EAGE

2025 EAGE ANNUAL
86TH CONFERENCE & EXHIBITION
TOULOUSE | FRANCE

BREAKING THE MOLD: REASSESSING POLYMER FLOODING AND THE OUTDATED 'PRIMARY, SECONDARY, TERTIARY' MODEL

Antoine THOMAS - eppok

NAVIGATING CHANGE: GEOSCIENCES SHAPING A SUSTAINABLE TRANSITION

Lay-out

- Introduction
- Status of oil recovery
- Why EOR and why early?
- Secondary vs. tertiary implementation
- Conclusions

IOR/EOR – Secondary/Tertiary

Clear and sound?

SPE 84908

2003 The Alphabet Soup of IOR, EOR and AOR: Effective Communication Requires a Definition of Terms

George J. Stosur, SPE, Petroleum Consultant; J. Roger Hite, SPE, Business Fundamentals Group; Norman F. Carnahan, SPE, Carnahan Corporation; Karl Miller, SPE, Consultant

2024 **Technical Report Provides IOR and EOR Terminology Clarifications and Recommendations for the SPE Community**

The SPE IOR-EOR Terminology Review Committee has released its recommendations for the use of IOR, EOR, and newly introduced term, assisted oil recovery (AOR).

November 8, 2024
Journal of Petroleum Technology

Are the terms important?

From engineering to psychology

Language shape thoughts, perceptions and impact creativity

Decisions impacted by our biases

- Confirmation bias
- Framing
- Loss aversion
- etc.

O&G industry: staged production – why?

- it works and/or we've always done like that?

Status of oil recovery
Where are we?

Primary/Secondary/Tertiary

- Secondary is often water injection, since 1920's

Where are we after 105 years following the same staged production approach?

- 35% recovery on average for conventionals
- 3 to 14 barrels of water produced
- Declining production, increasing emissions

OilPrice.com
177,617 followers
2w •

Global oil markets face a looming supply crunch: just 25–30% of annual oil use is being replaced by new discoveries. As US shale peaks, Saudi Arabia and Venezuela may define the next era—one with fewer, more strategic swing producers. #OilMarkets #EnergyOutlook #OPEC

Has this staged approached been efficient?

Factually

Is it efficient? Is it unexpected?

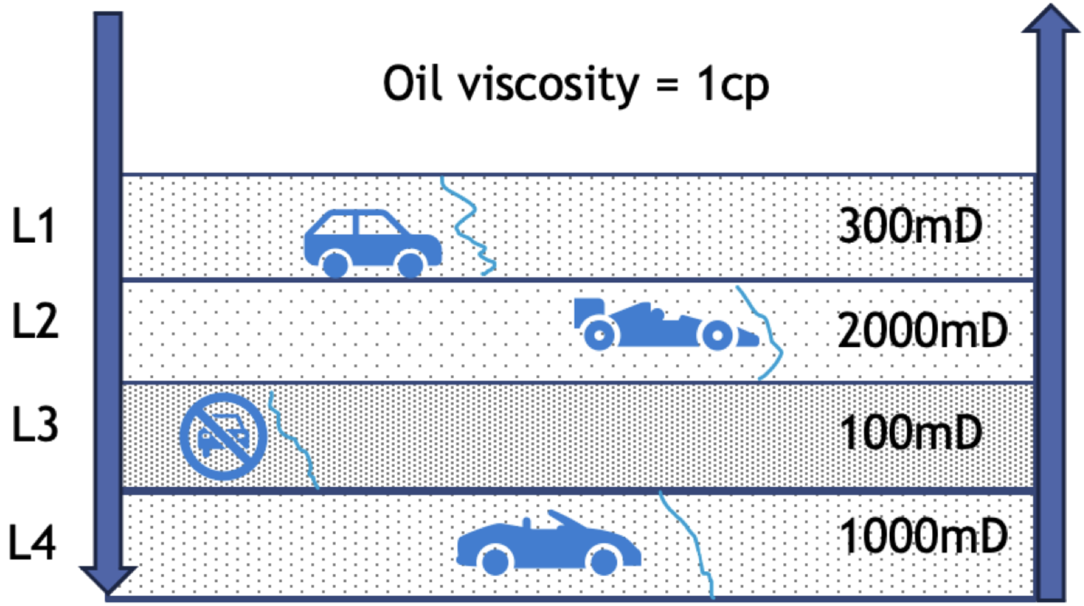
- With 35% recovered, no

Why are the recovery factors low?

- Dealing with a heterogeneous black box
- Fluids follow the path of least resistance

Why do we keep doing it?

- NPV? UTC? Risk? Fear? Lack of expertise?



Lateral view

Excuse n°1

It's risky

Chemical EOR – Polymer Flooding

Field reviews that cover >70 projects over 50 years show ≥ 80 % of polymer floods meet or exceed their incremental-oil target (40 successes, 6 discouraging cases in 72 projects).

Worst-case: chemistry fails, project is stopped and field reverts to profitable waterflood; stranded capex limited to polymer facilities and residual chemical inventory.

Exploration

2023 global high-impact campaign: 64 wells, 13 commercial finds ⇒ 20 % CSR overall; every one of the 7 true frontier-basin tests failed. Norway 2014-23 average CSR 28 %; Barents frontier CSR < 10 % (Westwood)

Dry hole = entire exploration capex written off; no salvage value.

Excuse n°1 bis

It's risky

	Polymer Flood (EOR)	Frontier Wild-Cat**
Probability of success	**0.8**	**0.2**
Incremental / discovery reserves	15 MMbbl	150 MMbbl (mean)
NPV per barrel*	$10	$8
Expected NPV	**$120 MM**	**$240 MM**

Assumes flat $50/bbl crude. ** Woodwest 2023

At first glance the frontier well looks 2× more attractive… but only if

- the find is ≥ 150 MMbbl,
- the fiscal terms stay unchanged for a decade, and
- you're happy with a downside of –$100 MM (a total write-off).

Apply a realistic, risk-averse utility function and that headline advantage disappears fast.

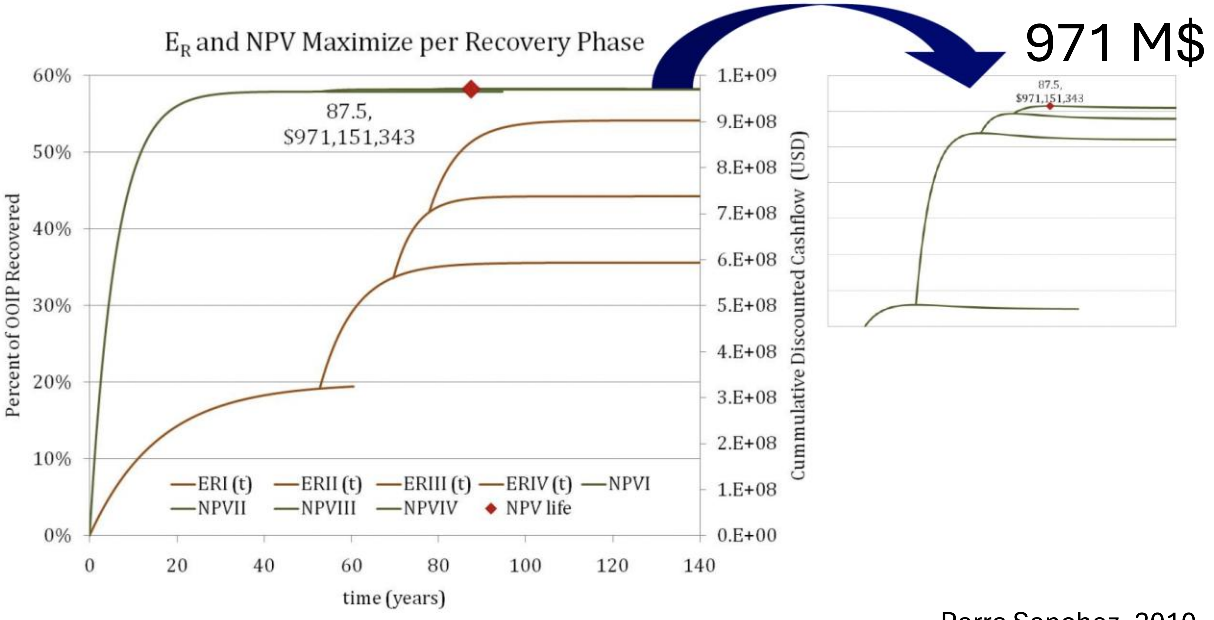
Excuse n°2

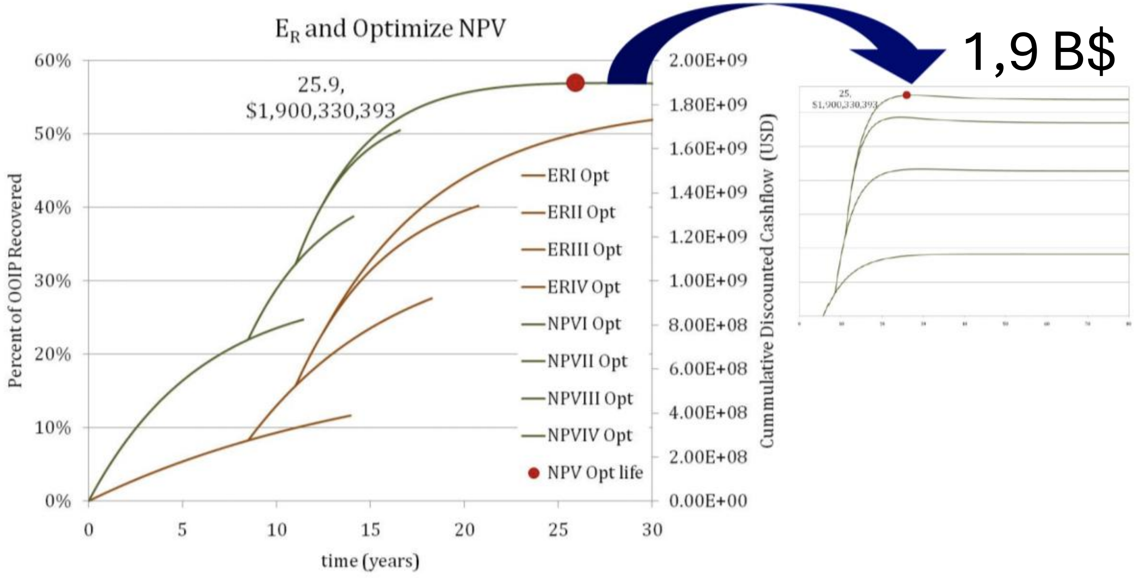
Bad NPV + expensive

Pay now, or pay later

- Why wait to reach low oil saturation to implement more expensive techniques?
- Is it easy and cheap to fix water breakthrough issues?

NPV: optimization over the field's life needed





Parra Sanchez, 2010

Excuse n°3

We need water to understand the reservoir

Engineers often argue that water injection helps to better understand the reservoir

35%

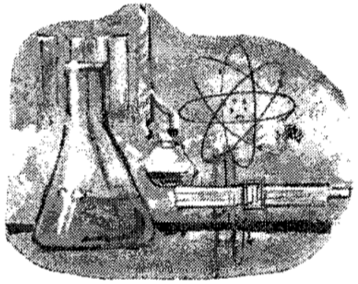
However, if this were true, recovery factors would be much higher after years of water flooding

How much water, to do what?

- Compatibility?
- Fracturing pressure?
- Boundaries?
- Connectivity?

So, why EOR?

A look at the past



RECOVERY
METHODS

The Future Outlook for Tertiary Recovery

I. F. ROEBUCK, JR.
MEMBER AIME

CORE LABORATORIES, INC.
DALLAS, TEX.

Roebuck, 1961

« On the other hand, it has been estimated that less than one-third of the total original oil in place will be recovered from currently developed reservoirs by primary production and conventional gas and water-injection operations. »

Why EOR?

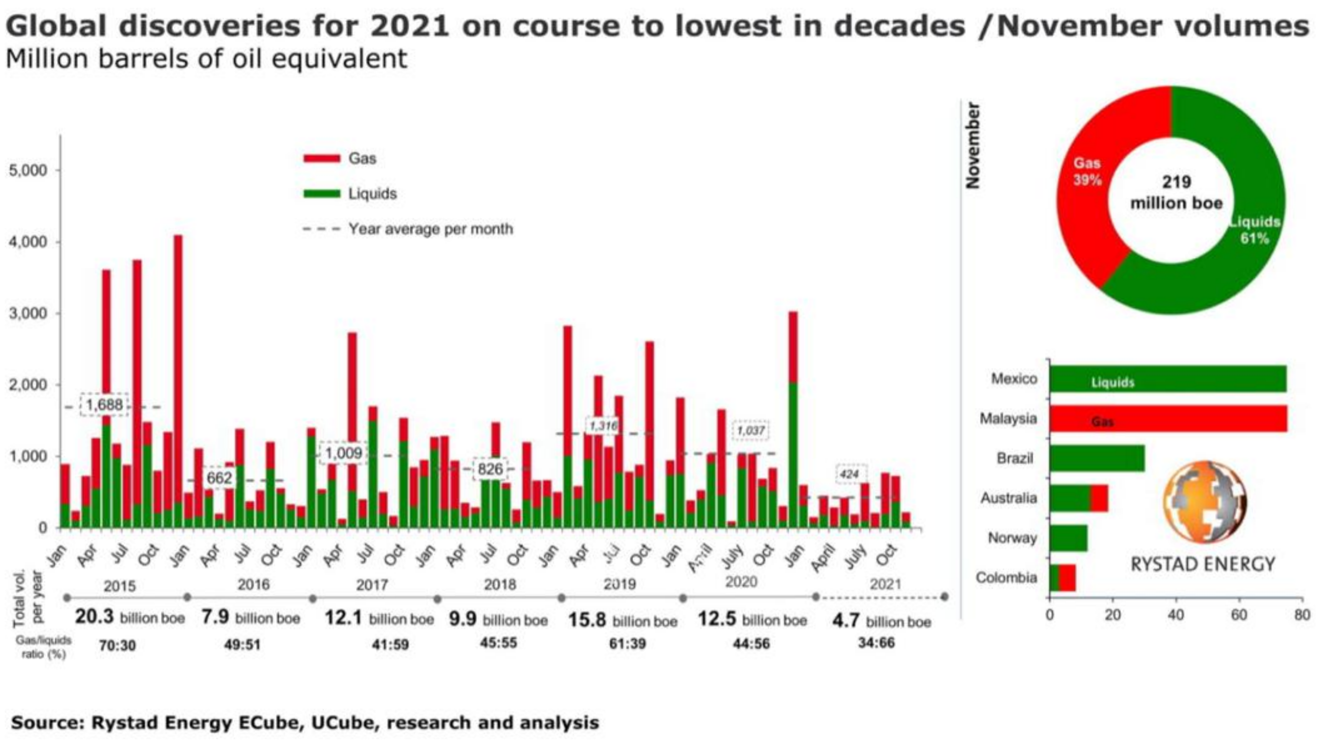
Few reasons

Discoveries decreasing

50+ % of oil left in place

Making the most of the money spent, infrastructure built, wells drilled…

Decreasing water volumes handled and CO2 emissions

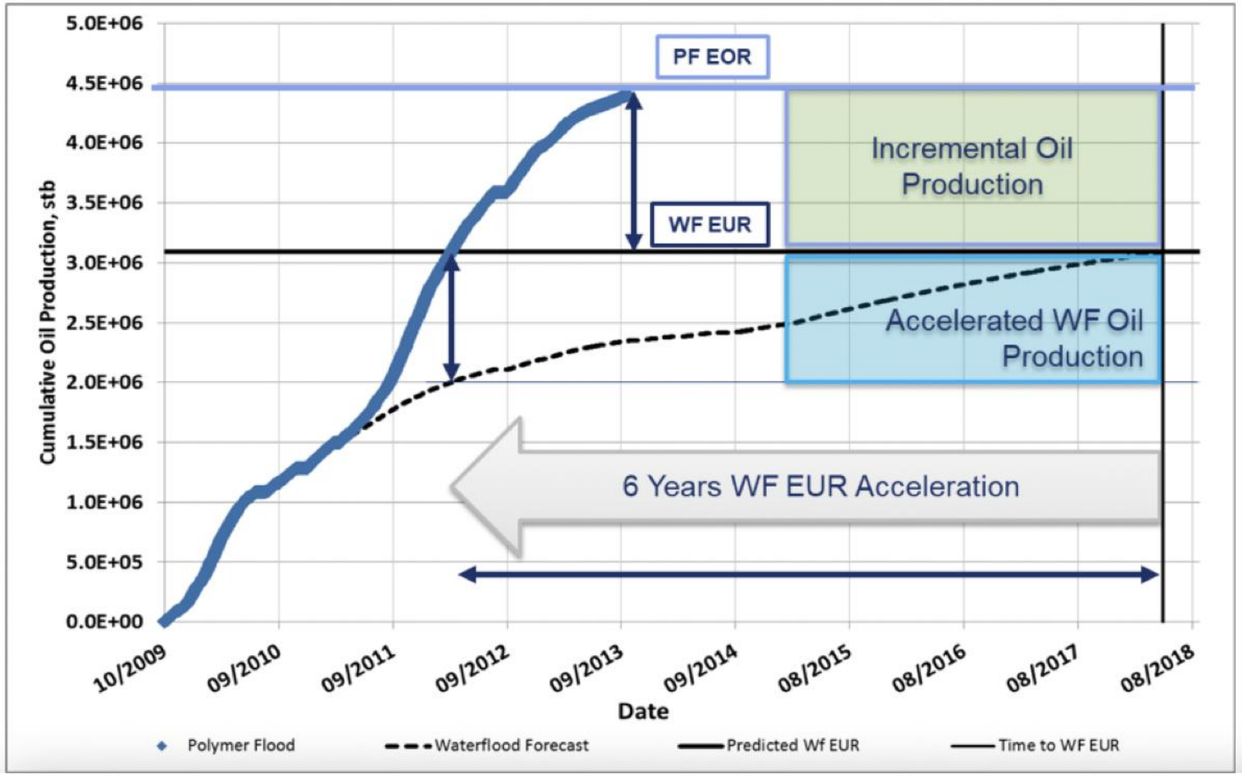


A case for polymer flooding

More oil, faster

Captain – offshore UK

- **Time Acceleration to EUR:** 6 years earlier than waterflood
- **Incremental Oil Recovery:** +1.4 MMSTB (beyond waterflood EUR)
- **Water Handling Reduction:** -25.2 MMSTB compared to waterflood
- **CO_2 Emissions Reduction: 35% lower** vs. **waterflood**



SPE190175

About the implementation timing

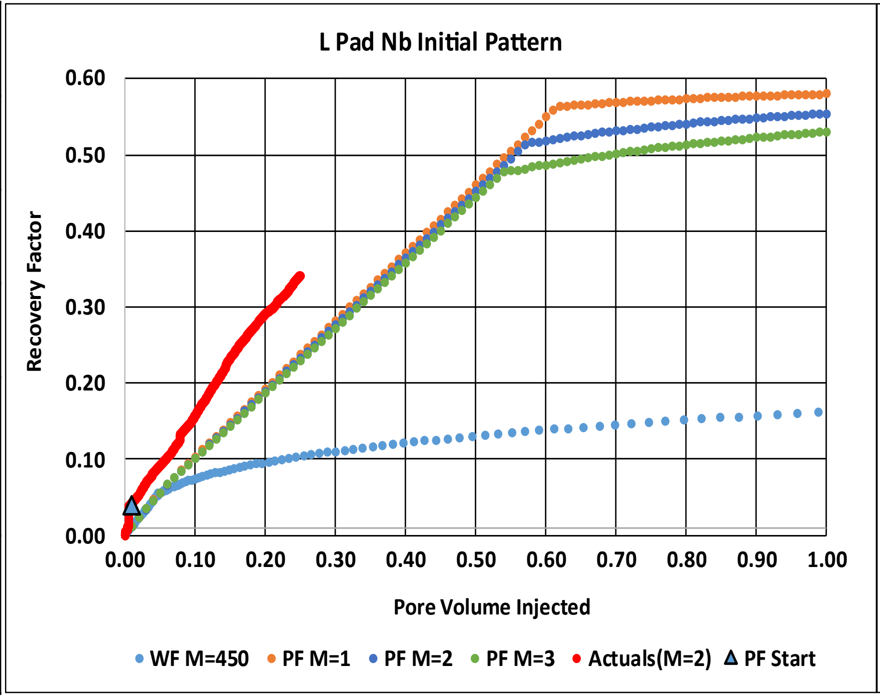
Secondary vs. tertiary

Discussing the timing (even if RE principles gave us the answer)

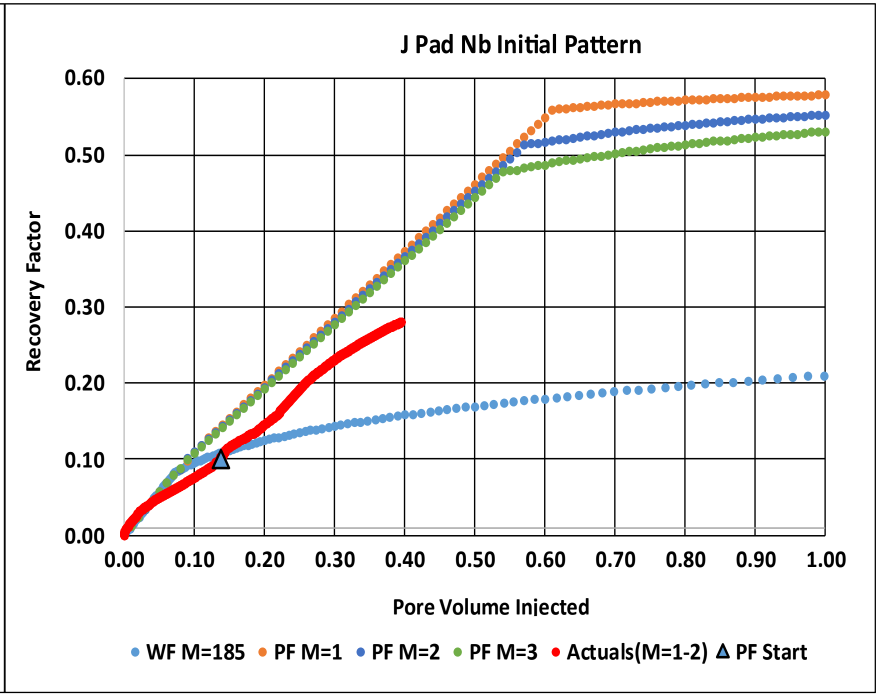
Hilcorp - Milne Point

Aspect	Details
Reservoir Depth (ft)	3600-4000
Temperature (°F)	70-90
Oil Viscosity (cP)	10-1300
Water Salinity (ppm)	25000
Injection Water Salinity (ppm)	3000

SPE218269



Secondary

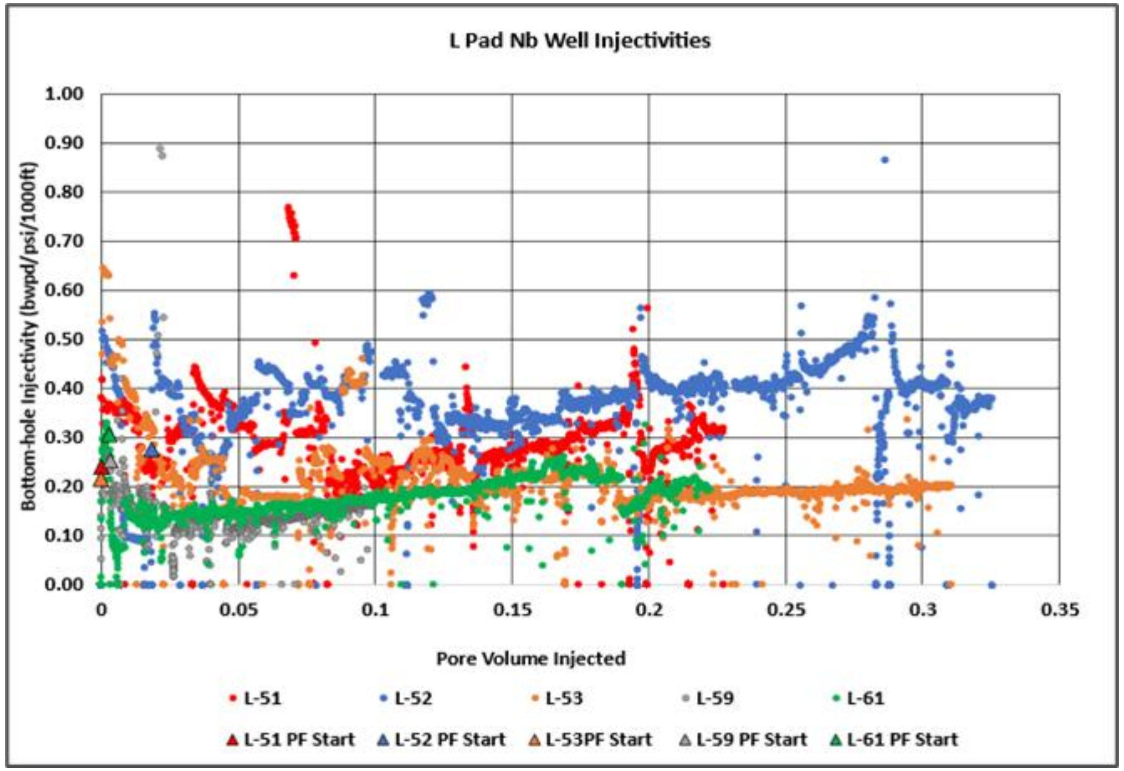


Tertiary

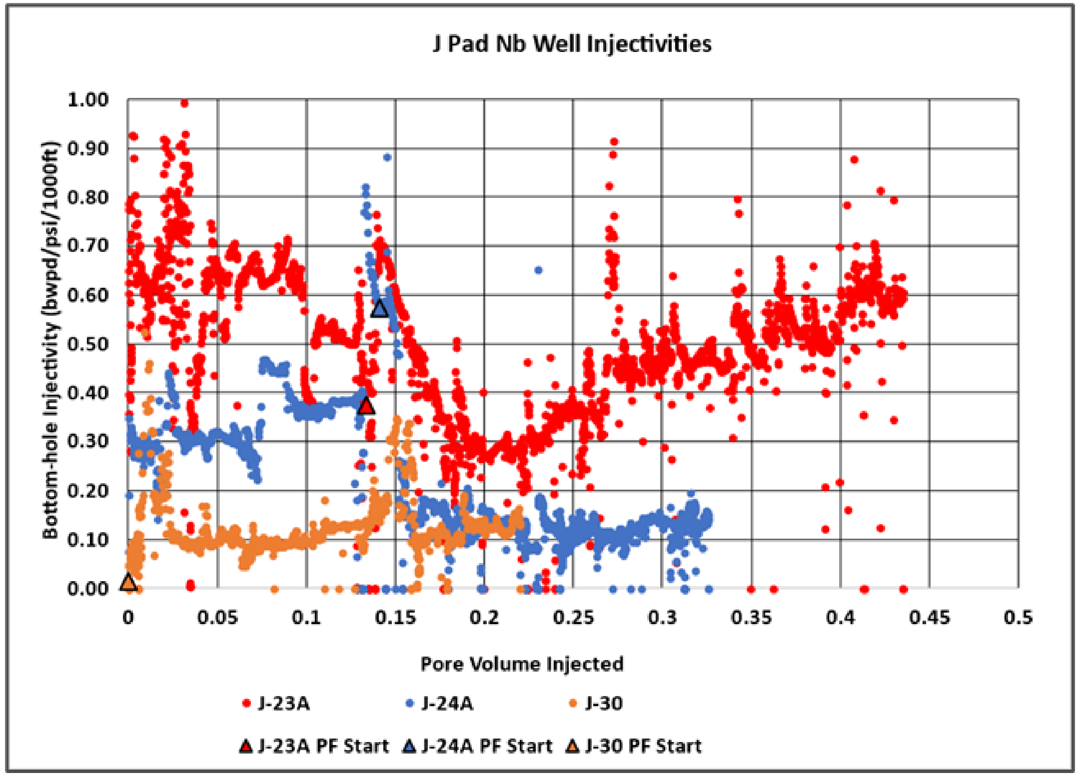
Discussing injectivity concerns

Do we need water injection before?

Discussing injectivity – do we need water injection before?



Secondary



Tertiary

Secondary vs. tertiary

Summary for Hilcorp

Aspect	Secondary Flood	Tertiary Flood
Recovery factor (RF)	Up to 34% (L Pad)	Up to 28% (J Pad)
Water Cut	Low (<10% for up to 21% PVI)	Reduced from high initial values (e.g., 65%-75% down to ~50%)
Injectivity performance	Stable or increased (L Pad)	Decreased by up to 60% (e.g., J Pad)
Pore volume injected (PVI)	Better recovery at lower PVI (e.g., exceeded waterflood RF at 1 PVI with 0.1 PVI polymer)	Moderate efficiency, higher PVI requirements
Injected mobility ratio	0.7–1.9 (optimal)	0.8–2.0 (moderate efficiency)
Oil viscosity range (cP)	85–850 (e.g., L Pad 850 cP)	350–450 (e.g., J Pad 350 cP)
Well spacing	400–800 ft (tighter spacing improves efficiency)	800–1100 ft (wider spacing reduces efficiency)
Throughput efficiency	3x higher throughput in tighter spacing (e.g., M Pad Oa North)	Lower throughput due to spacing and injectivity losses
Notable observations	Early application avoids hysteresis; maintains low water cut	Demonstrated recovery potential even after waterflood inefficiencies

SPE218269

Conclusions

After 105 years of staged production, there is likely sufficient data to predict the outcome of the staged approach Primary/Secondary/Tertiary where Secondary consists in injecting water in heterogeneous reservoirs: 35% RF

Field cases like Hilcorp, Pelican Lake, show secondary works better than tertiary

From a pure risk-adjusted economic standpoint, polymer flooding in a known reservoir consistently beats drilling a wild-cat in untested acreage. The industry's contrary intuition comes from cognitive biases, mis-aligned incentives, and the seductive narrative of "big-elephant" exploration, not from the underlying statistics

Can we do better? Do we want to? Or is it fine with everyone?

Thank you for your attention

Questions?

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