Artificial Lift
R&D Council

Case study comparing wall loss measurements due to sucker rod wear, erosion and corrosion on boronized versus untreated OCTG production tubing in a rod pumped oil well

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2023 International Sucker Rod Pumping Workshop
Aug 28-31, 2023. Midland TX

- **Craig Zimmerman is a leading expert in boriding**
  - B.S. & M.S. Metallurgical Engineering, University of Wisconsin-Madison
  - 28 years of hands-on involvement with boriding processes
  - Authored two chapters on Boriding/Boronizing in ASM Metals Handbooks along with several published papers
  - Extensive R&D work enabled many technical and cost reduction improvements to boriding process

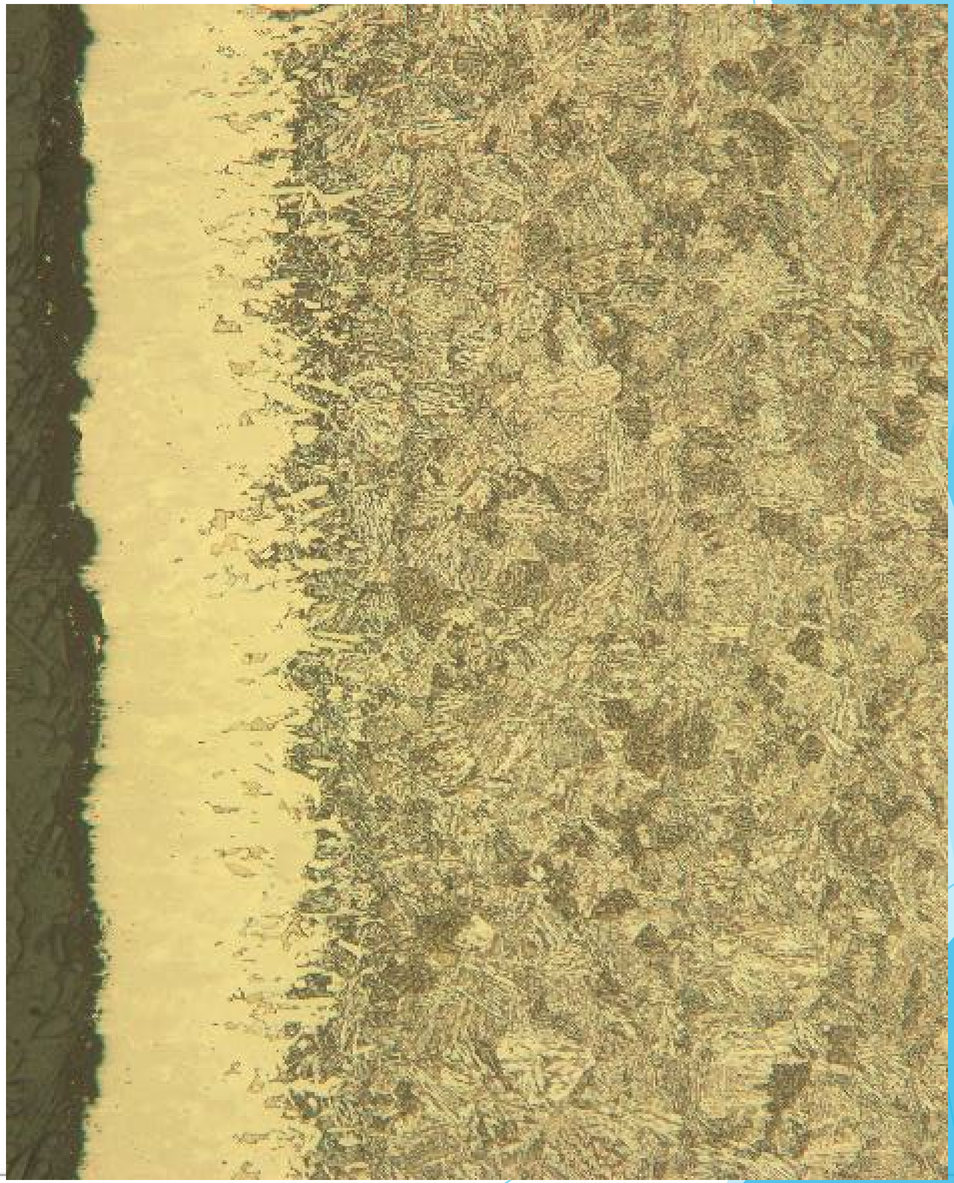
- **Bluewater is the largest provider of boriding in the USA**
  - High volume boriding of small to medium size parts
    - Variety of industries such as agriculture, oil and gas, chemical, turf management, concrete cutting, aerospace/defense. etc…
  - Borided tubing production in Houston treats thousands of tubes each month
    - Smaller components and accessories borided as well

- **General Benefits of Boriding for all industries**
    - Extremely wear and erosion resistant
        - Harder than tungsten carbide
    - Enhanced corrosion resistance against many acids and corrosive conditions present in oil wells.
- **Specific Benefits of Borided 1Cr OCTG tubing**

    Able to make the inside surface of oil field tubulars more resistant to rod wear, pump discharge erosion, sand erosion, and corrosion pitting.

Properties of Boride Layers in BOR-1Cr tubing

- .005-.015” diffusion zone present below the surface of a BOR-1Cr borided steel joint
- 1300-1800 HV hardness of boride layer
- Uniform thickness, 100% coverage



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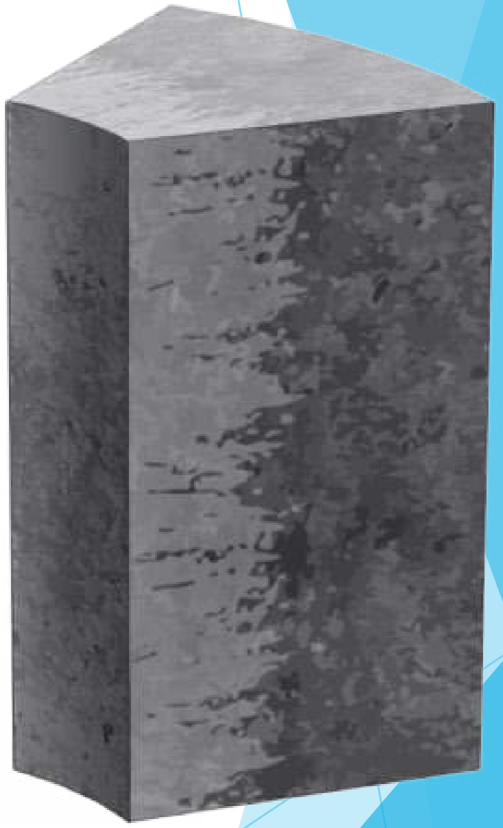
- **Boride layer is diffusion layer, not a coating**
  - Diffusion of boron into the surface of the tubing means that there is no build-up or added material on bore surface
    - No change in size or dimensions.
    - Full bore diameter is still open
    - Can be worked in holes with standard downhole tools and no special handling
  - Adhesion is never a problem because the boron enters the steel surface and becomes part of the steel.
    - No concerns over this treatment flaking, peeling, delaminating or any material coming loose off of the tube bore surface that could fall into a pump

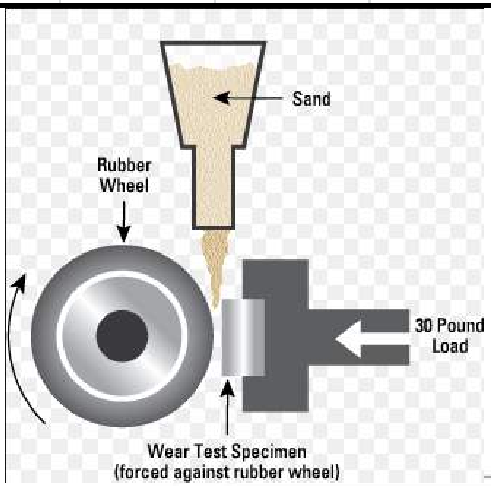


Laboratory Test Results

ABRASIVE WEAR TESTING

Summary of ASTM G65 Abrasion Wear Test

Sample	Starting weight (grams)	Final Weight (grams)	Mass lost during test (grams)	Average result (grams)	Factor of improvement
Untreated 1	186.900	184.433	2.467	2.303	19.5x less wear on borided specimens
Untreated 2	187.793	185.654	2.139		
Borided 1	193.516	193.392	0.124	0.118	
Borided 2	190.933	190.821	0.112		



AUTOCLAVE CORROSION TESTING

Comparison of Corrosion Rates with H_2S and CO_2 between Plain Carbon Steel, 1Cr Steel, and Borided 1Cr steel

Test Conditions

- **Type of Test** — **Static Autoclave**
- **Temperature** — **275F**
- **Pressure** — **4,000 psig**
- **Duration** — **6 days**

Gas Mixture (1/3 of cell volume)
- 30% Hydrogen Sulfide (H_2S)
- 3% Methane
- 2% Ethane
- 65% Carbon Dioxide (CO_2)

Liquid Phase (2/3 of cell volume)
1/3 Nace Brine solution
1/3 Hydrocarbon (30% Toluene, 70% Kerosene)

Sample ID and condition	Weight	Mass lost due to corrosion during test (Improvement)
Untreated Plain Carbon Weight before test	199.2189 grams	
Untreated Plain Carbon Weight after test	196.9193 grams	2,299 mg on Plain Carbon Steel
Untreated 1Cr Weight before test	192.4720 grams	
Untreated 1Cr Weight after test	191.1180 grams	1,354 mg on Untreated 1Cr Steel 1.7x
Borided 1Cr Weight before test	190.2268 grams	
Borided 1Cr Weight after test	189.9098 grams	317 mg on Borided 1Cr Steel 7.3x

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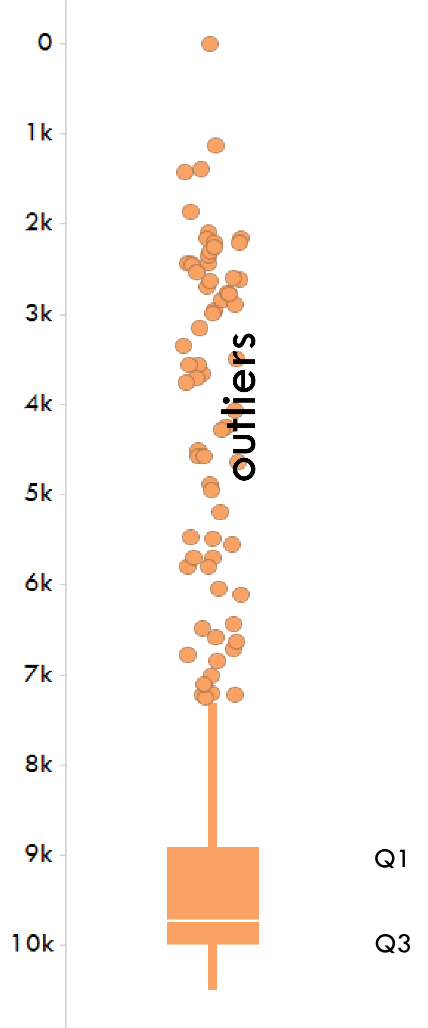

Count	405 tubing failures
Outliers	69
P10	4,567 ft from surface
Q1	8,915 ft from surface
Median	9,725 ft from surface
Q3	10,000 ft from surface
P90	10,156 ft from surface

- Typical placement and usage of borided tubing
    - 75% of failures occur within bottom 1,000 feet (30 joints) above pump
    - 50% of failures occur within bottom 500 feet (15 joints) above pump
    - Higher temperatures at bottom of well accelerate wear-corrosion-wear mechanism of material loss
    - Rod buckling more severe at bottom
    - Erosion from pump discharges most severe at the pump location
    - Outliers at shallower depths generally associated with collar leaks or wear associated with deviation (DLS)
- Rod pumped wells typically 6-20 joints at bottom of tubing string
- ESP pumped wells typically 1-2 joints at bottom to act as blast joints
- Every producer in the Bakken uses a minimum of 1-2 joints in every well that they operate.

- **Real World Case Study - Comparison of wall loss**
  - Compared 20 borided BOR-1Cr tubes to the next 20 untreated joints above them in one well
  - Used 24 arm caliper tool on wireline truck to measure wall loss of each tube in the well after this well had failed due to a hole in tubing
  - Bluewater has a published case study available upon request with more information and complete data for this well

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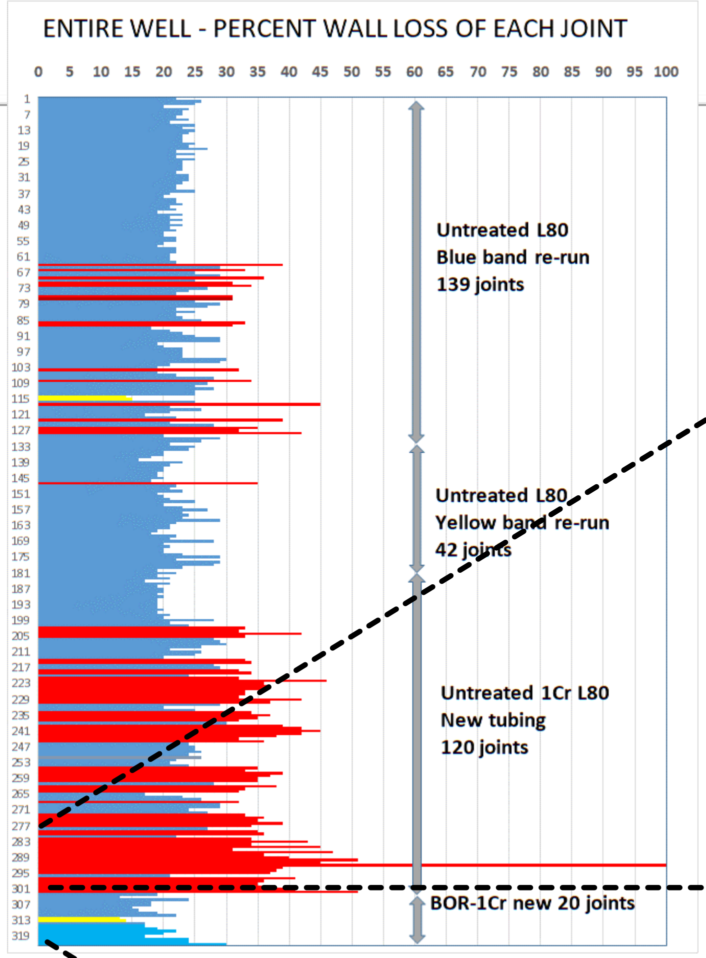

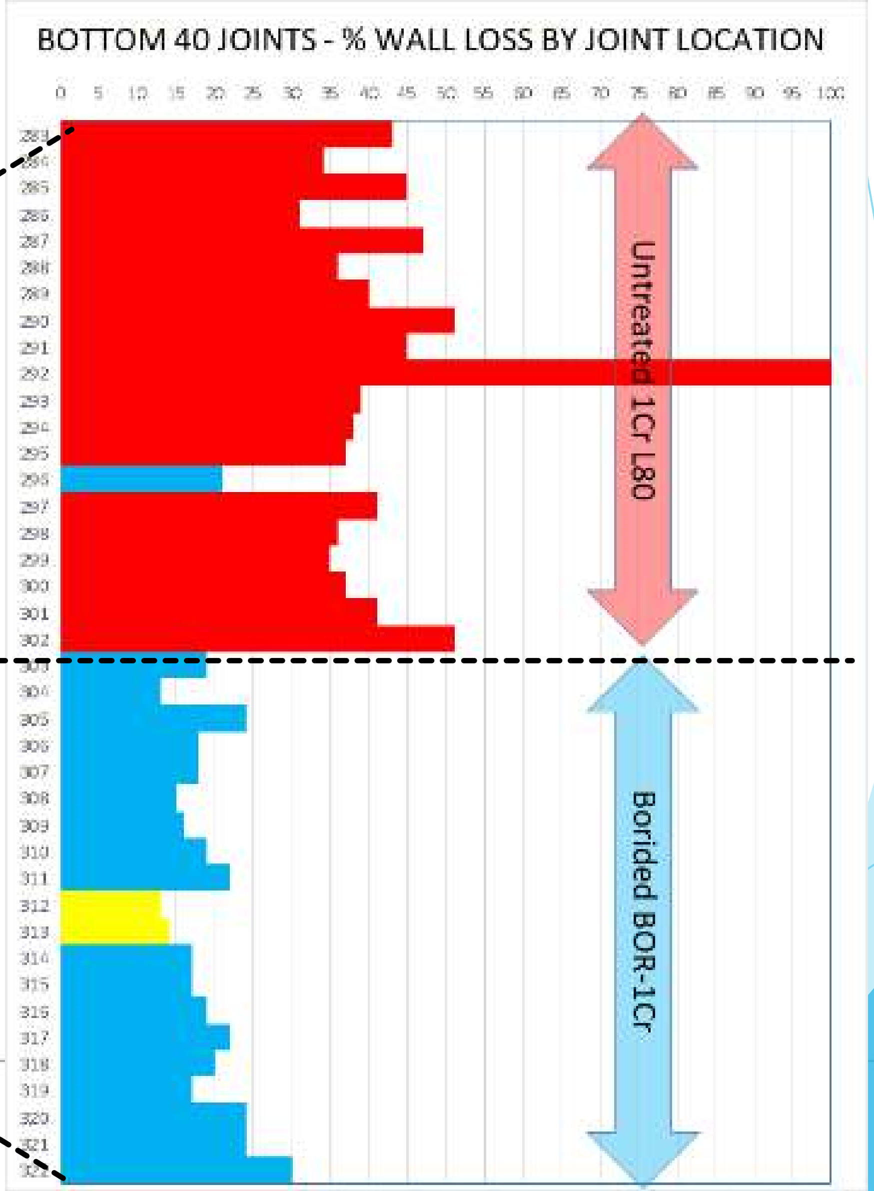

40% avg wall loss in untreated tubing

18% avg wall loss in BOR-1Cr tubing

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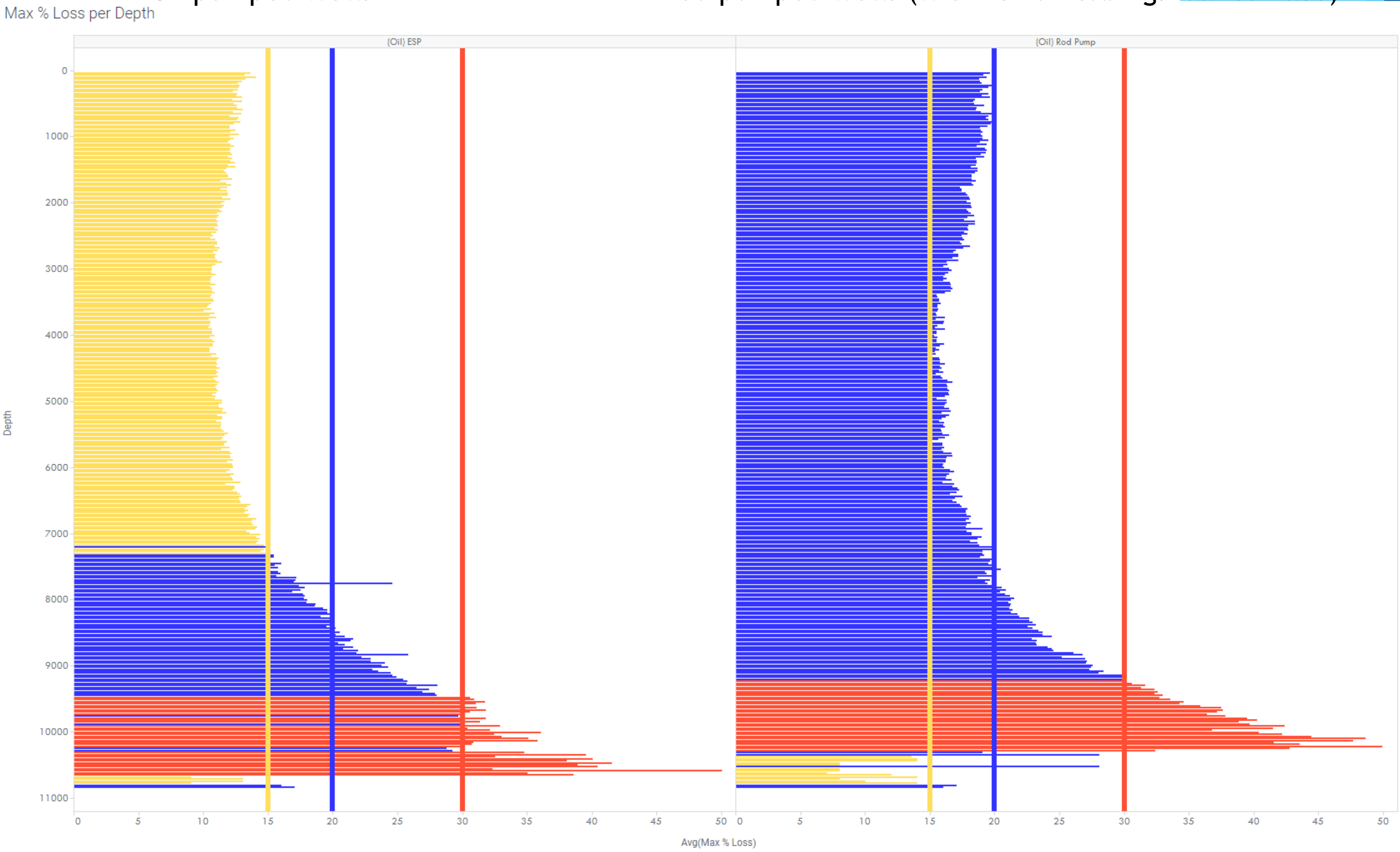
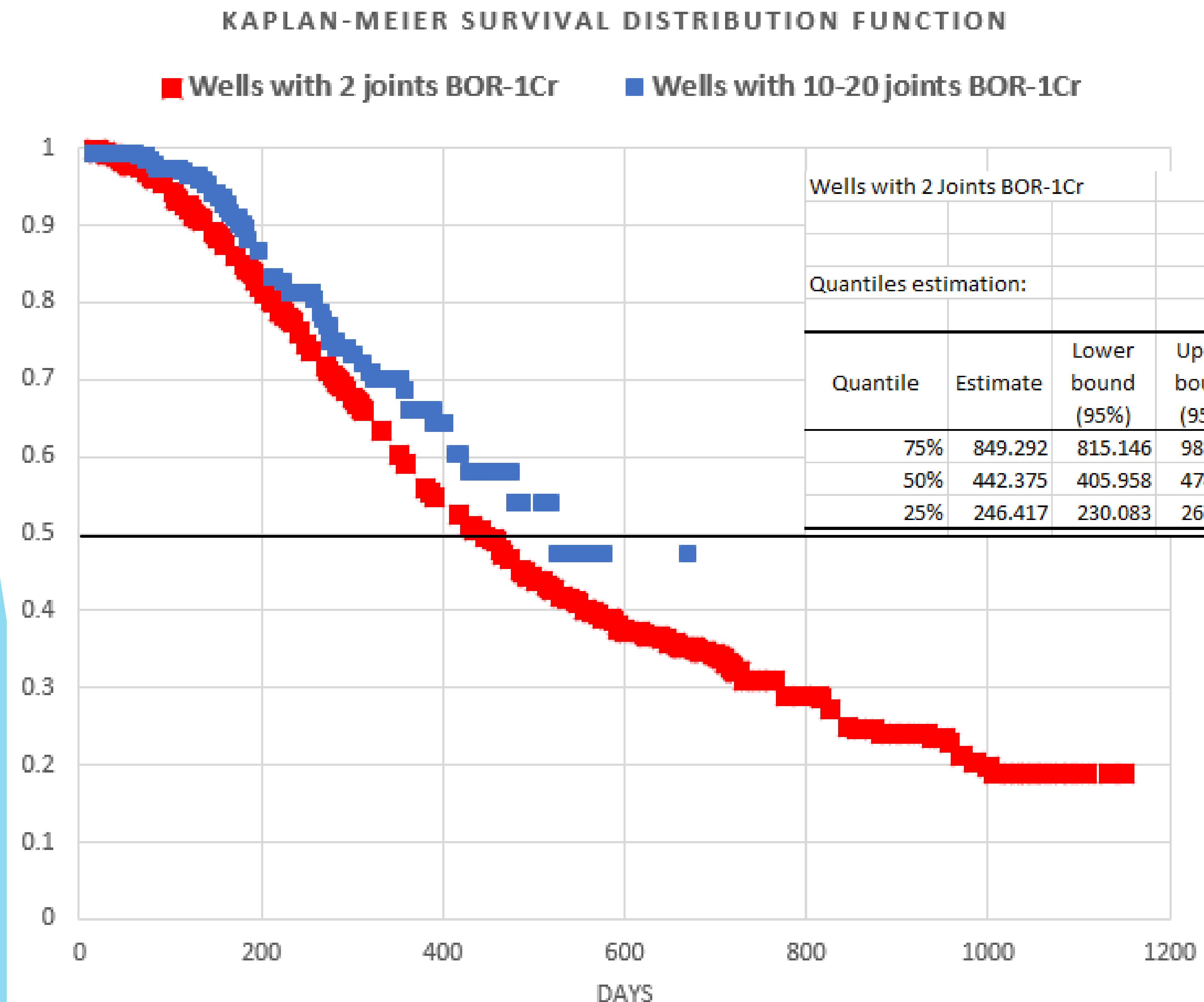
Average Wall Loss vs Depth on all wells (2019-2022) using borided tubing

ESP pumped wells | Rod pumped wells (with re-run tubing near surface)





Wells with 2 Joints BOR-1Cr

Quantiles estimation:

Quantile	Estimate	Lower bound (95%)	Upper bound (95%)
75%	849.292	815.146	981.292
50%	442.375	405.958	474.774
25%	246.417	230.083	267.917

Wells with 10 to 20 Jonts BOR-1Cr

Quantiles estimation:

Quantile	Estimate	Lower bound (95%)	Upper bound (95%)
75%			
50%	525.813	407.208	
25%	277.167	230.021	361.833

Not all failures are hole in tubing failures. These run times could have ended for any type of failure

Rod Pumped – 2 Joints per Well

Mean run time of 442 days

0.826 workovers per year
x $130,000 per workover
$107,380 in annual workover costs

Opportunity cost of lost oil production

10 days lost production per workover
30 bbls per day of oil
$70 per bbl oil price
x 0.826 workovers per year
$17,346 in annual lost oil production

Total annual cost
$124,726 in annual workovers and lost oil production

Rod Pumped – 20 Joints per Well

Mean run time of 525 days

0.695 workovers per year
x $130,000 per workover + $11,000 for 18 more BOR-1Cr joints
$97,995 in annual workover costs

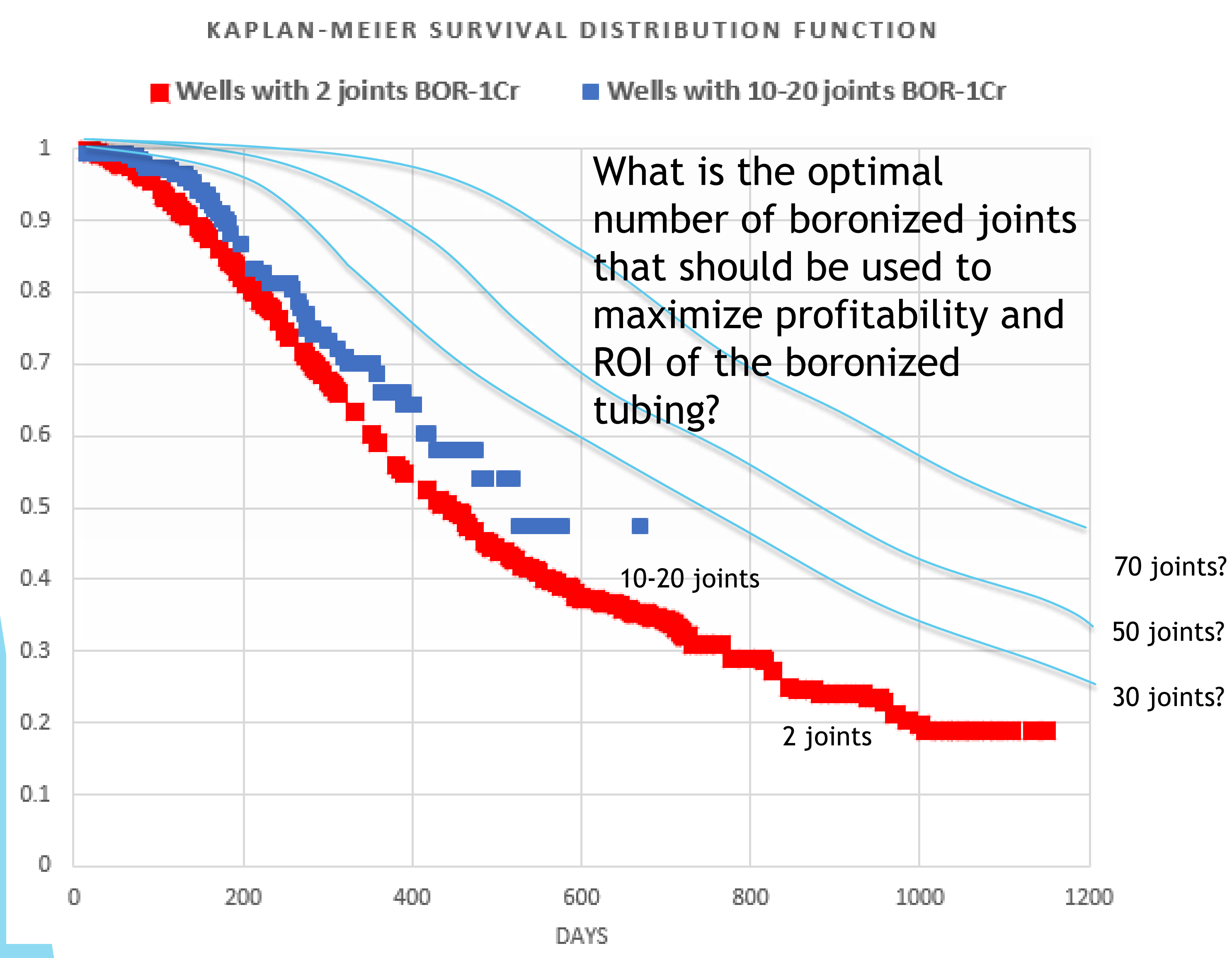
Opportunity cost of lost oil production

10 days lost production per workover
30 bbls per day of oil
$70 per bbl oil price
x 0.695 workovers per year
$14,595 in annual lost oil production

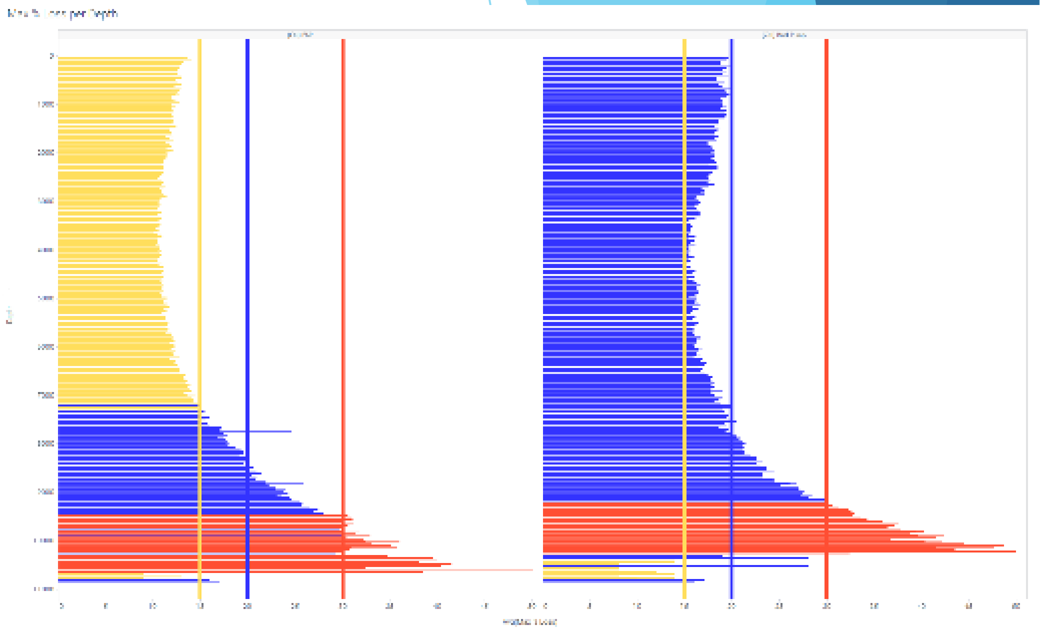
Total annual cost
$112,590 in annual workovers and lost oil production

$1.2 million per 100 wells being operated in savings

And don’t forget about ESG benefits of performing fewer workovers per year….



What is the optimal number of boronized joints that should be used to maximize profitability and ROI of the boronized tubing?



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What else can be borided to also improve well performance?

- Sand separator components that see high erosive wear
- Subs or pup joints
- Pump components
- Sucker rod couplings
- Plungers
- Gas lift mandrels
- Pump barrels
- Any thing else that wears, erodes or corrodes downhole

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Conclusions

- **BOR-1Cr tubing has been shown to have over 50% less wall loss compared to standard L80 joints running side by side in the same tubing string**
  - Borided tubing is placed in locations that are known to be “first to fail” in order to improve overall tubing string life. Blast joints around pumps, Bottom of string in rod pumped wells, known deviations or doglegs
- **Running 10-20 joints of BOR-1Cr tubing instead of just 2 joints per well has been shown to increase MTBF from 442 days to 525 days for one operator**
  - Economic benefit estimated to be around $12,000 in annual savings per well as number of annual workovers are reduced
- **Future work is a multi-company study where we vary number of joints per well and monitor MTBF performance to determine the optimal number of joints per well that will maximize overall profitability.**
  - Additional work could be done to select and characterize inputs and conditions of each well monitored in the study and develop predictive algorithms where number of BOR-1Cr joints recommended per well would vary depending on each individual well’s characteristics and operating parameters.

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