

## High-Build RSS Performance Delivers Improved Well Consistency in the Marcellus Shale

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### Abstract

The Marcellus Shale in the northeast US is emerging as one of the most prolific and fastest-growing shale gas plays. Multipad horizontal drilling, tight lease boundaries, complex well profiles, anti-collision considerations (for close-proximity wellbores) and critical landing zones (for wellbore placement in the target reservoir) make this a challenging drilling environment.

To overcome these challenges, an operator and a service provider teamed up to strengthen performance and consistency. Using new high build-rate rotary steerable technology, complex multiple 3D well profiles were planned and successfully drilled from a single pad to reach the target reservoir intervals (and stay within tight target windows more efficiently than previous conventional drilling methodologies).

An approach which included specifically optimizing the drill bit for the rotary steerable tools enabled the high build-rate curve and lateral intervals to be drilled in one run. The operator's costs were lowered through improved performance and vastly improved well-delivery consistency and quality. The average number of drilling days per horizontal curve and lateral well were reduced by 51.9%. The operator is able to better predict drilling costs with consistently improved well planning measures. The high build-rate technology enabled the operator to successfully drill 16 wells in the Marcellus Shale.

### Introduction

Shale gas has become an increasingly important source of natural gas in the United States (US) since the start of this century (Stevens, P., 2012). In 2000, shale gas provided only 1% of US natural gas production; as of September 2012, it was 35% and the US government's Energy Information Administration (EIA) predicts that 46% of the US natural gas supply will come from shale gas by 2040 (Fig.1).

One of the most important shale gas plays in the US is the Marcellus (PA and WV) comprising 23% of total production, followed by Haynesville (LA and TX) with 27%, and Barnett (TX) with 20% (Fig. 2).

The Marcellus Shale is part of the rapidly growing Appalachian Basin in New York, Pennsylvania, West Virginia and Ohio (Fig.3) and is divided into three assessment units (AU): Western Margin, Foldbelt and Interior.

For the economic viability of these unconventional gas plays,

two technologies are especially relevant: horizontal drilling and hydraulic fracturing. Fig. 4 illustrates Pennsylvania's relatively recent transition from conventional vertical wells to horizontal wells, drilled mostly in sections of the Marcellus, Utica, and Genesee/Burket shale formations in the northeast and southwest portions of the state.

Pennsylvania's declining new rig count can be attributed to (Fig. 5) horizontal wells and pad drilling technology (where multiple wells are drilled from the same rig). In 2012, rig counts declined while the number of wells per rig increased.

According to the EIA, Pennsylvania's natural gas production more than quadrupled from 2009 to 2011 because of expanded horizontal drilling combined with hydraulic fracturing as shown in Fig. 6. Prior to 2009, most wells were vertical, and produced about 400 to 500 MMcf/D of natural gas. As horizontal well usage grows, production averages grow as well; in 2011, horizontal well production neared 3.5 Bcf/D. Natural gas wells accounted for nearly all (99%) the horizontal wells begun in 2011.

The Marcellus Shale is not only the second-largest US producing play, but also the largest holder of unproved reserves. The EIA's latest 2012 update on unproved technically recovered resources (TRR) shows Marcellus as the biggest shale gas play in the US with 141 Tcf (Fig.7). These estimates, over time, will become less uncertain as more horizontal and hydraulic (fractured) wells are drilled.

The operator began exploring Pennsylvania's natural resources in 2007 and is now one of the state's leaders in exploration and production. Most of the operator's drilling activity is in the Pennsylvania counties of Washington and Greene (Fig.8), where wet gas is found (Fig.9).

Marcellus arose in the Middle Devonian period; it is characterized by black shale containing limestone beds and concentrations of pyrite and siderite. Fig. 10 shows general stratigraphic columns in the northern part of the Appalachian Basin province. The Marcellus reservoir's depth ranges from less than 2,000 ft up to 9,000 ft and less than 50-ft thick in the Western Margin; less than 2,000 ft to 11,000-ft deep and 50-plus-ft thick in the Interior; up to more than 11,000 -ft deep and a few feet thick to more than 350-ft thick in the Foldbelt (USGS, 2011).

## Drilling Challenges of Horizontal Wells in the Marcellus Shale

Land-based drilling operations present numerous challenges and typical Marcellus horizontal wells also present their own specific set of challenges. Average Marcellus horizontal well plans require curve build-up rates between 8 and 10°/100ft.

Traditional bent-angle mud motors and polycrystalline diamond compact (PDC) bits present specific drilling challenges (Hummes, et.al., 2011) in the NE area and in Marcellus horizontal wells:

- Inconsistent curve build-up rates (BUR) requiring increased bent-angle mud motor settings;
- Higher bend-angle mud motor settings limit the drill string revolutions per minute (RPM) due to fatigue potential and reduces the effective rate of penetration (ROP);
- Diverse inter-bedded formation groups with differently reacting formations (with respect to BUR);
- Fast-changing formation consistencies make PDC tool faces difficult to control and conform to well plan requirements;
- Excessive sliding to achieve well plan requirements;
- Potentially tortuous well profiles, which affect weight transfer with increased torque and drag;
- Increased trips between curve and lateral well profile sections to adjust conventional mud motors (to achieve the required well plan trajectory);
- Critical landing targets for optimal reservoir placement and avoidance of high, unconfined compressive strength (UCS) formations that lie below the Marcellus Shale (Onondaga limestone);
- Tightly spaced on surface multi-well pads create considerable anti-collision considerations;
- Tight leasing units and boundaries.

The geological cross plot of **Fig.11** is typical of southwest Pennsylvania formation tops and their commonly known names. The plot re-enforces the bullet points describing the difficulties of well planning with quickly changing formation consistencies. **Fig.11** shows the difficulties encountered when building a curve for a horizontal well profile in the Marcellus shale. Directional drillers with conventional bent-angle mud motors typically have an inclination and azimuth directional sensor approximately 60-plus-ft away from the bit (depending on the BHA configuration). This makes depicting motor yields for slide intervals and forward drilling projections difficult to anticipate because the formation characteristics quickly change. One key piece of high-build RSS is near bit inclination (NBI). NBI enables directional drillers to easily sense bit inclination and rapidly adjust drilling parameters while on bottom (if required).

Prior to high-build-rate rotary steerable systems, conventional high-bend-angle mud motors were used to build the wellbore curve profile; typically, either a lower-bend-angle mud motor or a rotary steerable system would have been chosen to drill a horizontal lateral well. **Fig.12** shows the benefits of higher build rates over traditional rotary steerable technology. The higher build rates have enabled one-run curve and lateral drilled sections

to become typical in Marcellus Shale wells. The advanced technology has enabled several efficiency gains to be made; its application has been instrumental in reducing the operator's days per well and increasing potential lateral reservoir exposure.

Another challenge in the Marcellus Shale is encountered in the lateral as a tight target window requires a drilling system to deliver the wellbore through geo-steering requirements while drilling. The operator believes keeping the wellpath in the critical zone of interest enables the most reserve value to be extracted during the well's lifecycle. Therefore, the drilling assembly must be able to hold inclination targets steady as defined by the geo-steering team. Conventional bent-angle mud motors observe the same challenges as previously defined for curve drilling intervals (where traditional gamma formation evaluation curves are utilized to steer a well 60+ ft. back from the bit). In tight or optimal target windows with a conventional system the bit may exit the target and deliver the well out-of-zone prior to the gamma formation evaluation sensor noting a difference. Hence, it is very tough to maintain a well in the optimal interval with traditional methods. However, new high-build RSS technology has enabled the gamma formation evaluation curve sensor to be closer to the bit than in conventional drilling assemblies. Therefore, it is much easier to keep wells in-zone using the high-build RSS system. **Fig.13** shows how keeping the well in a 6 ft. total target window for a 8,000 ft. lateral interval, and is much easier when the gamma formation evaluation curve sensor shows a data change much earlier than conventional tools. Through technology improvements, formation trends are now noticed quicker along with ability to rapidly adjust steering requirements due to formation trends while drilling ahead on-bottom.

Operators also seek financial consistency of "predicting" overall well construction costs (from rig mobilization to drilling and completions). This is a critical challenge because downtime related to rig activities works against targeted schedules, planning, and overall well economics. Drilling an exceptional well is not enough; consistent repeatable drilling performance is necessary. The collaborative environment between operator and service company, and within each one's departments, plays an important role in finding a balance for an optimized scenario.

## High Build Up Rate Rotary Steerable Drilling System

In 2011, the service provider began aggressively field testing its newly developed high build up rate (HBUR) rotary steerable system (RSS), capable of building up to 15°/100ft drilling (in environments including Eagle Ford, Granite Wash, Cana Woodford, Fayetteville, Utica and Marcellus). In 2012, the tool became commercial and as of early 2013 has accumulated more than three million feet drilled and 60,000 total circulation hours.

The technology incorporates the proven steering concept with changes in BHA stiffness, three-point geometry, hardware and software. Additionally, the entire bottomhole assembly (BHA) (**Fig.14**) is shipped to the rig in one piece, thus avoiding breaking sensitive electronic connections at the rig site and simplifying transportation logistics.

The system consists of a dedicated drill bit developed specifically for each application, a stabilized steering unit with near-bit inclination and vibration sensors, a flexible probe with

gamma, directional and vibration (lateral, axial and stick-slip) sensors, and a pulser/power module.

The steering unit comprises a downhole closed-loop system with three expandable pads on a short steering sleeve near the bit. The slow rotating sleeve reduces the steering action from drillstring rotation, which becomes insensitive to stick-slip. A smooth, continuous steering adjustment leads to a precise, quality wellbore, minimizing backreaming time and improving completion operations. The system's unique design enables it to be programmed downhole to drill a smooth, controlled lateral with minimal tortuosity after completing the curve section and doing so in one run.

In addition to the gamma (for better reservoir navigation closer to the bit) and measurement while drilling (MWD) services (optional battery for flow-off surveys for motor assisted BHAs), a flexible probe provides drilling dynamics and the flexibility required for achieving higher doglegs.

The turbine-driven pulser/power module generates power for all BHA functions, and uses mud pulse telemetry for bi-directional communication with the surface. The turbine and pulser were extensively tested and optimized for plugging resistance and uninterrupted function in high lost circulation material (LCM) contents in laboratory and field tests.

The complex interaction between many different technological and environmental factors caused the design of the HBRSS to be a comprehensive consideration of the entire system, including the BHA, drill bit, drillstring, and drilling fluid, to achieve predictable results. According to targeted bit features, three-point geometry and engineered BHA stiffness, the HBRSS has delivered BUR greater than 17°/100 ft in field test applications. The well profiles discussed in this paper required a BUR of 8-10°/100 ft.

With high build rates under continuous rotation, material fatigue from cyclic bending is a concern requiring special attention. While developing the new RSS, extensive finite element analysis (FEA) simulations on different scales (from drillstring to component levels) were conducted to ensure long part lives (Hummes, et al., 2012).

Higher build rates require a more flexible BHA than conventional RSS. Consequently, the steering actuators and control system must provide increased agility and response to tightly control trajectory and avoid unwanted deviations and local doglegs. The new system includes improved control electronics and algorithms, as well as increased steering forces and steering pad travel, to compensate for formation trends and borehole irregularities.

While maximum deflection is needed to drill curves at the highest possible BUR, low tortuosity is critical in long tangent sections to optimize ROP and hole cleaning, and also improve the efficiency of casing operations and plug-and-perf or sliding-sleeve fracturing completions. In vertical sections, a precise, straight wellbore is critical to meet collision avoidance requirements in pad applications. The new system provides an oriented kickoff from vertical (or from any other inclination) to ensure the desired kickoff direction is immediately met, without need for corrections, or increasing collision risk with adjacent wellbores. The continuously adjusting steering forces enable the

system to seamlessly transition between maximum curvature, tangents, and any intermediate profiles, to drill an entire hole in a single BHA run.

While most steering adjustments are automated in the downhole system, the driller can send changes to the trajectory via a computerized downlink system that creates a pattern of small mud flow variations which is decoded by the downhole tool. For example, a target inclination and maximum force equating to a desired build rate can be sent from the surface, and the tool then steers toward the inclination and maintains it, compensating for formation tendencies without further interaction from the surface. Combined 3D build and turn curve section profiles are steered effectively with little effort. To further increase penetration rates and extend step-outs, the system can be deployed with an additional mud motor and an optional battery to enable flow-off surveys, saving additional time at each survey point.

Finally, all functions are accessible via remote operations centers so expert advice is immediately available.

### Drill Bit Design for System Approach

An important aspect of the system's success is the approach used to configure bit technology to compliment the tool's performance potential. This project utilized a six-bladed bit design with a 19mm primary cutting structure and 16mm backup cutters. Prior system-specific drill bit features were developed by assembling an overall summary of the area, geology, present issues and risks, as well as goals and objectives that had to be met. Previous bit design objectives (for the HBRSS system) used in Marcellus Shale applications included bit stability and resistance to vibrations, improved hole quality, maximum steerability and BURs, improved ROP, and optimized hydraulic cleaning action. The new six-bladed bit design incorporated all of the features developed in previous HBRSS designs. However, this project had the added objective of increasing bit durability and preserving the sharpness of the cutting structure through a highly interbedded and abrasive silty-shale formation being drilled before reaching the KOP of the curve.

Several design features and technologies were evaluated. The current design's dull analysis was taken into account, and noted that there were signs of severe abrasive wear to the shoulder and drill bit cutting structure gage, as shown in **Fig. 15**. The excessive wear was originally thought to be a result of the need to ream through short intervals of sand formations and through tight spots in the vertical section while tripping to bottom with the RSS tool because of hole swelling and BHA stiffness. However, heavy shoulder and gage cutter wear were also observed on stronger, more durable bit designs when no reaming was required, as shown in **Fig. 16**. In these cases, the BHA only drilled through what appeared to be a relatively soft formation known as the Middlesex Grey Shale before reaching the curve KOP.

The excessive wear to the shoulder of the cutting structure resulted in two main concerns. The first, and most detrimental, concern was a lack of BUR's in the curve section. The lack of BUR's was a direct result of the damage to the cutting structure in the bit shoulder. The bit shoulder is critical in maintaining adequate side-cutting. The RSS tool's side force acts directly

upon the cutting structure in the drill bit's shoulder. If that cutting structure is worn or damaged, a loss in side-cutting ability and a reduction in BUR potential are noticed. The second concern was a loss of ROP and drilling efficiency. In addition to providing the drill bit's side-cutting action, the shoulder area also has the highest cutter work rate, which is a measurement of the total volume of rock removed per cutter. The shoulder cutters rotate on a larger path and remove the majority of rock. If the shoulder becomes damaged or worn, the efficiency and ROP suffer proportionally.

As a result of the dull analysis, focus was placed on optimizing bit durability through design changes in addition to analyzing the geology and formations being drilled, and drilling parameter optimization (to preserve the cutting structure and provide a single, fast run).

### Drill Bit Design Specific to the Application

The drill bit design was maximized for durability. The blade count was increased from five blades to six blades (to increase the diamond volume present in the cutting structure). The cutting structure was changed from a 16mm cutter to a deep-leached, abrasion-resistant 19mm polished cutter. The deep-leached 19mm cutters used were much more abrasion resistant in lab testing. A larger cutter also maximized cutter exposure, providing higher top-end ROP in soft shale formations in the curve and lateral well section. The mirror polish applied to these cutters reduces cutter surface friction so cuttings slide off easily. The result is increased hydraulic cleaning efficiency and ROP. Polished 16mm backup cutters were also included in the design to increase diamond volume and cutting structure durability. To optimize the drill bit's stability and hydraulics, the operators' typical run parameters were included in the software model. **Fig. 17** shows the dull after the first run, using the same drilling parameters as offset wells. The dull condition was improved compared to the offset dulls, but signs of wear and damage to the cutting structure in the bit's shoulder were still evident.

### Geology/Formation Analysis

To prevent premature damage or wear to the drill bit shoulder, an analysis of the formations encountered had to be conducted to determine exactly where in the well path the damage was occurring. The entire section length was drilled in shale or silt formations, with the exception of a single limestone formation called the Tully Limestone, near the curve KOP. A normal shale formation is physically incapable of producing the abrasive wear to the cutting structure of the bits observed in the dull analysis, because shale is inherently non-abrasive. Offset well analysis indicated some bits were being pulled with heavy shoulder wear before encountering the Tully Limestone. This data resulted in the investigation's focus to shift to the shale formations above the Tully formation. Analysis found the Middlesex Grey Shale was actually tightly interbedded shale and silt layers. The shale and silt layers were so tightly interbedded that the silt had permeated into the shale formations, making it impossible to differentiate between the two via the gamma track while drilling. Therefore, an in-depth mud sample analysis was necessary to identify the silt of this region. The silt present was highly abrasive with signs of

quartzite. Data from offset wells and dull analysis indicated the abrasive silt in the Middlesex Grey Shale formation was caused by premature wear on the drill bits' cutting structure.

### Optimized Drilling Parameters

After the formation causing the bit damage was identified, the drilling parameters were changed to mitigate and prevent the issue. Previous run parameters included high RPM's combined with low WOB. The high RPM's and low ROP resulted in a shallow cut depth, and therefore, a very small percentage of the cutting structure engaged the formation, and bit whirl was encountered. To fully engage the cutting structure and stabilize the bit while drilling, the WOB was increased and the RPM's decreased to levels that allowed the RSS tool to function properly while mitigating bit wear. The increased depth of cut (DOC) stabilizes the drill bit, preventing premature wear to the cutting structure. **Fig. 18** shows the dull bit after being run with optimized parameters through the Middlesex Shale. The dull shows no signs of wear or damage to the shoulder or gage area of the cutting structure. This success is evidence that an optimal working relationship between bit designers, geologists and operator can result in an optimized drill bit solution.

### Technology Implementation and Results for Consistency Improvement

Many factors have contributed to the success of this project. However, one key element is through the alignment of utilizing the HBRSS and the drill bit as a total effective system. As previously discussed, the drill bit is matched to the geological environment and the bit is also matched for the specific application that it is placed into service with the HBRSS. The matched system enables the two systems to work together, minimizing the amount of altered variables, and ultimately providing the operator consistent, dependable performance.

The HBRSS made significant positive impacts on the operator's drilling program. All data was gathered from horizontal multipad drilling operations and is an average of challenging two-dimensional, three-dimensional, and negative vertical section well profiles. All of the included performance charts only evaluate the curve and lateral sections of the well, or just from the curve KOP to the lateral total depth (TD). **Fig. 19** shows the HBRSS system enabled the operator to tackle longer well profiles. Thus, using longer laterals the operator effectively reached more reservoir rock, and expanded production potential.

**Fig. 20** shows that the wells to the left were drilled with conventional bent-angle mud motors and the wells on the right side of the chart (in blue) were drilled with the HBRSS. Keeping in mind (**Fig. 19**) where the well profiles are actually longer with respect to drilled footage, it is an amazing trend to see that the operator and service company together are effectively reducing drilling days per well with overall longer drilled laterals.

Overall well penetration rates also improved using the HBRSS over conventional bent-angle mud motors. **Fig. 21, 22, and 23** present the depths drilled per day for both the curve and lateral intervals. The HBRSS system consistently showed positively increasing trends of drilled footage per day. The average HBRSS drilled 435 ft/day more than conventional tools in the well curve

section, resulting in a 165% improvement in curve drilled footage per day. In the lateral interval, on average, the HBRSS drills 555 ft/day more than conventional tools, resulting in a 62% average gain in lateral drilled footage per day. The combined curve and lateral drilled footage per day (Fig. 23) increased 638.3 ft on average with the HBRSS deployments as compared to conventional tools (for a combined curve and lateral performance enhancement of 136%). Performance trends in the day versus depth plot (Fig. 24) reinforce the trend in the footage per day plots. All wells in the days versus depth plot show data trends from the curve KOP to the lateral TD point. The red lines show conventional tool deployments and the blue lines show HBRSS tool deployments. The HBRSS deployments on the left side of the plot show the trend of drilling deeper more quickly and more consistently than with conventional tool deployments. The averages between the HBRSS drilled curve and lateral intervals (in comparison to the conventional tool deployments) indicate 8.2 drilling days were saved utilizing the HBRSS.

The oil and gas industry recognizes performance is a substantial requirement, and typically a condition of employment between the operator and service company. Quantity (performance) is only part of the total equation, with the other critical factor being quality. Wells can be fast with high penetration rates, but if not kept in the optimal target reservoir, the overall economics of the wells decline as total production is not realized (despite wells being drilled quickly and drilling costs minimized). Hence, a consistent drilling system is vital to an operator's drilling program.

Fig. 25 and 26 represent two wells drilled from the same horizontal multi-well pad and shown in 3D (with a well planning software program). Both wells are shown through a 10 power zoom (for consistency). The red well was drilled with a conventional motor and from a quick view one can note the imposed tortuosity from geo steering versus the HBRSS tool which utilizes its NBI and close proximity gamma formation evaluation curve to better stay within the target reservoir interval. The red well stayed within a 10-ft-target interval for 4,500 ft, whereas the blue well drilled with the HBRSS stayed within a three-ft-target interval for 6,000 ft. Thus, the HBRSS technology enabled the operator to better align the wellbore profile with geologic formation trends and keep the wellbore in the optimal reservoir target.

Expanding further on well quality, a plot of lateral inclination as drilled from the wellbore surveys versus the operator's desired target inclination (Fig. 27) was prepared in the form of a quality control chart. The red lines show the operator's on-site geologists request for desired target inclination, and the blue dots are the HBRSS actual survey inclination points within the wellbore. The left side of the plot is a scale from 88° of inclination to 92° in 0.2° intervals. The plot shows that actual surveys average within 0.1° of the desired inclination and consistent repeatable performance regardless of lateral length. The quality control chart in fig. 27 reinforce the observed trends in fig. 13, 25, and 26, which are all graphics that show the HBRSS has provided improved wellbore quality and reservoir access over conventional tool deployments. As of February 2013, the operator has been able to effectively show repeatable performance with lateral lengths to 9,600 ft. The

operator is planning 10,000 ft. + lateral lengths during its 2013 drilling program because of the repeatable and predictable performance the HBRSS system has delivered.

Fig. 28 evaluates data similar to that of the day versus depth plot, but in the form of a scatter plot which compares effective lateral length to drilling days of both the curve and lateral. The data output in the scatter plot shows the trend of the HBRSS tool as all wells are tightly knit within the highlighted blue circle on the plot. Because the data shows a tighter knit trend, a linear trend line can be drawn through the HBRSS wells which allows the operator to better predict well costs and exposed drilling days per well. This is a substantial improvement over that of the red dots which show the inconsistencies of conventional tool deployments. With the operator able to predict their exposed drilling costs per lateral length and do so with predictable accuracy, they have been able to better control their financial planning and budgeting measures with respect to drilling operations. Aligning this with reduced days per well, drilling longer and more complex well profiles with repeated performance has allowed the operator to gain considerable cost savings in both wellbore quality and quantity.

## Conclusions

Drilling horizontal wells is not simple. There are challenges that exist in drilling the Marcellus Shale wells that do not exist in other areas of the US. These drilling challenges are overcome through teamwork and specifically applicable tools for the drilling environment they are utilized in. To maximize drilling efficiencies and fine-tune drilling performance, variables must be consistent and controlled. The HBRSS enabled the drilling system (drill bit and BHA) to fit the operator's application and identified goals. The system approach reduced the amount of operational deployment variables and enabled consistent, repeatable performance. Utilizing NBI and close proximity gamma formation evaluation curves enabled the operator to visualize the performance value and repeatability of the HBRSS system. A close working relationship between the operator and service provider led to a reliable one run curve and lateral deployments.

Utilizing HBRSS technology enabled the operator and service company to increase the quality and quantity of wells drilled. The resulting drilling performance and data enabled the operator to effectively predict associated drilling costs, drill longer and more difficult well profiles, and deliver wells more effectively in-zone to improve potential well production characteristics. All data has indicated the HBRSS tool made a significant impact on the operator's drilling program and led to reduced planning costs, and more consistent, repeatable drilling performance.

## Acknowledgments

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## Nomenclature

<i>AU</i>	= Assessment Unit
<i>BHA</i>	= Bottom Hole Assembly
<i>BUR</i>	= Build Up Rates
<i>DLS</i>	= Dogleg Severity

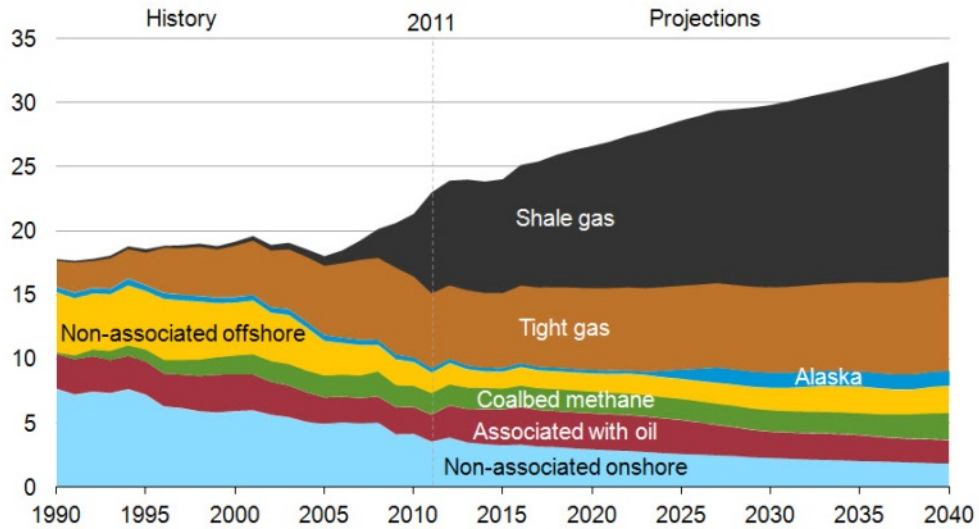
*DOC* = *Depth of cut*  
*KOP* = *Kick-off Point*  
*MD* = *Measured depth*  
*MWD* = *Measurement while drilling*  
*LWD* = *Logging while drilling*  
*LCM* = *Lost circulating material*  
*RSS* = *Rotary Steerable System*  
*HBRSS*=*High Build Rotary Steerable System*  
*TD* = *Total Depth*  
*TRR* = *Technically recovered resources*  
*NBI* = *Near Bit Inclination*  
*UCS* = *Unconfined Compressive Strength*

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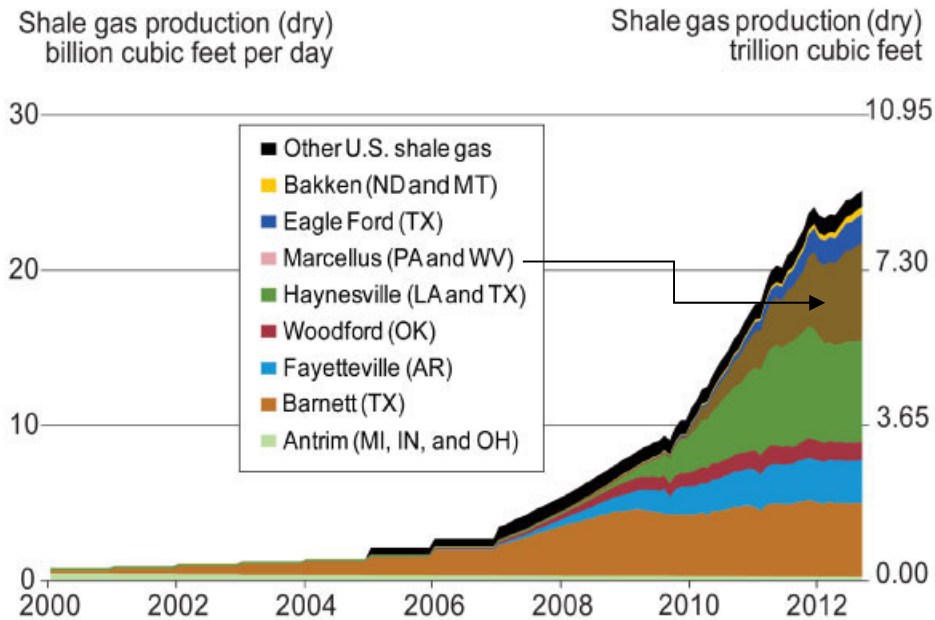
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**U.S. dry natural gas production  
trillion cubic feet**



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2013 Early Release*

**Fig 1. US dry natural gas projection (EIA, 2013).**



Sources: LCI Energy Insight gross withdrawal estimates as of September 2012 that are converted to dry production estimates with EIA-calculated average gross-to-dry shrinkage factors by state and/or shale play.

**Fig 2. Shale gas production from 2000 to 2012 (EIA, 2012).**

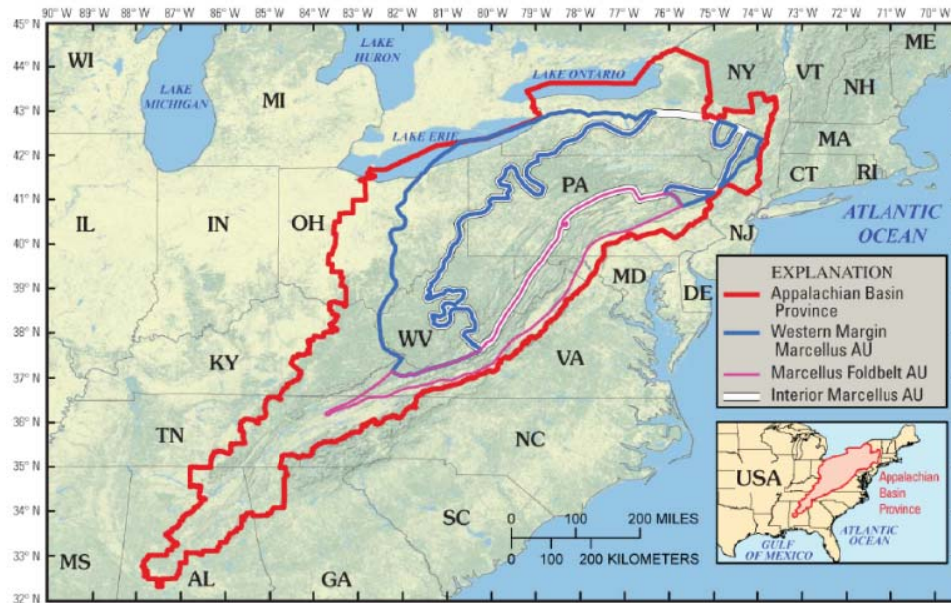


Fig 3. Appalachian Basin province with Marcellus Shale assessment units (USGS, 2011).

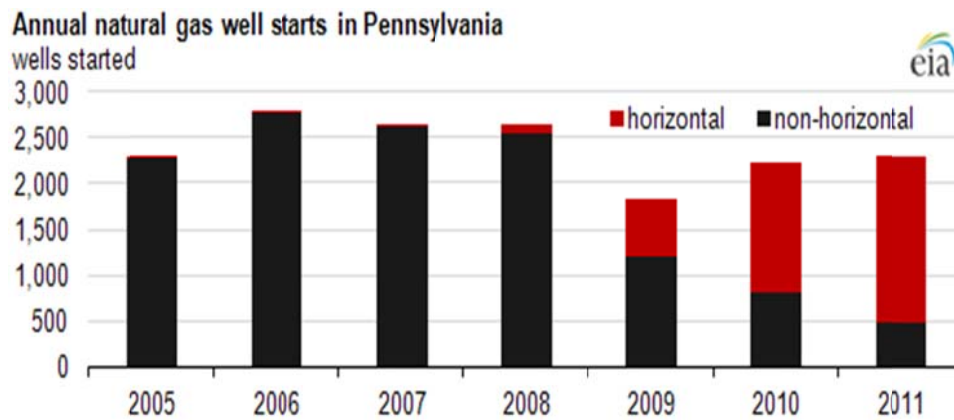


Fig 4. Horizontal versus non-horizontal natural gas wells in Pennsylvania (EIA, 2012).

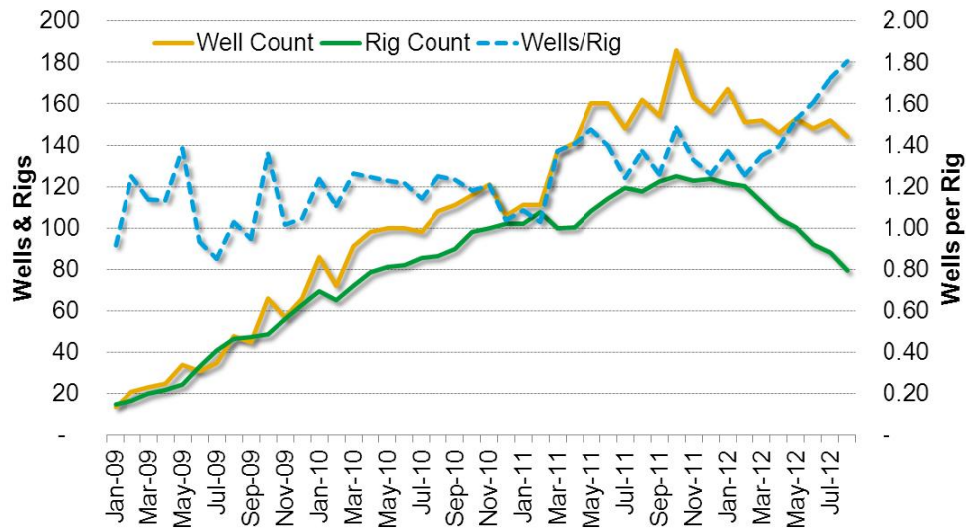
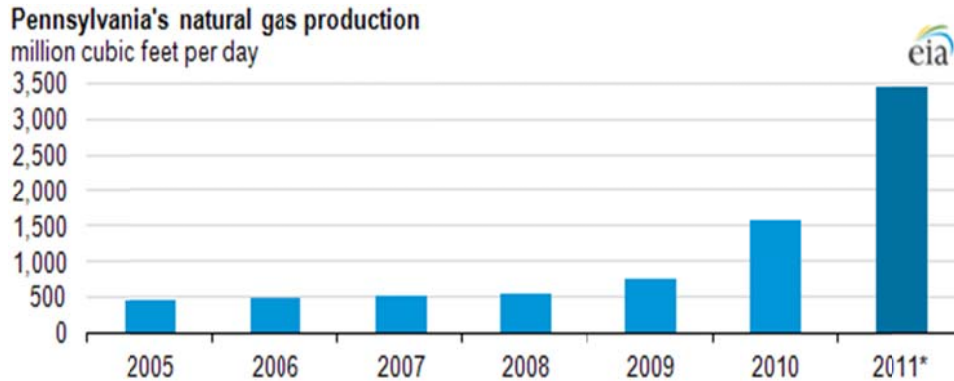
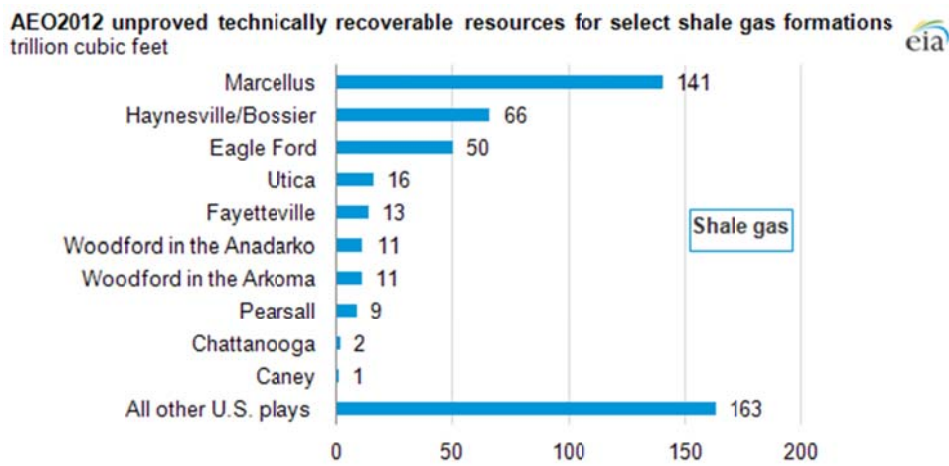


Fig. 5. Marcellus rig activity profile from 2009 to 2012 (Baker Hughes, 2012).



Note: \*EIA production data are used for 2005-2010 due to reporting issues with 2010 data provided by the Pennsylvania Department of Environmental Protection (DEP). DEP data are used for 2011 as EIA data are not yet available; EIA volumes are expected to be similar.

**Fig. 6. Pennsylvania's natural gas production (EIA, 2012).**



**Fig. 7. US shale gas unproved technically recovered resources (TRR) (EIA, 2012).**



**Fig. 8. Operator's shale drilling activity (Rice Energy, 2012).**

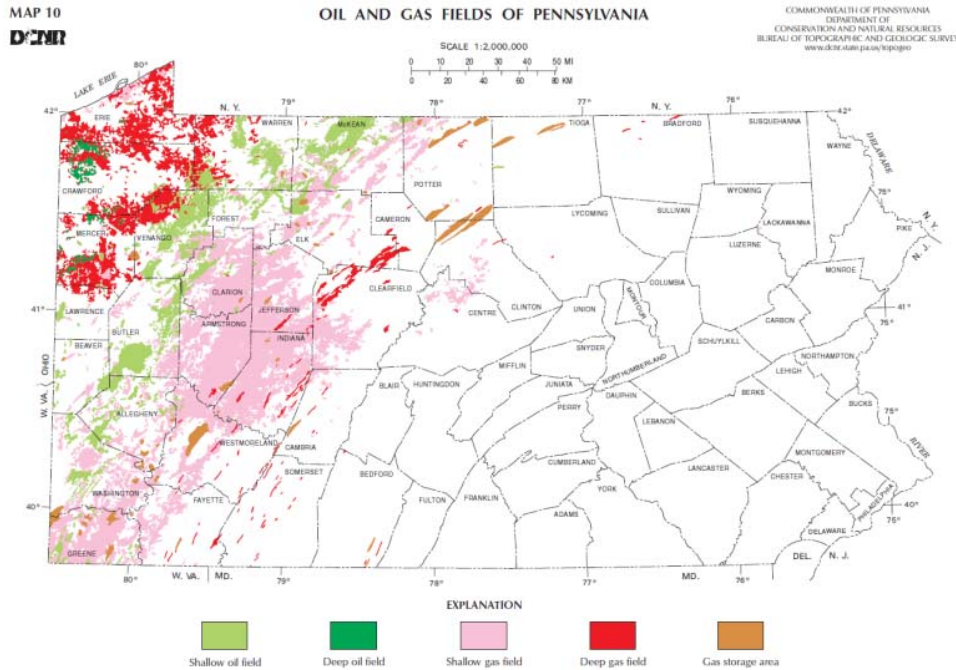


Fig. 9. Oil and gas fields of Pennsylvania (DCNR, 2007).

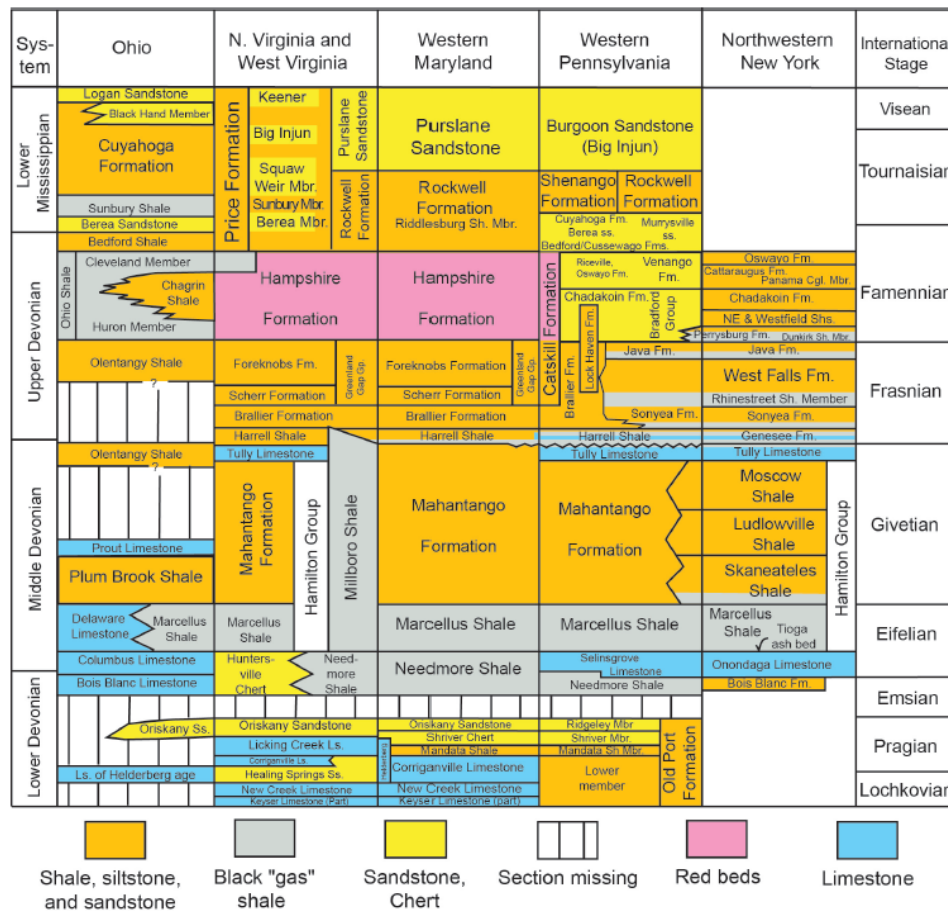


Fig. 10. General stratigraphic nomenclature showing Marcellus Shale in the Middle Devonian (USGS, 2011).

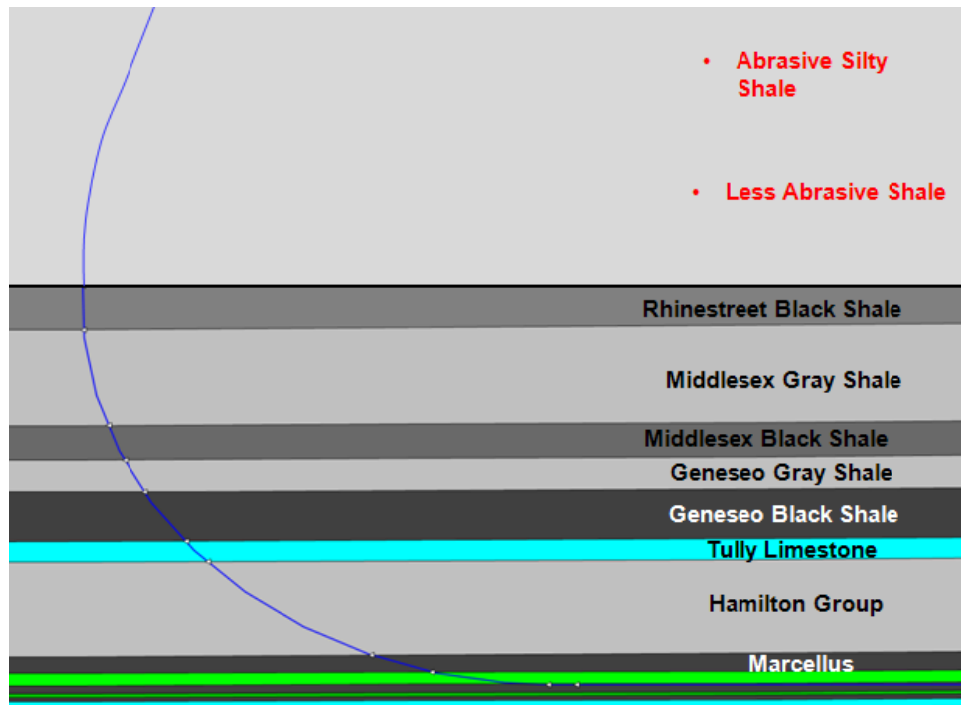


Fig. 11. Marcellus well horizontal curve profile and encountered formation tops (Rice Energy, 2013).

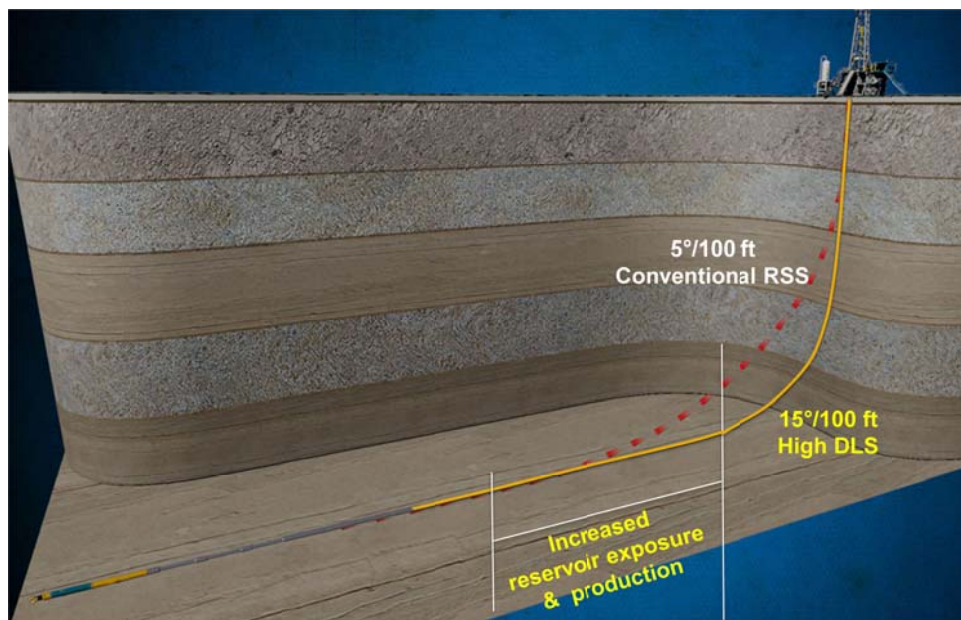


Fig. 12. High dogleg curve well schematic (Baker Hughes, 2012).

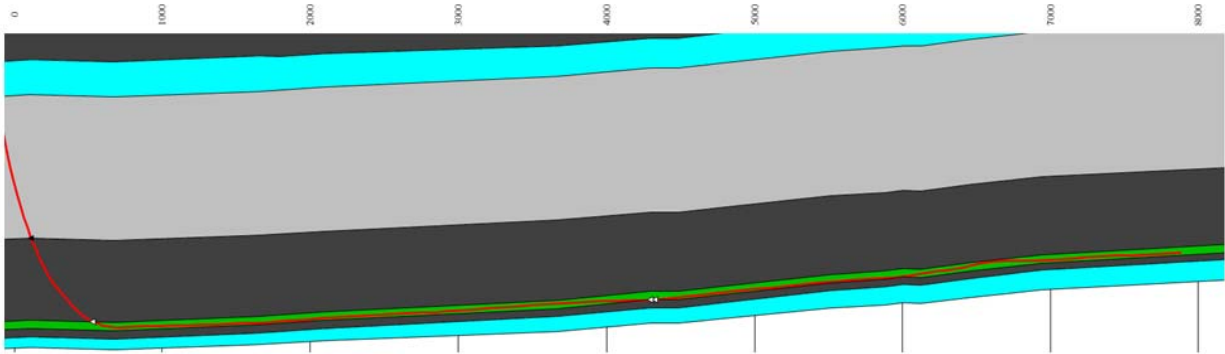


Fig. 13. Reservoir navigation in Marcellus shale by RSS – 6ft target window and 8,000ft lateral (Rice Energy, 2013).

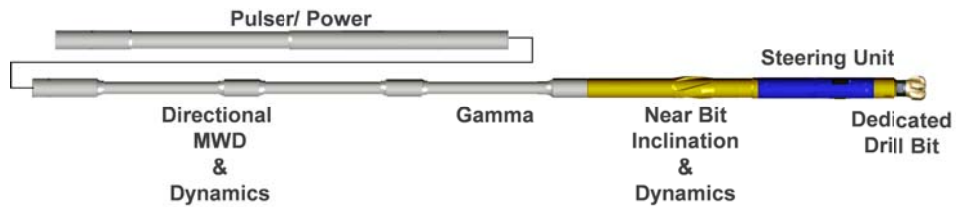


Fig. 14. New high build-up-rate rotary steerable system (Baker Hughes, 2012).



Fig. 15. Initial bit dull for assessment.

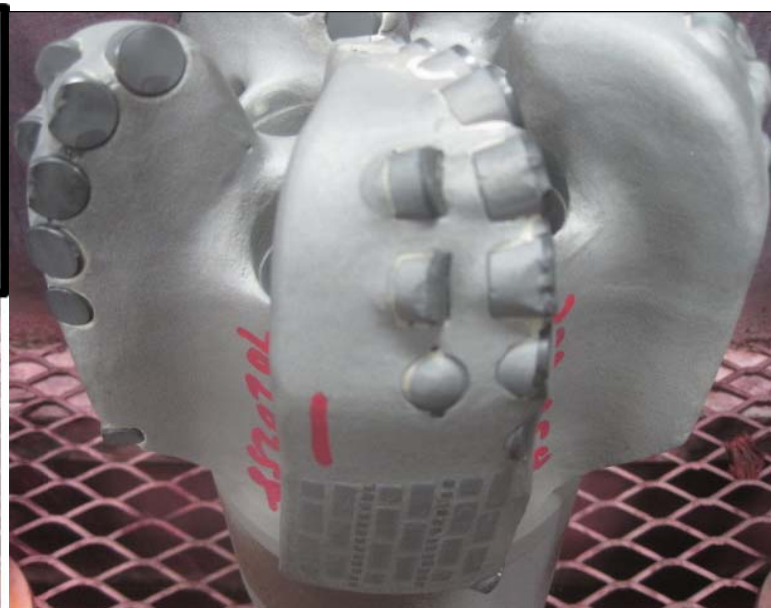


Fig. 16. Heavy wear still present on more durable bit design.



Fig. 17. Bit dull after integrated application-specific features.



Fig. 18. Bit dull following optimized drilling parameter deployment.

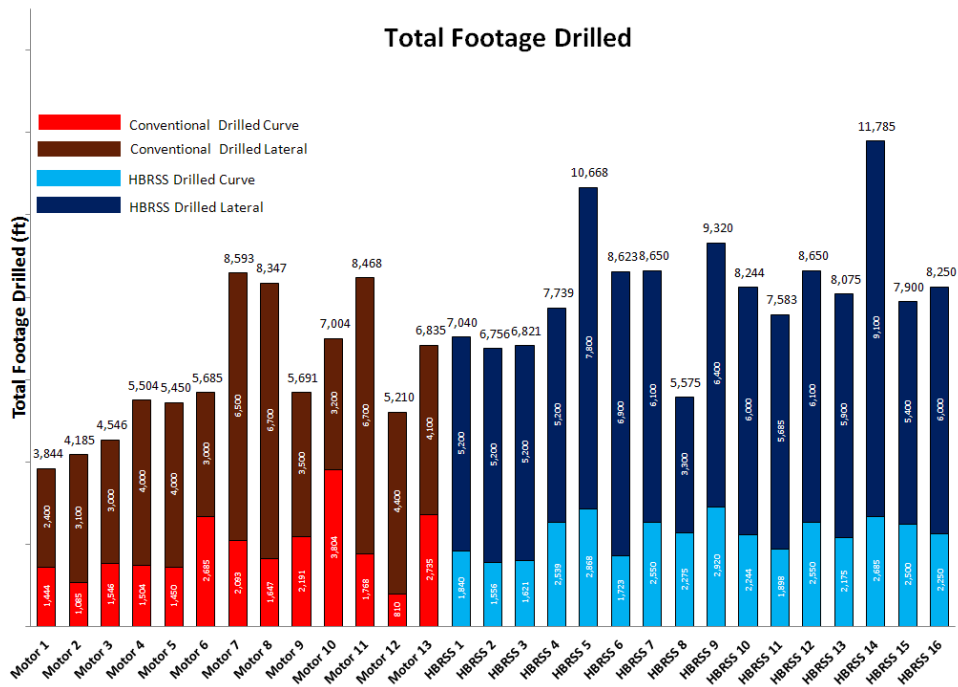


Fig. 19. Total footage drilled.

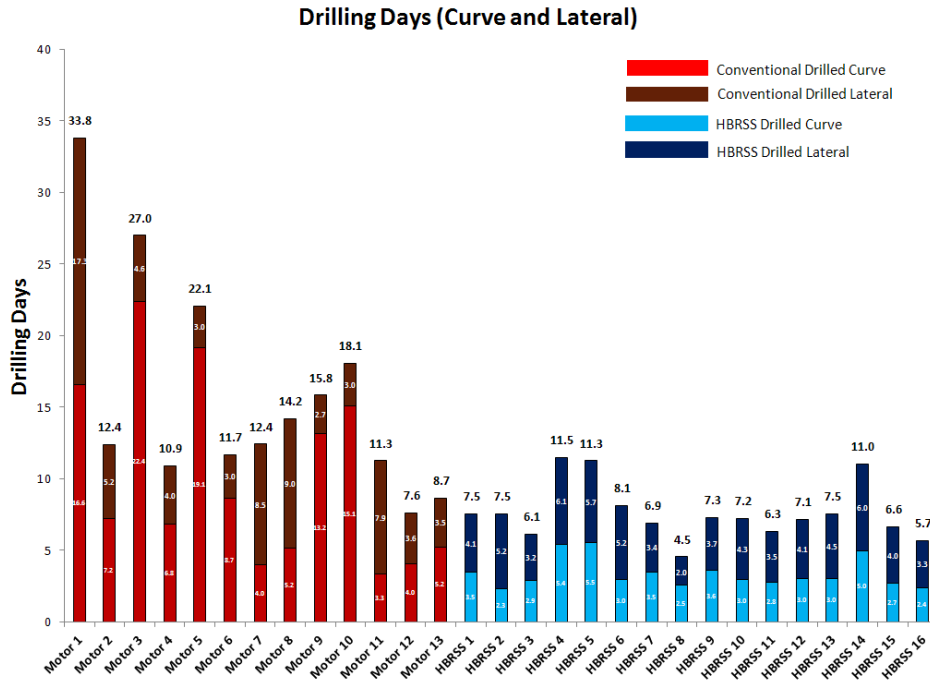


Fig. 20. Drilling days of the curve and lateral.

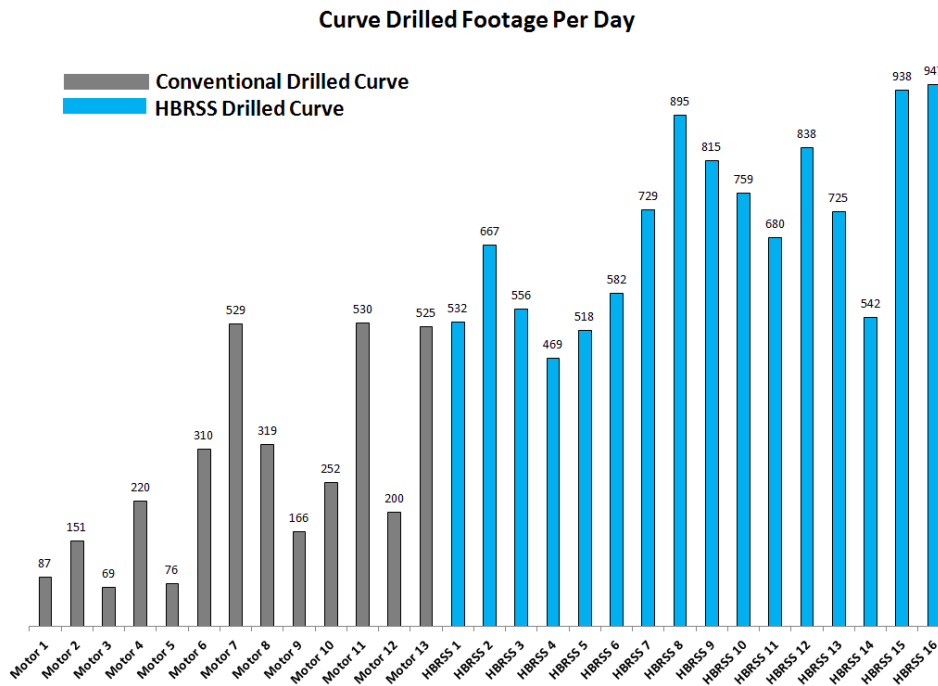
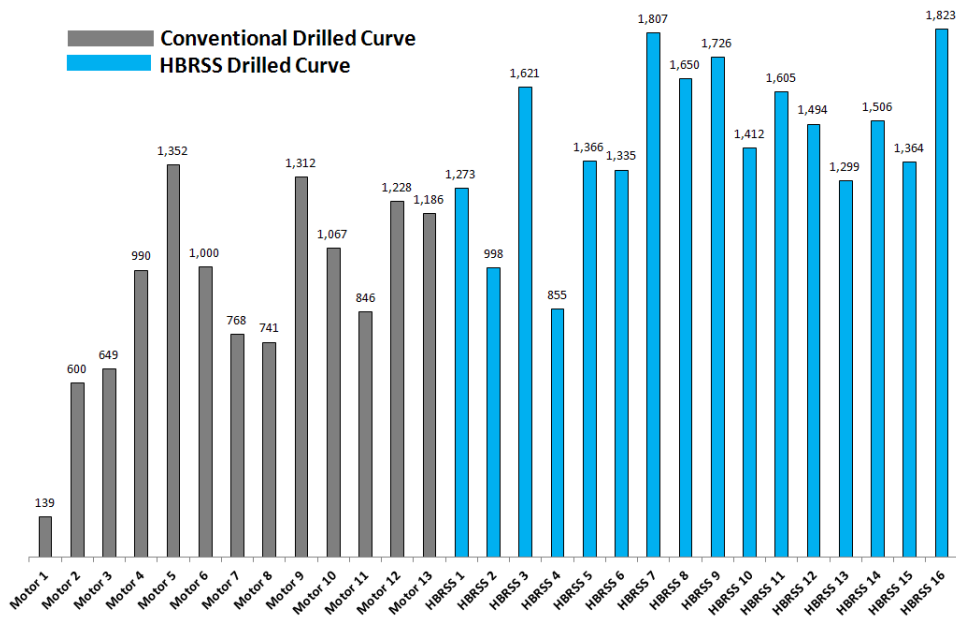


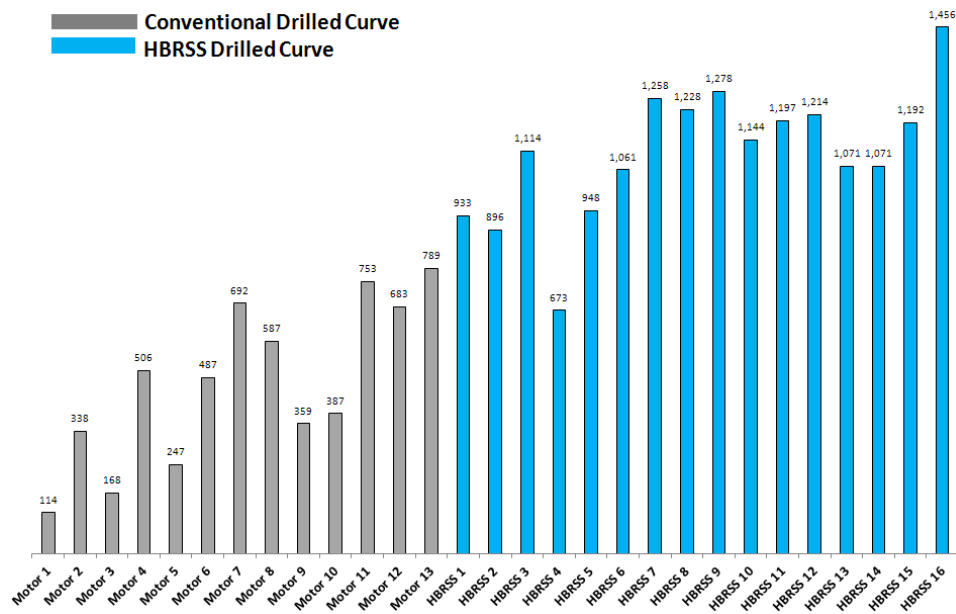
Fig. 21. Curve drilled footage per day.

**Lateral Drilled Footage Per Day**



**Fig. 22. Lateral drilled footage per day.**

**Combined Curve and Lateral Footage Per Day**



**Fig. 23. Combined curve and lateral drilled footage per day.**

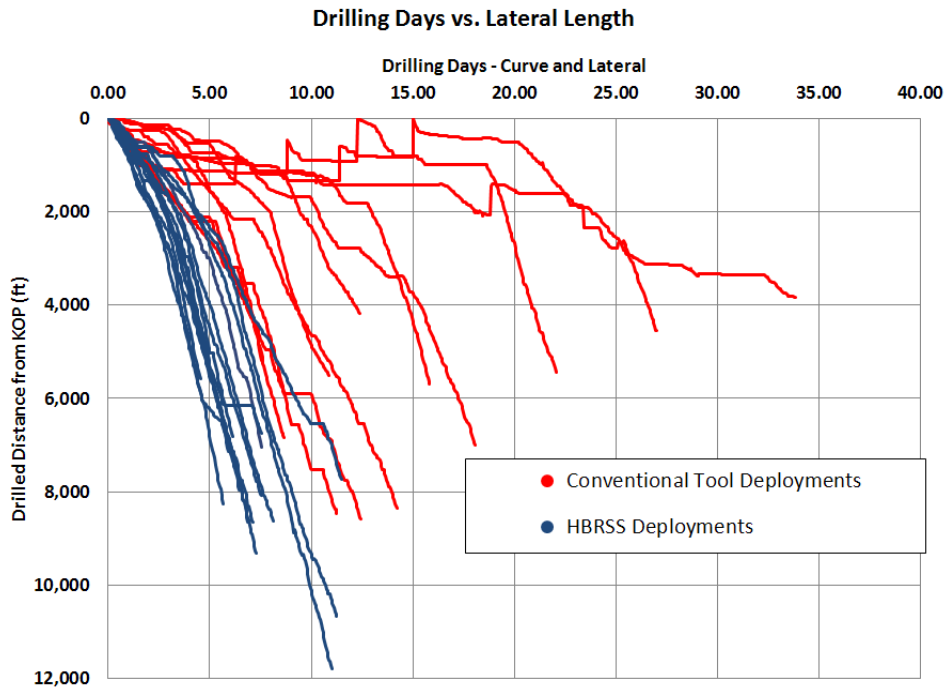


Fig. 24. Days vs. measured depth (ft) from curve KOP to lateral TD.

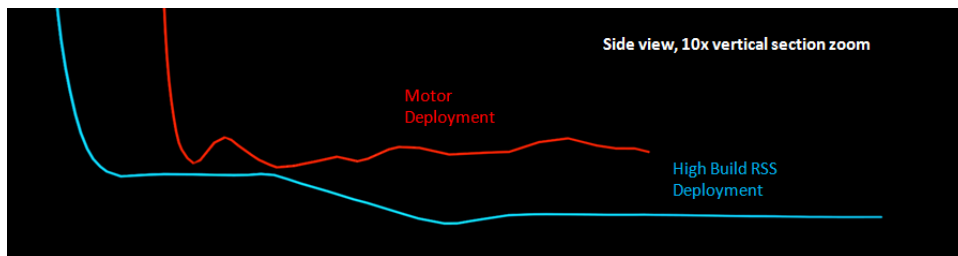


Fig. 25. Side view lateral drilling systems comparison.

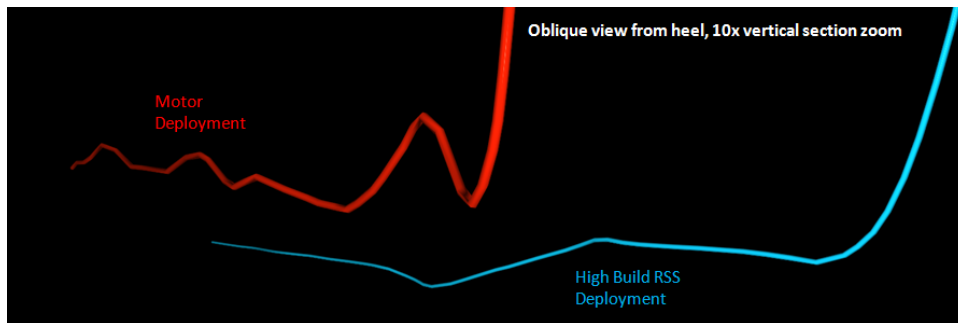
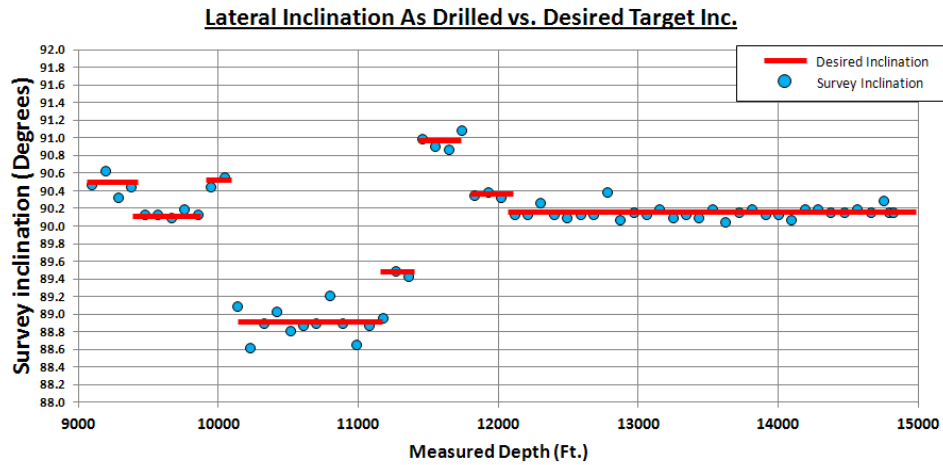
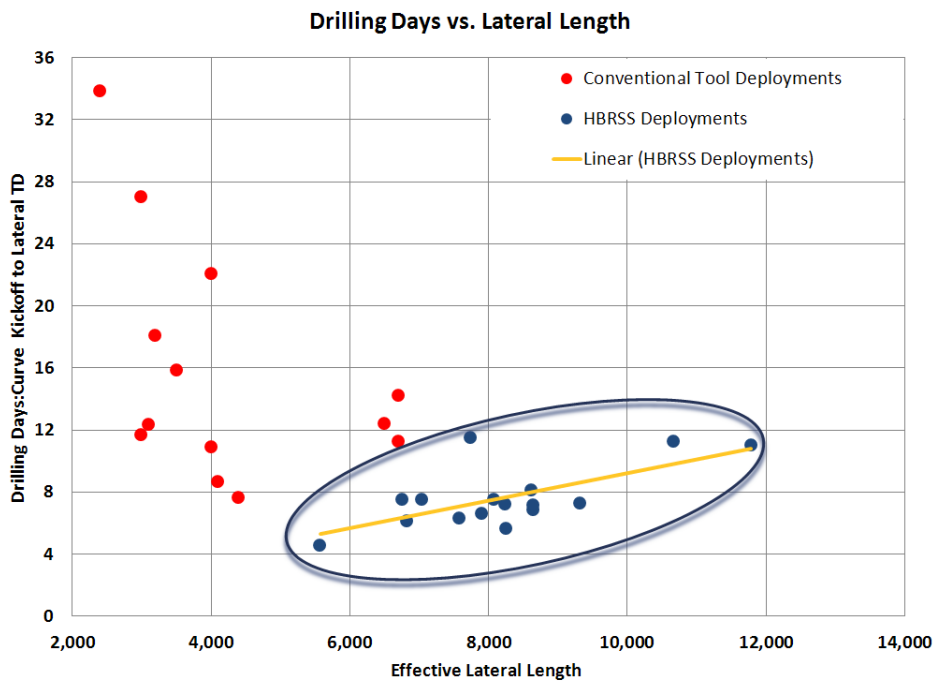


Fig. 26. Heel view lateral drilling systems comparison.



**Fig. 27. Lateral inclination comparison (As-drilled survey points vs. desired target inclination).**



**Fig. 28. Drilling days vs. lateral length scatter plot.**