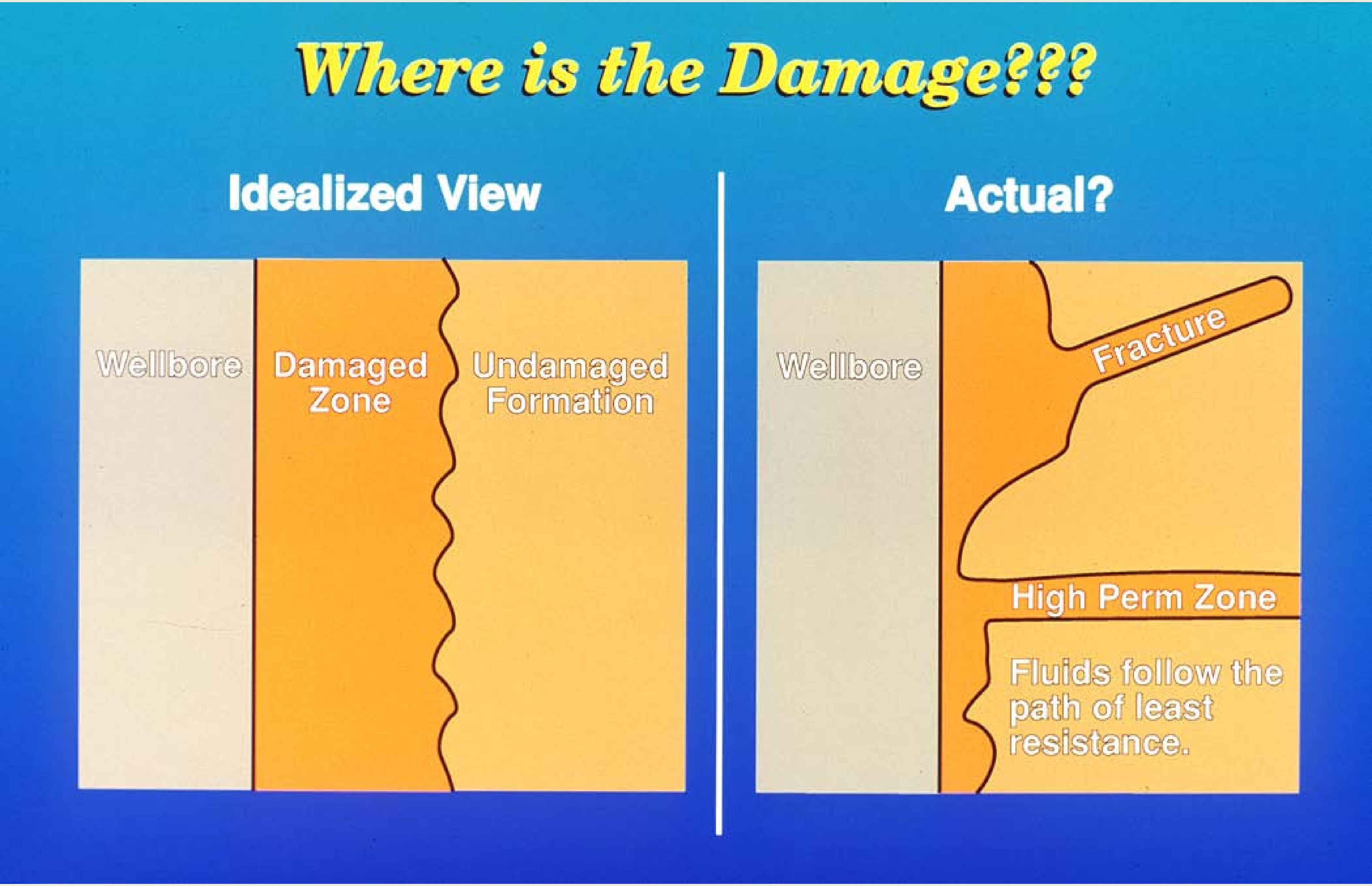
Formation Damage – Effects and Overview

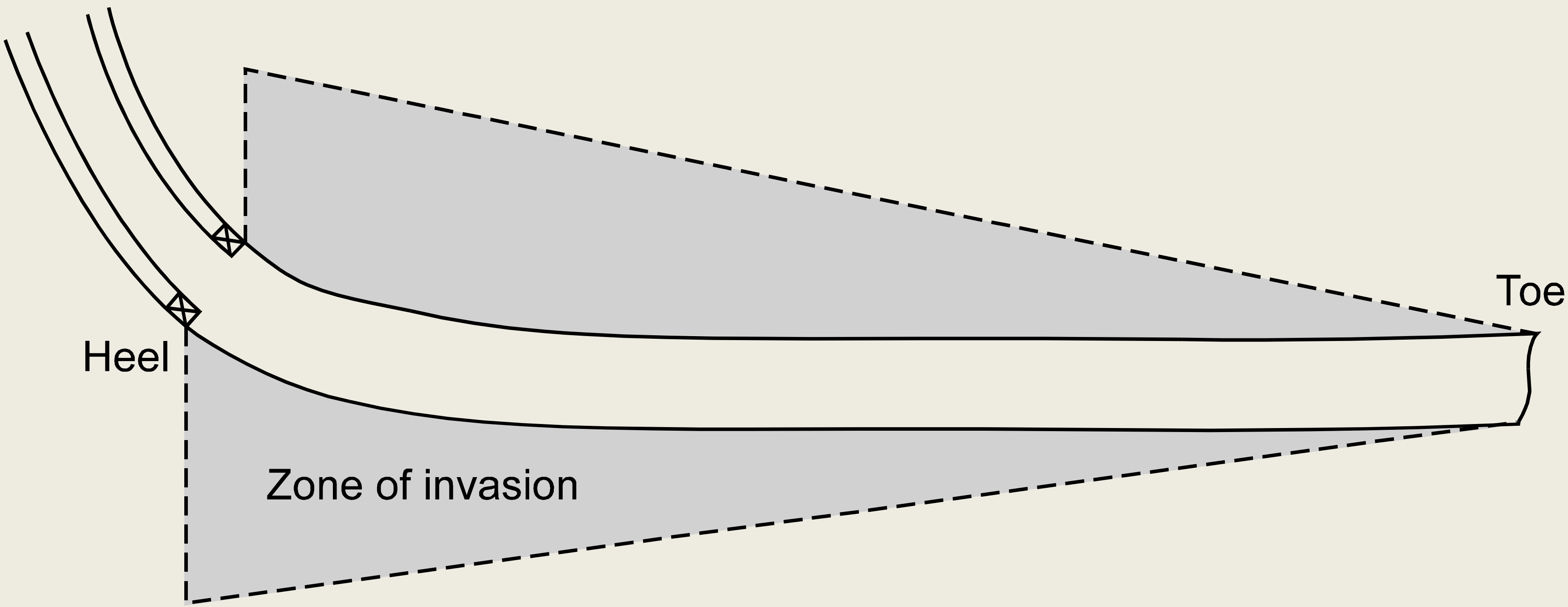
- Where is the damage?
- How does it affect production?

Impact of Damage on Production

- Look at Effect of Damage
- Type of Damage
- Severity of Plugging
- Depth of Damage
- Ability to Prevent/Remove/By-Pass

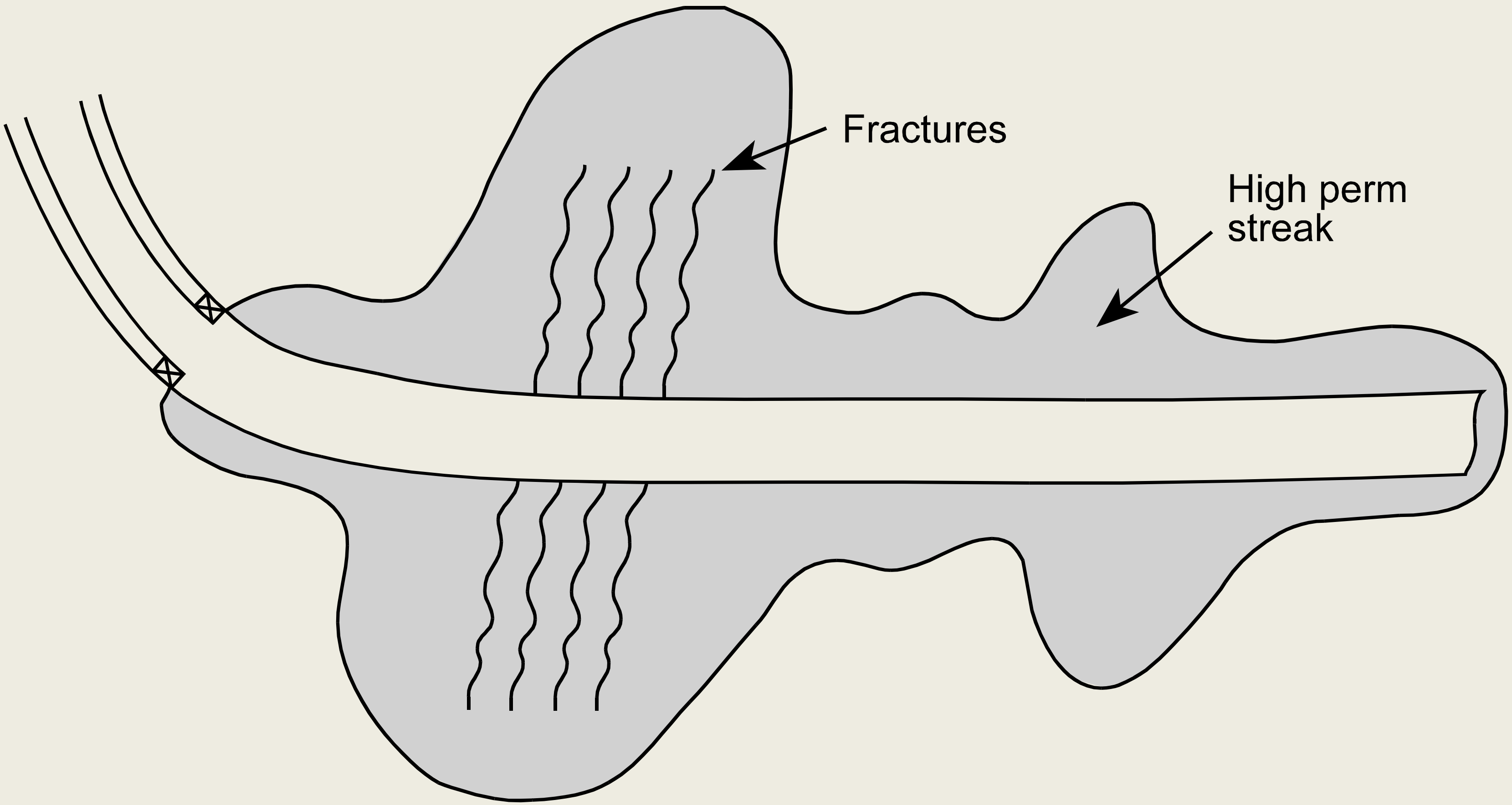

Where is the Damage???
Idealized View
Actual?
Wellbore
Damaged Zone
Undamaged Formation
Wellbore
Fracture
High Perm Zone
Fluids follow the path of least resistance.

Horizontal Well Formation Damage Theories
Zone of Invasion - Homogeneous Case



Is damage evenly spread out along the well path or does it go down the highest permeability streaks?

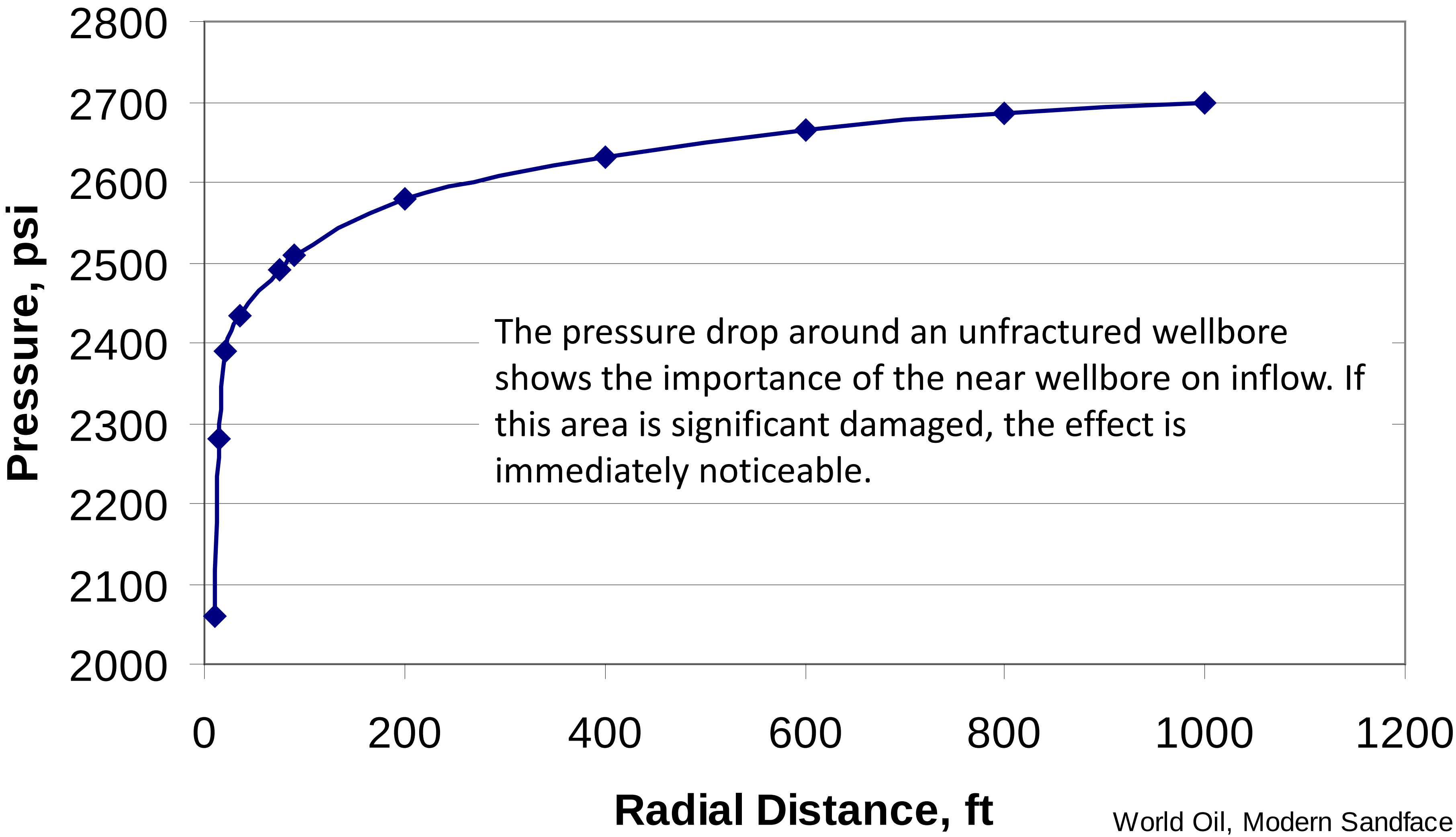
Horizontal Well Formation Damage Theories
Zone of Invasion - Heterogeneous Case



Observations on Damage

1. Shallow damage is the most common and makes the biggest impact on production.
2. It may take significant damage to create large drops in production
3. The problem, however, is that the highest permeability zones are the easiest to damage, and that can have a major impact on productivity.

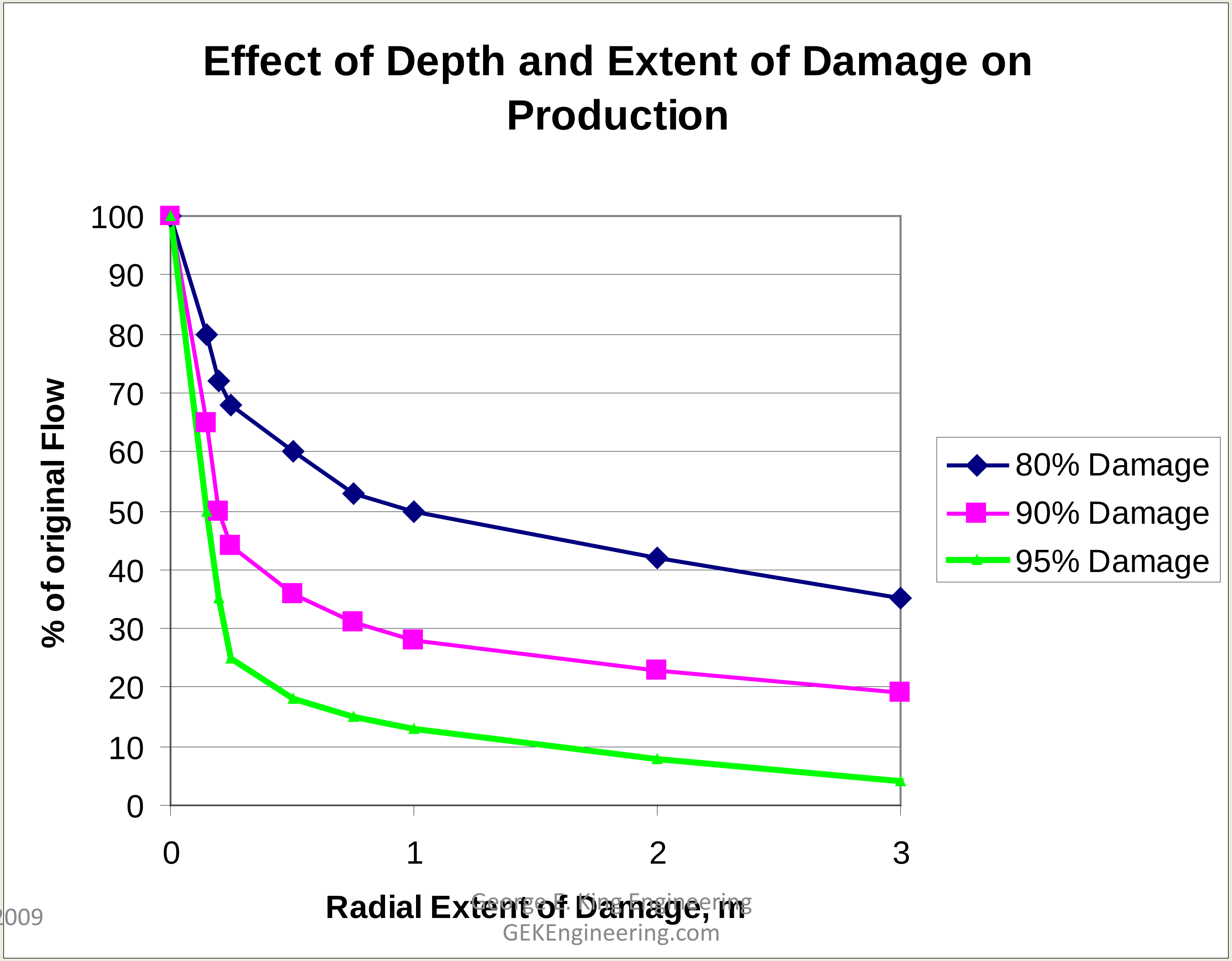
Pressure Distribution Around a 200 md Oil Well



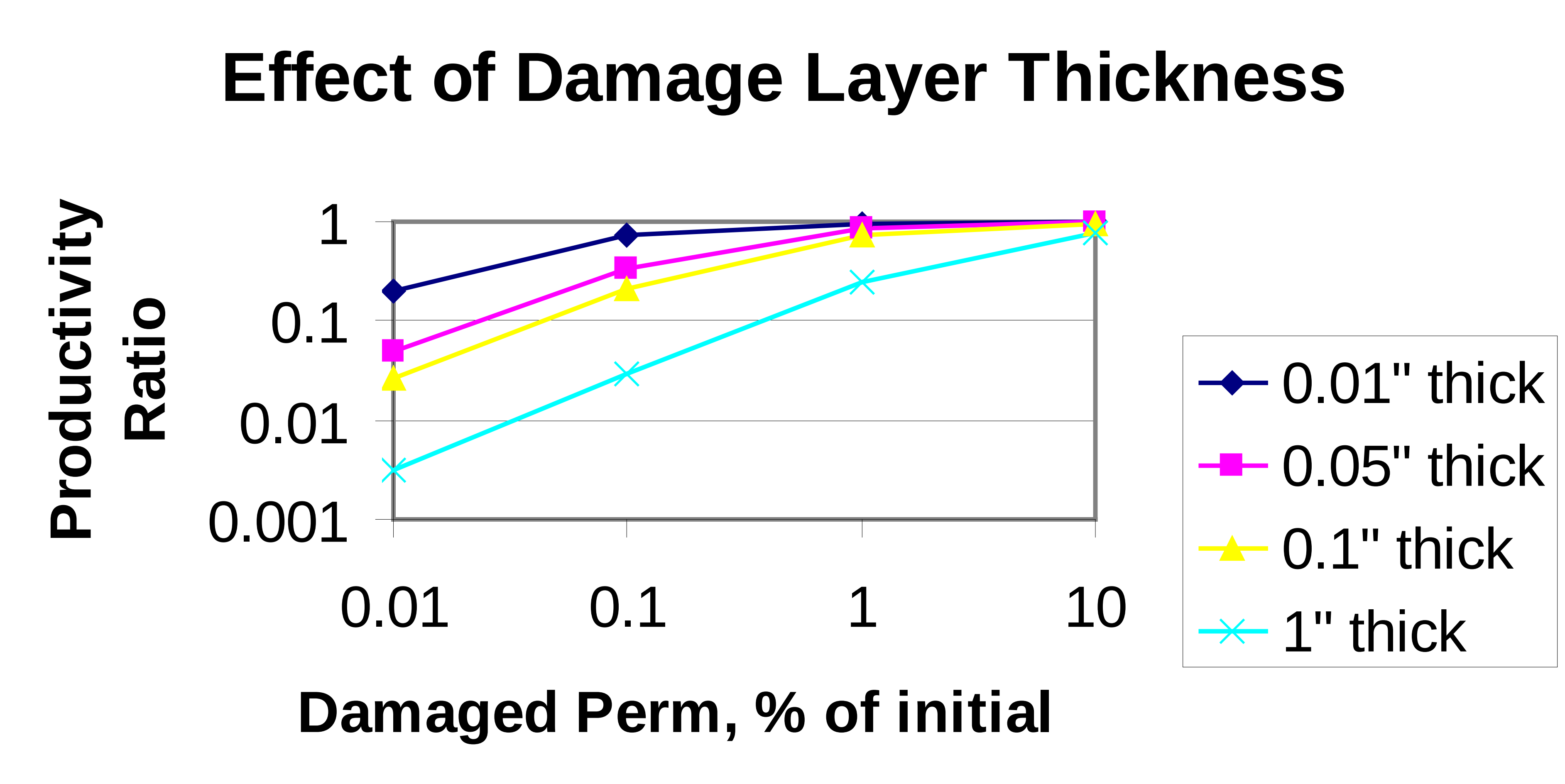
The pressure drop around an unfractured wellbore shows the importance of the near wellbore on inflow. If this area is significant damaged, the effect is immediately noticeable.

World Oil, Modern Sandface Completion Practices, 2003

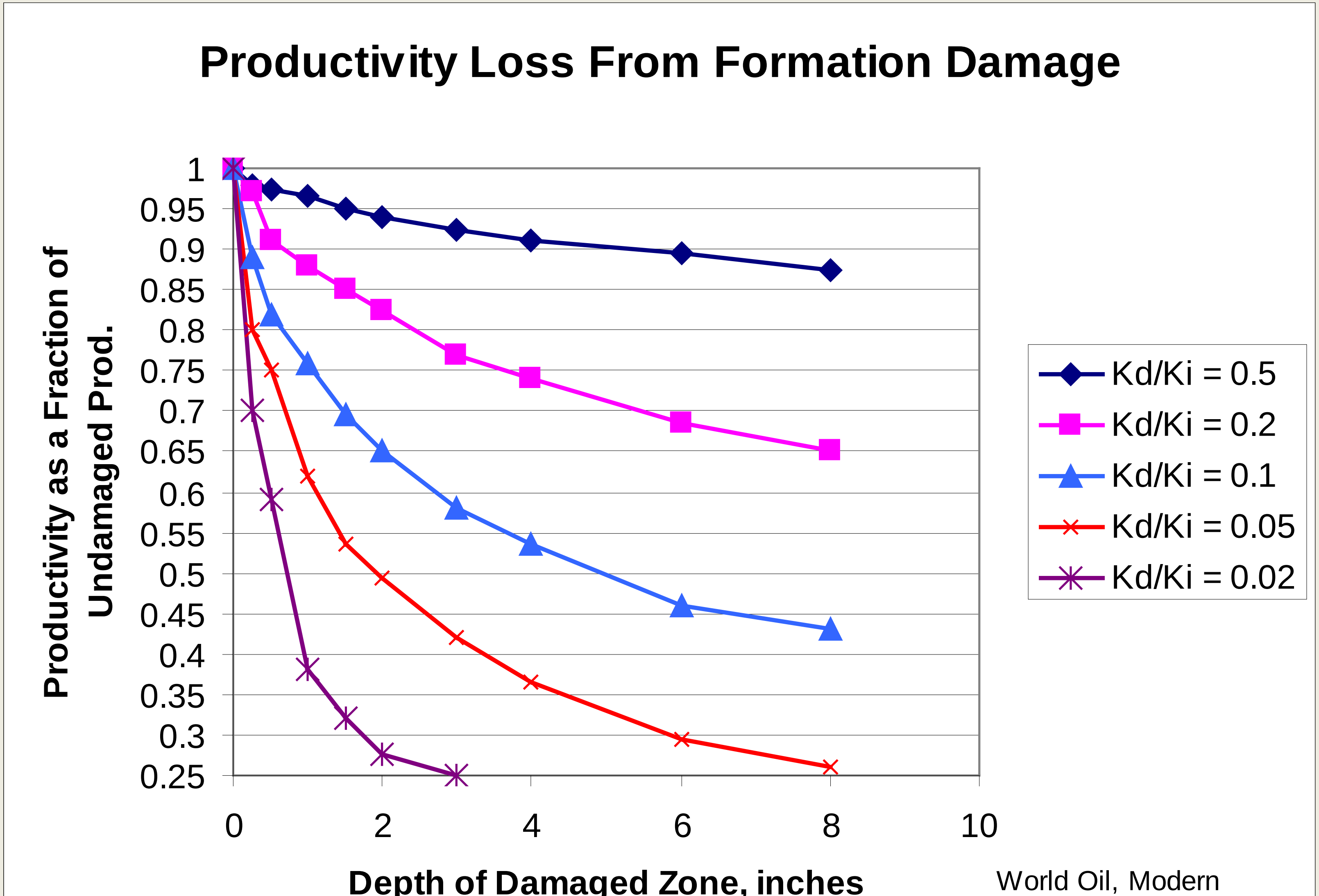
1. The most noticeable damage impacts the the well in the first 30 cm or 12 inches of the formation.



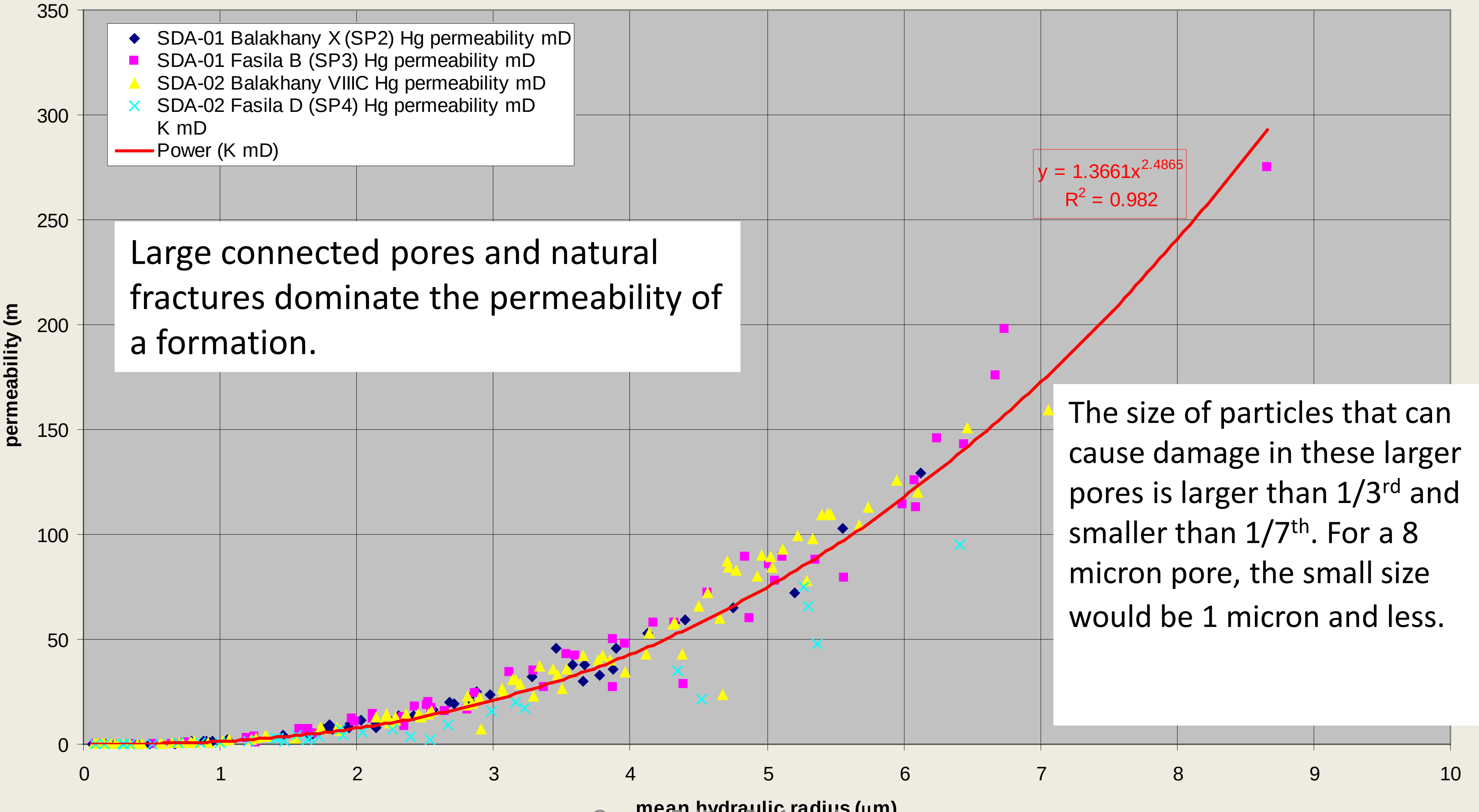
2. The effect of the damage thickness compared with the amount of damage (as a percent of initial permeability). Only the most severe damage has a significant effect in a thin layer. (Darcy law beds-in-series calculation)



2. (continued) As the damage layer thickens and becomes more severe, the impact on production builds quickly.



3. Highest permeability zones are easiest to damage: Pore Size vs. Permeability



Large connected pores and natural fractures dominate the permeability of a formation.

The size of particles that can cause damage in these larger pores is larger than 1/3rd and smaller than 1/7th. For a 8 micron pore, the small size would be 1 micron and less.

MI for BP SD field

The Effect of Damage on Production

Rate = (ΔP x k x h) / (141.2 μ_o β_o s)

Where:

ΔP = differential pressure (drawdown due to skin)

k = reservoir permeability, md

h = height of zone, ft

μ_o = viscosity, cp

β_o = reservoir vol factor

s = skin factor

What are the variables that can be improved, modified or impacted in a positive way?

Productivity and Skin Factor

- $Q_1/Q_o = 7/(7+s)$

Just an estimation, but not too far off between skin numbers of zero and about 15.

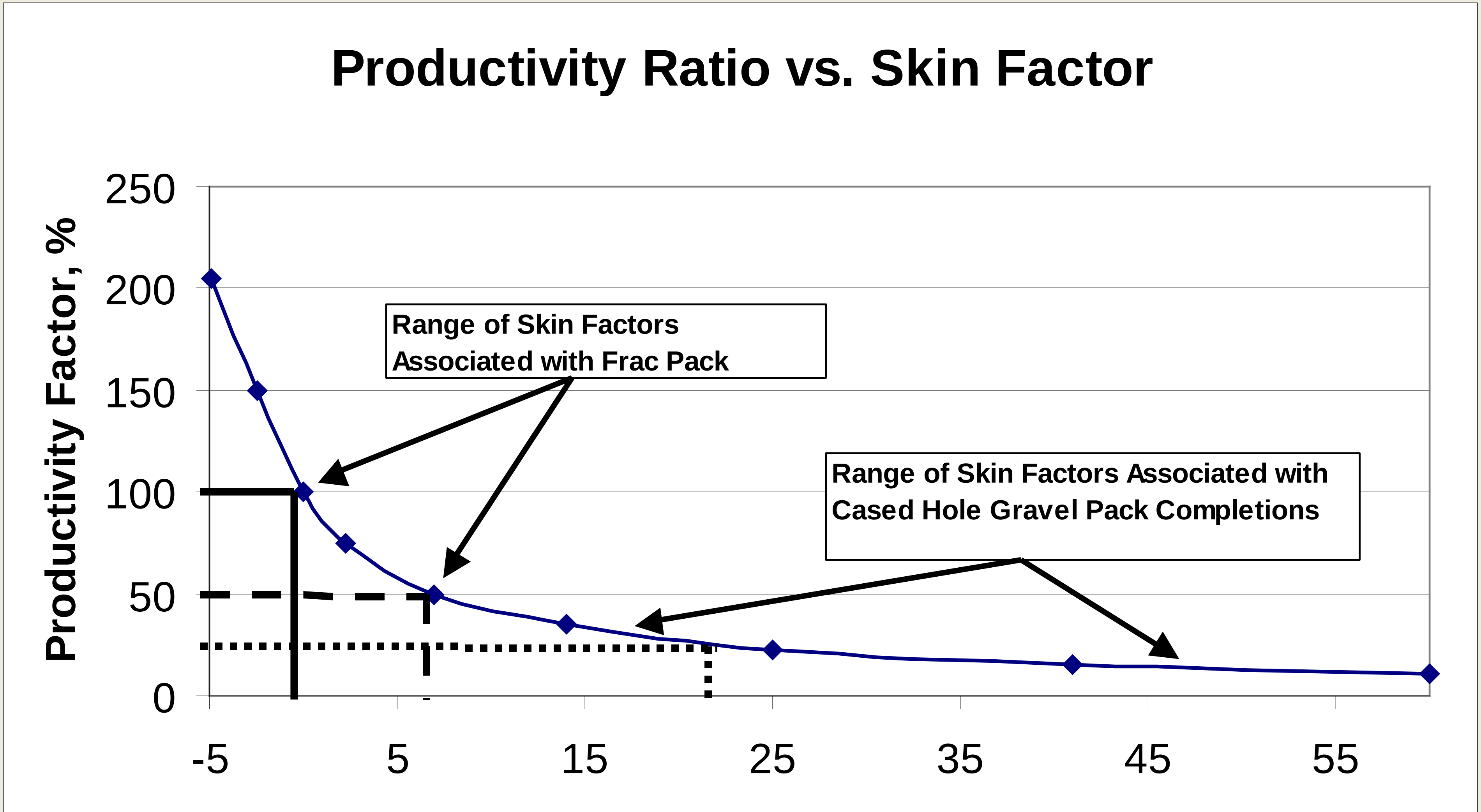
Where:

Q_1 = productivity of zone w/ skin, bpd

Q_o = initial productivity of zone, bpd

s = skin factor, dimensionless

A better presentation of the damage from increasing skin factor. Skin only has an impact if the well can really produce the higher rate and the facilities can process it.

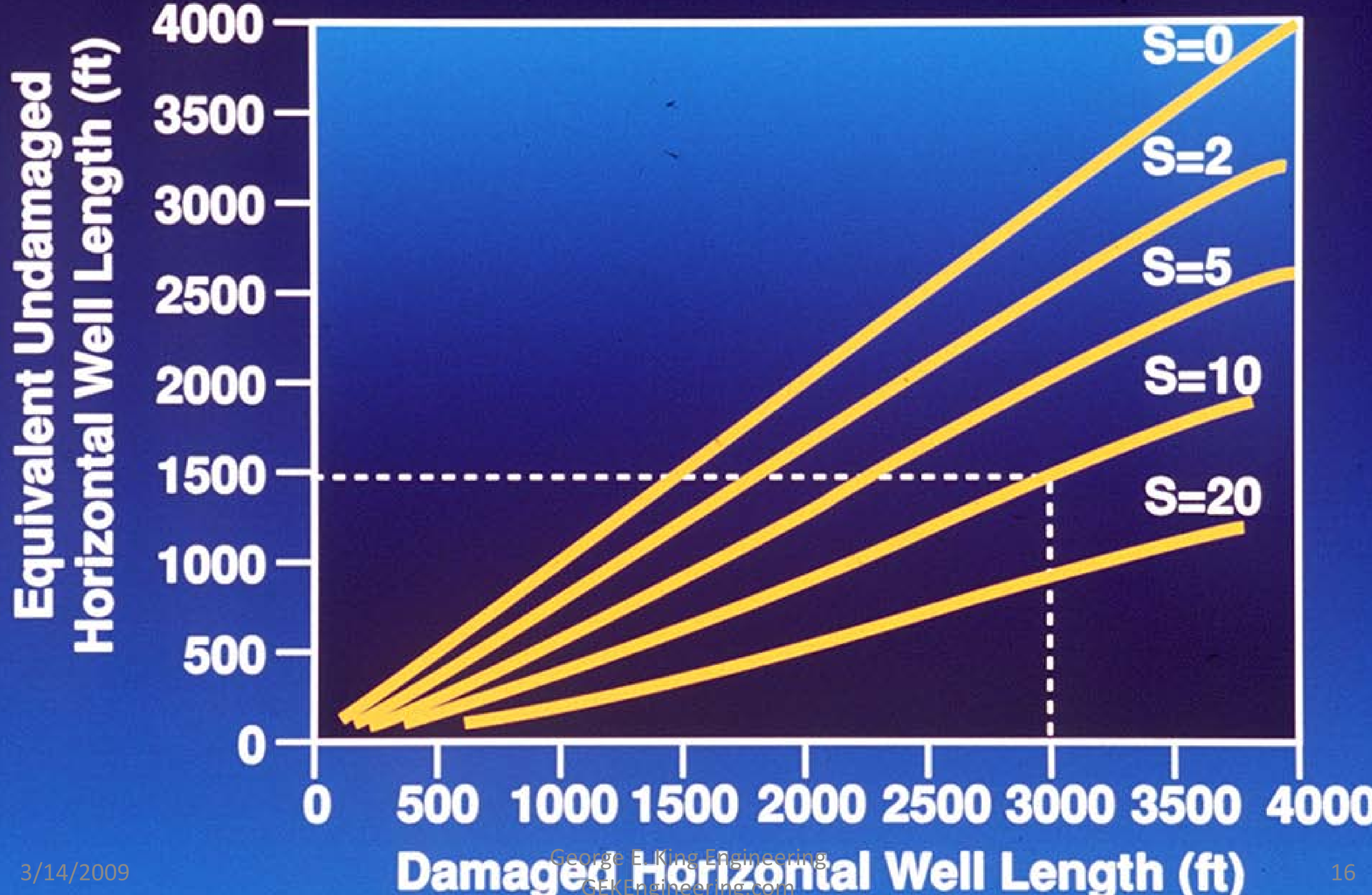


Example

- Productivity for skins of -1, 5, 10 and 50 in a well with a undamaged (s=0) production capacity of 1000 bpd
- $s = -1$, $Q_1 = 1166$ bpd
- $s = 5$, $Q_1 = 583$ bpd
- $s = 10$, $Q1 = 412$ bpd

- The best stimulation results are usually for damage removal and damage by-pass.

Another way of stating damage - Damage in a horizontal well – increasing skin makes the well behave like the drilled lateral was much shorter.



Damage Causes

- Obstructions in the natural flow path in the reservoir.
- “Pseudo” damage such as turbulence - very real effect, but no visible obstructions
- “Structural” damage from depletion – matrix compression, etc.

Flow Path Obstructions

- Scale, paraffin, asphaltenes, salt, etc.,
- Perforations – 12 spf w/ 0.75” / 1.9 cm holes only opens 2% of the casing wall.
- Tubing too small - too much friction
- Any fluid column in the well, even a flowing fluid column holds a backpressure on the well:
  - Salt water = 0.46 psi/ft
  - Dead oil = 0.36 psi/ft
  - Gas lifted oil = 0.26 psi/ft
  - Gas = 0.1 psi/ft (highly variable with pressure)

"Pseudo" Damage

- Turbulence
  - high rate wells
  - gas zones most affected
- Affected areas:
  - perfs (too few, too small)
  - Near wellbore (tortuosity)
  - fracture (conductivity too low)
  - tubing (tubing too small, too rough)
  - surface (debottle necking needed)

"Structural" Damage

- Tubular Deposits
  - scale
  - paraffin
  - asphaltenes
  - salt
  - solids (fill)
  - corrosion products

Perforation Damage

- debris from perforating
- sand in perf tunnel - mixing?
- mud particles
- particles in injected fluids
- pressure drop induced deposits
  - scales
  - asphaltenes
  - paraffins

Near Well Damage

- in-depth plugging by injected particles
- migrating fines
- water swellable clays
- water blocks, water sat. re-establishment
- polymer damage
- wetting by surfactants
- relative permeability problems
- matrix structure collapse

Deeper Damage

- water blocks
- formation matrix structure collapse
- natural fracture closing

Other Common Damages

- fines migration (increasing skin)
- water blocks
- scale
- emulsions
- paraffin and asphaltenes
- turbulence – rate dependent skin
- perf debris
- Initial damage from mud and DIF’s

Skin Components and Determination

- Total Skins (s') = $S_{\mathbf{o}} + S_{\mathbf{tp}} + D\,Q$

Where:

So = laminar skin

S_{tp} = 2-phase skin

D = rate dependent skin

Q = rate

Skin Components and Determination

- Multi-rate tests => S_o, S_{tp}, D
- B/U Test => total skin, k
- 2 B/U Tests => S_o, D, k

Cleaning Damage

- Most damage is removed by simple clean-up flow.
- How much drawdown?
- How long to flow it?
- How soon to flow it?
- To do it?

Root Causes of Residual Damage After Clean-up Flow….

- High perm formations less affected?
  - <u>Major damage removers</u>:
    - Flow Rate per unit area,
    - Flow Volume per unit area,
    - Pressure pulse?
- Drawdown per unit area – a control?

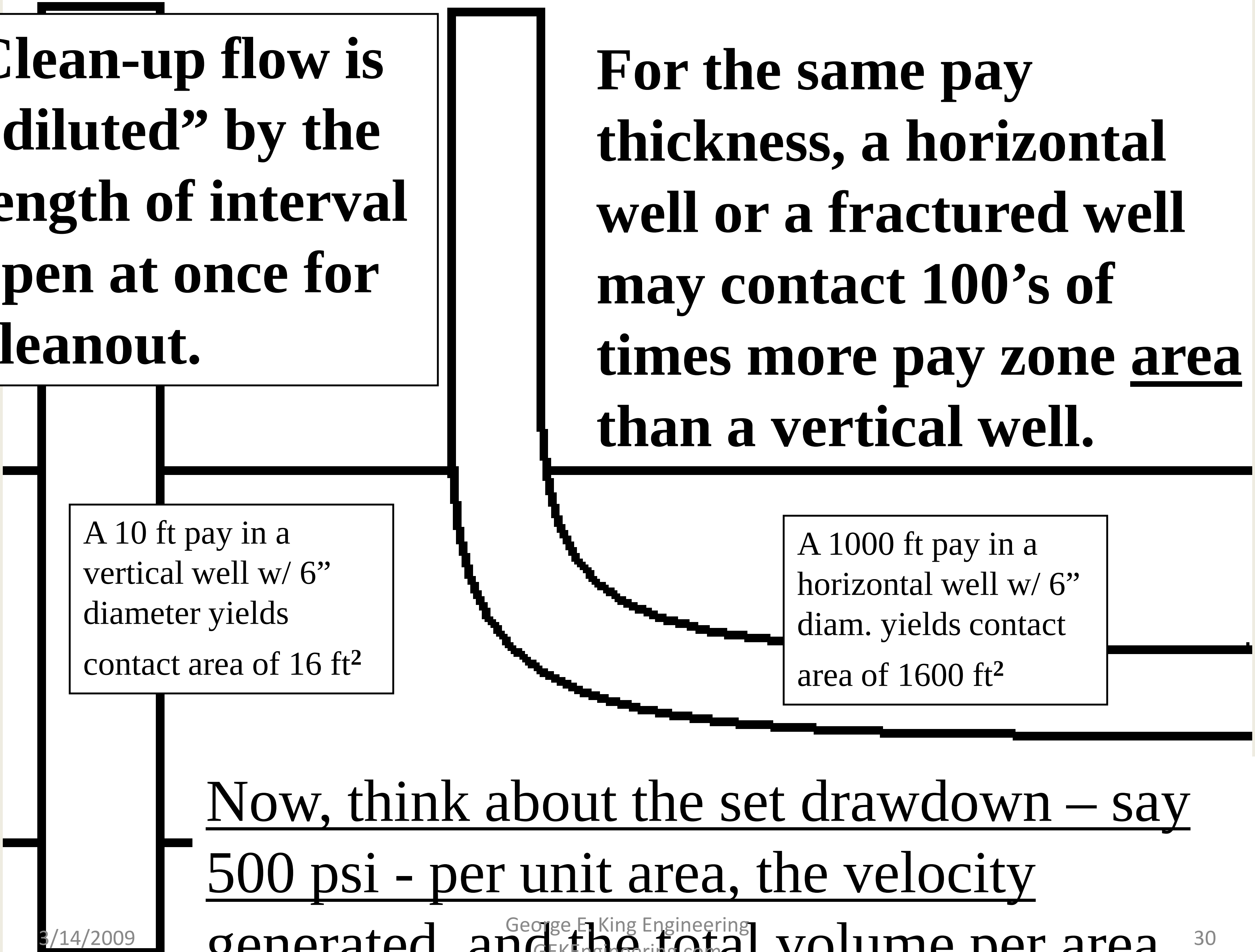
First Problem

We don’t understand cleanup by flow…

It’s a matter of flow rate and volume through a given area.

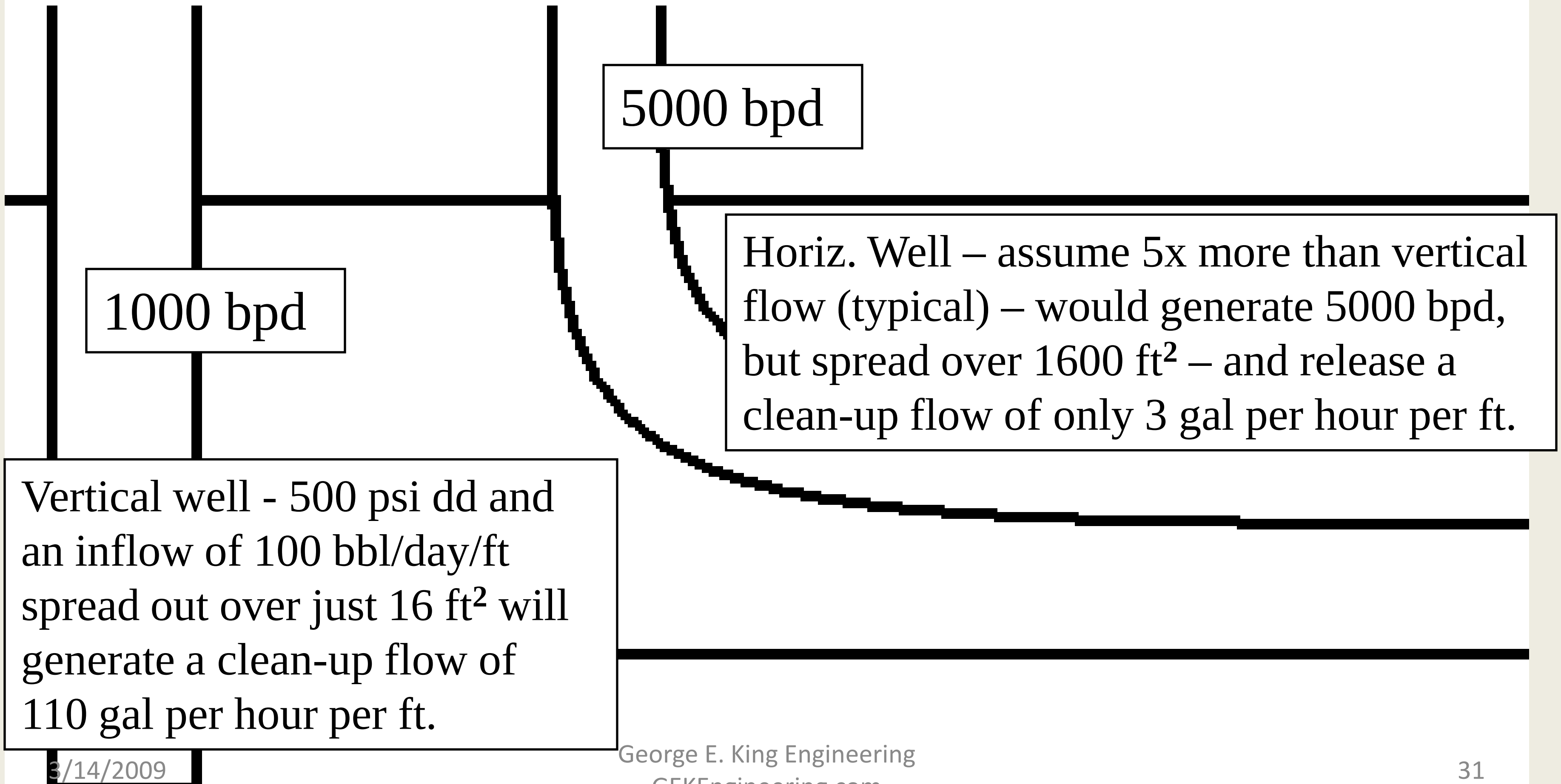
Clean-up flow is "diluted" by the length of interval open at once for cleanout.

For the same pay thickness, a horizontal well or a fractured well may contact 100's of times more pay zone <u>area</u> than a vertical well.



<u>Now, think about the set drawdown – say 500 psi - per unit area, the velocity generated, and the total volume per area.</u>

Which has the potential of cleaning up faster and more completely?

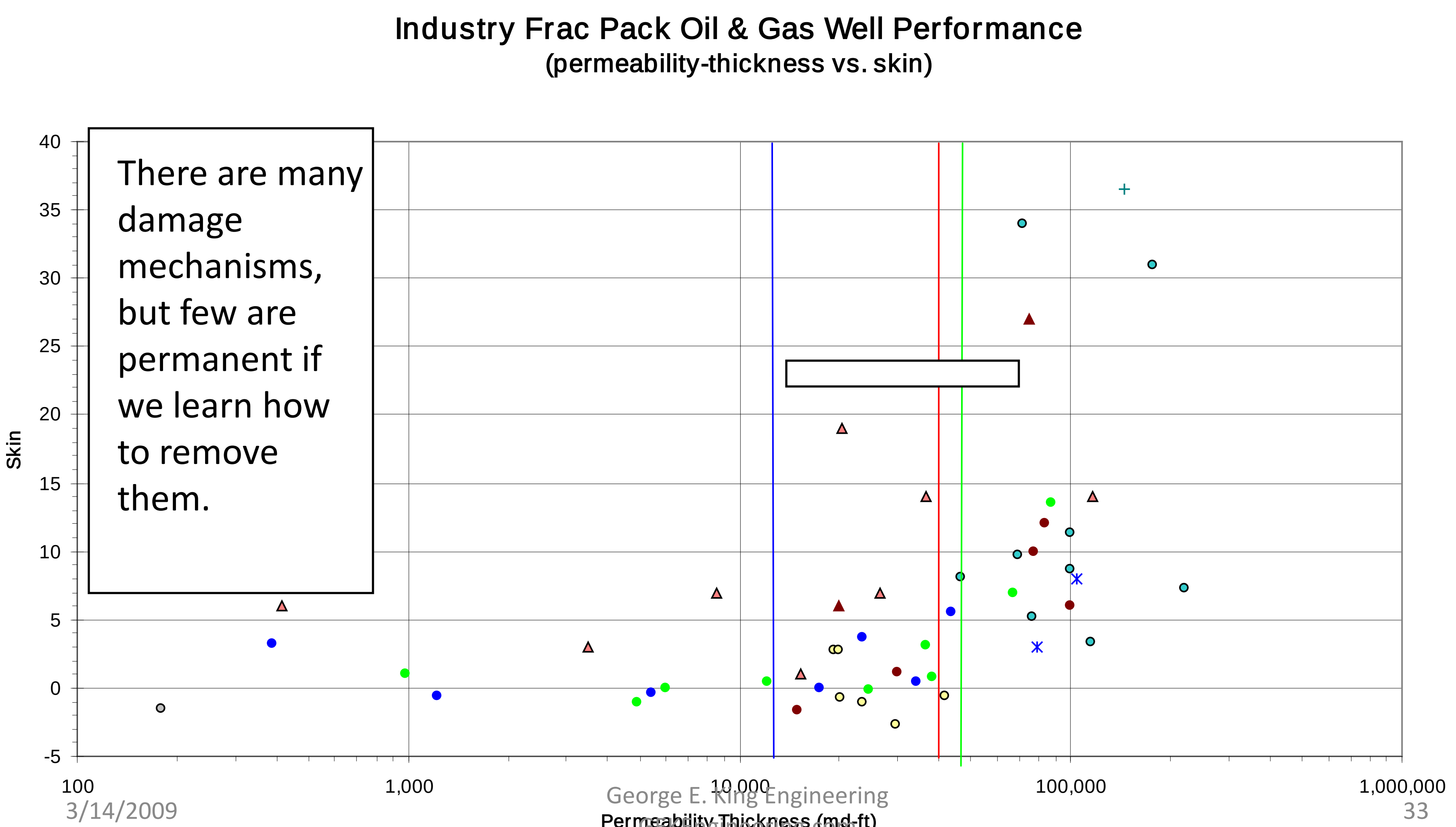


Second Problem

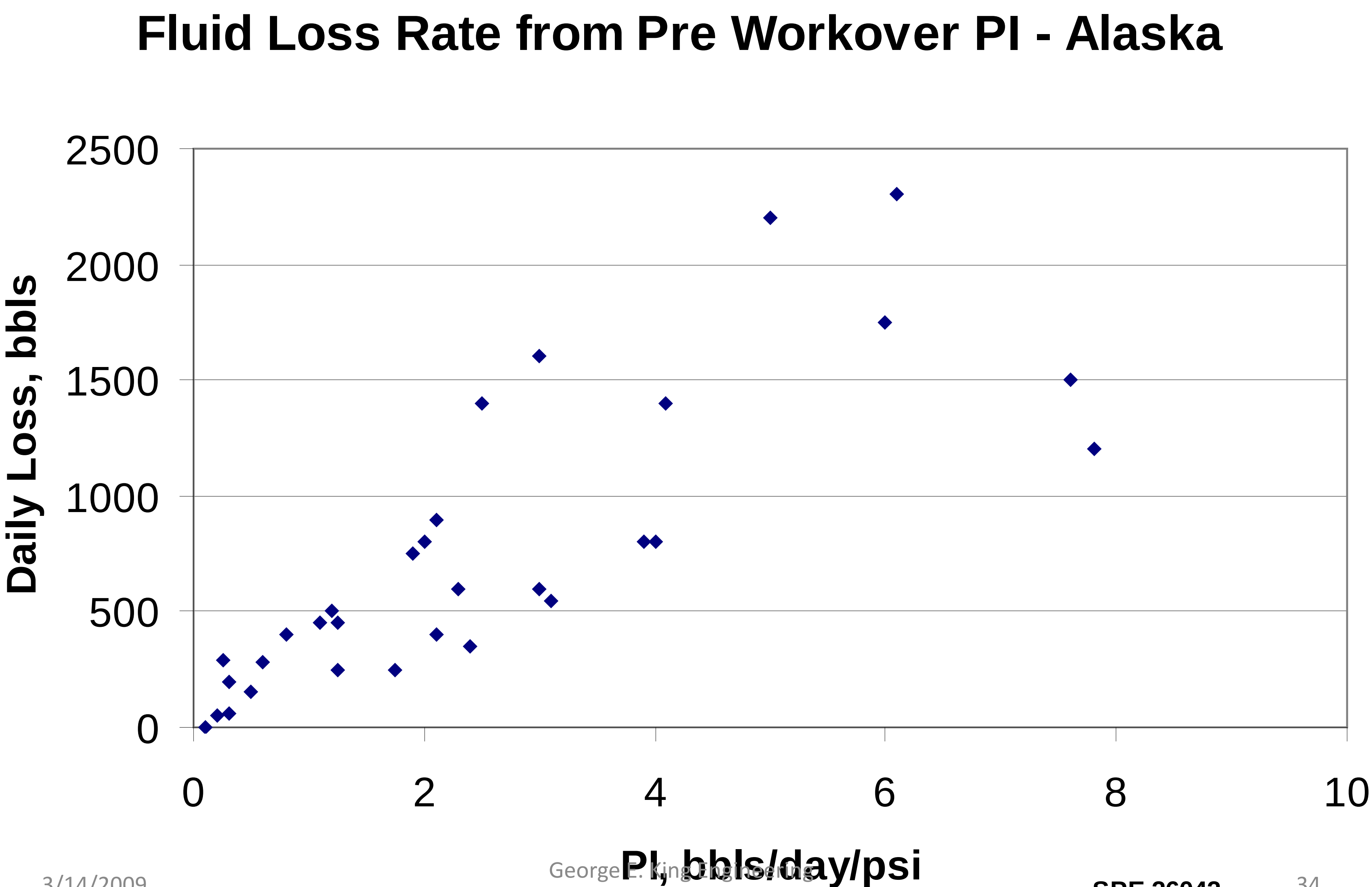
- We don’t understand damage.
  - **How it got there**
  - **How it is removed.**
  - **How to prevent it.**
  - **What operations put the well’s productivity at risk.**

Some examples of GOM skins versus md-ft

Note the increasing skin in higher conductivity wells – why? It should be easier to remove damage in higher perm formations. The key here is that turbulent (non-darcy or non mechanical) skins are nearly always higher in high capacity wells – especially gas.

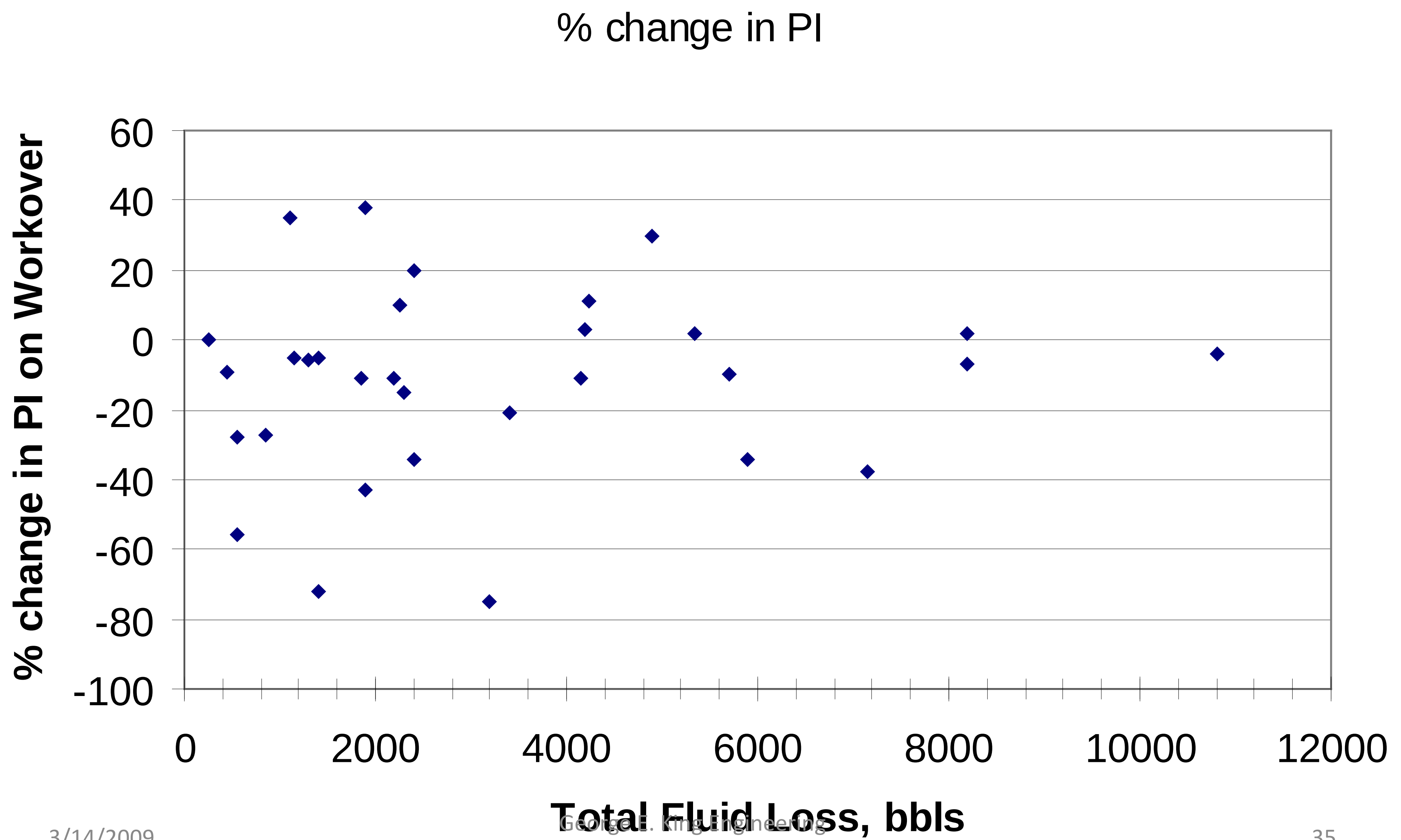


Cleanup examples from Alaska wells – high losses into high PI wells, but…….

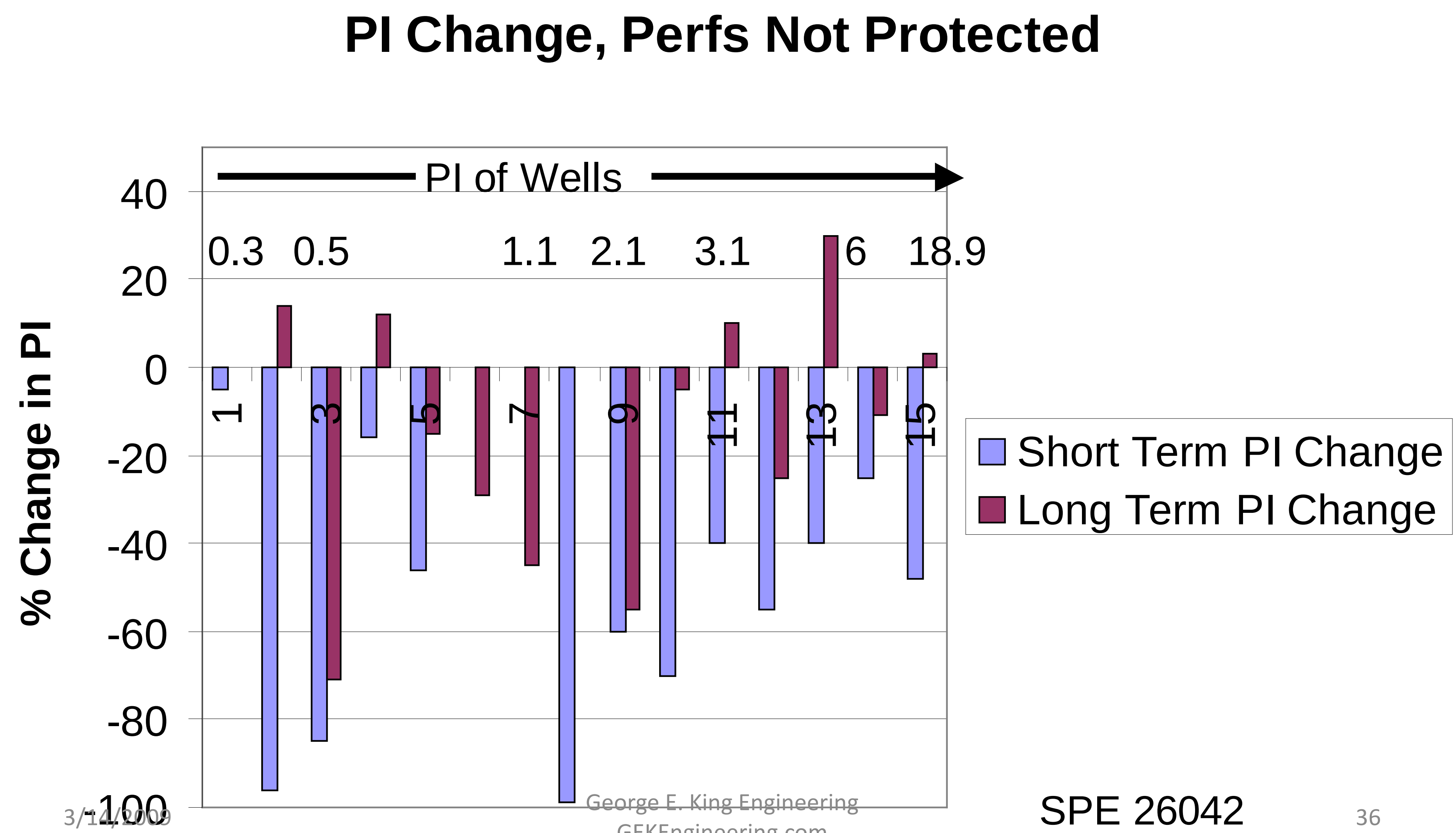


SPE 26042

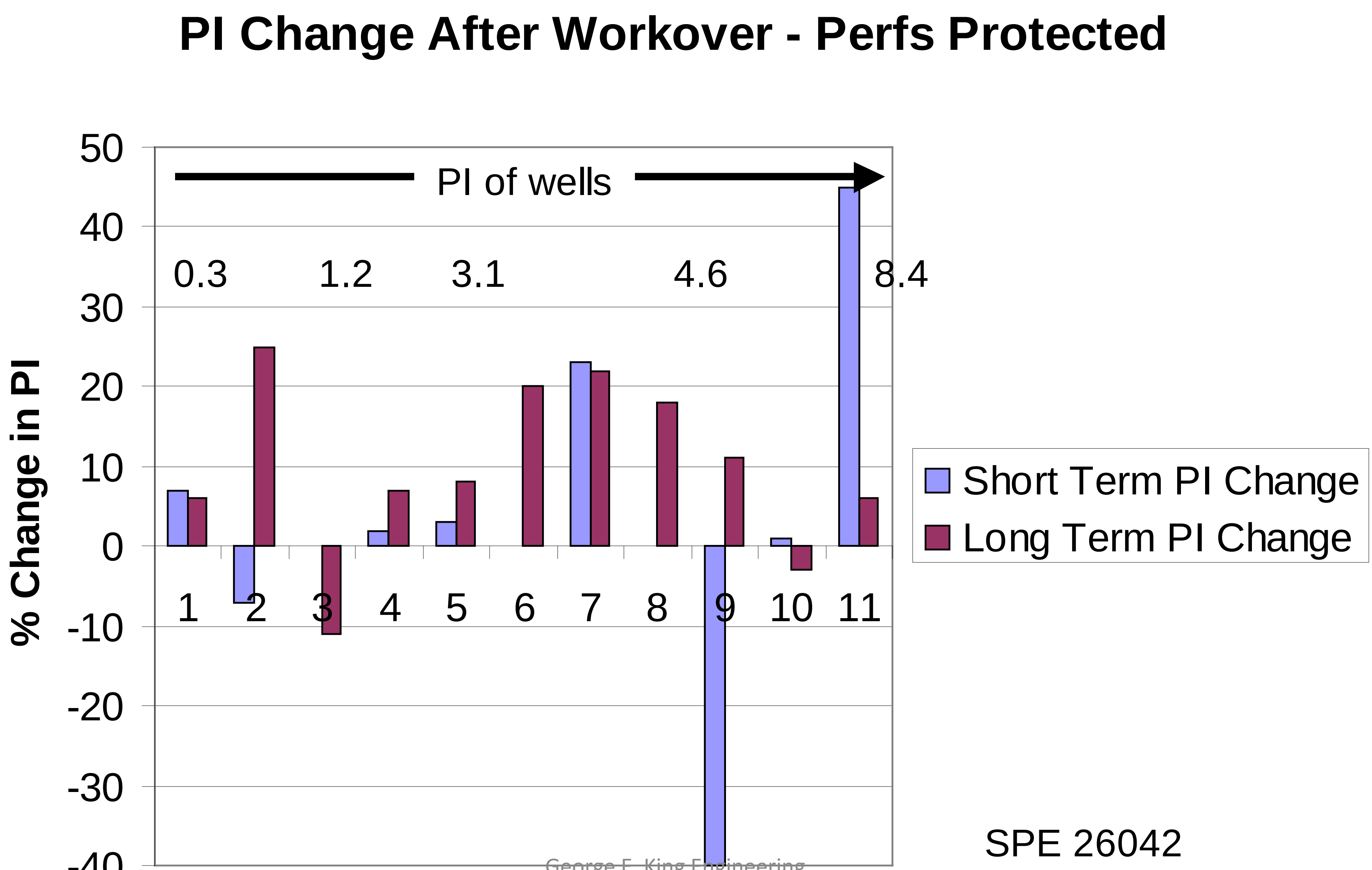
…there was actually little correlation with amount lost.



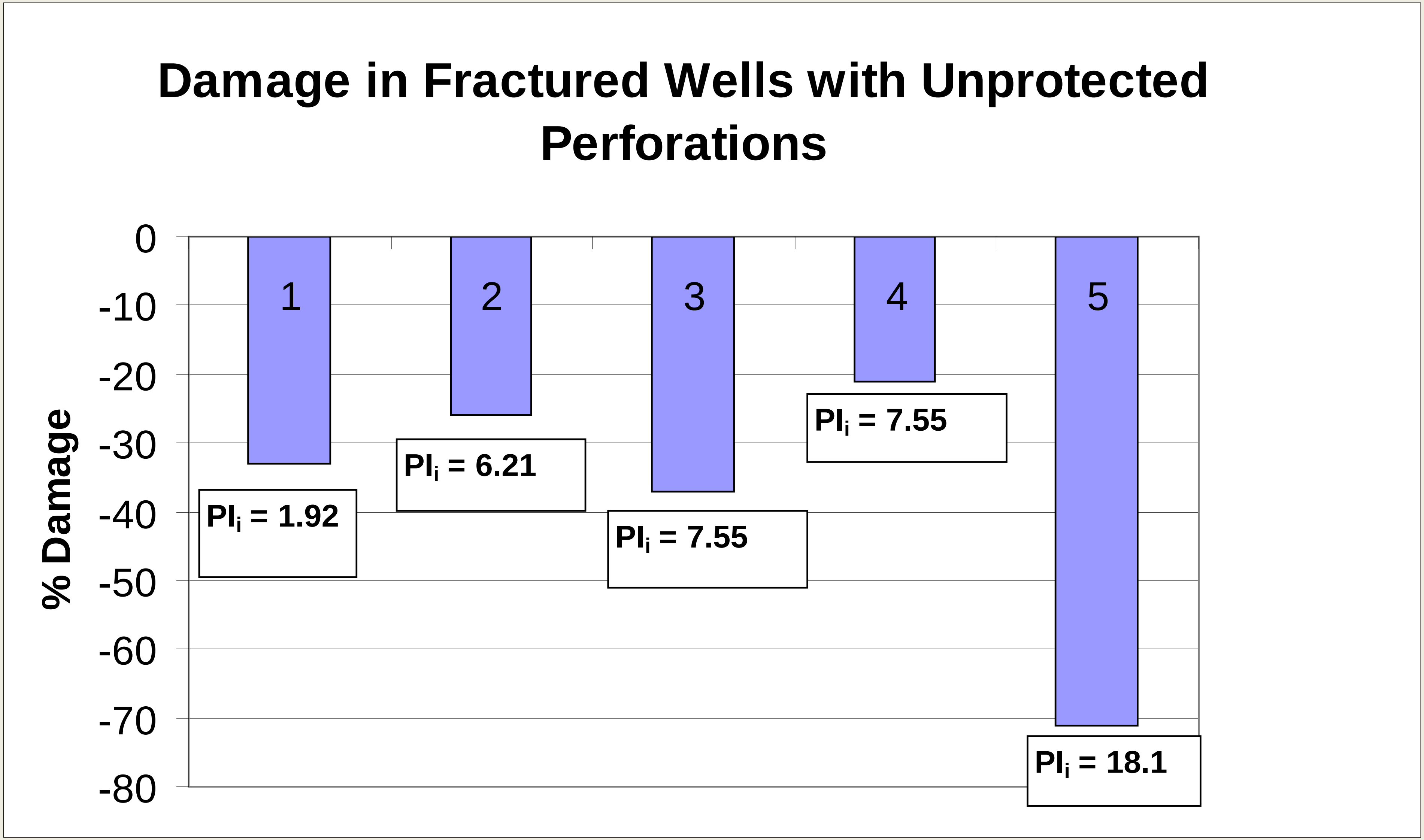
Of higher importance was whether the perfs were protected or not.



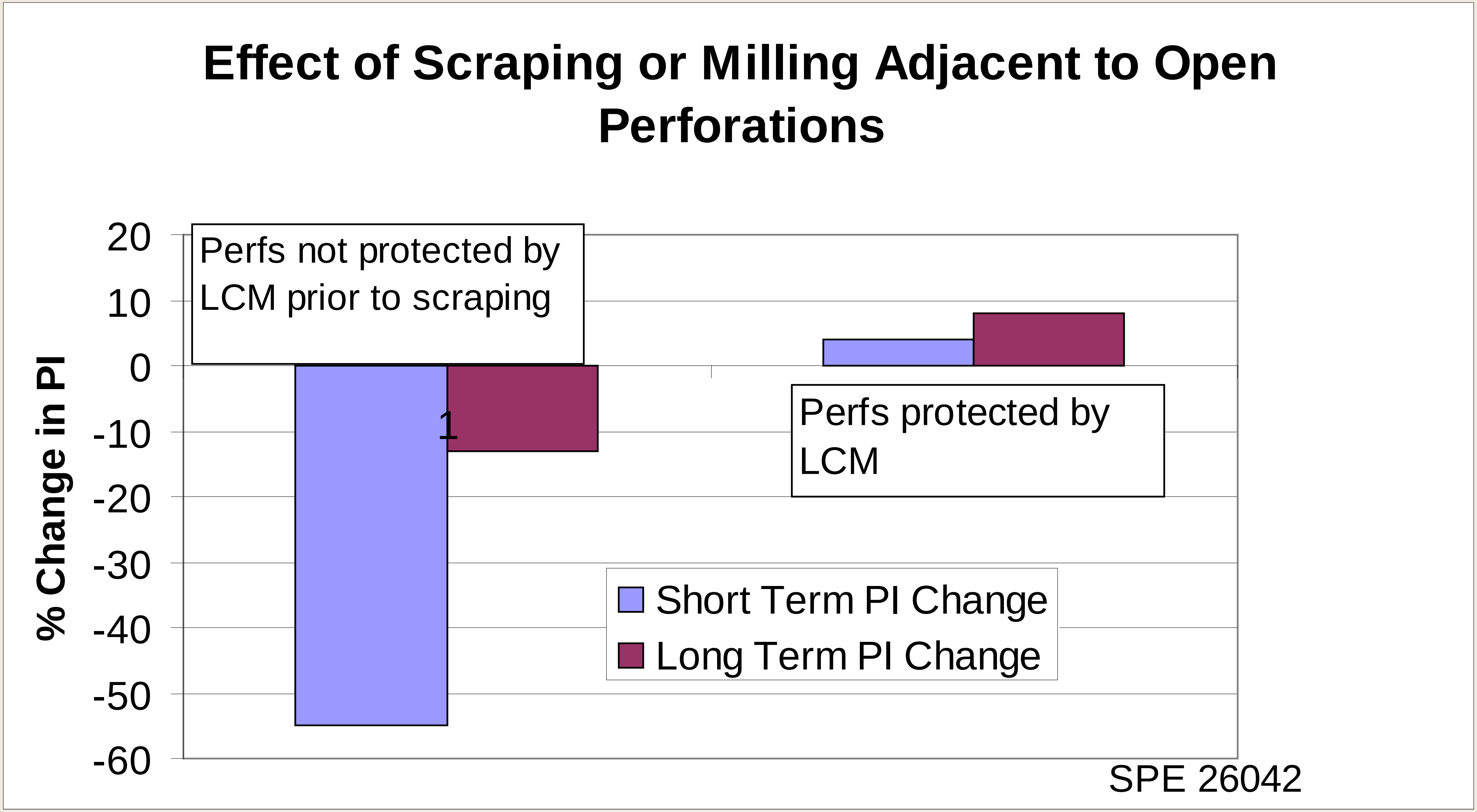
When perfs were protected, that was little risk of long term damage.



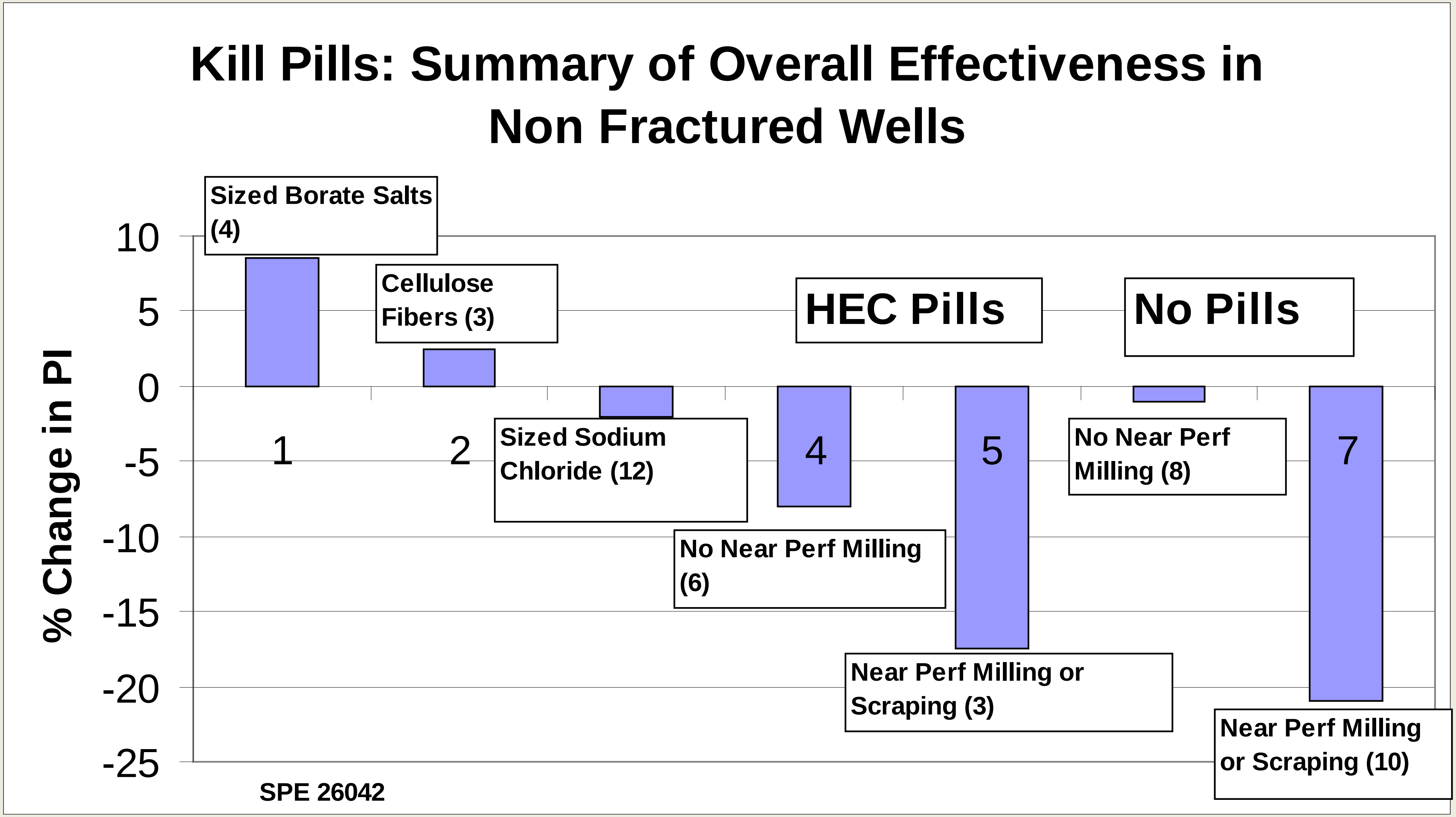
When the perfs were not protected, the well was damaged.



One very detrimental action was running a scraper prior to packer setting. The scraping and surging drives debris into unprotected perfs.



Sized particulates, particularly those that can be removed, are much less damaging than most polymers, even the so-called clean polymers.



Third Problem

- **We don't know enough about timing of damage removal.**
  - **Variety of causes**
    - **Polymer dehydration**
    - **Decomposition of materials**
    - **Adsorption, absorption and capillary effects**

- **Field data from Troika (100,000 md-ft) show initial flow improves PI, but later flow does not.**

Deepwater Well Cleanup Lessons

- On initial cleanup, PI erratically increased as choke opened. Typical response was a decrease, as if well / flow path were loading up, then sharp PI increase, seemingly when the obstruction was unloaded.
- Little partly broken polymer recovered, but early load water recovery matched PI incr.
- Lower skins were linked to both sand flow before completion (sand surge removed damage), increased cleanup flow volumes (and drawdown) on initial cleanup, and more effective frac stimulations.

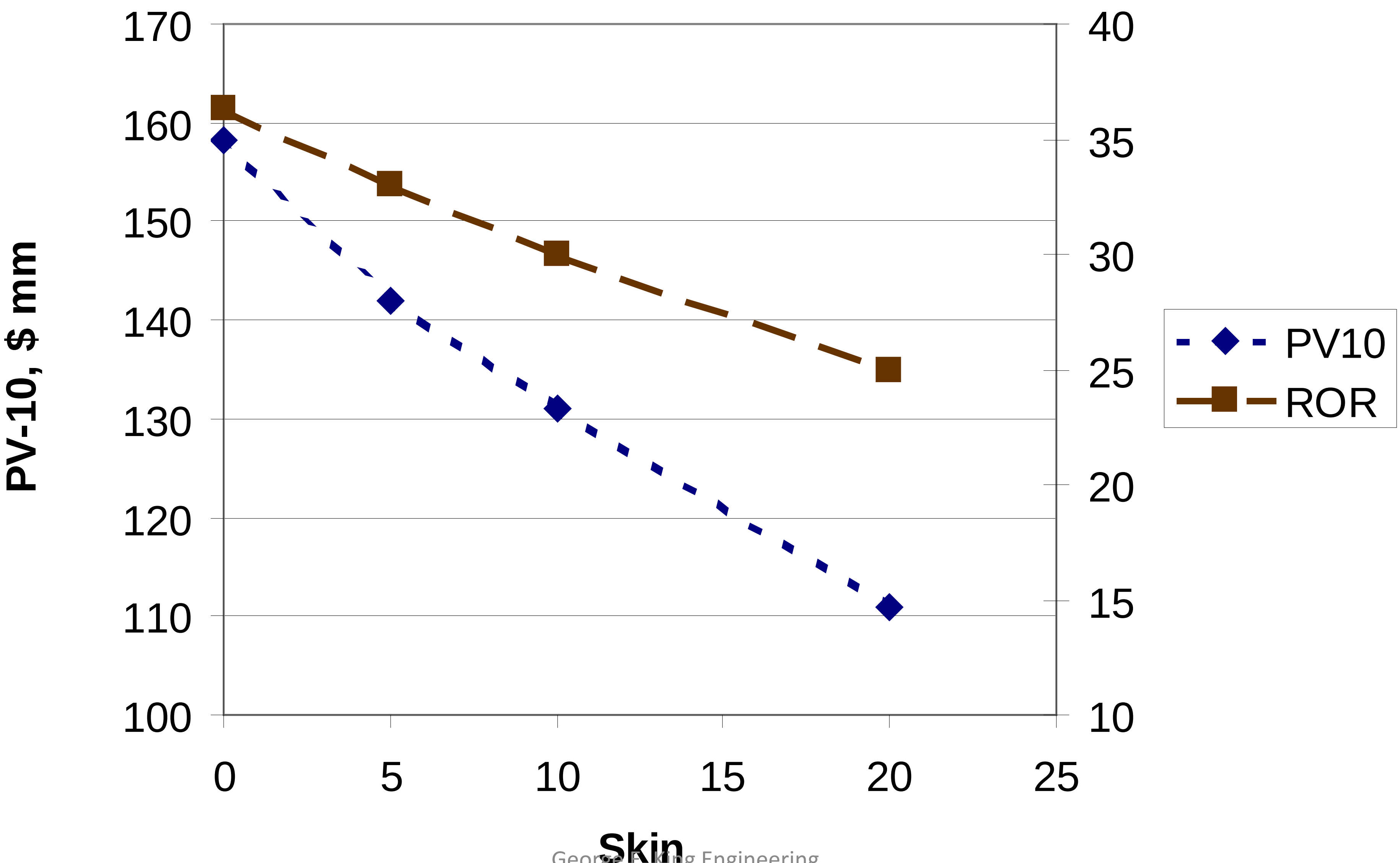
Deepwater Cleanup Lessons

- Wells cleaned up with increasing drawdown immediately following backflow start. Cleanup was increasing, measured by increasing PI, at the end of the first short cleanup periods prior to shut-in of the well.
- After initiation of production operations - after first cleanup flow, no further cleanup of damage was seen, regardless of drawdown. The reason is not known, but may be due to polymer adhering or cooking out?

Fourth Problem

- We don't understand how damage impacts economic return.

Example Economics - Skin Sensitivity



An example of a completion method that minimizes damage.

- Perforating, but with enough underbalance to create the flow necessary to clean the perforations.

Look at some of the most common damage mechanisms. In some formations, a specific damage is very detrimental, while in another formation, the damage is insignificant.

Type of Damage	Most Probable Location	Impact on Productivity if not Removed	Surge Pressure Needed for Removal?	Flow Vol. Or Time Needed for Removal?	Removal Hampered by Limits on Cleanup Vol?	Alternate Methods of Removal or Prevention
Mud Cake in Pay Zone	Formation Face	Moderate to Severe	Yes	Spurt Volume	Yes	Acids, Soaps, Enzymes
Mud Filt.	<12”	Minor - mod.	No		No	
Whole Mud Loss	Fractures and large vugs	Severe	Possible, Can help in few cases.	Depend on Cond. few cases similar	Yes, flow combined with solvent treatment	Few successful whole mud removals when vol. > 200 bbls.
Cement Filtrate	<12” into pay	Only if clay damage	No		No	
Perforation Crush Zone	½” around perf	Moderate to Severe	Yes	4 to 12 gal/perf	Yes	Surge small zones into chamber, acids, pulses, fracs
Formation sand in perfs	perf tunnels	Most severe	Cleanup and reperf		Depends on initial &later actions	Develop good perf and prepack actions

When looking at the range of skins, it is useful to know that some wells have high skins but are really restricted by other factors such as tubing flow limits, facility limits, etc., and are not really limited by the skins.

Type of Damage	Skin range	Comments
Mud Cake in Pay Zone	+5 to +300, +15 is typical	Mud skin is usually shallow and has more impact when turbulence and non-darcy skin problems are most severe. Mud cake is usually by-passed by perforating.
Mud Filtrate	+3 to +30	Filtrate usually recovered by steady flow and time. Related to relative perm effects. This is usually a short lived problem (1 to 3 weeks)
Whole Mud Loss (in pay zone)	>+50	Options depend on mud volume lost. Enzymes, solvents and acids for small volumes (<10 bbls). Sidetrack if over 1000 bbls. Low solids mud can be removed by concentrating on viscosifier destruction or dispersment.
Cement Filtrate	+10 to +20	Very shallow clay problems. Perforate with deep penetrating charges to get beyond. Use leakoff control on cement.
Perforation Crush Zone	+10 to +20	Perf small intervals underbalanced. Isolation packer breaksown, explosive sleeve breakdown (very simple) - must be accomplished prior to gravel packing.
Formation sand in perfs	>+50	Most severe typical damage - cleanout and recompletion required

Table 3: Completion Efficiency Factors (Stracke, SPE 16212) Shown as a percent of wells in each bracketed completion efficiency range.

Factor	100-75%	75-50%	50-25%	25-0%
Underbalance perf w/ surge chamber	26	26	26	23
Perforate and wash perfs	25	40	19	15
Underbalance perf w/ surge chamber + wash perfs	71	14	14	0
Surge Vol < 4 gal/ft	23	19	35	23
Surge Vol > 4 gal/ft	43	29	14	14
Surge differential < 1000 psi	27	24	24	24
Surge differential >1000 psi	19	27	31	23
Drilling overbalance <300 psi	15	48	19	19
Drilling overbalance >300 psi	31	31	23	16
Drilling overbalance >1000 psi	27	31	23	19
Completion overbalance <300 psi	25	39	25	12
Completion overbalance >300 psi < 600 psi	21	36	21	21
Completion overbalance >600 psi	47	21	5	26

This data is difficult to understand unless the attention is focused at those factors which deliver the most wells in the 100% to 75% efficiency range, e.g., underbalance perf w/surge chamber and wash perfs.

Notice that underbalance perforating at high underbalance (which causes flow) delivers a perforation that is from 40% to nearly 300% larger than the other methods of perforating.

Table 4: Perforation Tunnel Volume Following Perforating at Different Conditions (Regalbuto and Riggs, SPE PE, Feb 1988)

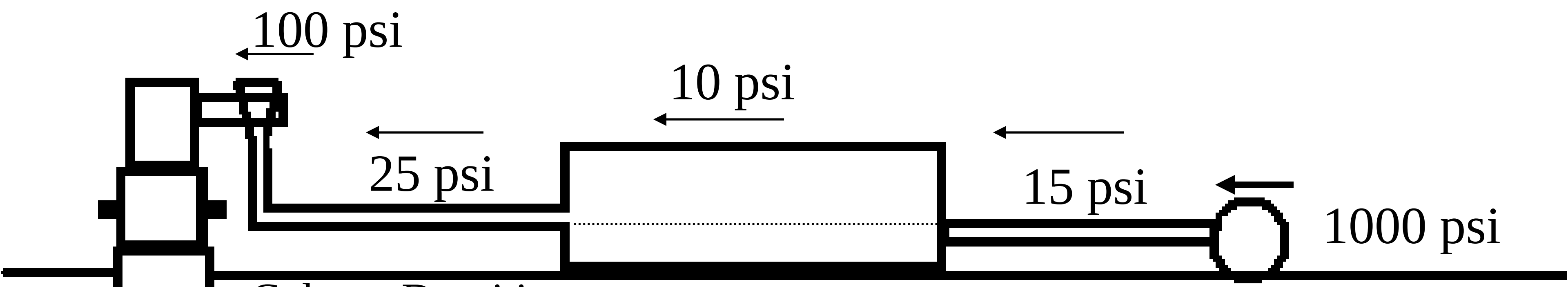
Pressure Differential	Hole Volume, perforated	Hole Volume, perforated/surged
Overbalanced, 500 psi, no surge	18 cc	
Balanced perforated, no surge	31 cc	
Underbalanced perforated, 500 psi	20 cc	42 cc
Balanced perforated, delayed 1000 psi surge	31 cc	48 cc
Underbalanced perforated, 1000 psi	50 cc	75 cc

Back to over-all damage – What is it?

- Divide the well into three parts:
  - Inflow: area from reservoir to the wellbore
  - Completion potential: flow to surface
  - Surface restrictions: chokes, lines, separators.

- Basically, anything that causes a restriction in the flow path decreases the rate and acts as "damage."

Differential pressure, ΔP, is actually a pressure balance



Column Densities:

Gas = 1.9 lb/gal = 0.1 psi/ft = 1000 psi in a 10,000 ft well

Dead oil = 7 lb/gal = 0.364 psi/ft = 3640 psi in a 10,000 ft well

Fresh water = 8.33 lb/gal = 0.433 psi/ft = 4330 psi in a 10,000 ft well

Salt water = 10 lb/gal = 0.52 psi/ft = 5200 psi in a 10,000 ft well

Gas cut flowing oil = 5 lb/gal = 0.26 psi/ft = 2600 psi in a 10,000 ft well

Press. Drop

Where does the ΔP come from?

10,000 ft

4600 psi

4600 psi reservoir pressure

-2600 psi flowing gradient for oil

- 150 psi press drop

- 100 psi through the choke

- 25 psi through the flow line

- 10 psi through the separator

- 15 psi through downstream flow line

-1000 psi sales line entry pressure

ΔP = 700 psi drawdown pressure

The first step…..

- For the purposes of this work, consider the flow connection between the reservoir and the wellbore as the primary but not the only area of damage.
- Now, is it "formation damage" or something else that causes the restriction?

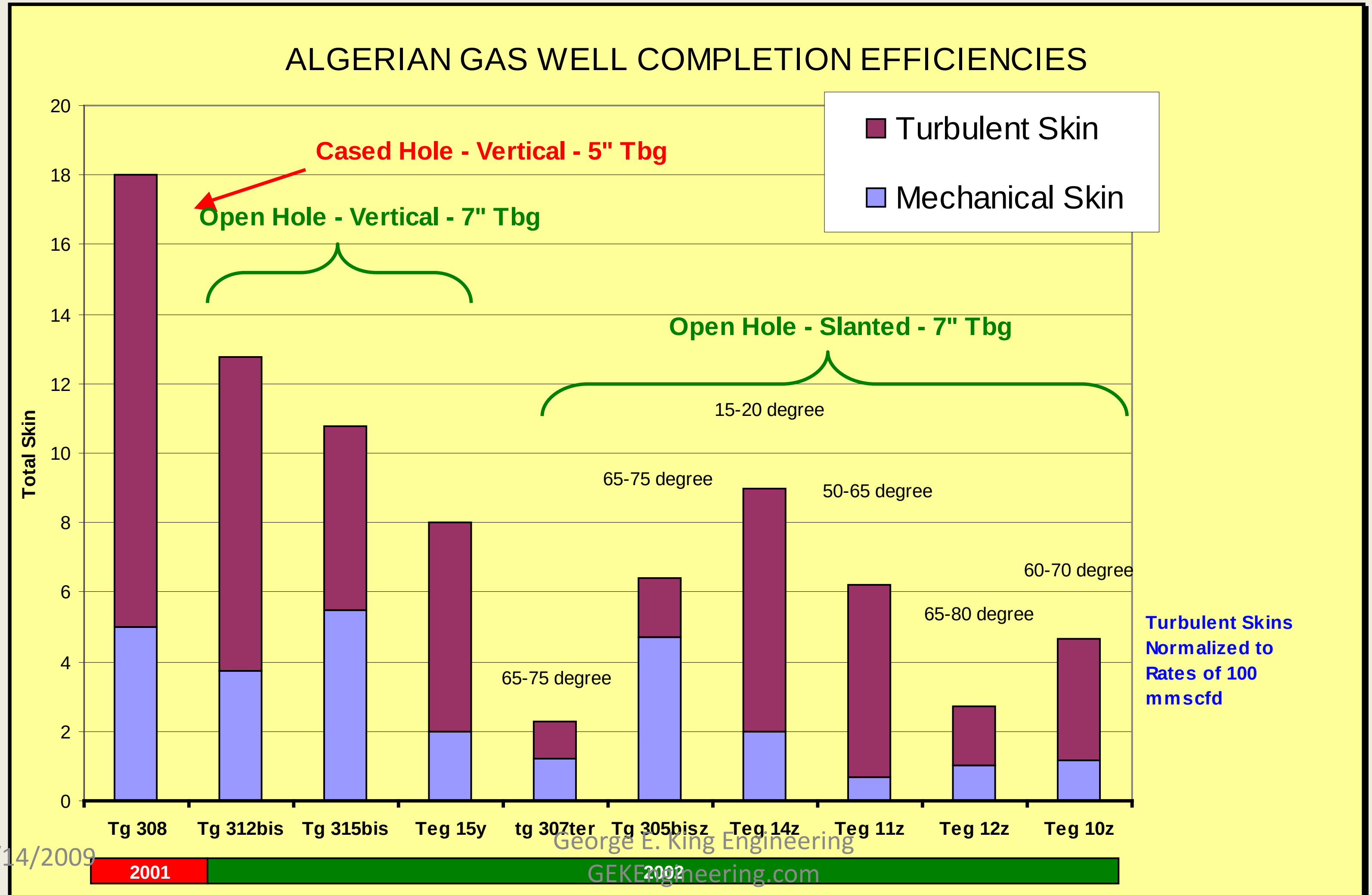
Some sources of the "damage" in the reservoir-wellbore "connection"

- **Wetting phases (from injected or "lost" fluids)**
- **Debris plugging the pores of the rock**
- **Polymer waste from frac and drilling fluids**
- **Compacted particles from perforating**
- **Limited entry (too few perforations)**
- **Converging radial flow – wellbore too small**
- **Reservoir clay interactions with injected fluids**
- **Precipitation deposits (scale, paraffins, asphaltenes, salt, etc)**

Note that not all are really formation damage – How do you identify the difference?

And some restrictions – in very high perm wells – is the casing and the very limited amount of open area that perforations create.

Data comparing cased and perforated skin with skins from open hole completed wells from Algeria.



Identification of Damage.

- How good are you at deductive reasoning?
  - Identifying the cause and source of damage is detective work.
    - Look at the well performance before the problem
    - Look at the flow path for potential restrictions
    - Look to the players:
      - Flow path ways
      - Fluids
      - Pressures
      - Flow rate

What is Completion Efficiency?

- A measure of the effectiveness of a completion as measured against an ideal completion with no pressure drops.
- Pressure drops? – these are the restrictions, “damage”, heads, back-pressures, etc. that restrict the well’s production.

Look again - The Effect of Damage on Production

Rate = $(\Delta P \times k \times h) / (141.2\ \mu_o\ \beta_o\ s)$

Where:

ΔP = differential pressure (drawdown due to skin)

k = reservoir permeability, md

h = height of zone, ft

μ_o = viscosity, cp

β_o = reservoir vol factor

s = skin factor

What changeable factors control production rate?

- Pressure drop – need maximum drawdown and minimum backpressures.
- Permeability - enhance or restore k? - yes
- Viscosity – can it be changed? – yes
- Skin – can it be made negative?

- These factors are where we start our stimulation design.

Formation Damage

- Impact
- Causes
- Diagnosis
- Removal/Prevention?

- Basically, the severity of damage on production depends on the location, extent and type of the damage. A well can have significant deposits, fill and other problems that do not affect production.

Conclusions

- Damage is usually shallow.
- Remove it or by-pass damage if it really causes a problem.
- Not every “damage” is in the formation.
- Not every drop in production is caused by damage.
- First, remove the pressure drops, everything else will take care of itself.