Well Integrity for Fracturing and Re-Fracturing: What is Needed and Why

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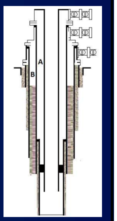
Fracturing => Peak Loads on Casing & Cement

(Make sure the well can withstand the pressures and fluids)

1. What are common well failures from fracturing?
2. How frequent are failures?
3. What causes the failures?
4. What components are at risk?
5. Are risks higher in older wells?
6. What can be done to reduce risk?



Common Failure Points (symptoms & causes)

- Design – casing alloy selection
- Drilling – DLS (dog leg severity) – worse than you think?
- Pipe Buckling – DLS, running procedures, long laterals
- Pipe make-up –specific make up requirements – connection type?
- Cement sheath stability – cyclic pressure effects?
- Production damage (corrosion, embrittlement, erosion and abrasion)
- Geologic forces (subsidence, faults, etc.)
- Unknowns – we rarely do a full postmortem on a failed well. We need to do more.

Tubular failures during fracturing are rare, usually less than one well in a thousand, and rarely result in emissions or leaks. Many failures are preventable with proper screening of candidates and knowledge of local failure causes.

3

Failures – Older Wells – Eliminate the Risks


Previous Wear?


Collapse


Burst – Above cement support


Hydrogen embrittlement – high strength P-110 Coupling

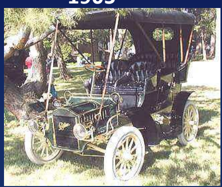
SPE 179120 - Well Integrity - King & Valencia

Era of Construction – Technology in Practice

Pollution potential & risk are functions of technology & maintenance in practice over time.

=> Old well behavior doesn't necessarily describe new well behavior.

1905 vs. **2015**

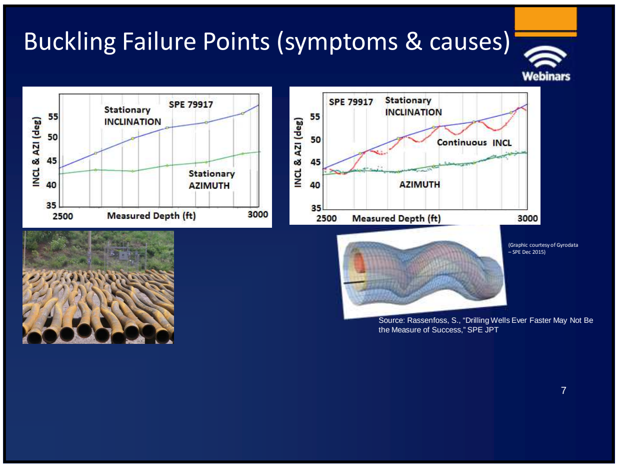

9 hp., 25 mph and every practical safety device known to man in 1905.

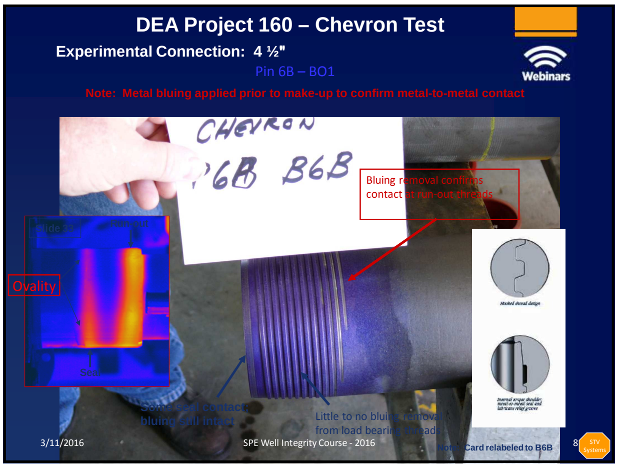

640 hp., 200 mph and every practical safety device known to man in 2015.

5

1st - Pre-Fracturing Checks…. Drilling & Completion

- Geological issues (faults, karsts, soft sands, high & low pressures)
- Pipe design suspect (corrosion resistance/embrittlement problems).
- Unknown cause of frequent shoe test failures.
- Poor coupling make-up (evidenced by numerous thread leaks).
- Dog leg induced casing buckling.
- Casing wear from drilling, fishing, milling, etc.
- Hole washouts (drilled hole > ~4" over pipe OD).
- Inadequate vertical pipe centralization.
- Inadequate mud conditioning
- Chemical flush prior to cementing. (=> mud channels?).
- Gas cut cement.
- Cement top below design.


Buckling Failure Points (symptoms & causes)
Webinars
SPE 79917
Stationary INCLINATION
Stationary AZIMUTH
INCL & AZI (deg)
55
50
45
40
35
2500
Measured Depth (ft)
3000
SPE 79917
Stationary INCLINATION
Continuous INCL
AZIMUTH
(Graphic courtesy of Gyrodata – SPE Dec 2015)
Source: Rassenfoss, S., "Drilling Wells Ever Faster May Not Be the Measure of Success," SPE JPT
7


DEA Project 160 – Chevron Test
Experimental Connection: 4 ½"
Pin 6B – BO1
Note: Metal bluing applied prior to make-up to confirm metal-to-metal contact
Webinars
CHEVRON
B6B
Bluing removal confirms contact at run-out threads
Ovality
Some seal contact; bluing still intact
Little to no bluing removal from load bearing threads
Hooked thread design
Internal torque shoulder, metal-to-metal seal and lubricant relief groove
Note: Card relabeled to B6B
3/11/2016
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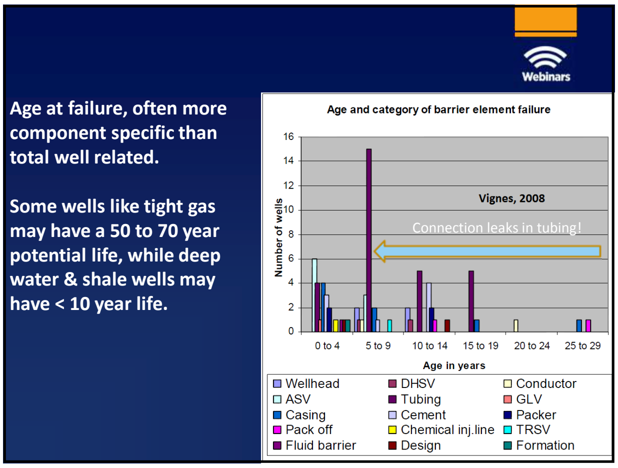
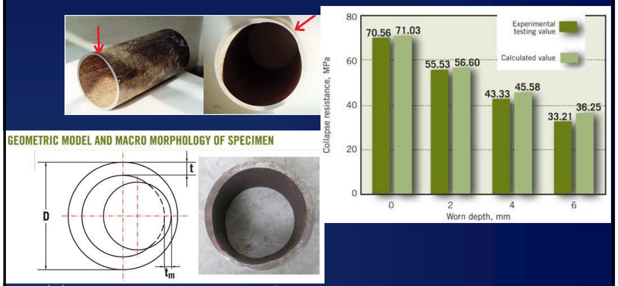
8
STV Systems


Webinars
Age at failure, often more component specific than total well related.
Some wells like tight gas may have a 50 to 70 year potential life, while deep water & shale wells may have < 10 year life.
Age and category of barrier element failure
Number of wells
16
14
12
10
8
6
4
2
0
Vignes, 2008
Connection leaks in tubing!
0 to 4
5 to 9
10 to 14
15 to 19
20 to 24
25 to 29
Age in years
Wellhead
ASV
Casing
Pack off
Fluid barrier
DHSV
Tubing
Cement
Chemical inj.line
Design
Conductor
GLV
Packer
TRSV
Formation

Casing Wear During Drilling

http://www.ogj.com/articles/print/volume-111/issue-02/drilling---production/empirical-formula-given-for-collapse.html

- Rotation, sliding, fishing can case abrasion wear.



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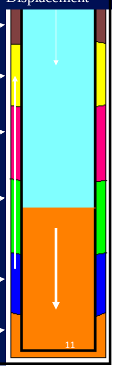
Chemical Flush Basics

1. Base fluid condition
2. Dispersant
3. Sweep
4. Spacer
5. Cement

A properly designed flush focuses on time of contact, fluid mixing, lift of solids and avoidance of cement contamination.



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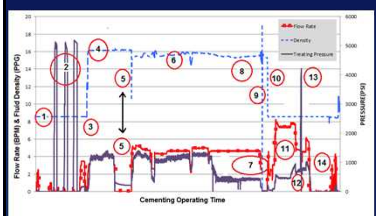
Is a CBL Needed before a Frac?

(CBL = Cement Bond Log)

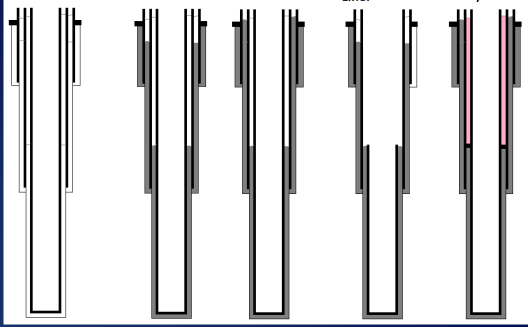


Perhaps surprisingly, cement pump chart information can be more useful than a CBL, especially in shallower casing strings where isolation is most critical.

1. Filling surface equipment with fresh water
2. Pressure test – two leaks in surface piping followed by a successful test.
3. Pump sweeps and spacers to clean mud and separate from cement.
4. Constant density batch mixed cement
5. Shut down to drop bottom plug & switch to on-the-fly mixed cement
6. Pumping on-the-fly mixed cement, note density variance.
7. Cement free-fall, heavy cement pushing out lighter mud. More fluid in than out.
8. Near end of cement pumping. Density variance past 0.5 ppg.
9. Shut down pumping, flush surface lines and drop solid top plug.
10. Bottom plug lands, diaphragm ruptures, cement flows into annulus.
11. Free-fall make up, more fluid flowing into well than flowing out.
12. Cement displacement pressure too low. Check top of cement as a precaution.
13. Top Plug "bump" (lands in shoe track). – cement placement complete.
14. Hold pressure until cement sets.

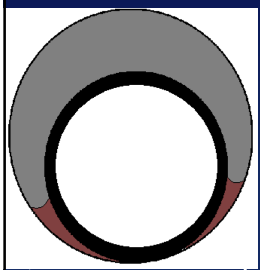
12

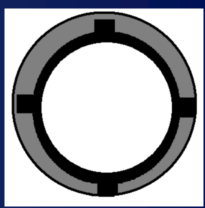
Casing Design - Options



Centralizers – require time and $ down, but often better isolation.

Use of centralizers improve the ability of the cement to surround the pipe, displacing the mud and creating a channel-free seal. Centralizers also assist running casing in deviated sections.





Area of undisplaced mud – a mud channel remains, requiring squeezing.

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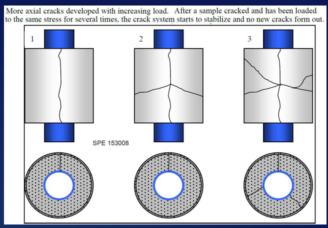
2nd - Pre-Fracturing Checks... Fracturing History

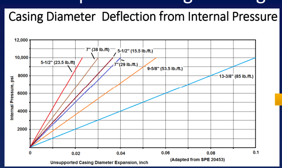
- Initial Frac or Refrac?
  - Application of pressure – sudden or incremental?
  - Cyclic pressure application
    - Highest pressure achieved.
    - Number of pressure cycles over 15? Over 30?
- Presence of uncemented upper vertical section (this is a special case, study needed)
- Erosion monitoring
- Very Old Wells?
- Frac Hits – problem?

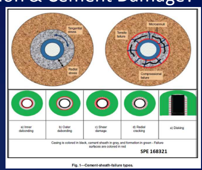
Cracking unloads stress – limited number of cracks.



Cracks open only under application of stress.
Cracks re-open as stress is reapplied.

Multiple Fracturing = Casing Expansion & Cement Damage?

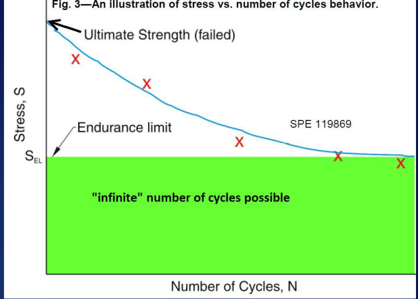




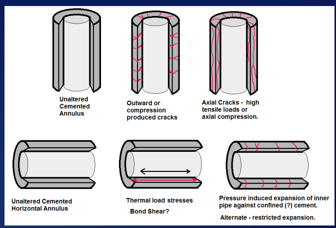
- Severe swings in Pressure & Temperature are main causes of cement cracks.
- Primary failure => microannuli that stay open at low pressures and seal at high pressures.
- Secondary effects after numerous cycles of pressure / temperature => cracks in cement?

Pressure Cycling

Fig. 3—An illustration of stress vs. number of cycles behavior.



Expansion Related Cracking – stress, thermal or fluid-applied pressure



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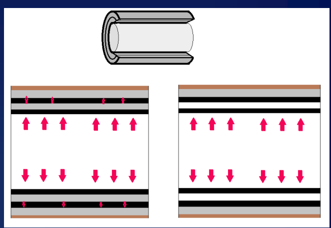
Adding an extra barrier may dampen or eliminate the pressure deflection – depending on the fill.

Will an extra steel and cement barrier eliminate the internal stress – likely will dampen it.

A gas filled gap will likely eliminate it.



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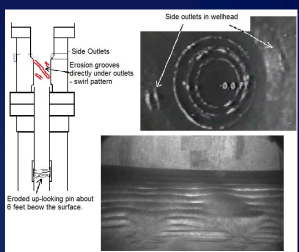
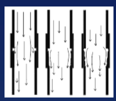
WELLHEAD PROBLEMS



Erosion in a well head after several fracture treatments.

21

EROSION – CORROSION: SMALL GAPS = TROUBLE?



Injection – high rate (+solids), short term

Production – lower rate, long term

Right: progressive erosion of the down-looking pin at high production rate.

22

Frac Hits – Major or Minor Impact?

Planar Frac

- **Most likely hit distance => less than 1500 ft. Longer hits => 4000 ft.**
- **Skips wells? => sometimes**
- **Mechanical damage potential => high**
- **Likely production effect in "hit" well => reduced production 5% to 15%.**
- **Prevention => pressure up w/field gas, liquids, auto shut in.**
- **Design change => increase well spacing, stagger perf clusters out of frac path.**

Complex Fracs

- **Most likely hit distance => about 500 ft. Longer hits => rare over 1000 ft, but 2500+ ft reported.**
- **Skips wells? => frequently**
- **Mechanical damage potential => low – water loading is main issue**
- **Likely production effect in "hit" well => increased 10% to 50%**
- **Prevention => most operators don't bother, some load well.**
- **Design change => stagger perf clusters if less than 500 ft.**

23

3rd - Pre-Fracturing checks Focuses on Previous Operations & Production History

- Unexplained annular pressure buildup.
- Cement squeezed perforations
- Packer setting points
- Cement isolation failure history – why?
  - Isolation in vertical
  - Isolation in horizontal
- Cement squeeze history.
- Wellhead Issues
- Production or proppant erosion of tubulars (> design velocity?)
- Pressure application and pressure cycling effects
- Subsidence effects
- Tubular damage from lift operations (tubing-on-casing abrasion, produced sand erosion, etc.)

24

Corrosion – both inside and outside the tubular

Corrosion rates that may reduce tubular strength to a point where fracturing puts the tubular at risk may happen in 20 years or more in some environments and much shorter in others.

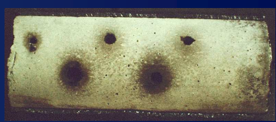
Corrosion is a cumulative effect – know the well's history.

25

Production Related Damage

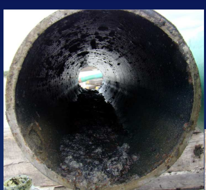
- Packer set points (slips harden the pipe – corrosion increases)

Does perforating harm the cement?



26

Eagle Ford MIC



Slow flow unable to sweep sludge and biomass out of pipes

SPE Presentation: Microbial Corrosion (MIC) in the Eagle Ford Shale (Patrick J. Breen – Marathon)

Event a small seepage leak may become severe in a short time - a few minutes to a few hours.

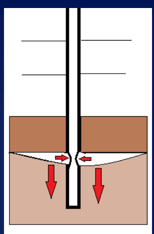
These “washouts” cannot be ignored when pressures are building or where the leak threatens overall well integrity.

Particularly troublesome seep leaks are those through threaded connections and pin hole leaks, especially in thin wall tubulars such at Coiled Tubing where tensile strength is threatened.

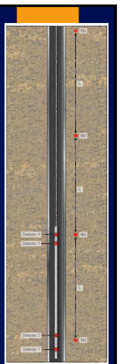
Erosion

Compaction, Subsidence & Collapse

- Removal of a load supporting element (gas/oil/water) means the formation matrix must support more load.
- Most severely affected are weak formations UCS (unconfined compressive strength) < ~2000 psi.
- As a formation shrinks – it can increase tension on the cemented casing.



Such events are rare, usually in soft sands and chalks. Particularly rare in onshore wells with hard sandstone or dolomite formations. .

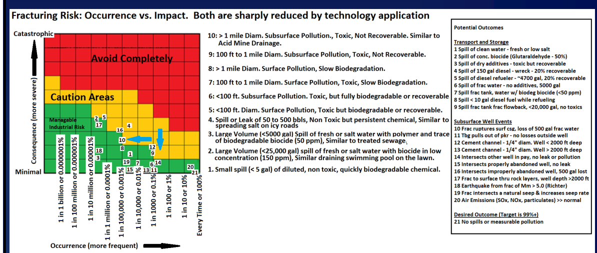


Monitoring radioactive bullets. A sonde with four gamma ray detectors minimizes the effect of unintentional tool movement by detecting two radioactive markers (RM) almost simultaneously. The bullet separation, S_1, S_2 and S_3, should be approximately equal to the mean separation between the top and bottom pairs of detectors.

https://www.slb.com/~/media/Files/resources/oilfield_review/ors06/aut06/compaction_and_subsidence.pdf

First. What are the significant Risks

Example – Frac Risk (SPE 152596)



Summary Points

- Several of the more common failures and causes have been identified along with the causal well construction practices, stimulation stresses and operational actions that may compromise well integrity to the extent that a frac or refrac could not safely be pumped.
- No one-size-fits-all check list of damage potential or risk can be offered to accurately address all damage mechanisms that would eliminate a well from consideration for fracture stimulation. Such a check list could conceivably be constructed for a specific area and set of wells, but determining every possible failure may not be feasible.

31