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# Four-blade bit helps reduce drilling time by as much as half

## The new bit also saved cost by repeatedly drilling the entire interval in one run.

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Williams Production RMT is one of the most active operators in the Piceance Basin near Parachute in northwest Colorado, operating about 25 rigs in the region. The operator produces more than 560 MMcfd of natural gas from more than 2,300 wells. Many of the rigs that the operator uses in the Piceance Basin are set on a drilling pad that can contain up to 22 directional-drilling well slots, typically about 7,000–9,500 ft total depth. The wells usually reach TD in 10–12 days, drilling the top 2,000 ft or so with a 13½-in. roller-cone bit and a 13½-in. PDC bit, then finishing the well with several five-blade 7⅞-in. PDC bits. In some wells, the operator was using as many as three to four 5-blade bits to complete the 7⅞-in. interval due to the various formations encountered.

Varel International designed, tested and produced a new four-blade PDC bit, the VTD416PH, that has reduced Williams' drilling time for the 7⅞-in. interval by one-third to nearly half in many cases. The new bit design resulted in faster drilling due to higher ROPs, and in many cases the interval was drilled with one bit, eliminating tripping in and out of the hole to change bits and BHAs.

The bit manufacturer used its proprietary PDC bit design and modeling software, to simulate the drilling and ensure that the new design would meet the ROP, rpm and steerability objectives for the operator's Piceance Basin formations.

As a direct result of the improved bit design, the operator now is not only able to bring wells online more quickly, but also at reduced drilling costs. Assuming rig spread costs of about $38,000 per day, including a rig rate of about $20,200, the typical Piceance Basin gas well costs the operator $380,000–$456,000 prior to reducing drilling time with the new proprietary four-blade PDC bit.

### PICEANCE BASIN

The Piceance Basin of northwest Colorado is a 6,000-mi$^2$, gas-rich area that is split approximately in half by Interstate 70 and the Colorado River, Fig. 1. The majority of the drilling is in Garfield County but extends north into Rio Blanco County and south into Mesa County. The operator's drilling activity runs generally from just west of Parachute to Rifle both north and south of Interstate 70. The current fields being drilled include Parachute, Rulison, North Rulison, Grand Valley and South Grand Valley.

When drilling a typical well, the first formation that is encountered is the Tertiary-age Green River Formation. The Roan Plateau north of Parachute and Rulison is predominantly Green River Formation and consists mostly of shales (including oil shale), marls and fine-grained sandstones. Immediately below the Green River is the Wasatch Formation, which is composed of sandstones and mudstones and often contains intervals of conglomeratic sandstones and other conglomerates. These conglomerates often require use of a 13½-in. roller-cone bit in addition to a 13½-in. PDC bit in the surface hole. The production hole (generally 7⅞-in. in diameter) is started in the Wasatch and extends into the Mesa Verde. The gas-bearing interval is part of the Mesa Verde and is known as the Williams Fork, which is late Cretaceous in age and was deposited in the form of tight, vertically stacked sand lenses. The Williams Fork ranges from 1,700 ft to 2,400 ft in thickness and is found at depths ranging from 4,000 ft to greater than 9,000 ft, Fig. 2.

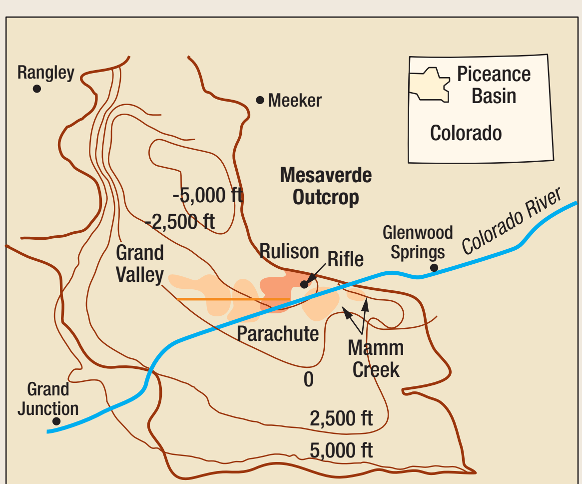


**Fig. 1.** Williams operates about 25 rigs in the Piceance Basin, most of which are set on drilling pads that can contain up to 22 well slots for directional drilling operations. Courtesy of Williams Production RMT.

### OUT-DRILLING FIVE-BLADE BITS

Until the introduction of the new proprietary four-blade PDC bit into the Piceance Basin, all of the operators working in the region used multiple five-blade and even some six-blade PDC bits in their directional wells. Before the new four-blade bit, five- and six-blade bits provided the directional driller with better control because of their less aggressive design than the typical four-blade design. A rule of thumb is that bits with more blades usually have more cutters and, thus, the bit weight per cutter is reduced in comparison to those designs with fewer blades and fewer cutters. This reduced depth of cut results in less torque fluctuation, a desirable feature on bits used by directional drillers to follow the planned well path.

The typically more aggressive four-blade PDC bit has a greater depth of cut that can lead to torque fluctuation, which can cause the bit to deviate from the drilling path due to its difficulty to steer. A four-blade bit takes bigger bites of the formation, but this also tends to direct the bit to the left while it rotates to the right. This movement to the left is caused by reactive torque on the downhole motor. From a directional drilling standpoint, the greater aggressiveness of a four-blade bit isn't generally accepted by directional drillers. However, after some skepticism among the directional drillers working in the Piceance Basin, they have come to view the new four-blade bit as easier to steer due to less reactive torque, better steerability and a generally higher ROP.

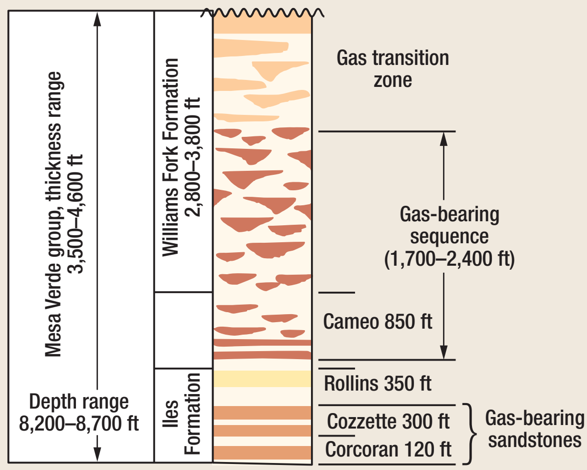


**Fig. 2.** The production hole is started in the Wasatch Formation and extends into the Mesa Verde, with the gas-bearing interval known as the Williams Fork. Courtesy of Williams Production RMT.

Part of the reason is the ability to control the bit as a result of the bit design, cutter placement and the cutters themselves, which results in significantly less cutter wear. The combination of a stable dual-row four-blade design and an improved cutter has reduced the amount of sliding required to steer the bit.

## DESIGNING THE FOUR-BLADE BIT

Several issues had to be addressed when designing the new four-blade bit for Williams' Piceance Basin operations. One was erosion. Bits are typically designed with one hydraulic nozzle per blade. However, due to the rig's high-power pumps and the need to help keep the bit face clean, it was desirable to add extra nozzles. The new four-blade bit has six nozzles.

The bit's cutting structure is less aggressive than other manufacturers' four-blade designs, resulting in better steerability. The original cutters on the four-blade bit were more impact resistant and less abrasion resistant than a second iteration of cutters. The newer cutters are more abrasion resistant and somewhat less impact resistant, which turned out to be a better combination for the formations encountered in the Piceance Basin. Giving up some of the impact resistance and gaining better abrasion resistance results in the bit pushing deeper into the 7⅞-in. formation and resulting in numerous one-bit-run intervals, Fig. 3.

**Fig. 3.** The proprietary four-blade bit.

The new four-blade bit is less aggressive than most other conventional four-blade designs, and even less aggressive than some five-blade bits due to the overall design. This means that it has a smaller depth of cut in the formation and, therefore, less torque fluctuation that can cause the directional driller to lose bit orientation. Typically when a bit takes a large bite of formation it tends to twist or wrap the drillstring. When the bit begins rotating normally, the drillstring unwinds, changing the bit's orientation. This torque fluctuation causes the fluctuation in tool-face reading, which is detrimental to steerability.

Overall, the new four-blade bit is more aggressive than most five-blade bits from a directional standpoint, but because the four-blade bit is lighter set, it allows the directional driller to use less WOB. The result is that the four-blade bit requires less weight to drill as fast as a five-blade bit. With less WOB, bit steering becomes easier. The result is a bit with higher ROP and greater steerability.

Additionally, four-blade bits in the past were too aggressive for directional drilling applications, as noted earlier. Taking both issues into consideration (erosion and bit aggressiveness), Varel began the bit design process based upon lithology information from offset wells, planned energy levels (WOB and rpm) and expected drilling practices. This information was used within the company's PDC design software to design the new four-blade PDC bit.

## SPOT BIT DESIGN PROCESS

SPOT, the PDC bit design and modeling software, was developed by Crystal Profor, a French-based PDC bit company that Varel purchased in 2000. The French company developed the software over about 10 years, using proprietary algorithms to model forces acting on the bit behavior and assuring maximum bit performance.

The proprietary bit design software uses laboratory and field data that contains full-bit and single-cutter test and field data. It is essentially a drilling simulator used for determining optimal bit designs for a specific application. It allows Varel to examine different cutting structures for a given area to develop the optimal design. Several different designs can be viewed simultaneously, enabling the engineers to work with one particular design and compare it with other potential designs, Fig. 4.

The bit's profile is determined in the bit design software, and the cutting structure is laid on the bit. Forces are calculated and the cutting structure is modified to optimize the axial and radial forces on the bit. Basically the bit was optimized for the operator's application by using all available information within the proprietary software and then virtually drilling with the bit in the simulator prior to manufacturing it. The directional tendencies of the design can then be easily modified to develop a bit for the specific application. The bit manufacturer's engineers will use Computational Fluid Dynamics (CFD) to determine the best nozzle orientation and fluid flow for the bit design. When the hydraulic design is finalized, the CFD information is combined with information from the bit design software and loaded into a solid modeling program from which programs for milling the bit's molds are produced.

When designing bits for directional wells, the bit design software can predict a PDC bit's directional behavior to match the operator's needs in terms of the bit's directional signature. It provides certain parameters including WOB required to drill, torque required to rotate the bit, lateral aggressiveness, axial aggressiveness, cutter wear and other drilling parameters and bit features.

Offset electric well logs from a field can also be entered into the bit design software through the use of a program called GeoScience, Varel's in-house lithology software and the trade name for a log analysis method for improving bit selection and optimization. The lithology/bit optimization software develops information on formation type, abrasivity, porosity, drillability and other formation data parameters. This information is then entered into the bit design software to help design a bit specific to the formation that will be drilled.

Pre-well planning with the lithology/bit optimization software and the bit design software can aid in optimal bit selection and customized design. The bit manufacturer's software combination is also used in post-well analysis to improve bit performance through modification to various design parameters, bit design and cutter technology.

In summary, the bit manufacturer uses a six-step process:

- Gather offset well data and analyze it using the lithology/bit optimization software.
- Use the bit design software along with information gained from the lithology/bit optimization software to design the cutting structure.
- Build the bit around the newly designed cutting structure. The manufacturing team is provided with the cutting structure that includes information about blade height, blade width, number of nozzles, gauge pattern design, etc.
- Run the bit design through CFD to test the nozzle pattern. If the nozzle pattern is not optimal the design is run through the modeling process once again until the fluid flow is correct.
- Provide the manufacturing plant with the final files to build the bit.
- Run the bit in the field, gather new data from the bit runs and begin the process again if the bit doesn't quite perform the way the customer required.

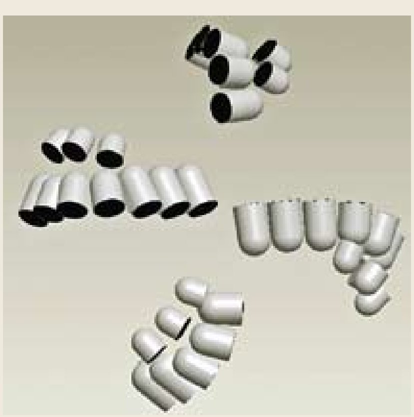

**Fig. 4.** The proprietary four-blade bit's cutting structure.

## BIT PERFORMANCE

As a result of significantly better drilling performance with the new four-blade bits, nearly all of Williams' Piceance Basin wells use this bit for at least a segment, if not all, of the 7⅞-in. interval.

The new four-blade bit has drilled numerous one-bit-run 7⅞-in. intervals in Williams' Piceance Basin wells, in many cases out-drilling competitors' bits when comparing ROP and footage drilled. Additionally, many of Williams' wells using five-blade competitor bits required as many as two to three different bits, increasing trip time.

In Well PA-A, the new four-blade bit drilled the 7⅞-in. interval with one bit, drilling a total of 5,171 ft between depth in at 2,922 ft and depth out at 8,033 ft, Table 1. Total drilling time was 64.5 hours, resulting in an average ROP of 80.2 fph. Based upon an hourly rig rate of $750, the cost per ft is an estimated $14.21.

In comparison, an offset well (PA-C) required two five-blade bits from two different manufacturers. Depth in was 2,300 ft and depth out was 8,038 ft. The first PDC bit drilled 3,127 ft in 67.5 hr for an average ROP of 46.3 fph. This section of the 7⅞-in. interval required three more hours to drill 2,000 ft less than the new four-blade bit for the entire interval. The cost per foot for this first competitor's PDC bit was nearly $19.00. A different competitor's PDC bit was used to drill the remaining 1,984 ft (6,054–8,038 ft) of the PA-C well to TD, requiring an additional 60 hr. Average ROP for this section was 33.1 fph and the cost per foot was more than $25.

In total, the 7⅞-in. interval of the PA-C well took twice as long and required twice as many bits than the PA-A 7⅞-in. interval with the new four-blade bit. These figures also do not account for trip time to change bits nor for the time to drill a 600-ft section of the interval that is not included in the table.

## PDC OPERATING PRACTICES

The Varel bits being used to drill entire intervals in these various Piceance Basin fields have used standard operating practices for the area. The flowrates used range from 470 to 520 gpm through nozzle configurations of 6 × 12 or 6 × 13. At an average flowrate of 500 gpm and a total flow area of 0.720 in.$^2$, the overall Horsepower per Square Inch (HSI) averages 2.7. Since these are directional wells, the normal practice is to run high-torque, low-speed motors that turn at a speed of about 110–120 rpm. In addition, a rotary speed of 30–50 rpm was normal for the drilling mode. The average WOB ranged from 5,000 lb to 26,000 lb. While drilling in some of the tougher cemented sand sections of the Williams Fork, it was found that as the bit's ROP slowed, it was often beneficial to slow the pumps so that the motor would also slow and allow the bit to get a better "bite" on the formation. This led to the recommendation to use low-rpm motors with high torque capabilities whenever possible.

## ADDITIONAL PERFORMANCE DATA

Table 2 illustrates several of the new four-blade bit's one-bit-run-per-interval

**TABLE 1. Comparison of proprietary four-blade bit with competitor bits drilled in offset wells**

| Well | Size, in. | Type | Depth in, ft | Depth out, ft | Footage, ft | Time, hr | ROP, fph | CPF, $/ft |
|---|---|---|---|---|---|---|---|---|
| PA-A | 7.875 | VTD416PH | 2,922 | 8,093 | 5,171 | 64.5 | 80.2 | $14.21 |
| PA-B | 7.875 | COMP.2 | 6,265 | 6,876 | 611 | 13.5 | 45.3 | $19.07 |
| PA-B | 7.875 | COMP.3 | 6,876 | 8,217 | 1,341 | 28.0 | 47.9 | $18.16 |
| PA-C | 7.875 | COMP.3 | 2,300 | 5,427 | 3,127 | 67.5 | 46.3 | $18.69 |
| PA-C | 7.875 | COMP.1 | 6,054 | 8,038 | 1,984 | 60.0 | 33.1 | $25.18 |
| PA-D | 7.875 | COMP.2 | 6,322 | 7,921 | 1,599 | 27.0 | 59.2 | $15.16 |

performances in a variety of Williams' Piceance Basin fields compared with several 7⅞-in. intervals drilled by multiple competitors' PDC bits. The table illustrates that the competitors' runs are not near the footage drilled by the proprietary four-blade bit.

For example, the new four-blade bit averages 5,591 ft per bit while the competitor bits run in the same fields averaged 2,967 ft per bit. Also, the ROP for the new four-blade bits averaged 65.2 ft per hour in comparison to 55.7 fph for the competing bits.

**Fig. 5.** The proprietary four-blade bit that drilled the entire 6,570 ft of a 7⅞-in. interval in one of the operator's Piceance Basin wells was graded as "1 1 CT C X I NO TD."

Usually, it will take multiple competitor bits to drill the same interval drilled with one new four-blade bit. This doesn't happen 100% of the time since there are many variables involved. However, over a three-month period, the new four-blade bits have been able to drill the entire interval five times more often than other bit types and designs. For example, in Well RWF-A of the Rulison Williams Fork Field, where drilling is recognized to be somewhat more difficult than in other fields, one new 7⅞-in. four-blade bit was used to drill the entire interval of 6,570 ft in 134.7 hr at an average of 48.8 fph. This well is an "S"-type directional well with a tangent section at 29°. The bit steered well and was used in the sliding mode to drill only 350 ft in 16.4 hr at an ROP of 21.3 fph. The bit was pulled and graded as "1 1 CT C X I NO TD," Fig. 5. For comparison, in Table 3, there are several separate wells shown where the average competitor bit drilled 2,779 ft in 50.1 hr at an average ROP of 55.5 fph.

## CONCLUSION

The new four-blade bit has provided everything desired in a good bit design: steerability, increased ROP and increased footage drilled. In addition, it has been shown many times that the new four-blade bit is able to drill the entire interval in one run. One-bit runs are good for saving costs, and also good for rig safety by eliminating bit trips. The result is that the operator drills its wells faster and at less cost, and is able to bring its natural gas production onstream and into the sales line more quickly. **WO**

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**TABLE 2. Performance of the proprietary four-blade bit during one-bit-run-intervals**

| Well | Size, in. | Type | Depth in, ft | Depth out, ft | Footage, ft | Time, hr | ROP, fph |
|---|---|---|---|---|---|---|---|
| RWF-A | 7.875 | VTD416PH | 2,900 | 9,470 | 6,570 | 134.7 | 48.8 |
| PA-A | 7.875 | VTD416PH | 2,922 | 8,093 | 5,171 | 64.5 | 80.2 |
| PA-B | 7.875 | VTD416PH | 3,017 | 8,382 | 5,365 | 75.0 | 71.5 |
| PA-C | 7.875 | VTD416PH | 2,820 | 7,915 | 5,095 | 84.5 | 60.3 |
| PA-D | 7.875 | VTD416PH | 3,170 | 8,590 | 5,420 | 79.5 | 68.2 |
| PA-E | 7.875 | VTD416PH | 2,325 | 7,518 | 5,193 | 61.5 | 84.4 |
| RPW-A | 7.875 | VTD416PH | 2,586 | 8,908 | 6,322 | 100.5 | 62.9 |

**TABLE 3. Competitor bits drilling the 7⅞-in. interval**

| Well | Size, in. | Type | Depth in, ft | Depth out, ft | Footage, ft | Time, hr | ROP, fph |
|---|---|---|---|---|---|---|---|
| RWF-B | 7.875 | COMP. 4 | 2,933 | 6,036 | 3,103 | 67.5 | 46.0 |
| RWF-B | 7.875 | COMP. 2 | 6,036 | 8,089 | 2,053 | 58.9 | 34.9 |
| RWF-B | 7.875 | COMP. 2 | 8,089 | 8,544 | 455 | 12.5 | 36.4 |
| RWF-C | 7.875 | COMP. 3 | 2,325 | 4,694 | 2,369 | 37.0 | 64.0 |
| RWF-C | 7.875 | COMP. 3 | 4,694 | 6,319 | 1,625 | 40.5 | 40.1 |
| RWF-D | 7.875 | COMP. 3 | 3,120 | 7,070 | 3,950 | 49.0 | 80.6 |
| RWF-E | 7.875 | COMP. 3 | 1,168 | 7,063 | 5,895 | 85.0 | 69.4 |
| PA-F | 7.875 | COMP. 4 | 1,145 | 4,798 | 3,653 | 51.0 | 71.6 |
| PA-F | 7.875 | COMP. 4 | 4,798 | 7,220 | 2,422 | 68.5 | 35.4 |
| PA-F | 7.875 | COMP. 4 | 7,220 | 8,410 | 1,190 | 29.0 | 41.0 |
| PA-G | 7.875 | COMP. 4 | 1,915 | 5,747 | 3,832 | 56.0 | 68.4 |
| PA-G | 7.875 | COMP. 3 | 5,747 | 7,536 | 1,789 | 33.0 | 54.2 |
| PA-H | 7.875 | COMP. 2 | 1,185 | 5,536 | 4,351 | 48.5 | 89.7 |
| PA-I | 7.875 | COMP. 4 | 1,930 | 6,429 | 4,499 | 68.0 | 66.2 |
| PA-I | 7.875 | COMP. 2 | 6,429 | 7,021 | 592 | 26.0 | 22.8 |
| RPW-B | 7.875 | COMP. 4 | 2,668 | 4,398 | 1,730 | 24.0 | 72.1 |
| RPW-B | 7.875 | COMP. 3 | 4,398 | 6,856 | 2,458 | 66.5 | 37.0 |
| RPW-B | 7.875 | COMP. 3 | 6,856 | 9,065 | 2,209 | 87.5 | 25.2 |

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