DRILLING TECHNOLOGY
ANTI-COLLISION BEST PRACTICES
DEVELOPED FOR HORIZONTAL DRILLING
ACROSS PRE-EXISTING HORIZONTAL WELLOBRES

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Introduction
In the Williston Basin alone there are over 13,000 vertical wells, 15,000 horizontal wells, and over 1,000 re-entry and directional wells drilled to date, with the first horizontal wells introduced to the basin over 30 years ago. Historically, the horizontal wells were drilled using a vast array of well designs and orientations due to the limitations of technology, industry practices and standards, and the insufficient understanding of the reservoir potential at the time.

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AROUND THE PATCH
PIVOT IN THE POWDER

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Monday, October 1, 2018

The Boner family works with Anschutz Exploration in developing Powder River Basin acreage that also serves to raise livestock.

We sometimes talk of a “tipping point,” when various factors cross a threshold and collectively gain much greater momentum than historically has been the case. Similarly, a variety of ingredients are brewing...

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GEO PRODUCT INTRODUCTION

KlayCon
New mud systems appear from time to time. Recent advancements in the drilling industry have provided several environmentally friendly fluids that replace oil in oil based muds or chrome in water based muds. These new fluids are typically much more expensive, more difficult to maintain and provide less reliable hole stability. They can only be justified in areas with very stringent discharge limits, such as the North Sea.

A new mud system is being used in the drilling scene in western U.S. It goes by a variety of names, most commonly Acid Mud because of the fact that it is unique among muds in its use of acid as a major ingredient to control pH. Actually, it is no more an Acid Mud than a mud with a salinity of 1000 ppm is a Salt Mud. Rather, it is a polyacrylate (Cypan/DMA) mud, with the pH level controlled at 6.0 to 7.0 by adding a variety of acids to the mud system. Supplemental treatments of GEO’s CFR lubricant or a comparable surfactant is also recommended to enhance lubricity and to further minimize clay packing.

GEO’s Acid Mud system is called KlayCon and is designed to retard hydration of highly reactive mud-making clays along with helping to stabilize pH and water sensitive shales. The overall mud cost of this system is generally 30% higher than a normal Cypan/DMA mud. However, this increase in costs is more than offset by a reduction in rig time spent on clay related problems such as excessive wiper trips, clay pack off and tight hole. Reduced rig time also results in less mud maintenance as well as all the associated rig costs.

KlayCon is not Oil Based Mud (OBM) and does not have the absolute inhibiting properties of that system, however, it is an economical alternative to achieve a degree of inhibition without adding salt which compromises fluid loss or using OBM which raises the mud costs geometrically on a shallow to moderate depth well (1,000’ to 10,000’).

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Advancements in drilling and completions technologies and a better understanding of the reservoir now allow leases to be reassessed for infill potential. This increased infill development has led to increasingly complex wellbore trajectories with collision concerns not only for existing vertical wellbores but now also for existing horizontal wellbores within the same or proximal horizons. In many cases the optimal orientation of the wellbores have changed along with the optimum lateral length. Early wells may have been only a couple thousand feet long while current laterals extend 2 to even 3 miles. While advancements in technology and understanding has progressed, the industry norm for anti-collision mitigation continues to err towards complete avoidance of drilling across pre-existing horizontal wellbores. This avoidance mentality results in unique well path variations solely for the sake of avoidance often creating non-ideal wellbore configurations with compromised orientations, lateral lengths, or additional wellbore requirements resulting in unnecessary and uneconomic wells.

In the Williston Basin operators are implementing programs for infill development. To date, there have been less than 80 wells to attempt horizontal drilling across pre-existing horizontal wellbores, which accounts for only 0.004% of the total horizontal wells drilled. The first horizontal to horizontal anti-collision in the Williston Basin was drilled in 2010. To effectively develop infill potential across mature basins, the industry needs to advance the current ultra-conservative collision avoidance practices and develop anticollision programs for drilling across pre-existing horizontal wellbores.

This paper focuses on the anti-collision method developed and implemented by Liberty Resources for horizontal drilling across pre-existing horizontal wellbores within the same horizon in the Williston Basin. For simplicity, this paper will only discuss anti-collision methodologies as they relate to wellbore-towellbore in the horizontal sections.

Process and Methodology
The methodology for horizontal-to-horizontal anti-collision needs to be a broad framework that allows for flexibility to adjust for distinct operational constraints while providing ease of implementation with personnel. The methodology developed uses best practices including directional and geologic planning considerations, current anti-collision theory and practices, operational tolerances and requirements including zonal determination, communication protocols, and risk management practices.

For ease of development, these practices are focused on the two main components of anti-collision operations, the geologic considerations and the drilling considerations addressing each component’s related issues. In reality, anti-collision development is a complex, highly collaborative effort with the planning of each component often happening in tandem.

Geologic Considerations and Planning
This anti-collision approach considers geologic placement to be a valued component for planning and operational implementation. Each individual formation has its own unique depositional environment, steering markers, and geologic hazards to weigh and consider. Sequence stratigraphy can range from simple and straightforward to extremely complex and have unresolved sequences between offsetting wellbores. Geosteering approach uses radial symmetry in the resistivity or gamma ray signature to steer the wellbore in the target formation nearly parallel to bedding planes (Meehan, 1994). Ideally, the new wellbore should be placed in a laterally continuous formation with clear and consistent steering markers. Porpoising throughout an entire lateral section will reveal unique steering signatures that will track movement of the wellbore within the formation as well as the structure of the formation.

The operational geologic considerations include the stratigraphic position, regional structure, and survey depths. Knowing the stratigraphic location and how it changes over the lateral section is paramount to mapping the proposed wellbore path. The stratigraphic location requires the existing wellbore’s data to be reinterpreted and reworked. This is extremely important due to interpretation discrepancies between individuals and companies. Reworking the data has the added benefit of converting the original well into the same datum definitions as the proposed well.

Reinterpreting the data includes, potentially changing the structure, stratigraphic placement, and apparent dips, ceating a way to organize the geology into several stratigraphic zones, (i.e. above target, below target, etc.). Once the existing wellbore is reworked and organized, the geologic data can be plotted aerially (Fig. 1). When considering the crossing point of the new wellbore, having a clear view of the existing wellbore geologically can influence the exact placement of the proposed wellbore. Sacrificing the wellbore conditions for the sake of wellbore placement should be weighed and mitigated if possible.
ANTI-COLLISION BEST PRACTICES DEVELOPED FOR HORIZONTAL DRILLING ACROSS PRE-EXISTING HORIZONTAL WELLBORES CONT’D

Incorporating a regional structure map utilizing the breadth of surrounding offset wells will benefit the geologic planning. Additional reinterpretation of profiles highlight the surrounding structure and expected apparent dips. Once all these pieces have been compiled, the framework for planning the geologic zones is in place.

Drilling Considerations and Planning

To appropriately develop a drilling plan assessing the drilling considerations and limitations, a proactive and systematic risk management assessment is required. To create a risk management assessment, current industry conservative well-collision avoidance practices and hazard identification combined with standard project management risk practices were used (Talib 2015, Poedjono et al. 2007, Poedjono et al. 2009, Sharma et al. 2009).

To develop the understanding of the potential risks for an aggressive anti-collision project, a risk matrix is used to develop a risk level chart by assessing the associated operational risks of anti-collision considering the probability or likelihood of an event compared to the event impact or severity, as shown in Fig. 2 below. The “events” used for assessment were the current standard drilling collision indicators commonly used in conservative well-avoidance practices to signal proximity to an offset wellbore. These indicators include indications of depleted zones such as loss in circulation, drop in WOB, increase in ROP, and/or erratic torque, additional geologic indications of proximity including changes in oil or gas shows, and operational indications of proximity including MWD azimuthal error readings, changes in the mud chemistry, and in instances of collision, even metal shavings (Petrowiki, Poedjono et al. 2007, Poedjono et al. 2009, Sharma et al. 2009).

In standard project management practices, once a risk matrix assessment is identified, a risk management process can be created. However, in anti-collision planning the risk matrix assessment and the subsequent plan were limited since they are highly dependent upon the wellbore placement, which contained two significant potential hazards: survey technology errors, and the associated “ellipse of uncertainty.” In order to create a methodology that encompassed the risk and drilling considerations, the survey error and ellipse considerations needed to be assessed.

Historically, MWD technology was considered less accurate and precise than the gyro technology counterpart for wellbore surveys. Advancements in technology have continued to improve survey quality for both gyro and MWD technologies. Conservative anti-collision practices commonly suggest or require gyro surveys to reduce the “directional uncertainties” of conventional MWD system (Poedjono et al. 2007, Poedjono et al. 2009, Sharma et al. 2009). Previous internal analysis across the Williston Basin of MWD surveys compared to gyro surveys at curve landing consistently showed differences between the survey technologies of one-hundredths of a degree of difference; deeming the difference negligible and allowing risk of the probability of collision due to survey error to be diminished in the risk matrix. The other potential hazard of the wellbore placement is based on concept of the “ellipse of uncertainty”. The “ellipse of uncertainty” is the concept that at any point in a wellbore the actual location of the wellbore could be anywhere within an ellipsoid “given by the variations of variables of inclination, azimuth, and measured depth,” as illustrated in Fig. 3 (Netwas Oil Group 2017).

Conservatively the ellipse is often determined from the surface point, expanding in volume as the wellbore deepens. With the increased confidence in the MWD survey data accuracy at curve landing point, for the purpose of our methodology, we adjusted the ellipse to start from curve landing point rather than surface, significantly decreasing the size of the ellipse in the horizontal portion of the wellbore. Then incorporating the geologic considerations including the expected regional geologic structure and the expected apparent dips with the distinct stratigraphic markers, we determined the gamma ray signature could be used as a confirmation of the stratigraphic placement in the “Y” or TVD direction. Allowing us to adjust the “ellipse of uncertainty” view towards a “plane of uncertainty” view, conceptualizing that the ellipse does not expand in the “Y” direction as the wellbore deepens.

Diminishing the effects of survey error and negating the expansion of the ellipse allowed the limitations of the wellbore placement in the risk matrix to be better quantified, simplifying the risk management assessment. While the geologic data does not necessarily improve the absolute location of the wellbores, it does improve the accuracy for the relative location of the wellbores. Using the geologic data helps greatly reduces the overall directional uncertainty for anti-collision planning allowing for further mitigation of risk and simplification of the subsequent risk management plan. This combination of the drilling and geologic considerations coupled with the simplified risk management assessment help create an aggressive yet encompassing anti-collision methodology dubbed the “Stoplight Method.”
ANTI-COLLISION BEST PRACTICES DEVELOPED FOR HORIZONTAL DRILLING ACROSS PRE-EXISTING HORIZONTAL WELLBORES CONT’D

Stoplight Method

The Stoplight Method is an incorporation of the directional and geologic planning considerations, the operational requirements, zonal determination, communication protocols, and risk management practices. This Method combines all these anti-collision considerations reducing them into clear instructions and visuals. The Stoplight Method creates a visual representation by tiering target zones to associated colors green, yellow, orange, and red. The zones colors are defined by the risk matrix and each zone contains specific operational requirements, geologic requirements, and communication protocols. These considerations and protocols include depth requirements (TVD and MD), survey requirements, drilling parameter adjustments, targets shifts, communication workflow with alert requirements.

The zones are defined in overlapping, stair-stepping geologic target windows for specific predefined intervals, essentially sectioning the wellbore into the “Stoplight” [as seen in Fig. 4]. The zones are defined using the risk matrix and the potential collision indicators. The right figure illustrates a cross-section of the Stoplight Method’s geologic overlapping target windows for each zone while the left figure is an aerial representation of the zones implemented across the planned wellbore.

The method applies these tiered zones to the risk management plan each with specific survey requirements, drilling parameter adjustments, targets shifts, and communication workflows.

Below briefly summarizes these shifting requirements by zone.

Green: No/Low Risk
- Standard operating practices. Use this zone to understand wellbore parameters and geologic signatures.
- No additional communication workflows outside of standard practices required.

Yellow: Low Risk
- Begin adjusting standard operations practices within this section towards the medium risk parameters allowing for operations to adapt to the changing parameters including directional steering towards the high risk geologic window.
- No additional communication workflows outside of standard practices required.

Orange: Medium Risk
- Medium risk parameters include small limitations in ROP, increased survey frequency for better geologic placement accuracy, and directional steering towards the high risk geologic window. Additional communication workflows outside of standard practices required. Communication workflow should outline communication requirements for any anti-collision indications and risk assessment events.

Red: High Risk
- High risk parameters include limiting ROP to sub 50 feet per hour to allow for wellbore adjustments and risk monitoring protocols, increased survey frequency for better geologic placement accuracy, and a tightened geologic window.

Heightened communication protocols. Communication workflow should outline communication requirements for any anti-collision indications and risk assessment events. If any indicators are encountered, stop operations; operations should only resume with both geology and drilling review and approval.

These zones become the risk management plan each with their distinctive mitigation requirements based on the adjusted risk matrix. To help further diminish wellbore placement concerns due to the potential for minimal survey error or offset wellbore magnetic inference concerns not previously mitigated, in all zones, real time survey monitoring with magnetic interference correction is used to diminish the negative effects of any near-wellbore interferences.

Case Studies

The “Stoplight Method” was designed and implemented in three case studies drilled in 2015 through 2017 designated DSU A, DSU B, and DSU C. Each case study provided unique challenges including geologic properties, operational conditions, offset wellbore considerations, geographic locality, etc. Fig. 5, below, shows the aerial view of all three case studies including pre-existing wellbores.

The orientation of the case study wellbores were all drilled in the North-South direction compared to the pre-existing wellbores which were drilled in an array of designs. DSU A was a Three Forks wellbore, containing a singular pre-existing wellbore with operations successfully drilling the horizontal well as close as 29 feet over the existing wellbore. DSU B was a Middle Bakken wellbore, containing three preexisting wellbores with operations successfully drilling the horizontal well as close as 8 feet under the existing wellbores. DSU C was a Middle Bakken wellbore, containing a pre-existing multilateral with three wellbores with operations successfully drilling the horizontal well as close as 13 feet under the existing wellbores.
The “Stoplight Method” is an effective anti-collision practice because it simplifies complex hazards and stringent operational requirements into an easily understandable system. By coding to known color representations (green = go, red = stop) it illustrates the risk management system into a recognizable system regardless of the experience of the personnel. Furthermore, the Method is adaptive to changing operational conditions allowing for fluid adjustments between zones as operations progress, simply by shifting the zone lengths as necessary.

While this methodology was successfully used in three case studies, it is up to the individual company to weigh the risks of each prospect before proceeding with an anti-collision program across pre-existing lateral wells. Lack of distinguishing data, sparse or poor quality data, or any other unknown geologic considerations, an aggressive anti-collision program may not be a logical path.

In areas where an aggressive anti-collision program is feasible, due to its basic structure and broad framework the “Stoplight Method” can be applied to a variety of reservoirs. Opening new opportunities to access additional resources previously considered unrecoverable due to pre-existing wellbores.

Conclusion

In the Williston Basin alone, there has been a significant increase in anti-collision practices for drilling horizontal wellbores across pre-existing horizontal wellbores since 2010. The percent of anti-collision wells drilled from 2010 (<0.1%) has drastically increased in the recent years (2016 had 4.25%). Indicating the progression from standard exploration practices towards infill drilling with increasingly complex wellbore trajectories with collision concerns. To effectively develop these increasingly complex wellbores, the industry needs to advance the current ultra-conservative collision avoidance practices and develop anticollision programs for drilling across pre-existing horizontal wellbores.

An aggressive anti-collision program requires a highly collaborative effort between disciplines integrating the considerations and risks of each discipline. This combination of the drilling and geologic considerations helps reduce the overall directional uncertainty for the anti-collision planning allowing operations to drill a wellbore considerably closer than standard ultra-conservative collision avoidance practices. Furthermore, it is this combination coupled with the adjusted risk matrix and the simplified risk management plan that helped create the aggressive anti-collision methodology dubbed the “Stoplight Method.”

Nomenclature

MWD = measurement while drilling TVD = true vertical depth MD = measured depth ROP = rate of penetration WOB = weight on bit DSU = drill spacing unit
There is a lot of caution out there with respect to delivering returns. Companies are trying to return capital to investors even if it means tamping down production growth. These days if E&P executives mention revising their budgets above prior guidance, they must run for cover to escape a barrage of negative investor sentiment.

“I see a virtual spiral of positive effects as you become more thoughtful on what you drill and as you become more consistent, that causes investors to lean in more. It creates a higher-quality set of assets,” said Luis Rodriguez, CEO of Denver-based Raisa Energy LLC.

“To me, where my mind goes when you ask about challenges is that there is the potential for a recession and thus, weakening demand, compounded by easing of the pipeline situation in the Permian, which will then increase U.S. oil production and drive down the oil price—which is why we hedge,” said Rodriguez. He is echoing the cause and effect cycle cited by many of the people we spoke to. His EnCap Investments-backed company buys minerals and royalties.

Rodriguez said the disruption of the MLP buyer universe has left a void in the market where lower-risk, mature assets can’t be connected with investors as easily as before, but he thinks this could begin to change in 2019 if investors who are tolerant of higher risk start to own these mature assets again. “Some flavor of yield-seeking funds will be created,” he told us.

On the bright side, ever-improving horizontal drilling and completions, plus the ability to move water more efficiently, are creating better economics everywhere, said Allen Gilmer, Drillinginfo Inc. CEO. Identifying any one play as standing out above the others is not as true now as it used to be, he told us. Gilmer thinks more of the large unconventional players could go back into conventional plays to take advantage of these technical advances.

Observers said private-equity players will have to hold onto their assets for a longer period and so, their portfolio companies are moving into full-field development or manufacturing mode, with consolidation among them the next wave. Indeed, everyone we spoke with mentioned corporate mergers being a strong possi-
CRystal Ball for 2019 Cont’d

bility through 2019. The scale and capital required to
do efficient cube development to maximize produc-
tion out of a drilling spacing unit is too great for the
small or medium-size operator. Boards cannot sup-
port a small-cap tying up millions of dollars to drill
a four-well pad and wait nine months to turn
it to sales.

“Unconventional plays really have made it matter
that you know what you’re doing. The technical staff
of a company has never been more of a value builder
or a value destroyer,” Gilmer said. “It’s still
very company-specific and whether you can box
above your weight.”

As we watch OPEC’s moves in the coming days, we
take to heart Gilmer’s advice: “Keep doing what
you’re doing. If you think about it, the oil and gas in-
dustry has given air cover to these U.S. industrialists
who decided not to attend the [recent Saudi investor
summit in Riyadh]. American fracking has allowed us
to say to OPEC and Saudi Arabia, ‘We’re not going to
support that.’”

GEO’S Mudmen’s Corner
Pore-Plugging Tester (PPT)

GEO Drilling Fluids, Inc. can provide data regarding the effectiveness of drilling fluids
and its components to form a semi permeable barrier beneficial in the protection
sensitive zones and/or formation. LCM size and quantities can also be
evaluated across known pore throat
sizes as to determine the most
effective type and amount. This enable GEO’s customers to select
the best products for their specific
formations and zones that require
Well Bore Strengthening and Lost
Circulation management.

The Permeability Plugging Tester
[PPT] is a modification of the stan-
dard 500-mL HTHP Filter press. It
may be used in the field or in a labo-
atory environment. The instrument
is useful for performing filtration
tests on plugging materials without
the interference of particles settling
on the filter medium during the heat
up process. The PPT is very useful
in predicting how a drilling fluid can
form a low permeable filter cake to
seal off depleted, under pressured
intervals and help prevent differ-
tential sticking. Typical differential
pressures are much higher than
those seen in standard
HTHP testing.

The pressure cell is similar to those
seen in standard HTHP filtration testing, but it is inverted with the filter medium and
the back-pressure receiver on top of the assembly. The conventional cell may be
operated to 2,000 PSI by using hardened steel set screws to secure the cell cap.
For elevated pressure, OFITE has designed a special cell with a working pressure of
up to 4,000 PSI, pressurized with the conventional hydraulic pump. The cell is pres-
surized with hydraulic oil and a floating piston separates the oil from the test fluid
within the cell.
Other publicly traded E&Ps, such as Anadarko Petroleum Corp. (NYSE: APC), Chesapeake Energy Corp. (NYSE: CHK) and Devon Energy Corp. (NYSE: DVN), have also planned or set in motion activity increases. Anadarko, for example, has boosted its already large acreage position, while Chesapeake has raised its operated rig count from four to five rigs and indicated it may add another rig next year. Devon is planning to double its rig count from two to up to four rigs.

Private E&Ps have long been major players in the PRB, and they, too, are in the forefront of the many new developments taking place in the basin. Anschutz Exploration Corp. plans large-scale development of at least three zones: the Turner and two targets in the upper Niobrara.

**PRB NRI**

Anschutz Exploration president Joe DeDominic offered a “very positive” outlook for the PRB, where recent successes included wells in the Turner Formation and the Niobrara.

“This is an outstanding basin in which to own and operate assets,” said DeDominic. “While it’s still relatively early in the horizontal development of all these plays in the Powder, it’s all very positive. Well results are exceptional, given we’re generally still at Generation 1 or 2, at most. It’s oil, not gas, so the economics are orders of magnitude better. We’re seeing multiple, stacked, economic horizons, with as many as six targets that can be drilled horizontally within the same drilling spacing unit [DSU]. “The land situation is very favorable,” he continued. “Our net revenue interest [NRI] on average ranges from 82% to 85% vs. an average of 75% or maybe less in the Permian. That difference of 10 percentage points is a lot from an economic standpoint. The midstream piece, as it stands today, is also favorable. And we’re in discussions with a number of midstream companies to stay ahead of our needs.”

DeDominic pointed to several factors that were also helping to accelerate activity in the PRB. One is a much improved federal permitting process, which no longer takes six or more months to procure a permit. A second is that the PRB has been catching up on its use of completion technologies commonly used in other basins, which is resulting in higher performing wells.

Contrasting the PRB with the Permian Basin, DeDominic noted Permian leases have shorter primary terms than federal leases and include, in some cases, Pugh clauses as well as continuous drilling obligations. “E&Ps in the Permian can’t wait; they’ve got to be out there drilling to preserve their acreage,” he said. By contrast, 10-year terms built into federal leases afford a “more moderate” pace, reducing the speed of development.

As a result, operators in the PRB in the past have had time to “be deliberate about where they are putting their investment dollars,” according to the Anschutz Exploration president. And that’s a prudent approach, given the great many horizons—a dozen or more—to choose from in the basin. The stacked pay ranges “from the Teapot all the way down to the Tensleep,” he noted.
Niobrara And Mowry Are Pervasive

Likewise, while testing has historically been less frequent in the Niobrara and the Mowry, both zones are believed to represent a huge footprint as source rocks for many of the basin's stacked pays.

“The Niobrara and the Mowry are pervasive across the basin. They are the two sources for the bulk of the hydrocarbon in the basin," said DeDominic. "The two are currently in the oil generation window, that is, deep enough and at a high enough temperature so the kerogen in the rock is converting to oil. If you can make these targets work with modern technology, the area to be developed in the Powder River is massive.”

As an example, the Anschutz Exploration president pointed to Chesapeake’s Barton pad, some 24 miles to the east of the Niobrara wells drilled on the Meatloaf pad. The Chesapeake well, targeting the lower portion of the upper Niobrara, had an IP-30 of 1,299 boe/d. The EUR ascribed to the well is put at 900,000 to one million boe (76% oil).

“You’ll see us and other operators testing these zones, and doing spacing tests, to demonstrate the lateral extent and the repeatability of the play. The individual well economics, coupled with the resource potential indicated by our technical work, should, in turn, attract additional capital investment,” said DeDominic. In the fourth quarter of 2018 and the first quarter of 2019, Anschutz has a mix of about eight Niobrara and/or Mowry wells lined up for drilling, he added.

Is it time for full-field development?

Confidence Is High In Economics

“We’re at that point now,” said DeDominic. “The confidence in the EURs and the economics are high, and we’re at the stage where we need to move forward. If you continue drilling standalone wells, there is a downside risk in terms of under-developing the asset, because it’s not efficient or effective to go back and infill the acreage due to parent/child pressure depletion. And if you wait a couple of years for further study, you end up pushing out and reducing the present value of the asset.”

Covering an area that measures 12 by 8 miles, Anschutz Exploration’s initial plan in its Converse County development is currently to have a combination of four wells targeting the Turner and 16 wells targeting the Niobrara per 1,280-acre DSU [a total of 20 wells off two pads per DSU]. The Niobrara wells will be completed in two of a possible four zones, depending on the area.

Anschutz Exploration estimates it has more than 1,000 net core locations targeting Turner, Niobrara and Mowry zones on its acreage in Converse and southern Campbell counties alone.

Anschutz Exploration has indicated that, at a current well cost of $8.5 million [including hookup, facilities and, later, artificial lift], a Turner well can create a PV-10 value [present value discounted at 10%] of a little more than 2.5 times its cost, assuming West Texas Intermediate at $55/bbl and natural gas at $3. DeDominic expects these well costs to come down as full-scale development takes off, narrowing the gap with EOG’s cost structure.
PIVOT IN THE POWDER CONT’D

Takeaway Issues
In terms of takeaway, all of the Anschutz Exploration wells completed as producers in 2017 to 2018 have been hooked up to pipelines, both oil and gas, in as little as three days, according to DeDominic. A scarcity of takeaway is “a common misconception,” he said. “We’re not too far from existing infrastructure. And our strategy is to be ahead of the game in terms of facilities, electrification and having the pipelines ready to go.”

Last August, Anschutz Exploration offered various growth forecasts, depending on the future number of rigs it employs, and assuming a “single-zone” scenario based on developing just the Turner Formation. The net production estimates related to only the southern portion of the basin and excluded nonoperated activity. From a recent base of 4,600 boe/d, net production would reach 12,000 to 15,000 boe/d in the first quarter of 2019, assuming a two-rig program in the second half of 2018 (for 1.5 average rigs in 2018). As the rig count is raised to an average of 2.5 rigs in 2019 and four rigs in 2020, net production would grow to roughly 70,000 boe/d, on average, in 2022. A six-rig program could boost output to as high as 100,000 boe/d over the same timeframe, added DeDominic.

Based on the 12,000 to 15,000 boe/d estimate for early next year, Anschutz Exploration would be generating free cash flow in the second quarter of 2019, according to the forecast.

A lot can happen between now and 2022, but what’s the confidence level about early 2019 output? “We’re right on schedule to meet that forecast,” said DeDominic.

A New PRB Record
Wold Energy Partners has been operating in the PRB for decades, and its long legacy helped form the foundations for a firm that can now boast of having some of the “most flexible assets in the basin,” according to CFO Court Wold. The assets are proving their worth, delivering a Frontier/Turner producer recently that had an IP-30 of more than 4,800 boe/d, a new record for the PRB.

Wold Energy was established in Casper in the 1940s and is run by CEO Jack Wold. At one time involved in a diversified minerals and energy platform, today the company’s focus is virtually 100% as a PRB oil and gas operator. With headquarters now in Denver, the firm has a blend of characteristics: family legacy, nimble, quick adopter and well-capitalized, with institutional partners that include NGP.

The company undertook a strategic review of Rockies basins in 2012 to 2014 and decided to “make a shift to become a pure-play operator in the Powder,” recalled CFO Court Wold. “We have a very different business model now. We had to adapt, and our nimbleness enabled us to compete in a capital-intensive industry with the complexity of unconventional operations.”

Simultaneously, Wold did an appraisal of its legacy PRB assets, studying the rock from a technical perspective in light of results attained by other players in the basin, he added. From the study, it drew an outline of an area it defined as its “Tier 1 focus area,” and then began a process of consolidating its acreage position from what was a “scattered legacy footprint” previously.

“We recognized the resource potential in Converse County,” said Jack Wold. “We went through a multistep approach to selectively divest noncore assets in order to re-invest in the heart of the basin during the downturn. We’re now 100% focused on oil and gas in this southern part of the Powder River, which is now showcasing its huge potential, particularly with new technology.”

Approximately 200 Transactions
The consolidation process, through a series of swaps and acquisitions, involved roughly 200 transactions during five years, in an effort to expand the scale of its operations, according to Jarred Kubat, Wold’s vice president of land, legal and regulatory. Wold now holds 145,000 largely contiguous net acres, predominately in Converse County, southwest Campbell County and southeast Johnson County. The effort has apparently paid off. Many of the 20-plus rigs operating in the PRB have migrated to the Converse-Campbell border area, what he calls “the heart of our acreage position.” The firm has received “more nonop proposals today than we’ve ever had in the past,” according to Court Wold. “And we look forward to participating in those programs with our neighbors and partners.”

In terms of permitting efforts, Wold ranks as the largest holder of state permits among private E&Ps in the PRB. From the outset, according to Kubat, its permits “have been set up in anticipation of pad development. In addition, they’ve been set up for ‘cube development,’ because we understood that’s how the resource is ultimately going to be most efficiently recovered.”

Far from being content to collect permits, Wold has recently been “involved in a substantial drilling program, and we’ve have had some tremendous success there,” he continued. “Those permitting efforts have set up optionality from the standpoint of choice of formation. At this point, we likely have the most flexible asset in the basin, with an ability to accommodate drilling year-round.”
PIVOT IN THE POWDER CONT’D

A Shift To Pad Development
As it moved into pad development, Wold looks to have set a new record for the basin with a 30-day IP of 4,811 boe/d by a well on its Tuesday Draw pad in Converse County. The well, one of a five-well program focused mainly on the Frontier/Turner, had an IP-30 production average of 2,717 bbl/d, 771 bbl/d of NGL and 6.2 MMcf/d. First production was in mid-June and, after 60 days, was still flowing more than 2,000 bbl/d of crude oil (42 API).

“It’s a very exciting well,” said Jack Wold. “It can compete with anything in the country right now, and we have a sizeable queue of similar locations to tackle as we shift to pad development.”

Remarkably, on the same Tuesday Draw pad, Wold previously completed a well with “excellent results” from the shallower Shannon Formation. The well had cumulative production of about 190,000 bbl of oil during a period of 18 months.

How are Wold’s plans for full-scale development progressing?
“So far, our permitting plans call for four wells in each of the horizons: Sussex/Shannon; Frontier/Turner; Niobrara; and Mowry,” said Jake Phipps, Wold’s operations manager. “We’ve seen others go up to 16 wells in the Niobrara and Mowry in a two-square-mile area. We’re excited to see that level of development.”

According to Phipps, most key factors are falling into place in the PRB. “The momentum is swinging in our favor, with now over 20 drilling rigs in the basin and the midstream companies coming in,” said Phipps. “We’re seeing more and more oilfield service companies moving into the area, as well as infrastructure for sourcing water and frac sand. These and other factors are driving costs down and efficiencies up. With the increase in EURs at the same time, it’s really an exciting time for this basin.”

Portfolio Of Premium Locations
EOG has yet to unveil some of the exact details of its development plan for the PRB, but the company is clearly preparing to shift to a higher gear in terms of its level of activity in the basin. And with a net resource potential estimated at 2.1 Bboe, the PRB “is poised to become a major asset in EOG’s diverse portfolio of premium plays,” the company said in second-quarter earnings release.

Like others, EOG had previously focused on established targets, such as the Turner, where it counted some 120 premium locations. But with its second-quarter earnings, EOG expanded its premium inventory by upgrading to premium status both the Niobrara and Mowry. This added 555 and 875 locations, respectively, to its premium inventory. In addition, the Turner inventory rose to 200.

In total, EOG said its 2.1 Bboe resource potential in the PRB was comprised of 1,845 net locations with an average 70% working interest and 58% NRI. The company had operatorship of 85% of its “core premium” acreage, it added, and recent trades consolidated an additional 90,000 net acres. Running an average of two rigs, EOG aimed to complete 45 net wells in 2018, up from 39 last year.

Picking Up The Pace
At its current pace, the premium inventory represents more than 30 years of drilling, but EOG plans to pick up the pace in the not-too-distant future.

“As far as the Mowry and the Niobrara go, we’ll be increasing activity in 2019 on those plays,” said David Trice, EOG’s vice president of exploration and production, on the company’s call. “The volume impact of those will be more likely weighted to late 2019 and into 2020, as we build out our infrastructure.”

To date, EOG has drilled nine Niobrara wells and nine Mowry wells since it began targeting the two source rocks in 2008 to 2009. With proprietary cores coupled with public data, the company has built full petrophysical models, which has allowed it to identify the best targets and assist it with its completions. This has been “really critical to the success of the plays,” according to Trice.

In addition, bringing down well costs has played a major role in improving the economics of the PRB. For example, 2-mile Turner wells are “routinely” drilled in six to seven days, and up to 10 stages per day are completed in the company’s zipper frack operations, noted Trice. “We’re a lot better at executing in the PRB,” he said, citing improved drilling and completion, facility and lease operating costs.

“Sustainable cost reductions and shorter cycle times, driven by efficiencies, were a big contributor to adding these two shale plays to our PRB premium inventory,” observed EOG’s CEO, Bill Thomas.

Overlap means less surface disturbance
As shale resource plays, the Niobrara and Mowry offer great potential for efficiencies in the future, according to Thomas. Tight downspacing is a “great fit” for drilling large packages, using multiwell pads, long laterals and zipper fracks. Moreover, since the two plays overlap on “much” of the EOG acreage, they can be co-developed, resulting in less surface disturbance and a reduced environmental footprint.
Recognizing that the degree of overlap is not perfect, EOG’s acreage position in the Niobrara is not as big as its Mowry footprint. Close to 100% of the Niobrara is expected to be co-developed with the Mowry, according to Trice. And viewed from the opposite direction, about 60% to 65% of the Mowry is likely to be co-developed with the Niobrara, he added.

EOG has roughly 140,000 net acres prospective for the Mowry. Assuming 880 total net locations, at 660-foot spacing, this translates into an estimated resource potential net to EOG of 1.23 MMboe, based on a gross EUR per well of 1.7 MMboe [net after royalty equals 1.4 MMboe]. Well costs are put at $6.1 million for a 9,500-foot lateral well. The 30-day IP of two recent wells averaged 2,190 boe/d.

About 90,000 net acres held by EOG are deemed prospective for the Niobrara. Assuming 560 total net locations, at 660-foot spacing, this translates into an estimated resource potential of 640 MMboe, based on a gross EUR per well of 1.4 MMBboe [NAR equals 1.15 MMBboe]. Well costs are put at $5.9 million for a 9,500-foot lateral well. EOG cited a 30-day IP of 2,090 boe/d for the Ballista 213-1301H.

The Turner differs from the two shales in needing wider spacing, at 1,700 feet, resulting in 405 total net locations on its almost 170,000 prospective net acres. This translates into an estimated resource potential of 200 MMboe, based on a gross EUR per well of 730,000 boe [NAR equals 500,000 boe]. Well costs are lower than in the resource plays, at $4.5 million for an 8,000-foot lateral well.

Hydrocarbon Mix
A notable variable is the hydrocarbon mix produced by each formation. The Mowry has a higher natural gas component, given a EUR split of 28% oil, 47% gas and 25% NGL. This compares to an EUR split of 48% oil, 36% gas and 16% NGL for the Niobrara and 46% oil, 39% gas 15% NGL for the Turner. The oil cuts in the Mowry are quite variable, according to Trice, ranging from 20% to 60%, depending on location. Setting aside mix issues, productivity is undoubtedly strong. EOG said its average IP-30 from two Mowry wells, at 2,190 boe/d, included 5.6 MMcf/d of gas. One of the two wells was the Ballista 204-1102H. An earlier well, the Ballista 213-1301H, producing from the Niobrara, had cumulative output of 225,000 bbl of crude and more than 1 Bcf of gas since coming online in June of 2016.

With its acreage in close proximity to EOG, Navigation Powder River LLC got off to a “great start” with its first two wells in the basin targeting the Turner Formation, and president Fred Miller sees a marked change in the PRB as industry exploration efforts transition to major development programs.

“The Powder used to always be someone’s back yard,” recalled Miller. But with the industry delivering “very good well economics that are not constrained by midstream,” the basin has given “birth to a new concept development. The way I see the Powder now is it’s the Permian without pipeline constraints.”

The Navigation team is a relative newcomer to the PRB, but not to the Rockies. After a few years of working on tight gas at Devon Energy, Miller moved to Carrizo Oil and Gas Inc. (NASDAQ: CRZO) and oversaw the development of more than 100 horizontal wells in the Denver-Julesburg Basin. Miller remembers drilling the first Niobrara well in November, 2010, fracking it, and “having oil in the tanks by Christmas.”

After co-founding Navigation in 2015, and raising funding during the downturn, there was “ample time” to pore over public data and other sources on the PRB, according to Miller. “We studied over 240 Turner wells in the basin before putting any money in the ground. We spent, literally, months just toiling through that data, and the data shed a whole new light on the reservoir.”

Earlier this year, Navigation, backed by private-equity sponsor Juniper Capital Advisors, announced results from its first two wells. The first, Adam Federal 35-43-73-2H, had a 30-day IP of 988 boe/d (88% oil), or 241 boe/d per 1,000 feet of lateral. The second well, Lucian Federal 3-42-73-3H, had a 30-day IP of 1,210 boe/d (86% oil), or 275 boe/d per 1,000 feet of lateral.

Accessing Laminations
Navigation had developed a new perspective on its Turner well completions as it relates to laminations, according to Miller. Whereas other E&Ps tended to bypass them, “we definitely are accessing the laminations that exist in the reservoir,” he said. “It’s like having another reservoir.”

To explain, Miller gave the example of a Turner section that might be 200 feet thick, of which 40 feet at the top might be comprised of a “clean, blocky section,” followed by a series of laminated sections. If even only half of the remaining 160 feet was made up of good sand pay, “you’re getting almost triple the access” to reservoir rock compared to prior E&P actions.

“The Powder used to always be someone’s back yard,” recalled Miller. But with the industry delivering “very good well economics that are not constrained by midstream,” the basin has given “birth to a new concept development. The way I see the Powder now is it’s the Permian without pipeline constraints.”
To illustrate, Navigation’s first well was drilled on a five-well per section spacing pattern, with an offsetting EOG well that had produced from the Turner for the last 2.5 years, he recalled. “It was about 900 feet away, and we saw no indications we were fracking into something that was depleted. As we brought our well on, it’s been fantastic; it’s on track to become a top percentile well in the basin.”

This makes an argument for further downspacing in certain areas of the Turner. “Operators have been sitting on the fence in terms of how to proceed with developing the Turner,” said Miller. “At first, it was two wells per section in the Turner, now it’s moved up to three to four, and with our most recent well we believe there’s clear-cut evidence it’s at least five or six wells in certain areas.”

For the balance of the year, Navigation has plans for three more Turner wells and two Niobrara wells. In one area, it sees both an A and a B bench in the Turner. In one of the benches, it expects to place four wells, with two or three wells in the other bench, depending on “how well the formation takes the frack.” In the Niobrara, it is targeting the B bench.

The Niobrara comprises “a giant swath of reservoir that’s over the majority of the Powder,” said Miller. “We’re extremely excited that we have some acreage near a couple of the hotspots,” he added. “And we have acreage that is on trend with one of the better Niobrara wells, namely the Ballista 213-1301H. PRB is ‘Growth Engine’

Described as its “growth engine,” the PRB is expected to drive a doubling of Chesapeake’s oil production next year from year-end 2018 levels. And as the company weighs the varied options offered by its “hotspot advantage” in Converse County, its focus is for now firmly on the Turner, where it can break even (minimum 10% return) at $25/bbl and $2.75/Mcf, according to the company.

“Right now, the Turner wells trump most other options we have in the PRB from a capital allocation perspective,” said Tim Beard, vice president, Rockies Division. “The Turner is taking the money because the well economics are so good, so prolific.”

In July, Chesapeake added a fifth rig to the Turner program. As of mid-August, Chesapeake had drilled some 24 wells in the Turner Formation, and a forecast accompanying its second-quarter results called for some 43 Turner wells to be drilled in 2018. Cycle times have improved, noted Beard, with three recent wells drilled in less than 20 days apiece vs. more than 50 days for the first Turner well. Well costs were about $8- to $8.5 million, with a line-of-sight to sub-$7 million soon, according to Beard.

Chesapeake has indicated it may add a sixth rig next year, although exact timing is uncertain, and it may be used to appraise additional targets, said Beard. Away from the Turner, the main targets to be developed in 2019 are the Niobrara and the Parkman. The latter wells are “shallow, cheaper and have high oil cuts,” noted Michelle Hileman, geoscience manager of the Rockies division.

Chesapeake’s formula for Niobrara wells has moved to longer laterals, markedly more well stimulation and wider spacing (from 660 feet to about 1,100 to 1,300 feet). Following its success with its Barton well, stimulated with about 2,000 pounds per foot of proppant, Chesapeake tested three drilled but uncompleted wells with completions of about 2,000, 3,300 and 4,000 pounds per foot with encouraging results.

Beard indicated Chesapeake is happy to proceed in stages in developing its PRB assets over time.

Making ‘Multiple Passes’

While some E&Ps are drilling Turner wells at spacing of four wells per section, said Beard, “our thoughts are two to three Turner wells per section. Right now, we’re drilling them at two wells per section, moving to three wells per section at most.” Likewise, when it comes to developing the Niobrara, Chesapeake is contemplating undershooting peers at “four to five wells per section.”

“We’re going to be making multiple passes,” observed Hileman. “As we build our pad and facilities, we’re planning for success in the other stacked formations. After the initial pass in the Turner, we’ll return to drill additional formations, assuming commodity prices are right. And we’ll continue that process over and over again.”

As for possible interference, “from the Turner to the Niobrara, you’re talking about close to 500 feet of section between them,” she said. “Interference is not an issue.” And when potential synergies arise, they can be captured if they make sense, said Beard, recalling an instance when Chesapeake drilled Parkman and Turner wells off the same pad. “When we drilled our first Turner well, the Sundquist Flats, we drilled a Parkman well off the same pad. And we’ve done similar tests in the Sussex and Niobrara,” he added.
PIVOT IN THE POWDER CONT’D

Another E&P that’s adding rigs is Devon Energy. The company indicated on its second-quarter earnings call that it has plans to pick up a third rig later this year and is likely to add a fourth rig sometime in 2019.

Looking ahead, Devon Energy’s capex plans in the PRB will be focused primarily on the Turner and Niobrara, supplemented by the Parkman, Teapot and other possible zones. In its Super Mario area, the company brought online two Turner wells, with an average IP-30 of 1,450 boe/d (75% oil). In the same area, it said its initial two Niobrara wells were still flowing back.

“We’re starting to define what the development plan will look like. We’re also having some positive results in the Niobrara,” said Devon Energy’s CEO, Tony Vaughn. “In 2019, we expect to be in full development there, with increased activity beyond that. Everything that we’re seeing in the Powder is developing just to plan.”

With the energy sector ramping up its development plans, how big could activity grow in the near term? One sign of the rate of growth may be judged by the course of an Environmental Impact Statement (EIS) for the Converse County area. Unofficially started in 2014, the EIS was backed by five public E&Ps and included plans for 1,500 wells. However, not surprisingly, the EIS lapsed during the downturn. Early this year, an outline of the now revived EIS was released, and the EIS now calls for as many as 5,000 wells—in just a portion of the PRB.

GEO PRODUCT INTRODUCTION KLAYCON CONT’D

There are several questions about any new mud systems that an operator might ask before he is willing to try it.

1. Will it work to drill the kind of well I am planning? In preparing a mud program for each new drilling project, GEO technicians and administration experts evaluate the potential drilling problems and cost effectiveness of various mud systems before making recommendations. In many cases KlayCon is recommended. Recaps and well histories of relevant wells are then included in the proposal to substantiate the program recommendations.

2. Will it provide a corrosion or safety concern to the rig, tubular goods, pumps, or crews? Is the mud system hazardous or are any of the components hazardous? KlayCon is not a strong acid. In fact, the following chart shows just how the mildly acidic the 6-7 pH of KlayCon is when compared to some common fluids.

<table>
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<tr>
<th>Liquid</th>
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<tr>
<td>Milk</td>
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The pH is maintained at a slightly acidic to neutral level with the addition of various acids into the mud system. While many products are available for this purpose, GEO primarily uses Citric Acid. This is fairly weak organic acid, which coincidentally acts as a mud thinner as well as imparting the particular inhibition of KlayCon.

The other acid most commonly used is Phosphoric Acid. Utilizing a small injection pump to control the rate of addition minimizes handling of Phosphoric Acid. Phosphoric Acid comes in a variety of strengths from 25-40% solution. The stronger the solution of acid is, the more hazardous. While none of it is especially hazardous, it does require additional Personal Protective Equipment (PPE).

3. How does it work? Can you explain the chemistry and/or physics that make this mud system better than the alternatives? Initially we ran this mud system without an exact understanding of how it worked. There were some vague theories about Hydrogen acting as an inhibitor, but the problem with that is that Hydrogen is a tiny, weak Cation, much weaker than Sodium and therefore unable to reduce the amount of water a clay platelet would absorb. Hydrogen bonding, however, is a significant force in polymer chains, polymer bonding, surfactant, and other processes at work in the mud system.

We were able to identify a significant difference between the pH of the filtrate and the pH of the mud. Lab experiments with various clays indicate that the hydrogen ions are associating with the clays. Solid particles have what is called Zeta Potential. This is the ability of a particle to hold a film of water only a few molecules thick. As we know, it takes water to wet Barite. This water remains with the Barite particle and is not free to move about and act as a thinning agent. Barite is basically inert and has a very small Zeta potential. Gel, on the other hand, is very active and has a very large Zeta potential. The result is that the clays not only absorb water into their matrix, they also adsorb water onto their surfaces. Drilled solids and native clays have a smaller Zeta potential than commercial clay, depending on their activity, and to some degree, in proportion to their Cation exchange capacity (CEC).
The effect of Zeta potential helps explain why muds appear “dehydrated” after a trip when, in fact, they still have just as much water. A portion of what was free water before is now tied to the newly added solids, or to solids that have been broken into smaller pieces and are exposing more surface area.

In the KlayCon mud acid is added to provide an abundance of hydrogen ions. At a neutral pH (7.0) there are equal numbers of hydrogen ions [H+] and hydroxyl ions [OH–]. When acid is added, the balance tips toward the H+ and when we check the pH of the mud it will be below 7.0. However, the H+ is attracted to the clays, which have a slightly negative charge, and some of them end up concentrated in the water adsorbed onto the clays because of the Zeta potential. This makes the clays slightly inhibited by means of what is called mass action. Mass action is a process which occurs when an abundance of ions [Cations or Anions] are attracted to an active solid. By their very presence in such massive numbers, they prevent water from reaching the matrix and causing swelling. This effect is somewhat short lived, especially in comparison to Cation exchange and the inhibiting effect of Potassium or Calcium. The bonding is very weak (Hydrogen bonding) and that leaves the ions free to effect the pH measurements of the mud.

When the mud is filtered, the adsorbed water remains with the clays of the filter cake. The filtrate, lacking the lost H+ (but with the same amount of OH–) has a more basic [higher] pH. In fact the filtrate almost always has a 7.0+ pH. This means that the pipe, pumps and well bore only see the neutral pH fluid. This answers the question of potential corrosion. But it still doesn’t explain how this fluid can change the dynamics of the well bore clays.

The mass action of H+ covering the clay particle satisfies the exposed negative charges along broken platelet edges. Without the negative charge, the platelet and pieces of clay are no longer attracted to other clays, since they all have positive charges, either from the massed H+, or from the Cations [Sodium, Calcium or Potassium] arrayed on their faces. This reduces Yield Point and Gel Strengths. Additionally, the clay cuttings undergo the same transformation as they start up the well bore, preventing them from being attracted to the clays exposed on the well bore itself which have also been inhibited. This keeps the hole clean, reducing drag, and the likelihood of pack off.

4. Is it expensive? Will the benefits outweigh the added costs? As mentioned previously, the KlayCon system is generally 30% more expensive than a conventional Cypan/DMA mud system. Over the past five years, GEO Drilling Fluids, Inc. has drilled many wells with this new mud type, accumulating experience and formulating procedures. While not every well drilled with KlayCon has been trouble free, on the whole these wells have had fewer clay related problems and have therefore been cheaper to drill than comparable wells drilled with the conventional Cypan/DMA mud. Savings in mud costs are derived from a reduction in drilling days, less frequent and troublesome wiper trips and thus fewer Tour treatments. The savings in rig time and associated drilling costs more than offsets the increased mud costs.

5. Solids Control Equipment A commitment to optimum solids control equipment is essential to the success of the KlayCon system. As with all drilling fluids, proper solids control is key to maintaining good hole conditions and keeping mud costs in line. Allowing for an excess build up of drill solids results in significantly higher material consumption, water dilution and disposal costs.

Normally recommended equipment includes a mud cleaner capable of processing 120% of the circulating volume and a centrifuge.

CONCLUSIONS

KlayCon has been successfully run all over western U.S. and is particularly suitable for areas with highly Bentonitic Clays. This system is as environmentally friendly as a regular Cypan/DMA mud, both as a finished product and each of the constituents individually.

The cost of running KlayCon is increased by the amount of Acid used, as it requires just as much Cypan, Omnipol II and CFR as a normal well. Some of the additional cost of Acid is offset by a reduction in drilling and rig time.

The KlayCon mud acts as a moderate clay inhibitor. While less effective than brines or oil, it is cheaper and easier to run. GEO’s KlayCon system is the new alternative to these expensive options.
### U.S. RIG COUNTS

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