Horizontal & Multi-Fractured Wells

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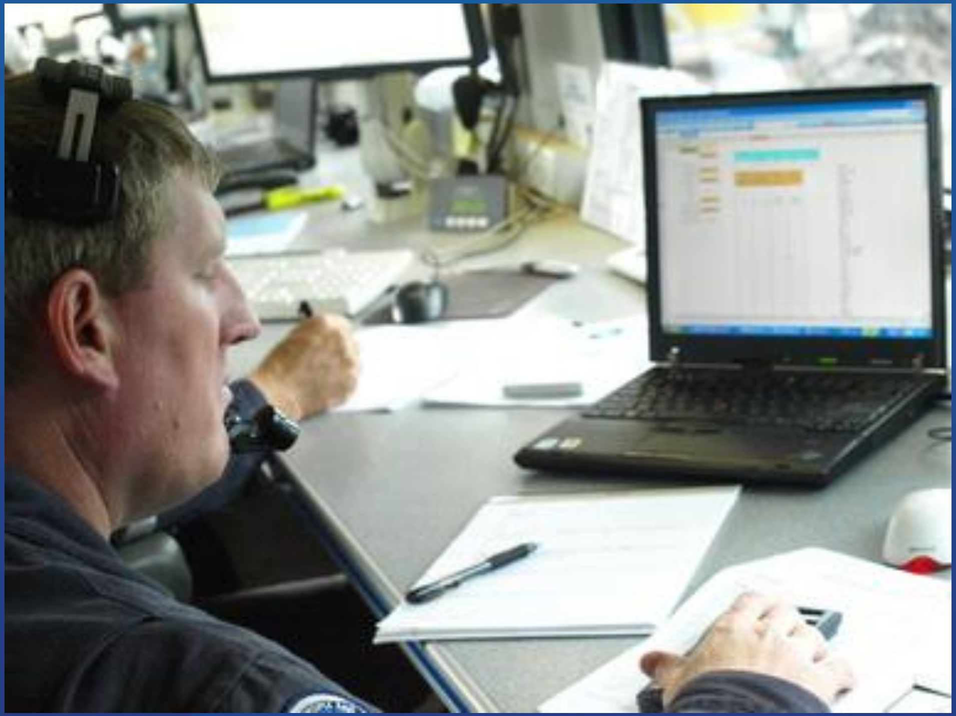
Fracturing Horizontal Wellbores



Vertical, Deviated or Horizontal?

- Vertical Wells
  - Cheap to Drill
  - Easiest to Fracture
  - Requires lots of wellbores and lots of locations
- Deviated Wells
  - Significant Fracturing Problems
  - Increased Costs
  - Reduced number of locations

Vertical, Deviated or Horizontal?

- Deviated Wells (continued)
  - Usually very complex connection between fracture and wellbore
    - Affects both treatment placement and production
  - Solution is to plan well correctly
    - Azimuth of deviated section parallel to maximum horizontal stress, or
    - Drill S-shaped wells to penetrate reservoir with vertical wellbore

Vertical, Deviated or Horizontal?

- Deviated Wells (continued)

Uncontrolled Wellbore Azimuth

Wellbore Azimuth Parallel To Fracture Azimuth

S-Shaped Wellbore

Cased and Cemented or Open Hole?

- Open Hole Fracturing
  - Easier Connection Between Fracture and Wellbore
  - Cost Savings
    - Liner, Cementing, Rig Time
  - Specialised Systems Required to Isolate Individual Sections to Control Fracture Initiation

Cased and Cemented or Open Hole?

- Cased Hole Fracturing
  - Increased Cost
    - Liner, Cementing, Rig Time
  - Requires Complex Completion Systems
  - Precise Control of Fracturing Process
  - Traditionally, Most Horizontal Wells that are Planned to be Fractured are Cased and Cemented
    - New Technology is Changing This

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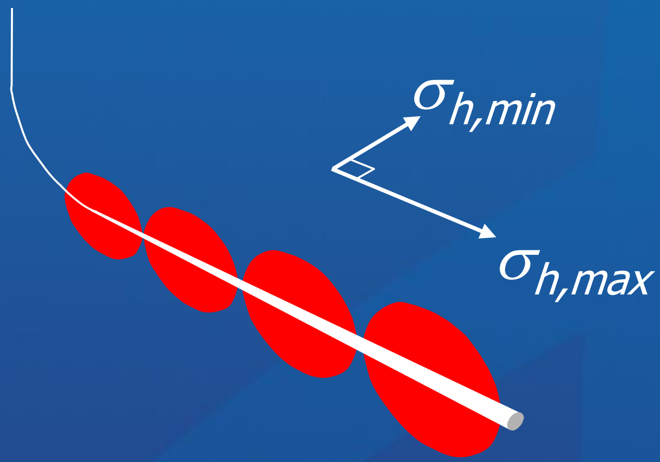
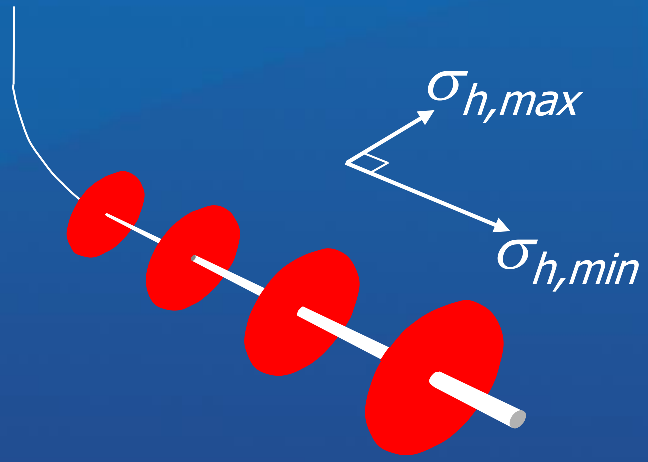
Horizontal Wellbores



Longitudinal Fracs

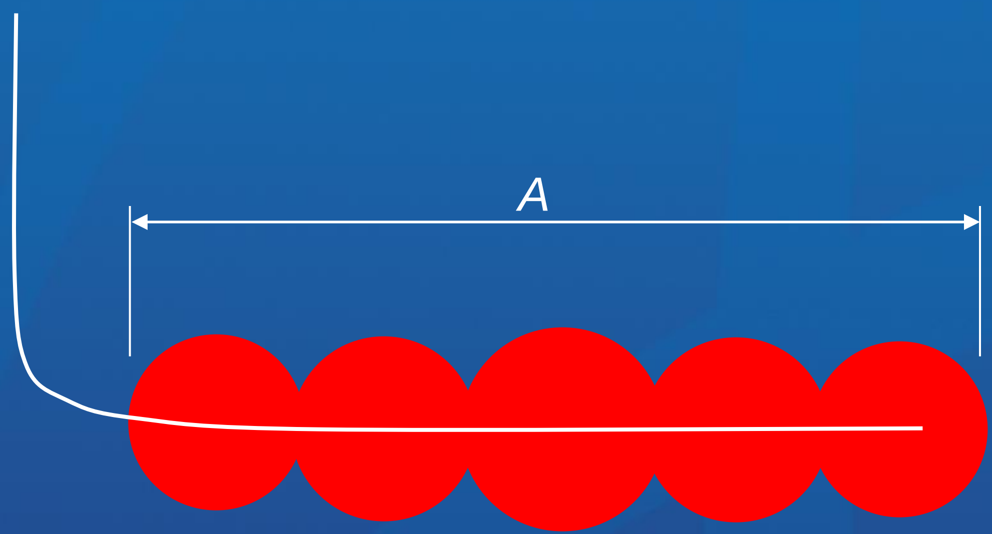


Transverse Fracs

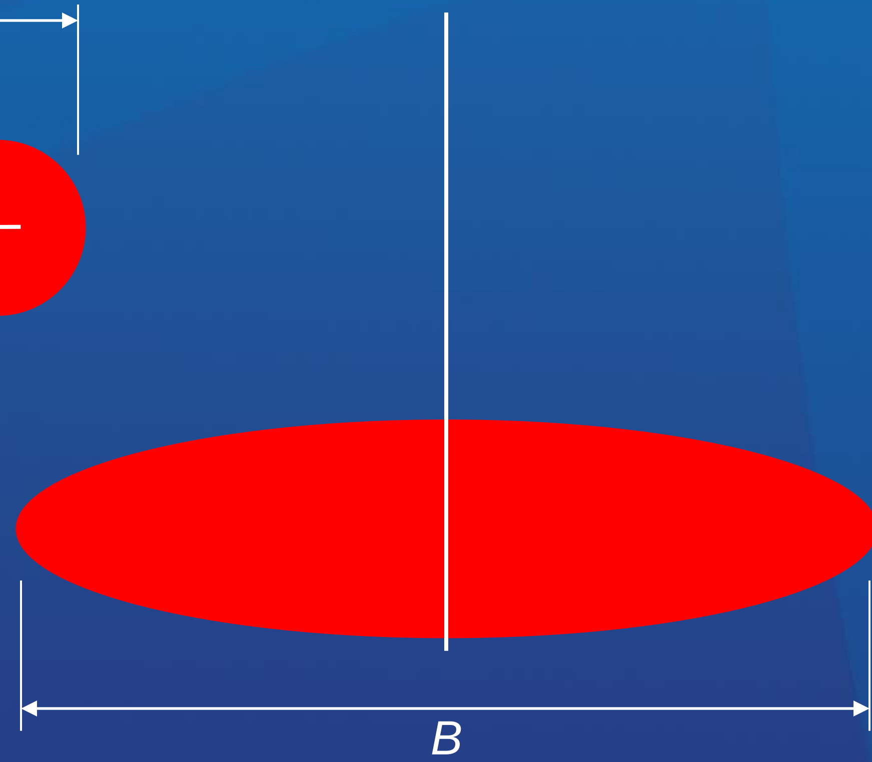
Longitudinal or Transverse?

- Longitudinal
  - Longitudinal fracs are easiest to pump and have the simplest connection to the wellbore
  - Post-fracture production is not “choked” at the contact between fracture and wellbore
  - Easiest to predict post-fracture production
  - Wellbore must be drilled within +/- 15 ° of maximum horizontal stress azimuth.
    - Anything else behaves like a transverse fracture

Longitudinal Fractures



Approximately Equivalent
Post-Frac Behaviour when
$A \approx B$



Longitudinal Fractures

- Designing Longitudinal Fractures
  - Start with “equivalent” single fracture on vertical wellbore
  - Use Unified Frac Design to design geometry of single fracture
  - Place multiple fractures along horizontal wellbore
    - Sufficient number to provide complete coverage
    - Maintain UFD length to width ratio

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Longitudinal Fractures

- Unified Frac Design:
  - Proppant number, N_p
  - A measure of how efficiently we are using a given volume of proppant
    - Calculated from proppant permeability, reservoir permeability, average propped width and the reservoir drainage dimensions

Economides *et al*, 2001

Longitudinal Fractures

- Dimensionless Fracture Conductivity, C_{fD}
  - A measure of how effective the propped fracture geometry is at draining the formation

$$C_{fD} = \left(\frac{\text{The ability of the fracture to deliver reservoir fluids to the wellbore}}{\text{The ability of the formation to deliver reservoir fluids to the fracture}} \right)$$

Longitudinal Fractures

– We use N_p to calculate the optimum dimensionless fracture conductivity $C_{fD,opt}$
  - $C_{fD,opt}$ gives us the best possible combination of propped length and propped width, for any given set of circumstances
  - Optimum fracture length, $x_{f,opt}$, and width, w_{opt}:-

$$\frac{w_{opt}}{x_{f,opt}} = C_{fD,opt} \frac{\text{Formation permeability}}{\text{Proppant permeability}}$$

– We use fracture simulators to determine a pumping schedule to produce $x_{f,opt}$ and w_{opt}

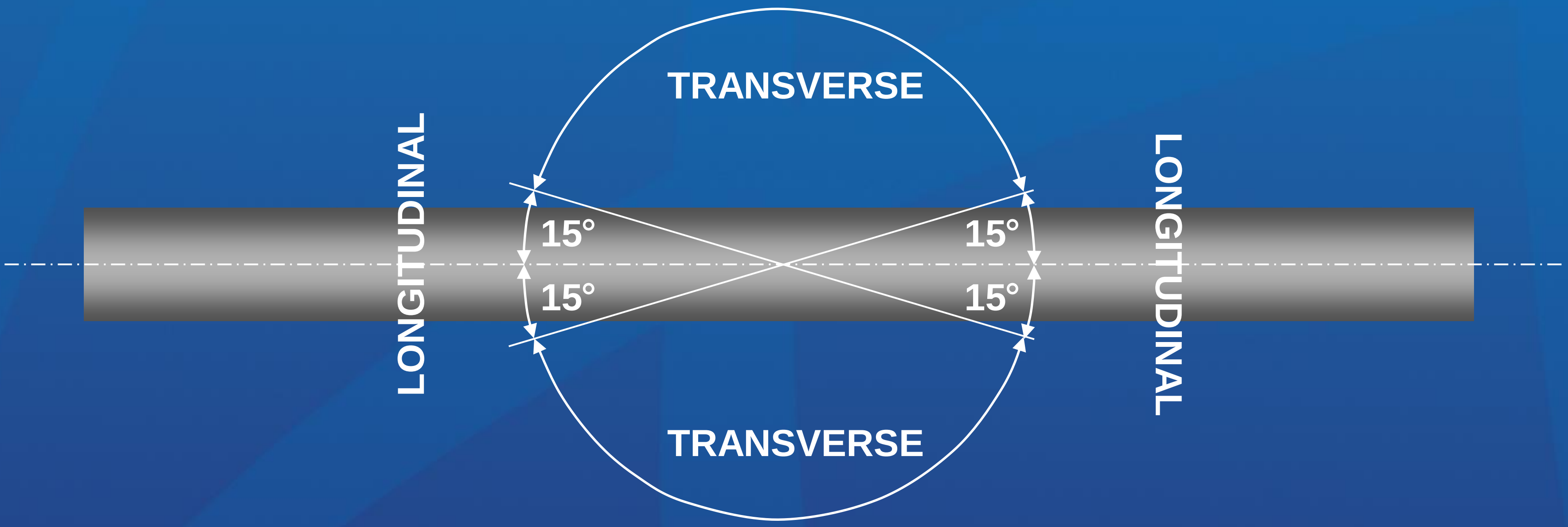
Longitudinal Fractures

- N_p is also used to calculate $J_{D,\max}$
  - J_D = dimensionless Productivity Index (PI)
    - Normal PI with the effects of permeability, viscosity and net height removed
    - Used to estimate post-treatment production
  - $J_{D,\max}$ is the maximum theoretical dimensionless PI after a frac job
  - Theoretical PI is compared to actual post-frac PI to measure effectiveness of treatment
    - Actual post-job J_D is usually 50 to 80% of $J_{D,\max}$

Economides & Martin, 2007

Transverse Fractures

Angle of Fracture from Wellbore

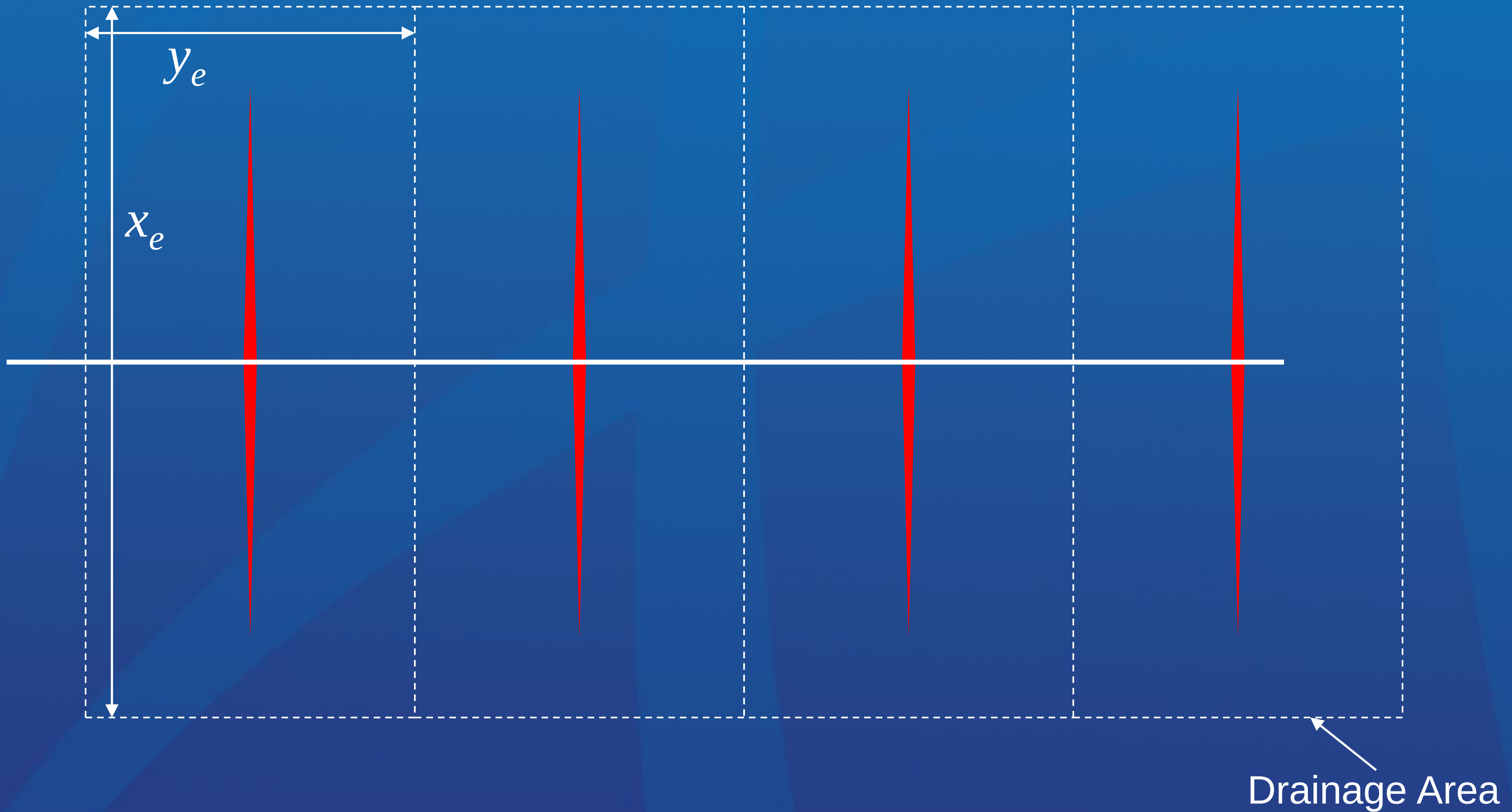


Most Wellbores, Drilled Without Knowledge of (or Planning for) Fracture Azimuth, will Produce Transverse Fracs

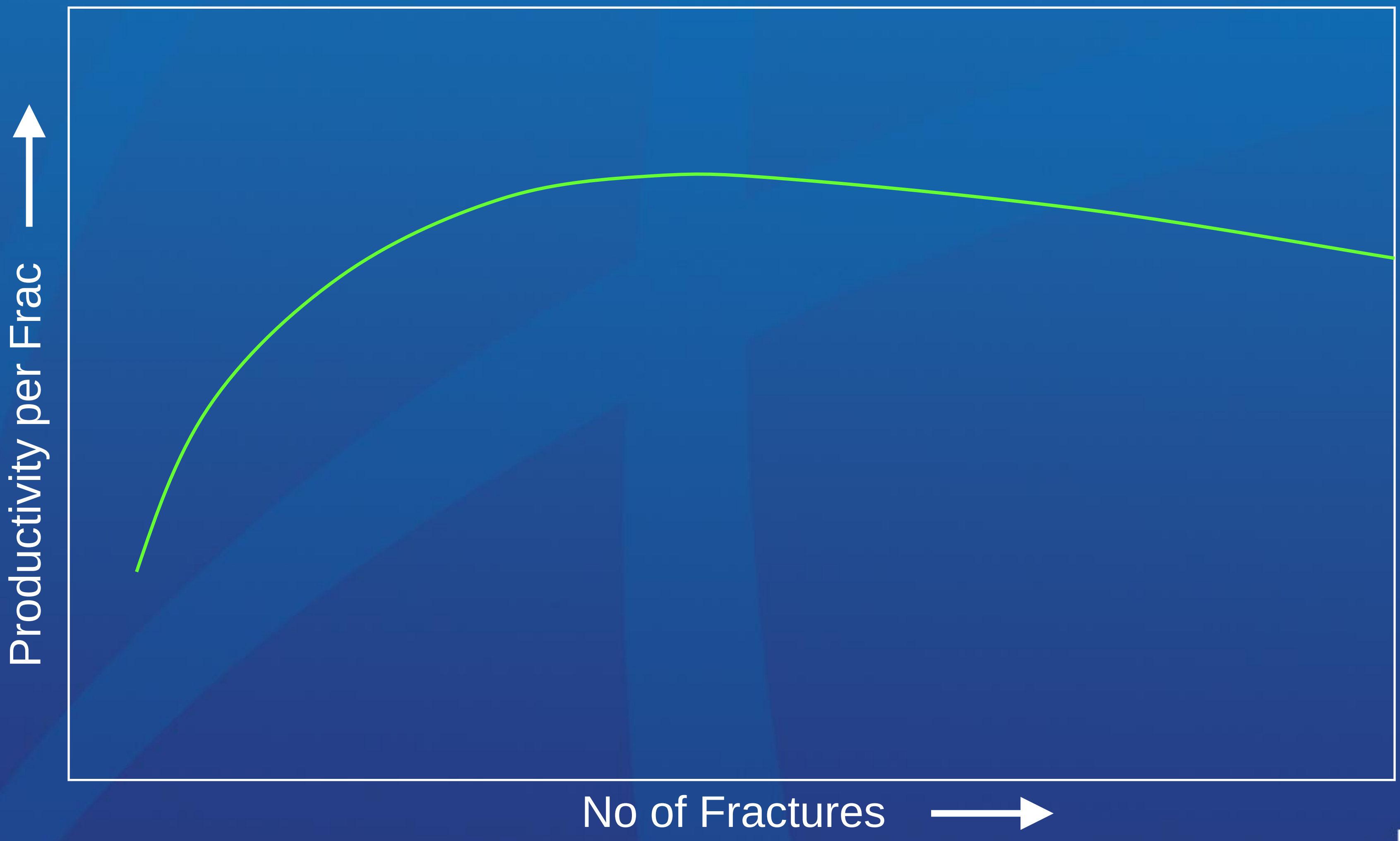
Transverse Fractures

- Transverse fractures have a very poor connection to the wellbore.
  - This makes frac jobs hard to pump due to tortuosity
  - This chokes production and dramatically reduces fracture effectiveness
  - Open hole fractures have a much cleaner connection between the fracture and the wellbore than cased and perforated fractures

Transverse Fractures



Transverse Fractures

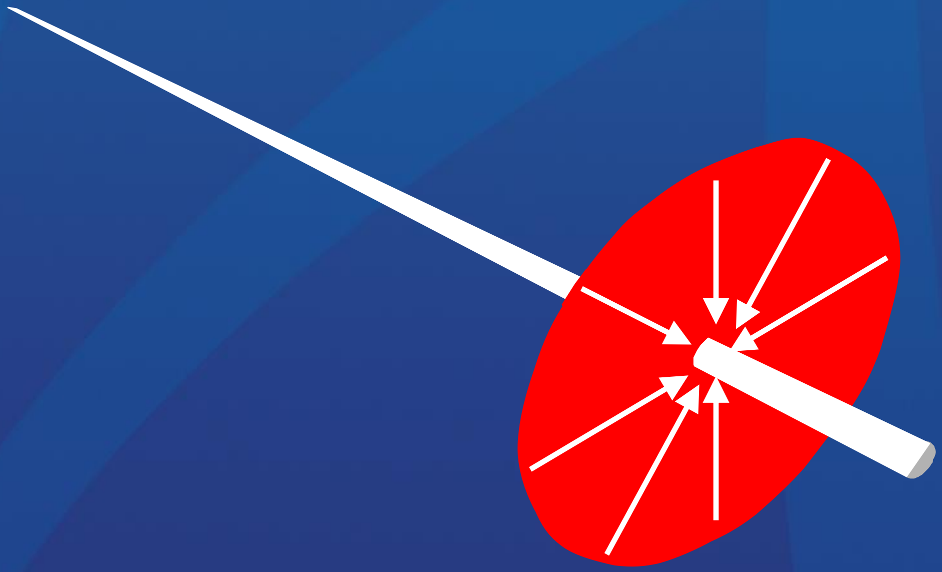


Transverse Fractures

- How Many Fractures?
  - Dependent upon x_f, k, k_f, x_e, and w_{ave}
  - Complex iterative process
  - Useful to fix a value of x_f based on height growth
    - Zone height, water or gas contacts
    - Find N_p and $C_{fD,opt}$ for fixed proppant volume
    - Calculate J_D per frac for optimum geometry
    - Calculate total J_D against number of fracs
    - NPV analysis to get optimum number of fracs
    - Repeat for different proppant volumes, to get plot of optimum NPV against proppant volume per frac, for various numbers of fracs
    - Repeat process for different values of x_f

Transverse Fractures

- Gas Wells – Important
  - Near well bore choking effect
    - Caused by the very limited area of contact between fracture and wellbore
    - Can seriously affect productivity in medium and high permeability gas wells



$$s_c = \frac{kh}{k_f w}\left[\ln\left(\frac{h}{2r_w}\right) - \frac{\pi}{2}\right]$$

$$J_{DTH} = \frac{1}{(1/J_{DV}) + s_c}$$

Economides & Martin, 2007, 2010

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Transverse Fractures

- Gas Wells – Important
  - Turbulent flow effects are also significant

$$k_{f,g} = \frac{k_f}{1 + N_{Re}}$$

- The combined effect of choking and turbulence can reduce the flow by 80 to 90% in high permeability gas formations

Economides & Martin, 2007, 2010

Completion Type

- Consider which type of completion is best for your gas well

Permeability Range, md	Best Technical Solution	Comments
> 5	Horizontal Wellbore, Longitudinal Fractures	In all cases
0.5 to 5	Horizontal Wellbore, Longitudinal Fracture OR Vertical Well with Fracture	Dependent upon relative costs of vertical and horizontal wells
0.1 to 0.5	Horizontal Wellbore, Transverse Fractures	Above 0.5 md, the choked connection means that transverse fractures are relatively inefficient
< 0.1	Horizontal Wellbore, Transverse Fractures OR Vertical Well with Fracture	Dependent upon relative costs of vertical and horizontal wells

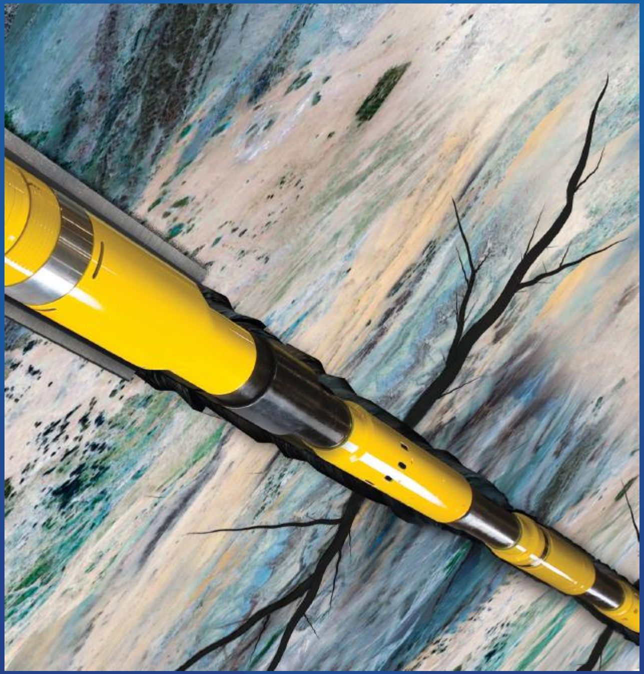
Economides & Martin, 2007, 2010

Fracturing Multiple Intervals

Completion Options

- Open Hole
  - Sliding side doors separated by open hole packers
- Cased Hole
  - Sliding side door systems
    - Liner-conveyed
    - Completion-conveyed
  - “Plug and Perf” systems
    - Various different systems available
  - Coiled tubing-based systems
    - Fracturing through CT
    - Annular

Open Hole Systems



- Multizone open hole completion systems use a series of sliding side doors, separated by open hole packers
- SSDs are initially closed and are opened by a ball landing on a seat
- Seats have progressively larger diameters moving upwards

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Open Hole Systems

- Up to 40 zones per completion
- 3 different types of packer available
  – Inflatable, swellable, squeeze
- Typically run as a liner
  – Liner hanger set conventionally
  – First ball sets the packers and opens the lowest interval
    - Swellables have to be left 24 to 48 hours
  – Subsequent balls open successive intervals and close off the previous interval
- All zones flowed back together after fracturing operations have finished

Open Hole Systems

- Applications
  - Horizontal or vertical wellbores
  - Cased or open hole
  - Acid or proppant stimulation treatments
- Advantages
  - One-trip installations
  - Reduction in completion time
- Disadvantages
  - Control of fracture initiation
  - Fluid recovery
  - Lack of flexibility
  - Ball recovery

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Open Hole Systems

- Disintegrating Frac Balls
  - New technology

Cased Hole Systems

- In general, cased hole systems offer greater flexibility and better control of fracture initiation
  - Most systems allow perforations to be designed zone by zone
  - The point of fracture initiation is tightly controlled
- However, in general cased hole systems are more expensive and require significantly more rig time
  - In addition to the time and expense of cementing a horizontal liner in place
  - In spite of this, there are still more cased and cemented horizontal multizone wells being completed than open hole wells

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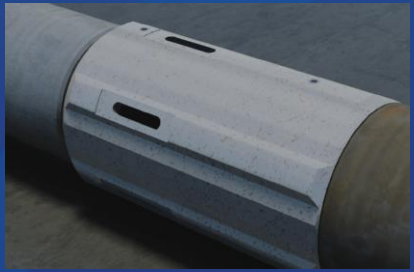
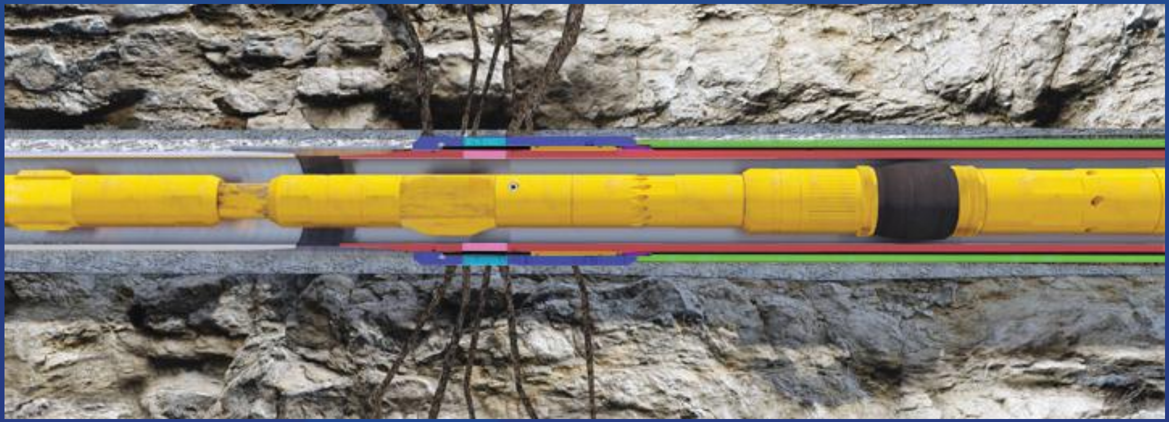
Cased Hole Systems

- Casing-Conveyed SSDs
  - SSD run on casing or liner and cemented into place
  - SSDs can be opened in several different ways
    - Coiled tubing, with a packer positioned below the SSD to provide isolation
    - Balls, similar to open hole systems
    - Darts or “frac bombs”
  - Fluid pressure is used to break cement behind SSD
    - Acid soluble cement systems are also used





Cased Hole Systems

- Completion-conveyed SSDs
  - A series of SSDs separated by squeeze packers are RIH on a tubing string.
    - Liner is perforated prior to completion running
    - SSDs manipulated by coiled tubing between zones
  - Technically the best system for zonal isolation, controlling fracture initiation and post-treatment fluid recovery
    - Very heavy on rig time

Cased Hole Systems

- “Plug and Perf” systems
  - Perforate, stimulate, isolate
  - Move from the bottom of the well to the top
    - Perforate the lowest interval
    - Perform the treatment
    - Recover the frac fluid, if desired
    - Isolate the interval
      - Wireline/CT conveyed plugs
      - Sand plugs
    - Repeat as often as required
    - Go back in with CT and remove isolation systems

Cased Hole Systems

- Coiled Tubing Methods
  - Fracturing through CT
    - All intervals perforated before frac operations
    - Straddle packer placed on the end of the CT
    - Treatments pumped down CT into perforations
      - Treating pressure “energises” packer elements
      - Circulating and reversing possible
    - Multiple zones treated consecutively using a single CT run
    - Much greater pressure can be placed on the CT than is normal
      - Static vs dynamic
    - Large diameter CT required

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Cased Hole Systems

- Coiled Tubing Methods
  - Annular CT Fracturing
    - No pre-perforating
    - Perforations either cut using jetting tool or shot via selective perforating guns on the CT
    - Zonal isolation
      - Packer placed below jetting tool or perforation guns
      - Sand plugs pumped down the CT/completion annulus
    - Treatment is pumped down the CT/completion annulus.
    - CT string used to monitor BH pressure
    - Multiple zones treated consecutively using a single CT run

Summary

- Transverse or Longitudinal?
  - Formation stresses
  - Wellbore azimuth
  - Gas?
- How many fracs?
- Cased or Open Hole?
  - Fluid recovery
  - Rig time
  - Operational flexibility
- Would a Vertical Well be Better?

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Horizontal & Multi-Fractured Wells

Thank you.
Any Questions?

