Water Shutoff

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Water Shutoff Topics

Oilfield Water Production Challenges and Costs

- Water production is increasing worldwide: 249 million B/D (Khatib, 2007)
- Water to oil ratio (WOR = 3/1) (Bailey et al. 2000)
- Hill et al. (2012) estimated water costs at $~50 billion/year.
- Veil (2019) says USA produced ~24.4 billion bbl water per year.
- Average produced water salinity is ~3.23% TDS (Benko and Drews, 2008). So you or your cows can't drink that or water your crops with it.

More Water → Less Oil → Higher Cost → Shorter Field Life

WHY DO WE WANT TO REDUCE WATER PRODUCTION?

REDUCE OPERATING EXPENSES

- Reduce pumping costs (lifting and re-injection):
  ~$0.25/bbl ($0.01 to $8/bbl range).
- Reduce oil/water separation costs.
- Reduce platform size/equipment costs.
- Reduce corrosion, scale, and sand-production treatment costs.
- Reduce environmental damage/liability.

INCREASE HYDROCARBON PRODUCTION

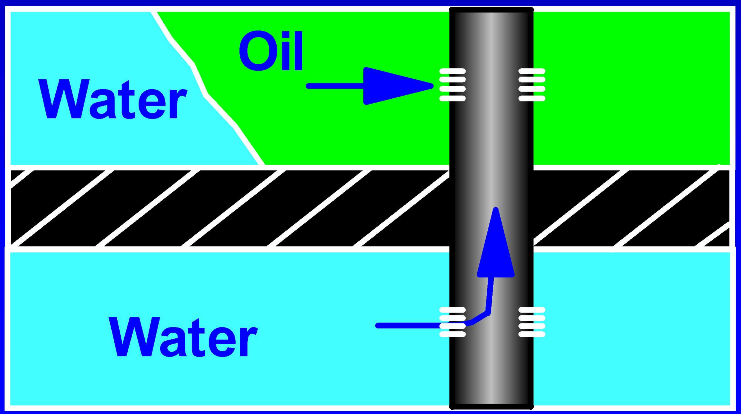
- Increase oil production rate by reducing fluid levels and downhole pressures.
- Improve reservoir sweep efficiency.
- Increase economic life of the reservoir and ultimate recovery.
- Reduce formation damage.

A COMMON OPTION: DO NOTHING

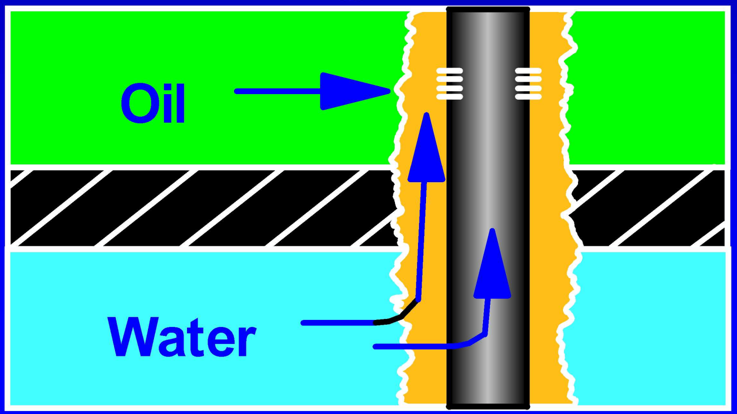
- Live with the water production.
- If oil is \$80-\$100/bbl and water costs \$1/bbl to treat and dispose, you may still make lots of money with a 95% water cut.
- This course is about cases where you want/need to reduce water production.

CAUSES OF EXCESS WATER PRODUCTION

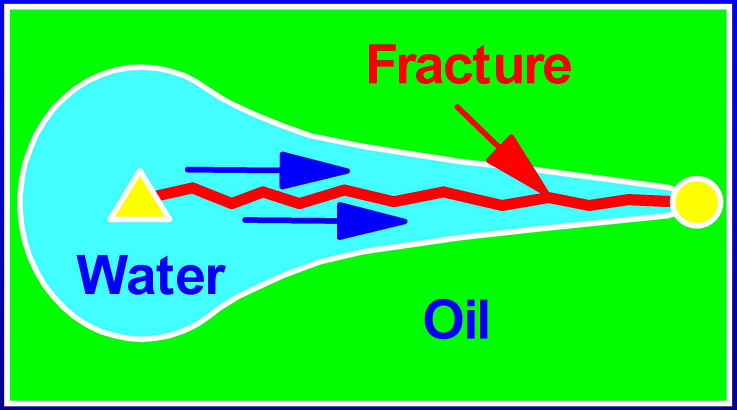
Open Water Zone



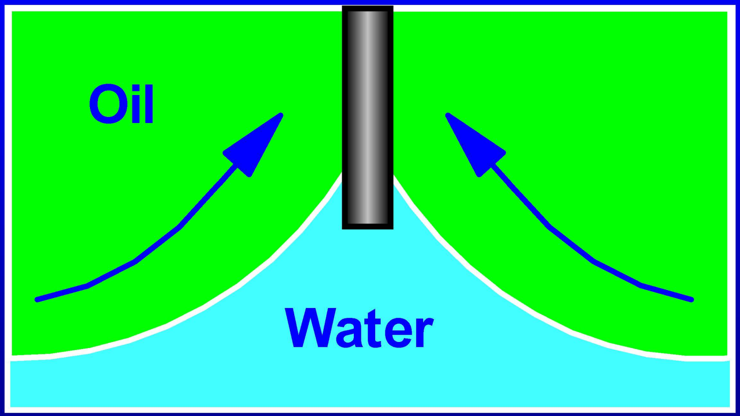
Flow Behind Pipe and Casing Leaks



Channeling from Injectors



Coning or Cusping



MAIN POINTS

Many different types of excess water production problems exist.

Each problem type requires a different approach (e.g., different blocking agent properties) for optimum solution.

Problem types should be adequately diagnosed before attempting a solution.

WATER CONTROL METHODS

- Cement, sand plugs, calcium carbonate.
- Packers, bridge plugs, mechanical patches.
- Pattern flow control.
- In fill drilling/well abandonment.
- Horizontal wells.
- Gels.
- Polymer floods.
- Resins.
- Foams, emulsions, particulates, precipitates, microorganisms, nanoparticles.

SOME MATERIALS FOR WATER SHUTOFF

CEMENTS
+ Have excellent mechanical strength.
+ Have good thermal stability (up to 450°C).
- Do not penetrate readily into tight areas.
- Do not always form a good pipe-formation seal.

RESINS
+ Can penetrate into rock matrix and tight areas.
o Stability depends on the particular resin (up to 250°C).
- Chemistry can be very temperamental.
- Are not reversible.
- Are expensive.

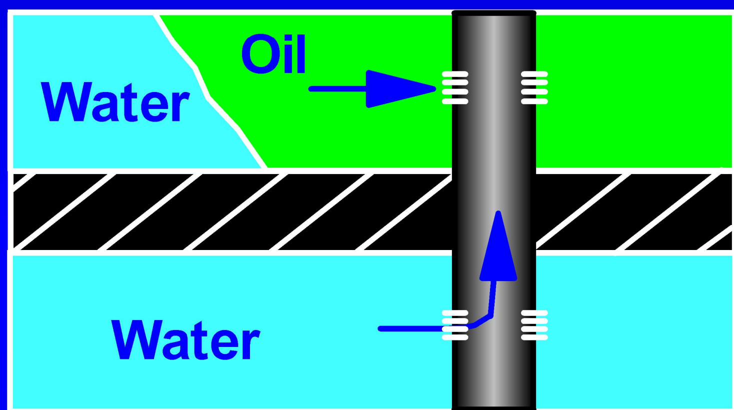
GELS
+ Can penetrate into rock matrix and tight areas.
+ Reliability of gelation chemistry depends on the gelant.
- Have lower thermal stability than other materials (<175°C).
- Have low mechanical strength outside rock matrix.

A STRATEGY FOR ATTACKING EXCESS WATER PRODUCTION

SPEPF (August 2003) pp. 158-169

CAUSES OF EXCESS WATER PRODUCTION

Open Water Zone



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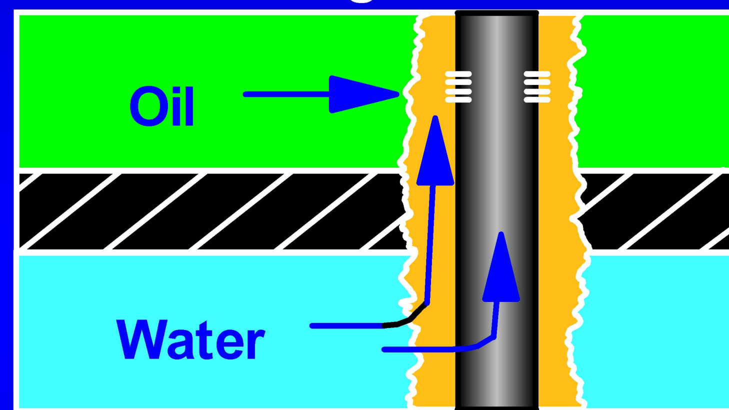

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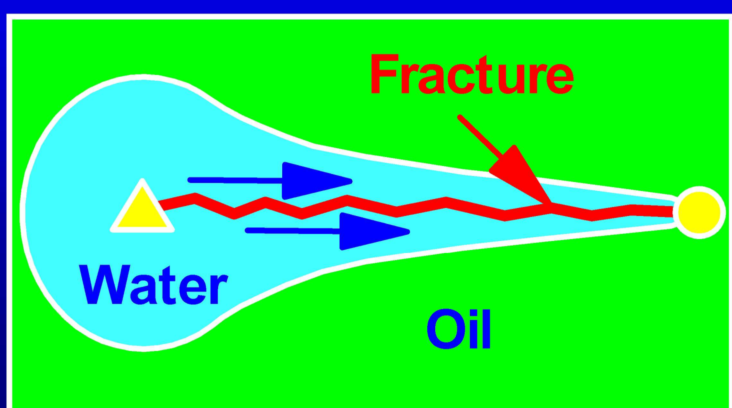
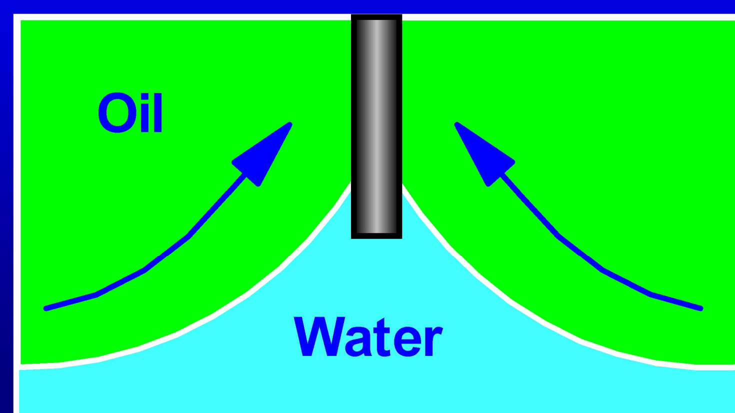
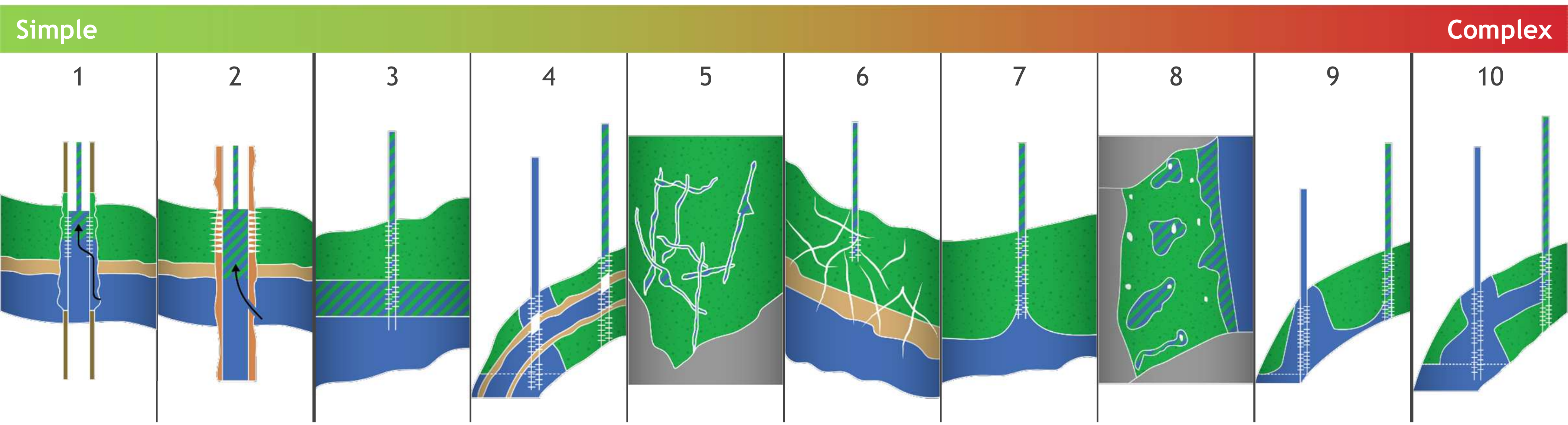


Coning or Cusping



Problem Types

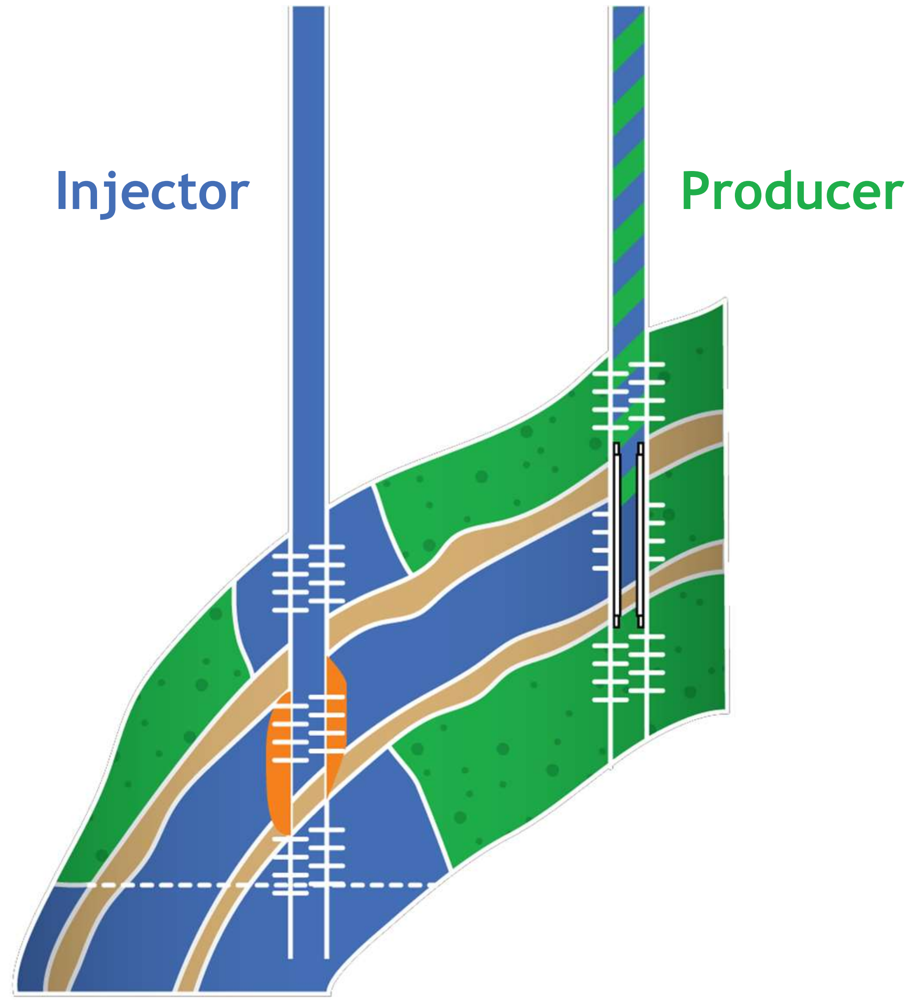
- **Wellbore Sources**
  - Casing leaks, tubing and packers leaks
  - Channels behind pipes
  - Barriers breakdown
- **Reservoir Related Sources**
  - Coning and Cusping
  - Channeling through high permeability
  - Fractures
  - Moving oil water contact
  - Gravity segregation



High Perm. Layer – No Crossflow

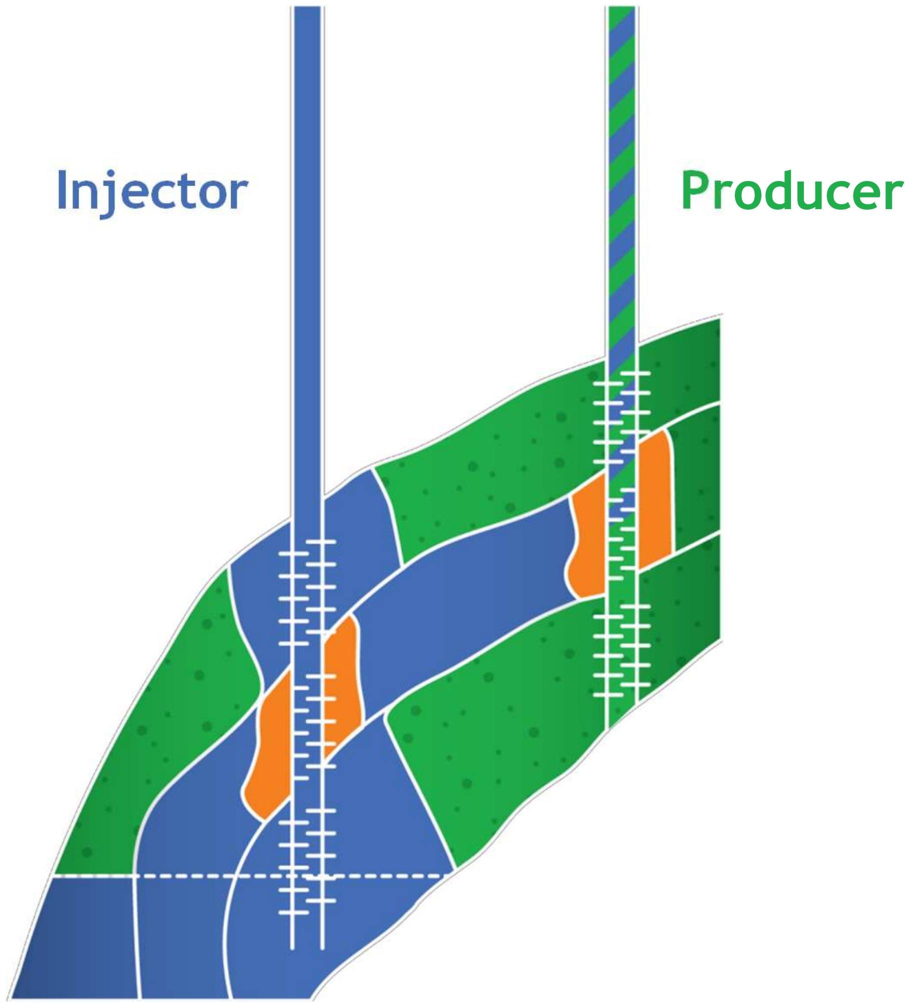
- **Vertical sweep problem**
  - Edge water
  - Water flood or aquifer
  - Thief layer/High perm. Streak

- **Shut off layer**
  - Producer or injector
  - Mechanical or chemical method



High Perm. Layer – With Crossflow

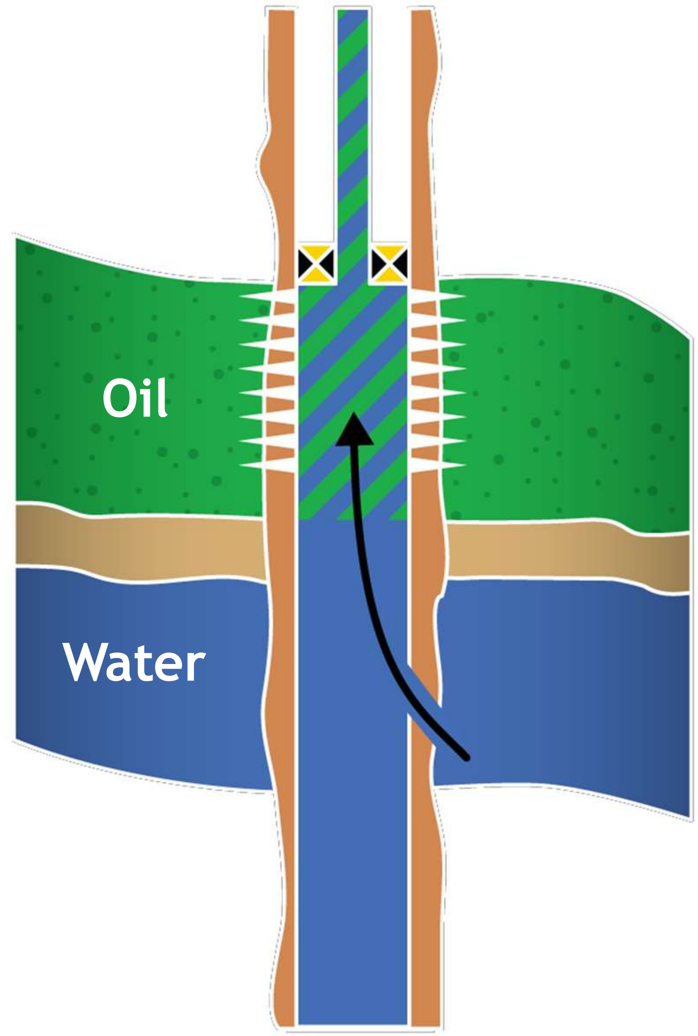
- **Vertical sweep problem**
  - Edge water
  - Water flood or aquifer
  - Thief layer/High perm. Streak



Bottom Water with Barrier

- **Simple problem type**
  - Cement
  - Casing

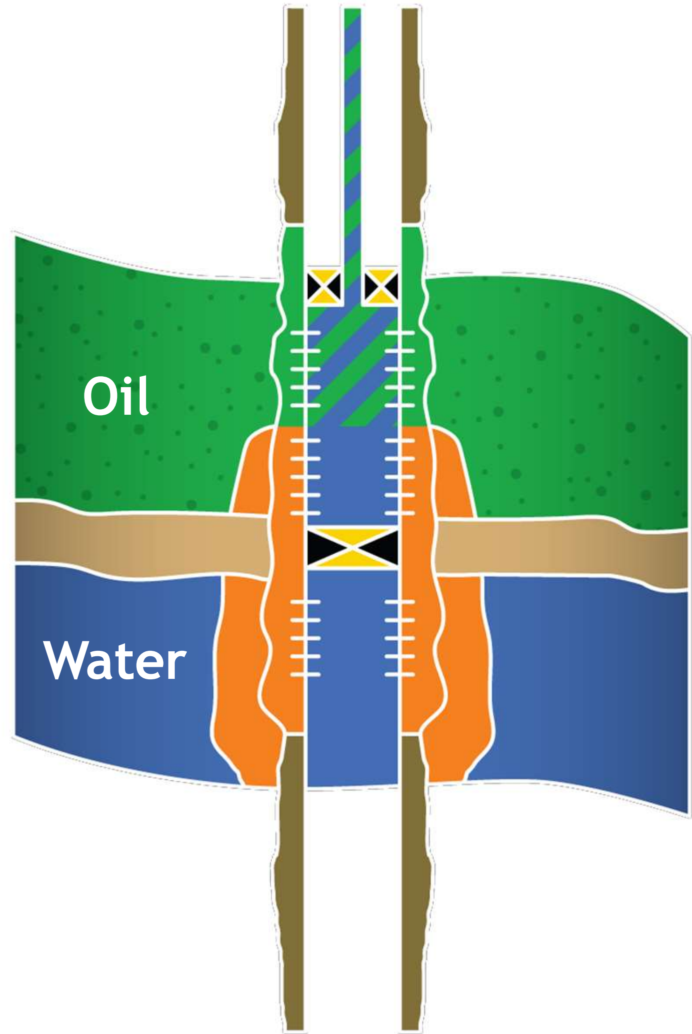
- **Plug back**
  - Cement
  - Bridge plug
  - Retainer



Near Wellbore Flow

- **Problem in or near wellbore**
  - Poor cement
  - Cave due to sanding
  - Channel behind pipe

- **Solution is case specific**
  - Cement
  - Gel
  - Resin

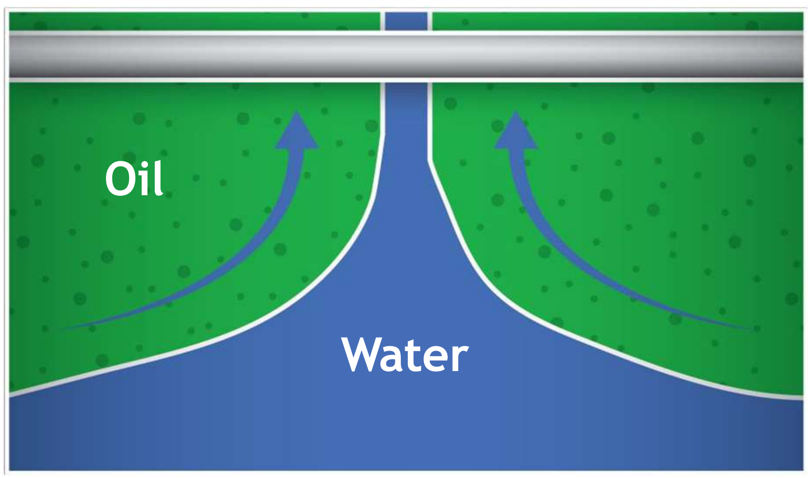


Water Coning

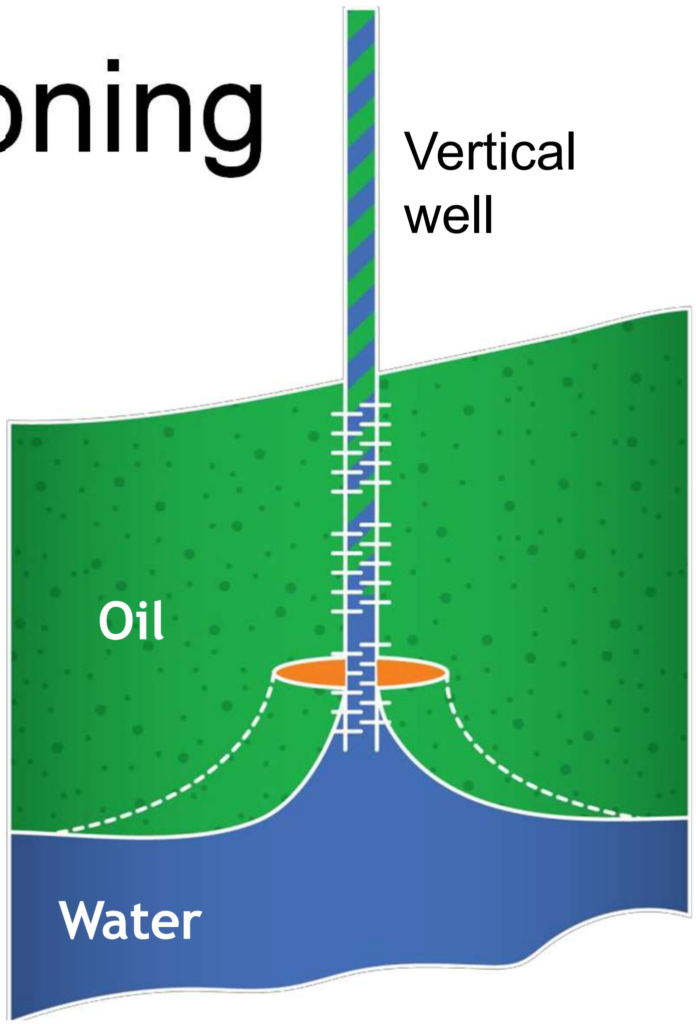
- **Bottom water**
  - Near oil / water contact
  - Critical oil rate
  - Depends on Kv

- **Horizontal wells** reduce pressure gradient and coning.

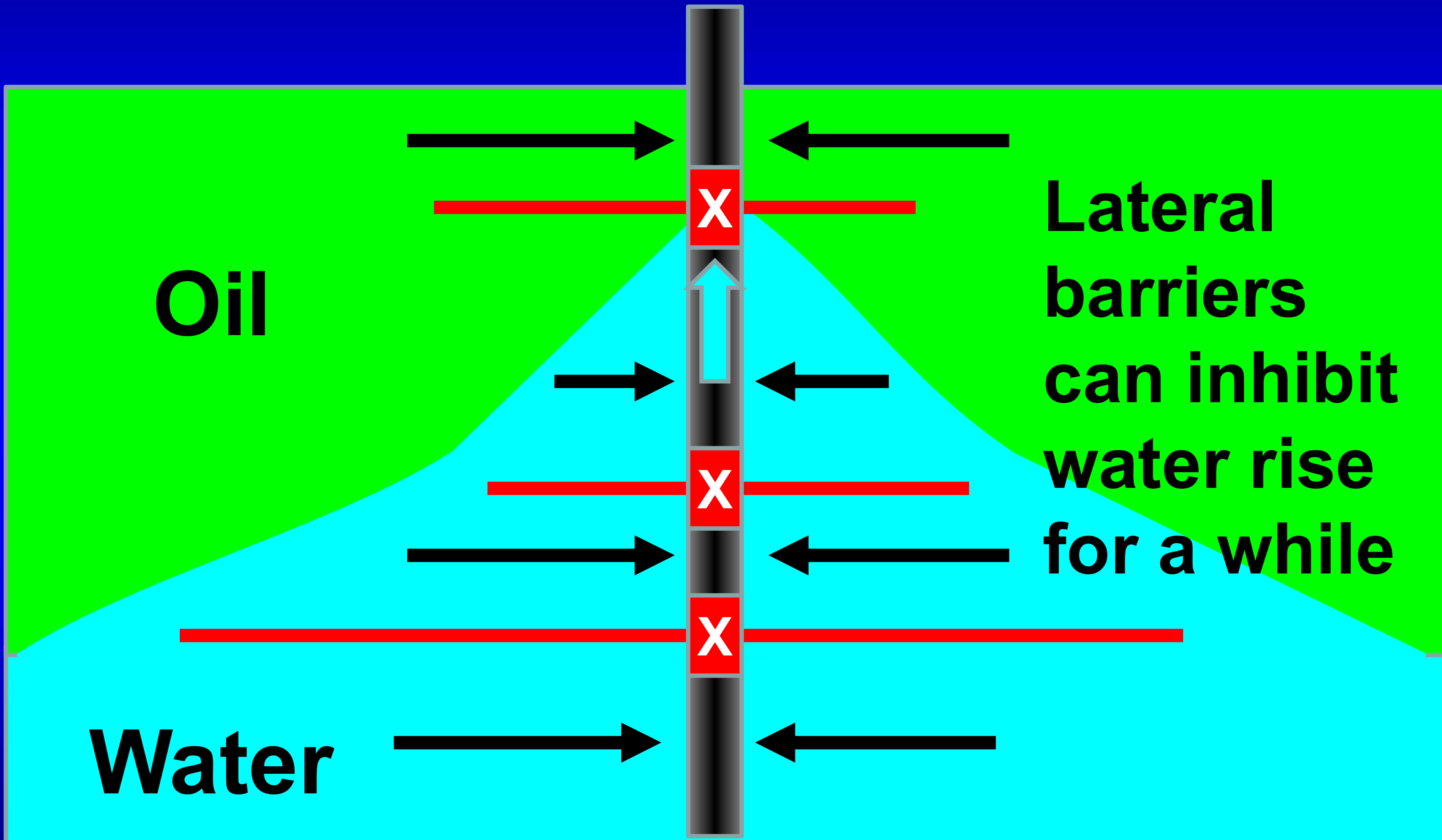
Horizontal well



Vertical well



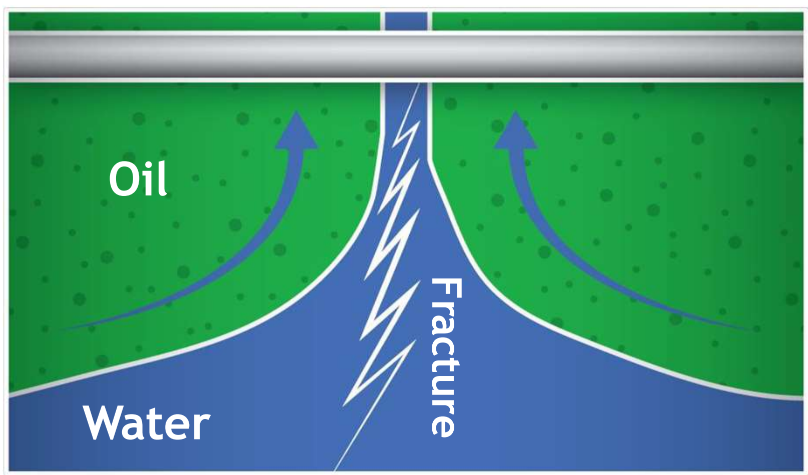
Plug backs to inhibit rising water

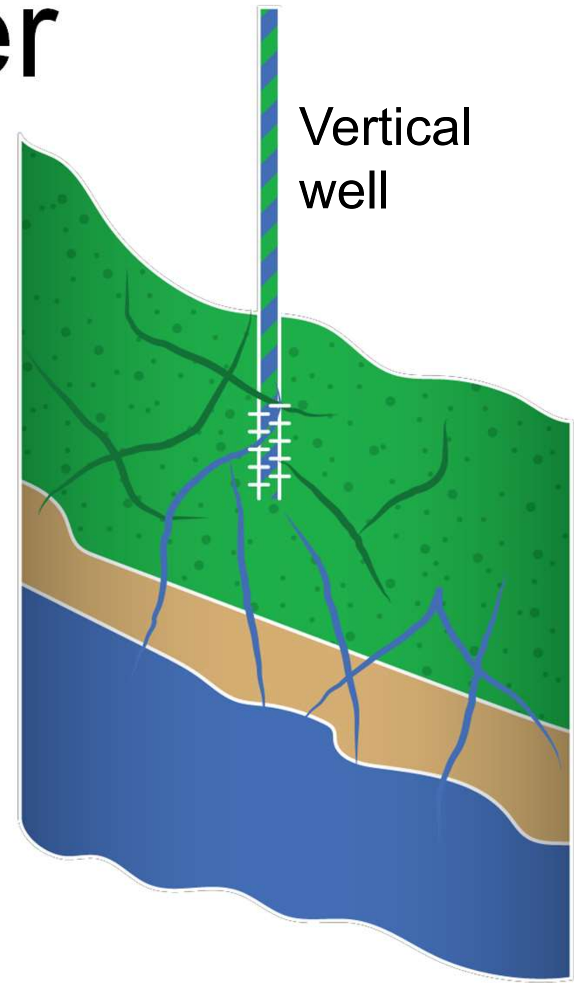


Fissures / Fractures to a Water Layer

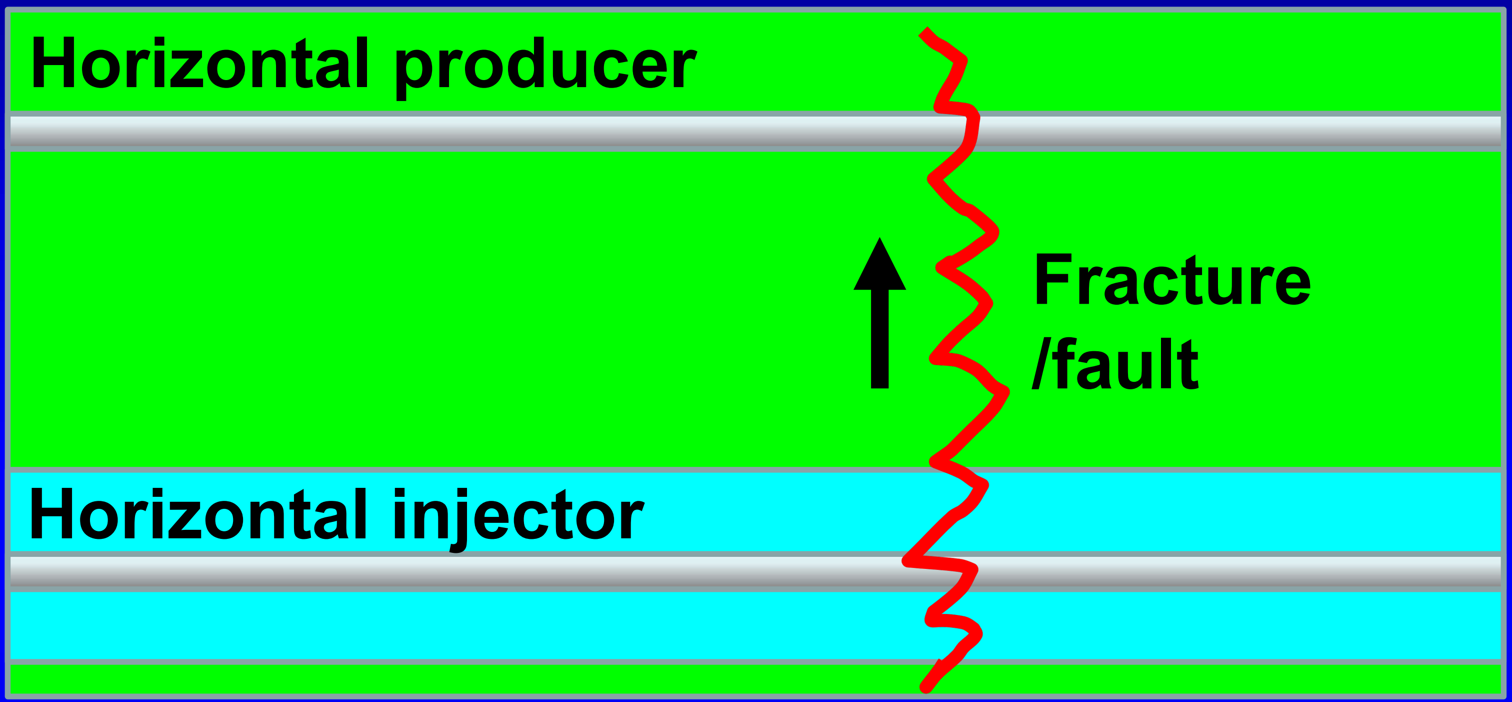
- **Oil bypassed by**
  - Natural fractures
  - Hydraulic fracture
  - Fault

Horizontal well

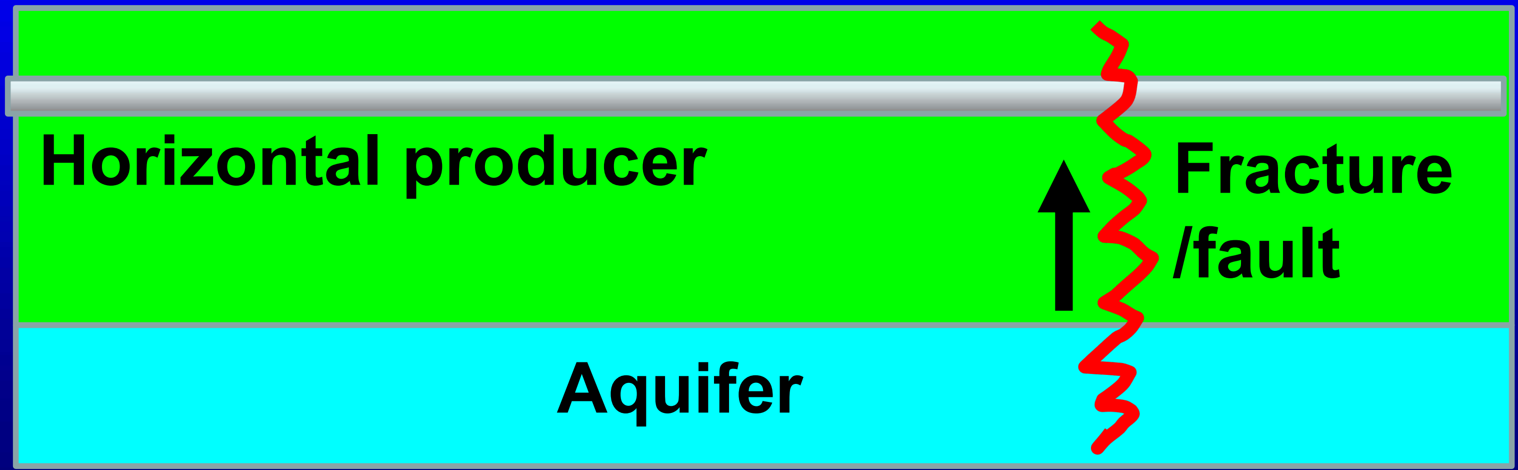




Fractures/Faults in Horizontal Wells



Top view



Side view

WATER CONTROL METHODS

- Cement, sand plugs, calcium carbonate.
- Packers, bridge plugs, mechanical patches.
- Pattern flow control.
- In fill drilling/well abandonment.
- Horizontal wells.
- Gels.
- Polymer floods.
- Resins.
- Foams, emulsions, particulates, precipitates, microorganisms.

PROBLEM

Operators often do not adequately diagnose the cause of their water production problems.

WHY NOT?

1. **Diagnosis requires money and time,**
2. **Uncertainty about which methods are cost-effective for diagnosing specific problems,**
3. **Preconception that only one type of problem exists or that one method will solve all types of problems,**
4. **Some companies encourage a belief that they have "magic-bullet" solutions.**

A STRATEGY FOR ATTACKING EXCESS WATER PRODUCTION

1. Consider and eliminate the easiest problems first.
2. Start by using information that you already have.

Excess Water Production Problems and Treatment Categories
(Categories are listed in increasing order of treatment difficulty)

Category A: "Conventional" Treatments Normally Are an Effective Choice

1. Casing leaks without flow restrictions.
2. Flow behind pipe without flow restrictions.
3. Unfractured wells (injectors or producers) with effective crossflow barriers.

Category B: Treatments with Gelants Normally Are an Effective Choice

4. Casing leaks with flow restrictions.
5. Flow behind pipe with flow restrictions.
6. "Two-dimensional coning" through a hydraulic fracture from an aquifer.
7. Natural fracture system leading to an aquifer.

Category C: Treatments with Preformed Gels Are an Effective Choice

8. Faults or fractures crossing a deviated or horizontal well.
9. Single fracture causing channeling between wells.
10. Natural fracture system allowing channeling between wells.

Category D: Difficult Problems Where Gel Treatments Should Not Be Used

11. Three-dimensional coning.
12. Cusping.
13. Channeling through strata (no fractures), with crossflow.

WHAT DIAGNOSTIC TOOLS SHOULD BE USED?

1. Production history, WOR values, GOR values
2. Pattern recovery factors, zonal recovery factors
3. Pattern throughput values (bubble maps)
4. Injection profiles, production profiles
5. Zonal saturation determinations (from logs, cores, etc.)
6. Injectivities, productivites (rate/pressure), step rate tests
7. Casing/tubing integrity tests (leak tests)
8. Temperature surveys, noise logs
9. Cement bond logs
10. Televiewers, FMI logs
11. Interwell transit times, water/hydrocarbon composition
12. Mud losses & bit drops while drilling
13. Workover & stimulation responses, previous treatments
14. Pressure transient analysis, Inter-zone pressure tests
15. Geological analysis, seismic methods, tilt meters
16. Simulation, numerical, analytical methods
17. Other

DIAGNOSTICS

We have A LOT of diagnostic methods available.
We need a strategy to decide which methods should be examined/applied first.

Possible approaches:

1. Use whatever tool is currently trendy and being pushed the hardest by my favorite service company.
2. Use the tools that have been popular in the past for this field.
3. Use a strategy that is focused finding the cause of channeling and/or excess water production.

Strategy:

1. Look for the easiest problems first.
2. Start by using information that you already have.

KEY QUESTIONS IN OUR APPROACH

1. Does a problem really exist?
2. Does the problem occur right at the wellbore (like casing leaks or flow behind pipe) or does it occur out beyond the wellbore?
3. If the problem occurs out beyond the wellbore, are fractures or fracture-like features the main cause of the problem?
4. If the problem occurs out beyond the wellbore and fractures are not the cause of the problem, can crossflow occur between the dominant water zones and the dominant hydrocarbon zones?

Respect basic physical and engineering principles.
Stay away from black magic.

DOES A PROBLEM REALLY EXIST?

- Are significant volumes of mobile hydrocarbon present?
- Are recovery factors and/or WOR values much greater than neighboring wells or patterns?
- Are recovery values much less than expected after considering existing drive mechanism, existing stratification, structural position of the wells, injection fluid throughput, and existing mobility ratio?

FIRST SET OF DIAGNOSTIC TESTS

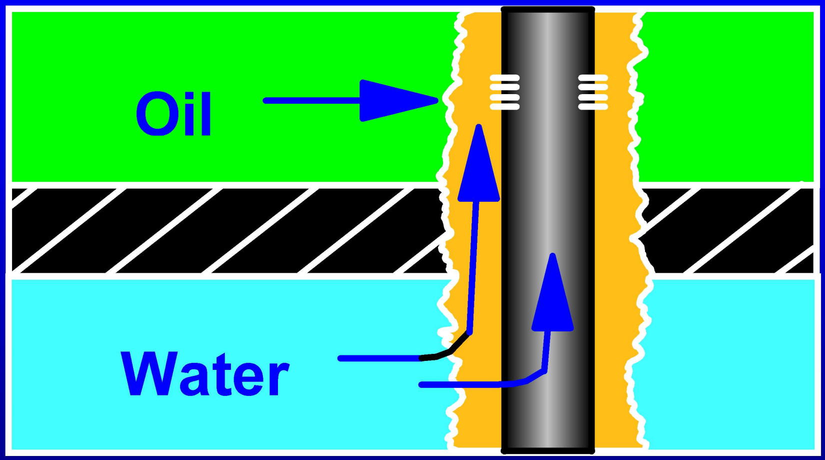
Recovery factor in view of:

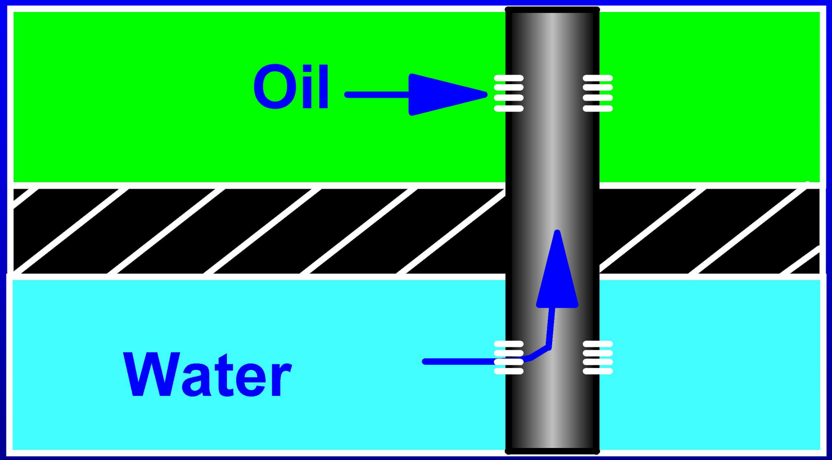
- **Producing water/oil ratio, GOR.**
- **Neighboring wells and patterns.**
- **Drive mechanism.**
- **Reservoir stratification.**
- **Structural position.**
- **Injection fluid throughput.**
- **Water/oil mobility ratio.**

CATEGORY A: EASIEST PROBLEMS

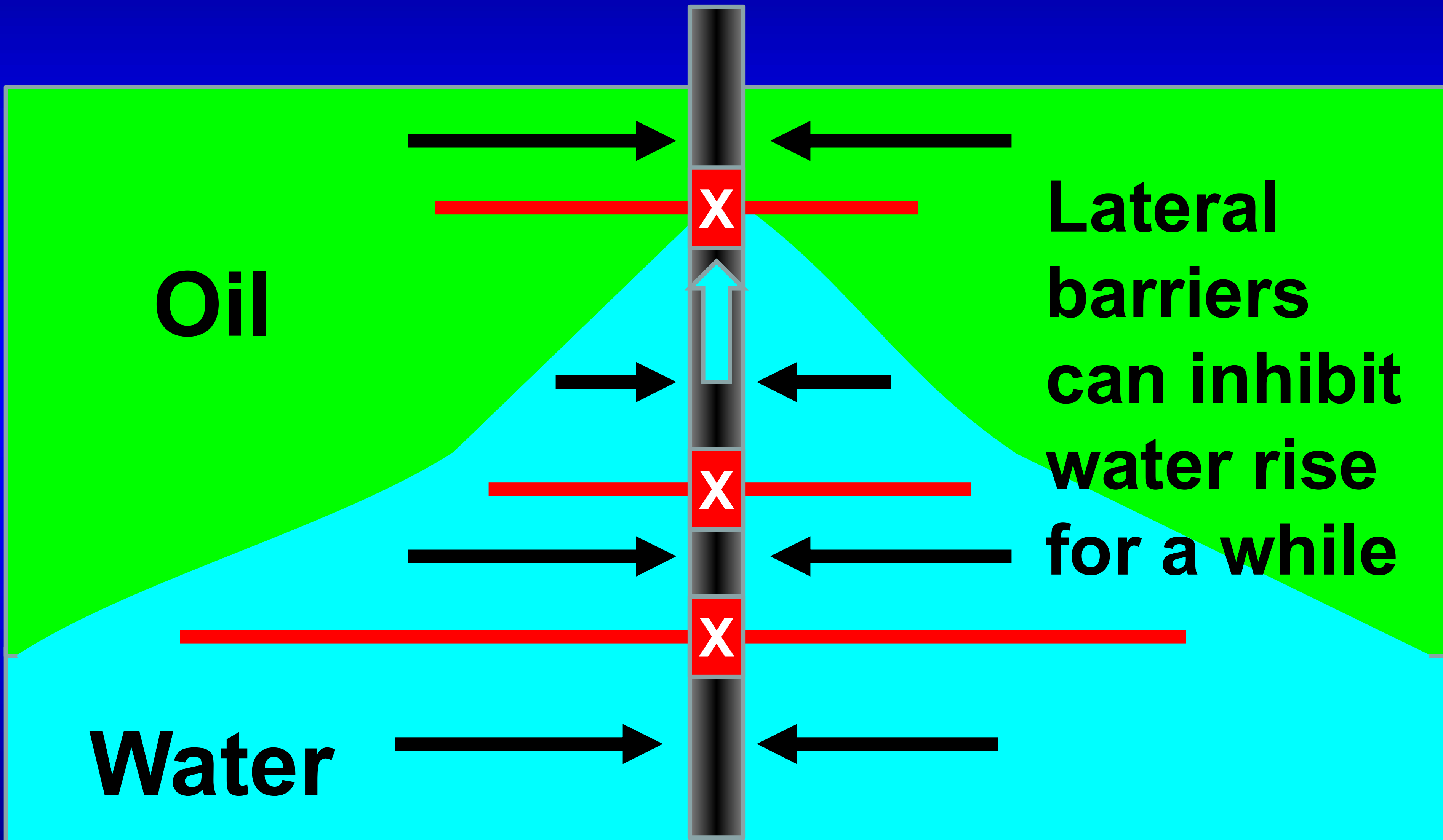
"Conventional" Treatments Normally Are an Effective Choice

1. Casing leaks without flow restrictions (moderate to large holes).
2. Flow behind pipe without flow restrictions (typically no primary cement).
3. Unfractured wells (injectors or producers) with effective barriers to crossflow.
4. Horizontal wells that cross fractures or faults.

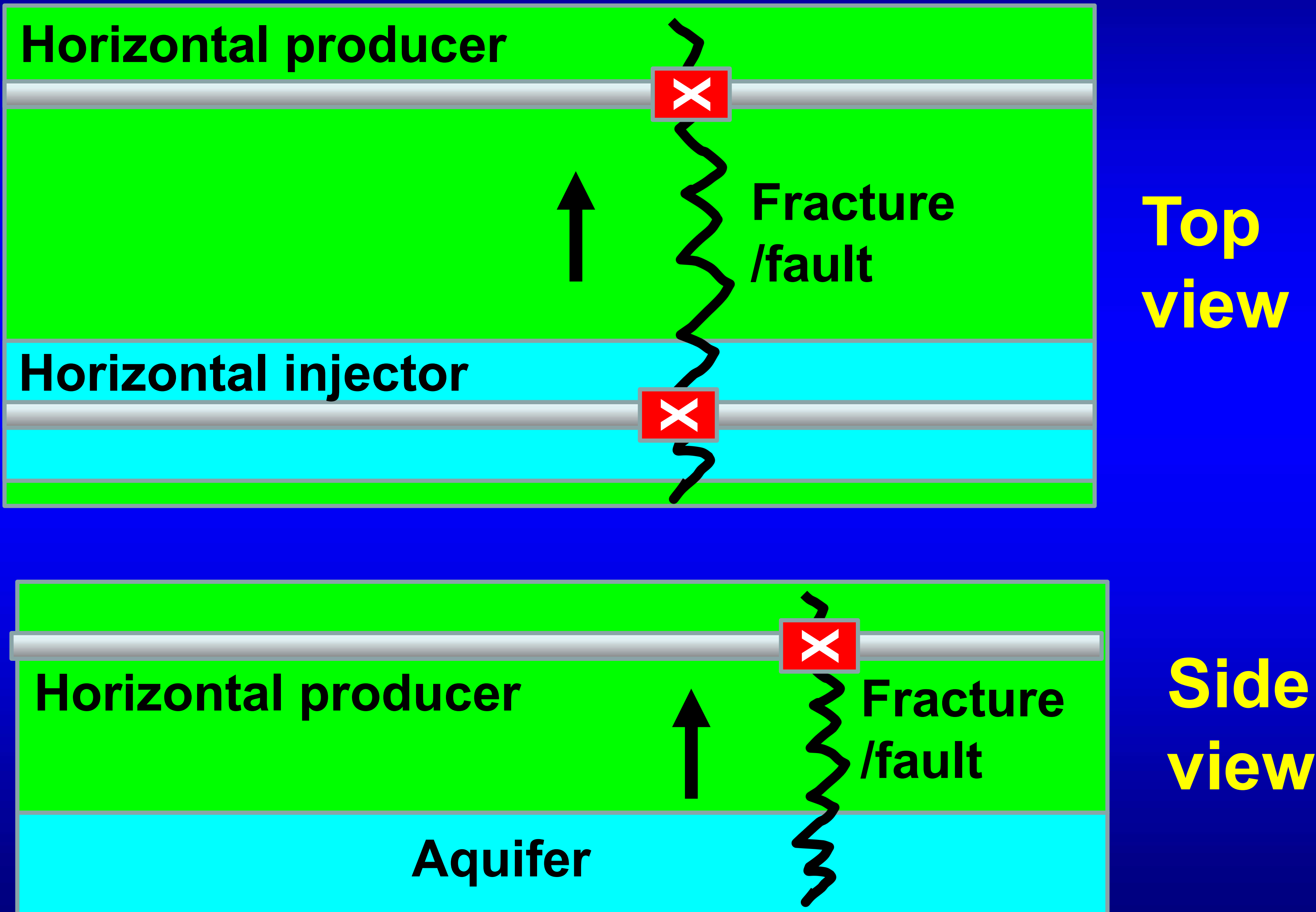




Plug backs to inhibit rising water



Fractures/Faults in Horizontal Wells Often Can Be Plugged with Small, Local Plugs



SECOND SET OF DIAGNOSTIC TESTS

Does the problem occur right at the wellbore?
Is the problem a leak or flow behind pipe?

- Leak tests/casing integrity tests
- Temperature surveys
- Radio-tracer flow logs
- Spinner surveys
- Cement bond logs
- Borehole televiewers
- Noise logs

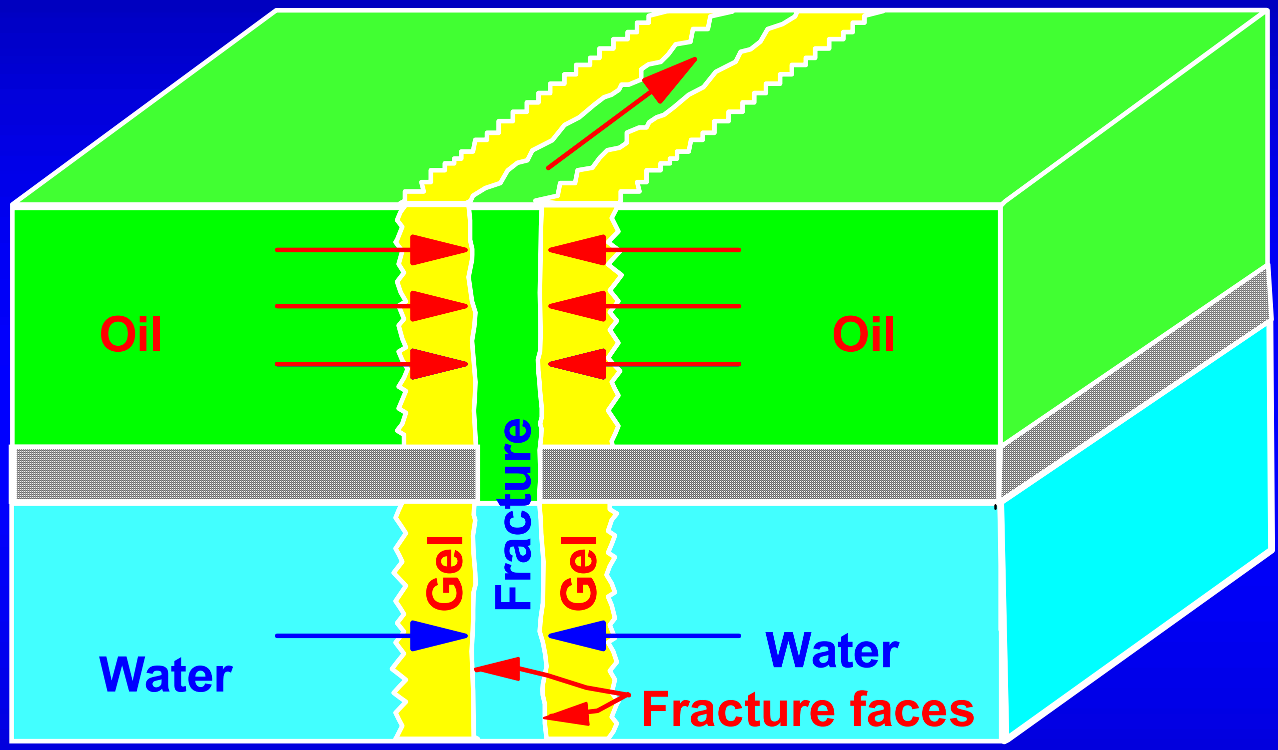
CATEGORY B:

INTERMEDIATE DIFFICULTY

Treatments with GELANTS Normally Are an Effective Choice

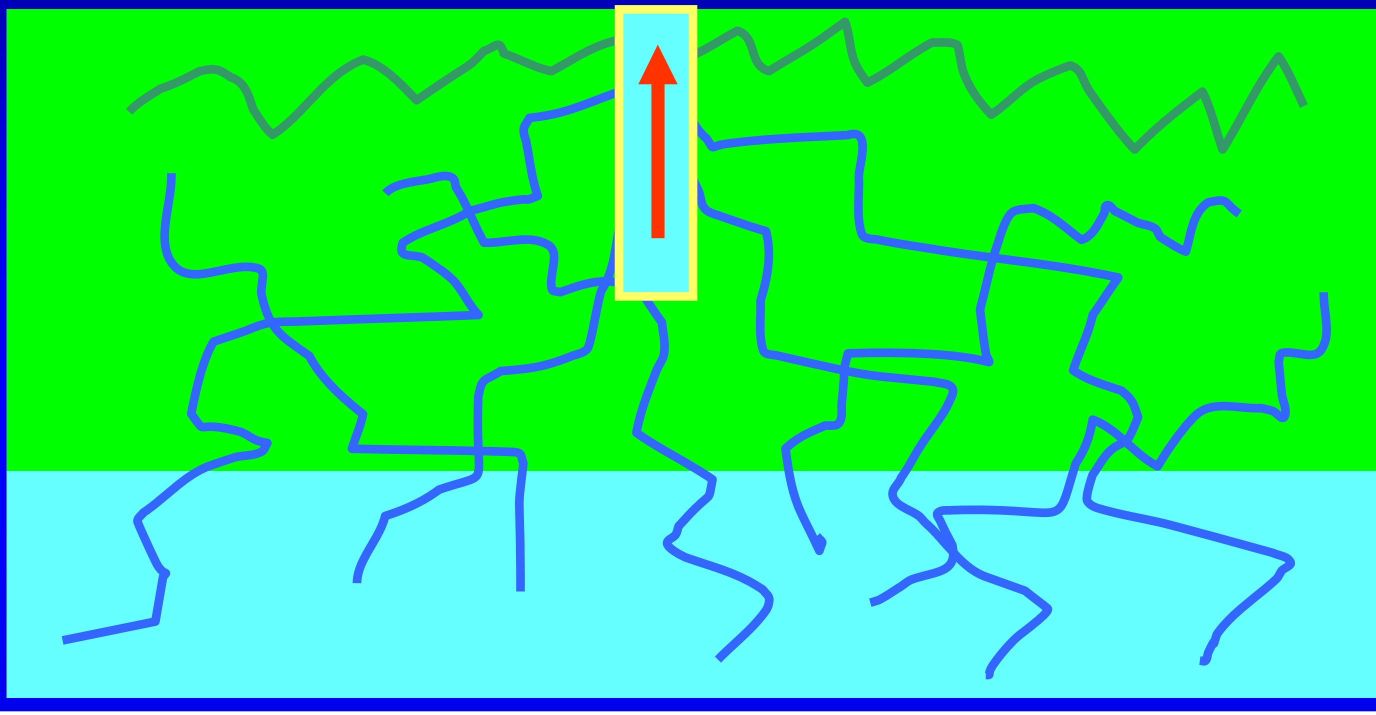
4. Casing leaks with flow restrictions (pinhole leaks).
5. Flow behind pipe with flow restrictions (narrow channels).
6. “Two-dimensional coning” through a hydraulic fracture from an aquifer.
7. Natural fracture system leading to an aquifer.

Problem 6: "Two-dimensional coning" through a hydraulic fracture from an aquifer.



- Need a gel that reduces k_w much more than k_o or k_{gas}.

Problem 7:
Natural fracture system leading to an aquifer.



- Many successful gelant treatments applied in dolomite formations.
- Treatment effects were usually temporary.
- Recent, longer lasting successes seen with preformed gels.

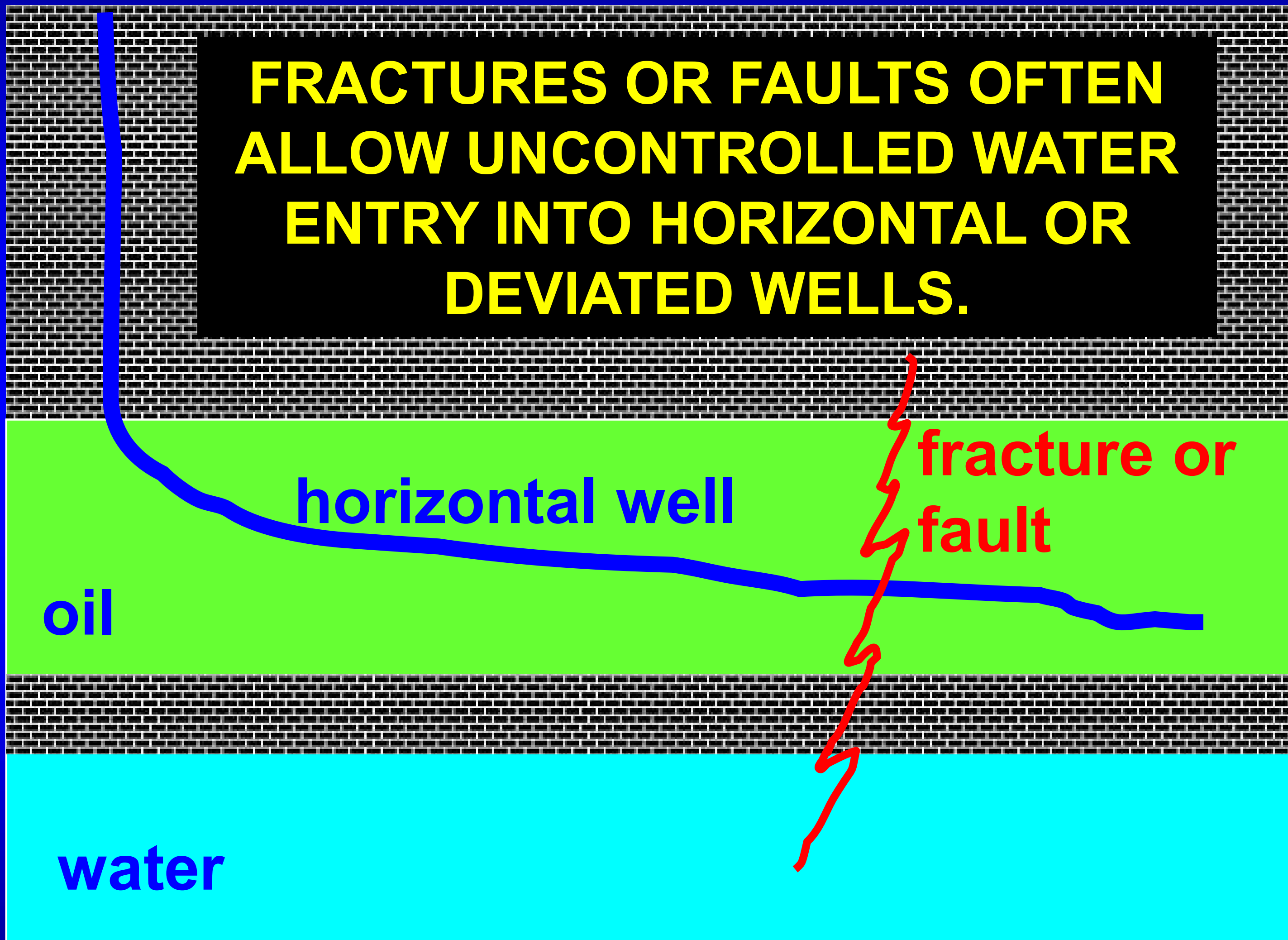
CATEGORY C:

INTERMEDIATE DIFFICULTY

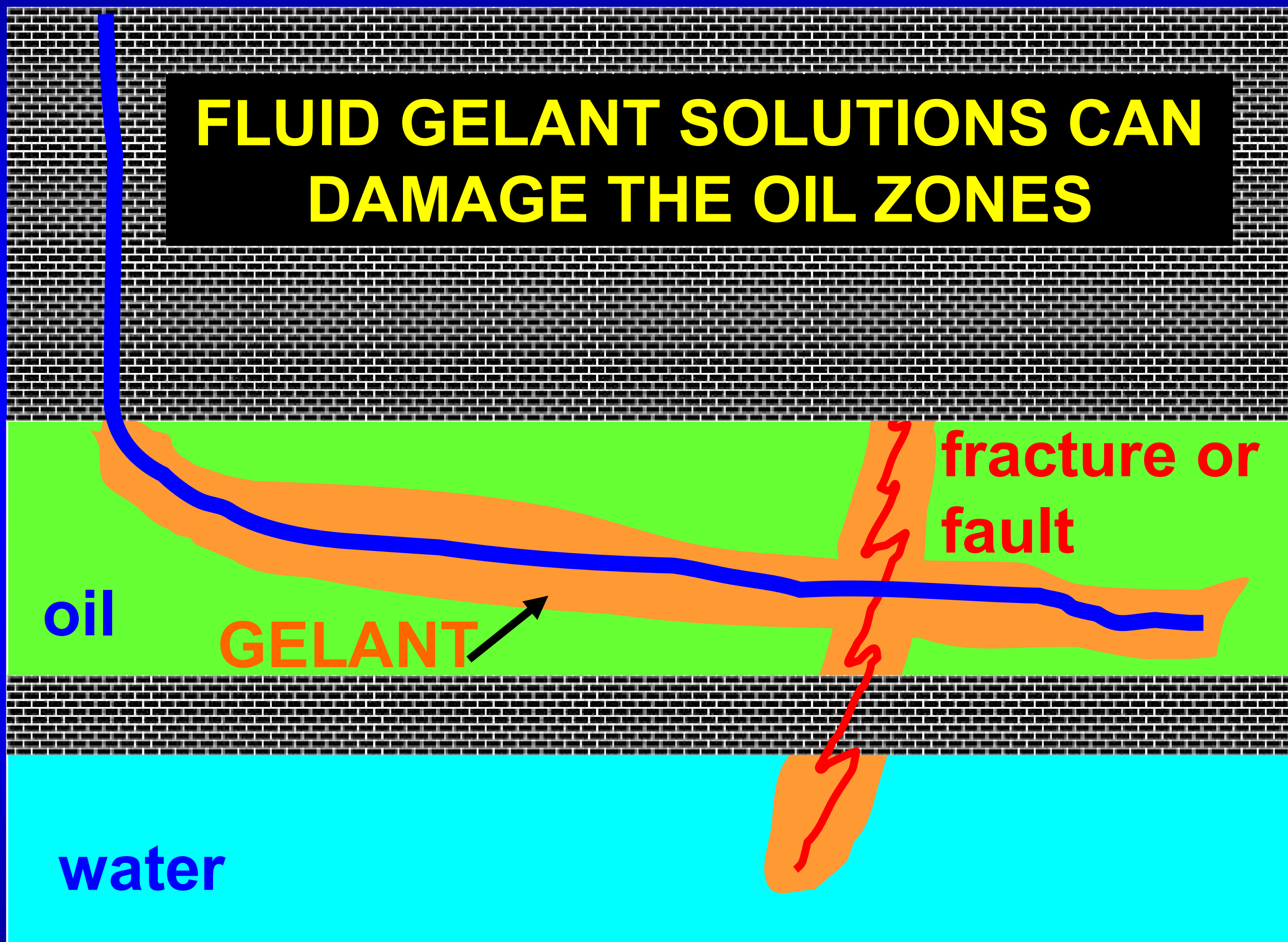
Treatments with PREFORMED GELS Are an Effective Choice

8. **Faults or fractures crossing a deviated or horizontal well.**
9. **Single fracture causing channeling between wells.**
10. **Natural fracture system allowing channeling between wells.**

Problem 8

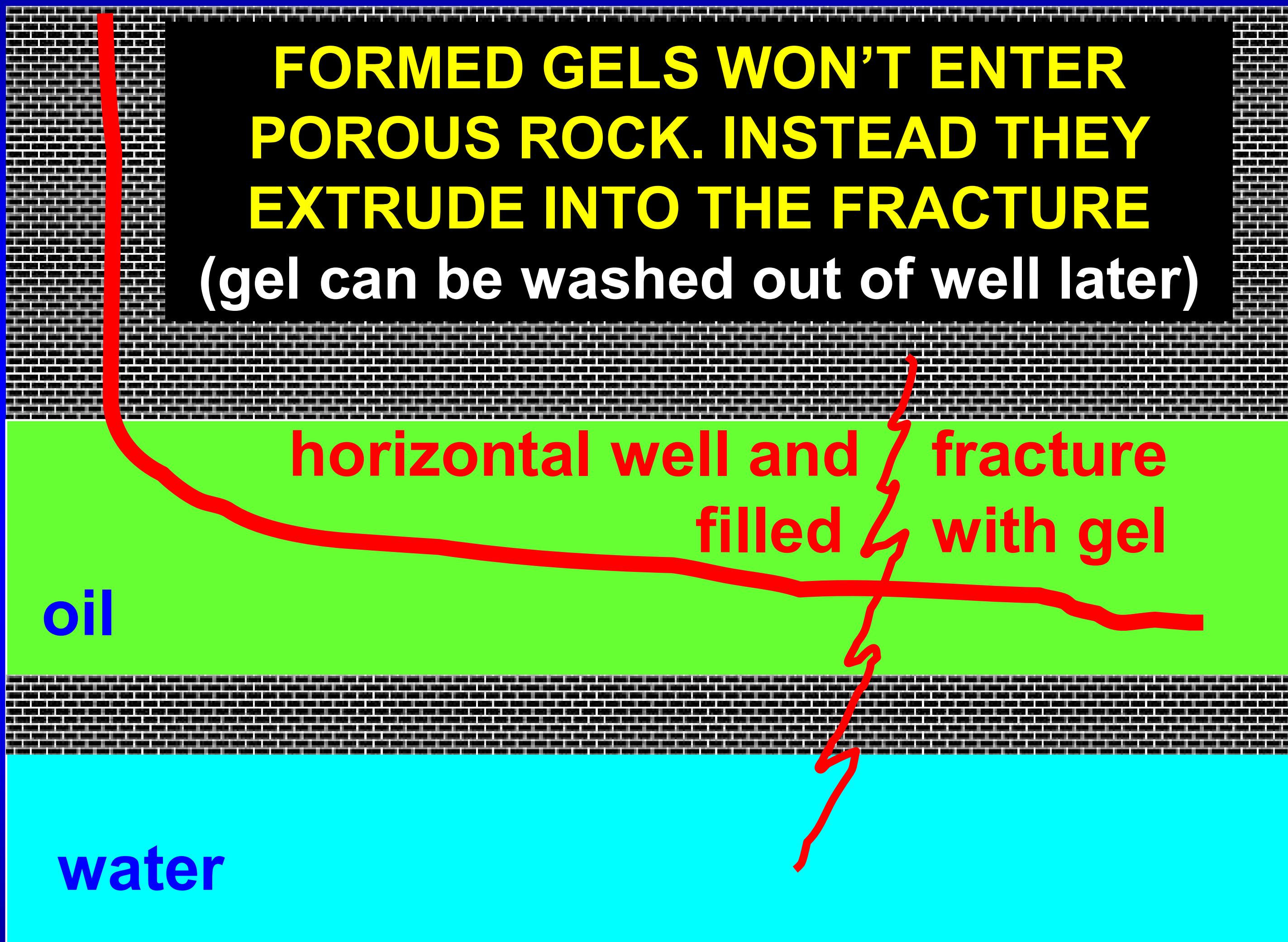

FRACTURES OR FAULTS OFTEN ALLOW UNCONTROLLED WATER ENTRY INTO HORIZONTAL OR DEVIATED WELLS.
horizontal well
fracture or fault
oil
water

Problem 8



FLUID GELANT SOLUTIONS CAN DAMAGE THE OIL ZONES
fracture or fault
oil
GELANT
water

Problem 8: SPE 65527



THIRD SET OF DIAGNOSTIC TESTS

HELPFUL INITIAL INDICATORS OF FRACTURES

- Well history (intentional stimulation).
- Injectivity or productivity much higher than expected from Darcy's law for radial flow.
- Results from step-rate tests.

- Speed of water breakthrough or other tracer.

- Fluid loss during drilling.
- Pulse test responses, or pumper observations.

- FMI logs
- Seismic

Does my well have a linear-flow problem?
(e.g., a fracture)

Injectivity or productivity data often provides a low-cost method for diagnosis.

Radial (matrix) flow probable:

$$q/\Delta p \leq (\Sigma\ k\ h)/[141.2\ \mu\ \ln\ (r_e\ /\ r_w)]$$

Linear (fracture-like) flow probable:

$$q/\Delta p >> (\Sigma\ k\ h)/[141.2\ \mu\ \ln\ (r_e\ /\ r_w)]$$

ESTIMATING FRACTURE CONDUCTIVITY FROM INJECTIVITY OR PRODUCTIVITY DATA

Assume:

- Vertical well with a vertical fracture
- If multiple fractures are present, the widest fracture dominates flow.
- The fracture has a much greater flow capacity than the matrix.
- The fracture has two wings.

$$q_{total} = q_{matrix} + q_{fracture} = (\Delta p\ h_f /\mu)\ [k_m/\ln(r_e/r_w) + 2k_f w_f/L_f]$$

$$k_f w_f = \{[q_{total}\ \mu/(\Delta p\ h_f)] - [k_m/\ln(r_e/r_w)]\}\ L_f /2$$

RELATION BETWEEN FRACTURE WIDTH, PERMEABILITY, AND CONDUCTIVITY

$k_f\ w_f$ (darcy-ft) = $1.13\times10^{-5}\ (k_f)^{1.5}$, where k_f is in darcys.

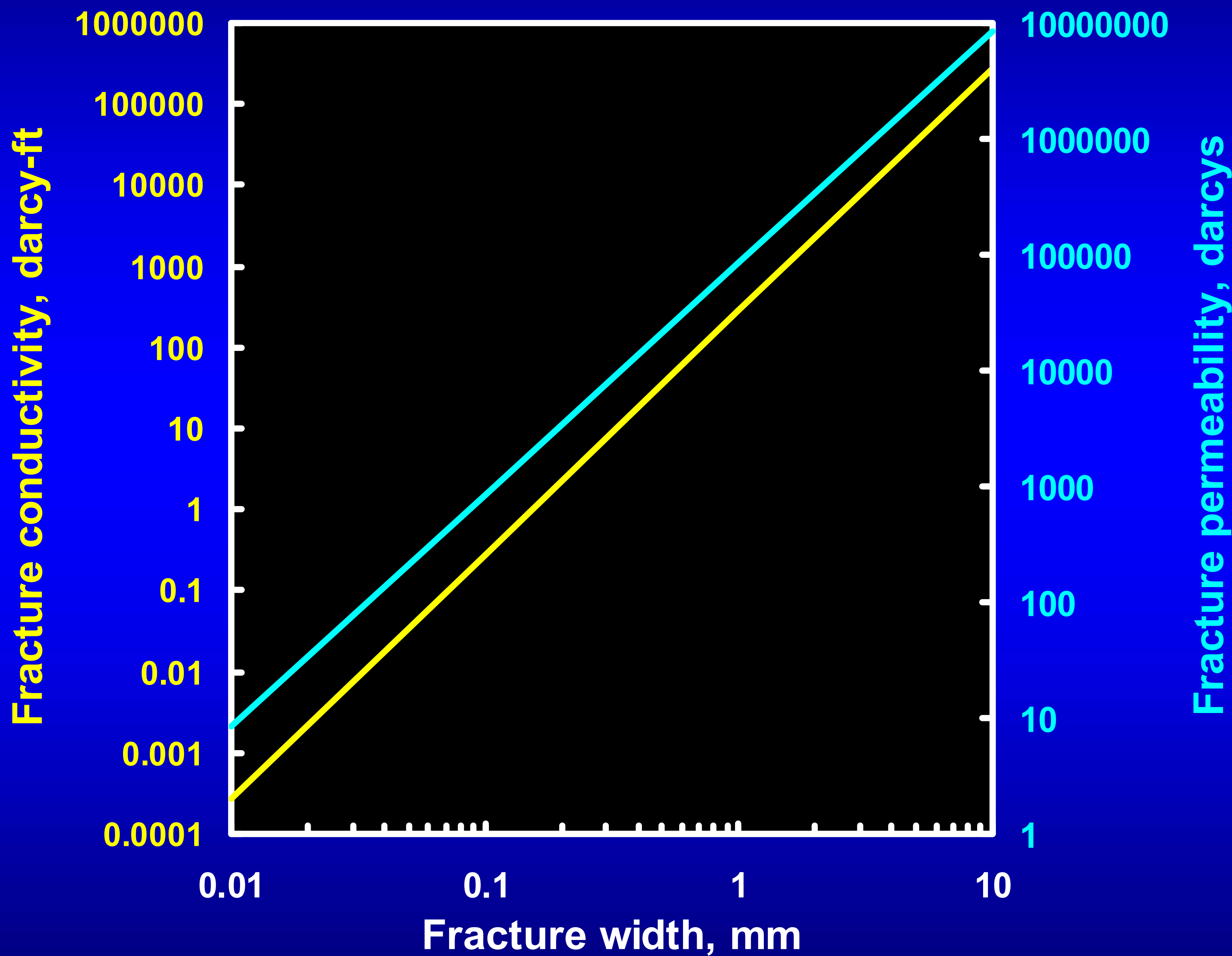
$k_f\ w_f$ (darcy-cm) = $3.44\times10^{-4}\ (k_f)^{1.5}$, where k_f is in darcys.

w_f (ft) = $5.03\times10^{-4}\ (k_f w_f)^{1/3}$, where $k_f w_f$ is in darcy-ft.

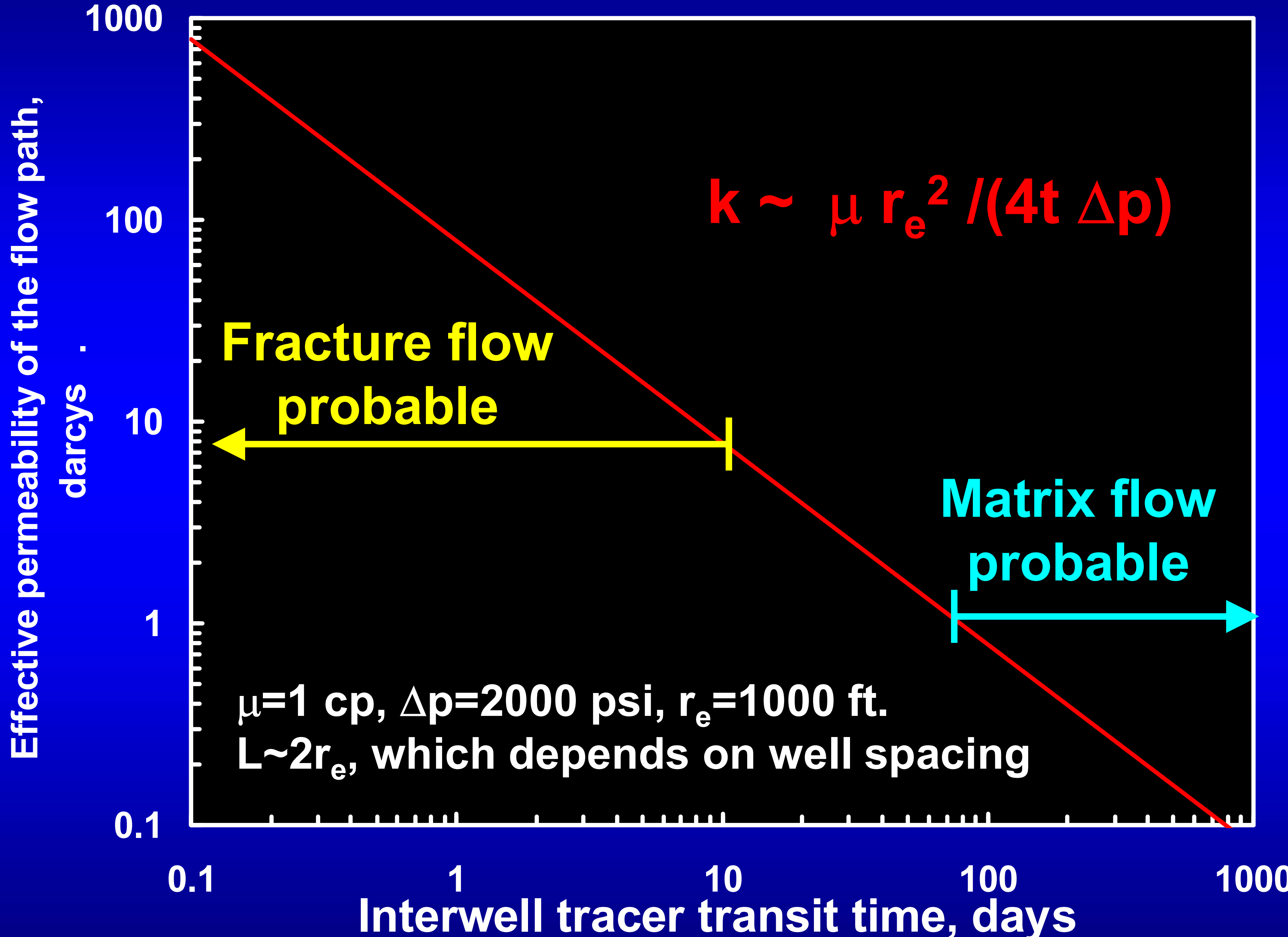
w_f (mm) = $0.153\ (k_f w_f)^{1/3}$, where $k_f w_f$ is in darcy-ft.

w_f (mm) = $3.44\times10^{-3}\ (k_f)^{0.5}$, where k_f is in darcys.

THE WIDEST FRACTURE DOMINATES FLOW



MATRIX OR FRACTURE FLOW?



ESTIMATING FRACTURE PERMEABILITY FROM TRACER TRANSIT TIMES

Assume the widest fracture dominates flow.

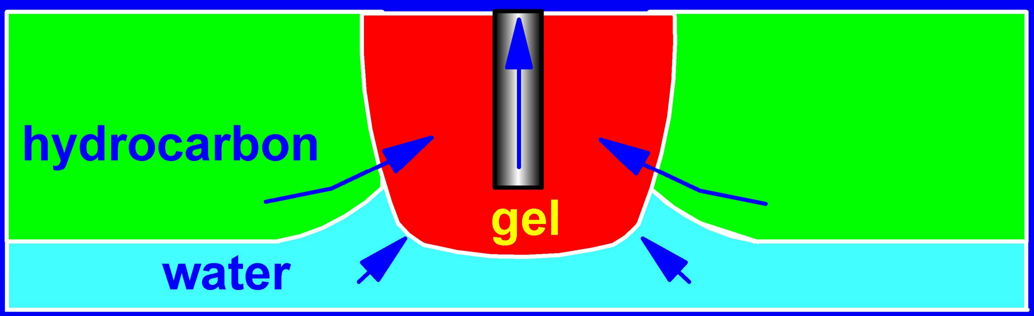
$$k_f = q\mu L/[h_f w_f \, \Delta p] = (L h_f w_f/t)\mu L/[h_f w_f \, \Delta p] = (L^2 \mu)/(\Delta p \, t)$$

Where:

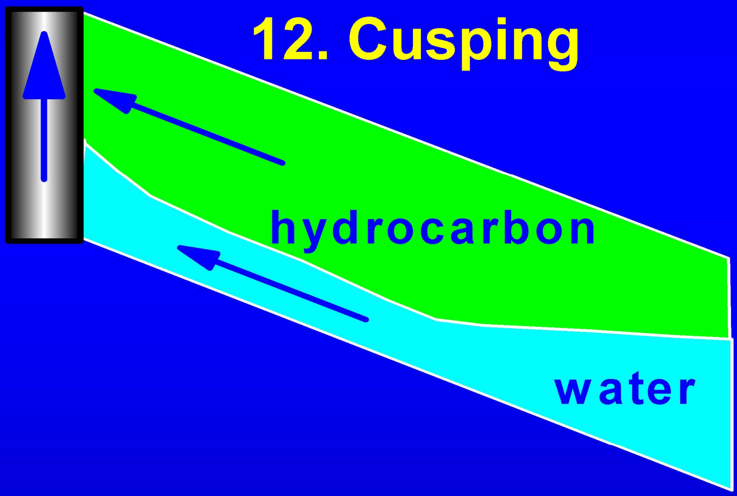
L is fracture length (~distance between wells),
μ is fluid viscosity (usually of water),
Δp is the pressure drop between wells,
t is tracer transit time between wells.

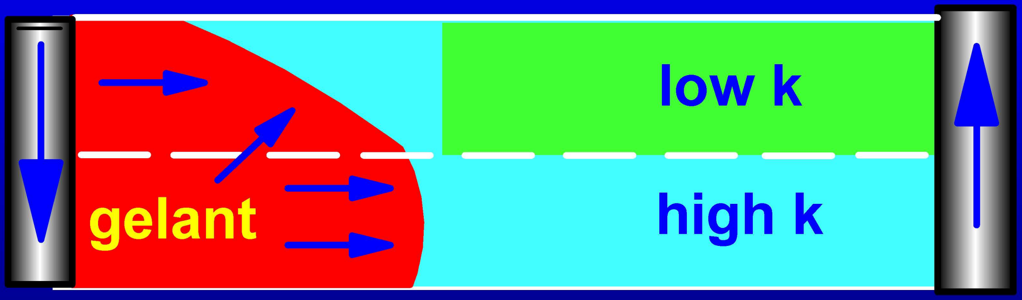
CATEGORY D:
MOST DIFFICULT PROBLEMS
GELANT or GEL Treatments Should NOT Be Used

11. Three-Dimensional Coning



12. Cusping





13. Channeling through strata (no fractures), with crossflow.

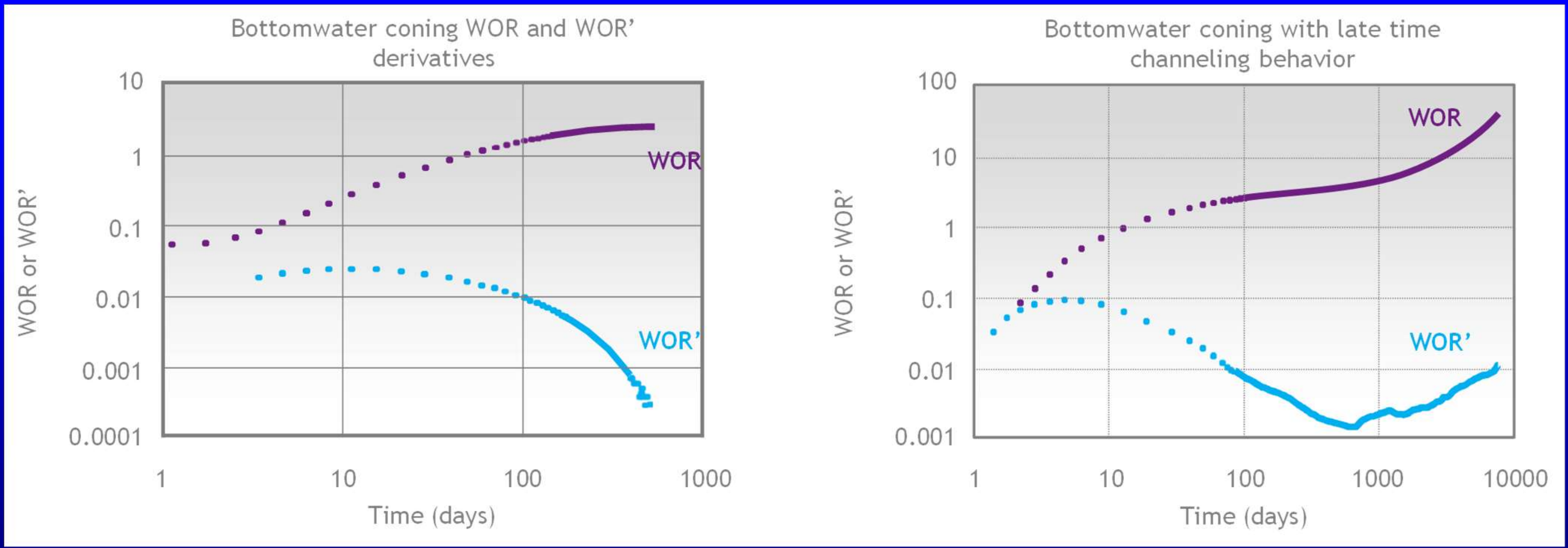
FOURTH SET OF DIAGNOSTIC TESTS

Is the problem accentuated by crossflow?

- Pressure test between zones,
- Various logs for determining fluid saturations, permeabilities, porosities, and lithologies
- Injection/production profiles
- Simulation
- Seismic and geophysical methods

Water Control Diagnostic Plots (Chan Plots, SPE 30775)

- Claims that derivatives of WOR plots distinguish between coning and channeling.
- No mathematical basis for the claim is apparent.
- Experimental basis of the claim is not apparent
- Is this method correct and of value?



WOR DIAGNOSTIC PLOTS

WOR vs. time can be very valuable in determining:

1. When the problem developed,
2. The severity of the problem,
3. What the problem is, IF VIEWED ALONG WITH OTHER INFORMATION.

BUT WOR or WOR derivative plots CANNOT by themselves distinguish between channeling and coning. See Chapter 2 of our 1997 Annual Report

Distinguishing between matrix and fracture problems is much more important than distinguishing between channeling and coning.

QUESTIONS FOR FIELD PROJECTS

- Why did you decide there was a problem?
- What did you do to diagnose the problem?
- What additional information do you need and how will you get it?
- What types of solutions did you consider?
- Why did you chose your solution over others?
- How did you size and place the treatment?
- Did it work? How do you know?
- What would you do different next time?

PREDICTING EXCESS WATER PRODUCTION
FACTORS LEADING TO PROBLEMS

1. Bad cement or factors inhibiting cementation.
2. Corrosive brines or gases.
3. Wellbore abuse during work-overs or well interventions.
4. Natural fractures (if oriented wrong).
5. Large permeability contrasts.
6. Low permeability rock (if induced fractures are oriented wrong).
7. Viscous oils or unfavorable mobility ratios.
8. Close proximity of an aquifer or gas cap.
9. Crossflow, under the wrong conditions (Items 5, 6, and 7 above).
10. Particulates or emulsions in injection water.

A STRATEGY FOR ATTACKING EXCESS WATER PRODUCTION

1. Consider and eliminate the easiest problems first.
2. Start by using information that you already have.

Excess Water Production Problems and Treatment Categories
(Categories are listed in increasing order of treatment difficulty)

Category A: "Conventional" Treatments Normally Are an Effective Choice

1. Casing leaks without flow restrictions.
2. Flow behind pipe without flow restrictions.
3. Unfractured wells (injectors or producers) with effective crossflow barriers.

Category B: Treatments with Gelants Normally Are an Effective Choice

4. Casing leaks with flow restrictions.
5. Flow behind pipe with flow restrictions.
6. "Two-dimensional coning" through a hydraulic fracture from an aquifer.
7. Natural fracture system leading to an aquifer.

Category C: Treatments with Preformed Gels Are an Effective Choice

8. Faults or fractures crossing a deviated or horizontal well.
9. Single fracture causing channeling between wells.
10. Natural fracture system allowing channeling between wells.

Category D: Difficult Problems Where Gel Treatments Should Not Be Used

11. Three-dimensional coning.
12. Cusping.
13. Channeling through strata (no fractures), with crossflow.

KEY QUESTIONS IN OUR APPROACH

1. Does a problem really exist?
2. Does the problem occur right at the wellbore (like casing leaks or flow behind pipe) or does it occur out beyond the wellbore?
3. If the problem occurs out beyond the wellbore, are fractures or fracture-like features the main cause of the problem?
4. If the problem occurs out beyond the wellbore and fractures are not the cause of the problem, can crossflow occur between the dominant water zones and the dominant hydrocarbon zones?

Respect basic physical and engineering principles.
Stay away from black magic.

Mechanical Methods

WATER CONTROL METHODS

- Cement, sand plugs, calcium carbonate.
- Packers, bridge plugs, mechanical patches.
- Pattern flow control.
- In fill drilling/well abandonment.
- Horizontal wells.
- Gels.
- Polymer floods.
- Resins.
- Foams, emulsions, particulates, precipitates, microorganisms.

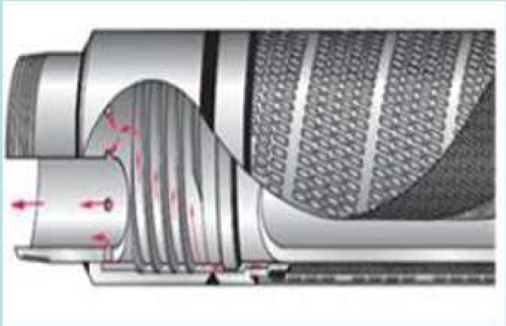
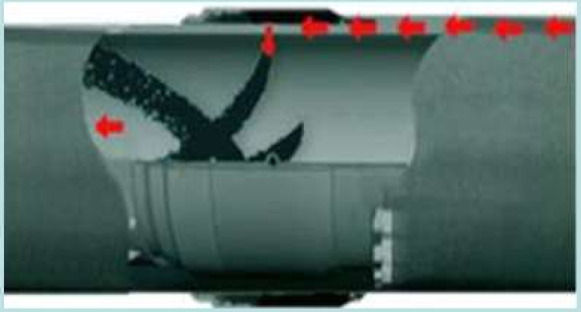
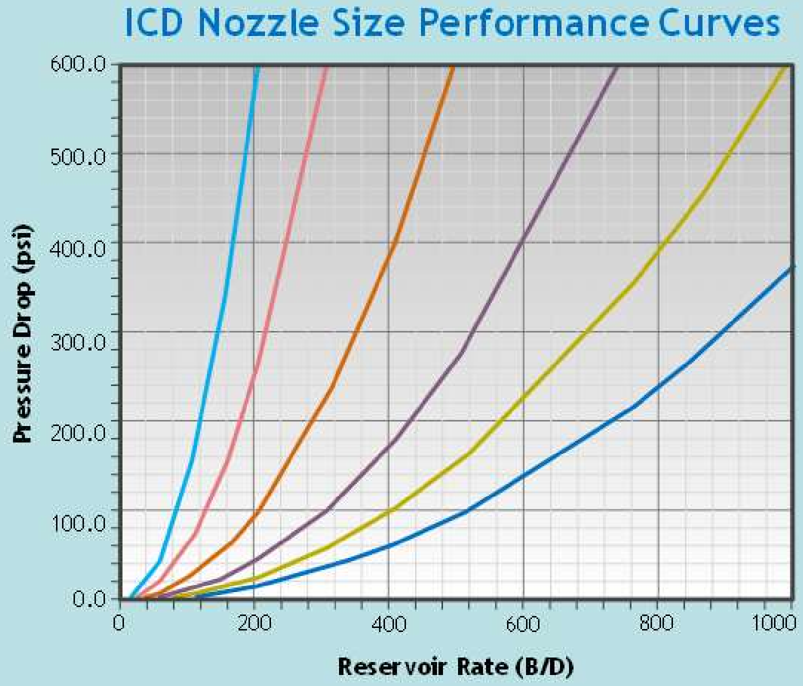
Some Mechanical Solutions

- Inflow (or injection) control device (ICD)
- Active ICD with sliding sleeve
- Multi-position sleeve with ICD
- Autonomous ICD???
- Density sensitive ICD?
- Expandable metal clad / patch to isolate the ICD port
- Inflow control valves (ICV)

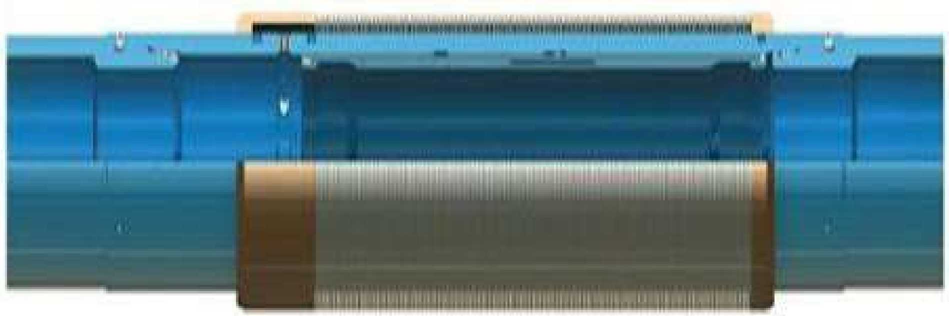
Inflow (or Injection) Control Devices

- Passive devices to balance inflow or injection along horizontal wells.
- Field adjustable ICD designs allow the flow regulation to be set at the rig site based on open hole logs.

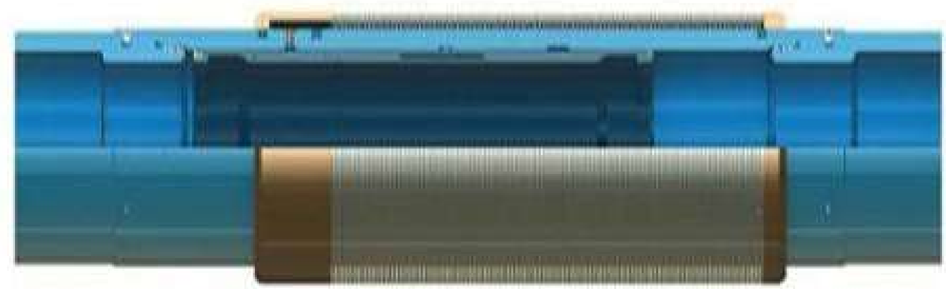


ICD with Sliding Sleeve

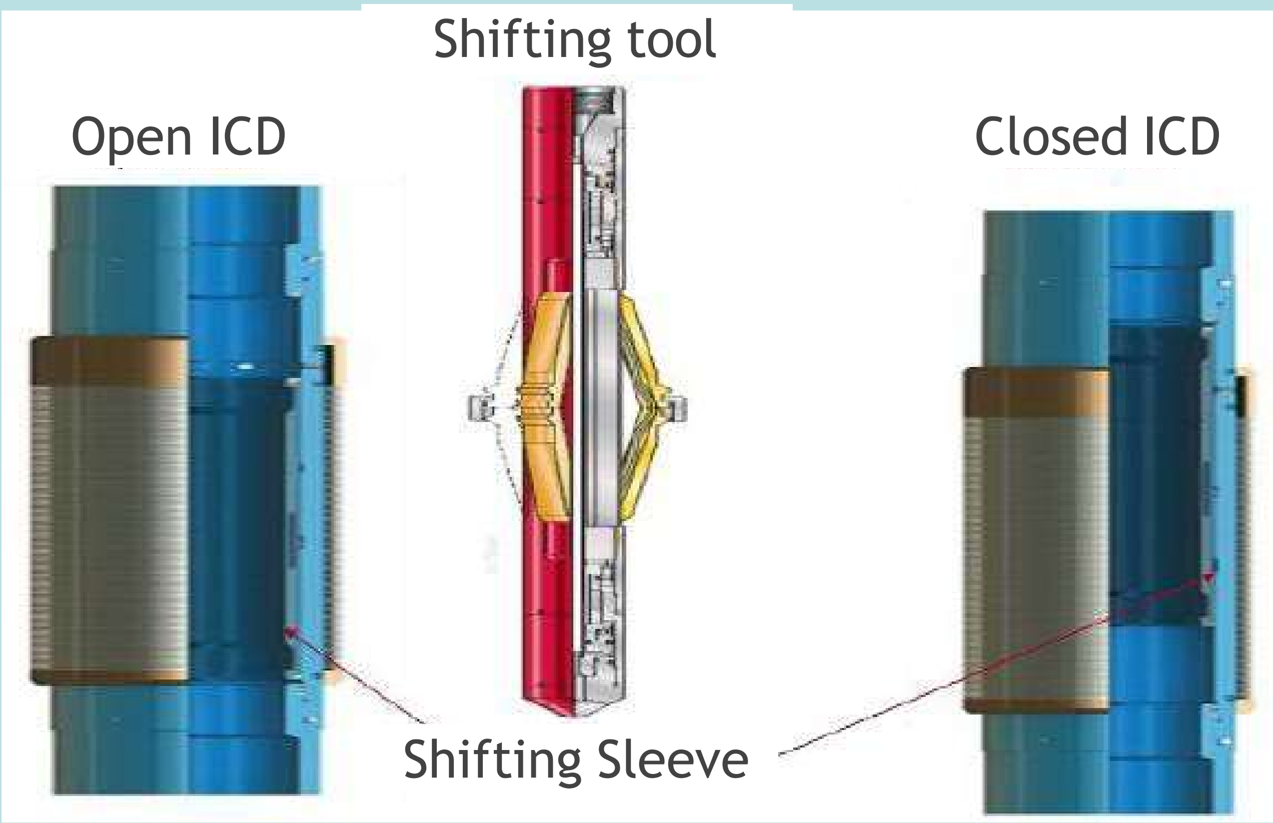


ICD Open



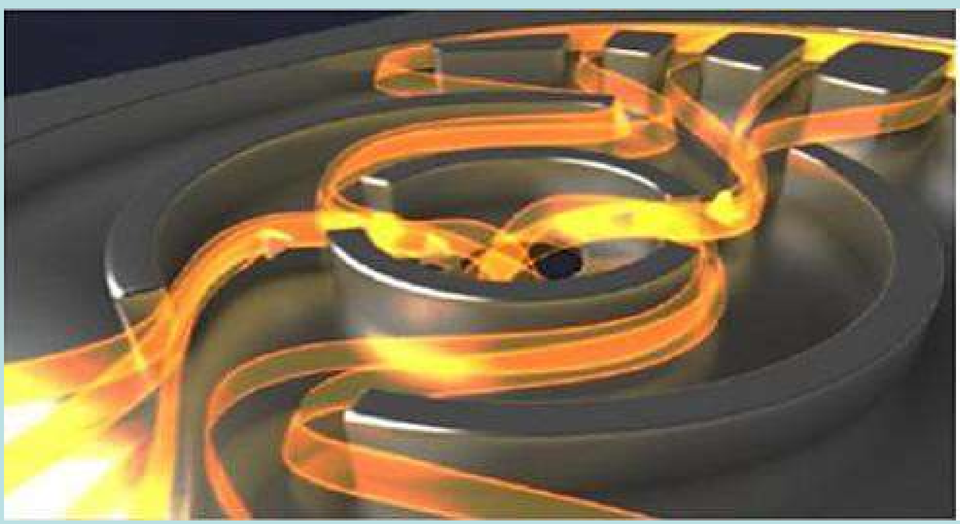
ICD Closed

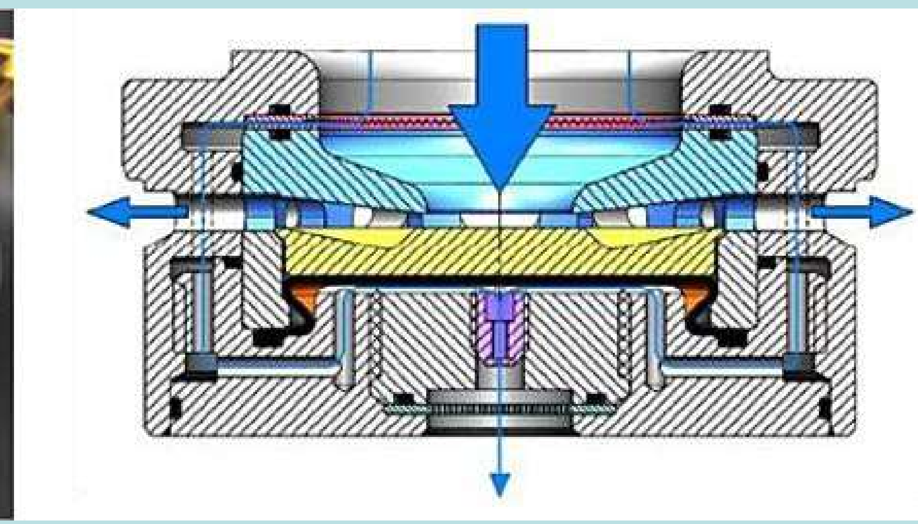
ICD with Sliding Sleeve Operation



Autonomous Inflow Control Device

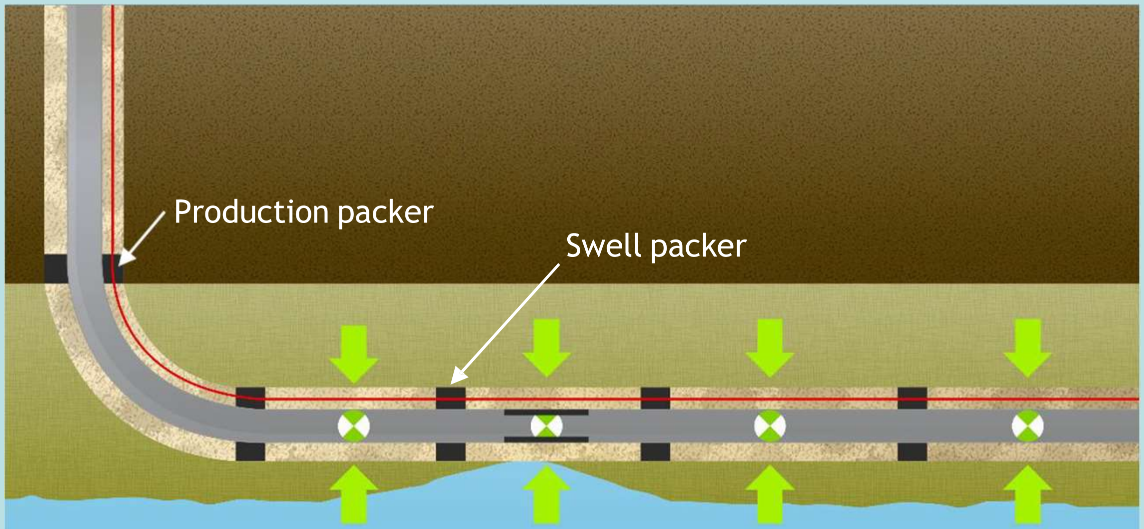
- Vendors claim it will auto control and adjust the system when water or gas arrives
- Claims flow regulation using the difference in viscosity / density between oil and water
- Do these really work?
- Claims appear to be false are misleading.





Density Sensitive ICD

- Restrictive position for water, relaxed position for oil
- Density solution to cover all future applications
- Performs well in super light oils with similar oil and water viscosity
- Water cut value to move from relaxed to restricted
- This technology is still in the design phase and bench prototype. The system will minimize and eventually completely close the ICDs port as fluid density changes



- **Nothing major changed during last 10 years**
- **Enhanced capabilities**
    1. Adaptive restriction: Density ICD
    2. Monitoring: Spoolable monitoring system
    3. Shut-off: ICD patch

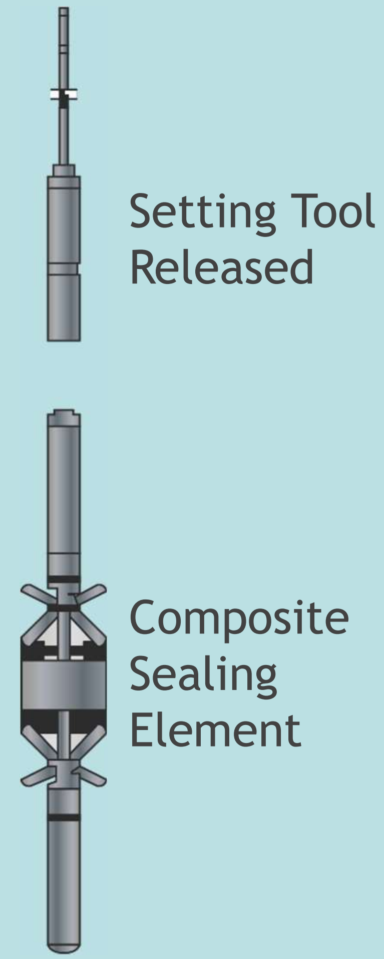
ICD Water Shut Off Patch

- This technology can be used to shut off one or multiple ICD ports in one run
- The patch is run through production tubing
- The patch is expanded to seal the ICD
- The running tool is pulled to the surface
- You can run other patches below it

Running Tool

Through Tubing Bridge Plugs

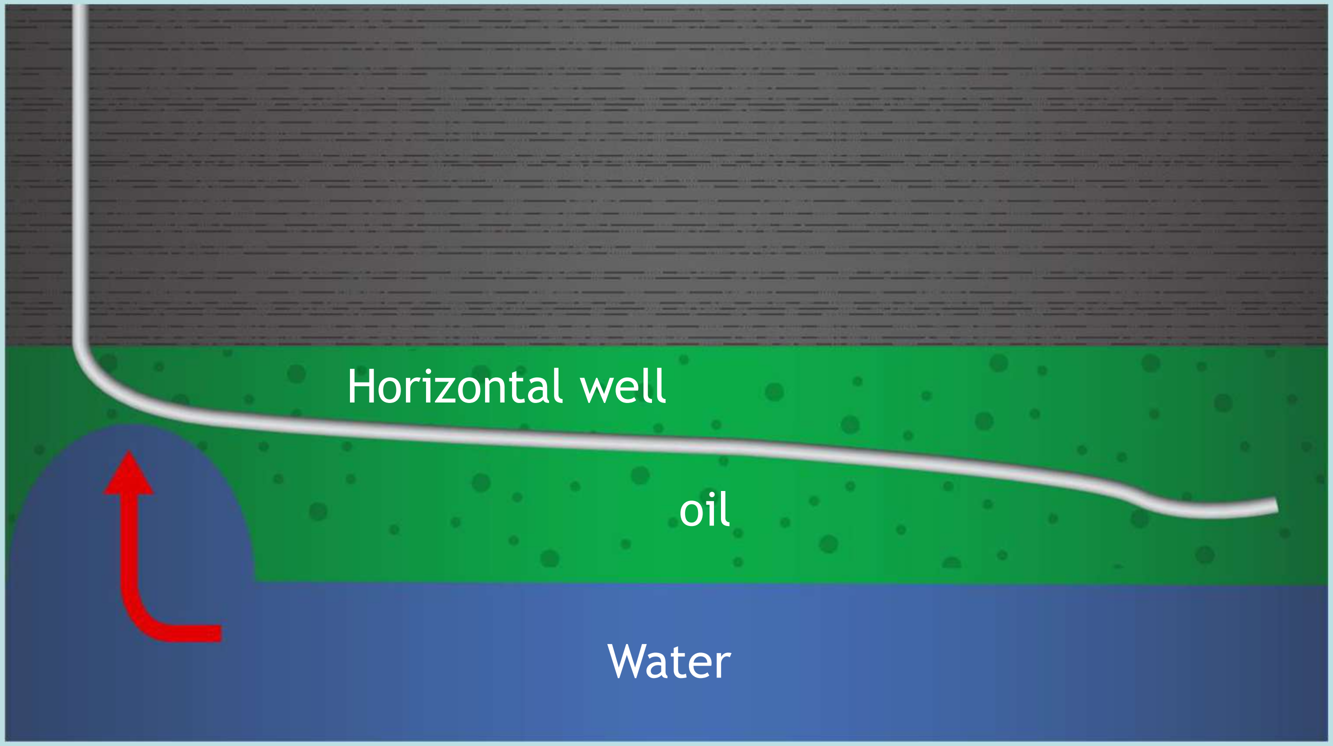
- Are drillable with an elastic sealing element and metal seal support
- Maximum ΔP ranges from 1000-1500 psi at 340°F
- Outside diameter is 1-11/16” (for 4.5” casing) or 2-1/8” (for 7” casing)
- Casing collar locator used for depth control
- 5-10 ft of cement cap used



Schematic Sketch of a TTBP

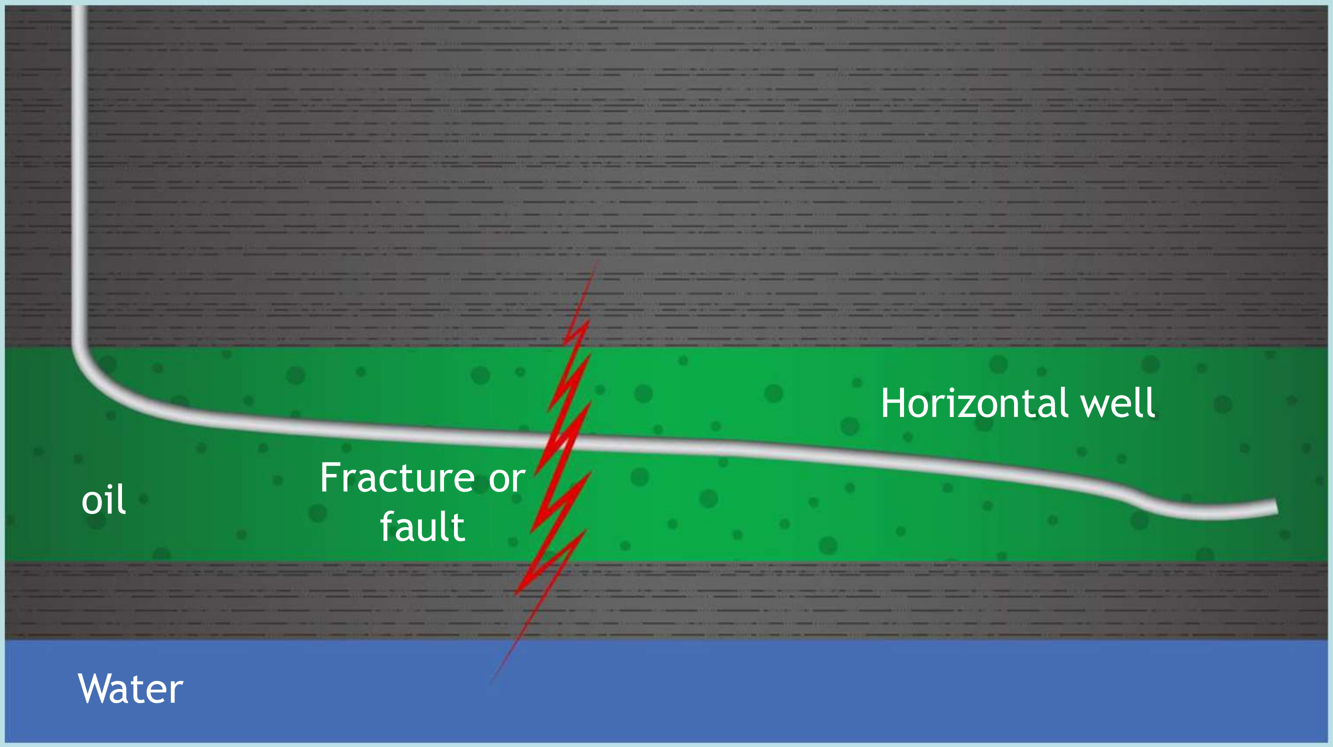
Horizontal Wells

- **Pressure drawdown is often greater at the well heel than at the toe**



Horizontal Wells

- Dramatically increase reservoir contact
- Substantially increase injectivity/productivity
- BUT increase exposure to heterogeneities that can promote channeling and excess water production



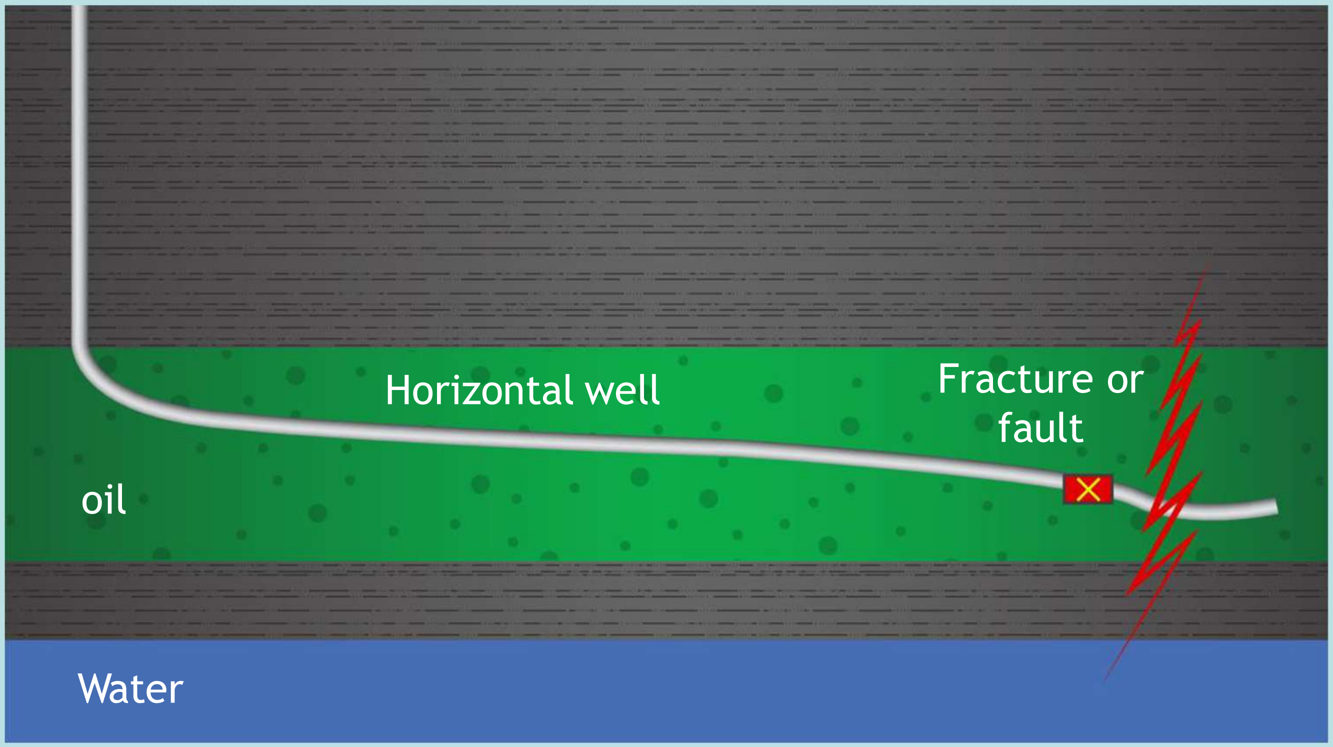
Horizontal Wells

- **If water source is at the toe, the problem can solved with:**

▪ Cement placed by coiled tubing

▪ Through-tubing bridge plugs

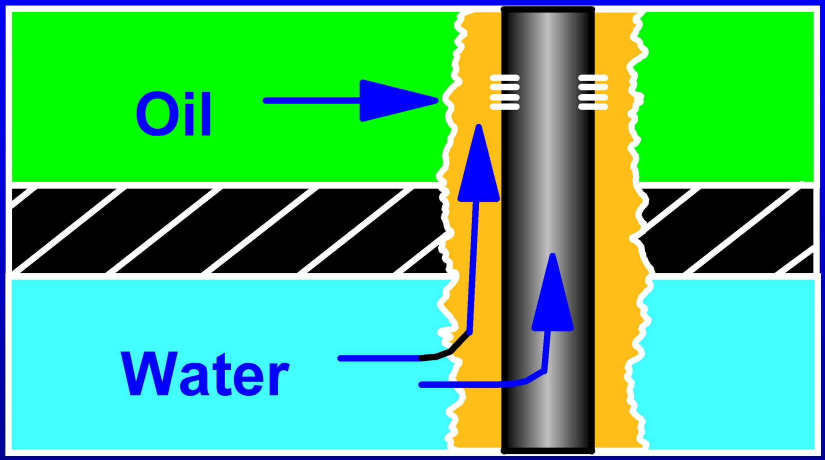
▪ Gels placed by coiled tubing

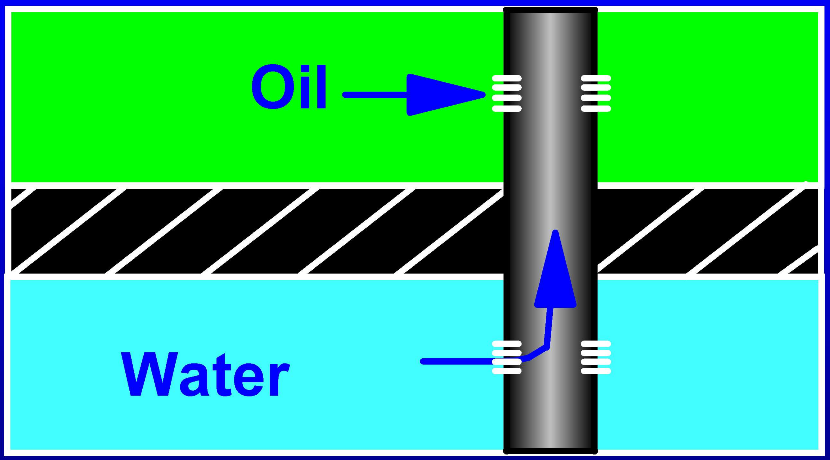


CATEGORY A: EASIEST PROBLEMS

"Conventional" Treatments Normally Are an Effective Choice

1. Casing leaks without flow restrictions (moderate to large holes).
2. Flow behind pipe without flow restrictions (typically no primary cement).
3. Unfractured wells (injectors or producers) with effective barriers to crossflow.
4. Horizontal wells that cross fractures or faults.





Methods to Control Water Entry in Horizontal Wells

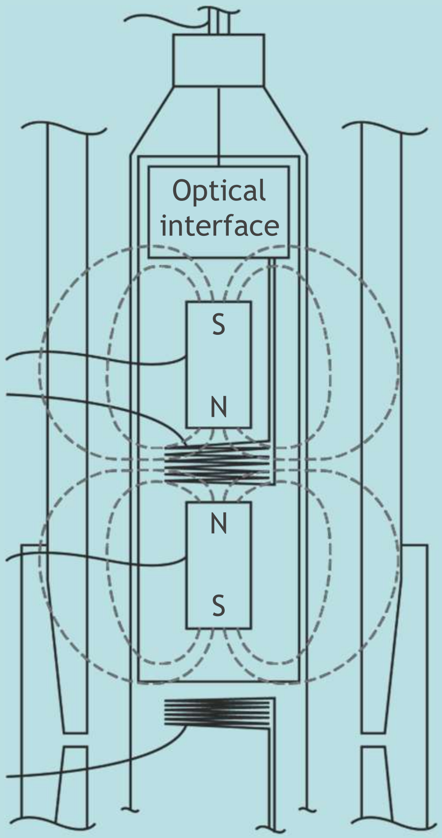
- Through tubing bridge plugs (SPE 81443, 92883)
- Through tubing inflatable packer (SPE 126063) with cement (SPE 117066).
- Coiled tubing with inflatable packers with gel treatments (SPE 114331, SPE 158747, IPTC 16637)
- Inflow control devices (ICDs), “autonomous” control devices (SPE 190816)
- Inflow control valves (ICVs)

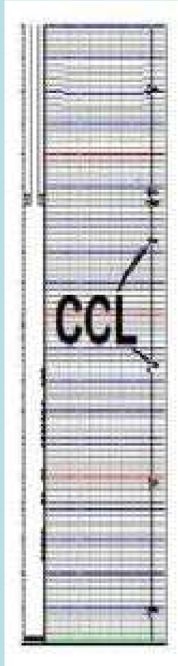
Nipple locator

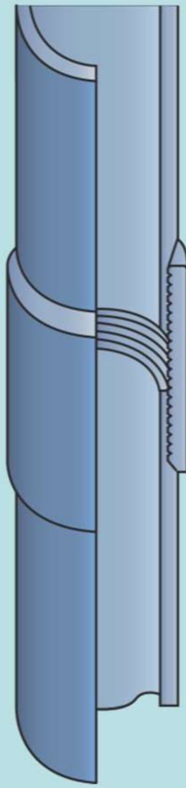
- The nipple locator has three leaf-type springs retained in the housing.
- An upset in the middle of the springs is at a diameter greater than the maximum ID of the nipple profile it is intended to locate, but the spring can deflect inwards enough to allow the spring to pass through the nipple.
- The contour shape of the spring is such that the tool moves down through restrictions easily but creates a drag force that can be detected at the surface when moving up through a restriction.
- Adjustment Rings under the Spring allows changing the force required to pull the locator through a nipple. These nuts effectively change the length of the leaf spring.
- The mechanical Nipple Locator will locate most nipples, but will not locate the end of the tubing.

Casing Collar Locator (CCL)

- A downhole tool used to confirm or correlate treatment depth using known reference points on the casing string
- The casing collar locator is an electric logging tool that detects the magnetic anomaly caused by the relatively high mass of the casing collar
- A signal is transmitted to surface equipment that provides a screen display and printed log enabling the output to be correlated with previous logs and known casing features such as pup joints installed for correlation purposes



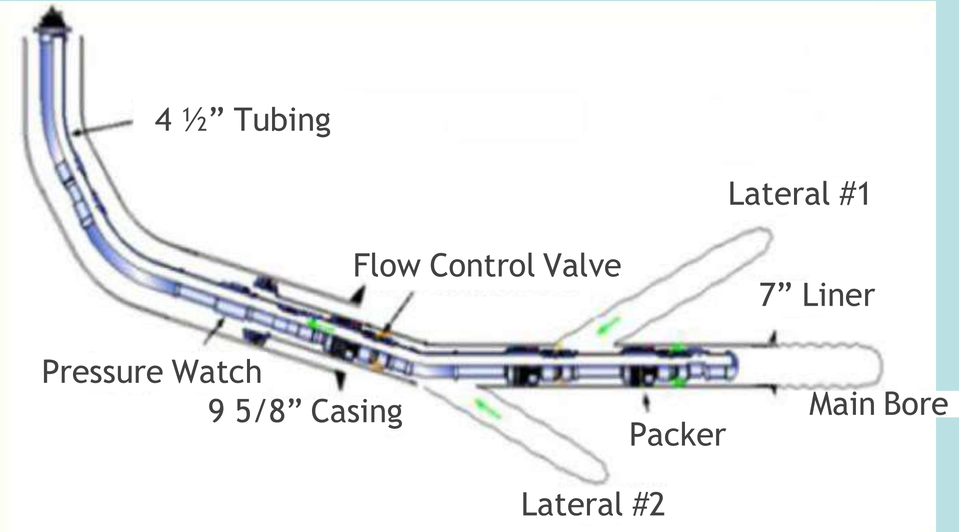




Inflow Control Valves

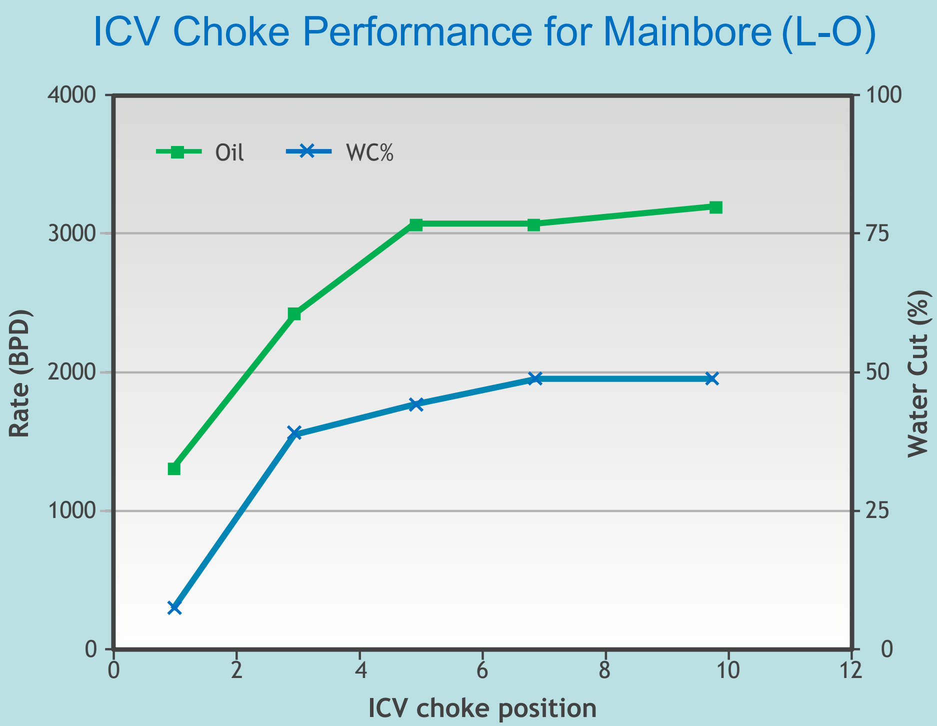
“Smart" maximum reservoir contact (MRC) wells equipped with “smart” completions within intelligent field capabilities

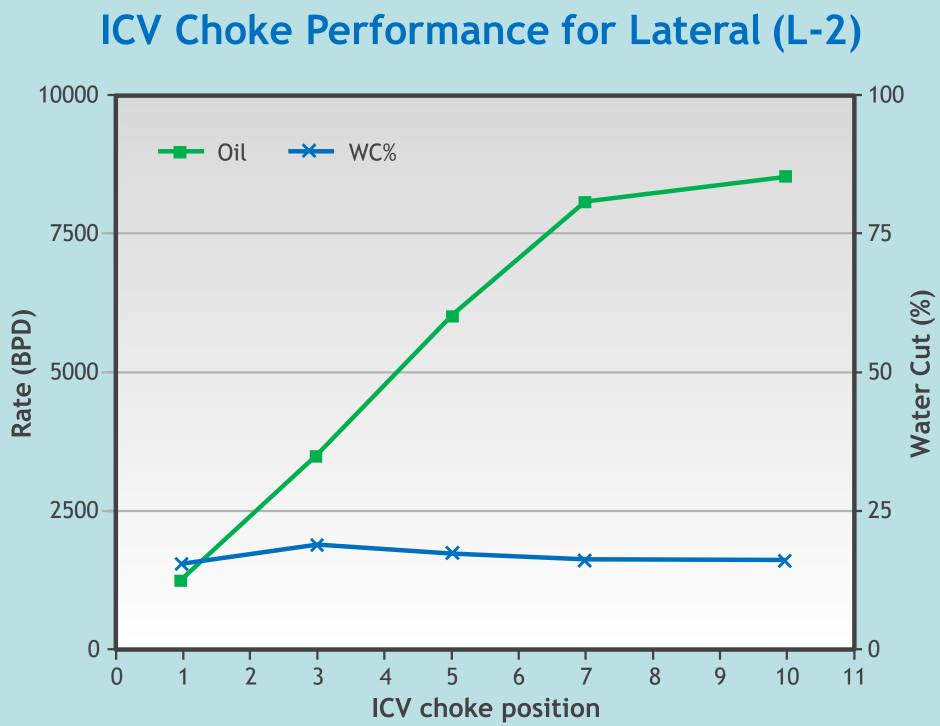
- Zonal isolation packer and flow control valve at each lateral
- Each valve has 11 choke positions
- Controlled from the surface



Schematic of a MRC smart trilateral well

Inflow Control Valves





Inflow Control Valves

Rate results of three tests with all laterals commingled for a typical smart MRC well

	Downhole Choke Position			Production Data	
Scenarios	Lateral-0	Lateral-1	Lateral-2	Oil Rate (MBD)	Water Cut (%)
1st	1	1	10	10.7	3.4
2nd	3	1	10	10.2	11.3
3rd	3	3	10	9.2	18.9

Chemical Methods

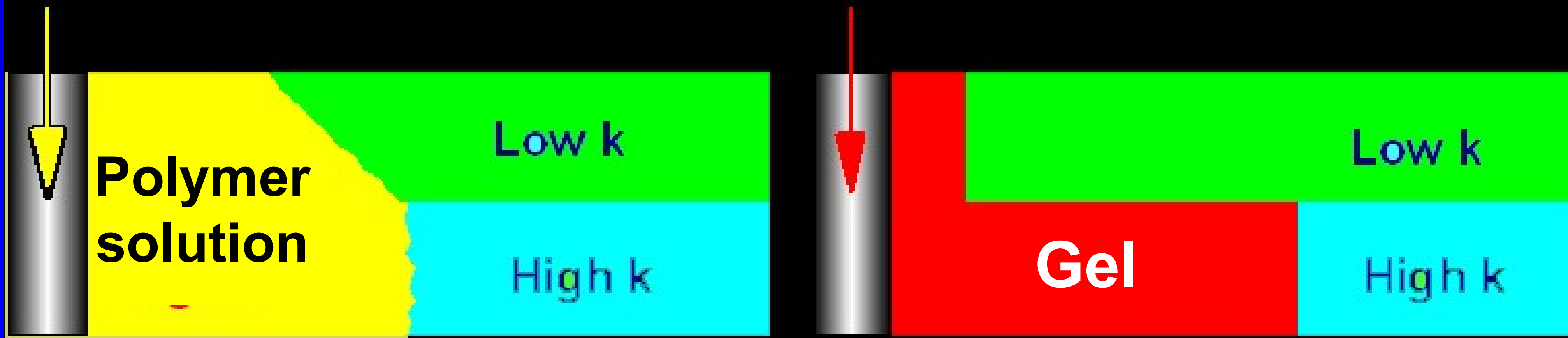
POLYMER FLOODS VERSUS GEL TREATMENTS

Polymer floods use polymer solutions. Gels add a crosslinker to the polymer solution.

- The "Windfall Profits Act of 1980" encouraged grouping the two methods together as "polymer augmented waterfloods".
- The Oil and Gas Journal does not distinguish the two methods in their biannual EOR survey.

What is the difference?

Distinction between a gel treatment and a polymer flood.

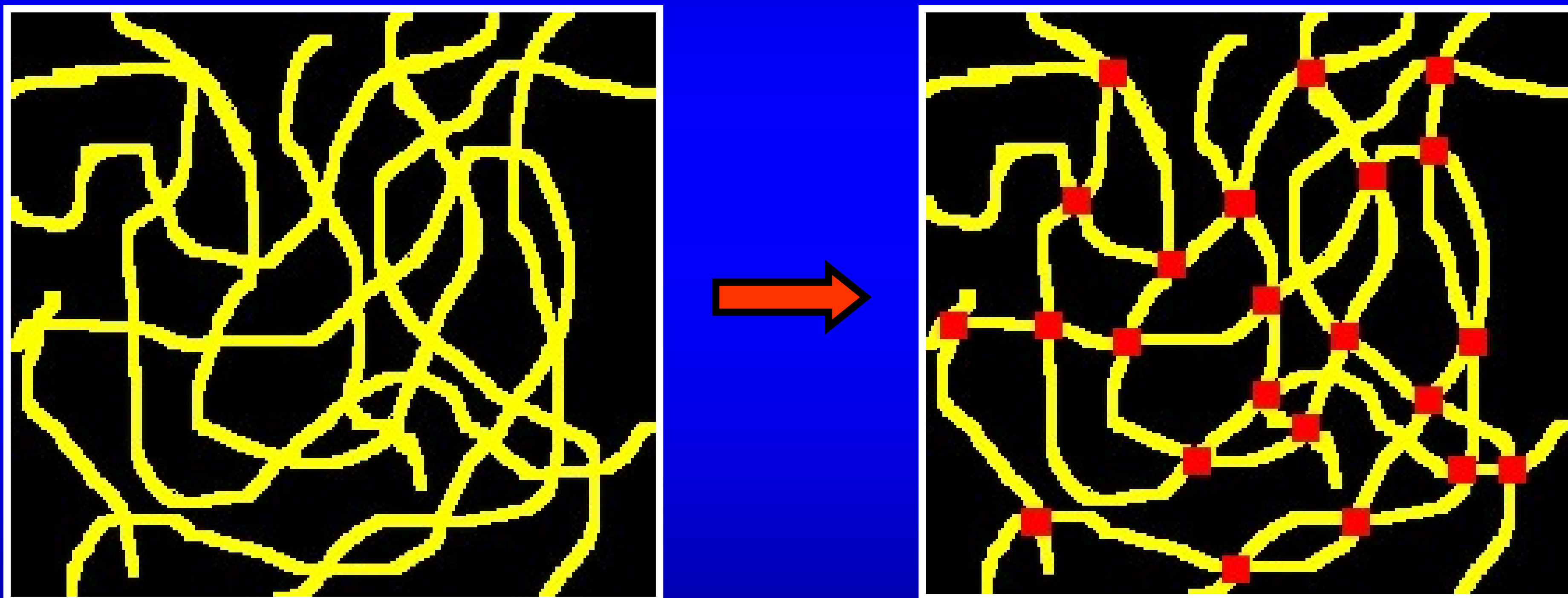


- For a polymer flood, polymer penetration into low-k zones should be <u>maximized.</u>
- For a gel treatment, gelant penetration into low-k zones should be <u>minimized.</u>

VISCOUS POLYMER SOLUTION

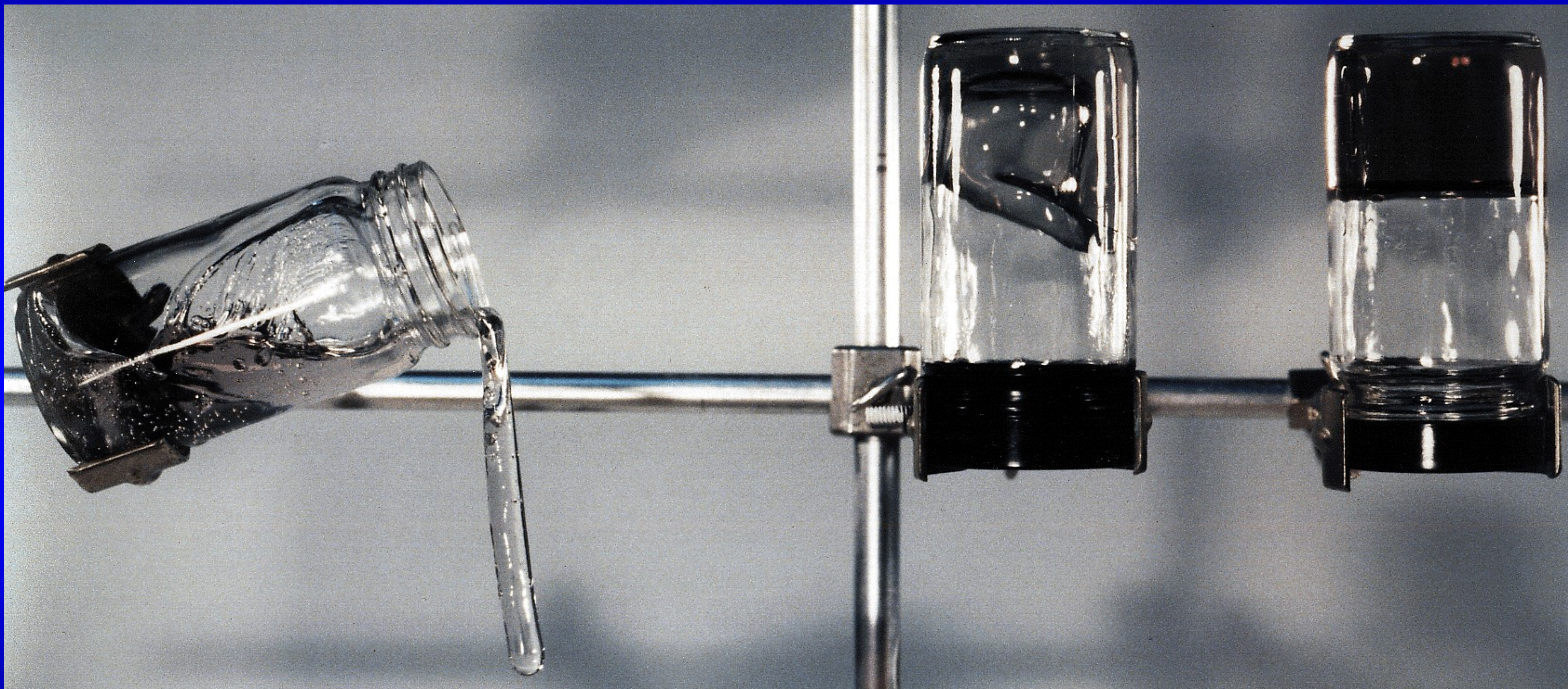
CROSSLINKED POLYMER (GEL)

Crosslink site



Gelant = Polymer + crosslinker solution before gel formation.
Gel = Crosslinked structure after reaction.

Higher polymer & crosslinker concentrations yield stronger gels



If not enough polymer or crosslinker is present, no gel forms.

GEL TREATMENTS ARE NOT POLYMER FLOODS

Crosslinked polymers, gels, gel particles, and "colloidal dispersion gels":

- Are not simply viscous polymer solutions.
- Do not flow through porous rock like polymer solutions.
- Do not enter and plug high-k strata first and progressively less-permeable strata later.
- Should not be modeled as polymer floods.

POLYMER FLOODING is best for improving sweep in reservoirs where fractures do not cause severe channeling.

- Great for improving the mobility ratio.
- Great for overcoming vertical stratification.
- Fractures can cause channeling of polymer solutions and waste of expensive chemical.

GEL TREATMENTS are best treating fractures and fracture-like features that cause channeling.

- Generally, low volume, low cost.
- Once gelation occurs, gels do not flow through rock.

WHY DO WE WANT TO REDUCE WATER PRODUCTION?

REDUCE OPERATING EXPENSES

- Reduce pumping costs (lifting and re-injection):
  ~$0.25/bbl ($0.01 to $8/bbl range).
- Reduce oil/water separation costs.
- Reduce platform size/equipment costs.
- Reduce corrosion, scale, and sand-production treatment costs.
- Reduce environmental damage/liability.

INCREASE HYDROCARBON PRODUCTION

- Increase oil production rate by reducing fluid levels and downhole pressures.
- Improve reservoir sweep efficiency.
- Increase economic life of the reservoir and ultimate recovery.
- Reduce formation damage.

MAIN POINTS I THINK YOU NEED TO KNOW

1. What polymers, gelants, and gels can/cannot do.

2. Why determining whether flow is radial (into matrix) or linear (through fractures) is critical in EVERY application.

3. A strategy for attacking problems.

PROPERTIES OF AVAILABLE GELANTS/GELS

1. Early in the gelation process, gelants penetrate readily into porous rock.

2. After gelation, gel propagation through porous rock is extremely slow or negligible.

3. The transition between these two conditions is usually of short duration.

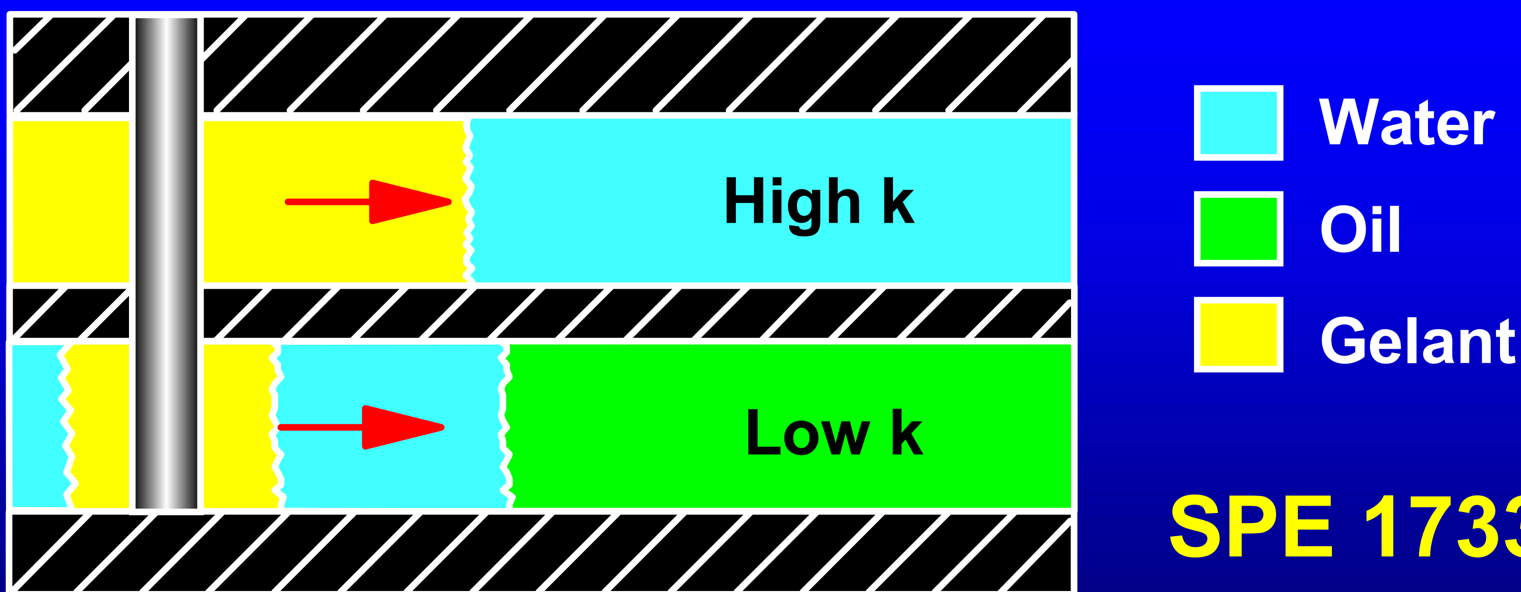
SPERE (Nov. 1993) 299-304; *IN SITU* 16(1) (1992) 1-16; and *SPEPF* (Nov. 1995) 241-248.

BASIC CALCULATIONS

Gelants can penetrate into all open zones.

An acceptable gelant placement is much easier to achieve in linear flow (fractured wells) than in radial flow.

In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.



SPE 17332

KEY QUESTIONS DURING BULLHEAD INJECTION OF POLYMERS, GELANTS, OR GELS

- Why should the blocking agent NOT enter and damage hydrocarbon productive zones?
- How far will the blocking agent penetrate into each zones (both water AND hydrocarbon)?
- How much damage will the blocking agent cause to each zone (both water AND hydrocarbon zones)?

BASIC PROPERTIES OF GELANTS AND GELS

A FEW OF THE HUNDREDS OF GEL SYSTEMS

Cr(III) acetate with high-Mw HPAM (Marcit CT)
Cr(III) acetate with low-Mw HPAM (Maraseal)
Cr(III) propionate HPAM (Aquatrol IV, Matrol III)
Cr(III) lactate/carboxylate HPAM. Cr(III) malonate HPAM
Preformed Particle Gels (PPG)
Nanoparticles (Nanospheres)

Silicates (Injectrol, Zonelock, Pemablock, Siljel V, Silica-Polymer-Initiator)

In situ polymerization of acrylamides, acrylates, or derivatives (k-Trol, Permseal)
Polyethyleneimine with t-butylacrylate/acrylamide copolymers (H2Zero)

HCHO or HMTA and phenolic/hydroquininone crosslinkers with PAM co- and terpolymers (Phillips and Unocal processes,Unogel, Organoseal, Multigel)

Crosslinked AMPS, NVP, acrylamide/acrylate co & terpolymers (HE)

Amphoteric polymers and terpolymers (WOR-Con, Aquatrol I, AquaCon)
Hydrophobically modified polyDMAEMA (WaterWeb, CW-Frac)
Crosslinked expandable polymeric microparticles (Bright Water)

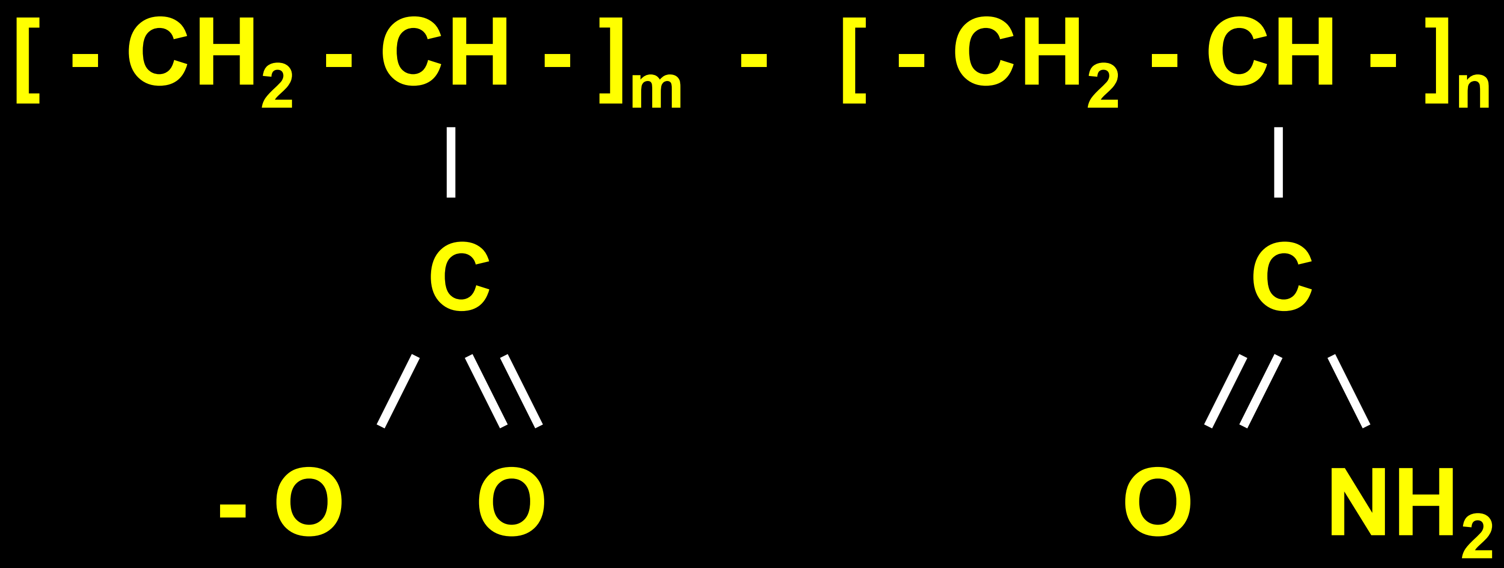
Al-citrate/HPAM (BP North Slope process)
Al-citrate/HPAM/CPAM (Cat-An, colloidal dispersion gel)
$AlCl_3/OH^-$ (DGS or Delayed Gelation System)
$Fe(OH)_3$ (Hungarian precipitation process)

WHY CHOOSE ONE MATERIAL OVER ANOTHER?

What do you want the gel to do?

- Cost
- Availability
- Sensitivity of performance to condition or composition variations
- Blocking agent set time
- Permeability reduction provided to water
- Permeability reduction provided to oil or gas
- Ability to withstand high-pressure gradients in porous rock
- Ability to withstand high-pressure gradients in fractures or voids
- Rheology and/or filtration properties
- Ability to penetrate into fractures or narrow channels behind pipe
- Stability at elevated temperatures
- Environmental concerns

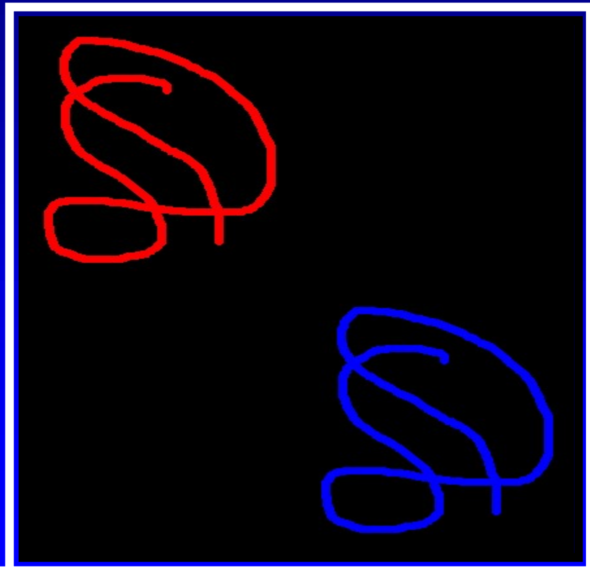
“Polyacrylamide” or “HPAM” Polymers



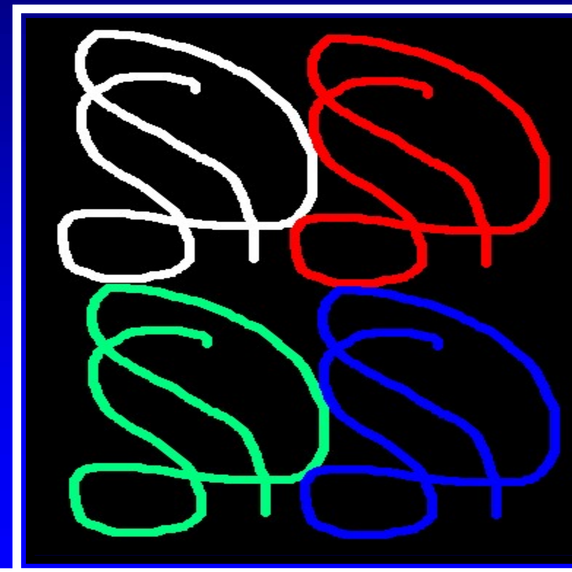
acrylate acrylamide

- “degree of hydrolysis” = fraction of acrylate groups
- **Polymer flooding:** Mw~18x10^6; ~30% deg of hydrolysis
- **Gel treatments:** Mw either ~5-10 million or ~0.1-0.5x10^6; ~5-10% degree of hydrolysis

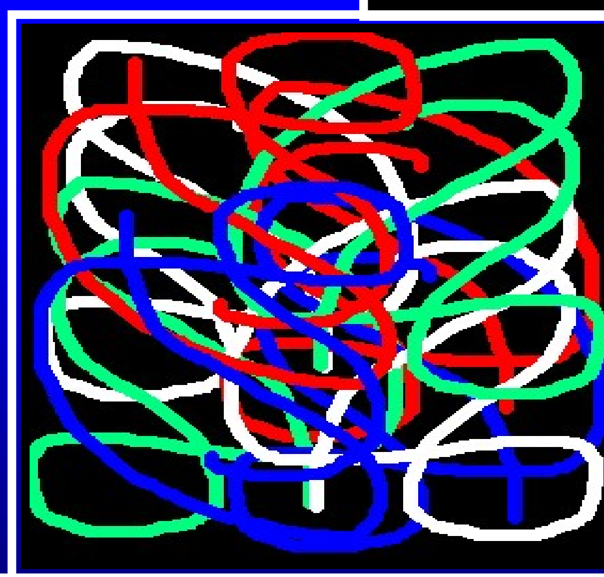
CRITICAL OVERLAP CONCENTRATION – C*



DILUTE SOLUTION: C < C*

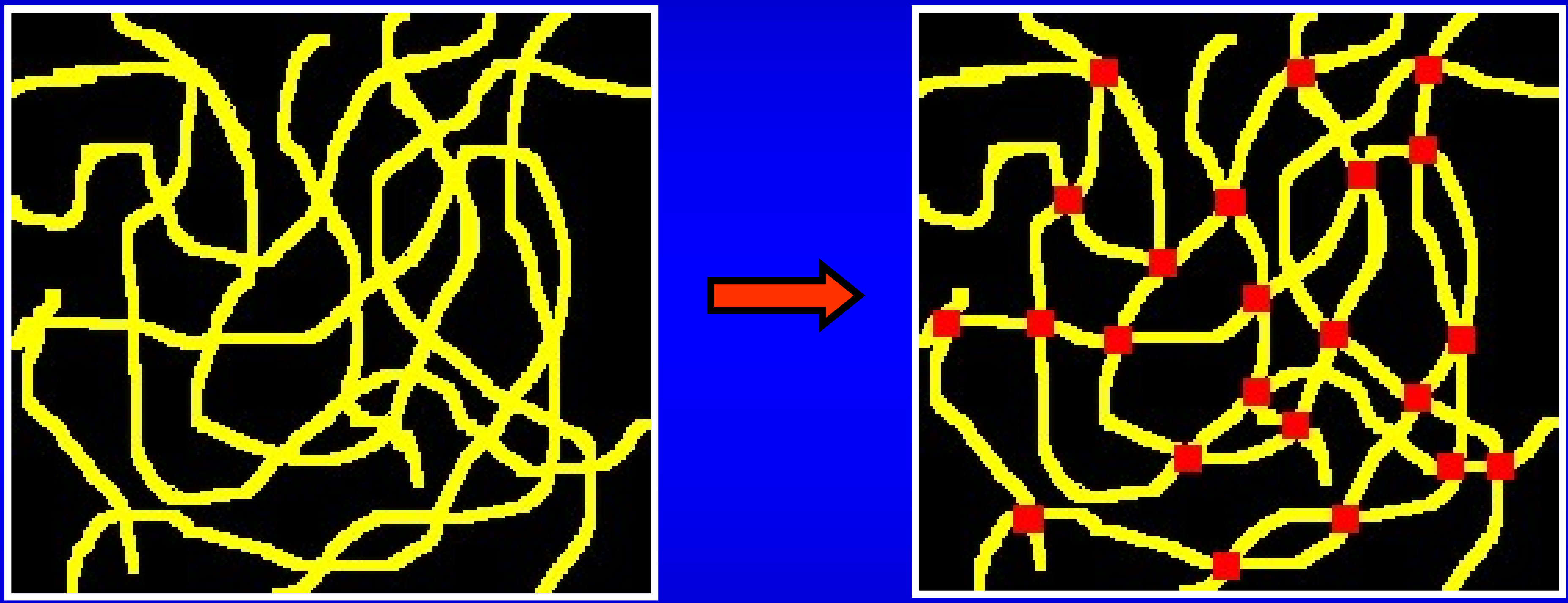


TOTAL POLYMER VOLUME = TOTAL SOLUTION VOLUME: C = C*



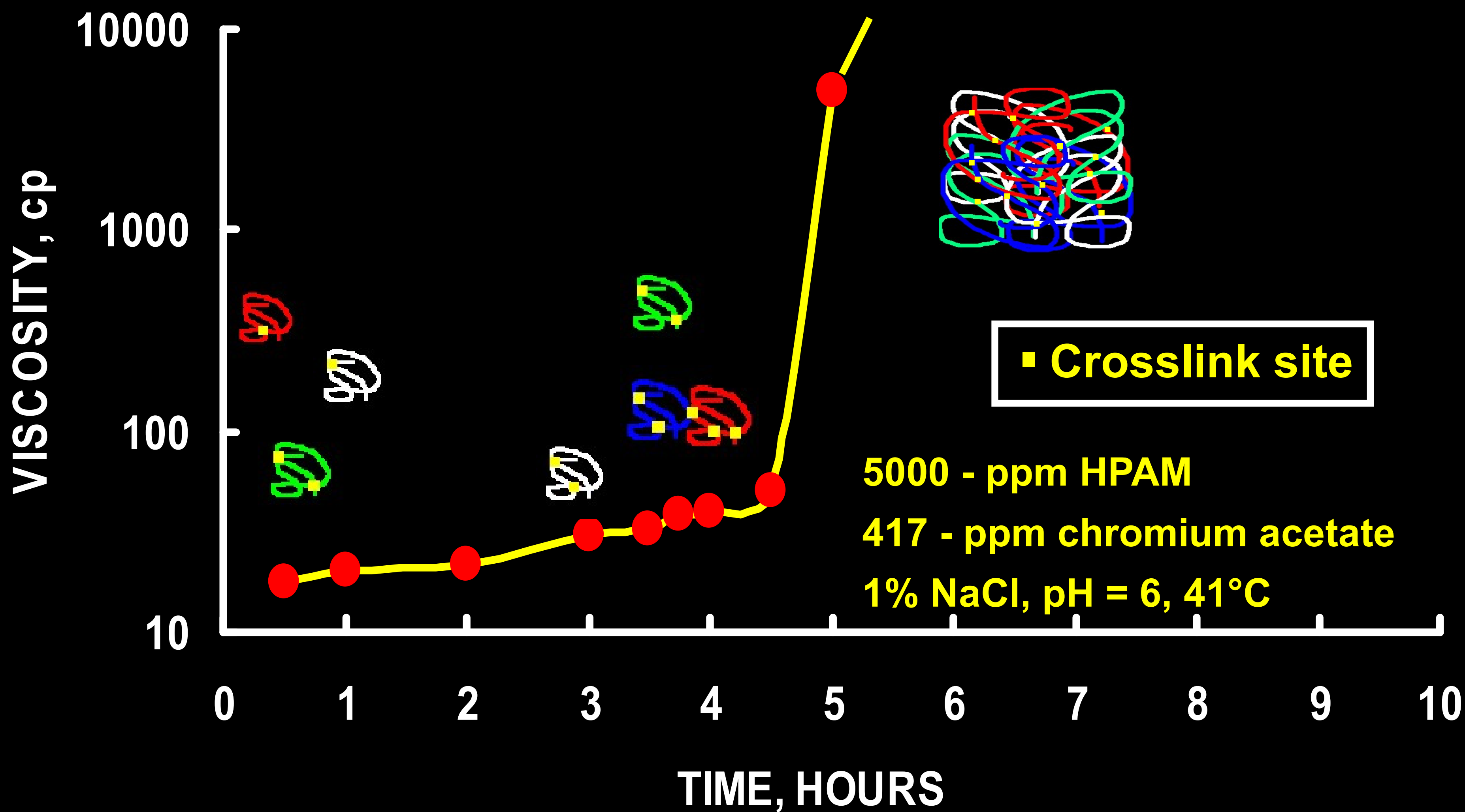
POLYMERS INTERTWINE: C > C*

POLYMER CROSSLINKING



Crosslink site

VISCOSITY VERSUS TIME DURING GELATION



GELANTS VERSUS GELS

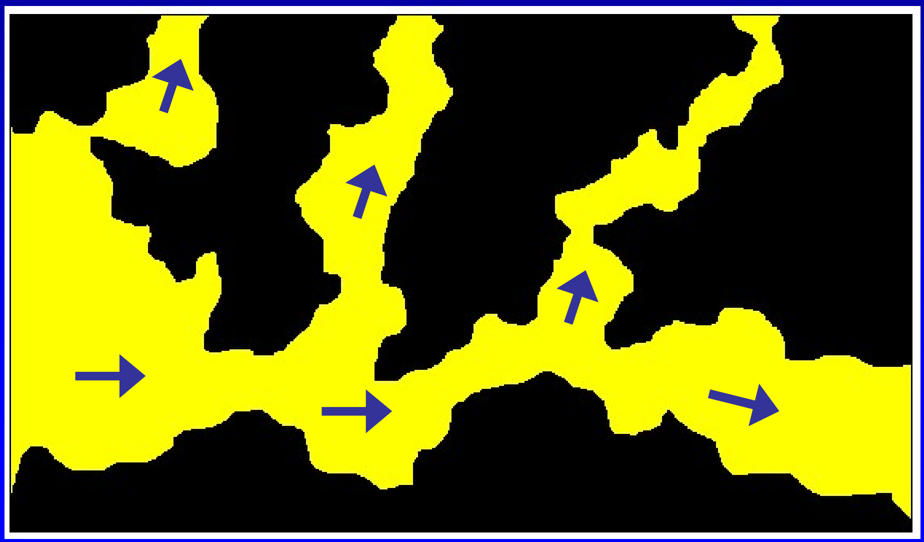
Polymer Solution [e.g., HPAM] + Crosslinking Agent [e.g., Cr(III)] = Gelant

In a gelant, few crosslinks have been made. Gelants can flow into porous rock just like uncrosslinked polymer solutions.

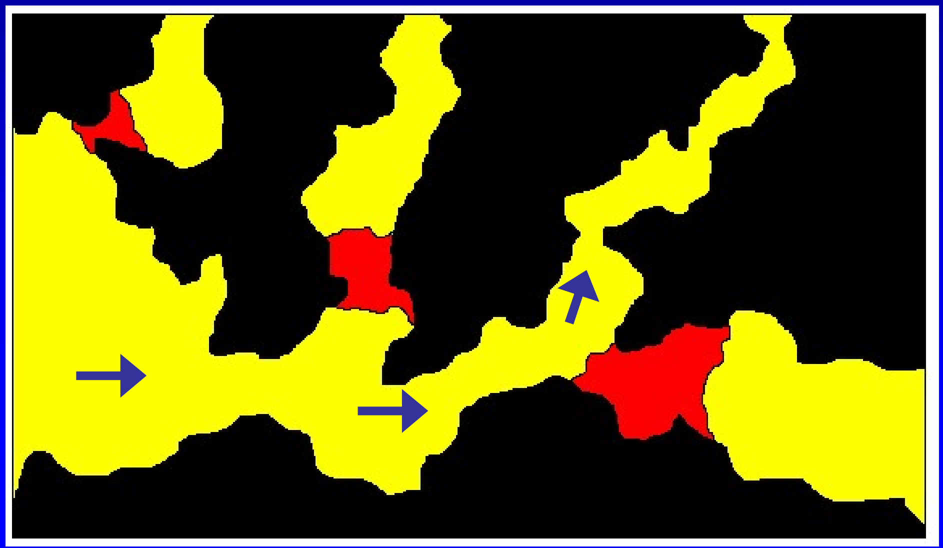
$$\text{Gelant} \xrightarrow[\text{(e.g. ~ 5 hrs)}]{\text{time}} \text{Gel}$$

Gels are 3-dimensional crosslinked structures that will not enter or flow through porous rock.

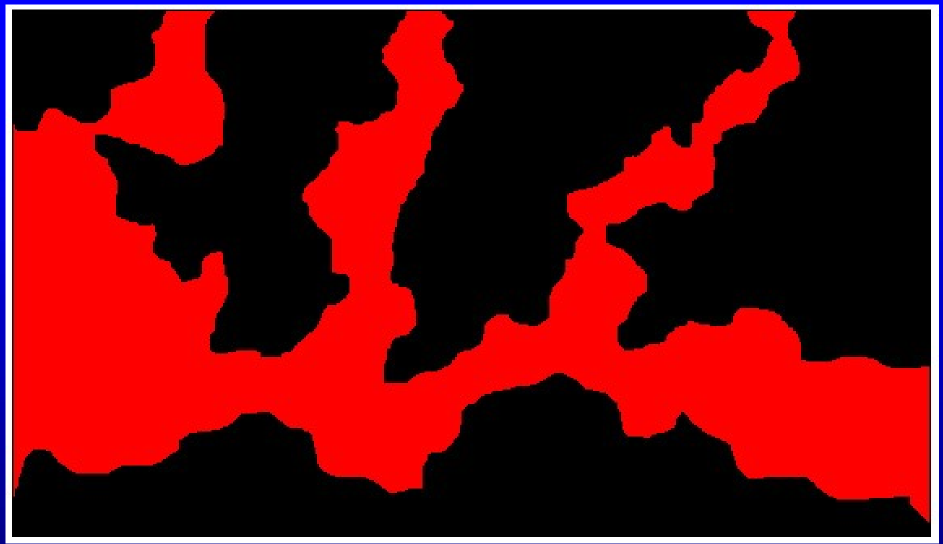
GELANTS FLOW THROUGH POROUS ROCK; GELS DO NOT



Gelant flows freely like a polymer solution



Partial gel formation



Gel filling all aqueous pore space

PROPERTIES OF AVAILABLE GELANTS/GELS

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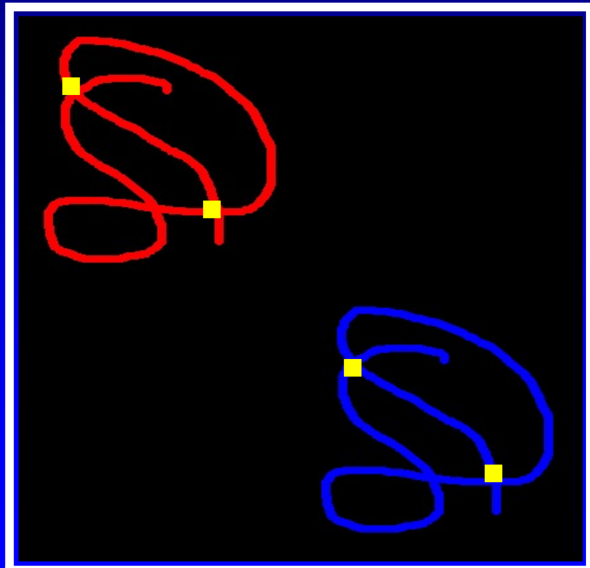
2. After gelation, gel propagation through porous rock is extremely slow or negligible.

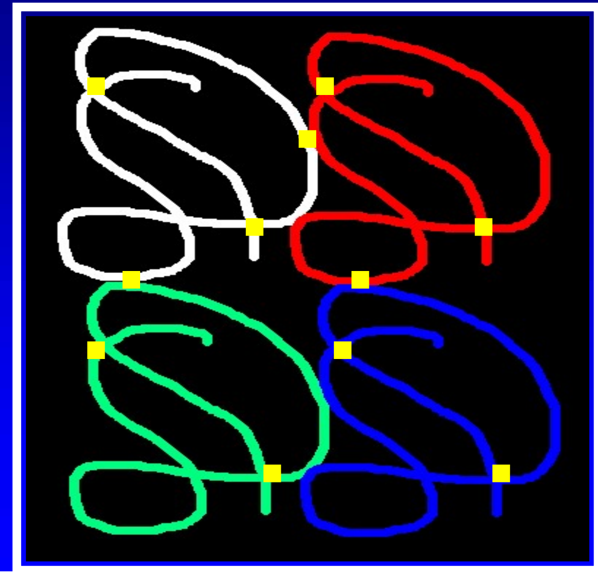
3. The transition between these two conditions is usually of short duration.

SPERE (Nov. 1993) 299-304; *IN SITU* 16(1) (1992) 1-16; and *SPEPF* (Nov. 1995) 241-248.

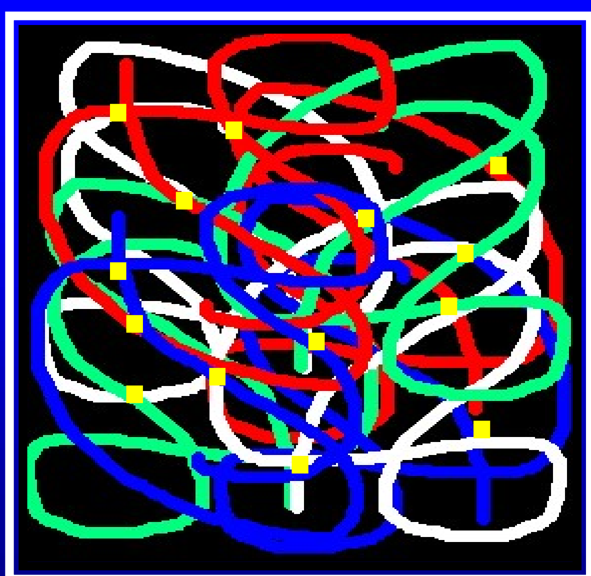
GELATION DEPENDS ON POLYMER CONCENTRATIONS



C < C*: No gelation



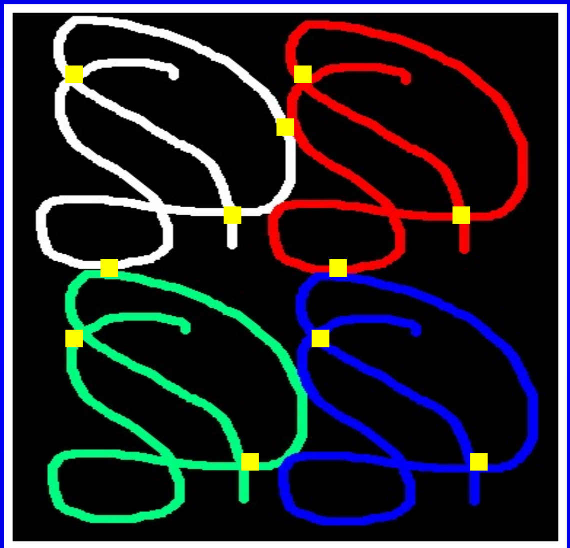
C ≈ C*: Gelation may or may not occur



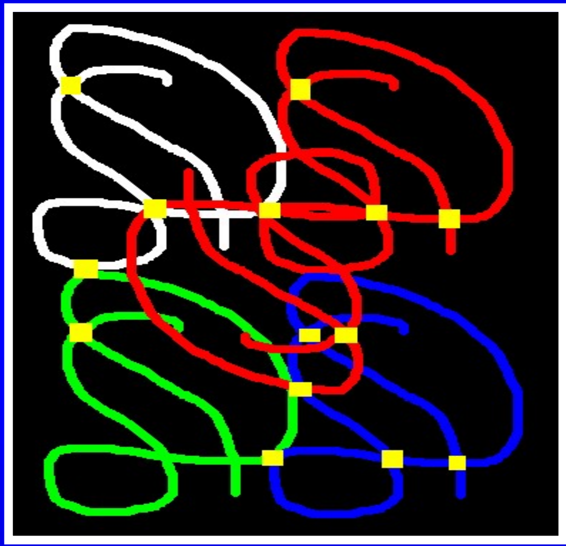
▪ Crosslink site

C >> C*: Best opportunity for 3D gel formation

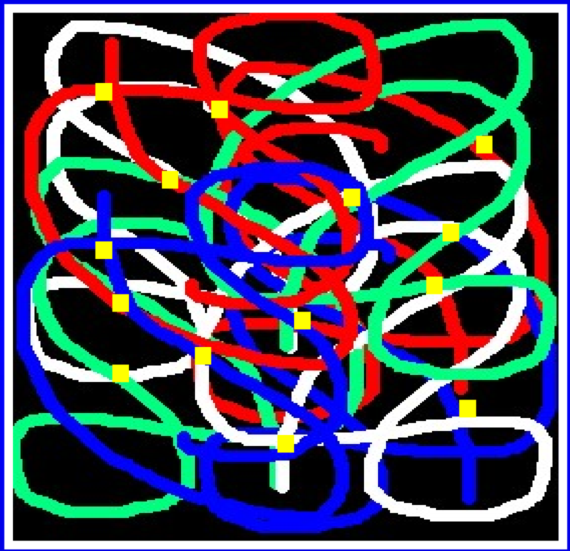
ABOVE C*, HIGHER CONCENTRATIONS OF POLYMER STRENGTHEN THE GEL



Low gel strength



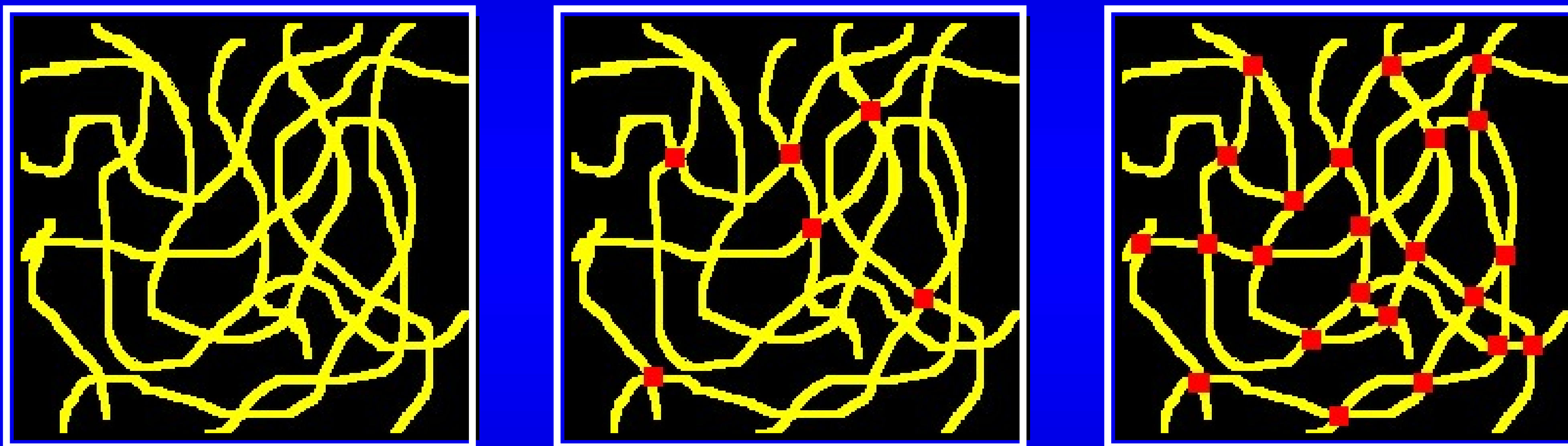
Intermediate gel strength



Strong gel

▪ Crosslink site

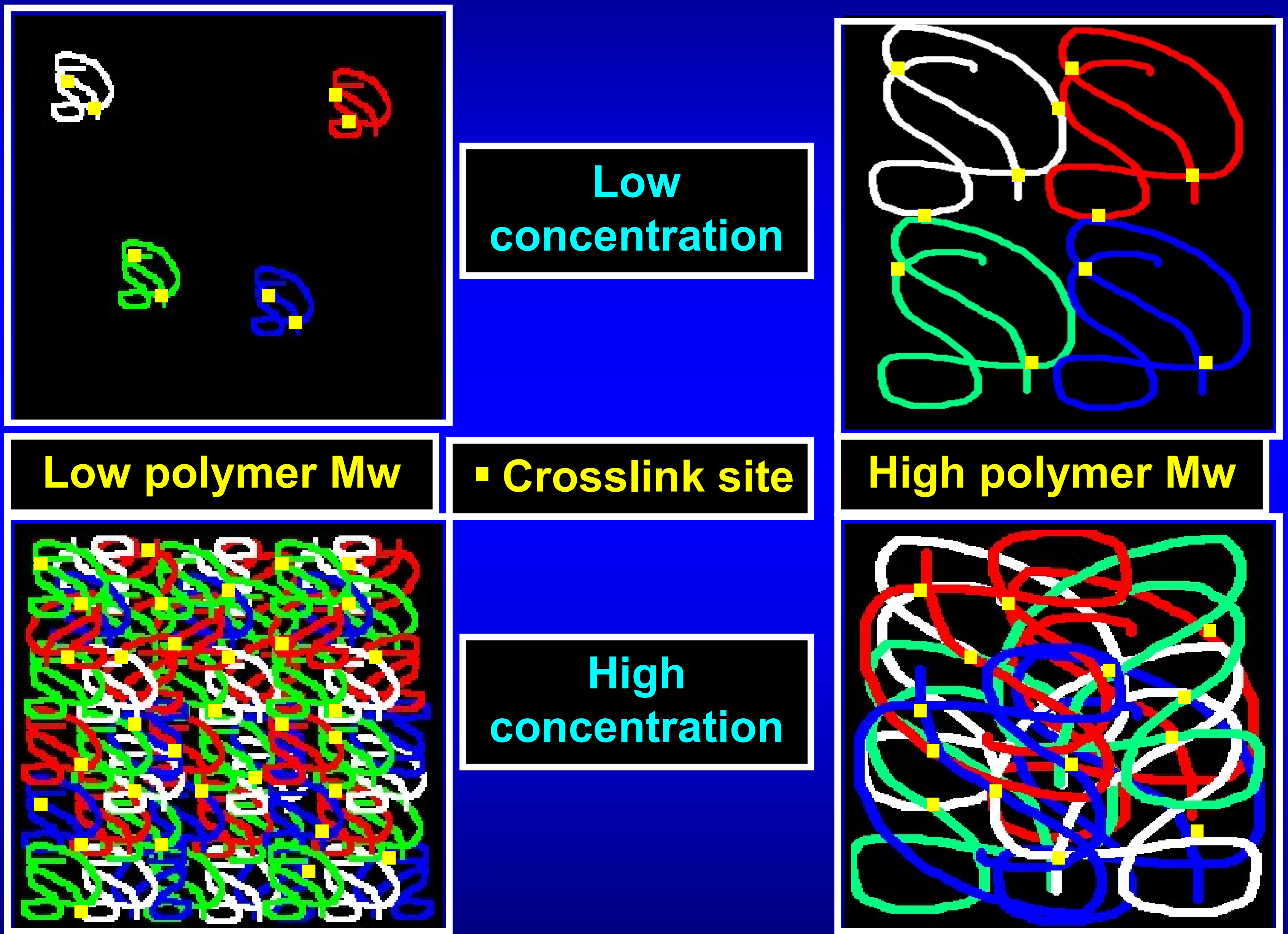
UP TO A POINT, CROSSLINK DENSITY AFFECTS GEL STRENGTH

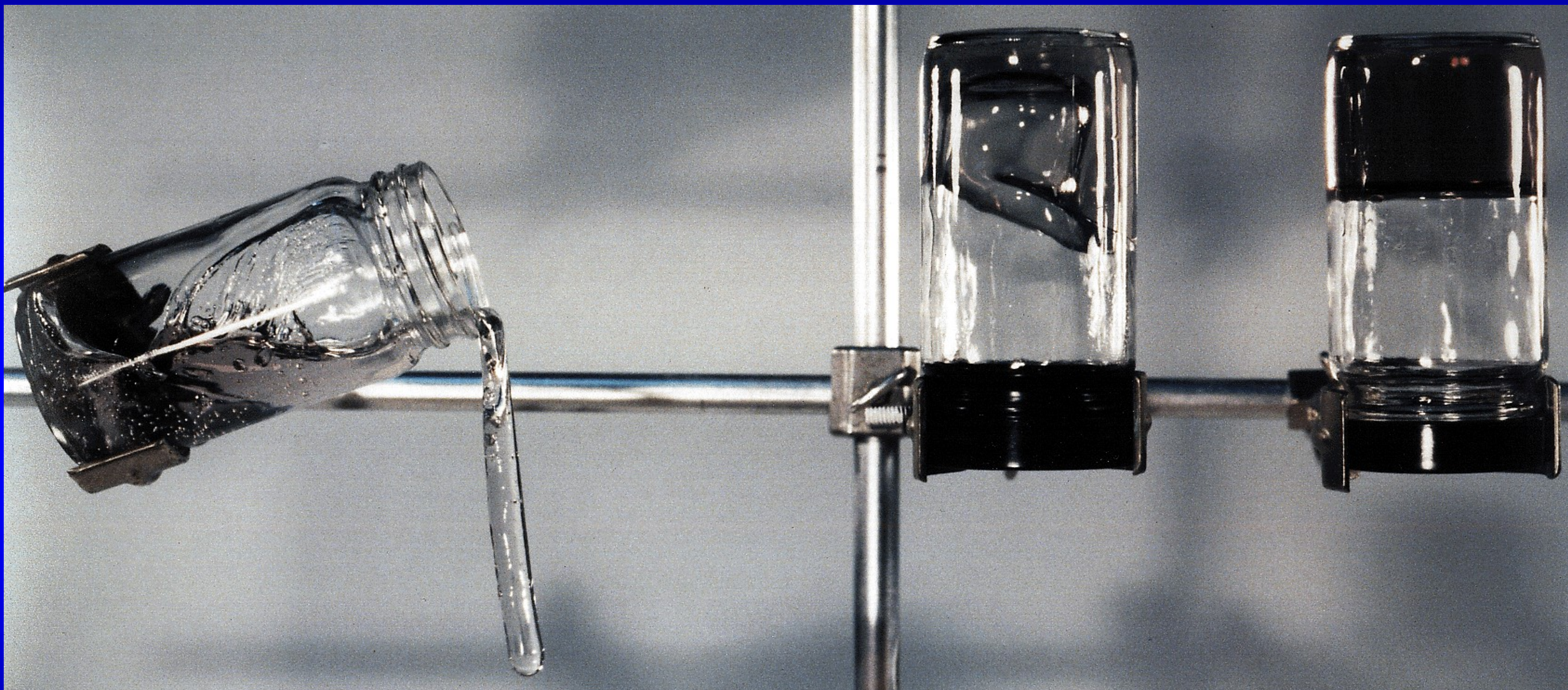


Viscous Fluid | Low gel strength | Strong gel

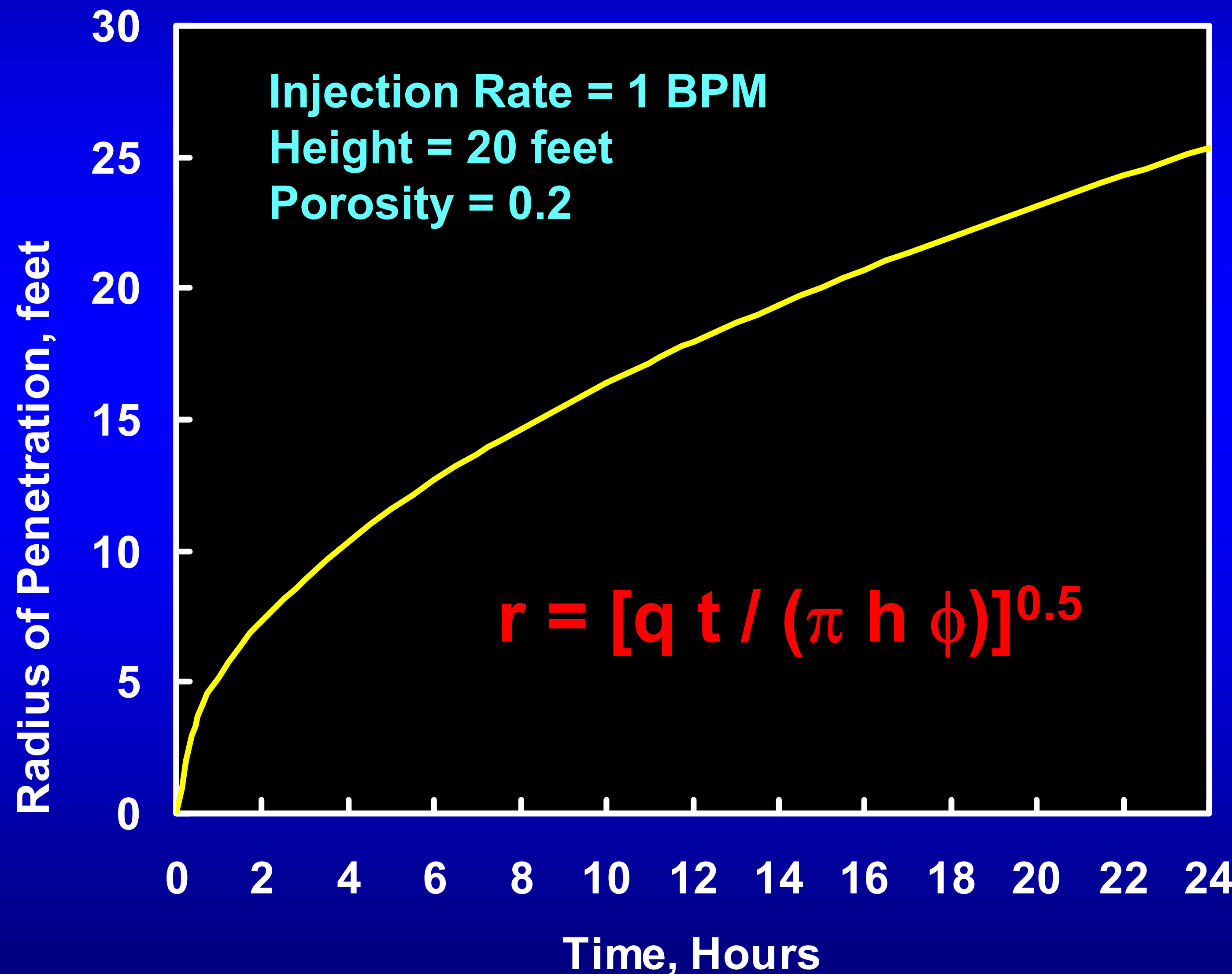
■ Crosslink site

HIGHER Mw POLYMERS REQUIRE LOWER CONCENTRATIONS FOR 3D GEL FORMATION





GELATION TIME DETERMINES HOW FAR A GELANT CAN PENETRATE INTO POROUS ROCK



PROPERTIES PROBLEM 1

Assume that a radius of 10 ft is needed for a gel treatment to be effective in a 30.5-ft-high formation that has an S_{or} of 30% and a porosity of 0.3. The selected gelant has a gelation time of 2 hours.

At what rate must the gelant be injected in order to reach the target radius of 10 ft?

$$q = r^2 \pi h \phi / t$$

$$q = [(62.4 \text{ lbs/ft}^3)/(350 \text{ lb/B})] (10 \text{ ft})^2 \times (3.14) (30.5 \text{ ft})(0.3)(1-0.3) / (2 \text{ hrs} \times 60 \text{ min/hr})$$

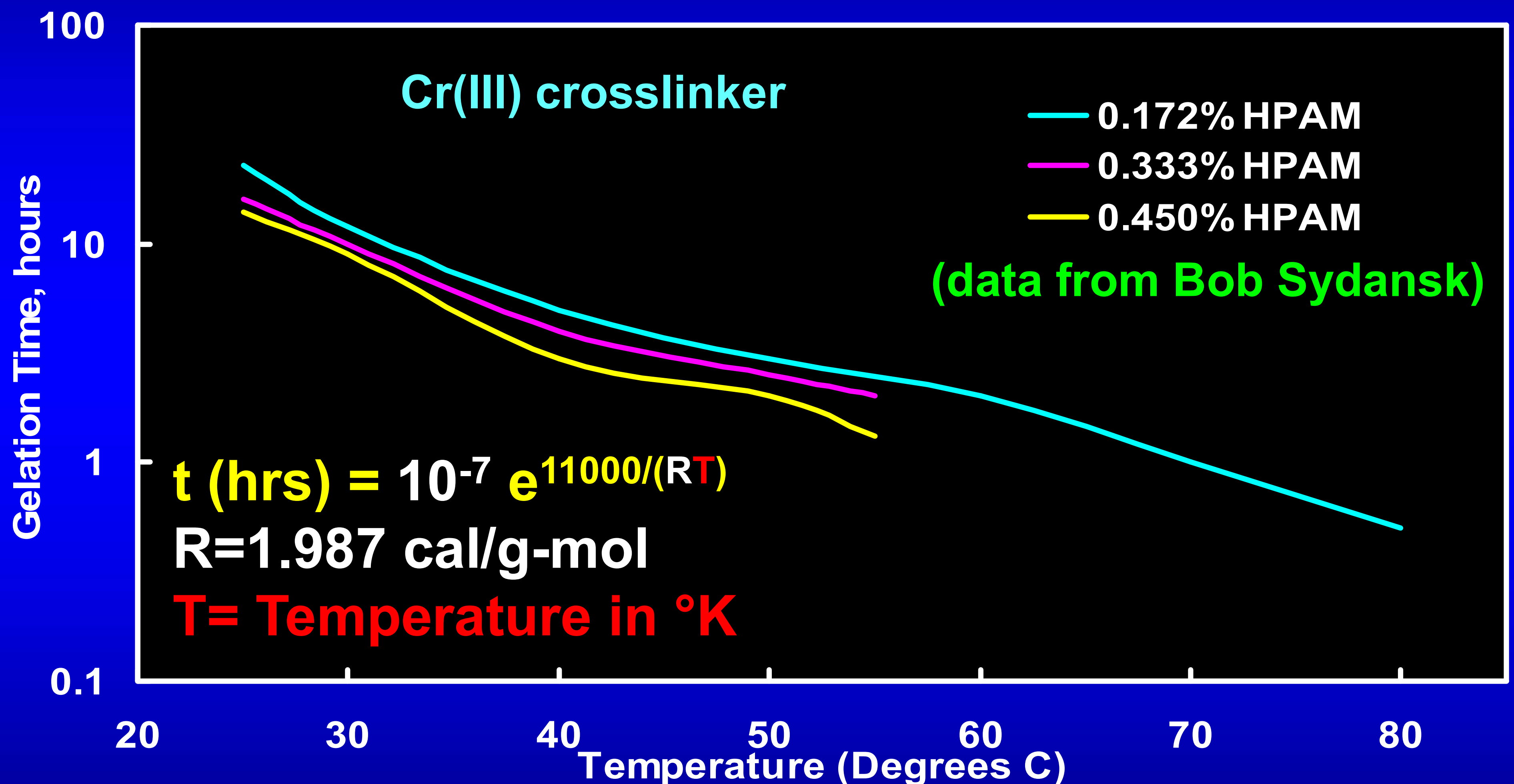
$$q = 3 \text{ BPM}$$

How much gelant should be injected?

$$V = \pi r^2 h \phi = 3.14 (10 \text{ ft})^2 (30.5 \text{ ft})(0.3)(1-0.3) (62.4/350)$$

$$V = 359 \text{ bbl}$$

GELATION TIME VERSUS TEMPERATURE



Increasing temperature by 10º C halves gelation time.

GELATION TIMES FOR MOST COMMERCIAL GELANTS ARE FAIRLY SHORT EVEN AT MODERATE TEMPERATURES

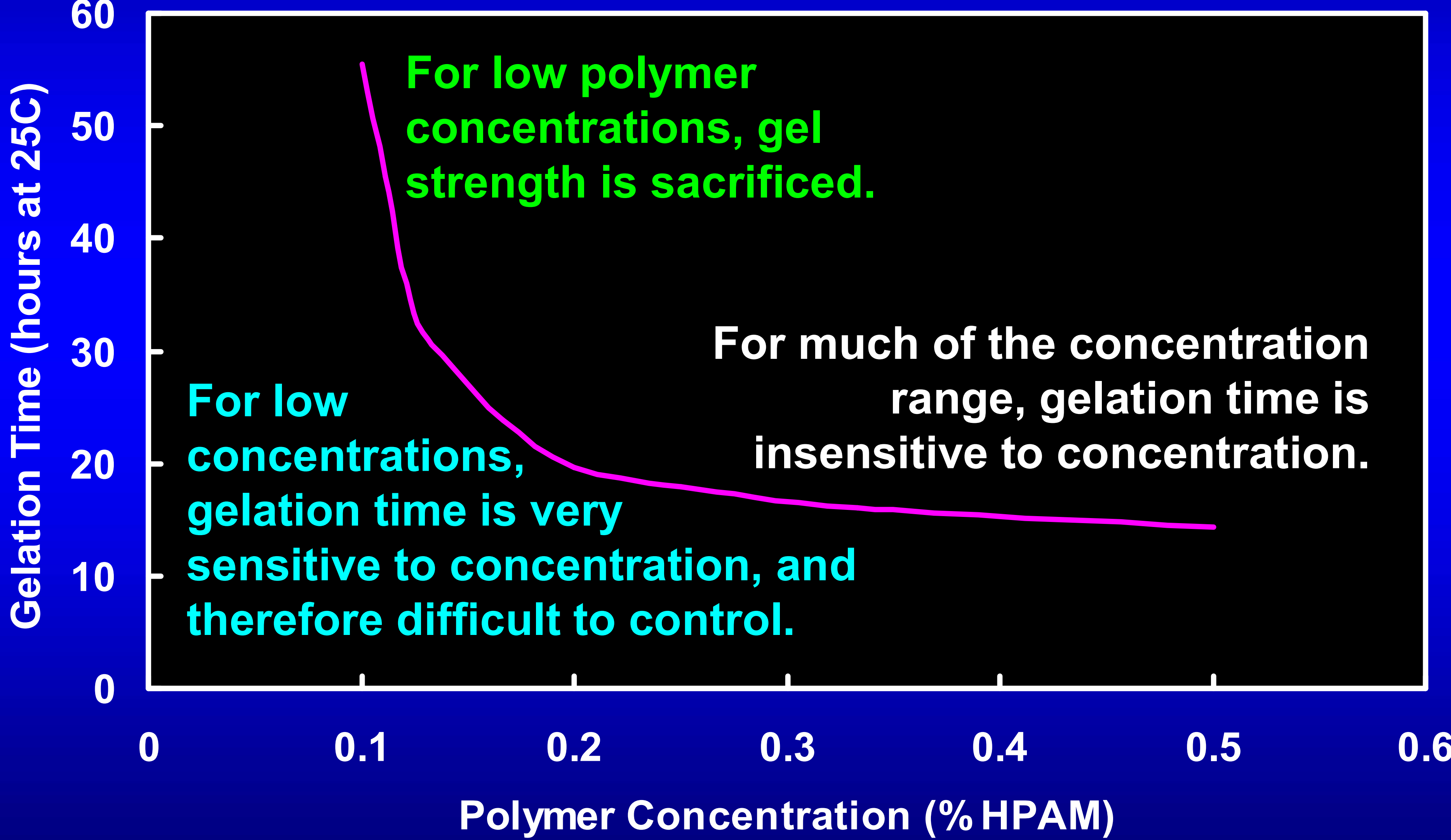
Some exceptions:

- **BP's PEI crosslinked/t-butylacrylate-acrylamide polymers.**
- **Unocal's organically crosslinked polymers. SPE 37246 and *SPEPF* May 1996, 108 - 112.**
- **Phillips' organically crosslinked polymers. SPE 27826.**
- **Eniricerche's Cr(III) - malonate crosslinked polymers. *SPEPF* Nov. 1994, 273 - 279.**

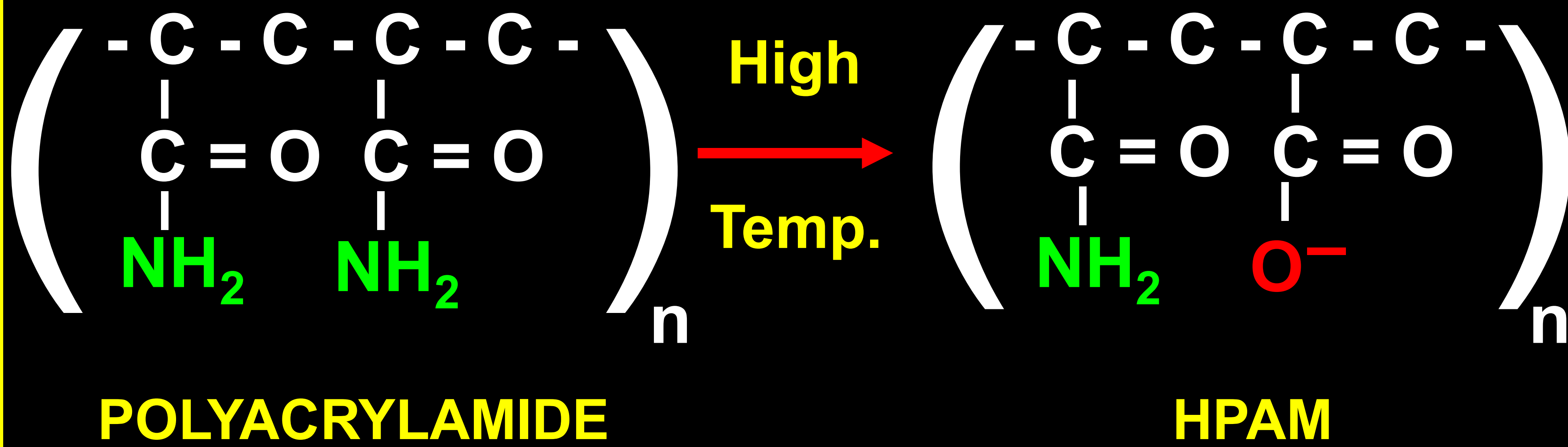
METHODS TO INCREASE GELATION TIMES

- Vary salinity, pH, or concentrations of chemical additives. SPE 27609.
- Use an unhydrolyzed polyacrylamide. With time, hydrolysis at elevated temperatures increases the number of crosslinking sites. SPE 20214.
- Cool the near-wellbore region prior to gelant injection. SPE 28502.
- Use a chemical retarding agent (e.g., lactate). *SPEPF* (Nov 2000) 270-278.

GELATION TIME VERSUS POLYMER CONCENTRATION



POLYMER HYDROLYSIS



- Only carboxylate groups react with Cr(III), so Cr(III) crosslinking is delayed until enough COO^- groups form.
- If too many COO^- groups form, polymer precipitates if Ca^{2+} or Mg^{2+} is present.
- Trick only works at high temperatures (~120°C) with low-Mw polyacrylamide polymers.

Gel Stability at Elevated Temperatures

- Some feel that gel stability is no better than the stability of the polymer in the gel.
- Gels can be made using polymers that are more stable than HPAM--e.g., amide/AMPS/NVP copolymers and terpolymers. *SPERE* Nov. 1987, 461-467.
- Some evidence exists that gel stability can be increased by using very rigid gels. SPE 20214.

Some papers examining gels for elevated temperatures

SPE 190266, 188322, 183558, 179796, 173185, 163110, 129848, 127806, 120966, 104071, 98119, 97530, 90449, 77411, 72119, 50738, 39690, 37246, 27826, 27609.

KEY MESSAGES:

1. HPAM polymers will hydrolyze at high temperature—risking gel syneresis if divalent cations are present.
2. Organic crosslinkers delay gelation but do not necessarily improve gel stability.
3. Polymers with high levels of ATBS or NVP promote polymer and gel stability.
4. More concentrated gels have greater stability.
5. Incorporating associative groups does not help stability.


CC/AP Gel
Aged at 300°F
for 2.5 Years

Gelant Sensitivity to pH

- For most gelants, the gelation reaction is sensitive to pH.
- Clays, carbonates, and other reservoir minerals can change pH -- thus interfering with gelation.
- Need to buffer gelants or develop gelants that are less sensitive to pH changes.

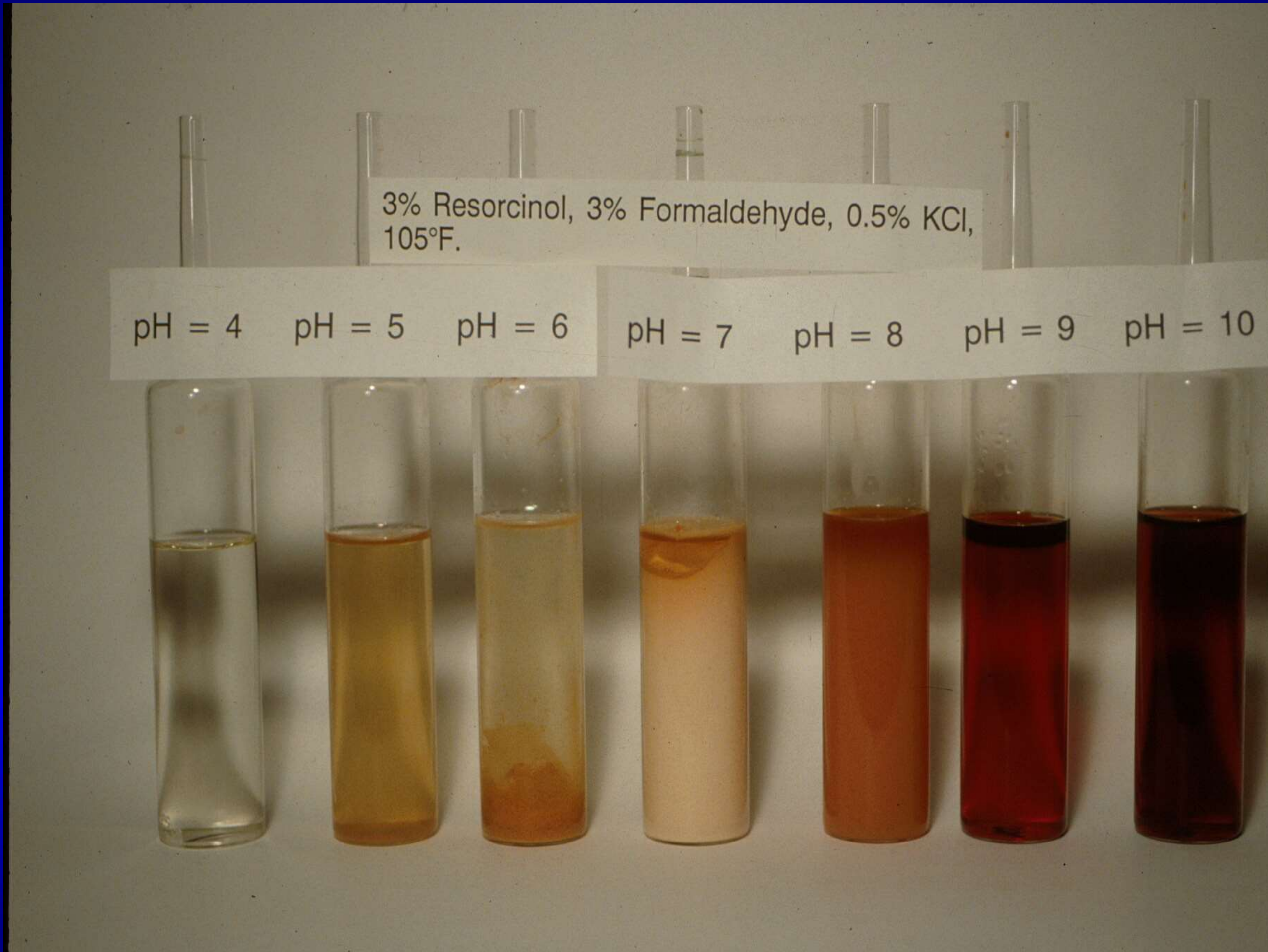
- Marathon: Cr(III)-acetate and lactate crosslinkers. SPE 17329.
- Phillips: Cr(III)-propionate crosslinker. *SPERE* Feb. 1988, 243-250.
- Eniricerche: Cr(III)-malonate and lactate crosslinkers. *SPEPF* Nov. 1994, 273-279.
- IFP: adsorbed polymers. SPE 18085.

Cr(IIII) can bind to:

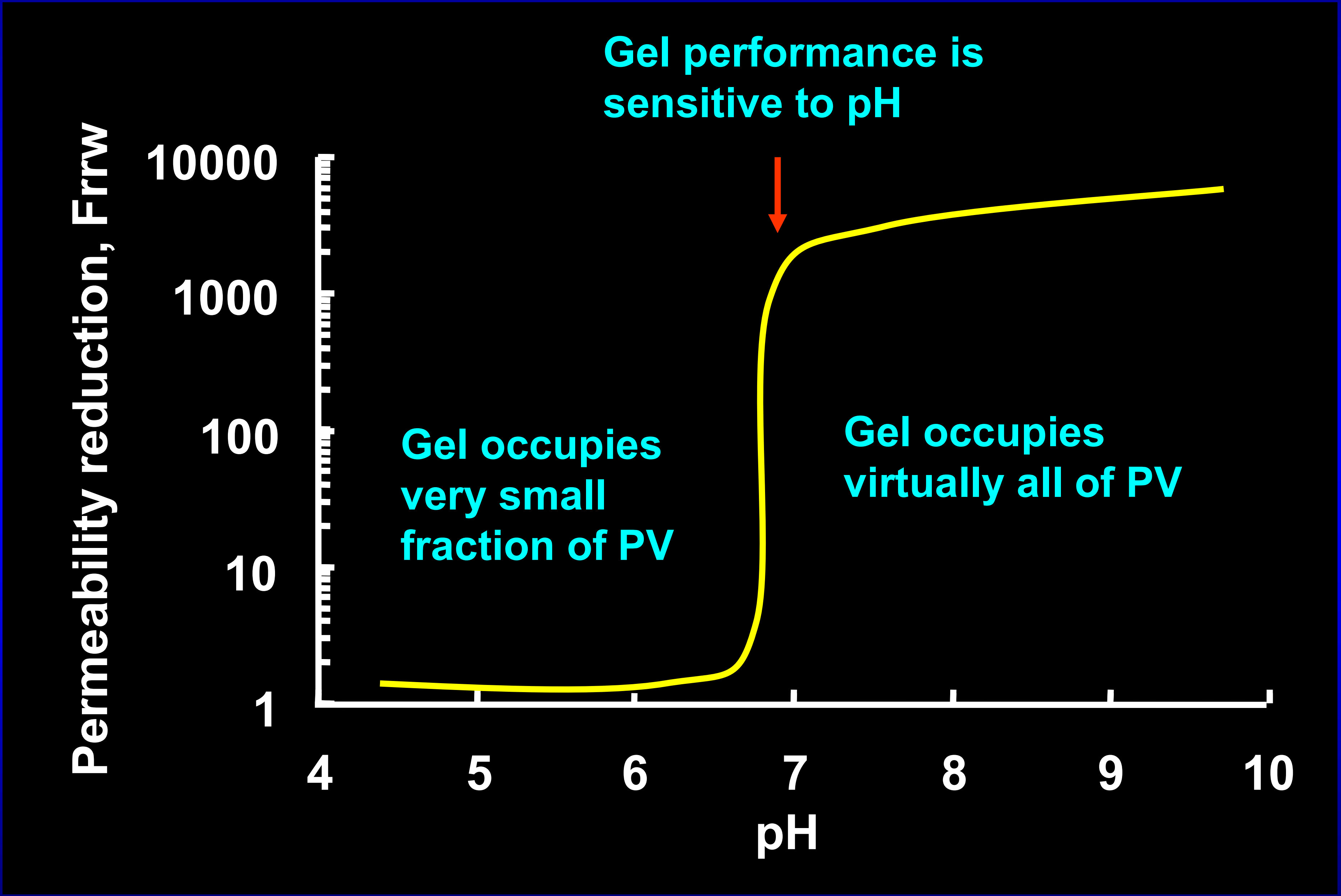
a. Polymer
b. Acetate or other carboxylate
c. Rock

Competition among the above affects gel stability, gel strength, gelant propagation, and gelation time.

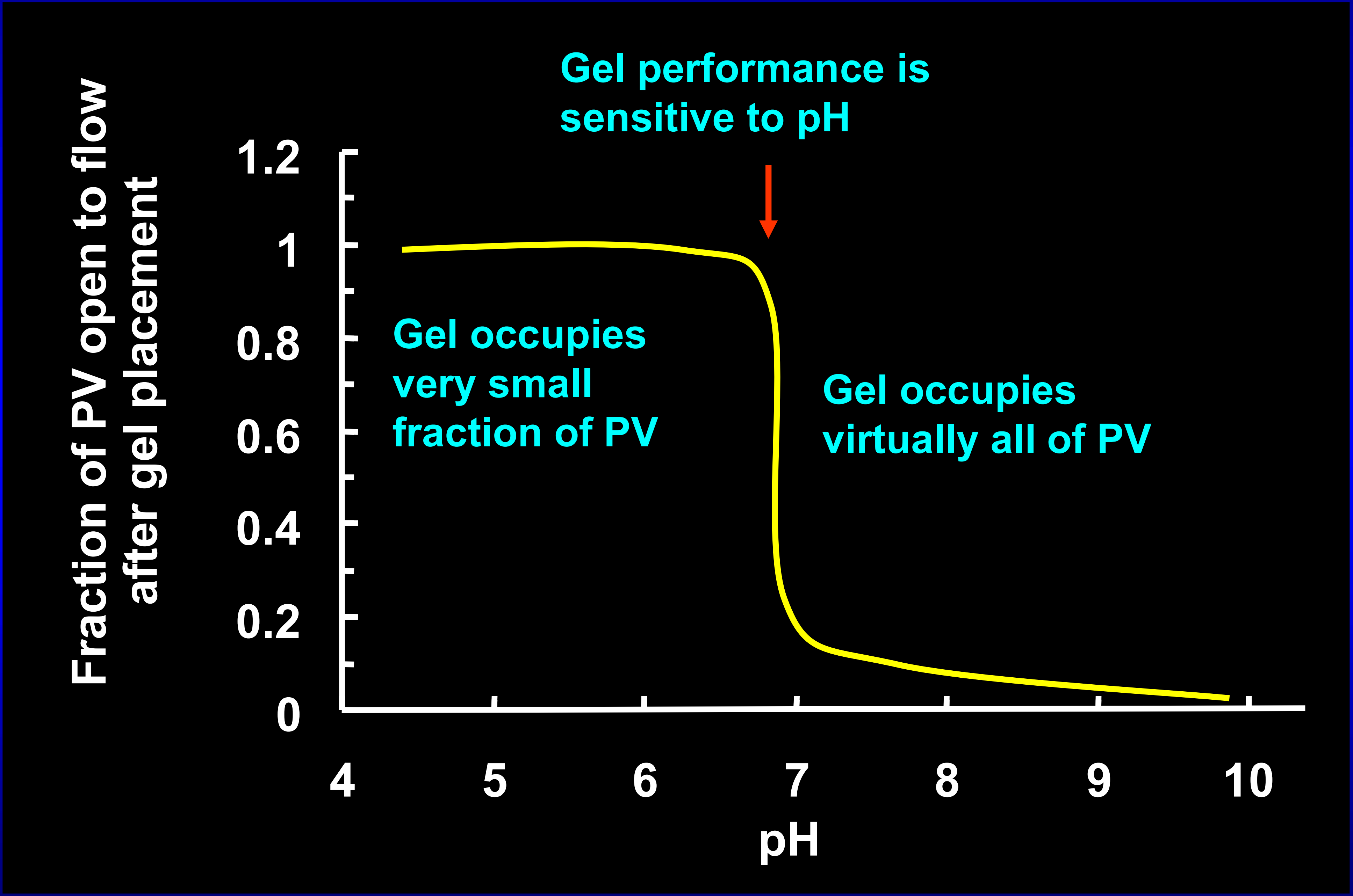
Gelation time at high temperatures can be varied by adjusting the ratio of acetate/lactate (or glycolate or malonate).


3% Resorcinol, 3% Formaldehyde, 0.5% KCl, 105°F.
pH = 4
pH = 5
pH = 6
pH = 7
pH = 8
pH = 9
pH = 10

pH OF GELATION AFFECTS PERMEABILITY REDUCTION



pH OF GELATION AFFECTS PV OCCUPIED BY GEL



Resistance factor = Water mobility ÷ Gelant mobility

$F_r = (k/\mu)_{water} / (k/\mu)_{gelant} \approx$ Gelant viscosity relative to water

Water residual resistance factor = $\dfrac{\text{Water mobility before gel placement}}{\text{Water mobility after gel placement}}$

$F_{rrw} = (k/\mu)_{water\ before\ gel} / (k/\mu)_{water\ after\ gel}$ = permeability reduction

Oil residual resistance factor = $\dfrac{\text{Oil mobility before gel placement}}{\text{Oil mobility after gel placement}}$

$F_{rro} = (k/\mu)_{oil\ before\ gel} / (k/\mu)_{oil\ after\ gel}$ = permeability reduction

WEAK GELS

- Occupy a very small fraction of the pore volume.
- Usually consist of small gel particles that block pore throats.
- Provide low to moderate permeability reductions.
- Are usually unpredictable in particle size, particle concentration, and permeability reduction provided.

ADSORBED POLYMERS

- Occupy a very small fraction of the pore volume.
- Usually block some fraction of the pore throats.
- Provide low to moderate permeability reductions.
- Because of mineralogical variations, are usually unpredictable in adsorption level and permeability reduction provided.

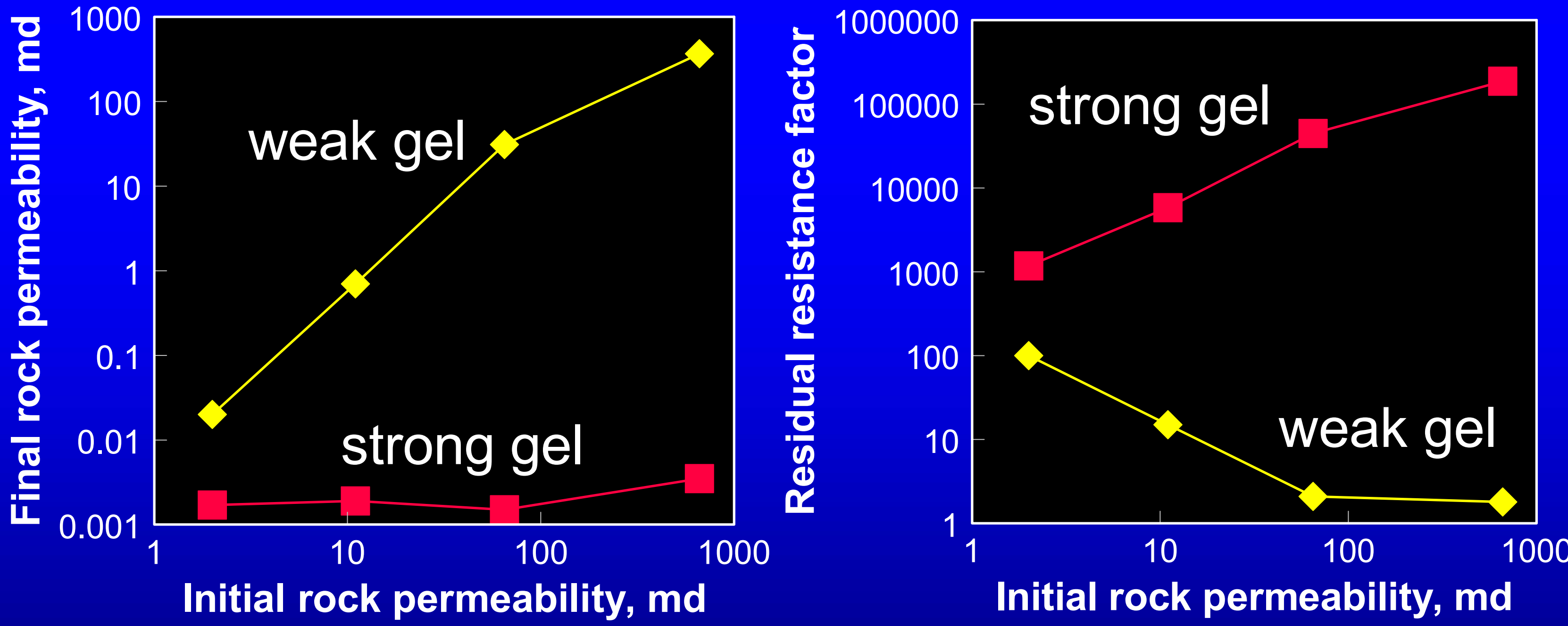
PORE-FILLING GELS

- Occupy most, if not all, of the aqueous pore space.
- Reduce permeabilities to microdarcy levels.
- Water flows through the gel itself.
- Provide high permeability reductions.
- Are much more predictable than weak gels and polymers.

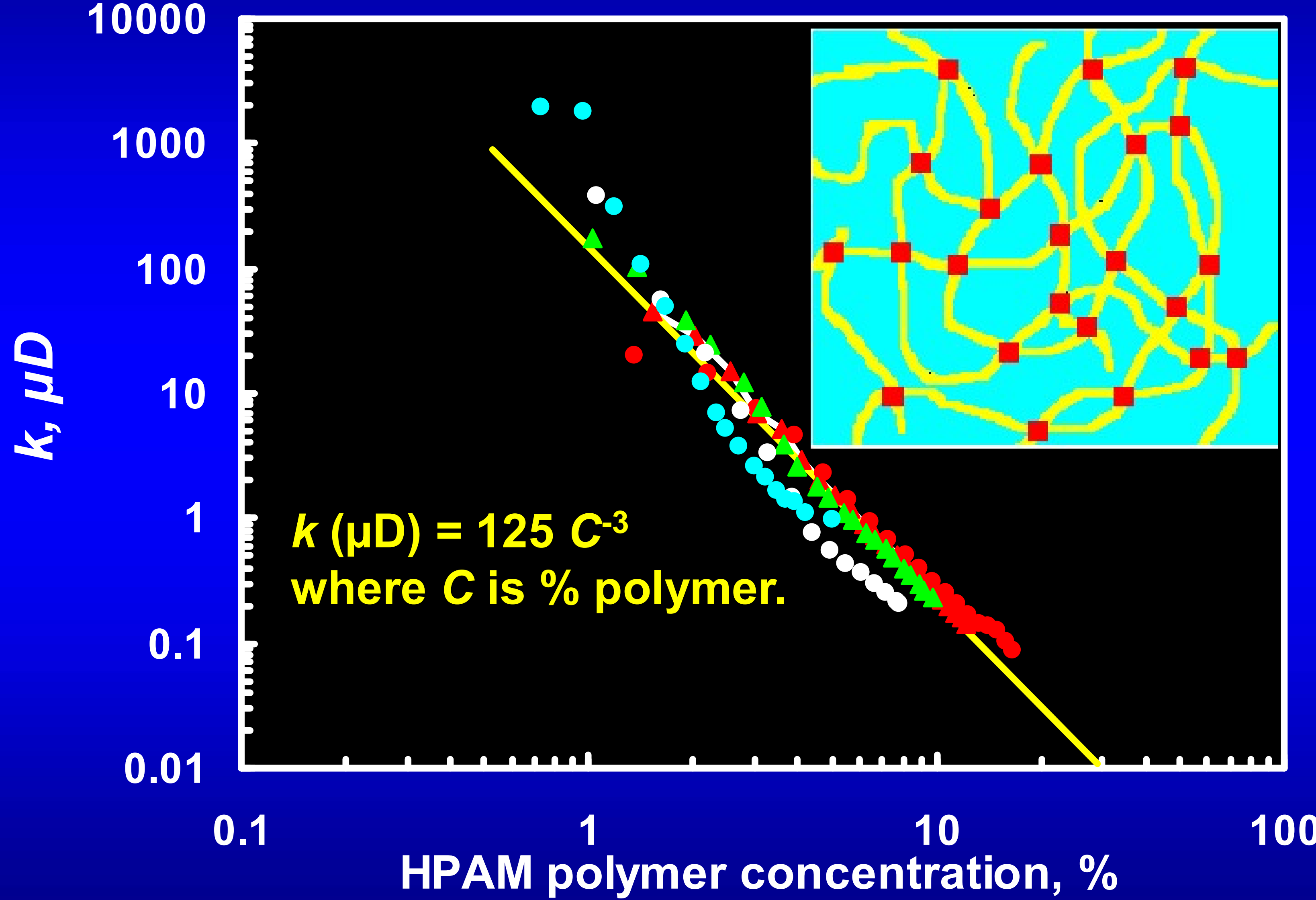
PERMEABILITY REDUCTION BY GELS

"Strong" gels reduce k of all rocks to the same low value.

"Weak" gels restrict flow in low-k rocks by a factor that is the same or greater than that in high-k rock.



Water can flow through gels although gel permeability is very low.



DISPROPORTIONATE PERMEABILITY REDUCTION

- Some gels can reduce k_w more than k_o or k_{gas}.
- Some people call this "disproportionate permeability reduction" or "DPR". Others call it "relative permeability modification" or "RPM". It is the same thing!
- This property is only of value in production wells with distinct water and hydrocarbon zones. It has no special value in injection wells!!!
- NO KNOWN polymer or gel will RELIABLY reduce k_w without causing some reduction in k_o !!!

- **IDEALISTIC GOAL OF WATER SHUTOFF TECHNOLOGY:** **Materials that can be injected into any production well (without zone isolation) and substantially reduce the water productivity without significantly impairing hydrocarbon productivity.**

- **Most previous attempts to achieve this goal have used adsorbed polymers or "weak gels" and most previous attempts have focused on unfractured wells.**

Problems with adsorbed polymers and weak gels (suspensions of gel particles):

- They show large variations in performance.
- F_{rr} values are greater in low-k rock than in high-k rock.
- F_{rro} values must be reliably less than 2 for radial flow applications.

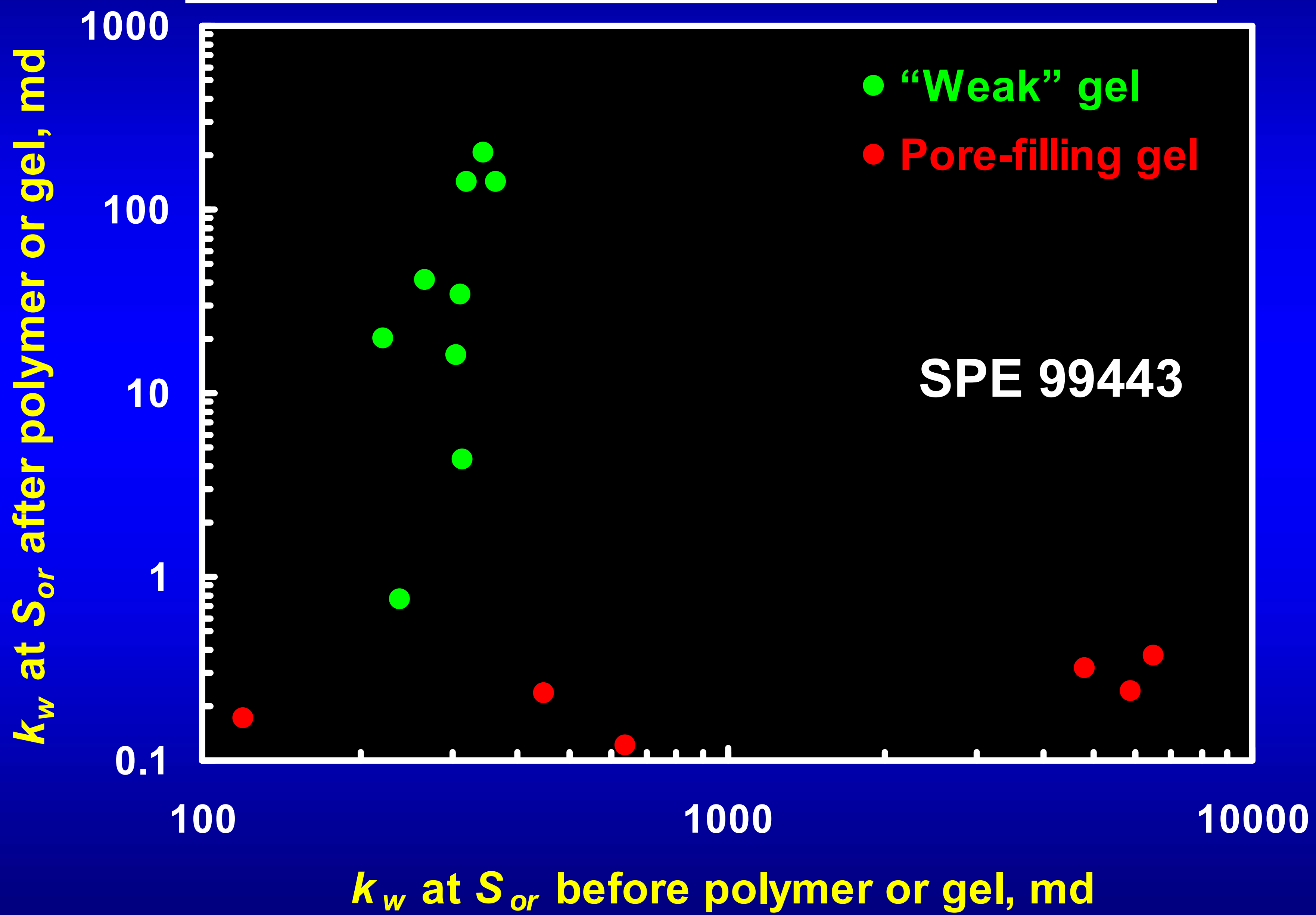
Why do adsorbed polymers and weak gels show large performance variations?

- Mineralogy varies within rock, so the level of adsorption also varies.
- Particle suspensions (e.g., weak gels) often have uncontrolled size distributions.
- Pore size distributions vary in rock.

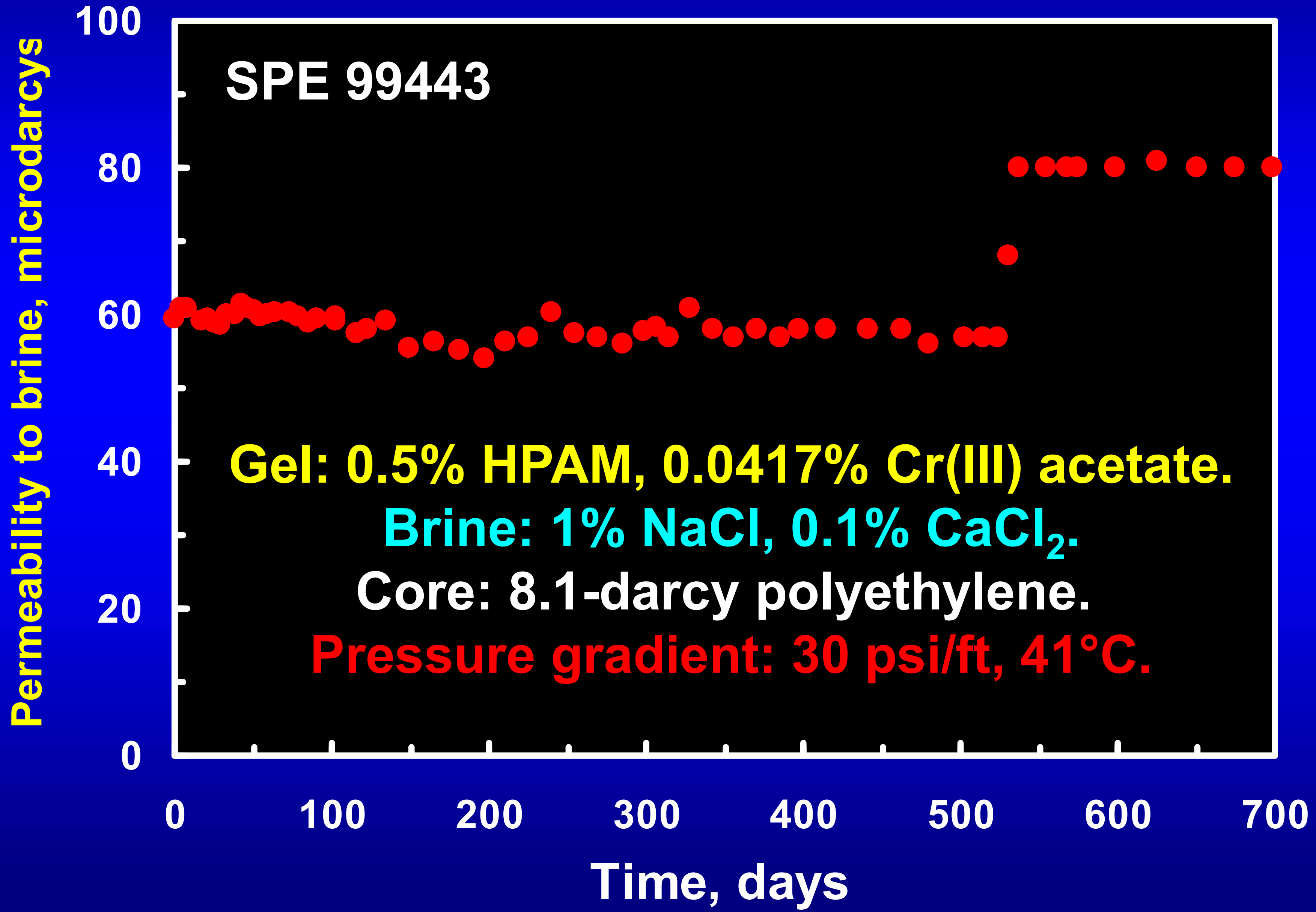
Conceptual solution to variations and *k*-dependence of gel performance:
USE A PORE FILLING GEL.

- Aqueous gels exhibit a finite, but very low permeability to water.
- If all aqueous pore space is filled with gel, k_{gel} will dominate k_w .
- So, rock with virtually any initial k_w should be reduced to the same final k_w .

Pore filling gels are more reliable than adsorbing polymers or weak gels.



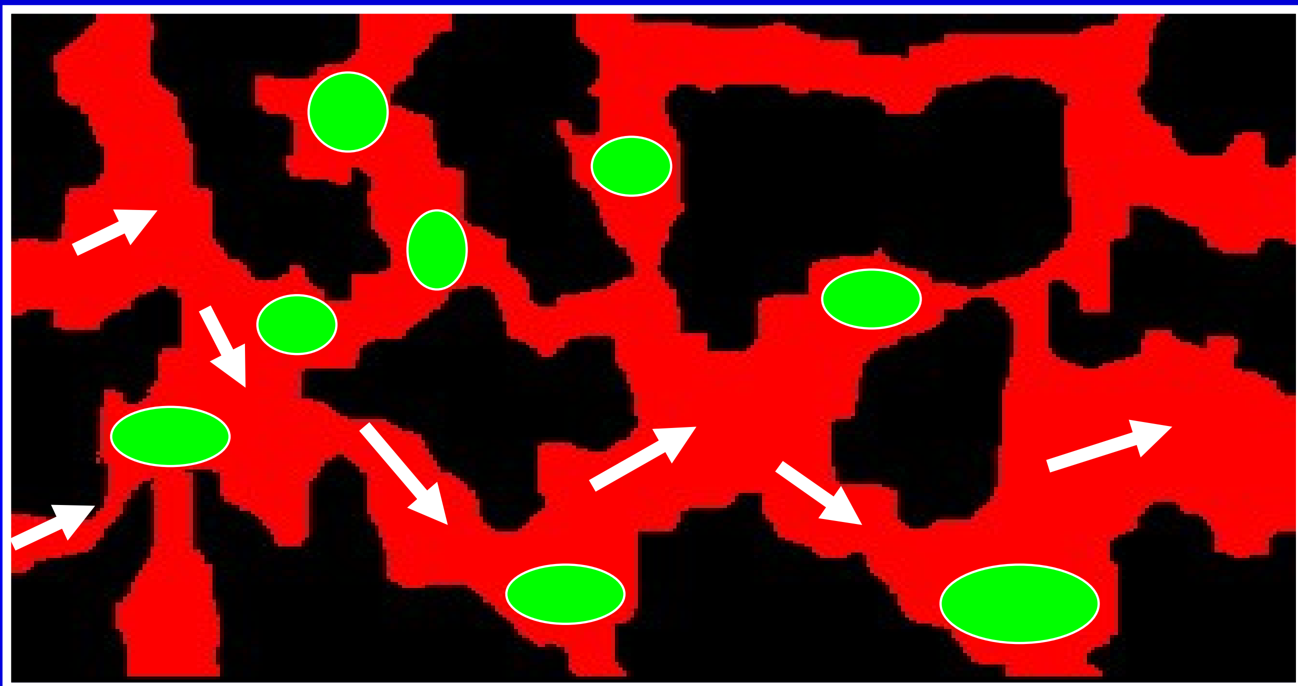
k_w can be quite stable to brine throughput and time.



WHY DO GELS REDUCE k_w MORE THAN k_o?

FIRST WATER FLOW AFTER GEL PLACEMENT

***SPEREE* (Oct. 2002) 355–364; *SPEJ* (Jun. 2006)**



IMMOBILE GEL

OIL

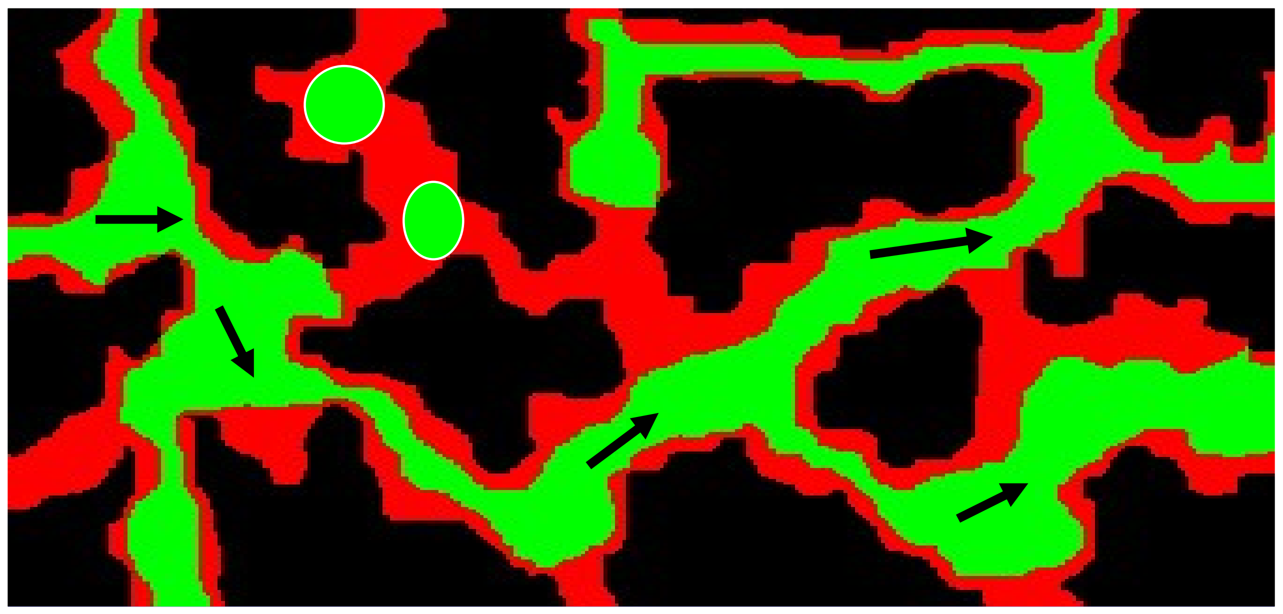
WATER FLOW THROUGH GEL

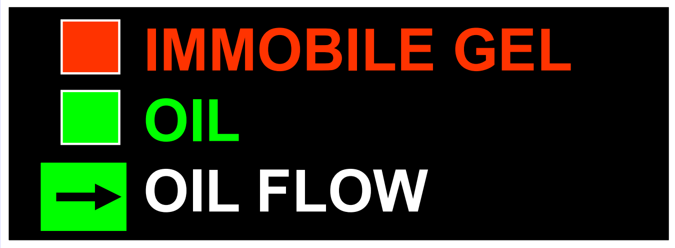
- **Strong gels fill all aqueous pore space.**
- **Water must flow through the gel itself.**
- **Gel permeability to water is typically in the μd range.**
- **Water residual resistance factor (F_{rrw}) is typically > 10,000.**

WHY DO GELS REDUCE k_w MORE THAN k_o?

FIRST OIL FLOW AFTER GEL PLACEMENT

SPEREE (Oct. 2002) 355–364; *SPEJ* (Jun. 2006)

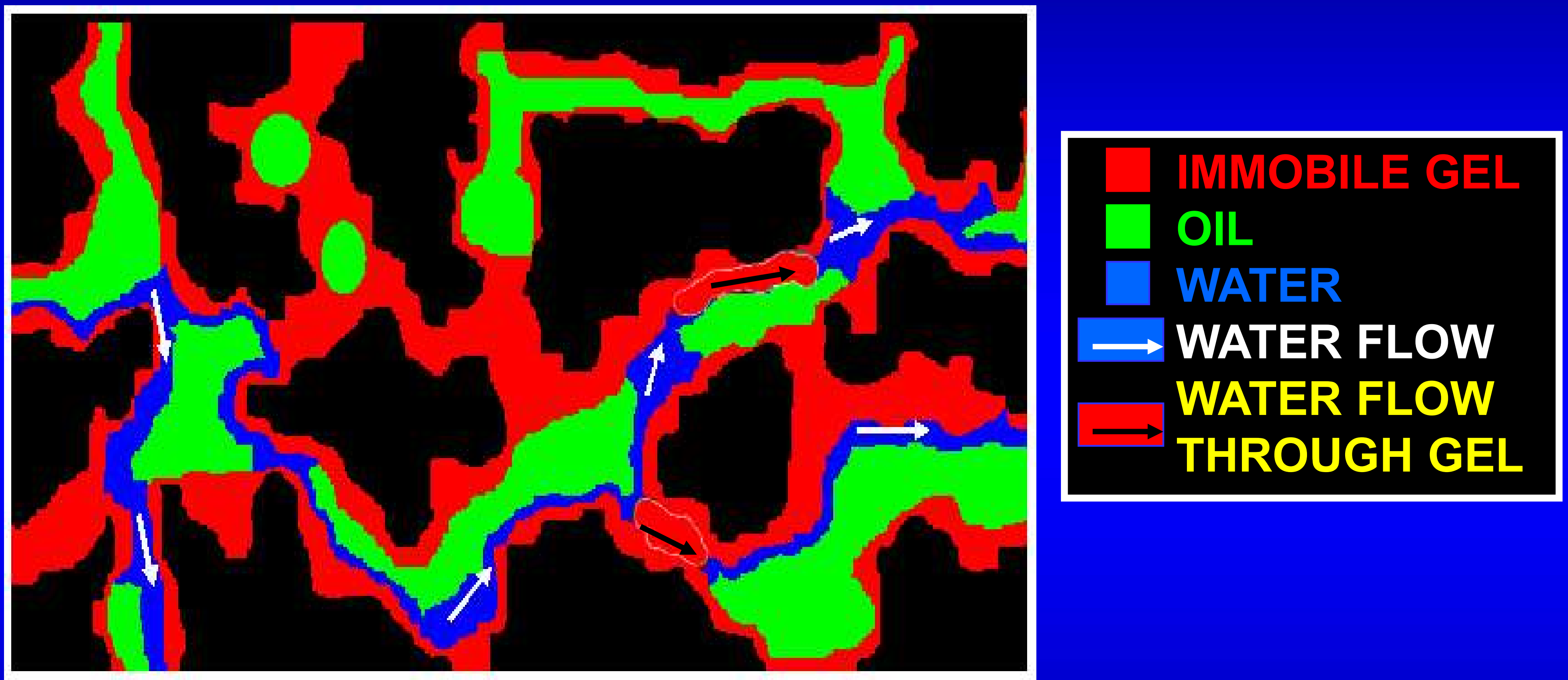




- Even with low pressure gradients, oil forces pathways through by destroying or dehydrating the gel.
- These oil pathways allow k_o to be much higher than k_w.
- Even so, k_o is lower than before gel placement.

WATER FOLLOWING OIL AFTER GEL PLACEMENT

SPEREE (Oct. 2002) 355–364; *SPEJ* (Jun. 2006)



- Gel traps more residual oil.
- Increased S_{or} causes lower k_w ($k_w \approx 1000$ times lower after gel than before gel placement).

A Challenge:

F_{rro} must be reliably < 2 for radial applications, but F_{rrw} must be reliably high (>100) for linear flow applications.

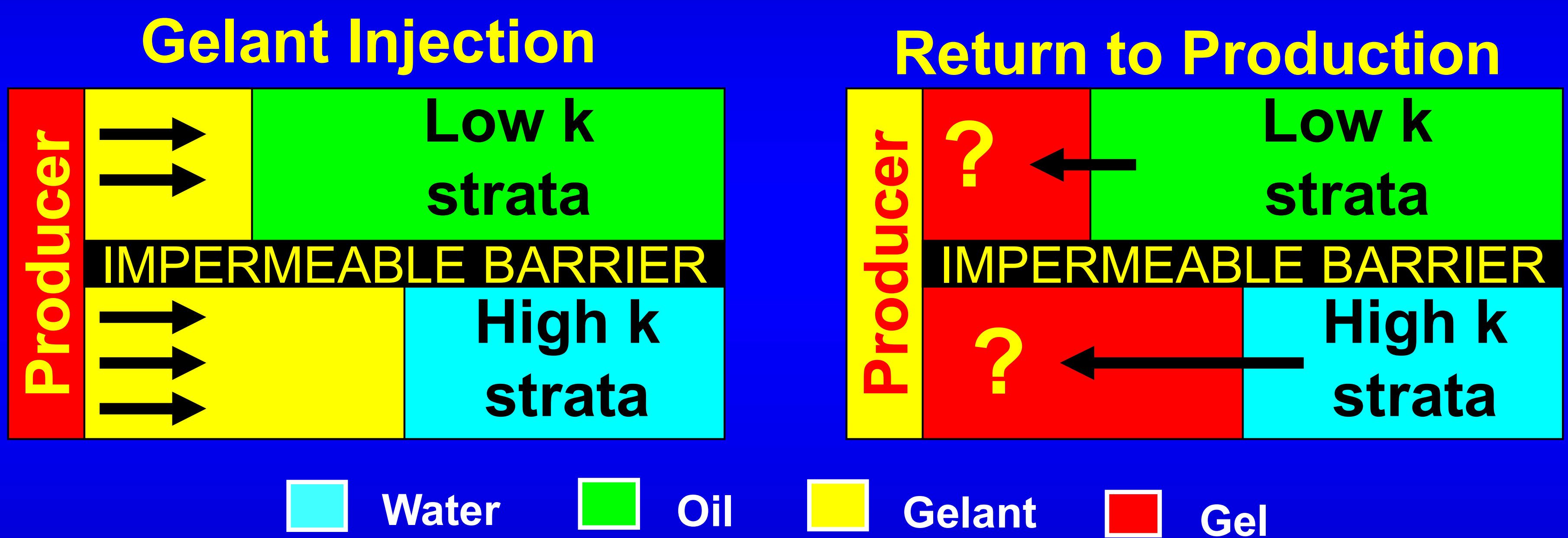
Can pore-filling gels meet this challenge?

F_{rrw} and final F_{rro} values for pore filling Cr(III)-acetate-HPAM gels in Berea sandstone.

Pre-gel k_w, md	HPAM in gel, %	Post-gel k_w, md	F_{rrw}	Final F_{rro}
356	0.5	0.015	23,700	1.2
389	0.5	0.005	77,800	1.2
31	0.5	0.007	4,430	2.2
40	0.4	0.019	2,110	2.0
270	0.3	0.055	4,980	1.7

SPE 99443

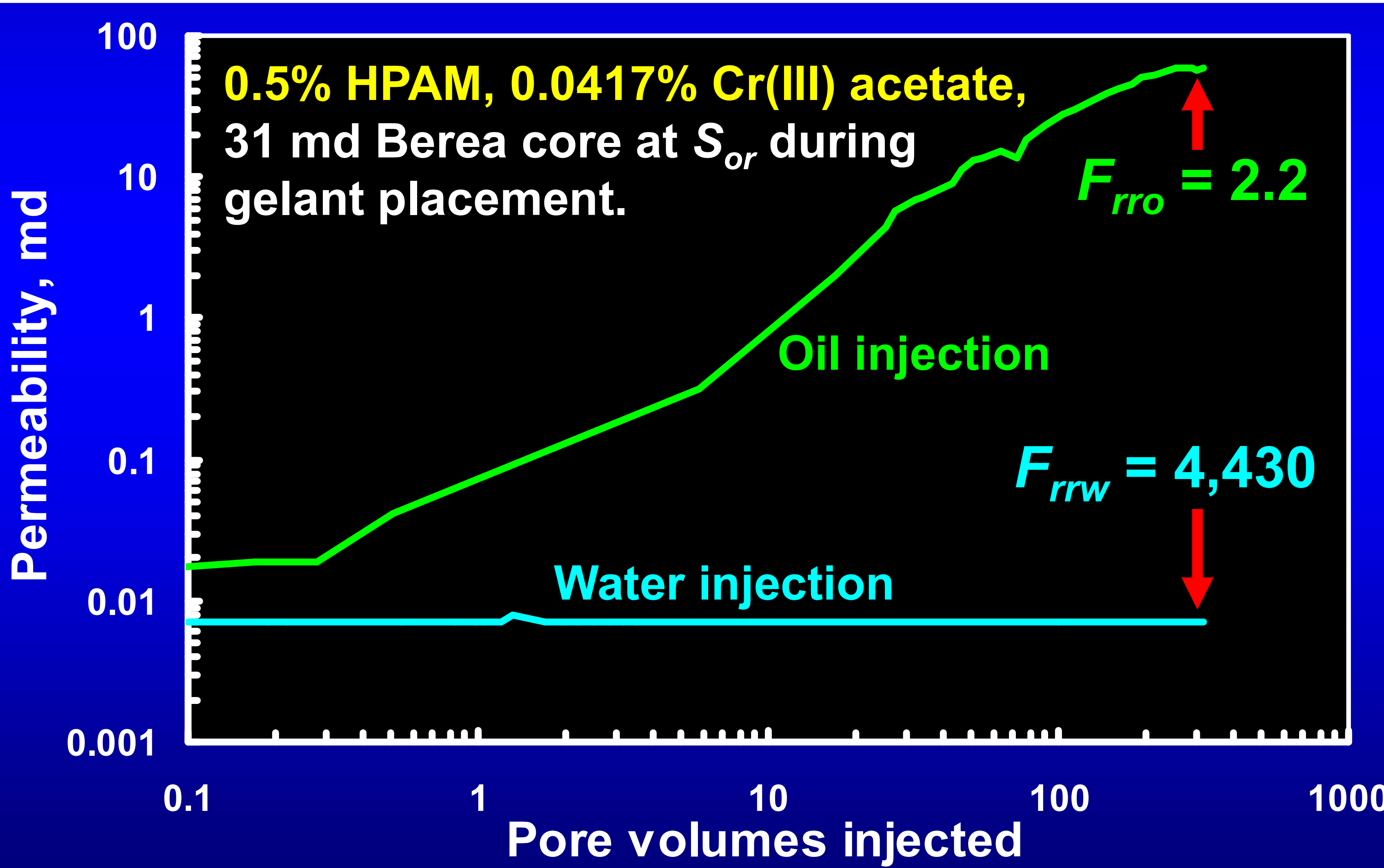
- **Polymers and gelants usually enter both oil and water strata when placed.**
- **Oil must flow or wormhole through the water or gel bank to reach the well.**



- **For some polymers and gels, $k_w << k_o$.**
- **However, some time is needed for oil rates to recover.**

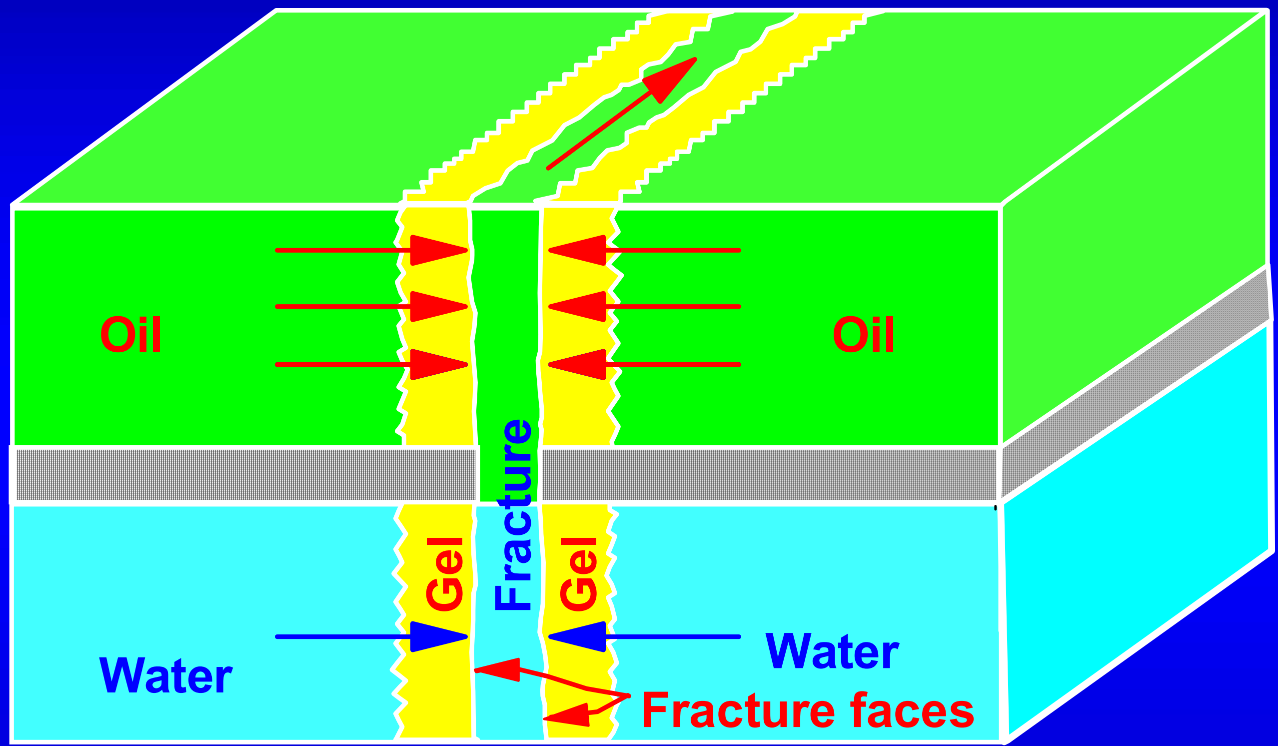
After gel placement, during water or oil flow,

- k_w stabilized very quickly at a low value.
- k_o rose gradually to a high value.



“DPR” or “RPM” is currently most useful in linear-flow problems (e.g., fractures)

Gel Restricting Water Flow into a Fracture



Equivalent resistance to flow added by the gel

- In oil zone: 0.2 ft x 50 = 10 ft.
- In water zone: 0.2 ft x 5,000 = 1,000 ft.

IN SITU 17(3), (1993) 243-272

DISPROPORTIONATE PERMEABILITY REDUCTION

- Pore-filling gels show much more reproducible behavior than weak gels or adsorbed polymers.
- For pore-filling gels, the first-contact brine residual resistance factor is typically determined by the inherent permeability of the gel to water.
- Re-establishing high k_o values requires large oil throughput.
- Achieving large throughput values in short times requires small distances of gelant penetration.

TREATING FRACTURES WITH GELANTS & GELS

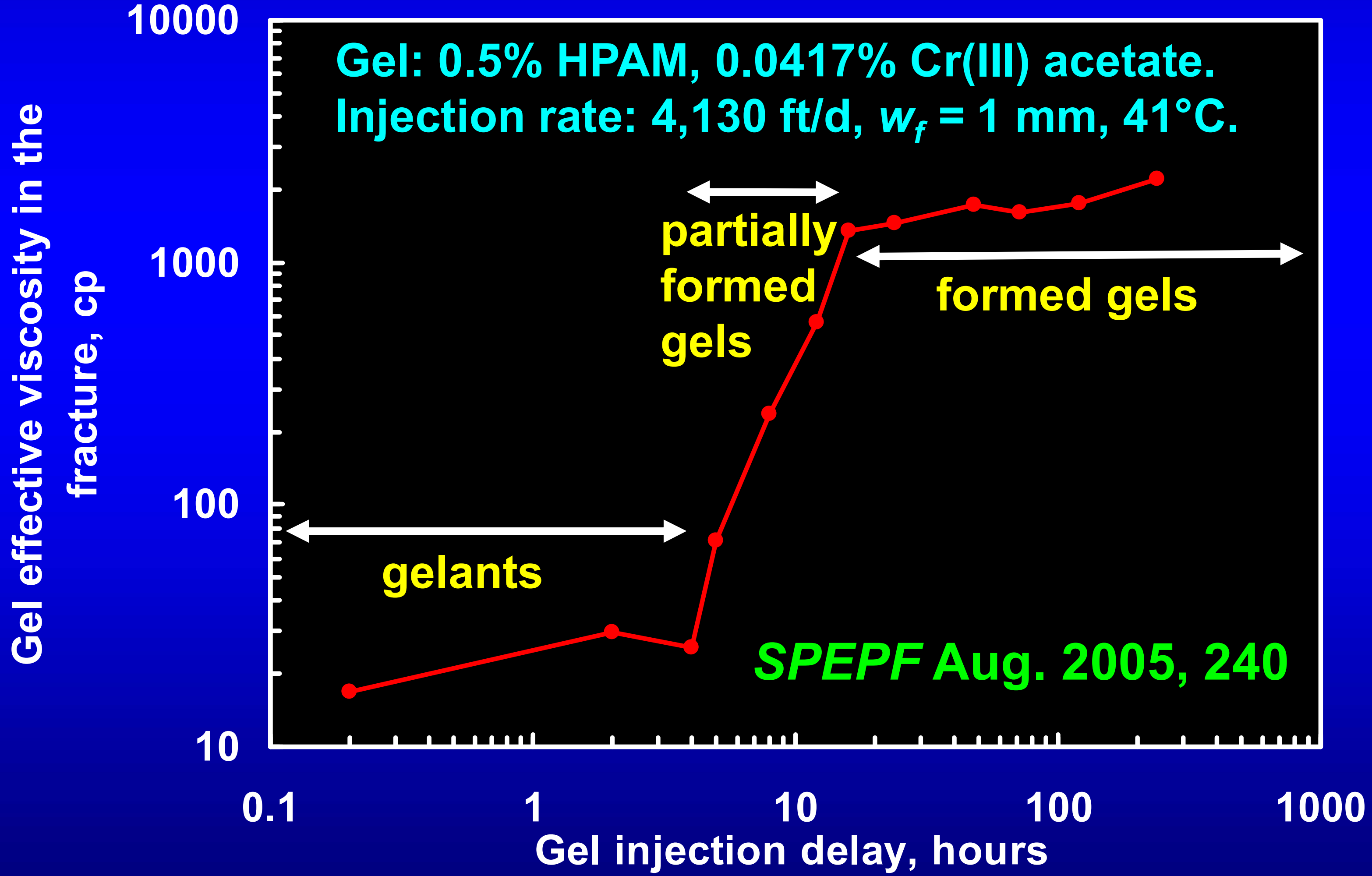
In most field applications, gel formulations:

- Enter the wellhead as gelants (very little crosslinking has occurred).
- Enter the formation as gelants or partially formed gels (i.e., shortly after the gelation time).

In small volume applications, gel formulations exist as fluid gelants or partially formed gels during most of the placement process.

In large volume applications, gel formulations exist as formed gels during most of the placement process.

- Compared with formed gels, gelants show much lower effective viscosities during placement in fractures.
- Low viscosities improve injectivity but often allow gravity segregation during placement in fractures.



PLACING FORMED GELS IN FRACTURES

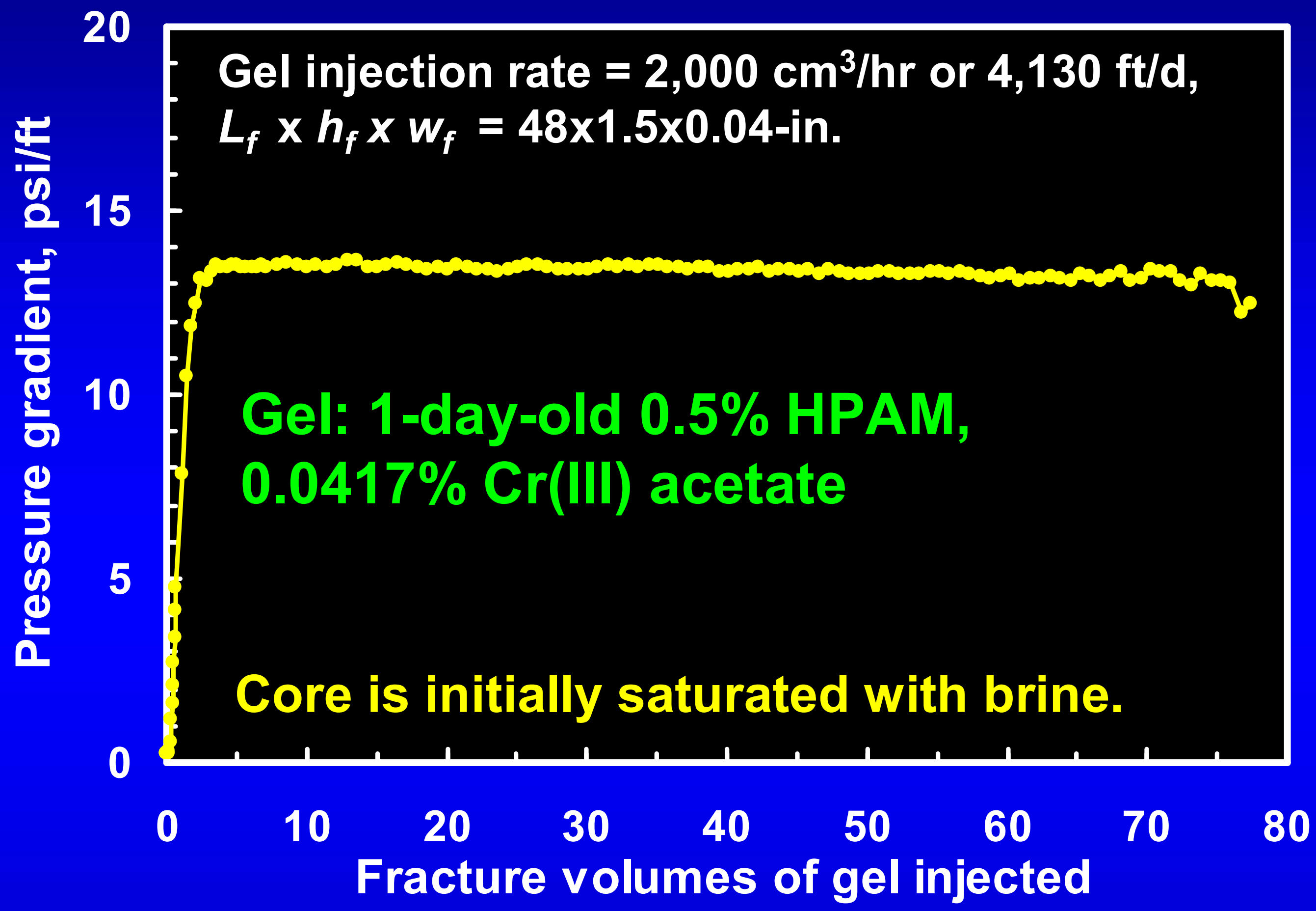
Successful large-volume Cr(III)-acetate-HPAM gel treatments in naturally fractured reservoirs:

- Typically injected 10,000 to 15,000 bbls gel per injection well.
- Injection times greater than gelation time by ~100X.
- Gels extruded through fractures during most of the placement process.

- What are gel properties during extrusion through fractures?
- How far can the gels be expected to propagate?
- How will the gels distribute in a fracture system?
- How much gel should be injected?

SPEPF (Nov. 2001) 225-232.

Pressure Behavior in a Fracture During Gel Extrusion

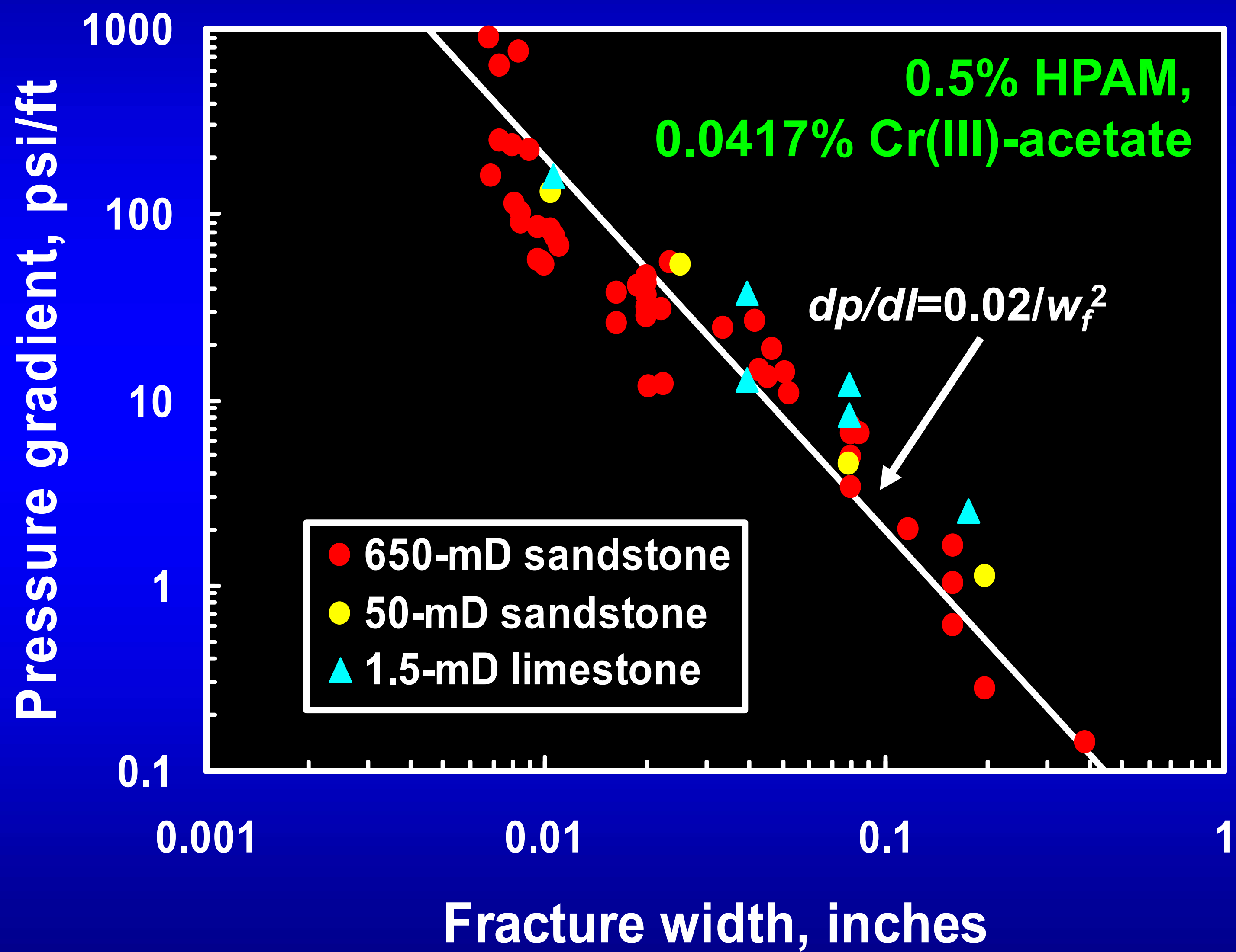


After gel breaks through at the end of a fracture, pressure gradients are stable (no screen out or progressive plugging).

PROPERTIES OF FORMED GELS IN FRACTURES

- A minimum pressure gradient must be met before a formed gel will extrude through a fracture.
- Once the minimum pressure gradient is met, the pressure gradient during gel extrusion is not sensitive to injection rate.
- The pressure gradient for gel extrusion varies inversely with the square of fracture width.

Pressure gradients required to extrude a Cr(III)-acetate-HPAM gel through fractures



PROPERTIES PROBLEM 4A

A formed gel containing 0.5% high-Mw HPAM crosslinked with Cr(III)-acetate was extruded into a 4-mm-wide, 100-ft high fracture at a rate of 1 BPM. What pressure gradient would occur in the fracture?

dp/dl (psi/ft) = 0.02/ $(w_f)^2$ where w_f is in inches

dp/dl (psi/ft) = 0.02/ $[(4\ \mathrm{mm})/(25.4\ \mathrm{mm/inch})]^2$

dp/dl = 0.8 psi/ft

PROPERTIES PROBLEM 4B

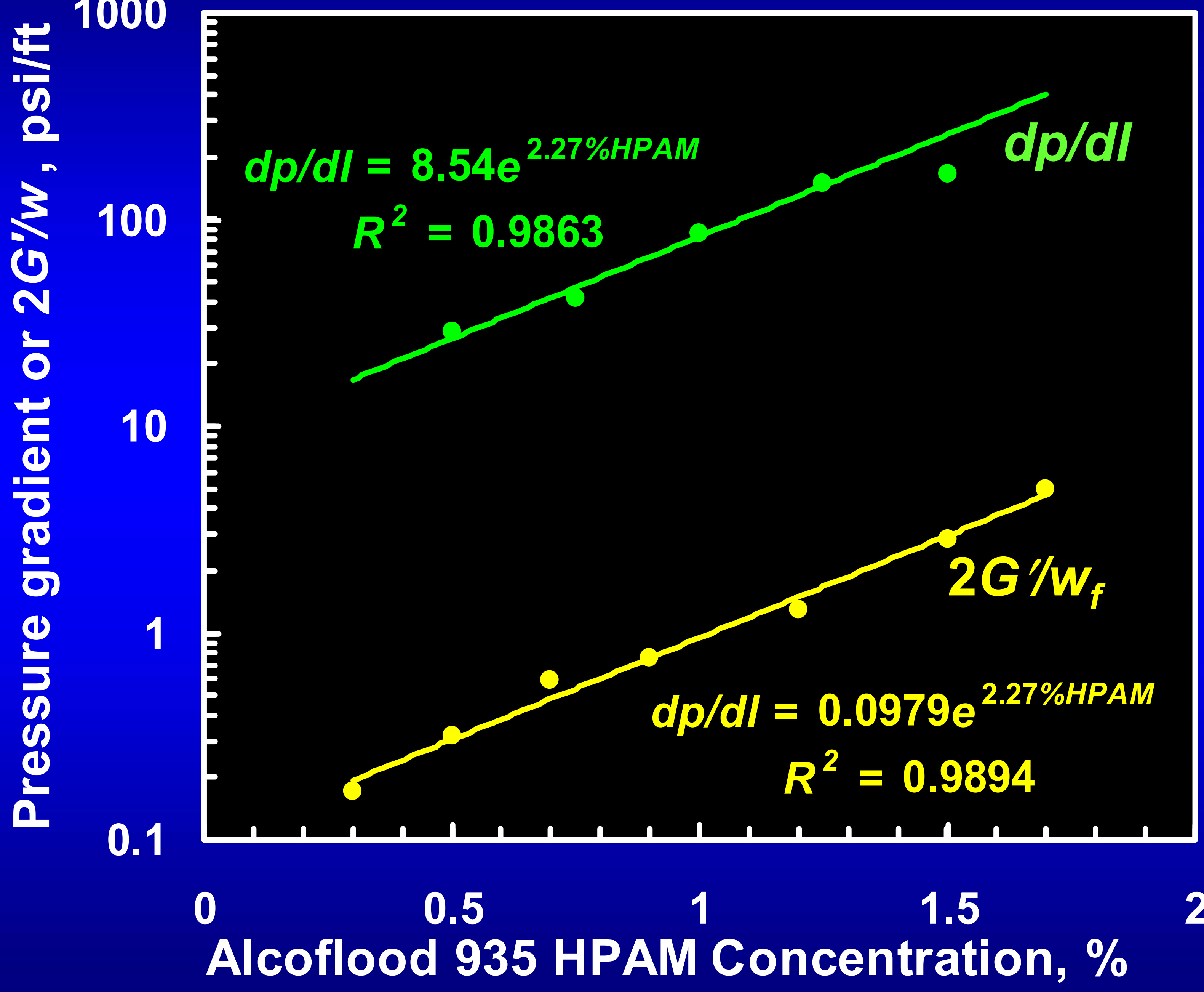
For the previous problem, the reservoir pressure (static downhole pressure) was 1000 psi. The maximum allowable downhole pressure during gel injection is 2000 psi. What is the maximum distance that this gel could be expected to penetrate into the fracture?

$L = \Delta p \,/\, (dp/dl)$

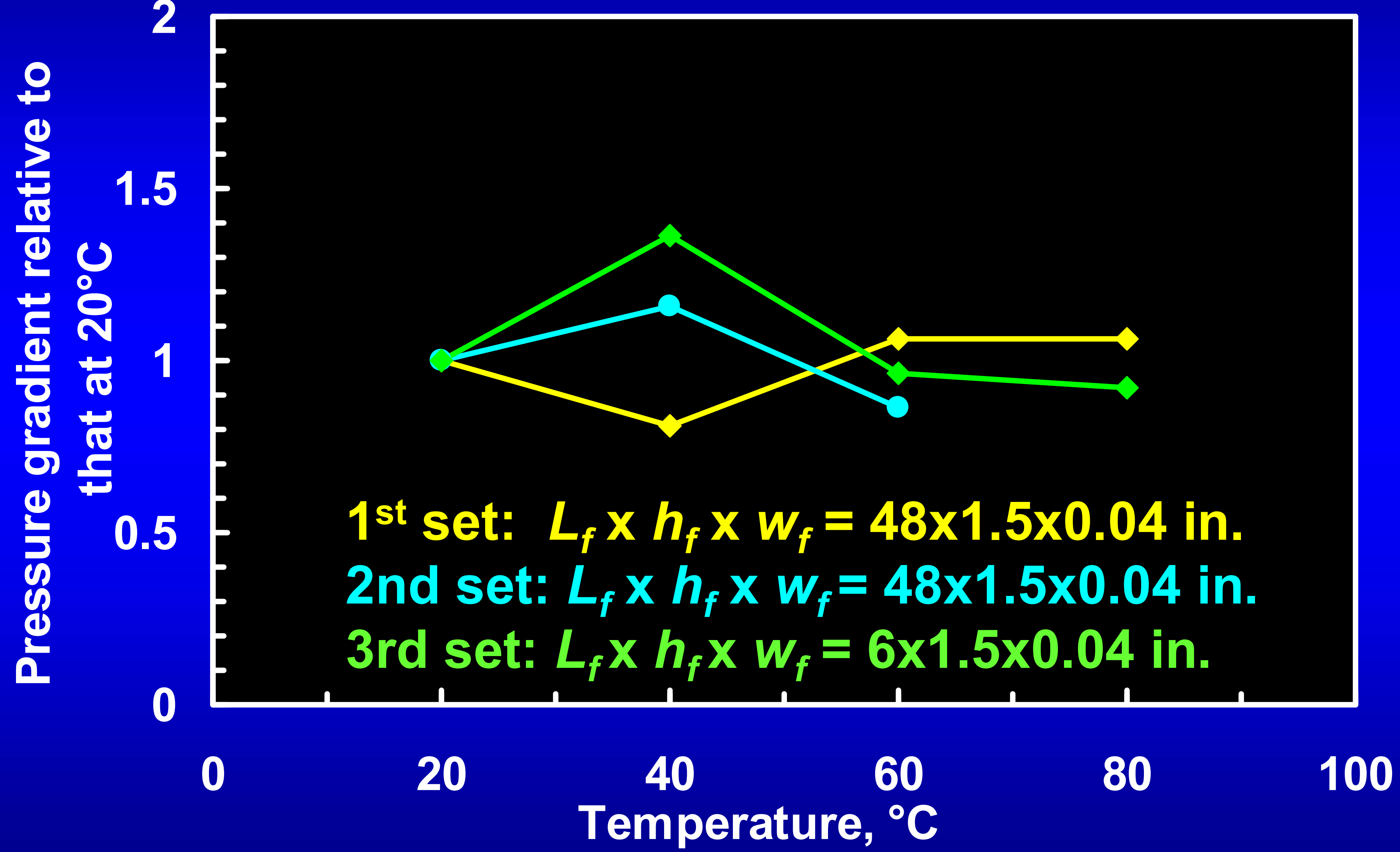
$L = [(2000 \text{ psi})-(1000 \text{ psi})]/(0.8 \text{ psi/ft})$

$L = 1250 \text{ ft}$

EFFECT OF POLYMER CONCENTRATION ON EXTRUSION PRESSURE



PRESSURE GRADIENTS DURING GEL EXTRUSION ARE NOT SENSITIVE TO TEMPERATURE



GELS DEHYDRATE DURING EXTRUSION

Cr(III)-acetate-HPAM gel

Fracture: L_f = 4 ft, h_f = 1.5 in., w_f = 0.04 in.

Injected 80 fracture volumes of gel (~4 liters)

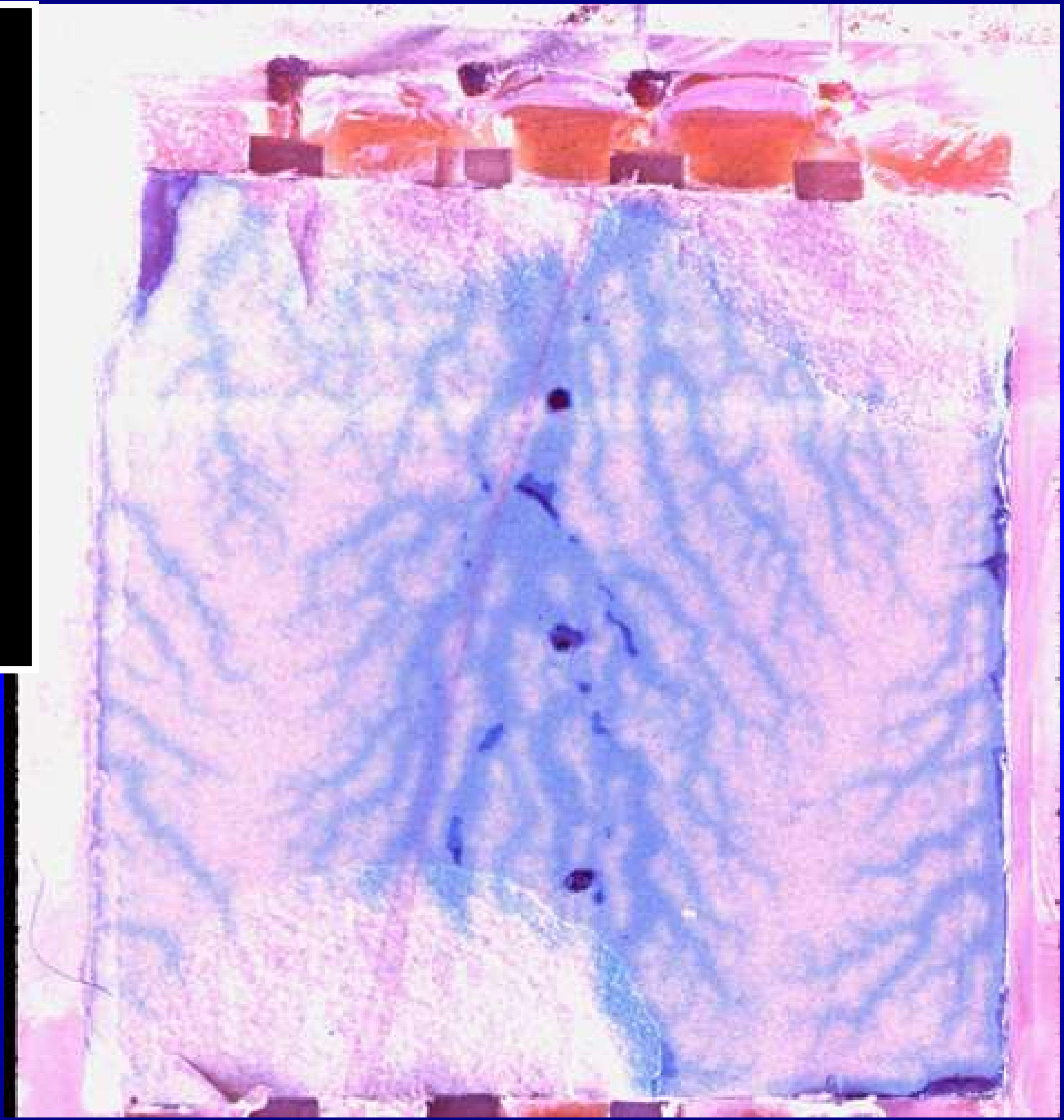
Injection flux, ft/d	413	1,030	4,130	33,100
Average *dp/dl*, psi/ft	28	29	40	18
Gel breakthrough, fracture volumes	15	6.0	4.0	1.7
Average gel dehydration, C/C_o	27	17	11	4

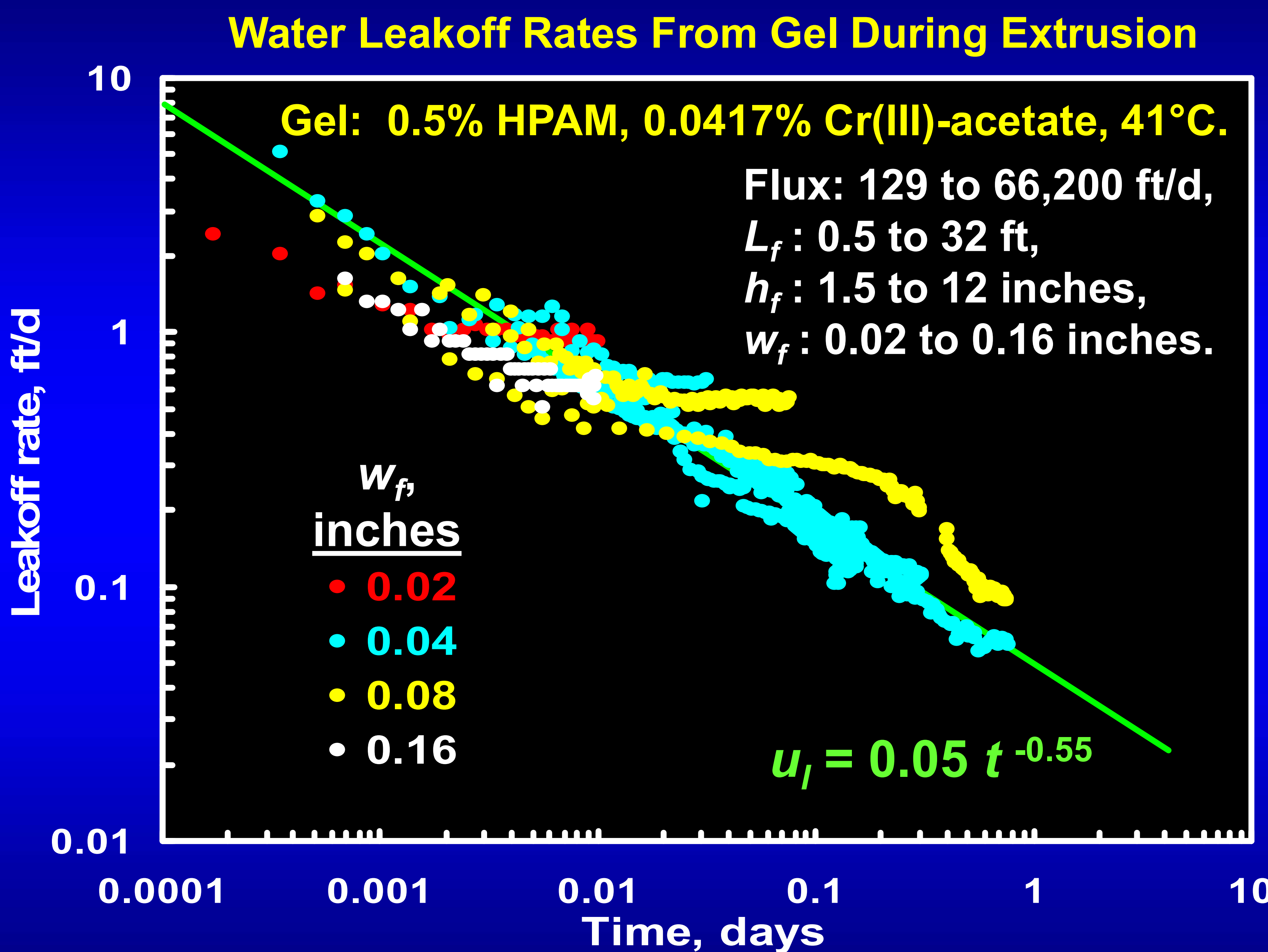
PROPERTIES OF Cr(III)-ACETATE-HPAM GEL DURING EXTRUSION THROUGH FRACTURES

- Gels dehydrate, thus retarding the rate of movement of the gel front.
- Although water leaks off through the fracture faces, crosslinked polymer cannot.
- Dehydrated (concentrated) gel is immobile.
- Mobile gel is the same as the injected gel.
- Mobile gel wormholes through immobile gel.

1-day-old 1X Cr(III)-acetate HPAM gel (in blue) wormholing through dehydrated gel that is 12 times more concentrated.

Fracture dimensions = 15x15x0.1 cm





Water Leakoff Rates From Gel During Extrusion
Gel: 0.5% HPAM, 0.0417% Cr(III)-acetate, 41°C.
Flux: 129 to 66,200 ft/d,
L_f : 0.5 to 32 ft,
h_f : 1.5 to 12 inches,
w_f : 0.02 to 0.16 inches.
w_f,
inches
0.02
0.04
0.08
0.16
$u_l = 0.05\ t^{-0.55}$
Leakoff rate, ft/d
10
1
0.1
0.01
0.0001
0.001
0.01
0.1
1
10
Time, days

WHAT IS THE RATE OF GEL PROPAGATION THROUGH A FRACTURE?

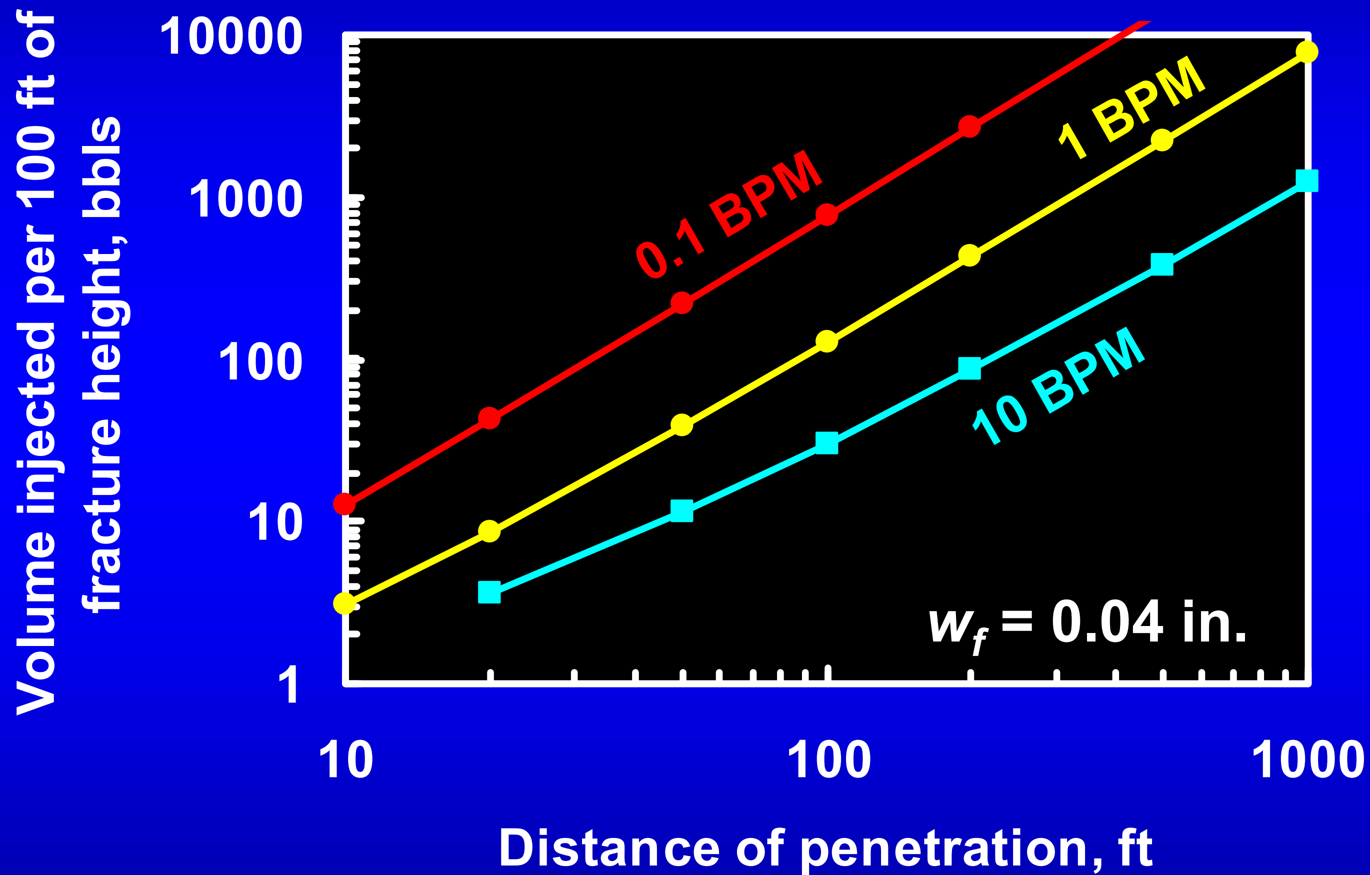
- The rate of water loss from the gel is given by: $u_l = 0.05\ t^{-0.55}$. Combine with a mass balance.

- Assuming two fracture wings, the rate of gel propagation, dL/dt, is:

$$dL/dt = [q_{tot} - 4h_f L\ u_l\ ] \,/\, [2\ h_f\ w_f]$$

$$dL/dt = [q_{tot} - 4h_f L\ 0.05\ t^{-0.55}] \,/\, [2\ h_f\ w_f]$$

Predictions in Long Two-Wing Fractures



- The degree of gel dehydration depends on injection rate and time.

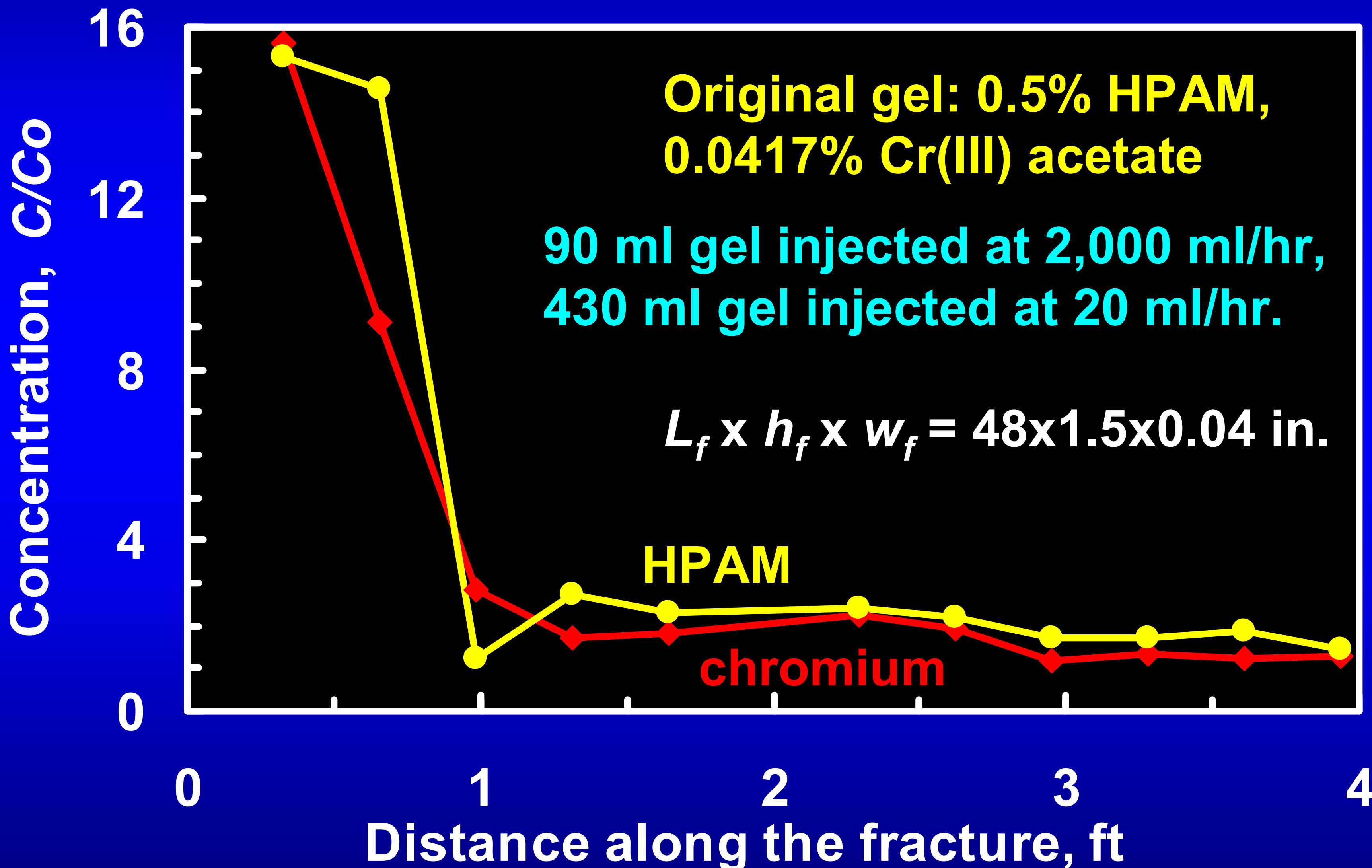
- When injecting gel into a fracture, can a more rigid gel plug be formed in the near wellbore portion of the fracture simply by reducing the injection rate?

Gel injected at low rate: maximum dehydration for greater rigidity and strength.

COMPOSITION OF GEL IN THE FRACTURE.

Injection rate = 2,000 ml/hr until fracture filled with gel.

Then the rate was dropped to 20 ml/hr.



PROPERTIES OF FORMED GELS DURING EXTRUSION THROUGH FRACTURES

- Dehydration limits the distance of GEL penetration along a fracture.
- For a given total volume of GEL injection, the distance of gel propagation will be maximized by injecting at the highest practical injection rate.
- To double the distance of GEL penetration into a long fracture, the GEL volume must be tripled.
- More concentrated, rigid GELS can be formed by injecting slower—decreasing the probability of gel washout.

Dehydration of Gels in Fractures by Imbibition (Brattekas: SPE 153118, 169064, 173749, 180051)

- Water-wet rock can suck water out of gels in fractures—thus collapsing those gels.
- This action could be of value for fractures in oil zones because you want those fractures to remain open to flow.
- For fractures in water zones, if no oil is present, no capillary action occurs so the gels remain intact in the fracture and flow remains restricted.
- Depending on the salinity of the gel and water post-flush, the flow capacity of gel-filled fractures can be varied.

PRE-FORMED PARTICLE GELS (PPGs) (Bai et al.)

- Are crosslinked polymers that are dried and ground to a desired particle size offsite.
- Swell upon contact with water.
- Swell less with more saline brines.
- Dehydrate during extrusion through fractures.
- Are expected to show performance similar to other preformed gels [e.g., extruded Cr(III)-acetate-HPAM].
- Show potential for plugging wider fractures.
- Bai references: SPE 190364, 190357, 180388, 188384, 188023, 187152, 182795, 181545, 180386, 179705, 176728, 176429, 175058, 174645, 172352, 171531, 170067, 169159, 169107, 169106, 169078, 164511, 129908, 115678, 113997, 89468, 89389.

WHY CHOOSE ONE MATERIAL OVER ANOTHER?

What do you want the gel to do?

- Cost
- Availability
- Sensitivity of performance to condition or composition variations
- Blocking agent set time
- Permeability reduction provided to water
- Permeability reduction provided to oil or gas
- Ability to withstand high-pressure gradients in porous rock
- Ability to withstand high-pressure gradients in fractures or voids
- Rheology and/or filtration properties
- Ability to penetrate into fractures or narrow channels behind pipe
- Stability at elevated temperatures
- Environmental concerns

PLACEMENT CONCEPTS

Objective of Water Shutoff Treatments

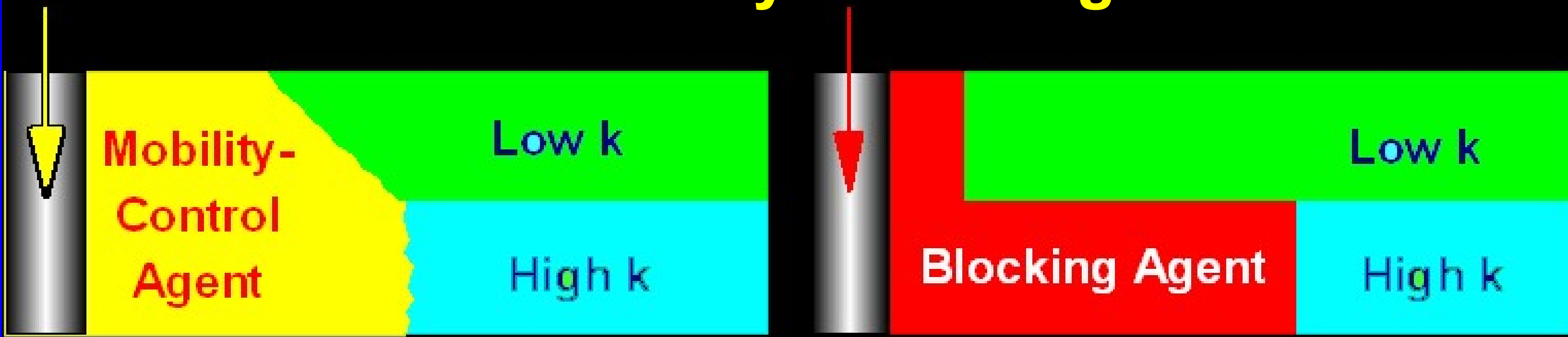
- Objective is to shut off water without seriously damaging hydrocarbon productive zones.
- Want to maximize blocking agent penetration into water-source pathways, while minimizing penetration into hydrocarbon zones.
- Want to maximize permeability reduction in water-source pathways, while minimizing permeability reduction in hydrocarbon zones.

GEL TREATMENTS ARE NOT POLYMER FLOODS

Crosslinked polymers, gels, gel particles, and "colloidal dispersion gels":

- Are not simply viscous polymer solutions.
- Do not flow through porous rock like polymer solutions.
- Do not enter and plug high-k strata first and progressively less-permeable strata later.
- Should not be modeled as polymer floods.

Distinction between a blocking agent And a mobility control agent.



- For a mobility control agent, penetration into low-k zones should be <u>maximized.</u>
- For a blocking agent, penetration into low-k zones should be <u>minimized.</u>

KEY QUESTIONS DURING BULLHEAD INJECTION OF POLYMERS, GELANTS, OR GELS

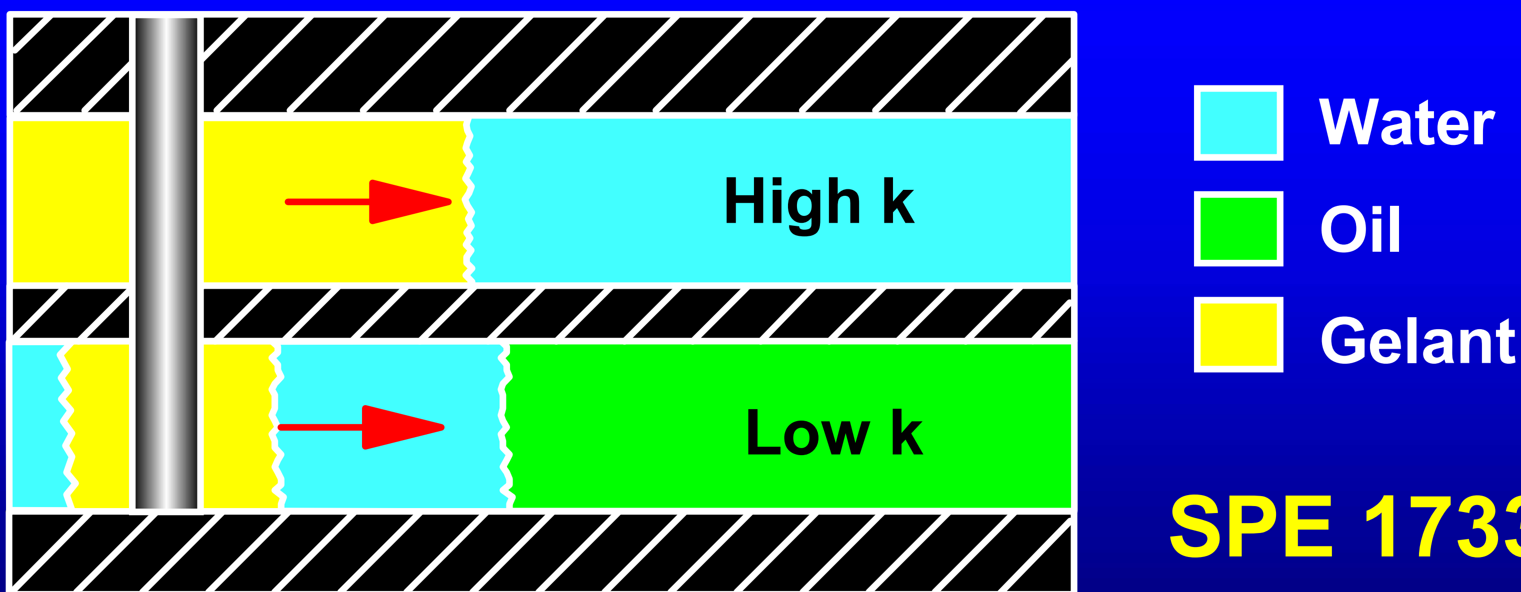
- **Why should the blocking agent NOT enter and damage hydrocarbon productive zones?**
- **How far will the blocking agent penetrate into each zones (both water AND hydrocarbon)?**
- **How much damage will the blocking agent cause to each zone (both water AND hydrocarbon zones)?**

BASIC CALCULATIONS

Gelants can penetrate into all open zones.

An acceptable gelant placement is much easier to achieve in linear flow (fractured wells) than in radial flow.

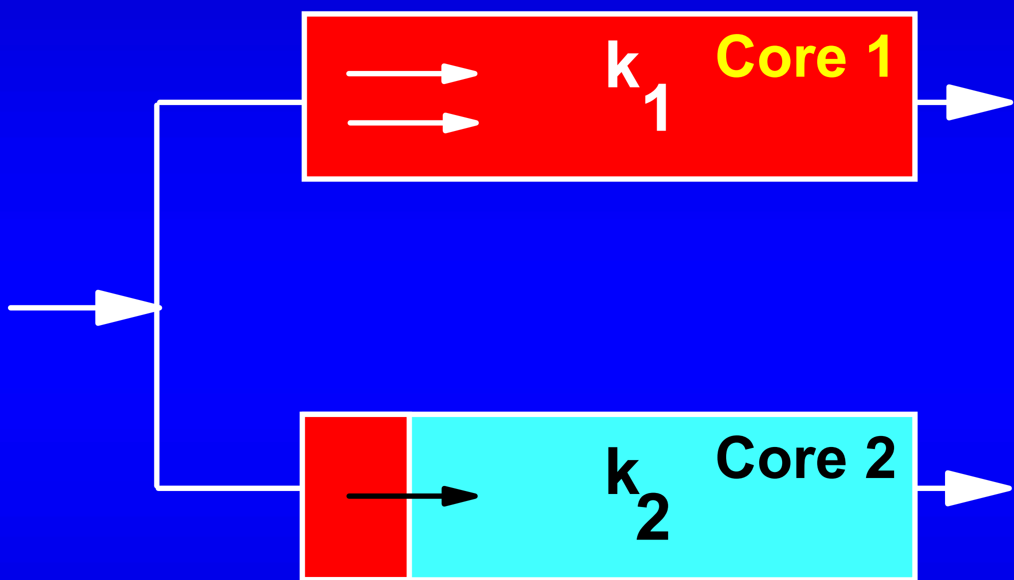
In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.

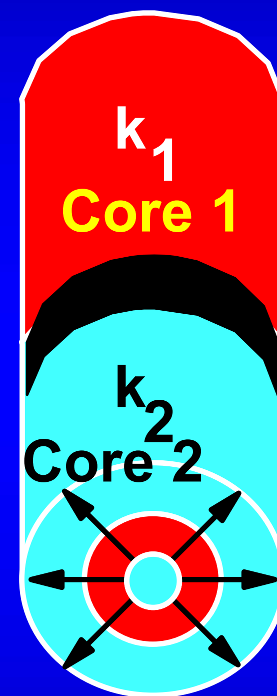


SPE 17332

LINEAR vs RADIAL FLOW

Example: $k_1/k_2 = 10$, $F_r = 1$, $F_{rr} = 10$



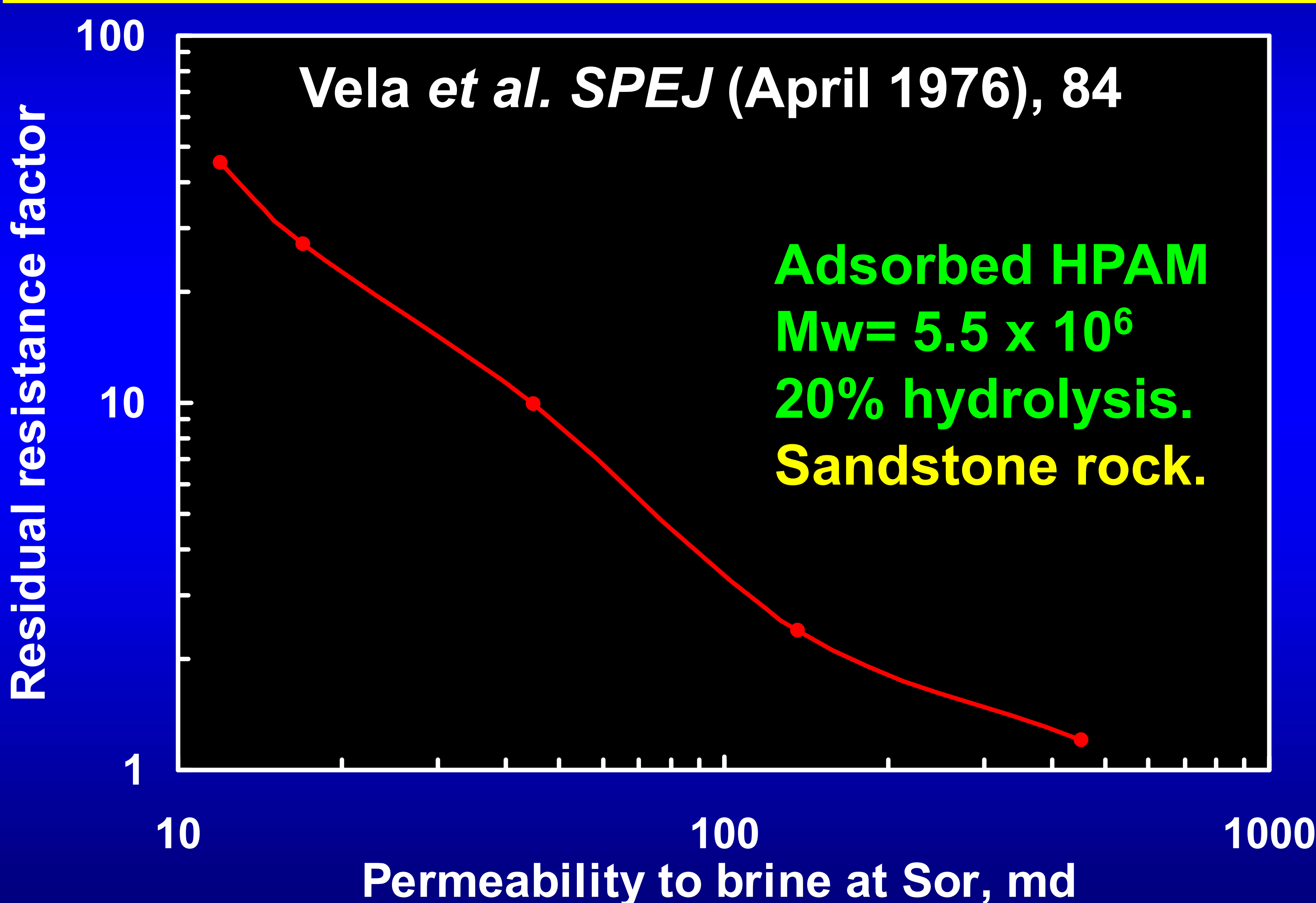


Water

Gel

	Injectivity Loss	
	Linear	Radial
Core 1:	90%	90%
Core 2:	47%	87%

Adsorbed polymers, "weak" gels, particle suspensions, and "dispersions" of gel particles reduce k in low-k rock more than in high-k rock.



Contrary to some claims, adsorbed polymers, "weak" gels, and gel "dispersions" can harm flow profiles!!!

Layer	k_w @ S_{or}, md	Gel radius, ft	Permeability reduction factor (F_{rrw})	Layer flow capacity, final/initial
1	453	30	1.2	0.94
2	137	16.5	2.4	0.71
3	45	9.5	9.9	0.31
4	17	5.8	27	0.15
5	12	4.9	45	0.10

GEL PLACEMENT IS CRITICALLY DIFFERENT IN RADIAL FLOW THAN IN LINEAR FLOW!!!

This conclusion is not changed by:

- **Non-Newtonian rheology of gelants.**
- **Two-phase flow of oil and water.**
- **Fluid saturations, capillary pressure behavior.**
- **Anisotropic flow or pressure gradients.**
- **Pressure transient behavior.**
- **Well spacing, degree of crossflow.**
- **Chemical retention & inaccessible pore volume.**
- **Different resistance factors in different layers.**
- **Diffusion, dispersion, & viscous fingering.**

See: http://baervan.nmt.edu/randy/gel_placement

SITUATION: Someone bullheads a conventional gel treatment into an "unfractured" well, without any special provision to protect oil zones. After the treatment, the flow profile "improved".

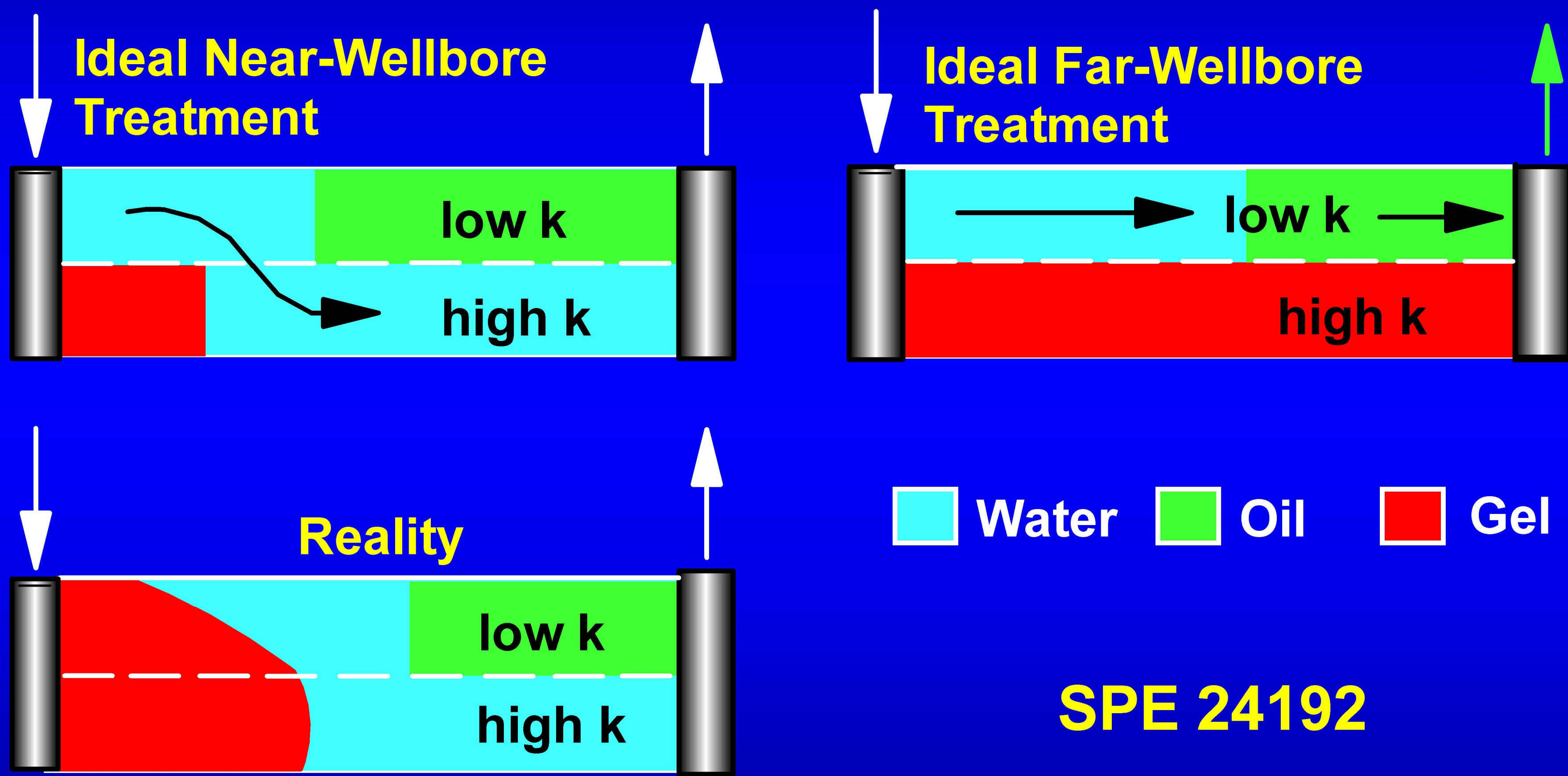
- Possibility 1: The claim is true, we need to rewrite all the petroleum engineering texts, and someone deserves a Nobel prize.
- Possibility 2: The well actually contained a fracture, fracture-like feature or void channel.
- If fluids can cross flow out beyond the wellbore, does a flow profile mean anything?

COMMON PHILOSOPHY: "I don't care whether my high-permeability streak is a fracture or not. I just want to fix it."

Your treatment has a much better chance of success if you decide in advance whether you have linear flow through fractures or voids versus radial flow through matrix!!!

- The appropriate composition for a fracture or void is different than for matrix.
- The optimum treatment volume for a fracture or void is different than for matrix.
- The proper placement method for treating a fracture or void is different than for matrix.

Gel Placement in Heterogeneous Systems with Crossflow

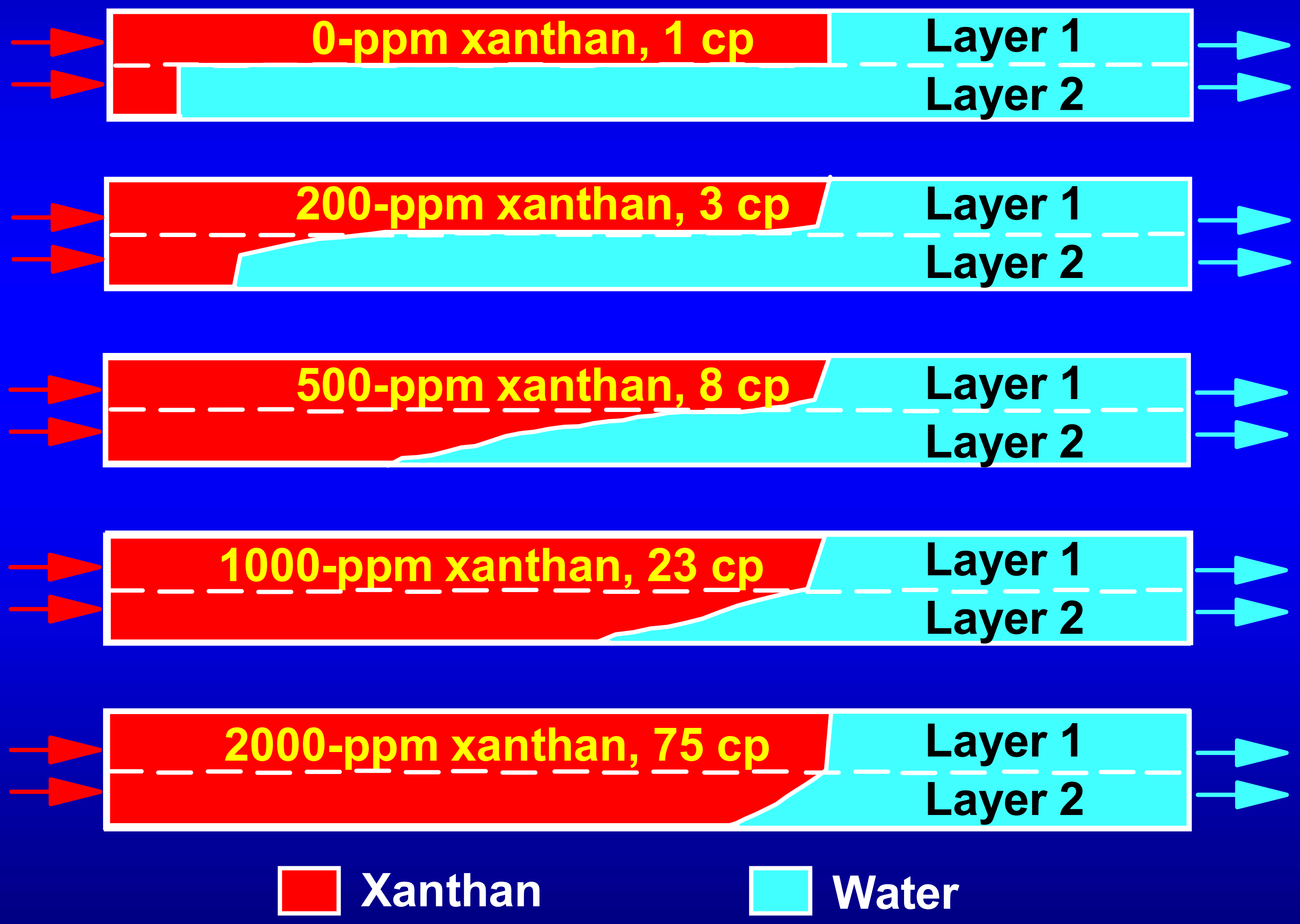


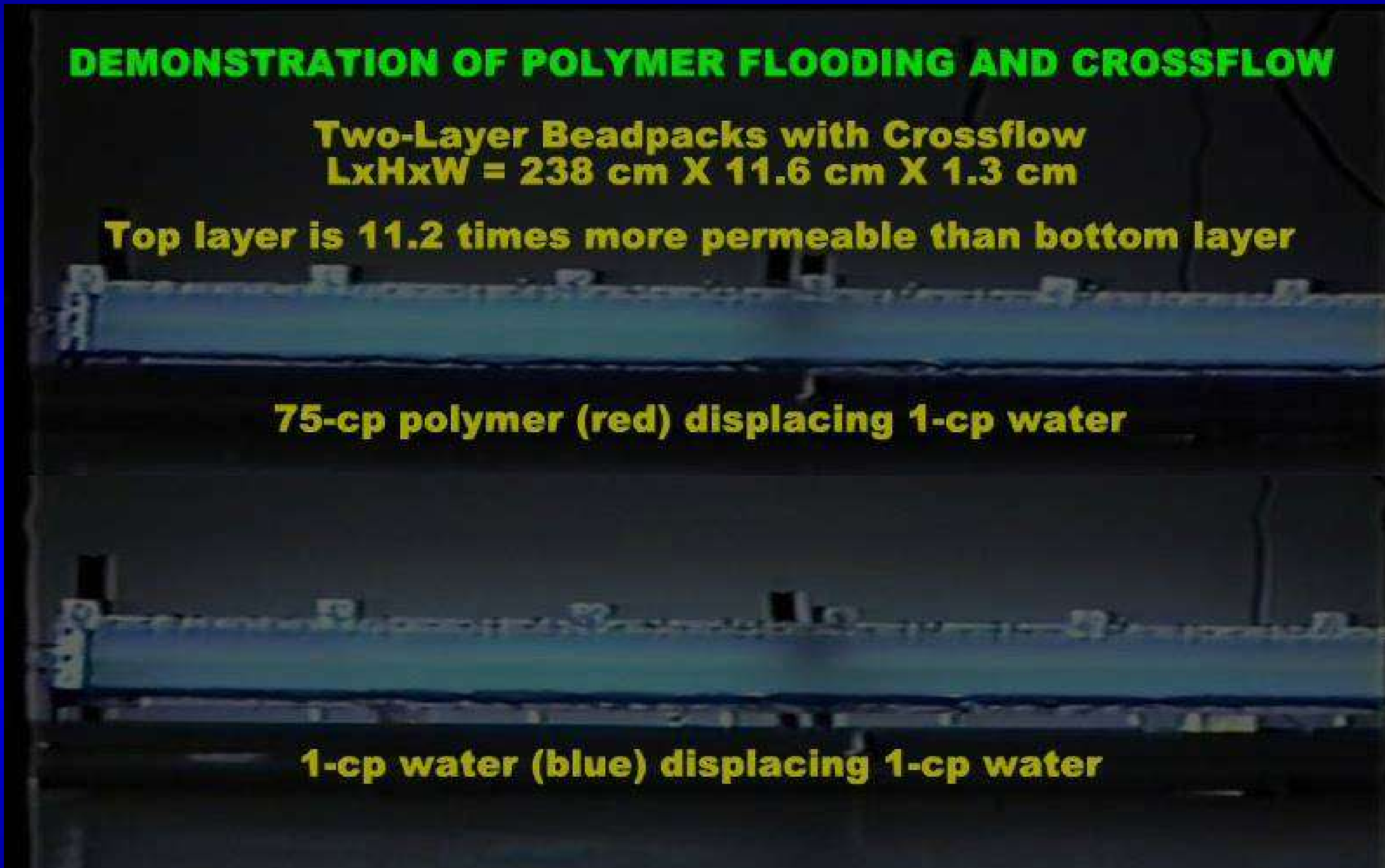
SPE 24192

CROSSFLOW MAKES GEL PLACEMENT MORE DIFFICULT!!!

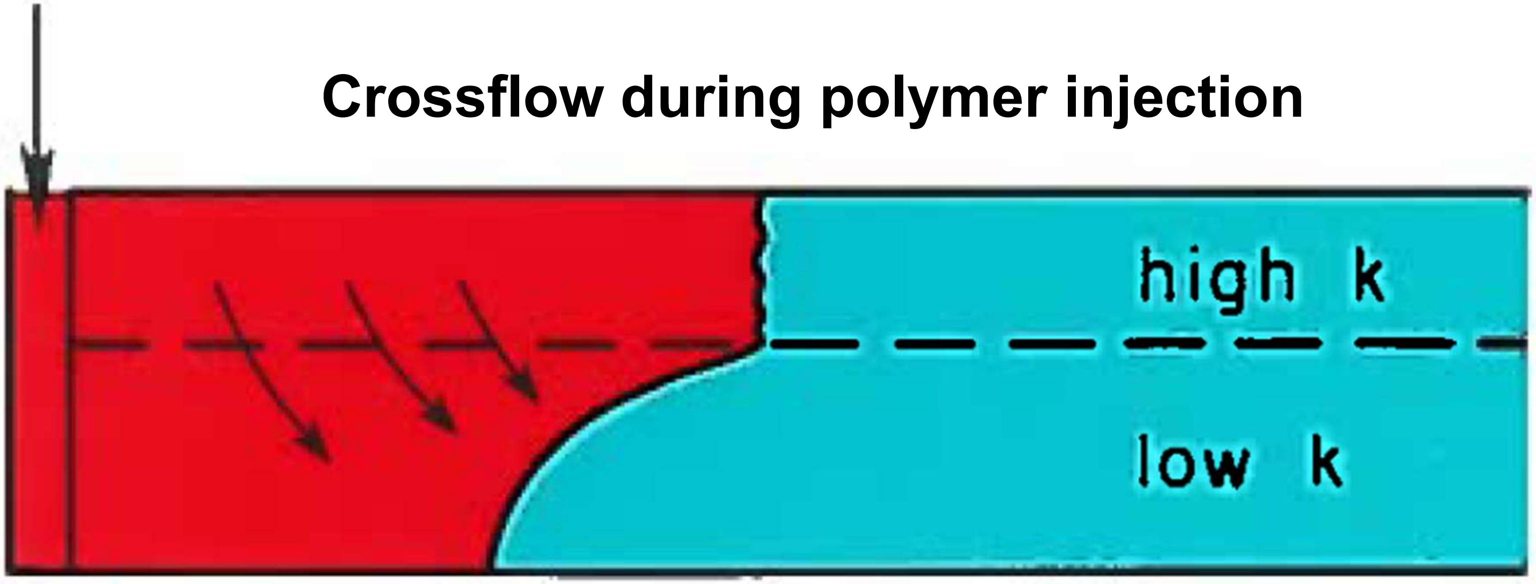
Crossflow in a two-layer beadpack. SPE 24192

Xanthan solutions displacing water; $k_1/k_2 = 11.2$.




DEMONSTRATION OF POLYMER FLOODING AND CROSSFLOW
Two-Layer Beadpacks with Crossflow
LxHxW = 238 cm X 11.6 cm X 1.3 cm
Top layer is 11.2 times more permeable than bottom layer
75-cp polymer (red) displacing 1-cp water
1-cp water (blue) displacing 1-cp water

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!

EFFECT OF GRAVITY ON GELANT PLACEMENT

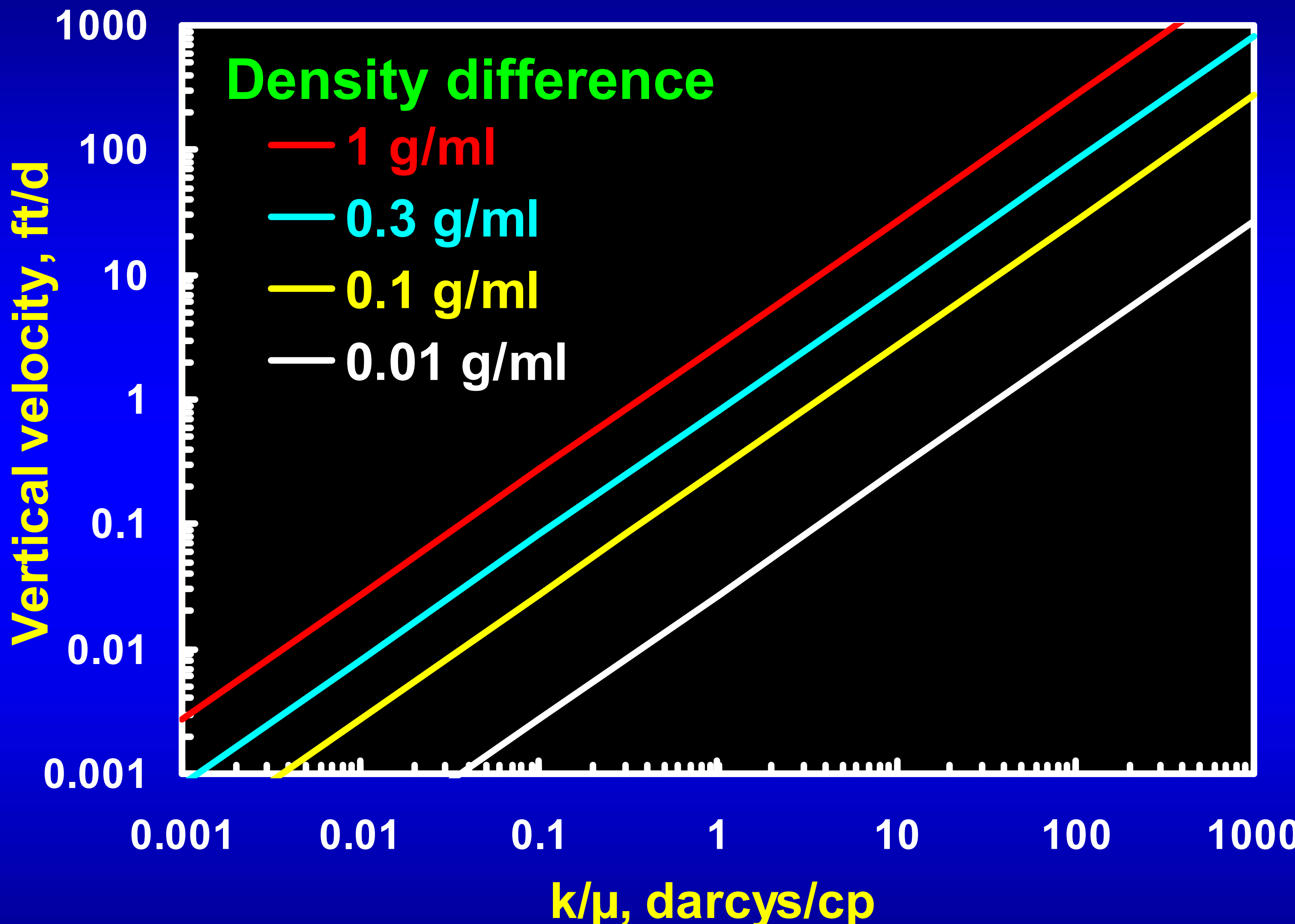
Gravity component of the darcy equation:

$$u_z = - k \, \Delta\rho \, g \, / \, [1.0133 \times 10^6 \, \mu] \text{ (Darcy units)}$$

Dimensionless gravity number:

$$G = [k \, \Delta\rho \, g \sin \theta] \, / \, [1.0133 \times 10^6 \, \mu \, u]$$

EFFECT OF GRAVITY ON GELANT PLACEMENT



SPEPF (Nov. 1996) 241-248

GRAVITY EFFECTS

1. During gelant injection into fractured wells, viscous forces usually dominate over gravity forces, so gravity will have little effect on the position of the gelant front.
2. During shut-in after gelant injection, a gelant-oil interface can equilibrate very rapidly in a fracture.
3. In radial systems (e.g., unfractured wells) viscous forces dominate near the wellbore, but gravity becomes more important deeper in the formation. Long gelation times will be required to exploit gravity during gelant injection in unfractured wells.

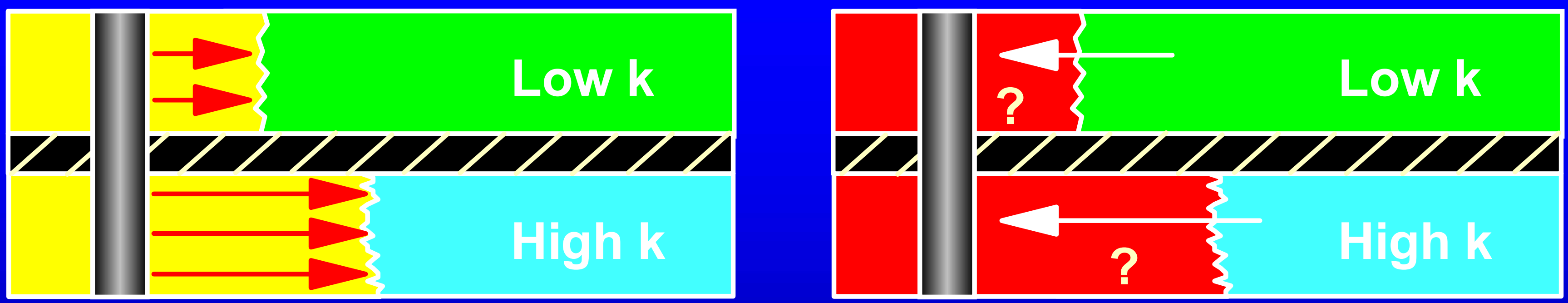
MISCONCEPTION: Water-based polymers and gelants won't enter oil zones.

If this is true, why does a waterflood work?

GEL PLACEMENT IN PRODUCTION WELLS

SPEPF (Nov. 1993) 276-284

Gelant Injection | **Return to Production**



Relative permeability and capillary pressure effects will not prevent gelants from entering oil zones.

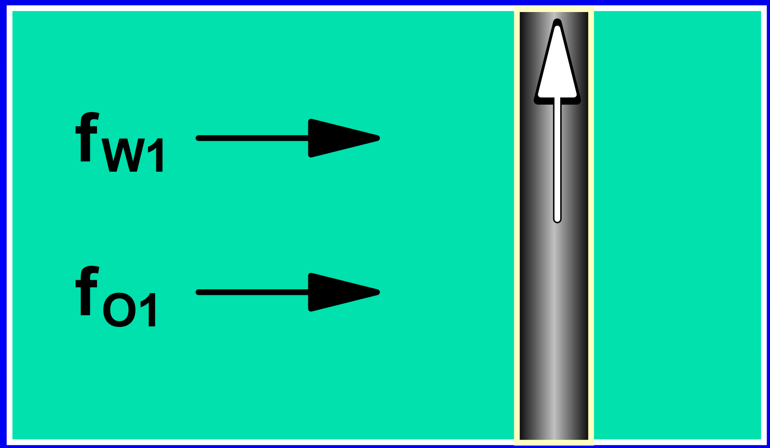
To prevent damage to oil zones, gel must reduce k_w much more than k_o.

Water | Oil | Gelant | Gel

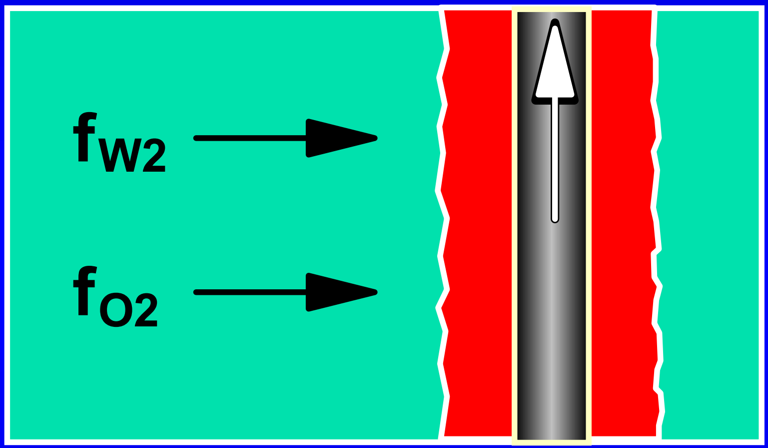
DISPROPORTIONATE PERMEABILITY REDUCTION

- Some gels can reduce k_w more than k_o or k_{gas}.
- Some people call this "disproportionate permeability reduction" or "DPR". Others call it "relative permeability modification" or "RPM". It is the same thing!
- This property is only of value in production wells with distinct water and hydrocarbon zones. It has no special value in injection wells!!!
- NO KNOWN polymer or gel will RELIABLY reduce k_w without causing some reduction in k_o !!!

In the absence of fractures, casing leaks, and flow behind pipe, gel treatments are not expected to improve the WOR from a single zone.



before gel

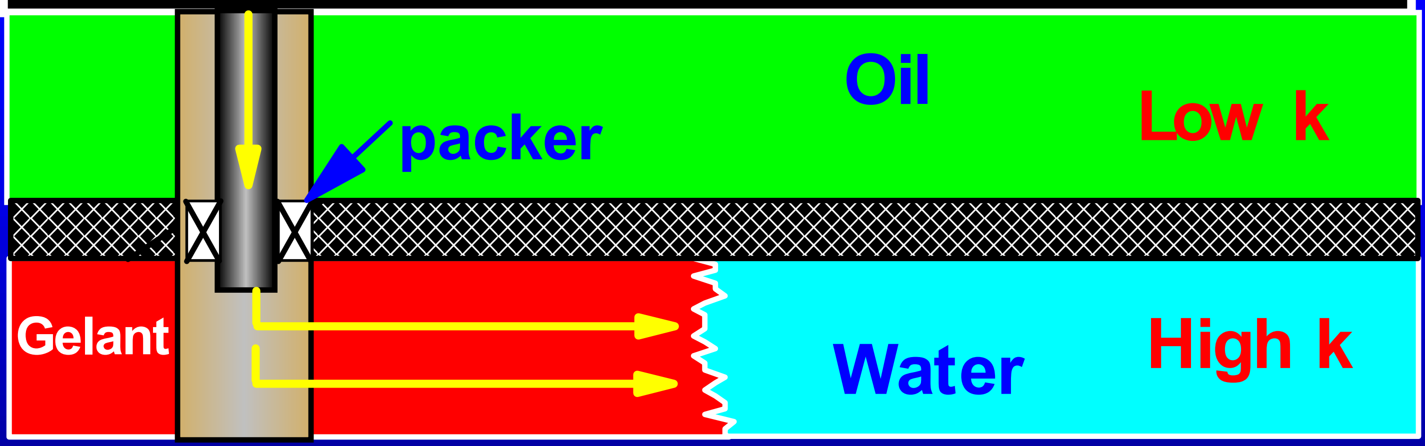


after gel: $f_{W2} = f_{W1}$ and $f_{O2} = f_{O1}$

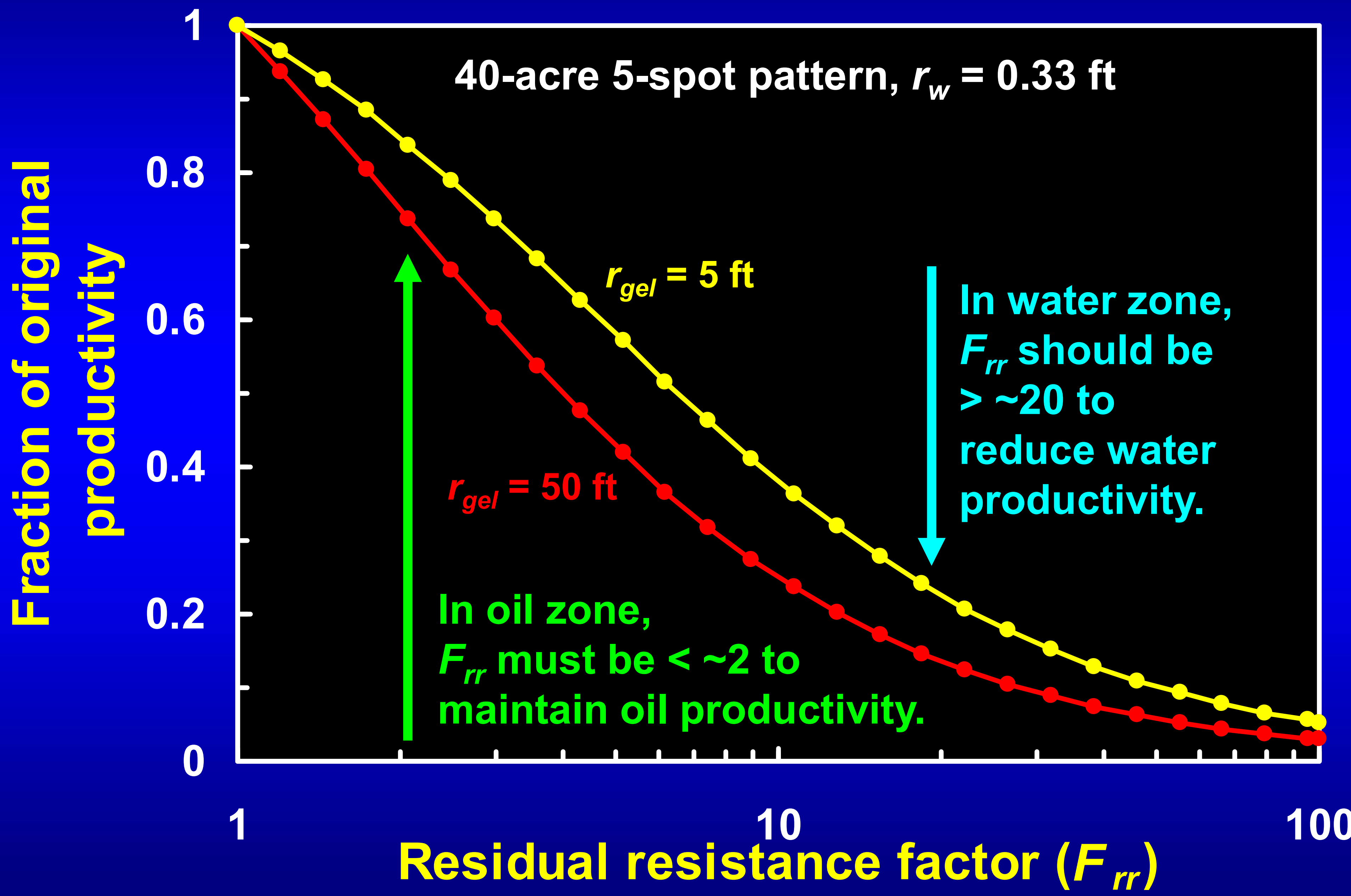
SPEPF (Nov. 1993) 276-284

GEL TREATMENTS FOR RADIAL FLOW PROBLEMS

- Zones MUST be separated by impermeable barriers.
- Hydrocarbon-productive zones MUST be protected during gelant injection.
- Loss of water productivity or injectivity is not sensitive to radius of gelant penetration between 5 and 50 ft.
- Gel permeability reductions > 20 cause > 80% loss of water productivity.



Radial Flow Requires That F_{rro} < 2 and F_{rrw} > 20

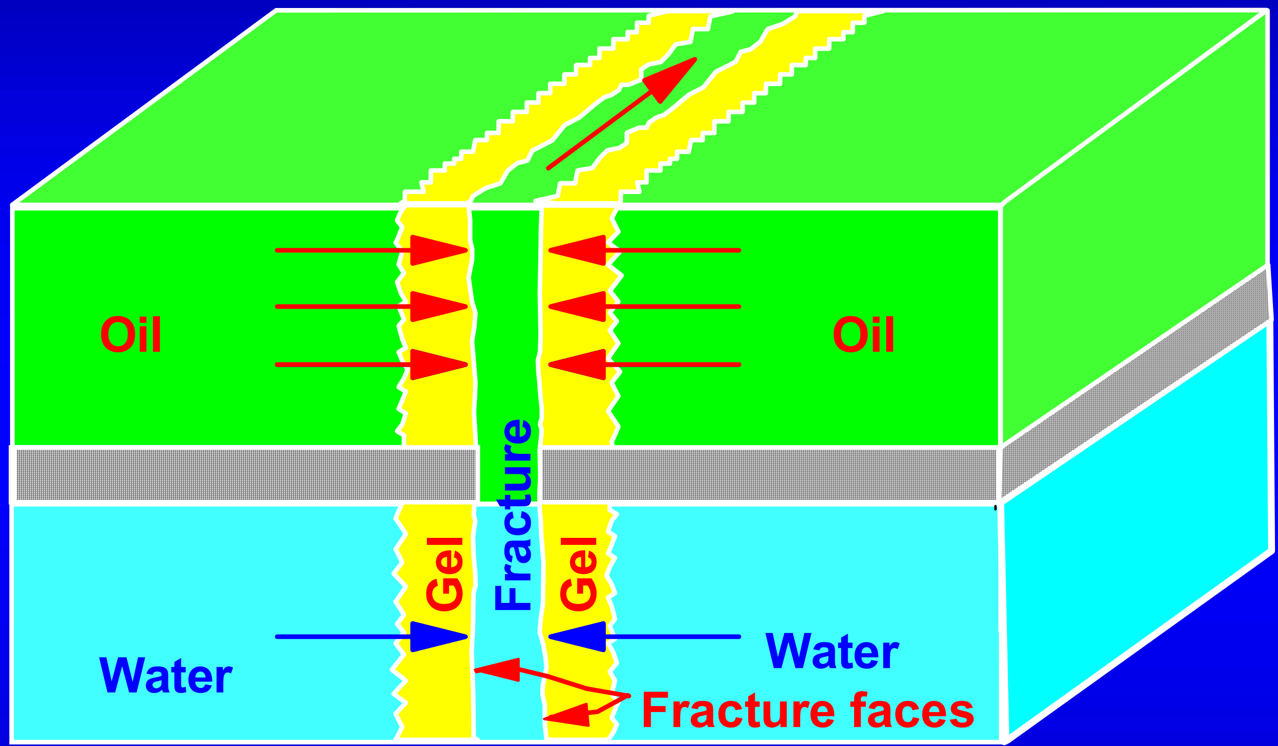


With present technology, hydrocarbon zones MUST be protected during gelant placement in unfractured production wells.

To avoid this requirement, we need a gel that RELIABLY reduces k_w by >20X but reduces k_o by < 2X.

"DPR" or "RPM" is currently most useful in linear-flow problems (e.g., fractures)

Gel Restricting Water Flow into a Fracture

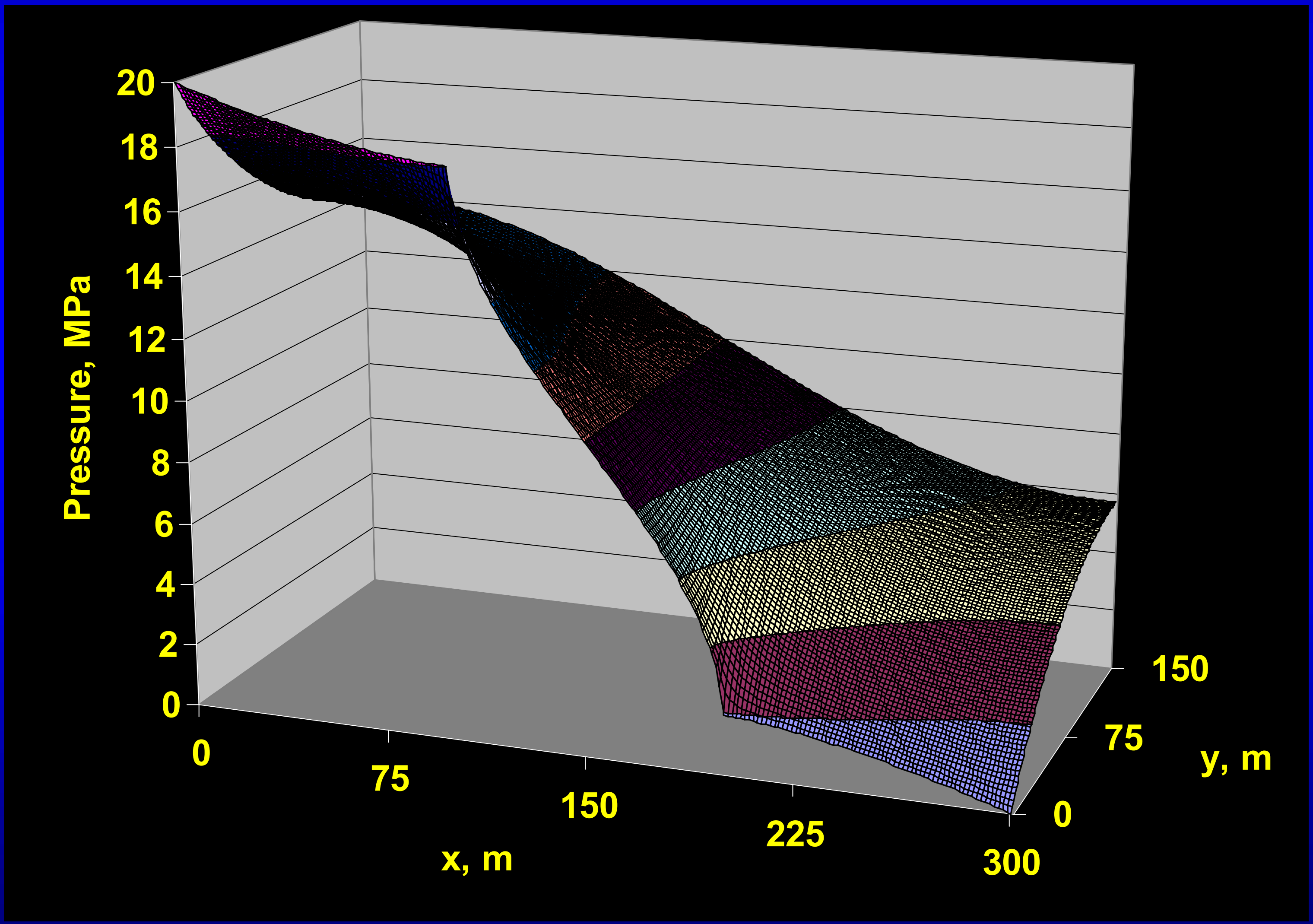


Equivalent resistance to flow added by the gel

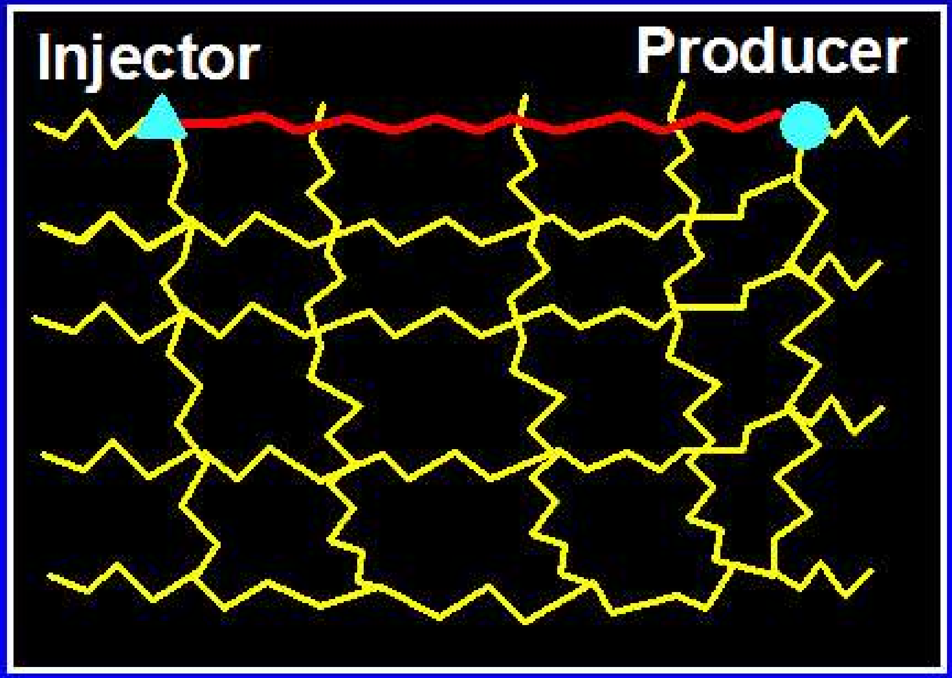
- **In oil zone: 0.2 ft x 50 = 10 ft.**
- **In water zone: 0.2 ft x 5,000 = 1,000 ft.**

IN SITU **17(3), (1993) 243-272**

When fractures cause severe channeling, restricting the middle part of the fracture provides the best possibility. (See our 2005 annual report).



NATURALLY FRACTURED RESERVOIRS

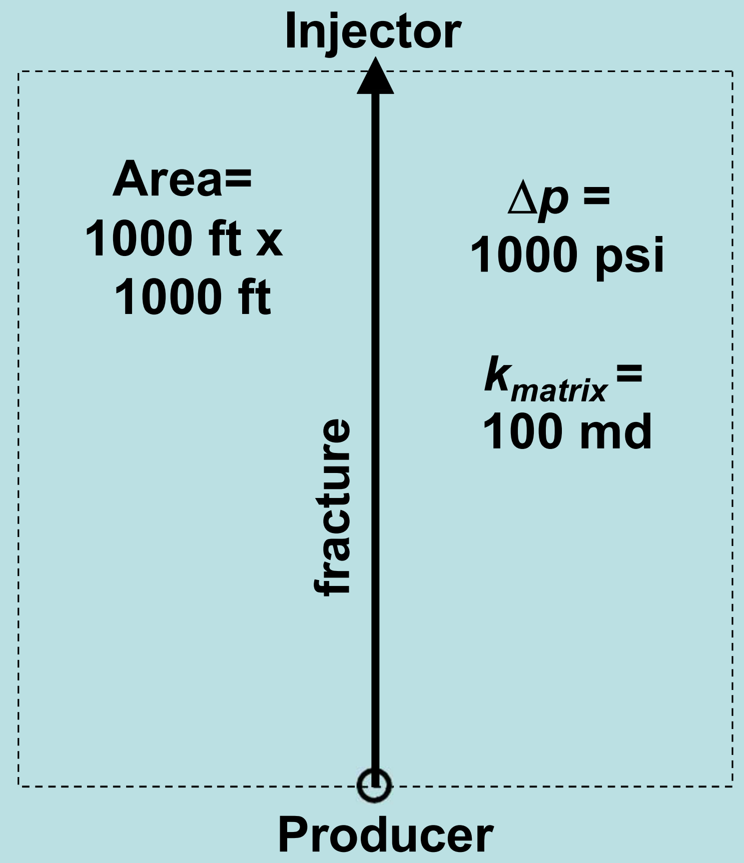


When multiple fracture pathways are present, some benefit will result from plugging the middle part of the most conductive fracture. (E.g., a 90% water cut is better than a 99% water cut.)

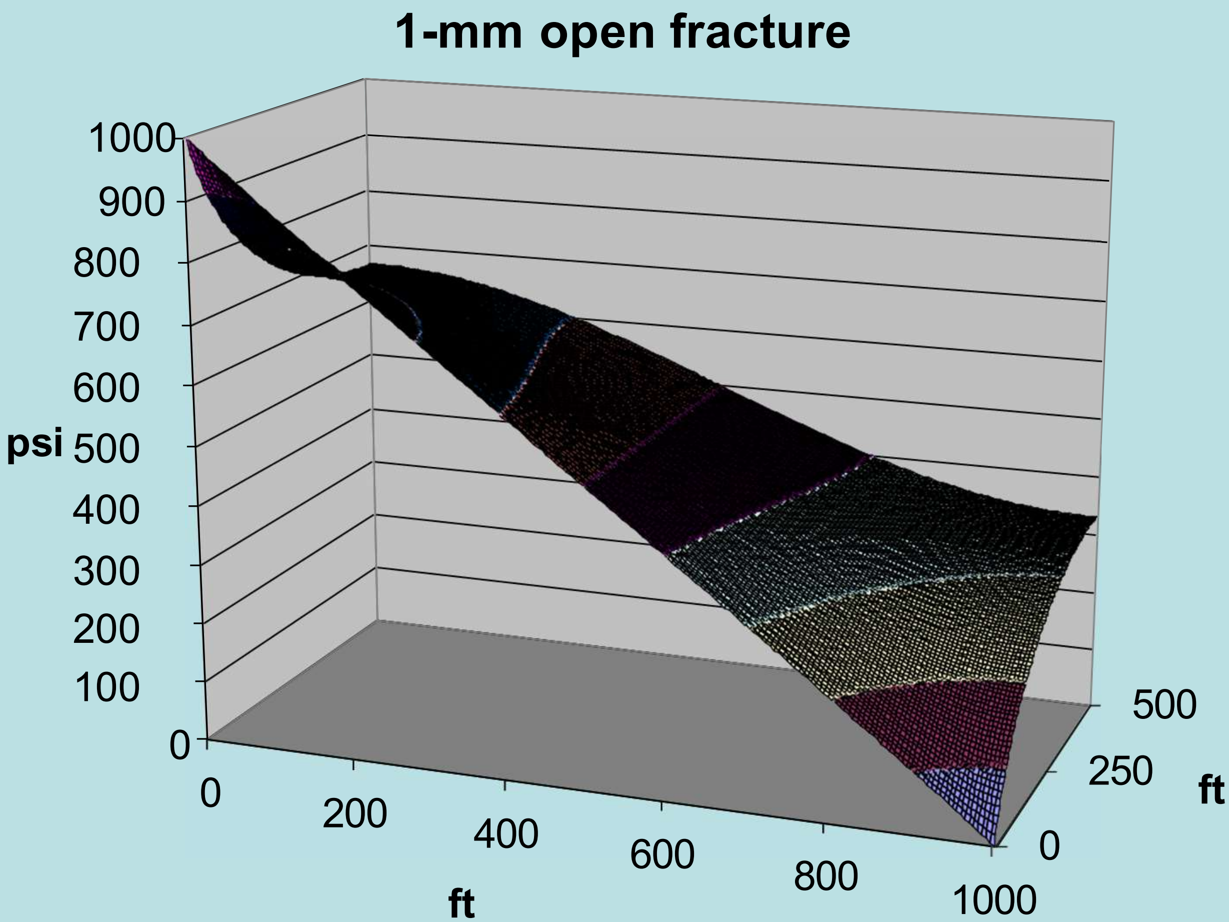
Summary for Optimum Plug Placement

- Direct fracture channel between two vertical wells
- A small near-wellbore plug (e.g., 25-ft long) dramatically reduces pattern flow rates (e.g., water channeling), but does not improve pattern pressure gradients in a manner that enhanced oil displacement from deep within the reservoir
- Significant improvements in oil displacement requires plugging of at least 10% (and preferably more than 20%) of the length of the offending fracture
- Ideally, this plug should be placed near the center of the fracture

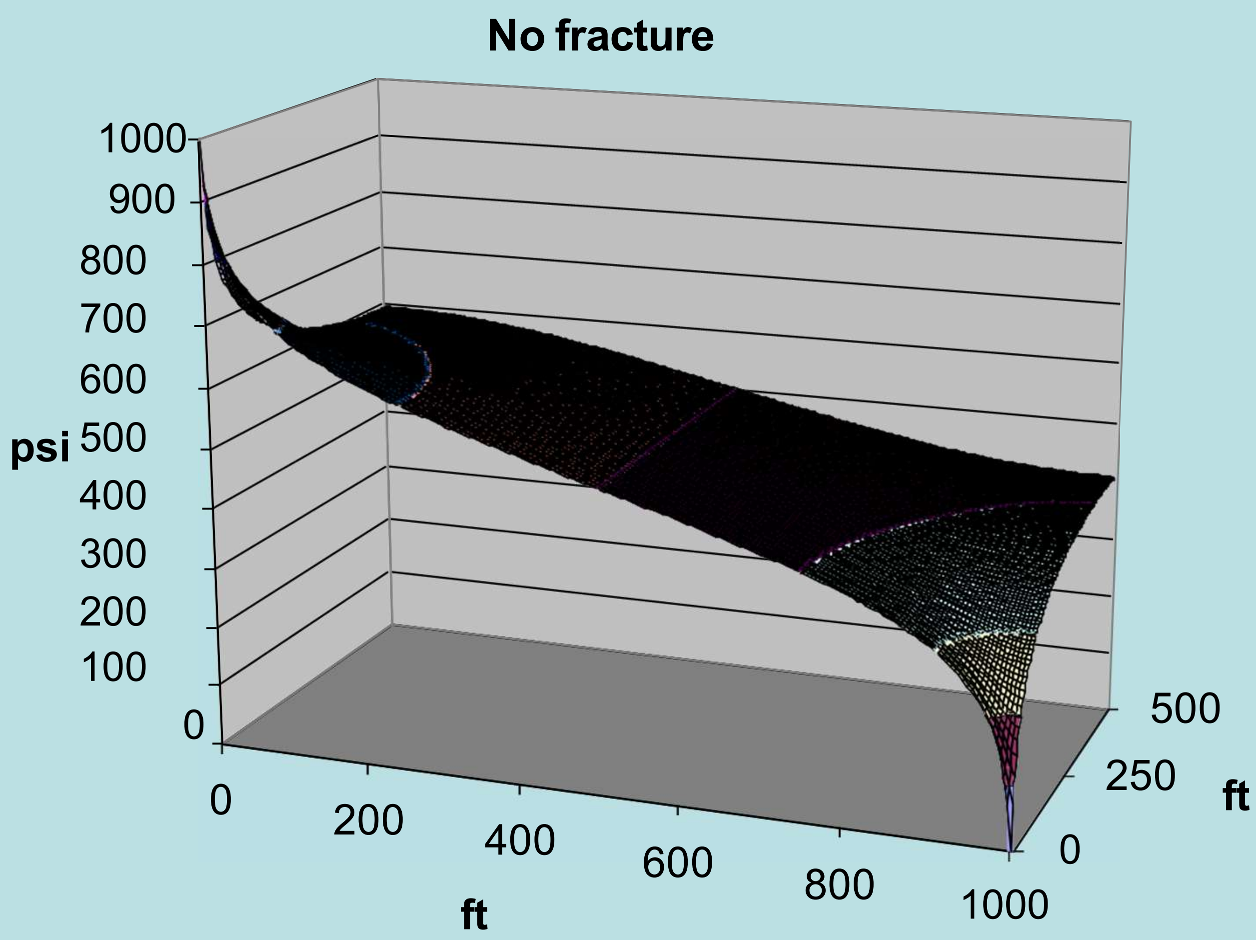
Areal view of fracture connecting an injection well and a production well



Pressure distribution when 1-mm fracture was fully open

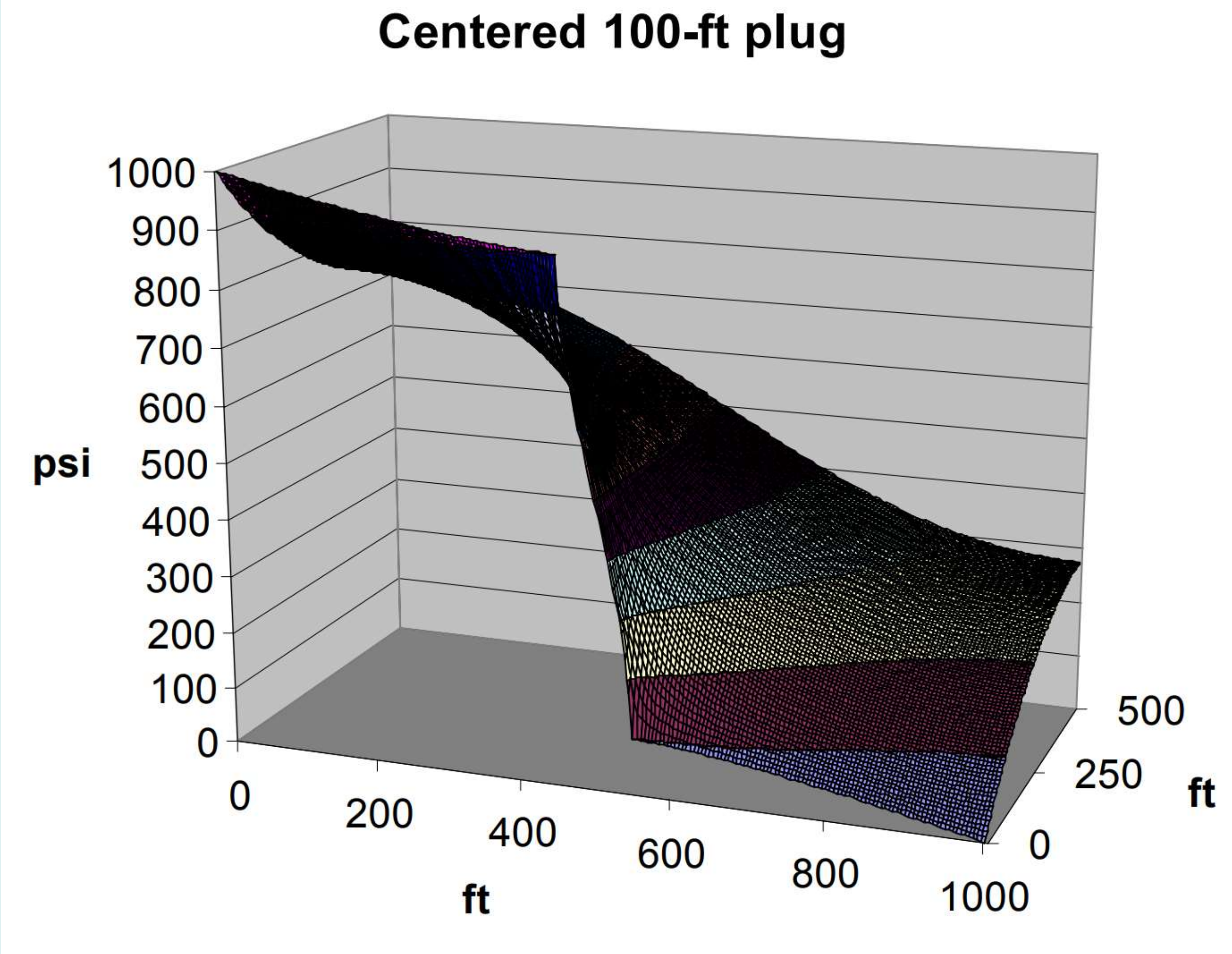


Pressure distribution with no fracture



Optimum gel placement in fracture

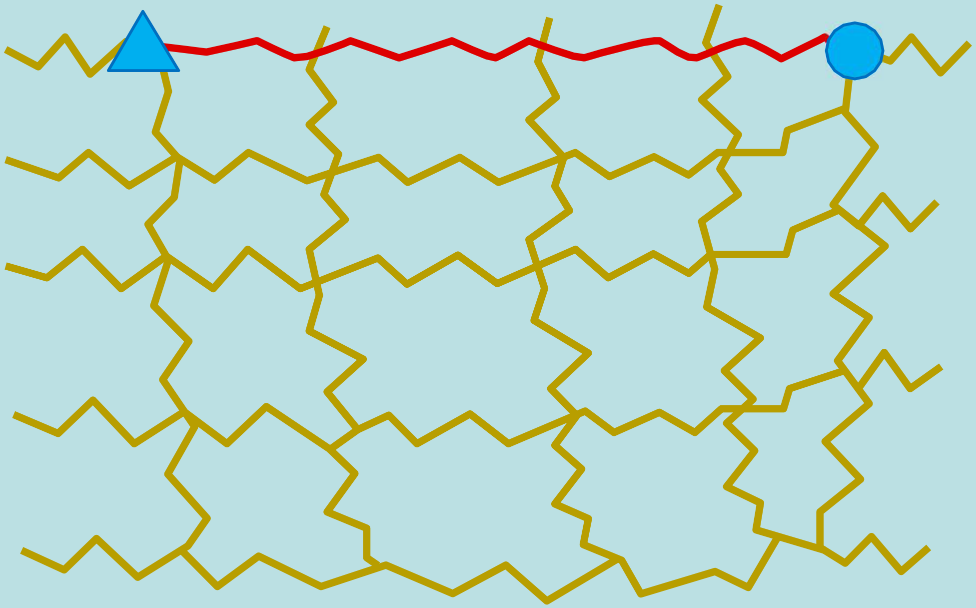
- When fractures cause severe channeling, restricting the middle part of the fracture provides the best possibility



Naturally Fractured Reservoirs

- When multiple fracture pathways are present, some benefit will result from plugging the middle part of the most conductive fracture (e.g., a 90% water cut is better than a 99% water cut)

Injector Producer

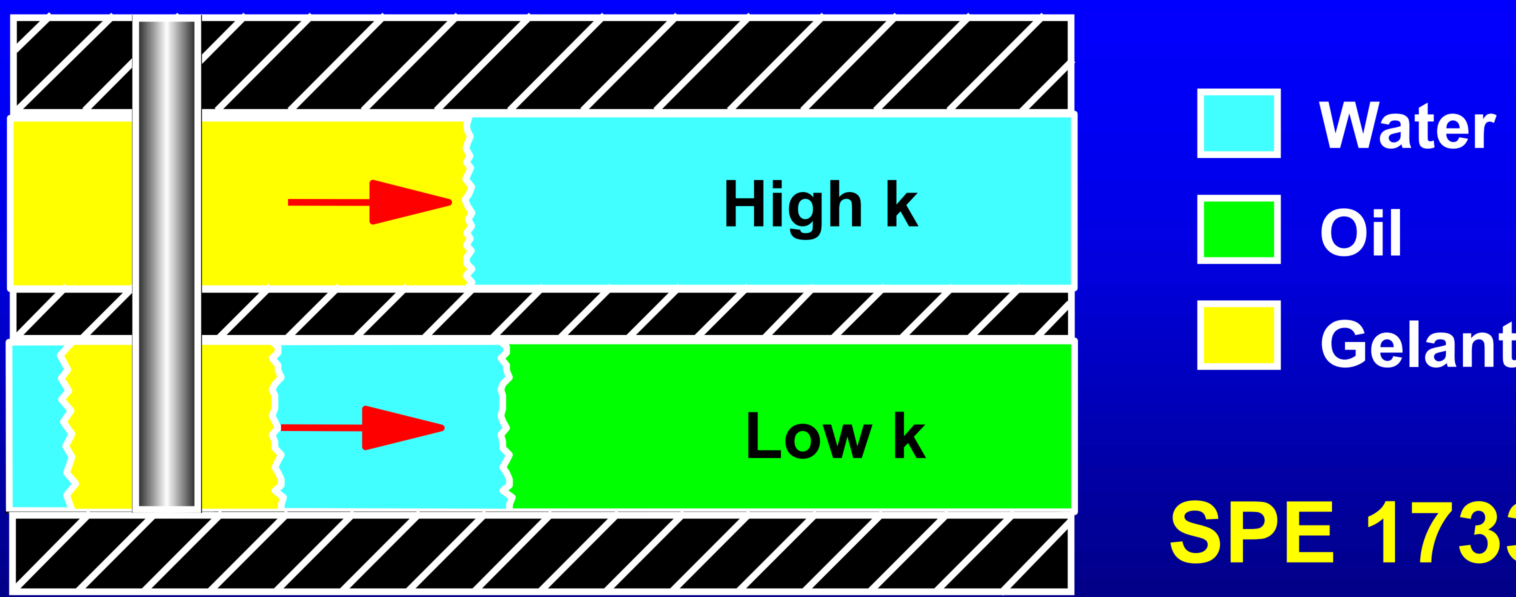


KEY PLACEMENT POINTS

Gelants can penetrate into all open zones.

An acceptable gelant placement is much easier to achieve in linear flow (fractured wells) than in radial flow.

In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.



SPE 17332

SPE 146087

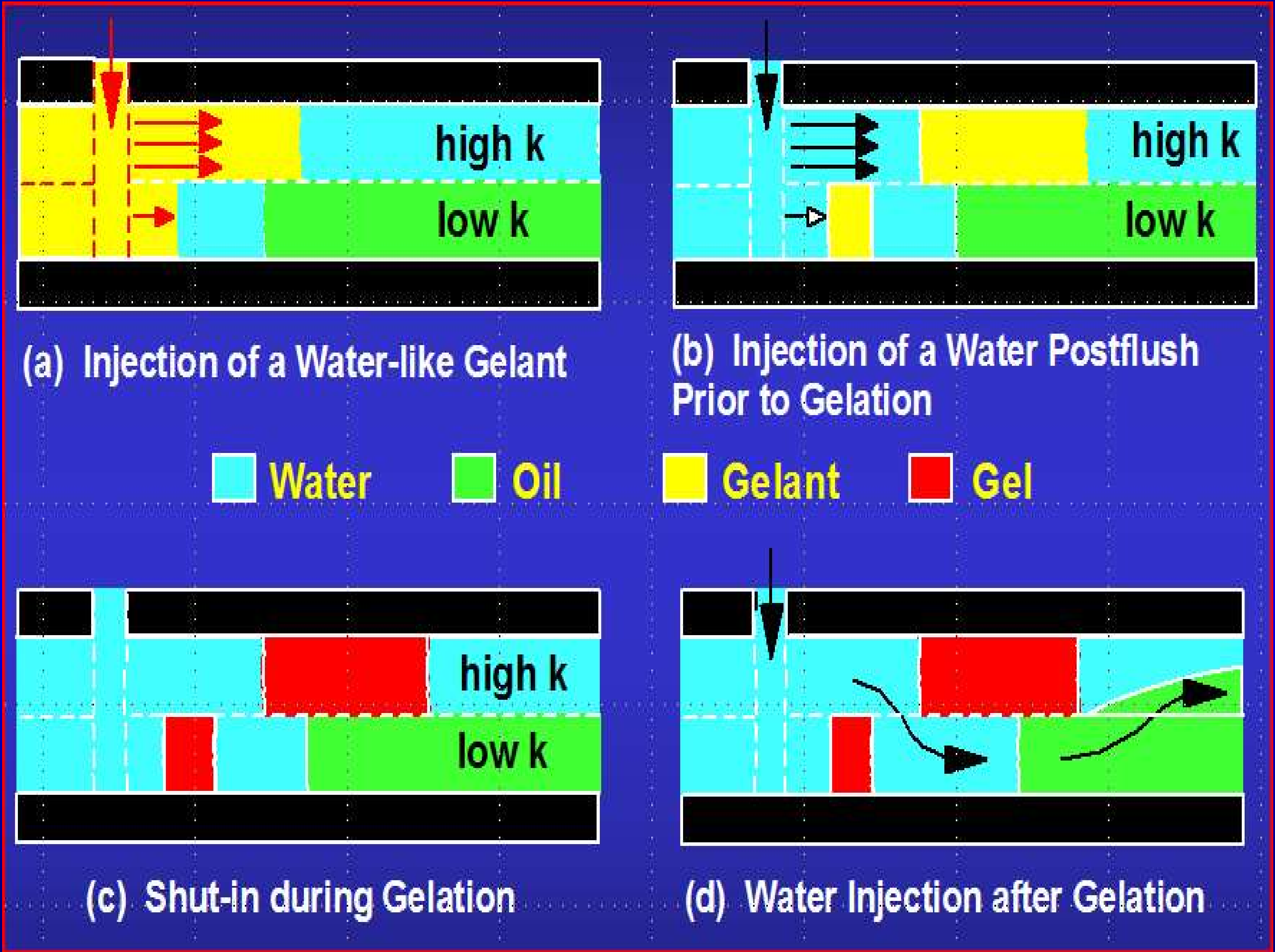
A COMPARISON OF POLYMER FLOODING WITH IN-DEPTH PROFILE MODIFICATION

BOTTOM LINE

1. In-depth profile modification is most appropriate for high permeability contrasts (e.g. 10:1), high thickness ratios (e.g., less-permeable zones being 10 times thicker than high-permeability zones), and relatively low oil viscosities.
2. Because of the high cost of the blocking agent (relative to conventional polymers), economics favor small blocking-agent bank sizes (e.g. 5% of the pore volume in the high-permeability layer).
3. Even though short-term economics may favor in-depth profile modification, ultimate recovery may be considerably less than from a traditional polymer flood. A longer view may favor polymer flooding both from a recovery viewpoint and an economic viewpoint.
4. In-depth profile modification is always more complicated and risky than polymer flooding.

IN-DEPTH PROFILE MODIFICATION

A specialized idea that requires use of a low-viscosity gelant.



ADVANTAGES AND LIMITATIONS

ADVANTAGES:

1. Could provide favorable injectivity.
2. "Incremental" oil from this scheme could be recovered relatively quickly.

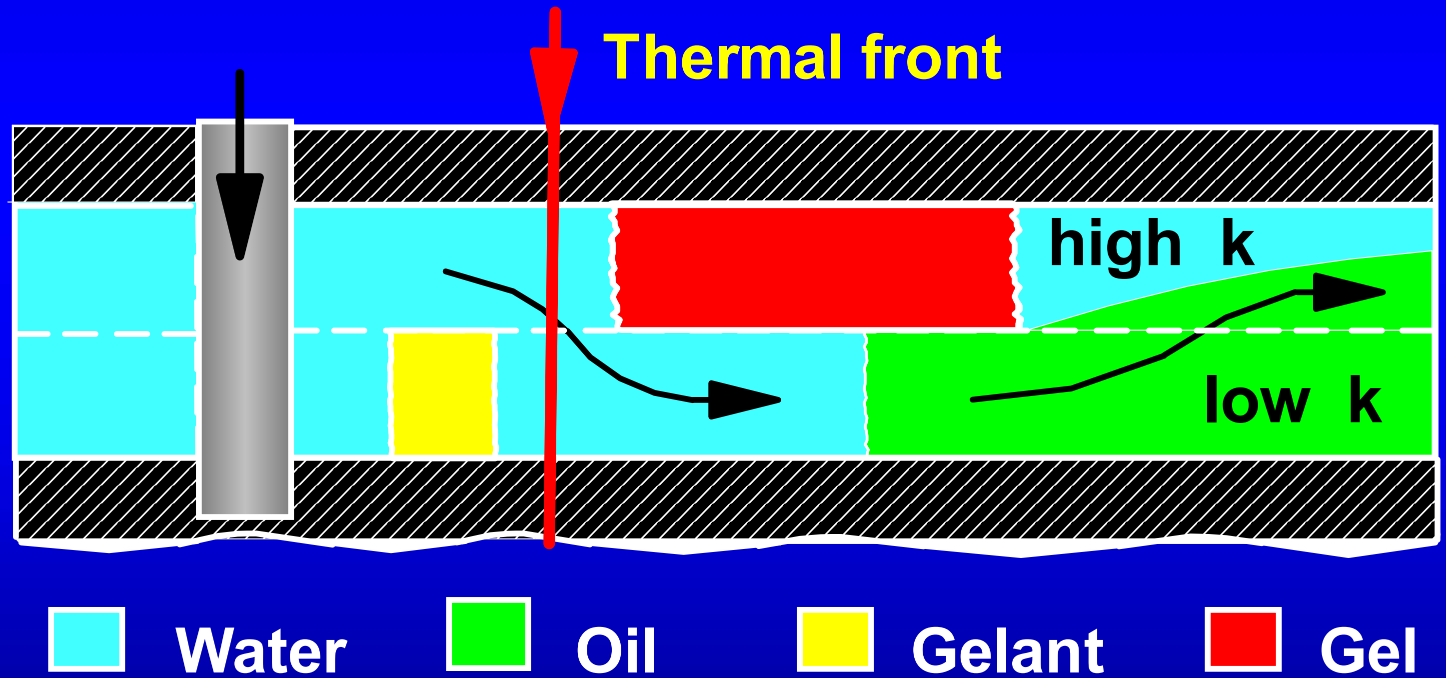
LIMITATIONS:

1. Will not improve sweep efficiency beyond the greatest depth of gelant penetration in the reservoir.
2. Control & timing of gel formation may be challenging.
3. Applicability of this scheme depends on the sweep efficiency in the reservoir prior to the gel treatment.
4. Viscosity and resistance factor of the gelant must not be too large (ideally, near water-like).
5. Viscosity and resistance factor of the gelant should not increase much during injection of either the gelant or the water postflush

Sophisticated Gel Treatment Idea from BP

In-depth channeling problem, no significant fractures, no barriers to vertical flow:

- **BP idea could work but requires sophisticated characterization and design efforts,**
- **Success is very sensitive to several variables.**



J. Polym. Sci. & Eng. (April 1992) 7(1-2) 33-43.

BRIGHT WATER—A VARIATION ON BP's IDEA
(SPE 84897 and SPE 89391)

- Injects small crosslinked polymer particles that "pop" or swell by ~10X when the crosslinks break.
- "Popping" is activated primarily by temperature, although pH can be used.
- The particle size and size distribution are such that the particles will generally penetrate into all zones.
- A thermal front appears necessary to make the idea work.
- The process experiences most of the same advantages and limitations as the original idea.

BRIGHT WATER

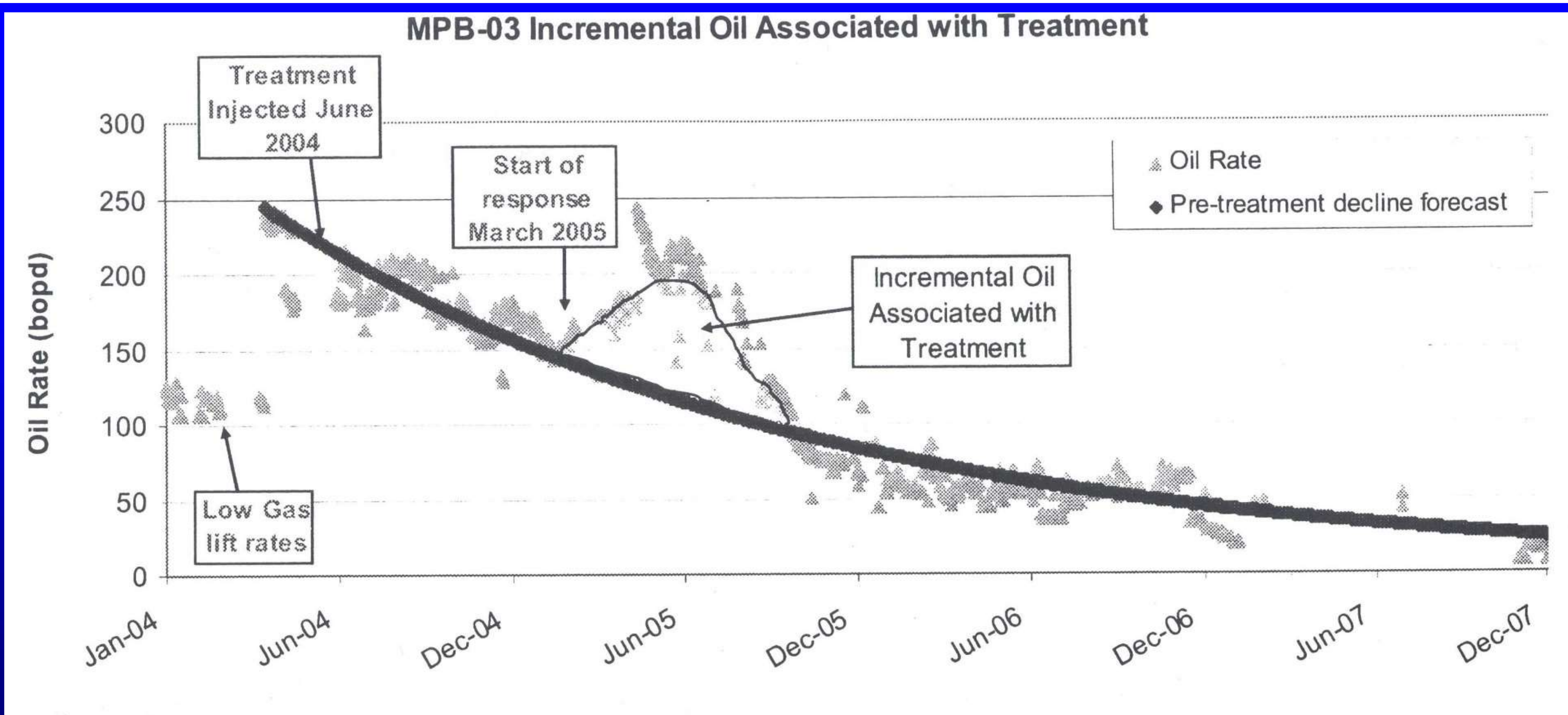
Had it origins ~1990.

Had an early field test by BP in Alaska.

Was perfected in a consortium of Mobil, BP, Texaco, and Chevron in the mid-1990s.

BRIGHT WATER—RESULTS (SPE 121761)

- BP Milne Point field, North Slope of Alaska.
- Injected 112,000 bbl of 0.33% particles.
- Recovered 50,000 bbl of incremental oil.
- 0.39 bbl oil recovered / lb of polymer (compared with ~1 bbl oil / lb polymer for good polymer floods).



ADDITIONAL CONSIDERATIONS

1. For small banks of popping-agent, significant mixing and dispersion may occur as that bank is placed deep within the reservoir—thus, diluting the bank and potentially compromising the effectiveness of the blocking agent. .
2. Since the popping material provides a limited permeability reduction (i.e., 11 to 350) and the popped-material has some mobility, the blocking bank eventually will be diluted and compromised by viscous fingering (confirmed by SPE 174672, Fabbri et al.). High retention (130 µg/g) is also an issue (SPE 174672).
3. If re-treatment is attempted for a in-depth profile-modification process, the presence of a block or partial block in the high-permeability layer will (1) divert new popping-agent into less-permeable zones during the placement process and (2) inhibit placement of a new block that is located deeper in the reservoir than the first block. These factors may compromise any re-treatment using in-depth profile

BOTTOM LINE

1. In-depth profile modification is most appropriate for high permeability contrasts (e.g. 10:1), high thickness ratios (e.g., less-permeable zones being 10 times thicker than high-permeability zones), and relatively low oil viscosities.
2. Because of the high cost of the blocking agent (relative to conventional polymers), economics favor small blocking-agent bank sizes (e.g. 5% of the pore volume in the high-permeability layer).
3. Even though short-term economics may favor in-depth profile modification, ultimate recovery may be considerably less than from a traditional polymer flood. A longer view may favor polymer flooding both from a recovery viewpoint and an economic viewpoint.
4. In-depth profile modification is always more complicated and risky than polymer flooding.

“COLLOIDAL DISPERSION” GELS (CDG) (ALUMINUM-CITRATE-HPAM, but sometimes low concentration Cr(III)-ACETATE-HPAM)

Two central claims have been made over the past 30 years. Two additional claims are more recent:

1. The CDG only enters the high-permeability, watered-out zones—thus diverting subsequently injected water to enter and displace oil from less permeable zones.
2. The CDG acts like a super-polymer flooding agent—add ~15-ppm Al to 300-ppm HPAM and make it act like a much more viscous polymer solution.
3. The CDG mobilizes residual oil.
4. The CDG acts like “Bright Water” (In depth profile modification)

Examination of Literature on Colloidal Dispersion Gels for Oil Recovery: http://baervan.nmt.edu/groups/res-sweep/media/pdf/CDG%20Literature%20Review.pdf

CDGs cannot propagate deep into the porous rock of a reservoir, and at the same time, provide F_r and F_{rr} that are greater than for the polymer without the crosslinker.

CDGs have been sold using a number of misleading and invalid arguments. Commonly, Hall plots are claimed to demonstrate that CDGs provide more F_r and F_{rr} than normal polymer solutions. But Hall plots only monitor injection pressures at the wellbore—so they reflect the composite of face plugging/formation damage, in-situ mobility changes, and fracture extension. Hall plots cannot distinguish between these effects—so they cannot quantify in situ F_r and F_{rr}.

Examination of Literature on Colloidal Dispersion Gels for Oil Recovery: http://baervan.nmt.edu/groups/res-sweep/media/pdf/CDG%20Literature%20Review.pdf

Laboratory studies—where CDG gelants were forced through short cores during 2-3 hours—have incorrectly been cited as proof that CDGs will propagate deep (hundreds of feet) into the porous rock of a reservoir over the course of months.

In contrast, most legitimate laboratory studies reveal that the gelation time for CDGs is a day or less and that CDGs will not propagate through porous rock after gelation.

Examination of Literature on Colloidal Dispersion Gels for Oil Recovery: http://baervan.nmt.edu/groups/res-sweep/media/pdf/CDG%20Literature%20Review.pdf

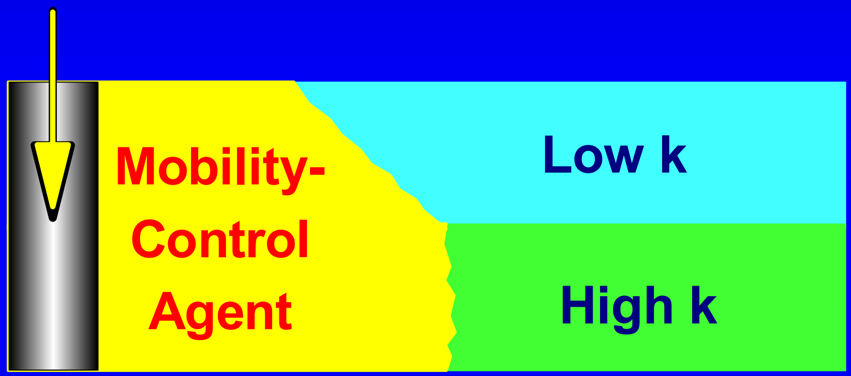
With one exception, aluminum from the CDG was never reported to be produced in a field application. In the exception, Chang reported producing 1 to 20% of the injected aluminum concentration.

Some free (unreacted) HPAM and aluminum that was associated with the original CDG can propagate through porous media. However, there is no evidence that this HPAM or aluminum provides mobility reduction greater than that for the polymer formulation without crosslinker.

Colloidal Dispersion Gels for Oil Recovery:

- Have enjoyed remarkable hype, with claims of substantial field success.
- Would revolutionize chemical flooding if the claims were true.
- Currently, no credible evidence exists that they flow through porous rock AND provide an effect more than from just the polymer alone (without crosslinker).
- Considering the incredible claims made for CDGs, objective labs ought to be able to verify the claims. So far, they have not.

Distinction between a blocking agent and a mobility-control agent.



- For a mobility control agent, penetration into low-k zones should be <u>maximized</u>.
- For a blocking agent, penetration into low-k zones should be <u>minimized.</u>

GEL TREATMENTS ARE NOT POLYMER FLOODS

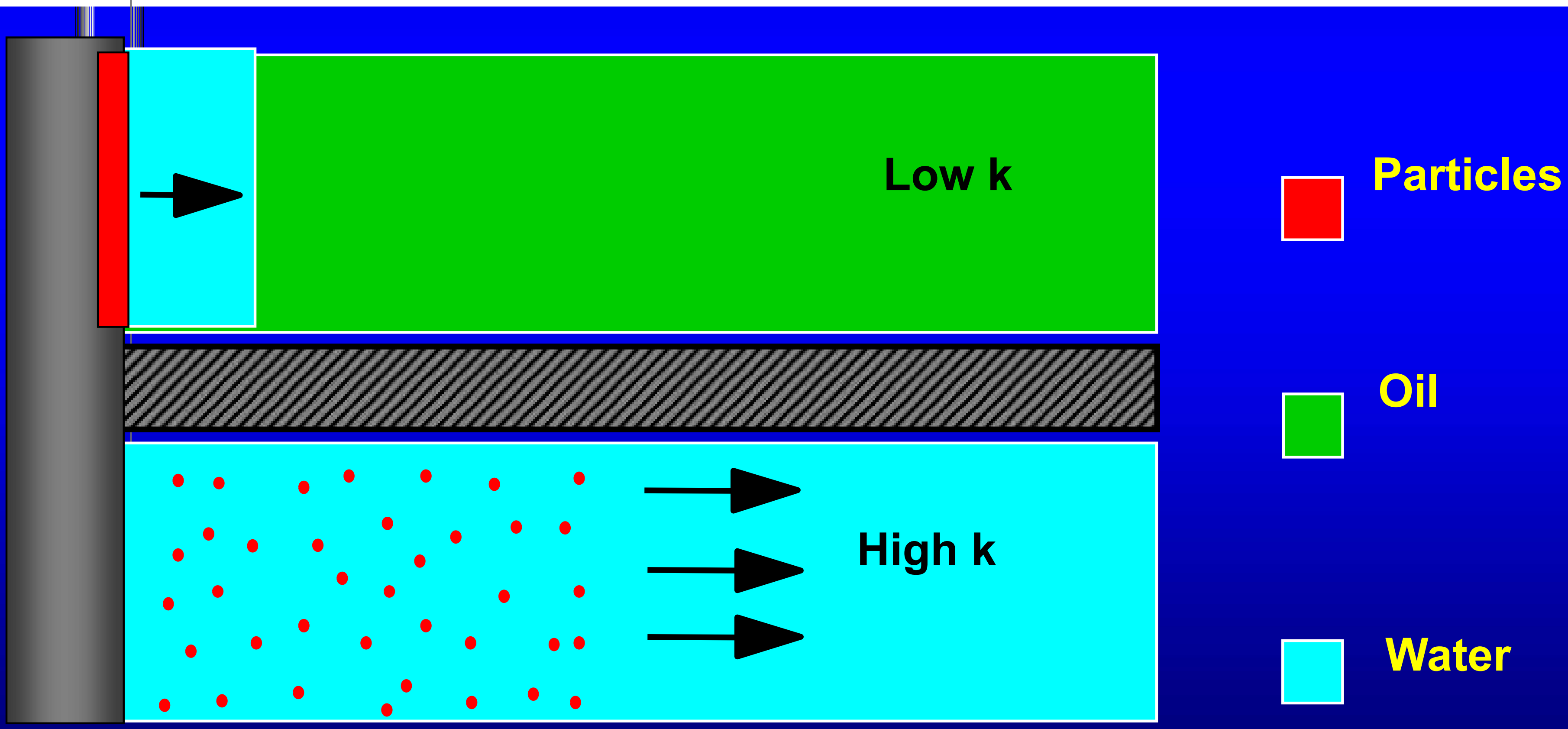
Crosslinked polymers, gels, gel particles, and "colloidal dispersion gels":

- Are not simply viscous polymer solutions.
- Do not flow through porous rock like polymer solutions.
- Do not enter and plug high-k strata first and progressively less-permeable strata later.
- Should not be modeled as polymer floods.

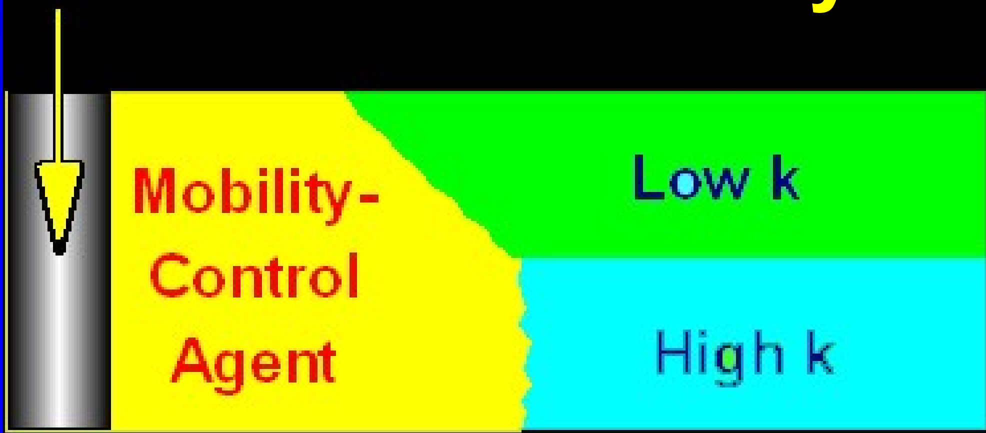
USE OF PARTICULATES (as a blocking agent)

One objective is to inject particles that are:

- small enough to flow freely into high-k zones,
- large enough not to enter low-k zones, and
- become immobile to divert water into oil zones.



Distinction between a blocking agent And a mobility control agent.

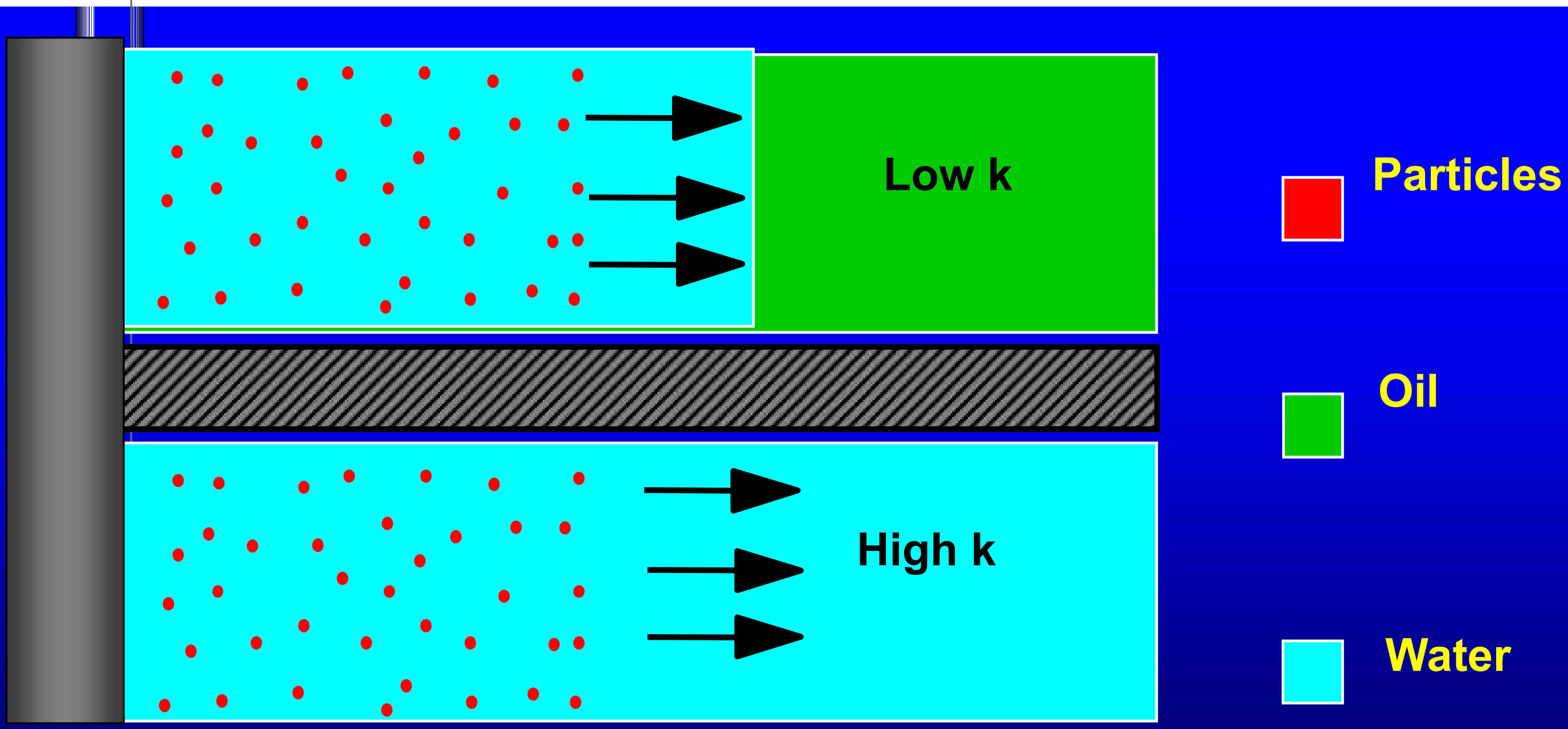


- For a mobility control agent, penetration into low-k zones should be <u>maximized.</u>
- For a blocking agent, penetration into low-k zones should be <u>minimized.</u>

USE OF PARTICULATES (for mobility control)

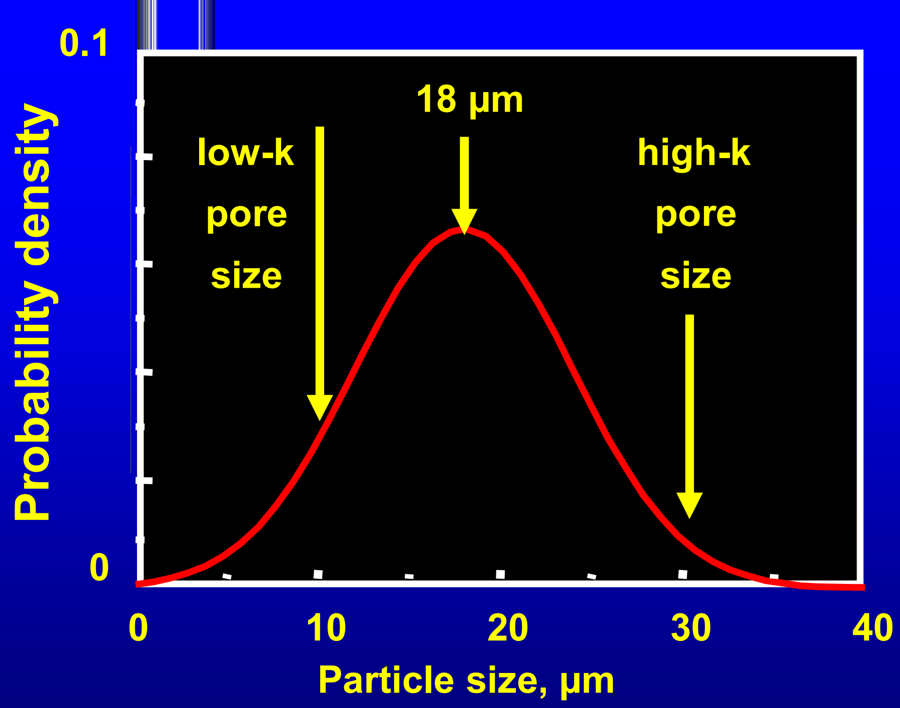
A different objective is to inject particles that:

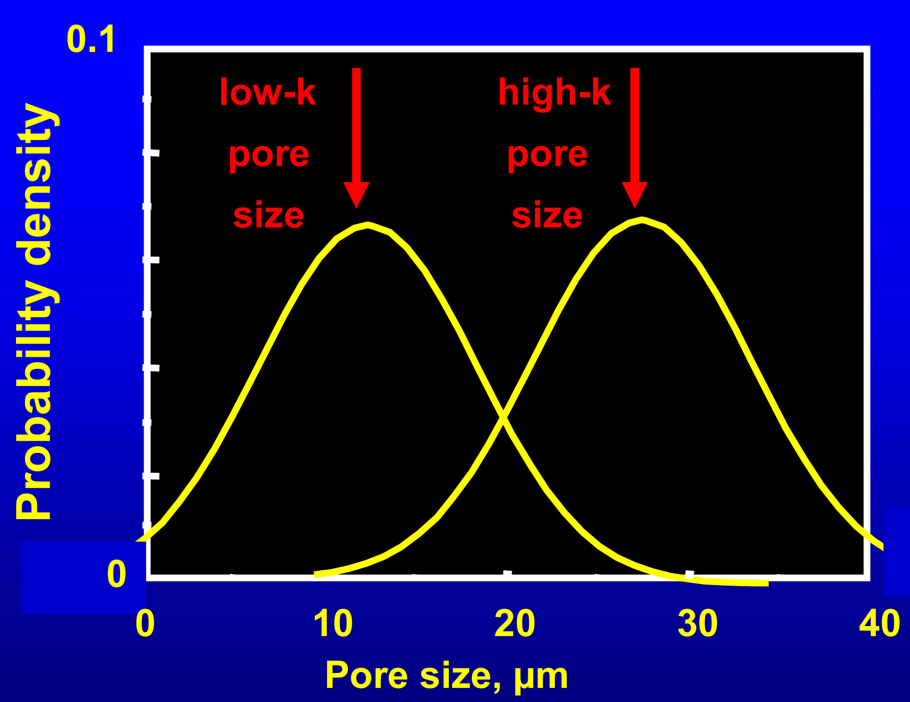
- deform as they extrude through pore throats,
- reduce water mobility, and
- Imitate a polymer flood.



USE OF PARTICULATES -- Problems

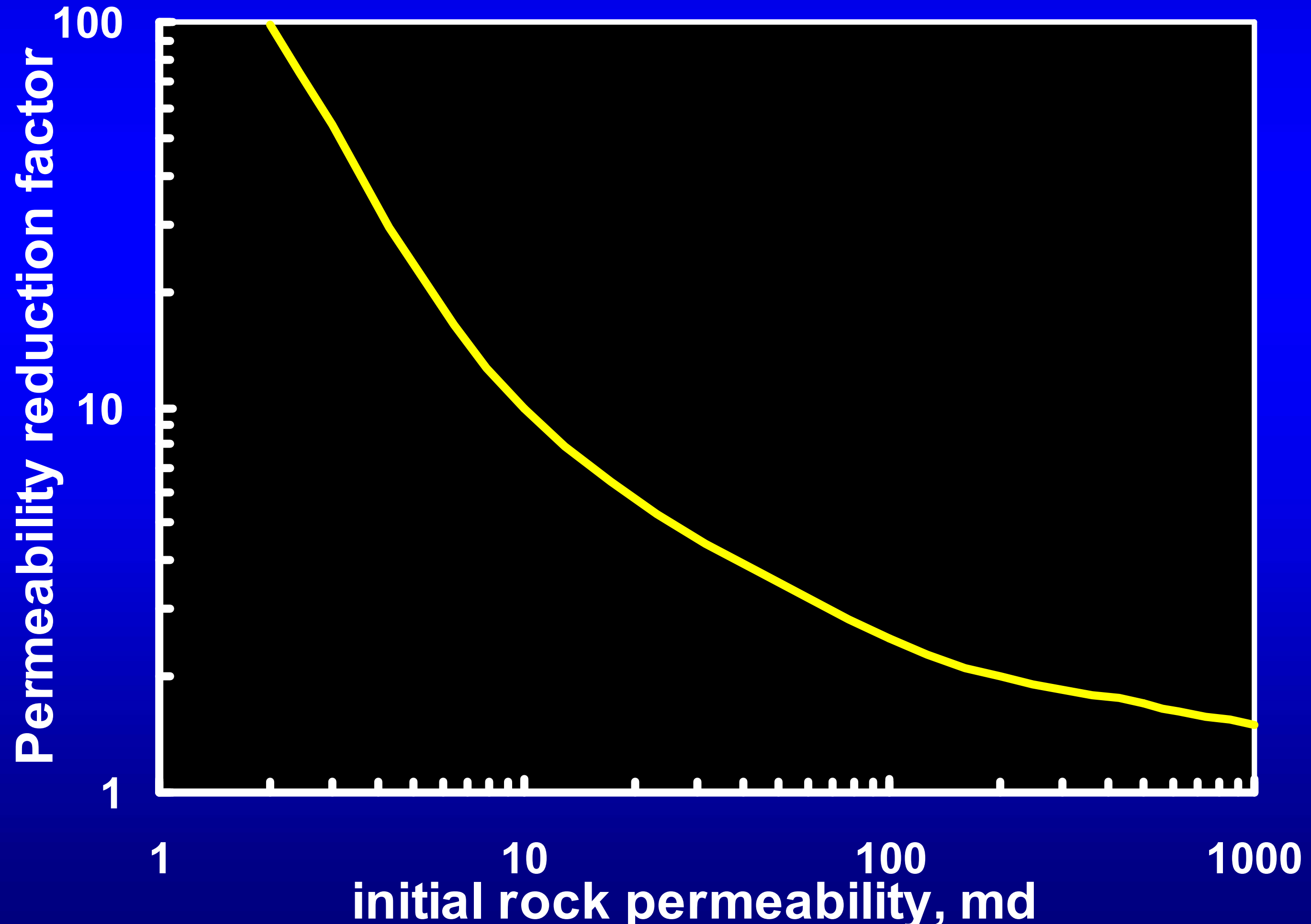
- Particles are not all the same size.
- Pores are not all the same size.
- Some particles will enter most or all pores.
- Permeability reduction may be greater in low-k pores than in high-k pores.



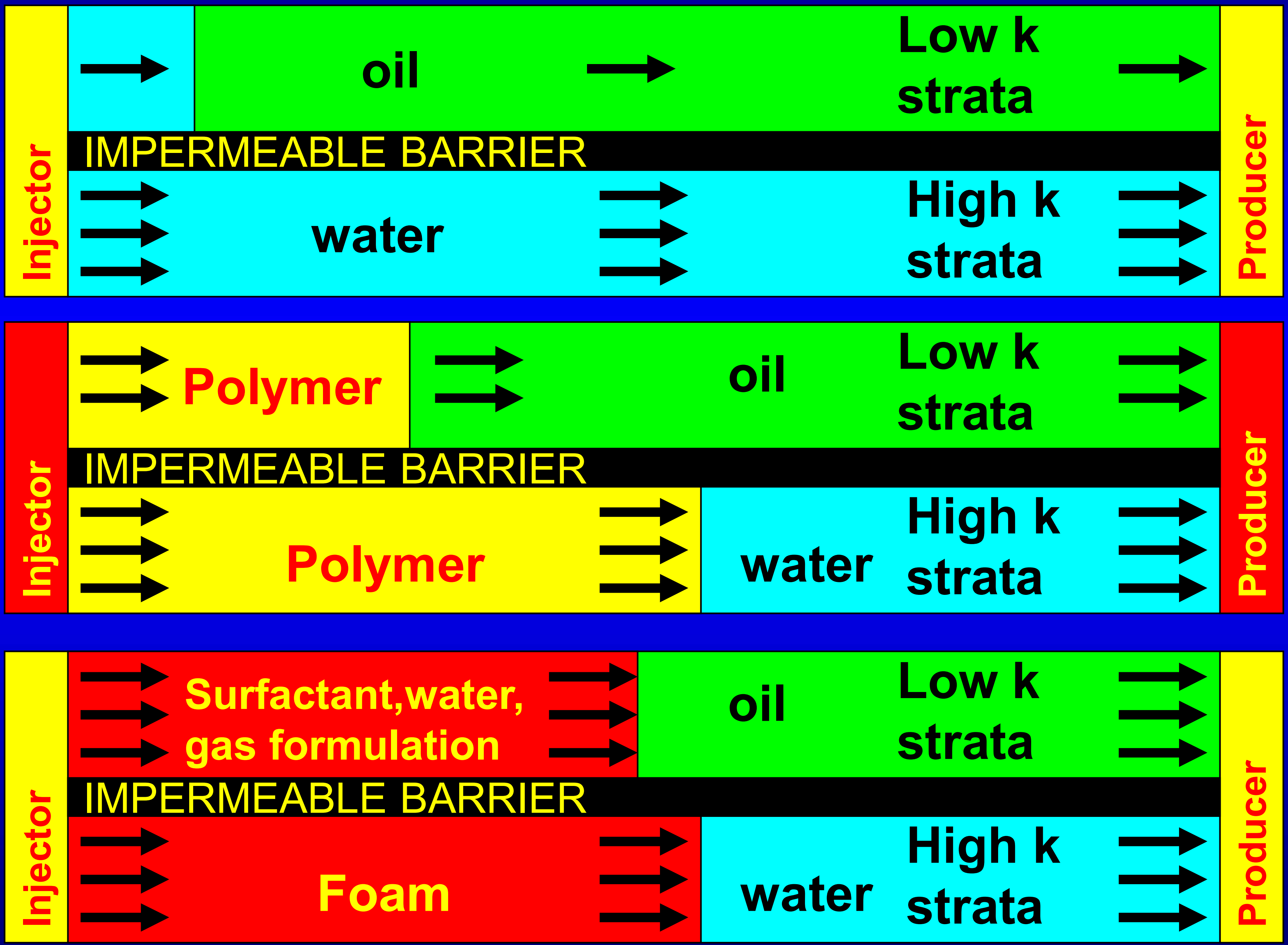


USE OF PARTICULATES -- Problems

- Particles tend to block small pores more than large pores.
- This bad for both polymer floods and blocking agent treatments.



If barriers prevent cross flow between strata, foams could provide better sweep efficiency than polymer solutions.



PROBLEMS WITH FOAMS

For various reasons, foam stability may not be sufficient.

Foam may not propagate as desired.

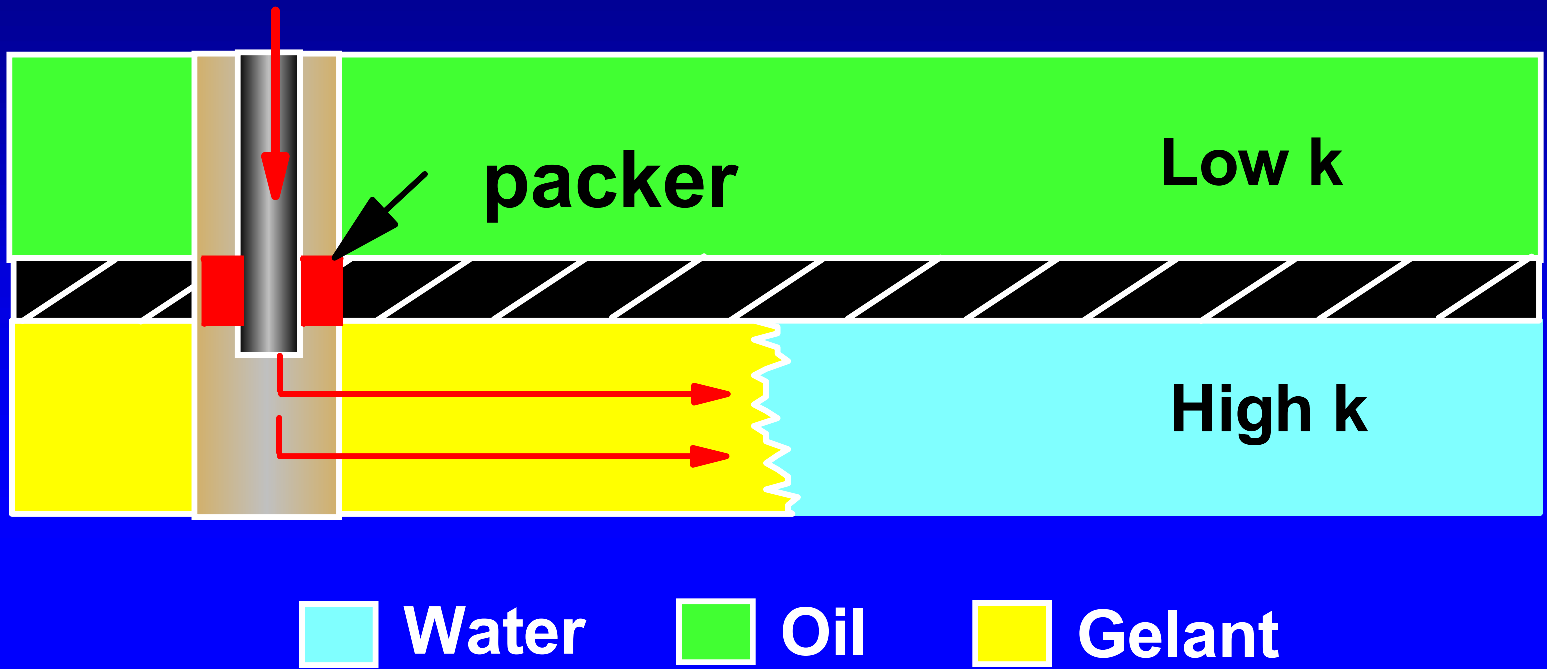
The desired level of mobility reduction may be difficult to achieve. (If mobility is too high, sweep is bad. If mobility is too low, injectivity is bad).

FIELD EXAMPLES

QUESTIONS FOR FIELD PROJECTS

- Why did you decide there was a problem?
- What did you do to diagnose the problem?
- What additional information do you need and how will you get it?
- What types of solutions did you consider?
- Why did you chose your solution over others?
- How did you size and place the treatment?
- Did it work? How do you know?
- What would you do different next time?

UNFRACTURED WELLS WITHOUT CROSSFLOW

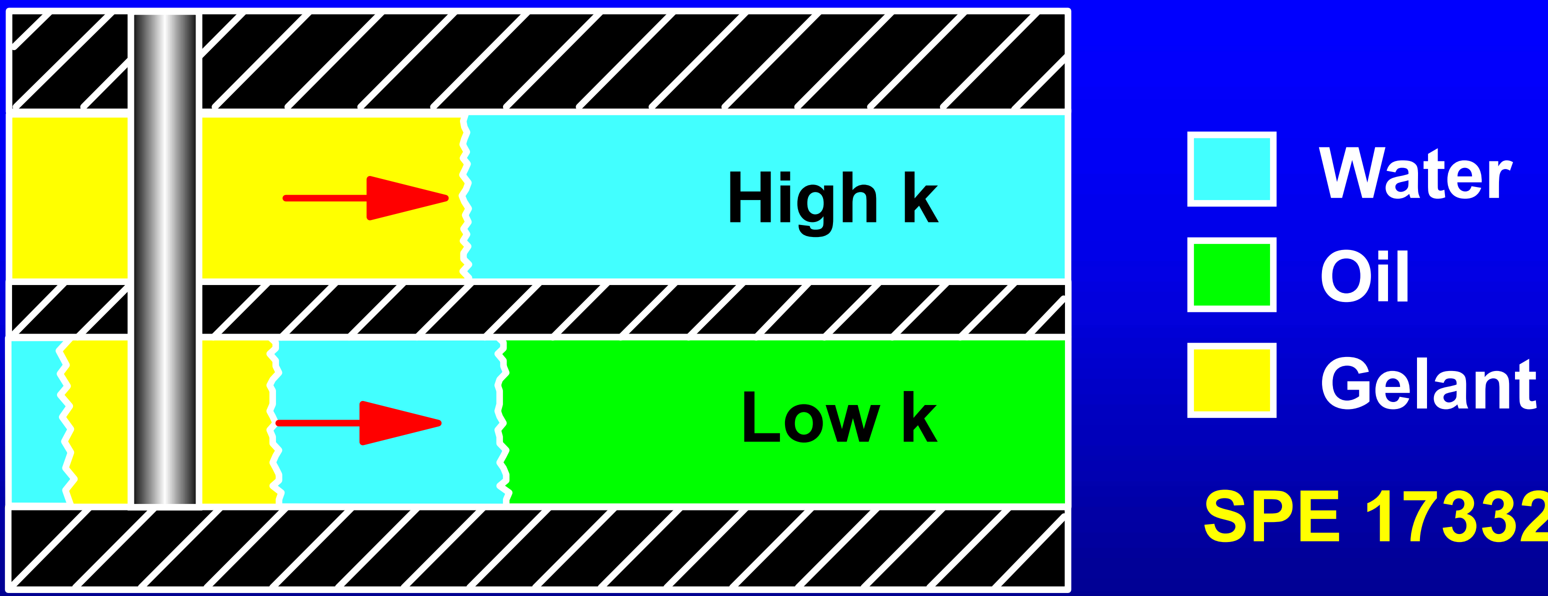


Possible Solutions

- Cement
- Sand plugs (if water zone is on the bottom)
- Mechanical devices (bridge plugs, packers)
- Gels
- Resins

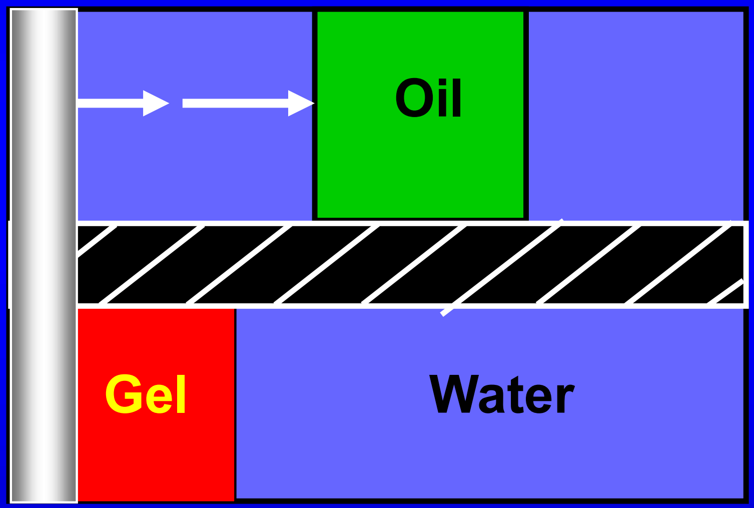
Blocking Agent Placement

- In both injection wells and production wells, gelants and similar blocking agents can penetrate into all open zones.
- In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.

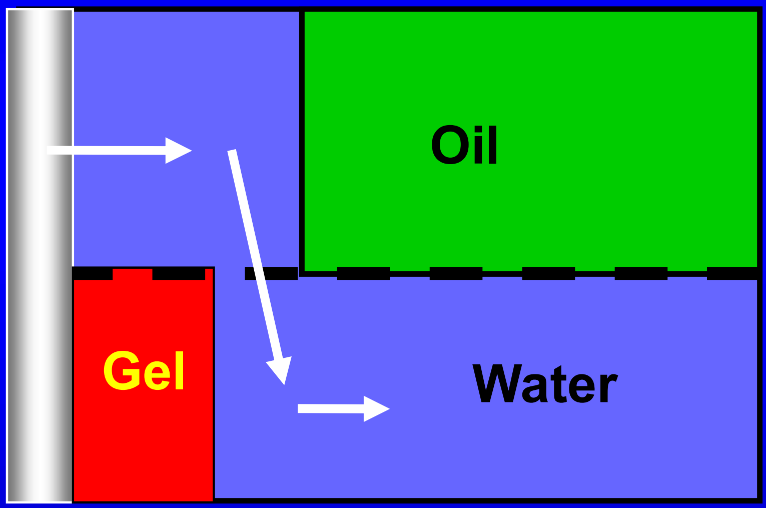


SPE 17332

Without crossflow--
gel can be effective.

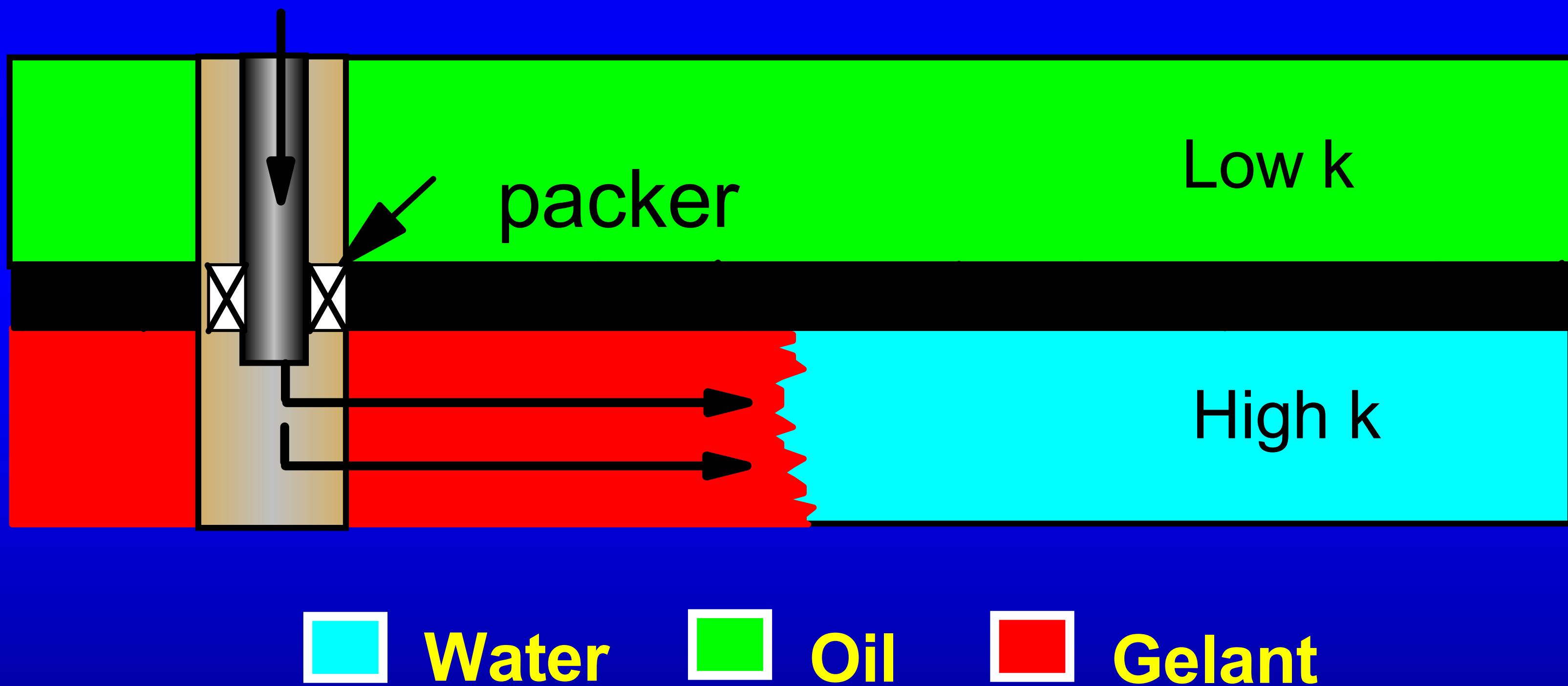


With crossflow--
gel is ineffective.

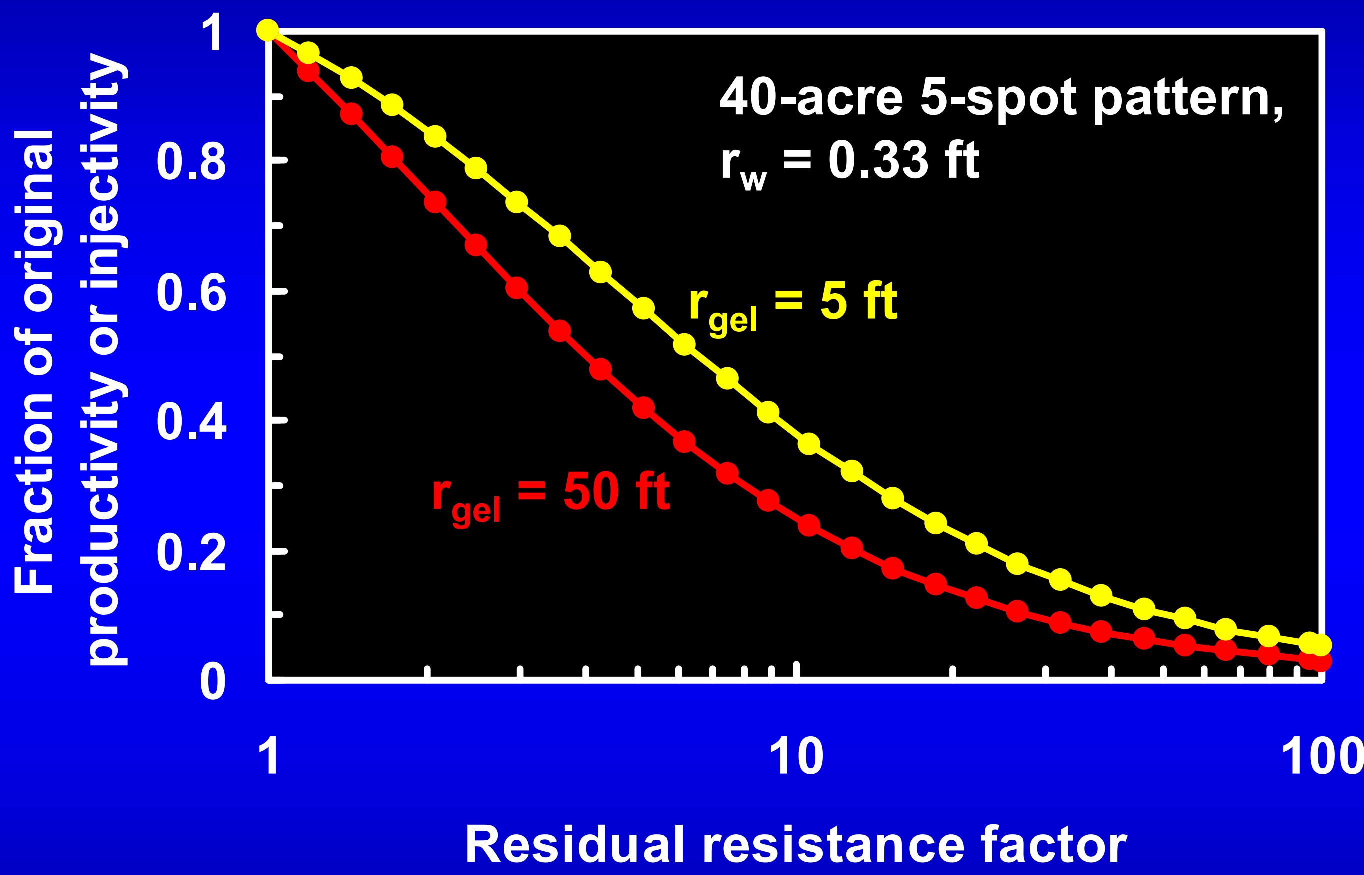


In-depth channeling problem, no vertical fractures, no vertical communication, zone isolation used:

- **Inject enough gelant to get desired injectivity or productivity reduction in the water zone.**



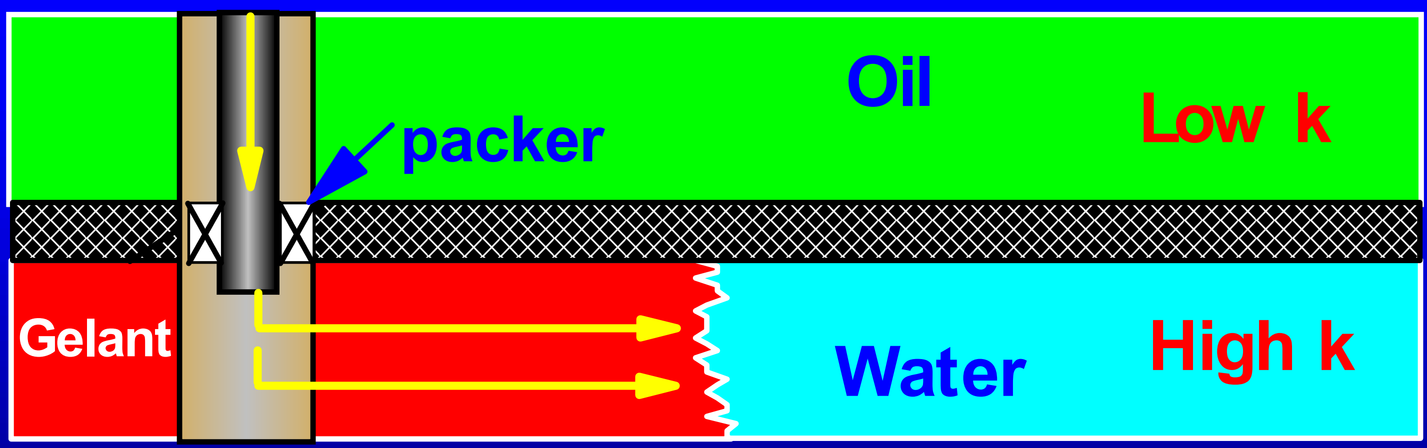
IN RADIAL FLOW, LOSSES ARE MORE SENSITIVE TO PERMEABILITY REDUCTION THAN TO RADIUS OF GELANT PENETRATION



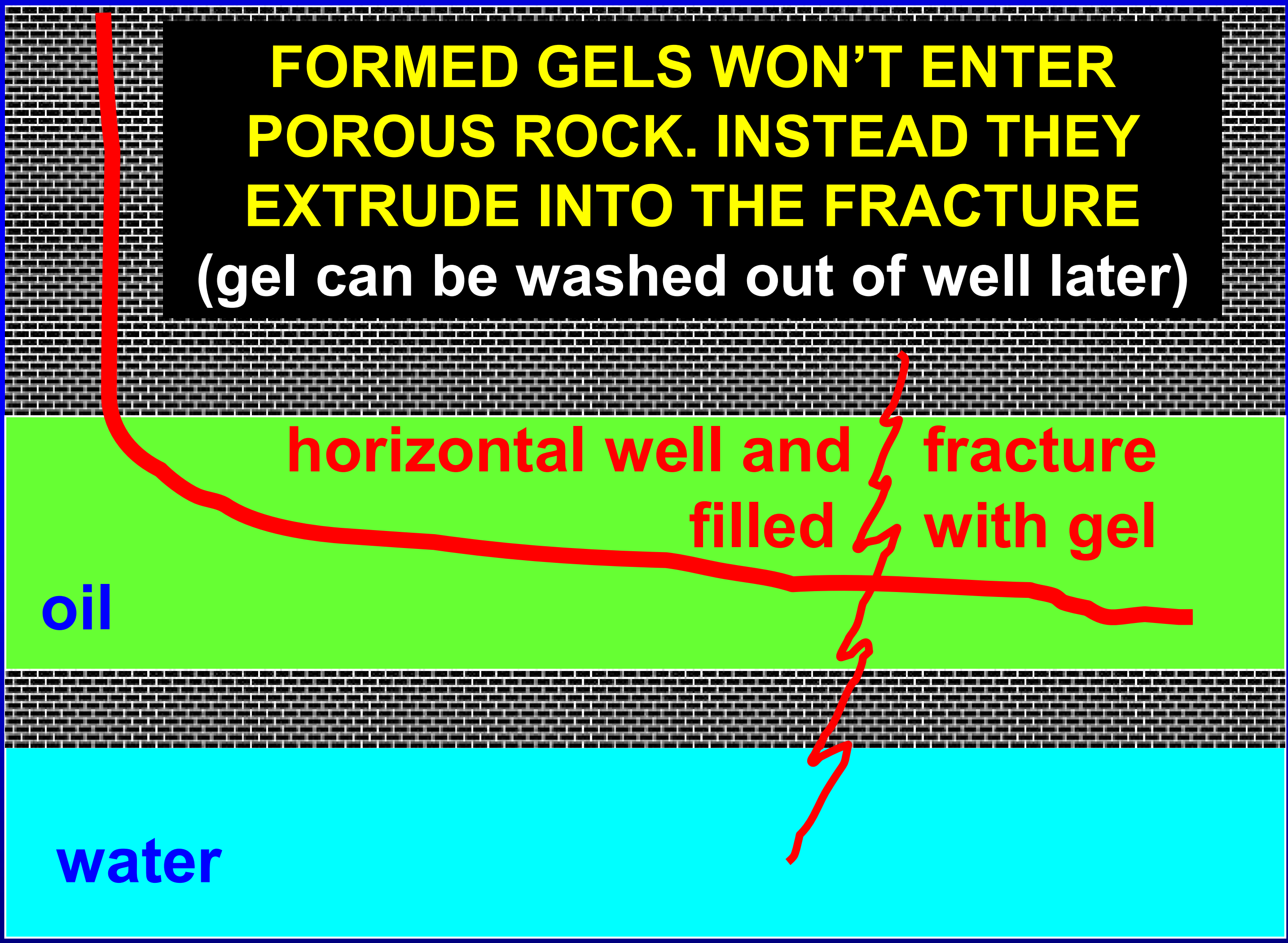
This figure applies to both injection and production wells.
It also applies to both oil and water production.

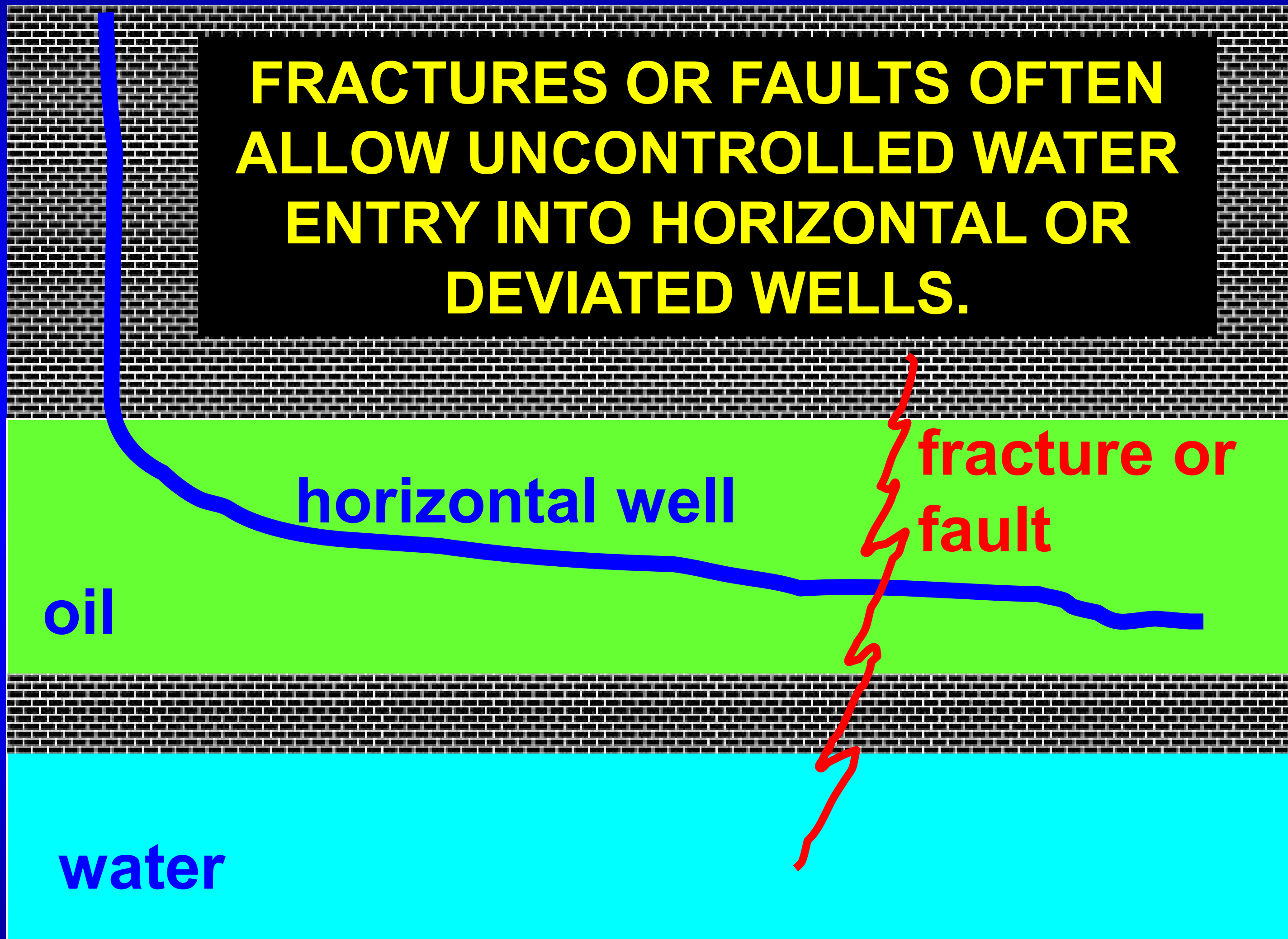
GEL TREATMENTS FOR RADIAL (MATRIX) FLOW PROBLEMS

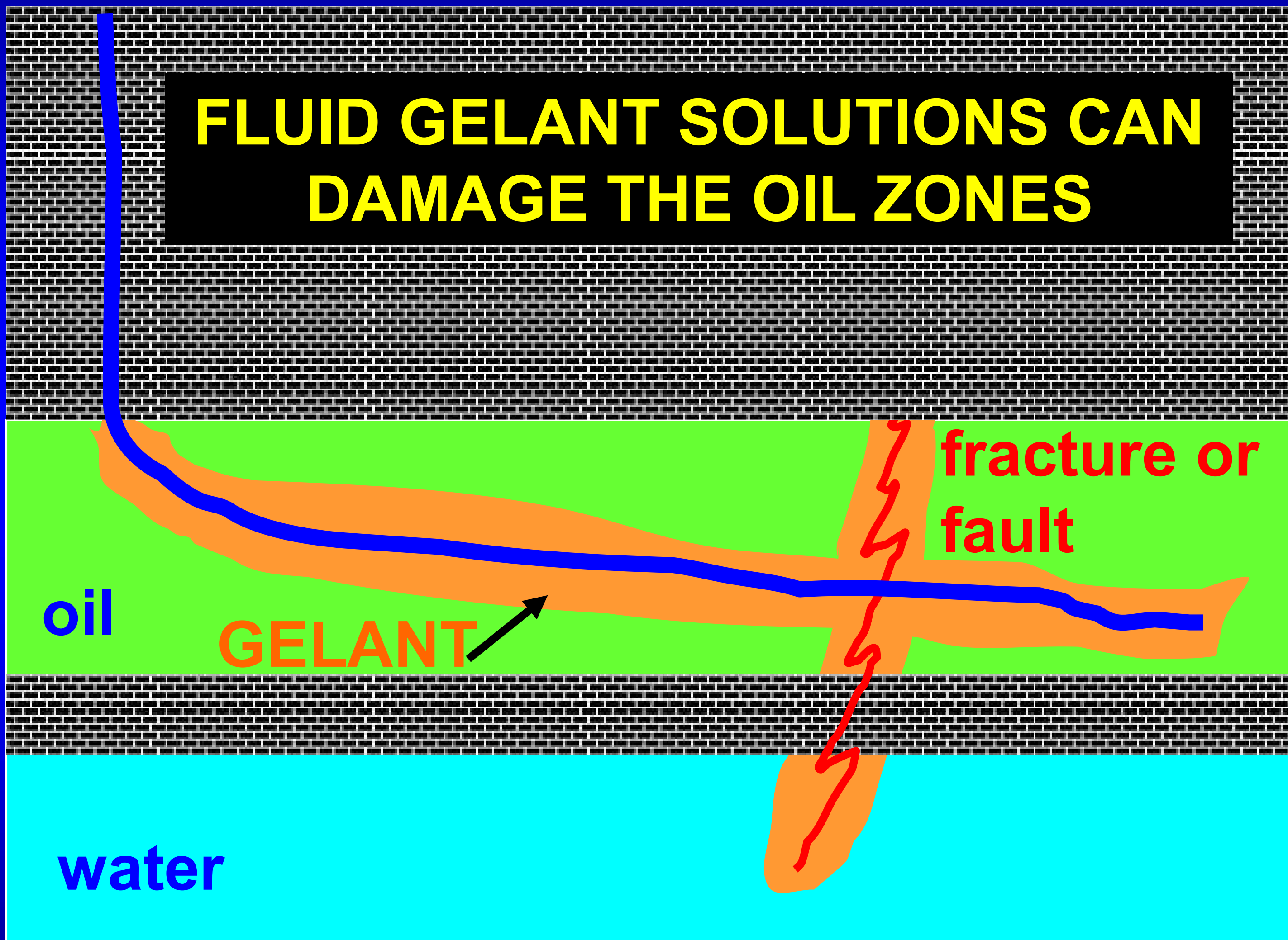
- Zones MUST be separated by impermeable barriers.
- Hydrocarbon-productive zones MUST be protected during gelant injection.
- Loss of water productivity or injectivity is not sensitive to radius of gelant penetration between 5 and 50 ft.
- Gel permeability reductions > 20 cause > 80% loss of water productivity.

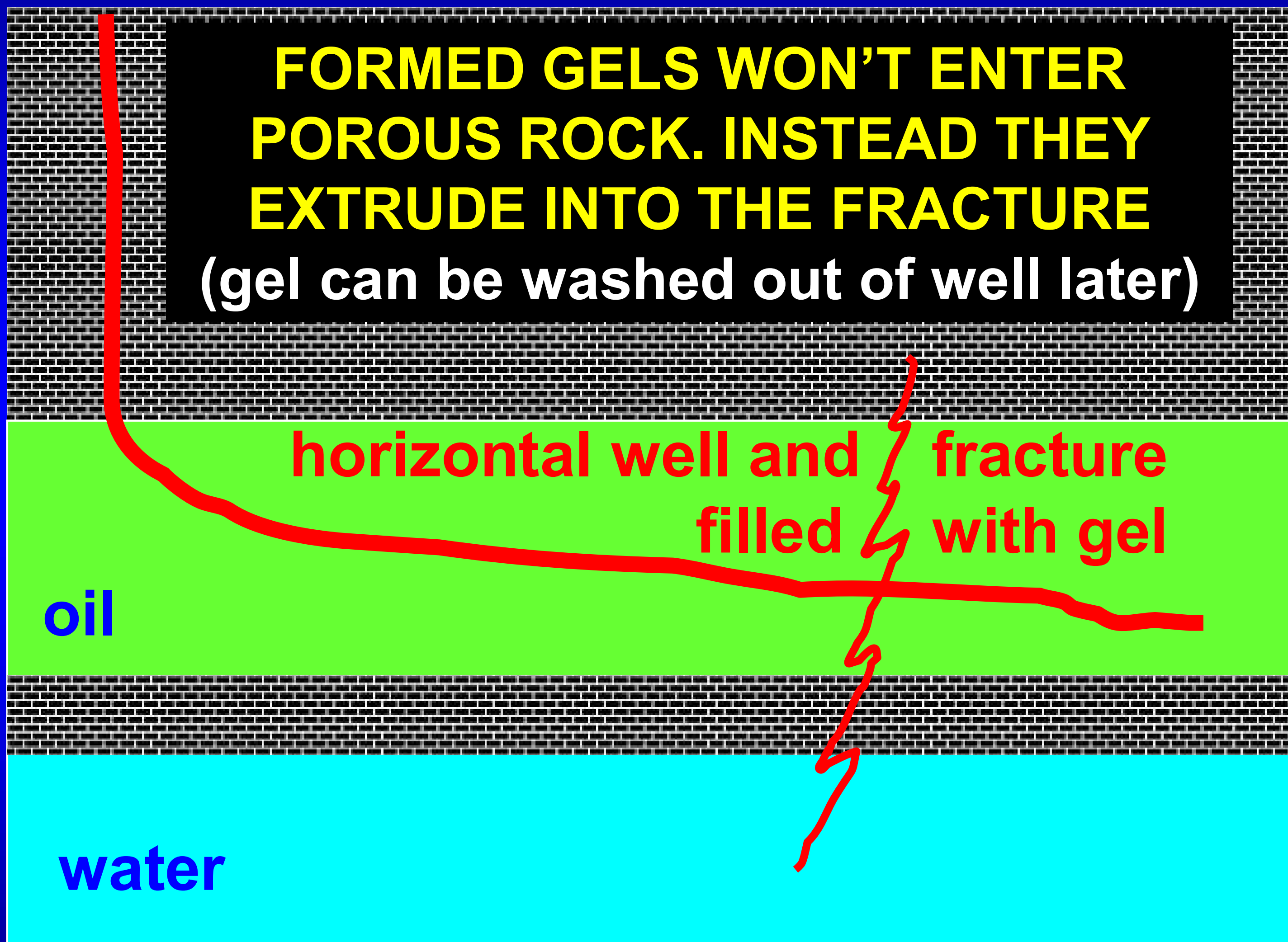


SPE 29475 & SPE 65527: ARCO's (Bob Lane) use of Cr(III)-acetate-HPAM gels to plug a fault intersecting a horizontal well.




FRACTURES OR FAULTS OFTEN ALLOW UNCONTROLLED WATER ENTRY INTO HORIZONTAL OR DEVIATED WELLS.
horizontal well
fracture or fault
oil
water


FLUID GELANT SOLUTIONS CAN
DAMAGE THE OIL ZONES
fracture or
fault
oil
GELANT
water



FORMED GELS WON'T ENTER POROUS ROCK. INSTEAD THEY EXTRUDE INTO THE FRACTURE
(gel can be washed out of well later)
horizontal well and fracture filled with gel
oil
water

SPE 29475

ARCO's (Bob Lane) use of Cr(III)-acetate-HPAM gels to plug a fault intersecting a horizontal well

- Prudhoe Bay near-horizontal (85°) well.
- 11,853-ft length, 9009-ft true vertical depth.
- Initial production was 1,500 BOPD with 24% water cut. After 3 months: 400 BOPD with 90% water cut.
- Reservoir pressure ~3,200 psi.

SPE 29475: Problem Diagnosis

- Lost circulation noted during drilling at 11,327 ft.
- Gamma ray/neutron logs showed washed out shale at 11,335 ft.
- Cement bond log indicated poor cementing above 11,338 ft.
- Spinner log indicated most fluid coming from 11,327 to 11,345 ft.
- Temperature anomaly at 11,338 ft.
- Water analysis indicated all of it was formation water.

Conclusion: A fault-like conduit exists near 11,338 ft that connects to the underlying Sadlerochit aquifer.

SPE 29475: Treatment, Sizing, and Placement

- **12,000 bbl Cr(III)-acetate-HPAM gel. (Cement squeeze was expensive and unlikely to work.)**
- **Treatment sizing was subjective. (12,000 bbl was all they felt that they could afford.)**
- **Bullhead injection of gel.**
- **Pump time was 100 hours. Gel was extruded into the fault during placement.**
- **Well shut in for 5 days to allow gel to cure.**

GEL INJECTION SEQUENCE

Polymer, wt %	Wellhead pressure, psi	Volume, bbls
0.3	400 – 0	22 (preflush)
0.3*	0 – 250	2,045
0.45*	225 – 525	5,500
0.6*	500 – 675	3,225
0.9*	725 – 800	740
0.3	800	100 (postflush)

2 BPM injection rate throughout.
*[HPAM]/[Cr(III) acetate] = 12/1.

TREATMENT RESULTS

Time	Oil rate, BOPD	Water rate, BWPD	Water cut, %	Oil PI, BOPD/psi	Water PI, BWPD/psi
11/93	466	4,290	90	0.32	2.95
Post-job	543	1,700	76	0.24	0.74
+ 1 mon.	727	1,895	72	0.30	0.78
+ 1 year	665	2,175	77		
+ 1.5 years	567	2,410	81		

CONNECTING LABORATORY & FIELD RESULTS (SPE 65527)

- Was the problem a fault or fracture?
- How wide was the fault or fracture?
- How far into the fault should the gel penetrate?
- Was the injected material a gel or gelant?
- How effectively did the gel seal the fault?

WAS THE PROBLEM A FAULT OR FRACTURE?

- Matrix or fracture flow?
- Fracture flow: $q/\Delta p >> k\ h\ /\ [141.2\ \mu\ \ln\ (r_e\ /\ r_w)]$.
- (4,290 BWPD + 466 BOPD)/[1,450 psi] = 3.3 BPD/psi.
- (100 mD x 0.1 x 18 ft)/[141.2 x 0.3 x 6] = 0.7 BPD/psi.
- 3.3 / 0.7 = 4.7.

Therefore, a fracture-like flow problems exists.

HOW WIDE WAS THE FAULT OR FRACTURE?

- Assume all water comes from fault.
- Radial flow into fracture:

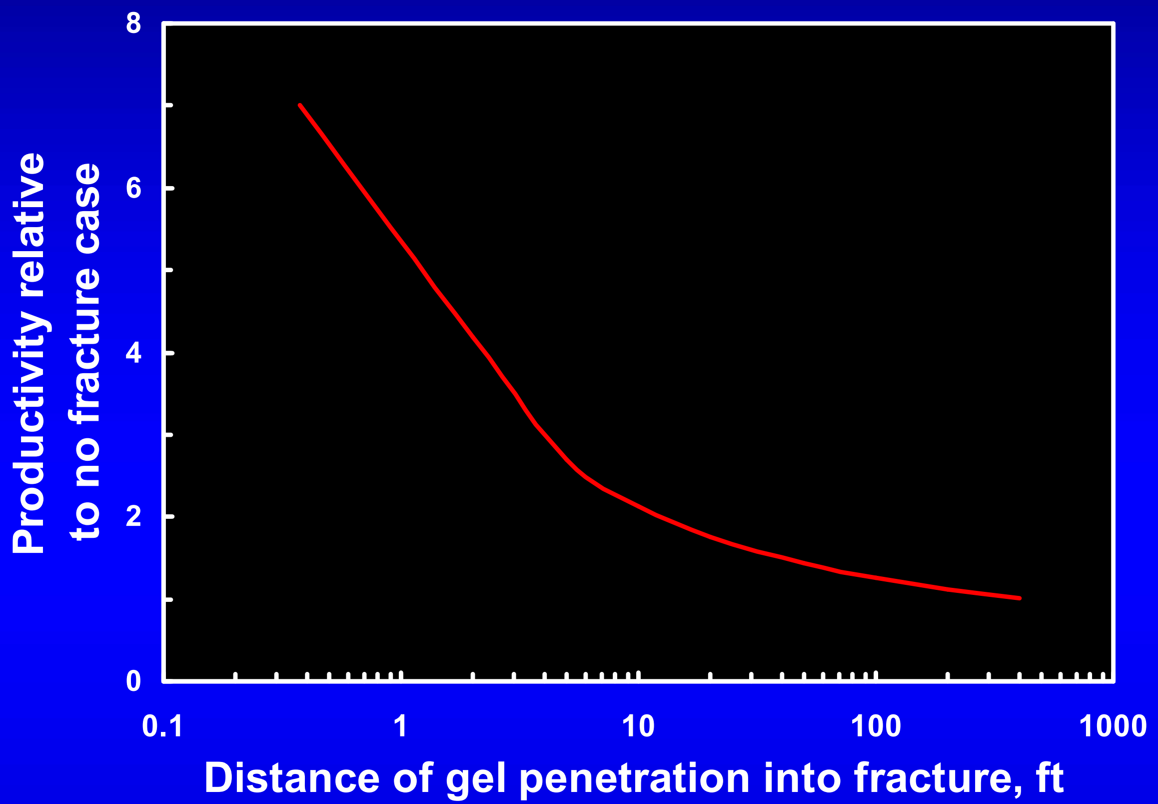
  $$q/\Delta p = k_f w_f / [141.2 \mu \ln (r_e / r_w)].$$

- Assume all water comes from fault: q = 4,290 BPD.

  Water PI = $q/\Delta p$ = 2.95 BWPD/psi.

- $\mu = 0.3$ cp.
- $\ln (r_e / r_w) \sim 6$.
- $k_f w_f = 2.95 \times 141.2 \times 0.3 \times 6 =$ 0.75 darcy-ft.
- $w_f = 12 \times 5.03 \times 10^{-4} \times (k_f w_f)^{1/3} =$ 0.0055 in. = 0.14 mm

HOW FAR SHOULD THE GEL PENETRATE?



- For single fractures that cut horizontal wells, only moderate gel penetration is needed.
- Conclusion is not valid in vertical wells or if multiple fractures or a natural fracture system is present.

WAS THE INJECTED MATERIAL A GEL OR GELANT?

- Injection rate: 2 BPM.
- Volume from wellhead to fault: 225 barrels.
- Transit time from wellhead to the fault: ~2 hours.
- Gelation time at 26°C: ~15 hours.
- Gelation time at 90°C: ~10 minutes.
- Total injection time: ~100 hours.

Injected material was gel during most, if not all of the gel placement process.

HOW EFFECTIVELY DID GEL SEAL THE FAULT?

BEFORE GEL:

- Radial flow into fracture: $q/\Delta p = k_f w_f / [141.2 \mu \ln (r_e / r_w)]$.
- Water PI = $q/\Delta p$ = 2.95 BWPD/psi.
- μ = 0.3 cp, $\ln (r_e / r_w) \sim 6$.
- $k_f w_f$ = 2.95 x 141.2 x 0.3 x 6 = 0.75 darcy-ft.

AFTER GEL:

- Water PI = $q/\Delta p$ = 0.78 BWPD/psi.
- $k_f w_f$ = 0.78 x 141.2 x 0.3 x 6 = 0.198 darcy-ft.

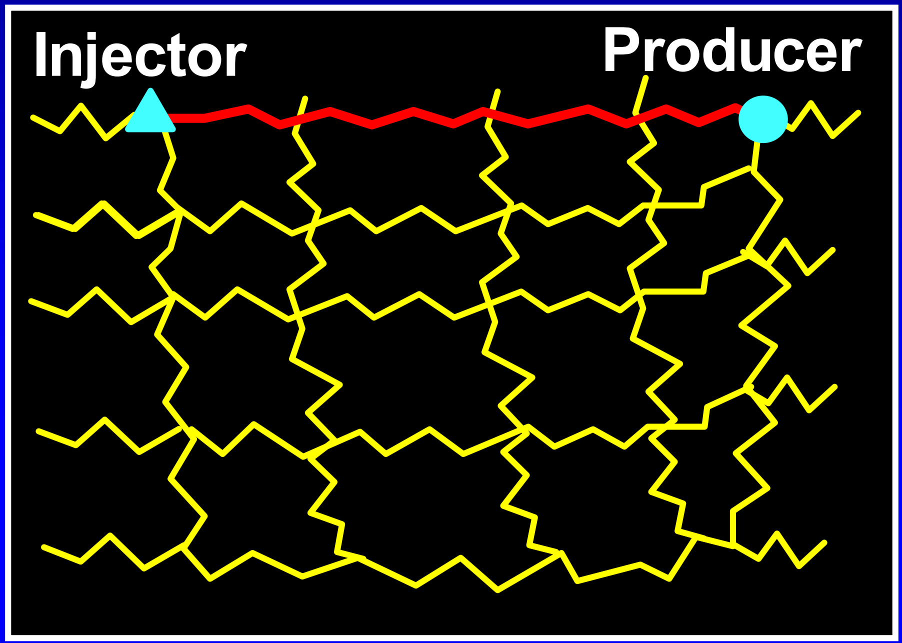
REDUCTION IN FRACTURE CONDUCTIVITY:

- (0.75-0.198)/0.75 = 74% reduction.
- Implies fault is not completely sealed but calculation is conservative because it assumes all water came from the fault.

- Simple calculations can give at least a rudimentary indication of the width of the fracture or fault that causes excess water production—which is relevant to the choice of gel.

- During field applications, accurate flowing and static downhole pressures should be made at least before and after the gel treatment is applied. Some very useful insights can also be gained if downhole pressures are measured during gel injection.

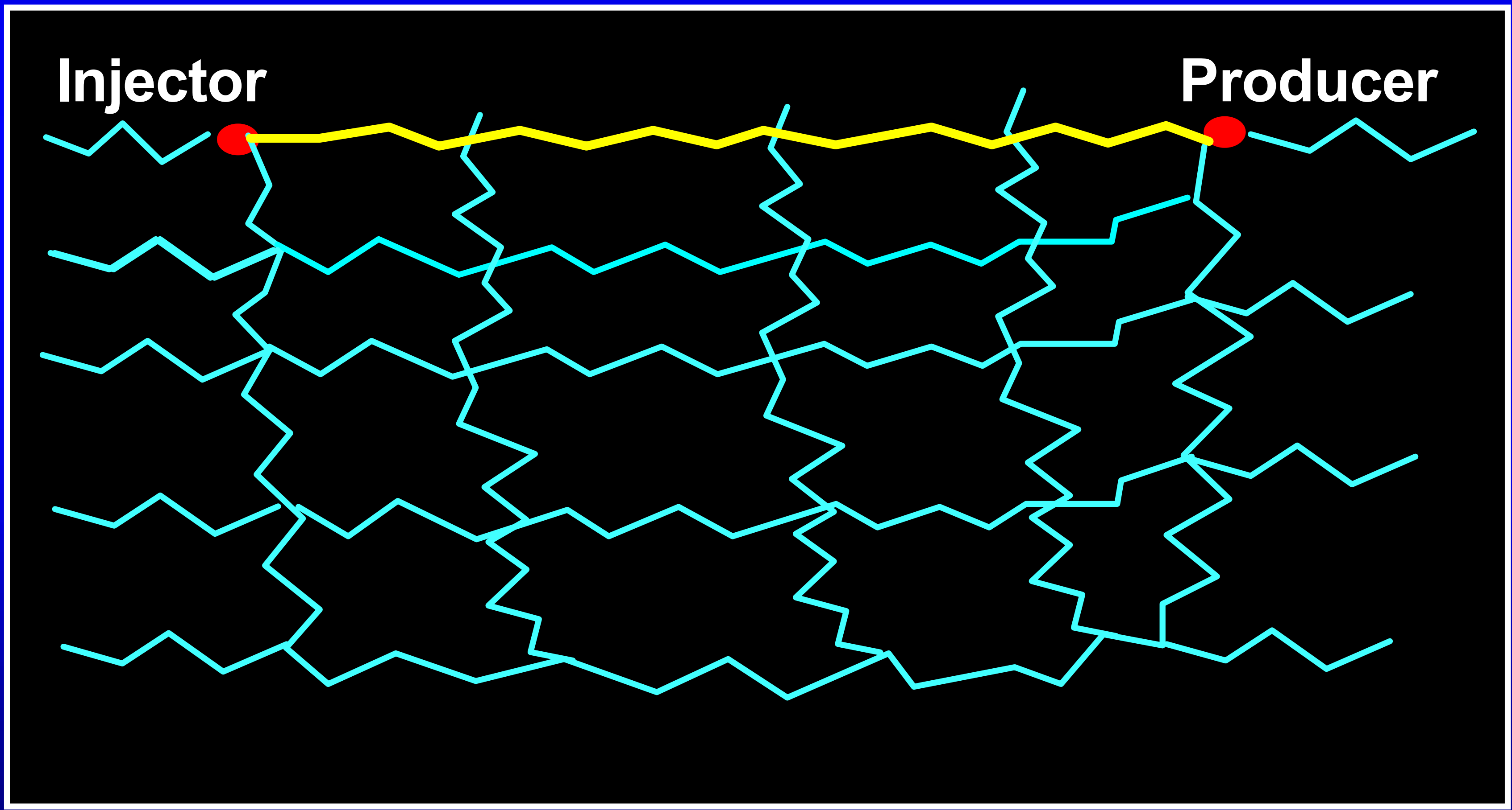
NATURALLY FRACTURED RESERVOIRS



- Want to restrict fluid channeling through the most direct fracture(s).
- Don't want to damage the secondary fractures (since they are important in allowing high well injectivities and productivities).

Naturally fractured reservoirs:

- Impressive well-documented cases,
- Greatest successes used large gel volumes,
- Optimum sizing unknown.



GEL EXTRUSION THROUGH FRACTURES

- Formed GELS injected instead of GELANT solutions.
- Gels extrude through fractures—no flow in porous rock.
- Successful field applications in treating:
  - Fractures or faults that cross horizontal wells.
  - Water or gas channeling through natural fractures.
- Gel dehydration and pressure gradients depend on w_f .
- Interwell tracers and injectivity/productivity data can indicate w_f for the most serious fracture(s).
- Gel sizing procedure is under development but:
  - Fastest injection yields the greatest gel penetration.
  - Slower injection increases gel's staying power.
  - At a given rate, a 3X increase in gel volume yields a 2X increase in distance of gel penetration.
- More information: SPE 65527, *SPEPF* (Nov. 1999) 269-276, *SPEPF* (Nov. 2001) 225-231.

Cr(III)-acetate-HPAM Treatments to Reduce Channeling during WAG CO_2 Projects in Fractured Sandstone Reservoirs

	Wertz	Rangely
SPE paper	27825	56008
μ oil, cp	1.38	1.7
k, md	13	10
Lithology	sandstone	sandstone
Thickness, ft	240	175
T, °C	74	71
No. of treatments	8	44
HPAM, ppm	5000-8000	3000-8000
Treatment size, bbl	10,000-20,000	8,900-20,000
EOR/well, BOPD	100-300	21
EOR, total bbl	735,000	685,000
Total cost, $	963,000	2,060,500

SPE 39612: Chevron's Large Volume Gel Treatments in Injection Wells During a CO_2 Flood in a Naturally Fractured Reservoir

- Rangely field. Weber eolian sandstone.
- 675 ft gross thickness, 175 ft net pay.
- 6 distinct sand units
- ϕ=11%, k=10 mD.
- 376 producers, 278 injectors
- Discovered: 1933. First produced: 1944. Perpherial waterflood since 1958. Pattern waterflood since 1969.
- CO_2 flood since 1986.

SPE 39612: Chevron's Rangely Field

Problem Diagnosis

- Extreme variability in CO_2 performance from pattern to pattern.
- Several patterns with rapid breakthrough.
- Pattern reports showed "under and over processed" zones.
- Chevron created a sophisticated rating system to quantify the merit for treatment.

SPE 39612: Chevron’s Rangely Field

Did Fractures Cause the Problem?

- Injectivity was 23X greater than expected from Darcy’s Law for radial flow.
- CO_2 breakthrough noted at 24 hrs with 1,300’ well spacing--55 ft/hr propagation rate.
- Average effective permeability = 10 md, yet they routinely placed 10,000 bbls of polymer gel into formation.
- Linear flow character seen in injection well fall-off test data.

Chevron's Rangely Field—
Conformance Methods Applied

- Selective injection equipment (SPE 21649).
- Water-alternating-gas (SPE 27755).
- Recompletion (SPE 27756).
- Pattern realignment (SPE 27756).
- Gelled foams (SPE 39649).
- Gels (SPE 39612).

SPE 39612: Chevron's Gel Treatments

<u>Treatment Design</u>

- Water injected for ~1 week before treatment.
- Cr(III)-acetate-HPAM gel.
- 10,000-20,000 bbl injected per treatment.
- Typical injection time: 8-10 days.
- 0.5% HPAM in gel mostly, but ramped up to 0.85% HPAM at end.
- Flushed with 3 tubing volumes of water at end.
- Shut well in for 1 week.
- Inject water first on return to injection.

SPE 39612: Chevron's Gel Treatments

Range of Responses (44 Treatments Total)

- No response.
- Smoothing of production.
- Reduction in water.
- Reduction in gas.
- Areal sweep improvement.
- Oil rate increase.
- Reduction or elimination of oil decline.
- Better pattern CO_2 retention & utilization.

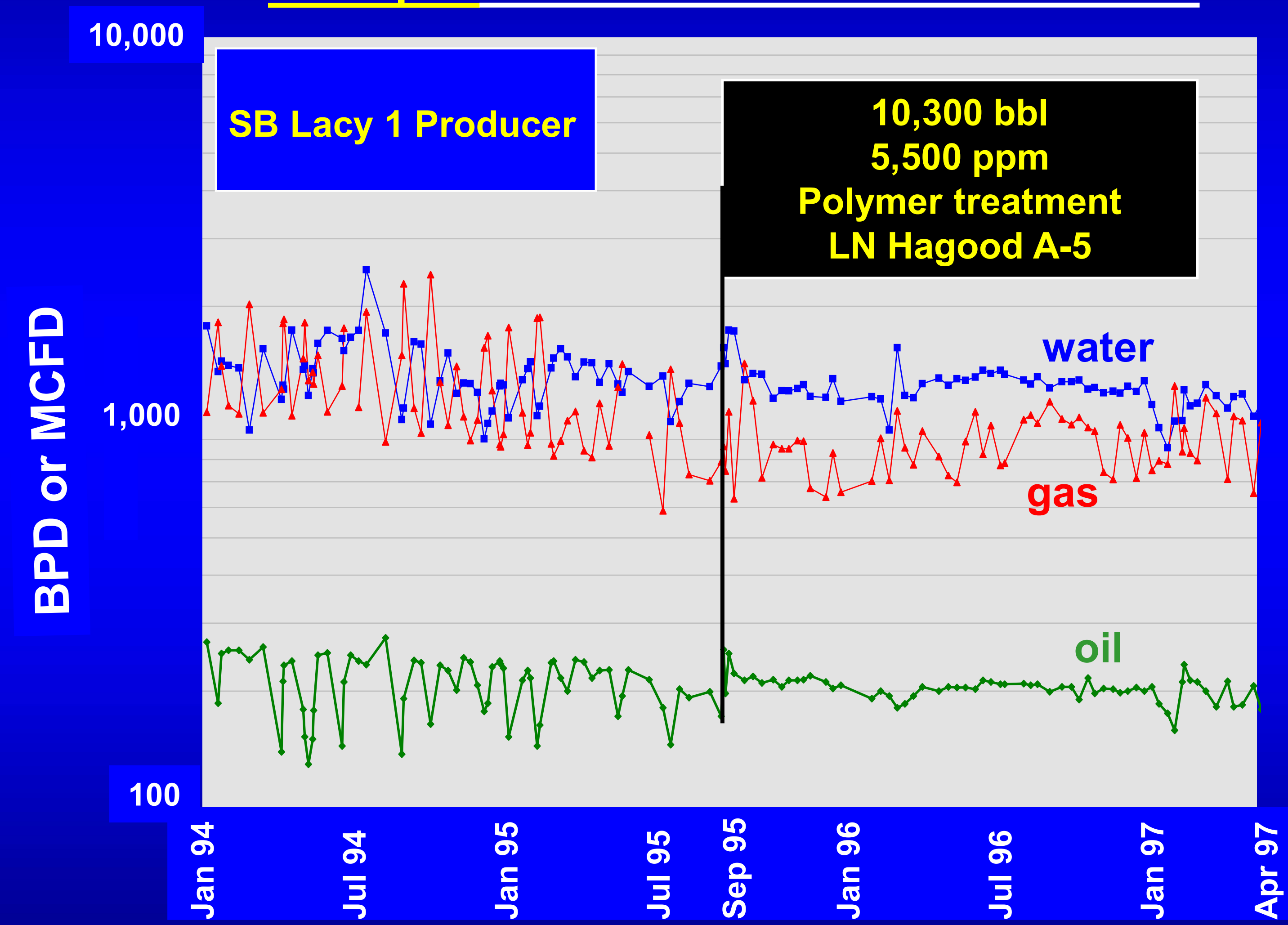
SPE 39612: Chevron's Gel Treatments

Example: Treatment Smooths Production

- Rapid breakthrough from injector to producer.
- No other producers supported.
- Thief appeared confined to one zone.
- Previous attempts at near-wellbore control were unsuccessful.
  - Liner, selective perforations.
  - Small-volume Cr(III)-acetate-HPAM treatments.

SPE 39612: Chevron's Gel Treatments

Example: Treatment Smooths Production



SPE 39612: Chevron's Gel Treatments
Results: 1994-1996

- Investment = $2,060,500.
- ROR: 365%. Payout: 8 Months.
- IOR: 685,000 BO.
- Success Rate: 80%.
- Average change per treated well:

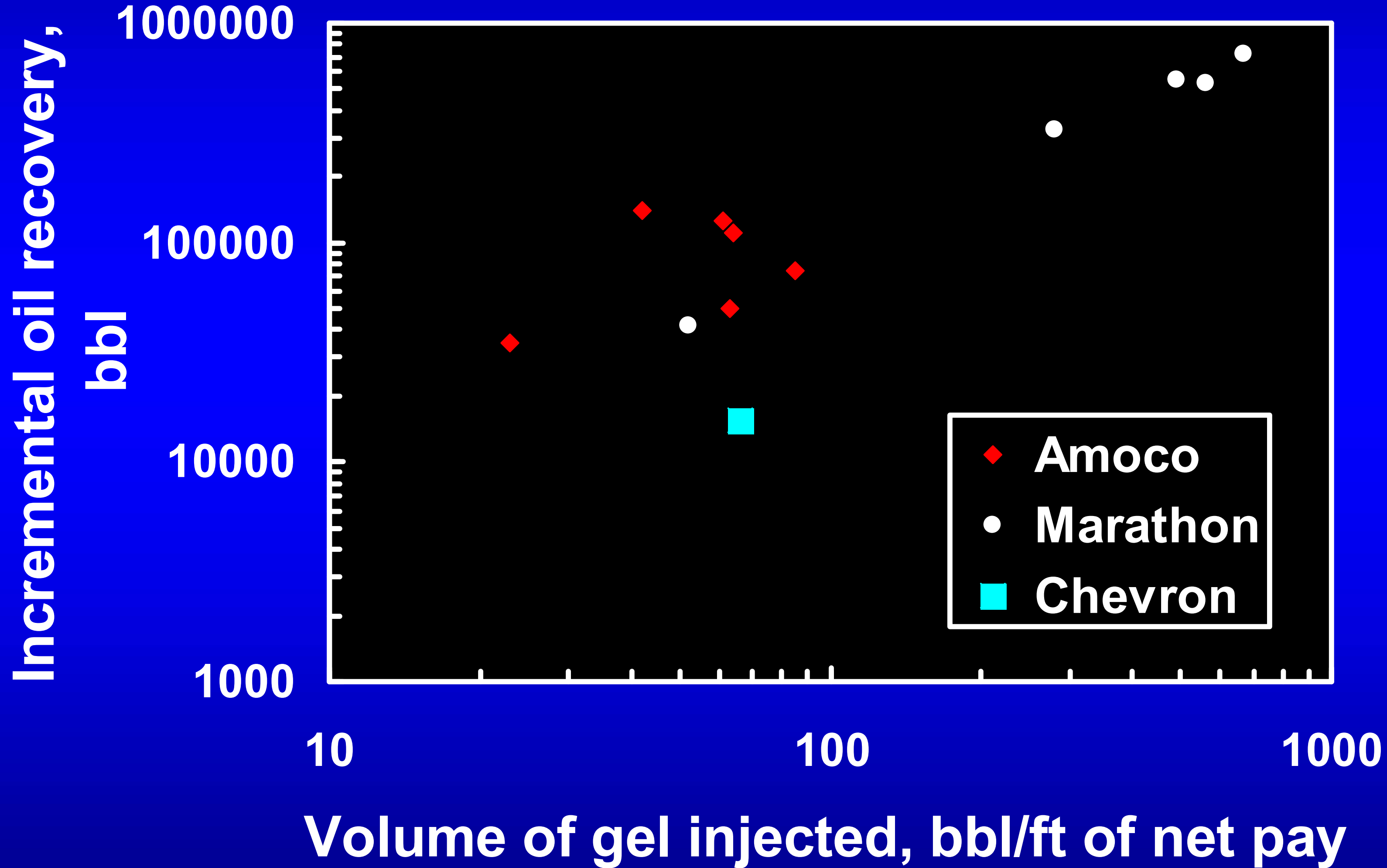
  +20 BOPD, -100 BWPD, -100 MCFPD

SPE 39612: Chevron's Gel Treatments

Lessons Learned

- Rapid communication and associated poor CO_2 economic performance are the most important candidate selection criteria.
- Larger, >15,000 bbl treatments have been successful.
- Chase well treatments are highly successful.
- Best results have been in the best part of the field.
- CO_2 thief should also be H_2O thief.
- H_2O injection rate > 1,200 BPD.
- Avoid high BHP area of field.
- Post-job reservoir management critical.

- Incremental oil recovery generally increased with gel treatment size.



Good Papers Where Naturally Fractured Injection Wells Were Treated

- Amoco's large-volume gel treatments in CO_2 injectors. SPE 27825.
- Marathon's large-volume gel treatments in waterflood injectors. SPE 27779 & *O&GJ* 1/20/92.
- Imperial's large-volume gel treatments waterflood injectors. SPE 38901.
- Chevron's use of multiple methods in the same field, including recompletions, polymer gels, gelled foams, pattern realignment and selective injection equipment. SPE 21649, 27755, 27756, 30730, 35361.
- Kinder Morgan SACROC treatments. SPE 169176

SACROC/KELLY-SNYDER FIELD SPE 169176

- Kinder Morgan WAG CO_2 flood. 19-md limestone.
- 500-1200 sacks of cement worked for some of the worst channeling problems.
- Mechanical methods sometimes helped if distinct zones were watered out.
- Crystalline polymer squeezes were the least successful method.
- 5000-10000 bbl Cr(III)-acetate-HPAM treatments did not last long. Judged too small.
- ~20,000 bbl Cr(III)-acetate-HPAM treatments.
- 5000-12000-ppm HPAM.
- Ending injection of 30,000-ppm HPAM or cement.

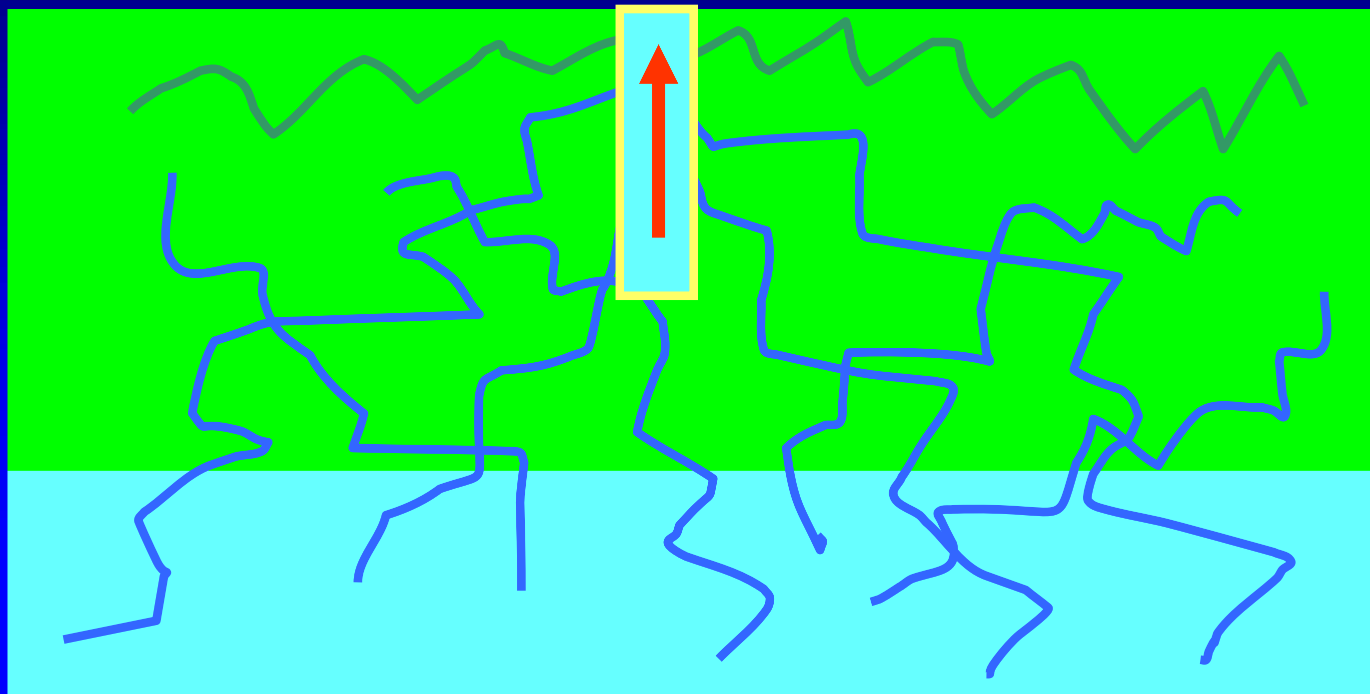
SACROC/KELLY-SNYDER FIELD SPE 169176

- In “P1” area, 29 treatments with ~13000 bbl gel/treatment—reducing GOR from 30 to 20 mcf/bbl and producing 770000 bbl EOR at a cost of $1.88/bbl.
- In “P2” area, 30 treatments with ~17000 bbl gel/ treatment—yielding $1.50 cost/bbl EOR.
- Biggest problem has been produced polymer. Suggested solution: build injection pressure more rapidly (e.g., by increasing HPAM content).
- In total, have injected over one million bbl of polymer during 77 treatments.

DETAILS OF ONE GEL TREATMENT.
KUPARUK RIVER UNIT—ALASKA
SPE 179649

- ConocoPhillips. Miscible hydrocarbon WAG.
- Highly fractured/faulted multilayer sandstone.
- A single 45000-bbl Cr(III)-acetate-HPAM treatment, increasing HPAM from 0.3%-1%.
- Describes detailed methodology associated with the design, execution, and assessment of the treatment.

Natural fracture system leading to an aquifer.



- Many successful polymer/gelant treatments were applied to reduce water production.
- Treatment effects were usually temporary.
- Optimum treatment materials, sizing, and design are currently unknown.
- HOW SHOULD THESE TREATMENTS BE DESIGNED AND EVALUATED?

JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments in Naturally Fractured Production Wells

- Arbuckle formation of western Kansas.
- Naturally fractured dolomite reservoirs produced by bottom-water drive.
- k ~ 140 md; oil column ~ 20 ft; completion interval ~ 5 ft.
- Pre-treatment production:
  - 5 to 20 BOPD
  - 500 to 1,600 BWPD

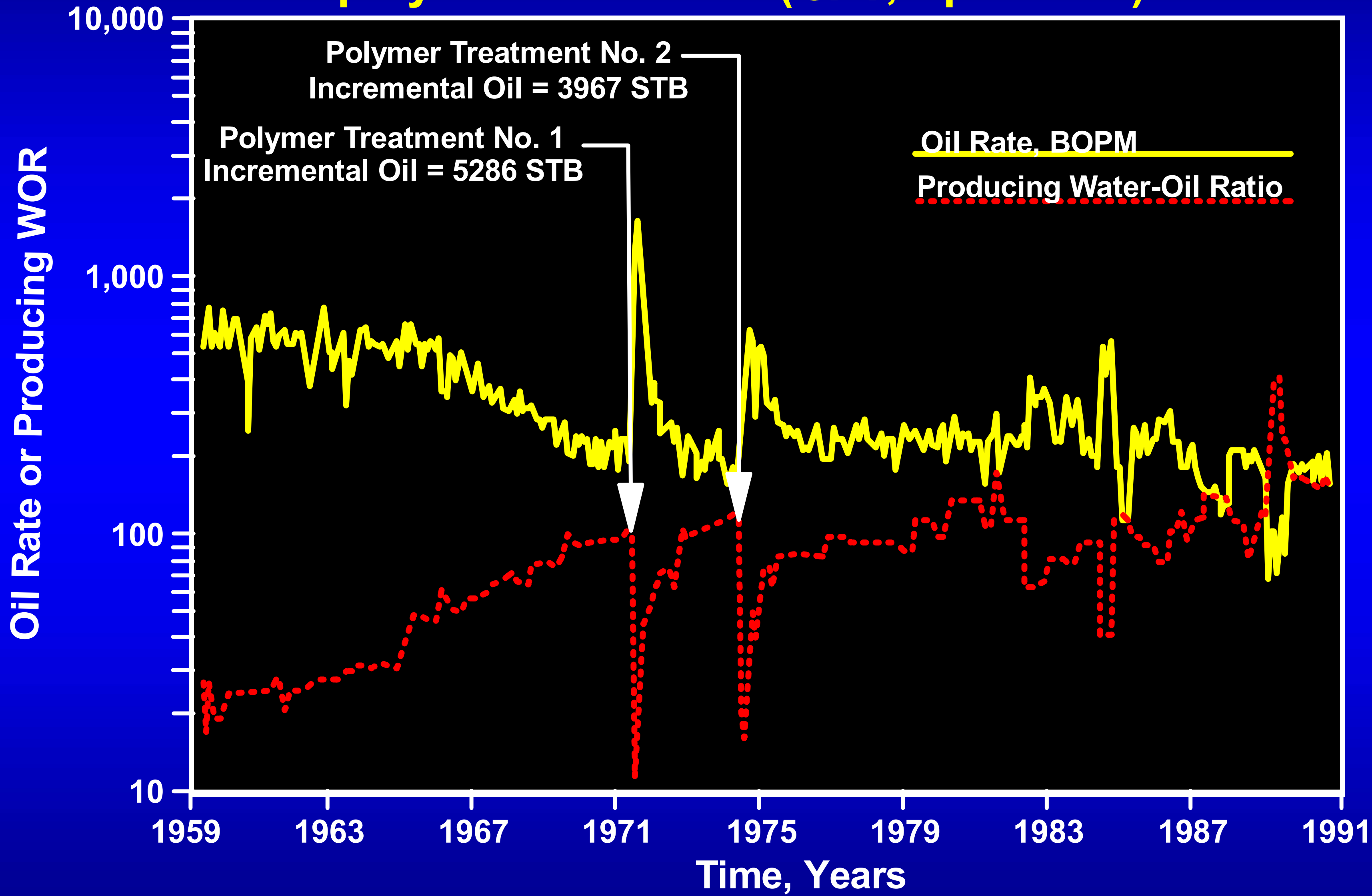
JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments: Problem Diagnosis

- Reservoirs were well known to be naturally fractured.
- Pretreatment productivities, q/dp, were 10-100 times greater than values expected for unfractured wells.

JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments:
Choice of Treatment, Sizing, and Placement

- Performed in the 1970's -- early in the development of the technology.
- Applied 37 treatments with 8 different polymer-crosslinker combinations.
- Average treatment size: 1070 lbs polymer. (Range: 390 to 1400 lbs).
- Treatments sizes subjective.
- Bullhead injection.

Phillips' well Hendrick #2 production response to polymer treatments (*JPT*, April 1993)



JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments:
Treatment Results

- Average incremental recovery: 1.9 STB/lb polymer. (Range: -1 to 13 STB/lb).
- Average treatment lifetime: 12 months. (Range: 2 to 43 months).
- Gel treatments typically reduced total fluid productivity by a factor of two, so the fractures were restricted but still open.
- Uncrosslinked polymers worked as well as gels.
- Many other materials have been used in the Arbuckle formation. Some say that anything will work.

JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments:
Treatment Results

- IOR, treatment lifetime, and WOR reduction did not correlate well with:
  - lbs. polymer injected (390 - 1,400 lbs/well),
  - type of polymer or gel treatment (8 types used),
  - productivity reduction induced by the treatment (1 - 5),
  - structural position of the completion,
  - completion type,
  - fluid level before the treatment,
  - Arbuckle reservoir.

JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments:
Questions

- Why did IOR not correlate with important variables?
- Why did treatments using uncrosslinked HPAM perform as well as any other type of polymer or gel?
  - Uncrosslinked HPAM has some unknown special property. NO
  - Uncrosslinked HPAM happened to be applied in the best wells. MAYBE
  - pH or other changes induced by the rock inhibited gelation. YES!
- What is the mechanism of action for water shutoff treatments in naturally fractured productions wells?
  - Partial plugging of fractures?
  - Selective plugging of porous rock next to fractures?
  - Other?

Gel Treatments Applied to the Kansas Arbuckle Formation Per SPE Paper 89464

- Over 250 gel treatments had been applied in the Kansas Arbuckle fractured carbonate formation (2000-2003)
- Incremental oil production was the driver for conducting these gel treatments
  - Often reduced water production by a factor exceeding 10 (not mentioned in this paper)

- 7 gel treatments were studied where BHP & buildup pressure data were obtained
  - Water-production rates decreased in every well (53–90%)
  - Incremental oil production obtained from 5 out of 6 wells that were produced for 6 mo.
  - Oil PI increased following the gel jobs
  - Incremental oil production increased with increasing volume of gel injected (for the open hole completions)
  - “The duration of the response should be a function of the volume of gelant injected…”

- Aggressive pre-gel-job acid treatments were preformed
- Initial oil production appears to increase, with decreasing gel-injection treating pressures
- Water shut off may increase somewhat, and last longer, with increasing gel-injection treating pressures

Economics of Arbuckle Gel Treatments

(Source: PTTC website, R. Reynolds, 10/03)

- ~300 treatments
  - By over 30 operators
  - Analyzed the performance of 37 treated wells
  - Shutoff 110,000,000 bbl water
  - Gross IOP = 1,600,000 bbl oil
- "All of the wells have responded with significant reduction in water production…." (2/03 Reynolds quote)

FIELD OPERATIONAL ISSUES

Robert Lane, SPE 37243

1. Sampling and quality assurance.
2. Polymer handling.
3. Rigup issues.
4. Treatment execution issues.
5. Chemical incompatibilities.
6. Post-treat well operations.

SAMPLING AND QUALITY ASSURANCE

1. Laboratory samples and testing conditions must be representative of field materials and conditions. (Vendors sometimes provide samples to labs that are different from field products.)
2. Water used in lab tests must be representative of field water. (Field & lab people MUST communicate any important changes, like water source changes.)
3. Lab tests in the field MUST verify the behavior of delivered products (e.g., polymer ability to dissolve, polymer solution viscosity, gel times).
4. Pumps, mixers, and filters must not shear degrade the polymer.
5. Field samples for testing should be drawn near the wellhead.

POLYMER HANDLING

Solid grade polymer (>90% active):

- Minimizes shipping costs.
- Requires specialized mixing equipment.
- Residue or incomplete hydration creates fisheyes.

Solution concentrate (~20% active):

- Easily pumped and diluted
- Less complex mixing equipment.
- Can be prepared “on the fly”, minimizing waste.
- Has significantly higher shipping costs.

Liquid, slurry, or emulsion polymers (30-50% active):

- Easily pumped and diluted (if lines are clean & dry).
- Less complex mixing equipment; injection on the fly.
- Intermediate shipping costs.
- Special care required for clean dry lines, tanks, etc.

FILTRATION

Views vary on what and where filters should be used.

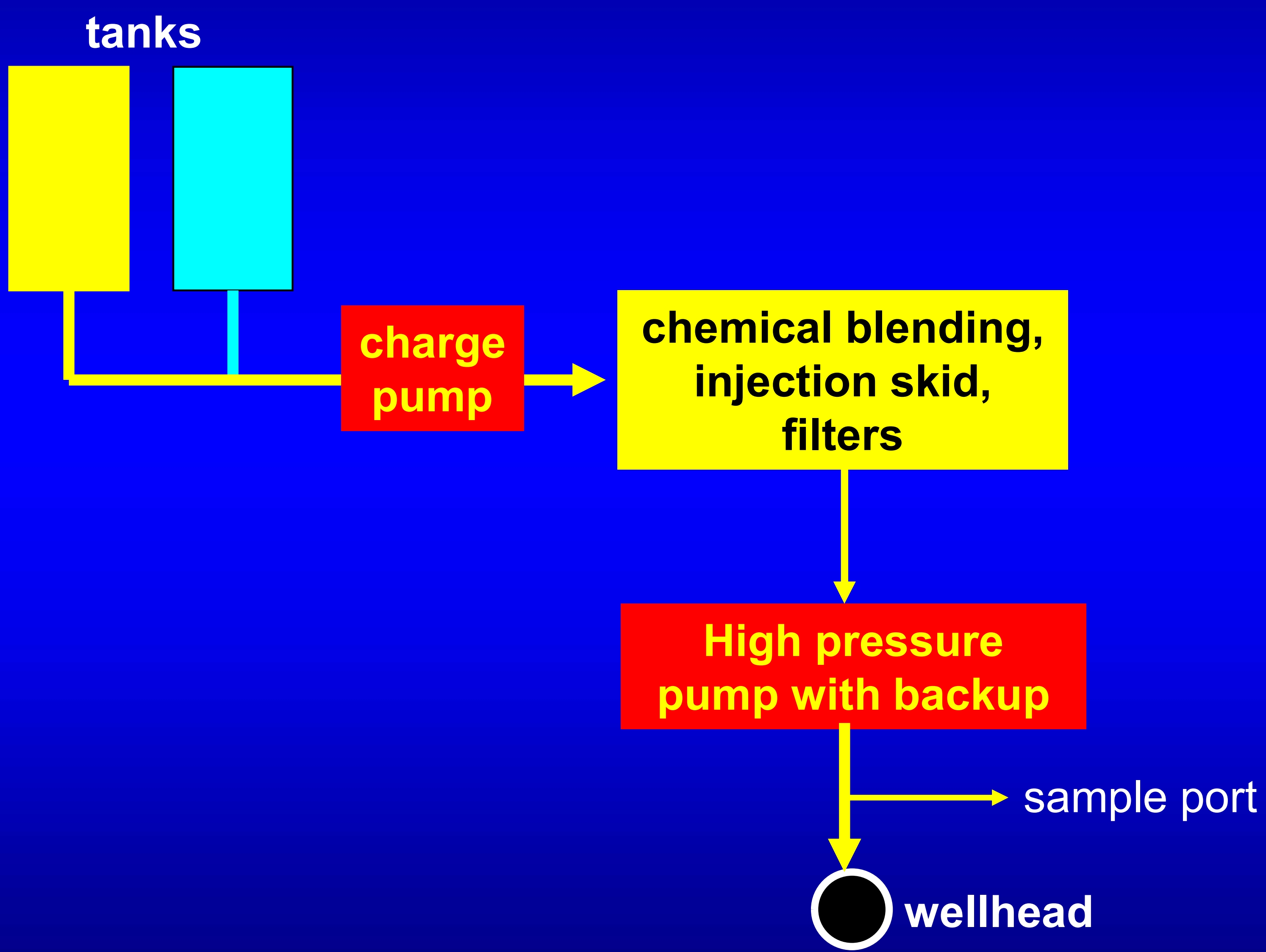
Advisable to have two filters (10 µm) in parallel downstream of the mixing equipment.

- Avoids well plugging.
- Gives a quality check on polymer preparation.

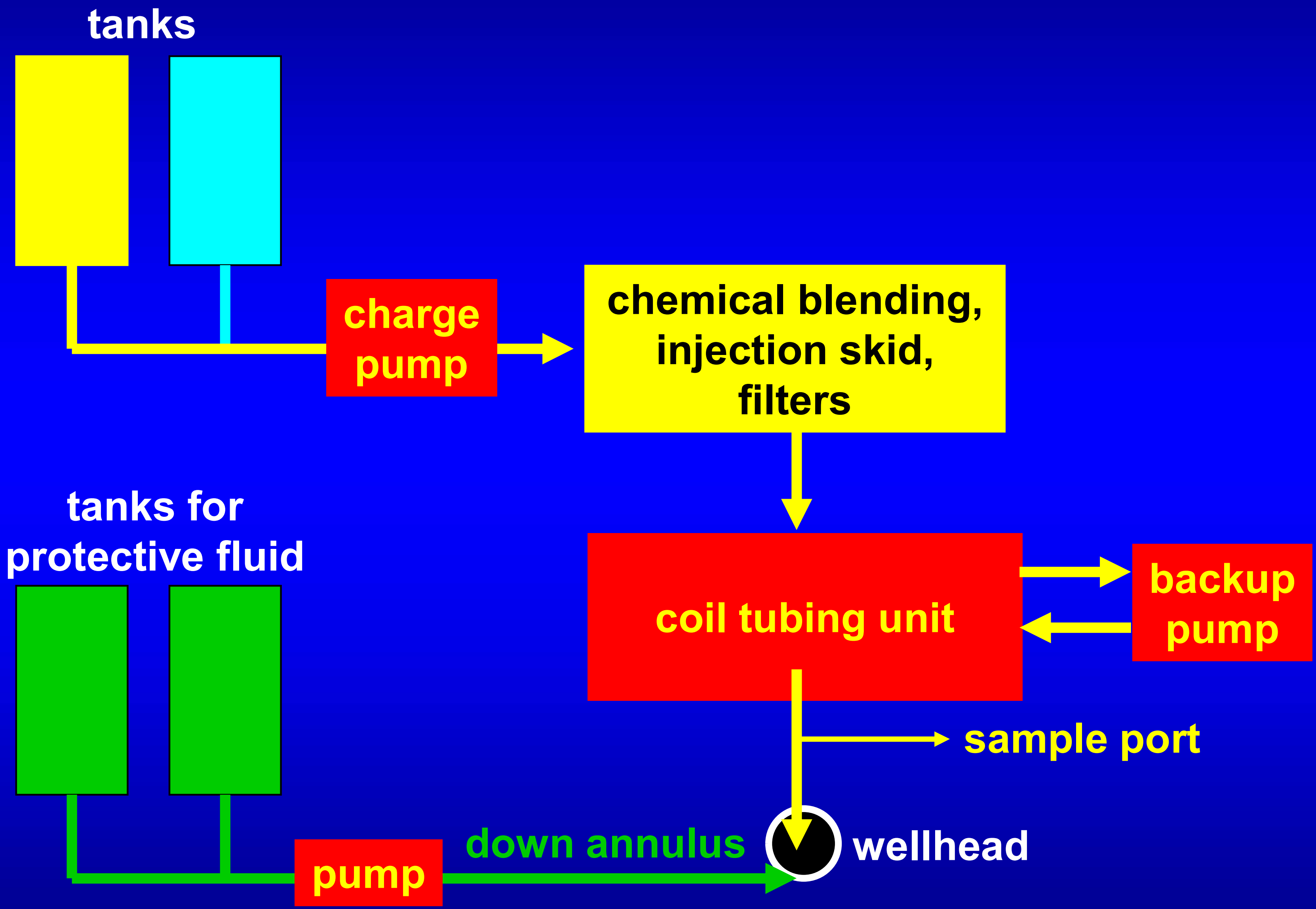
RIG UP ISSUES

1. Many equipment configurations are possible.
2. Other things being equal, simpler is better.
3. All transport trucks, tanks, hoses, pumps, lines and mixing equipment MUST be clean and inspected by someone who has a major stake in project success.
4. "Clean" means carefully flushed with water compatible with gelant.
   - Residual water must be clear with neutral pH.
   - No oily or solid residues.
   - With slurry polymer, lines, tanks, etc. must be DRY.
5. Temperature extremes should be avoided, especially for connecting hoses.

SIMPLE RIG UP EXAMPLE



COMPLEX RIG UP EXAMPLE



RIG UP ISSUES—TANKS, PUMPS & HOSES

1. Many tank options exist (frac tanks, transport trucks, etc). Tanks should be sized so refilling and switching occurs at reasonable times (hours not minutes).
2. Low-pressure hoses, tanks, charge pumps, blenders, and filters used before the final high pressure pump.
3. Pumps, mixers, and filters must be selected to minimize mechanical degradation of the polymer.
4. Locate filtration equipment at blender discharge.
5. Although "on the fly" mixing is conceptually attractive, polymer mixing is often inadequate.
6. High pressure injection pump is the final equipment before the wellhead.
7. Sample port must be close to the wellhead.

TREATMENT EXECUTION ISSUES

1. Gelation time usually determines the pump time (except for some large treatments in fractures).
   - Downtime during pumping must be avoided.
   - Good polymer/gel quality control is needed.
   - Equipment redundancy can reduce downtime.
2. Surface equipment may limit the surface pressure. It's best to have a pump with a high rate limit.
3. Parting pressure often limits downhole pressure.
4. Pressure drop from surface to formation is usually negligible unless coiled tubing is used.
5. Hall plots help monitor pressure trends. (They do NOT indicate where the gel is placed.)

CHEMICAL INCOMPATIBILITIES

- Cationic corrosion inhibitors precipitate with anionic polymers (e.g., HPAM).
- Scale inhibitors can destroy gels made with metal crosslinkers [e.g., Cr(III)].

- Don't apply these chemicals too soon before or after a gel treatment.
- Check lines, equipment and make-up water for these contaminants.
- Lab tests may help to establish compatibility.

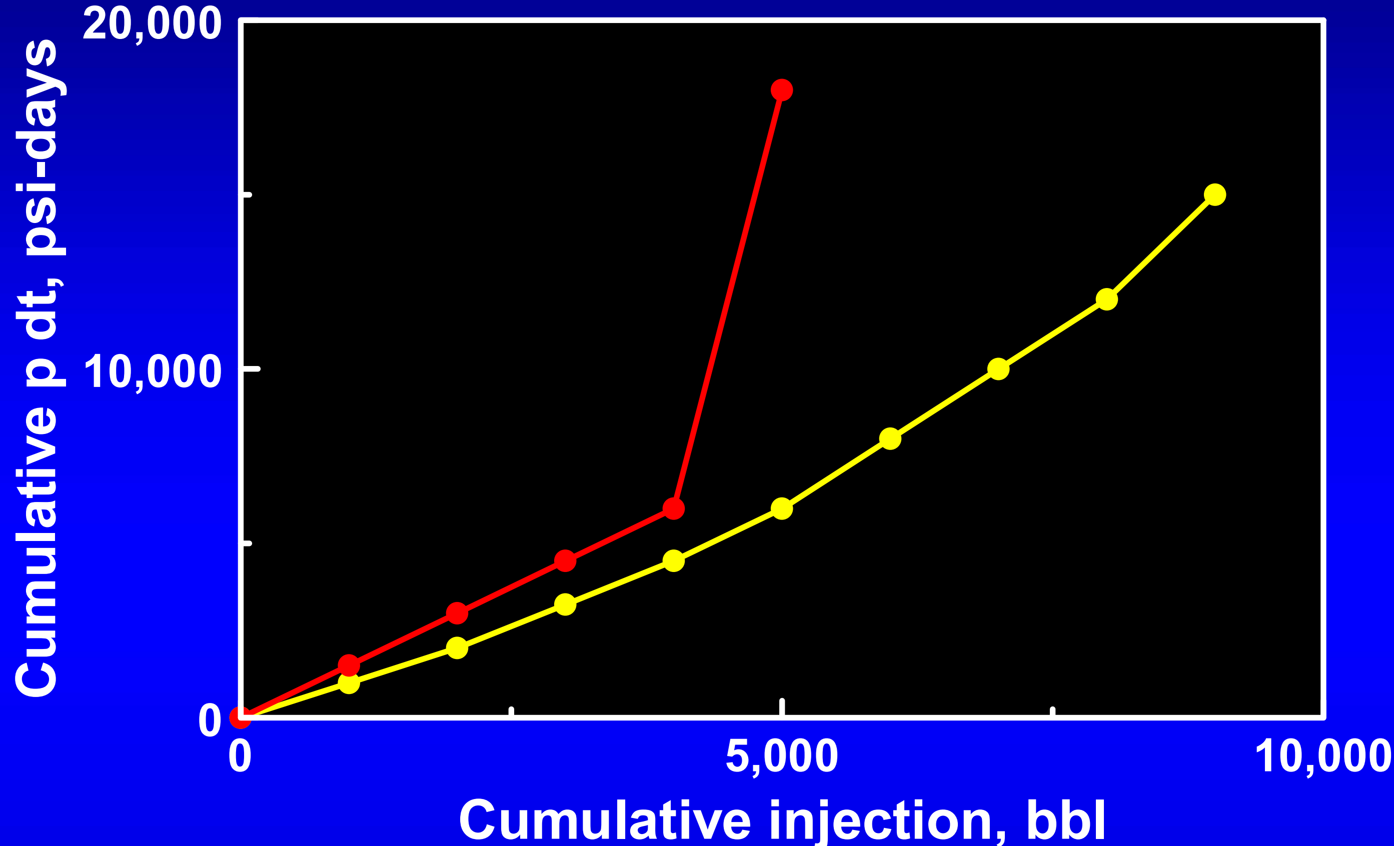
- Rust, crude components, emulsion breakers, defoamers, water clarifiers, floatation aids, oxygen scavengers, H_2S, and chlorine may affect gel chemistry.

HALL PLOTS

- provide a useful indication of the rate of pressure increase,
- indicate when gelant injection must be stopped because of pressure limitations,
- do not indicate the selectivity of gel placement,
- do not indicate whether a treatment was sized properly.

Reference: DOE/BC/14880-5, pp. 73-80.

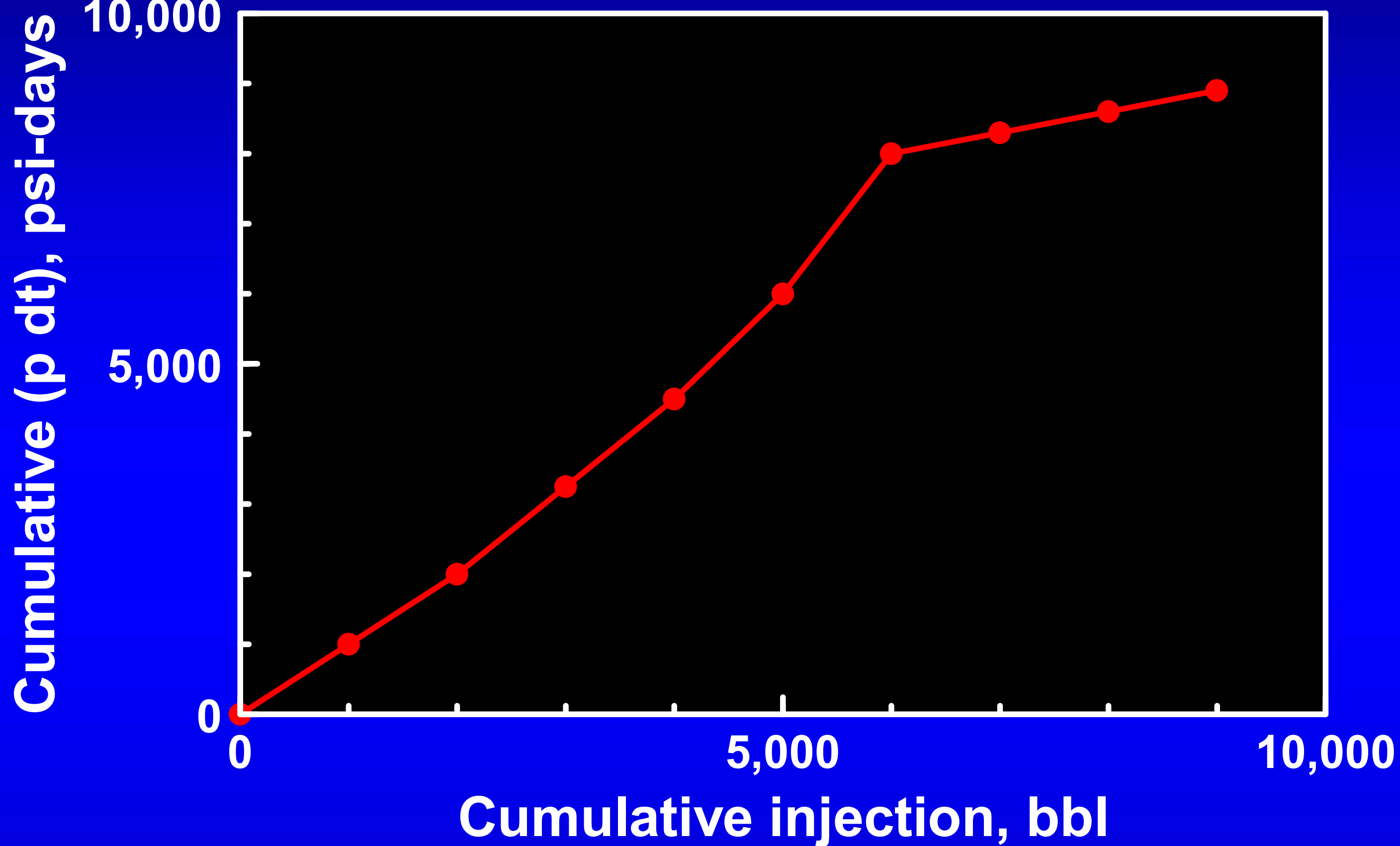
HALL PLOTS FOR WELLS WITH RADIAL FLOW



An increasing slope could result from:

- plugging the high-k zones more than the low-k zones,
- plugging the low-k zones more than the high-k zones, or
- plugging all zones to the same extent (most likely possibility).

HALL PLOTS FOR FRACTURED WELLS



A decreasing slope could result from:

- opening or fracturing into previously unswept zones,
- re-opening a fracture that the gel had recently sealed,
- opening a fracture that cuts through all zones.

POST-TREATMENT WELL OPERATIONS

- Shut-in times depend on the gel and the nature of the problem treated.
- After shut-in, bring the well back into full service gently (over the course of days or weeks rather then hours).
- Post-treatment procedures should consider whether the gel treatment will be compromised (corrosion inhibitors, injecting above parting pressure, acid jobs, etc.).

REVIEW OF THE MOST IMPORTANT CONCEPTS

- The cause of the water production problem must be identified.
- Different design, sizing, and placement procedures must be used for different types of problems.
- For radial flow, hydrocarbon-productive zones must be protected during placement of chemical blocking agents.

GEL TREATMENTS ARE NOT POLYMER FLOODS

Crosslinked polymers, gels, gel particles, and "colloidal dispersion gels":

- **Are not simply viscous polymer solutions.**
- **Do not flow through porous rock like polymer solutions.**
- **Do not enter and plug high-k strata first and progressively less-permeable strata later.**
- **Should not be modeled as polymer floods.**

A STRATEGY FOR ATTACKING EXCESS WATER PRODUCTION

1. Consider and eliminate the easiest problems first.
2. Start by using information that you already have.

Excess Water Production Problems and Treatment Categories

(Categories are listed in increasing order of treatment difficulty)

Category A: “Conventional” Treatments Normally Are an Effective Choice

1. Casing leaks without flow restrictions.
2. Flow behind pipe without flow restrictions.
3. Unfractured wells (injectors or producers) with effective crossflow barriers.

Category B: Treatments with Gelants Normally Are an Effective Choice

4. Casing leaks with flow restrictions.
5. Flow behind pipe with flow restrictions.
6. “Two-dimensional coning” through a hydraulic fracture from an aquifer.
7. Natural fracture system leading to an aquifer.

Category C: Treatments with Preformed Gels Are an Effective Choice

8. Faults or fractures crossing a deviated or horizontal well.
9. Single fracture causing channeling between wells.
10. Natural fracture system allowing channeling between wells.

Category D: Difficult Problems Where Gel Treatments Should Not Be Used

11. Three-dimensional coning.
12. Cusping.
13. Channeling through strata (no fractures), with crossflow.

KEY QUESTIONS IN OUR APPROACH

1. Does a problem really exist?
2. Does the problem occur right at the wellbore (like casing leaks or flow behind pipe) or does it occur out beyond the wellbore?
3. If the problem occurs out beyond the wellbore, are fractures or fracture-like features the main cause of the problem?
4. If the problem occurs out beyond the wellbore and fractures are not the cause of the problem, can crossflow occur between the dominant water zones and the dominant hydrocarbon zones?

Respect basic physical and engineering principles.
Stay away from black magic.