



Case History: Updated Drilling Practices for the Carthage (Cotton Valley) Field

Fred McDougal, Anadarko Petroleum

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Abstract

Aggressive use of new technology and an overhaul of drilling practices have reduced drill times and resulted in production friendly wellbores for Anadarko in the Carthage (Cotton Valley) field. This paper describes some of the challenges faced by Operators in the mature Carthage (Cotton Valley) field and changes in drilling practices Anadarko has made over the last 3 years which have cut drill time by a third and improved wellbore reliability. Specifically, bit application and cementing practices are covered in this paper. The benefits of these changes are clearly demonstrated by trends in drill time and improved wellbore integrity.

The Carthage (Cotton Valley) field is an important part of the active Cotton Valley play. The play includes many different operators and drilling practices. This paper extends the discussion on drilling practices in the play and will give an engineer new to the Cotton Valley trend some of the drilling practices Anadarko has found successful.

Introduction

The Carthage field and surrounding Panola County, Texas (located 35 miles southeast of Longview, Texas) have been prolific gas producers since discovery of gas there in 1936. Lower Cretaceous carbonates and the underlying Lower Cretaceous and Jurassic sandstones have produced 7.7 TCF and 2.2 TCF respectively¹. The productive Jurassic sandstones in Carthage are the Cotton Valley sands and have been the target of over 500 wells drilled by Anadarko Petroleum (APC) since the late 1970's. APC is still actively developing its acreage in the play 30 years later.

A description of APC's Carthage Cotton Valley wellbore configuration and geology with nominal depths follows. Most of APC's development wells require 2 strings of casing; a string to protect the freshwater sands, usually set at 1000'; and a production string set at total depth of approximately 9700'. Fast hole is made out from under surface to the top of the Austin Chalk (2300'). Drilling continues at a slower pace through the remaining carbonates. Mud weight is increased to control potential salt water flows in the Duck Creek (2500') and Rodessa (5000'). The shallowest major

producing interval is the Pettit at 5900'. The Pettit was responsible for the bulk of the 7.7 TCF produced by the Lower Cretaceous carbonates. At the base of the Pettit, the lithology changes from predominately carbonate to sandstones and shale from the Travis Peak (6100') through the Cotton Valley (8300'). APC's Cotton Valley wells typically reach total depth (9700') in the Bossier shale.

Conditions have changed significantly since the 1970's. The Pettit, Travis Peak and Cotton Valley reservoir pressures have declined from the huge gas withdrawal that has taken place. Simultaneously, porous intervals within the Rodessa and Duck Creek formations have been used for salt water disposal (SWD), elevating their reservoir pressures well above normal. The combination of production and SWD sets up a system of layers ranging from less than 1 ppg to 12 ppg reservoir pressure. Mud weights and properties have to be managed to prevent salt water influxes, mud losses and differential sticking. Cement coverage and bond are also impacted from these variable pressure gradients.

The Cotton Valley and overlying Travis Peak sandstones present other difficulties. In addition to depletion, the sands have compressive strengths ranging to 25,000 psi. The Travis Peak sands are extremely abrasive due to their rock failure mode². Another troubling aspect of the Travis Peak is its fracture gradient can be as low as 11.5 ppg, below the pore pressure in the SWD zones in some areas. The low fracture gradient in the Travis Peak can lead to massive mud losses particularly in the southeast end of the field.

For the purposes of this paper the interval from the surface casing shoe to the top of the Travis Peak will be referred to as the "pre-Peak" interval. "Hard rock" interval will refer to the Travis Peak and Cotton Valley.

A summary of the major challenges faced by operators in Carthage are: 1) Reserves targeted by new wells decrease as well density increases. Therefore, it is very important to constantly improve drilling efficiency and control costs. 2) Differential sticking in depleted zones, particularly the Pettit, is always a danger. Mud properties must be managed and proper pipe handling practiced to prevent stuck pipe, fishing and/or sidetracking. 3) The Duck Creek and Rodessa reservoir

pressure can be charged above normal due to SWD activity. Maintaining sufficient mud weight to control the SWD zones can induce massive mud losses to the 3 deeper producing intervals. This situation can quickly become unmanageable and require intermediate casing in severe cases. 4) The Travis Peak/Cotton Valley section or "hard rock" interval contains high compressive strength sandstones which are very abrasive. Historically this interval has been drilled with IADC 637 to 747 insert bits. Fortunately, new PDC bit technology is allowing this interval to be drilled much faster resulting in a significant reduction in overall drill time. 5) The production string must have adequate cement coverage to protect it from the corrosive waters in the SWD zones. Unprotected casing can develop leaks within 2 years of spud.

This paper covers APC's solution to challenges concerning well costs and casing leaks. The solutions involve replacing roller cone bits with fixed cutter bits, and in some cases running the fixed cutter bits on positive displacement motors (PDM). APC also had to address deficiencies in their cementing practices and implement necessary changes.

Breaking away from 25 day Drill Times

A large component of drilling costs is a function of drill time, measured in days from spud (DFS). New practices, ideas, and technology are constantly employed in an attempt to decrease drill time. If the same practices are used without variation, improvements in drill time will diminish with each generation of wells. A review of the historical drill time for APC's Carthage Area wells is shown in Figure 1. Drill time drops from 29 to 25 DFS from 1995 to 1998. Drill time appears flat at 25 days from 1998 through 2001, this was during a time with very little successful variation in practices. At this point APC had become very proficient with their accepted drilling procedure but without the successful introduction of some new technique or technology, improvements in drill time would continue to diminish. In 2002 drill time starts a steady decline from 25 to 16 DFS by late 2004. This 33% improvement is due primarily to improvement in PDC cutter technology and PDC bit design. The steady decline occurs as APC becomes more skilled with the new technology and bit designs continue to improve. This magnitude of improvement in such a short period of time is similar to what other operators have experienced in the play³.

CGU 23 and CGU 24 – Drilling Practice Evolution

To illustrate the drilling process evolution and identify where the time savings have occurred, an area consisting of 1300 acres located in the northeastern portion of Carthage was chosen for a detailed look at drill time. APC has drilled 42 wells in Carthage Gas Units 23 and 24 since the mid-1970s. This particular

area was chosen because drilling conditions have changed less in this area than in other parts of the field. While depletion is a factor in this area, the effects of SWD are minimal. Four wells representing drilling advances from the mid-1970s to present were selected from these 2 units and are detailed in Table 1. Two intervals are focused on; *pre-Peak* – includes drilling the carbonate section, and *hard rock* – includes drilling the Travis Peak and Cotton Valley sandstones. The table illustrates how the advancement of drilling technology, mainly drill bit technology, has impacted drilling each section of rock over a 27 year period.

In the mid-1970s APC started developing its Cotton Valley reserves. At that time the entire well was drilled with roller cone bits. The CGU 24-3 took 11.5 days to drill the pre-Peak interval and 31.5 additional days to reach TD. Thirteen (13) insert bits were used to drill the hard rock interval in this early well. Each bit run averaged 247' at 6 fph. The pressure gradient encountered was relatively undisturbed and abnormal hole conditions were rare.

By the mid-1990s PDC bits began to be used to drill the pre-Peak. Better penetration rates and footage for PDCs led to reducing the pre-Peak drill time by a day. Though the improvement in drill time was modest the potential for PDC bits in the pre-Peak was recognized. Insert bit technology had also improved to the point where 6 bits could drill the hard rock interval. The insert bits averaged 850' at 8 fph. These new insert bits had better than 3 fold increase in footage but only a modest improvement in ROP over wells drilled 20 years prior.

By 2000, APC had settled into a routine of drilling the pre-Peak with a 5 blade PDC bit followed by 3 insert bits to drill the hard rock interval. The CGU 23-14 took 3.5 days to drill the pre-Peak and an additional 15.5 days to drill the hard rock. Focus was placed on minimizing bits used. Later, as hard rock PDC bits started entering the market, the focus would shift to maximizing ROP instead of minimizing number of bits.

CGU 23-18, drilled in early 2004, is representative of APC's current procedure. CGU 23-18 took 2 days to drill the pre-Peak and 5.5 more days to reach TD. The pre-Peak was drilled with a 6 blade PDC on a low speed positive displacement mud motor (PDM). Total depth was reached with 2 additional PDCs in 5.5 incremental days. The hard rock PDCs averaged almost 1800' at 31 fph per bit. The hard rock interval took about a third of the time seen in 2000.

Drill time has been reduced in both the pre-Peak and hard rock intervals. APC has found enough drill time is saved by adding a straight-hole mud motor to the pre-Peak PDC run to justify its use. However, the biggest impact of new technology has been in the hard rock section. The following discussion details improvements in both the pre-Peak and the hard rock PDC runs.

pre-Peak PDC Run

Figure 2 shows APC's last 69 pre-Peak PDC runs in Panola County and contrasts bit runs with PDMs and without PDMs. All 69 bit runs are full runs from surface pipe shoe to the Travis Peak. The runs are split roughly 70% PDC bits on PDMs and 30% PDC bits without PDMs. The addition of the PDM improves the average ROP from 63 to 108 fph. But the potential for 150 fph runs with PDMs is substantial. Conversely, runs without PDMs rarely beat 90 fph in APC's experience as seen in Figure 2. The improved ROP easily justifies the PDM with 1.5 days rig time savings on average.

Hard Rock PDC Run

The hard-rock portion of the hole drilled with new PDC bit technology has seen the most improvement in drill times. This interval was traditionally drilled with IADC 647-747 insert bits. As indicated earlier, insert bit footage had been significantly improved but ROP still lacked substantial improvement. ReedHycalog marketed one of the first PDC cutters capable of consistently drilling the hard rock interval. Later, they combined the cutter with an extremely stable bit design which limited impact damage to the cutters. This was the first PDC bit design to seriously challenge insert bit performance in the hard rock interval⁴. APC started employing bits with the ReedHycalog cutter in the Carthage area during the summer of 2002 and started using the new bit design in the fall of 2002. Soon other bit manufacturers introduced their own hard rock PDC bits, and several have since eclipsed ReedHycalog's initial design.

A comparison was made between the latest 285 insert bit runs in Panola County and the latest 180 hard rock PDC bit runs and is shown in Figures 3 and 4. Figure 3 shows the distribution of bit footages for insert and hard rock PDC bits (Note: The last bit run on a well was eliminated from the footage comparison since the footage might be artificially shortened due to reaching TD). The average hard rock PDC drilled 1200' versus 800' for insert bits. Hard rock PDCs average 50% longer runs than insert bits. But hard rock PDCs have the potential for runs in excess of 3000'. Figure 3 shows 25% of the hard rock PDCs will drill over 1500'. While an insert bit will rarely drill more than 1300 feet.

Figure 4 shows the distribution of ROP for the two bit types. Insert bits are tightly grouped from 5 to 14 fph, with an average of 11 fph. The average hard rock PDC will drill at twice the insert bit ROP. But again, there is potential for much higher ROP. Nearly 40% of the hard rock PDCs will average better than 25 fph.

In some cases an insert bit run cannot be avoided. When an insert bit must be run they respond favorably to high weight on bit (WOB). APC routinely runs 65,000 lbs on 7⁷/₈" insert bits with favorable results.

There is a recognizable relationship between bit hydraulic horsepower per square inch (HSI) and hard

rock PDC performance. Figure 5 is a plot of ROP versus hydraulic horsepower per square inch at the bit (HSI). HSI is shown for 2 different hard rock PDCs models, from different bit manufactures, with significant differences in style, and run in 2 different geographic areas. Also shown is a simple linear regression straight-line fit through the data. Despite all the differences noted above, both Bit A's and Bit B's ROP demonstrate similar sensitivity to HSI. Bit A shows more scatter to its ROP data but its relation to HSI is the same. The relationship between footage and HSI is not as clear but is also arguably positive.

Insert bit runs have been all but eliminated in APC's Carthage wells. Exceptions are where the Travis Peak/Cotton Valley transition is too difficult to drill with PDCs and insert bits are still required.

Cement Coverage and the mixed Pressure Gradients in Carthage

Intervals of overpressure and depletion will be penetrated in the process of drilling to the Cotton Valley in Carthage. Mud properties such as weight, water loss, low gravity solids (LGS) content, plastic viscosity and lost circulation material loading are constantly being balanced to maintain control of the SWD zones and avoid losses in the depleted producing zones. Salt contamination can alter rheological properties and cause shale stability problems in the pre-Peak section. Thick, permeable wall cake from high LGS can easily stick drill collars left stationary across the Pettit. The intervals of mixed pressure gradients have led to many fishing jobs and the occasional sidetrack. But of greater economic impact has been the negative effect of the mixed pressure gradients on protecting the production string with cement. The production string must be insulated from the corrosive waters in the Duck Creek and Rodessa SWD zones. However circulation is easily lost in the Pettit, Travis Peak and Cotton Valley during cement work.

Lost circulation during the displacement of the production string cement was common in APC's Carthage wells. Between 2000 and 2001, lost circulation during displacement of the production string cement job was reported on over 50% of APC's wells. When circulation was lost it normally occurred with less than half of the displacement pumped. Carthage production string cement jobs were designed to cover the shallowest active SWD zone by a few hundred feet. When half of the displacement is lost, the top of the cement could easily be 1000' below the intended top. During the period, 2000 to 2001, when losses occurred during half the cement jobs, 15% of the new wells developed casing leaks within 2 years of spud due to exposure to the highly corrosive SWD zones.

While the average cost to repair a casing leak is substantial at \$90,000, the larger financial loss is impaired production. Early in life a Cotton Valley well

might be strong enough to keep a small casing leak unloaded and so go undetected. But a Cotton Valley well produces half of the gas it will ultimately recover during the first 3 years of a 30 year life⁵. Impairing the production with a casing leak during this critical early production will significantly reduce the well's NPV.

Ninety casing leaks starting in the mid-1980s to present were investigated in detail. At least 70% of the leaks occurred from 2000' to 6500', which is the interval of most intense SWD activity. Figure 6 shows the frequency of casing leaks as a function of well vintage. Since the mid-1980s 9% of APC's new wells have developed casing leaks. The persistent 15% of new wells developing leaks from 1999 to 2001 was a troublesome trend. Not only were an above average number of new wells developing leaks, they were developing leaks earlier. Figure 7 shows how much time lapsed from spud until the casing leak was discovered. Figure 7 shows starting in the late 1990s casing leaks were occurring earlier on the new wells. Casing leaks were not showing until 2 to 3 years after spud before 1997. From 1997 to 2001 many of the leaks were detected a year or less after spud. One might argue the leaks were being detected earlier because of the focus casing leaks were getting during 2000 and 2001. If leaks are starting to be detected earlier in a particular generation of wells, then it is reasonable to assume more total leaks will ultimately occur for that same well vintage. These two factors pressed APC to find a solution to reverse the casing leak trend.

Cement Coverage Solution

As previously discussed, the leaks were suspected to be occurring because of the lack of cement coverage across the SWD zones. Two different options for preventing the leaks were pursued, better cement placement and coverage, and cathodic protection. APC worked with its cement supplier on slurry weights and additives. It was found a simple package of lost circulation additives added to APC's typical cement slurries allowed cement to be consistently circulated to surface on the production string. When cement is not circulated on a production string or some other problem is suspected with cement coverage, cathodic protection is installed. Casing leaks have not occurred on any of the 72 wells drilled since this practice was adopted.

Conclusions

- The introduction of hard rock PDCs to replace the IADC 647-747 insert bits used in the hard rock interval is responsible for most of the 33% improvement in drill times. By 2001, APC had hit a plateau in further optimizing their drilling process and little additional improvement could be expected without advancement in technology. Through Operator encouragement and industry competition,

bit manufacturers successfully developed PDC bits capable of drilling the hard rock interval.

- The average hard rock PDC bit runs 50% longer and at twice the ROP as the average insert bit. Even more encouraging, hard rock PDC bits have been shown to have much higher potential in both footage and ROP. Hard rock PDC footage and ROP has also been found to respond favorably to increasing HSI.
- The 70% increase in ROP when using a PDM on the pre-Peak PDC run easily justifies its use.
- Cement coverage is essential to maintaining wellbore integrity. Adequate coverage is jeopardized when circulation is lost during cement displacement. The unprotected production casing can develop casing leaks within a year of being drilled due to corrosion. APC has found bringing cement to surface on the production string cement jobs is cost effective in insuring future wellbore integrity.

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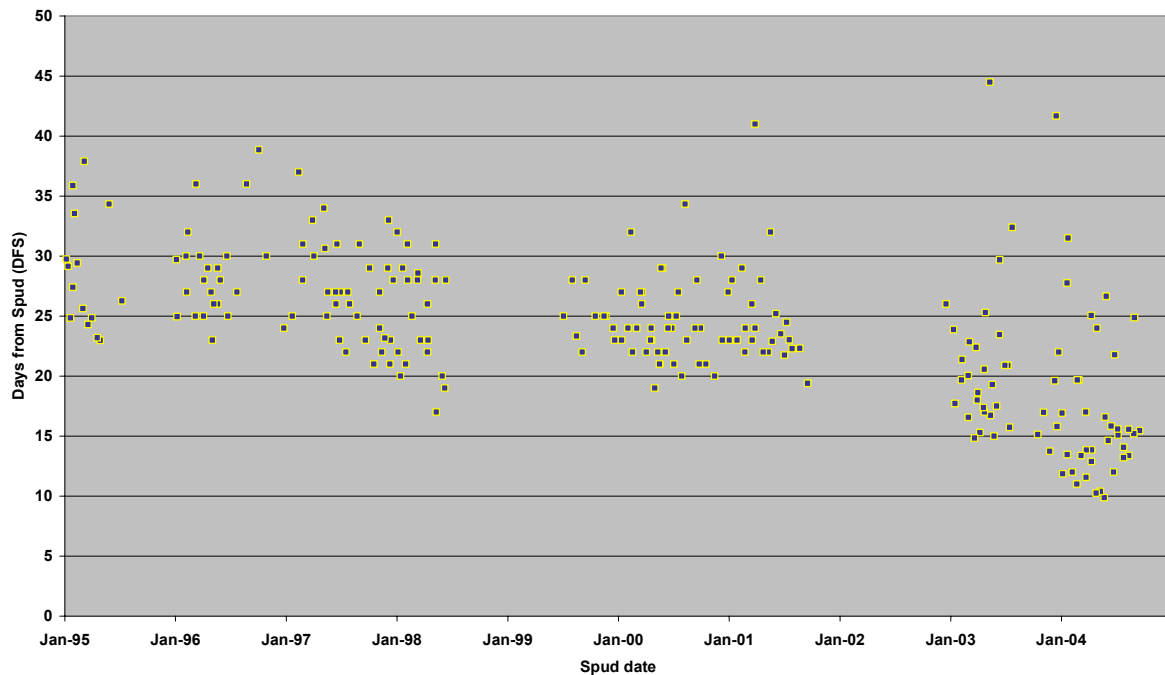


Figure 1 – Drill times for APC's Carthage Cotton Valley wells as a function of Spud Date

Well	CGU 24-3	CGU 23-10	CGU 23-14	CGU 23-18
Year Spud	1977	1995	2000	2004
surface shoe to top of Travis Peak:				
Time to Drill interval	11.5 days	10.5 days	3.5 days	2.0 days
Bits Used:				
Milltooth	2	0	0	0
Insert	1	0	0	0
PDC	0	2	1	1
top of Travis Peak to Total Depth:				
Time to Drill interval	31.5 days	19.5 days	15.5 days	5.5 days
Bits Used:				
Milltooth	0	0	0	0
Insert	13	6	3	0
PDC	0	0	0	2
Total Time - Spud to Rig Release	49.0 days	33.5 days	22.5 days	11.0 days
Total Bits	17	9	5	4

Table 1 – The Effect of Drill Bit technology on Drill Time in Carthage Gas Units 23 and 24

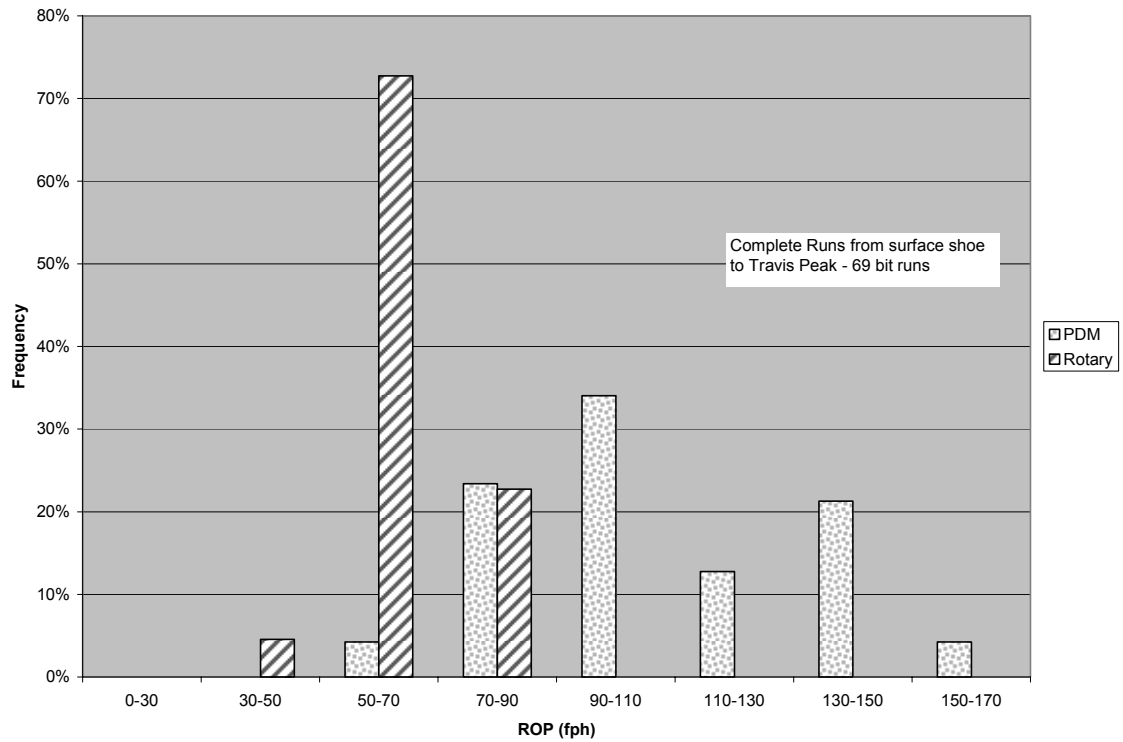


Figure 2 – Advantage of Running PDC out from under Surface Shoe on Positive Displacement Motor

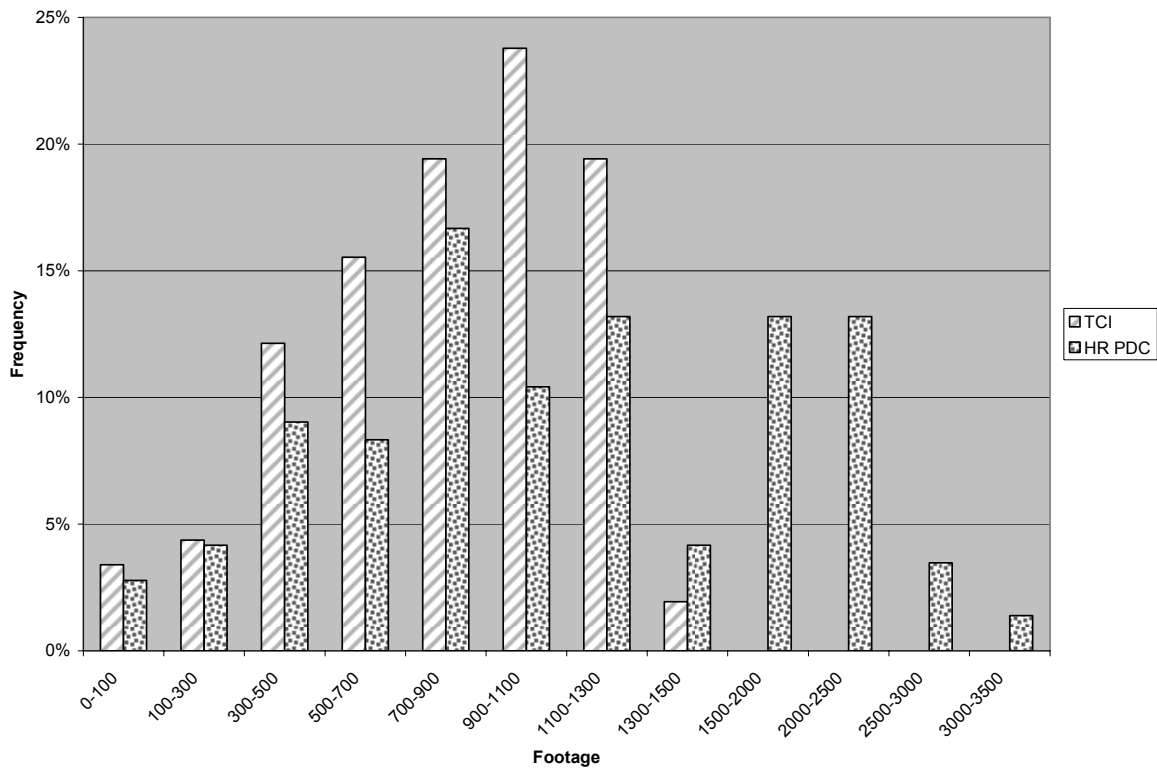


Figure 3 – A footage comparison of Hard Rock PDC bits to Insert bits

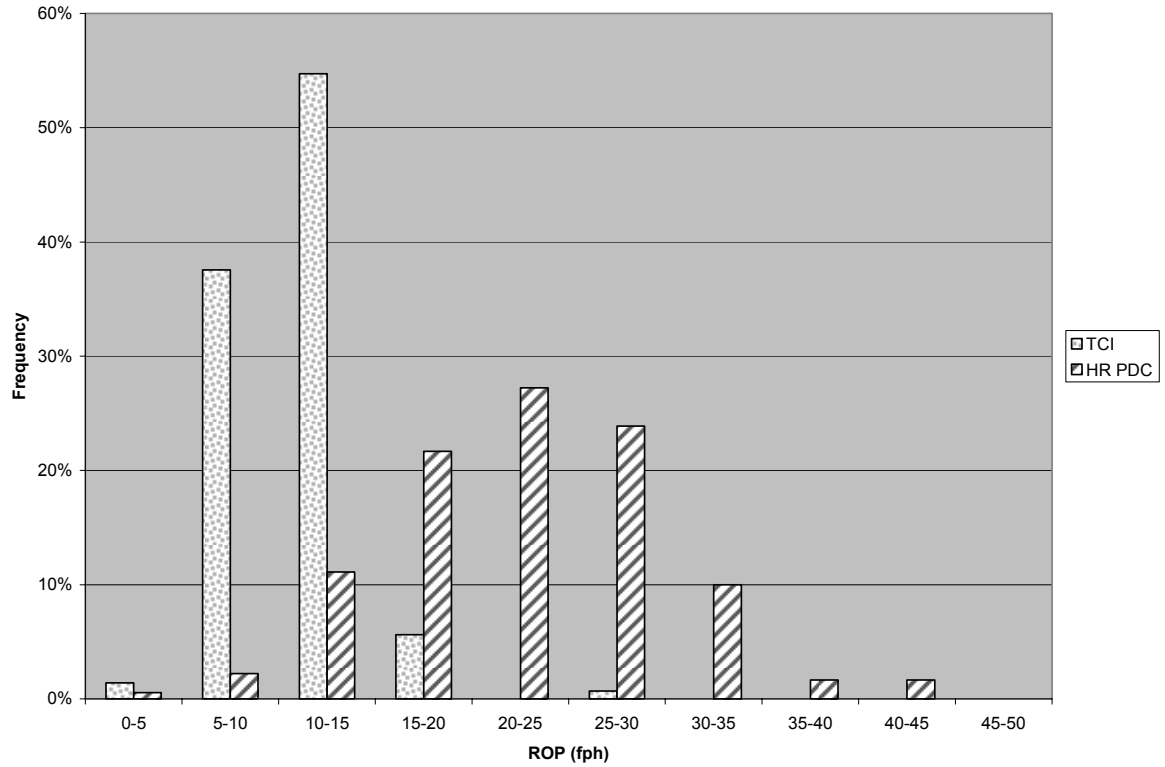


Figure 4 – A ROP comparison of Hard Rock PDC bits to Insert bits

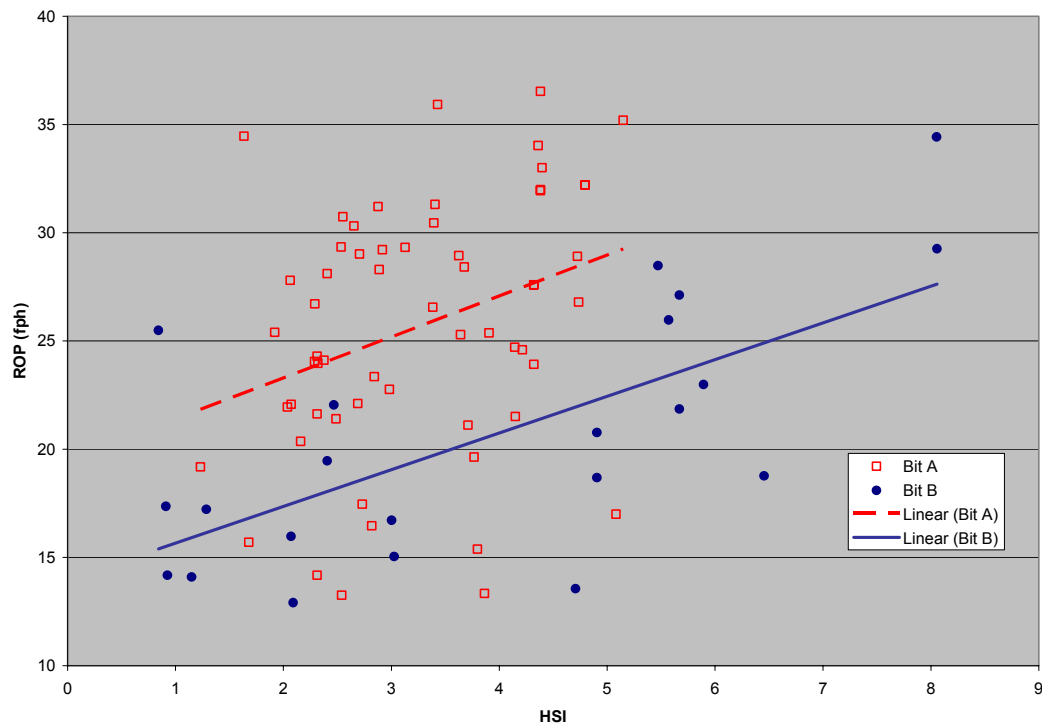


Figure 5 – Influence of HSI on Hard Rock PDC bit performance

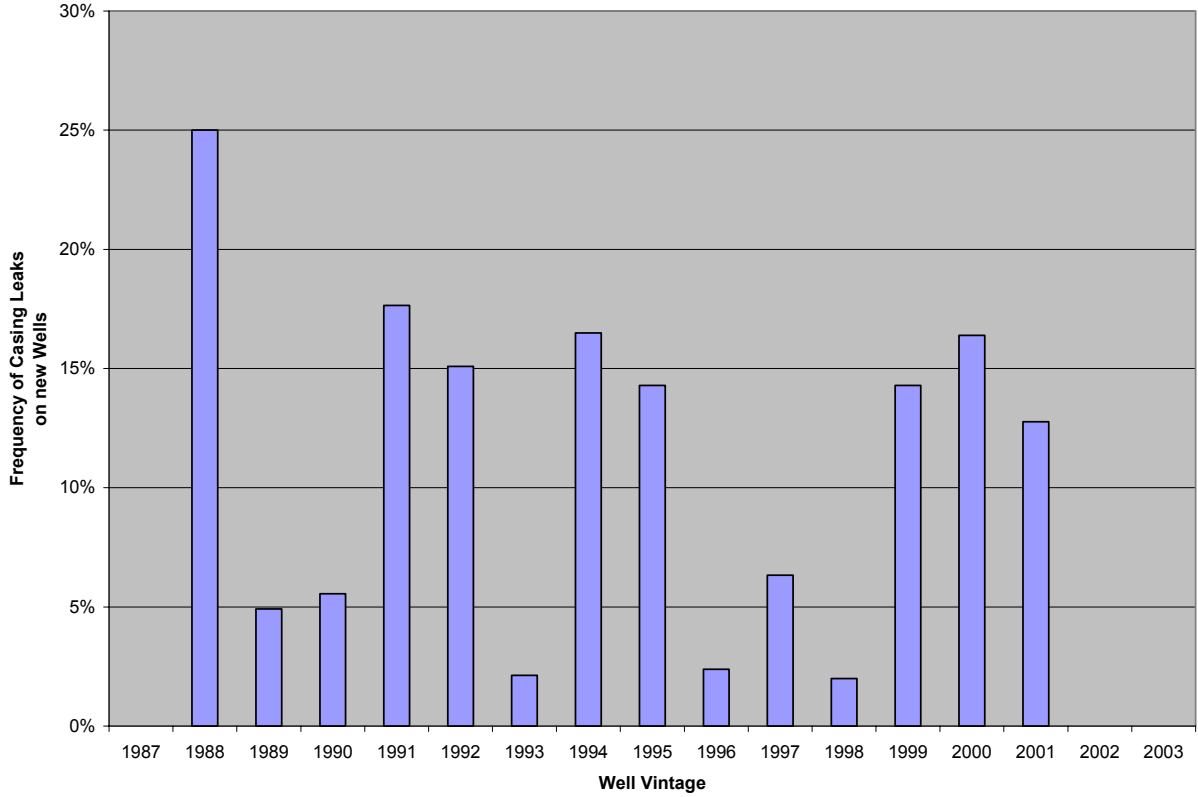


Figure 6 – Frequency of Casing leaks as a function of Well Vintage

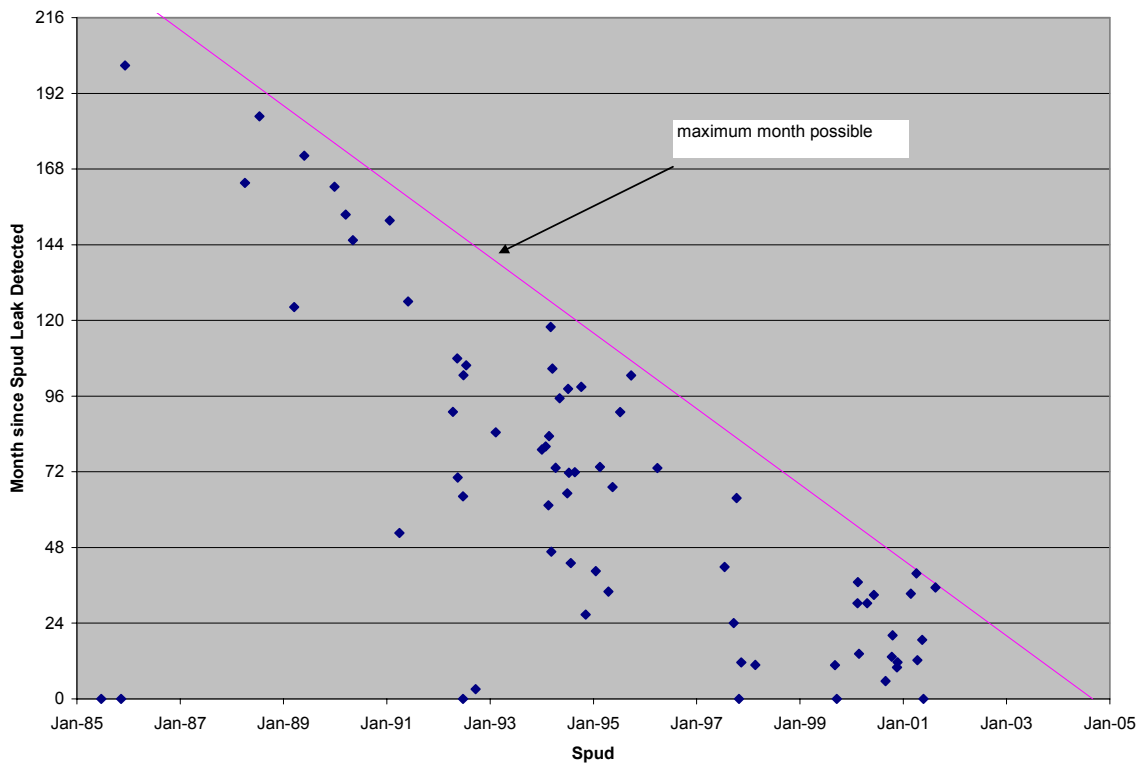


Figure 7 – Time between Spud and when Casing Leak was detected as a function of Spud Date