactant methods	2	3	1	3	1	1	11
Gas injection / miscible or near-miscible gas	3	2	2	1	3	1	12
WAG / hybrid gas-water EOR	3	3	2	3	3	1	15
Thermal stimulation	2	2	3	1	1	1	10
Microbial / biochemical EOR	3	2	1	2	1	1	10

Table 11 - Interpretation of the integrity-qualification matrix and required next-stage evidence

EOR method group	Qualification-burden interpretation and next-stage evidence
Conventional/modified waterflooding	Moderate burden (S=10; R=1.67). Scale/corrosion control must be qualified; displacement performance requires direct coreflood or validated simulation.
Low-salinity or engineered-water flooding	Moderate burden (S=11; R=1.83). Requires brine-rock compatibility, sulfate control, and method-specific wettability/displacement testing.
Polymer flooding	Moderate burden (S=10; R=1.67). Requires polymer stability/rheology in high-salinity/high-hardness brine, retention/injectivity, and displacement corefloods.
Surfactant/alkali-surfactant methods	Moderate burden (S=11; R=1.83). Requires phase behavior, salinity compatibility, adsorption/retention, emulsion/separation, and displacement testing.
Gas injection/miscible or near-miscible gas	Moderate burden (S=12; R=2.00). Requires PVT/miscibility qualification, corrosion/flow-assurance assessment, and direct displacement or compositional-simulation validation.
WAG/hybrid gas-water EOR	High burden (S=15; R=2.50). Couples aqueous scaling/corrosion, emulsion, and gas-phase PVT constraints; requires integrated coreflood, compositional simulation, and pilot validation.
Thermal stimulation	Moderate burden (S=10; R=1.67). WAT/viscosity data support temperature sensitivity, but thermal feasibility, heat loss, well/facility integrity, and displacement response were not tested here.
Microbial/biochemical EOR	Moderate burden (S=10; R=1.67). Requires microbiology/SRB, souring, biocide compatibility, and direct displacement validation before pilot consideration.

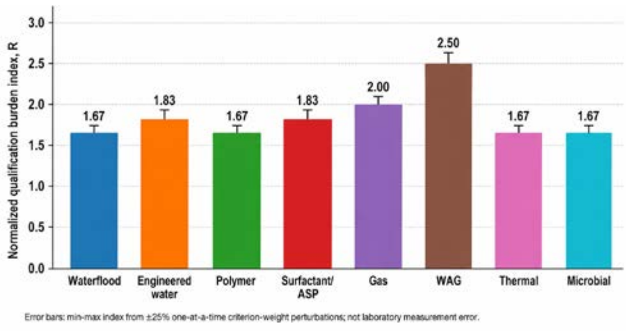

Figure 10 - Normalized EOR qualification-burden index under criterion-weight sensitivity. Error bars indicate the minimum-to-maximum index obtained from ±25% one-at-a-time criterion-weight perturbations and do not represent laboratory measurement uncertainty

Discussion

Implications for water-based methods

Conventional waterflooding and modified water injections remain candidates for further evaluation when $BaSO_4$ scaling and corrosion are controlled. Field X-Field Y formation-water mixtures show zero predicted precipitate at 60 °C in the supplied calculation, whereas cooling increases predicted precipitation. Consequently, any water-based EOR design should include sulfate-barium compatibility, oxygen management and corrosion inhibition, followed by method-specific injectivity and displacement testing. The temperature sensitivity is particularly relevant to offshore systems where reservoir, wellbore and surface temperatures differ substantially.

Implications for chemical EOR

Chemical EOR requires targeted qualifications because polymer, surfactant and alkali-surfactant systems can be affected by salinity, hardness, scale and emulsification. The present matrix does not establish chemical-EOR displacement efficiency. Instead, it defines the minimum follow-up program: polymer viscosity retention in representative brines, surfactant/alkali phase behavior, adsorption and retention, injectivity, emulsion/separation response, scale-inhibitor and corrosion-inhibitor interference, and direct displacement coreflooding before any pilot recommendation.

Implications for gas-based and hybrid methods

Gas injection and WAG remain candidates for subsequent displacement evaluation after integrity qualification. PVT recombination provides a controlled fluid-preparation boundary, while the organic-deposition dataset identifies Field Y DST-1 as the most temperature-sensitive oil among the tested samples. WAG has the highest integrity-qualification burden in the matrix (S=15; R=2.50) because it simultaneously couples water-phase scaling/corrosion, emulsion behavior and gas-phase PVT constraints. This designation does not mean that WAG has the highest EOR performance or the highest probability of failure; it means that the largest number of integrity domains require method-specific qualification before recovery performance can be evaluated.

Implications for thermal and microbial/biochemical methods

The viscosity-temperature and WAT data show that increasing temperature reduces the measured viscosity of Field X DST-3 and moves the system away from wax-appearance conditions; however, the present dataset does not establish the recovery efficiency of a thermal process. Thermal methods therefore require dedicated heat-loss, well-integrity, surface-facility, and displacement-feasibility studies. Microbial/biochemical EOR likewise requires SRB/biocide, souring-risk and fluid-compatibility qualification followed by direct displacement testing. These method groups are retained as screening candidates rather than declared technically admissible technologies.

Study scope, validation level and limitations

No direct oil-displacement experiments with polymer, surfactant, gas, WAG, thermal, or microbial systems, no reservoir-simulation cases, and no field-pilot data are included in the supplied study dataset. Consequently, the framework cannot quantify recovery factor, incremental oil production, sweep efficiency, miscibility benefit, or field economic value. Its validated output is limited to organizing the available laboratory compatibility evidence and identifying the relative integrity-qualification burden of method groups. The added weight-sensitivity analysis tests robustness of the ordinal decision layer, not physical EOR performance. The appropriate next validation stage is method-specific coreflooding and/or compositional reservoir simulation, followed by a pilot where warranted. A second limitation is incomplete legacy metadata for several laboratory procedures; specimen dimensions, preparation details, instrument models, test duration, replicate counts, standard identifiers, and instrument uncertainties should be recovered from the original laboratory reports before claiming full experimental reproducibility.

Scientific contribution

The contribution of this study is a transparent pre-pilot decision layer that treats corrosion, scaling, organic deposition, emulsion behavior, PVT stability, and filtration compatibility as EOR qualification domains rather than disconnected production-chemistry observations. Unlike reservoir-property screening or data-driven ranking, the framework does not claim to identify the method with the highest recovery. It identifies which candidate methods are most strongly coupled to the documented operational-integrity constraints and therefore require the most extensive qualification before displacement testing. The scoring definitions, equal-weight assumption, burden thresholds, data-type classification, and weight-sensitivity analysis make the decision logic auditable and reduce ambiguity between laboratory compatibility evidence and EOR performance prediction.

Conclusions

An integrity-constrained pre-pilot EOR screening workflow was developed for the Field X-Field Y system using six laboratory domains: corrosion, inorganic scaling, organic deposition, emulsion behavior, PVT/phase stability, and filtration compatibility. The workflow is an operational-qualification gate and is not a displacement-efficiency or recovery-factor model.

Corrosion is the most severe measured infrastructure constraint in the supplied dataset. Untreated rates reach 11.586 mm/year at the ESP outlet and 2.942 mm/year at the wellhead; inhibitor screening reduces the best reported test values to 0.107–0.112 mm/year, demonstrating the need for chemical protection and field validation in any EOR design that increases corrosive exposure.

Formation-water compatibility is temperature sensitive. The supplied precipitation calculations give zero precipitate at 60 °C for all Field X/Field Y ratios but up to 18.849 mg/L at 30 °C for the 75/25 mixture. The broader marine-water case reaches a predicted 58.79 mg/L under the evaluated low-temperature/low-pressure condition.

Organic-deposition and emulsion data identify Field Y DST-1 as the most restrictive tested oil for flow assurance: paraffin content is 10.6 wt.%, WAT evidence spans 17.4–22.4 °C, and artificial emulsions retain up to 80% water. Field X DST-3 emulsions retain up to 70% water.

Gas/hybrid laboratory preparation requires PVT control. For the selected associated-gas analogue, the supplied recombination evidence supports a gas-oil-ratio boundary of ≤90 m^3/t at 18 MPa and 60.5 °C to maintain the intended single-phase preparation condition.

The filtration-compatibility record shows up to 7% permeability decline after interaction of the alternative injection water with Field X brine and rock. This endpoint supports only compatibility screening; it does not replace method-specific injectivity or displacement coreflooding.

The revised matrix uses a defined 1–3 ordinal method-domain coupling scale and equal criterion weights. WAG has the highest qualification burden (S=15; R=2.50), followed by gas injection (S=12; R=2.00). Under ±25% one-at-a-time criterion-weight perturbations, WAG remains highest (R=2.44–2.57) and gas injection remains second (R=1.96–2.04), indicating robustness of the burden ordering to moderate weighting changes.

The study does not contain direct EOR displacement tests, reservoir simulation, or field-pilot validation; therefore, no conclusion is made regarding incremental oil recovery, recovery factor or economic superiority of the screened methods. The matrix identifies the qualification work required before those performance questions can be answered.

The next technical stage should combine recovered laboratory metadata and replicate-level uncertainty, method-specific displacement corefloods, and–where gas or WAG is considered–compositional reservoir simulation before pilot selection.

Data availability. The laboratory and calculation data supporting the reported numerical results are available from the author upon reasonable request, subject to confidentiality requirements related to anonymized field information. The current compiled archive does not contain complete replicate-level raw records and instrument metadata for every legacy test; these items should be recovered from the originating laboratory reports for full procedural reproducibility.

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Ауыр мұнайлы карбонатты коллекторлар үшін пайдалану сенімділігі шектеулерін ескеретін EOR әдістерінің зертханалық скринингі

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ТҮЙІНДЕМЕ
Мұнай өндіруді арттыру (МӨ) әдістерін скринингтеу әдетте қабат пен флюид қасиеттеріне, ығыстыру механизмдеріне және мұнай өндірудің күтілетін әлеуетіне негізделген. Алайда, техникалық тұрғыдан күрделі теңіз жүйелері үшін әдісті таңдау кезінде коррозияны, бейорганикалық тұздардың шөгуі, органикалық шөгінділерді, эмульсия тұрақтылығын, фазалық тұрақсыздықты және ұңғыма маңы аймағының зақымдануын ескеру қажет. Бұл жұмыста X–Y кен орындарының интеграцияланған жүйесі үшін пайдалану сенімділігінің шектеулерін ескеретін пилотқа дейінгі зертханалық скрининг әдістемесі әзірленді. Әдістеме судың химиялық құрамы мен үйлесімділігін талдауды, коррозия мен ингибиторларды сынауды, парафиннің пайда болу температурасы (WAT) мен тұтқырлық деректерін, эмульсия тұрақтылығын, PVT-рекомбинациясын және сүзу үйлесімділігін біріктіреді. Ингибиторсыз коррозия жылдамдығы электрлік батырмалы сорғы шығысында 11,586 мм/жылға, ұңғыма сағасында 2,942 мм/жылға жетті. Қабат сулары 60 °C-та үйлесімді болды, ал 30–50 °C-та негізінен $BaSO_4$ шөгіндісінің болжамды мөлшері артты: 30 °C-та 75/25 қоспасы үшін 18,849 мг/л, ал теңіз суы сценарийінде 58,79 мг/л-ге дейін. Field Y DST-1 органикалық шөгінділер бойынша ең шектеуші мұнай болды: парафин мөлшері 10,6 масс.%, WAT 17,4–22,4 °C. Жасанды эмульсиялар Field X DST-3 үшін 70%-ға, Field Y DST-1 үшін 80%-ға дейін суды ұстап қалды. Таңдалған ілеспе газ аналогы үшін бірфазалы рекомбинация шегі 18 МПа және 60,5 °C-та ≤90 м³/т болды. Алты компонентті матрица мұнай өндірудің ранжирлеу құралы емес, тең салмақты реттік квалификациялық жүктеме индексі ретінде қайта құрылды; ең жоғары

жүктеме WAG үшін анықталды (S=15; R=2,50) және критерий салмақтарын ±25% кезекпен өзгерткенде де сақталды. Әдістеме coreflood сынақтары, композициялық модельдеу және пилоттық валидация алдында қажетті пайдалану сенімділігі шектеулері мен зертханалық квалификацияны анықтайды, бірақ қосымша мұнай өндіріліуін сандық түрде бағаламайды.

Түйін сөздер: мұнай өндіруді арттыру, МБА скринингі, коррозия, барий сульфаты шөгіндісі, парафин пайда болу температурасы, PVT тұрақтылығы.

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Лабораторный скрининг методов увеличения нефтеотдачи с учетом ограничений эксплуатационной надежности для тяжелонефтяных карбонатных коллекторов

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АННОТАЦИЯ

Скрининг методов увеличения нефтеотдачи (МУН) обычно основан на свойствах пласта и флюидов, механизмах вытеснения и ожидаемом потенциале нефтеотдачи. Однако для технически сложных морских систем выбор метода должен также учитывать коррозию, солеотложение, органические отложения, устойчивость эмульсий, фазовую нестабильность и повреждение призабойной зоны. В работе разработан предпилотный лабораторный скрининг для интегрированной системы месторождений X–Y с учетом ограничений эксплуатационной надежности. Методика объединяет анализ химии и совместимости вод, коррозионные и ингибиторные испытания, данные по температуре появления парафинов (WAT) и вязкости, устойчивости эмульсий, PVT-рекомбинации и фильтрационной совместимости. Скорость коррозии без ингибитора достигала 11,586 мм/год на выходе ЭЦН и 2,942 мм/год на устье. Смешение пластовых вод было совместимым при 60 °C, тогда как при 30–50 °C возрастало прогнозируемое выпадение преимущественно $BaSO_4$: до 18,849 мг/л при 30 °C для смеси 75/25; в сценарии с морской водой — до 58,79 мг/л. Field Y DST-1 характеризовался наибольшим риском органических отложений: 10,6 масс% парафина и WAT 17,4–22,4 °C. Искусственные эмульсии удерживали до 70% воды для Field X DST-3 и 80% для Field Y DST-1. Для выбранного аналога попутного газа граница однофазной рекомбинации составила ≤90 м³/т при 18 МПа и 60,5 °C. Шестикомпонентная матрица представлена как равновзвешенный порядковый индекс квалификационной нагрузки, а не как инструмент ранжирования нефтеотдачи; максимальная нагрузка установлена для WAG (S=15; R=2,50) и сохранялась при ±25% поочередном изменении весов критериев. Методика определяет ограничения эксплуатационной надежности и объем лабораторной квалификации перед coreflood-испытаниями, композиционным моделированием и пилотной валидацией, но не количественно оценивает прирост нефтеотдачи.

Ключевые слова: повышение нефтеотдачи, МУН-скрининг, эксплуатационная надежность, коррозия, сульфат бария, температура появления парафинов, PVT-стабильность.

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