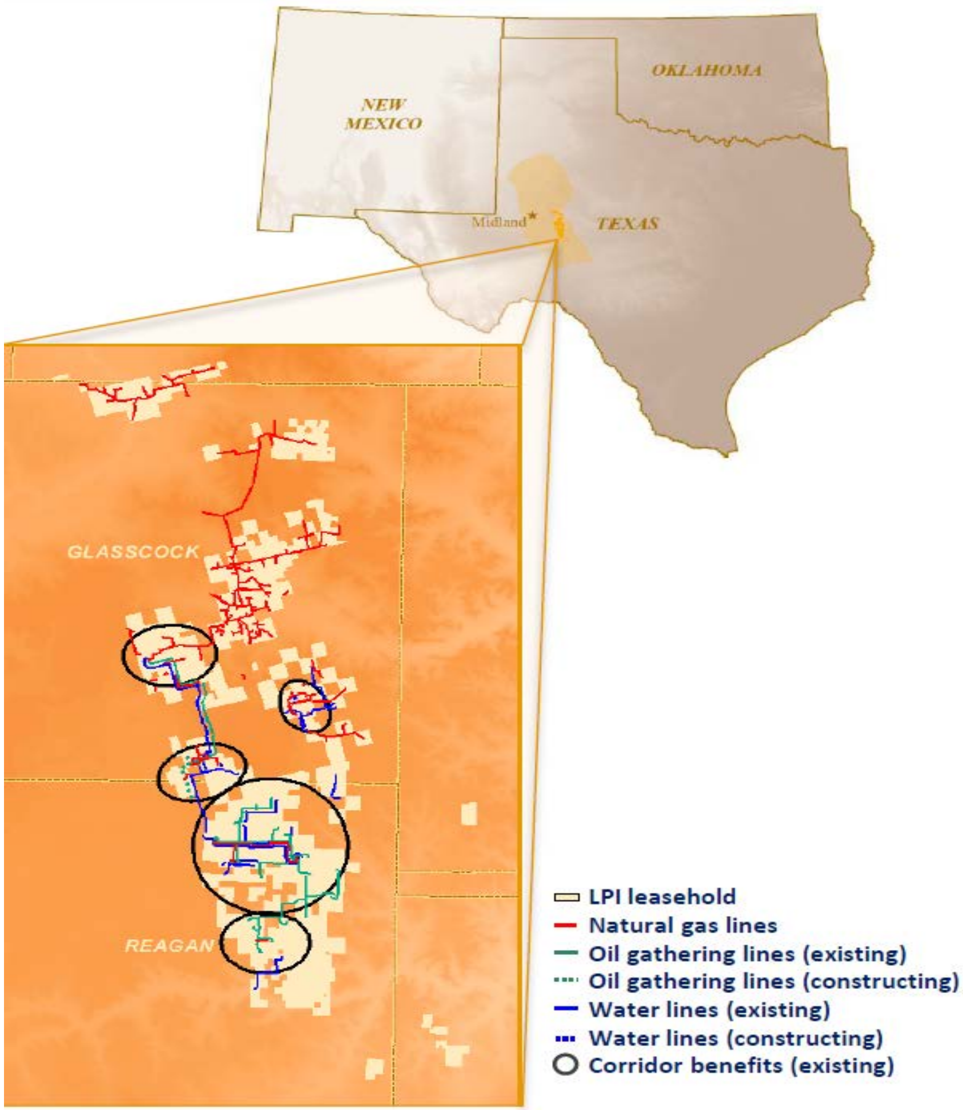
LAREDO PETROLEUM

Permian Basin ERD Optimization

LPI Company Overview



2008: Began Permian land acquisition

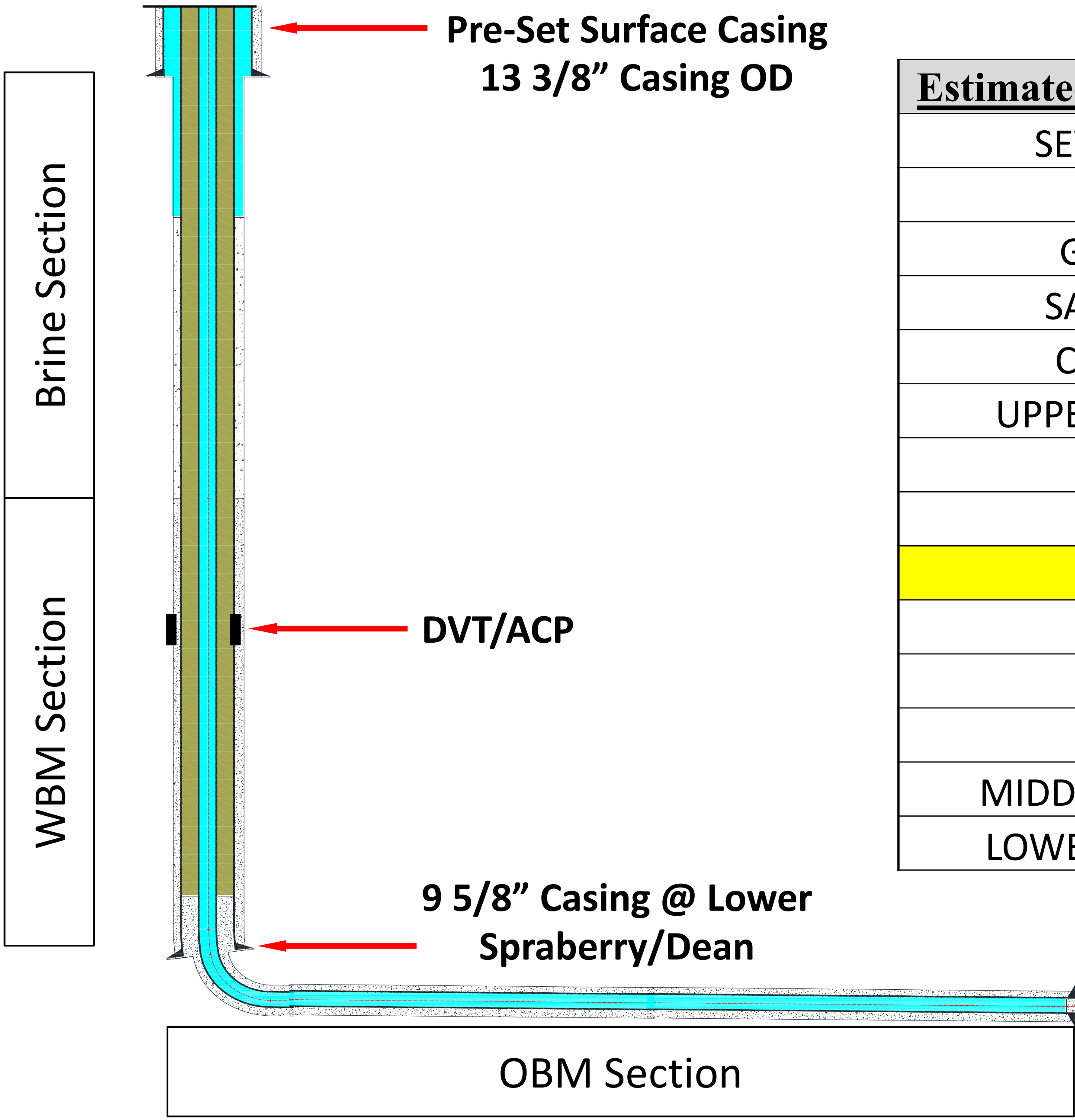
2009: First Permian horizontal drilled

Ongoing Wolfcamp development utilizing contiguous acreage position

Sugg D 104 #4SU

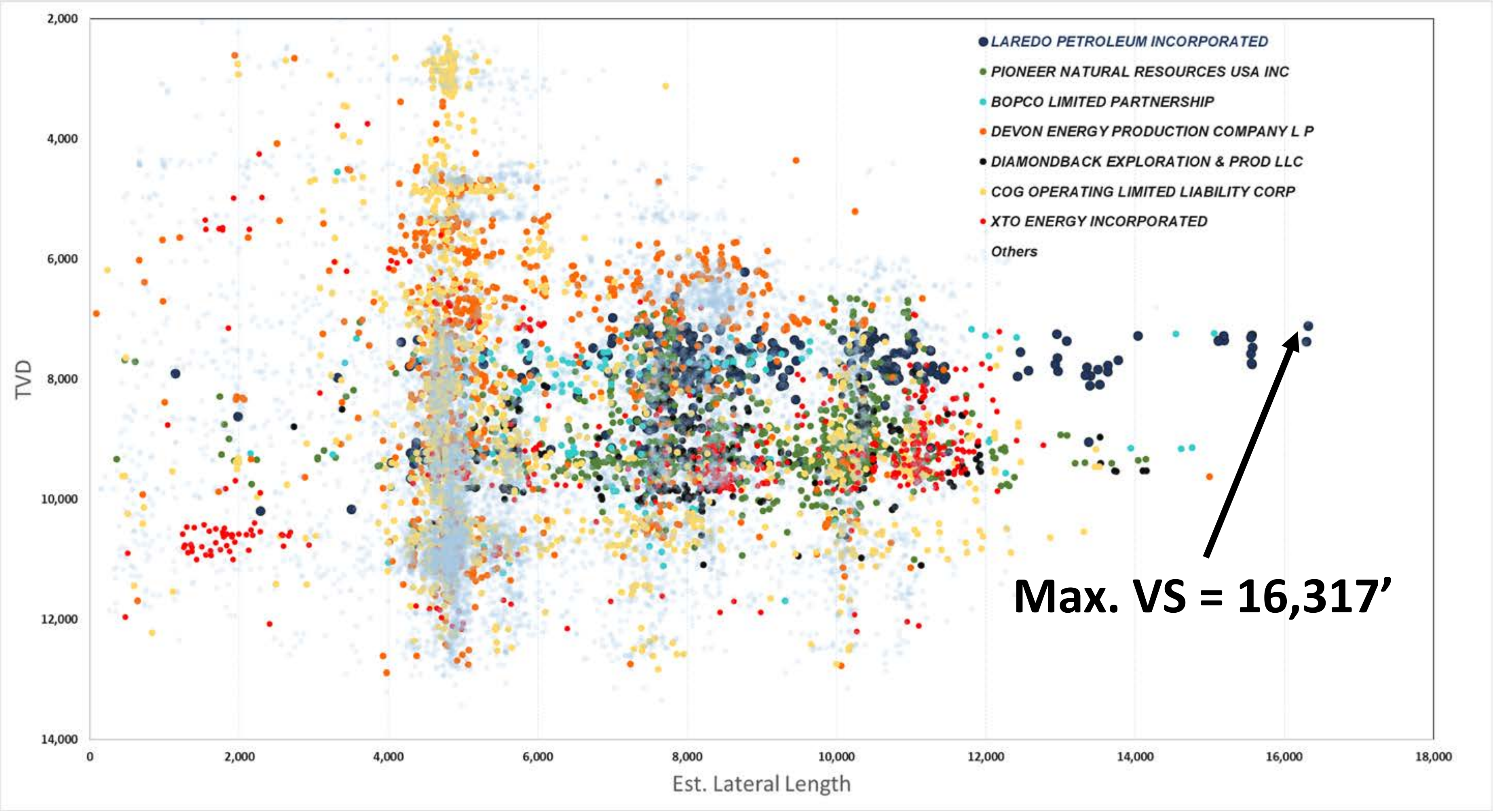
Rig: Ensign 776

LAREDO PETROLEUM, INC.



Estimated Formation Tops	MD
SEVEN RIVERS	1,512
QUEEN	1,802
GRAYBURG	1,992
SAN ANDRES	2,092
CLEARFORK	4,572
UPPER SPRABERRY	5,502
DEAN	6,952
UW-A	7,047
UW-B	7,132
UW-C	7,212
UW-D	7,282
UW-E	7,332
MIDDLE WOLFCAMP	7,422
LOWER WOLFCAMP	7,917

Lateral Length by Operator – 01/01/2010 to Present



*Data from Enerdeq, Glasscock, Reagan, Midland, Martin, Upton Counties

Laredo ERD History

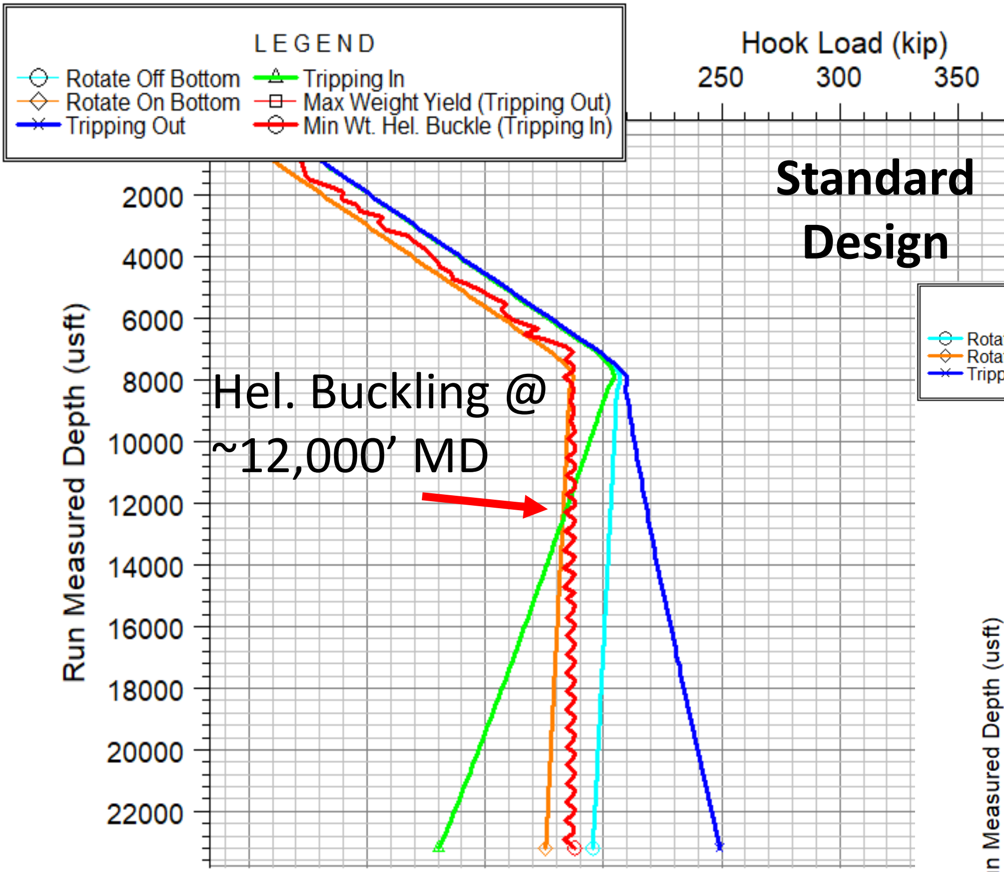
- Sugg A 171-173 4 Well Package – April 2016
  - Average Vertical Section = 13,435’
  - 2 wells drilled each w/ RSS and conventional directional tools
  - Average Rig Accept to Rig Release:
    - RSS = 16.25 days (2,576 ft/day avg. in lateral)
    - Conventional = 19.07 days (2,102 ft/day avg. in lateral)
- Sugg A 185-187 3 Well Package – November 2016
  - Average Vertical Section = 12,784’
  - All wells drilled w/ conventional directional tools
  - Average Rig Accept to Rig Release = 17.53 days
- Barbee B 47-1 2 Well Package – December 2016
  - Average Vertical Section = 13,842’
  - Both wells drilled w/ RSS BHA
  - Average Rig Accept to Rig Release = 25.74 days
    - 1st Well = 20.67 days
    - 2nd Well = 30.81 days

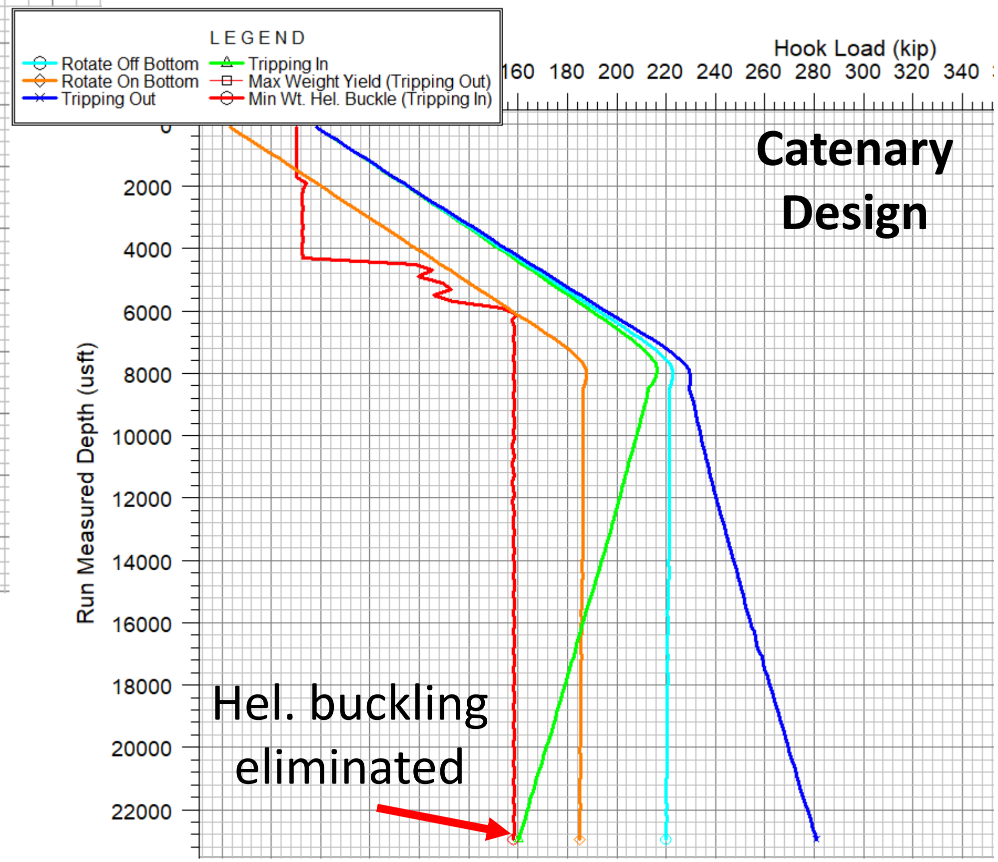
How can we transfer weight through the lateral?

Pseudo-Catenary Curve

- Pros
  - Reduce build rates
  - Improve T&D in lateral
  - Reduce risk of issues tripping RSS through curve
- Cons
  - Lose vertical section in lateral
  - May require directional work in intermediate section

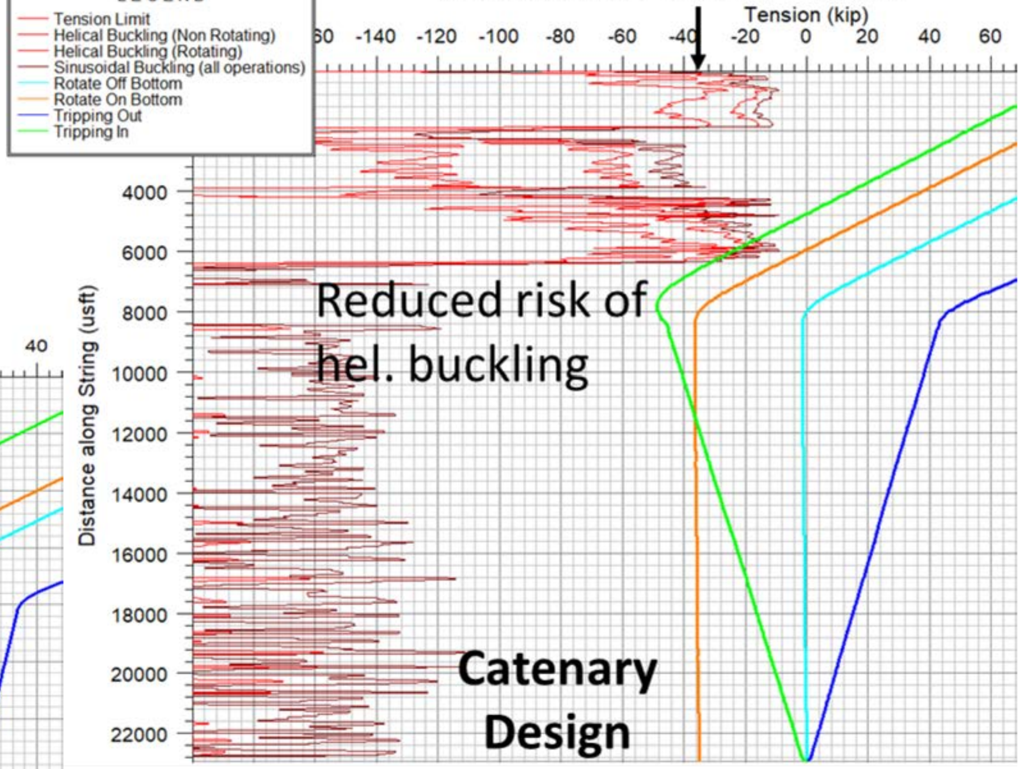
Tripping in Hole with Drilling Assembly

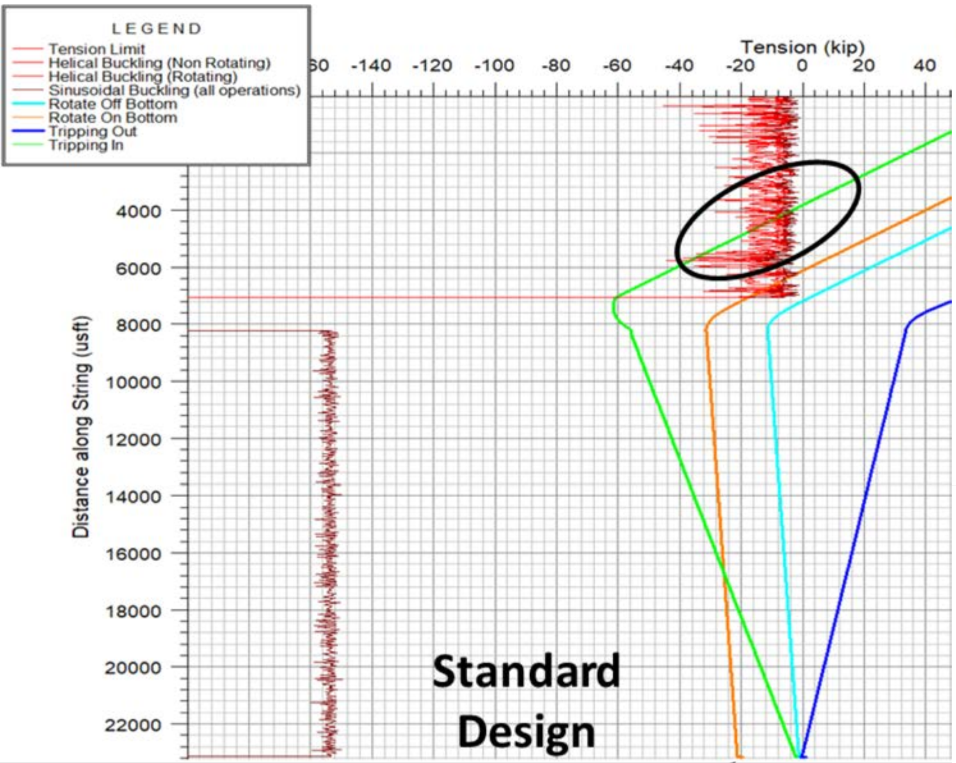




Rotating with Drilling Assembly

Available WOB = 35K

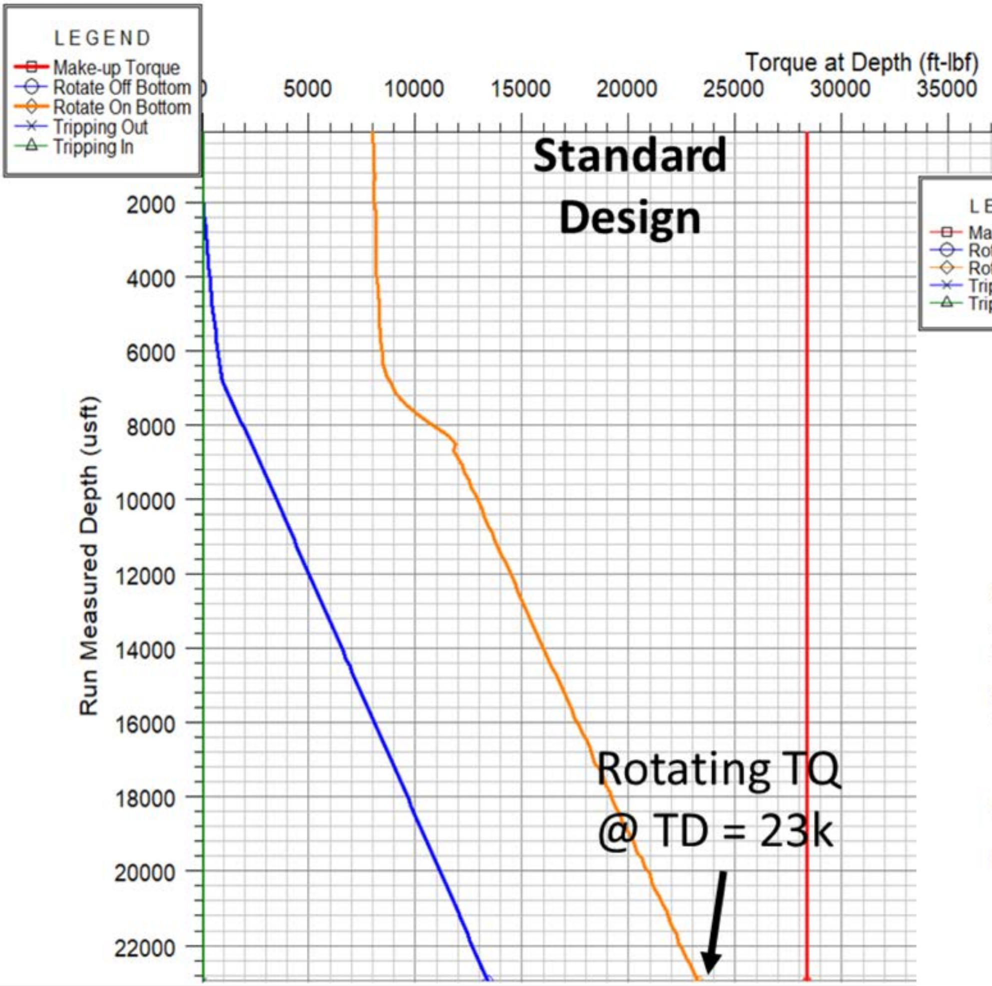


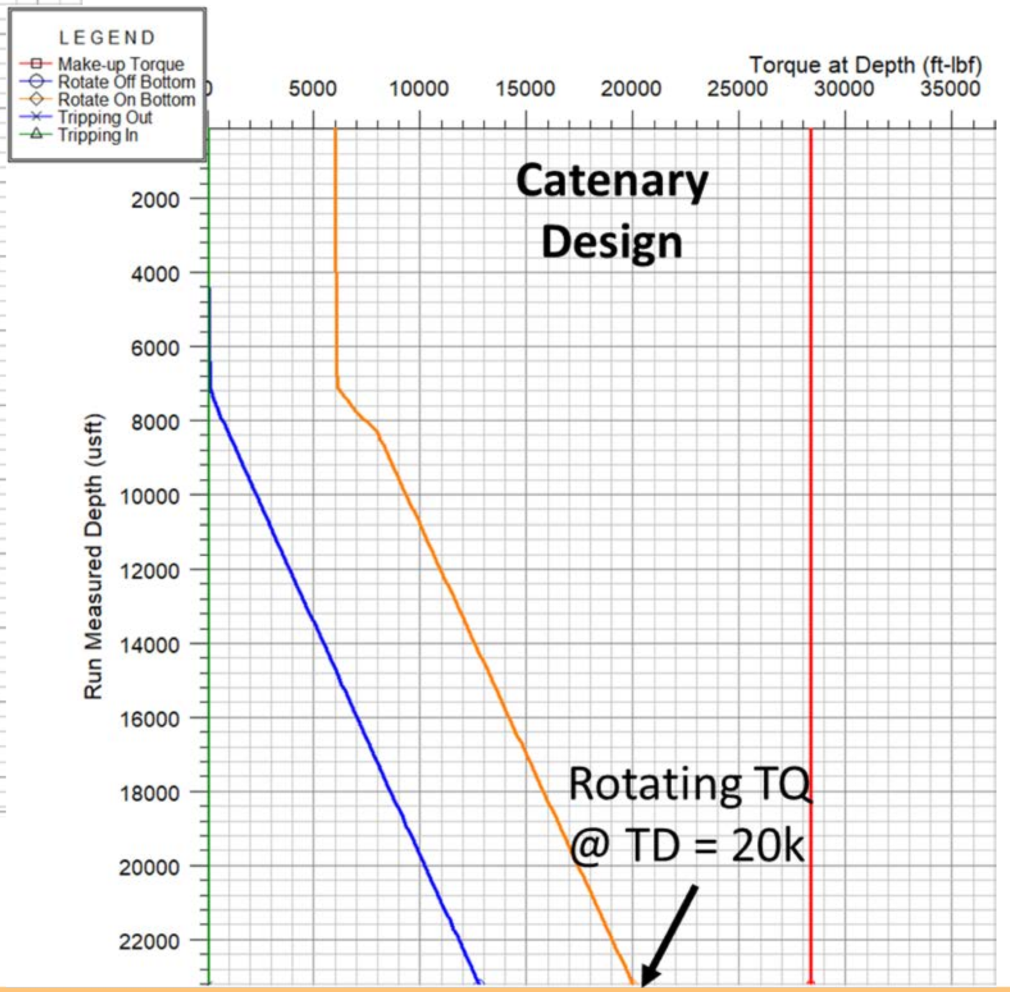


Available WOB = 20K

75% increase in available WOB @ TD

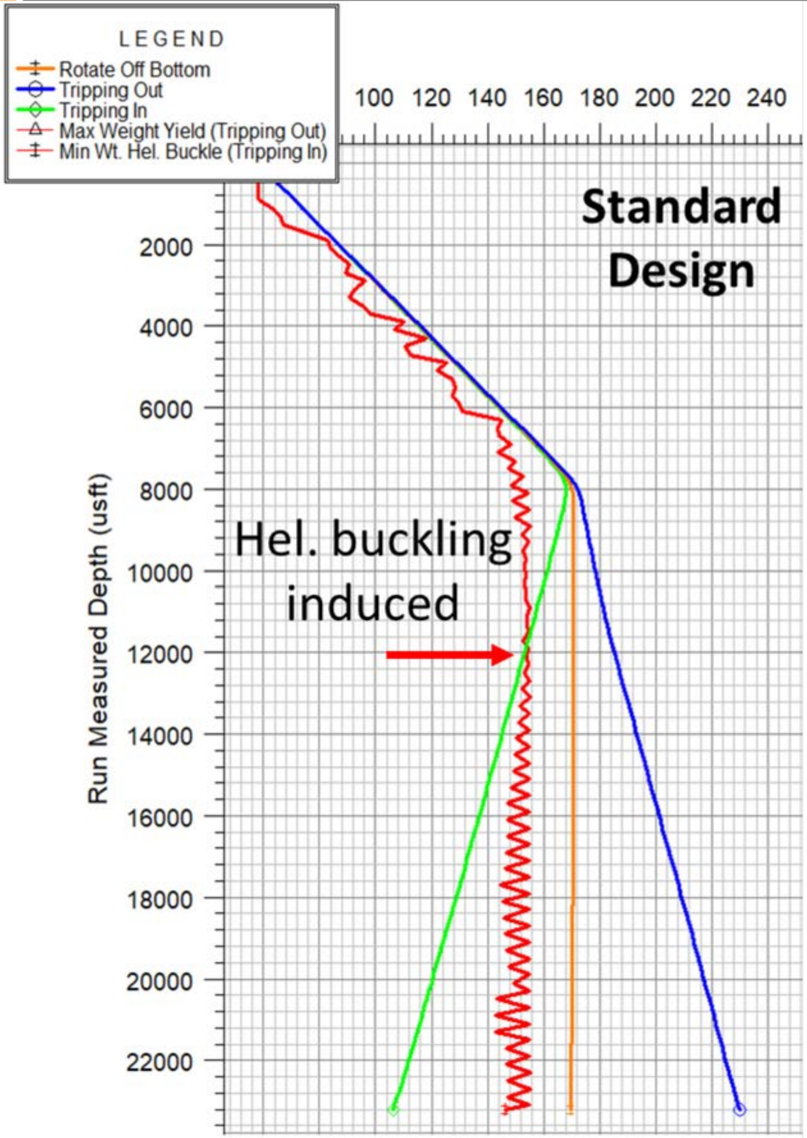
Rotating with Drilling Assembly

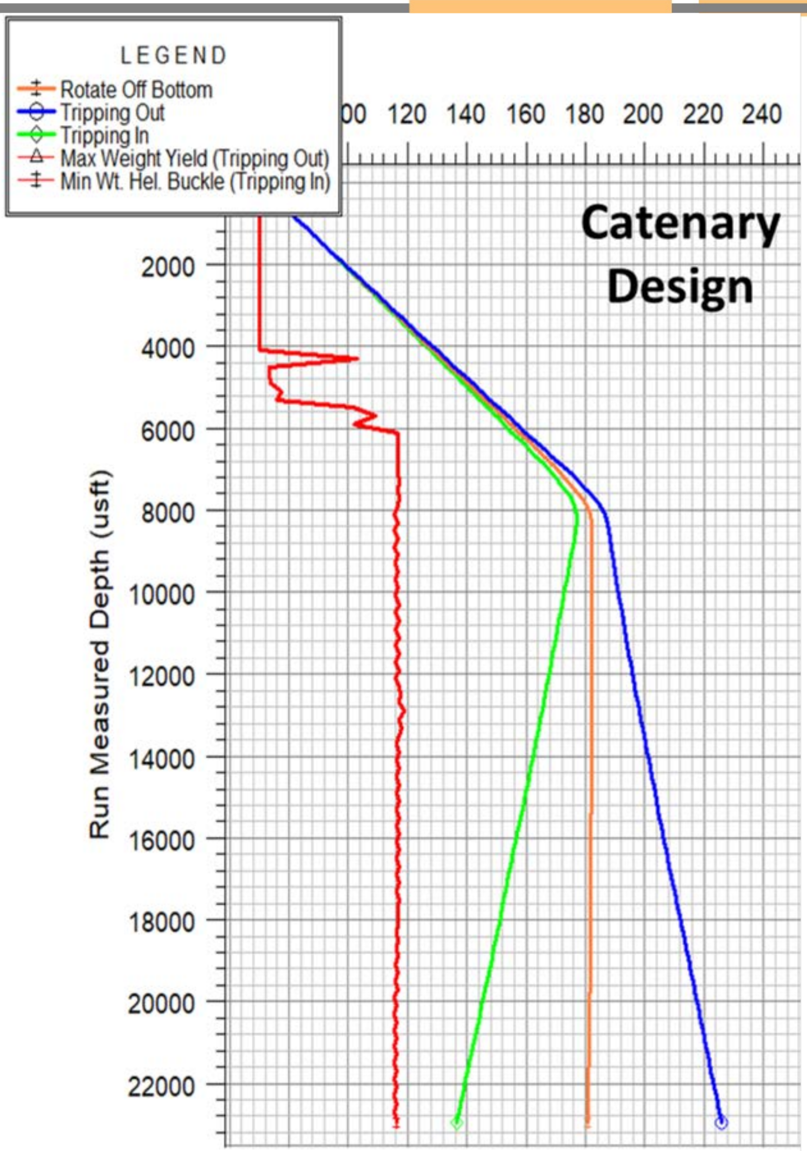




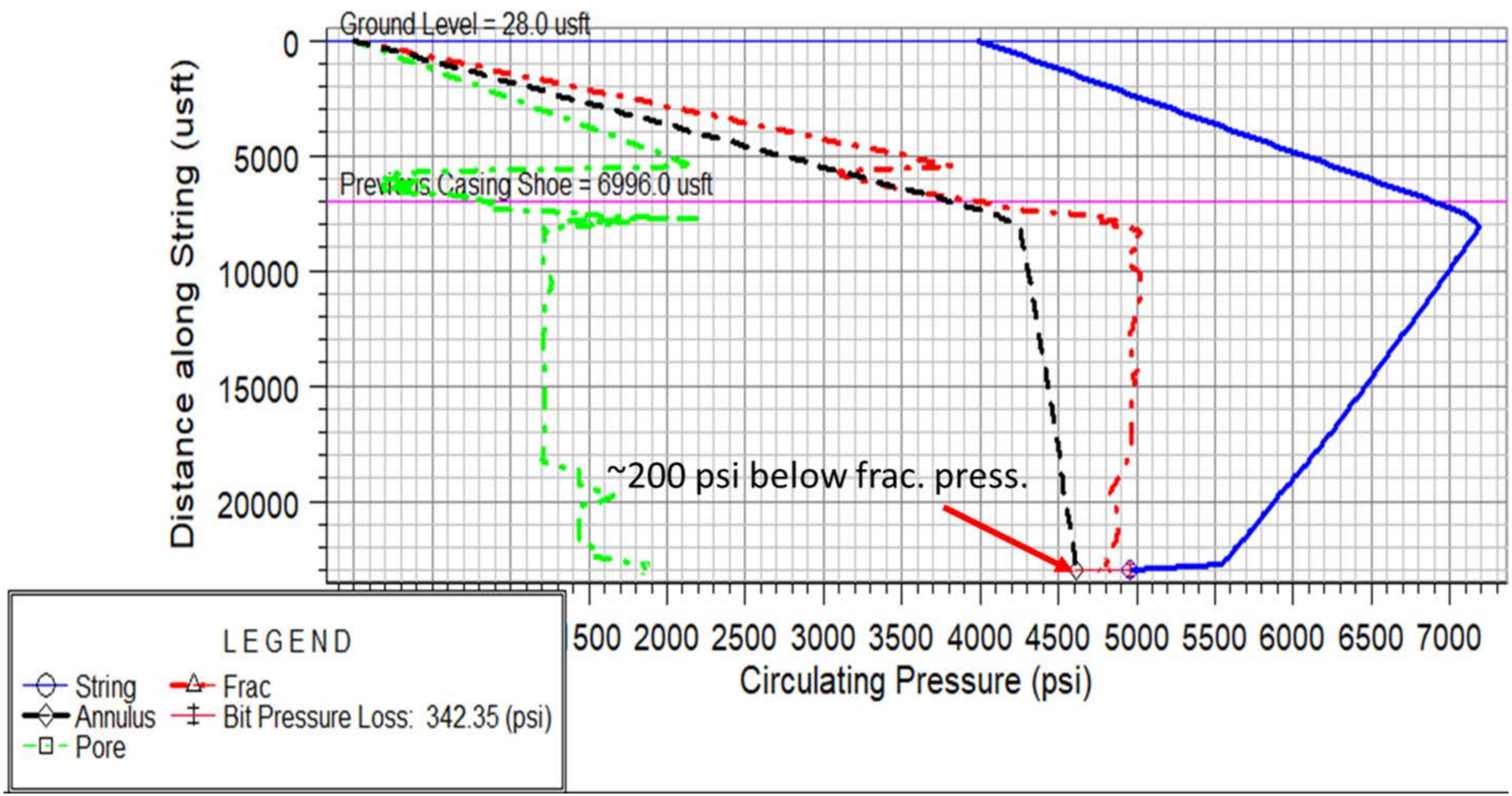
<u>~15% reduction in drilling torque @ TD</u>

5 ½" Casing Run





Circulating Pressure – Oil Based Mud



- Max. Anticipated ECD @ TD = 11.3 ppge
- Max. Anticipated ECD @ CSG Shoe = 10.4 ppge
    - FIT test to 11.5 ppge

Circulating Pressure – Cement

Pumping Schedule

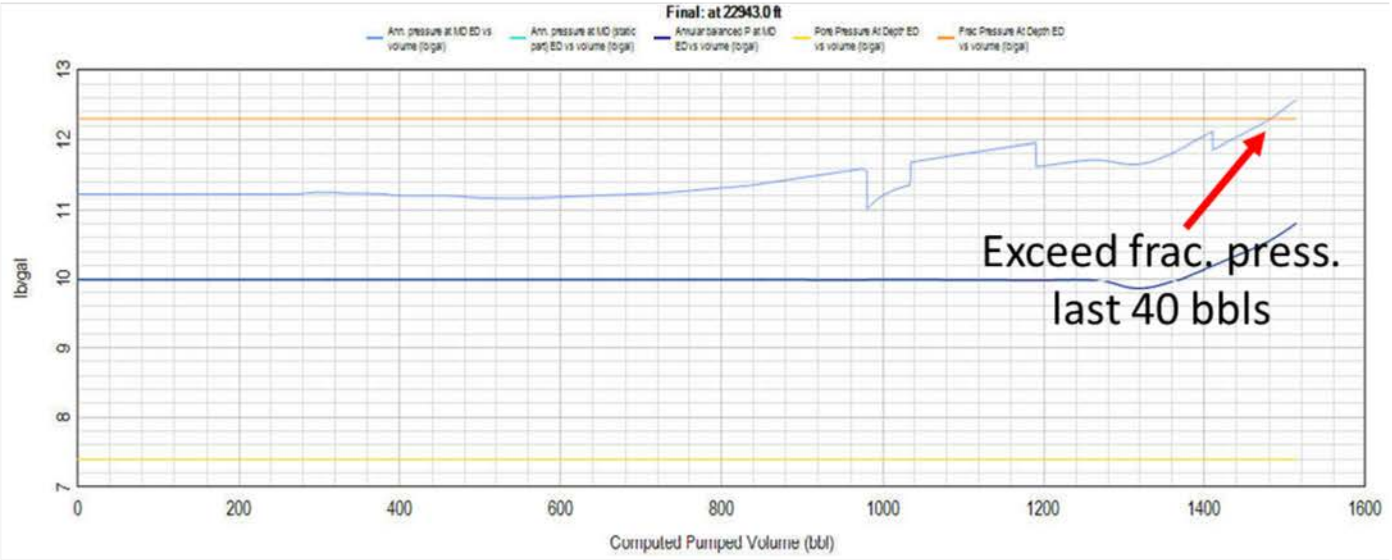
Fluid Name	Duration hr:mn	Volume bbl	Pump Rate bbl/min	Injection Temperature degF	Comment	Cumulated Time hr:mn
Gelled Water	00:07	40.0	6.0	68		00:07
10.5 ppg MPE Spacer	00:03	20.0	6.0	68		00:10
11.8 ppg Lead	00:26	154.3	6.0	68		00:36
13.2 ppg Tail 1	00:17	105.0	6.0	68		00:53
15.0 ppg ASH Tail	02:11	655.9	5.0	68		03:04

Completion requirement for acid soluble tail slurry

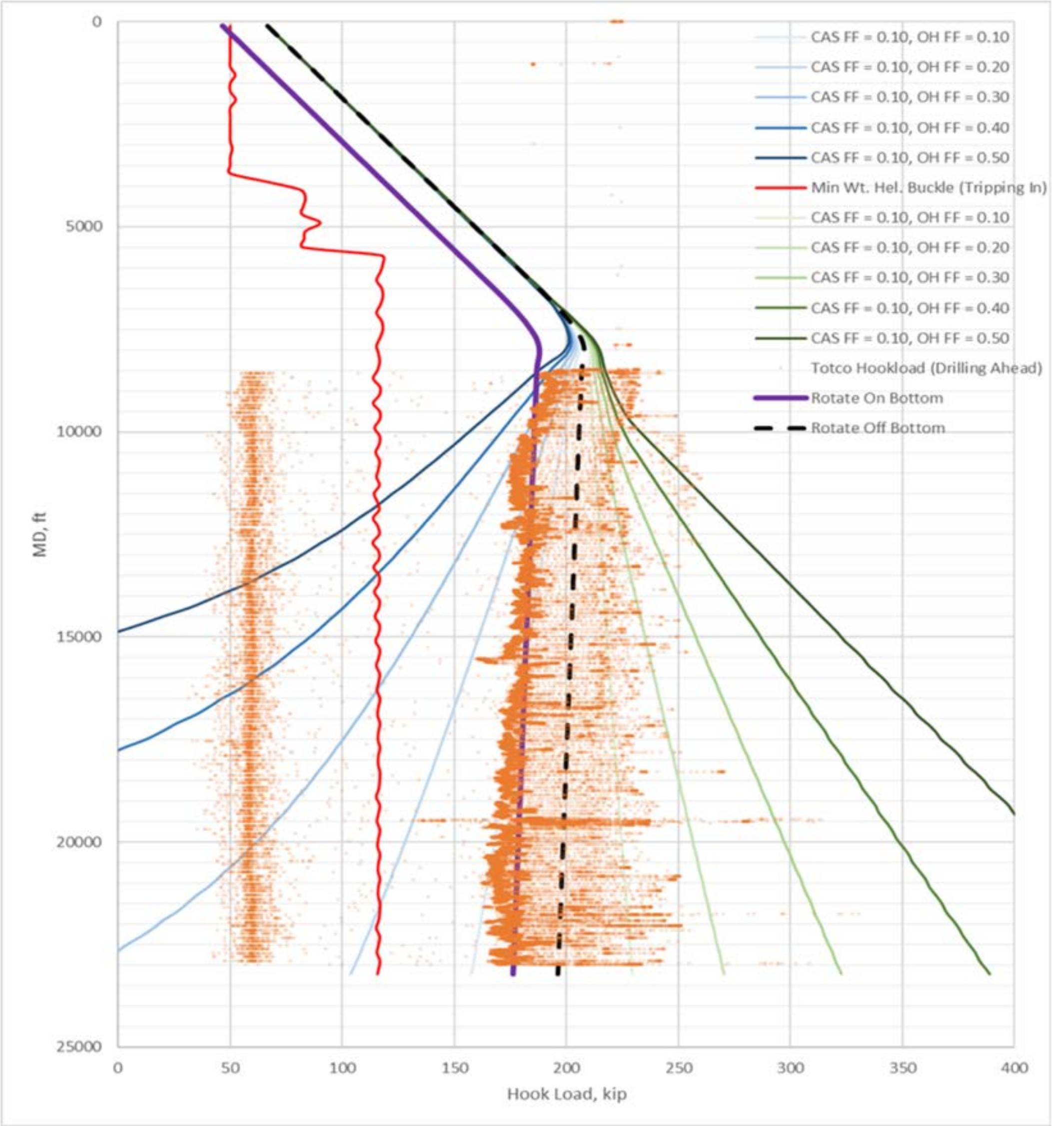
Three slurry blend reduces ECD @ TD and meets completion requirements

Predicted **92% of acid soluble tail to be displaced with full returns**

Must follow pre-planned pump down schedule

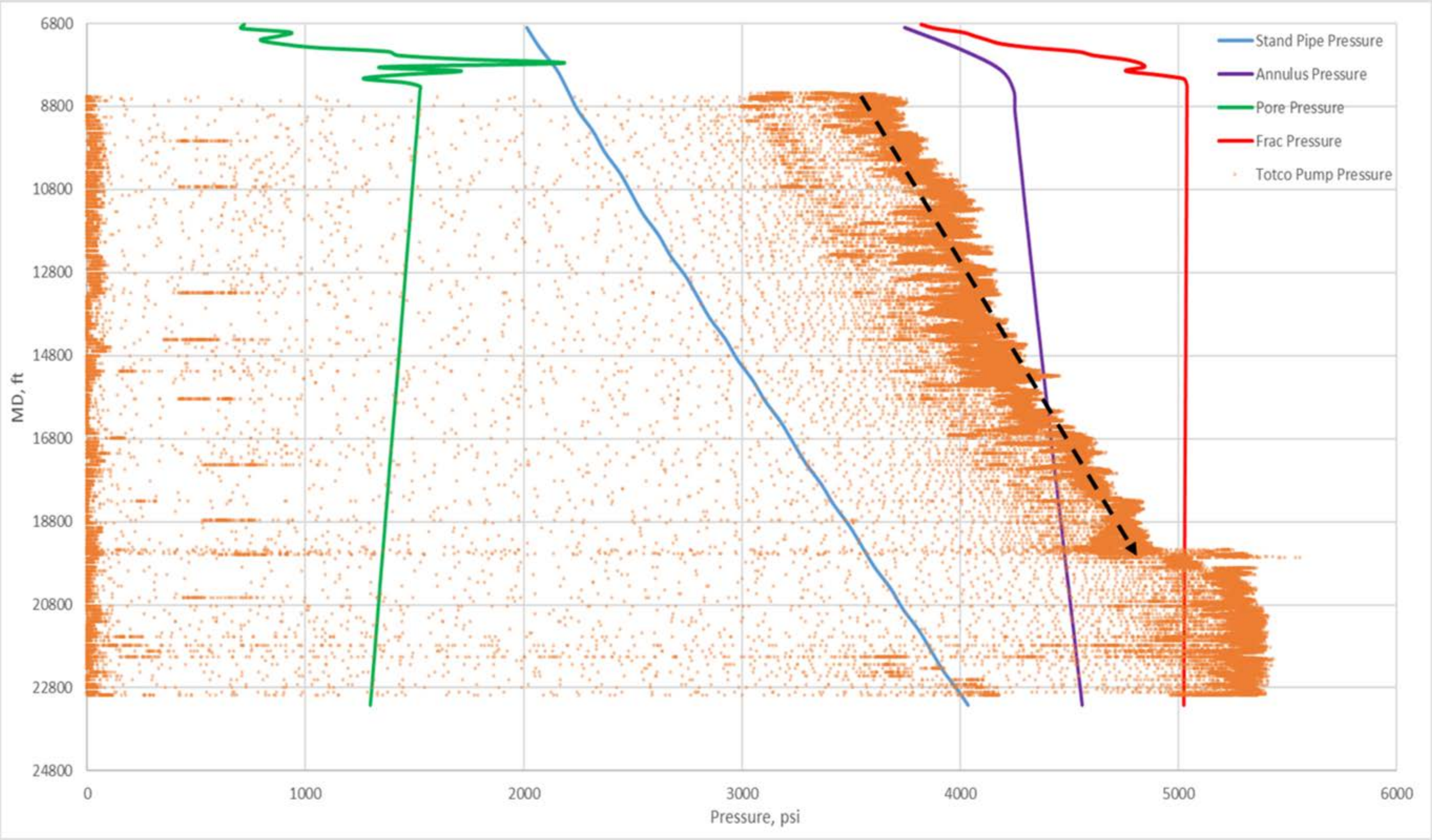


Planned vs. Actual – Rotating On Bottom



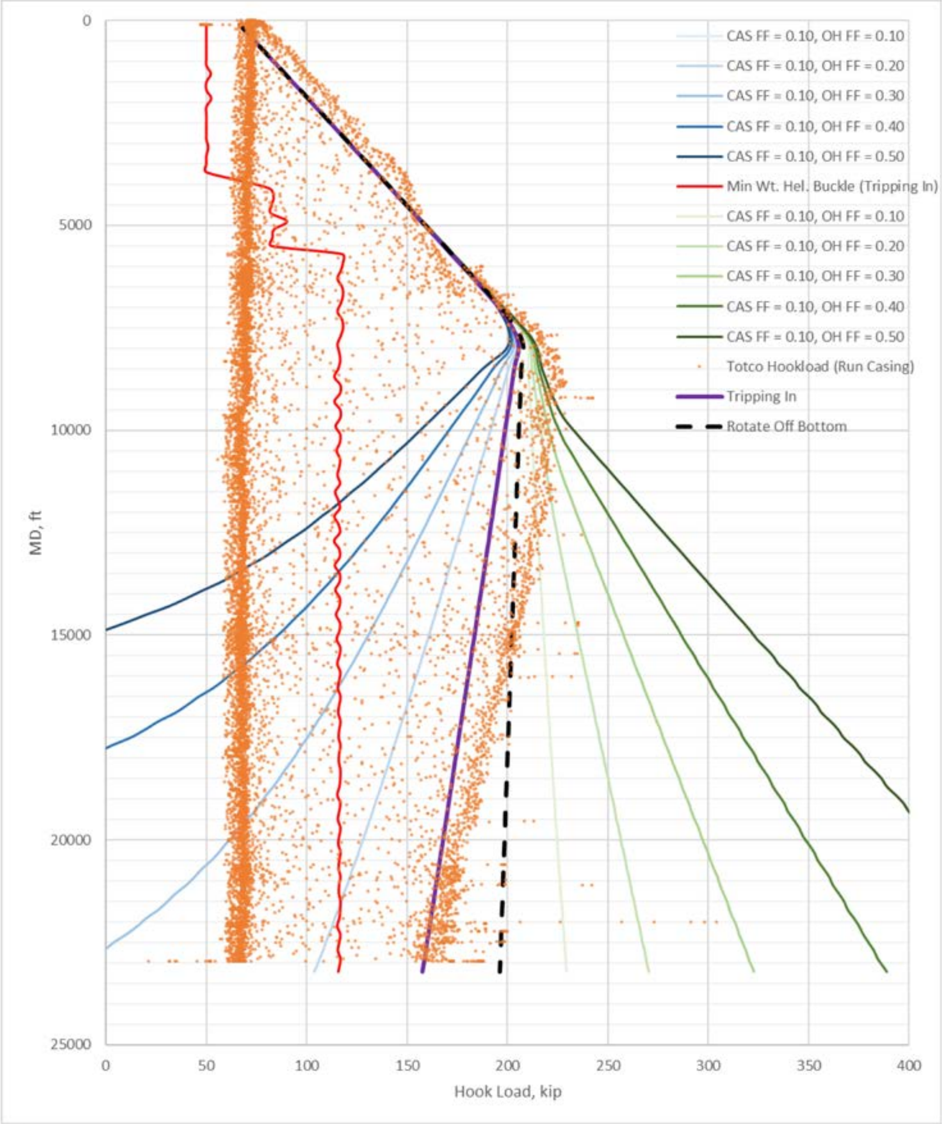
Actual hook load values averaged **within 5%** of anticipated values while drilling ahead

Planned vs. Actual – OBM Circulating Pressure



No losses observed – annular pressure remained below fracture pressure

Planned vs. Actual – 5 ½” Casing Run



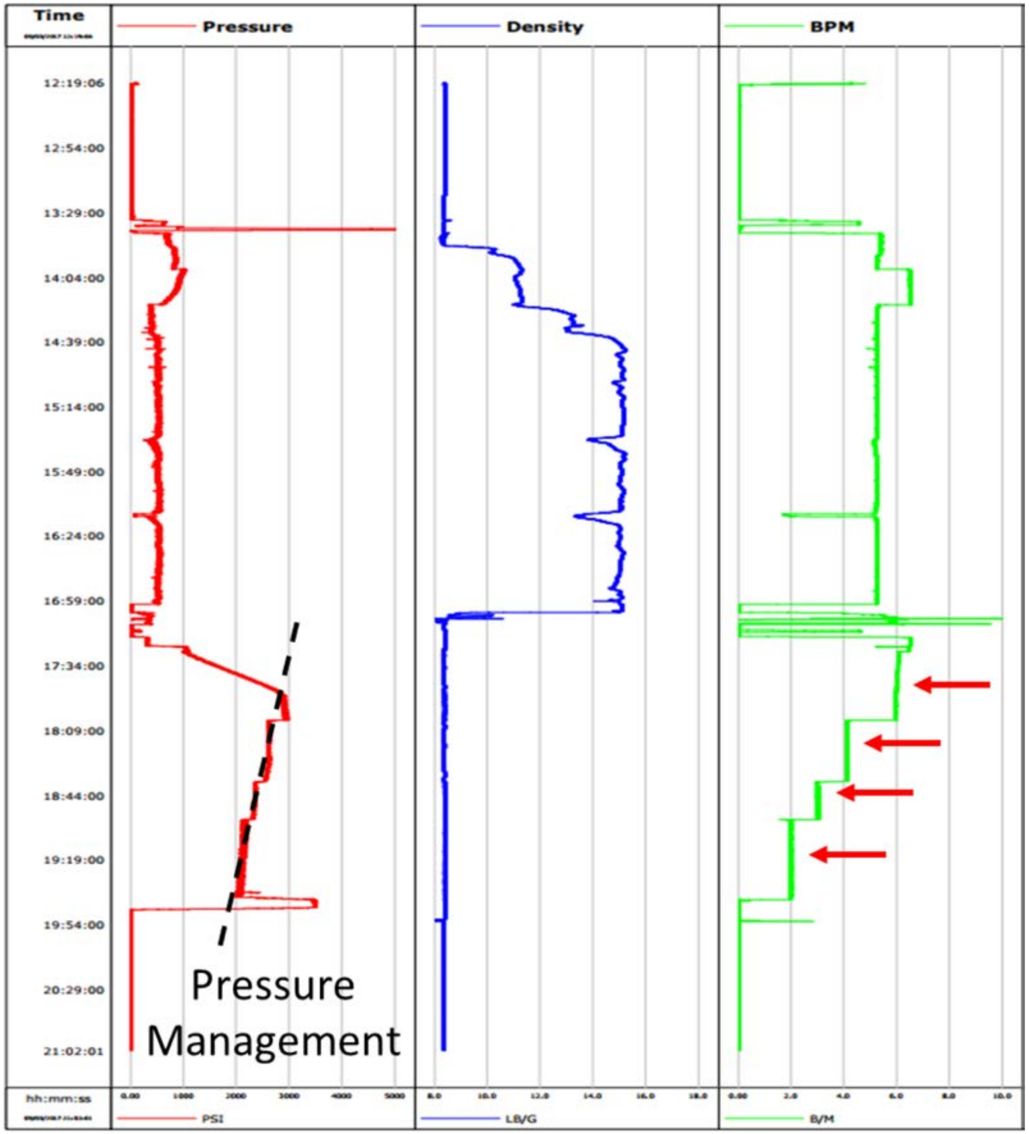
Close correlation @ TD

Friction factor around 0.1 in open hole (anticipated 0.1-0.2)

Average lateral DLS = 1.06 deg/100’

No rotation necessary to reach TD

Planned vs. Actual – Cement Circulating Pressure



Pre-Planned pump down schedule manages downhole pressure

Full returns until 380 bbls displaced (514 bbls total displacement or **74% of displacement**)

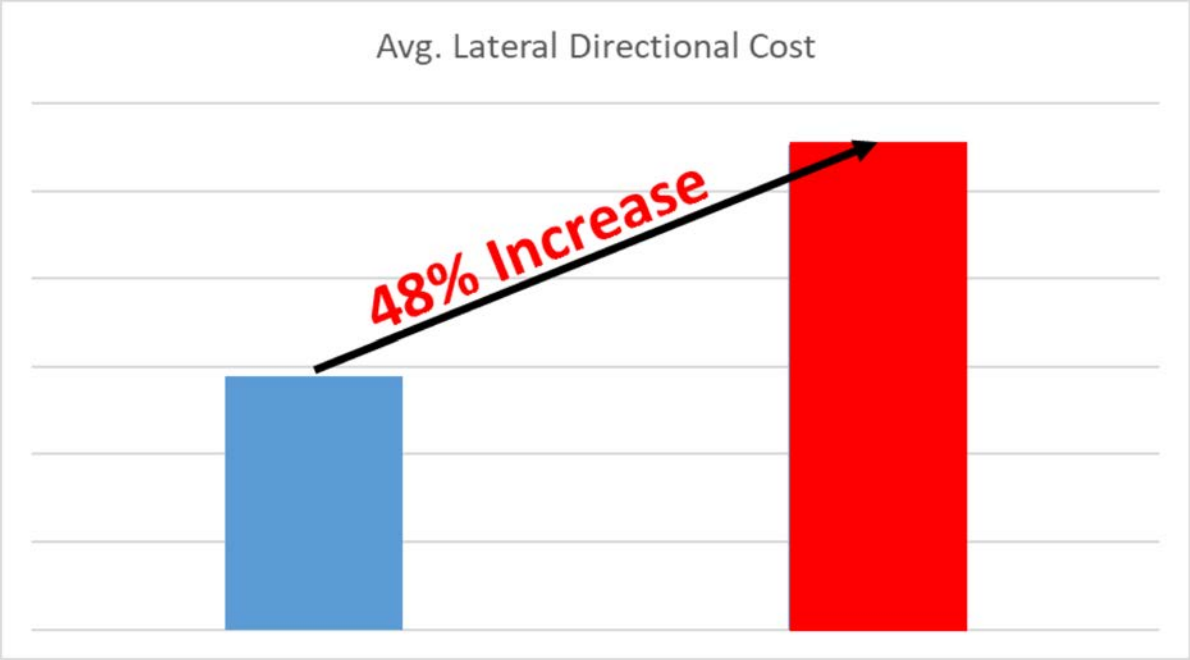
Initial 15k Project – Sugg A 157 Package Results

- 3 Well Package
  - Average Vertical Section = 15,636'
  - All three wells drilled w/ RSS BHA
  - Average Rig Accept to Rig Release = 20.5 days
    - Max. = 22.0 days
    - Min. = 19.3 days
    - Avg. 2,073 ft/day in lateral
- No Major Issues
- 1 out of 3 wells drilled lateral w/ one BHA run
  - Other 2 wells both used 2 BHAs due to tool failures
- Average DLS below 1.1 for all 3 laterals
- Performance on par with 10k laterals

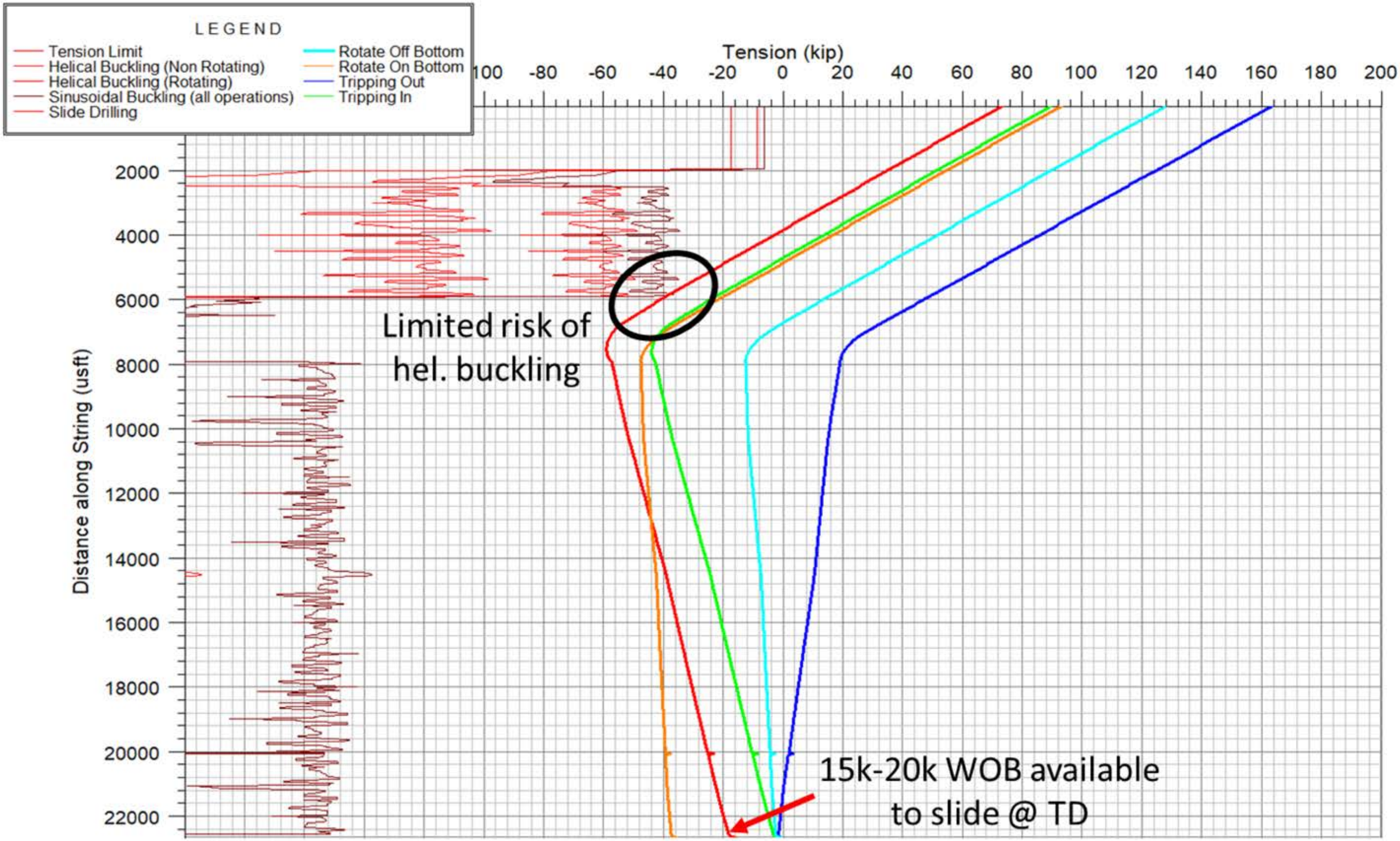
Optimizing 15k Wells – Eliminating RSS

- RSS Advantages
  - Continual rotation
  - “Smoother wellbore”
  - “Faster ROP”
- RSS Disadvantages
  - Tool reliability
  - Dedicated curve
  - Change of directional personnel
  - Cost

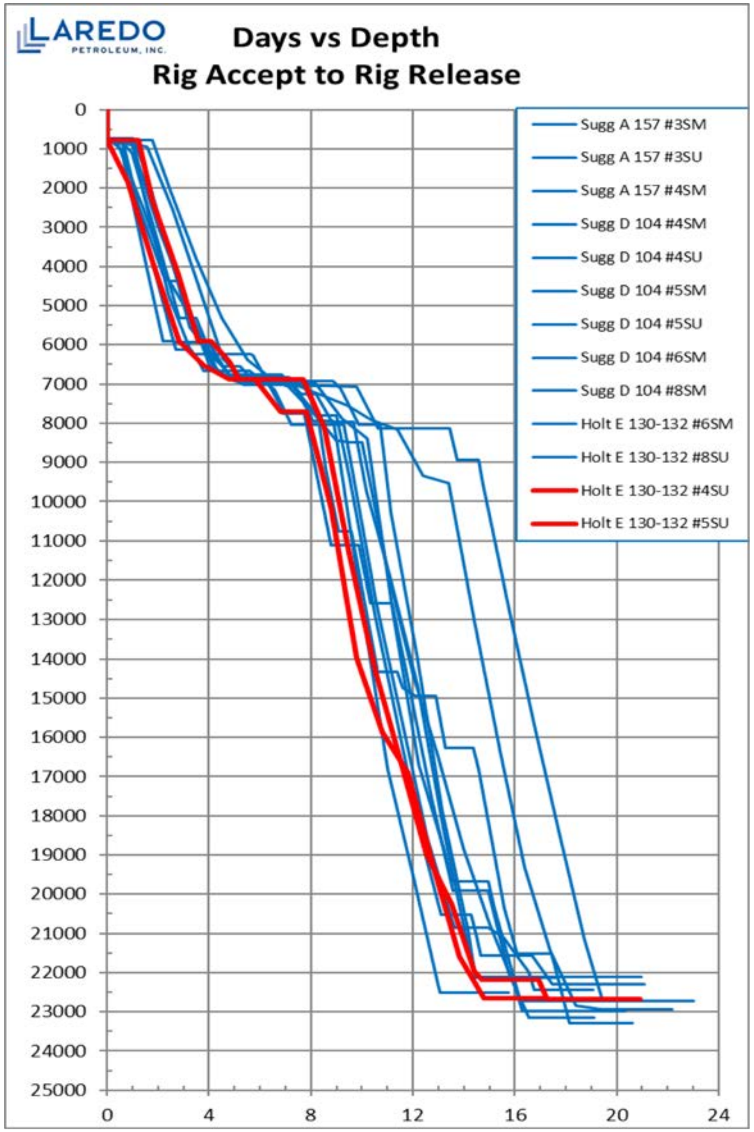
Directional Cost Comparison



Optimizing 15k Wells – Eliminating RSS



Optimizing 15k Wells – Eliminating RSS

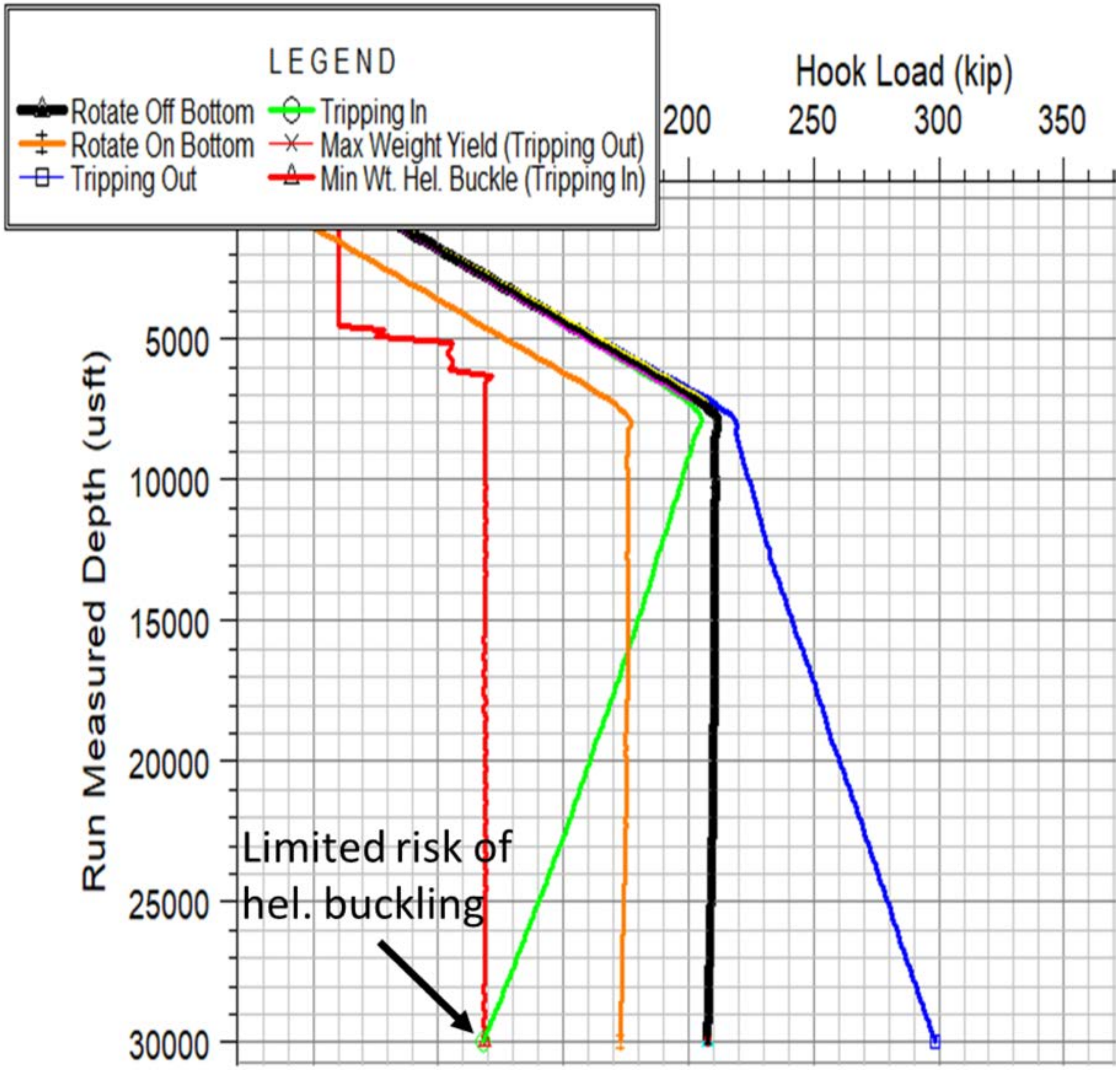


- RSS vs. Conventional Performance

RA to RR Days			
BHA System	Min.	Avg.	Max.
RSS (11 wells)	15.75	19.86	23.00
Conventional (2 Wells)	17.08	19.00	20.92

Lateral Ft/Day			
BHA System	Min.	Avg.	Max.
RSS (11 Wells)	1380.00	2089.53	3617.97
Conventional (2 Wells)	2091.00	2217.29	2343.58

Future ERD Opportunities – 20k Lateral Potential



Modeling suggests 30,000' MD (+/- 20k vertical section) is **feasible across Upper/Middle Wolfcamp horizons**

Available WOB to reach TD while rotating

Torque below make up value

Remain under **fracture pressure** while drilling

Reach TD with **5 ½" casing** without the need for rotation or flotation

No design changes necessary

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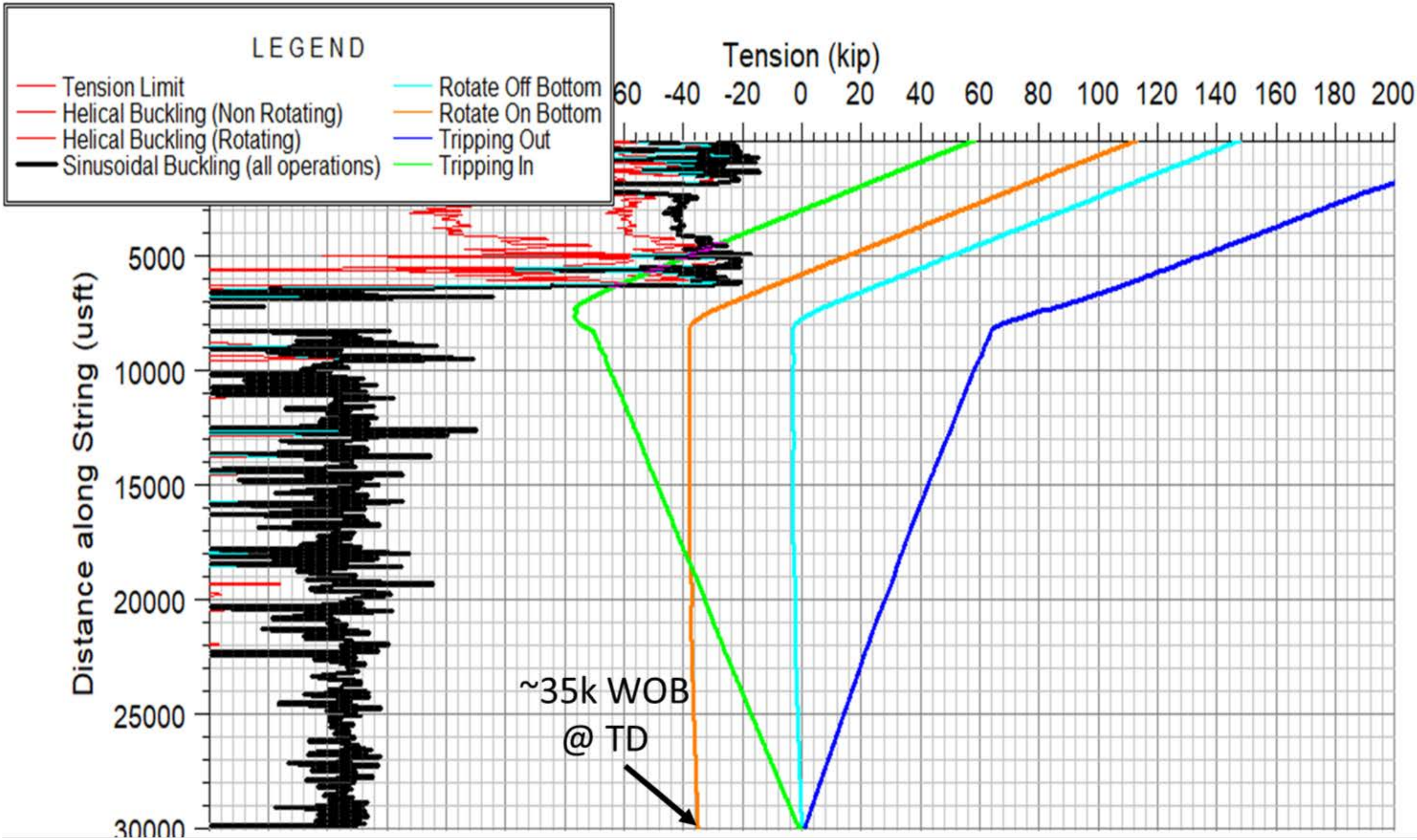

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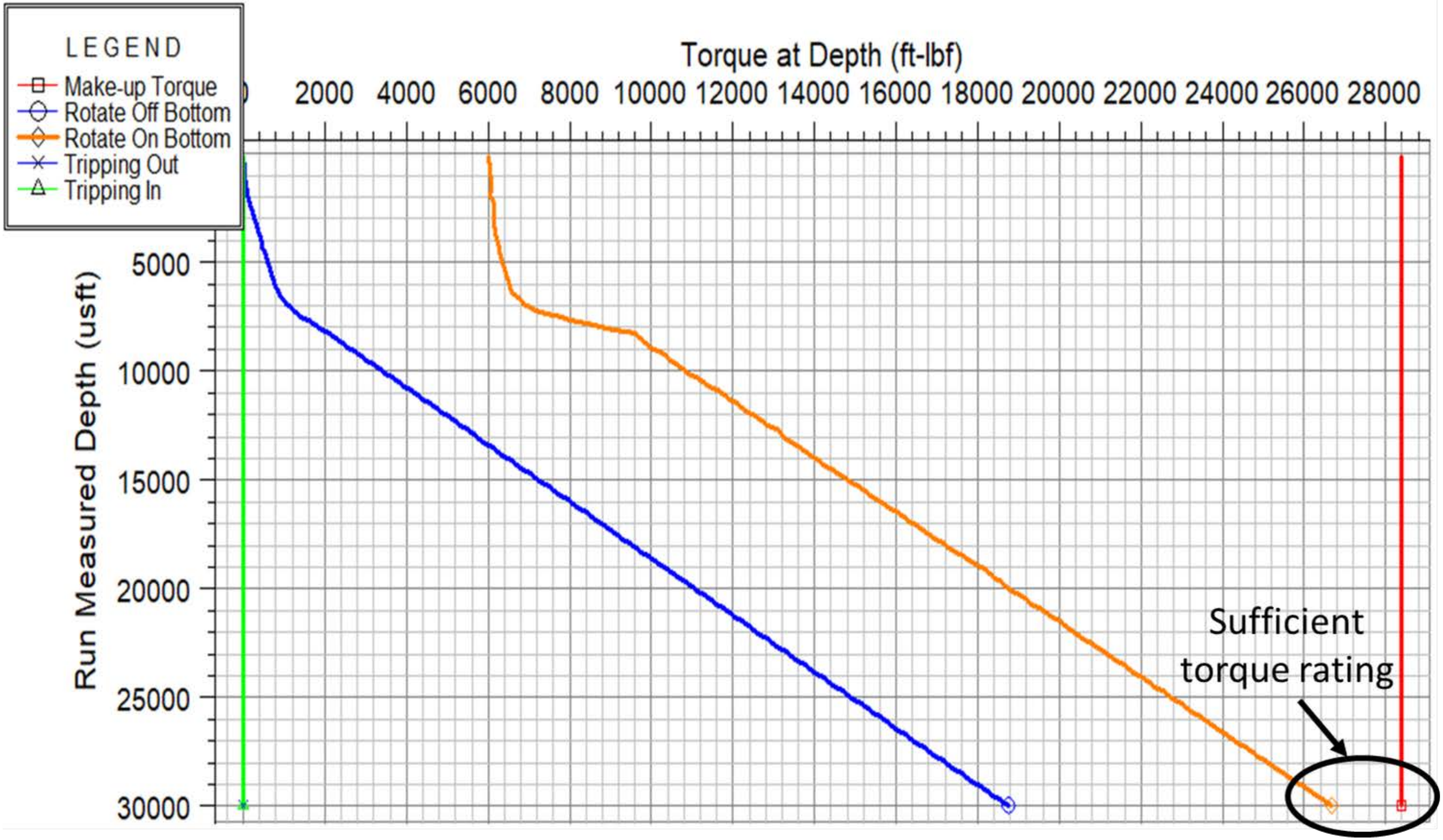

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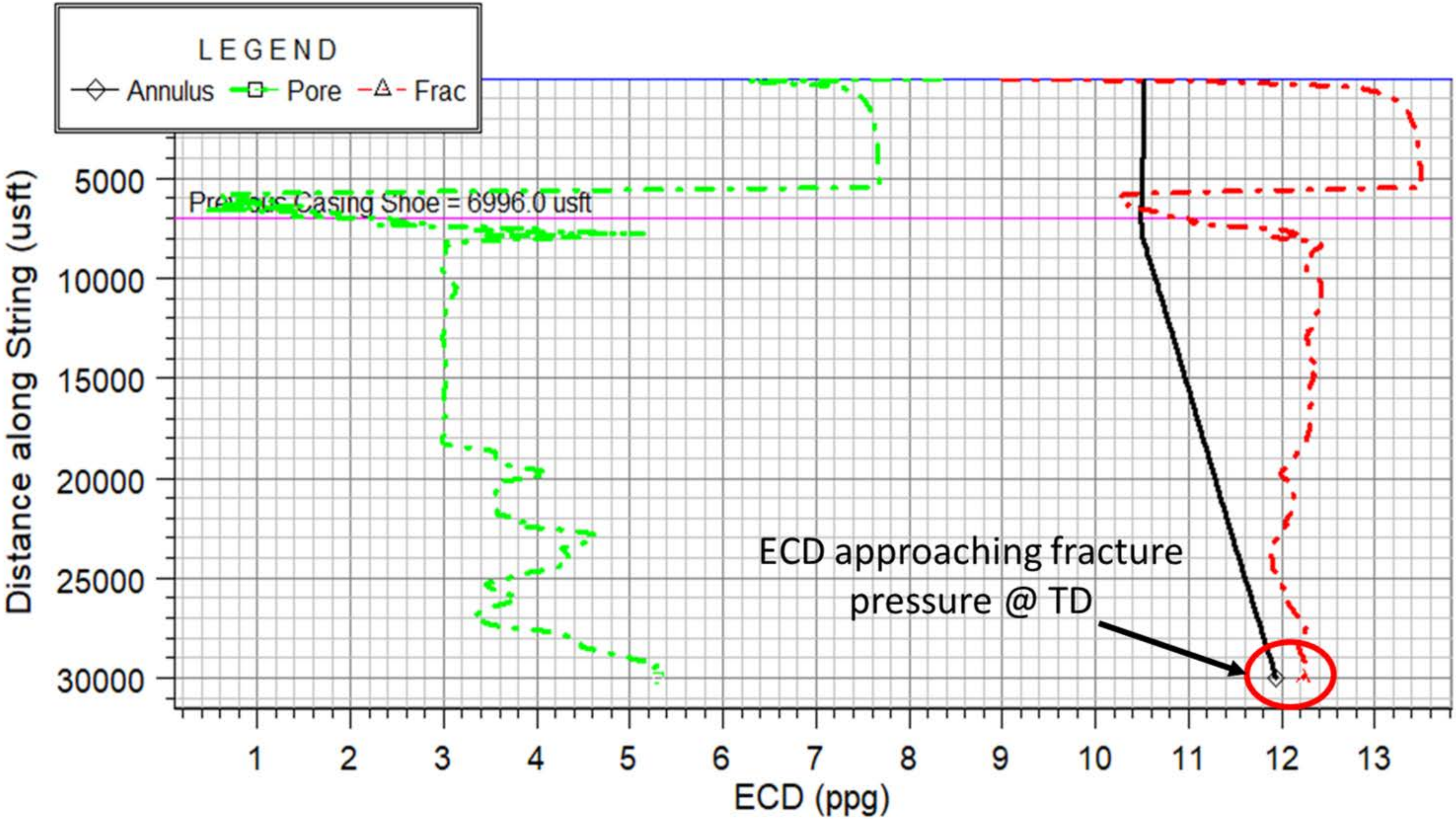

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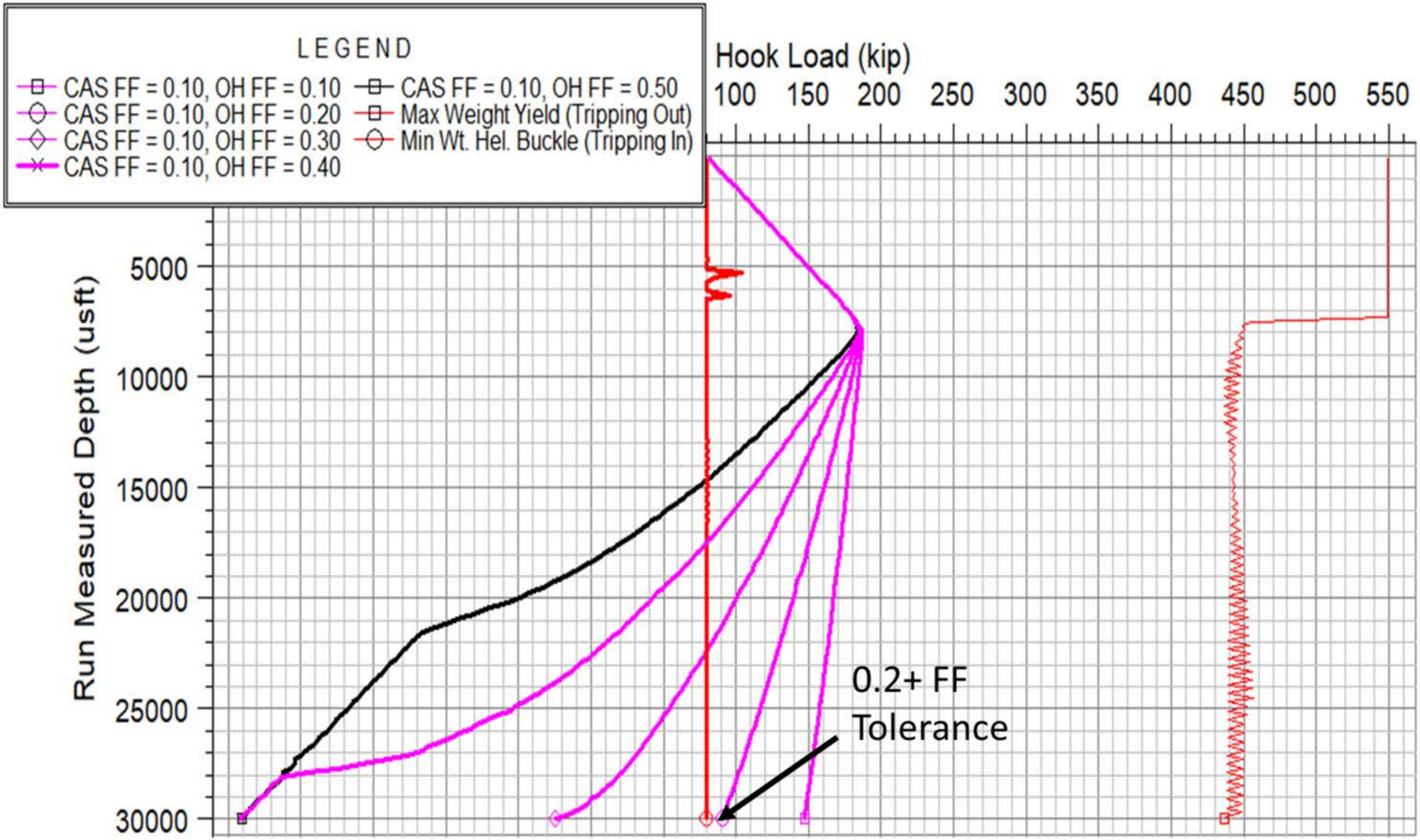

Closing Thoughts

- Permian Basin is currently the most innovative oil & gas play
  - Opportunities exist to more efficiently develop natural resources
- Challenge technical “limitations” and conventional wisdom
  - Limitation today can be standard practice tomorrow
  - No room for complacency within our industry
- Continuous learning drives process improvement
  - Build on previous successes
  - Thorough understanding of failures
- Attack the problem, not the symptom