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# Physics-Based Limiter Redesign and Bit Performance Analysis at The Geysers

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**ABSTRACT**

As part of a U.S. DOE Geothermal Technologies Office funding opportunity, Geysers Power Company, LLC (GPC), an indirect subsidiary of Calpine Corporation, partnered with Sandia National Labs, EGI at the University of Utah, and Texas A&M University to demonstrate increased drilling performance at The Geysers Geothermal Field. The performance target in the drilling demonstrations is at least a 25% improvement in rates of penetration, with increased footage on bottom for each bit coupled with increased bit life and time drilling. The project leverages advances in oil and gas drilling technologies including PDC bits, along with the physics-based limiter redesign techniques championed in drilling demonstrations conducted at the Utah FORGE geothermal site. The planned drilling demonstrations are being conducted as part of an existing drilling campaign intended to enhance reservoir utilization. The wells are typically drilled to the top of the reservoir with mud and then air-drilled to total depth (TD) through fractured zones at temperatures ≥ 450°F. A major goal of the project is to assess the effectiveness of implementing mechanical specific energy (MSE) and drilling dysfunction diagnosis and remediation in these challenging environments, as well as alternate rock reduction technologies. The first demonstration well has been completed, with 15 PDC bit runs in the 17.5", 12.25" and 8.5" sections. Initial analysis shows ROP gains in all three sections, especially in the 17.5" and 12.25" sections, compared with conventional roller cone bit runs in the demonstration well and offset wells. However, in the 8.5" hole, wear and damage to the PDC bits resulted in relatively short bit runs. Analysis is underway to take advantage of the positive results and remediate the challenges.

This paper provides updates on drilling activities conducted since the Phase 1 demonstration well at GDC-36 which was drilled from November 2023-January 2024. Additional analysis of the bit performance has been conducted. Furthermore, in subsequent wells drilled by GPC, PDC bits have been used extensively, building on the gains realized at GDC-36. GPC has continued to work with bit vendors to identify designs that last longer in the harsh, air-drilled 8.5" portions of the wells. Planning for the Phase 2 demonstration at Prati-44 is ongoing.

## 1. INTRODUCTION

A primary obstacle to increased use of geothermal energy is adequately cost-effective resource development to compete with other resources in the marketplace. Studies estimate the price of geothermal power in the range of $3,000–$6,000 per kilowatt installed [1], largely due to drilling costs. One approach to lowering installed and operating cost is to consistently improve drilling rates and efficiency. Improving drilling rate of penetration (ROP) without sacrificing tool life has the potential to dramatically lower well construction time and drive down the cost per kilowatt of geothermal power.

Roller cone drill bits have been used extensively in geothermal applications based on historical performance and convention. Previous drilling campaigns at The Geysers have used roller cone bits as the primary rock reduction technique. Internal data from these campaigns indicate instantaneous rates of penetration in the formations have ranged from 10's-100 ft/hr. However, the typical duration for reaching 8,000 ft measured depth ranges from 40-60 days. Polycrystalline diamond compact (PDC) drill bits have been tried at various times with limited success.

By combining physics-based practices along with the resources and technology available to the drilling industry at large significant performance gains have been made in a variety of oil and gas industry settings. The same concept translates to geothermal

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development in high strength, hot rock. Drilling at Utah FORGE has demonstrated the performance gains possible when implementing physics-based, limiter redesign workflows [2, 3]. At Utah FORGE, in a relative homogeneous granitoid, within the span of four (4) wells, instantaneous drilling rates were improved by nearly 500% while bit life was improved by nearly 200% (Figure 1).

These gains were made by educating the crews on physics-based drilling concepts and implementing limiter redesign workflows. Although the work leveraged advances in PDC bit technology, as well as directional drilling and drilling fluid vendor tools and resources, the physics-based drilling process was the critical aspect in providing the workflow and framework to understand, implement and maintain last performance gains. Similarly, in a geothermal field in the Philippines, major gains in performance were achieved by optimizing the design and operating parameters of PDC bits [4].

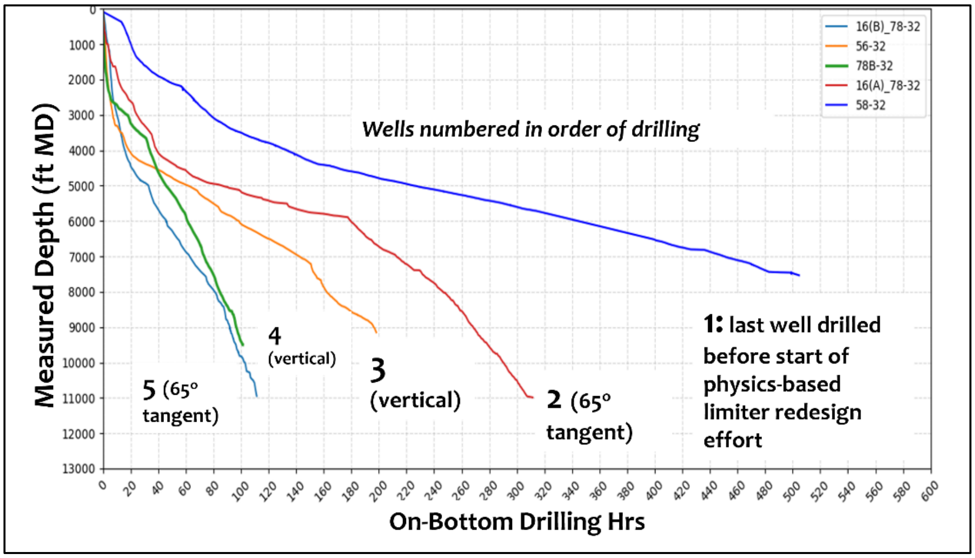


**Figure 1. Reduction in on-bottom time in sequential wells at FORGE during physics-based limiter redesign drilling effort. At the same time ROP was increased, bit life in the hard granite was more than doubled (courtesy Fred Dupriest and Sam Noynaert).**

The limiter redesign workflow is agnostic to the rock reduction techniques used for drilling. It is built around understanding the physics of bit performance in addition to empirically-driven approaches. When the entire drill team understands the physics of drilling, the question becomes what is limiting the application of weight-on-bit (WOB) and/or rotary speed (RPM) at any given time. Redesign may incorporate any number of aspects of the drilling operation but is often focused on the drill bits, bottomhole assemblies (BHA) and drilling fluids.

## 2. PHASE 1 DRILLING DEMONSTRATION

The Phase 1 drilling campaign focused on implementing off-the-shelf PDC bits in intervals traditionally drilled by roller cones. While drilling these intervals, periodic trips enabled physically assessing and grading bits and bottom hole assemblies. EDR data were available for offsite post-processing. Each of the project team members analyzed the data as desired to independently assess the drilling performance.

The team engaged multiple bit vendors to select commercially available bits that were suited to the formation conditions at The Geysers. This allowed us to assess the state of PDC bits and their suitability for geothermal applications. Maximizing performance (rate of penetration and bit life) is the objective function.

The first well in this evaluation program was GDC-36 which is a typical well in the north-central Geysers area. Figure 2**Error! Reference source not found.** shows a map of The Geysers Geothermal Field, with the surface location of GDC-36.


**Figure 2. Map of The Geysers Geothermal Field, California, showing the surface location of GDC-36, the first demonstration well for this project.**

A typical campaign well (Figure 3) completion starts with a 30” conductor in a 36” hole drilled to 30’. A 26” diameter hole is then drilled to nominally 500’ and 20” casing is cemented to surface. A 17 ½” diameter well is drilled with mud to approximately 2500’ with directional work starting in this section. A 13 3/8” casing is cemented to surface in the 17 ½” hole. A 12 ¼” diameter hole is drilled on mud to approximately 5,000’ MD where the top of the steam reservoir is encountered. Then, 9 5/8” casing is cemented to surface. The last section of the well is drilled using 8 ½” bits on air to a total depth of approximately 9,000’ and completed with a slotted liner and tieback.

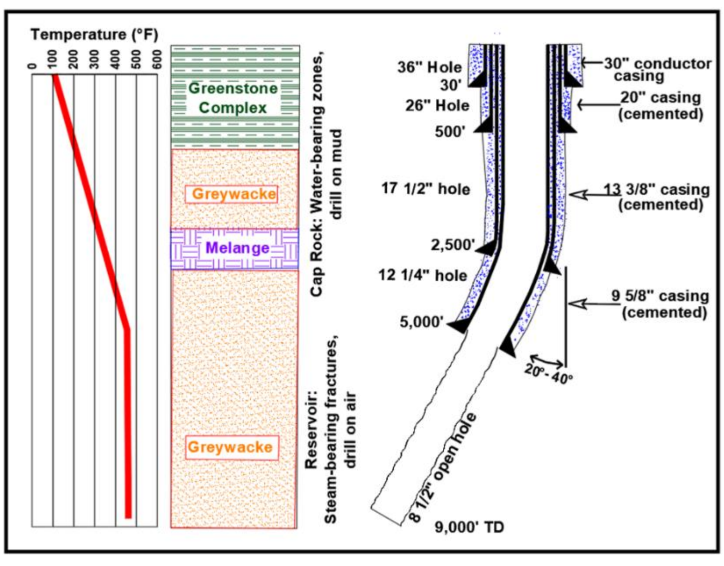


**Figure 3. Schematic of a representative Geysers well for the drilling campaign.**

Specific to GDC-36, the intermediate 17.5” borehole was drilled from 428’ 2,452’. The next interval was from 2,452’ to 3,344’ using a 12.25” bit. The final air-drilled section extended from 3,344’ to 9,220’. The team planned to use up to five bits for each of the demonstration zones. The bits included a mix of roller cone and PDC bits and a percussive hammer at the bottom of the air-drilled 8.5-inch interval. Additional trips for diagnostics and bit replacement were run as required.

For each of the demonstration zones (17.5”, 12.25”, and 8.5”), conventional roller cone bits were run along with PDC bits - providing a basis for performance comparison. The target distance for each of the PDC bit runs was 500’ in the 8.5” hole with longer distances in the other zones. Roller cones in contrast are run for 24 hrs and pulled as standard practice for the 8.5” section.

Bits from multiple vendors were tested to assess the best commercially available off-the-shelf options for PDC bits. In addition to the roller cone and PDC bits, a percussive hammer, modified for high-temperature, was deployed at the end of the well.

For reference, the lithology for the entire well is shown in Figure 4.

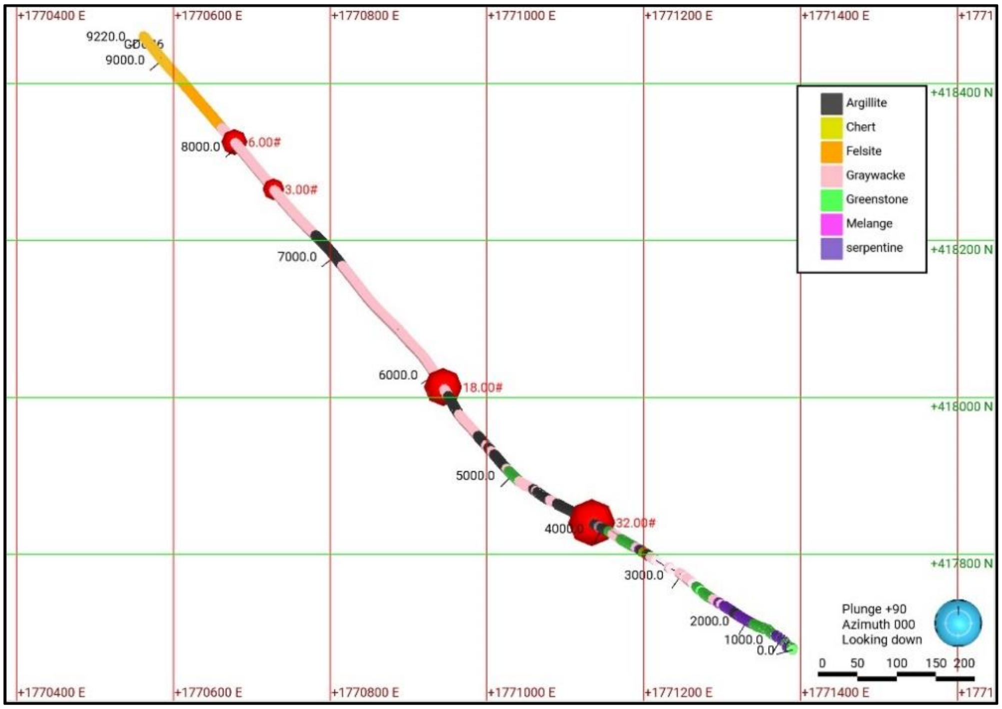


**Figure 4. Geologic information for GDC-36**

### 2.1. Limiter Redesign

Prior to spud, the drilling team, rig crews and service personnel, along with the research team participated in a multi-day training session on physics-based drilling practices. The training covered physics-based limiter redesign, with emphasis on physics-based understanding of expected Geysers drilling dysfunctions and how to identify them using electronic drilling records (EDR) data. Emphasis was placed on identifying drilling dysfunctions, and then engineering redesigns to eliminate those dysfunctions. This project followed a traditional physics-based approach where the question asked is "what is limiting the application of additional WOB."

The wellsite team was taught how to identify dysfunctions in real-time and what can be done in terms of real-time mitigation. If a dysfunction or limiter is identified in real-time and the limits of real-time mitigation practices are reached, the question for the team then becomes what needs to be done in terms of redesign of equipment or practices to increase performance on subsequent runs. By addressing collateral risks and redesigning tools and practices in a physics-based manner instead of empirically, the resulting performance gains can be much more rapid and lasting than those empirically derived.

The workflow only requires standard electronic drilling recorder (EDR) data. One key metric used was downhole Mechanical Specific Energy (MSE) when using a mud motor in the intermediate intervals and surface MSE when drilling the 8 ½" interval. For this research-centric project, bottom hole (in-bit measurement sensors) data were collected in the 12.25" section to enable post-drilling analysis of the process and to diagnose the actual limiters being observed. Performance limiters such as cuttings removal rates or ability to manage weight-on-bit or torque during drilling were addressed in real time.

### 2.2. Drilling Results

The well plan for the first demonstration well estimated approximately 60 days to reach total depth (TD). This included 15 days of drilling and completion in the 17.5" section, 11 days in the 12.25" hole, and 20 days in the 8.5" section. These three intervals were included in the demonstration zone. The actual and planned days vs. depth plot is shown in (Figure 5). The actual days includes time associated with rig repairs and other non-drilling time (NDT). The on-bottom hour reduction when compared to a group of analog offset wells showed significant improvement (Figure 6). It should be noted this representation of drilling performance does not account for run length (which entails trip time to change bits) and other collateral activities which need to be addressed in a drilling program. This is particularly true in the 8 ½" hole section where run lengths were quite limited, possibly because of fractures, which created extreme interfacial severity problems.

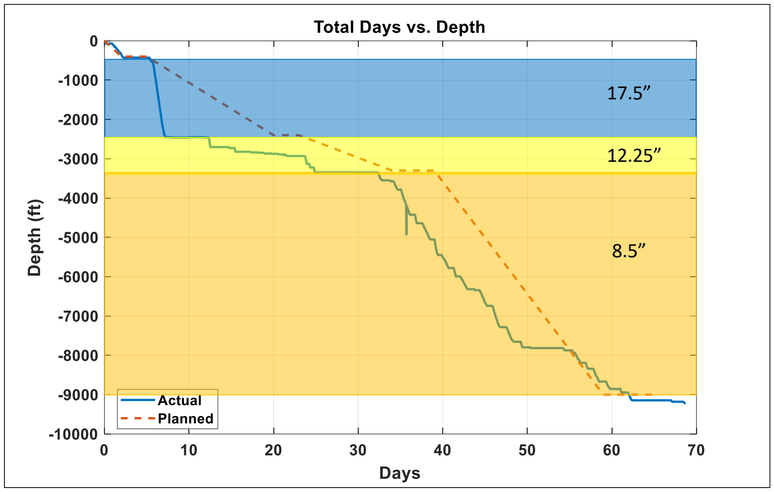


**Figure 5. Actual and planned days vs. depth for GDC-36.**

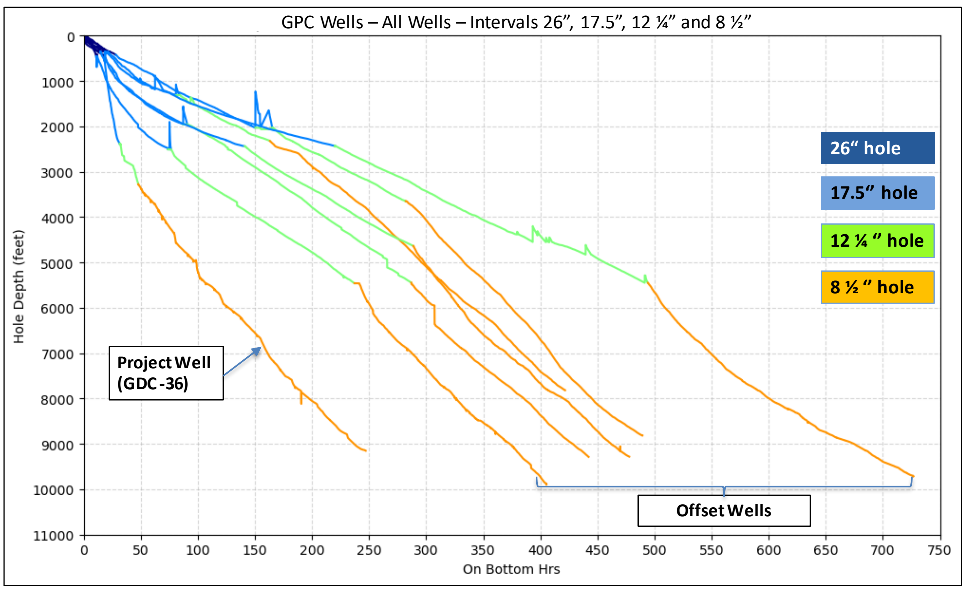


**Figure 6. On-bottom hours comparing first project well to analog offset wells. When combined with days vs depth or similar plots, an understanding can be gained of on-bottom drilling performance, off-bottom time (planned and unplanned) and their relationship.**

Instantaneous rates of penetration (ROP) at depth are shown in Figure 7. As also indicated by the days vs. depth plot in Figure 5, the fastest drilling occurred in the 17.5" interval. The subsequent intervals presented challenges that resulted in increased total rig time. These included lost circulation zones in the 12.25" section, which were treated by setting multiple cement plugs. In the air-drilled 8.5" interval, major slowdowns were incurred because of short PDC bit life, interpreted to be due to damage incurred in fractured zones. Although there were drilling challenges in those zones, the improvement in on-bottom performance showed the opportunity and value potential in future wells. For the off-bottom non-bit or BHA limiters and non-productive time events, there were positive lessons learned in how to manage the formation challenges in subsequent wells.

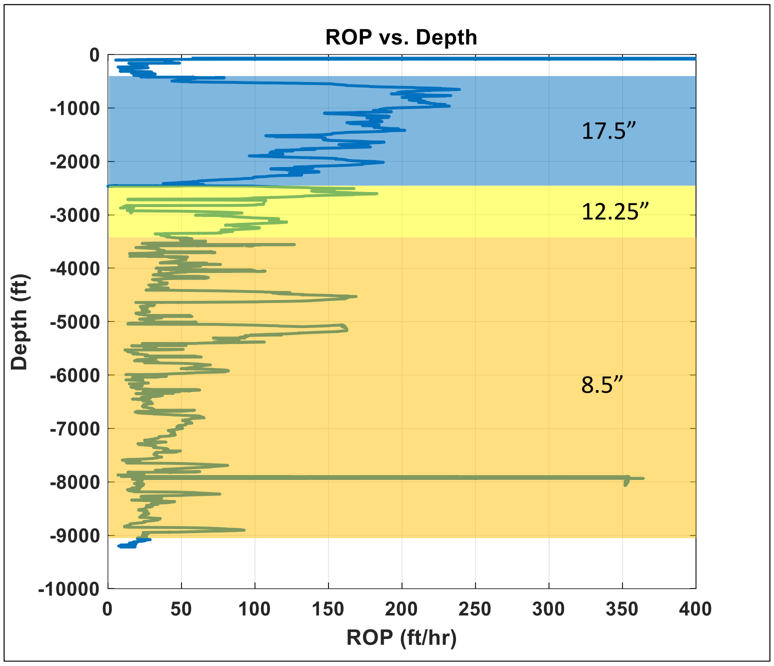


**Figure 7. Instantaneous ROP vs. depth for the entire well.**

We also analyzed bit run data from GDC-36 and six previous baseline wells (drilled without PDC bits and without physics-based drilling concepts) to get a preliminary idea of performance of the PDC bits vs. a baseline. Note that the bit run data consist of footage drilled and hours spent per bit run, which includes time for drill pipe connections. Therefore, the bit run ROPs are always slower than the Instantaneous ROPs discussed above. However, since the bit run data are readily available from GPC's drilling database for the baseline wells, we are using it to get an early look at performance trends.

Figure 8 shows the baseline vs. GDC-36 performance based on bit run data. In the 17.5” and 12.25” hole sections, the performance improvement using PDC bits is unmistakable and impressive, approximately 400% and 700%, respectively. In the 8.5” section, performance was about 70% better than baseline, and 50% better than the roller cone runs in GDC-36.

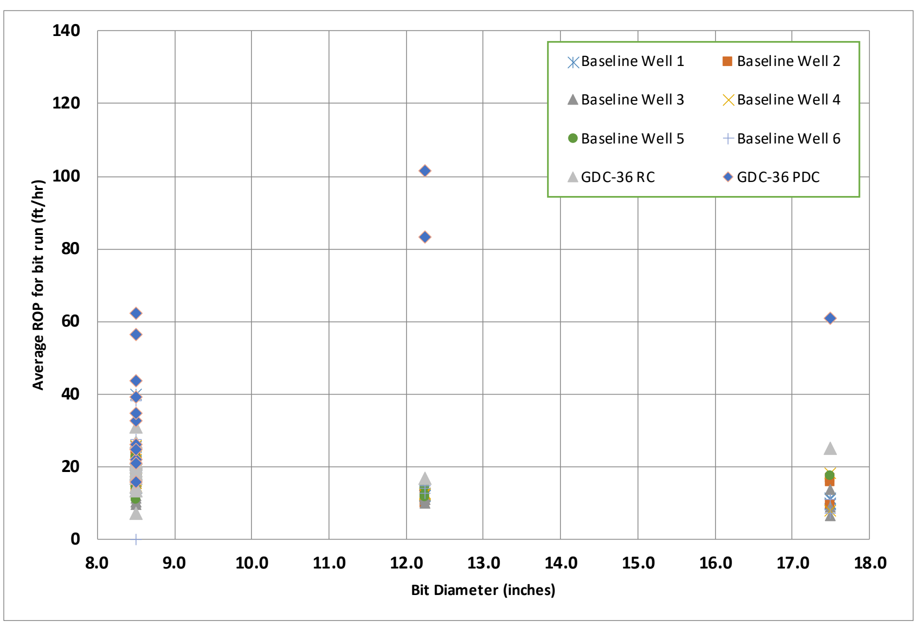


**Figure 8. Bit-run ROP for 6 baseline wells, GDC-36 Roller Cone (RC) runs and GDC-36 PDC runs (all intervals).**

**Table 1. Tabularized results for baseline wells and GDC-36 bit runs (all intervals).**

| | | | | ROP (ft/hr) | | Bit Runs (ft) | | N |
|---|---|---|---|---|---|---|---|---|
| **Group** | **Bit Dia** | **Total Ft** | **Total Hr** | **Mean** | **Std Dev** | **Mean** | **Std Dev** | **127** |
| Baseline | 17.5" | 9,557 | 811.5 | 11.8 | 3.7 | 683 | 489 | 14 |
| GDC-36 RC | 17.5" | 100 | 3.5 | 28.6 | N/A | 100 | N/A | 1 |
| GDC-36 PDC | 17.5" | 2,014 | 32.5 | 62.0 | N/A | 2014 | N/A | 1 |
| Baseline | 12.25" | 14,288 | 1,149.0 | 12.4 | 1.4 | 680 | 336 | 21 |
| GDC-36 RC | 12.25" | N/A | N/A | N/A | N/A | N/A | N/A | - |
| GDC-36 PDC | 12.25" | 941 | 9.5 | 99.1 | 21.1 | 314 | 171 | 3 |
| Baseline | 8.5" | 27,889 | 1,494.0 | 18.7 | 5.7 | 372 | 175 | 75 |
| GDC-36 RC | 8.5" | 3,586 | 169.0 | 21.2 | 4.9 | 299 | 161 | 12 |
| GDC-36 PDC | 8.5" | 2,212 | 68.5 | 32.3 | 14.9 | 201 | 154 | 11 |

17.5" Interval

The 17.5" interval was drilled using a 1.5° bent-sub mud motor with stabilizers. The BHA setup, including stabilization was based on prior experience at The Geysers. The 17.5" interval was drilled from 428 ft MD to 528 ft MD, using a roller cone as a baseline for comparison with the subsequent PDC test runs. A commercial off-the-shelf (COTS) PDC was used to drill the remaining interval to 2,452 ft MD. The average gross overall ROP (including connection times) over that interval was approximately 60 ft/hr, with instantaneous ROP generally in the range of 100 to 200 ft/hr in this interval (Figure 9).

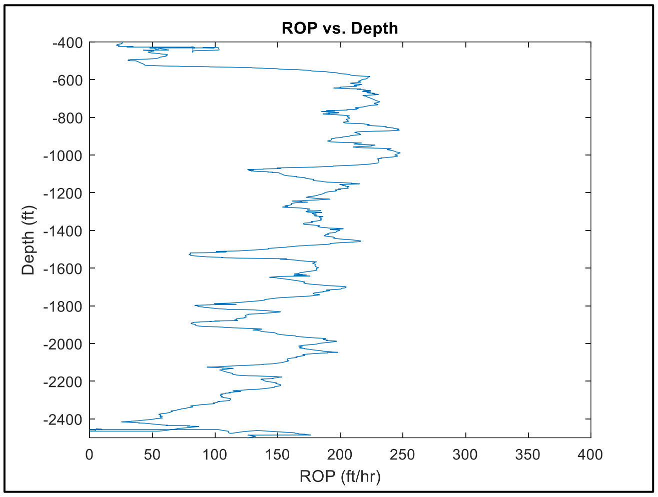


**Figure 9. Instantaneous ROP vs. Depth in the 17.5" interval.**

Some cutters were sheared off the gage of the bit near the end of the run that cut just over 2000 of hole. The overall performance for the application of PDC bits at The Geysers was an encouraging sign for the subsequent intervals. Photographs of the 17.5" PDC bit are shown below (Figure 10).

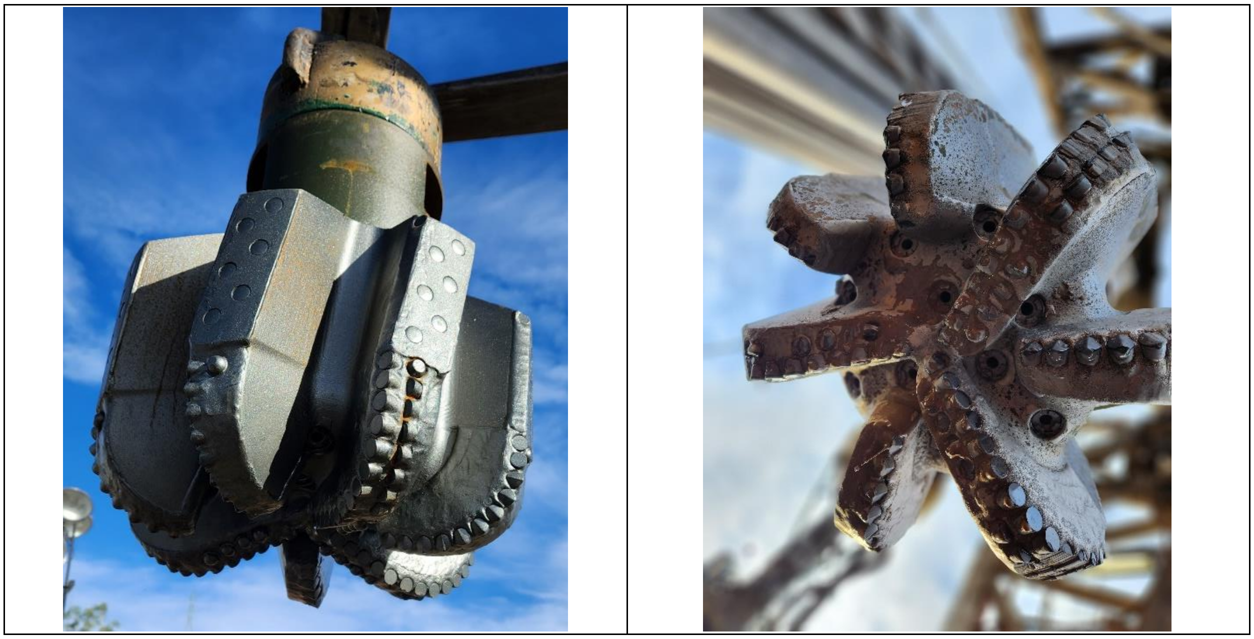

**Figure 10. 17.5" PDC before (at left) and after run (at right).**

<u>12.25" Interval</u>

The 12.25" was also drilled with a directional BHA and downhole motor. The interval contained lost circulation zones that were remediated with cement plugs. The plugs had poor results in preventing lost circulation in the zone. In the end, the team decided to drill through the losses and was able to reach the end of the interval with a combination of roller cones and PDCs. We were unable to execute a single continuous 500 ft run with a PDC bit due to the multiple trips for the cement plugs for lost circulation, a standard practice in the field. The instantaneous ROP vs. depth is shown in Figure 11. Again, during normal drilling, instantaneous ROPs were mostly in the range of 100 – 200 ft/hr for PDC bits. Slower intervals shown in the chart were either due to use of roller cones or control drilling during the lost circulation events and while drilling out cement plugs.

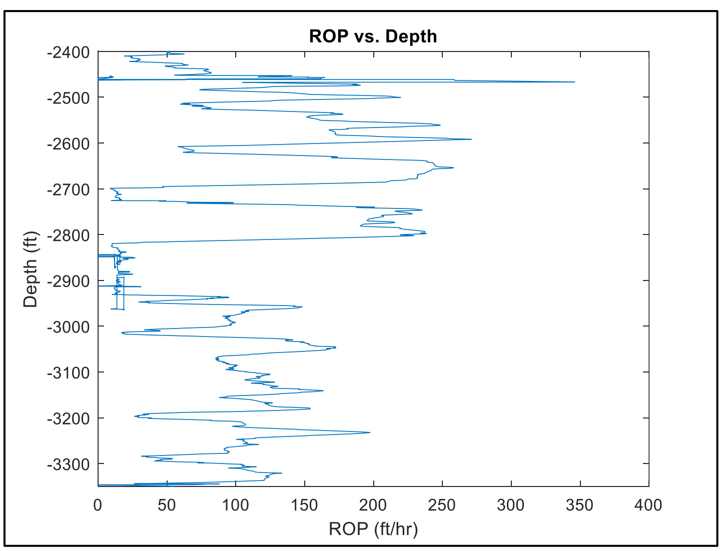


**Figure 11. Instantaneous ROP vs. depth (12.25" interval).**

Two PDC bits were run in this interval. The first was pulled due to severe lost circulation of approximately 250 barrels per hour after drilling 245 ft to a depth of 2702 ft. The second PDC drilled 94 ft and was pulled due to concerns over high temperatures damaging downhole measurement subs and the need to replace the downhole motor; the same bit was tripped back in and produced an additional 414 ft. Hence this bit produced a combined footage exceeding 500 ft. Note that neither bit was pulled because of bit performance, and neither was damaged beyond repair (DBR). The two bits are shown in Figure 12. These bits both incorporated shaped PDC cutters.

**Figure 12. Bit 1 (left) and Bit 2 (right) used in the 12.25" interval.**

<u>8.5" Interval</u>

<u>PDC and Roller Cone</u>

The 8.5" interval is arguably the most challenging section of the well since it is air-drilled, fractured, and there is high temperature. This is typically air-drilled due to the vapor-static pressure gradient, moisture-sensitive formation, and fractured zones. Additionally, the temperatures in that zone exceed 450°F negating the use of mud motors. The drill string was rotated from the surface using the rotary table. The on-bottom ROP over the interval varied widely depending on the formation conditions and the bit design (Figure 13).

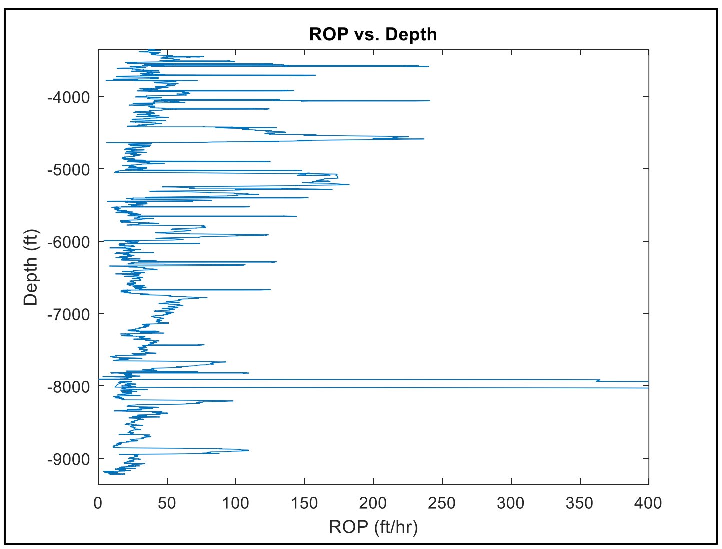


**Figure 13. Instantaneous ROP vs. depth (8.5" interval).**

Air-drilling is very abrasive on the entire drill string, and typically bits are dulled or out of gauge after less than 24 hours of drilling. Since round trips to change bits averages about 12 hours, bit life becomes a significant value driver in addition to ROP. Figure 14 shows the interval lengths drilled for each bit run in the air-drilled 8.5" hole, for both roller cone (RC) and PDC bits. Almost all these PDC bit runs were terminated because of damage associated with interfacial occurring over very short intervals (several feet). Figure 14 shows a wide scatter of bit run lengths. On average, the PDC bits lasted only about 200 ft, while the RCs lasted about 300 ft. For comparison, roller cone bit runs in the 8.5" hole in the previous six wells at The Geysers averaged 372'. In GDC-36, there also appears to be some correlation between bit life and lithology, with the longest bit runs occurring in the greywacke/argillite intervals, while bit runs were shorter in the mélange, hornfels and felsite intervals. However, most of the PDC bit dulls showed obvious shearing of cutters. This indicates the limiter is not a gradual wearing trend seen in some high strength rocks but instead is effectively a near-instantaneous event. The variability in run length could be due to variability in fracture distribution within the reservoir.

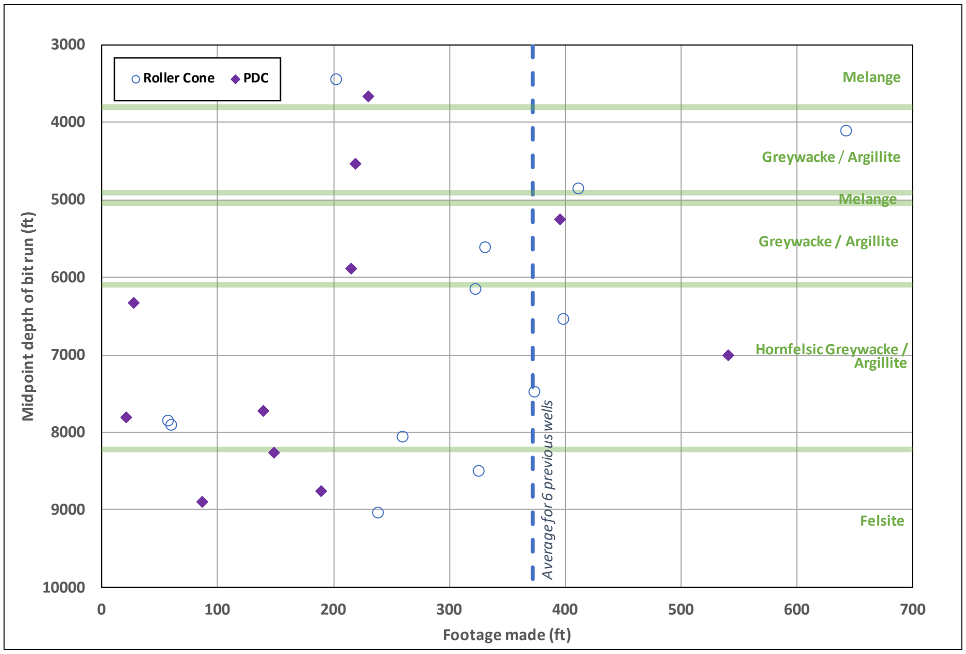


**Figure 14. Bit run length vs. depth in 8.5" interval. Geologic units are generalized from Figure 4.**

**Table 2. Average footage in 8.5" intervals (roller cones and PDC)**

| Average footage | RC (ft) | PDC (ft) | All (ft) |
|---|---|---|---|
| All rock types | 299 | 201 | 252 |
| Melange | 202 | 230 | 216 |
| Greywacke/Argillite | 427 | 277 | 363 |
| Hornfels | 230 | 182 | 208 |
| Felsite | 282 | 142 | 190 |

GDC-36 PDC Bit Analysis in the 8½” Interval

The PDC bit penetration rate performance varied throughout the run depending on the formation, the bit cutting structure and the operating conditions. The PDC bit suite for the 8½” section is summarized in Table 3**Error! Reference source not found.**. The penetration rate and footage of the PDC bits used in the 8½” section are shown in Figure 15 and Figure 16 along with the mean values of all PDC bits in this interval. Remarkably, the cutters performed extremely well in the air-drilling environment. In this research setting, most of the bits in the GDC-36 suite were pushed hard with high WOB to remove potential ROP limiters. This largely contributed to most of the bits being damaged beyond repair, as shown in Table 4. Failure modes included ring shear on the outer gage of the bit; cone failures on the bit center; and cutter wear, chipping and bulk failures.

**Table 3. PDC bit suite performance in GDC-36 8.5" interval.**

| Bit No. | Depth In (ft) | Depth Out (ft) | Hole Made (ft) | ROP (ft/hr) |
|---|---|---|---|---|
| 10 | 3548 | 3778 | 230 | 22.0 |
| 12 | 4421 | 4640 | 219 | 62.3 |
| 14 | 5051 | 5447 | 396 | 56.6 |
| 16 | 5778 | 5993 | 215 | 39.1 |
| 18 | 6316 | 6342 | 26 | 26.0 |
| 20 | 6741 | 7282 | 541 | 32.8 |
| 22 | 7655 | 7794 | 139 | 34.8 |
| 23 | 7794 | 7815 | 21 | 21.0 |
| 28 | 8192 | 8341 | 149 | 24.8 |
| 30 | 8666 | 8855 | 189 | 15.8 |
| 31 | 8855 | 8943 | 88 | 43.5 |

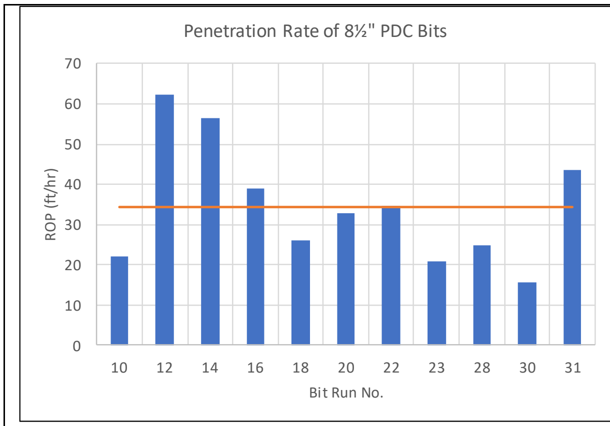


**Figure 15. PDC bit ROP performance in the 8 1/2" interval.**

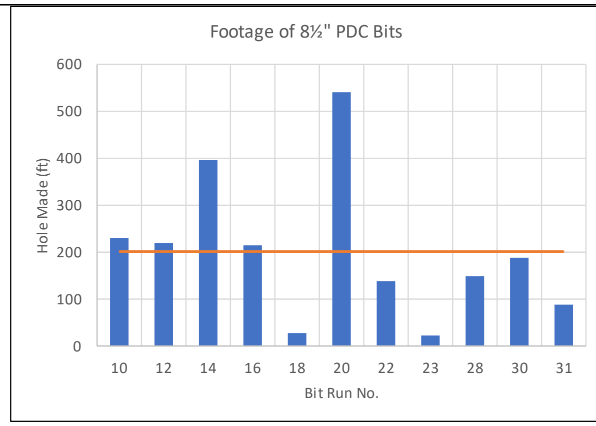


**Figure 16. PDC bit footage performance in the 8 1/2" interval.**

Since drilling and formation conditions change throughout a hole, each bit run should be governed or operated relative to its potential response to optimize that bit's respective drilling conditions. It is desirable to have a method to discern when the bit health has advanced beyond normal wear and tear to a failed state, typically denoted damage beyond repair (DBR). Tracking specific energy of the bit response relative to its nominal response has proven to be a valuable approach to discern when the bit has likely failed. Sandia demonstrated this at Utah FORGE [5] using the Detournay [6] rock reduction model and electronic drilling record (EDR) data.

**Table 4. PDC bit pulled condition in 8.5" interval.**

| Bit No. | DBR | Ring Out | Cone Failure |
|---|---|---|---|
| **10** | X | X | |
| **12** | X | X | |
| **14** | X | X | |
| **16** | X | X | |
| **18** | X | | X |
| **20** | X | X | |
| **22** | X | | X |
| **23** | X | | X |
| **28** | | | |
| **30** | | | |
| **31** | X | | |

It's interesting that the only two undamaged bits were both in felsite. Based on EDR ROP, Bit #30 was degradation was gradual wear. The same cannot be surmised for Bit #28. Not so clear on #28. Compared to other parts of the formation, felsite is very similar to FORGE granite in terms of rock homogeneity, although the felsite does have fracs and is hotter. Still, the lack of damage to bits #28 and 30 suggests that the felsite is where higher WOB and RPM might yield better performance without sacrificing bit life.

The Detournay model assumes the rock-cutter interaction on a PDC drag bit consists of two processes, cutting and friction. Cutting is characterized by intrinsic specific energy ($\varepsilon$) and a cutting force ratio ($\zeta$) and friction by the coefficient ($\mu$). The cutting force ratio, $\zeta$, represents the ratio of normal ($F_n$) to tangential ($F_s$) cutter forces for a sharp cutter, i.e., in the absence of friction. The internal specific energy, $\varepsilon$ is a measure of the energy necessary to cut a volume of rock.

The bit specific energy used here represents the rotational energy component of the overall mechanical specific energy and corresponds to the work done by torque, T, to drill a unit volume of rock using a drag bit of radius r, at a depth of cut δ:

$$E = \frac{2T}{r^2\delta} \tag{1}$$

A related parameter in the Detournay model is the drilling strength, S, using the weight on bit, W:

$$S = \frac{W}{r\delta} \tag{2}$$

The Detournay model represents a constraint on the response of a PDC bit based upon the assumption of cutting and frictional processes. By developing a force balance on the bit subject to the assumptions of cutting and frictional processes, the following model relations are derived (see also [5]):

$$E = E_0 + \mu\gamma S \tag{3}$$

where

$$E_0 = (1 - \beta)\varepsilon \tag{4}$$

and

$$\beta = \gamma\mu\zeta \tag{5}$$

The interpretation of the Detournay model is shown in Figure 17. The E-S diagram for a bit include a friction line with a slope representing the product μγ, where the constant, γ, embodies the influence of the bit design on its mechanical response. The E-S diagram depicted in Figure 17 is used for both a sharp single cutter (dotted cutting locus) and a full bit (solid friction line). The model is used herein to track the condition of the bit and detect end of life by evaluation of the surface EDR data. At high WOB, the bit response will be on the trendline near the intersection with the cutting locus; as the bit wears, the operating point will move up the friction line of the bit.

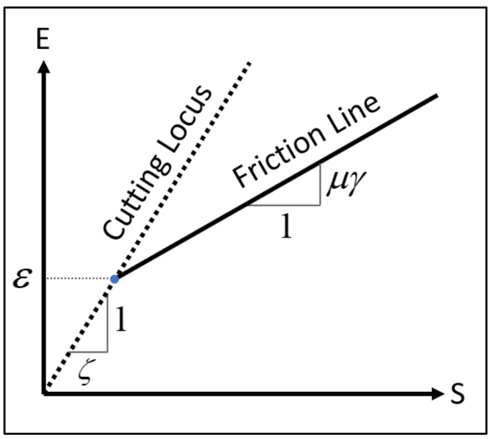


**Figure 17. Specific Energy vs Drilling Strength Diagram.**

The method was applied to all PDC bits in the GDC-36 well, and is demonstrated here for representative bit runs. Since both ROP and bit life are desirable features in bit performance, the product of these metrics (ROP x footage drilled) is one concise measure of successful bit performance. This is shown in Figure 18 for the GDC-36 bit suite in the 8-1/2” interval.

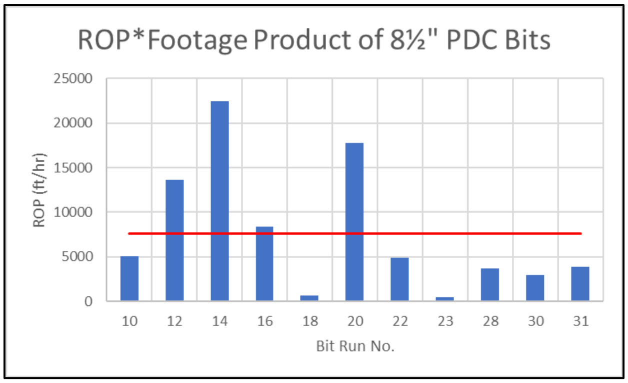


**Figure 18. (ROP x Footage) product of GDC-36 Bits in the 8-1/2" Interval.**

The average of this product is 7,612 $ft^2$/hr for all 8-1/2" PDC bits on GDC-36. This metric would be expected to be greater in formations where the rock is softer - resulting in higher ROP, and greater in formations where the rock is less abrasive – resulting in greater bit footage. These conditions can be anticipated to be higher in the formations encountered in GDC-36. As seen in Figure 18, notable positive performers are bits 12, 14 and 20; substandard performance was manifested by bits 18 and 23 – although successful runs with identical bits were observed on bit runs 20 and 22, respectively. These bit runs are addressed sequentially below.

The drilling record for bit 12 from the one-second EDR data is shown in Figure 19. The panel shows the drilling inputs (WOB and RPM) and the bit response (bit torque and ROP) in offset panels. This bit produced high ROP that resulted in high depth of cut per revolution that may have damaged the cutting structure later in the run. The *E* and *S* Detournay model parameters are also plotted in the panel. The EDR data maps well onto the Detournay plane in Figure 20a suggesting a friction line distribution for the bit from the one-second EDR history for the bit run. Zooming in on this figure in Figure 20b provides improved definition of the bit response. The data are used unfiltered directly from the EDR and show outliers due to connections and non-drilling conditions. Pre- and post-drill photos of the bit are shown in Figure 21 showing bulk cutter failure within the cone. The bit likely experienced cutting structure damage at the high depth of cut experienced after 4,540'.

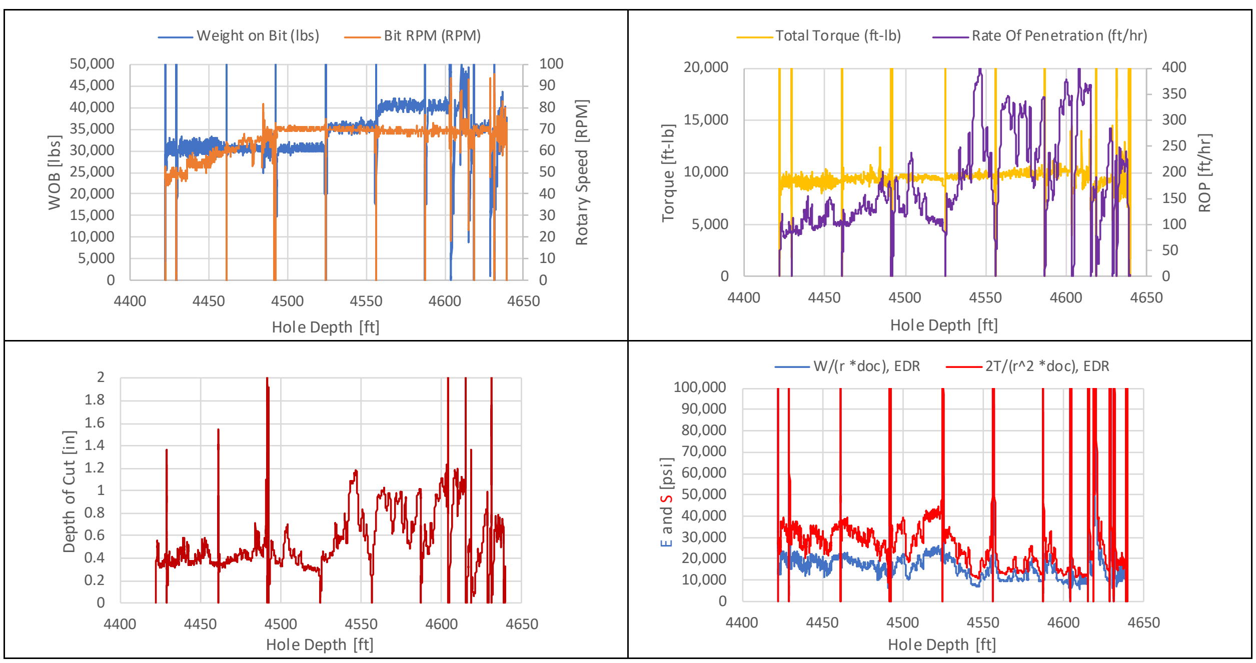


**Figure 19. Bit 12 drilling panel showing: a) drilling system inputs (WOB and RPM), b) bit response (Torque and ROP); c) depth of cut, and *E* and *S* strip chart versus drilling depth.**

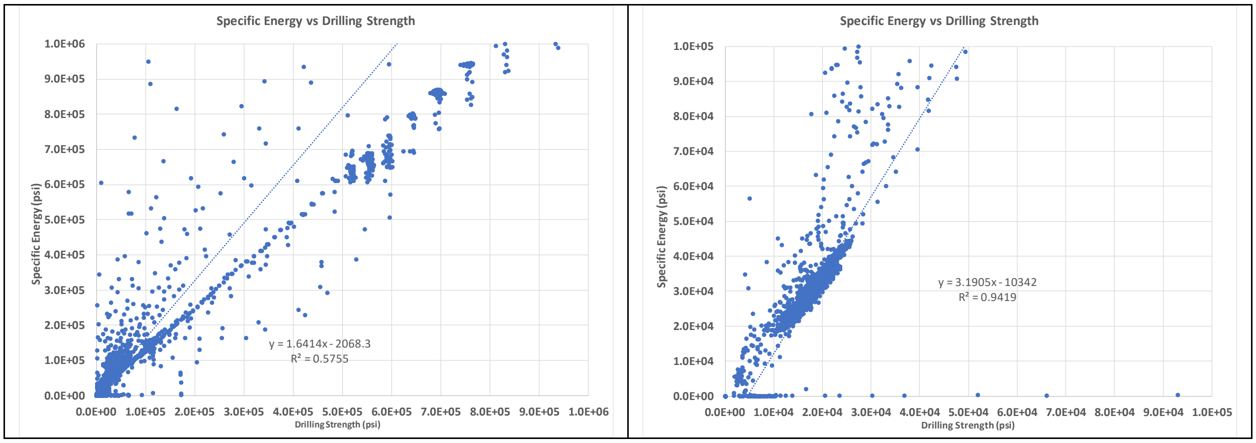


**Figure 20. Bit 12 response in E vs S plane (left) and zoomed-in (right).**

**Figure 21. Bit 12 pre-drill (left) and post-drill (right) photographs.**

This method was also applied to Bit 14. Drilling panel results are shown in Figure 22 where the EDR data are filtered to remove non-drilling condition outliers. The data are plotted in the *E-S* plane in Figure 23 wherein the *E-S* state points are colored to indicate their evolution through the drilling interval; the fresh bit states operate at low specific energy indicated in red and migrate to dark blue near the end of the bit run. The loss of proportionality between specific energy and drilling strength evident in the *E* and *S* strip chart late in the run is indicative of possible damage to the cutting structure. Ring shear is evident in the bit photograph shown in Figure 24.

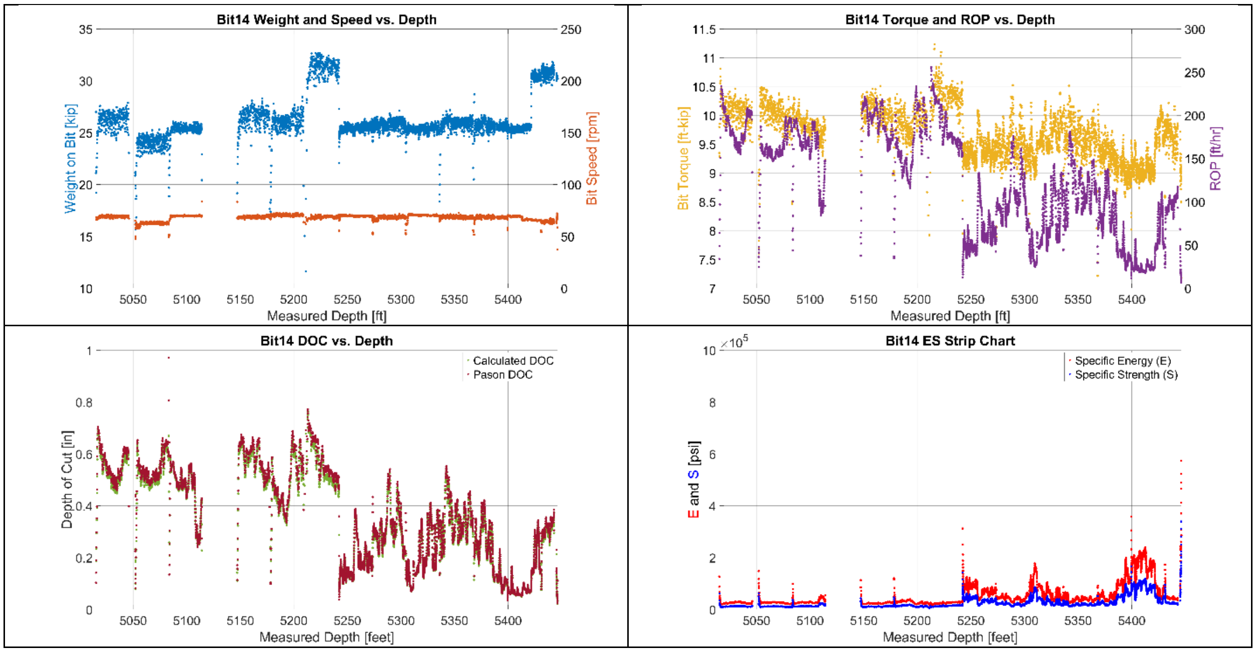


**Figure 22. Bit 14 drilling panel showing drilling system inputs and response.**

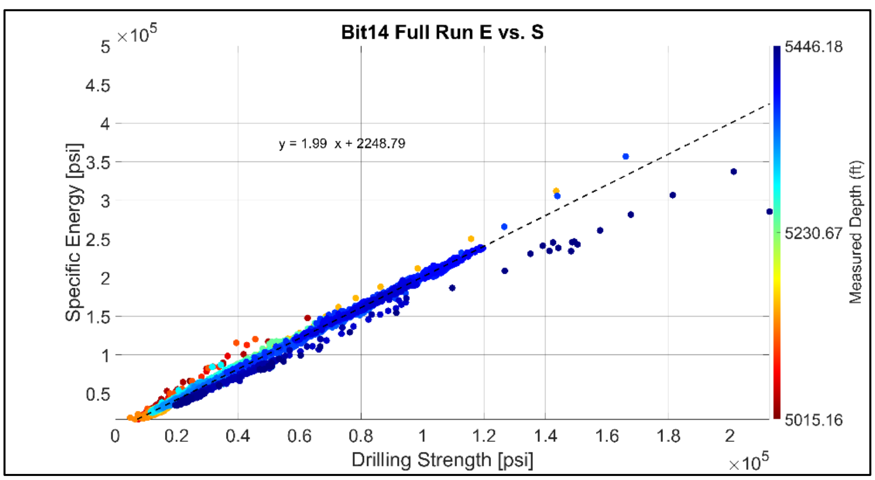


**Figure 23. Bit 14 E-S plane showing the state points moving up the bit trendline throughout the run.**

**Figure 24. Bit 14 showing ring shear.**

Notably, Bit 20 produced 541 ft of hole, longer than any other 8.5" PDC bit, at an average ROP of 32.8 ft/hr. The drilling record for this bit is shown in Figure 25**Error! Reference source not found.**. Pre- and post-drill photos are shown in Figure 26. The strip charts show stable torque response throughout the bit run and progressively decreasing ROP, likely in response to cutter wear. As noted, the specific energy should be proportional to drilling strength throughout the run for an intact cutting structure. Bit 20 generally displays this as shown in the plot below until a depth of 7,150' where a shift in response is observed. Even with increasing levels of drilling strength the specific energy displays proportionality until the very end of the run - indicative of possible damage to the bit cutting structure. This divergence is clearly seen in the E-S plane by comparing all the EDR data points for the run (Figure 27) to those occurring before a depth of 7150' (Figure 28).

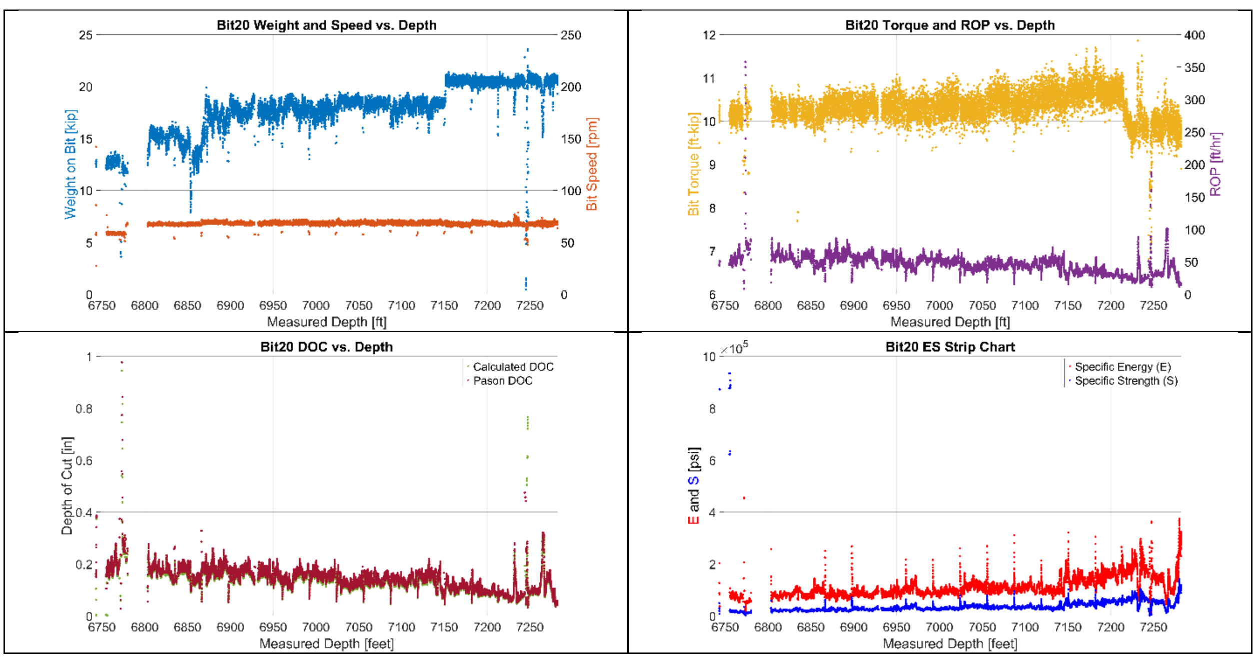


**Figure 25. Bit 20 drilling record from one (1) second EDR data including: panel a) Drilling system inputs WOB and RPM (top left) and panel b) drilling system response Torque and ROP (upper right). Also shown are panel c) Depth of Cut per Revolution (lower left) and panel d) Specific Energy and Drilling Strength.**

**Figure 26. Bit 20 before (left) and after (right).**

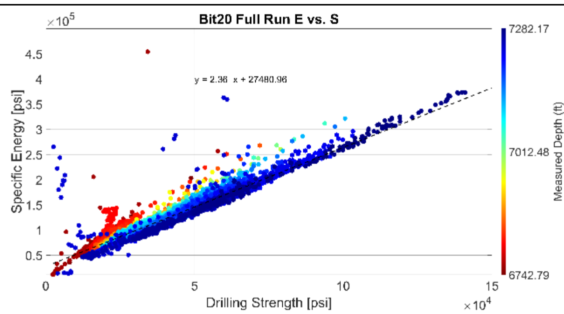


**Figure 27. Bit 20 E-S diagram for the entire run.**

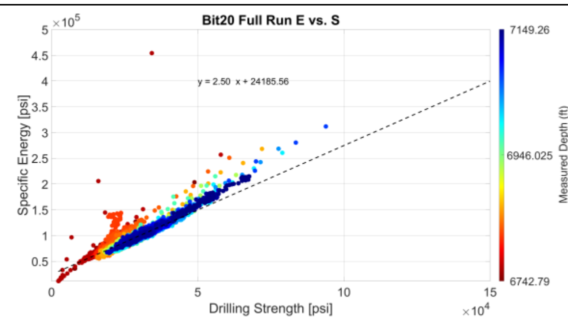


**Figure 28. Bit 20 E-S diagram for points preceding a depth of 7150 feet.**

Notable negative deviations from the mean in the bit records in Figure 18 are noted for Bits 18 and 23. Bit 18, however, is the same bit as Bit 20, which performed very well, as noted above. Likewise, Bit 23 is the same as Bit 22 which exhibited a more average performance. Comparing Figure 18 with previous ROP and footage plots (Figure 15 & Figure 16) for the bit suite shows that these low products are dominated by low footage on these bits. Examining the records of these two bits shows anomalous performance likely due to high ROP excursions – presumably due to the bit encountering fractures and experiencing high ROP until reengaging the formation. This is shown for Bit 18 in Figure 29 where the ROP surged near the end of the run- resulting in high depth of cut. This most likely resulted in the cutting structure damage shown in Figure 30. Note after the acute dynamic conditions, the specific energy did not return to a nominal value indicative of likely damage to the cutting structure.

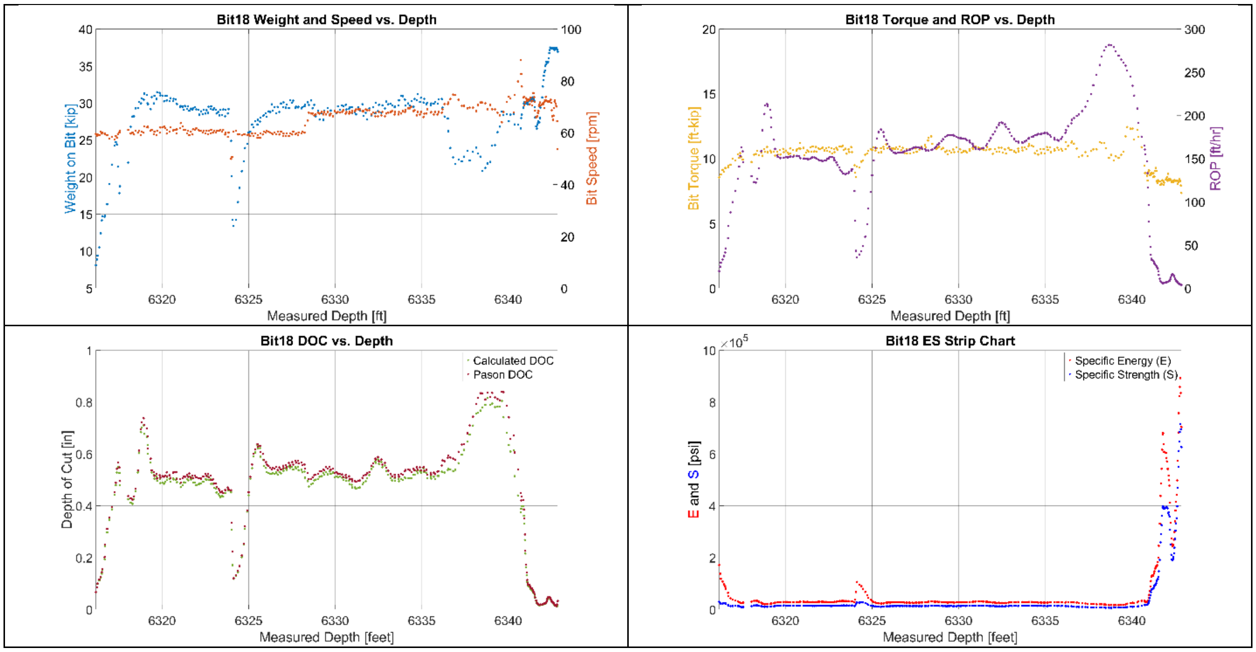


**Figure 29. Bit 18 drilling record.**

**Figure 30. Post drill photograph of Bit 18.**

This bit is the same as Bit 20 which, as reported above, performed very well. The E vs. S plot for Bit 18 is shown in Figure 31 for all depths. The green bit response is evident from the early data points yet the trendline is dominated by the weighting of the high specific energy points used in a full run linear regression.

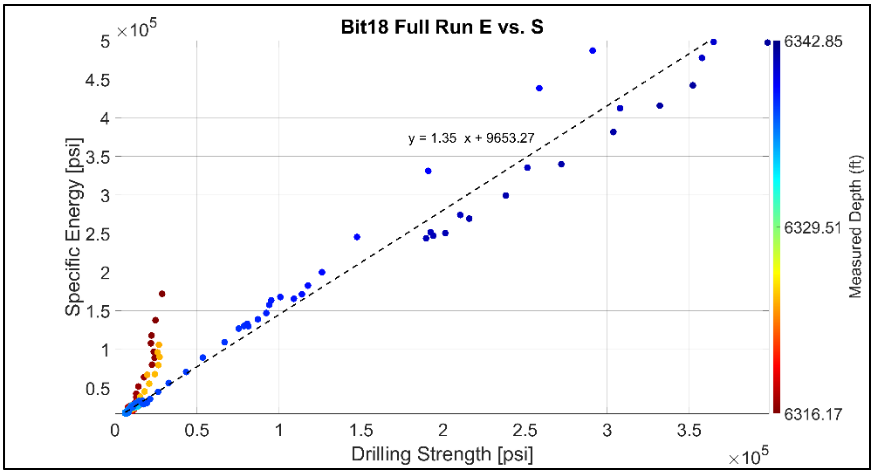


**Figure 31. E-S diagram for Bit 18.**

Likewise, Bit 23, summarized in Figure 32, experienced large ROP variations most likely resulting in the cone failure shown in Figure 33. Bit 23 failed after drilling 21ft. An identical bit exhibited a more uniform performance in bit run 22 shown in Figure 34, although it also ended in a cone failure.

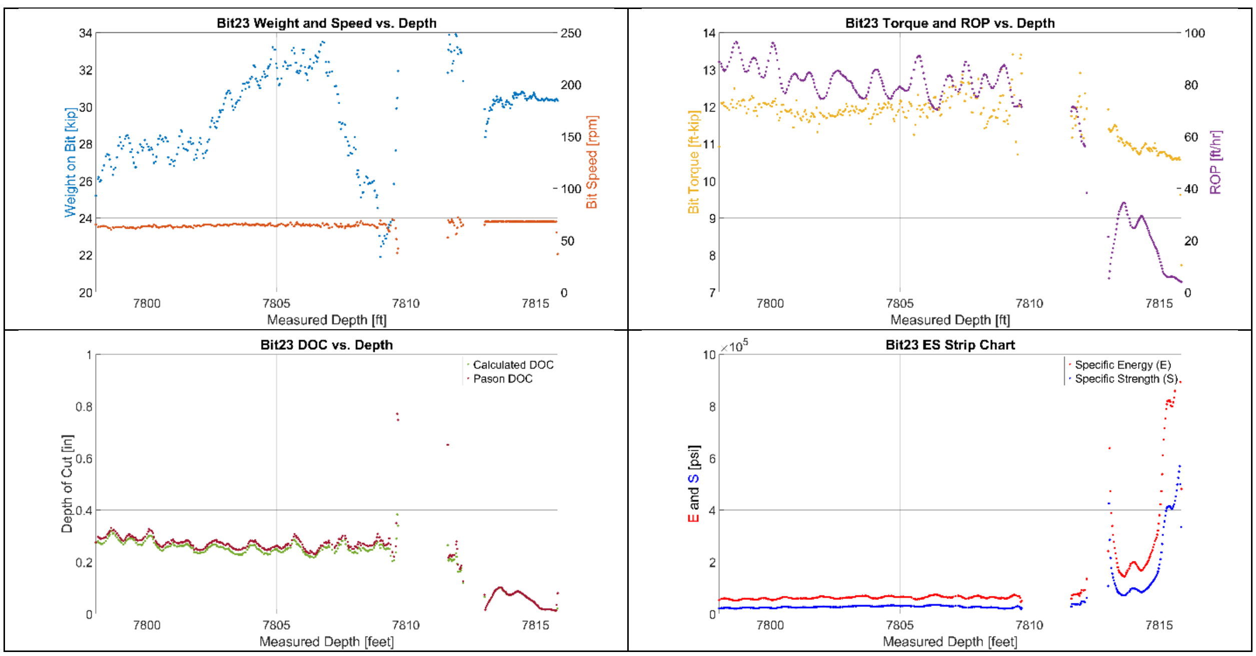


**Figure 32. Bit 23 drilling record.**

**Figure 33. Bit 23 cone failure.**

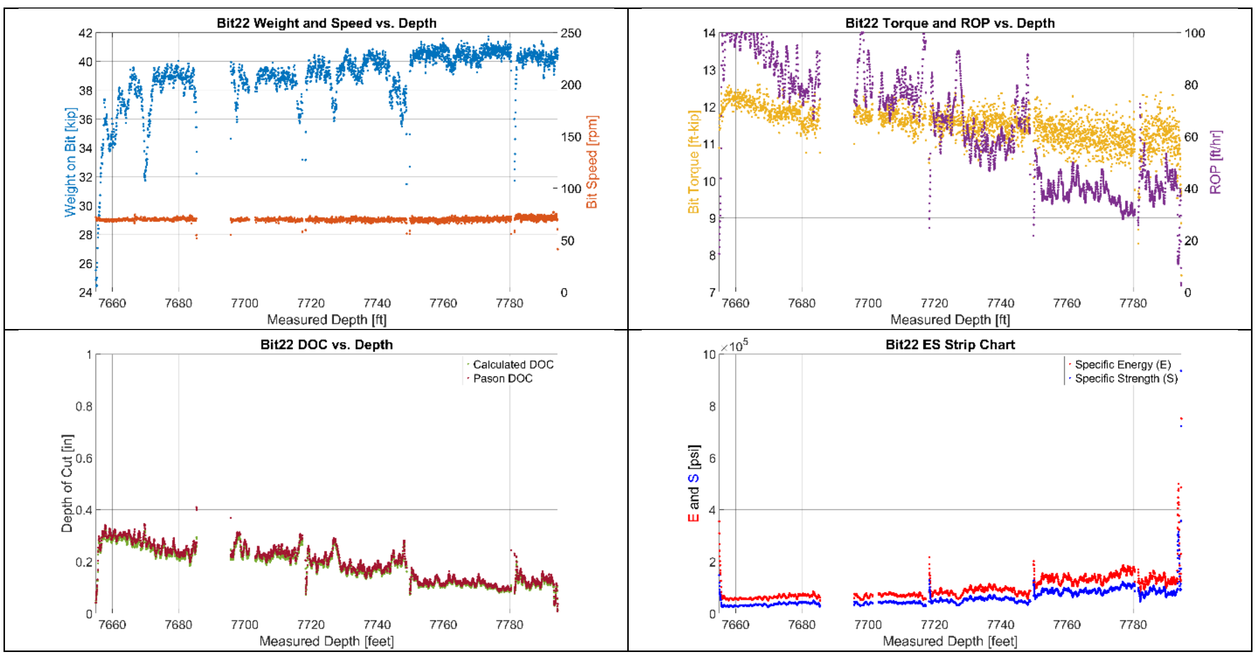


**Figure 34. Bit 22 drilling record.**

This analysis highlights how EDR data may be used in a bit constraint model to monitor the condition of the bit. These methods will be applied on the Phase 2 well to monitor bit condition and improve drilling processes in real-time.

## 3. WELLS FOLLOWING GDC-36

Since the original Phase 1 demo at GDC-36, additional wells have been drilled at The Geysers to support production. Due to the observed performance improvements from GDC-36, GPC has continued to pursue the use of PDC bits in portions of subsequent wells. Prati wells at the Geysers have been drilled since GDC-36. The reservoir in Prati area is deeper with higher temperatures than the GDC area. Also, the felsite/granite is deeper and will not be encountered when drilling in Prati.

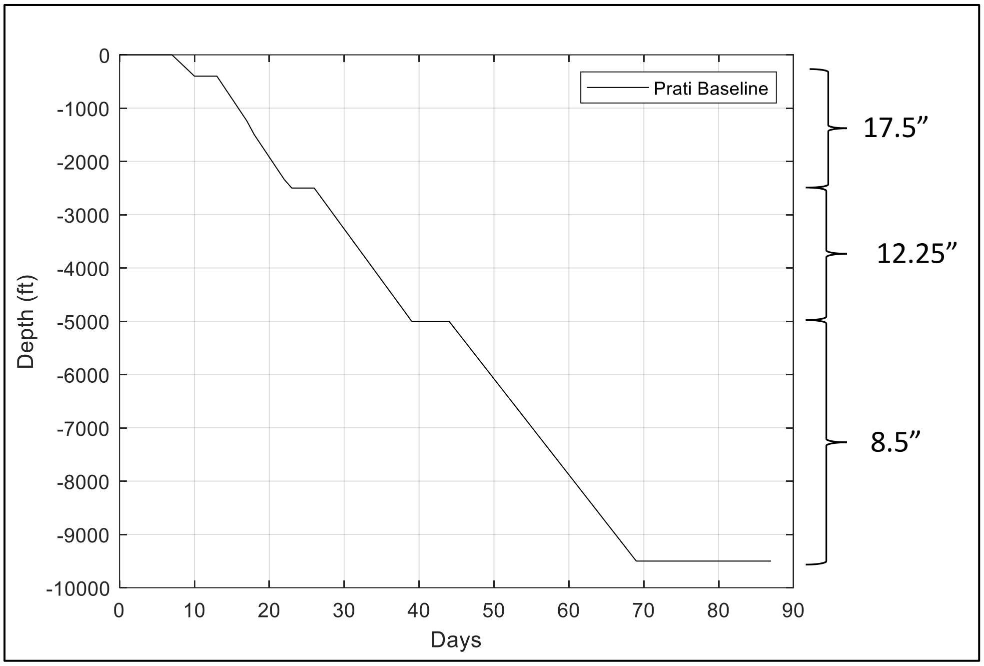


**Figure 35. Prati baseline drilling plan**

A baseline drilling plan for Prati wells is shown in Figure 35. After the conductor pipe is installed, the 17.5” section is drilled from approximately 400 ft to 2500 ft. The duration for this section is around 10 days. The 12.25” interval extends from 2,500 ft to 5,000 ft and is estimated to take 13 days. The remaining 8.5” interval extends to around 9,500 ft and is planned for 25 days of drilling.

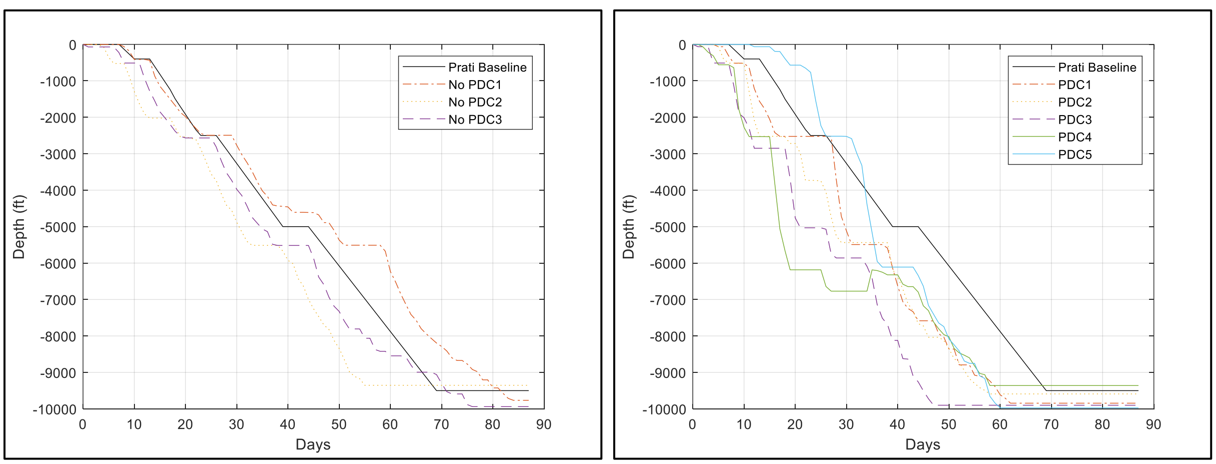


**Figure 36. Days vs. Depth comparison of Prati wells drilled with roller cones (left) vs. PDC's (right)**

The results from wells drilled with roller cones and PDC’s are shown in Figure 36. The figure on the left shows days vs. depth for wells that were drilled using traditional roller cone bits and practices. The expected duration to reach total depth is approximately 70 days, with rates in the individual sections of the well based on historical ROP. The right side of the figure shows wells that have been drilled with PDC’s following the Phase 1 demonstration well GDC-36. Using the same drilling forecast for reference (solid black line), it is clear there are visible gains made in the upper portions of the well, particularly the 17.5” and 12.25” sections. The 8.5” sections are currently drilled with a combination of PDC’s and roller cones.

Additional work has continued with bit vendors for addressing performance limiters encountered in the air-drilled section of the formation. Adjustments to cutter types and bit designs are ongoing and being implemented in current work at The Geysers.

Compared to GDC, the Prati wells, have longer 17.5” and 12.25” sections, hence there is more value added by speeding up those sections.

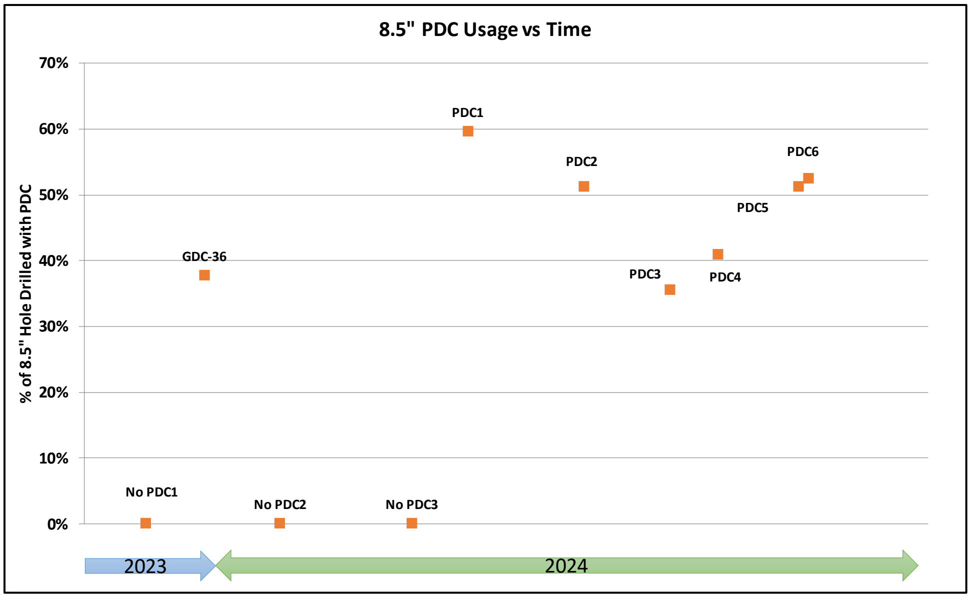


**Figure 37. 8.5" PDC usage vs. time at The Geysers**

An increase in footage made using 8.5" PDC's is readily apparent in Figure 37. Following GDC-36, a concerted effort was made by GPC to deploy PDC's in standard operations. This was due to the performance gains that were demonstrated in the Phase 1 wells. Adjustments were made to operating conditions, particularly maximum WOB, to extend the life of the bits. Although this operational practice is contrary to the notion of limiter redesign, it was a necessary step to extend the life of the bits without additional downhole and logging data.

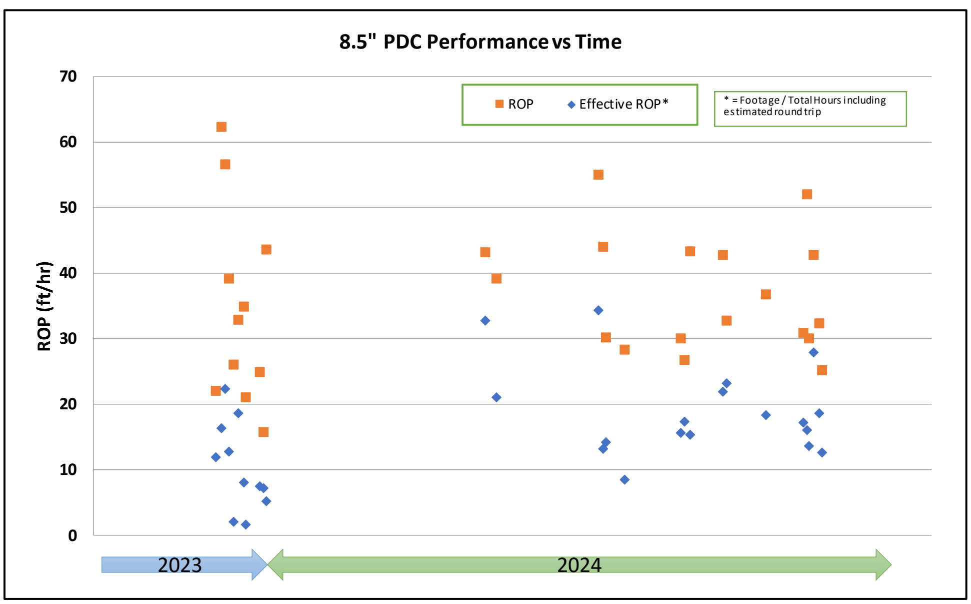


**Figure 38. PDC ROP vs. time for wells following GDC-36**

Additional visualizations for the improvements gained since GDC-36 are shown in Figure 38. The measured ROP of the 8.5" PDCs has consistently exceeded that of traditional roller cones. In this case, success breeds success, and the increase in PDC usage in that interval is also resulting in increases in footage drilled for each of the bits.

In Figure 38, an "effective ROP" is defined and plotted for each bit run. This effective ROP is defined as follows:

$$EROP = F/(T_d+T_t)$$

where EROP is the effective ROP in ft/hr, F is footage drilled by the bit, $T_d$ is hours drilling (including connections) and $T_t$ is hours for the round trip (note that round trip hours are estimated for each bit run based on an empirical linear trend established between depth and trip time. This eliminates variability associated with individual round trips). Since EROP accounts for trip time, it is always lower than the instantaneous ROP.

Figure 38 shows that EROP for the 8.5" PDC bits greatly increased, nearly doubling from an average of 10.8 ft/hr in GDC-36 to 20.5 ft/hr in the wells drilled since GDC-36. This improvement is almost entirely due to increased bit life, which is readily apparent in Figure 39. For comparison, baseline EROP using 8.5" roller cone bits is about 12 ft/hr.

Like the ROP*footage product plotted in Figure 19, EROP is a way of combining two key metrics that drive the economics of bit performance. The EROP can be multiplied by an hourly rig "burn rate" to estimate rig cost per foot drilled. However neither EROP nor ROP*footage accounts for bit cost. PDC bits are far more expensive than roller cones, and that cost differential skyrockets when the PDC bits are DBR'd. A full cost-per-foot analysis must account for bit cost, as well as rig time spent surveying, circulating, and non-productive time.

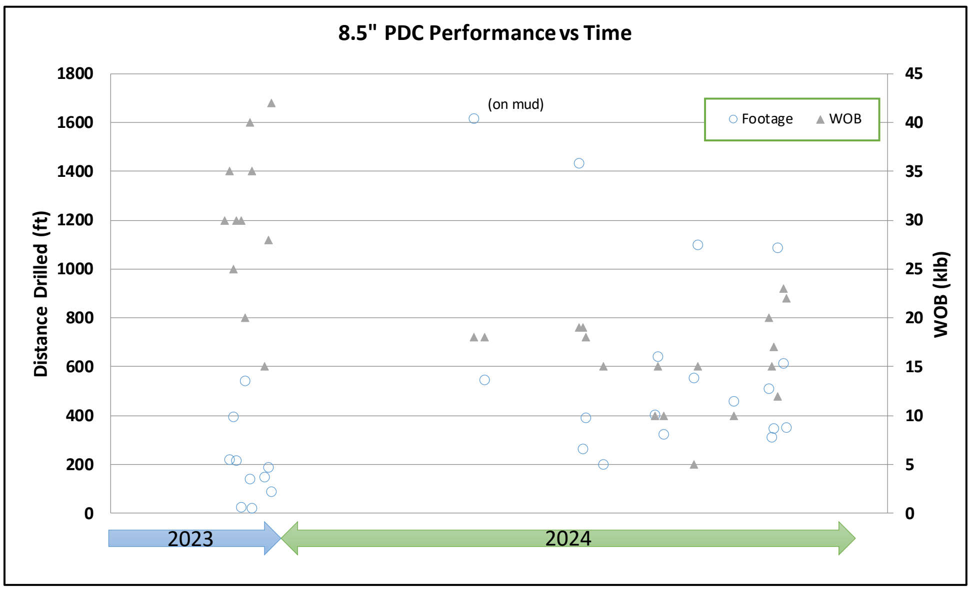


**Figure 39. PDC distance and applied WOB vs. time for wells following GDC-36**

Figure 39 shows that PDC bit life has more than tripled, from an average of 201' in GDC-36, to 620' post-GDC-36. It is not immediately clear why those improvements have been achieved. However, the drillers have worked with the bit vendors independently of the science team to develop solutions that have improved the PDC bit life.

## 4. PHASE 2 WELL (PRATI-44) PLANNING

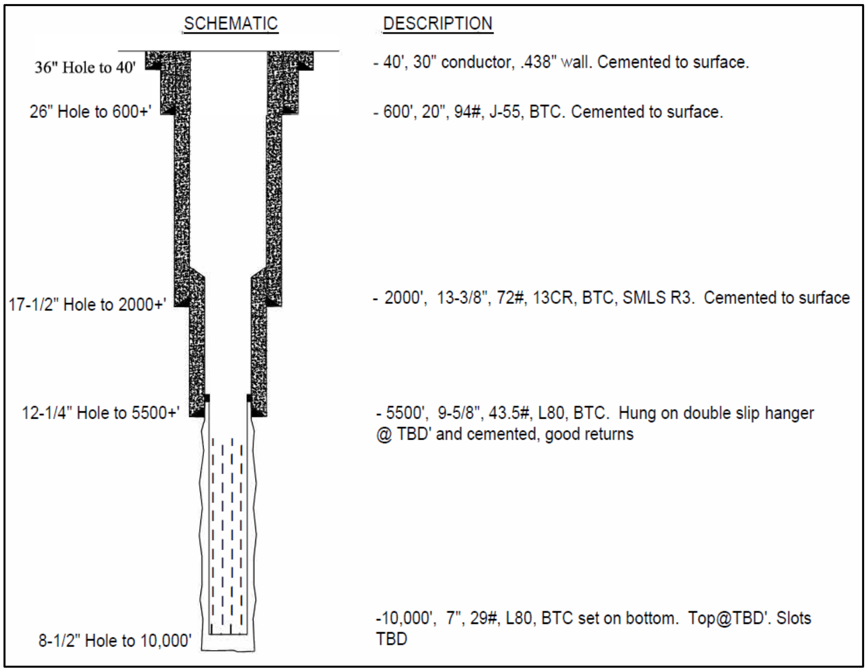


**Figure 40. Phase 2 demonstration well (Prati-44) well schematic**

The plan for Prati-44 is shown in Figure 40. The demonstration zone will focus again on the 17.5”, 12.25”, and 8.5” sections of the hole. The 17.5” section will be drilled from approximately 600 ft to 2,000 ft. 12.25” hole will be drilled from 2,000 ft to 5,500 ft. Both sections will be drilled with PDC bits and mud, which has now become the standard procedure for GPC. The final portion of the hole will be drilled at 8.5” from 5,500 ft to 10,000 ft. This air-drilled 8.5” section continues to be the most challenging portion for implementing the alternative bit selection program. We will also pursue the percussive hammer that was tested at the end of the GDC-36 run. It showed promise when drilling at 9000+ ft, and will be used earlier in the 8.5” section for Prati-44.

Additional data collection and analyses will be conducted in those zones to support the science conducted for the demonstration wells. These data collections will include wellsite information transfer standard markup language (WITSML) capability included with Pason EDR as well as additional tests to evaluate stick-slip and other drilling dysfunctions in real-time.

PDC bits from four vendors will be used in the test sections of the well. Based on previous performance in the 17.5” and 12.25” sections, it is likely that only one bit will be used, even with potential lost circulation zones.

We anticipate more challenges will exist in the 8.5” air-drilled section. We will take the learnings from the offset wells and apply them to this section to extract the maximum performance in this regime. We anticipate that

## CONCLUSIONS

A physics-based limiter redesign workflow was implemented at an injection well drilled in The Geysers geothermal field. PDC bits were deployed in three distinct drilled diameters with unique formation conditions. The first section of the well (17.5”) using a commercial off-the-shelf PDC bit performed exceptionally well. Nearly 27 hours of rig time were saved in the 17.5” portion of the hole alone. In the 12.25” interval, aside from the lost circulation zones, the PDC bits also performed much better than roller cone bits. WOB step tests were successfully executed and the rig team and the research team coordination were well-orchestrated.

Compared to the offset wells, we were approximately 100 on-bottom hours ahead of the next fastest well at the last intermediate hole TD. For the baseline group, we were at a minimum 150 hours ahead of the group average. Overall, the experimental effort on GDC-36 did not add additional time to the project.

The air section proved to be more challenging for 8.5-inch PDC bits. One positive result is that PDC cutters did not routinely experience thermal-related failures even at the much higher than normal formation temperatures for these bits. This was a primary concern at the outset of the project. However, we believe fractures in the formation caused acute, high-torque events, commonly called interfacial severity in oil and gas drilling, which resulted in run-ending damage over very short intervals. The performance opened the door for alternative bit monitoring protocols and WOB procedures to address significant interfacial severity damage.

Additional analysis is being conducted on the large body of data collected during the demonstration. This paper provides a summary of the current results and on-going analysis. The team is currently identifying redesigns and process improvements to address limiters that were encountered in the first demonstration well and assessing how to implement those changes in the next demonstration well.

## ACKNOWLEDGEMENTS

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