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Application Specific Steel Body PDC Bit Technology Reduces Drilling Costs in Unconventional North American Shale Plays

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Abstract

As drilling activity in conventional land-based plays continue to decline, technology focus is shifting to the unconventional shale gas prospects (Haynesville, Marcellus, Eagle Ford). Efficient and repeatable drilling practices, along with cost-effective technologies, are paramount to economically exploit the known hydrocarbon reserves because of the large number of horizontal wells required to develop the vast acreage plays. The drilling challenges include high bottom hole temperatures, high mud weights and hole/bit cleaning issues. The key to reducing field development costs and improving project economics is increasing rate of penetration (ROP) in the lateral interval that typically extends 3000 to 6000ft after completing the build section.

To solve the penetration rate and hole cleaning challenges, an engineering team analyzed the latest polycrystalline diamond compact (PDC) technologies and best drilling practices to achieve the operator’s ROP optimization goals. An FEA-based engineering software system was utilized to predict the dynamic behavior of the bit and BHA components in lithologies comparable to the specific field application. To ensure proper utilization of the available hydraulic energy, engineers used computational fluids dynamics (CFD) to ensure appropriate nozzle placement and orientation to effectively clean the bit face and hole bottom. Conclusions from the dual analysis were instrumental in developing new steel body PDC bit designs specifically engineered for emerging North American shale plays.

The new steel body PDC design and the associated bit technologies and updated operating practices have been run in the Bossier City, Louisiana and Tyler, Texas areas with outstanding results. The new PDC technology has increased lateral interval ROP by as much as 80%-100% compared to conventional matrix bodied PDC bits. The authors will present several case studies that document the significant cost savings.

Introduction

In 2009, the service provider conducted an engineering initiative to improve PDC bit performance in the curve and lateral sections of the Haynesville Shale in North Louisiana and East Texas. The challenge was to develop an application-specific PDC bit capable of increasing the rate of penetration (ROP) in the curve and lateral sections while maintaining predictable and reliable toolface control.

In an attempt to increase performance in the curve and lateral sections, the sales and engineering team began running an established line of matrix body PDC bits in extended-reach shale applications. However, early in the campaign it became clear the matrix body PDC bits, optimized for long horizontal sandstone and limestone applications, did not perform up to operator expectations in this new environment. After field and laboratory analysis, several key issues were identified including bit balling, poor directional behavior and loss of toolface control were causing low penetration rates and short runs. The main thrust of the design initiative would be to optimize steerability while maximizing penetration rates.

Application and Lithology Challenges

The PDC bit in the Haynesville shale play application was a hydraulic challenge from the very beginning. PDC bits had issues with plugged nozzles due to the lack of hydraulic energy for the drill bit. Often the hydraulic horsepower (HHP) expended at the bit is less than 1.0 HHP and can go as low as 0.2 HHP. The pressure across the nozzles is less than 60 pounds per square inch (psi) in these cases, which doesn't provide much protection against nozzle plugging.

The extended reach lateral in the Haynesville Shale further compounds hydraulic issues because the bit is tripped through a long lateral hole section loaded with cuttings. The cuttings can build-up in front of the bit and plug a nozzle with either full fluid flow or restricted flow caused by low pressures across the bit. The problem is exacerbated in high temperature applications (ranging from 280°F to 360°F) where shale cuttings can become packed and then baked on the bit body.

The primary challenges in the curve and lateral sections in the Haynesville Shale include building the curve with build rates between 8 to 12°/100 ft and drilling the extended reach lateral while achieving acceptable ROP in both the curve and lateral.

The most common mud type utilized in the Haynesville Shale is oil based mud (OBM) with mud weights ranging from 14.0 pounds per gallon (ppg) to 17.0 ppg. The typical flow rate in the predominant 6¾" hole size ranges from 200 to 260 gallon per minute (GPM).

The compressive strength of the rock in the build section through the Bossier Shale/Bossier Sand ranges from 3,000 to 9,000 UCS while the compressive strength in the lateral section through the production zone (Haynesville Shale) ranges from 3,000 to 6,000 UCS.

PDC Bit Development

Initial product development for shale plays was done using matrix body bits. These efforts met with little success. Several design iterations were also made on steel body bits to prevent nozzle plugging by repositioning and reorienting the nozzle. Although limited by its brittle nature, matrix blade height variations were also explored, but nozzle plugging was never successfully minimized to an acceptable level.

Transition from Matrix Body PDC to Steel Body PDC

Once the transition was made to steel, design changes streamlined the bit body allowing cuttings to pass by the bit. This proved successful in significantly reducing nozzle plugging issues. These changes included a bullet shaped bit body, taller blade heights and a reduced body diameter. While previous design work had been done to optimize nozzle placement and orientation, without redesigning the bit body to overcome nozzle plugging issues all other efforts would have had limited value.

Throughout the development of the shale play product line, computational fluid dynamics (CFD) was used to calculate the available hydraulic energy. Emphasis of the CFD work was placed on cutting structure cleaning and cuttings evacuation.

Plugged Nozzles - Potential Causes

Design engineers determined that there are many opportunities for cuttings to plug a nozzle bore if the hydraulic energy is low or totally restricted (not flowing):

- Insufficient hydraulic energy at the drill bit to prevent cuttings from moving into the nozzle bore
- Movement of cuttings into the nozzle bore during connections with no fluid flow
- Cuttings driven into the nozzle bores while pushing through cuttings bed in the lateral hole section
- Compression of cuttings into nozzle bores caused by contact with the hole bottom during tripping if blade height is insufficient

Any of the above situations can lead to nozzle plugging if cuttings cannot efficiently move around the bit or escape from the bit center into the junk slots and up the annulus.

Plugging During Connections

A common problem in extended reach shale drilling is the tendency for cuttings to collect in front of the bit face during connections. If the design of the body and junk slots do not allow for efficient movement of cuttings past the bit, a build-up of cuttings can occur and push into the nozzle bore plugging the nozzle (**Figure 1**). Cuttings can likewise be pinched between the hole bottom and the bit face when a bit is returning to bottom, which can also lead to plugged nozzles.

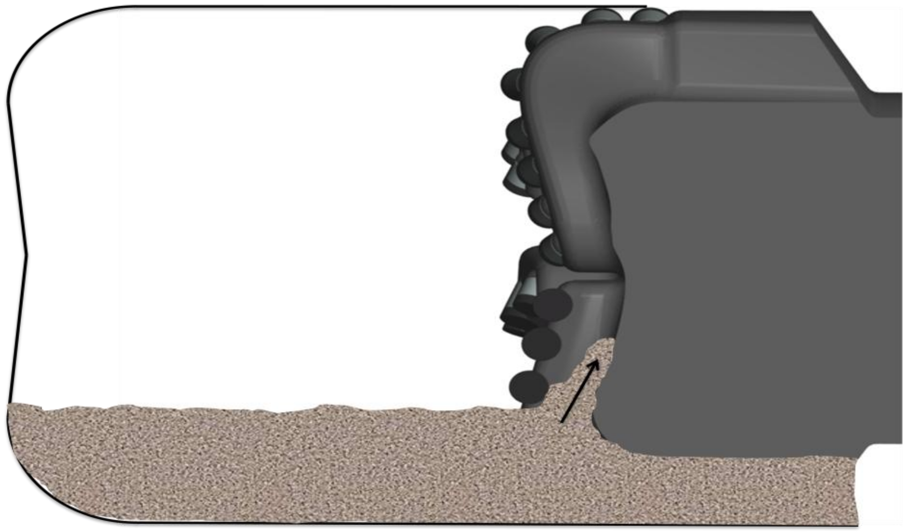


Figure 1 – Borehole wall and PDC bit cross section depicting plugging event during connections (matrix test bit)

FEA Based Modeling Analysis

Since the bit manufacturer was unable to obtain actual cores samples, laboratory technicians used UCS and rock strength analysis software (**Figure 2**) to identify rocks in the drilling laboratory that best matched actual field formations. The study would use instantaneous ROPs from the field with equivalent modeled ROPs for a given WOB and RPM. Geologic experts determined that Wellington and Mancos shales are sufficiently comparable to field formations and would be well suited for laboratory work.

Several design iterations were performed to arrive at a final PDC design that would satisfy the specific application's requirements. The number of design iterations varied from one location to another and between bit sizes. On average, at least 50 modeling iterations were performed before each specific PDC design was finalized.[1-10]

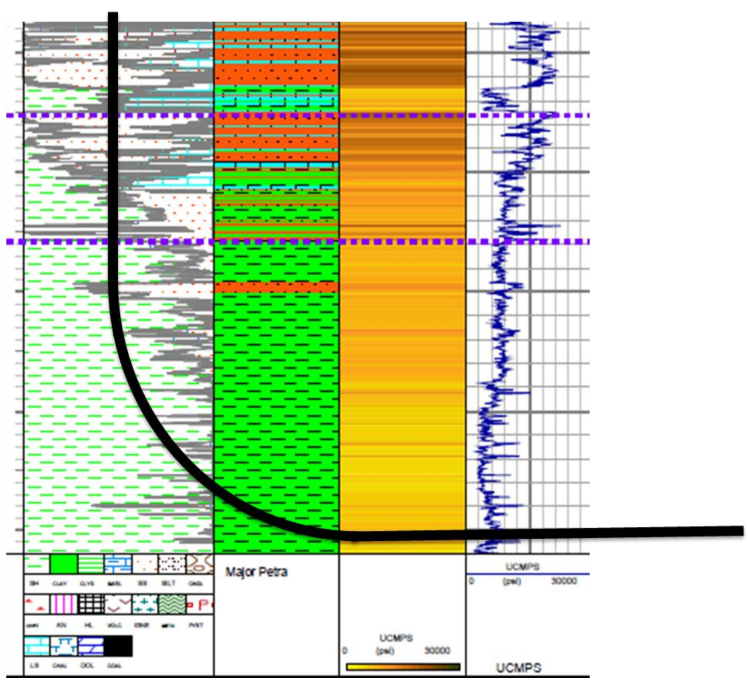


Figure 2 – DBOS log of Haynesville formation composed mainly of shale
Bossier Shale/Bossier Sand (3-9 Kpsi) and Haynesville Shale (3-6 Kpsi)
Note: Typical directional wellbore profile of shale drilling application

Design Process Details

The major objectives for the application specific bit were:

1. Drilling the curve – Steerability, toolface control, less time spent on corrections, ability to deliver the required dogleg between 8-12°/100 ft.

2. Drilling the lateral - Increased ROP

During the modeling process, engineers focused attention on stability challenges to rectify the design's limitations. They also ran tests with small (11mm-13mm) and large cutters (16mm-19mm) to verify field results and explore for performance improving options. Modeling simulation tests revealed that cutting structures with flatter profiles provide the least resistance to change in inclination (ability to achieve the required DLS), which is important to all three shale plays. Accordingly, the manufacturer uses flat and short profiles for all the cutting structures.

<u>Stability</u>

PDC bit stability is important to help achieve directional control. If the cutting structure vibrates with a given drilling system (BHA-drill bit-rock interaction), the bit will be difficult to steer in the required direction. This situation requires the directional driller to reorient the toolface in the proper direction to achieve the required directional objectives. The modeling software helped engineers design a stable bit body/cutting structure for a given drilling system.

Stabilizing a bit in the curve during kick-off before the bend is fully established was difficult, as was stabilizing the design for rotate/slide mode. The poor weight-to-bit transfer during sliding at the end of the curve and also in the lateral made dynamic stability a challenge as well. Several different BHAs were used based on each application and hole size, but most had at least one slick BHA validation (BHA with no stabilization) to ensure the design was stable.

One of the challenges in this application was the wide range of input parameters (WOB, surface RPM, motor RPM and motor bends). There are several operators drilling these applications with several directional drilling companies. Without exception, every operator drills the curve and lateral with a different BHA and input parameters. Given this wide range, each design iteration had to be validated with several BHAs and a wide range of input parameters.

<u>Cutter Size</u>

Several variations in bit types were manufactured and run as an experiment based purely on the directional driller's past preferences and previous run success:

- SDi513 – 5 blades, 13mm cutters - lateral
- SDi611 – 6 blades, 11mm cutters - curve/lateral
- SDi711 – 7 blades, 11mm cutters – curve and curve/lateral

Field performance with 11mm and 13mm cutters has been good. The small cutters have a shallow depth-of-cut compared to large 16mm and 19mm cutters. The 16mm/19mm cutters' substantial depth-of-cut creates a higher instantaneous torque response which can cause the driller to lose toolface control. Since controlling directional response is essential to the success of a shale drilling application, the bit manufacturer will remain committed to using 11mm and 13mm cutters.

Make Up Length (Matrix vs Steel)

One of the inherent advantages of building steel body PDCs for a directional application is the reduced make up length (MUL). In the targeted applications, directional drillers use a steerable motor with a bent housing to steer the bit. Because of this, the bit-to-bend length plays a direct role in achieving the desired dogleg severity. A high bit-to-bend angle puts excessive torque on the motor/bit, especially when drillpipe is rotated in the curved hole section. Any BHA attribute that reduces the bit-to-bend length is considered an additional benefit by the directional driller. According to directional drilling experts, one to two inches of reduced MUL can have a positive influence on the dogleg capability of a PDC bit. In any case, a shorter MUL is preferred by most directional drillers.

Manufacturing Details

The steel body PDC has a shorter MUL (**Figure 3**) than a matrix body bit. Matrix bits are made up of three major components, while a steel body version has two. Clearance requirements for the steel blanks (mandatory for product reliability) means the matrix designs are a few inches taller than the steel body versions.

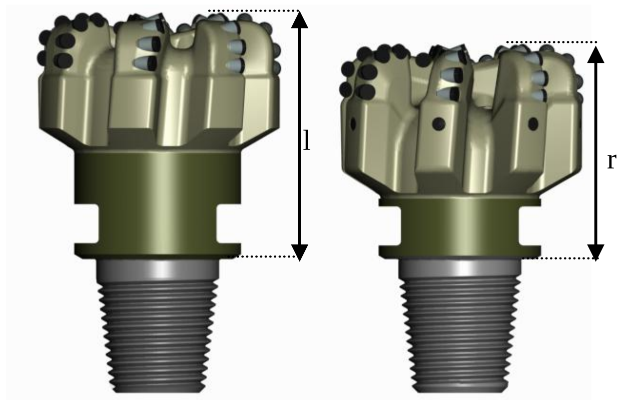


Figure 3 – Make-Up-Length: Comparison of Matrix Body (l) vs Steel Body (r)

Bullet Body

The following review of the bullet bit (BB) body (**Figure 4**) is offered to highlight how the redesign helps reduce nozzle plugging.

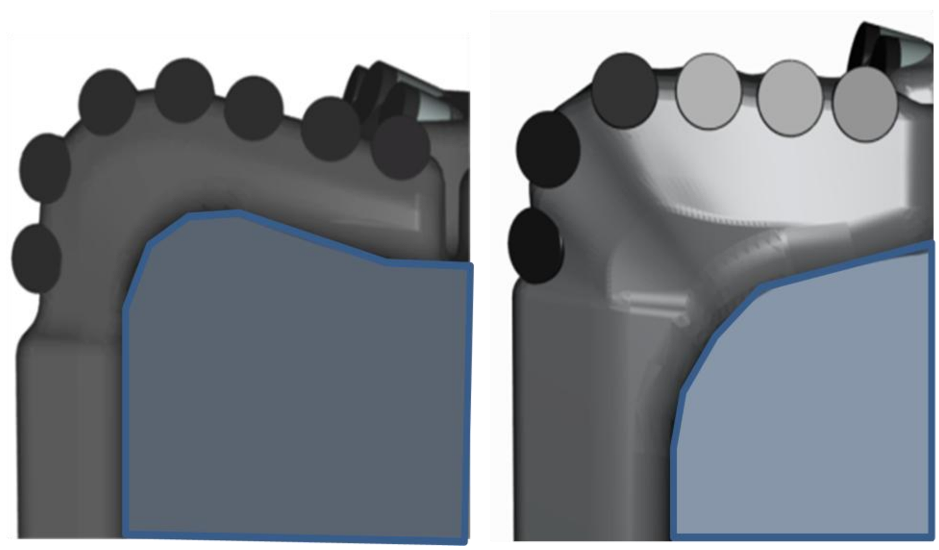


Figure 4 – Comparison of standard body (left) vs bullet body design (right) and resulting streamline shape

<u>Bullet Shaped Body</u>

The bullet-shaped body (BB) streamlines the bit making it easier for cuttings to sweep around the body instead of building up on the bit as it pushes through a cuttings bed. This design also makes it easier for cuttings coming off the face of the cutter to be pushed to the outside and into the junk slot. BB also creates a diverging distance between the cutter profile and the bit body, making it more difficult for cuttings to become trapped and compressed between the body and the hole bottom.

<u>Reduced Body Diameter</u>

The reduced body diameter increases the distance between the borehole and the bit body in the junk slot. This improves the ability of cuttings to pass through the junk slots without building up in front of the bit face.

<u>Increased Blade Height</u>

Increasing the blade height reduces the instance of cuttings from the bit face pushing into the nozzle bore prior to exiting the bit. With a taller blade, cutting ribbons are weakened and can break away from the bit body and move promptly into the junk slot areas.

Thinner Blades

Reducing the blade thickness decreases the surface area in front of the bit where cuttings tend to build up. Also, cuttings can flow around a thin blade more readily than a thick blade, reducing the chance of packing into a nozzle.

Initial Bit Body Testing (Matrix vs Steel)

Initial testing with matrix designs were limited by the aspect ratio (blade height/blade width), which hindered engineers from implementing the preferable tall, thin blades because of blade breakage concerns. Since steel is fundamentally tougher than matrix, it allowed the blade to extend further from the bit body with much less potential for failure or breakage due to impact. Because of the applications' low hydraulic energy and negligible formation abrasiveness, bit body erosion is not a concern.

The 6¾" matrix test bit was an MDi711. The 6¾" steel body version was an SDi711. Although the cutting structure and hydraulics are identical, the overall junk slot and face volume differences give the two bits noticeably different profiles (**Figure 5**). Also included in Figure 5 is the 6 bladed, 11mm design. In spite of the limited number of matrix version bit runs, we can draw some strong conclusions about why the steel version of this design performed well from the outset.

Matrix - 7 Bladed Bit Body   Steel -7 Bladed Bit Body   Steel - 6 Bladed Bit Body

Figure 5 – Steel manufacture allows PDCs to have reduced blade width and additional blade height increasing space between the bit body and the borehole wall

Integrity Ratio

The design approach of increasing blade height while reducing blade width raised potential hydraulic issues and concern. In applications with sufficient hydraulic energy, opening up the junk slot and face volume areas can create hydraulic inefficiencies. However, in the shale plays, there is generally insufficient hydraulic energy available, thus there are no measurable inefficiencies encountered due to the larger open areas. Also, low drilling fluid flow rates in the shale play applications are a major contributing factor leading to a deep bed of cuttings in the lateral hole section that causes packed blades and plugged nozzles. Accordingly, the greater area around the steel body design allows the bit to pass over or through a cuttings bed alleviating the blade packing and nozzle plugging issues. The following analysis shows the dramatic difference between junk slot and face volume areas of the two test bits.

Junk Slot Area	**Face Volume**
MDi711: 8.0 sq in	MDi711: 37.0 cubic in
SDi711: 11.6 sq in	SDi711: 51.0 cubic in
SDI611: 13.0 sq in	SDi611: 58.0 cubic in
SDi711vs. MDi711 - An increase of 45%	SDi711vs. MDi711 - An increase of 38%
SDi611vs. MDi711 - An increase of 63%	SDi611vs. MDi711 - An increase of 57%

Bullet Body

A bullet type bit body helps channel cuttings away from the center of the bit where nozzle plugging is particularly problematic. A bullet-shaped bit body inherently increases blade height, which can be a problem with matrix blades, but the design change issues are overcome with steel body manufacture. Applying the BB design feature also limits balling during connections, because cuttings cannot collect in the bit's center when the pipe is pulled out and tripped in. The bullet body design concept is well established and has been incorporated into previous product lines (PS250) as well as vertical shale PDC styles with good success.

Bit Body Summary

The ordered combination of changes outlined below directly contributed to the success of the steel body design compared to the matrix version, especially given that their cutting structures and hydraulic nozzle locations are identical.

1. Thinner/taller bit blades
   - Improved face volume
   - Improved junk slot volume
2. Sculpted bit body - bullet body geometry

Hydraulic Evaluation

Given the unique downhole conditions in the Haynesville Shale (high mud weight, high bottom hole temperature) and limited hydraulic energy available at the bit, engineers performed computational fluid dynamics (CFD) analysis with the following field operating parameters:

- Haynesville Shale
- Flow Rate: 200-250 GPM
- TFA: (7) 12/32" nozzles = 0.773sq. inch
- Hydraulic Configuration
  - Seven nozzle version
    - (7) 12/32 N40's

The CFD simulations were run and documented. **Figure 6** shows the fluid path lines on the bit face. The nozzle placement and orientations were optimized to minimize recirculation on the bit face. This optimization leads to the efficient cuttings evacuation, thus reducing the potential for bit balling. Each of the seven colors represents particles exiting the respective nozzle.

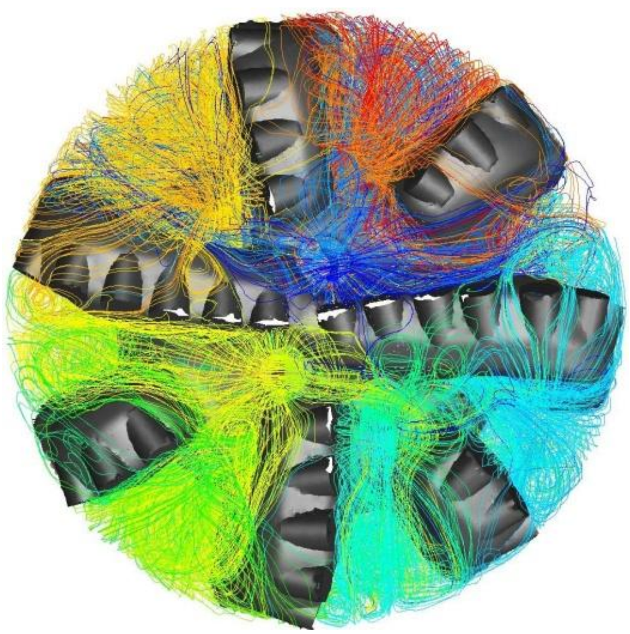


Figure 6 – Fluid path lines (face view), seven nozzles – 6¾" SDi711

Similarly, nozzle orientation is adjusted to minimize recirculation regions in the junk slot near the gauge pads. **Figure 7** shows the side view of the flow pathlines exiting the junk slot. Minimizing recirculation zones help prevent the cuttings from reentering the bit face.

Figure 7 – Fluid path lines (side view), seven nozzles – 6 ¾" SDi711

Hydraulics Development Summary

The shale play bits have been specifically designed to efficiently drill a long lateral hole section with low hydraulic energy through a relatively deep bed of cuttings. The unique design characteristics of the steel bit body have made it possible to overcome the hydraulic challenges and avoid nozzle plugging. Computational fluid dynamics (CFD) efforts were focused on cleaning the cutting structure and optimizing evacuation routes for the passage and removal of cuttings around the bit.

Case Studies – Wellbore Profile

Two case studies are presented to illustrate how the application specific steel body bit deigns have increased performance in the Haynesville Shale play. **Figure 8** shows a typical wellbore schematic for a Haynesville Shale well and applies to both case study 1 and case study 2. The bits identified in both case studies are used below the 7-5/8" casing to total depth (TD) of the well in the Bossier and Haynesville Shale sections.

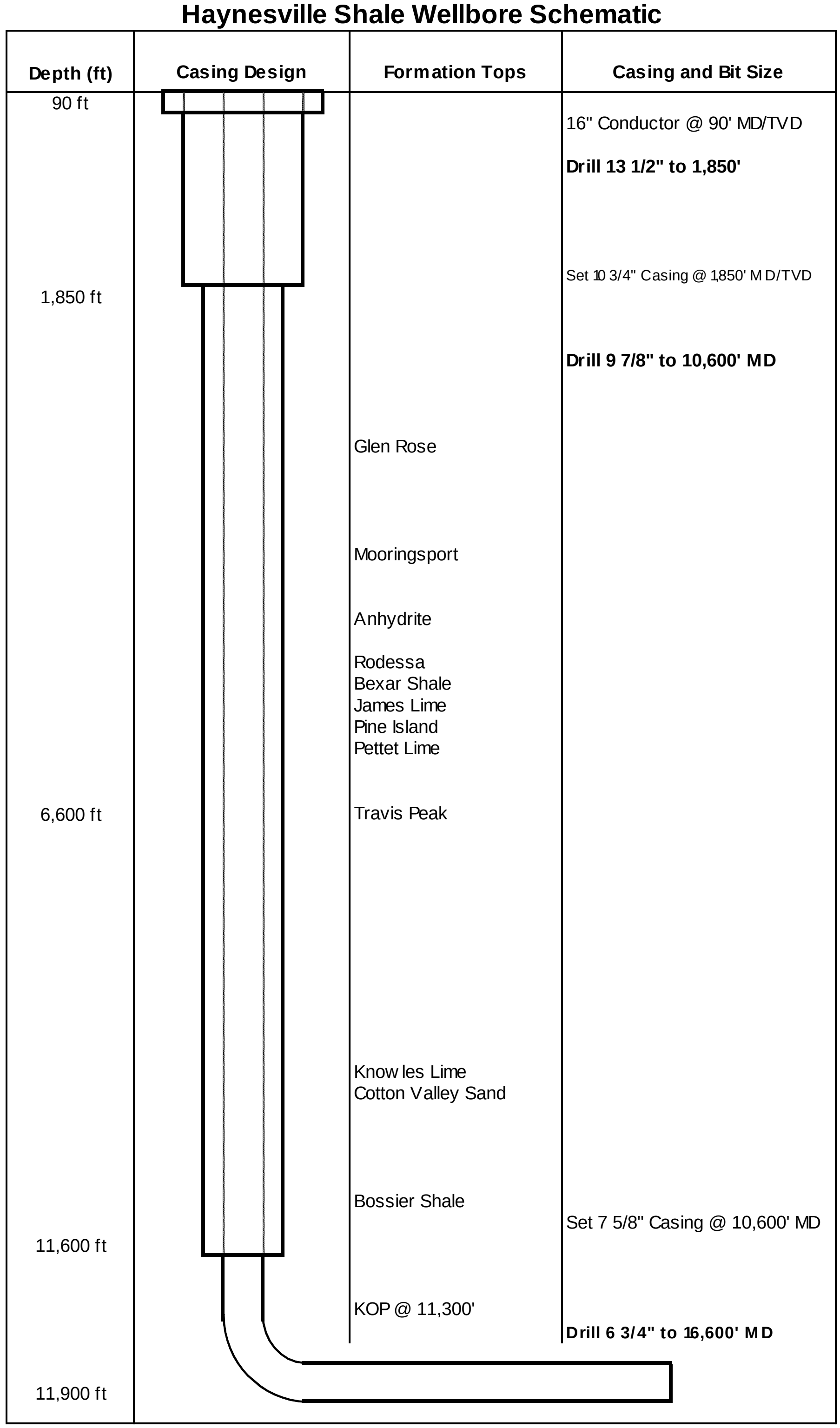


Figure 8: – Wellbore Profile, Haynesville Shale

The wells highlighted in the case studies are representative of the performance step change the new PDC bit technology has delivered over the past two years in the Haynesville Shale Play. The primary objective of the project was to reduce the number of days in the curve and lateral section by designing application-specific PDC bits capable of achieving the high build rates in the curve section while at the same time producing high ROP in the lateral section. Proper cleaning of the bit face and efficient removal of cuttings from the around the bit body were a primary challenge that needed to be solved to successfully achieve the project goals. The dual approach of bit design and hydraulic layout was instrumental and critical to the success of the engineering project.

Case Study 1 illustrates the application of a new steel body 7 bladed, 11mm cutter shale PDC bit offsetting traditional matrix designs through the same interval (curve and lateral). Prior to the introduction of the new technology, multiple trips were required to change out the bottom hole assemblies for adjustments to the bend angle or downhole motor or MWD failure(s). The new 7 bladed, 11mm cutter bit proved capable of achieving the required build rates on PDMs with lower than traditional bend angles allowing the operator to successfully build and land the curve and continue drilling to total depth without having to make costly trips for bottom hole assembly changes or downhole tool failures.

Case Study 2 illustrates the application of a new steel body 6 bladed, 11mm cutter shale PDC bit designed to increase the ROP potential in the lateral while maintaining steerability in the curve section of the hole.

Both case studies document an improved bit performance and the resulting reduction in cost per foot. The performance improvement was made possible by matching the bit design to the specific bottom hole assembly and drilling parameters used in the build and lateral sections of the Haynesville Shale wells.

Case Study 1

For this case, a 7 bladed, 11mm cutter steel body PDC bit was utilized to drill out below 7-5/8" casing set at 10,600 ft. The bit was run on a steerable BHA with a 2.25° bend angle (**Figure 9**). The entire 6,293 ft interval was drilled in 188.5 hrs at an average ROP of 33.4 fph to a total measured depth of 16,893 ft. **Figure 10** shows the actual dull of the 7 bladed, 11mm cutter bit used in the case study. **Figure 11** shows the typical dull condition (plugged nozzles) of two matrix bits (one 7 bladed, 11mm cutter bit and one 5 bladed, 13mm cutter bit) that were run prior to the development of the new steel body PDC bit product line. **Figure 12** shows the bit performance and cost analysis of the 7 bladed, 11mm cutter bit versus a direct offset utilizing multiple bits and several different bottom hole assemblies. **Figure 13** shows the wellbore trajectory for the build and lateral sections. The direct offset shows the performance of traditional matrix bodies and milled tooth bits through the curve and lateral hole sections. The offset bits drilled from 10,600 ft to 16,500 ft (5900 ft) in 329.5 hrs for an average ROP of 17.9 fph. The new style bit reduced total drilling hours from 329.5 hrs to 188.5 hrs and round trip hours fell dramatically from 65.6 hrs to just 16.5 hrs (four fewer bit/BHA trips). The associated bit cost was also reduced from four bits (a one bit was rerun on the offset well) to one bit. The one bit curve and lateral section saved the operator a total of $700,000.

Component	O.D. (in)	I.D. (in.)	Length (ft)
PDC Bit	6.75		0.5
PDM (5:6, 8.3 stage, 2.25 degree bend, 1.01 rev/gal)	4.75	2.0	28.20
Float Sub	4.75	2.375	3.13
Muleshoe Sub	4.75	2.25	2.67
Non-Mag Flex Drill Collar	4.75	2.75	30.74
Non-Mag Flex Drill Collar	4.75	2.75	30.72
Cross Over Sub	5.437	3.75	3.19

Figure 9 - Bottom Hole Assembly – Case Study 1

Figure 10 - Dull photos of 7 bladed – 11mm cutter PDC bit – Case Study 1

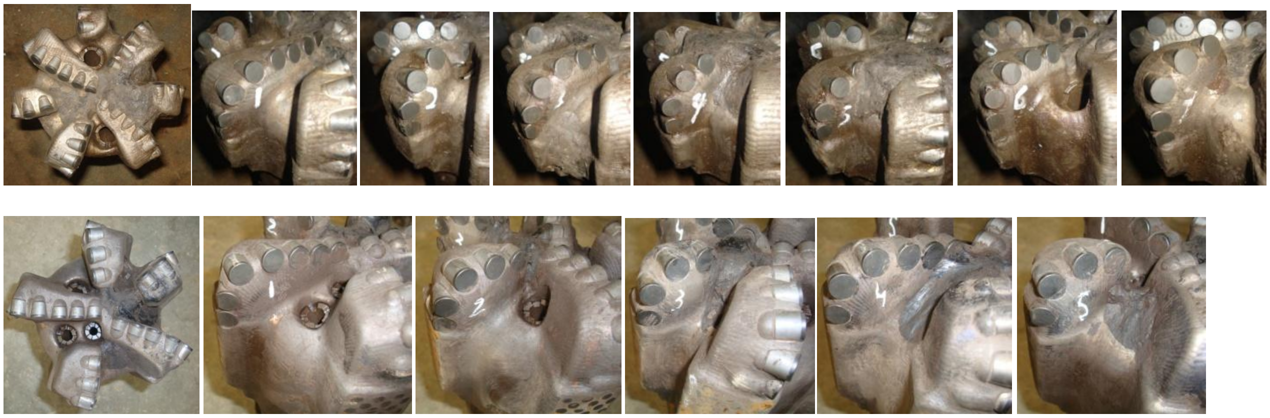


Figure 11 - Typical dull condition of 7-bladed and 5-bladed matrix bits

Bit Performance Cost Report

CASE STUDY 1

7 Bladed - 11mm Cutter Bit

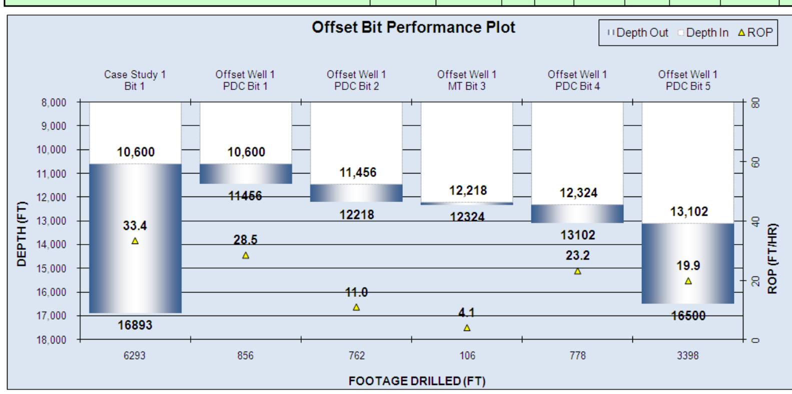
Operator :	**Haynesville Shale Operator**
Well :	**Case Study 1**

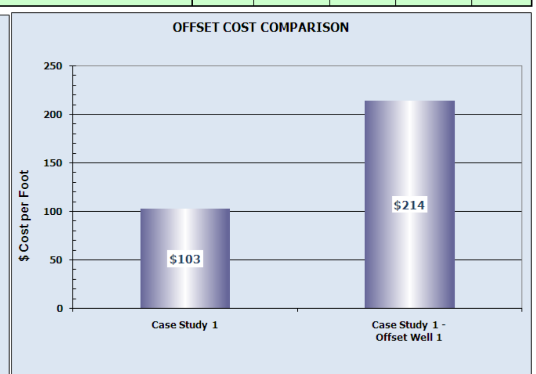
Total Savings on Case Study 1			
Offset Well	**$/ft**	**Cost @ 6293'**	**Savings v Offset**
Case Study 1	$102.77	$646,718	**$702,341**
Case Study 1 - Offset Well 1	$214.37	$1,349,059	

Well Name	Bit Size	Bit Type	Bit s/n	MD In	MD Out	Inc In	Inc Out	Feet Drilled	Drlg. Hours	ROP ft/hr	Trip Hrs	Dull Grade	Run Economics: Bit Cost	Drilling	Trip	Total	$/ft
Case Study 1	6.75	Case Study 1 Bit 1		10,600	16,893		90.80	6,293	188.5	33.4	16.9	0-0-NO-A-X-X-X-IN-NO-TD	$10,000	$584,350	$52,368	$646,718	$102.77
Case Study 1				**10,600**	**16,893**	**0.00**	**90.80**	**6,293**	**188.5**	**33.4**	**16.9**		**$10,000**	**$584,350**	**$52,368**	**$646,718**	**$102.77**

Offset Well for Comparison

Well Name	Bit Size	Bit Type	Bit s/n	MD In	MD Out	Inc In	Inc Out	Feet Drilled	Drlg. Hours	ROP ft/hr	Trip Hrs	Dull Grade	Offset Economics: Bit Cost	Drilling	Trip	Total	$/ft
Case Study 1 - Offset Well 1	6.75	Offset Well 1 PDC Bit 1		10,600	11,456		0.6	856	30.0	28.5	11.5	1-1-WT-A-X-X-X-IN-NO-HP	$10,000	$93,000	$35,514	$138,514	$161.81
Case Study 1 Offset Well 1	6.75	Offset Well 1 PDC Bit 2		11,456	12,218		63.3	762	69.0	11.0	12.2	1-1-WT-A-X-X-X-IN-NO-BHA	$10,000	$213,900	$37,876	$261,776	$343.54
Case Study 1 Offset Well 1	6.75	Offset Well 1 MT Bit 3		12,218	12,324		74.5	106	26.0	4.1	12.3	0-1-ER-N-E-E-E-IN-NO-BHA	$10,000	$80,600	$38,204	$128,804	$1,215.14
Case Study 1 Offset Well 1	6.75	Offset Well 1 PDC Bit 4		12,324	13,102		89.0	778	33.5	23.2	13.1	0-0-NO-A-X-X-X-IN-NO-BHA	$10,000	$103,850	$40,616	$154,466	$198.54
Case Study 1 Offset Well 1	6.75	Offset Well 1 PDC Bit 5		13,102	16,500		90.5	3,398	171.0	19.9	16.5	2-2-WT-A-X-X-X-IN-BT-TD		$530,100	$51,150	$581,250	$171.06
Case Study 1 - Offset Well 1				**10,600**	**16,500**	**0.00**	**90.5**	**5,900**	**329.5**	**17.9**	**65.6**		**$40,000**	**$1,021,450**	**$203,360**	**$1,264,810**	**$214.37**





Spread rate ($/hr) = $3,100

Trip rate (ft/hr) = 1000

Figure 12 - Bit performance and cost analysis – Case Study 1

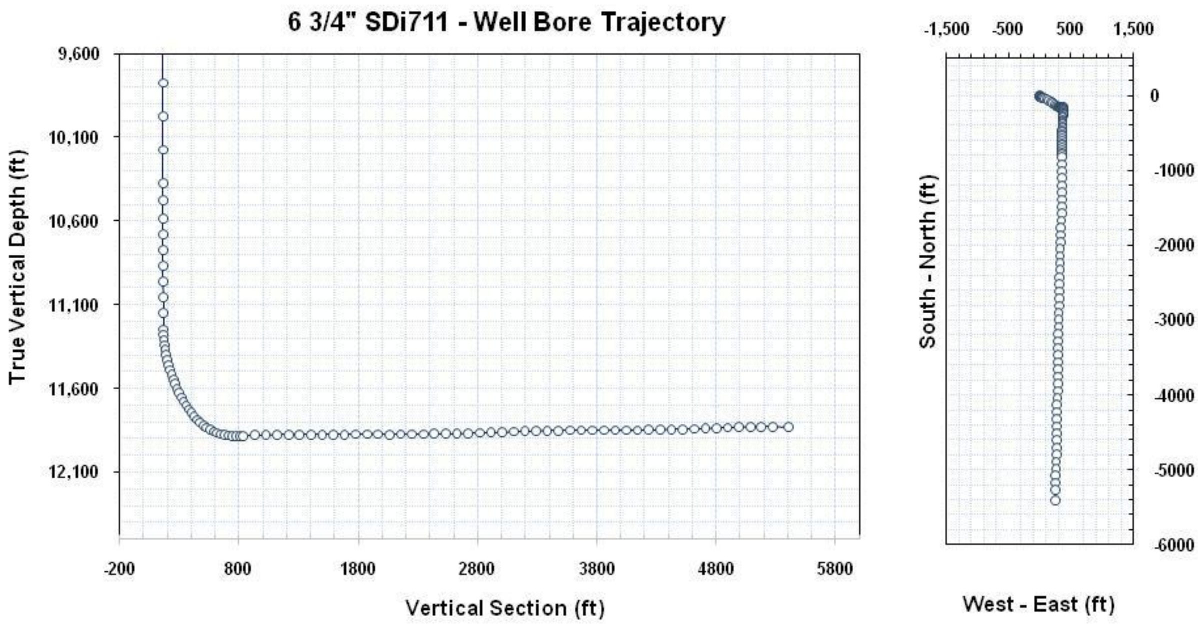


Figure 13 - Wellbore Trajectory – Case Study 1

Case Study 2

For this case, a 6 bladed, 11mm cutter steel body PDC bit was utilized to drill out below 7-5/8" casing set at 10,375 ft. The bit was run on a steerable BHA with a 2.12° bend angle (**Figure 14**). The entire 6,015 ft interval was drilled in 149.0 hrs at an average ROP of 40.4 fph to a total measured depth of 16,390 ft. **Figure 15** shows the actual dull of the 6 bladed, 11mm cutter bit used in the case study. **Figure 16** shows the bit performance of the 6 bladed, 11mm cutter bit versus a direct offset utilizing multiple bits and bottom hole assemblies. **Figure 17** shows the wellbore trajectory for the build and lateral sections. The direct offset shows the performance of a 7 bladed matrix bit and a 5 bladed steel bodied bit through the curve and lateral sections of the hole. The offset bits drilled from 10,385 ft to 16,190 ft (5,805 ft) in 251.5 hrs for an average ROP of 23.1 fph. Not only were the drilling hours reduced from 251.5 hours to 149.0, but the round trip hours were reduced from 28.4 hours to 16.4 hours (one less bit trip). The associated bit cost was also reduced from two bits to one bit. The one bit curve and lateral section saved the operator a total of $400,000.

Component	O.D. (in)	I.D. (in)	Length (ft)
PDC Bit	6.75	1.75	0.5
PDM (5:6, 8.3 stage, 2.12 degree bend, 1.01 rev/gal)	4.75	2.794	28.02
Double Bore Float Sub	4.75	2.25	3.76
Integral Blade Stabilizer	4.75	2.50	4.95
Non-Mag Double Pin Cross Over Sub	4.75	2.25	1.63
Non-Mag Hang Off Drill Collar	4.75	2.50	31.12
Downhole Screen Sub	4.875	2.125	4.68
Cross Over Sub	5.25	2.50	4.1

Figure 14 - Bottom Hole Assembly – Case Study 2

Figure 15 - Dull photos of 6 bladed – 11mm cutter PDC bit – Case Study 2

Bit Performance Cost Report

Case Study 2

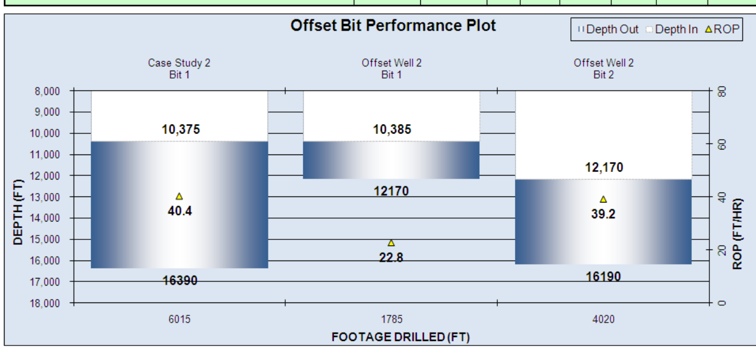
6 bladed - 11mm Cutter Bit

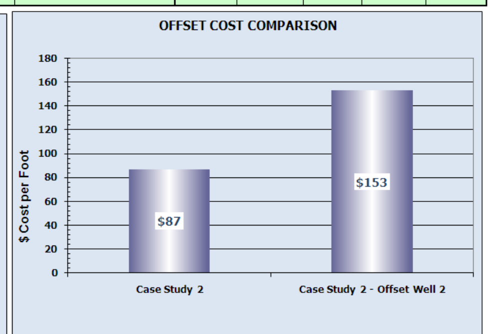
Total Savings on Case Study 2			
Offset Well	**$/ft**	**Cost @ 6015'**	**Savings v Offset**
Case Study 2	$86.90	$522,709	$396,965
Case Study 2 - Offset Well 2	$152.90	$919,674	

Operator :	Haynesville Shale Operator
Well :	Case Study 2

Well Name	Bit Size	Bit Type	Bit s/n	MD In	MD Out	Inc In	Inc Out	Feet Drilled	Drlg. Hours	ROP ft/hr	Trip Hrs	Dull Grade	Run Economics Bit Cost	Drilling	Trip	Total	$/ft
Case Study 2	6.75	Case Study 2 Bit 1	JE4781	10,375	16,390	0.62	90.8	6,015	149.0	40.4	16.4	0-0-NO-A-X-X-X-IN-NO-TD	$10,000	$461,900	$50,809	$522,709	$86.90
Case Study 2				**10,375**	**16,390**	**0.62**	**90.80**	**6,015**	**149.0**	**40.4**	**16.4**		**$10,000**	**$461,900**	**$50,809**	**$522,709**	**$86.90**

Offset Well for Comparison																	
Well Name	**Bit Size**	**Bit Type**	**Bit s/n**	**MD In**	**MD Out**	**Inc In**	**Inc Out**	**Feet Drilled**	**Drlg. Hours**	**ROP ft/hr**	**Trip Hrs**	**Dull Grade**	**Offset Economics Bit Cost**	**Drilling**	**Trip**	**Total**	**$/ft**
Case Study 2 - Offset Well 2	6.75	Offset Well 2 Bit 1		10,385	12,170	0.95	82.3	1,785	135.0	22.8	12.2	2-1-WT-A-X-X-X-IN-BF-BHA	$10,000	$418,500	$37,727	$466,227	$261.19
Case Study 2 - Offset Well 2	6.75	Offset Well 2 Bit 2		12,170	16,190	82.3	93.8	4,020	116.5	39.2	16.2	2-3-BT-A-X-X-X-IN-CT-TD	$10,000	$361,150	$50,189	$421,339	$104.81
Case Study 2 - Offset Well 2				**10,385**	**16,190**	**0.95**	**93.8**	**5,805**	**251.5**	**23.1**	**28.4**		**$20,000**	**$779,650**	**$87,916**	**$887,566**	**$152.90**





Spread rate ($/hr) = $3,100
Trip rate (ft/hr) = 1000

Figure 16 - Bit performance and cost analysis - Case Study 2

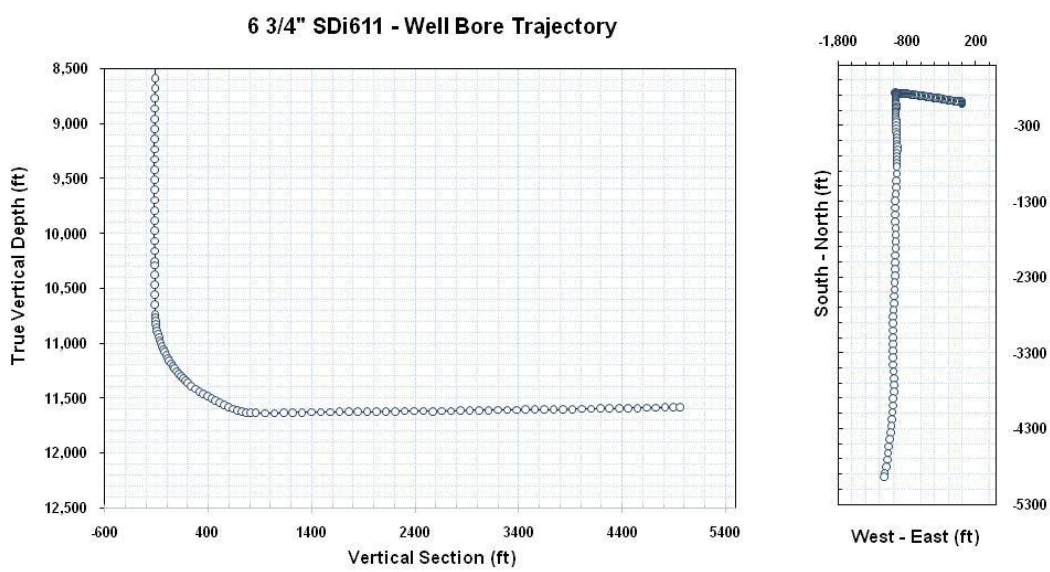


Figure 17 - Wellbore Trajectory – Case Study 2

Conclusions

The targeted steel body PDC development for shale drilling applications has successfully delivered a new bit technology platform. The shale gas bits can efficiently drill both the curve and lateral hole sections while delivering the required build-rates in the curve and high ROP in the lateral.

The new bit technology has led to a step change in drilling performance in the Haynesville Shale Gas play. On the case study wells, the shale bits significantly reduced total drilling hours and bit consumption saving the operator $1,100,000 on just two wells. The new optimized shale PDC bits are also being successfully applied in the Marcellus and Eagle Ford plays with similar results.

The new generation of steel body PDC bits are enabling operators to increase overall drilling efficiency, reducing development costs and enhancing project economics. Further engineering refinements are underway and additional gains are expected.

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