# SPE 179543

## How Much Polymer Should Be Injected during a Polymer Flood?

# Bottom Line

1. Base-case method: $F_r = M * k_1/k_2$. (You must be realistic about your choices of mobility ratio and perm contrast.)
2. Injection above the formation parting pressure and fracture extension are crucial to achieving acceptable injectivity—especially for vertical injectors—increasing injectivity, sweep efficiency, and reducing mechanical degradation. The key is to understand the degree of fracture extension so that fractures do not extend out of zone or cause severe channeling.
3. Many field cases exist (Daqing, Suriname, Canadian floods) with no evidence that fractures caused severe polymer channeling or breaching the reservoir seals, in spite of injection significantly above the formation parting pressure.
4. Experience and technical considerations favor using the largest practical polymer bank. Channeling can be severe when water injection occurs after polymer injection.
5. Although graded banks are commonly used or planned in field applications, more work is needed to demonstrate their utility and to identify the most appropriate design procedure.

# What polymer viscosity/concentrations were used in the past?

**1960-1980: (Manning *et al*. 1983)**

**MEDIAN VALUES: 250-260 ppm HPAM (2-10 cp); 17%PV**

**Why so little? Because of an incorrect belief that HPAM provides a significant permeability reduction in a reservoir (either resistance factor is >2X viscosity or residual resistance factor is >2).**

**Why is this belief wrong?**

1. **The very high Mw part of HPAM that causes this effect is destroyed by mechanical degradation and removed by flow through a few feet of porous rock. So it will not materialize deep in a reservoir.**
2. **During brine injection to displace polymer, the effect is usually seen because of insufficient flushing of lab cores.**

# What polymer viscosity/concentrations were used in the past?

**1980-1990: (Seright 1993)**

**MEDIAN VALUES: 460 ppm HPAM (5-10 cp); 10% PV**

**Category 1:** **Legitimate polymer floods typically using 1000-1500 ppm HPAM and 25-100% PV.**

**Category 2:** **Tax floods whose only goal was to achieve a reduction from the Windfall Profits Tax Act of 1980. Very little polymer. Very little engineering. Very little project surveillance.**

**Consequence**

**"Statistical analysis" of polymer floods from this period lead to the erroneous conclusion that polymer flooding is applicable in virtually every conventional oil reservoir (SPE 168220).**

# What polymer concentrations, viscosities, and bank sizes were used in the past?

**1960-1980: (Manning *et al*. 1983)**
**MEDIANS: 250-260 ppm HPAM; 6 cp; 17%PV**
**1980-1990: (Seright 1993)**
**MEDIANS: 460 ppm HPAM; 8 cp; 10%PV**

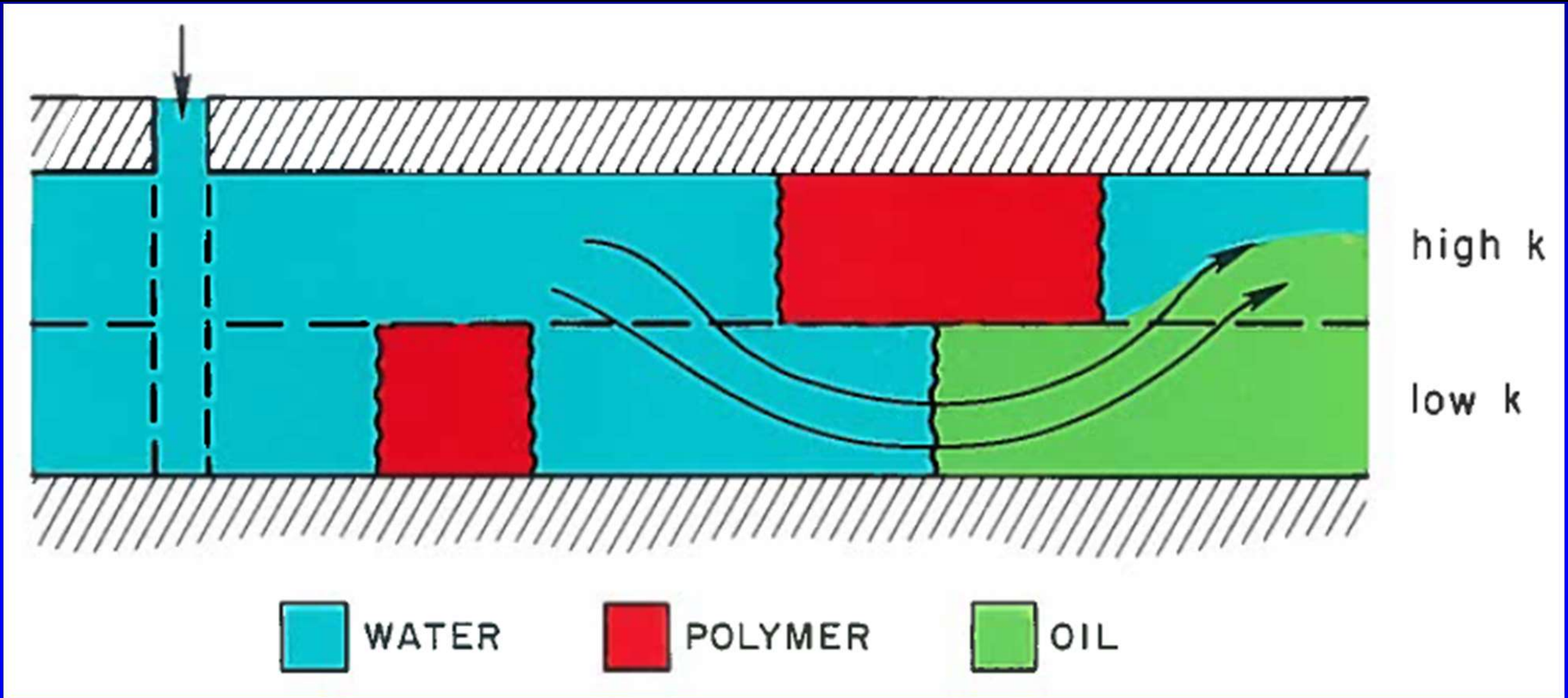
## Why so little?

1. An incorrect belief that HPAM reduced permeability substantially, even in high-permeability strata.

2. An incorrect belief that water injected after the polymer would be diverted into and displace oil from low-permeability strata.

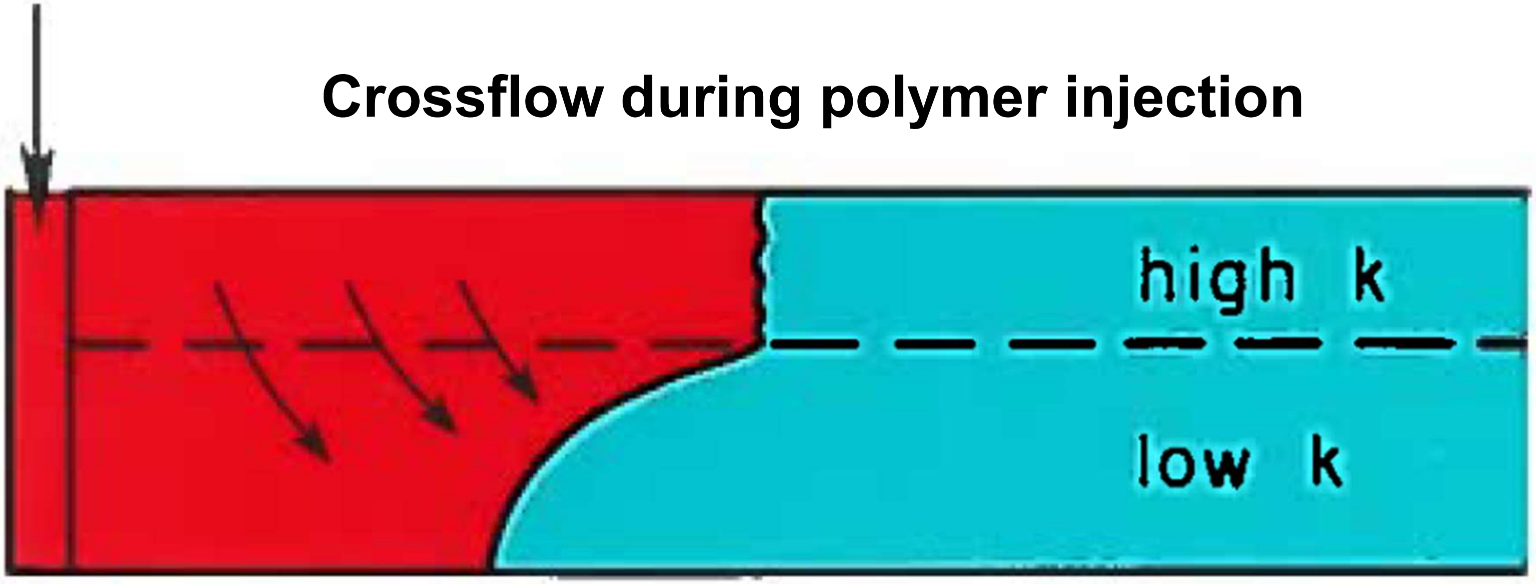
**1990-present: MEDIANS: 1400 ppm HPAM; 30 cp; 50%PV**

# INCORRECT VIEW OF POLYMER FLOODING




- **If this view was correct, we could use very small polymer banks and not worry so much about polymer degradation.**
- **This incorrect view is still being pushed in recent publications.**

## Crossflow during polymer injection

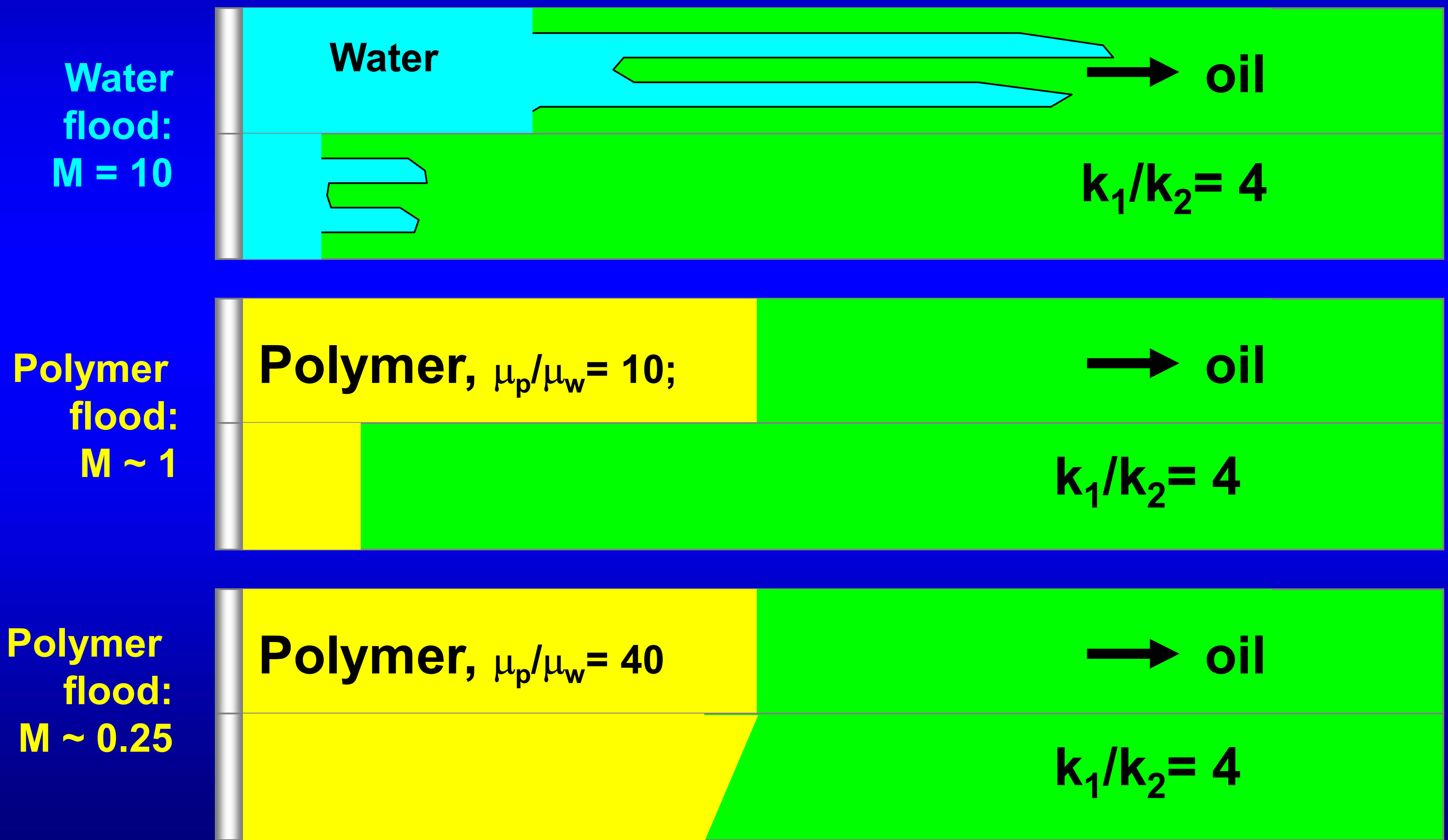



**Viscous fingering during water injection after polymer:**

**In which place will water fingers break through the polymer bank? IN THE HIGH-K PATH!**

# SELECTION OF POLYMER VISCOSITY

- Want to make the water flood mobility ratio favorable.
- Want to overcome the permeability contrast.



**Needed Resistance Factor =**
**(Mobility Contrast) x (Permeability Contrast)**

**Simplified Conversion From Dystra-Parsons Coefficient of Permeability Variation ($K_v$) to Permeability Contrast ($k_{cont}$ or $k_1/k_2$)**

| $K_v$ | $k_{cont}$ or $k_1/k_2$ |
|---|---|
| 0.4 | 2 |
| 0.5 | 2.5 |
| 0.6 | 3.5 |
| 0.7 | 5.1 |
| 0.8 | 8.8 |
| 0.9 | 23 |

**Must have clearly identifiable zones.**

# Recent Polymer Floods

| Field | $C_{poly}$, ppm | $\mu_{poly}$, cp | $\mu_o$ @ Res. T, cp |
|---|---|---|---|
| Daqing, China (1996-~2008) | 1000-1300 | 40-50 | 9-10 |
| Daqing, China (~2008-2015) | 2000-2500 | 150-300 | 9-10 |
| Gudao/Shengli, China | 2000 | 25-35 | 50-150 |
| Shengtao/Shengli, China | 1800 | 30-50 | 10-40 |
| ShuangHe, China | 1090 | 93 | 7.8 |
| Bohai Bai, China | 1200-2500 | 98 | 30-450 |
| Pelican Lake, Canada | 600-3000 | 13-50 | 1000-3000 |
| East Bodo, Canada | 1500 | 50-60 | 417-2000 |
| Mooney, Canada | 1500 | 20-30 | 100-250 |
| Seal, Canada | 1000-1500 | 25-45 | 3000-7000 |
| Suffield Caen, Canada | 1300 | 32 | 69-99 |
| Wainwright, Canada | 2100-3000 | 25 | 100-200 |
| Dalia, Angola | 900 | 3 | 1-11 |
| Diadema, Argentina | 1500-3000 | 15-40 | 100 |
| El Corcobo, Argentina | 1000 | 20-25 | 160-300 |
| Matzen, Austria | 900 | 10 | 19 |
| Canto do Amaro, Brazil | 1000 | 30 | 50 |
| Carmopolis, Brazil | 500 | 40 | 10.5 |
| Buracica, Brazil | 500 | 10 | 7-20 |
| Bockstedt, Germany | 300 (biopoly) | 25 | 11-29 |
| Mangala, India | 2000-2500 | 20 | 9-22 |
| Marmul, Oman | 1000 | 15 | 80-90 |
| Tambaredjo, Suriname | 1000-2500 | 45-140 | 325-2209 |

# Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-case Calculation?

**"Relative permeabilities allow much more favorable displacement than expected."**

**"Resistance factor & residual resistance factor limit the need for viscous polymer solutions."**

**"Viscous solutions reduce injectivity too much."**
**"Viscous solutions cause fracture channeling."**
**"Viscous solutions cause flow out of zone."**

**"Economics limit polymer concentrations."**

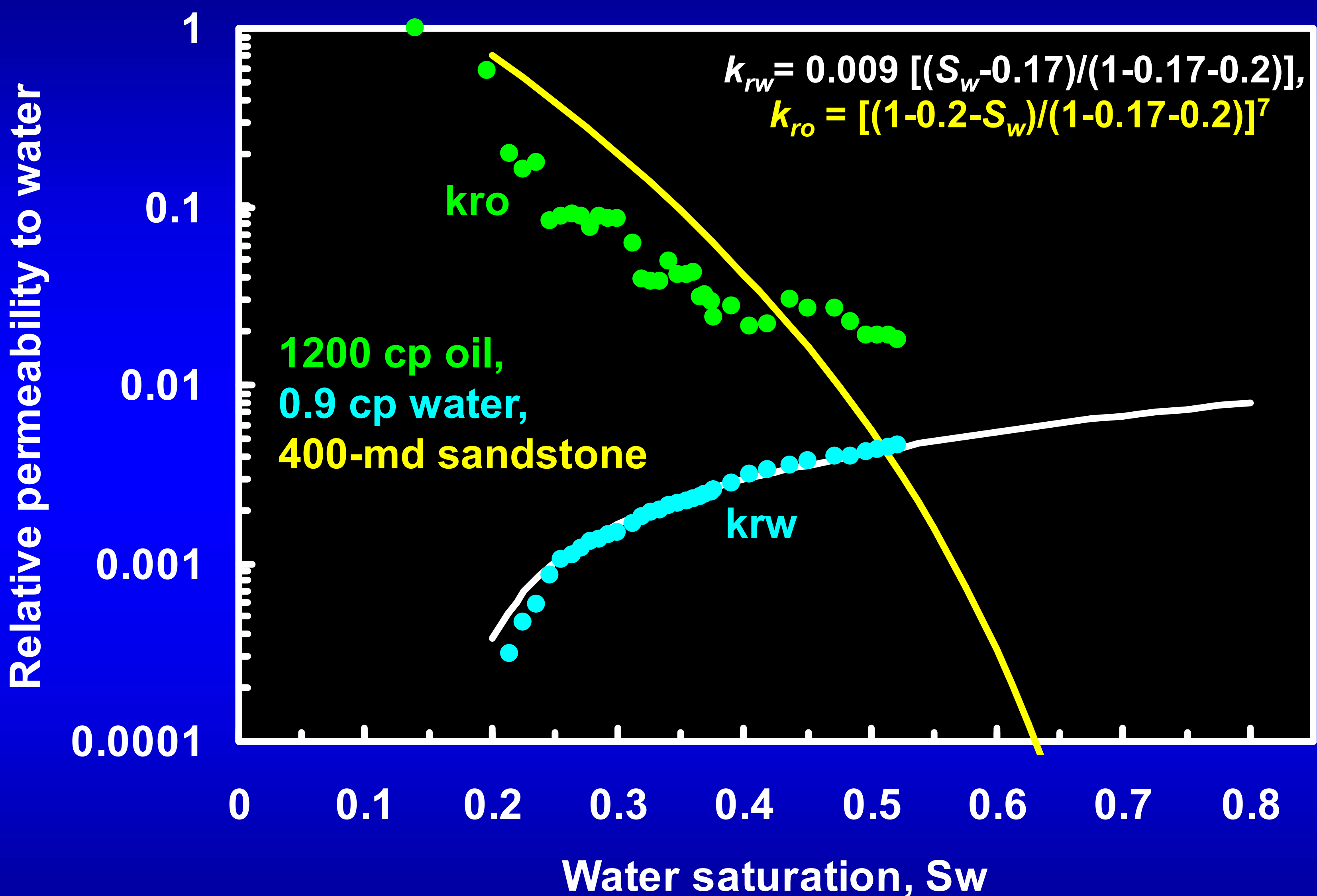
## Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-Case Calculation?

"Relative permeabilities allow much more favorable displacement than expected."

If true, this is a good reason to choose low polymer concentrations, BUT …

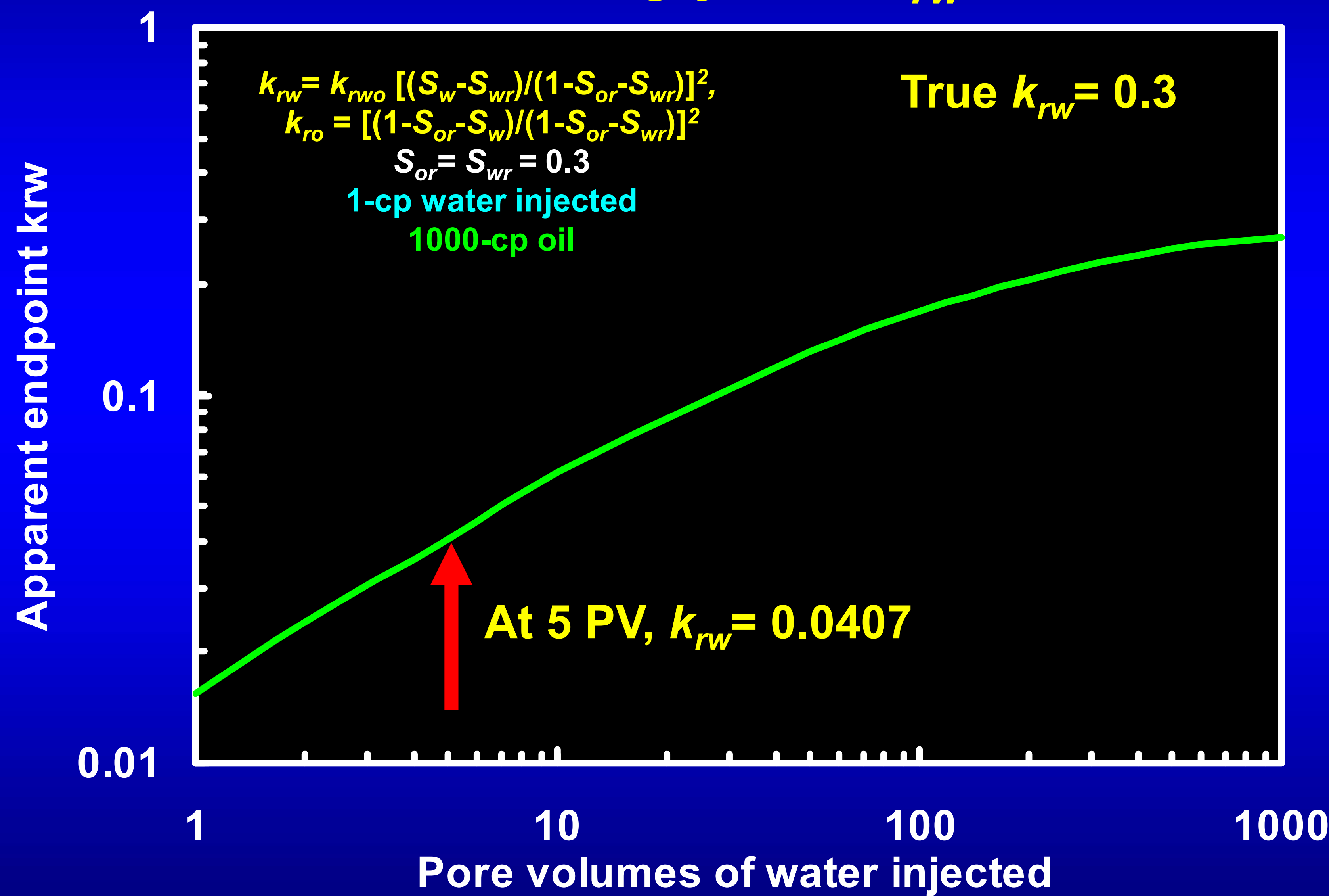
1. Relative k curves are difficult to obtain for viscous oils (Maini 1998).
2. Injecting insufficient water gives an unrealistically low relative permeability to water.
3. Use of mobility ratios at the shock front do not always correlate well with displacement efficiency.
4. Underestimating the polymer requirements leads to early polymer breakthrough.

## Favorable relative permeability characteristics can occur with viscous oils, but you must confirm that you have them.




For the above case, flooding with 25 cp polymer performed as well as with 50 cp or 200 cp polymer. (6 & 15 cp was not as good.)

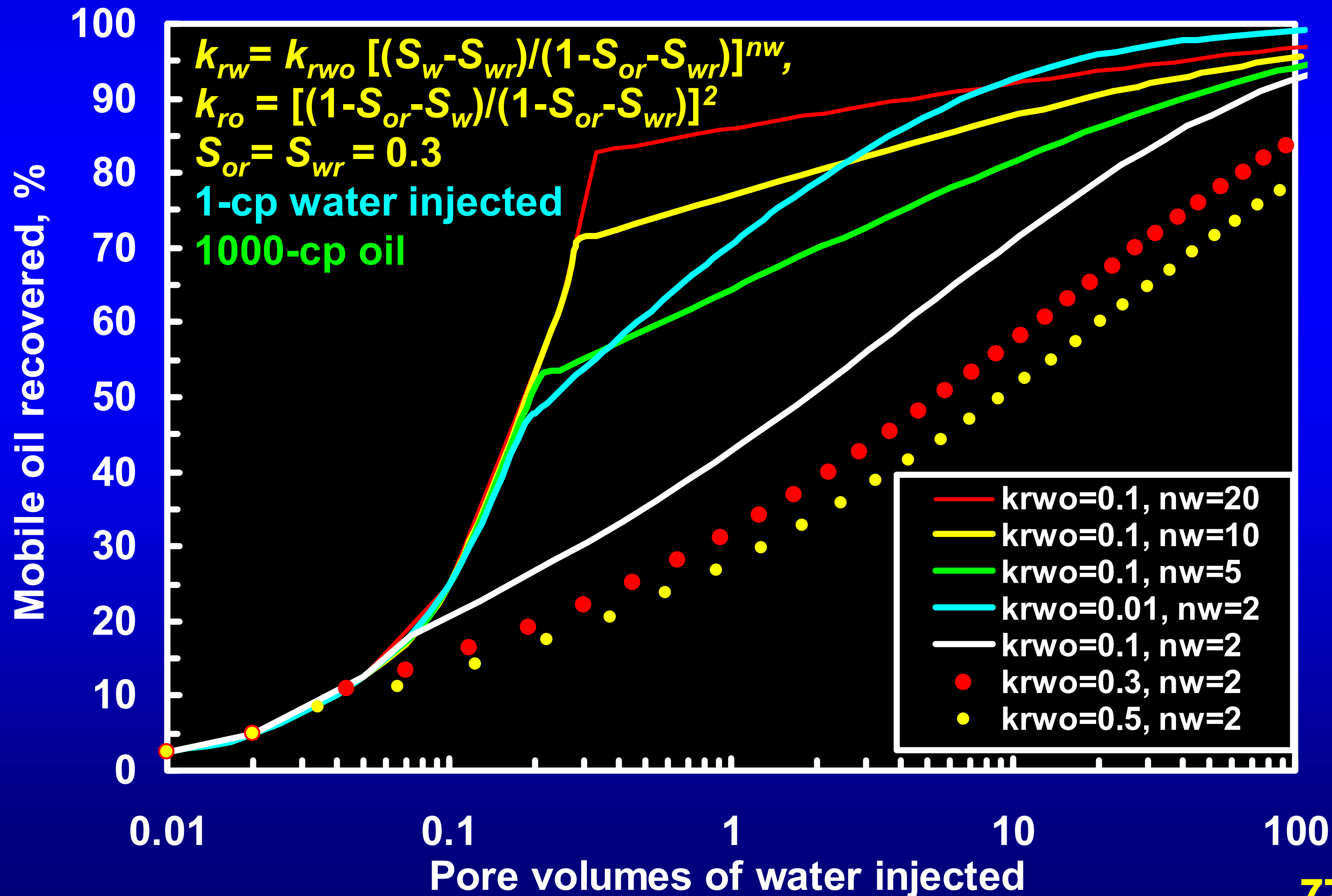
# Insufficient throughput yields misleadingly low $k_{rw}$ values



Favorable displacements can be seen if $k_{rwo}$ is low or nw is high.
But are these values realistic?

| $k_{rwo}$ | nw | Endpoint mobility ratio | Mobility ratio at shock front | Mobile oil recovery at 1 PV |
|---|---|---|---|---|
| 0.5 | 2 | 500 | 1.92 | 27% |
| 0.3 | 2 | 300 | 1.87 | 32% |
| 0.1 | 2 | 100 | 1.80 | 43% |
| 0.01 | 2 | 10 | 1.40 | 71% |
| 0.1 | 5 | 100 | 2.04 | 64% |
| 0.1 | 10 | 100 | 1.62 | 77% |
| 0.1 | 20 | 100 | 1.14 | 86% |

Mobility ratio at the shock front is not always the best indicator of an efficient displacement.



## Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-case Calculation?

"Resistance factor & residual resistance factor limit the need for viscous polymer solutions."

## 1960's Dow HPAM Claim

**HPAM can reduce water mobility both by increasing water viscosity and by reducing permeability:**

$$\lambda = k / \mu$$

**Resistance factor (*$F_r$* or *RF*)**

$$F_r = (k / \mu)_{brine} / (k / \mu)_{polymer}$$

**This effect is typically seen in short laboratory cores using fresh, gently-handled solutions.**

**Mechanical degradation and/or flow through a few feet of reservoir destroys this effect.**

## Pye, *JPT*, August, 1964

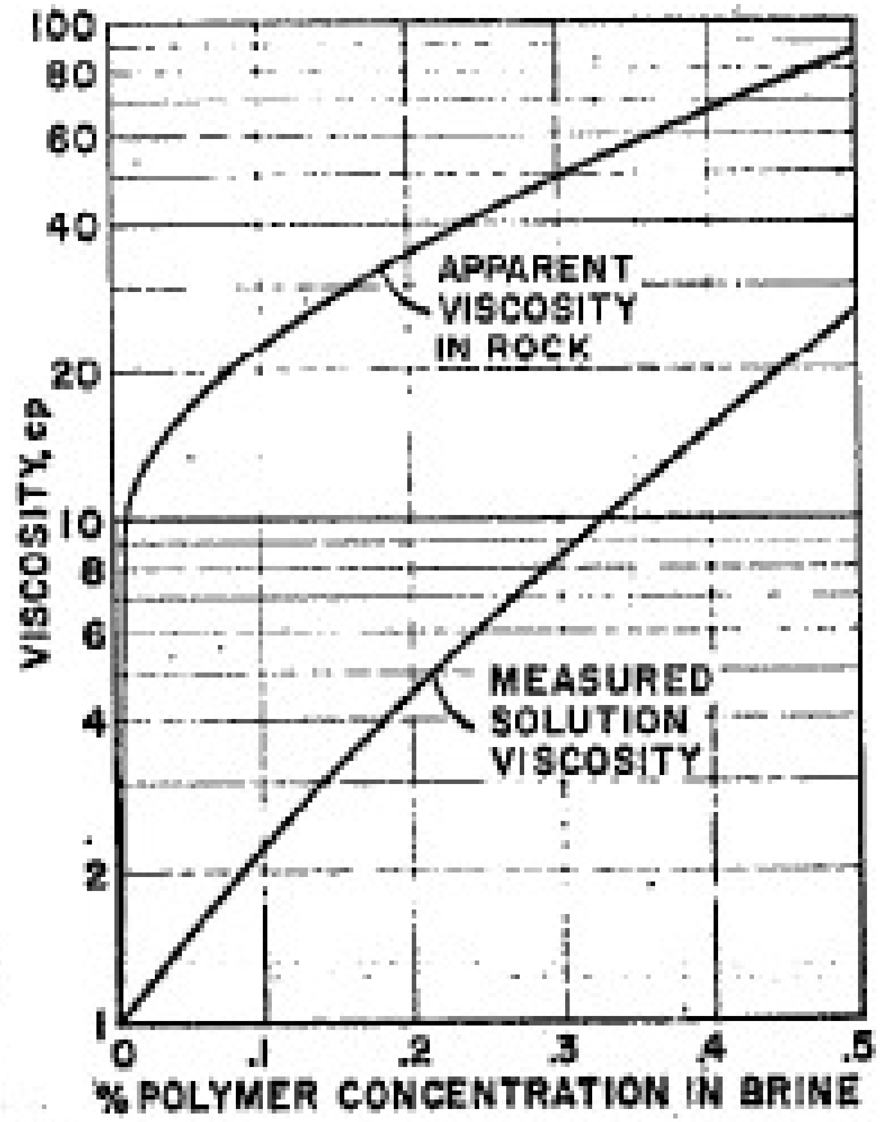



FIG. 1—POLYMER RESISTANCE EFFECT IN 250-MD BEREA SANDSTONE

Resistance factor ($F_r$ or *RF*) $= (k / \mu)_{brine} / (k / \mu)_{polymer}$

Residual Resistance Factor ($F_{rr}$ or *RRF*)
$= (k / \mu)_{brine\ before\ polymer} / (k / \mu)_{brine\ after\ polymer}$

RRF is a measure of permeability reduction caused by polymer.

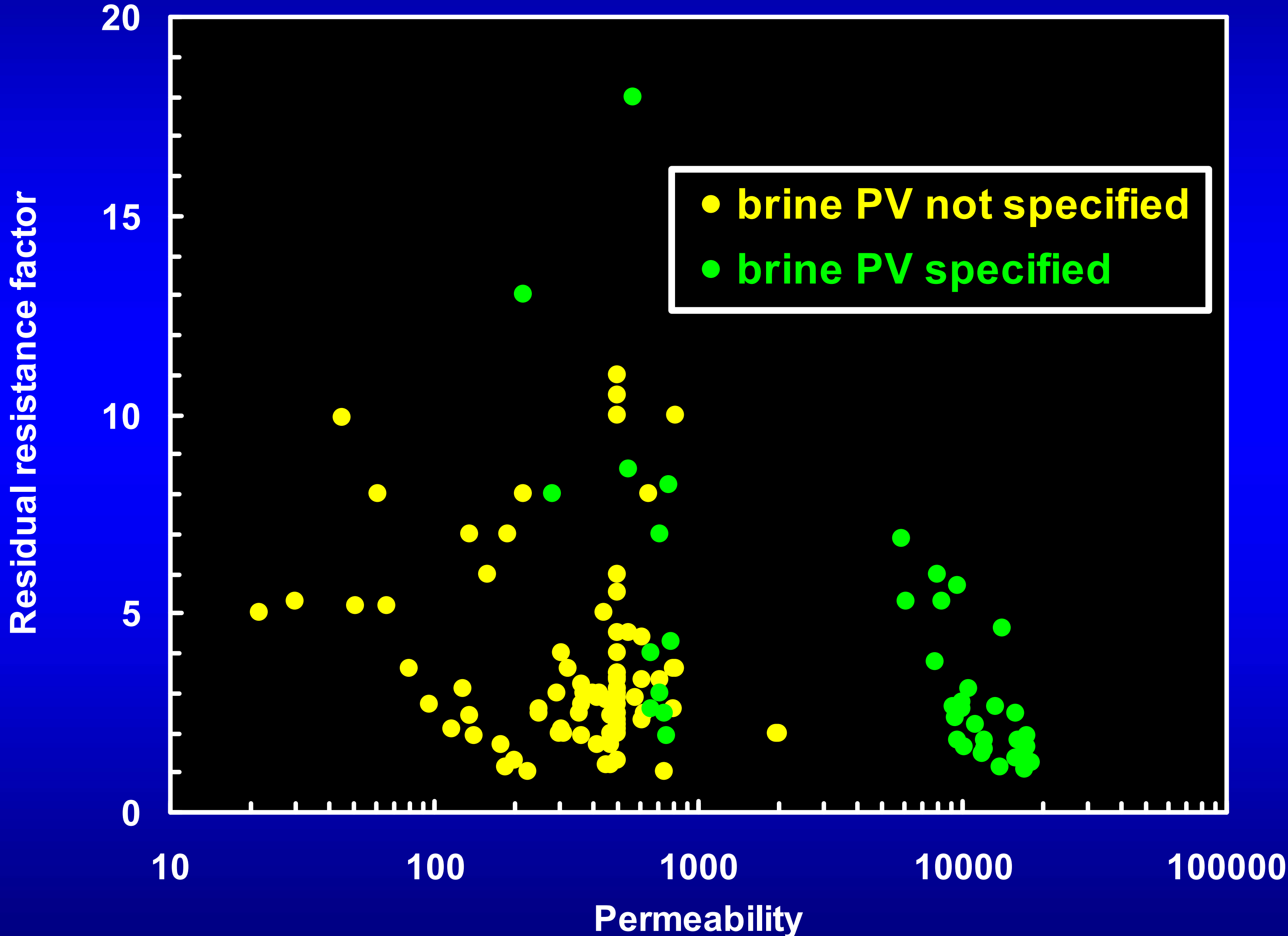
If RRF = 1, the polymer causes no permeability reduction, so a large polymer bank must be used.

If RRF = RF, a very small polymer bank can be used.

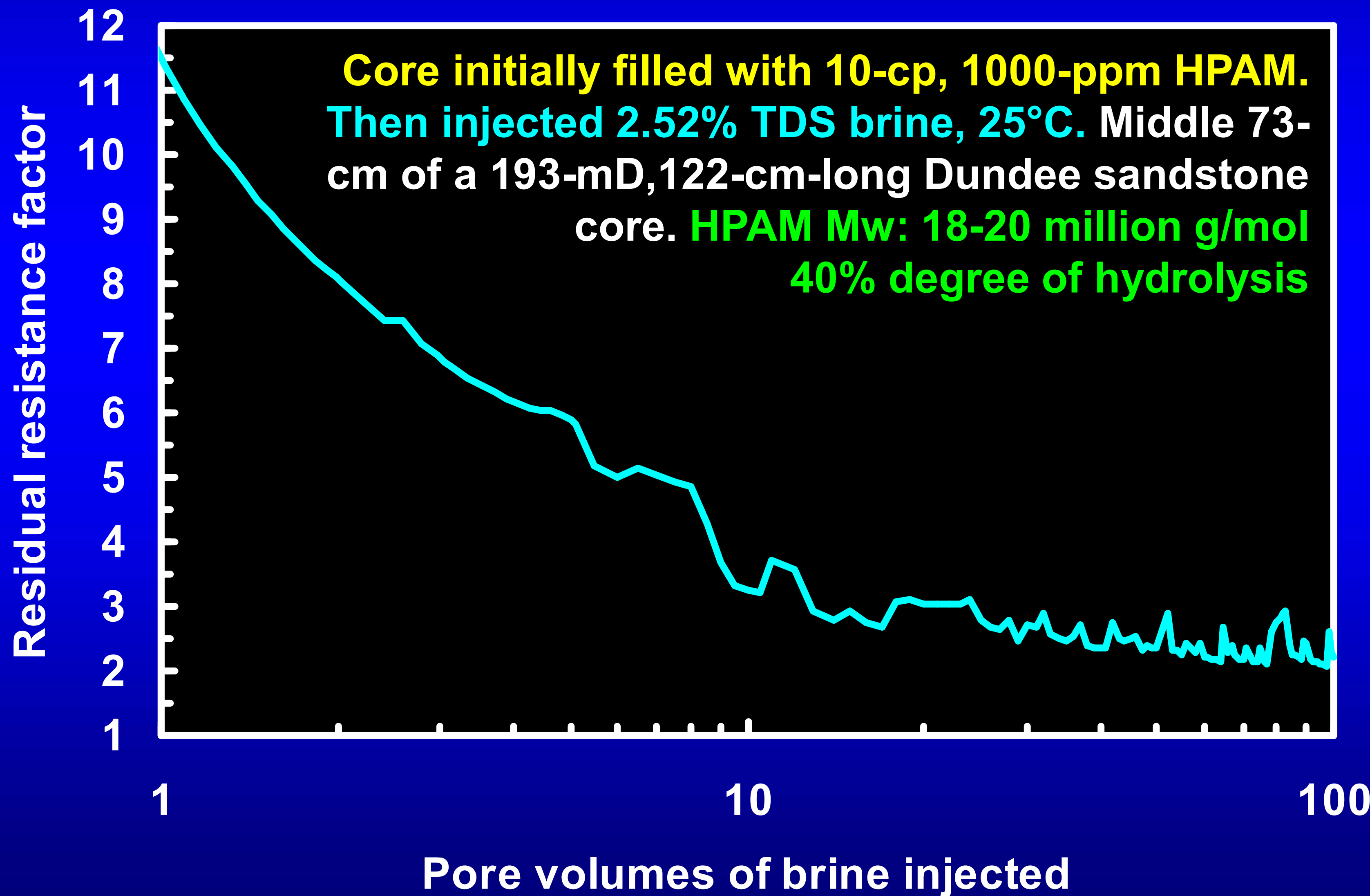
High RRF values occur when (1) not enough brine is injected, (2) no internal pressure taps are used during core floods, (3) rock permeability is too low to allow polymer propagation.

Most real polymer flood RRF values are less than 2.
Simulations should assume RRF =1 to be conservative.

- **Most literature values for RRF do not report PV injected.**
- **Those that do usually injected less than 10 PV of brine.**



- If not enough brine is flushed to sweep out the polymer, a high residual resistance factor (RRF) is seen.
- Real RRF values rarely exceed 2 unless *k* is low.
- A conservative polymer flood design assumes RRF=1.



# Permeability reduction is greater in low-permeability rock than in high-permeability rock.

**This effect could harm vertical sweep efficiency.**

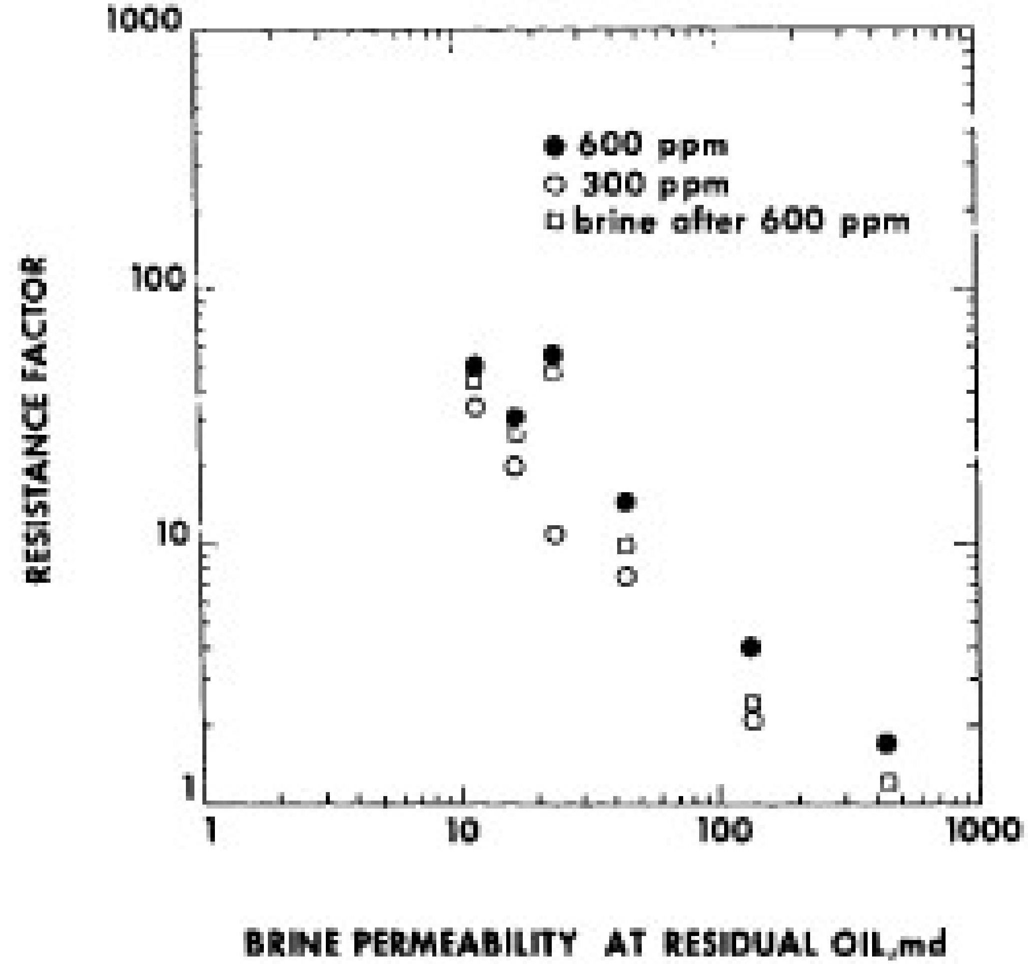


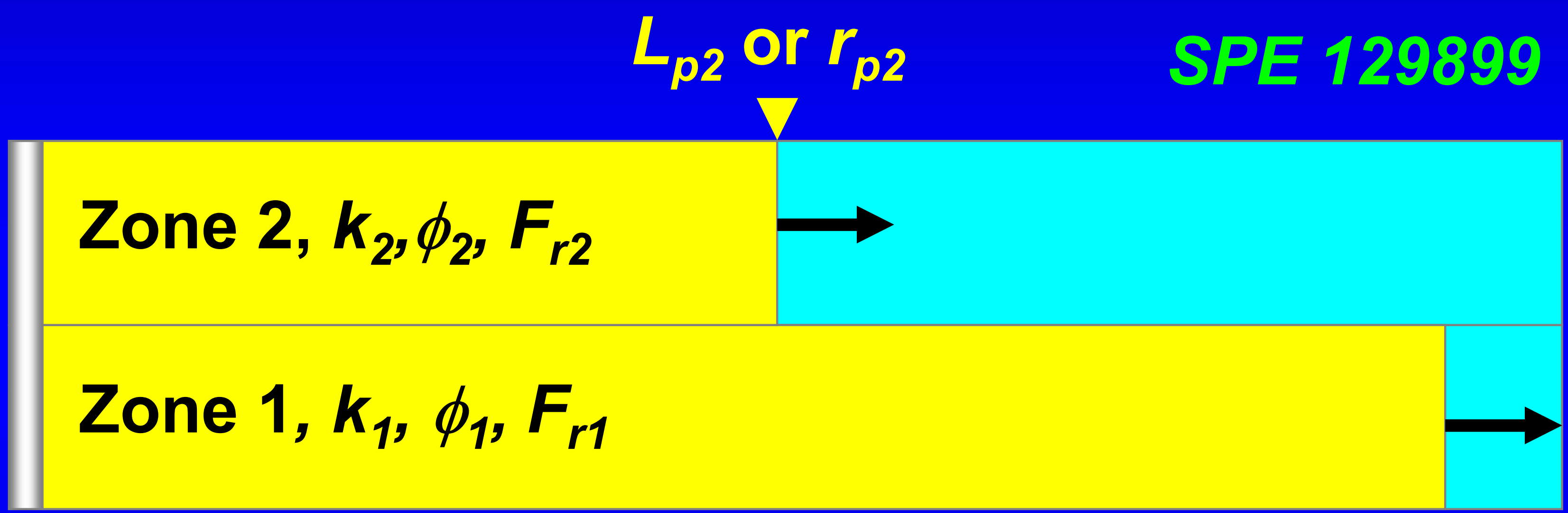

FIG. 4 — VARIATION OF POLYMER RESISTANCE FACTORS WITH PFRMEABILITY.

Vela et al. SPE 5102

HPAM
Mw= $5.5 \times 10^6$
20% hydrolysis.
Sandstone rock.

**If polymer molecular weight is too high, $F_r$ values increase with decreasing $k$. (A pore-plugging effect.)**
**What if $F_{r1} < F_{r2}$? How does that affect vertical sweep?**

*SPE 129899*




$F_r$ = resistance factor (apparent viscosity)

**For radial flow & no crossflow, $F_{r2}/F_{r1}$ must be < 1.4.**
**For linear flow & no crossflow, $F_{r2}/F_{r1}$ must be < $k_1/k_2$.**
**For free crossflow, vertical sweep is insensitive to $F_{r2}/F_{r1}$.**

# HPAM Effectiveness versus Permeability and Molecular Weight. From Wang et al. 2008, SPE 109682

**TABLE 3—EFFECTIVENESS FOR DIFFERENT $M_w$ AND $k_{water}$**

| $k_{water}$ ($10^{-3}$ $\mu m^2$) | Waterflood Recovery (%OOIP) | Ultimate Recovery (%OOIP) | Polymer EOR (%OOIP) | $M_w$ ($10^6$ Daltons) |
|---|---|---|---|---|
| 330.3 | 50.46 | 72.48 | 22.02* | 38 |
| 333.3 | 50.00 | 68.86 | 18.86 | 25 |
| 364.3 | 59.26 | 67.38 | 8.12 | – |
| 456.8 | 58.89 | 67.54 | 8.65 | 15 |
| 327.0 | 61.29 | 68.85 | 7.56 | – |
| 96.9 | 56.73 | 63.63 | 6.90 | 8 |
| 85.85 | 57.87 | 64.61 | 6.74 | – |
| 46.9 | 44.25 | 48.62 | 4.37 | 5.5 |
| 51.96 | 48.44 | 52.96 | 4.52 | – |
| 9.11 | 43.21 | 46.91 | 3.70 | 2.4 |
| 16.63 | 41.39 | 45.26 | 3.87 | – |

* Polymer mass = 500 mg/L•PV for this case. Polymer mass = 570 mg/L•PV for the other cases.

## Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-Case Calculation?

"Viscous solutions reduce injectivity too much."

Injection has occurred above the formation parting pressure for most polymer floods.

Fractures simply extend to accommodate the rate and viscosity of the fluid injected. So injectivity may not be a limitation, depending on the pressure constraint that is imposed.

What is a reasonable pressure constraint? What degree of fracture extension is too far?

## Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-case Calculation?

**"Viscous solutions reduce injectivity too much."**
**"Viscous solutions cause fracture channeling."**

**Cases exist where rapid polymer channeling has occurred through fractures—but only for a limited fraction of the existing wells.**

**Deal with those wells on a case-by case basis:**
**(1) reduce polymer viscosity/injection rate, (2) shut-in the well or re-align flow, (3) gel treatments.**

# DAQING

**Were fractures present?**

**YES**

**Fracture widths:**

- **1.5 to 5 mm from injectivity analysis during polymer injection.**
- **0 to 1.8 mm from injectivity analysis during water injection.**
- **~0.01 mm from interwell tracer analysis of polymer breakthrough.**

# DAQING

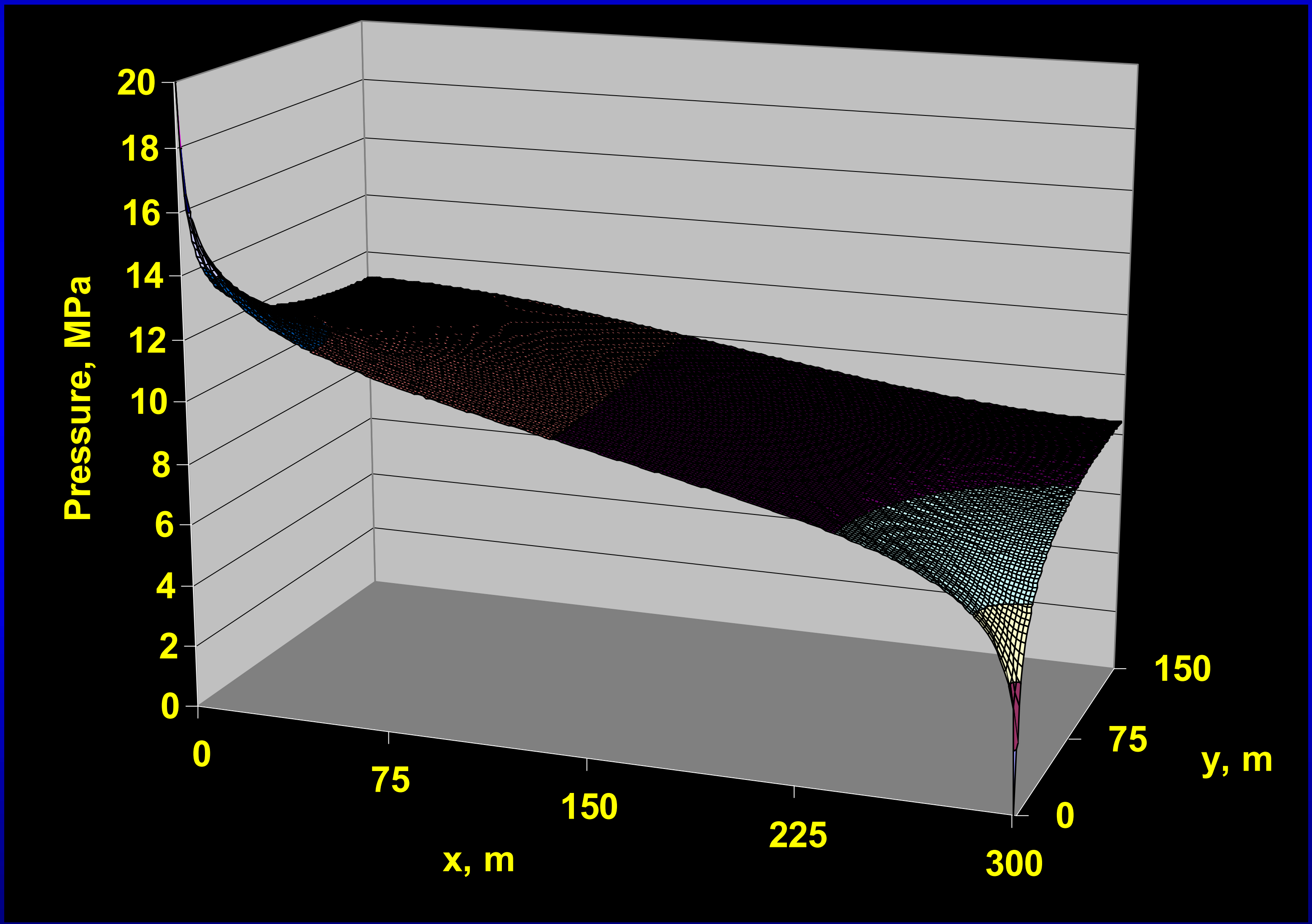
Why were the fractures apparently wider during polymer injection than during water injection?

Higher pressures during polymer injection could have flexed the fractures open wider than during water injection.

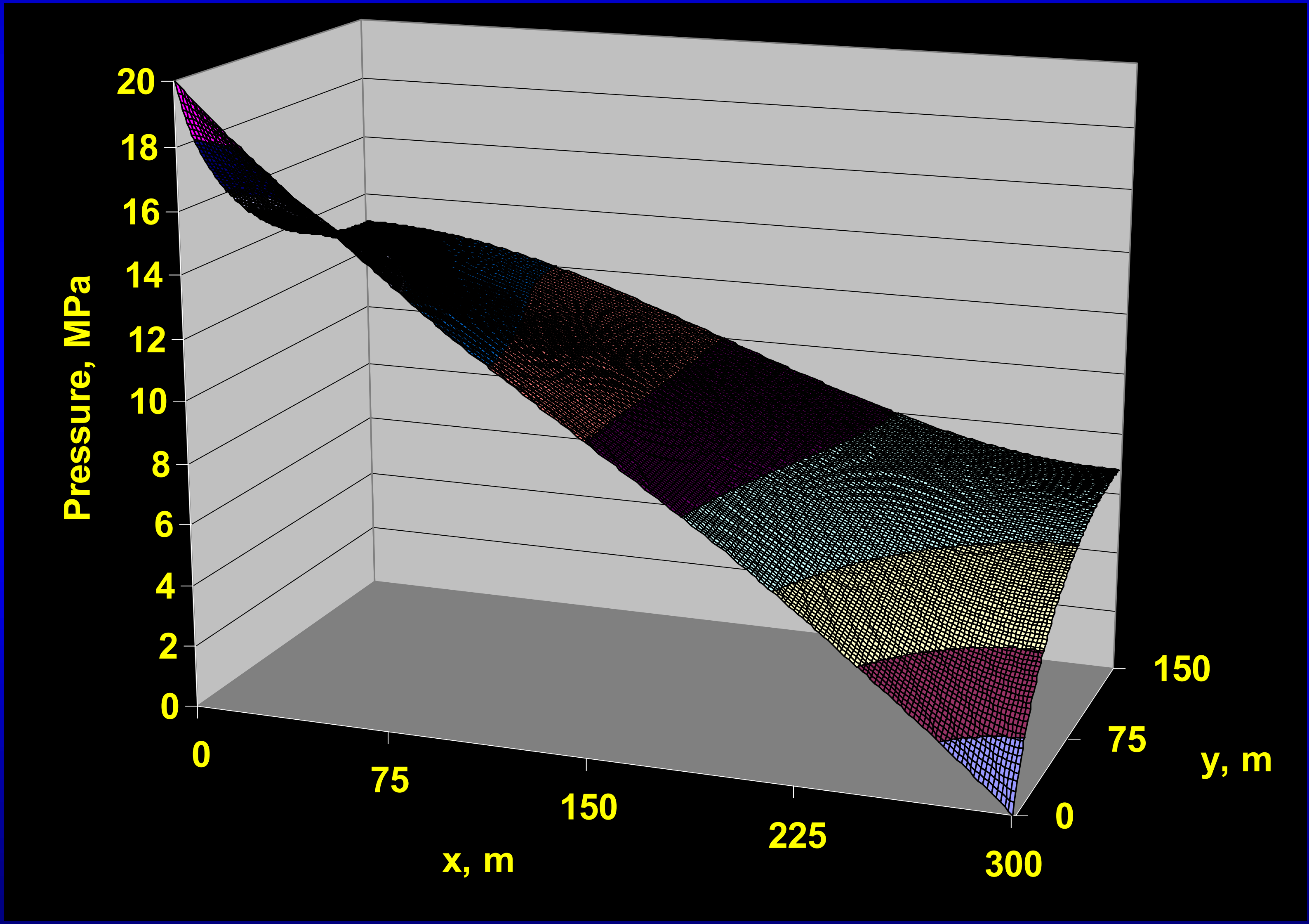
Why were fracture widths from injectivity analysis greater than from tracers?

Fractures were wider near wells than deep in the formation.

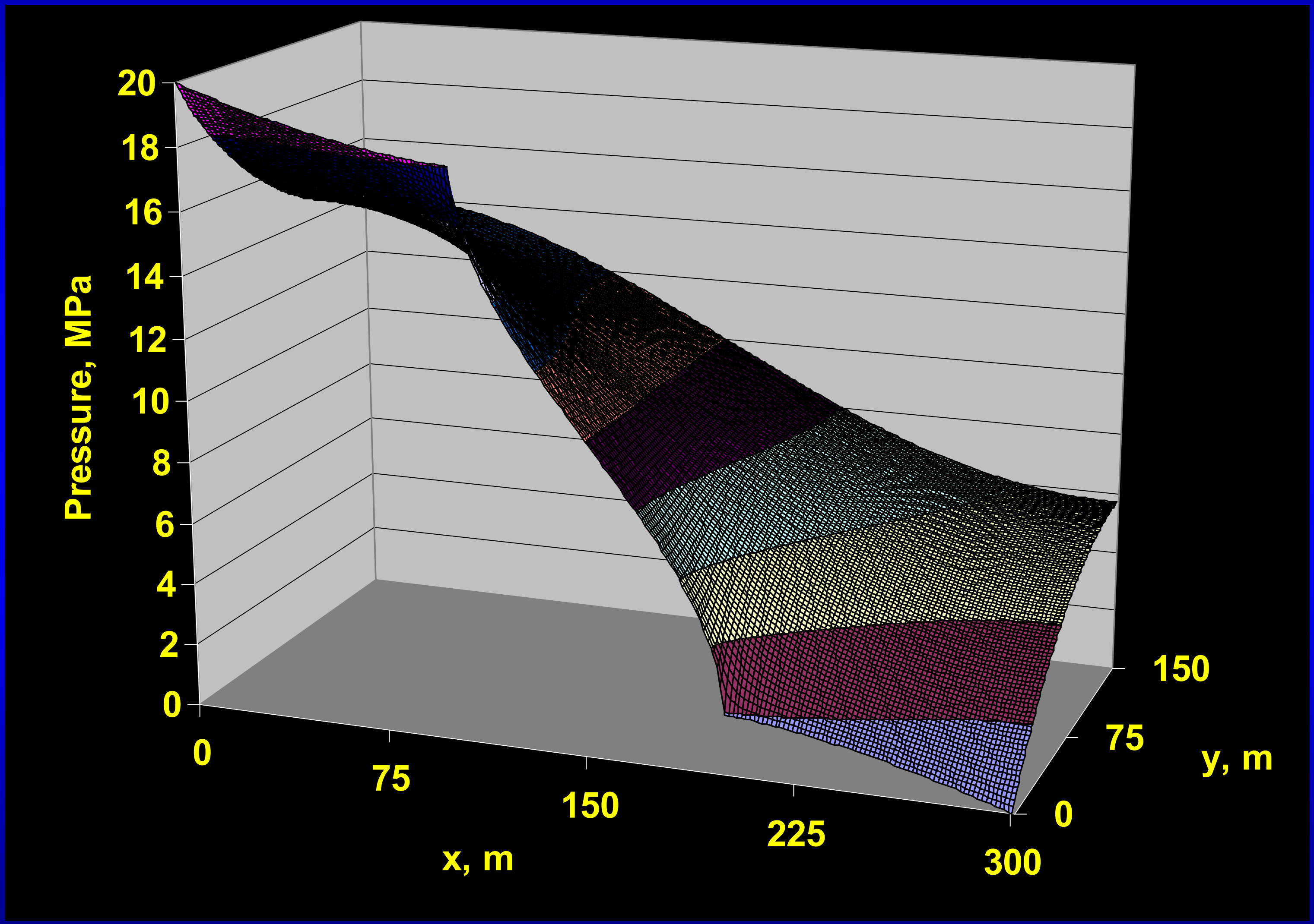
## Normal Radial flow: No channeling, but low injectivity/productivity, and low pressure gradients within most of the pattern.



# A 1-mm open fracture between two wells allows high injection/production rates but also allows severe channeling.



## Restricting the middle third of the fracture provides the best possibility.

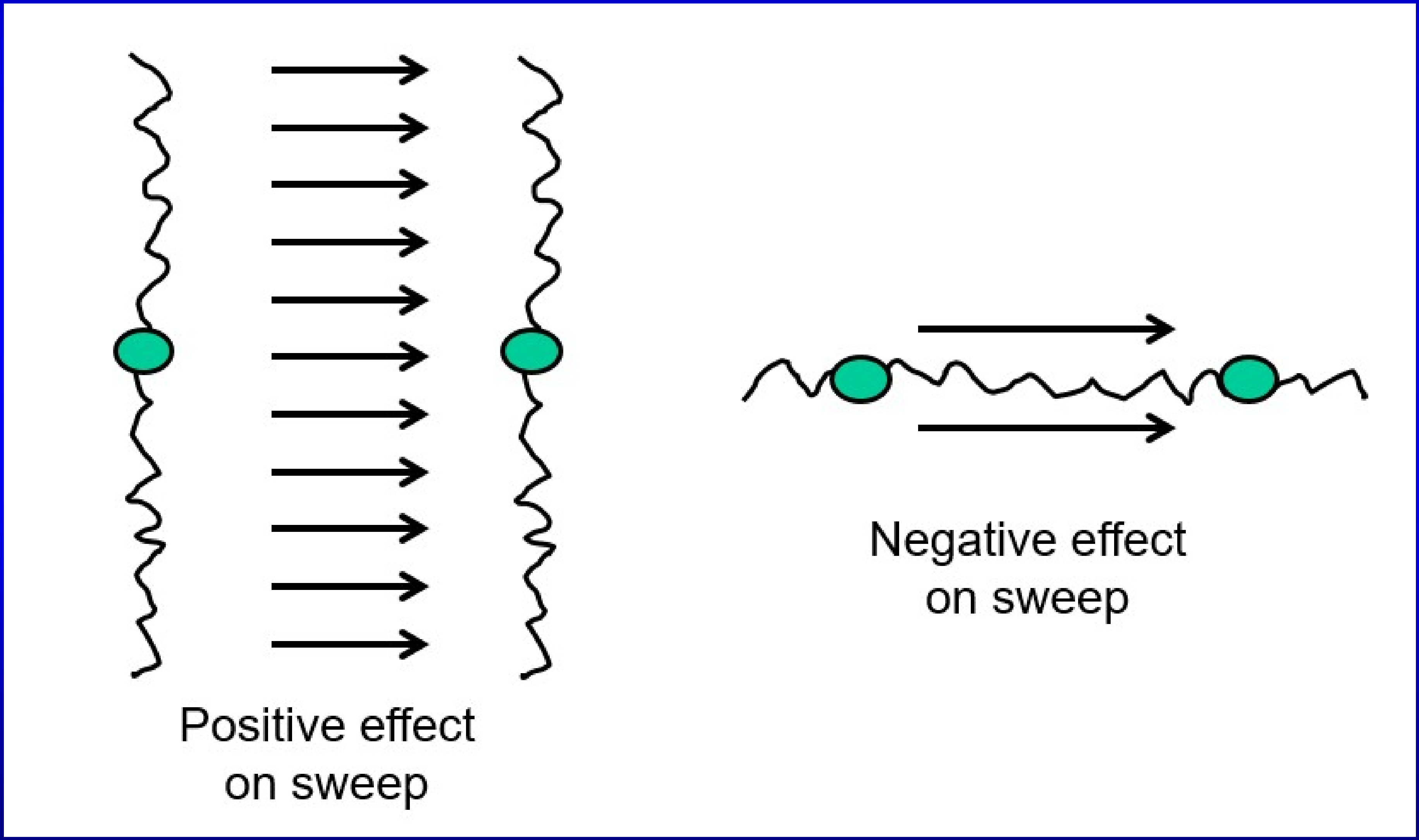


Moderate-length fractures can substantially increase injectivity and productivity and can improve areal sweep efficiency.

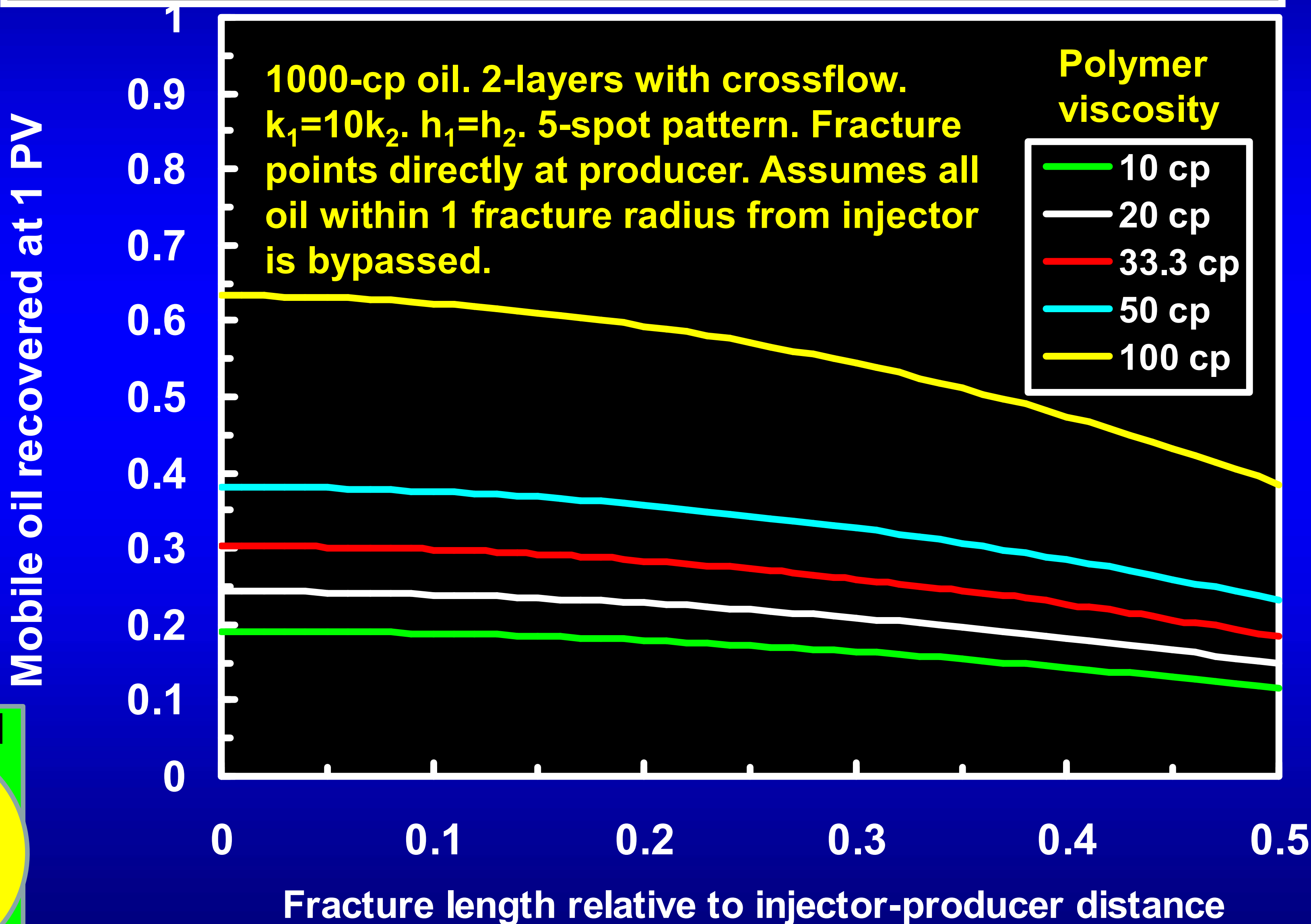
Moderate-length fractures could have considerable value for future EOR projects if very viscous fluids must be injected to maintain mobility control.

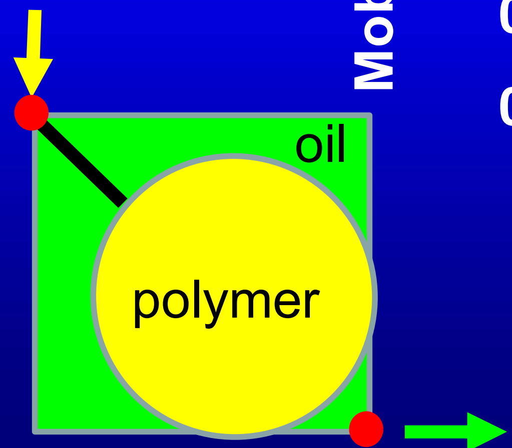
Utilizing fractures in this way requires a good understanding of fracture formation, length, width, height, and orientation.

# Importance of Identifying Fracture Trends in the Reservoir



**Increasing fracture length to 30% of the total interwell distance reduces sweep efficiency from 0.63 to 0.53.**
**Increasing polymer viscosity from 10 to 100 cp increases recovery from 0.16 to 0.54.**



# Injectivity and Fracture Extension

Tambaredjo Field (Suriname), Moe Soe Let et al. (2012): horizontal fractures extended <30 ft from the injection well (well spacing was 300 ft).

Matzen Field (Austria), Zechner et al. (2015): vertical fractures only extended 43 ft from the injection well (well spacing was 650-1000 ft).

No problems were reported with injectivity, or of fractures compromising the reservoir seals or causing severe channeling during the Daqing project (Han 2015), even injecting 150-300-cp polymer.

# Field Demonstration of Effect of Fractures on HPAM Injectivity and Mechanical Degradation (Sagyndikov, Kazakhstan, SPE 208611)

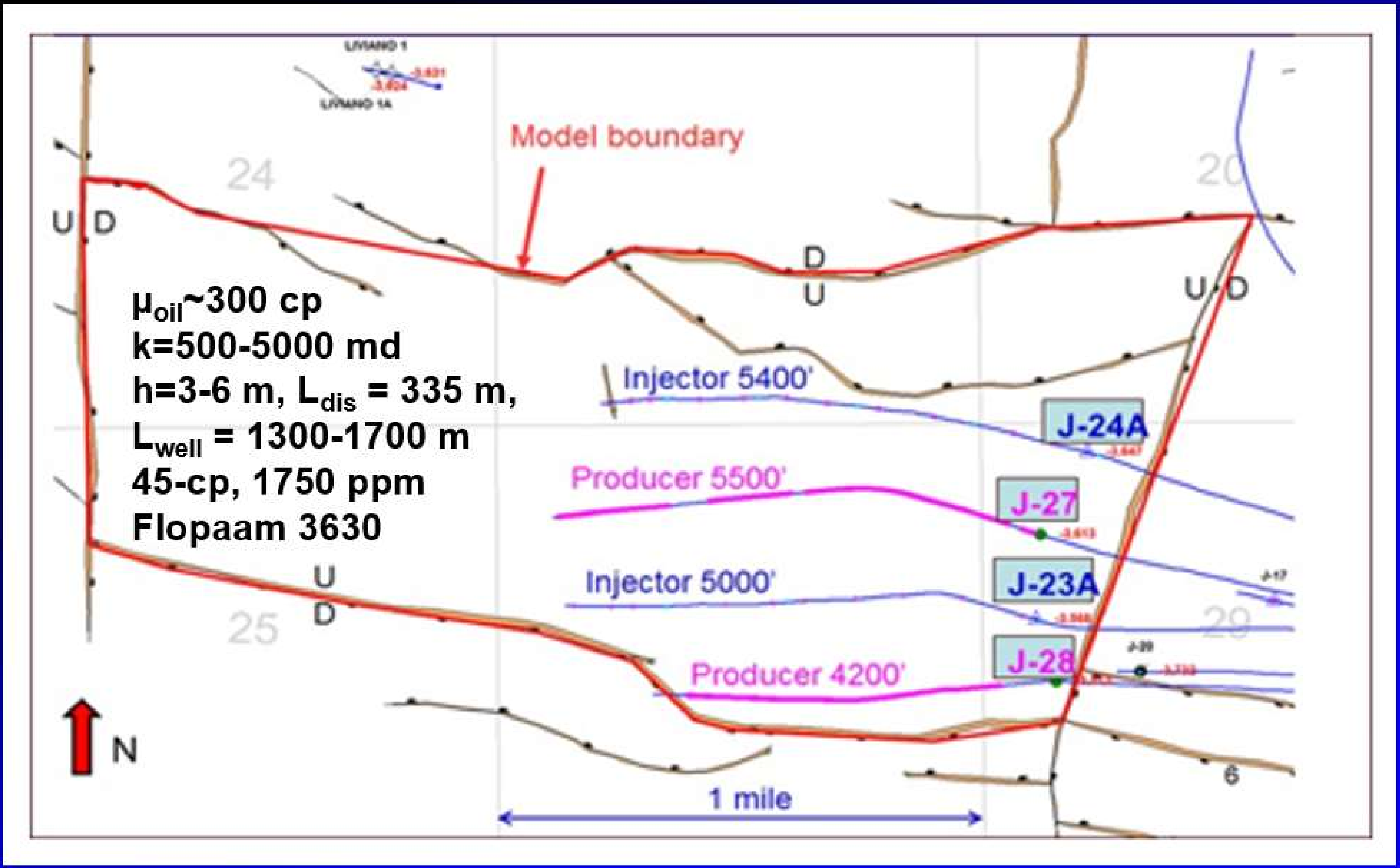
- Developed a method to collect HPAM samples from polymer injection wells without degradation.

- Demonstrated existence of fractures in vertical polymer injectors.

- Demonstrated back-flowed HPAM samples were not degraded, when severe degradation was predicted if the fracture was not present.

- Demonstrated that contact with the formation removed dissolved oxygen from injected HPAM solutions.

## Hilcorp Milne Point Polymer Flood: Water cut decreased from ~70% during water flood to ~10% during polymer flood.



# MILNE POINT, NORTH SLOPE ALASKA, USA (SPE 209372)
# NORTH-SOUTH HORIZONTALS BETTER THAN EAST-WEST

- Polymer breakthrough at J-Pad after 0.1 PV (East-West horizontals). ~300-cp oil.
- No polymer breakthrough at L-Pad after 0.27 PV (North-South horizontals). ~850-cp oil.
- North-South horizontals mitigate channeling through N-S fractures.

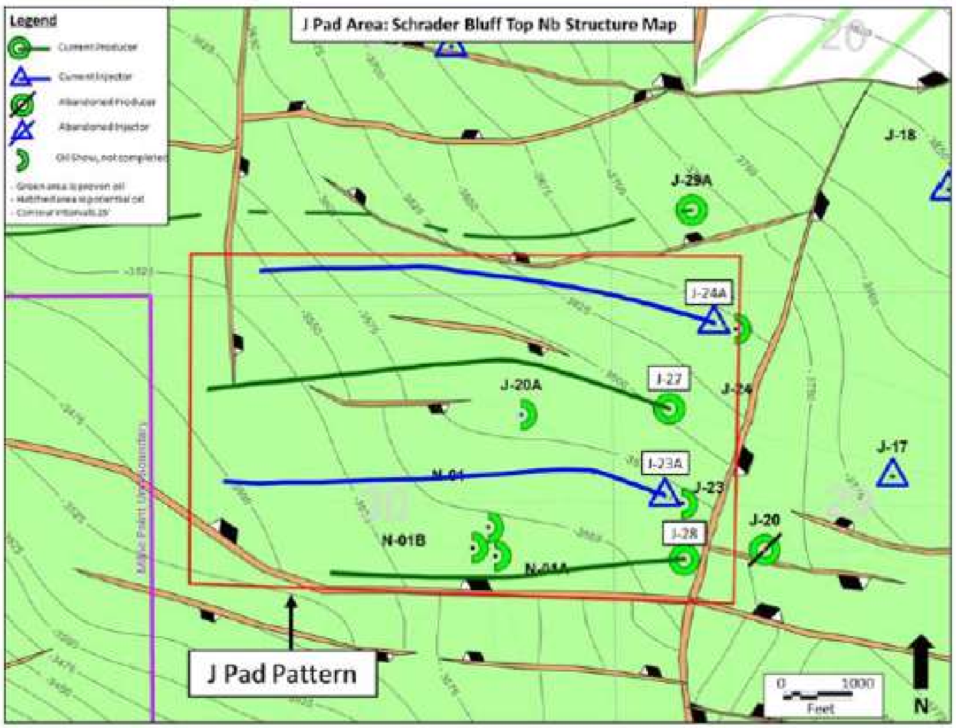



Figure 11—Location Map of J Pattern, well inside red box part of initial pattern and wells outside were drilled as part of expansion

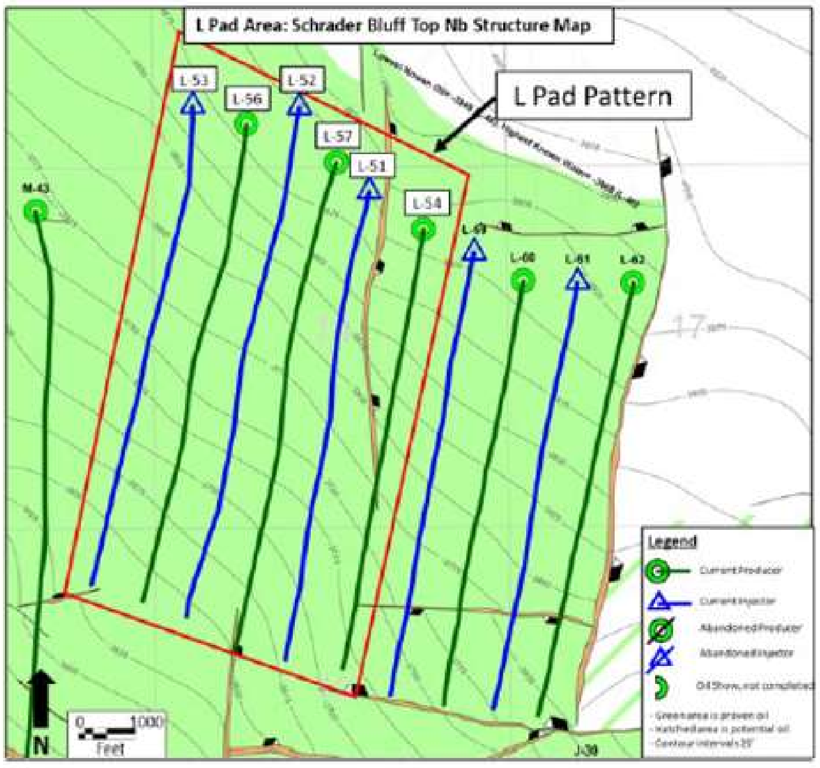



Figure 17—Location Map of L Pad Pattern

# Will Fractures Break "Out of Zone"?

Difficult to predict.

De Pater (SPE 173359) notes, in general, that actual growth of fracture height has been less than predicted by simulations.

Ratios up to 80:1 have been noted for fracture length to fracture height in soft formations (SPE 173359).

Since injectivity is so important to the economics of a polymer flood, it is worthwhile to determine the limits of acceptable fracture extension.

## Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-case Calculation?

**"Economics limit polymer concentrations."**

## Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-Case Calculation?

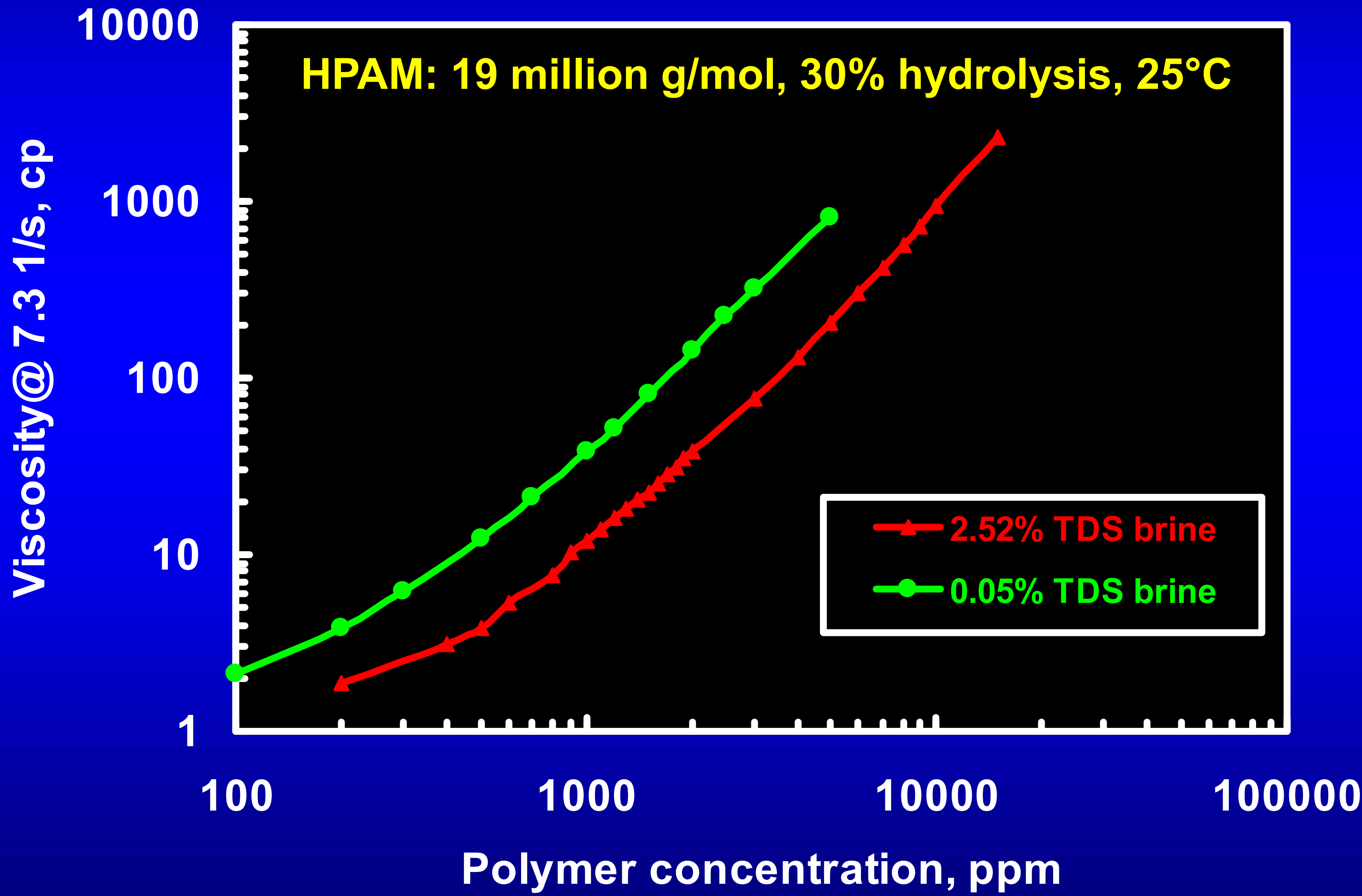
"Economics limit polymer concentrations" (to a value less than that given by the base-case calculation).

This is not true if injectivity is not restricted.

Factors favoring use of higher viscosities:

- Viscosity vs polymer concentration relation.
- Value of produced oil / cost of injected polymer.
- Capital outlay.
- Delayed polymer breakthrough.

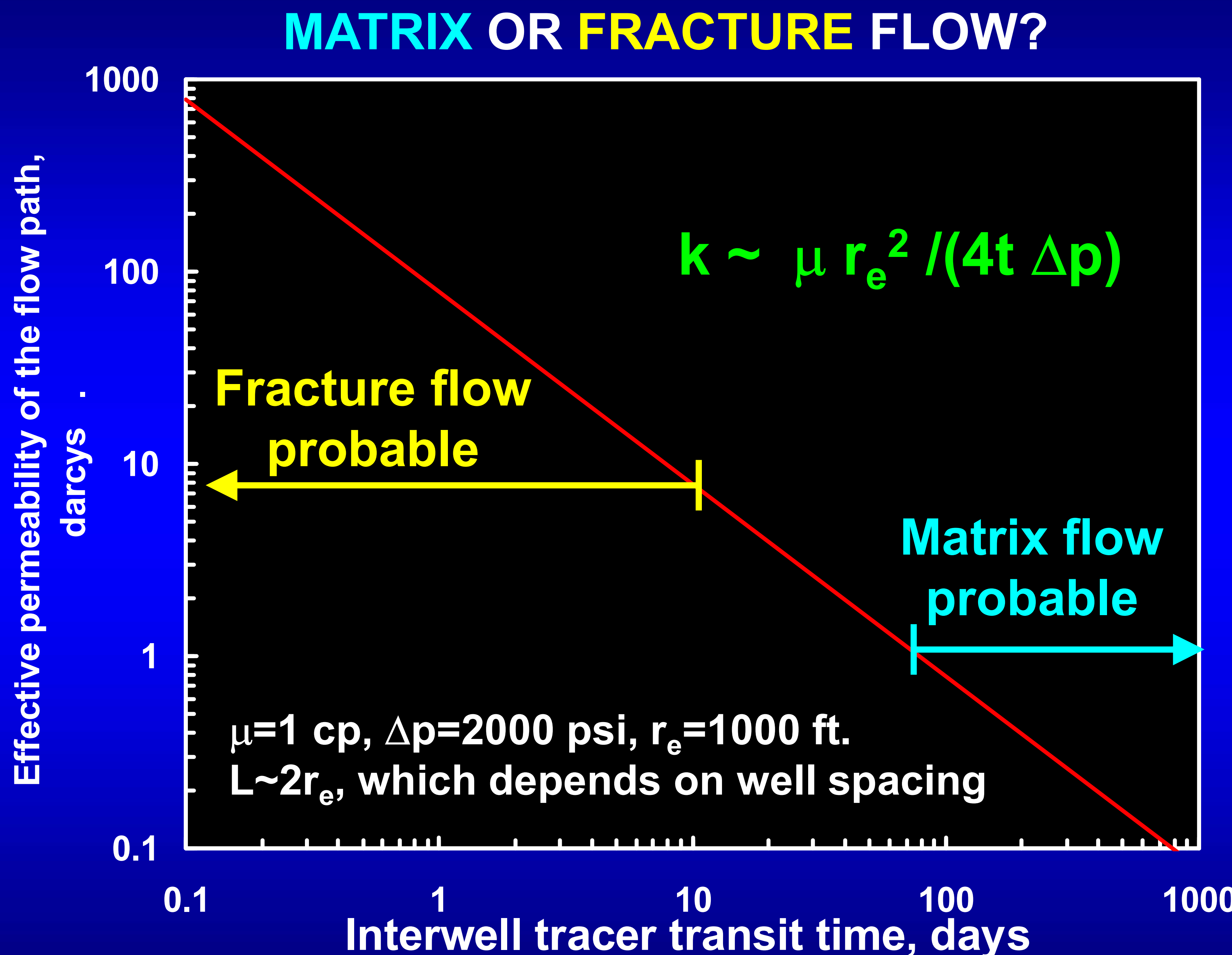
**Polymers are more efficient viscosifiers at high concentrations: $\mu \sim C^2$ (i.e., only 40% more polymer is needed to double the viscosity).**



## A DILEMMA FOR POLYMER FLOODING

1. Injecting above the parting pressure is often necessary for adequate injectivity.
2. If polymer breaks through early, how can you tell if it is because of a fracture or viscous fingering?
3. If breakthrough occurs from a fracture, you should decrease the injection rate and/or polymer viscosity.
4. If breakthrough occurs from viscous fingering, you should increase the polymer viscosity.

- Transit through fractures that cause severe channeling should occur fast—days or less.
- Transit through viscous fingers typically takes months.


MATRIX OR FRACTURE FLOW?
k ~ μ r_e^2 /(4t Δp)
Fracture flow probable
Matrix flow probable
μ=1 cp, Δp=2000 psi, r_e=1000 ft.
L~2r_e, which depends on well spacing
Effective permeability of the flow path, darcys
Interwell tracer transit time, days
1000
100
10
1
0.1
0.1
1
10
100
1000

# Should more polymer be injected than the base-case design?

**Wang Demin (Daqing, China)**

- **Injected 150-300 cp HPAM solutions in thousands of wells to displace 10-cp oil.**

- **HPAM solutions reduced $S_{or}$ from 36.8% (with waterflooding) to 21.75% (for polymer flooding) using a constant capillary number under oil-wet, weakly oil-wet, and mixed-wet conditions.**

- **The mechanism is not understood, and this effect is not always in operation, so you must check for it on a case by case basis.**

# When should polymer injection be reduced or stopped?

**Technical Considerations**

- **Assume residual resistance factor is one.**
- **Small polymer banks do not exclusively enter high-permeability zones and divert subsequently injected water into low-permeability zones.**
- **Water injected after polymer fingers almost exclusively through the high-permeability path.**

# When should polymer injection be reduced or stopped?

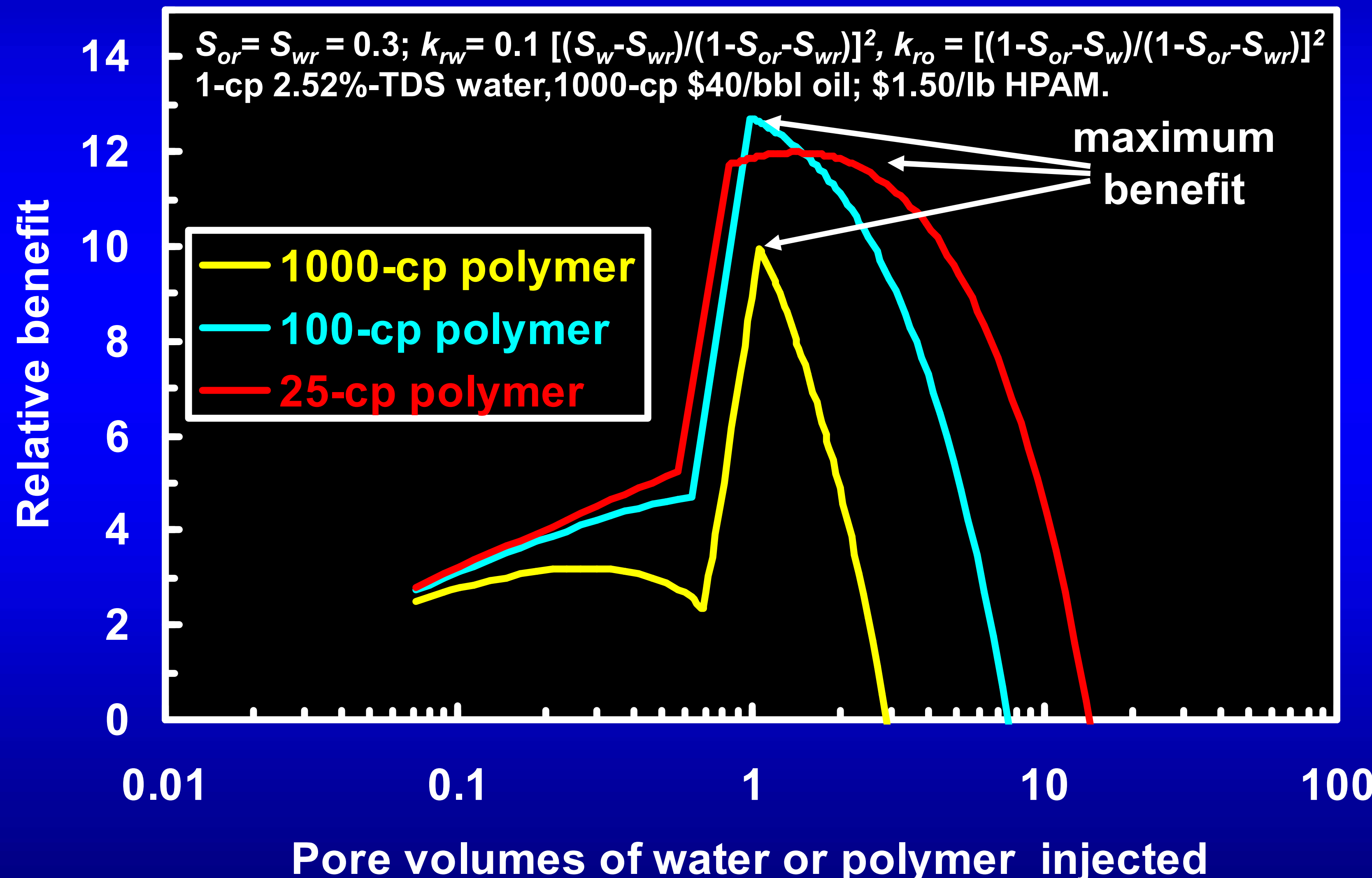
## Economic Considerations

- Depends on oil price, polymer cost, well-spacing, and many individual factors specific to the field. So a "one-size-fits-all" formula is not available (PETSOC-09-02-55, SPE 109682, SPE 114342, SPE 179603).

- Daqing has the most experience and reports with this question. Others are just facing it now.

- A major flaw with many simulations has been incorrect handling of polymer injectivity (artificially restricting injectivity in the simulator by assuming no fractures are open).

# At some PV, a peak is seen in the total value of the produced oil minus the cost of injected polymer (and minus other costs).



# Should You Grade the Polymer Bank?

Claridge (SPE 6848, 14230) developed a method for decreasing polymer viscosity near the end of a flood—most appropriate for homogeneous reservoirs.

Cyr (1988) argued that grading won't work in heterogeneous reservoirs.

After 1 PV of polymer, Daqing saw water breakthrough indication at ~0.02 PV of water (but 0.23 PV to stability).

Our experiments with $k_1/k_2$=11.2:1—during water injection after polymer, water breakthrough in the high-k layer occur after advancing the front by 70% with 8 cp polymer, 40% for 23-cp polymer, and 25% for 75-cp polymer.

# Strategies When Oil Prices Fall

- Maintain injection viscosity and rate?
- Switch to water injection immediately?
- Grade the polymer bank?
- Slow the injection rate?
- Stop injection and rely on compaction drive?
- Other?

# Bottom Line

1. Base-case method: $F_r = M * k_1/k_2$. (You must be realistic about your choices of mobility ratio and perm contrast.)
2. Injection above the formation parting pressure and fracture extension are crucial to achieving acceptable injectivity—especially for vertical injectors—increasing injectivity, sweep efficiency, and reducing mechanical degradation. The key is to understand the degree of fracture extension so that fractures do not extend out of zone or cause severe channeling.
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