Permian Basin Drilling Optimization

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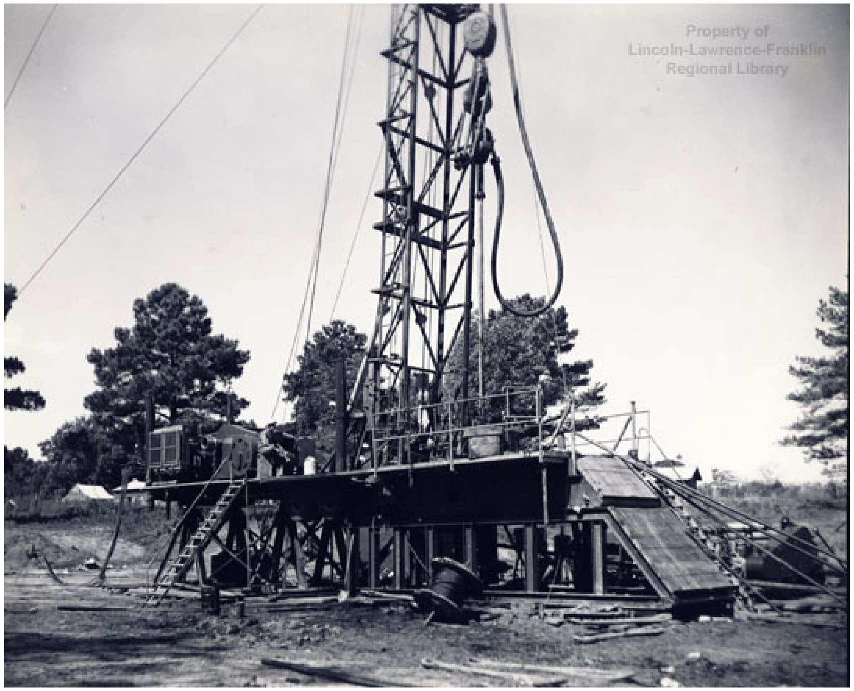
"often we become satisfied with an established procedure and only the press of circumstances will bring about improvement in that procedure… **We need to be less self-satisfied with existing programs or techniques and be more venturesome in various other areas in which we operate."**

J.H. Marsee
(Phillips Petroleum, Odessa, Texas, **1952**)

Quoted in Leonard Franklin's **1952** SPE Paper "Drilling & Completion Practices, Spraberry Trend"

What did a rig look like in 1952?



How does Permian Basin drilling data look 63 years later?

	1952	2015	2075
No. Producing Wells	2,000	82,000	?
No. Rigs	200	500	?
Well MD (ft)	7,000	18,000	28,000
Drilling Days per well	33	25	10
Ft/Day Drilling	212	720	1,900
Bits per well	35	3	1 Laser ?
Foot per bit	200	6,000	?
Drill Tools	Cable and rotary	Bent motors and RSS	Automated Robot ?
Well design	10-3/4" x 5-1/2"	3 String with 10,000' Hz	20,000' Hz
Completion Type	Open hole	Plug & Perf	?
Frac Design	Single Stage 1,500 gals	30 stages, 4.2 million gals	Single Stage 1,500 gal nuclear frac ?
Well IP Oil	300 bpd	1,500 bpd	?

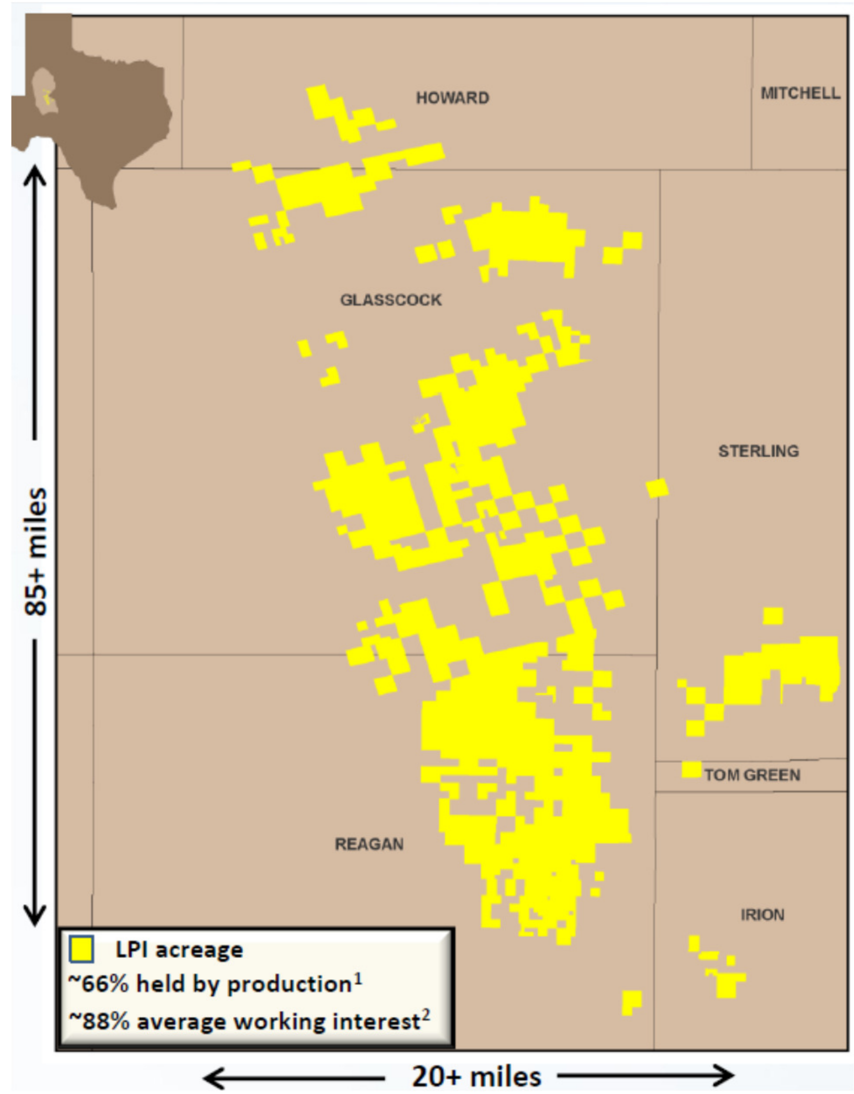
In 1952:

- 90% of vertical wells were 2 string (300’ of surface)
- 82% of wells were “hydrofraced”
- Majority of wells were open hole completions with 5-1/2” casing set into the top of the Spraberry

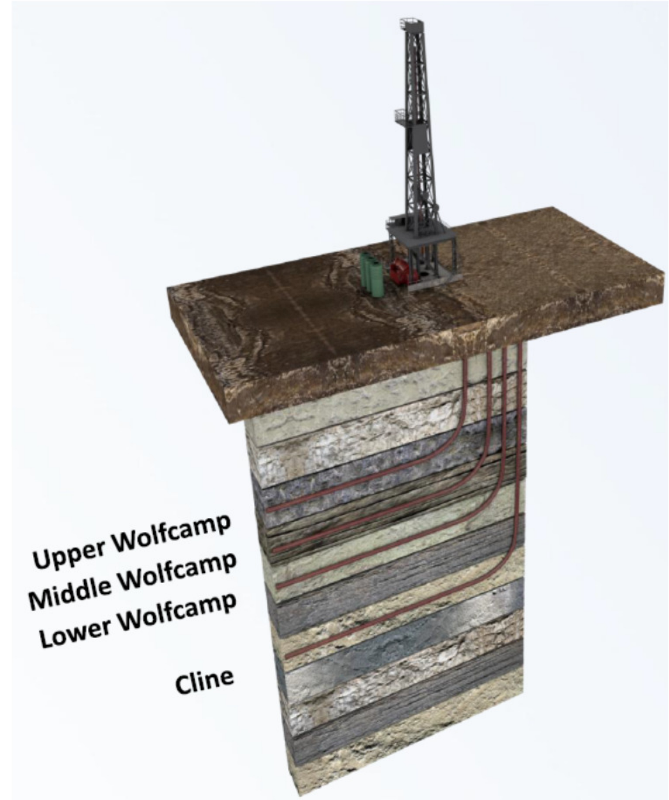
All 1952 data credited to Leonard Franklin, SPE 52-128. Number of producing wells from RRC website.

Project Background

- **Garden City Project: SE Glasscock and NE Reagan Cty**
- **3 String Well Design:** 13-3/8" x 9-5/8" x 5-1/2"
- **1 to 3-well pads**
- **2 Rigs in this data set:** 1500 hp, 5000 psi, walking rigs with 5" DP
- **21 Hz wells in data set:** all wells drilled by these 2 rigs from 4/1/14 thru end of year



Drilling Data Background



4 Horizontal Targets

– Upper Wolfcamp	± 7,500' TVD, 9.5 ppg
– Middle Wolfcamp	± 8,000' TVD, 9.8 – 11.2 ppg
– Lower Wolfcamp	± 8,500' TVD, 11.3 ppg
– Cline	± 9,000' TVD, 12.5 ppg

4 key performance metrics for normalizing drilling efficiency

- Spud to RR Ft/Day = Total Measured Depth divided by Total Days from Spud to RR
- Cost/Ft = Total Drilling Cost divided by Total Measured Depth
- 12-1/4" Intermediate Section Ft/Day = Interval Footage divided by Total Days from Drill Out to TD
- 8-1/2" Curve/Lateral Ft/Day = Interval Footage divided by Total Days from KOP to TD

'Spud to RR' data is days from spud of 12-1/4" section to rig release

- Due to turnkey pre-set of surface casing by spudder rig for efficiency
- To compare to rig data that includes surface, add 2 days
- To compare to other well data that includes rig moves, add 5 days

Importance of a Data-Driven Approach

Permian Basin is “Rich in Learning Opportunities”

Some important best practices differ greatly by target zone

Hard to keep up with 4 target zones

One rig may only drill 2-3 wells of each zone per year and they may be 6 months apart

Company strategy can change quickly: CDC vs. Development

Data collection is critical and it must drive your decisions

Coaching Analogy
&
Giving Credit Where Credit is Due

“If you want to be a great coach, you have to recruit great players”

“I didn’t make any tackles out there today”

Rig Team Results with a Data-Driven Approach

Target Zone	Q1 2014 Days Spud to RR	**Q4 2014** Days Spud to RR	Days Reduced	Improvement
Upper Wolfcamp	28	**18**	10	**36%**
Middle Wolfcamp	28	**16**	11.8	**43%**
Middle Wolfcamp	-	**26**	-	**-**
Lower Wolfcamp	37	**24**	12.5	**34%**
Cline - Wolfcamp	-	**30**	-	**-**

Looks even better when normalized for Depth and Lateral Length….

Target Zone	Q1 2014 Ft/Day Spud to RR	**Q4 2014** Ft/Day Spud to RR	Delta	Improvement
Upper Wolfcamp	532	**837**	305	**57%**
Middle Wolfcamp	537	**992**	455	**85%**
Middle Wolfcamp	-	**600**	-	**-**
Lower Wolfcamp	426	**672**	246	**58%**
Cline - Wolfcamp	-	**644**	-	**-**

21 wells on 2 rigs in study since April 2014. Spud to RR is spud of 12-1/4” section due to turnkey pre-set of surface with spudder rig for efficiency

12-1/4” Intermediate Drilling Best Practices

1. Reduce impact damage by keeping PDC bit engaged on bottom by maintaining constant differential pressure of 400-600 psi.
   - Our record runs on L15 were “drilled by hand” with differential pressure without use of the auto-driller

2. 716 PDC bit with 11-3/4” stabilizers above and below 7/8 lobe, 0.3 rpg, 1.83° motor

3. Run (3) Stds of 8” NC56 DC and (3) Stds of 5” HWDP (No 6” DC)
   - In accordance with API RP 7G which recommends BSR ≤ 2.75
   - NC56 connection has 12 times the box fatigue life vs. 6-5/8” Reg (See SPE 87197, Ellis, Reynolds, Lee)

4. Do not back off of differential pressure at top of San Andres or other harder formations. This will encourage vibration and whirl and will actually lead to impact damage to PDC cutters.
   - In accordance with Fred Dupriest Exxon Mobile Presentation

5. Where possible, minimize sliding if anti-collision requirements are met

6. Displace to light gel polymer system 200’ above the Spraberry and dump and dilute to not exceed 9.1 ppg (frac gradient is 9.4 ppg). High gel system will be more susceptible to flocculation caused by saltwater and chloride leeching whereas a light gel polymer mud will be less reactive while still achieving viscosity and better filter cake.

7. Use of Oil Based Mud (OBM) in Intermediate section may lead to faster drilling time and easier hole conditions but the total fluid management cost is $400,000 more per well more on average vs. WBM

9-5/8" Casing & Cementing Best Practices

1. Place DV Tool and External Casing Packer 200' above top of Clear Fork formation

2. Circulate for 4 hours between stages to allow Stage 1 cement to set up in case the packer doesn't fully isolate weak zones below

3. Plan minimum cement slurry density and height to meet RRC requirements to reduce the chances of lost returns
   - Stage 1: 500' of 13.2 ppg H-plus tail, 11.9 ppg 50/50 H-Poz (10% excess)
   - Stage 2: 300' of 13.5 ppg C (100% excess), 11.9 ppg 50/50 C-Poz (250% excess)
   - Understand cost/bbl of lead cement and compare to spread rate cost to run temp log. Break even point is circulating and dumping roughly 200 bbls of cement to surface (don't be afraid to pump high excess on stage 2 lead)

4. Do not over-displace any portion of shoe tract. Not much downside to having to drill out a little extra cement (different for production casing)

5. For this geographical area, in this data set, we have been 100% successful in achieving required shoe integrity for all target zones when placing the 9-5/8" shoe 60' above KOP with the curve planned on 8s

6. If insufficient cement top is achieved, and temp log is inconclusive, run Ultrasonic Inspection Log to determine top of cement. The lightweight lead cement often doesn't show up on a traditional bond log but is visible on the USIT log.

8-1/2” Curve/Lateral Best Practices

1. Where possible, utilize short bit-to-bend (4.2’ to 4.5’) 1.83° motors and 516 PDC bits that are efficient in both the curve and lateral which allows for one-run BHA strategy

2. Utilize K&M drilling parameters (70- 90 RPMs) in the lateral for optimal hole cleaning and ROP

3. Target 450 – 650 differential pressure when rotating in the lateral

4. Weight up to max expected mud weight by 30° in the curve to avoid instability

5. Utilize 4/5 Lobe, 0.5 rev/gal high speed motors in Upper and Upper Middle zones and 7/8 Lobe, 0.3 rev/gal, slow speed motors in Lower & Cline zones. This allows you to run high rotary for hole cleaning while reducing revs at the bit to prolong bit life in harder formations.

6. Cline: utilize 7/8 Lobe 0.3 rev/gal slow speed 2.12° short bit to bend motor to build curves. Then trip at the base of the curve and pick up a 1.5° short bit to bend motor to drill the lateral.

7. Plan curves on 8° /100 to avoid cost of ± $180,000 2-trip scenario for insufficient BRs

8. Always know your lowest landing limit and your DL needed to land at the limit prior to tripping for a higher bend motor

9. Perform Formation Integrity Test after drilling out 9-5/8” shoe to confirm integrity of primary cement job and to confirm ability to achieve the mud weight required to drill the planned landing point

10. Prior to spending > $30,000 to pull rods and run a gyro survey in offset vertical wells, determine NPV of existing well, and utilize a risk-based calculation to determine chance of collision and risked cost of collision.

5-1/2" Casing & Cementing Best Practices

1. At TD, circulate at 80-90 rpms for 8 – 14 hours depending on lateral length. Spotting beads and planned wiper trips have been proven unnecessary. Rack back 10 stands and start laying down pipe if first 10 pull slick. Adjust as needed for observed hole conditions

2. Mix cement at maximum practical rates and displace at a minimum of 5-7 bpm to achieve adequate displacement efficiency in lateral interval where casing is laying on low side of hole and mud on low side has the potential to be bypassed.

3. If concerned with lost returns, model hydraulics of cement job, adjust design accordingly, and consider slowing down displacement rate once the cement reaches 30 degrees in the curve (and begins to lift)

4. Utilize a low cost cement scavenger to recover OBM left on the annulus of the production casing.

2014 Fleet Records

Ft/Day Spud to RR	Metric
Upper Wolfcamp	923
Middle Wolfcamp	992
Lower Wolfcamp	697
Cline	612

12-1/4" Ft/Day WBM	Metric
Upper Wolfcamp	2,073
Middle Wolfcamp	1,995
Lower Wolfcamp	1,831
Cline	929

8-1/2" Curve/Lateral Ft/Day	Metric
Upper Wolfcamp	2,134
Middle Wolfcamp	1,668
Lower Wolfcamp	1,272
Cline	1,298

Spud to RR (Not Normalized)	Metric
Upper Wolfcamp	14.6
Middle Wolfcamp	15.9
Lower Wolfcamp	21.4
Cline	30.0

Questions

Final Thoughts

Anecdotal vs. Data-Driven

Best practices are hidden in the data

Hz Wolfcamp is a complex project

Study failures

Re-inventing the wheel vs. Continuous Improvement

Pressing circumstances