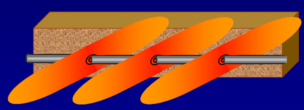
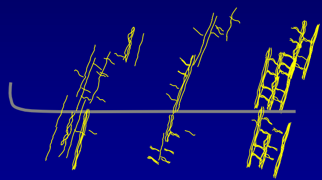
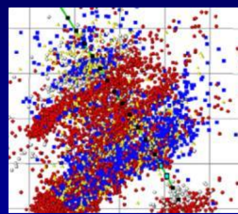
Confessions of a Frac Engineer:

Your Reservoir is Much More Productive than we Thought…

It's my Frac that is Failing







Mike Vincent

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Fracwell LLC Insight Petroleum Consulting

Microseismic image: SPE 119636

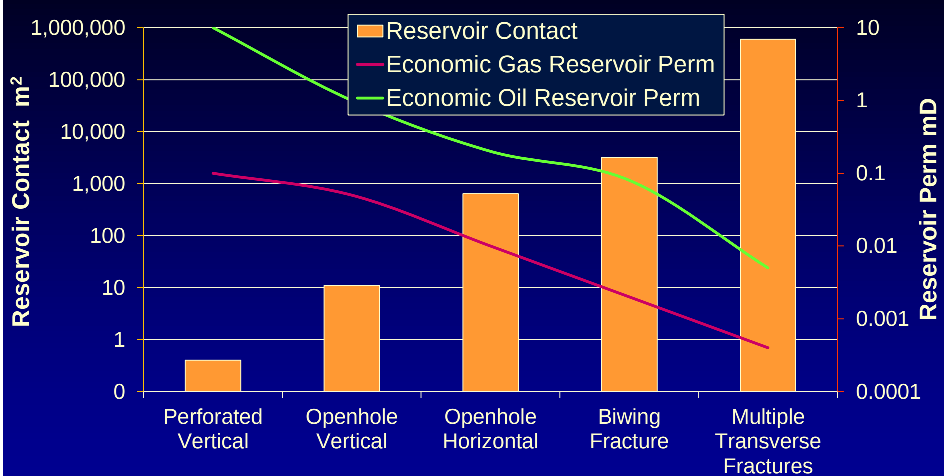
Outline

- Goals of fracturing and incredible industry achievements
- Shock and awe
  - Irrefutable field data we can no longer ignore
  - Fracs do NOT perform like we thought
- Plausible mechanisms responsible for underperformance
- Evidence we can do better
  - Field results – refracs & improved frac designs
  - We often *incorrectly* blame underperformance on insufficient reservoir quality.
  - It is now clear that the formations have greater potential than we thought! The fracs are not capturing well potential.

Two basic design goals for fracture treatment

- Adequate reservoir contact (frac length)
- Adequate flow capacity (conductivity)

Technology Progression



Increasing our reservoir contact by 1,000,000 fold
has allowed pursuit of reservoirs with thousands of times lower perm.

Tremendous (partially recognized) impact on global reserves

Two basic design goals for fracture treatment

- Adequate reservoir contact (frac length)
- Adequate flow capacity (conductivity)

If a frac job were “optimized” the next dollar invested in frac length would provide the same return on investment as the next dollar invested in conductivity.

For the past 20 years, I’ve tried to examine the technical reasons that we have failed to balance these two challenges and we are not optimized.

Today, we will mostly examine field data.

How big is 10,000,000 ft^2 of contact?

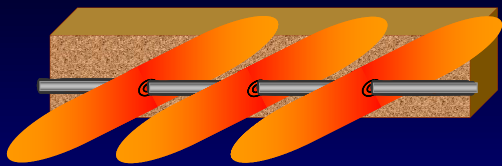
290 yds x 215 yds = ~560,000 ft^2

Architect claims 1.7mm ft^2 including all decks, concourses, stairs, etc

So maybe envision 18 NFL stadium footprints as the surface area of contact.

Images: ESPN, BSOblacksportsonline; Wikipedia, ticketini, turnerconstruction.com

How large are the connections between a transverse frac and the wellbore?



Cemented & Perfed:
Suppose we have four perfs in a cluster that are connected to the frac. Suppose they erode to ¾" diameter
Footprint of 4 dimes ~ 1.6 in^2

Openhole, uncemented:
Suppose frac is 1/10" wide after closure. Suppose perfect full circumference connected around 6" hole (~18" circumference). 1.8 in^2 About 1/10th of a \$5 bill

If I optimistically assume I successfully initiate and sustain 100 transverse fracs, I get a connection equivalent to 10 bills

Images: ebay, us-cash.info

Ratio: contact to connection?

Envision 18 NFL stadium footprints as reservoir contact.

The cumulative area of connection of 100 perfectly executed transverse fracs is about the size of one hash mark

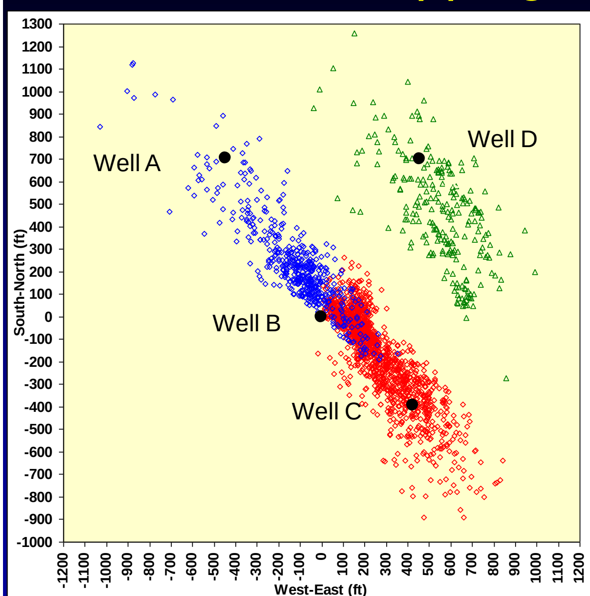
10,000,000 ft^2 : 180 in^2
8 million :1

The frac conductivity may be a bottleneck!?!

Images: ESPN, BSOblacksportsonline; Wikipedia, footballidiot.com

Some field examples that challenge our understanding

Microseismic mapping – tight gas sand



Well B designated monitor well, not completed.
Based on this would you frac it?

Well A & D came on at 8 mmcfd.
Well C came on at 7 mmcfd
(within normal variability)

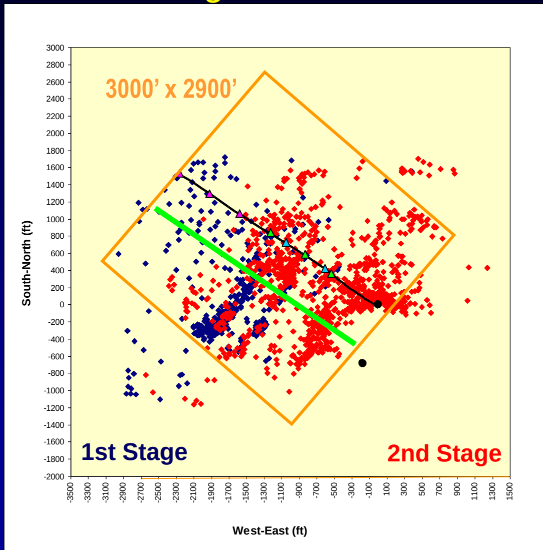
Well B was eventually frac'd, came on at 7 mmcfd, no indication of detrimental impact or interference with surrounding wells.

After 1 year, most declined to 3 mmcfd. After 5 years all around 1 mmcfd

No apparent interaction

Fracs can have enormous reach

Two Stage Cemented Barnett Shale Lateral



= First Stage Perf Clusters
= 2nd Stage Initial Perf Clusters
= Revised 2nd Stage Perf Clusters

Fracs can extend >1500 feet

We know we can bash offset wells with both water and RA tracer

9 million square feet >200 acres

What would happen if we drilled an infill well here?

SPE 90051

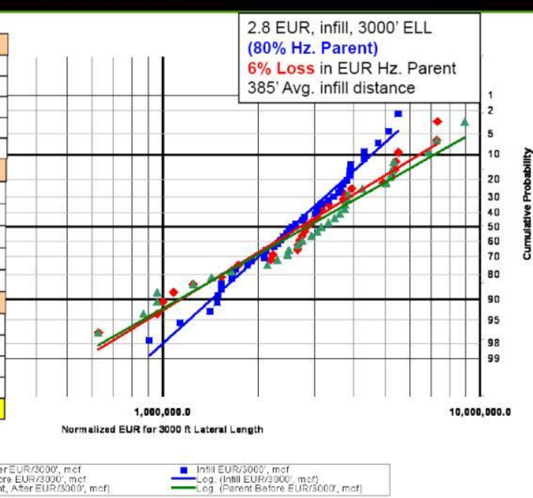
How far do we drain? Barnett Infill Drilling

Fort Worth Basin – Barnett Shale

Hz. Parent and Hz. Infill EUR Distribution

Parent Before EUR/3000', mcf	
# of Data Points	31
P_{10}	6,544,40
P_{50}	2,838,08
P_{90}	1,230,77
Statistical Mean (Trunc)	3,408,08
Parent, After EUR/3000', mcf	
# of Data Points	31
P_{10}	5,920,43
P_{50}	2,705,57
P_{90}	1,237,33
Statistical Mean (Trunc)	3,179,08
Infill EUR/3000', mcf	
# of Data Points	43
P_{10}	4,374,28
P_{50}	2,546,19
P_{90}	1,482,09
Statistical Mean (Trunc)	2,761,11

2.8 EUR, infill, 3000' ELL
(80% Hz. Parent)
6% Loss in EUR Hz. Parent
385' Avg. infill distance



When operators have infill drilled on **385' avg spacing**

Infill wells "steal" 6% of parent EUR

Infill wells produce 80% of parent EUR

* ELL: Estimated Lateral Length

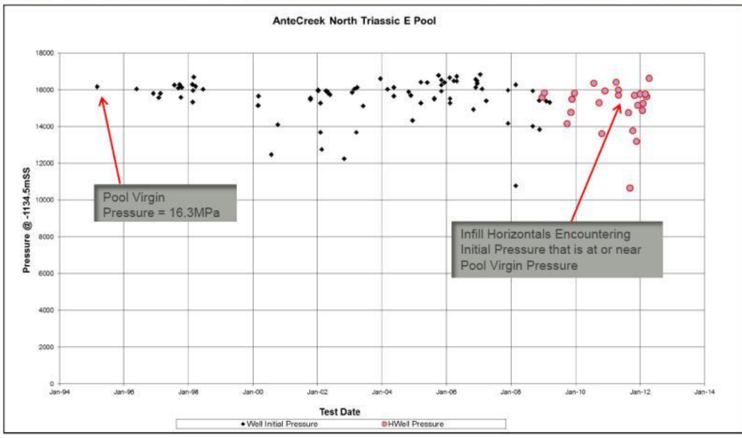
urce: Based on a statistical analysis of public data from wells in the Forth Worth Basin.

EnCana Corporation

Source: Brian Posehn, EnCana, CSUG April 28, 2009

How effectively do we drain?
Ante Creek, Montney Oil

ANTE CREEK OIL
OPPORTUNITY FOR DOWNSPACING



Infill Hz drilling is encountering High Pressure Reservoir – this implies substantial incremental reserves to be produced by the new wells.

16 years later encountering near-virgin pressure.

Demonstrates that initial wells were insufficient to recover all available reserves.

Is this due solely to reservoir discontinuity? Well locations? Frac insufficiency?

Similar findings in Niobrara, Bakken, many Permian formations, etc

Source: ARC Investor Presentation Nov 2012

Fractures Intersecting Offset Wellbores

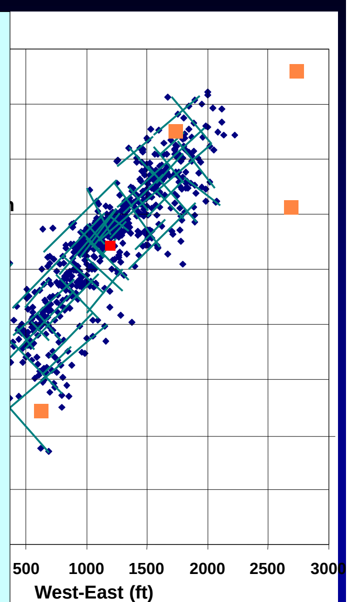
Evidence frac'd into offset wells (at same depth)

Microseismic mapping
Slurry to adjacent well
Increased watercut
Solid radioactive tracer (logging)
Noise in offset monitor well

Documented in

Tight sandstone (Piceance, Jonah, Cotton Valley, Codell)
High perm sandstone (Prudhoe)
Shale (Barnett, Marcellus, Muskwa, EF)
Dolomite (Middle Bakken)
Chalk (Dan)

Often EUR, "pulse tests" "interference tests" fail to indicate sustained hydraulic connectivity!



SPE 77441

Fractures Intersecting Bakken Laterals

- Sometimes adjacent wells are *improved* by bashing!

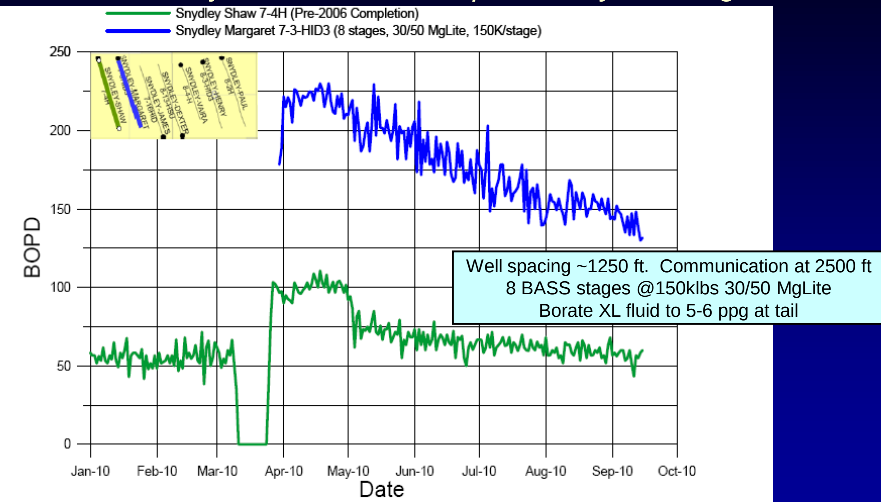
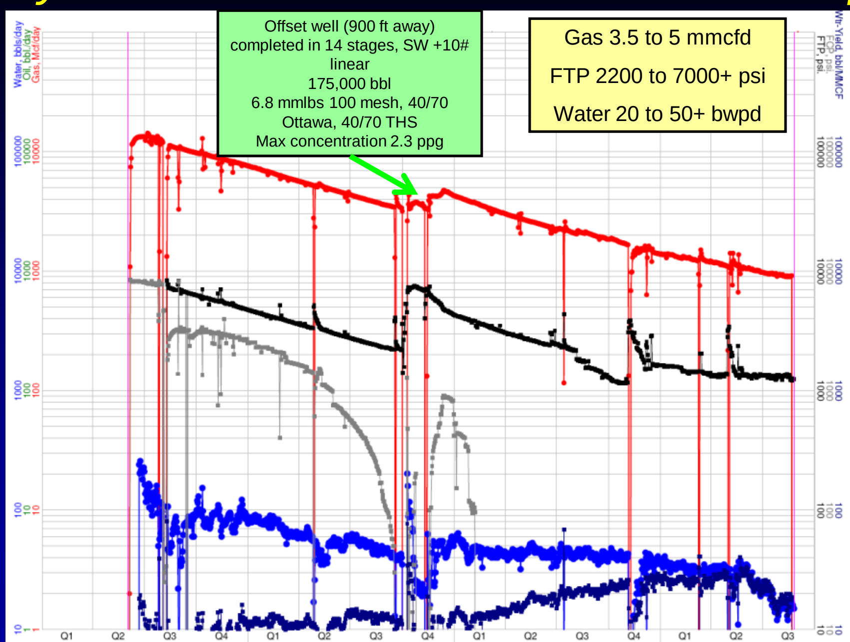


Figure 17. Comparison Production Plot of Snydley-Margaret 7-3-HID3 to Snydley-Shaw 7-4H (40 BOPD Gain)

Enerplus SPE 139774 – Jan 2011

Haynesville Beneficial Interference Example

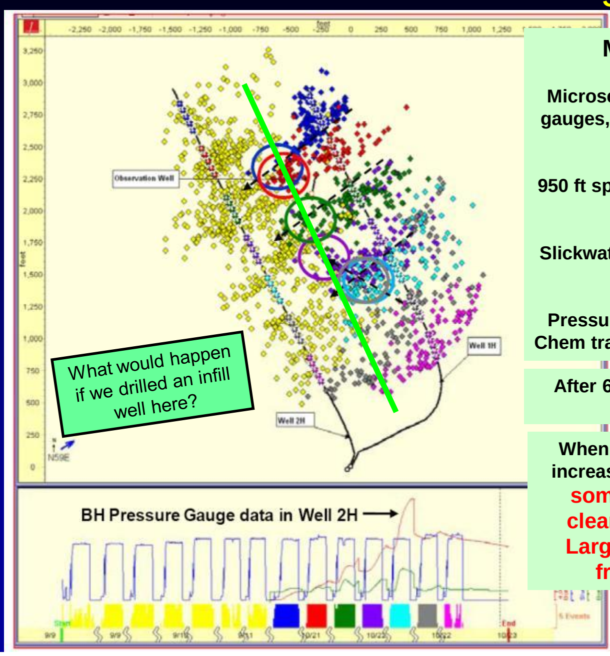


Permission secured to share without operator name

These examples are perhaps subject to interpretation . . .

- Are there irrefutable examples that demonstrate fracs may not be highly conductive, durable conduits as traditionally implemented?

Marcellus Fractures Intersecting Offset Laterals



Marcellus - Slickwater

Microseismic, DFITS, downhole pressure gauges, PTA, chemical tracers, production interference

950 ft spacing. 1H treated 5 weeks after 2H

Cemented, 7 stage PnP
Slickwater 100 mesh, 40/70 and 30/50 sand
~6000 ft TVD

Pressure communication in 6 of 7 stages
Chem tracers from 2,3,5,6,7 recovered in 2H

After 6 months of production, each well producing ~1 mmcfd

When one well is shut in, the other well increases in rate by ~20% demonstrating some degree of connection, but clearly imperfect after 6 months. Large pressure losses inside the fractures. Can we fix this?

Mayerhofer SPE 145463 – Nov 2011
Pinnacle and Seneca

Marcellus – Wells on 500 ft spacing do not appear to share reserves

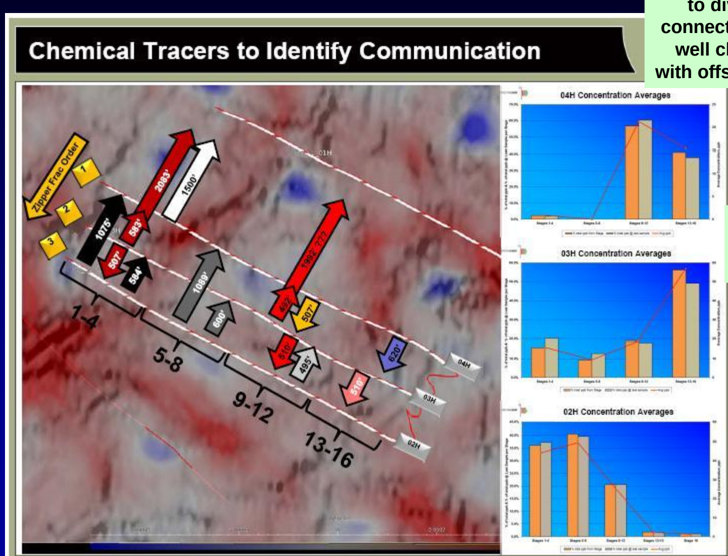
- SPE 140463 – Edwards, Weisser, Jackson, Marcotte [EQT&CHK]
  - All diagnostics (microseismic, chemical tracers, surface pressure gauges, etc) indicate fracturing treatments interact.
  - Well-to-well connection while the reservoir is dilated with frac fluid.
  - Microseismic suggests lengths >1000 ft
  - Production analysis estimates ~150 ft effective half length after 6 months
  - However, wells drilled on 500 ft spacing are similar in productivity to those on 1000 ft spacing, suggesting they are not competing for reserves

Similar findings in Niobrara, Eagle Ford, Barnett, Bakken, Wolfcamp, Spraberry, etc.

We can infill drill on much closer spacing that anticipated.
We are leaving reserves behind!

Eagle Ford: Fractures Intersecting Offset Laterals

The intent of zipper fracs was to divert/deflect and not connect fracs. Yet center 03H well clearly communicated with offsets during stimulation.



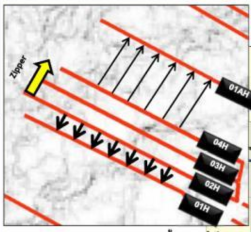
Communication during frac confirmed with chemical tracers

Murray, Santa Fe ATW, Mar 2013, and URTeC 1581750

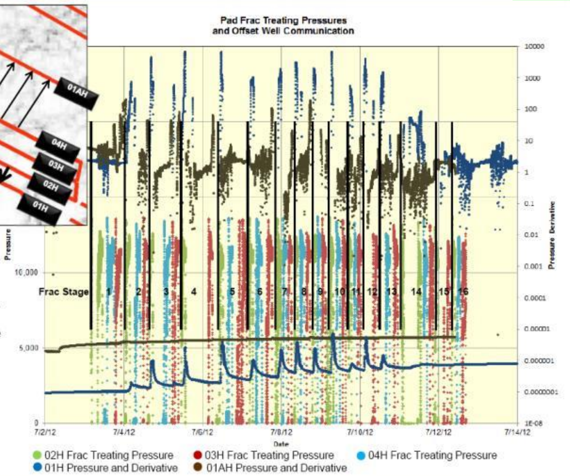
Eagle Ford: Fractures Intersecting Offset Laterals

Frac Treatment Pressure Response

Communication during frac evident from treating pressures



- 02H frac increased pressure in 01H more than 1,500 psi (500 ft).
- Slight pressure response in 01AH due to 04H frac (1,700 ft).

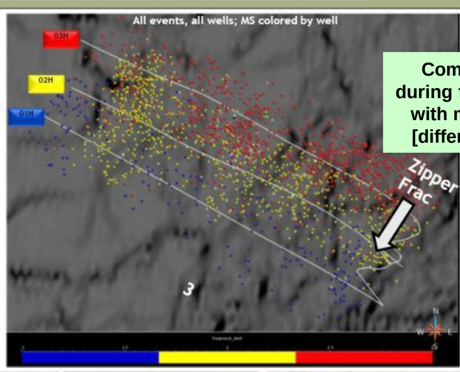


Murray, Santa Fe ATW, Mar 2013, and URTeC 1581750

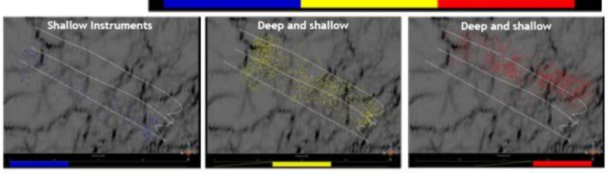
Eagle Ford: Fractures Intersecting Offset Laterals

Micro Seismic Data Collection

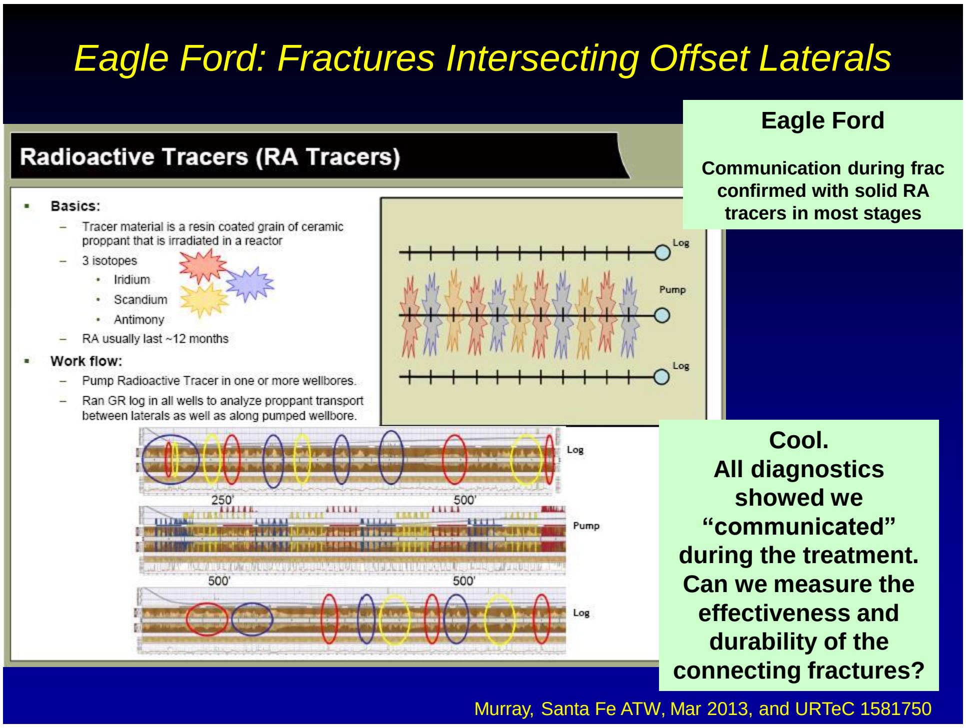
- Well 01H used for deep monitoring for wells 02H and 03H zipper fracs.
- Well 01H frac'd after zipper frac of wells 02H and 03H.
- Limited micro seismic data collected on well 01H because no deep instruments.
- Zipper frac order
  - 03H
  - 02H

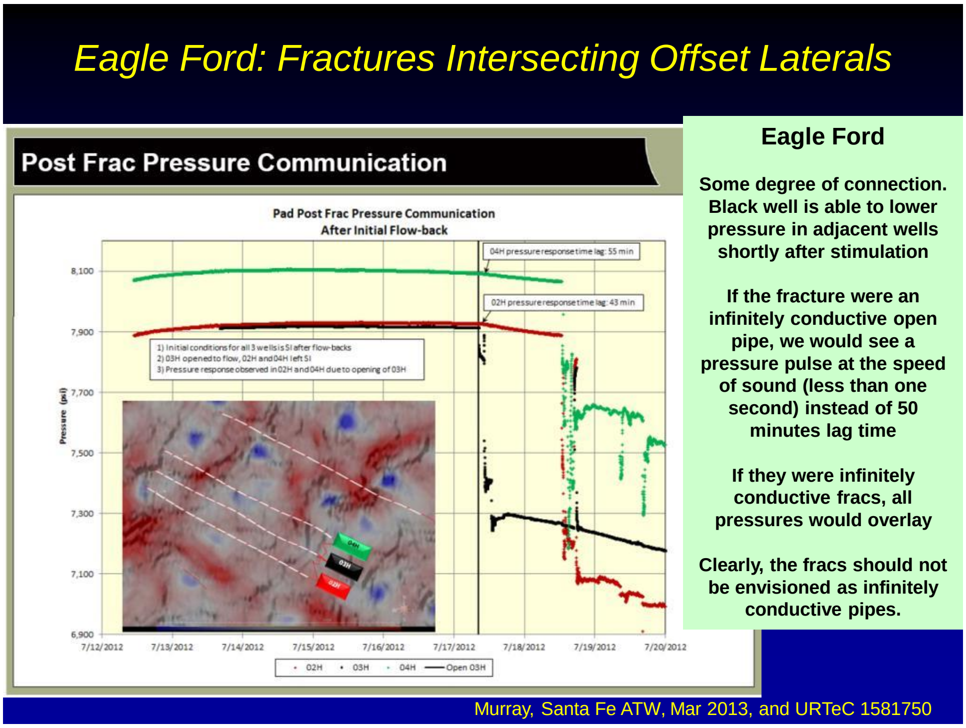


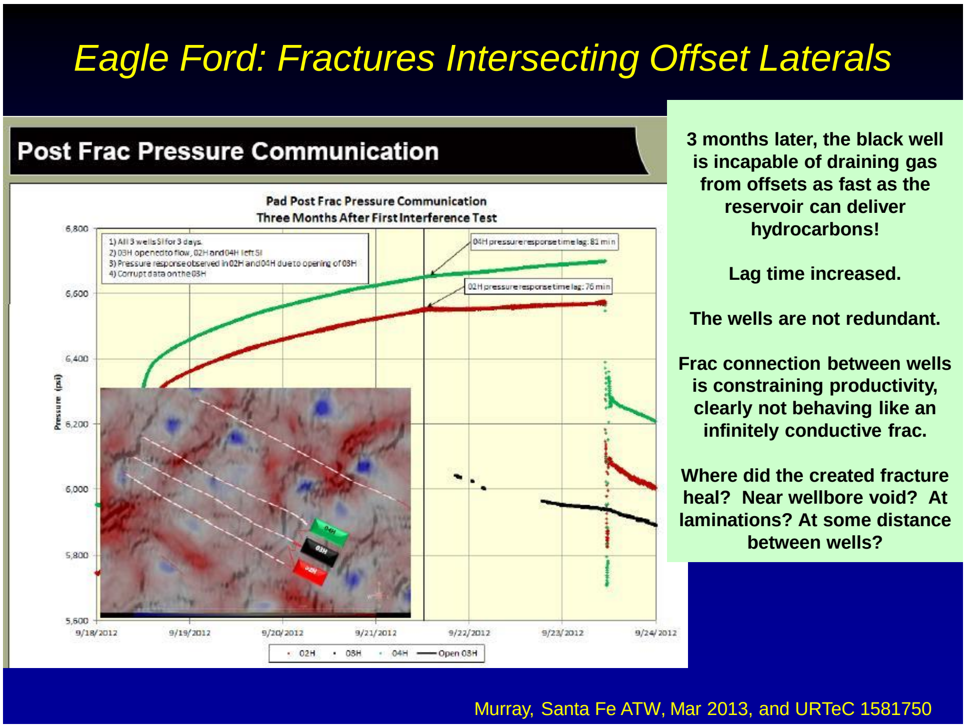
Communication during frac confirmed with microseismic [different well set]

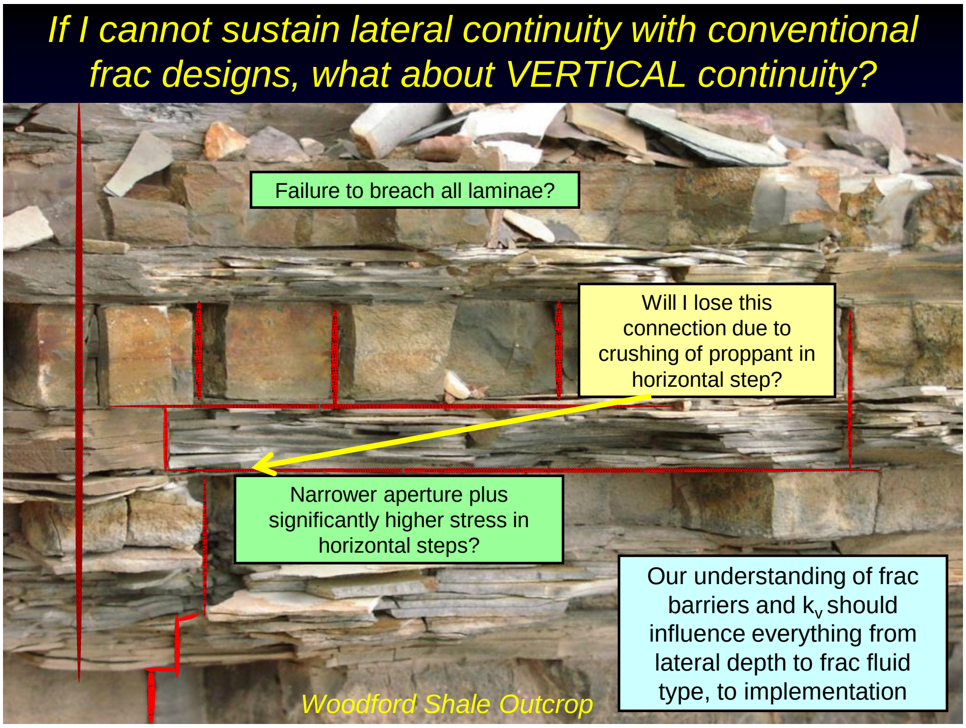


Murray, Santa Fe ATW, Mar 2013

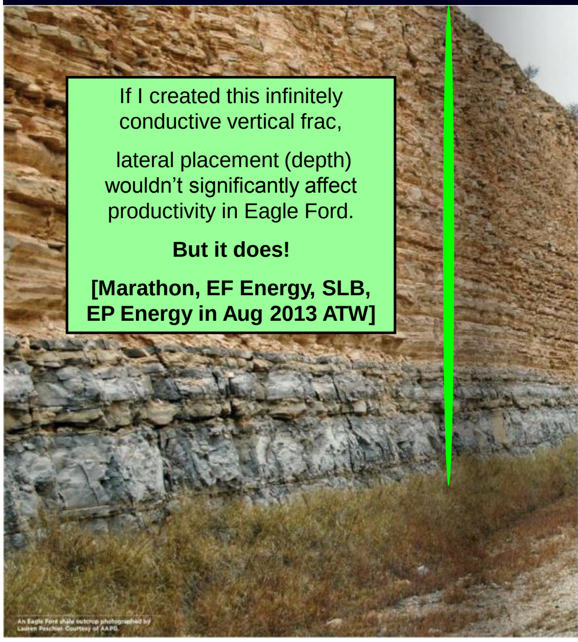

Eagle Ford: Fractures Intersecting Offset Laterals
Radioactive Tracers (RA Tracers)
Basics:
Tracer material is a resin coated grain of ceramic proppant that is irradiated in a reactor
3 isotopes
Iridium
Scandium
Antimony
RA usually last ~12 months
Work flow:
Pump Radioactive Tracer in one or more wellbores.
Ran GR log in all wells to analyze proppant transport between laterals as well as along pumped wellbore.
Log
Pump
Log
Log
250'
500'
Pump
500'
500'
Log
Eagle Ford
Communication during frac confirmed with solid RA tracers in most stages
Cool.
All diagnostics showed we "communicated" during the treatment.
Can we measure the effectiveness and durability of the connecting fractures?
Murray, Santa Fe ATW, Mar 2013, and URTeC 1581750


Eagle Ford: Fractures Intersecting Offset Laterals
Post Frac Pressure Communication
Pad Post Frac Pressure Communication
After Initial Flow-back
04H pressure response time lag: 55 min
02H pressure response time lag: 43 min
1) Initial conditions for all 3 wells is SI after flow-backs
2) 03H opened to flow, 02H and 04H left SI
3) Pressure response observed in 02H and 04H due to opening of 03H
Pressure (psi)
8,100
7,900
7,700
7,500
7,300
7,100
6,900
7/12/2012
7/13/2012
7/14/2012
7/15/2012
7/16/2012
7/17/2012
7/18/2012
7/19/2012
7/20/2012
02H
03H
04H
Open 03H
Eagle Ford
Some degree of connection. Black well is able to lower pressure in adjacent wells shortly after stimulation
If the fracture were an infinitely conductive open pipe, we would see a pressure pulse at the speed of sound (less than one second) instead of 50 minutes lag time
If they were infinitely conductive fracs, all pressures would overlay
Clearly, the fracs should not be envisioned as infinitely conductive pipes.
Murray, Santa Fe ATW, Mar 2013, and URTeC 1581750


Eagle Ford: Fractures Intersecting Offset Laterals
Post Frac Pressure Communication
Pad Post Frac Pressure Communication
Three Months After First Interference Test
1) All 3 wells SI for 3 days.
2) 03H opened to flow, 02H and 04H left SI
3) Pressure response observed in 02H and 04H due to opening of 03H
4) Corrupt data on the 03H
04H pressure response time lag: 81 min
02H pressure response time lag: 76 min
Pressure (psi)
6,800
6,600
6,400
6,200
6,000
5,800
5,600
9/18/2012
9/19/2012
9/20/2012
9/21/2012
9/22/2012
9/23/2012
9/24/2012
02H
03H
04H
Open 03H
3 months later, the black well is incapable of draining gas from offsets as fast as the reservoir can deliver hydrocarbons!
Lag time increased.
The wells are not redundant.
Frac connection between wells is constraining productivity, clearly not behaving like an infinitely conductive frac.
Where did the created fracture heal? Near wellbore void? At laminations? At some distance between wells?
Murray, Santa Fe ATW, Mar 2013, and URTeC 1581750


If I cannot sustain lateral continuity with conventional frac designs, what about VERTICAL continuity?
Failure to breach all laminae?
Will I lose this connection due to crushing of proppant in horizontal step?
Narrower aperture plus significantly higher stress in horizontal steps?
Our understanding of frac barriers and k_v should influence everything from lateral depth to frac fluid type, to implementation
Woodford Shale Outcrop

Logic: Can I be creating highly conductive vertical fracs?



If I created this infinitely conductive vertical frac,

lateral placement (depth) wouldn't significantly affect productivity in Eagle Ford.

But it does!

[Marathon, EF Energy, SLB, EP Energy in Aug 2013 ATW]

Either my fracs:

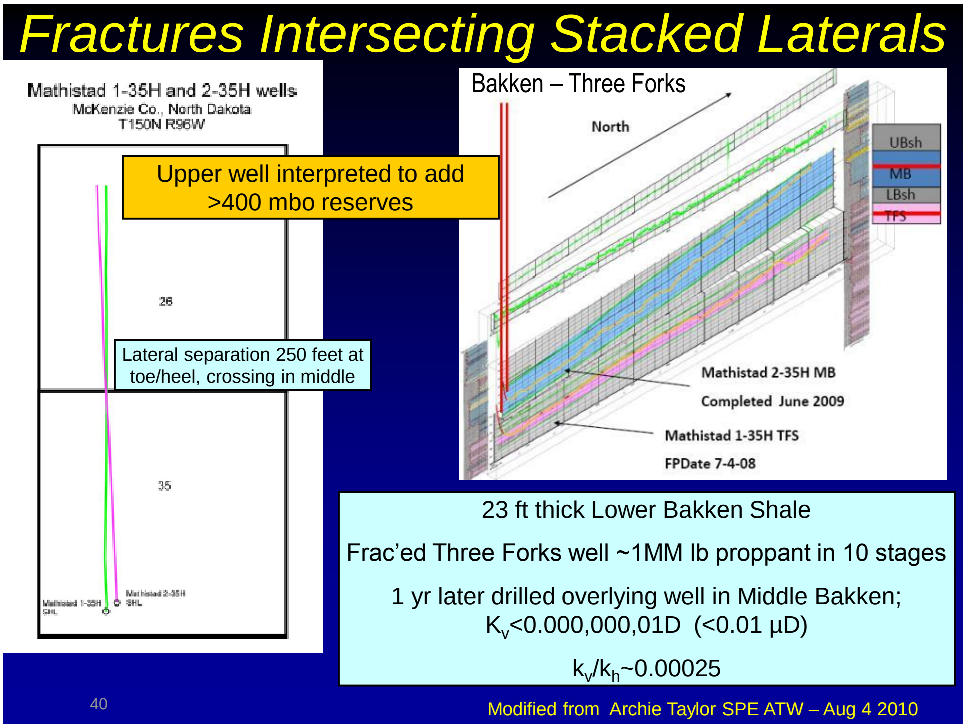
1. fail to penetrate all the pay, or
2. pressure losses are very high in my fracs, or
3. I'm losing continuity
4. Other mechanisms (liquid banking, etc.)

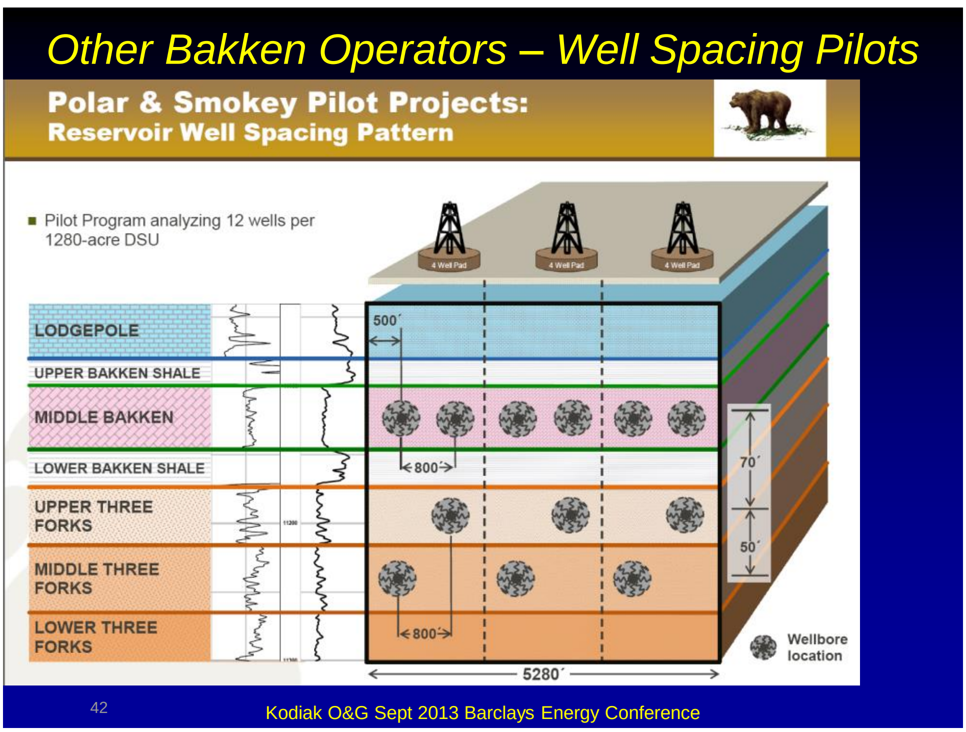
There are logical adjustments to frac design to attempt to address each mechanism

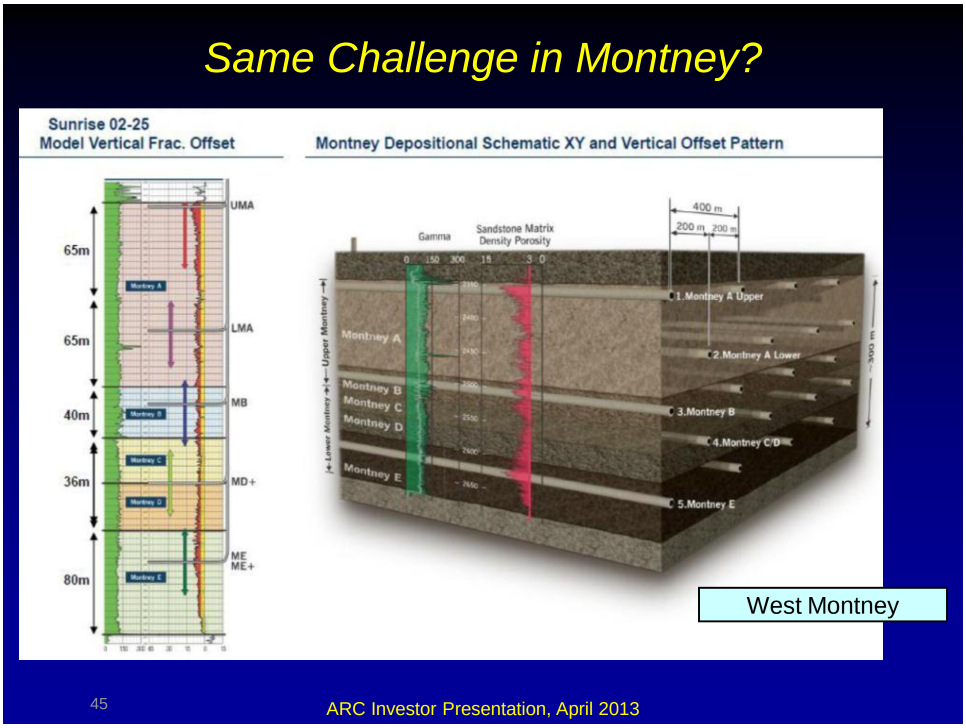
Eagle Ford Shale Outcrop
Peschler, AAPG

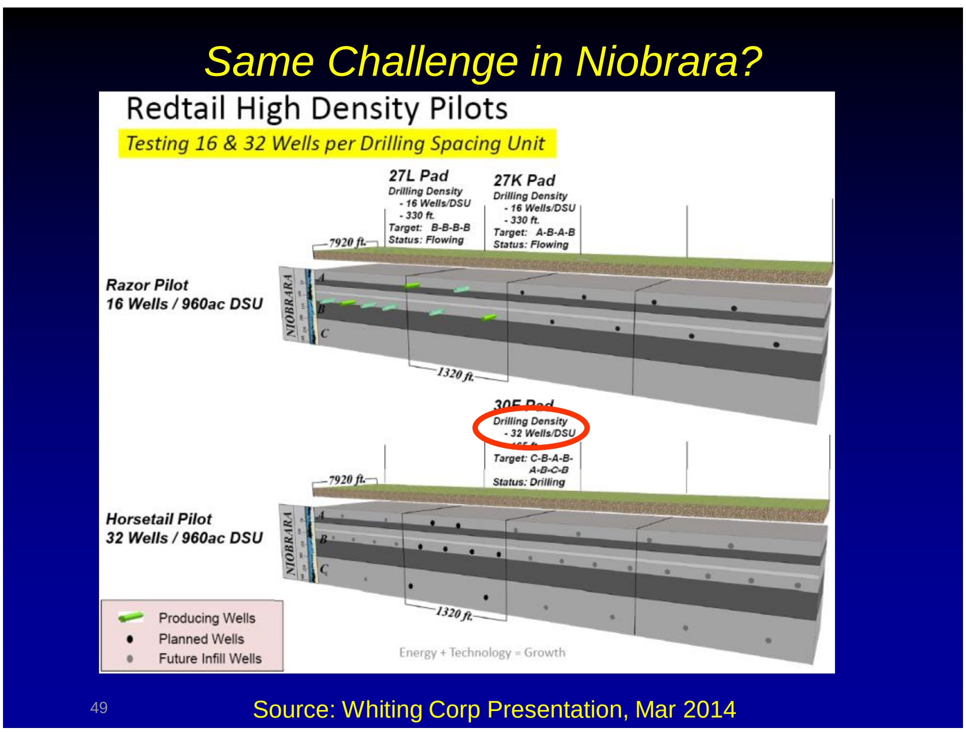
Laminated on every scale?

Figure 2 – On every scale, formations may have laminations that hinder vertical permeability and fracture penetration. Shown are thin laminations in the Middle Bakken [LeFever 2005], layering in the Woodford [outcrop photo courtesy of Halliburton], and large scale laminations in the Niobrara [outcrop and seismic images courtesy of Noble]

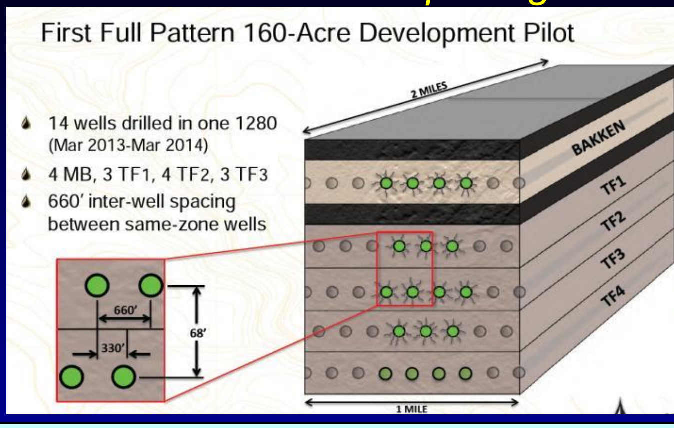

Fractures Intersecting Stacked Laterals
Mathistad 1-35H and 2-35H wells
McKenzie Co., North Dakota
T150N R96W
Upper well interpreted to add >400 mbo reserves
26
Lateral separation 250 feet at toe/heel, crossing in middle
35
Mathistad 1-35H SHL
Mathistad 2-35H SHL
Bakken – Three Forks
North
UBsh
MB
LBsh
TFS
Mathistad 2-35H MB
Completed June 2009
Mathistad 1-35H TFS
FPDate 7-4-08
23 ft thick Lower Bakken Shale
Frac'ed Three Forks well ~1MM lb proppant in 10 stages
1 yr later drilled overlying well in Middle Bakken; K_v<0.000,000,01D (<0.01 µD)
k_v/k_h~0.00025
40
Modified from Archie Taylor SPE ATW – Aug 4 2010


Other Bakken Operators – Well Spacing Pilots
Polar & Smokey Pilot Projects:
Reservoir Well Spacing Pattern
Pilot Program analyzing 12 wells per 1280-acre DSU
4 Well Pad
4 Well Pad
4 Well Pad
LODGEPOLE
UPPER BAKKEN SHALE
MIDDLE BAKKEN
LOWER BAKKEN SHALE
UPPER THREE FORKS
MIDDLE THREE FORKS
LOWER THREE FORKS
500´
800
800
70´
50´
5280´
Wellbore location
42
Kodiak O&G Sept 2013 Barclays Energy Conference


Same Challenge in Montney?
Sunrise 02-25
Model Vertical Frac. Offset
Montney Depositional Schematic XY and Vertical Offset Pattern
65m
65m
40m
36m
80m
UMA
LMA
MB
MD+
ME
ME+
Gamma
Sandstone Matrix Density Porosity
400 m
200 m
200 m
300 m
Upper Montney
Lower Montney
Montney A
Montney B
Montney C
Montney D
Montney E
1.Montney A Upper
2.Montney A Lower
3.Montney B
4.Montney C/D
5.Montney E
West Montney
45
ARC Investor Presentation, April 2013


Same Challenge in Niobrara?
Redtail High Density Pilots
Testing 16 & 32 Wells per Drilling Spacing Unit
27L Pad
Drilling Density
- 16 Wells/DSU
- 330 ft.
Target: B-B-B-B
Status: Flowing
27K Pad
Drilling Density
- 16 Wells/DSU
- 330 ft.
Target: A-B-A-B
Status: Flowing
7920 ft.
1320 ft.
Razor Pilot
16 Wells / 960ac DSU
NIOBRARA
A
B
C
30E Pad
Drilling Density
- 32 Wells/DSU
Target: C-B-A-B-A-B-C-B
Status: Drilling
7920 ft.
1320 ft.
Horsetail Pilot
32 Wells / 960ac DSU
Producing Wells
Planned Wells
Future Infill Wells
Energy + Technology = Growth
49
Source: Whiting Corp Presentation, Mar 2014

Continuity Loss
Necessitates vertical downspacing?



A number of operators are investigating "vertical downspacing" in the Bakken petroleum system. Similar efforts underway in Niobrara, Woodford, Montney and Permian formations.

Is it ***possible*** that some number of these expensive wells could be unnecessary if fractures were redesigned?

"Array Fracturing" or "Vertical Downspacing" Image from CLR Investor Presentation, Continental, 2012

50

Wow

1. We know we have pumped proppant from one wellbore into another.
2. We can directly interrogate the conductivity and durability of the fracs.
3. The results are not pretty.

So what are some of the culprits that cause fracs to not perform as we modeled?

Portions of the following list are discussed in URTeC 1579008

52

Potential Mechanisms – Frac Collapse (1 of 2)

- Degradation of proppant over time
- Overflushing of proppant from the near-wellbore area in transverse fracs
- Flowback of proppant from near-wellbore area in transverse fracs
- Failure to place sufficient proppant concentrations throughout the created network (both lateral and vertical placement)
- Insufficient conductivity to accommodate high velocity hydrocarbon flow due to convergence near-wellbore, especially in liquid-rich formations
- Embedment of proppant
- Thermal degradation of sand-based proppants
- Introduction of extremely low quality sand and low quality ceramic proppants during past decade
- Complex frac geometry requiring stronger or more conductive proppant in the turns and "pinch points". Inability to push proppant through tortuous network.
- Perf design, poor alignment with frac or other issues
- Losing/wasting proppant out of zone – poor contact with "pay". Or poor transport.
- Insufficient proppant concentrations, resulting in discontinuous proppant packs after frac closure. This problem is compounded when operators specify intermediate or high density ceramics but pump the same mass concentration, resulting in reduced fracture width and 20% to 30% smaller frac geometry.
- Wellbores plugged with frac sand somehow providing complete isolation

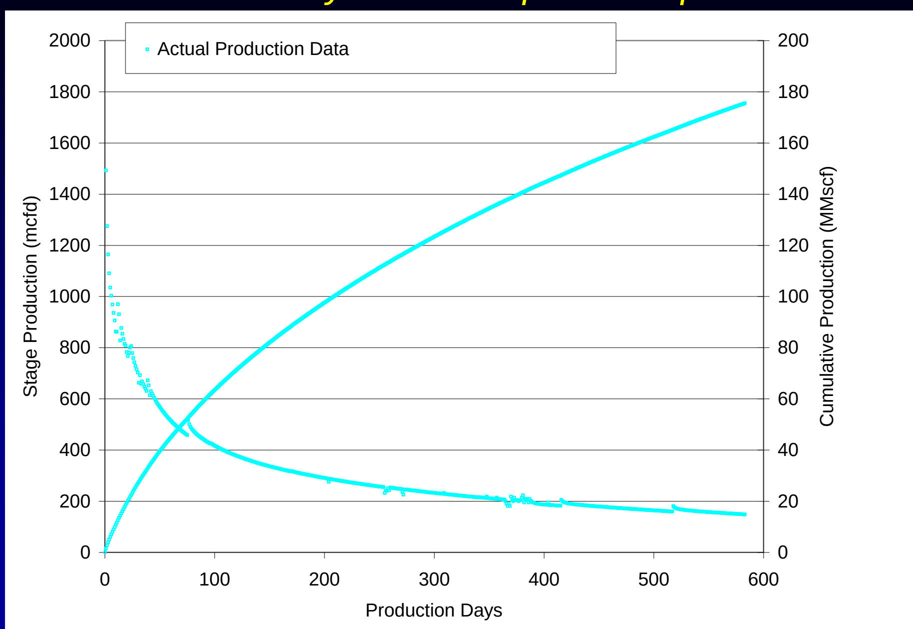
Potential Mechanisms – Frac Collapse (2 of 2)

- Fluid sensitivity – evidence that some frac fluids "soften" the formation allowing more significant embedment and/or spalling
- Gel residue or durable gel filtercakes deposited using crosslinked fluids that may completely occlude narrow propped fractures
- Precipitation of salt, asphaltenes, barium sulfate and calcium carbonate scales or migration of fines (formation fines or pulverized proppant). Bio-slime or induced corrosion?
- Potential for chemical diagenesis of proppant (controversial and conflicting laboratory studies). To date, proppant samples recovered from wells do not appear to indicate formation of zeolites
- Failure to recover water from liquid-submerged portions of the fracture below the wellbore elevation
- Aggressive production techniques to report high IPs (some fracs vulnerable to drawdown)
- Industry rush to secure acreage as "held by production" without adequate attention to completion effectiveness or optimization. Frenetic development pace has reduced many completion engineers' primary responsibility to be scheduling and assuring materials are available, with less time devoted to optimization of well productivity
- Rel perm/condensate banking/capillary pressure/water block Emulsions
- Other unrecognized mechanisms
  - Stress shadowing causing unanticipated issues
    - Next stage "compresses" existing frac. Might move slurry in existing fracs containing XL gel
  - Continued slippage of frac faces after closure impacting continuity
  - Pore pressure depletion/subsidence/compaction "stranding" thin proppant ribbons
  - Others?

These direct measurements are compelling. Our fracs are NOT highly conductive and durable.

Why didn't the industry recognize many years ago that frac conductivity was insufficient?

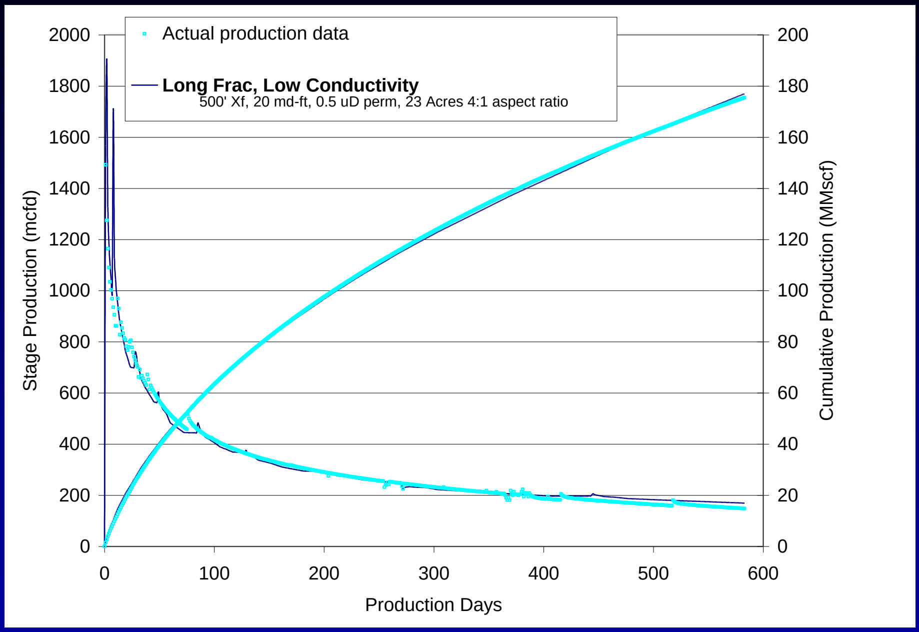
With what certainty can we explain this production?



56

SPE 106151 Fig 13 – Production can be matched with a variety of fracture and reservoir parameters

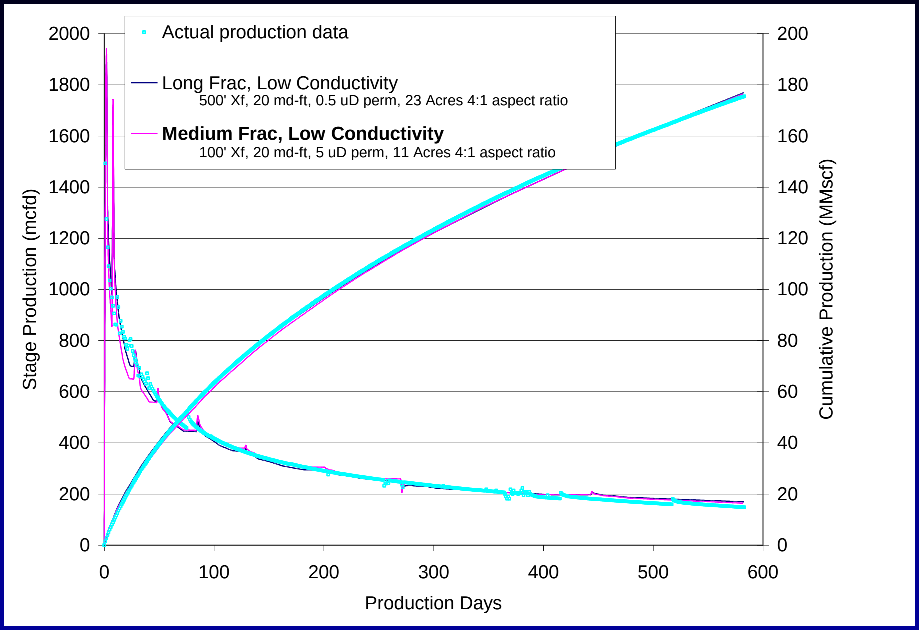
Nice match to measured microseismic, eh?



57

SPE 106151 Fig 13 – Production can be matched with a variety of fracture and reservoir parameters

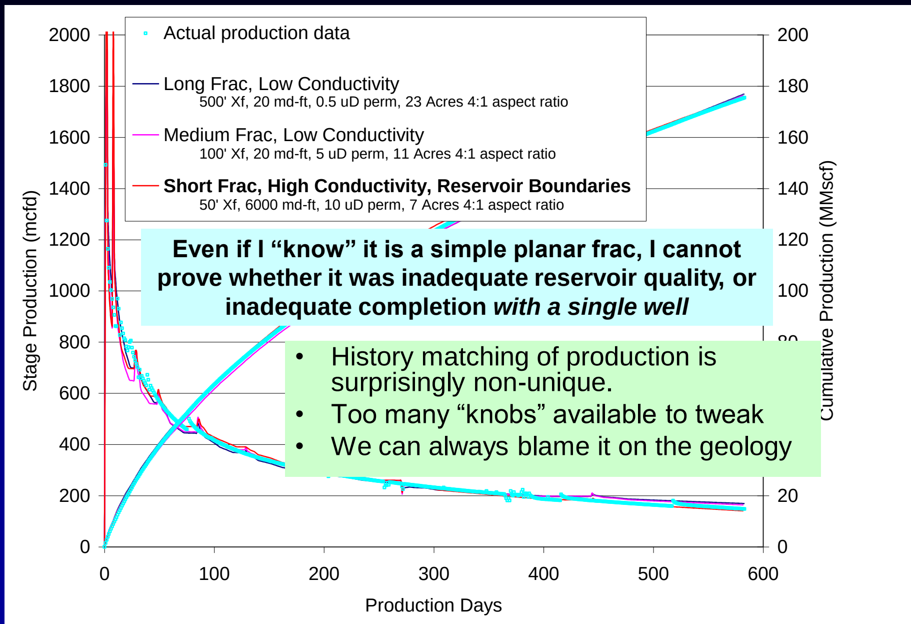
Is this more accurate? Tied to core perm



58

SPE 106151 Fig 13 – Production can be matched with a variety of fracture and reservoir parameters

Can I reinforce my misconceptions?



Even if I "know" it is a simple planar frac, I cannot prove whether it was inadequate reservoir quality, or inadequate completion *with a single well*

- History matching of production is surprisingly non-unique.
- Too many "knobs" available to tweak
- We can always blame it on the geology

59

SPE 106151 Fig 13 – Production can be matched with a variety of fracture and reservoir parameters

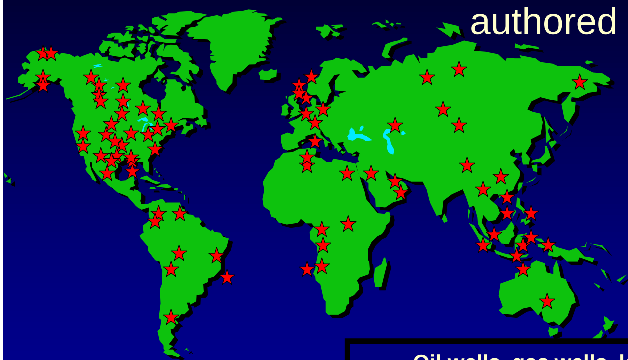
Removing the Uncertainty

- If we require a production match of two different frac designs, we remove many degrees of freedom
  - lock in *all* the "reservoir knobs"!
  - Attempt to explain the production results from initial frac *AND* refrac
    - 143 published trials in SPE 134330
    - 100 Bakken refracs 136757
  - Require simultaneous match of two different frac designs in same reservoir!
    - 200+ trials in SPE 119143

60

Field Studies Documenting Production Impact with Increased Fracture Conductivity

>200 published studies identified, authored by >150 companies



Oil wells, gas wells, lean and rich condensate
Carbonate, Sandstone, Shale, and Coal

Well Rates	**Well Depths**
1 to 25,000 bopd 0.25-100 MMSCFD	100 to 20,000 feet

62

SPE 119143 tabulates over 200 field studies 2009, dominated by vertical and XLG

Production Benefit

- In >200 published studies and hundreds of unpublished proppant selection studies,
- Operators frequently report greater benefit than expected using:
  - Higher proppant concentrations (if crosslinked)
  - More aggressive ramps, smaller pads
  - Screen outs (if sufficiently strong proppant)
  - Larger diameter proppant
  - Stronger proppant
  - Higher quality proppant
  - More uniformly shaped & sized proppant
- Frac conductivity appears to be much more important than our models or intuition predict!

64

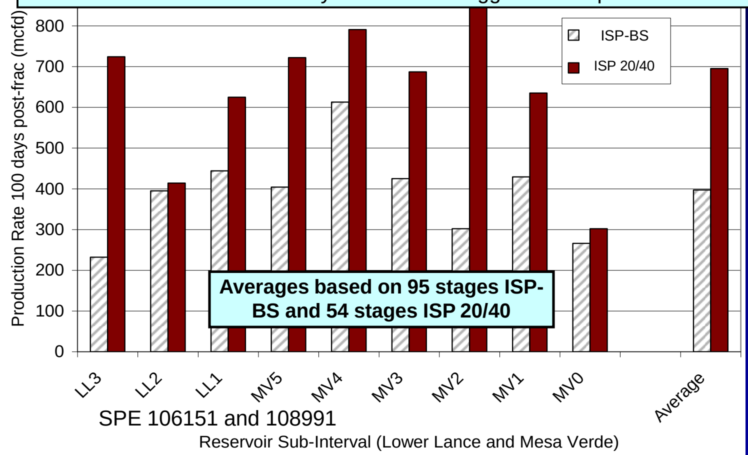
A tabulation of 200 papers in SPE 119143

We are 99.9% certain the Pinedale Anticline was constrained by proppant quality

The important takeaway is NOT that you need Proppant B versus Proppant A

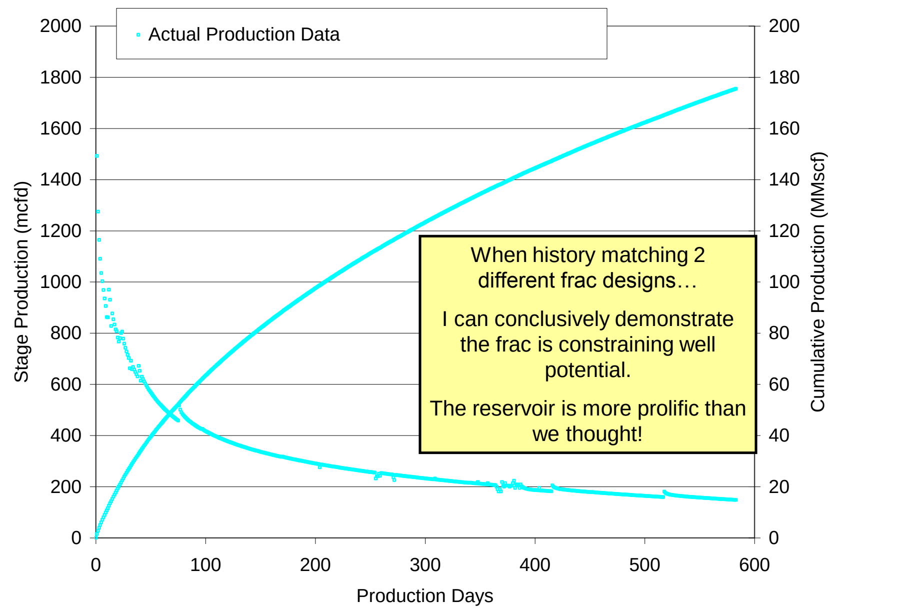
The critical learning is that you are NOT optimized and the reservoir is capable of significant increases in production

If you can make the wells 70% more productive with a modest design change, how much better would they be with more aggressive improvements?



70% increase in productivity achieved with a more uniformly sized proppant!

With what certainty can we explain this production?



When history matching 2 different frac designs…

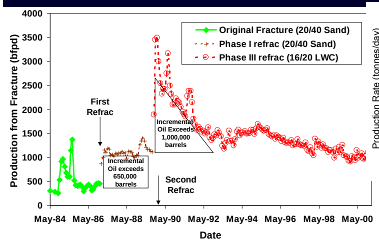
I can conclusively demonstrate the frac is constraining well potential.

The reservoir is more prolific than we thought!

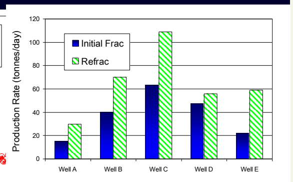
SPE 106151 Fig 13 – Production can be matched with a variety of fracture and reservoir parameters

Increased Conductivity Refracs?

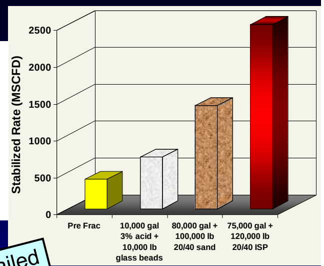
Dozens of examples in literature



Pospisil, 1992 – 6 years later, 20 mD oil

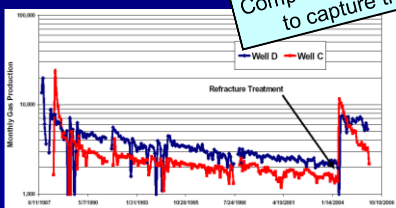


Dedurin, 2008, Volga-Urals oil

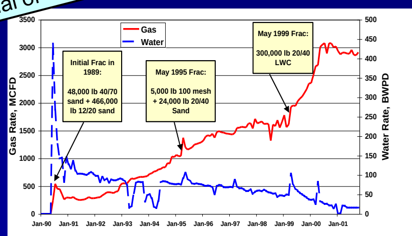


...nnis, 1989 – sequential refracs, tight gas

Compelling evidence that our initial fracs failed to capture the potential of the reservoir



Shaefer, 2006 – 17 years later, tight gas



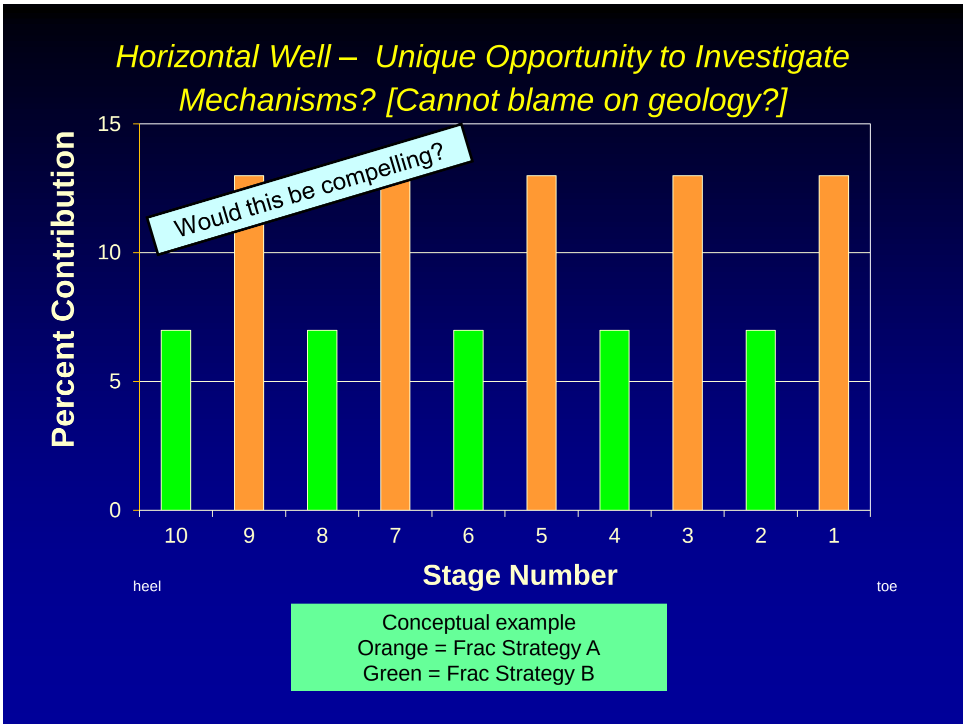
Vincent, 2002 – 9 years later, CBM

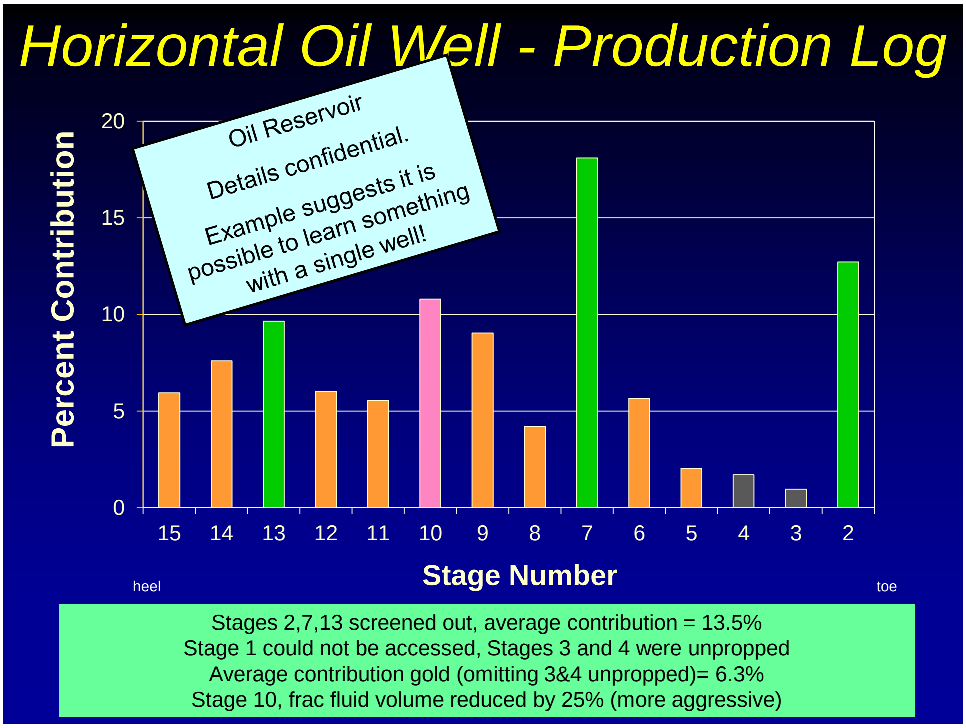
69

See SPE 134330 and 136757

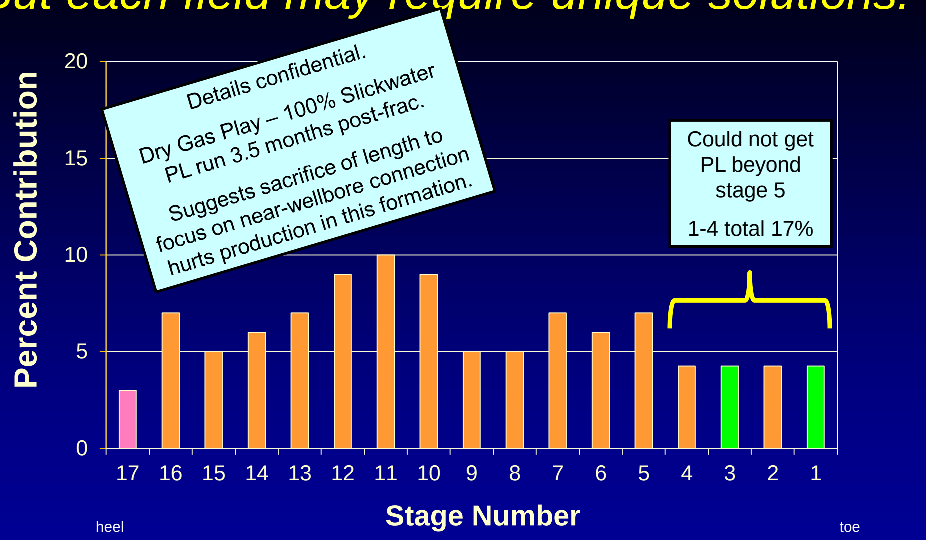
Successful refracs have been performed in Barnett, Eagle Ford, Bakken, Marcellus, Haynesville, Niobrara, Spraberry, Wolfcamp…

What did we miss the first time?


Horizontal Well – Unique Opportunity to Investigate Mechanisms? [Cannot blame on geology?]
Would this be compelling?
Percent Contribution
15
10
5
0
10 9 8 7 6 5 4 3 2 1
Stage Number
heel
toe
Conceptual example
Orange = Frac Strategy A
Green = Frac Strategy B


Horizontal Oil Well - Production Log
Oil Reservoir
Details confidential.
Example suggests it is possible to learn something with a single well!
Percent Contribution
20
15
10
5
0
15 14 13 12 11 10 9 8 7 6 5 4 3 2
Stage Number
heel
toe
Stages 2,7,13 screened out, average contribution = 13.5%
Stage 1 could not be accessed, Stages 3 and 4 were unpropped
Average contribution gold (omitting 3&4 unpropped)= 6.3%
Stage 10, frac fluid volume reduced by 25% (more aggressive)

But each field may require unique solutions!



Could not get PL to TD; Stages 1-4 total contribute 17%
Stages 1 and 3 screened out, placing 20% and 93% of designed job
Stages 5-16, initiated sweeps, increased perf density 3 to 6 spf, max concentration around 1 ppg
Stage 17 did not screenout despite 2.5 ppg & no sweeps. 40% the fluid, similar proppant mass.

Conclusions

- Hydraulic Fracs
  - The premier way to touch rock
  - We look like heroes even with poorly designed fracs
- Optimized?
  - Not even close
  - Perhaps 90% of the created frac volume is ineffective?
  - Traditional frac design logic is flawed, yielding non-optimal outcomes
- Ramifications
  - To recover the available reserves, you must either infill drill, refrac, or improve initial frac effectiveness
- Field Results
  - Demonstrate there is large potential to improve well productivity and profitability