Permian Basin ERD Development: The 15k Project
Permian operators are pushing lateral lengths further.

*IHS data dating January 2016 through October 2017 across Howard, Midland, Martin, Glasscock & Reagan Counties. Estimated horizontal displacement greater than 12,000'.
Case Study: Laredo’s ERD History

Sugg A 157
15k Pad

Sugg A 185-187 Pad

Sugg A 171-173 Pad

Barbee B
47-1 Pad
Sugg A 171-173 Package

• 4 Well Package
  – 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)

• Issues
  – Insufficient Build Rates in 8 ¾” Curve – performance below 8 ½” curve
  – Difficulty Sliding w/ Conventional Tools
  – Had to Rotate Casing to Bottom on 1 Well (fastest RSS run w/ highest average DLS)
  – Justify RSS Cost
Sugg A 185-187 Package

• 3 Well Package
  – Average Vertical Section = 12,784’
  – All wells drilled w/ conventional directional tools
  – Average Rig Accept to Rig Release = 17.53 days

• Issues
  – No major issues
  – Further examine RSS vs. conventional BHA performance
## Barbee B 47-1 Package

- **2 Well Package**
  - Average Vertical Section = 13,842’
  - Both wells drilled w/ RSS BHA
  - Average Rig Accept to Rig Release = 25.74 days
    - 1\textsuperscript{st} Well = 20.67 days
    - 2\textsuperscript{nd} Well = 30.81 days

- **Issues**
  - 1\textsuperscript{st} well, no major issues
  - 2\textsuperscript{nd} well, hole instability, stuck pipe
Early ERD Lessons Learned

• **BHA Limits**
  – +/- 13,500’ VS appears to be the practical limit for conventional directional tools under standard well design – 8 deg/100’ curve
  – RSS seen as a need rather than an optimization tool
  – Conventional BHA optimization ongoing

• **8 ¾” Curve Optimization**
  – Significant performance difference from 8 ½” curve
  – Reduce planned build rates to mitigate performance impacts and benefit torque and drag effects in lateral

• **Fundamentals Are Key**
  – Mud Properties
  – Hole Cleaning
  – Minimize DLS in Lateral
  – Communication
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
  – Requires directional work in 12¼” section

Benefit > Burden
Eliminates helical buckling

Hel. Buckling @ ~12,000’ MD

Standard Design

Catenary Design

Tripping in Hole with Drilling Assembly

Eliminates helical buckling

Hel. buckling eliminated
Available WOB = 35K

Severe risk of hel. buckling

Reduced risk of hel. buckling

Standard Design

Available WOB = 20K

75% increase in available WOB @ TD

Rotating with Drilling Assembly

Catenary Design
~15% reduction in drilling torque @ TD

Rotating TQ @ TD = 23k

Rotating TQ @ TD = 20k
Success highly probable

Buckling reduces chance of success

5 ½” Casing Run

Hel. buckling induced

Buckling reduces chance of success

Success highly probable
- Max. Anticipated ECD @ TD = 11.3 ppg
- Max. Anticipated ECD @ CSG Shoe = 10.4 ppg
  - FIT test to 11.5 ppg

Surface Pressure While Drilling

- ~200 psi below frac. press.
Cement Considerations

**Pumping Schedule**

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<th>Fluid Name</th>
<th>Duration hr:mn</th>
<th>Volume bbl</th>
<th>Pump Rate bbl/min</th>
<th>Injection Temperature degF</th>
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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

Exceed frac. press. last 40 bbls
Actual hook load values averaged within 5% of anticipated values while drilling ahead.
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
Pump Pressure

No losses observed – annular pressure remained below fracture pressure

Increase in pump pressure trend likely due to debris in RSS tool
Planned vs. Actual Cementing Pressure

Pre-Planned pump down schedule manages downhole pressure

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

• Rotary Steerable System
  – Initial perception of conventional motor assembly drove decision
  – Re-designed curve challenging this notion

• 8 ¾” Curve
  – Reduced build rates increases success rate
  – 2 out of 2 wells drilled 8 ¾” curve on first attempt w/ minimal performance loss
  – Third well attempted 8 ½” curve w/ RSS

• Real time monitoring of parameters, T&D, cuttings return, etc. led to high quality wellbore
  – Compared against modeling to determine the state of the well
  – Accuracy of model increases confidence to predict future wells
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
Future ERD Development

• Conventional 15k Laterals
  – No RSS BHA = significant cost savings

• Multi-Horizon 15k Laterals
  – Proven in Upper/Middle Wolfcamp
  – Potential to expand to Lower Wolfcamp & Cline targets

• 20k Lateral
  – Challenge technical limitations
Conventional 15k Laterals
Available Slide WOB

Limited risk of hel. buckling

15k-20k WOB available to slide @ TD
Continue to explore options to reduce and/or mitigate risk of helical buckling
Multi-Horizon 15k Laterals
5 ½” Casing Run

Lower Wolfcamp
0.3 FF Tolerance

Cline
0.15 FF Tolerance*
*Ability to rotate and/or float casing
Modeling suggests 30,000’ MD (+/- 20k vertical section) is feasible across Wolcamp horizons.

Available WOB to reach TD with RSS.

Torque below make up value.

Remain under fracture pressure while drilling.

Limited risk of hel. buckling.

Reach TD with 5 ½” casing without the need for rotation or flotation.
20K Lateral Potential Available WOB

~35k WOB @ TD
20K Lateral Potential Drilling Torque

Legend:
- Make-up Torque
- Rotate Off Bottom
- Rotate On Bottom
- Tripping Out
- Tripping In

Torque at Depth (ft-lbf)

Run Measured Depth (usft)

Sufficient torque rating
20K Lateral Potential
ECD vs. Depth

Distance along String (usft)

Prev. Casing Shoe = 6996.0 usft

ECD approaching fracture pressure @ TD

ECD (ppg)
20K Lateral Potential
5 ½” Casing Run

LEGEND
- CAS FF = 0.10, OH FF = 0.10
- CAS FF = 0.10, OH FF = 0.20
- CAS FF = 0.10, OH FF = 0.30
- CAS FF = 0.10, OH FF = 0.40
- Max Weight Yield (Tripping Out)
- Min Wt. Hel. Buckle (Tripping In)

Hook Load (kip)
100 150 200 250 300 350 400 450 500 550

Run Measured Depth (usft)
0 5000 10000 15000 20000 25000 30000

0.2+ FF Tolerance
Conclusion

• 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