

The 5th Mile: A Review of the Limiters to Reaching Further in Unconventionals

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Abstract

Advanced horizontal drilling technology and consolidated acreage incentivize longer laterals. As laterals increase in length, fluid limiters impact well economics. Sensitivity analysis reviewing rig capabilities, hydraulics optimization, and torque mitigation was performed to highlight potential limits and operational risks with narrowing technical margins.

A key to drilling further is repeatable, consistent success at the lowest practical cost. Since 2010, the average lateral length in the Permian Basin has grown from 4000 feet to 10,000 feet. The definition of a “long lateral” continues to grow. In the Marcellus, some lateral lengths exceed 20,000 feet. An important contributor to these advances was improved hydraulics from new rig equipment. Future limiters, such as excess torque and high circulating pressures, will require new fluid solutions with a different approach to secure efficiencies and preserve economics.

Narrower operating windows provide additional opportunities for automated fluid monitoring to ensure quality control and optimized drilling practices. Recent applications demonstrate improved fluid consistency during treatments to avoid fluctuations in drilling fluid density and viscosity.

Across the globe, extended reach wells achieve measured depths approaching 50,000 feet using innovative technologies and techniques that will someday enable low-cost, high-volume wells to break their own records. This paper reviews fluid limiters throughout the unconventional revolution and compares advances generated from historical record-breaking extended reach projects. Modeling and drilling fluid analysis reveal key fluid properties impacting success rate of lateral extension.

Introduction

The low-cost, high-volume unconventional environment continues to drive innovation that enables economic development of progressively longer laterals. In areas such as the Northeast United States, expensive location requirements accelerated demand to maximize reservoir contact with fewer wells and many of the longest laterals are drilled there today. Across other shale basins, consolidation creates more opportunities to lower costs through longer laterals.

Longer laterals require multiple advances to remain practical. Currently, per-foot productivity declines are offset by the reduced well count (Cui and Cross, 2022). New

completion technologies and techniques will be required to recover hydrocarbons from the greatest reaches of a well.

Extended reach drilling campaigns across the globe demonstrate the feasibility of drilling longer unconventional wells. Many of the technologies developed for these signature projects are mature, available, and relatively affordable for unconventional drilling economics.

Extended Reach Projects Comparison

Extended reach wells are characterized as wells where the measure depth is more than twice the true vertical depth (Petrowiki, 2016). Major projects (Table 1) are cited for comparison throughout this paper. This list is not exhaustive of all major projects or wells, but they were selected due to their industry impact and insightful documentation to inform the discussion for unconventional laterals.

Table 1: Select ERD projects

Key Well – Project Location	MD	TVD
Alfa Sur 3 - Tierra Del Fuego (Naegal et al, 1998)	27928	5300
Chayvo Z-44 – Sakhalin (Gupta et al, 2014)	41667	7688
Sacate SA-15 - California (Walker, 2008)	33435	7663
Wytch Farm M11PSZ/SPY – United Kingdom (Meader et al, 2000)	34967	5266
Maersk Al Shaheen BD-04A - Qatar (Sonowal et al, 2009)	40320	3842
Upper Zakum - Abu Dhabi (Alabed et al, 2023)	50000	8135
Hibernia OPA2 - Canada (Woodfine et al, 2011)	33209	13692
5- Mile Unconventional Lateral Well	35000	10000

A conceptual unconventional 5-mile lateral would have a true vertical depth of around 10,000 feet for most (not all) basins for a measured depth of 35,000 feet – well within the parameters of wells more than a decade ago. Figure 1 displays the TVD:MD ratio of the wells in Table 1 along with the conceptual unconventional well profile.

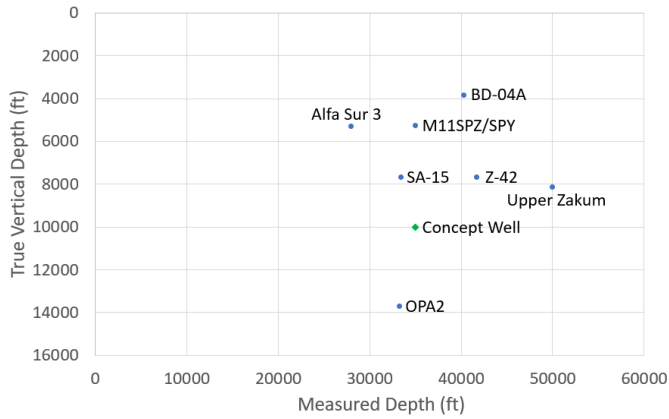


Figure 1: TVD:MD ratio comparison

Rig Capabilities

At the time many of these wells were drilled, rig upgrades provided the latest in available power and capabilities. These features are standard on many land rigs today. Some upgrades, such as extra drilling fluid storage, have few restrictions compared to these remote land and offshore locations.

To characterize the challenges of the 5-mile concept well, key rig specifications are compared against two types of today’s state-of-the-art land rigs. In most cases, equipment meets or exceeds that utilized to drill record extended reach wells in the past.

Flow rate is an essential factor in hole cleaning efficiency. Insufficient flow rate may require supplemental techniques or controlled drilling. Figure 2 summarizes the maximum circulating pressures from select wells and the maximum circulating pressures of industry standard unconventional drilling rigs.

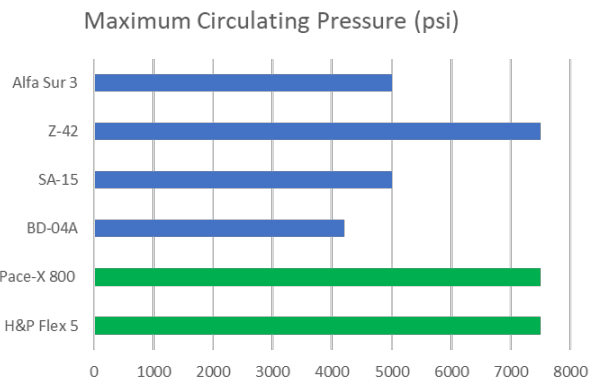


Figure 2: Maximum circulating pressures from wells Alfa Sur 3 (Naegal et al, 1998), Z-42 (Walker, Veselka, and Harris, 2009), SA-15 (Walker, 2008), BD-04 (Sonowal et al, 2009), and two current industry standard rig offerings (Helmerich and Payne, 2023, Nabors, 2024)

Drilling torque is an important factor for efficient drilling. Excess torque limits energy at the bit, diminishing rate of penetration. All the rigs used in the comparison feature top drive systems. Figure 3 demonstrates that today’s land-based drilling rigs have sufficient drilling torque to deliver long laterals. Torque is listed as the documented maximum sustained torque, except for well SA-15 where the value is presented as

90% of the maximum nameplate capacity.

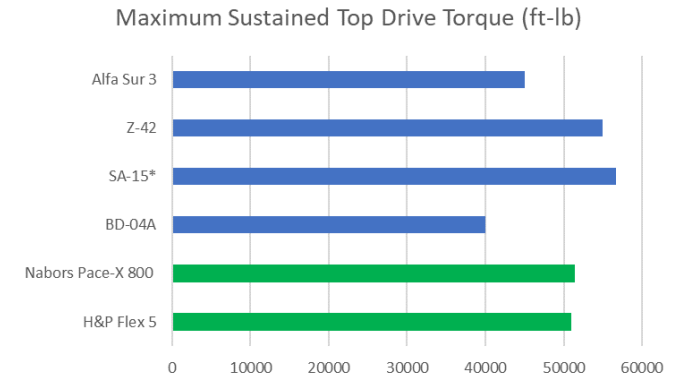


Figure 3: Maximum sustained top drive torque from Alfa Sur 3 (Naegal et al, 1998), Z-42 (McDermott et al, 2005), SA-15 (Walker, 2008), BD-04 (Sonowal et al, 2009), and two current industry standard rig offerings (Helmerich and Payne, 2023, Nabors, 2024). *SA-15 torque is calculated as 90% of 63,000 ft-lb of nameplate.

Pipe rack capacity impacts drilling efficiency because any extra stands of pipe must be laid down and picked up instead of racked in the derrick. Pipe capacity is sometimes listed by weight because monkey boards can be adjusted to accommodate different sizes of pipe. In Figure 4, 5” pipe is cited in most cases, except for the SA-15 well and the H&P Flex 5. The SA-15 well cited 5 ½” pipe and the H&P Flex 5 was calculated from 622,000 lb of 24.7 lb/ft of 5 ½” drill pipe.

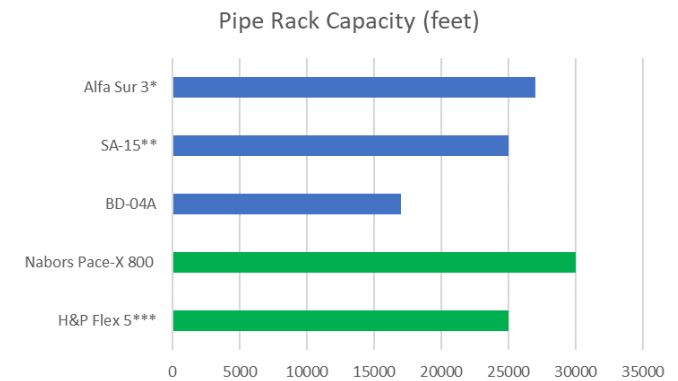


Figure 4: Estimated pipe capacity Alfa Sur 3 (Naegal et al, 1998) *converted from 8300m, SA-15 (Walker, 2008) **5 ½” pipe cited, BD-04A (Sonowal et al, 2009), and two current industry standard rig offerings (Helmerich and Payne, 2023, Nabors, 2024).

For a 5-mile lateral with a 10,000-foot true vertical depth, Figure 5 calculates the cost to trip when the derrick is limited to 25,840 feet of drill pipe and spread rates are \$80,000 per day based on the ability to rack back 3350 of pipe per hour versus laying down 1400 feet per hour.

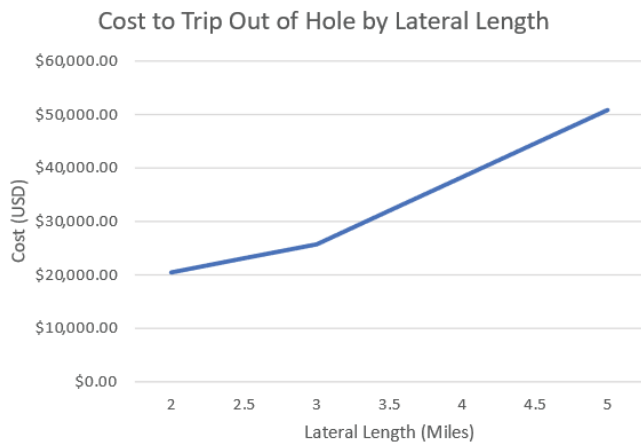


Figure 5: Trip cost increases with increased lateral length as pipe length exceeds derrick capacity

Well Properties

There are important distinctions between many ERD wells and an unconventional well that include the size and type of hole, reservoir contact length, and days drilling. Unconventional wells focus on repeatability at minimal cost. The other projects cited were world-class case studies in engineering. Drilling a single 5-mile unconventional lateral is insufficient to impact a shale development project. Longer unconventional wells are only impactful when they set a new standard for drilling tens or hundreds of wells.

The details of hole-cleaning will be discussed later in this paper, but it is important to distinguish the comparison case studies from a typical unconventional well.

Well trajectory and hole size play an important role in hole cleaning complexity. Larger hole sizes in build sections present the greatest challenges, particularly at angles between 30° and 70°. In the select ERD projects, hole cleaning discussions are in the context of such challenges. Casing profiles are designed to step out and reach a distant reservoir target.

In shale drilling, the entire lateral section is the reservoir. Short, small-diameter build sections simplify hole cleaning because there is limited area for cuttings to avalanche and annular velocities remain high across the section.

Table 2 highlights large hole sizes across critical angles. Unconventional wells feature long reservoir contact, but do not feature extended build sections or large intermediate hole sizes to reach the production section.

Many of the ERD wells cited were documented as engineering feats. Extensive planning and cutting-edge technologies were employed to reach reservoirs. Many drilling locations were remote with relatively elevated daily costs. In contrast, unconventional wells in most basins are driven by minimal daily cost using mature technologies.

A single unconventional well may break a record, but a true change in development drilling requires repeat delivery of a well every 15-20 days. In easier drilling environments, such as the Marcellus shale, drilling 2+ miles in a single day is expected. Other basins and benches will vary in achievable rate of penetration, but sub 15-20-day wells are expected. Figure 6

provides a comparison of historical wells versus conceptual 5-mile lateral unconventional wells.

Table 2: Key build sections with hole sizes and reservoir lengths

Key Well – Project Location	Build Section + Hole Size	Reservoir Length
Alfa Sur 3 - Tierra Del Fuego (Naegal et al 1998)	17 ½" to 76.4° at 3251' 12 ¼" to 86.5° at 25322'	2657'
Chayvo Z-42 – Sakhalin (Gupta et al 2014)	24" to 36° at 2709' 17 ½" to 82° at 14,932'	11,562'
Sacate SA-15 - California (Walker 2008)	17 ½" x 20" to 35° at 2996' 14 ¾" x 17 ½" to 86° at ~4600' ICP at ~8,000'	~3599
Wytch Farm M11SPZ/SPY – United Kingdom (Meader et al 2000)	17 ½" x 24" to 14° at 3609' 17 ½" to 83° at ~4360' 12 ¼" to 28,394'	7860
Maersk Al Shaheen BD-04A - Qatar (Sonowal et al 2009)	16" to ~2944' 12 ¼" to 89.8° at 4881'	35,449'
Upper Zakum - Abu Dhabi (Alabed et al 2023)	16" to 54.5° 12 ¼" to 85°	33,500'
Hibernia OPA2 - Canada (Woodfine et al 2011)	Not disclosed	~6949
5- Mile Unconventional Lateral Well	8 ½" to 90° (~1000' build)	35,000'

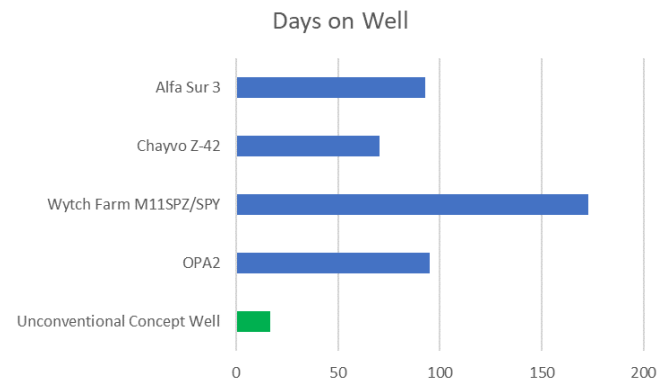


Figure 6: Approximate days on well comparison of Alfa Sur 3 (Naegal et al, 1998), Z-42 (Gupta et al, 2014), M11SPZ/SPY (Oil and Gas Online, 1998), and OPA2 (Woodfine et al, 2011)

The Fifth Mile Well

An unconventional 5-mile lateral is not beyond reach. 4-mile plus laterals are part of new drilling programs. The recent wave of consolidation among shale plays creates more acreage where longer laterals are both possible and new drivers of efficiency.

With proper engineering, current technology and rig equipment are more than capable of drilling a 5-mile lateral. As with other ERD projects, a wholistic approach of the drilling system is required to capture opportunities to optimize well delivery.

Fluid Selection

Fluid selection remains the prerogative of the operator based on typical selection criteria such as total cost of ownership, performance, environmental restrictions, and familiarity. Engineering tolerances come into focus as lateral lengths increase.

Most long laterals are drilled with invert emulsion fluids. Invert emulsion systems are easy to maintain, offer inherent lubricity, and have limited formation interaction. Conventional and flat rheology systems have delivered most extended reach wells. In many cases, a combination of organophilic clays and polymers is used to maintain the drilling fluid. Hydraulic modeling comparing conventional and flat rheology systems will help select the appropriate fluid to avoid excess cost.

Unconventional laterals lack many of the well properties flat rheology systems were designed to address. Developed for thermal variations in deepwater drilling, flat rheology invert emulsion systems are cited as candidates for unconventional wells to reduce circulating pressures. Fluids are cited under many names, including “clay-free”, “flat rheology”, or “fragile gel”, but they all rely upon reduced or no organophilic clay with supplemental polymeric viscosifiers to limit gelation and thickening in cold-temperature and excess thinning at elevated temperatures. Knox, Bulgachev, and Cameron (2015) offer technical characteristics to define these fluids by viscosity across a range of temperatures, but there is no specific standard set by the industry.

Polymer chemistries in flat rheology systems require solids to generate a network for suspension. For fresh fluid, this can include clays such as sepiolite or attapulgite, organophilic clays, and calcium carbonate. Once drilling commences, polymers act on drill solids, which may result in excess viscosity. For large circulating systems found offshore, the overall effect is minimal, and economics justify limiting low gravity solids through supplemental dilution when required. Onshore, rigs feature smaller circulating volumes and increased low gravity solids limits where these polymers become problematic. This can either create issues with excess rheology or promote supplemental dilution to maintain properties.

The concept well assumes an invert emulsion is selected, but the authors recognize many record wells have been drilled using water-based fluids with supplemental lubricants. It is surmised that water-based options would be considered after other engineering practices are refined drilling the initial wells with invert emulsion systems.

Hydraulic Optimization

Improper hole cleaning can result in many drilling problems including over-pull on trips, high rotary torque, packing off, and stuck pipe. Hydraulic modeling software was employed to determine optimal parameters for hole cleaning / removal of drill cuttings from the wellbore.

Historically, rheological properties such as the yield point (YP) and the 6-rpm reading have been indicators for hole cleaning capability of drilling fluid. Bigger mud pumps (7500 psi or greater) have enabled higher flow rates. Turbulent flow, which directs more energy at cuttings, can now be achieved

with lower viscosity fluids. Excess viscosity risks diminishing turbulent flow regimes that promote better hole cleaning in small diameter wellbores (Parsons, Strickland, and Offenbacher, 2018).

Table 3 summarizes the subject well characteristics used to run modeling. Well profile and other key hydraulic inputs were gathered from a 4-mile lateral well drilled in the Delaware subset of the Permian Basin. The same well is extended an additional mile (5280 ft.) for this study.

Model assumptions include a rotary steerable system using 5 ½” drill pipe drilling an 8 ½” hole with 9 ⅝” casing in the intermediate section. Figure 7 provides a breakdown of pressure loss across the circulating system between a 4- and 5-mile well. Rate of penetration is set at 150 feet per hour and rotation is set at 100 rev/min. Flow rate is 577 gallons per minute.

Table 3: General well profiles compared for hydraulics study

Well Type	4-mile lateral (actual)	5-mile lateral (model)
Mud Weight, lbm/gal	11.6	
Producing Formation	Wolfcamp A	
9 ⅝” Interval Casing TD/TVD ft.	10517 / 10510	
8 ½” Open Hole TD, MD/TVD ft.	32954 / 11293	38234 / 11293
Landing Point, ft	11763	
Lateral Length, ft	21191	26400
Lateral Length, miles	4.01	5.00
BHA / Drillstring Notes	5.5” 21.9 ppf drill pipe / RSS	
Rate of Penetration, ft/hr	150	
Pipe Rotation, rev/min	100	
Flow Rate, gal/min	577	

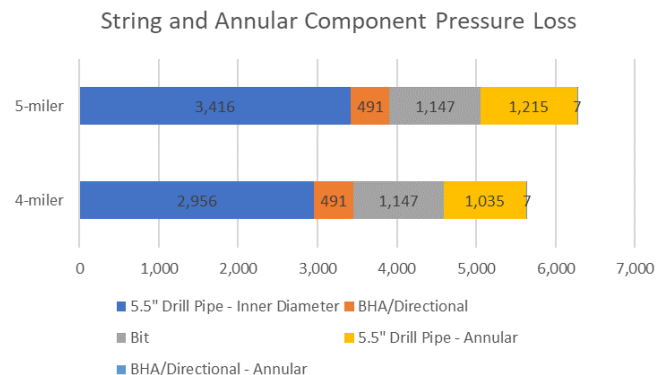


Figure 7: Pressure loss breakdown using conventional invert emulsion system

Fluid Comparison

Table 4 compares rheological values of a conventional OBM (COBM) vs. a flat-rheology system (FRS). Note that the plastic viscosity, a key factor in circulating pressures, is somewhat similar for both fluids.

Table 4: Fluid Comparison

Fluid Property at 150°F	COBM for 4- and 5-mile simulation	FRS for 4- and 5-mile simulation
600 rev/min, degrees	53	49
300 rev/min, degrees	31	29
200 rev/min, degrees	23	22
100 rev/min, degrees	15	15
6 rev/min, degrees	6	6
3 rev/min, degrees	5	5
PV, cP	22	20
YP, lb/100ft ²	9	9

Modeling output shown in Table 5 demonstrates a modest difference in equivalent circulating density and standpipe pressure. This simulation suggests that the contribution of flat rheology systems for the purpose of reduced circulating pressure requires scrutiny.

Table 5: Hydraulic modeling output for ECD and standpipe pressures

Measure	4-mile COBM	4-mile FRS	5-mile COBM	5-mile FRS
ECD at bit, lb/gal	13.45	13.41	13.77	13.72
ECD at shoe, lb/gal	12.13	12.12	12.13	12.12
SPP, psi	5616	5520	6276	6165

There are other use cases for flat rheology systems. Maintaining lower solids to sustain the rheological profile can increase rate of penetration and reduced gelation after long static periods can mitigate surging the wellbore during casing running. Lower clay content improves invert emulsion stability during water flows, a common occurrence in some basins. As with any fluid option, good engineering will lead to proper utilization to lower cost and save time.

Mud Weight Selection

The lowest mud weight possible is preferred because it reduces material cost, facilitates higher rate of penetration, and reduces risk of losses. Insufficient mud weight creates the risk of wellbore collapse, risking packoff and mechanical sticking.

Insufficient mud weight is a common source of wellbore instability issues in unconventional wells. The associated cavings and fractured rock requires higher mud weights than if the proper mud weight was selected prior to drilling (Otteson, 2010).

Offset studies using data analytics tools captures effective mud weights from nearby locations, reducing the error in mud weight selection.

Fluid Monitoring and Maintenance

Fluid modeling provides optimal parameters, but as the drilling system approaches technical limits, tolerances across the system narrow. Traditionally benign or limited impact events suddenly stress the system, requiring rapid response in

the narrow margin environment.

For drilling fluids, this means faster responses to changes in fluid properties and consistent treatment to smooth or limit fluctuations.

Practical Automated Drilling Fluid Measurement

The drilling fluid specialist at the rigsite has a dynamic role that extends beyond completing the required mud checks. The mud check documents the activities of the previous hours without specifically capturing actions to address issues, plan for operational activities, or any other number of tasks. Throughout this flurry of activity, even a seasoned drilling fluids specialist risks missing periodic changes in drilling fluid properties.

Automated drilling fluid measurement technologies present new opportunities to assist the drilling fluids specialist as system costs decline and reliability improves. Real-time drilling fluid monitoring provides insight into drilling fluid mixing efficiency and changes in fluid properties from downhole events or solids accumulation.

Equipment continues to mature with improved reliability and lower cost. This allows for onshore automated drilling fluid monitoring, leveraging trends and non-API measurements to provide greater consistency. This also enables advanced troubleshooting and analysis with real-time drilling fluid properties appearing alongside drilling data (Petty et al 2023).

Bring Back the PWD

Pressure while drilling (PWD) sensors are standard in offshore and technically challenging environments. Sensor data provides near-bit pressure inside and outside of the drill pipe. Data sets are transmitted via measurement while drilling (MWD) tools present in the drill string.

Many rotary steerable systems include PWD, and an independent PWD sensor package is available for less than \$100 per day. Given the opportunity to provide near-time downhole information, it is difficult to understand how this equipment remains overlooked in unconventional wells.

Throughout their implementation, PWD tools have demonstrated their ability to decipher downhole events. For example, a longer lateral may require extended cleanup cycles at TD to circulate remaining cuttings from the well. PWD trends can help to determine hole condition in real time and distinguish between tight spots from cuttings accumulation or wellbore creep that may require increased drilling fluid density (Mallary, Martin, and Quinn, 2002).

In hydraulic modeling, PWD data provides a helpful tool for calibration of fluid models to eliminate errors. When PWD data and hydraulic models diverge, model inputs can be modified to replicate measured data to identify root causes to unplanned events (Peng et al, 2003).

Torque

Torque is a primary challenge for extended laterals. Loss of energy from frictional forces has multiple implications:

- Reduced rate of penetration
- Increased risk of doglegs
- Diminished pipe life

Lower rate of penetration impacts the immediate economics of the well by increasing rig time. Poor wellbore quality increases the risk of leaving the target zone, sticking, and running casing to bottom. Undulating wellbore trajectories also increase the risks to effective well cleanout (frac-plug removal) and artificial lift installation and efficiency.

Another risk is shortened pipe life. Pipe failure during drilling risks loss of the drilling assembly and a well sidetrack. In most cases, pipe inspection frequency increases to prevent such catastrophic failures. Hard-banding replacement adds to maintenance requirements until the pipe requires complete replacement. A new drill string costs millions of dollars, and operators have placed significant focus on extending pipe life to limit the recurrence of pipe replacement.

A clean, quality drilling fluid is an important step towards limiting excess torque; however, the performance benefits are difficult to quantify during drilling. As drilling torque approaches programmed limits, many drillers are tempted to reduce rotation to reduce torque readings, which impacts hole cleaning efficiency (Sanchez et al, 1999). This has the possibility to offer the opposite effect as cuttings accumulate in the wellbore.

Most long laterals utilize invert emulsion drilling fluid, where the inherent lubricity of an oil-continuous system provides significant benefits. Supplemental lubricants have a mixed track record, but new chemistry in the correct application may provide additional torque reduction.

As more of the drill string rests on the bottom of the lateral, back-reaming becomes a necessity. The difference between rotation and static pick-up weight becomes too great to pull out on elevators alone. This has implications for tripping practices, but when included as part of the overall drilling program, back-reaming can be limited to the minimum required.

Tool Compatibility and Reliability

Early trials of low-cost RSS for unconventional drilling demonstrated their potential for improved wellbore quality and rate of penetration. These gains were undermined by poor reliability.

Long laterals limit weight on bit to maintain the horizontal directional profile. Using a directional motor requires additional sliding time to correct doglegs and impacts hole cleaning efficiency (Cocking, Bezant, and Tooms, 1997). Rotary steerable systems (RSS) eliminate sliding requirements, improving drilling efficiency and wellbore quality. It is expected that the longest extended reach laterals will utilize a RSS. In 4+ mile laterals in the Northeast, RSS remains the standard for well delivery.

Early in their adoption, RSS reliability was a critical area of focus. Any failure requires extended trip times to replace the

failed equipment. In longer laterals, this time is extended by the necessity to lay down drill pipe when there is insufficient capacity in the derrick.

In one unconventional RSS trial, reliability issues limited adoption. Data confirmed improved drilling rates with the RSS, but repeat failures meant that overall drilling days lagged conventional motors.

RSS reliability requires commitment from the entire drilling team. Too often, RSS providers place immediate blame on drilling fluid conditions without evidence or working knowledge. This leads most drilling fluids providers to become defensive. Root cause analysis and performance-based contracts have shown that reliability improvements are possible (Viktorin et al, 2006).

Automated Drilling Fluid Measurements and Tool Reliability

There are several opportunities for drilling fluids specialists to assist in root cause analysis. Automated drilling fluid measurements provide a third-party assessment of changes in fluid properties prior to and at the onset of a tool failure. Sensor data also captures mixing behavior that could result in tool plugging. For example, if barite additions create large fluctuations in fluid density, the drilling team can review best mixing practices to avoid a plugging incident when other products are added.

Petty et al (2023) demonstrated that an equipment filter in an automated drilling fluid measurement system can provide secondary detection of shaker screen bypass to limit solids accumulation that can impact tool reliability. When a pressure alert is activated on the unit, screens are inspected and replaced.

Analytical Tools for Root Cause Analysis

Many drilling fluids providers have analytical labs with equipment and refined methods to aid in root cause analysis. X-ray diffraction (XRD) and x-ray fluorescence (XRF) can identify minerals and elements of material found within a failed RSS or MWD. Without proper scrutiny, the weight abundance of barite in most samples leads to the assumption that barite caused a tool failure. Barite is so abundant in any weighted drilling fluid that results without it would be suspect – particularly when the output reports material by weight percent.

Table 6 lists XRD results from a tool failure investigation. The presence of iron oxide is of interest because it is a possible indicator of metallic material plugging the tool.

Table 6: XRD results from tool failure investigation

Mineral Type		Mineral Abundance, Weight Percent
Silicate	Quartz	9.3
	Illite-Mica	7.2
	Plagioclase	2.0
	K-Feldspar	0.5
Carbonate	Calcite	1.1
	Dolomite/Ankerite	0.9
Iron Oxide/Iron Sulfide	Pyrite/Goethite	3.0
Sulfate	Barite	75.7

Table 7 lists XRF results from a tool failure investigation. Note that elemental barium is converted to barium sulfate by mass. The abundance of iron – as well as elements present in exotic metallurgy – indicates either fluid-borne metal accumulation or internal failure from within the tool itself is worth further investigation for a source.

Table 7: XRF data from a tool failure investigation

Element	Unit	Results
Na	mass%	0.4
Mg	mass%	0.5
Al	mass%	3.3
Si	mass%	10.7
P	ppm	417.0
Cl	mass%	1.2
K	mass%	1.0
Ca	mass%	2.6
Mn	ppm	1350.0
Cr	ppm	1350.0
Fe	mass%	12.6
Ni	ppm	296.0
Cu	ppm	244.0
Zn	ppm	364.0
Pb	ppm	115.0
Nb	ppm	52.0
Mo	ppm	218.0
Ti	ppm	422.0
I	ppm	475.0
Sr	ppm	1460.0
BaSO ₄ *	mass%	67.0

Hadley et al (2023) provide a case study on root cause analysis and subsequent steps to mitigate tool issues for failures observed in Western Canada. This includes stronger ditch magnets to capture metal debris, monitoring barite recovery systems, and attention when onsite hard banding or new pipe increases iron introduction into the system.

Bypass Subs

Tool plugging, particularly from loss circulation material (LCM), is a common concern. When the drilling fluid provider recommends an LCM program, the directional company comments on perceived incompatibility based on experience or their own tables of acceptable material. There is no standard size of fine, medium, or coarse LCM. Most charts do not state acceptable sizes by particle size distribution or recommend very low concentrations of material. None of these charts can capture acceptable mixing rates, where mixing too fast can cause plugging regardless of the LCM size.

Bypass subs alleviate many of these risks, particularly for critical loss scenarios. These subs can completely bypass tools for LCM placement into the annulus, keeping the full suite of LCM options available. After treatment, the bypass sub can close for a return to drilling.

Solids Control

Solids control is one of the most critical factors in drilling fluid efficiency for extended reach wells. Long laterals expose cuttings to greater friction and degradation forces. Excess shear forces in RSS are known to further contribute to the breakdown

of material into fine solids that solids control cannot remove.

An abundance of fine solids impacts rate of penetration and risks downhole tool failure. Excess low gravity solids require aggressive dilution to maintain fluid properties, but chemical consumption and dilution volumes are limited with effective equipment.

A complete solids control system depends on any number of factors, but typical invert emulsion system processing includes primary and dryer shakers and two centrifuges. New technologies and processing methods continue to evolve, but any system requires a full evaluation, performance monitoring, and training for personnel to insure best performance.

A five-mile unconventional lateral will be part of multiple wells on the same pad. Subsequent laterals will encounter more challenges with solids as fluid reuse continues. Measuring particle size distribution at each well helps to determine if fluid requires dilution or even swapping if fines accumulate beyond accepted values. Figure 8 illustrates particle size degradation by well sequence for three different pads while drilling the Utica shale. Note the rates of fine solids accumulation.

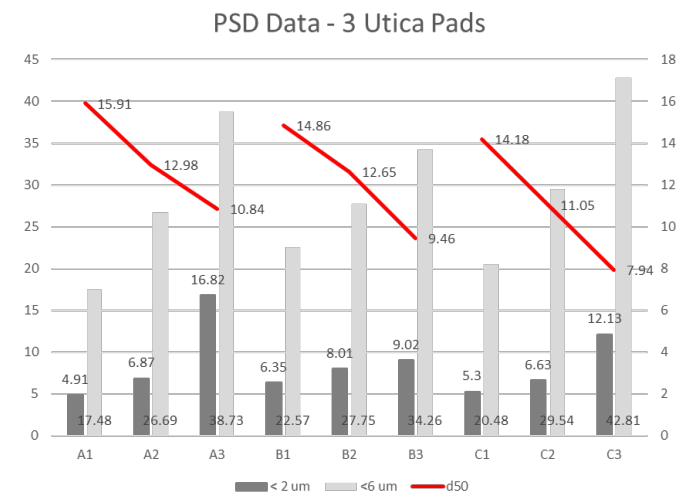


Figure 8: 3 Utica pads with particle size distribution measurement. The bar charts represent the volume percent below 2 and 6 microns, respectively. The red line graph is the D50 (in microns) for each well.

Conclusions

Limiting evaluation of historical ERD and long-lateral wells demonstrates the technical feasibility of 5+-mile, unconventional laterals. Narrowing tolerances require careful consideration of all aspects of the drilling system:

- Hydraulic modeling provides insight into hole-cleaning feasibility adjusted to current rig capabilities and well scenarios.
- Fluid selection should include hydraulic modeling to compare and justify the benefits of different systems
- Monitoring and maintenance become more critical as margins narrow. Automated measurement systems offer great opportunities to improve consistency and reduce risk.

- Tool reliability is critical to drilling efficiency. Collaboration and root cause analysis is required to take the next steps.
- Longer laterals will require attention to solids control to maintain fluid quality.

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