ADNOC · CHEMICAL EOR PROGRAMME · KHALIFA UNIVERSITY

A Retention-Controlled Screening Framework for Chemical EOR

High-temperature, high-salinity (HTHS) carbonate reservoirs. A surfactant-only GAC/IOS system screened on dynamic retention, and the cost gate that follows from it.

PREPARED BY

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01

Where HTHS carbonates break chemical EOR

Two failure points, three retention mechanisms, and a gap of at least one order of magnitude between reported retention and the field-feasibility band.

THE SETTING

Chemical EOR in HTHS carbonate fails at two points

Thermal and aqueous stability decide whether the chemistry survives. Retention decides whether it can be afforded.

SCREENING TEMPERATURE

100 °C

Corefloods, phase behaviour and adsorption; thermal aging ran at 120 °C

FORMATION WATER

243,028 ppm

TDS. The first formation brine carries 167,301 ppm TDS

FORMATION-WATER HARDNESS

26,520 ppm

As $CaCO_3$, against 2,122 ppm as $CaCO_3$ in the injection seawater

INJECTION SEAWATER

43,373 ppm

TDS. The brine already being injected into the target reservoir

Anionic class	Reported thermal range (°C)	Against 100 °C screening
Sulfate	≤ 60	40 °C below
IOS	90 – 100	At the upper limit
GAC	≥ 120	20 °C above

Source: manuscript p.1-2 and Table 1; brine analyses Tables 3 and 4, p.4.

WHY RETENTION BINDS

Three mechanisms take surfactant out of the flood

Field-feasibility screening sits at 0.1–0.2 mg/g-rock. Anionic systems in carbonate commonly report multi-mg/g-rock retention.

1

Electrostatic adsorption

Anionic head groups bind to the positively charged calcite surface.

Γ_s = 0.78–0.87 mg/g-rock at 100 °C

2

Winsor II phase trapping

Above optimum salinity the surfactant partitions into the oleic phase and is left behind.

S^* = 46,000 ppm TDS

3

Divalent-cation precipitation

Calcium and magnesium precipitate the anionic surfactant out of the aqueous phase.

26,520 ppm as $CaCO_3$

FIELD-FEASIBILITY BAND

0.1 – 0.2 mg/g-rock

Dynamic retention threshold applied when screening a field candidate

CONVENTIONAL ANIONIC IN CARBONATE

> 2 mg/g-rock

Reported for sulfate systems; anionic retention in carbonate is commonly multi-mg/g-rock

Source: manuscript p.2 and Table 1; static adsorption p.9; brine hardness Table 3, p.4.

02

A formulation engineered to the injection path

Five formulations screened. The co-surfactant substitution that moved optimum salinity onto the seawater flood already in place.

FORMULATION SCREEN

Optimum salinity moved from 88,400 to 46,000 ppm TDS

Splitting the co-surfactant between IOS15 and IOS20, in place of IOS15 alone, moved SF4 onto the injected seawater: a 46,000 ppm TDS optimum against 43,373 ppm TDS injection brine.

Formulation	S^* (ppm TDS)	Aqueous stability (ppm TDS)	R^* (cm^3/cm^3)	σ_{os} at 100 °C (mN/m)
SF0	88,400	105,000	9.0	2.50×10^{-2}
SF1	37,000	50,000	7.0	4.20×10^{-3}
SF2	40,000	60,000	9.0	2.58×10^{-3}
SF3	45,000	70,000	9.5	3.07×10^{-3}
SF4	46,000	75,000	12.0	1.93×10^{-3}

SF0 · SINGLE IOS GRADE

88,400 ppm TDS

SF4 · IOS15 + IOS20

46,000 ppm TDS

INJECTION SEAWATER

43,373 ppm TDS

Source: manuscript Table 2 (p.3) and Table 6 (p.6); workbook sheets Phase Behavior (F3) and IFT Data (F4).

STABILITY

SF4 held 30 days at 120 °C and stays single phase to 75,000 ppm TDS

The stability limit sits about 30,000 ppm TDS above the injection brine and below both formation waters.

THERMAL AGING

30 days

At 120 °C in sealed glass ampoules; single phase at endpoint

AQUEOUS STABILITY LIMIT

75,000 ppm

TDS at 100 °C, above which SF4 no longer stays single phase

BUFFER ABOVE INJECTION BRINE

30,000 ppm

TDS above the 43,373 ppm TDS injection seawater

FORMATION WATER

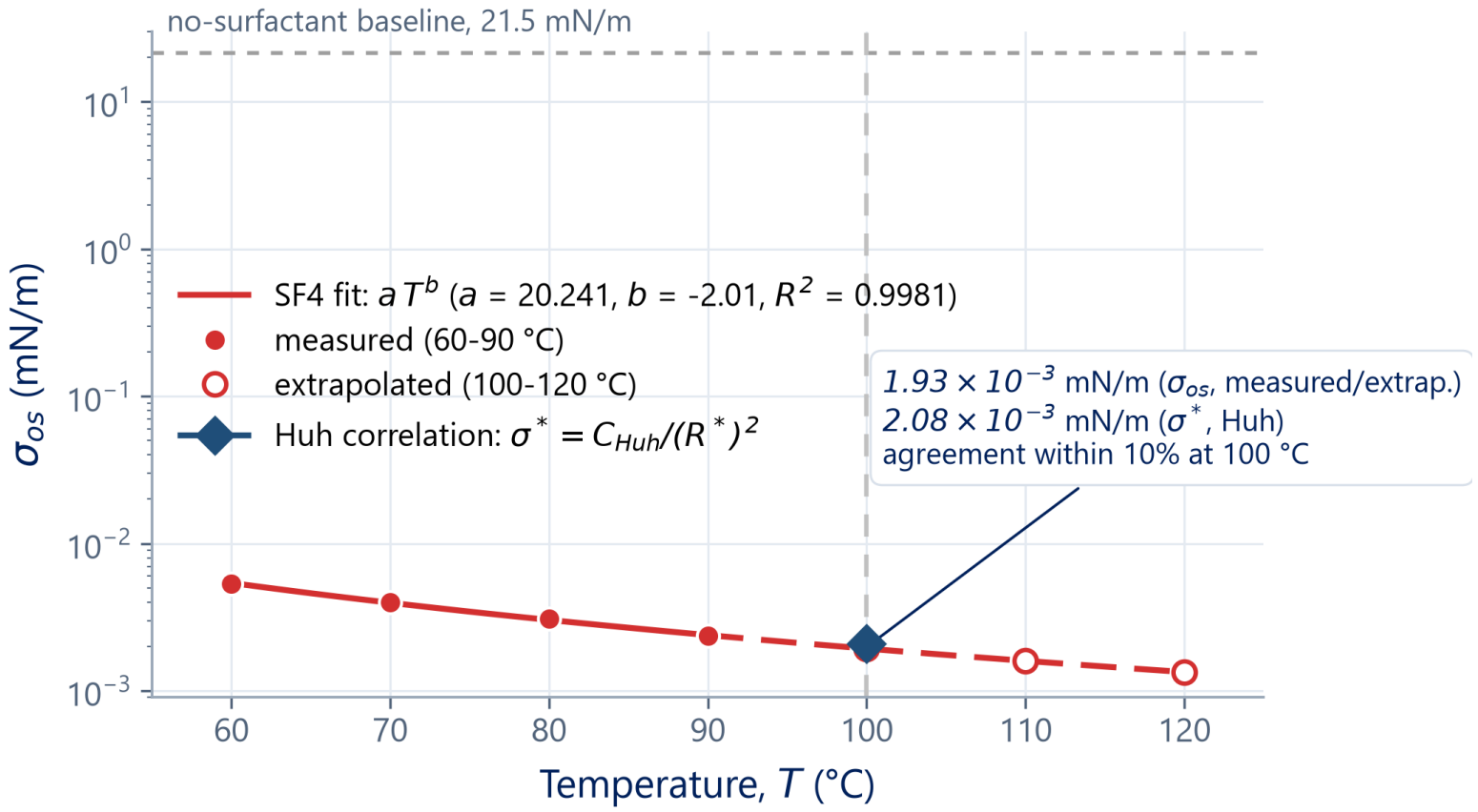
243,028 ppm

TDS, above the stability limit; a seawater pre-flush is required

- A seawater pre-flush is required. Both formation waters, 167,301 and 243,028 ppm TDS, sit above the 75,000 ppm TDS stability limit.
- The salinity path has to hold the leading edge of the slug below that limit; field-scale dispersion broadens the transition that laboratory step changes make sharp.

Source: manuscript p.5-7, p.16, Tables 6 and 8; workbook sheet Phase Behavior (F3).

Two independent routes agree within 10 %



σ_{os} (mN/m, log scale) against temperature, SF4. Filled markers: spinning-drop, 60–90 °C. Hollow: power-law extrapolation, IFT(T) = a·T^b, a = 20.241, b = −2.010, R² = 0.9981. Diamond: Huh value σ at S*.*

WHAT IT SHOWS

Measurement and correlation give 1.93×10^{-3} against 2.08×10^{-3} mN/m at 100 °C.

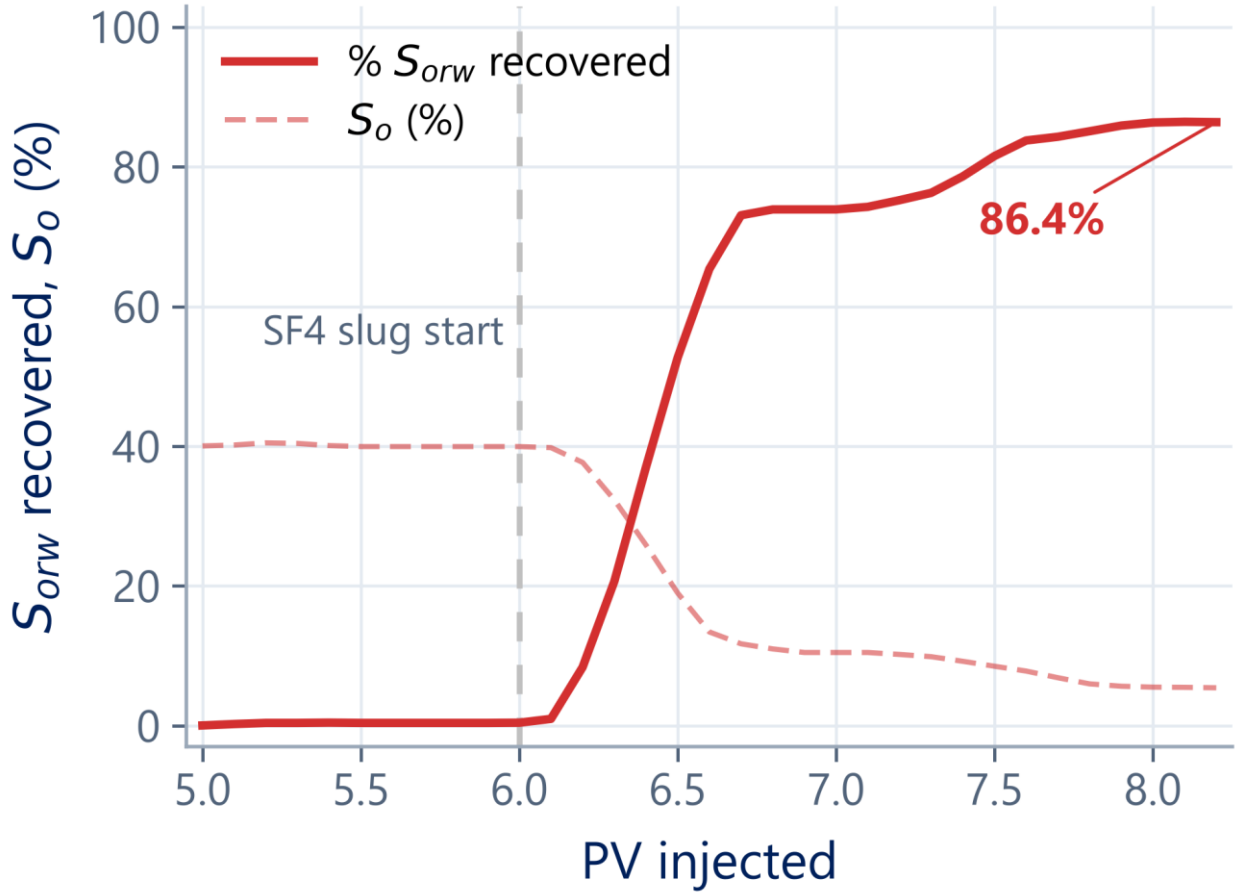
- Spinning drop was measured at 60–90 °C; the 100 °C value is extrapolated by power-law regression, R^2 = 0.9981.
- The Huh correlation at R^* = 12.0 cm³/cm³ gives $\sigma^* = 2.08 \times 10^{-3}$ mN/m.
- Without surfactant the crude/seawater baseline is 21.5 mN/m — four orders of magnitude higher.
- The two routes converge because S^* and the seawater salinity nearly coincide.

03

What the corefloods returned

Two floods at 100 °C, surfactant only — no polymer and no alkali. Recovery, retention, and the salinity-gradient post-flush that closed the gap.

Surfactant alone mobilized 86.4 % of S_{orw}



Percentage of S_{orw} recovered (solid) and S_o (dashed) against pore volumes injected, Core-2 (SN7), reservoir carbonate, k_w = 4.42 mD, S_{orw} = 40.0 %. Dashed vertical: start of the SF4 slug at 6.0 PV.

WHAT IT SHOWS

86.4 % of S_{orw} recovered and S_{orc} falls to 5.43 %, at k_w = 4.42 mD.

- Reservoir carbonate at 100 °C: seawater pre-flush, then a 1.0 PV SF4 slug to zero oil cut.
- 73.8 % of S_{orw} was mobilized during the slug alone; the rest came in the post-flush.
- ΔP rose from a 5.50 psi baseline to 14.85 psi at 6.51 PV, then returned toward baseline.
- $N_c \approx 2.0 \times 10^{-3}$, one to two orders of magnitude above the trapping-curve plateau.

manuscript Fig. 7 and Table 7 · workbook sheet Coreflood SN7 (F7) · 100 °C, 0.25 cm³/min, 200 psi back-pressure

DYNAMIC RETENTION

The salinity-gradient post-flush brought retention into the band

Post-flush salinity steps: 43,373 → 20,000 → 10,000 ppm TDS after the slug. Material balance closes within ± 5 %.

FIELD-FEASIBILITY BAND

0.1 – 0.2 mg/g-rock

Screening threshold for a field candidate

MEASURED, BOTH FLOODS

0.16 – 0.17 mg/g-rock

After the stepwise salinity post-flush

STATIC, CRUSHED ROCK

0.78 – 0.87 mg/g-rock

At 100 °C — a complementary screening metric, not a substitute for dynamic retention

Core	k_w (mD)	Γ after slug (mg/g-rock)	Γ after post-flush	Desorbed (% of retained)
Core-1 · Indiana limestone	27.0	0.23	0.16	30.4
Core-2 · reservoir carbonate	4.42	0.21	0.17	19.0

Source: manuscript p.9 and Table 7 (p.9); workbook sheets Coreflood A10 (F6) and SN7 (F7).

BENCHMARK

86.4 % against 92.0 %, at one-sixth the retention

Ten published carbonate corefloods were compared; three report 11 mD or less. The higher-recovery cases used surfactant–polymer (SP) or alkali–surfactant–polymer (ASP).

Study	k (mD)	T (°C)	Recovery (% of S_{orw})	Γ (mg/g-rock)
This work · Core-2 · surfactant only	4.42	100	86.4	0.17
Jabbar et al. · SP	6.3	98	92.0	1.00
Lu et al.	6	100	66.0	0.086
Parra et al.	11	78	69.4	not reported
Abalkhail et al. · ASP	181.7	100	93.6	0.083

Source: manuscript Table 9 (p.12-13) and p.13; published cases as cited there. Two of the ten rows report no retention value.

IMPLICATION

Displacement and interfacial tension are settled by measurement. Retention is the quantity that still has to be priced.

86.4 % of S_{orw} at 4.42 mD with Γ = 0.17 mg/g-rock, and 76.1 % at 27.0 mD with Γ = 0.16 mg/g-rock. Neither flood carried polymer or alkali, and both retention values sit inside the 0.1–0.2 mg/g-rock band.

RECOVERY, CORE-2

86.4 %

of S_{orw}, reservoir carbonate at 4.42 mD

DYNAMIC RETENTION

0.17 mg/g-rock

Inside the 0.1–0.2 mg/g-rock band

CHEMICAL SYSTEM

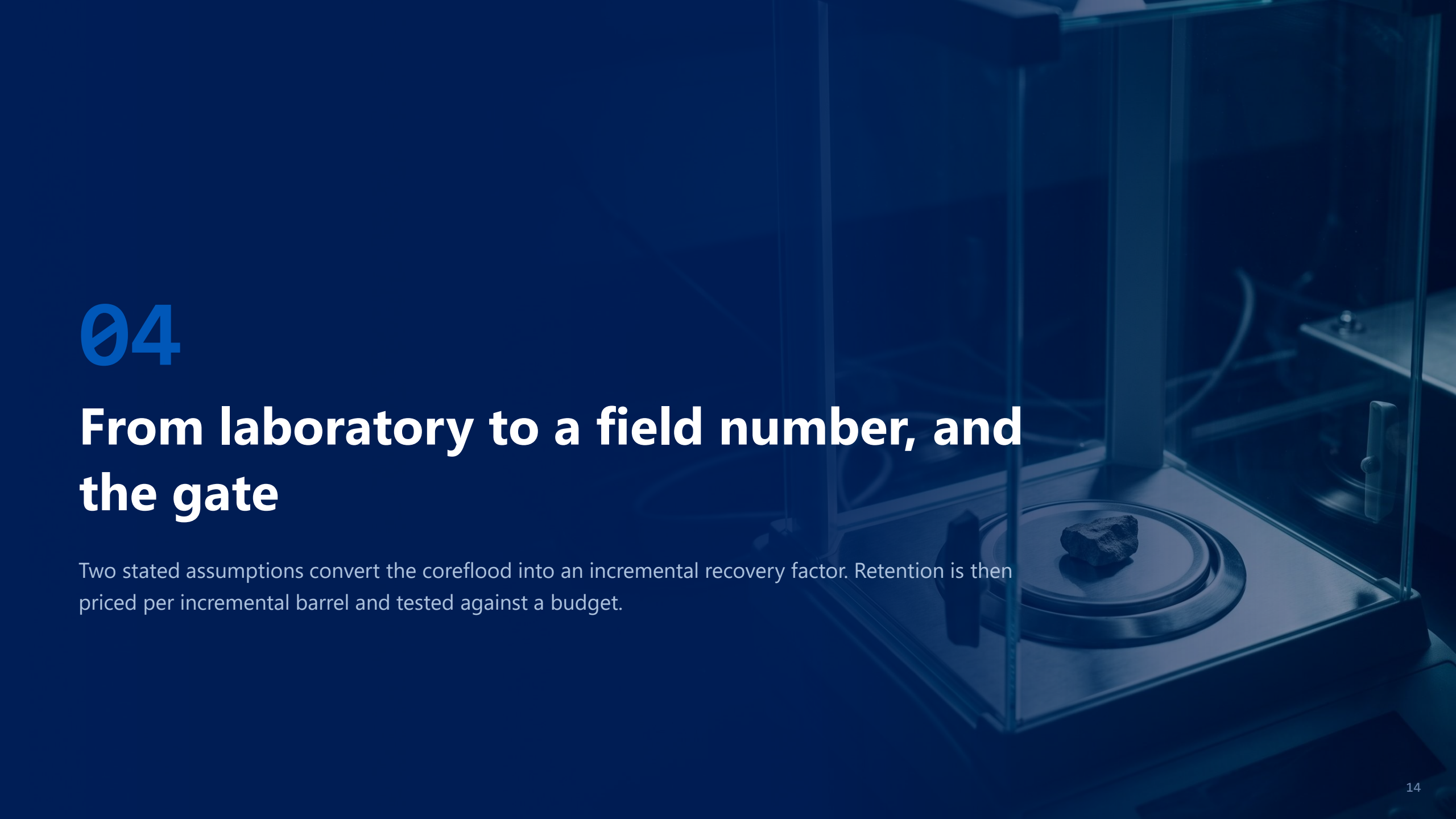
Surfactant only

No polymer, no alkali in either flood

04

From laboratory to a field number, and the gate

Two stated assumptions convert the coreflood into an incremental recovery factor. Retention is then priced per incremental barrel and tested against a budget.



FIELD TRANSLATION

Two assumptions convert the coreflood into a field number

Only Core-2 is upscaled; it is the only reservoir rock in the dataset. Recovery is quoted against original oil in place (OOIP).

$$RF_{inc} = min(RF_{lab} \cdot (S_{orw} / S_{oi}) \cdot E_v , \; RF_{tech})$$

RF_{lab} = 0.864, measured on Core-2 · S_{orw}/S_{oi} = 0.50, maturity ratio, assumed · E_v = 0.60, volumetric sweep efficiency, assumed and conditional on polymer-assisted sweep · RF_{tech} = 30 % OOIP, the volumetric ceiling

LABORATORY RECOVERY

0.864

RF_{lab} — fraction of S_{orw} mobilized in Core-2 (measured)

MATURITY RATIO

0.50

S_{orw}/S_{oi} — assumed, from sector ranges S_{oi} 0.70–0.80 and S_{orw} 0.35–0.40

SWEEP EFFICIENCY

0.60

E_v — assumed, conditional on polymer-assisted sweep, which these floods do not establish

INCREMENTAL RECOVERY

25.9 % OOIP

RF_{inc} — against a volumetric ceiling of 30 % OOIP

Source: manuscript p.14, Eq. (8); workbook sheet Assumptions & Parameters rows 11-15.

RETENTION COST

Retained surfactant costs 5.69 USD per incremental bbl

The gate prices retained surfactant only — not polymer, alkali, water handling or facilities. It is a retention gate, not a project cost estimate.

$$C_{ret} = (P_s \cdot M_{loss}) / Q_{inc}$$

C_{ret} = retention cost (USD per incremental bbl) · P_s = surfactant purchase price, active basis (USD/lb) · M_{loss} = retained surfactant mass (lb per incremental bbl) · Q_{inc} = one incremental bbl, by construction

1

Contacted rock

One incremental bbl at 25.9 % OOIP implies 3.86 STB in place, 6.62 RB of pore volume and 30.1 RB of bulk rock at φ = 0.220.

m_{rock} = 22,300 lb

2

Retained mass

Γ_{base} = 0.17 mg/g-rock is 1.7×10^{-4} lb per lb of rock across that mass.

M_{loss} = 3.79 lb

3

Retention cost

Priced at a surfactant purchase price of 1.50 USD/lb on an active basis.

C_{ret} = 5.69 USD/inc. bbl

4

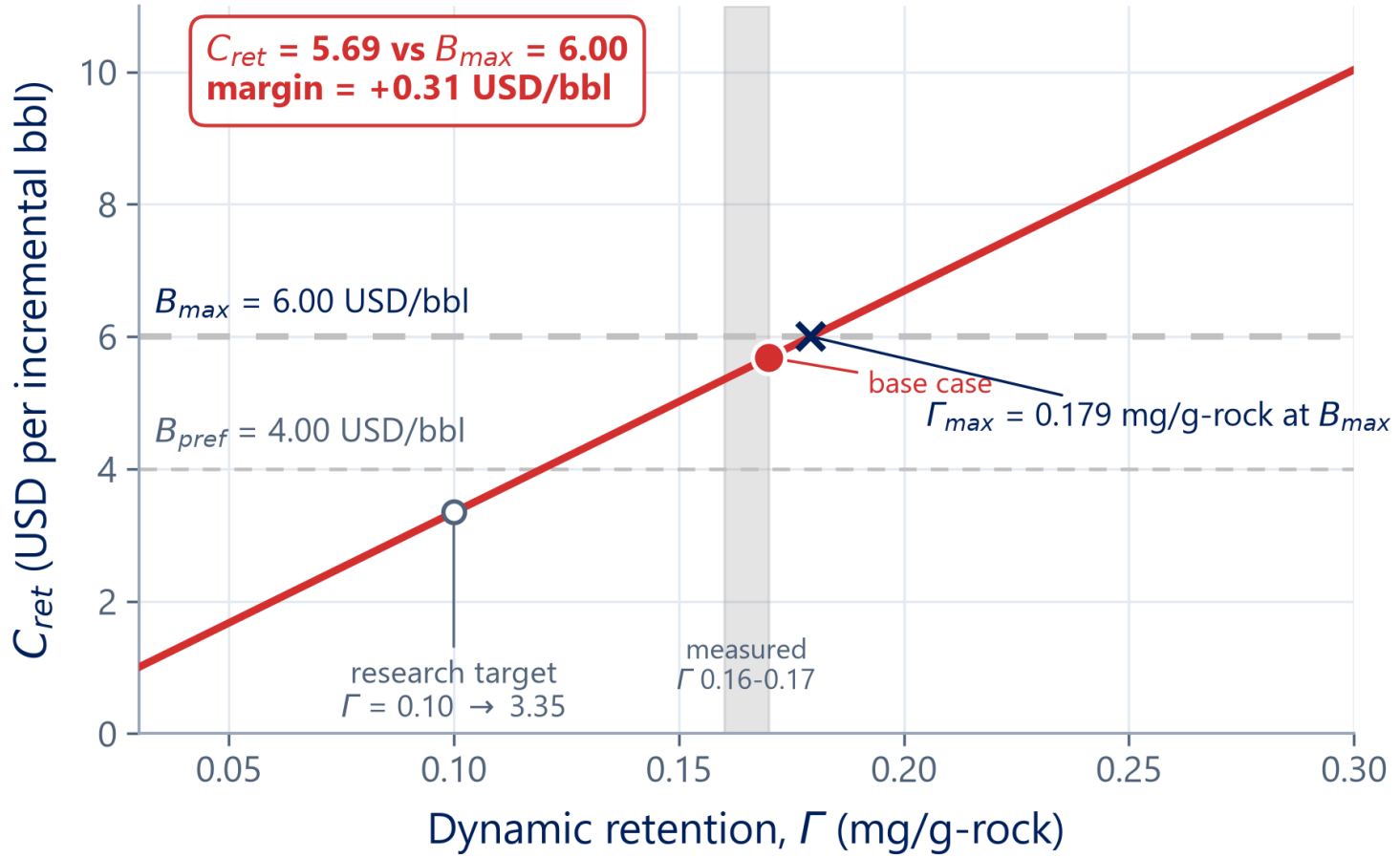
Gate

Tested against a retention budget of 6.00 USD per incremental bbl.

Margin = +0.31 USD/inc. bbl

Source: manuscript p.14, Eq. (9) and derivation chain; workbook sheet Assumptions & Parameters rows 19-24, 31-36.

The gate passes by 0.31 USD per incremental bbl



C_{ret} (USD per incremental bbl) against dynamic retention Γ (mg/g-rock), Eq. (10). Grey band: measured retention, 0.16 to 0.17. Silver dashed: budget ceilings B_{max} = 6.00 and B_{pref} = 4.00.

WHAT IT SHOWS

C_{ret} = 5.69 clears the retention budget B_{max} = 6.00 by 0.31 USD per incremental bbl.

- C_{ret} is linear in Γ, so the gate inverts: Γ_{max} = 0.179 mg/g-rock at B_{max} = 6.00.
- Measured retention is 0.16 and 0.17 mg/g-rock, against that 0.179 ceiling.
- At the preferred budget B_{pref} = 4.00, the ceiling falls to 0.120 mg/g-rock.
- The margin is 5 % of the budget. It is the whole of the screening decision.

THE DECISION

The screening gate passes on a margin of 0.31 USD per incremental bbl.

C_{ret} = 5.69 against B_{max} = 6.00, on assumptions of E_v = 0.60 and P_s = 1.50 USD/lb. A 5 % movement in either consumes the margin: the gate fails below a sweep efficiency of about 0.57, and above a surfactant price of 1.58 USD/lb.

RETENTION COST

5.69 USD/inc. bbl

C_{ret} at Γ = 0.17 mg/g-rock

BUDGET CEILING

6.00 USD/inc. bbl

B_{max}, the screening budget

MARGIN

0.31 USD/inc. bbl

5 % of the budget

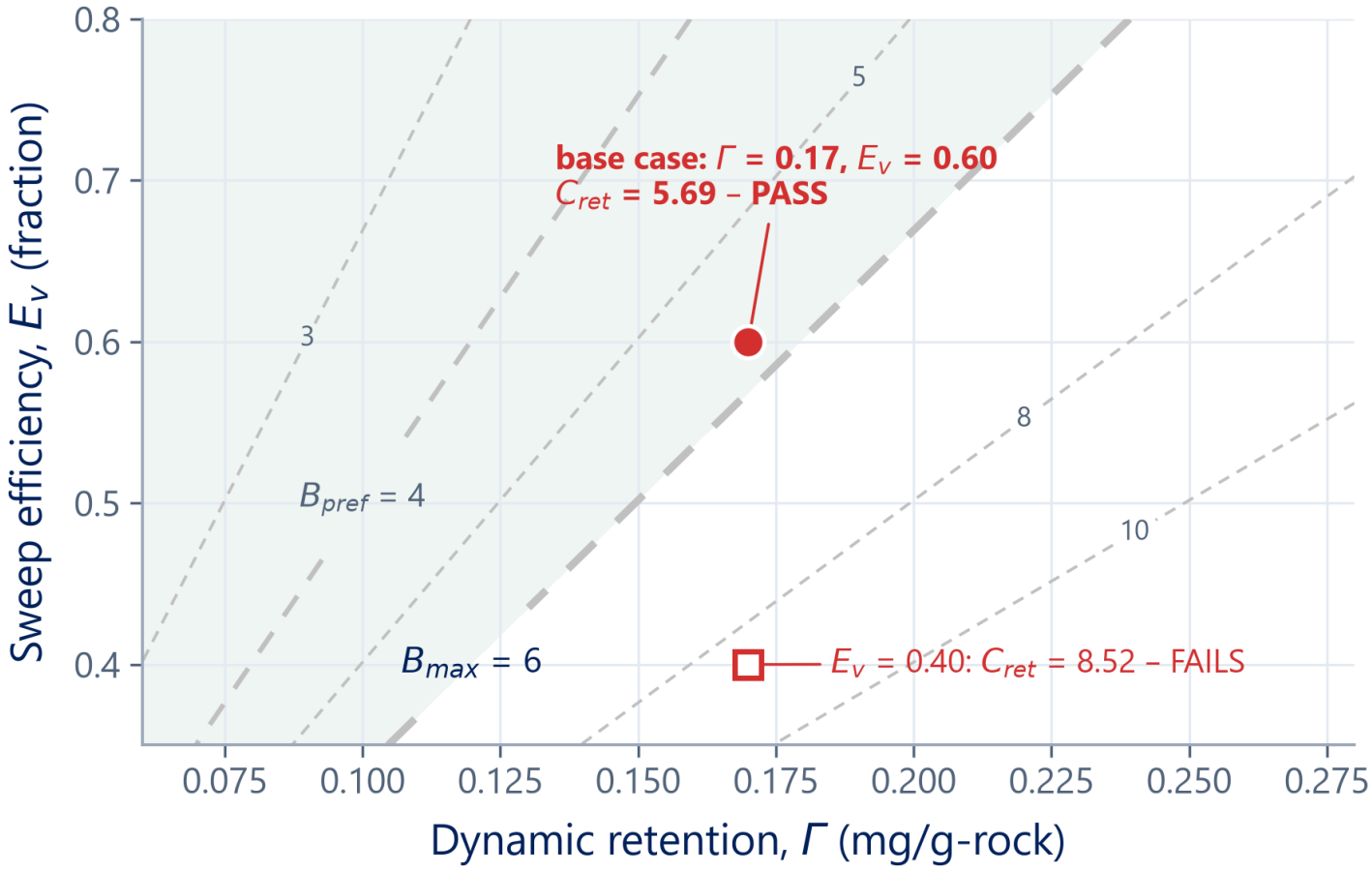
05

Where the remaining margin can be moved

Retention cost is linear in Γ. Sweep and chemistry draw on the same 0.31 USD per incremental barrel.

RESPONSE MAP

Sweep and retention compete for the same margin



C_{ret} = КГР$_s$/E_v contoured over Γ (horizontal) and E_v (vertical) at P_s = 1.50 USD/lb. Green tint: C_{ret} at or below B_{max} = 6.00. Circle: base case, passes. Square: E_v = 0.40, fails.

WHAT IT SHOWS

At the base retention, the gate fails once E_v falls below about 0.57.

- C_{ret} rises as sweep falls: fewer incremental barrels carry the same retained mass.
- At E_v = 0.40 with Γ held at 0.17, C_{ret} = 8.52 USD per incremental bbl.
- Returning to the boundary there requires Γ = 0.119 mg/g-rock, a cut of about 30 %.
- E_v = 0.60 is conditional on polymer-assisted mobility control, not established here.

manuscript Fig. 10 · workbook sheet Model Equations rows 18-19 · surfactant price 1.50 USD/lb

SCENARIO SCREEN

Cutting retention adds margin; losing sweep removes it

Three cases evaluated through the study's own retention-cost relation. These are screening cases run against the gate, not production forecasts.

Case	Γ (mg/g-rock)	E_v	RF_{inc} (% OOIP)	C_{ret} (USD/inc. bbl)	Gate vs B_{max} = 6
Base case	0.17	0.60	25.9	5.69	Pass
Retention target	0.10	0.60	25.9	3.35	Pass
Sweep downside	0.17	0.40	17.3	8.52	Fail

BASE CASE

+0.31 USD/inc. bbl

Gate margin at Γ = 0.17 and E_v = 0.60

RETENTION TARGET

+2.65 USD/inc. bbl

Gate margin at Γ = 0.10; recovery unchanged at 25.9 % OOIP

SWEEP DOWNSIDE

−2.52 USD/inc. bbl

Gate margin at E_v = 0.40; RF_{inc} falls to 17.3 % OOIP

Source: computed from this study's retention-cost relation, manuscript Eqs. (9)-(11) and p.14-16; case values as reported there. Screening cases, not forecasts.

WHAT WOULD MOVE Γ

Four candidate paths, none of them yet measured

Γ from 0.17 to 0.10 mg/g-rock releases 2.34 USD per incremental bbl — larger than the entire remaining gate margin.

1

Sacrificial agents

Compete for adsorption sites ahead of the surfactant front.

No Γ reduction measured

2

Adsorption suppressors

Salinity-tolerant additives that reduce binding to calcite.

No Γ reduction measured

3

Hybrid alkali

Carbonate-compatible alkali; slug cost scale of about 1 USD/bbl at 0.30 PV and 1 wt %.

≈ 1 USD/inc. bbl

4

Brine and pre-flush design

Softened brine and pre-flush sizing to control the salinity path.

Field pre-flush not sized

- Polymer at 100 °C: E_v = 0.60 rests on mobility control this dataset does not demonstrate.
- Retention as a distribution: field dispersion broadens the salinity transition that drove desorption here.
- Injectivity at field velocity: both floods ran at 0.25 cm^3/min with Re ≈ 0.36, and no rate scan was performed.

Source: manuscript p.15-16 (candidate paths, alkali slug cost) and p.5, p.9, p.14 (measurement gaps).

NEXT STEP

Retention reduction is where the screening decision can be moved

- Fund retention-reduction work: Γ from 0.17 to 0.10 mg/g-rock releases 2.34 USD per incremental bbl, more than the entire remaining gate margin.
- Screen polymer at 100 °C before the sweep assumption is carried into any pilot case; the gate fails below a sweep efficiency of about 0.57.
- Carry retention into pilot evaluation as a distribution: field dispersion broadens the salinity transition that produced the measured desorption.

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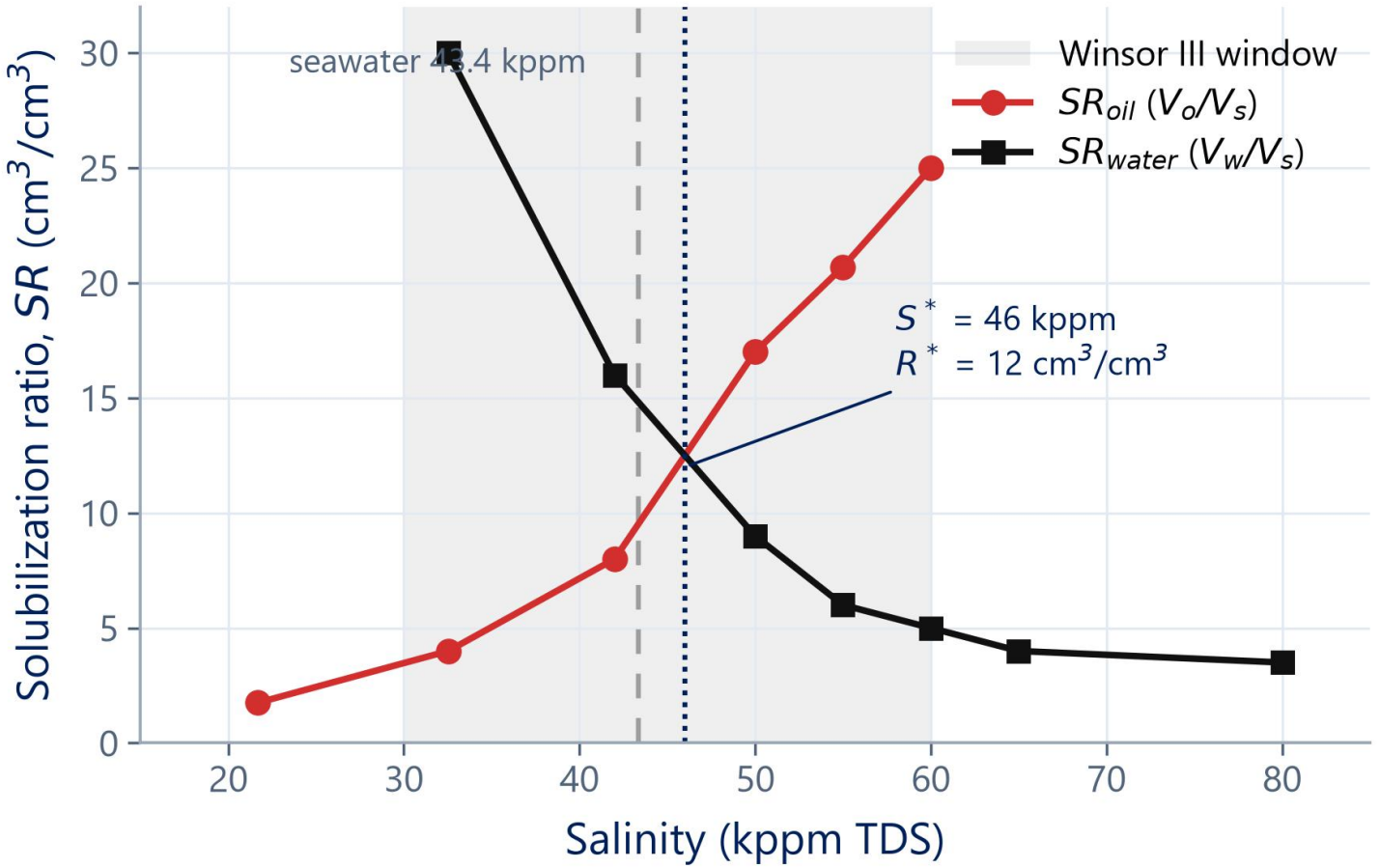
Optimum salinity sits above the injection brine



Solubilization ratio (cm^3/cm^3) against salinity (kppm TDS) for SF4. Squares: water; circles: oil. Shaded band: Winsor Type III window, 30 to 60 kppm. Grey dashed: injection seawater, 43.373 kppm. Dotted: S^* = 46 kppm, R^* = 12.

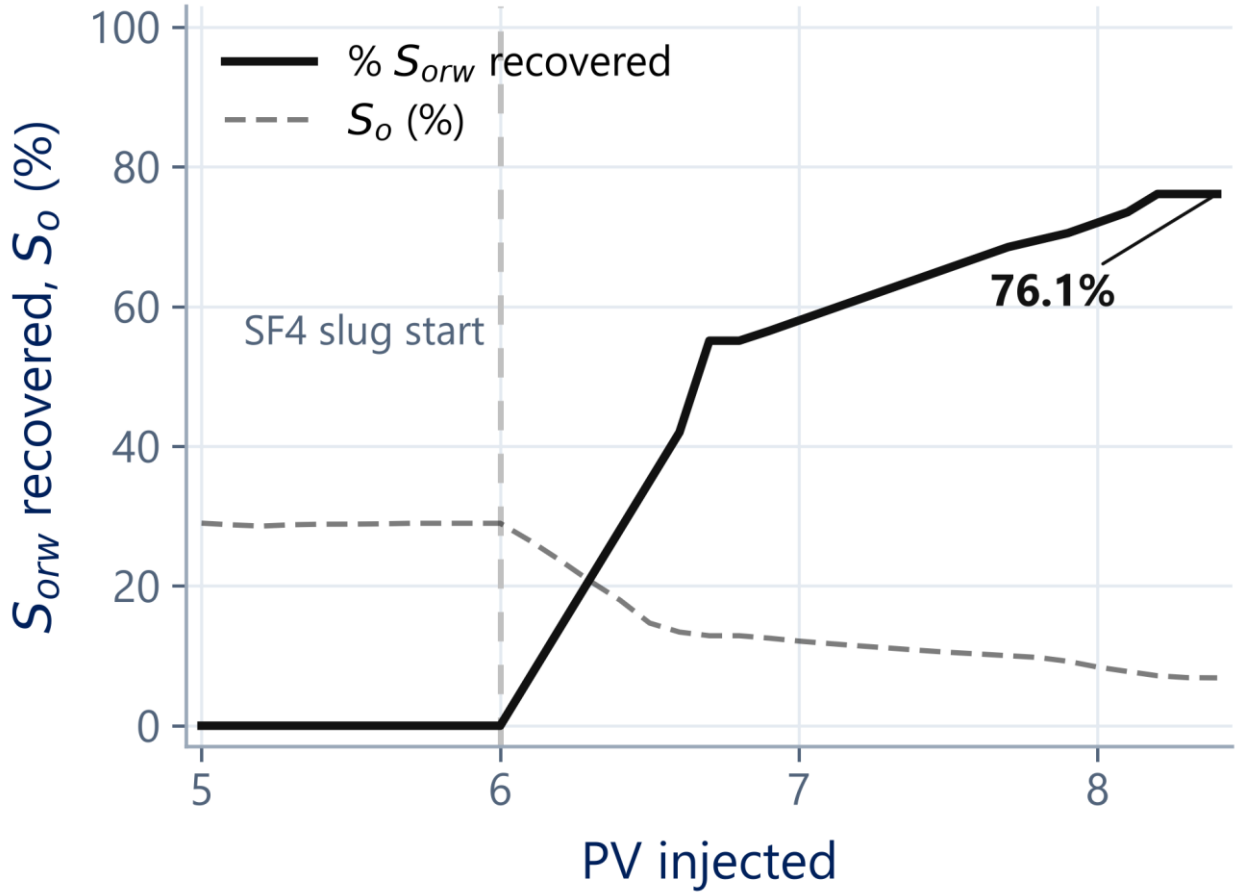
WHAT IT SHOWS

S^* = 46,000 ppm TDS sits 2,600 ppm above seawater, inside the 30,000–60,000 ppm Type III window.

- R^* = 12.0 cm^3/cm^3 at S^*, the highest of the five formulations screened.
- Phase behaviour was equilibrated two weeks at 100 °C.
- The Winsor III window spans 30,000 to 60,000 ppm TDS.

manuscript Fig. 3 and Table 6 · workbook sheet Phase Behavior (F3)

The outcrop plug returned 76.1 % at 27.0 mD



Percentage of S_{orw} recovered (solid) and S_o (dashed) against pore volumes injected, Core-1 (A10), Indiana limestone outcrop, k_w = 27.0 mD, S_{orw} = 30.1 %. Dashed vertical: start of the SF4 slug at 6.0 PV.

WHAT IT SHOWS

76.1 % of S_{orw} recovered and S_{orc} falls to 7.20 %, at k_w = 27.0 mD.

- 0.8 PV SF4 slug to zero oil cut; 55.1 % of S_{orw} came during the slug alone.
- Γ fell from 0.23 to 0.16 mg/g-rock across the salinity-gradient post-flush.
- ΔP rose from a 0.95 psi baseline to 1.70 psi at 6.4 PV.
- Not carried into the field translation — only reservoir rock is upscaled.

manuscript Fig. 6 and Table 7 · workbook sheet Coreflood A10 (F6) · 100 °C, 0.25 cm³/min

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Thank you

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