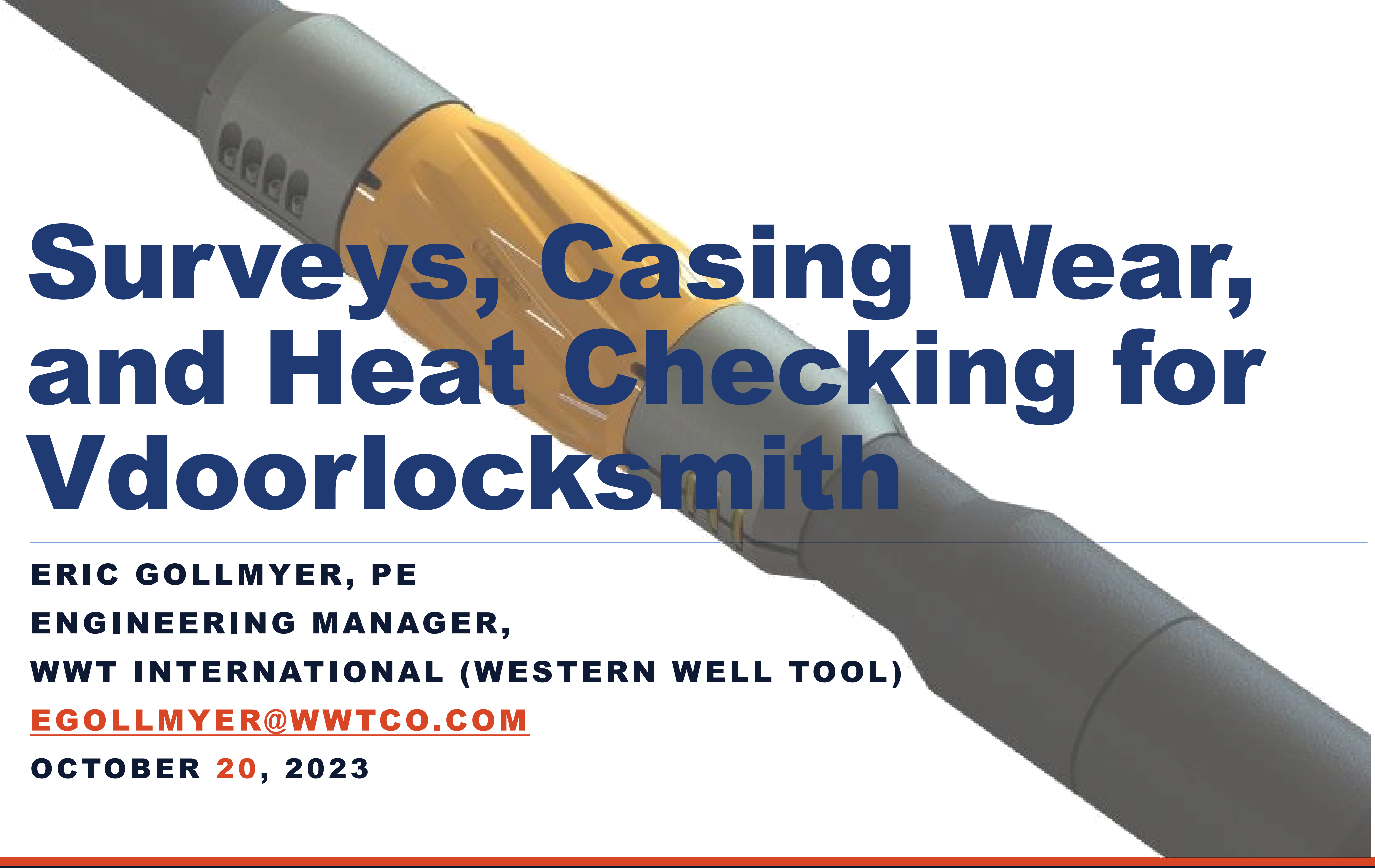

Surveys, Casing Wear, and Heat Checking for Vdoorlocksmith

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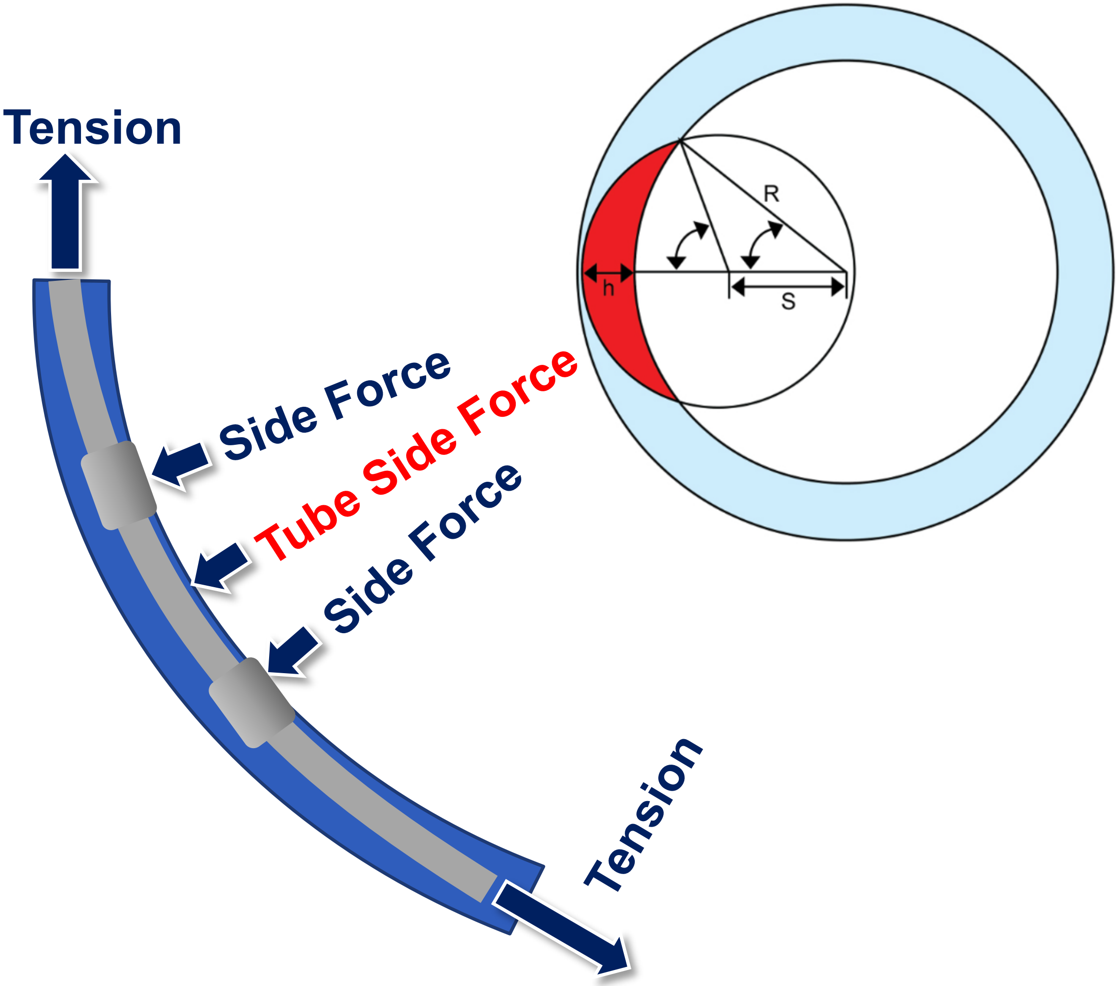
Goal: Expand on Torque and Drag Series
Side Force x Distance = Casing Wear, Heat Checking

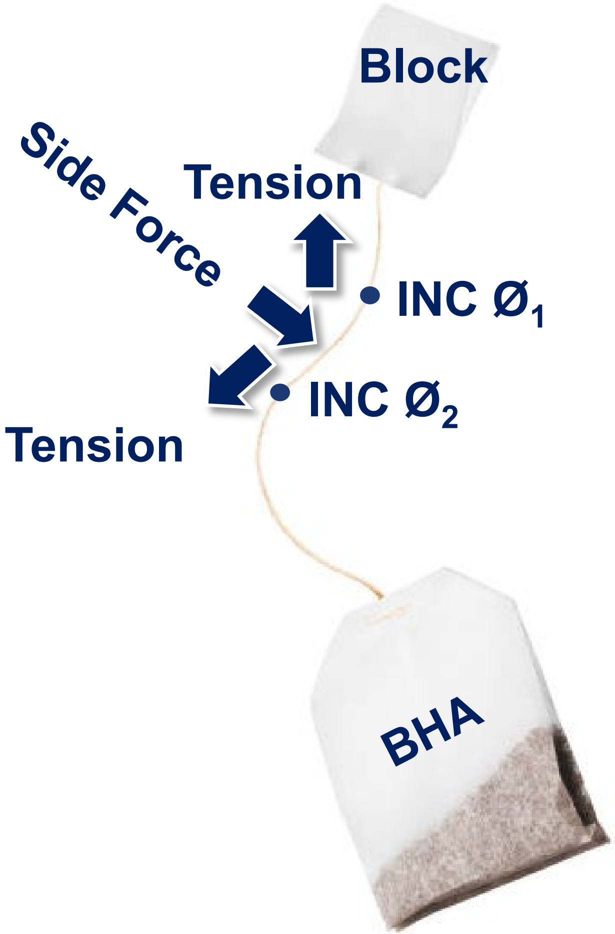


- Planned well paths and actual surveys
- Side force
  - Tension x survey deviation
  - lb/joint (normalized) or lb
- Casing wear (side force x revolutions)
  - Work (ft-lb) x wear factor $\frac{in^3}{lb\ in}$
  - in^3 wear volume presented as % of casing wall thickness
- Heat checking (power or work/time)
  - Heat-cool cycles to crack casing

WWT's Perspective as a Service Company

- Help on the 1% most challenging wells
- Non-definitive surveys with urgent decision needed
- Fast, confidential, and free torque and drag and casing wear analysis
- Simple tools to solve complicated problems

Side Force, Free Body Diagram



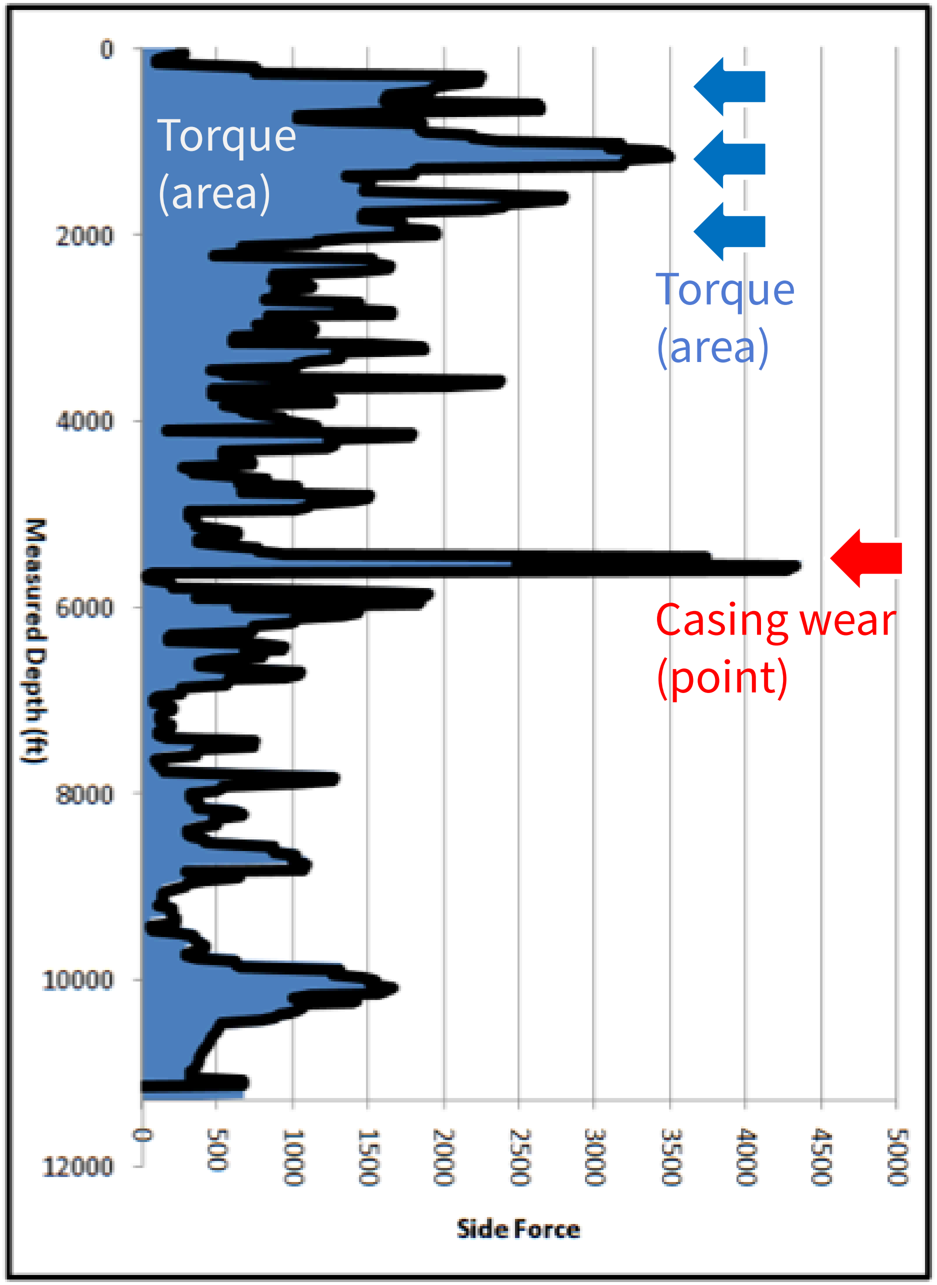
- Side force:
  - Tension (hanging weight) x inclination angle change
  - Check the units:
    - lb/joint (normalized) or lb
  - 200 klb x sin(1°)/100ft
    =3,490 lb/100 ft
    =1,082 lb/31 ft (or lb/range 2 joint)
  - 1,000 klb tension x sin(0.4°)/124 ft
    =6,981 lb/124 ft
    =2,477 lb/44 ft (or lb/range 3 joint)

Casing Wear vs. Torque/Drag Models
What's the Difference?

Torque is related to the blue area under the side force curve. Concerning high torque shown by BLUE ARROWS.

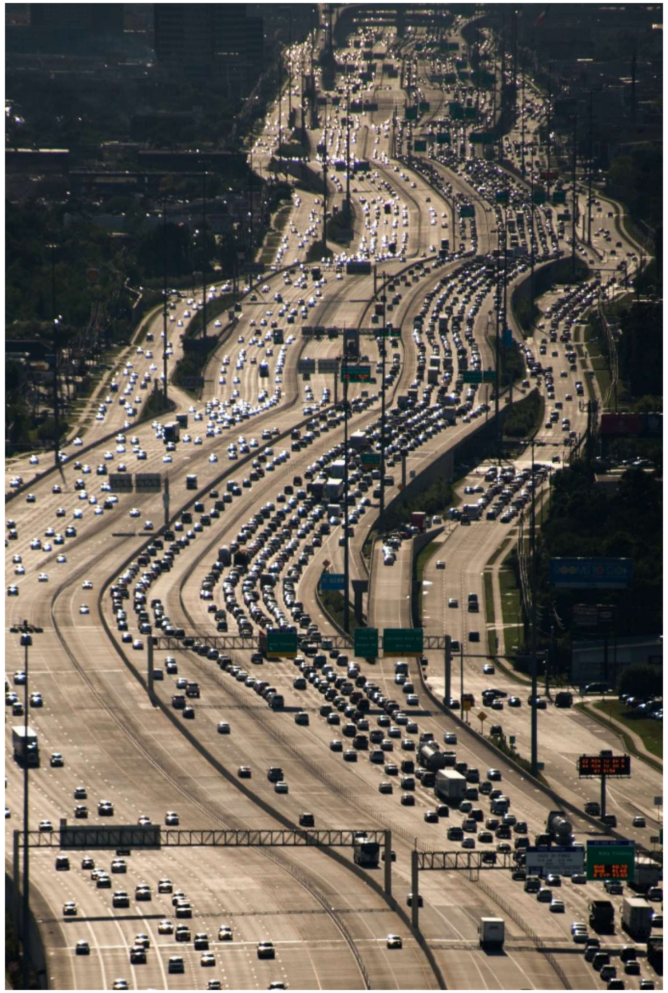
Casing wear will be most severe in the area with the greatest contact force, even over a short distance, such as the area shown by the RED ARROW.

- Often, a hole or severe wear is only 20 to 50ft in length (shorter than standard MWD surveys).



Deviation, Dogleg

- “The vertical section is straight.”
- “The conductor was jet in vertical.”
- “We’ll hold a steady build rate.”
- “We’ll run a gyro later.”



Visualize 8°/100ft Dogleg

- Straight
- Fixed far end

- 18” displacement at 40ft length
- 8°/100ft dogleg
- 1,000 lb lateral force required

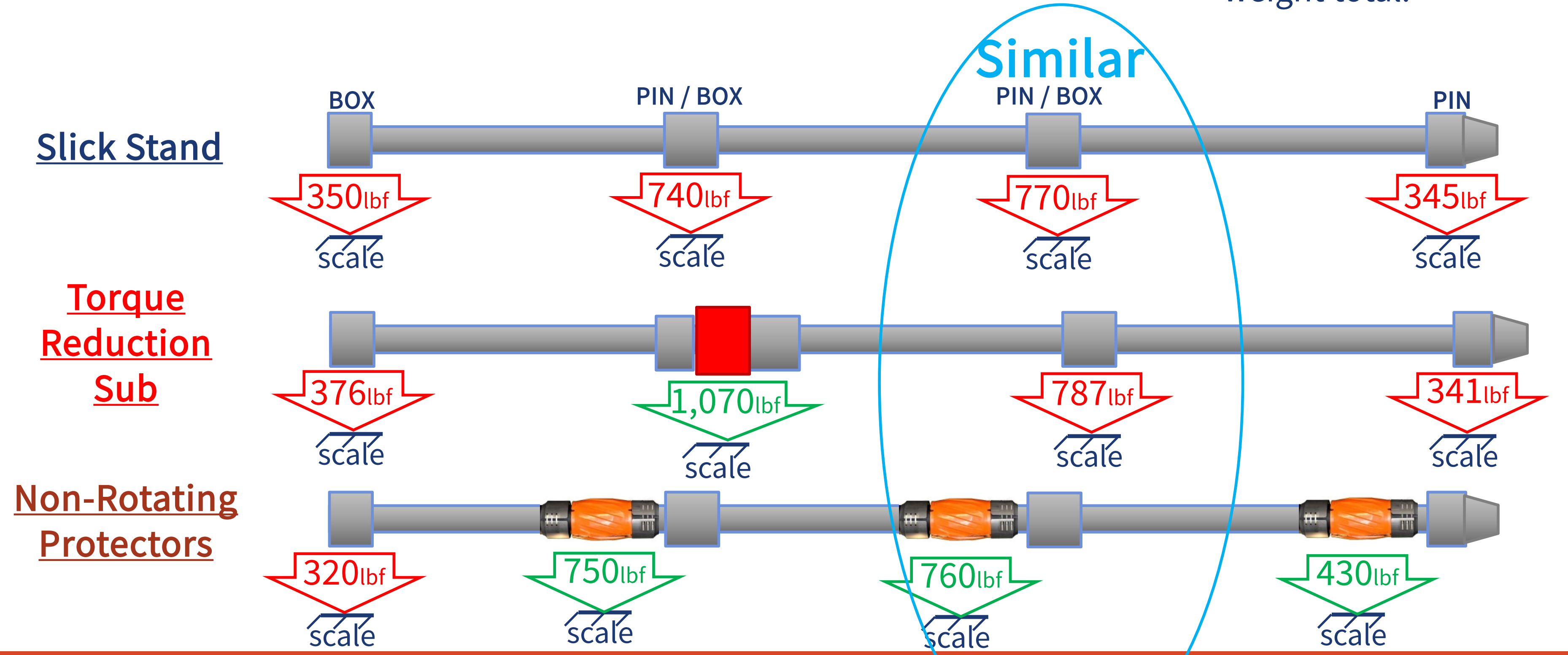
Drill Pipe Flexibility Demonstration

- Full stand (3 joints) of 4” and 5-1/2” drill pipe.
- Forces (weight) measured under each tool joint connection, TRS or NRP.
- Conclusion:
  - Drill pipe is flexible enough to allow each tool joint to contact the casing.
  - Use of NRP, TRS, or slick pipe, results in the similar total side force.
  - A torque-reduction sub does not reduce the force at the adjacent tool joint.
  - Each joint must be protected to create stand off.

Side Force Demonstration, 5-1/2" Drill Pipe

- Scales placed under each tool joint, NRP or TRS to measure vertical force.

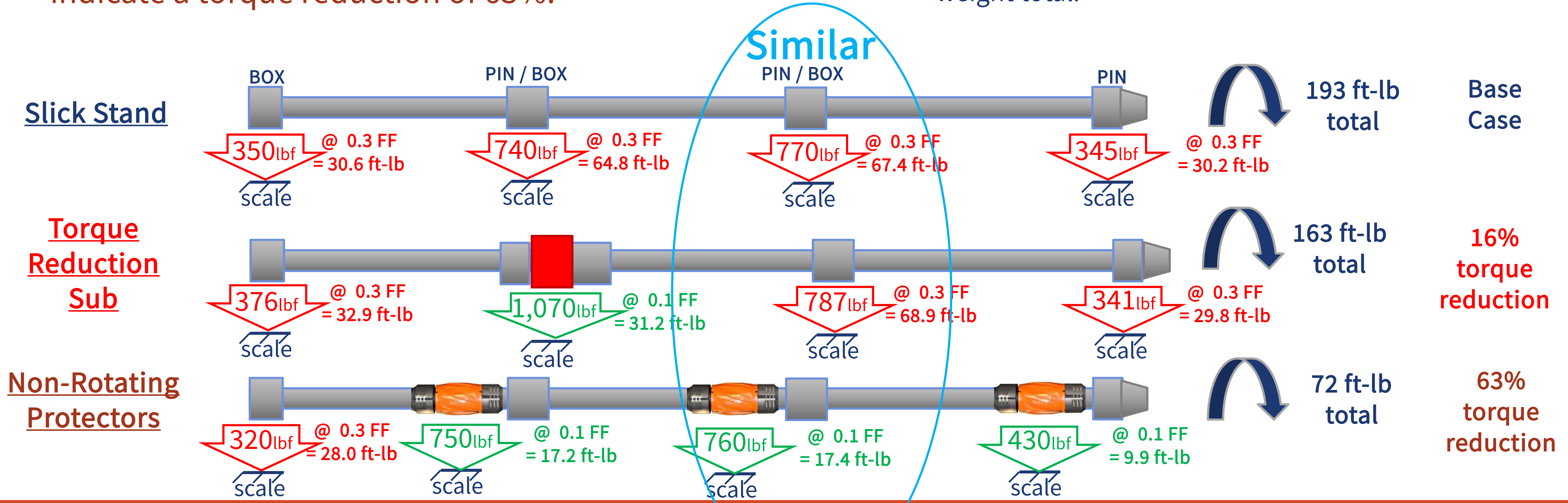
- Setup details
- Assumed 0.30 friction factor (FF) at tool joint connection and 0.10 FF at TRS and NRPs.
- 5-1/2" 21.9ppf drill pipe, 7" OD tool joint connection.
- TRS: 8-1/8" sleeve OD, 7" mandrel OD, 295 lbf dry weight.
- NRP: 7-3/4" sleeve OD, 31 lbf dry weight each, 93 lbf dry weight total.



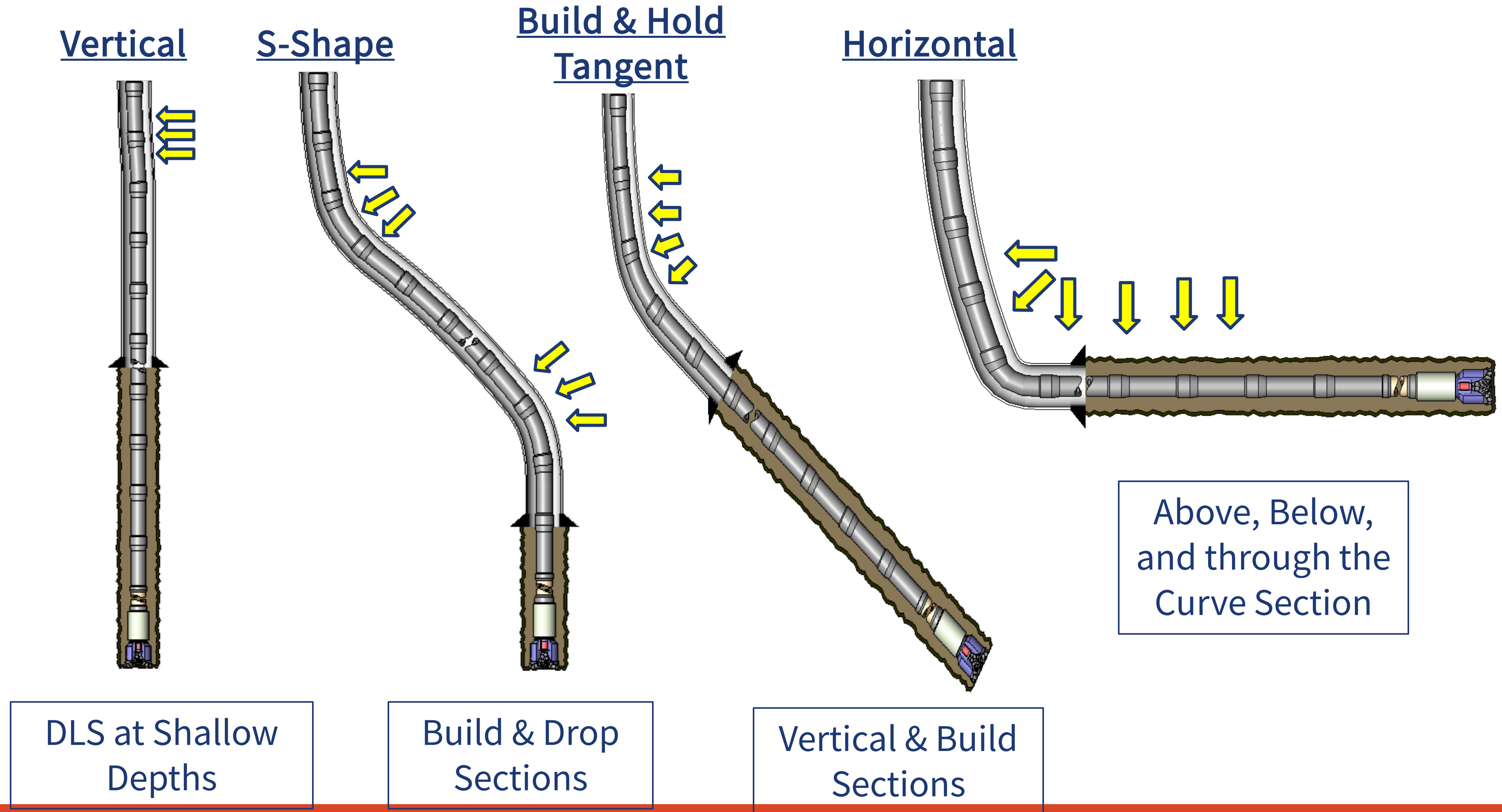
Side Force Demonstration, 5-1/2” Drill Pipe

- Scales placed under each tool joint, NRP or TRS to measure vertical force.
- One TRS per stand held 42% of the stand weight. Calculations indicate a torque reduction of 16%.
- Three NRPs held 86% of the stand weight. Calculations indicate a torque reduction of 63%.

- Setup details
- Assumed 0.30 friction factor (FF) at tool joint connection and 0.10 FF at TRS and NRPs.
- 5-1/2” 21.9ppf drill pipe, 7” OD tool joint connection.
- TRS: 8-1/8” sleeve OD, 7” mandrel OD, 295 lbf dry weight.
- NRP: 7-3/4” sleeve OD, 31 lbf dry weight each, 93 lbf dry weight total.



Areas of Concern for Casing Wear and Torque



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Drill Pipe Tube Contact, Hand Calcs

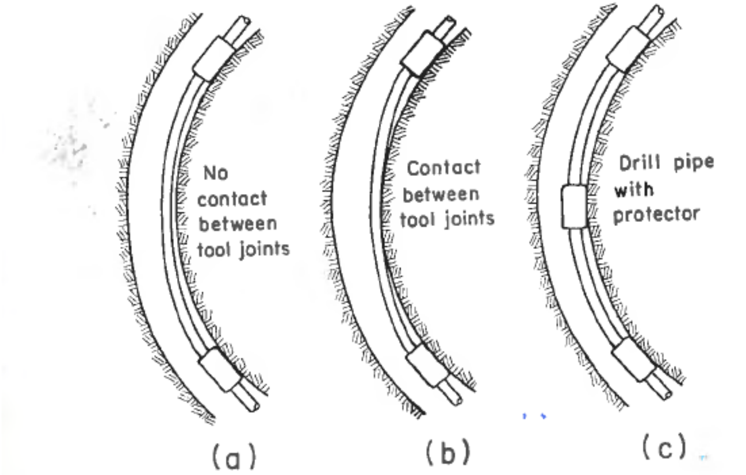


Figure 7-1. Drill pipe-to-hole contact in a gradual dog-leg.

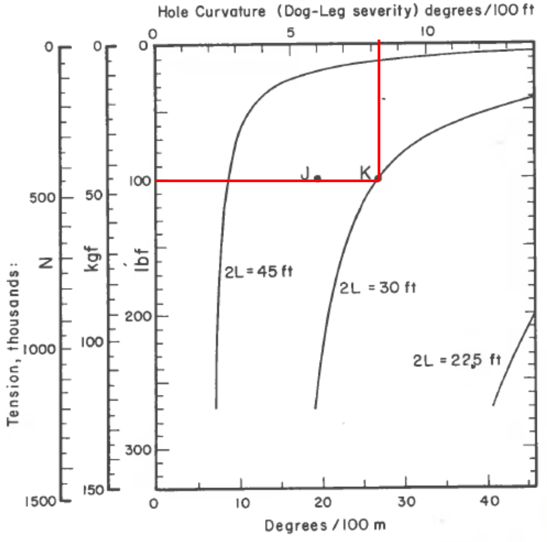


Figure 7-4. Curves of drillpipe-to-hole contact in gradual dog-legs (4½ in., 16.6 lb/ft drill pipe with 6¼ in. supports).

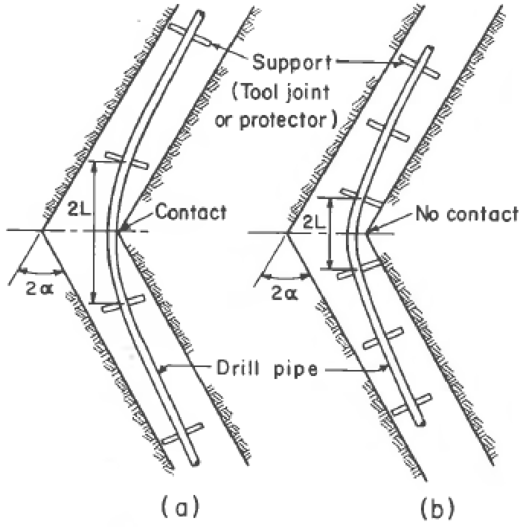


Figure 7-5. Drillpipe-to-hole contact in an abrupt dog-leg.

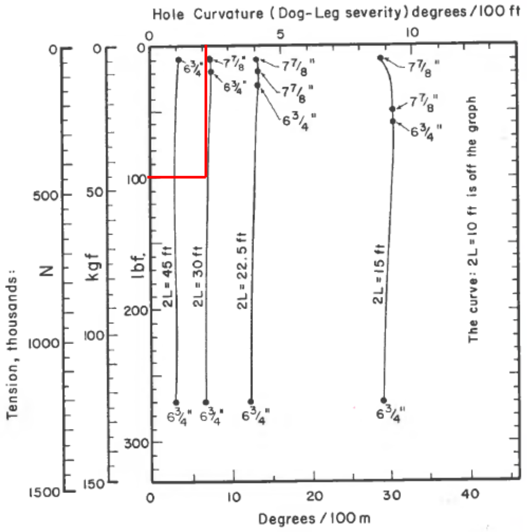


Figure 7-6. Curves of drillpipe-to-hole contact in abrupt dog-legs (4½ in., 16.6 lb/ft drillpipe with 6¼ in. supports).

- Gradual dogleg: 8°/100ft DLS will cause drill pipe tube contact in most range 2 pipe
- Abrupt dogleg: 2°/100ft DLS will cause drill pipe tube contact in most range 2 pipe
- *Developments in Petroleum Engineering*, Lubinski 1988

Drill Pipe Tube Contact, Hand Calcs

- With 100 klb tension tube contact will occur at:

- 8°/100ft DLS on Range 2 (31 ft joints)
- 2°/100ft DLS on Range 3 (44 ft joints)

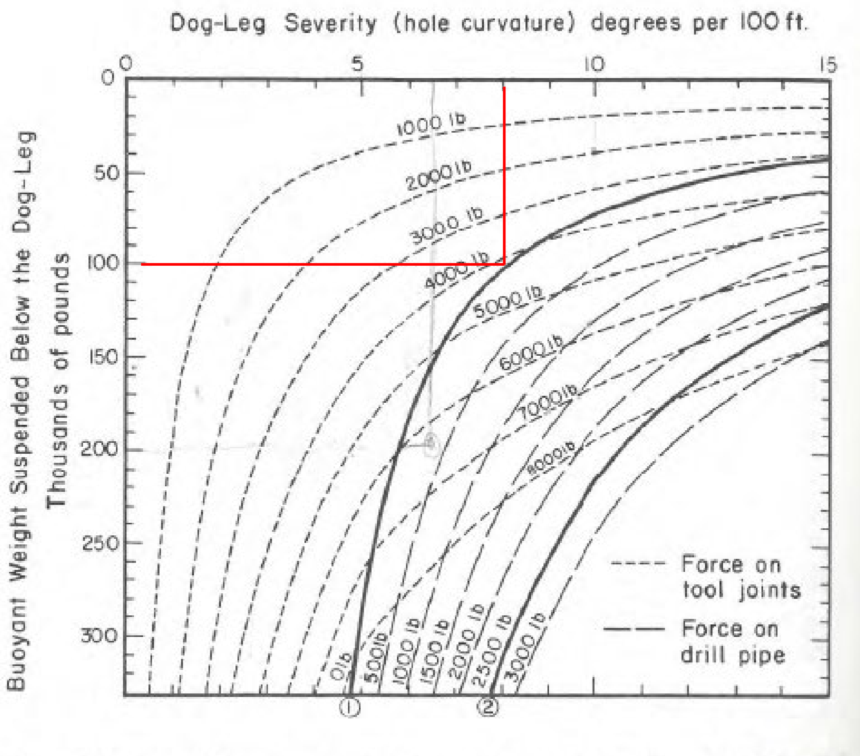


Figure 5-18. Lateral forces on tool joints and Range 2 drill pipe, 5 in. OD, 19.5 lb/ft, with 6⅜ in. tool joints.

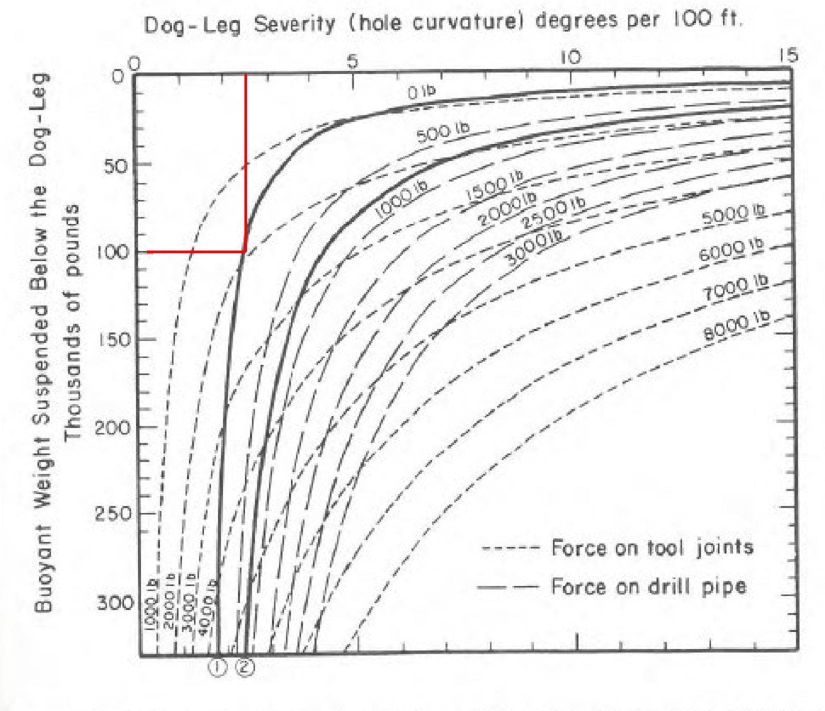
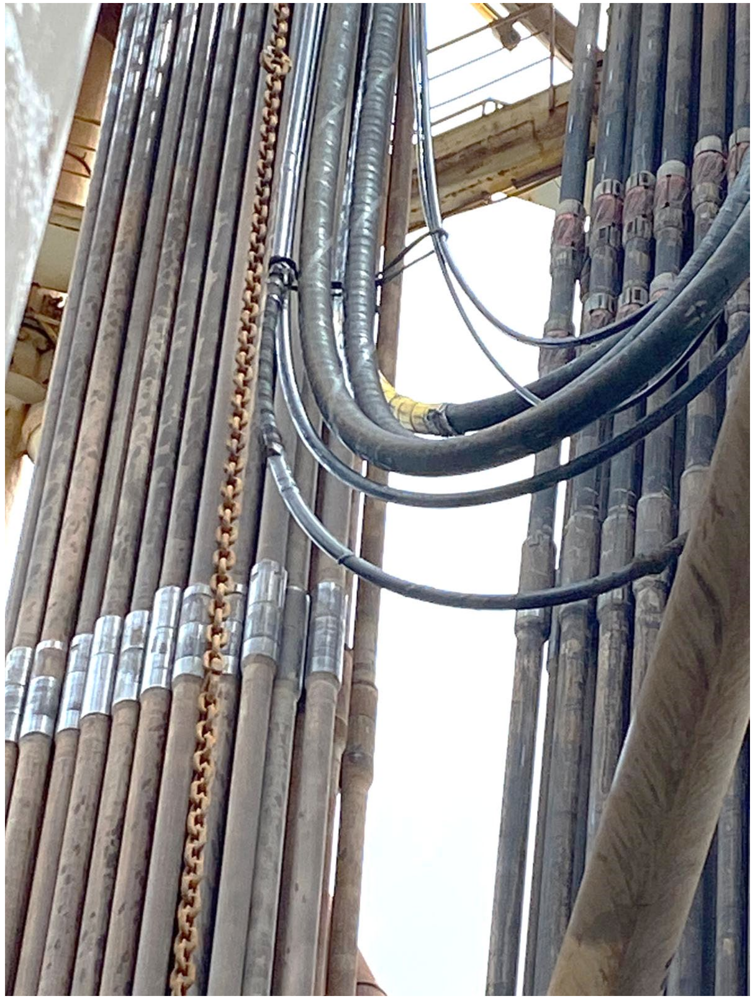


Figure 5-19. Lateral forces on tool joints and Range 3 drill pipe, 5 in. OD, 19.5 lb/ft, with 6⅜ in. tool joints.

Look for Shiny Drill Pipe

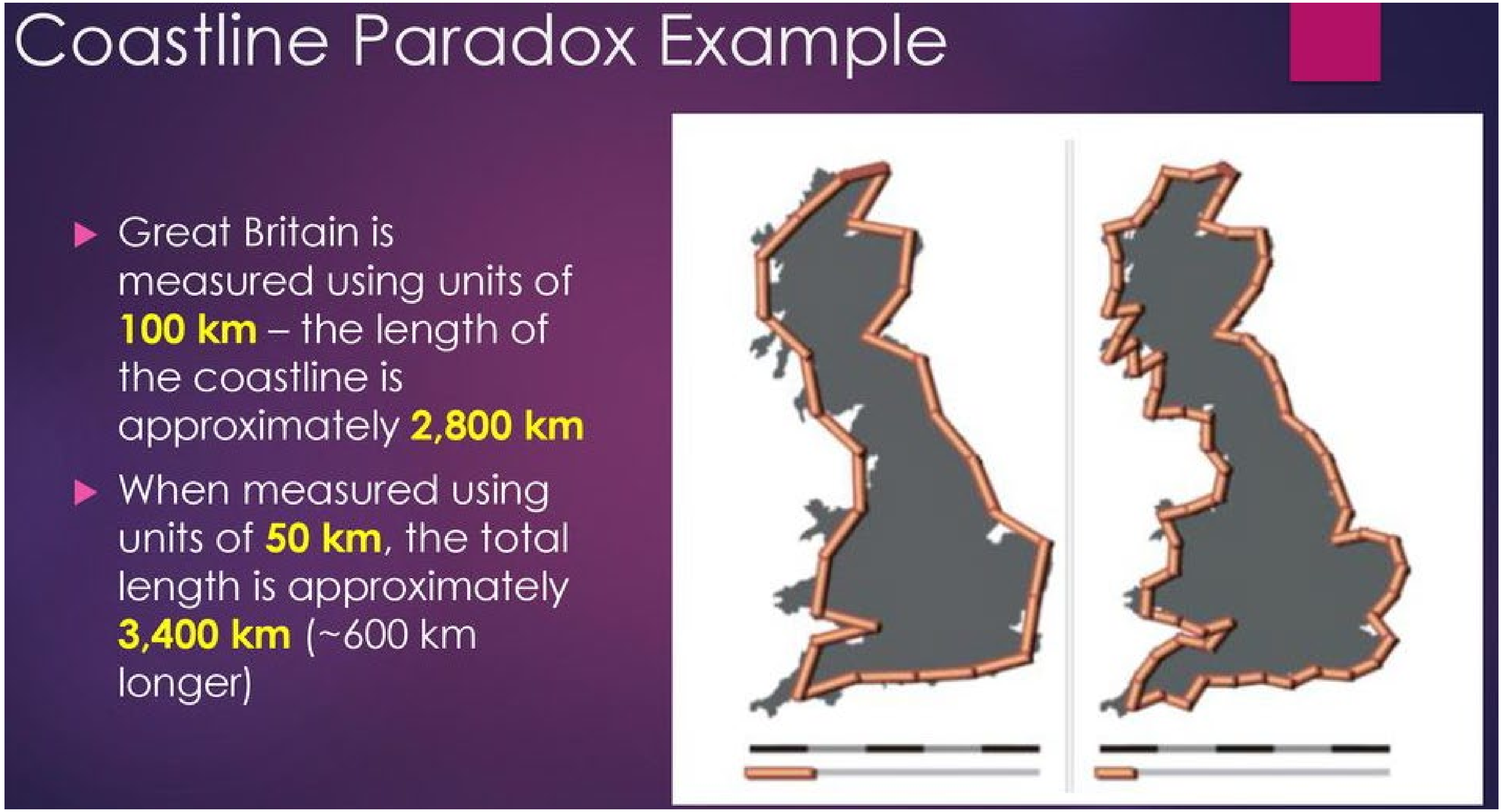
- Protectors midspan on tube in open hole for buckling

- Protectors at tool joint connection for torque reduction and casing wear mitigation



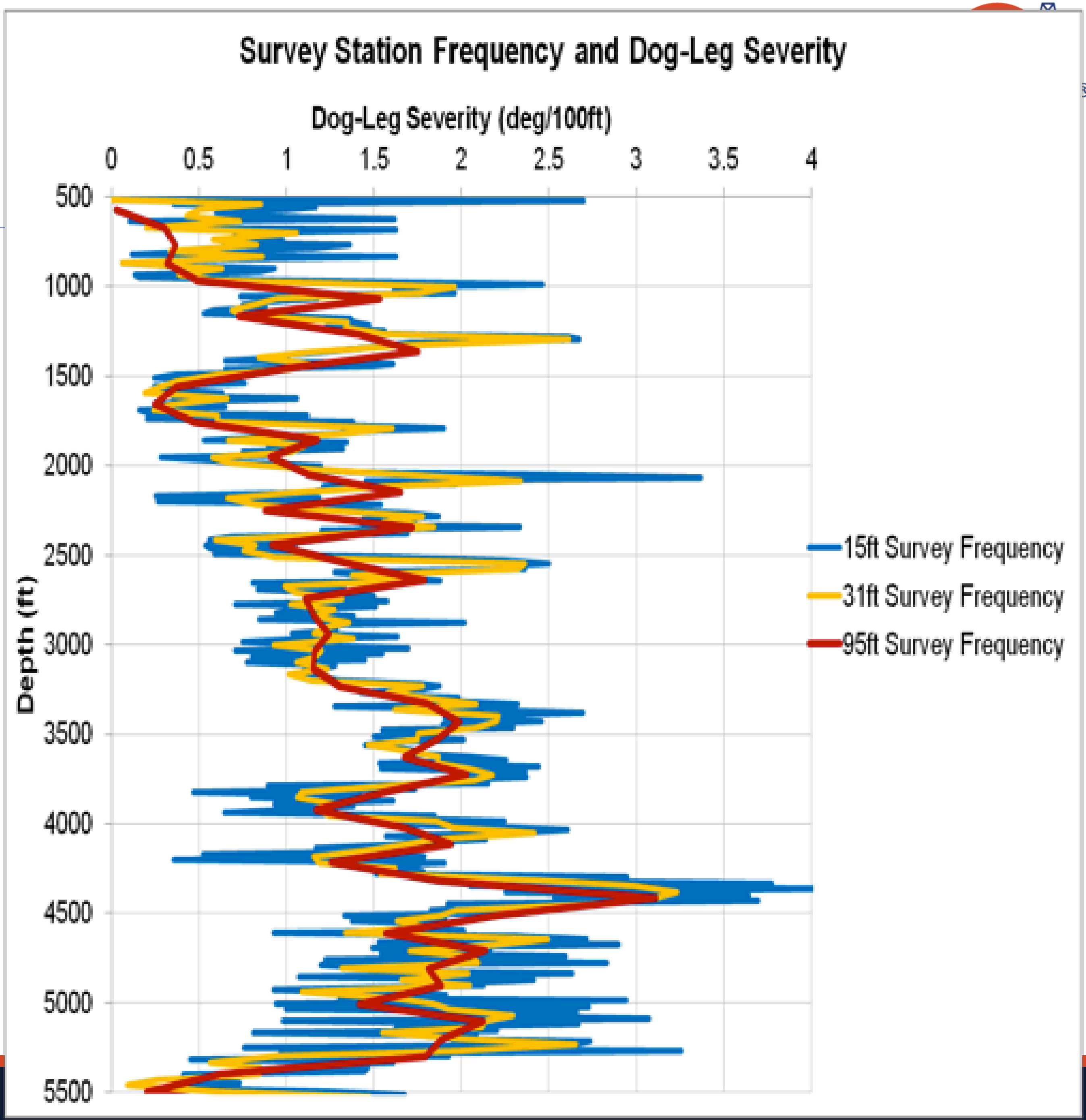
Frequency of Survey Affects Dogleg

- Standard is still °/100ft or °/30m
- Frequency of survey ≠ frequency of side force calculation.
- Beware of software optimization and limitations.
- 30ft or 10m surveys are a sweet spot for side force analysis.
- Ed Stockhausen Vdoorlocksmith
- Angus Jamieson Vdoorlocksmith



Survey Frequency

- Surveys taken at 95ft intervals can underestimate DLS significantly.
- At 95 ft or more, modeled casing wear will be significantly less than maximum measured casing wear.
- Surveys taken at intervals less than 15ft introduce too much noise.
- Surveys taken too close or too spread out can skew casing wear factors and friction factors.
- Recommended survey stations are 31ft (10m) - ideal “curve fitting.”



Directional Slides Shorter Than Survey Spacing

- The biggest doglegs are often undermeasured
- 10°/100ft used to be rare
- 15°/100ft build rates are common
- *Directional Drilling Tests in Concrete Blocks Yield Precise Measurements of Borehole Position and Quality* SPE 151248

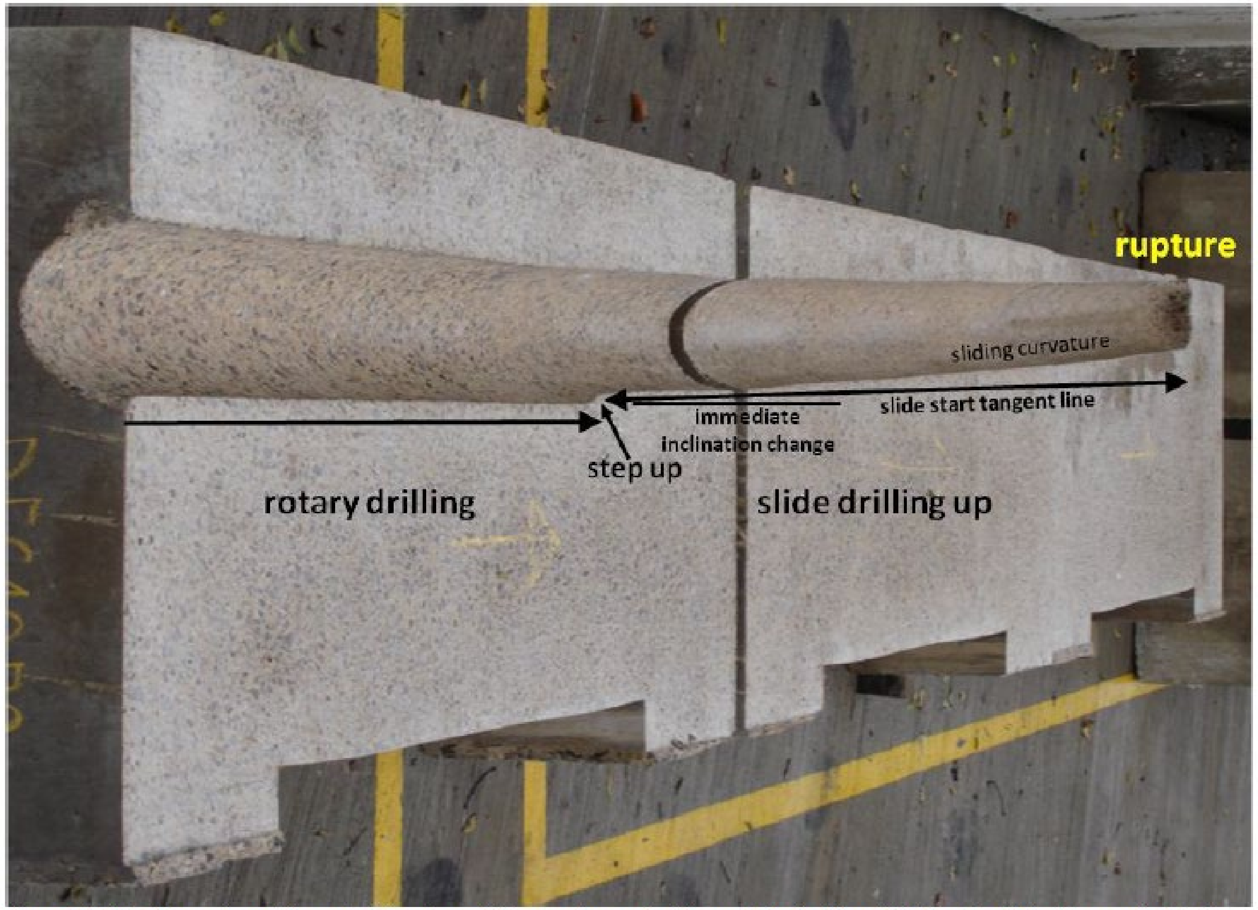
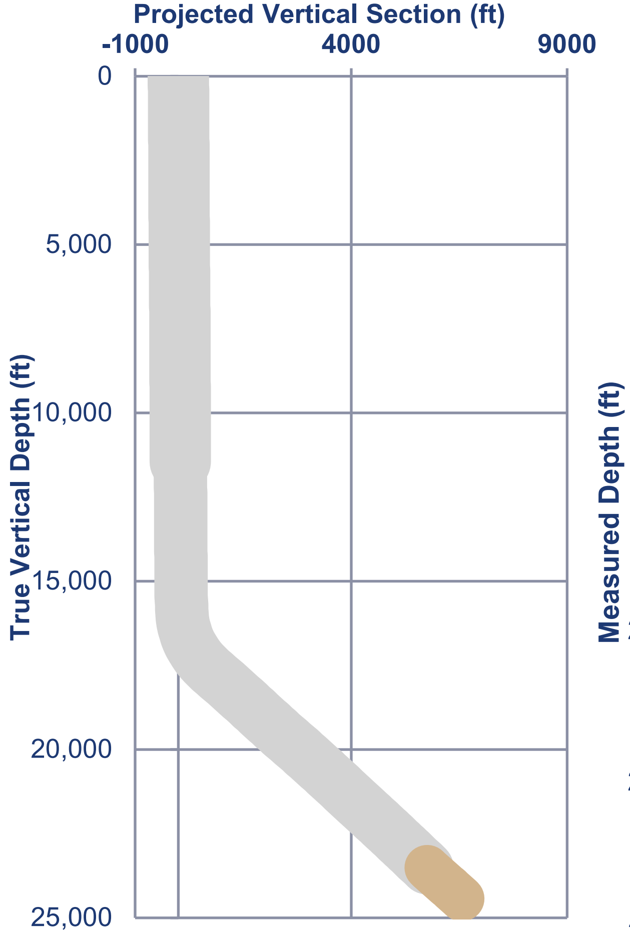
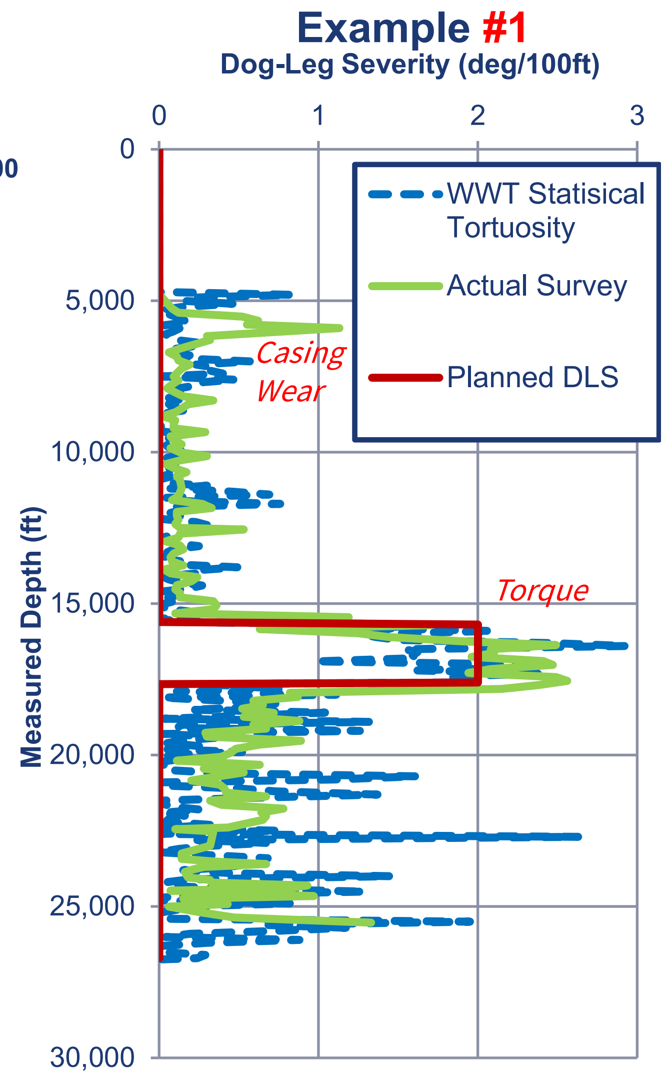


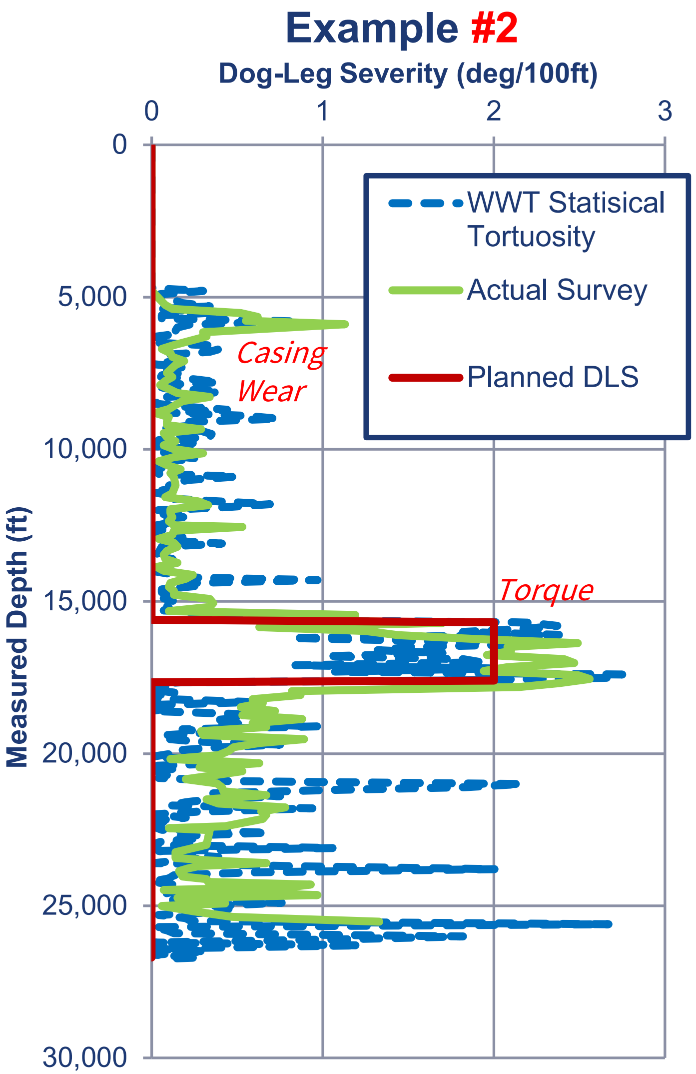
Figure 10. This figure shows the end of the rotary drilling section and slide-up in blocks 9 and 10 of test 1. While this resulted in the rupture at the top of block 10, ending the test, it preserved a slide section intact before additional rotation altered it. Note the larger hole in the rotary section, the step up (shallower TVD) and immediate inclination change at the rotate/side interface. The curvature of the slide can be seen in comparison to the slide start tangent line.

WWT Statistical Tortuosity Example Gulf of Mexico Well, SPE 191495

Build/hold to 39°





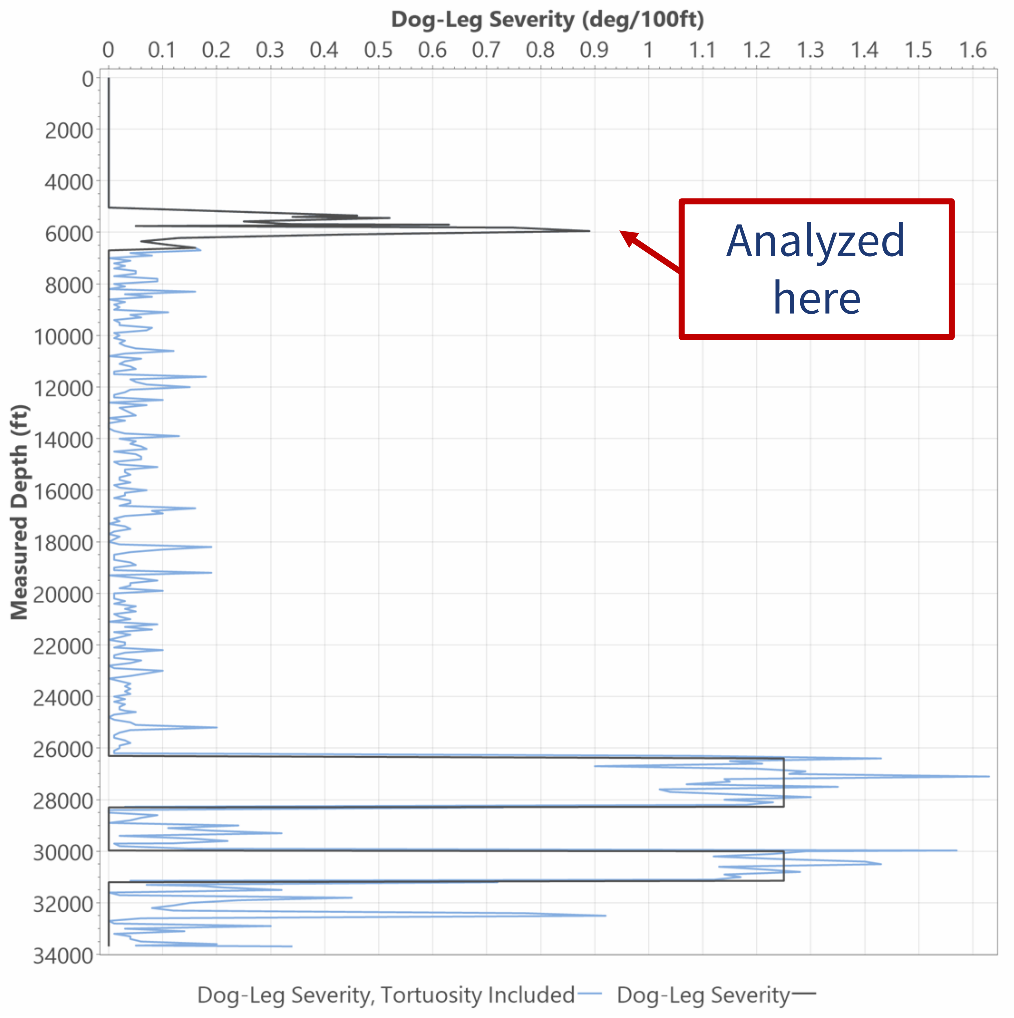


- Useful tool for assessing risk before drilling
- Vertical (mostly)
  - 1-2 points of concern of 100 survey points
- Build / curve
  - Oversteer and understeer
- Hold Tangent
  - Oversteer and understeer

Shallow Deviation, Deepwater Well

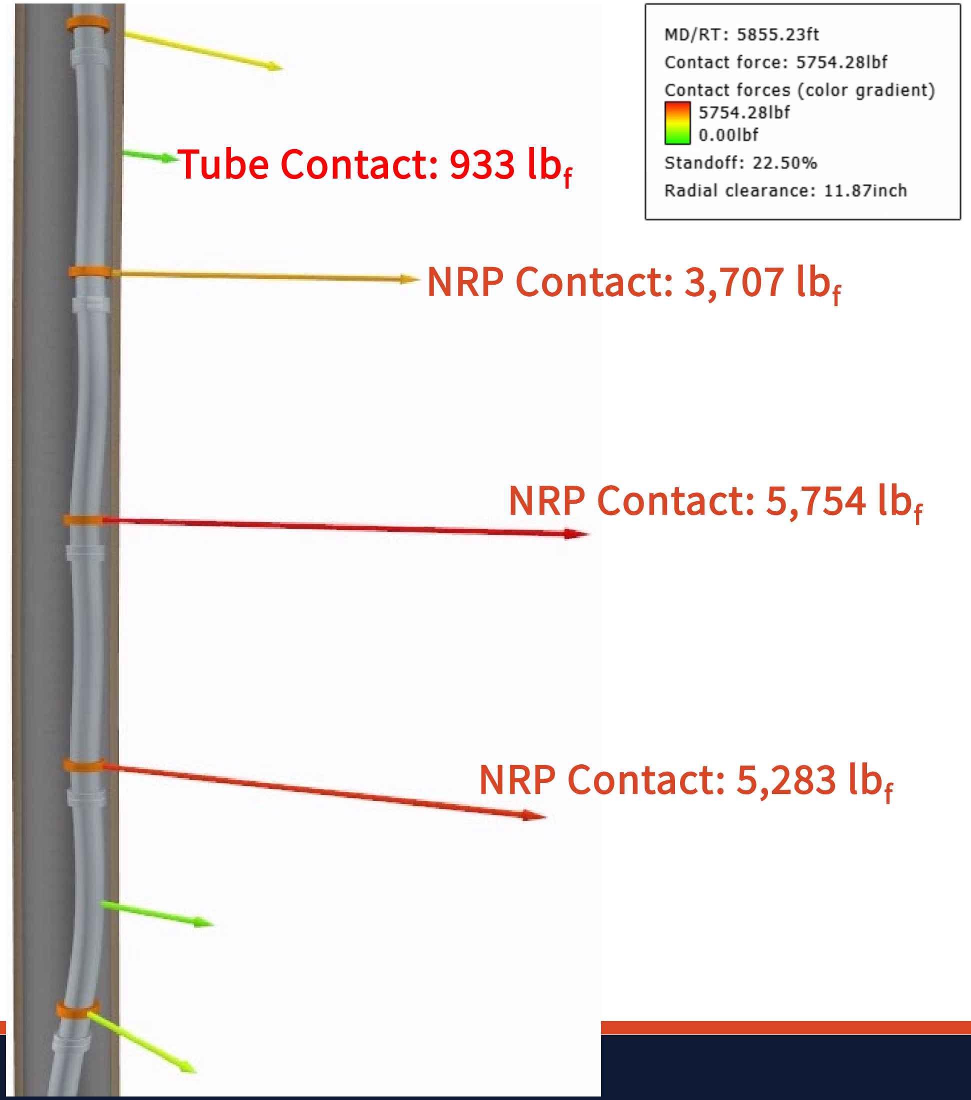
MD (ft)	Survey-Survey (ft)	Incl (°)	Azim Grid (°)	TVD (ft)	DLS (°/100ft)
5684.00	-	1.26	121.46	5683.90	0.34
5704.00	20.00	1.18	125.98	5703.90	0.63
5754.00	50.00	1.20	125.23	5753.88	0.05
5817.00	63.00	1.15	148.46	5816.87	0.75
5951.00	134.00	0.55	229.44	5950.86	**0.89**
6083.00	132.00	0.04	6.25	6082.86	0.44
6218.00	135.00	0.14	168.72	6217.86	0.13

- Is this dogleg real and concerning?
- Can this well be drilled?

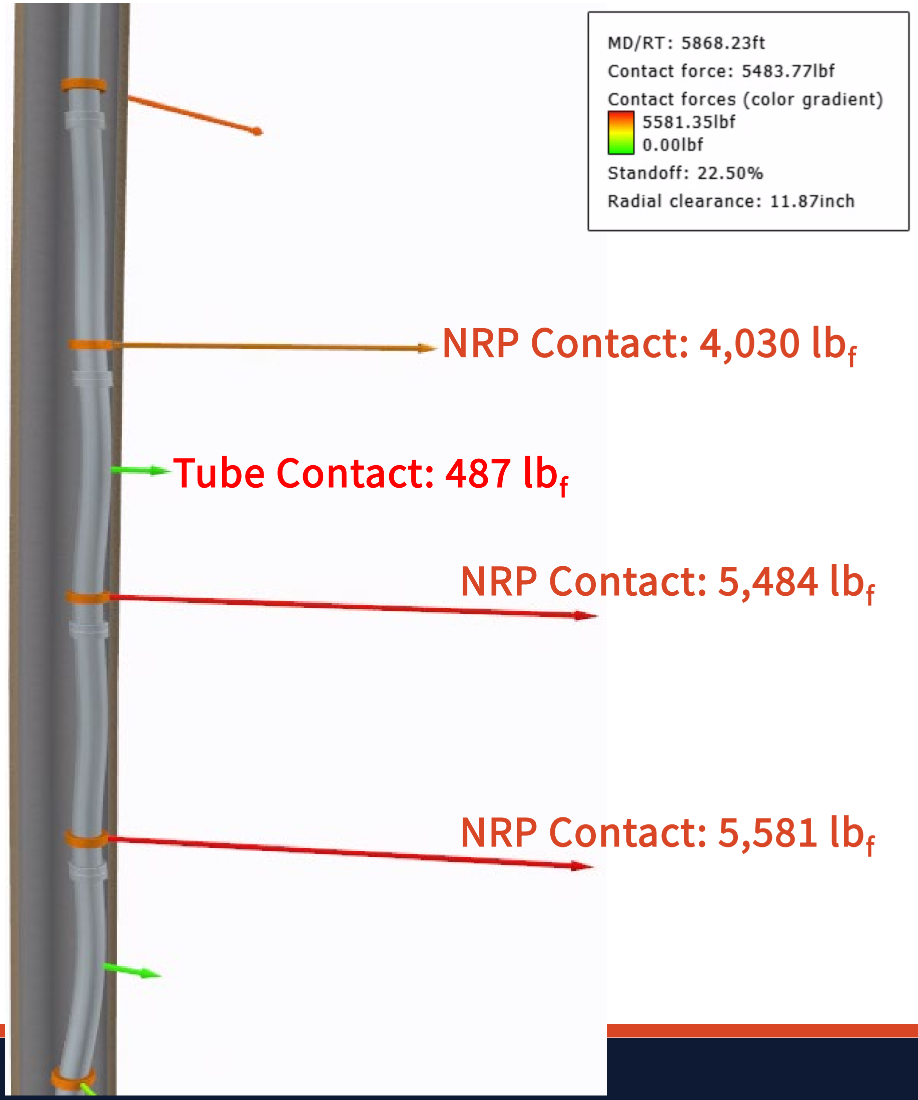


Side Force Distribution at 5,900' MD

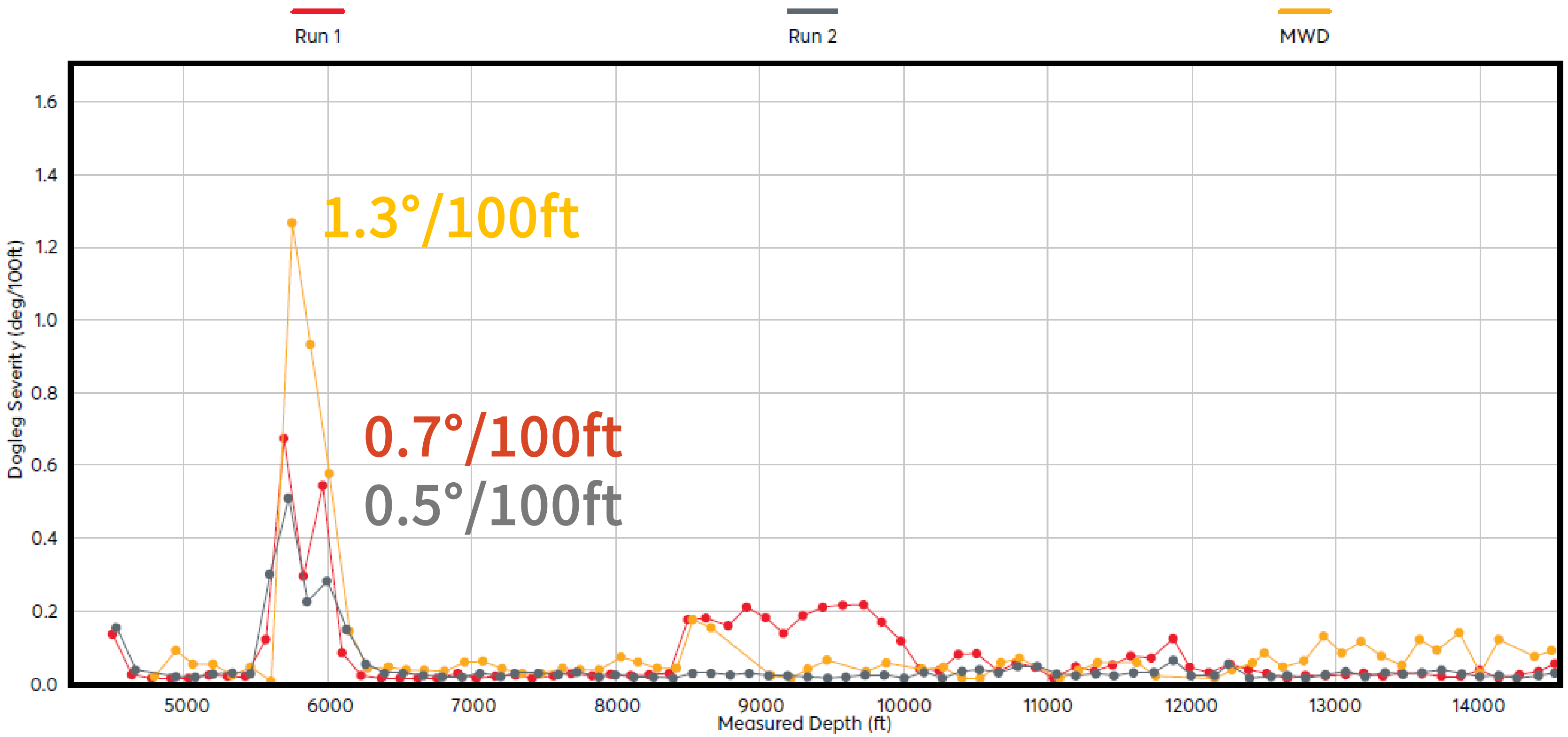
Max Tube & NRP Contact
(Bit @ 29,737' MD)



Bit @ TD
(Bit @ 29,750' MD)



Gyro Example: Deepwater Well



- The system helped the operator understand where the drillpipe centralizers should be placed to reduce casing wear/fatigue, eliminating future need to return to the section to patch up holes in the casing.
- The Omega^{X} system eliminated the need for a comparable gyro run on wireline, saving at least 12 hours of rig time.

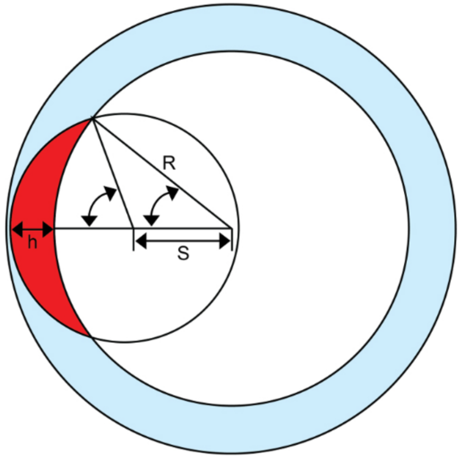
The Omega^{X} system verified that the original spike in dogleg severity was at 5,740 ft. In addition, the Omega^{X} system revealed an additional area of slightly elevated dogleg severity from approximately 8,500 to 10,000 ft that wasn't originally visible due to missing MWD data.

40 gyrodata YEARS OF INNOVATION

https://www.gyrodata.com/wp-content/uploads/2021/01/16_OmegaX_GOM-REV2.pdf

Casing Wear Factor

- Mechanical work (ft-lb) x wear factor $\frac{in^3}{lb\ in}$ or (1/psi) x 10^{-10} causing casing wear
- in^3 of wear volume presented as % of casing wall thickness (crescent)
- Wear factor can vary greatly as it encompasses several characteristics, not just friction.
- Cataloged wear factors for various hardbanding and fluid types are a starting point for analysis if no other option.
- WWT uses linear WF for comparing and extrapolating (2, 5, 10).
- Some software uses non-linear wear factors (1, 2), quickly reaching 7% wear to compensate for manufacturing tolerance and initial wear rate. API 5CT allows 5-12.5% imperfections as "new."



Back-Modeled Casing Wear Factors

- Back-modeled wear factors, to match average and max casing wear.
- 2 is ideal, 5 is safe and 10 is cautious. **In DEA-42 WF range: 0.03 (rubber protector) – 30 (tungsten carbide hardbanding)**
- Lab conditions may be too ideal: erratic pipe motion, sticking, galling, rough hardbanding, solids, choked flow, etc

Well Type	BHA Type	Location	Mud Type	Wear Factor to Match Average Wear, E-10psi^{-1}	Wear Factor to Match Maximum Wear, E-10psi^{-1}
Horizontal	Conventional	North Dakota	OBM	60	240
Horizontal	Conventional	North Dakota	OBM	30	60
Horizontal	RSS	Texas	OBM	20	20
Horizontal	Conventional	Oklahoma	OBM	10	20
Deepwater	**RSS**	**Gulf of Mexico**	**SBM**	**2-5**	**10**
Deepwater	**RSS**	**Gulf of Mexico**	**SBM**	**7**	**7**
Deepwater	**RSS**	**Gulf of Mexico**	**SBM**	**3**	**10**
S-Shape Directional	RSS	Colombia	OBM	1.5	2
S-Shape Directional	RSS	Colombia	OBM	1.5	2.5
S-Shape Directional	RSS	Colombia	OBM	1.5	3
S-Shape Directional	RSS	Texas	WBM	5	10
S-Shape Directional	Conventional	Rockies	WBM	10	18

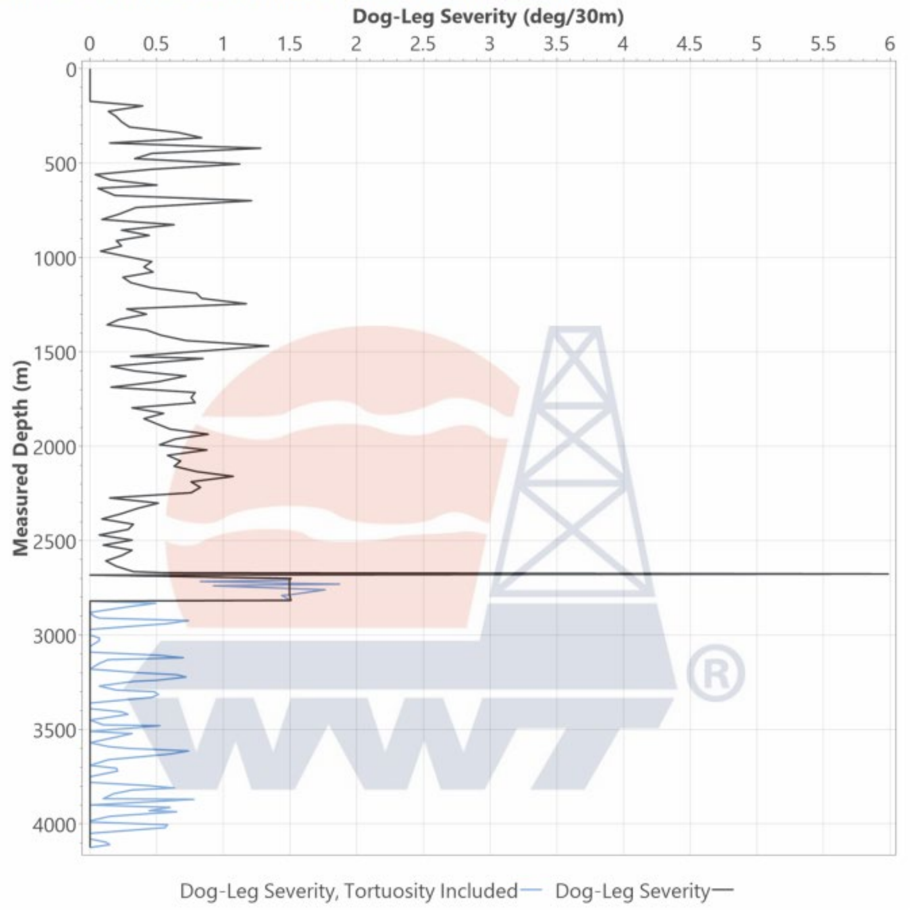
Casing Wear Analysis

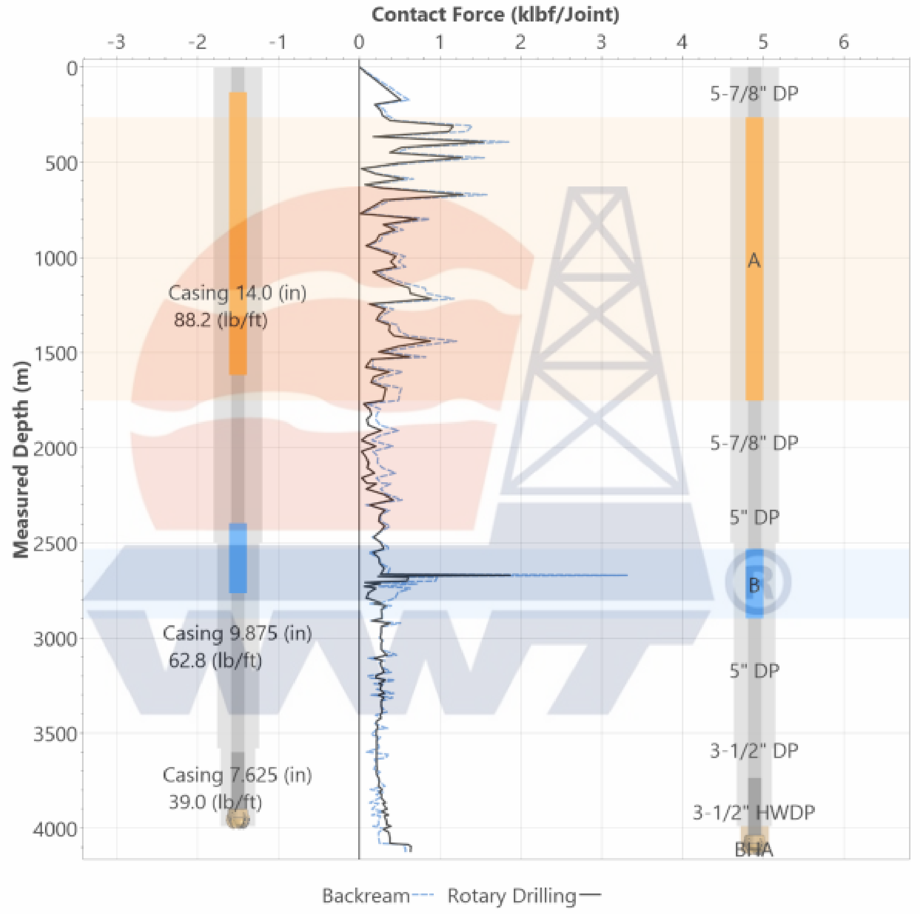
- Multiple hole sections after a sidetrack
- Protectors reduce wear factor at side force

Gráfica de fuerzas de contacto y posicionamiento de protectores

Area of Concern	Placement MD: Start of Run			Placement MD: End Of Run			Protectors Per Joint	Protector Quantity	Model
Zone	Top	Bottom	Joints	Top	Bottom	Joints			
A	130	1618	159	265	1753	159	1	159	SS3-578
B	2398	2763	39	2533	2898	39	1	39	S4-500

Gráfica de la severidad de los dog-legs o patas de perro (Curvatura)





Casing Wear Analysis

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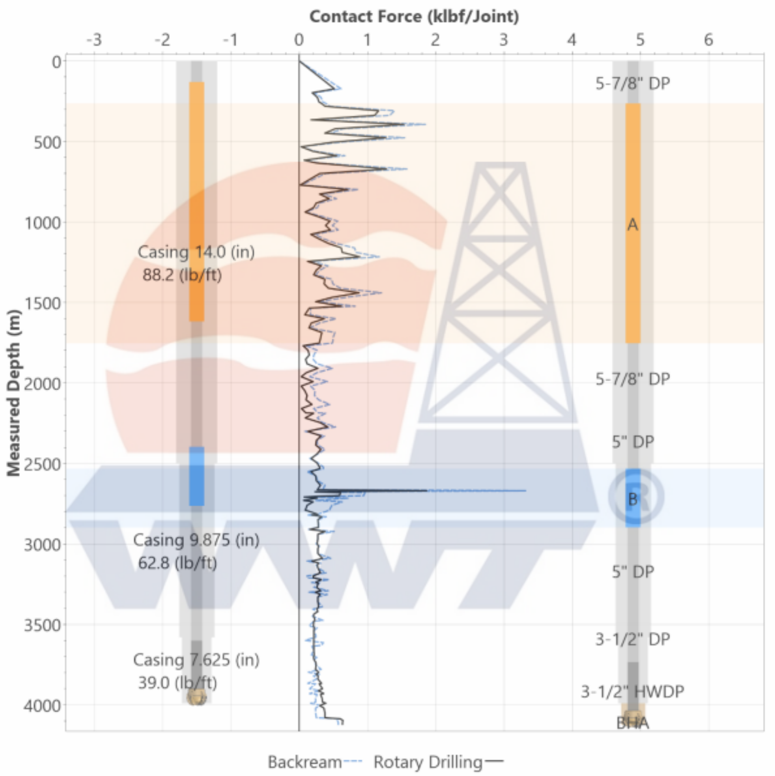
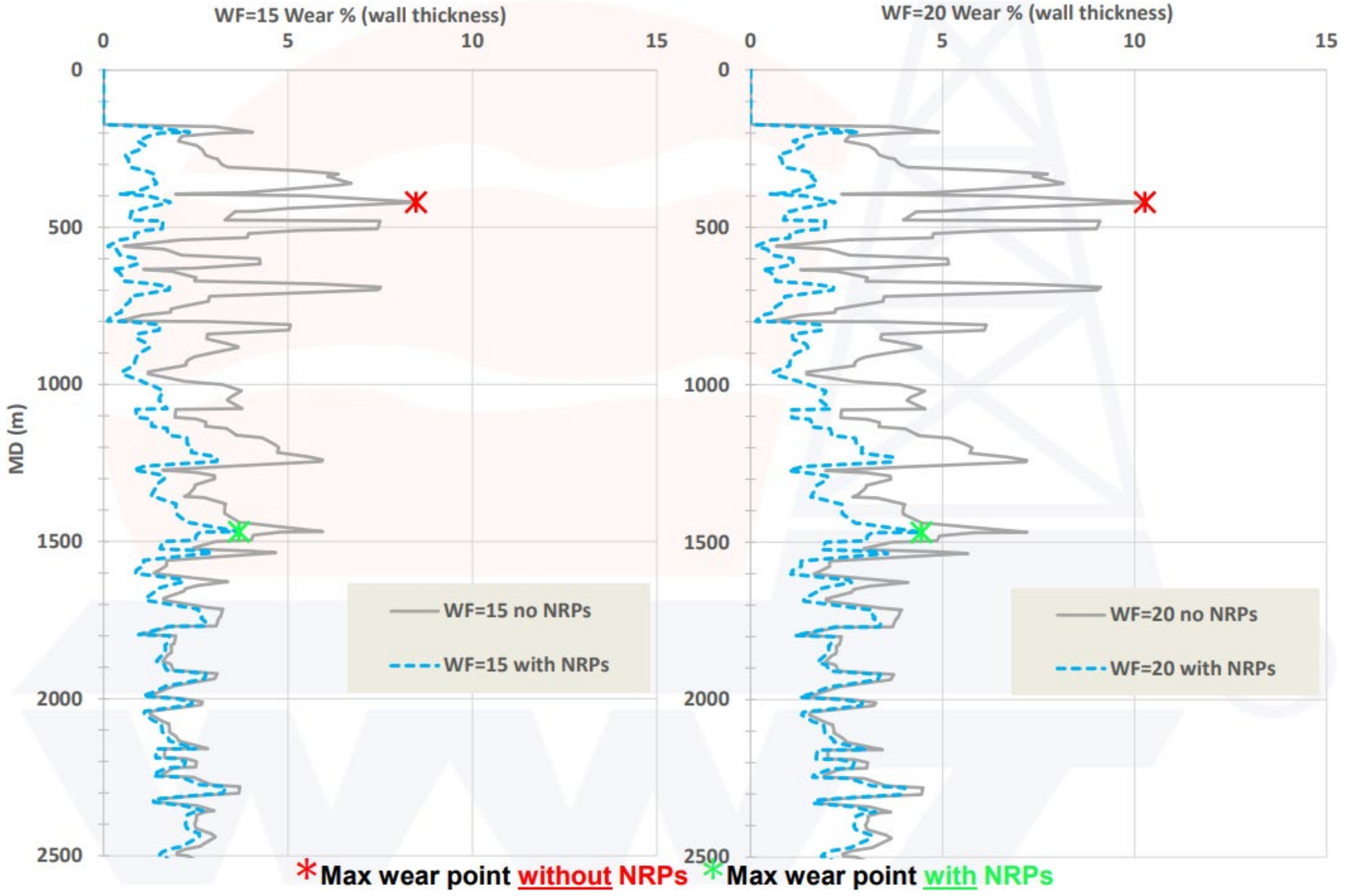




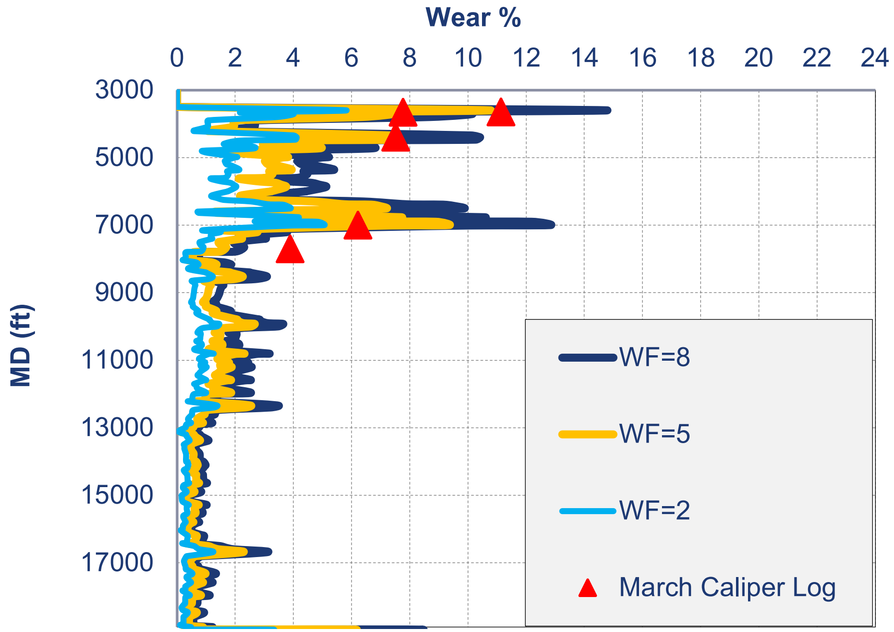
Casing Wear Analysis, GOM Example

16.15" Casing Wear Estimations

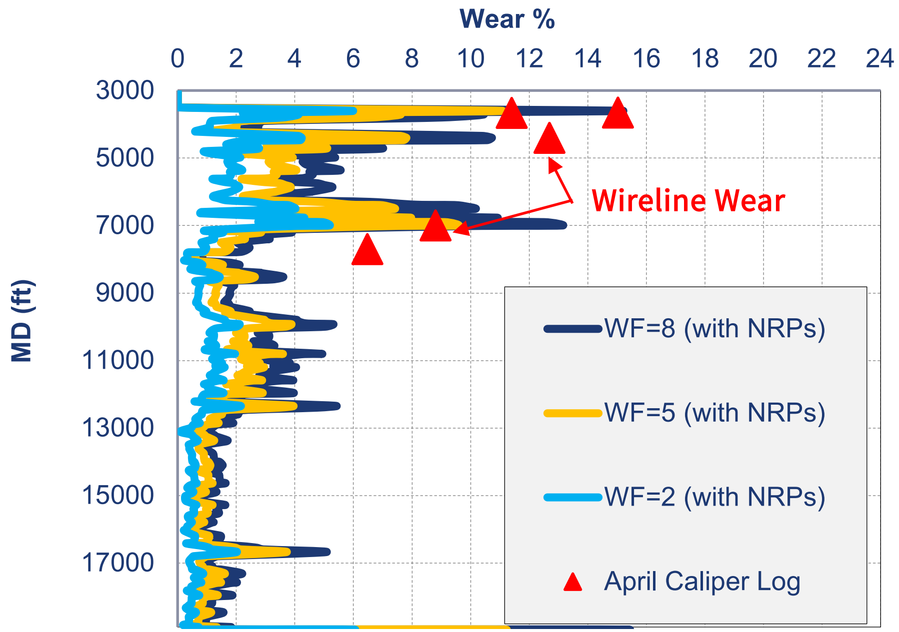
NRPS INSTALLED ON THE LAST TWO HOLE SECTIONS

Hole Section	Start Depth (ft)	End Depth (ft)	Depth Drilled (ft)	ROP (ft/hr)	RPM	Rotating Hours	Drilling Revs (x1000)	Maximum 16.15" Casing Wear WF=2	WF=5	WF=8
14-1/2" x 16-1/2" Section (no NRPs)	18875	22712	3837	96	180	40	431	2.2%	4.0%	5.5%
12-1/4" x 14-1/2" Section (no NRPs)	22663	28545	5698	57	180	99	1073	5.8%	10.7%	14.7%
10-5/8" x 12-1/4" Section with NRPs	28498	31292	2794	32	126	88	662	5.9%	10.9%	15.0%
8-1/2" x 9-7/8" Section with NRPs	31254	32550	1296	31	160	42	401	6.0%	11.1%	15.2%
					Total	269	2567			

Cumulative Wear After Drilling 12-1/4" x 14-1/2" Section WITHOUT NRPS INSTALLED

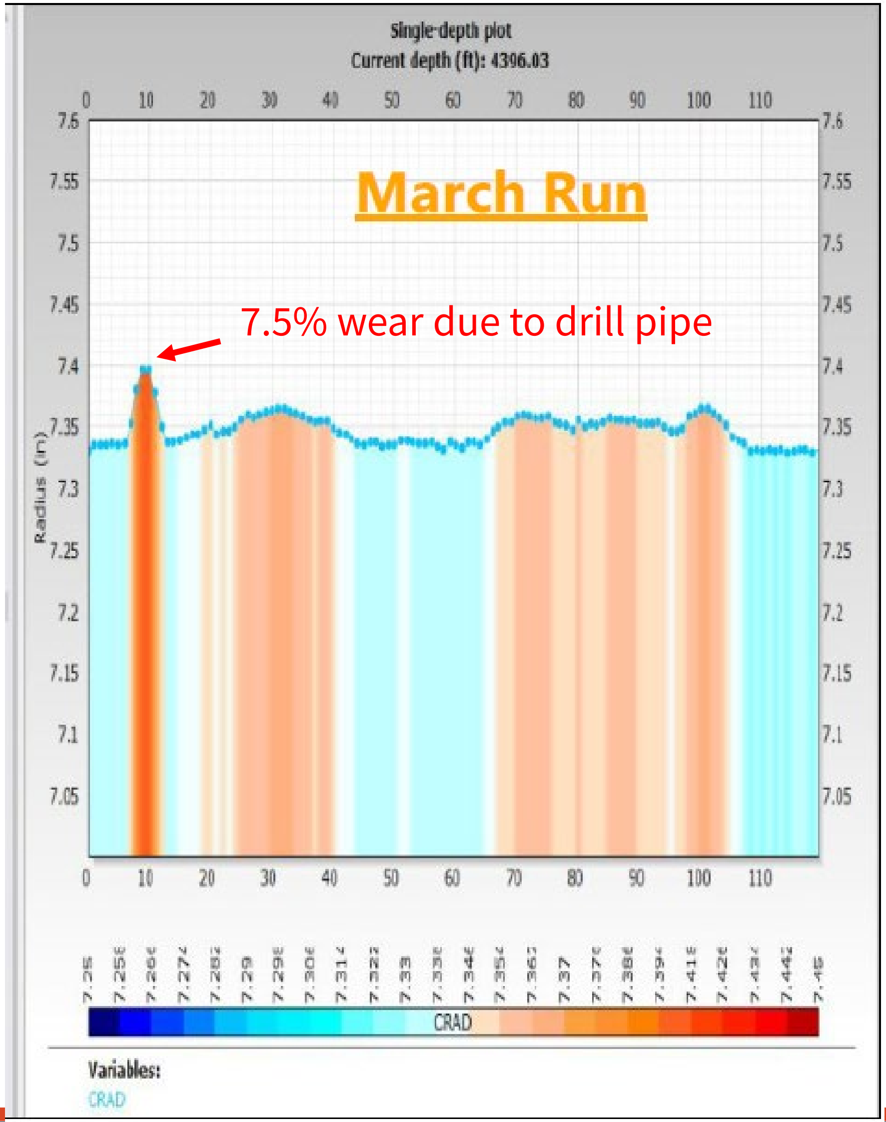


Cumulative Wear after Drilling 8-1/2" x 9-7/8" Section NRPS INSTALLED ON THE LAST TWO HOLE SECTIONS

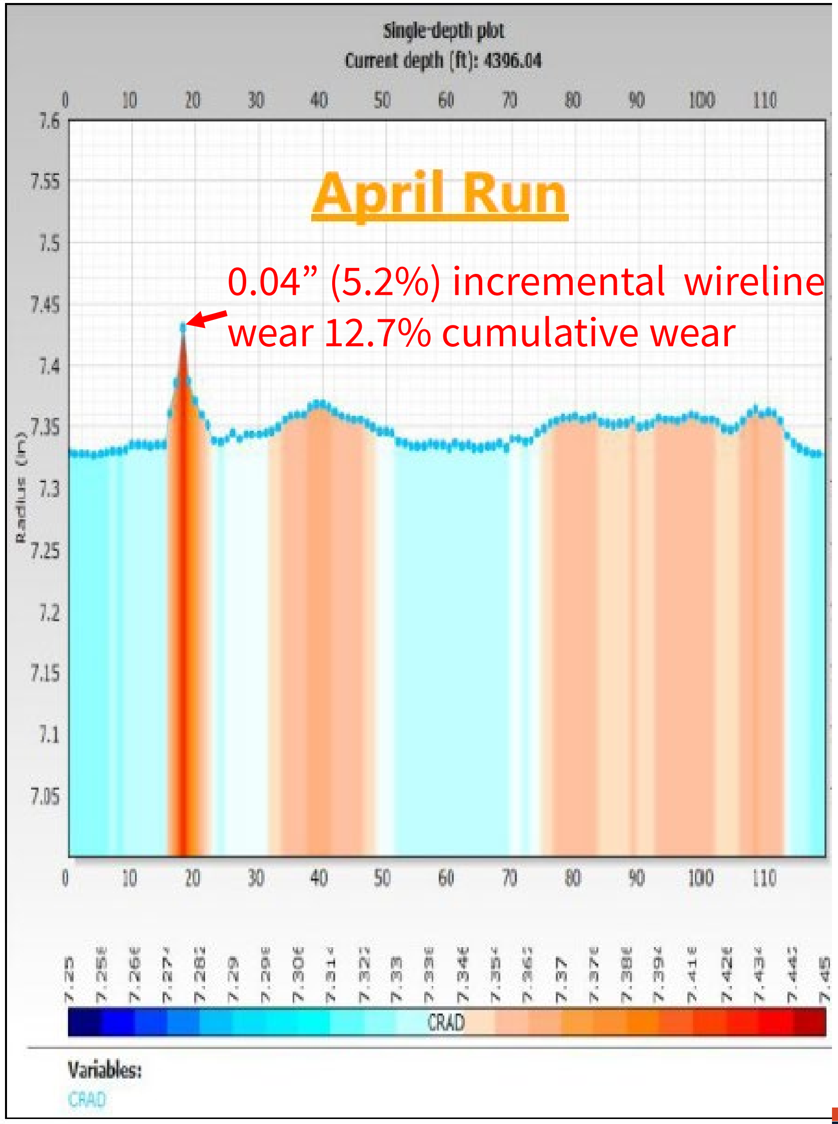


Casing and Wireline Wear, Caliper

1.5 million cumulative DP revs

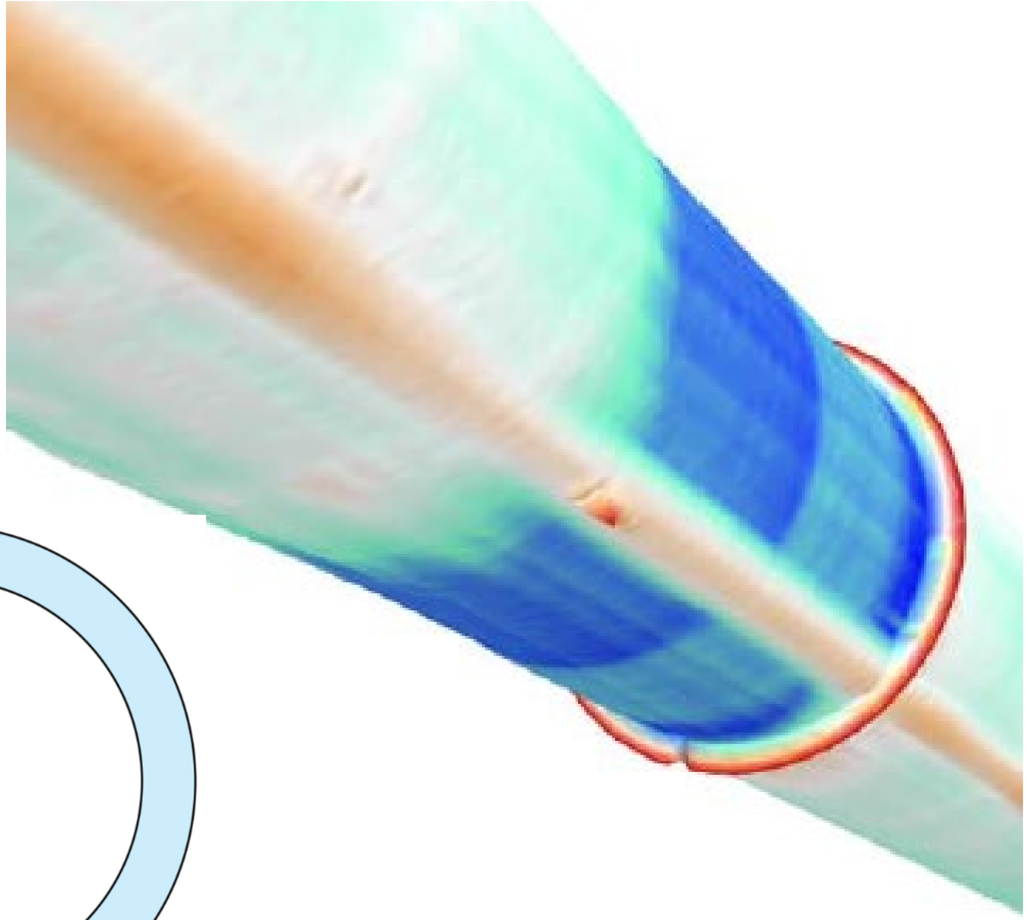


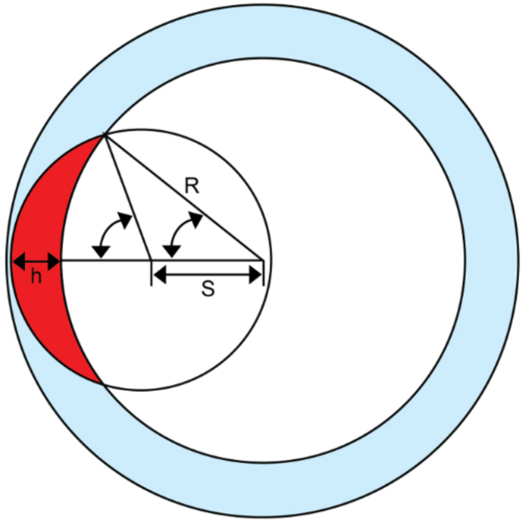
2.6 million cumulative DP revs



Casing Wear and Heat Checking

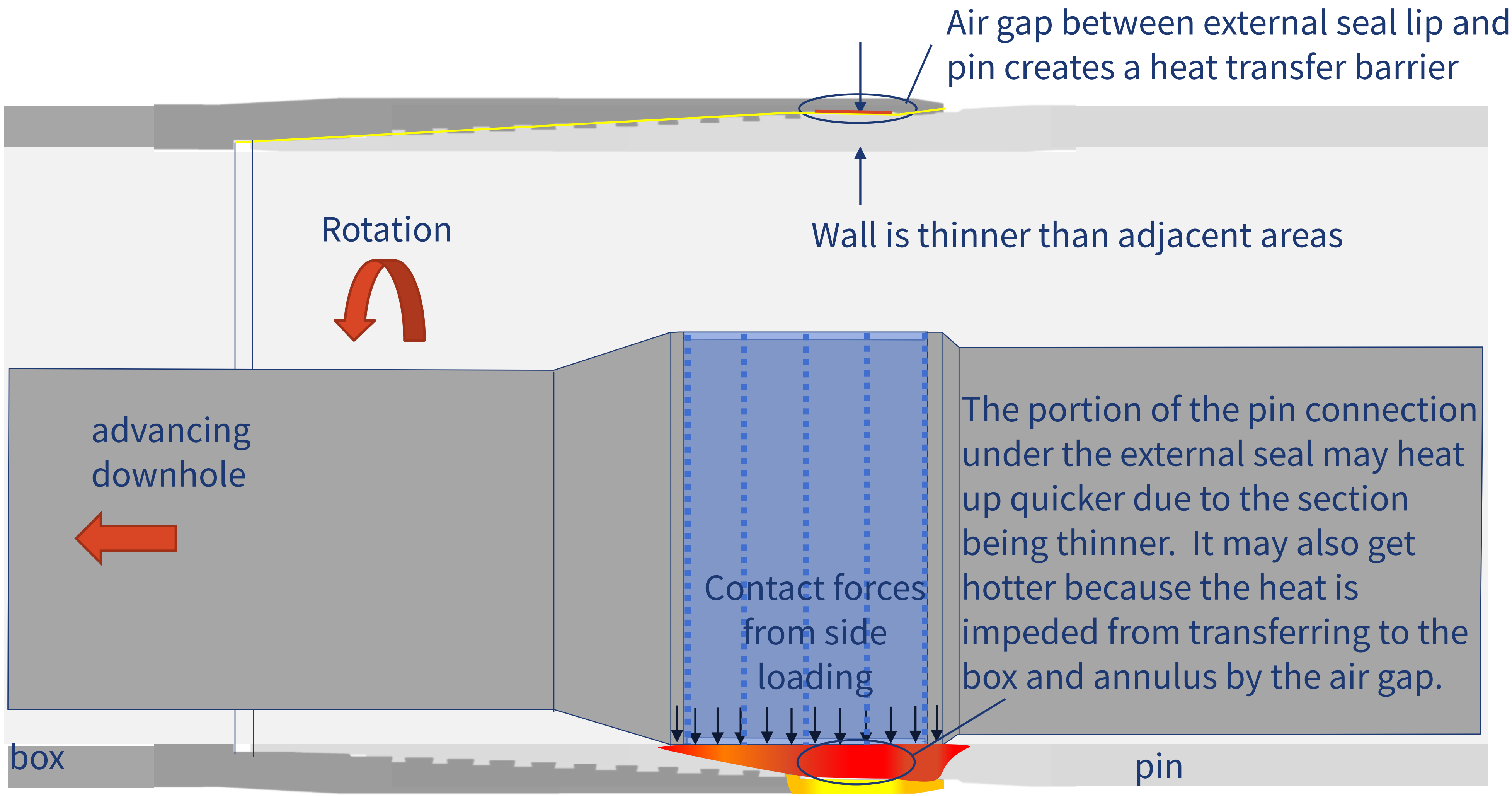
- Side force and wear concentrated at casing connections
  - Increased stiffness
  - Slightly small ID, semi-flush
  - Metal-metal seals susceptible to wear
- Drill pipe follows the wear groove
  - Small drill pipe can be worse!
  - Dig deeper in the groove
  - Wireline can be worse still





Heat Checking Casing Connection

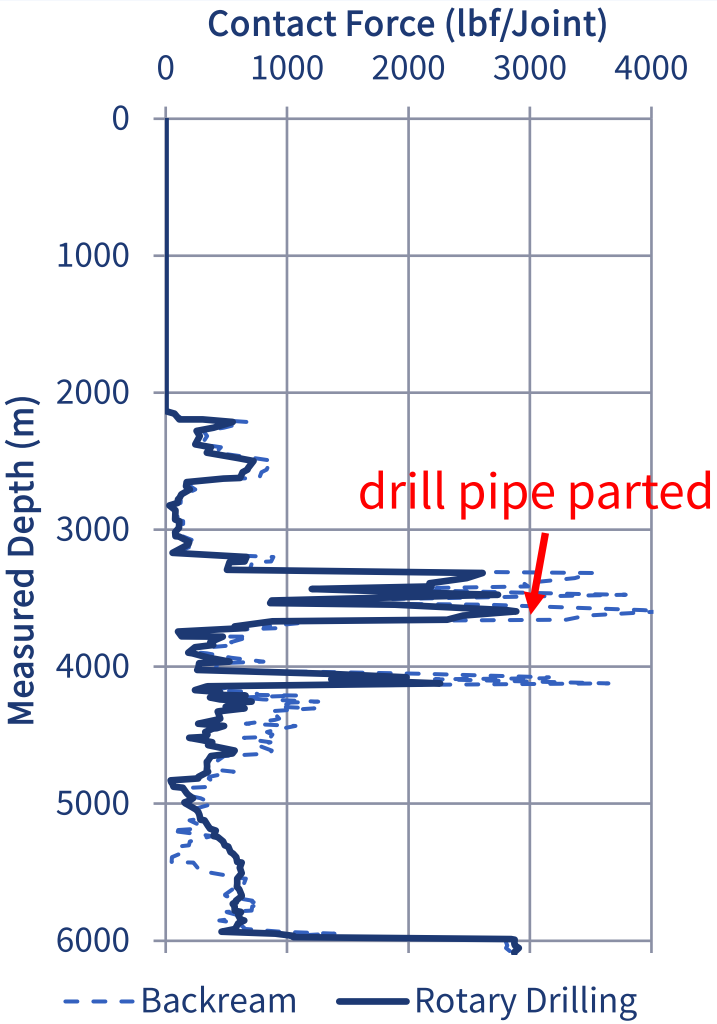
Potential for quench cracking in the pin connection under the external seal may be greater.



Theorized temperature gradient in connection (red = hotter)

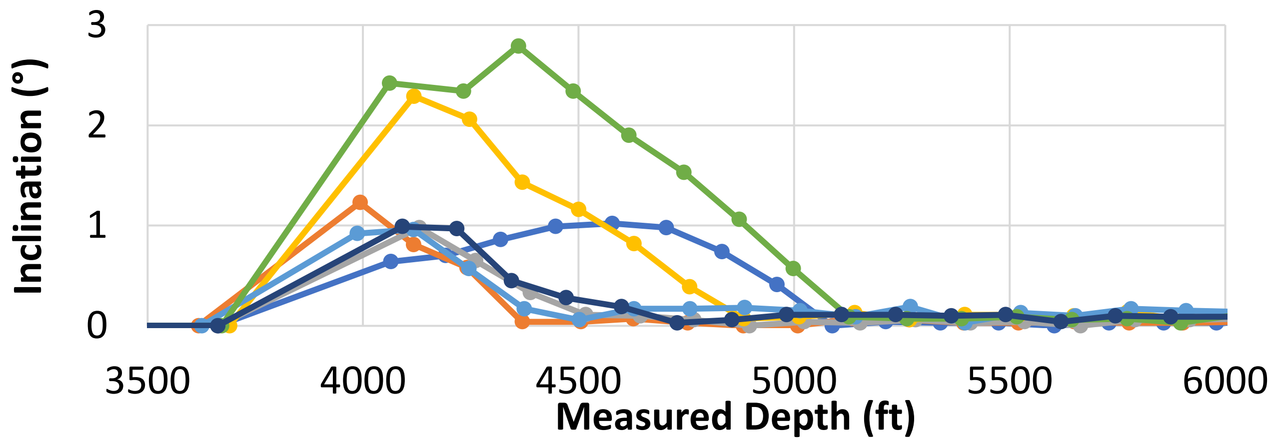
Drill Pipe Heat Checking

- 5-7/8” drill pipe parted at 12,000 ft (3600 m)
- 2,900 lbf/joint drilling side force.
  - 160 klb tension below 4.5°/100ft dogleg
- 350K DP revs before box end parted.
- Cracks on other tool joint box ends.



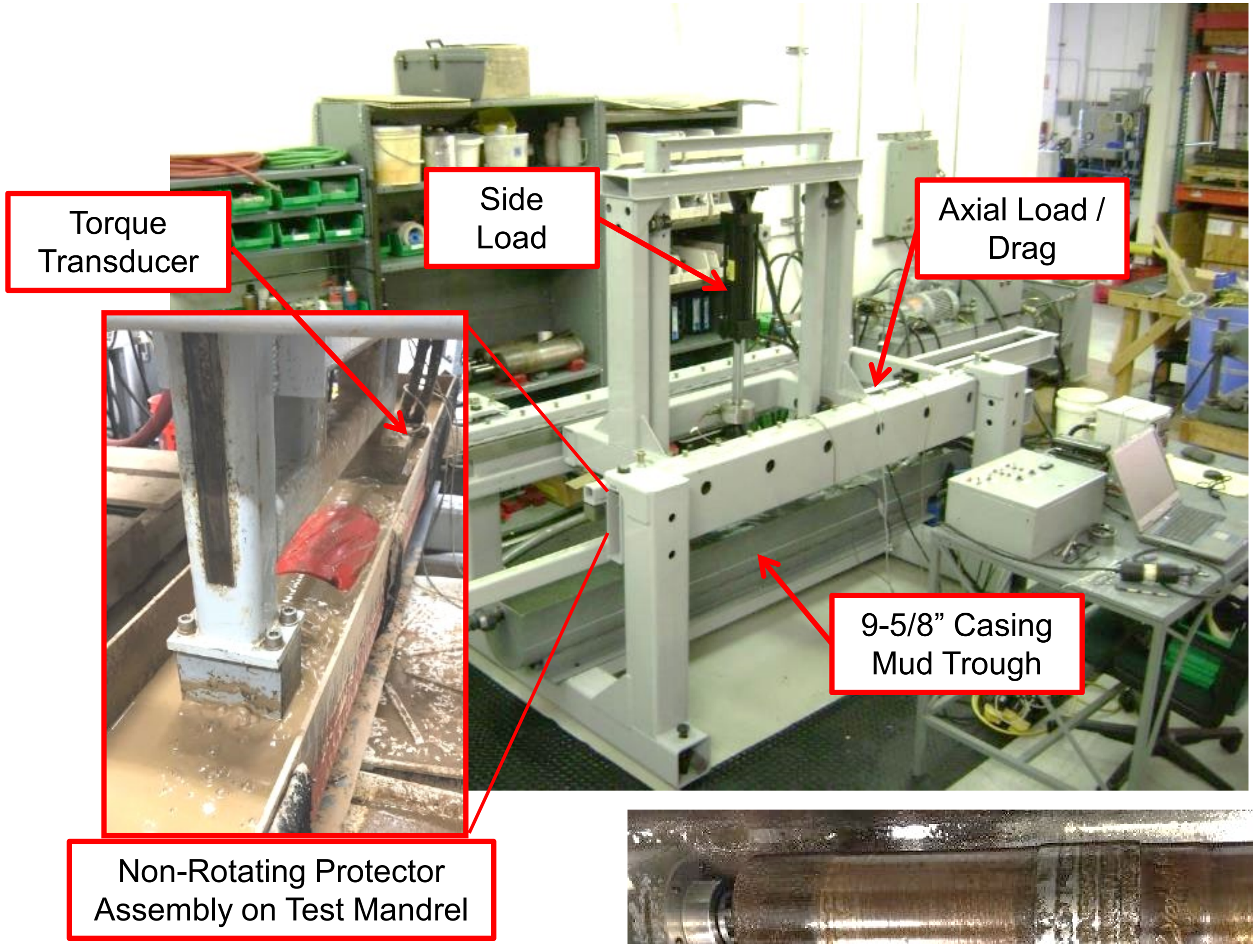
Inclination Drilling Out 36" Casing Shoe in 7 Similar Wells

WH Angle (0 / 90)	1.0 / .75	.75 / 0	.75 / .75	0 / 0	0 / .5	0 / .5	.25 / .25
ROV Slope Indicator	0.5				0.25		
Angle at 36" Shoe	.9	1	1.4	.6	.8	2.3	2.4
Krevs	4265	5641	3040	5998	1901	2103	NA
Max. Wear Groove Depth	0.08" at 3,603'				0.096" at 3,656'	0.17" at 4,568'	



WWT Drilling Test Fixture

NRP or tool joint mandrel loaded with side force and cycled along casing trough.



9-5/8" Casing Trough

Tool Joint Mandrel with Hardbanding (6-5/8" OD)

Testing (cont)

Heat Checking Casing Insert Setup

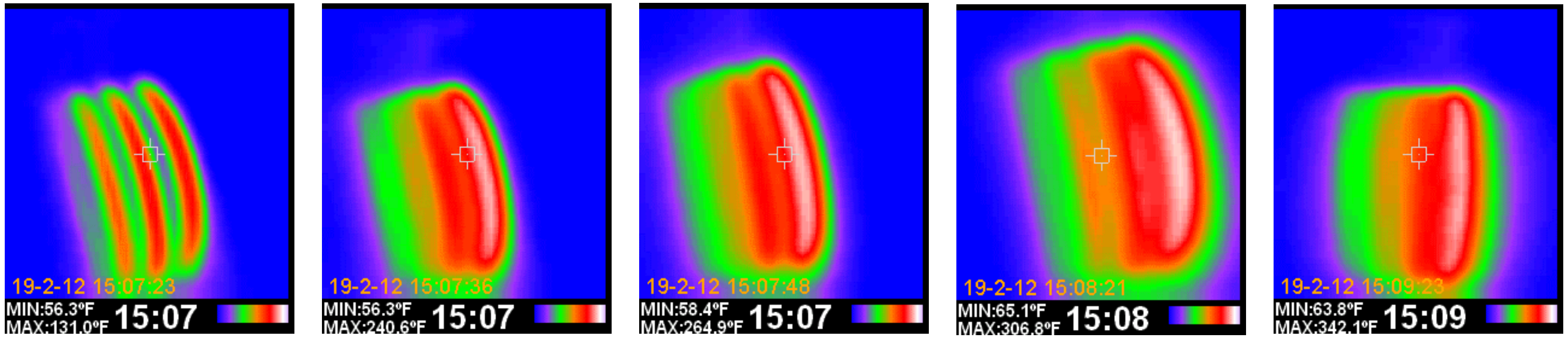
- 0.20” thick, 24” long casing insert fits into 9-5/8” casing trough
- Thermocouples in grooves of various depths in outer diameter
- Measurement of temperature close to tool joint contact location

Groove / Channel #	Depth (in)	Radial thickness from Contact (in)
1	0.175	0.025
2	0.175	0.025
3	0.150	0.050
4	0.125	0.075

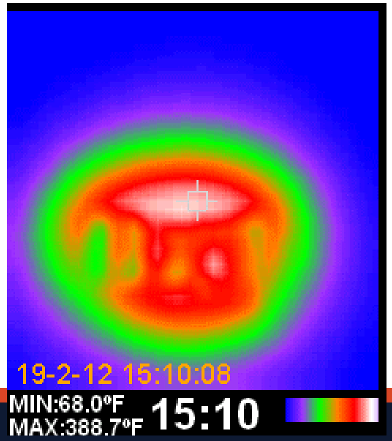
Grooves in casing insert OD

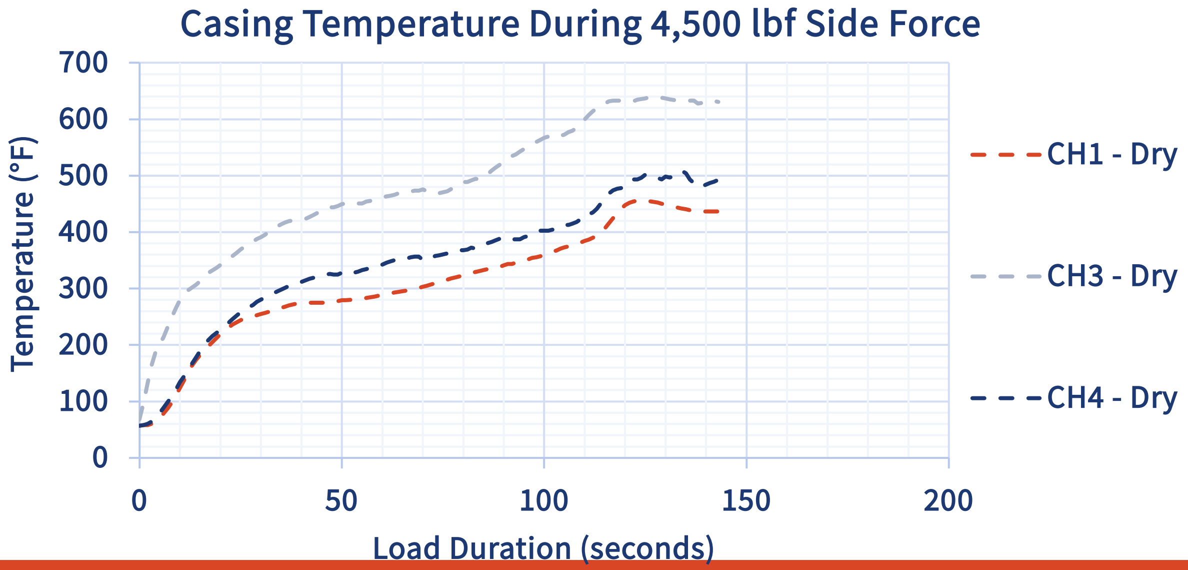
Heat Checking Test # 3
4,500 lbf, dry (residual oil), 2 minutes, 180 rpm

Tool joint hardbanding heats to 342°F during 2-minute test.



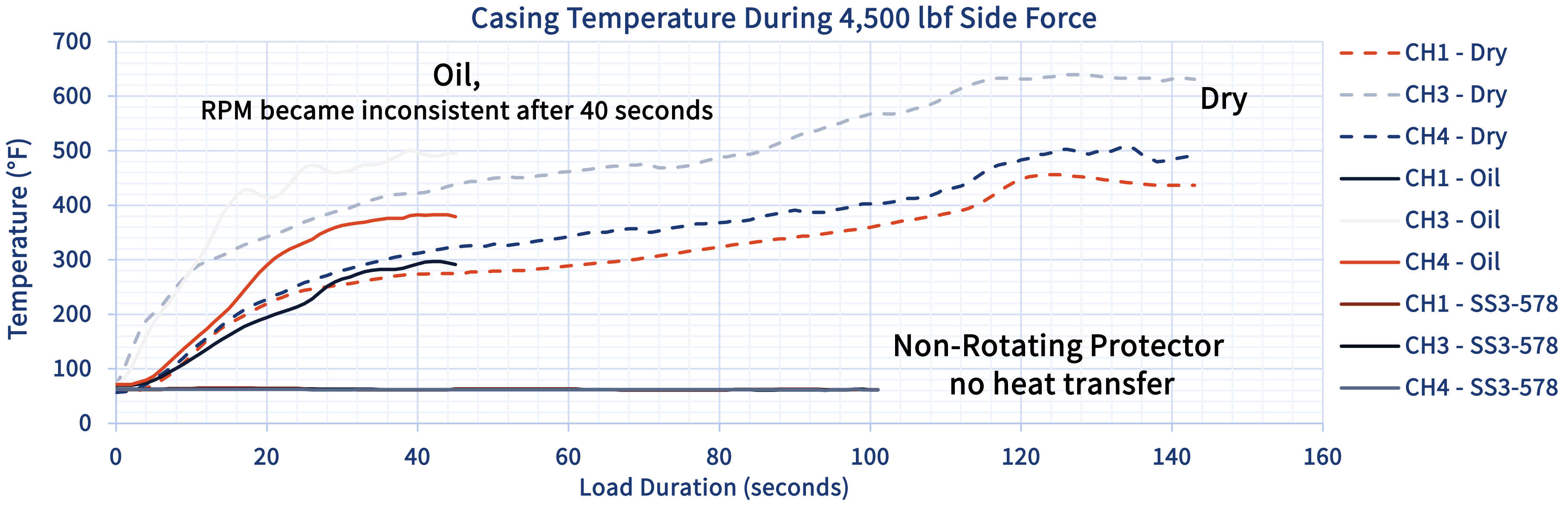
Casing 389°F 30 seconds after unloading tool joint.





Heat Checking Testing Summary

Test #	Side Force (lbf)	RPM	Duration (min)	Max Temp (°F) Ch 1	Ch 3	Ch4	Tool Joint (Infrared)	Comments (Ch 2 removed, faulty reading upon inserting into trough)
1	2000	180	5	394	381	318	-	Dry, minor residual oil
2	4000	180	5	613	864	754	394	Dry, minor residual oil, relocated axially 0.5" from Test 1
3	4500	180	2.5	456	639	509	342	Dry, minor residual oil, relocated axially 0.5" from Test 1 (same location as Test 2)
4	4500	180	<1	296	501	386	279	Oil submerged in 1" of fluid. Relocated axially 0.5" from Test #1 (same location as Test 2)
5	4500	180	1.5	65	63	63		Oil submerged in 1" of fluid. Relocated axially 0.5" from Test #1 (same location as Test 2)



Casing Wear after Heat Checking Testing

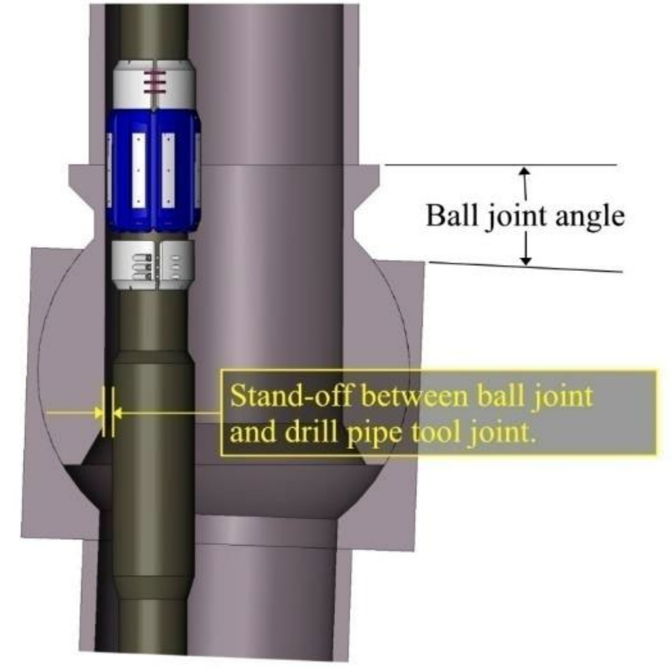
Wear greater than 0.025" radially, exposing grooves 1-2

Groove / Channel #	Depth (in)	Radial thickness from Contact (in)	Axial Distance from Insert Edge (in)
0 (Hole)	Through	-	10.875
1	0.175	0.025	11.125
2	0.175	0.025	11.375
3	0.150	0.050	12.125
4	0.125	0.075	12.250

Thermocouple leads and scorched epoxy on outer diameter of casing insert after test

Riser, Flex Joint, and Stress Joint

- Side force varies on riser deflection (bullseye, currents).
- Protector creates standoff between drill pipe and riser to prevent rotational wear.
- Protectors have been safely used on more than dozens of wells for riser protection on floating rigs, and many more for riser protection on TLP's and spar platforms.



Riser Wear: Side Force at Variable Dogleg

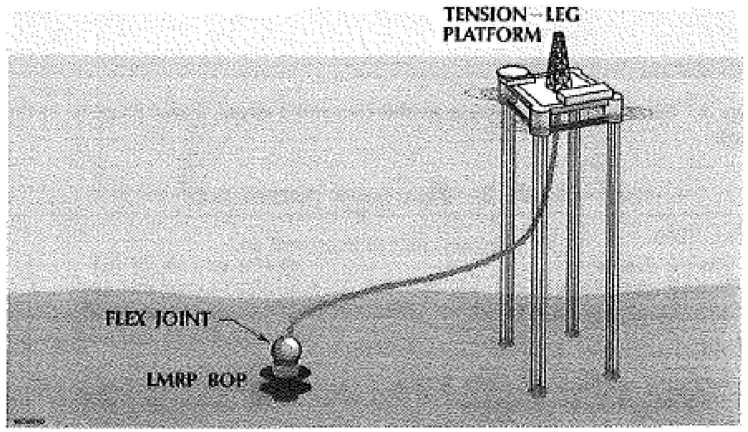


Fig. 1 Conceptual illustration of the sharp dogleg possible at the riser flex joint

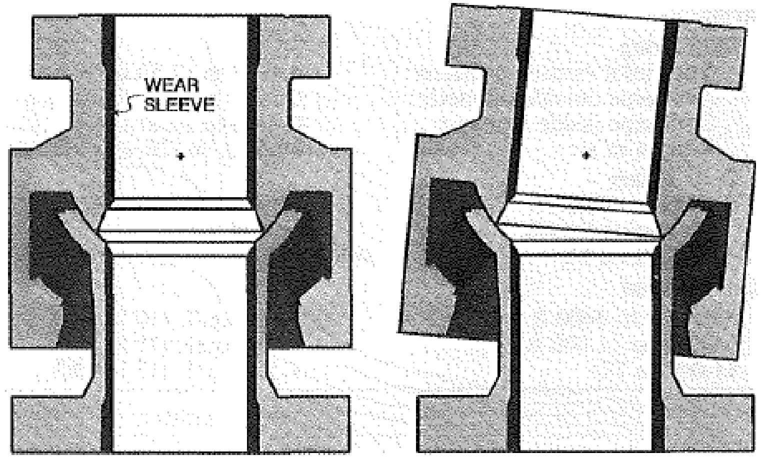


Fig. 2 Conceptual illustration of the flex joint, showing the wear sleeve cylinders. When the flex joint is bent, the bend occurs over a short 1-ft length.

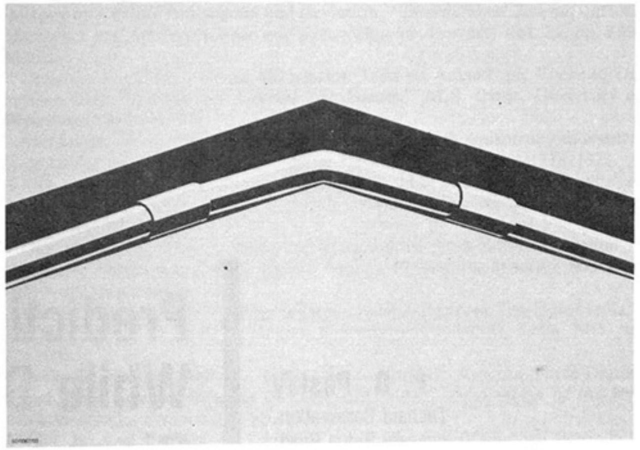


Fig. 5 Shape of the drillpipe when the tool joints are on each side of the kink rather than at the kink

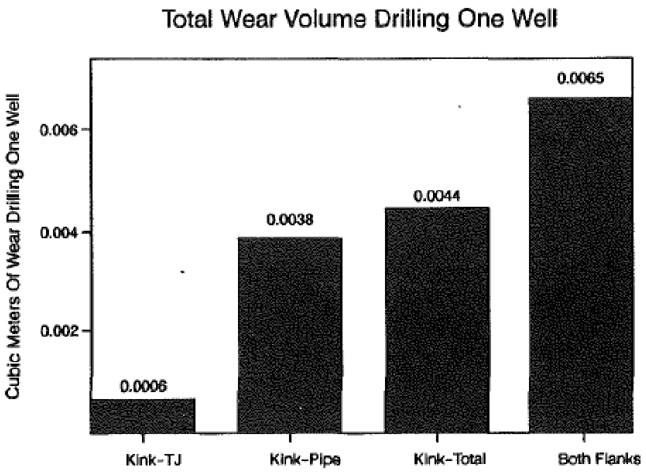
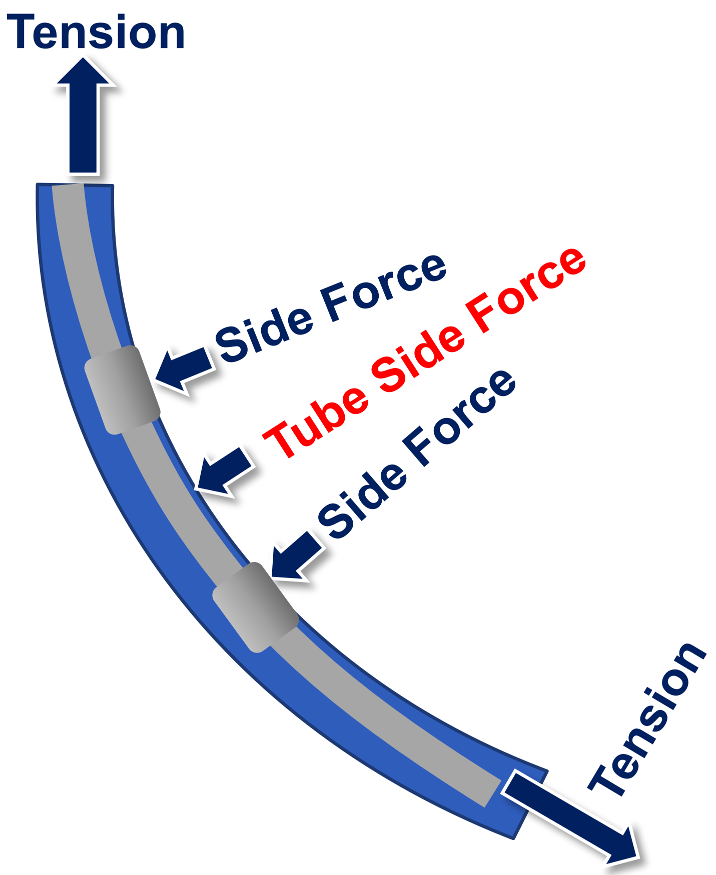


Fig. 12 Wear volume predicted for the flex joint wear sleeves (the kink) and the flanks above and below the flex joint, for drilling one well with a high wear rate mud/steel combination

- The pipe tube wears the kink more than the tool joints.
- Much of the wear volume occurs from drill pipe tube contact on each size of the kink, the riser flanks.
- *Prediction of Wear and Stresses While Drilling Through a Riser Flex Joint Journal of Energy Resources Technology, P. R. Paslay Cernocky, 1994*

Side Force x Time = Consequence



- Planned well paths and actual surveys
  - Gyros, near bit inclination, casing smoothing
  - Standard is still °/100ft or °/30m.
- Side force, torque and drag
  - Tapered string, torque reducers, lubes, OBM
- Casing wear and heat checking
  - Wear logs, monitor ROP/RPM, tougher casing material, polish hardbanding, casing protectors