



**Presented to IADC World Drilling Conference 2009**

## **A Case History**

# **Innovative Drilling Rig Delivers Increased Drilling Performance in Permian Basin**

### **Author and Co Authors:**

J. Gregory Nutter, Xtreme Coil Drilling  
Reg Layden, Xtreme Coil Drilling  
Cody Grasmick, XTO Energy  
Don Eubank, XTO Energy

### **Abstract**

Wells have been drilled in the Permian Basin since 1920 and drilling activity continues there today. For an upcoming drilling campaign in 2008 one producer sought to improve drilling rates of penetration (ROP) and to reduce overall well construction costs by implementing a well construction plan that included new and innovative technologies. The company analyzed offset bit records in the area and, after consultation with bit companies, they moved from roller cone bits to polycrystalline diamond compact (PDC) bits. After this technology was proven and implemented, XTO, the operator, decided to take a new direction in terms of the drilling rig. They replaced the standard drilling rig with an innovative drilling rig design that combines both a full top drive rotary rig and a coiled tubing drilling rig into one rig model. This paper details the wells drilled with this innovative drilling rig and outlines additional reductions in well construction costs.

### **Optimized Use of PDC Bits**

Wells have been drilled in the Permian Basin for more than 80 years. Just as in the rest of world, historical detailed bit records are used in the well planning process. In this paper the wells discussed are in developed fields where the well plans and drilling curves have changed very little even though drilling technology has changed substantially.

In the Permian Basin the status quo was to drill most wells with 5-4-7 IADC and 6-2-7 IADC type roller cone bits due to the extremely hard heterogeneous formations. In these formations, compressive strengths can change abruptly from 5,000 psi to 30,000 psi. XTO sought to reduce drilling costs and analysed new PDC bit technology for its potential to reduce rotating hours. Discussions with local bit vendors indicated there were few PDC bit offsets and not many successful implementations of PDC bits in most areas of the Permian Basin. Recent developments in the quality of diamond cutters showed some promise with regard to bit strength and durability.

A program to optimize a fit-for-purpose PDC bit required establishing a partnership between the operator and the bit company who worked together to develop the appropriate well plan, drilling parameters, and changes to bit designs. The operator, XTO, first reviewed a developed field northwest of Odessa, Texas where a few PDC bits runs had been attempted, but with little success. The 7-7/8 inch production portion (1,400 to 6,700 ft) of the well was routinely being drilled with two 5-4-7 IADC type roller cone bits in an average of 185 rotating hours (Figure 1, CAG Roller Cone AVG).

Through the partnership established between XTO and Ulterra Drilling Technologies, the previous unsuccessful PDC bit runs were analyzed, allowing Ulterra to provide a new durable PDC bit with the latest technology in diamond cutters. The operator was committed to running the PDC bit to total depth (TD) without concern for how many bit runs were required to reach TD. This allowed the team to gather valuable data for drilling operations with PDC bits and for future bit designs. The initial well required three PDC bits to drill to TD and drilled the production hole in 116 rotating hours, 69 hours faster than with the two roller cones (Figure 1, CAG #1704). After examining all three dull PDC bits, the bit company again made changes to the bit design. The newly designed PDC bit was modified, built and on location by the time the bits were needed for the next well. The production hole portion of next well, with the new durable bit design, was drilled with one PDC bit in 97 rotating hours (Figure 1, CAG #1708).

Once again , Ulterra was able to evaluate the dull condition of the PDC bit using the knowledge gained regarding running parameters required to get the PDC bit through the hard formations with WOB (35 - 40k lbs) and RPM (65 – 70 RPM). The high WOB and low RPM parameters are opposite of industry norms and were incorporated into the design of a new bit before the next well commenced drilling. Discussions between the drilling engineer, drilling superintendent and the bit company resulted in a decision to pull the first PDC at 5,100 ft. after it drilled through a known hard transition zone, and then to install a new PDC bit in the BHA with new sharp cutters. Both PDC bit runs were extremely successful and the production hole portion of the well was drilled in 87 rotating hours, which was 98 hours faster than the average two roller cone bit runs that had been characteristic over the past several years (Figure 1, CAG #1709).

After that well, further changes were made to the 7-7/8 inch, 6 blade, 16 mm cutter PDC bit. These changes included:

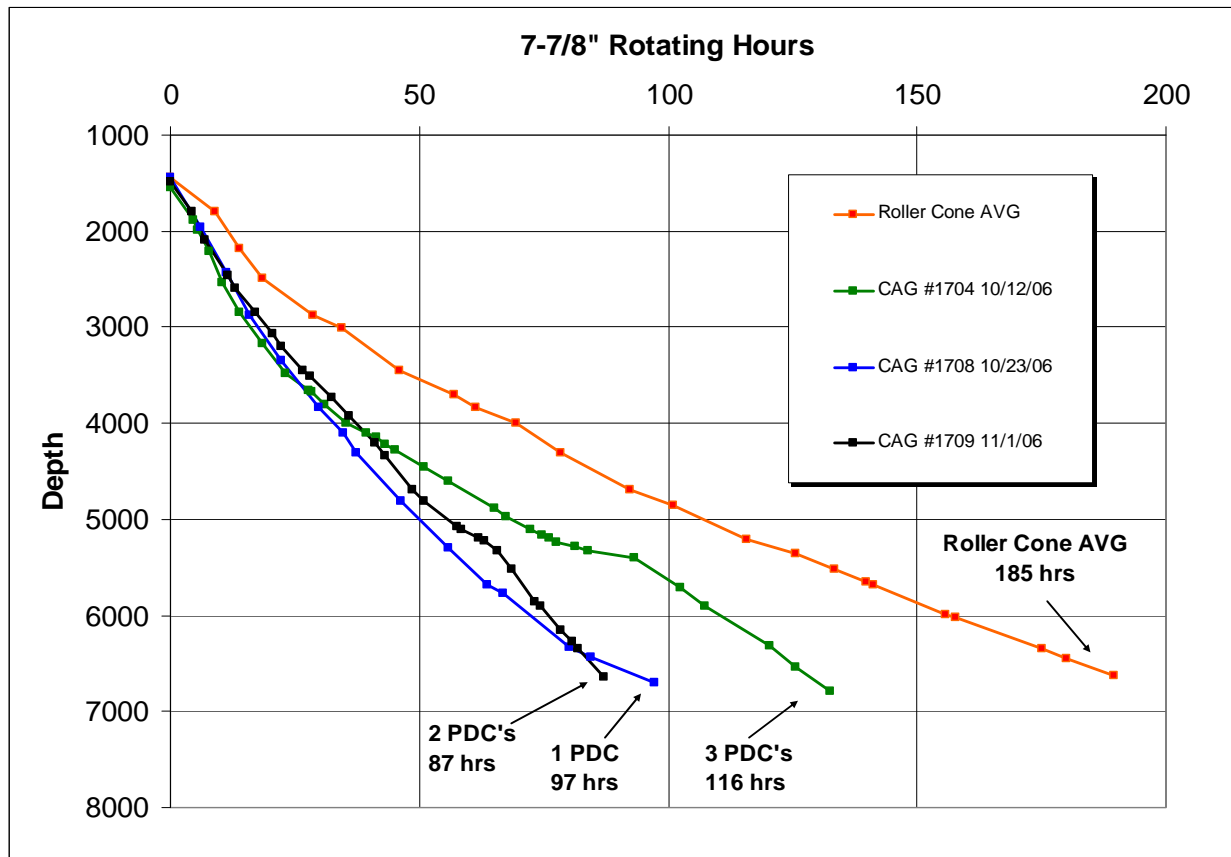
- a) additional cutters for better weight distribution per cutter;
- b) extra matrix webbing to the center of the bit for better durability; and,
- c) changes in chamfer angle on the cutters for more or less aggressiveness depending on whether it was the first or second PDC bit run from under surface casing.

The wells that followed the three experimental wells led to an overall optimization of well planning, drilling parameters, and changes in design of drilling operations. Today, in this field, the operator is consistently drilling wells in 85 rotating hours and has set a field record of 78.25 rotating hours.

The reduction from two roller cone bits at 185 hours to two PDC bits at 85 hours is more than a 50 percent reduction in rotating hours and has since lowered drilling costs by reducing wells from an average drilling time of 15 days to an average of 9 days .

**Figure 1**

Wells drilled in the Goldsmith area using a rotary rig and introducing PDC bits.



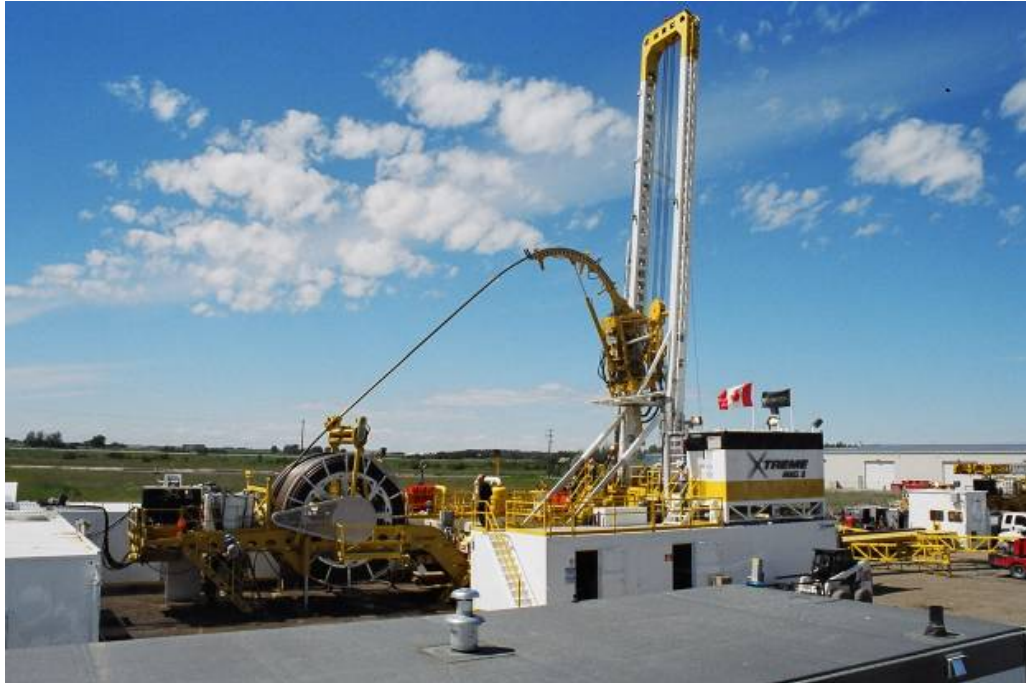
**Use of a Dual Purpose Rig to Reduce Rotating Time**

After successful introduction of PDC bits into this area of the Permian Basin reduced rotating hours by more than 50 percent, XTO began investigating further opportunities to continue to reduce drilling times. One method their engineers researched was the use of coiled tubing to drill the 7-7/8 inch hole to TD. The operator conducted discussions with a drilling company regarding the application of their newly designed dual purpose rigs for drilling some re-entry wells in the Permian Basin as well as their capability to drill vertical wells in developed fields. The rig selected was a newly built drilling rig with a full top drive combined with a full coiled tubing unit (see Figure 2). XTO selected several grass roots vertical wells for drilling with the dual purpose rig in the Prentice NE Unit. Wells in this field have well known lithology which allowed the drilling engineer to fully optimize two PDC bit runs using conventional rotary drilling rigs. Further reduction of drilling time required further innovation.

The documented reductions in drilling times utilizing coiled tubing drilling are usually based on reduction of non-productive drilling time (NPT). Coiled tubing drilling generally delivers reduced NPT by eliminating connections with faster tripping speeds and generally quicker rig up/rig down time. In the case discussed here, expected NPT reductions were taken into account but further drilling time reductions were also captured.

**Figure 2**

Photo of the Xtreme Coil Drilling Rig 200 Series in coil drilling mode with the coil injector over the hole.



**Reduced On/Off Bottom Issues (Continuous Coil Feed)**

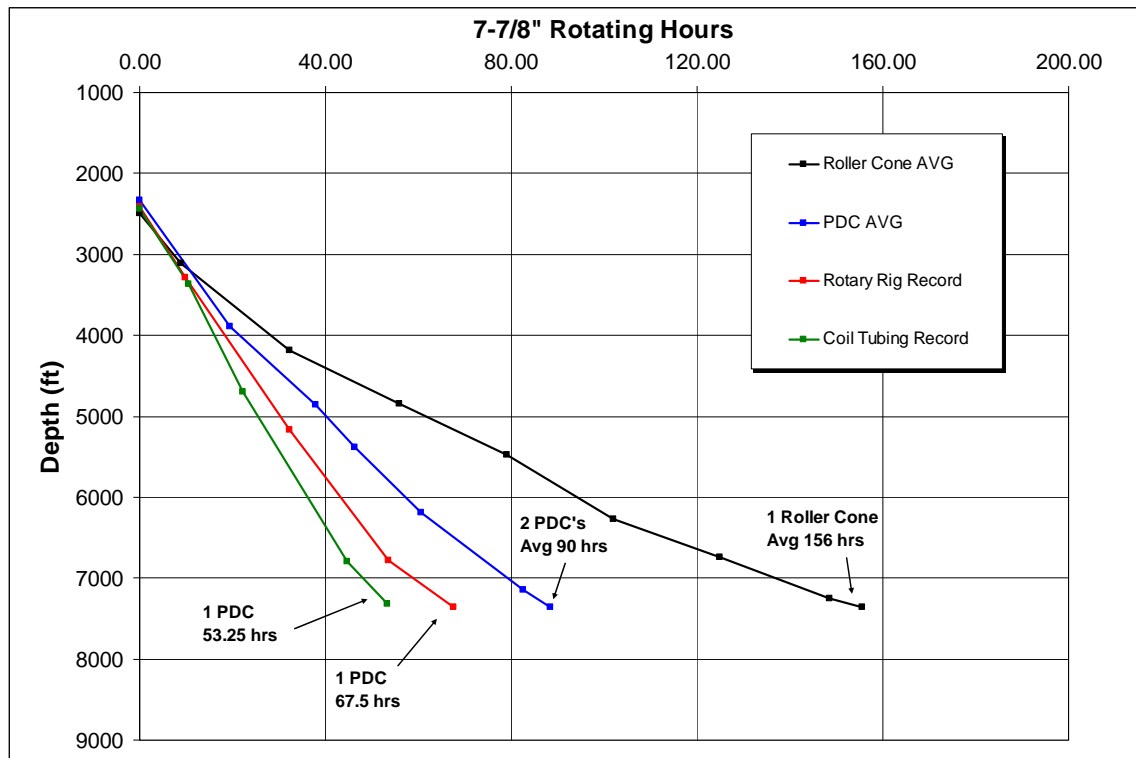
While optimizing the use of the PDC bits on a rotary rig, every connection creates the possibility of damaging the PDC bit when not allowing proper drill off time or by setting the bit back on bottom too hard. Both of these events can cause uneven loading of cutters which, in turn, creates delaminating, chipping or breaking of individual cutters. The use of coiled tubing reduces the potential for catastrophic damage to the PDC bits from these on bottom/off bottom events and can result in longer bit life and reduction in required bit trips.

While drilling with coiled tubing in the Prentice NE Unit, we anticipated the reduction in on/off bottom events at connections would prolong the life of the first PDC bit from under surface casing at 2,400 ft and the bit would be able to drill to TD the well at 7,400 ft. Once equipment issues were resolved from the first well and the upper portion the second well, the section from 3,434 to 7,720 ft on the second well was drilled in 42.25 rotating hours (average ROP of 101 fph), with the bit only being picked up off bottom 10 times (every 500 ft as opposed to every 31 ft to make connections) to take inclination surveys. Previous wells in the field were drilled with two PDC bits in an average of 90 rotating hours on a rotary rig. However, this second well drilled with coiled tubing completed the entire section of the production hole with one PDC bit in a field record of 53.25 total rotating hours (see Figure 3). The previous record for rotating hours was 67.5 hours completed with one PDC bit on a conventional rotary drilling rig. Very few wells in that field were drilled with one PDC bit and none of the conventional rigs were able sustain the ROP of the coil rig due to the increased damage caused by the on/off bottom events. The PDC bit used on coiled tubing dull graded as a 1-3-WT-A-X-IN-NO-TD, a much improved dull condition than the bit that set the previous record which had a dull grading of 2-3-BT-A-X-1-DL-TD.

The reduced damage and improved dull condition generated lower cost per foot for the PDC bits due to reduced rebuild costs and the potential to rerun bits on future wells.

**Figure 3**

Wells drilled in the NE Prentice Unit with roller cone bits, PDC bits and rotary rigs and a coil rig.



## No Connection Time

Drilling a 5,000 ft open hole section with a rotary rig in this basin requires about 160 connections. If each connection takes five minutes to complete, then up to 13 hours of NPT is created. If connections take longer, more NPT is created. Connection times can increase when the driller must backream and then circulate these cuttings out of the hole to reduce ECD. After the connection, the time to return the bit to bottom can increase if downhole tools need to synchronize and new drilling parameters are established. Observations show certain cases where connection times can be as high as 20 minutes from off bottom to on bottom. While utilizing coiled tubing drilling there are no connections required so a direct reduction in NPT is observed when compared to drilling with drill pipe.

Another advantage of drilling with coil is delivery of continuous and constant control of WOB. This drives a near 100 percent efficiency of on bottom time dedicated to the drilling process. Drilling ahead is controlled by the driller or automatic driller on the drill floor. The dual purpose rig can use either WOB or downhole motor pressure increases or can combine both of these variables to control the automatic driller. The driller can send real time data to the operator's office for review by the drilling engineers and staff. During drilling of the first well, the rig automatic driller was not functional. In this case, the driller drilled the well using feedback from the dual purpose rig surface system. The last three wells had the automatic driller functioning and the driller used WOB to control the drilling process.

### Figure 4

Photo of the Xtreme Coil Drilling Rig 200 Series in rotary drilling mode with the top drive over the hole.



## Two Rigs in One

During the drilling planning phase, the operator viewed the rig design featuring a full top drive rig and a full coiled tubing drilling rig or two rigs in one. If there were any issues with the planned coiled tubing drilling phase, the operator could revert to use of the rig's top drive capability. The rig features a top drive and draw works with a hook load capacity of 200,000 lbs (88,000 DaN) and a coiled tubing injector system capable of pulling 200,000 lbs (88,000DaN) or snubbing 60,000 lbs (26,400 DaN). See Figure 5 for more information on rig features.

The mast is vertical when the rig is drilling with drill pipe. When the mast is vertical, the rig's top drive is located above the well center (see Figure 4). With the mast tilted at 15 degrees, the rig transitions from drilling with jointed drill pipe to drilling with coiled tubing and the coil injector is placed over the well center so that coil can enter the well (see Figure 2). This mast tilt enables a quick transition from one mode to the other. The coiled tubing stays stabbed into the injector while the rig is on location. This also saves time while changing from one mode to the next. A programmable logic controller (PLC) located in the doghouse manages all rig functions.

### Figure 5

Table of Xtreme Coil Drilling 200DT<sup>Plus</sup> rig features.

Feature	XTC 200DT <sup>Plus</sup>
Coil Size (in)	3-1/2
Coil Depth Rating (ft)	10,000
Coil Injector Rating (lbs)	200,000
4" DP Depth Rating (ft)	8,200
AC Drawworks Rating (lbs)	200,000
Drawworks Horsepower (hp)	600
Pump Horsepower (hp)	1,000 (2)
Crew Size	5
Rig Move Loads	13
Rig Move / Rig Up Time	2-4 hrs

While drilling the first well with coiled tubing there were issues during drilling that could not be addressed quickly on site. The operator decided to continue by switching from coiled tubing drilling to deepen the hole with drill pipe using the top drive. The change from coiled tubing to drill pipe was accomplished in less than four hours, including handling of the bottom hole assembly. The first well was drilled to TD using drill pipe. However, the next three wells were drilled to TD with coiled tubing.

### **Rig Moves**

There have been significant advances in recent land rig design and construction. One of the reasons for rig redesign is to move the rig more easily and faster. Breaking down the rig into rational loads that make sense to the rig crew improves the efficiency and speed of the rig move. The ease of rigging down and then rigging back up is simplified for the rig crew by minimizing the connections required between loads and by standardizing load placements on the drilling pad.

The rotary drilling rig the operator had previously used delivered acceptable rig move performance. This rig could be moved in approximately 12 hours. One reason the operator made the change to the dual purpose drilling rig was to take advantage of the new design which was optimized for simple, quick and efficient rig moves.

The newer dual purpose rig performed in-field moves in six hours, a reduction of 50 percent versus the conventional rotary rig. The new rig's best move time was 4.5 hours. The new rig requires only 12 loads making in-field rig moves considerably quicker.

### **Forward Issues**

One issue requiring resolution to achieve general acceptance of coiled tubing drilling in the Permian Basin is stuck pipe due to lost circulation. In many parts of the Permian Basin, many shallow productive zones have been drilled in the past and production has reduced the in-situ pore pressure levels. When liquid drilling mud escapes into these zones and since the coil tubing is not rotating, a differential sticking hazard is created. The coiled tubing rig can alleviate most of the stuck pipe risks by continuously moving the pipe, which is made easier because there are no tool joints. No incidents of stuck pipe occurred in this example.

In this case history the risk of differential sticking was low, which justified the use of coiled tubing drilling to management. After using both drill pipe and coil, the decision to use a dual purpose rig to drill future wells will be made based on successful track record. In other areas of the basin more analysis is required to determine how to best to drill these wells with coiled tubing drilling and an underbalanced drilling package.

## Summary

The introduction of PDC bits and dual purpose drilling rigs to a mature basin provided the operator with newly developed technologies to deliver wells in reduced drilling time. PDC bits perform best when continuous development can be driven from the wellsite to the manufacturing of the next bit. This cycle is shortened to the point that bits are developed not only according to the geology but, also, according to what was learned as recently as yesterday. This shortened cycle of development leads to reduced rotating times when compared to roller cone bits. The step change of moving from roller cone bits to PDC bits delivered a 50 percent reduction in drilling times.

A second step change occurred when the operator moved from a conventional rotary drilling rig to a dual purpose rig that can drill with either coil or drill pipe. The operator selects the mode used to drill the well and can change modes at any time during drilling. By optimizing the on bottom time, reducing PDC bit damage and tripping faster, overall drilling times are reduced. Reductions in drilling times were up to 40 percent when compared to the average drilling times of a conventional rotary drilling rig.

The authors of this report express their appreciation to XTO's management for agreeing to the presentation of the data related in this case history.