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Development of a System to Provide Diagnostics-While-Drilling

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ABSTRACT

This report describes development of a system that provides high-speed, real-time downhole data while drilling. Background of the project, its benefits, major technical challenges, test planning, and test results are covered by relatively brief descriptions in the body of the report, with some topics presented in more detail in the attached appendices.

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Abstract:
This report describes development of a system, called Diagnostics-While-Drilling (DWD), that provides high-speed, real-time downhole data during drilling. Background of the project, its benefits, major technical challenges, test planning, and test results are covered in the body of the report, with additional detail on some topics in the attached appendices.

Project summary:
Project origin – The DWD project originated with the concept that drilling research should aim to complement incremental improvements with new technology that would provide a revolutionary advance in drilling. Sandia National Laboratories convened two workshops aimed at defining a research goal, and concluded that the target technology would be incorporated into an advanced geothermal drilling system that met the following criteria:

1) The system would perform all the necessary functions for drilling a model geothermal well.
2) The system would reduce the cost or economic risk of drilling a geothermal well and/or improve the lifetime productivity of the well, thereby reducing well cost/unit heat.
3) The system would contain one or more key components that do not currently exist, but which might be developed with DOE funding.

Emphasis on a systems approach differed from most previous work on advanced drilling, because earlier work focused on the rock reduction process, i.e., the drill bit. Although improved rate of penetration and bit life remain important elements of cost-effective drilling, those benefits are sometimes negated because other parts of the drilling process cannot take advantage of improved bit performance. An essential element of the program, then, was the choice of an enabling technology that would link all drilling functions and improve all parts of the drilling process. After considerable discussion, a consensus emerged that the single greatest deficit in most drilling functions was the lack of real-time knowledge and control of what was actually happening down the hole. By gaining this critical feedback capability, all functions can be optimized for highest efficiency and lowest risk, creating the greatest probability for significantly reducing geothermal well costs. (This conclusion was independently corroborated by a Drilling Engineering Association workshop in 1998 that rated real-time data acquisition and processing as the Number 1 technology need for flat-time reduction.) More detailed description of the workshops in which these discussions were held is given in Appendix F.

Synthesis with hard-rock bit program – Because DWD crosscuts almost all aspects of drilling, we have tried to integrate it with other program elements within the Geothermal Research Department. The most productive short-term application is to use the real-time, high-speed data to control forces and vibrations on polycrystalline diamond compact (PDC) bits in hard rock, because considerable evidence indicates that chatter, whirl, and stick-slip are important PDC failure modes that are difficult to detect from the surface. These considerations also shaped the system definition:

- Performance of PDC bits, which offer significant advantages in rate of penetration (ROP), is highly dependent on minimizing damage to the bit. That damage is often caused by phenomena with rapid onsets and high-frequency behavior, such as chatter and bit whirl.

- Conventional wellbore data transmission by mud-pulse telemetry is very slow, which not only increases the reaction time for a damaging condition to be recognized but also implies the application of downhole processing to the various dynamic signals. Downhole processing requires expensive, heat sensitive, electronic components to be placed in a rigorous environment that is further complicated, for geothermal drilling, by high temperature. It also means that only a diagnostic "word", determined by pre-loaded algorithms and with the structure of the raw data obscured, comes back to the surface. DWD brings all the data back to the surface in real time, allowing changes in processing or display on the fly.
- Geothermal drilling often uses air or aerated mud, either of which precludes mud-pulse telemetry.
- High-temperature batteries are an emerging technology, so there are many advantages, especially for a prototype system, in powering the measurement sub from the surface.

As part of the bit-development effort in the Geothermal Research Department, we have signed a single-laboratory/multiple-partner CRADA (Cooperative Research and Development Agreement) among Sandia and four bit companies, with the CRADA linked to the Proof-of-Concept (POC) test for the DWD system (see p. 17).

Development of POC criteria – In considering how to demonstrate the benefits of DWD, the combined measurement and enhancement of PDC bit performance appeared to be a straightforward method for a proof-of-concept test. The life and penetration rate of a given PDC bit generally depend on four qualities: bit and cutter design (including material), formation being drilled, bottom-hole assembly, and operating parameters. If we hold the first three factors constant, while controlling the operating parameters, then we can prove the DWD concept by demonstrating that real-time, dynamic, downhole data improves bit performance. To define the requirements for this kind of test, we convened a group of researchers and bit-company representatives in Albuquerque in April 2000 and developed a specific test plan for a proof-of-concept. This plan comprised drilling two holes through an interval of hard rock at the Catoosa test site (near Tulsa, OK), where the lithology is extremely well characterized because of the dozens of holes that have been drilled there. The first hole (Phase 1) would be drilled while taking data with the DWD system, but not using it to control the drilling, whereas the driller would use the feedback data in drilling the second hole (Phase 2). Bit life and rate of penetration would then be compared to evaluate the benefit of using downhole data.

The test plan developed at the workshop contained detailed specifications for the drilling conditions, measurements to be made, drilling intervals, and bottom-hole assembly (see Appendix A), and the plan was also updated several times using suggestions from the Technical Advisory Committee with whom Sandia staff met regularly to review the project. Ideally this sort of test would encompass several runs under each condition to provide greater statistical validity, but time and budget considerations did not allow that for the POC test.

Summary of results – In conjunction with Phase 1 of the POC, we ran the DWD system with both a tri-cone rollerbit (while drilling the overburden to reach the top of the test interval) and a PDC drag bit (in the test interval). In all, we drilled more than 600 feet through varied formations, including over 200 feet through the hard Mississippi limestone interval that features a section known as "The Wall", which has historically been very difficult to drill with PDC bits. During this drilling, the DWD downhole data system recorded a wide variety of bit dynamics and operating condition measurements: weight, torque, and bending at the bit; three-axis and angular accelerations; and downhole pressure and temperature.

Our strategy for Phase 1 was to have an experienced driller get as far as possible through the Mississippi limestone and The Wall using traditional surface instruments, but without benefit of the downhole data being provided by DWD. Starting with the PDC test bit at approximately 1100' depth, drilling progressed into the consistently hard Mississippi formation beginning at 1274' and through The Wall (approximately 1385' to 1395'), and the driller was able to reach a final depth of 1492' (total bit life of approximately 390') before an experienced drilling engineer judged that the bit was at the end of its useful life. Although the driller began to detect some vibration on the rig floor near the end of the bit run, downhole measurements showed violent bit bounce and vibration shortly before the bit's failure.

Figure 1 – Layout of DWD measurement sub

In Phase 2, engineers in the doghouse used the real-time downhole data to coach the driller on when to change weight-on-bit (WOB), lift off bottom, or change rotary speed. By avoiding or correcting vibration, bit whirl, and stick-slip, the coached driller was able to advance the second hole from the 1100' starting depth to a final depth of 1615', and he only stopped at that point because no more time was available in the drill rig's test schedule. Total PDC bit life in Phase II was approximately 515', or 32% more than in Phase I; more importantly, bit life after beginning penetration of The Wall increased from approximately 105' to at least 230', which constitutes a 120% improvement. The difference in rate of penetration was less definitive; this issue is discussed in detail on p. 15.

Throughout both phases of the test the DWD system provided reliable data, with only minor malfunctions in a few sensors. In summary, the testing was successful in showing the benefits of high-speed, real-time downhole data and in demonstrating a system that can provide that data.

Technical objectives:

Technical choices and capability development activities relevant to implementing the four principal DWD system elements: the downhole measurement sub, the format in which data will be transmitted, the data link between surface and downhole, and the surface data display are summarized below.

Measurement sub – There are many possible downhole measurements but, to be consistent with Sandia's Hard-Rock Bit Technology Project, we have focused on those forces and accelerations that are relevant to bit dynamics (see Appendix A for detailed sensor specifications). The sub is a tubular tool, 7" in diameter by approximately 85" long, with a central electronics/sensor package suspended by three-legged supports inside the structural housing (see Figure 1). The metal parts of the tool are made from non-magnetic materials to allow proper magnetometer operation, and the structural case is sized for the loads typical in drilling 8-1/2" hole. Strain gauges for torque, bending, and weight on bit are bonded to the outer case and covered with metal "clam-shells" that protect the gauges from mud flow in the annulus but are vented to the annulus pressure. Other sensors are mounted in the central package.

Downhole electronics acquire analog signals from the sensors, condition them, convert them to digital format, multiplex them, and transmit them uphole. Sandia designed and assembled all the electronic circuits, some of them based on previous work in measurement-while-drilling (MWD). Mechanical parts of the tool were designed collaboratively by Sandia and Stress Engineering Services (SES) in Houston, and were fabricated by Godwin SBO, Inc. in Houston. After the metal parts were completed, Sandia personnel fit-checked the parts at SES shops, where strain gauges were mounted and calibrated. Following the strain-gauge work, all components were shipped to Sandia for final assembly and checkout.

Data-transmission format – All data is sent uphole in a stream of digital, bi-phase encoded frames, each of which contains twelve 16-bit words. The frames are sent at the rate of 1041.7 times per second, with some of the high-frequency signals (acceleration, strain gauge) sampled in each frame and other, less transient, signals sampled every two to sixteen frames (see Appendix B for frame definition and data-flow schematic). The frame stream is decoded, or decommutated, by "decom" hardware and software at the surface, where a computer stores the raw numerical data in a binary file. The raw data are also sent to display hardware and software that apply engineering units, show a real-time moving plot of each measurement, and also show results of some manipulated measurements (e.g., Fast Fourier Transforms, or FFTs, of acceleration measurements).

Because the data stream is transmitted as a series of voltage changes that represent either "ones" or "zeroes", the transition between these changes is blurred as the wireline length increases, and it becomes more difficult to distinguish the value at a given time. With the current electronics, it is unlikely that we could drive a reliable signal through more than 3000 feet of conventional wireline. The next generation tool will probably use frequency-based transmission, which relies on detecting a change in frequency to identify a binary bit and which should be able to send data at the same rate as the present system but increase wireline length capability well above 10,000 feet.

Data link – Because the digital data rate is approximately 200,000 bits per second, conventional data transmission from downhole (mud pulse) is inadequate. Other possible data links include methods that have been researched by Sandia, such as acoustic transmission through the drill pipe, optical fiber, and wired pipe (with the signal medium embedded in the drill pipe), but for demonstration of the DWD principle, we chose a commercially available wet-connect wireline data link. The wireline is a conventional single-conductor cable with connections that can be made and broken while immersed in drilling fluid, and with an electrical swivel that allows the lower part of the cable to rotate relative to the upper part while maintaining electrical continuity.

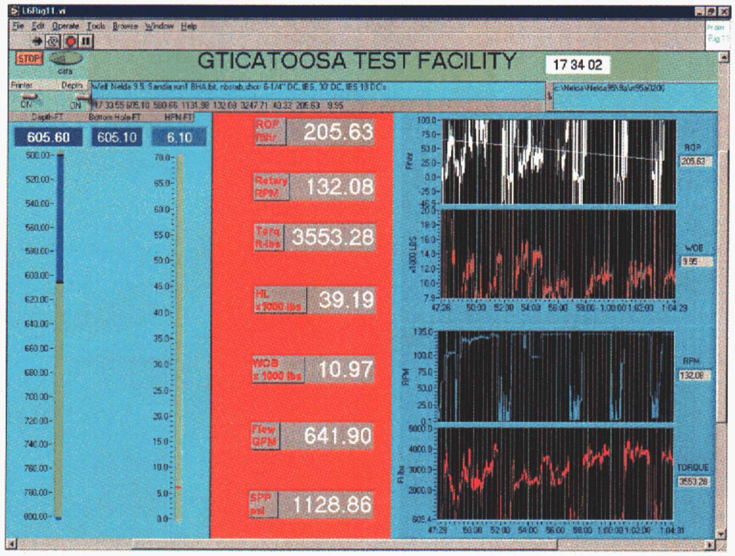

Figure 2 – Catoosa screen for surface data

This wireline system has at least two major advantages in addition to its commercial status: the downhole electronics can be powered from the surface, obviating the need for downhole batteries, and the wireline can be quickly extracted from the drill string for any required maintenance or repair. This technology was demonstrated in preliminary tests to assure that its electrical performance and data carrying capacity were adequate for the DWD drilling tests. Appendix C contains details of the wet-connect system and preliminary testing.

Surface display – An essential feature of the DWD system is integration of surface and downhole data, so our goal is to display a selectable set of downhole and surface measurements for easy access by the driller. Time and budget limitations to date have not allowed complete integration of these displays, so the display used for the POC comprised two screens of downhole data from the measurement sub and two screens of data from surface measurements (which we described as "mud logger" data). Any combination of the downhole data measurements could be displayed on their two screens, subject to considerations of readability for the display size.

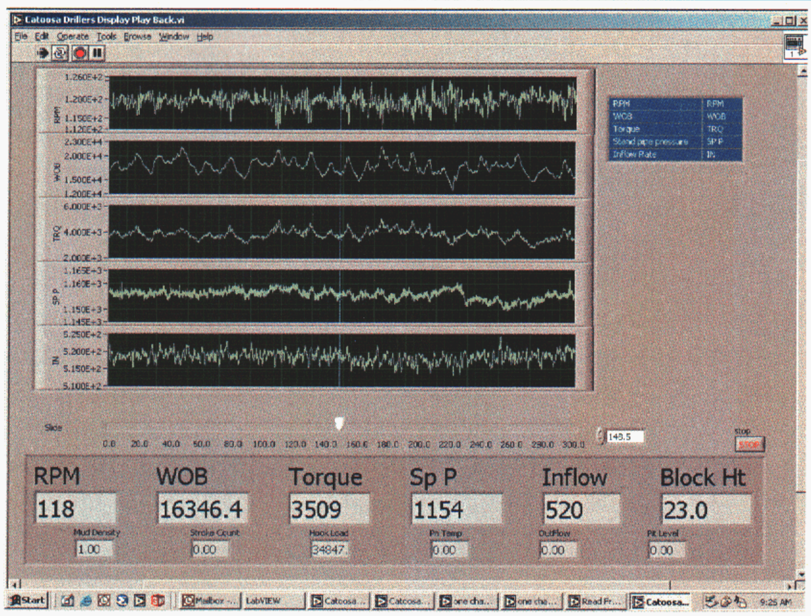

Figure 3 – Surface-data screen from Sandia

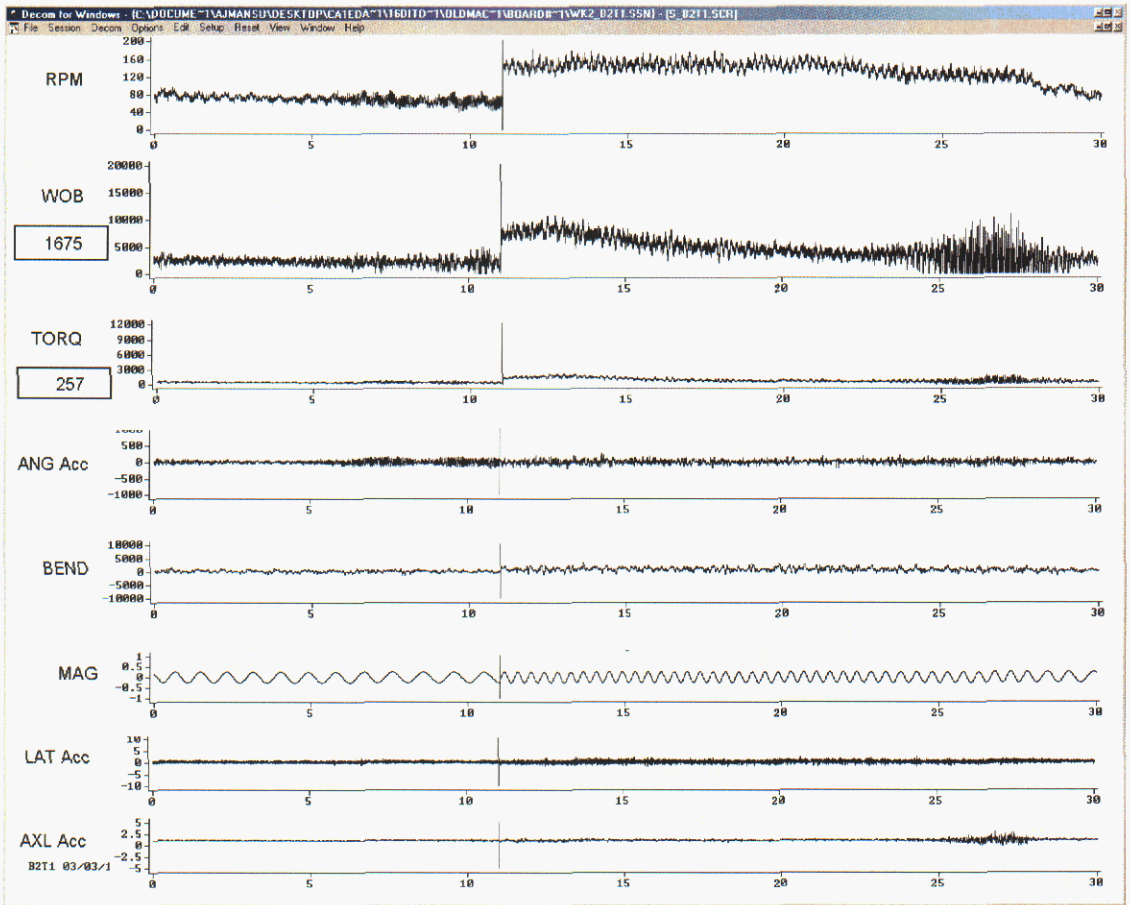

Figure 4 – 30-second downhole-data screen

Testing before the POC:

Vibration testing – A fundamental question of data quality is the degree to which forces and the consequent accelerations imposed by the drillstring on the outer case of the measurement sub are accurately measured by the accelerometers in the electronics/instrumentation housing. To answer that question, we mounted the measurement sub with its instrumentation and signal-conditioning electronics on one of Sandia's vibration tables, then shook it along three axes while measuring both the shaker's input control signal and the output of the onboard accelerometers in the measurement sub. In general, agreement between the measurements was good – a more detailed description of the vibration tests is given in Appendix D.

Laboratory drilling – The next evolutionary step in system testing was to exercise the tool in a laboratory environment that allows drilling with a representative bit, while rotating the tool and circulating fluid through it, in selected rock types. This exercise also included acquiring data from the measurement sub and displaying it on the surface data system, giving as near a representation as possible to actual drilling, but with considerably more control and less expense.

Laboratory drilling with the DWD system was done at the Reed-Hycalog lab in Houston, where there is a "drill rig" with the capability of turning a full-diameter drilling assembly with bit at realistic rotary speeds, axial loads, and torque. In addition to conventional bits, we also used special "laboratory" bits that had been designed specifically to generate bit whirl and other dysfunctions. With this predictable capability, we could assure that we saw data from the measurement sub that was representative of various downhole conditions. This laboratory testing is also described in more detail in Appendix D.

Narrative description of Catoosa drilling tests:

Data display – Data display for Phases 1 and 2 of the POC comprised four monitors, two for surface data and two for downhole data. All surface data and all downhole data were recorded and archived, but the displays did not include all measurements taken.

One surface-data display was the standard screen used by Catoosa for their drilling tests; it includes digital displays of weight on bit, torque, rotary speed, standpipe pressure, flow rate, bit depth, hole depth, rate of penetration, and statistical manipulation of some of these quantities (Figure 2). The values on this screen were derived by sampling the various quantities 300 times per second and then displaying a running average of those samples. (The averaging algorithm is, however, unknown.) The other surface-data screen used a Sandia-developed process in LabVIEW™ software to take the same raw data as the Catoosa screen and display selected measurements graphically (Figure 3). The graphic plots showed current values plus the 5-minute history of those values, giving an immediate sense of trends in the measurements.

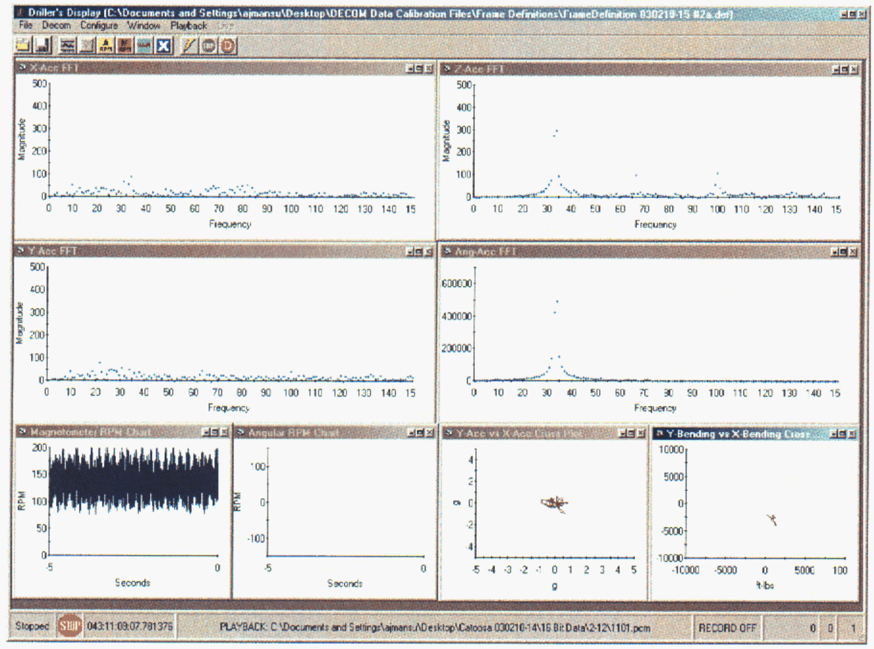

Figure 5 – 5-second display of downhole data

The downhole-data screens showed a set of measurements that were selected to be the most useful in avoiding bit damage. One screen (Figure 4) showed a 30-second trace of eight variables; that is, the vertical bar at about the 11-second mark sweeps across the full width of the screen showing 30 seconds of data, with the values immediately to the left of the bar the most recent and the values to the right of the bar 30 seconds before that. From top to bottom in the figure, the parameters are the downhole values of rotary speed, WOB, torque, angular acceleration, bending stress, the magnetometer signal (the frequency shown in this signal is analogous to rotary speed; note that in this data interval speed has decreased), lateral acceleration, and axial acceleration. The other downhole-data screen (Figure 5) showed 5-second traces of magnetometer signal and rotary speed, and cross-plots of x- and y-bending and x- and y-lateral acceleration as well as instantaneous displays of Fast Fourier Transforms of lateral, axial, and angular acceleration. Limits on the time spans displayed came from the two different computers and software packages that drove the two display screens.

Phase 1 test – Phase 1, as defined in the test plan, comprised drilling through an upper, softer interval (from approximately 800 to 1100 foot depths) with a roller-cone bit to get baseline data for future comparison with PDC performance and then drilling from the end of that interval at approximately 1100 feet to a depth at which the bit would be worn or damaged to the point that it could no longer make useful progress. During all this drilling, downhole data would be recorded but not used to control the weight-on-bit, rotary speed or other drilling parameters.

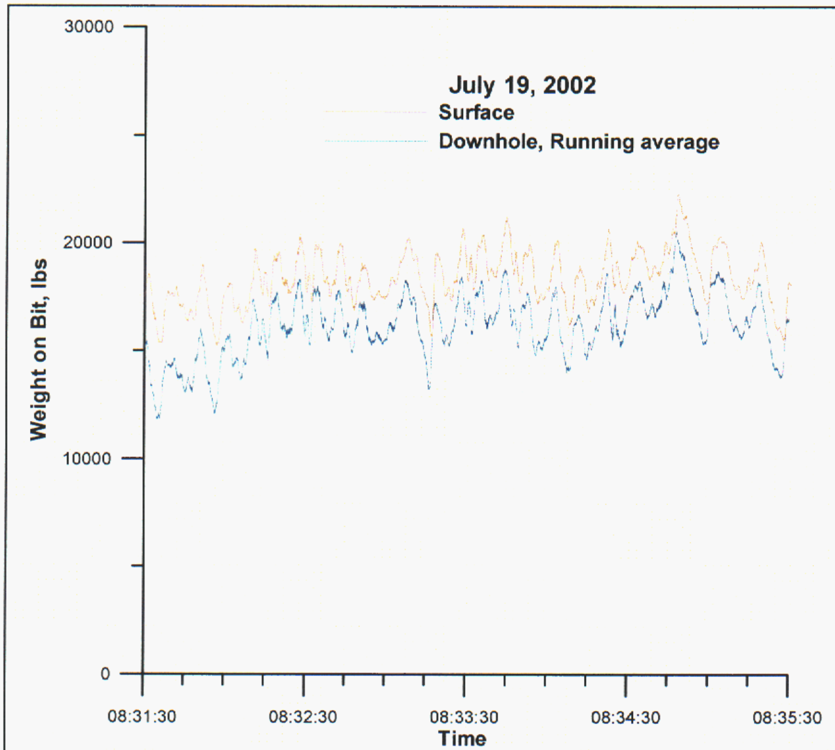

Figure 6 – WOB while drilling in the upper part of hard limestone formation

Starting on Monday, 15 July, the first two test days were consumed by picking up the bottom-hole assembly and DWD tools, reaming the deviated part of the hole, experimenting with the best way to configure the wet-connect wireline system, and drilling with data acquisition from approximately 823' to 895' with a Security-DBS roller-cone bit (8-1/2" insert type SS86FL; IADC 5-3-7M). The DWD system worked very well in this interval, collecting all the desired data with few dropouts apart from those caused by failure in the wireline system.

On Wednesday, 17 July, we continued smooth drilling, with DWD data collection, to approximately 1105', where we tripped out to pick up the PDC test bit – a Security-DBS model PD5 bit equipped with 24 PDC cutters on its face. The bit design is relatively old, dating from about 1995, but the test bit has been retrofitted with newer-technology cutters. Drilling above this depth with the roller-cone bit was an opportunity to collect baseline data for comparison with PDC performance in a soft formation but the DWD Proof-of-Concept test began at this point.

The driller was instructed that, each time the bit had been off bottom, he should start or resume drilling with a specific procedure that has been developed through general experience with PDC bits: bring rotary speed up to 30-40% of drilling rpm, set the bit on bottom at approximately 50% of desired WOB, then bring up rotary speed to final value, and finally bring up weight to final value. He was also instructed to do this fairly quickly, so that the bit does not "drill off" or lose the initial WOB while bringing up rotary speed; beyond this, he was given no other guidance on how to choose drilling parameters. This driller is experienced and has drilled these formations at Catoosa many times, although not with this specific bit, so overall drilling management was left to his judgment. Ending the day on Wednesday, we had drilled to approximately 1122' but a problem with the rig motor required shutting down for the night.

On Thursday, 18 July, we resumed drilling with WOB about 12,000-15,000 lbs and rotary speed nominally 120 rpm, and the hole advanced very quickly with more than 70 feet drilled in the first hour. Some hard stringers at about 1196 feet produced a noticeable change in the brake noise. We lost wireline signal at 1216' and pulled up to repair wireline. Drilling resumed at a very high rate in a shale section, over 100 feet per hour (fph), and the driller was instructed to limit ROP to less than 100 fph to avoid bit balling – this meant that WOB was under 5,000 lbs. This drilling continued down to the first hard formation at 1277' where the driller increased WOB back above 10,000 lbs, causing noticeable vibration on the rig floor. The driller backed off on WOB, reducing vibration, and we continued through this hard section to approximately 1318', at which point we pulled out to inspect the bit. This interval included initial penetration into the hard Mississippi limestone, beginning at ~1274 feet.

Bit damage was mild, with only three cutters showing any wear or chipping. All three of these were on the bit face – one near the center and two near the periphery. Damage was most severe for the central cutter, even though it was aft of the more peripheral cutters because the bit face is concave. For this cutter, a piece broke off through the diamond table and the substrate back to the tungsten carbide stud. In addition to the bit, the DWD measurement sub was also inspected and found to have a few loose screws in the strain-gauge cover plates. None

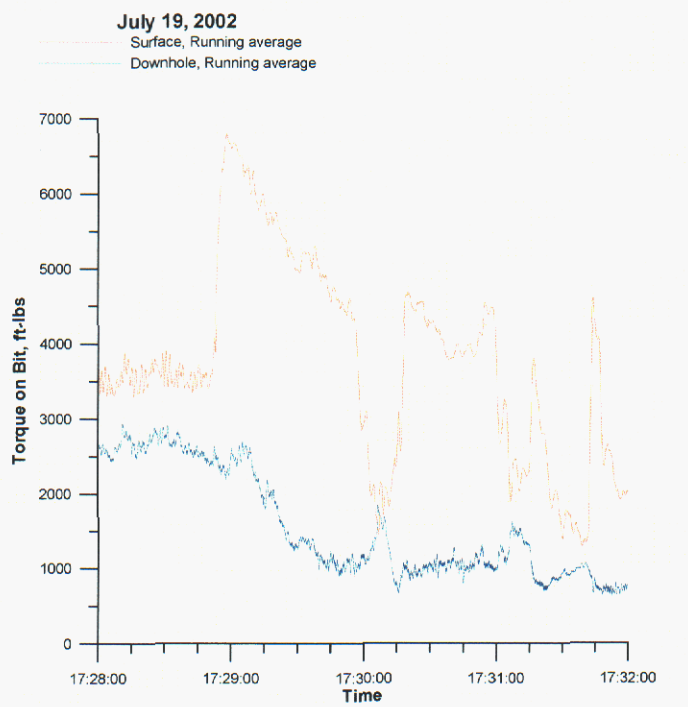

Figure 7 – Comparison of surface and downhole torque at high vibration event

of the screws had come out of the tool, so all screws were re-torqued. After bit inspection we ran back in the hole to continue drilling but one of the bit nozzles was plugged, so we pulled out, cleared the nozzle, and ran partway back in the hole before quitting for the night. The downhole DWD internal and external pressure measurements were able to clearly identify the plugged nozzle, confirming what we suspected from surface measurements.

On Friday, 19 July, we resumed drilling at a relatively high rate (63 feet in one hour), with smooth operation and good agreement between surface and downhole measurements (Figure 6) in spite of continuing through some hard formation. Drilling was generally good down to the next bit inspection point at 1420', where we pulled out of the hole. The interval from 1318' to 1420' includes some soft streaks, but mostly involves hard limestone with spot strengths above 40,000 psi. At this inspection, seven face cutters had significant damage and three face cutters had slight wear. Remaining face and gauge cutters showed no measurable damage or wear. Even though this was significantly more damage than at the 1318' inspection, it was not enough to suggest that the bit should be pulled, especially with the high performance it had just exhibited.

After bit inspection at 1420' drilling continued at a reasonably good ROP (~30 fph) although WOB was up to 15-20,000 lbs at a rotary speed of ~120 rpm. This continued until 1492', where high vibration (Figure 7) shook the rig floor and caused noticeable lateral motion in the drill pipe. The driller picked up off bottom, but vibration continued as long as the drill string was rotating. We attempted to resume drilling with the standard procedure but it was very rough, with considerable vibration. The driller applied WOB above 20,000 lbs, but the ROP did not exceed 5-6 fph, so an experienced drilling engineer judged from surface indications that the bit was past its useful life. At this point, we stopped trying to drill, stopped taking data, and pulled out of the hole. Inspection of the bit showed significant new damage to face cutters near the periphery and even more severe damage to several cutters near the center of the bit. Bit damage is described in more detail, with photos, in Appendix E.

On Saturday, 20 July, we attempted to resume drilling with the roller-cone bit used in the preparatory overburden drilling so that we would have baseline comparisons between the same bit in soft and hard rock. We were able to drill approximately 20' (from 1492' to 1512') while taking data, but this run was ended by failure of the second wireline swivel. This concluded Phase 1 testing.

Phase 2 test – The test plan for Phase 2 was to drill from approximately 810' to 1105' (the same interval drilled with the roller-cone bit at the beginning of Phase 1) with a PDC bit identical to the one used in Phase 1, thus providing baseline comparison of PDC and roller-cone performance in relatively soft formation. At 1105' (the same depth as in Phase 1) we would then pick up the second test bit, which was the same bit body used in the Phase 1 tests but refurbished with new, identical cutters.

Drilling began on Monday, 5 August, at approximately 800' in a hole that had been kicked off from the "mother" hole used in the Phase 1 test. At a depth of 980', however, the returns were essentially all cement, indicating that the hole trajectory had fallen back into the previous hole. Because there was no chance of kicking off this hole and getting far enough away from the existing wellbore by the depth at which the Phase 2 test should begin, we elected to move the drill rig to an existing hole (Nelda 9) that was already drilled to 796'. After tripping the drill string to move the rig, we inspected the PDC bit and found no damage whatsoever, and so decided to continue using this bit when drilling was restarted in the test interval below 1105' depth.

The second hole was 12-1/4" diameter at 796' depth and was deviated approximately 10° from vertical. Modeling of critical frequencies for the BHA had indicated that the critical rotary speed is strongly dependent on hole inclination, so we felt it necessary to bring this hole back to approximately the same inclination (2°) as the hole used in Phase 1. Consequently, we arranged for a directional driller to be on location first thing Tuesday morning and the hole-correction drilling occupied the remainder of that day and until almost midday on Wednesday. All the directional drilling was done with the same roller-cone bit used in Phase 1 and final hole inclination at 1105' was 2.3 degrees. The DWD sub was not in the BHA during directional drilling.

Following completion of the directional correction, we laid down the directional tools, picked up the DWD measurement sub and the same PDC test bit used in the aborted hole, and began drilling the relatively soft interval at that depth. The drilling strategy for this phase was that Sandia and industry engineers would observe DWD data in the doghouse and would communicate with the driller by intercom. The driller was to begin drilling at what he believed to be the best WOB and RPM to maintain 60 ft/hr, nominally using the same conditions (about 120 rpm and 12,000 lb WOB) as in Phase 1, but when a damaging condition appeared on the display, engineers would give him the signal to "pick up." The driller was then to follow a specific procedure: immediately drop rotary speed to about 30 rpm, lift off bottom, bring rotary speed to zero for 20-30 seconds, and resume rotating at a low rate, not over 30 rpm. After consensus among the engineers on the next step, the driller would get the signal to "resume drilling" with a specified WOB and rotary speed, and he would then set down on bottom at about half the specified WOB value, build up rpm to about half of the specified value, then build up WOB to the full value, and bring up rotary speed to the final value. The driller was also instructed to use his own discretion if he felt or saw some phenomenon that appeared harmful. For consistency, we had also ensured that the same driller would be at the controls for Phase 2 as for Phase 1.

With these ground rules in place, drilling began at approximately 1500 hours on Wednesday afternoon, 7 August, and went quickly, with the first stand of pipe (64') requiring only 44 minutes to drill down (87.3 fph). After adding another stand of pipe, rapid drilling continued (51' – to a depth of 1221' – in 35 minutes = 87.4 fph) until we saw a sudden increase in flow rate and, later, a drop in standpipe pressure. Drilling was stopped until the problem was diagnosed, but it turned out to be a rupture in the hose that runs from the charge pump to the triplex mud pump (downstream of the magnetic flow meter). Although downhole pressure was not being monitored in real time, later examination of the readings confirmed that the downhole pressure drop had not changed, showing that there was no washout. The hose was repaired and drilling resumed.

Smooth, rapid drilling continued to a TVD of about 1275', which is the top of the hard Mississippi limestone. At this point, ROP fell and we increased WOB from approximately 4000 lbs, which had provided very good penetration in the shales above, to 12-15,000 lbs. With this increase in weight, ROP returned to a relatively high value (12' in 16 minutes = 45 fph). We reached kelly down at 1296', then added pipe and drilled to TMD of 1327', which matched the Phase 1 bit inspection depth of 1318' TVD (the difference in depths is caused by the higher deviation in the upper part of this hole). ROP was good through this interval (30' in 32 minutes = 56.2 fph), which included breaking out of the hard formation into a softer stratum for the last five feet. We stopped drilling, pulled back to 796' (bottom of the 12-1/4" interval), and shut down for the night.

On Thursday morning (8 August) the trip out was completed and the bit was inspected – only one cutter showed damage, which involved fracture through the diamond table and partially through the substrate; all remaining face and gage cutters had no measurable wear or damage. Drilling resumed with good results, although there were several wireline dropouts and one complete loss of signal. ROP was fairly high (37' in 34 minutes = 65.3 fph), but we picked up downhole vibration at 1395' that also caused complete loss of downhole data signal. The driller pulled up off bottom, stopped rotation, and went back on bottom to resume drilling with good signal. We saw significant bending at 1396' and picked up again. The drilling rate had fallen to approximately 30 fph with 70 rpm and 20,000 lbs WOB, so we tried to increase rotary speed to 120 rpm but got excessive downhole vibration. Drilling continued to 1427', which was the planned bit inspection depth, and was mostly smooth, although the driller was signaled a number of times to pick up off bottom because of torque and bending oscillations. The bit was tripped out of the hole for inspection at the end of Thursday.

The bit showed more damage than it did in Phase 1 at this same depth – eleven face cutters had significant fracture damage, although no major cutter wear was observed. This result was surprising because we did not see any downhole data indicating that the bit had undergone severe loading conditions; the occasions at which the driller was instructed to pick up were precautionary and did not appear to continue long enough for significant damage. There was no damage or wear on the gage cutters and the 8.5-inch ring gage fit snugly around the bit OD. The nozzles were undamaged, and were checked for tightness. Possibly corresponding to the increased cutter damage, the interval from 1318'-1420' TVD was drilled in approximately 90 minutes (68 fph) in Phase 1, but required approximately 120 minutes (51 fph) in Phase 2. It is not clear what the damage mechanism was, or whether the damaged cutters reduced the rate of penetration in Phase 2. Although downhole data enabled us to avoid catastrophic conditions, we should at least consider the idea that repeatedly lifting the bit off bottom as a precaution and then re-engaging it to resume drilling may be harmful. It is also possible that, although there was no visible damage, the preliminary drilling in cement in the original wellbore somehow made the cutters more susceptible to fracture in the harder formation.

After running back in the hole on Friday morning, 9 August, drilling continued until that current stand of pipe was drilled down to a measured depth of 1480 feet. Drilling was generally smooth, although we signaled the driller to "pick up" a number of times because of torque, weight, and bending oscillations. We also experimented over a broad range of WOB

(12-28,000 lbs) and rotary speed (70-120 rpm) to improve the rate of penetration without exciting excessive vibration. Unsurprisingly, the optimum combination of rotary speed and weight varied with formation, but drilling was controlled at relatively smooth conditions while penetrating 54' in 136 minutes (23.8 fph).

Following this drilling interval, we added another stand of pipe and drilled down to 1542' (61' in 169 minutes = 21.6 fph). This stand of pipe was drilled almost continuously, with only one brief interval to re-boot one of the computers. Although the Catoosa lithology column chart shows the previous interval to contain somewhat harder rock, the rate of penetration was slightly higher there. We also used higher average WOB in the lower interval, up to 35,000 lbs at times. After drilling down this stand, we tripped for bit inspection, which showed 12 cutters with significant impact damage and one cutter with a significant wear flat.

We began Saturday, 10 August, by tripping back into the hole and drilling down one joint to 1574' (31' in 68 minutes = 27.4 fph), all of which was in relatively hard formation. Drilling was fairly smooth, with high WOB (up to 35,000 lbs), moderate rotary speed (65-70 rpm), and moderate torque (3500-4500 ft-lbs).

We picked up another joint of pipe and continued drilling with approximately the same conditions as the last interval, but appeared to experience some stick-slip, whereupon we raised rotary speed to approximately 80 rpm. We drilled into a shale section at 1580' and the ROP increased drastically (> 100 fph) but large bending oscillations also started. We raised rotary speed to 90 rpm but bending increased, so we backed off to 75 rpm and bending fell back to an acceptable level. We continued drilling the shale section with high penetration rate but also with high torque (consistently over 6000 ft-lbs) and were kelly down at 1605 feet (31' in 32 minutes = 58.1 fph). This depth is just above the top of the Misener sandstone, a hard and very abrasive formation.

We then picked up another joint of pipe and drilled ahead at about the same conditions as immediately before, but observed stick-slip while still in the shale. We adjusted rotary speed and WOB until we reached a high ROP, although this was accompanied by high torque. When we entered the Misener, torque increased even more (periodically over 7000 ft-lbs) but ROP remained high to 1627' (22' in 23 minutes = 57.4 fph), where we lost the DWD signal. After repairing the wireline connection we attempted to resume drilling but were called away from the rig floor because of a lightning storm in the area. After approximately 20 minutes we once again tried to resume drilling, but both the electronic and hydraulic gauges showed a significant drop in standpipe pressure (at the same flow rate) compared to conditions before leaving the floor. We did not want to risk drilling with what might be a washout and there was not enough time left in the day to resolve the problem. We had exhausted our allotted test time, and GTI had more work scheduled immediately after ours, so the Phase 2 test ended at this point.

POC results:

System performance – The principal components of the DWD system worked, in general, very well. The downhole measurement sub survived more than 1400' (and 26 hours) of drilling with no serious problems. One screw holding the strain-gauge cover plates (Figure 8) backed partially out prior to one inspection, but never came completely out; other screws were observed to be not fully torqued when the tool was tripped out, but the thread sealant prevented this causing any serious problem. A few of the signals (e.g., angular acceleration) were also sporadic, but this appears to have been a matter of loose connections. There were no leaks into the electronics package and there was no serious erosion from drilling fluid flow through the tool, both of which had been concerns before the field tests.

The wet-connect wireline system was adequate for high-rate data transmission, as we had demonstrated in preliminary tests, but it suffered longevity problems during extended periods of drilling. There were two kinds of failure: a break in the center conductor, causing an open circuit, and either complete failure or severe data interruption in the electrical swivel. The first problem was more common in Phase 1, but was greatly alleviated by building some slack into the conductor at the top of the wireline spear and by providing more support with a longer housing. There were fewer instances of this failure mode in Phase 2 than Phase 1, despite the longer drilling interval. The swivel problem was more surprising, because this equipment is commonly used for directional drilling in many locations, and the swivel is off-the-shelf equipment. The swivel also had fewer problems in Phase 1 than in Phase 2. We intend to devote considerable effort to improving this capability before the next field tests.

The software and data acquisition systems worked well, with virtually all data successfully recorded, although there were brief intervals when all the displays did not operate at once. A major goal for controlling drilling with this display is to reduce the total number of quantities shown by eliminating the measurements that do not appear critical (all measurements would still be recorded, but not displayed to the driller or analyst). As described above, all the monitors were in the doghouse, with a group of engineers reaching consensus on when to signal the driller to either "pick up" or "resume drilling", but the eventual goal is to have a monitor with only a few measurements in front of the driller and to have a relatively simple set of instructions for him on what changes in the data should cause him to react in a specific way. These changes are not so important for the CRADA bit tests, because each bit company will have an experienced drilling engineer using the data, but this improvement is essential for wide field application of the system. These software changes, whether done by Sandia or industry, are a high priority because DWD will not be a commercial success without display simplification.

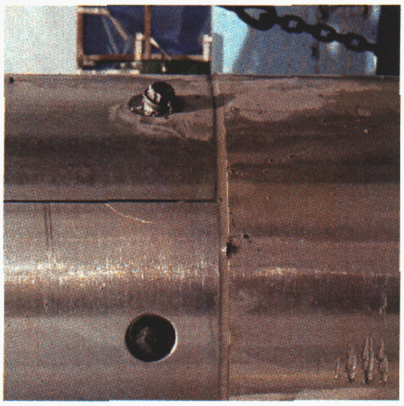

Figure 8 – Loose screw in cover plate

Bit damage/life – The DWD downhole sub and PDC bit (Security DBS, Model PD5) were tripped out of the hole multiple times for inspection during Phases 1 and 2 of the DWD POC.

On these occasions, the condition of the bit and its individual cutters (24 each x 19-mm diameter stud-mounted face cutters; 9 each x 13-mm diameter cylindrical gage cutters) was examined and documented. Table 1 shows depth intervals drilled between inspections and a summary of bit damage at each inspection. Some of the damage mechanisms shown in the table are not exclusive; i.e., cutters described as having wear flats might have been classified as fractured in a previous interval.

Interval	Number of cutters / damage type			
Phase 1	M	F	WF	S
1106-1318	2	1		
1318-1420	3	7		
1420-1492	10	10	5	
Phase 2				
1106-1327	1			
1327-1427		11		
1427-1542	3	15		
1542-1631		2 severe	15	1

Table 1- Bit damage at inspection points
M = minor damage
F = fracture (more than minor chipping)
WF = significant wear flat
S = cutter sheared off

Detailed results of the bit inspections, with photos of individual cutters, are given in Appendix E, organized by drilling interval and phase.

Damage is the principal measure of bit life, but the damage does not have to be obviously catastrophic to degrade performance enough to end the bit's useful life. As an example, a few broken cutters at approximately the same radius can leave a ridge of rock that prevents further bit advance even though all of the other cutters are relatively undamaged.

Rate of penetration – Another important measure of drilling efficiency is rate of penetration, and many drillers use this as their primary feedback because bit life or damage is often difficult to assess from surface measurements only. Table 2 shows comparative rates of penetration over given depth intervals in Phases 1 and 2; the depth equivalence is not exact because deviation in the Phase 2 hole caused its true vertical depth to be approximately 7' less than measured depth, whereas TVD and TMD were essentially identical in Phase 1. It is also important to note that the ROP values are not derived from instantaneous measurements but are calculated by summing the total time spent on bottom and rotating for each stand (or joint) of drill pipe.

Approximate Depth Interval	Rate of Penetration, feet per hour	
	Phase 1	**Phase 2**
1105-1169	105.6	84.6
1169-1233	115.8	88.8
1233-1296	69.0	76.2
1296-1357	66.0	62.4
1357-1420	63.6	45.0
1420-1481	72.0	24.0
1481-1542		21.7
1542-1574		28.2
1574-1605		58.1
1605-1627		57.4

Table 2 – ROP in drilled intervals

The table shows that rates of penetration were reasonably comparable, although Phase 2 ROP was often less than in Phase 1, especially notable in the 1420-1481 ft interval. These results are presented graphically in Figure 9, which has ROP calculated over somewhat shorter intervals and therefore gives better resolution. The figure shows that for much of the 1420-1481 ft interval, WOB was lower in Phase 2 than in Phase 1, but it is also useful to gain some insight to drilling efficiency by normalizing ROP relative to WOB and rotary speed. Figure 10 presents plots of ROP divided by the product of WOB and rotary speed. This figure clarifies the point that, in the 1420-1481 ft interval, the bit in Phase 2 drilled less efficiently than in Phase 1. It should also be noted that the WOB values used in Figures 9 and 10 are downhole measurements, and that the figures imply, at fairly coarse resolution, the relative magnitudes of rock strengths through the drilled intervals.

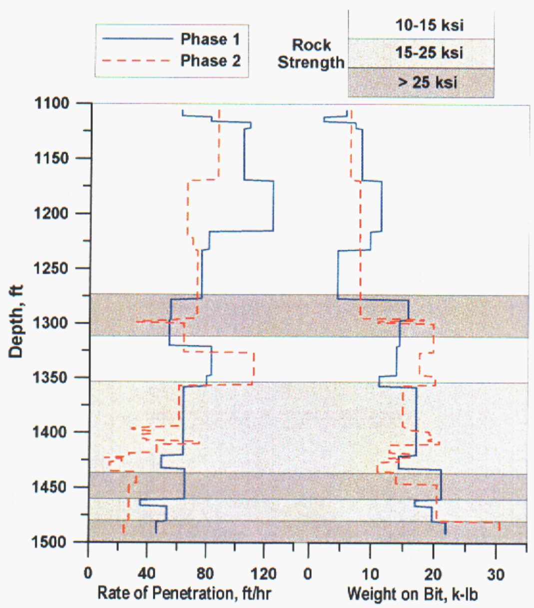

Fig. 9 - ROP and WOB for Phase 1 and Phase 2

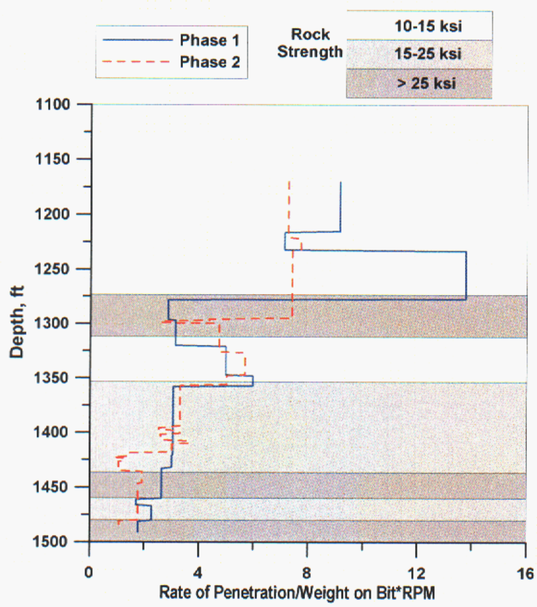

Fig. 10 - Normalized ROP for Phase 1 and Phase 2

Another interval of interest is that from approximately 1230-1275 ft, where the drilling efficiency for Phase 1 appears to be much higher than for Phase 2. Performance in these intervals is not completely understood, but possible explanations include:

- A near-bit stabilizer was between the measurement sub and the bit. Because of deviation in the upper part of the Phase 2 hole, it is possible that drag on the stabilizer affected the downhole WOB reading, especially in the 1230-1275 ft interval when the drill collars were still in the bent part of the hole. This would mean that, even with downhole measurements, the bit was not actually bearing the indicated load.
- In Phase 2, we knew from Phase 1 experience that the 1420-1481 ft interval was difficult to drill and, in fact, caused the failure of the previous bit. Consequently, we were very cautious and signaled the driller many times to pick up off bottom while we reached consensus on proper drilling conditions. Even though this time off bottom was not included in the ROP calculation, the interruptions prevented reaching an equilibrium drilling condition. This is a natural effect of being on a learning curve, and the learning was shown to be effective by the increased bit life compared to Phase 1.

- Bit inspection showed more damage at 1420 ft in Phase 2 than in Phase 1; this damage could have affected rate of penetration. The reasons for the increased damage are unclear, but it is possible that the bit was damaged by drilling cement in the upper part of the hole, even though there was no visible sign when the bit was inspected before starting the test interval.

Except for the noted exceptions, Figure 10 generally shows reasonable behavior; i.e., ROP decreases in harder rock and drilling efficiency decreases with bit wear and damage.

Background of drag-bit CRADA: In June 2002, Sandia National Laboratories executed a Cooperative Research and Development Agreement with four bit companies whose current designations are:

- ReedHycalog, A Grant Prideco Company (formerly Schlumberger Technology Corporation);
- Security DBS a Product Service Line of Halliburton Energy Services, Inc.;
- Smith Bits – GeoDiamond; and,
- Technology International, Inc.

The goal of this CRADA is to advance the state-of-the-art and commercial acceptance of PDC bits for use in the kinds of hard, fractured formations that are typical of geothermal reservoirs. An early concept for the CRADA was simply to compare drilling performance – i.e., bit life and rate of penetration – among "best effort" bits from the participating manufacturers; however, with the advent of the DWD project, both efforts clearly benefited from a combination of the DWD proof of concept (POC) with the CRADA drilling tests. Phases 1 and 2 of the POC coincide with CRADA Tasks 1 and 2, which involve the generation of baseline hard-rock drilling data for conventional drag and roller-cone bits. The terms of the CRADA stipulate that Sandia provide all data from the POC to the participating bit companies to support their development of "best effort" hard-rock PDC bit designs and DWD-based drilling strategies. CRADA Task 3 involves the field demonstration of these designs and strategies under the same conditions (i.e., drilling interval and BHA configuration) as the drilling in the POC.

Summary of CRADA tests and results:
As of the date of this report, CRADA Task 3 drilling had been completed with the "best effort" bits supplied by three of the four participating companies. Testing of the fourth "best effort" bit was awaiting design modifications and repairs to the DWD tool, which was damaged near the end of each of the second and third "best effort" bit tests.

Like POC Phases 1 and 2, an entire week of rig time at the GTI Catoosa Test Facility was scheduled for each "best effort" bit demonstration. During its designated week, each bit company provided one state-of-the-art drag bit along with an on-site team of one or more engineers to control the drilling process for its bit. Prior to the initiation of Task 3 activities, Sandia implemented a number of improvements in the DWD software and display features, and each bit-company team met individually with Sandia staff to define its own "customized" display of DWD data.

In every case to date during Task 3 work, the bit-company drilling engineers paid close attention to the real-time displays of DWD data, and routinely utilized it to make decisions regarding adjustments in operating conditions. Their acceptance and application of this new capability for downhole diagnostics was universally enthusiastic, despite some intermittent wireline/swivel problems. In fact, all teams freely elected to forego opportunities to continue drilling "blind" (i.e., without downhole data) during wireline outages; instead, they chose to await the necessary repairs at the expense of additional time on bottom. Encouragingly, the "best effort" bits coupled with DWD feedback have consistently, and significantly, outperformed the baseline PD5 results (obtained with and without DWD feedback) in terms of both ROP and bit life.

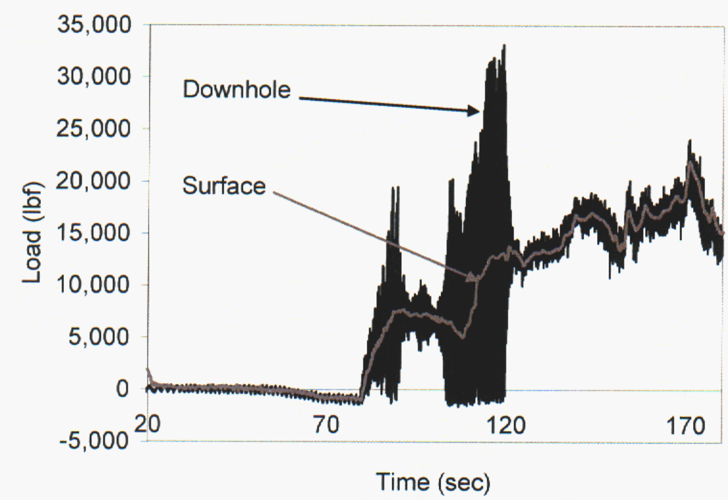

Figure 11 – Comparison of surface and downhole WOB at drilling start-up

After its week of testing, each company was presented with a full set of the DWD and surface data acquired for its particular bit by Sandia. Under the terms of the CRADA, this detailed information will not be shared with third parties, including the other CRADA participants. However, overall comparative results are currently being documented on an anonymous basis in a summary report for public release. This report will be finalized upon completion of Task 3 drilling with the fourth commercial CRADA partner.

Conclusions – POC:
The Proof-of-Concept testing validated the successful function and utility of the DWD system. All drilling objectives were met and performance of the interconnected DWD hardware and software elements was, especially for a complex new system with no history of drilling in an actual hole, outstanding. Specific conclusions are described in more detail below.

Downhole data clearly showed vibrations and oscillations that were not apparent at the surface. This was the key assumption from the beginning of the DWD project, along with the idea that real-time drilling control to avoid or mitigate those forces would improve bit performance. An example of this phenomenon is shown in Figure 11, which compares surface and downhole measurements of WOB as the bit reengaged the bottom of the hole to resume drilling. For this event, surface data indicates that weight (and torque) increase relatively smoothly as the driller uses the prescribed procedure for setting the bit on bottom, but downhole measurements clearly show significant vibration and bounce. The bit is apparently losing contact with the hole bottom, creating both axial (and torsional) impact loading.

The technology for sending high-speed, real-time data from downhole is viable, regardless of the fact that some existing system components require improvement and that the present design may not constitute the ultimate "field-ready" DWD configuration. One must remember that the present body of work was just a proof-of-concept test; in other words, the system used here – comprising the downhole sub, wireline, and surface display – was only a prototype that enabled us to explore the concept of real-time control. To that end, it performed admirably, acquiring essentially all the data required by the test plan with relatively few delays caused by equipment problems. To gain broader acceptance and application, the highest priority is replacement of the wet-connect wireline system with a data link that is more transparent to the drilling operation. Even for continued use of the wireline, we need improved performance from its electrical swivel.

Different bit dysfunctions can be distinguished in the downhole measurements. Among the downhole conditions to be avoided are bit whirl, drill collar oscillations, stick-slip, and bit bounce. These are often difficult or impossible to sense and distinguish quickly, or at all, with surface measurements, and the appropriate corrective action can be different for each phenomenon. Accordingly, the ability to detect dysfunctions in real time, and to react in the proper way, is extremely important. It was also clear in post-test processing that the combined use of downhole and surface measurements is more effective than using either alone.

In general, the correct measurements to control drilling with bit dynamics criteria have been chosen. Because viewpoints differ on which dynamic measurements are most important to control drilling performance, our original approach was to make as many measurements as possible at the highest practicable sampling rate. (Post-processing also shows that real-time bit displacement relative to the rock face appears to be possible and could be a useful additional parameter for monitoring.) Meeting this combination of criteria was limited by the maximum data rate that could be driven by the downhole electronics over a given length of wireline. A high priority is to refine the measurement set by eliminating certain measurements or by lowering the sample rate, but we do not yet have data from enough different conditions/formations to make those choices. It will also be important to distinguish between the data and displays that could be used as research tools by engineers and analysts, versus the display that would be most effectively presented to the driller for real-time control.

Effective use of this new kind of data involves a significant learning curve. This is related to the previous point; the driller or the engineer can view a large number of measurements, both surface and downhole – choosing the set that will be most effective to control drilling may not be immediately obvious. It may also be that the optimum measurement set will vary with the formation being drilled, the type of bit being used, or the depth. Using downhole data can also be a way of training the driller, so that he can see instantaneously when the bit is on bottom and doesn't have to "feel" his way down. Similarly, he can learn the acceptable limits to which he can "drill off", or let the WOB decrease, without causing bit bounce or whirl.

Many of the corrective actions that should be taken when various bit dysfunctions occur are counter-intuitive; for example, it is often necessary to increase WOB to suppress downhole vibration when one might think that decreasing it would be better. Downhole measurements can show immediately whether the corrective action being used is effective.

Conclusions – CRADA:

Conventional drag-bit designs and cutter materials can effectively drill hard-rock formations, particularly when operated with DWD-derived feedback control for the drilling process. The present bit demonstration has clearly shown that extended hard-rock intervals can, indeed, be drilled successfully at high penetration rates – even with an older drag-bit model. Moreover, bit life (i.e., total footage) can be dramatically enhanced by continuously adjusting drilling parameters (e.g., WOB, TOB, and RPM) on the basis of real-time observations of the downhole bit dynamics. As noted above, ongoing tests of state-of-the-art "best effort" bits coupled with DWD feedback have substantially exceeded the baseline PD5 results noted in this report for ROP and bit life. This success presents a strong argument for a follow-on demonstration of one or more state-of-the-art drag bits during production drilling at a geothermal site. For the sake of optimal bit performance, this demonstration should include simultaneous deployment of the latest available version of the DWD system.

Improvements in bit life derived from active DWD-based intervention in the drilling process may involve some trade-off for penetration rate. The Phase 1 and Phase 2 ROP values matched closely during the mostly smooth drilling for depths up to about 1400'. Beyond this depth, more frequent DWD indications of undesirable downhole dynamics led to numerous adjustments in operating conditions during Phase 2, with a bias toward less aggressive use of the bit. As a result, the effective ROP over the interval from 1400' to 1492' was significantly lower during Phase 2 than during Phase 1. Of course, the bit failed at 1492' in Phase 1, whereas it was still viable at 1615' during Phase 2. The relative impact on overall drilling cost per foot must be considered in light of the respective costs for the bit and rig time. Clearly, excessive intervention at dynamic loading levels below minimum damage thresholds may lead to an increase in cost. Unfortunately, these thresholds are difficult to define without a substantial database and associated model for bit and cutter failure. Ultimately, such a database and/or model may be developed and incorporated as part of the DWD system to achieve maximum drilling economy on a real-time basis.

Program direction:

Based on experience and results to date, the following recommendations will serve to advance the Diagnostics-While-Drilling program.

- *Acquire data in other formations and with other bits* – The design of the POC test required repeatable formations, BHAs, and bits, but to extend use of the system we must show that it provides comparable benefits under drilling conditions much different than those encountered at Catoosa. Specifically, we should test the system both for its survivability and its data-collection benefits in harder, more geothermal-like formations.
- *Acquire data with different BHA configuration* – The workshop that selected the BHA to be used in the POC test recommended a near-bit stabilizer (NBS) between the bit and the measurement sub, primarily for protecting the sub from excessive bending loads. From

the standpoint of assessing bit performance, however, this stabilizer masks some of the loads imposed on the bit. It would be useful to run the DWD system without the NBS, through an interval previously drilled with the stabilizer, and then compare the data.

- *Unify data displays* – One result of the POC tests was to show the value of having surface and downhole measurements displayed on the same screen. It is not possible to do that with the software/hardware in the prototype system, but this capability is not a serious technical challenge and should be implemented before any future CRADA or production-drilling tests if possible.
- *Develop field-ready system* – The prototype system described in this report has performed very well but has a number of operational disadvantages that limit its wide acceptance. The four principal activities required to bring it nearer to industry application follow:
  - ◊ <u>Choose optimum data rate</u> – We approached the subject of bit dynamics with the intent to make as many relevant measurements as possible and to sample the data at the highest practicable rate. This resulted in a data stream of approximately 200,000 bits/second; this high data rate places restrictive requirements on both the transmitting and receiving electronics. While useful for research purposes, the large number of measured parameters also provides much more data than the driller can use effectively. A high priority is to define the most important measurements, the necessary frequency with which they should be sampled, and the manner in which they should be processed for most effective presentation to the driller.
  - ◊ <u>Investigate alternative data links</u> – The wet-connect wireline system used in the POC suffered several malfunctions that cost time for repair or replacement. Even if these tools worked perfectly, however, there are many drillers and service companies who are strongly opposed to deployment of wire inside the drill string because they see it as a source of trouble or as an impediment to other wireline operations. Among the alternative data links that could be investigated are optical fibers, acoustic transmission through the drill pipe, and "wired pipe" in which the transmission medium is embedded in the structure of the drill pipe. Sandia has experience with all of these techniques, but our first step should be testing a commercially developed wired pipe that now exists in the prototype stage.
  - ◊ <u>Upgrade measurement sub for high-temperature</u> – Because this system concept originated as a way to improve geothermal drilling, we must prepare a reasonably detailed design for a high-temperature DWD measurement sub. This design will include not only high-temperature electronics, but also high-temperature sensors and mechanical seals, which may be the more difficult part of the design. This design will also be strongly driven by choices on the data rate and alternative data link, and the very advantageous possibility of two-way communication should be seriously considered.
  - ◊ <u>Redesign measurement sub</u> – Other features of the measurement sub should be redesigned for improved assembly, survivability, convenience, and reliability. Although a number of improvements are apparent from experience to date, the optimal time for this redesign would be after experiments and tests in other formations.
- *Organize industry support* – To successfully bring DWD technology to market, it is essential to gain industry acceptance, which would be strongly signified by their willingness to cost-share the development. We should contact drilling contractors, service companies, and operators to assess the possibilities for a multi-partner CRADA to pursue

further DWD development. If these contacts are not productive, we should prepare a proposal to the Drilling Engineering Association for a Joint Industry Project that will cost-share development of a field-ready system.

Acronyms and abbreviations:

BHA	bottom hole assembly; the collection of drill collars, stabilizers, and other drilling components below the drill pipe
DC	drill collar; the heavy tubular components, at the lower end of the drill string, that provide the axial force on the bit
fph	feet per hour; the conventional units for rate of penetration (see below)
IBS	integral blade stabilizer; a short cylindrical drillstring component, almost wellbore diameter and usually near the bit, used to reduce the clearance between the BHA and the wellbore, thus reducing the lateral vibrations at the bit
kpsi	kilo-pounds per square inch; units of rock strength
PDC	polycrystalline diamond compact; drag bit cutters that are made from disks of synthetic diamond and attached to the face and outer diameter of the bit
POC	proof of concept; the overall designation of the Phase 1 and 2 tests at Catoosa
ROP	rate of penetration; the speed at which the bit advances the hole
rpm	revolutions per minute; units to measure the rotary speed of the drill string
TMD	true measured depth; the length of the wellbore, measured from some reference point
TOB	torque on bit; torque applied to the bit, which is a measure of its cutting efficiency
TVD	true vertical depth; the vertical distance from a reference point to the end of the wellbore – if the well, or part of it, is not vertical then the TVD < TMD
WOB	weight on bit; the axial force applied to the bit – sometimes significantly different when measured at the surface and downhole

Appendix A
Test Plan
and
Measurement Sub Specifications

I. Test plan

A series of three testing phases simultaneously supported both the hard-rock bit technology and the Diagnostics-While-Drilling programs. The description below reflects the actual test procedures, which varied only slightly from the original test plan. The tests generally involved drilling in a relatively hard formation with PDC bits while taking high frequency bit-dynamics data with a downhole sub and transmitting it back to the surface in real time with a high-speed data link. Measurements taken during the DWD POC and bit-CRADA (Cooperative Research and Development Agreement) tests were:

- 3-axis acceleration
- High-frequency axial acceleration
- Angular acceleration
- Magnetometer (rotary speed)
- Weight on bit, torque on bit, bending moment
- Drill-pipe and annulus pressure
- Drill-pipe and annulus temperature

The underlying principle was to eliminate as many test-to-test variations in drilling conditions as possible, so that post-test data interpretation could focus on the effect of DWD on drilling performance and, later, on the comparative performance of PDC bits from various manufacturers. Variations in formation and bottom-hole assembly were eliminated by running all tests through the same interval of rock and with the same BHA. The selected formation at the Catoosa test site was the hard (compressive strength > 35 kpsi) Mississippi limestone interval between about 1274' and 1550' depth, which includes a section known as "The Wall" that features a compressive strength of about 50 kpsi. The BHA was a packed-hole assembly with:

- 8-1/2" bit
- Near-bit Integral Blade Stabilizer (IBS), 1/16" under gauge, hard-faced and ground smooth
- Crossover sub, approximately 18" long
- DWD measurement sub
- Crossover sub, approximately 18" long
- IBS
- 6-1/4" DC, ~30 long
- IBS
- approximately 500-600 feet DC (to give 55,000 lb WOB)
- 4-1/2", 16.6 #/ft steel drill pipe

The procedure specified for the two drilling phases (1 and 2) in the POC is given below, but there were minor variations in this because of budget and schedule limitations; these are defined in the Narrative.

- The test holes will be kicked off from a common conductor/intermediate-casing string set at approximately 500'. Kickoff will be done with a "utility" bit, not one of the test bits, and the DWD system will not be used for kickoff.
- Once the hole is deviated, pick up a roller-cone bit for Phase 1 and a PDC bit for Phase 2, and drill from the kick-off point (approximately 600-800') to approximately 200' above the top of the Mississippi limestone formation (~1274 ft). Use the DWD system to record baseline comparison data during these intervals.
- POOH (pull out of hole) at ~ 1100' and pick up Security DBS Model PD5 test bit. RIH (run into hole) and drill to 1400' measured depth with maximum practical (or optimum) ROP.
- POOH and inspect bit for wear and impact damage.
- RIH and continue drilling to approximately 1600'; POOH and measure wear before top of Misener sandstone. Assess impact damage.
- RIH and continue drilling to 1800'.
- POOH and inspect bit. Test will be ended at this point even if bit still appears to be usable.

The exact test procedures for Phases 1 and 2 are described in the body of the report.

Follow-on objectives for both the DWD and hard-rock bit programs will be accomplished in Phase 3: After each of the CRADA-participating PDC bit companies has received Phase 1 and 2 data, Sandia will acquire a "best effort" bit from each bit company. The "best effort" bits will then be used to drill the same Phase 1/Phase 2 test interval with the DWD data system in operation. Each bit company will provide a drilling engineer to supervise operation of their bit and each company's engineer may specify what surface display (of the downhole measurements) he wishes to see. Each engineer will be free to control WOB, rotary speed, and mud flow throughout his test. Detailed and complete Phase 3 data will be distributed to each bit company about its own bit, with a summary report released to all bit companies, DOE, and the public. Specific design data (dimensions, materials, cutter layout, etc.) supplied to Sandia by a bit company will be protected as proprietary to that company. In the summary report, results of the "best effort" Phase 3 bit tests will be anonymously identified by reference to bits from "Company A", "Company B", and so on. The CRADA (No. SC02/01655, "Advanced Drag Bits for Hard-Rock Drilling") that defines intellectual property rights and requirements for protecting design and test data between Sandia and the bit companies has been signed and will control data distribution after the tests.

II. Specifications for measurement sub and sensors

Mechanical specifications for sub

- OD: 7" for use with 8-½" bits; Length max ~96"
- Collapse/burst pressure: >10,000 psi; Differential pressure: <5,000 psi

- Impacts to ~200 g
- WOB: up to 55k lb
- Torque: up to 20k ft-lb
- Electronics space: 2.0" minimum ID by 33" minimum length
- Rotary speed: 0-250 rpm
- Temperature: <250°F.
- Mud: nominal flow rate 500-600 gpm, <10 lb/gal, no barite
- Depth of usage: <5000 ft
- Wireline tool passage: no–centralized sensor placement required
- Non-magnetic materials are required

Measurement specifications

- 14 bits with a minimum of 1000 samples per second for every channel
- WOB: -20 – 80k lb; resolution better than 100 lb, sensitivity ~ 2.3 lb, noise level ~15 lb, zero drift ~3k lb
- Torque: ± 20k ft-lb; resolution better than 100 ft-lb, sensitivity ~0.64 ft-lb, noise level 30 ft-lb, zero drift ~365 ft-lb
- Bending: ± 17k ft-lb, sensitivity ~2 ft-lb, noise level ~2.5 ft-lb, zero drift ~70 ft-lb
- Linear Acceleration: 3-axis, ± 100 g; resolution ~ 0.03g, resonance 5.5 kHz, sensitivity 0.01 g, noise level ~0.016 g, zero drift ~0.4 g
- High Frequency Axial Acceleration: z-axis, ± 30 g; resolution ~ .004g, resonance 32 kHz, sensitivity 0.004 g, noise level ~0.016 g, zero drift ~0 g
- Angular Acceleration: ±50k rad/s^2; resolution ~ ±6.1 rad/s^2, resonance 3 kHz, theoretical sensitivity 1.75 rad/s^2, noise level ~5.7 rad/s^2, zero drift ~320 rad/s^2
- Magnetometer: 3-axis, ± 2 gauss span, resolution ~ ± 40 μgauss
- Pressure: internal 0 - 7,000/ external 0 - 2,000 psi; resolution better than 1 psi
- Temperature (internal & external): 50 - 250 °F; resolution 0.1 °F

Accelerometer info

Axis	Type	model	sensitivity	resonance	zero measured output
X	Endevco	290A	19.53 mV/g @ 100 Hz	5500 Hz	2.7 mV
Y	Endevco	7290A	19.64 mV/g @ 100 Hz	5500 Hz	-0.3 mV
Z	Endevco	7290A	19.55 mV/g @ 100 H z	5500 Hz	0.8 mV
Z high-freq.	Wilcoxon	726	95 mV/g	32 kHz	
Angular	Endevco	7302B	3.488 μV/rad/sec^2	3000 Hz	

Complete details on accelerometers are available at http://www.endevco.com/ and http://www.wilcoxon.com/

Filtering

Anti-aliasing filtering was applied as follows, where the corner frequency is the –3 dB point:

- Linear accelerometers --------------------- 143 Hz corner, 8 pole Bessel
- High frequency axial accelerometer ------ 286 Hz corner, 8 pole Bessel
- WOB, TOB, & Bending ------------------ 150 Hz corner, 3 pole Butterworth
- Magnetometers ---------------------------- 23.6 Hz corner, 8 pole Bessel

Pressure transducers

The original measurement sub design called for Quartzdyne pressure transducers because of their exceptional accuracy. These transducers have several drawbacks for this application, however, and were replaced with Paine Model 210-40 units. The latter transducers have adequate accuracy with their strain-gauge based signals and respond faster because they do not have the delay required to accumulate counts in the digital output of the Quartzdyne. This faster response is important because of the pressure effect on the weight-on-bit readings. As internal pressure increases in the measurement sub, it effectively stretches the tool, reducing the weight-on-bit strain gauge reading. There is a data-processing algorithm to account for this in real time, but for it to be effective the pressure must be updated quickly, and the Quartzdynes were thought to be too slow for this. The Paine transducers are also much smaller than the Quartzdynes, which made for easier packaging. They run on 10 VDC excitation with a sensitivity of 2.5 mV/V at full scale. Complete details are available at www.painecorp.com/Products.

Appendix B
Data-flow Schematic
and
Frame Definition

I. Data flow

The two principal criteria for data management are that 1) all the data are acquired and archived, and 2) we can always recover "raw" data: that is, digital data as it is transmitted up the wireline without being manipulated through variable gains or conversions into engineering units. Accordingly, the raw data are redundantly archived, and manipulated data are archived separately. A schematic of the data flow is shown below.

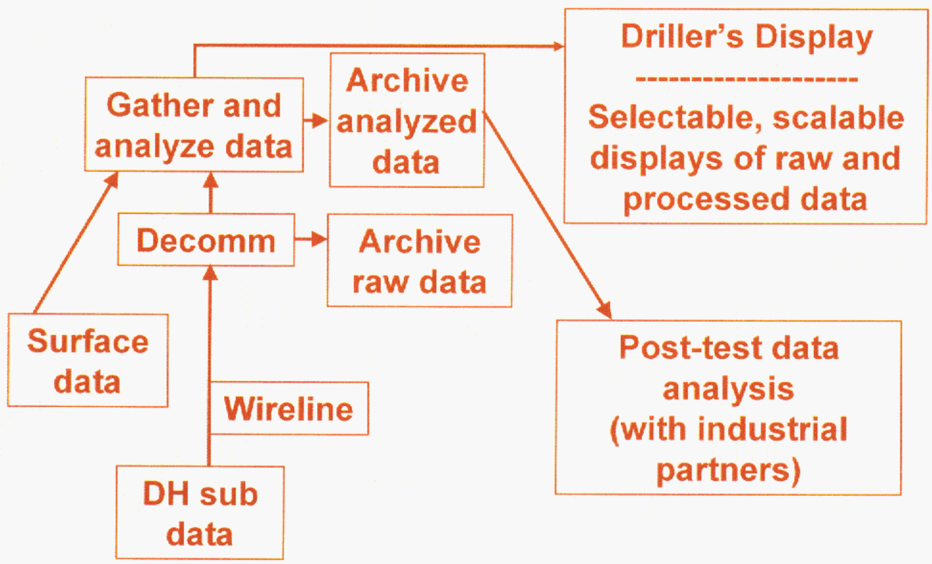

Figure B-1 – Schematic of data flow in DWD system

In reality, however, the data system that has been used in testing to date is not as cleanly organized as the diagram indicates. There are four major components in the data display/archive stream: the "16-bit" display/archive for downhole data; the "32-bit" display/archive for downhole data; the display/archive for surface, or "mudlog" data; and the separate archive for "comments", which can be entered from any one of several computers. The existence of these separate components leads to problems described in more detail below.

II. Frame definition

The downhole electronics package converts analog signals from the sensors into digital quantities and sends them up the wireline as a stream of bi-phase pulses. The pulses are first organized into "words" and the words then make up minor frames. Each minor frame has a specific hexadecimal word at its beginning to trigger the receiver, or decommutator, into translating that minor frame. Minor frames are generated 1041.7 times a second, and the downhole measurements with the highest frequency content (accelerometers, strain gauges) are sampled for each minor frame (the high-frequency axial accelerometer is sampled twice each minor frame – columns 8 and 9 in Figure B-2). Other signals of a less transient nature, such as temperature, are sampled less often. For example, each magnetometer is read at 1/8 the rate, and each pressure and temperature at 1/16 the rate, of the high-frequency measurements. A group of 16 minor frames is called a major frame, which indicates that a sampling cycle is completed in each major frame, and each major frame receives a reference time tag from the decommutator. This is summarized in the frame definition table shown below.

	Sync	1	2	3	4	5	6	7	8	9	10	11
0	D600	X-Mag	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
1	D601	Y-Mag	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
2	D602	Z-Mag	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
3	D603	Ex-Press	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
4	D604	In-Press	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
5	D605	X-RMS	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
6	D606	Y-RMS	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
7	D607	Z-RMS	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
8	D608	X-Mag	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
9	D609	Y-Mag	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
10	D60A	Z-Mag	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
11	D60B	In-Temp	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
12	D60C	Ex-Temp	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
13	D60D	FrmCount	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
14	D60E	PCB-T	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend
15	D60F	Bat-V	X-Acc	Y-Acc	Z-Acc	Ang-Acc	WOB	TOB	Z-Hi-Acc	Z-Hi-Acc	X-Bend	Y-Bend

Figure B-2 – Typical major frame definition; each row represents a minor frame

III. Proposed data system

While the system described above has provided reasonable data for the early DWD tests, it has a number of serious drawbacks: 1) the existing system does not respond as quickly as necessary; 2) the four subsystems do not start at the same time, so it is difficult to synchronize the data for analysis; and, 3) because of the lack of an overarching database structure, it is very difficult to have either real-time or playback display of comparative data from the surface and downhole systems. A second-generation surface system is currently in the early design stages.

When describing data systems, the term "real time" has a somewhat different meaning than the conventional usage that just means the data is displayed almost instantaneously after it is collected, either at the surface or downhole. A real-time data system has a dedicated operating system that is fully controlled and not subject to the interrupts inherent in the Windows-based architecture used in testing to date. That is, the time intervals between frames will be extremely uniform, instead of varying by up to an order of magnitude as in the existing computer hardware/software. Each individual measurement, from each of the possible sources, will be entered into the same database, or archive, and each will be time-tagged from the same time reference. This data structure means that the previous difficulties with synchronization and time slips should be eliminated and the new system should also be more reliable than the existing one. There is, however, no easy way to accomplish this change; implementation of the new data architecture will involve a substantial investment of time and effort in new software that will control and integrate the system.

Appendix C
Wet-connect Wireline System
Description and Testing

The Proof-of-Concept tests and the CRADA bit tests used a wet-connect wireline (WCWL) system to transmit data from the downhole measurement sub to the surface display unit. This wireline system contains an electrical swivel that allows rotation of the drill pipe (i.e., relative rotation between the top and bottom of the wireline) and a wet-connect assembly (see Figure C-1) that allow the wire to be electrically and mechanically separated and reconnected while submerged in a conductive fluid. Commercially available WCWL systems are used for directional drilling or other downhole measurements, particularly when aerated mud or air drilling means that mud-pulse MWD cannot function. For those applications, however, data transmission is at a relatively low rate of approximately 1000 baud.

I. Laboratory tests

Before going forward with the POC test plans, it was necessary to verify the data-handling capacity of the WCWL system to assure its capacity to carry a minimum data rate of 100 k-baud. It was also important to measure electrical properties (resistance and capacitance) of the wireline so that its response could be modeled and performance at other wireline lengths (different from the test lengths) could be predicted. To perform these tests, we rented selected components from a commercial wireline company and attached them to a 5/16", single-conductor Sandia wireline as described below. The following measurements were then made:

1. Bare cable – Resistance and capacitance of a 6455' length of 5/16" wireline were measured in the lab. Measured values were capacitance = 39.7 pf/ft and resistance = 6.8 mΩ/ft. After these measurements were made, two shorter pieces (1088' and 2250') were cut off the original cable and the electrical measurements were confirmed on these segments.

2. Wet-connect assemblies, air – The short pieces of wireline were connected to the wet-connect components as shown in Figure C-2. There were then two possible test configurations – 1088' of wireline with one wet-connect (assembly 1) or a total of 3338' of wireline with two wet-connects and the swivel (assembly 2). Each of these configurations was tested by putting a –5 to +5 volt square wave into one end and measuring the output wave at the other end. Over a range of 50 kHz to 5 MHz, there was no measurable difference between bare wire and the assemblies with wet-connect components.

3. Wet-connect assemblies, fresh water – In the next step, the wet-connects were immersed in a barrel of water, each connector was pulled apart and reconnected 10 times under water, and measurements were made over the range of 50 kHz to 500 kHz. Again, there was no measurable change in performance from the same assemblies in air, but an effect was noted when the wet-connector was not fully seated. Capacitive coupling enabled high-frequency signal transmission (with some voltage drop) but, of course, no DC

current could flow. This effect was noted in all the submerged tests. This effect means that a downhole tool powered solely from the surface would not function if the wet-connect were not fully latched.

4. Wet-connect assemblies, brine – The tests done in fresh water were repeated in saturated brine (weight ~ 10.2 ppg), with no measurable difference between the outputs in fresh water, salt water, and air.

5. Wet-connect assemblies, mud – The same tests, including breaking and making the connection (in the mud) 10 times were done in 8.5 ppg bentonite mud. There still was no measurable change in the output, compared to bare wire.

Under static conditions, with no hydrostatic pressure and no rotation, the wet-connect components showed an immeasurably small effect on the wireline's data-transmission capability. The resistance and capacitance of the wireline dominate the signal transmission, and introduction of the additional components is negligible compared to this. Tests also confirmed the computer-simulated wireline model. This enables prediction of wireline performance under other conditions and line lengths.

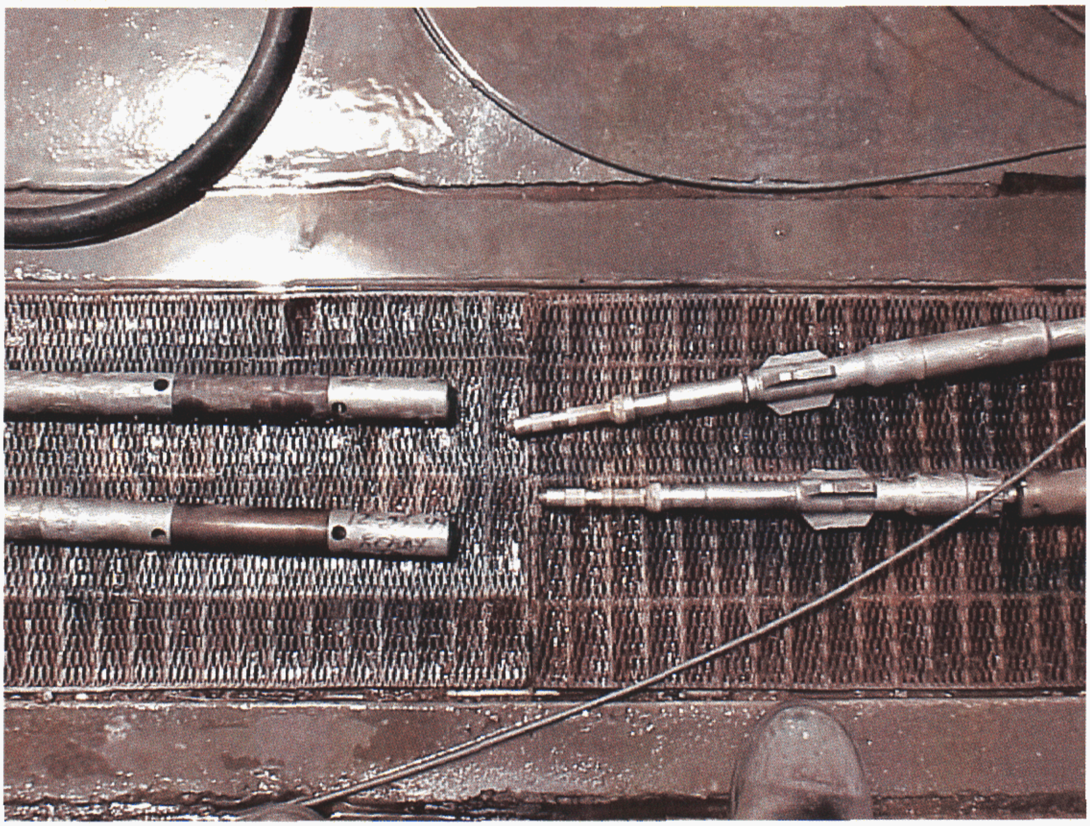

Figure C-1 – Wet Connect male (right) and female (left) connections

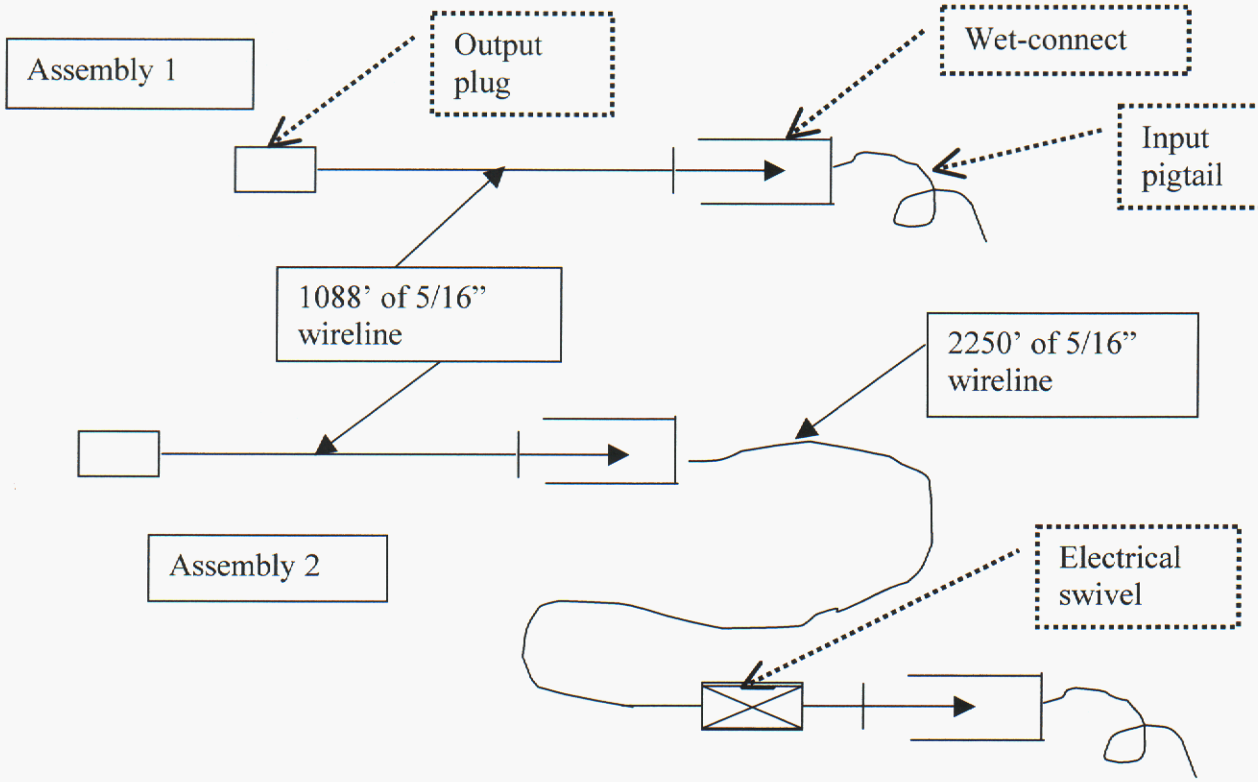

Figure C-2 – Schematic of laboratory testing

II. Field tests

The laboratory test of the WCWL system was followed by a field test at the GTI Catoosa Test Facility in January 2001. The purpose of this test was to confirm successful signal transmission through the wet connect system, under realistic drilling conditions, while using a high-speed downhole telemetry device to generate the transmitted signal.

The wireline-logging service company provided all test equipment except the high-speed signal generator. Electrical properties of the logging truck's spooled Comesa single-conductor wireline were measured at the service company's facilities. This wireline has a 5/16 in. outside diameter and was 5000 ft. in length. The electrical parameter measurements, Table C-1, were made with a Fluke digital multi-meter (DMM) and confirmed with an Elenco DMM.

DMM Instrument	Fluke	Elenco
Line Resistance	13.8Ω	
Armor Resistance	9.8Ω	
Total Resistance	23.6Ω	25.6Ω
Line Capacitance	0.224uF	0.227uF
Line Inductance		1.485mH

Table C-1
Electrical properties of wireline

A CEC model F34 function generator was also used to test some of the wireline's AC parameters. The 10V peak-to-peak square wave signal was injected into one end of the cable, and characteristics of the received signal were measured at the other end by an oscilloscope. The higher frequency signals were definitely distorted and reduced in amplitude. Table C-2 shows the results of these frequency tests.

Frequency, kHz	Output amplitude, mV
62.5	200
125	90
250	30
500	10

Table C-2
Amplitude vs. frequency

The high-speed, signal-generating telemetry unit (HSTU) was initialized for a bit rate of 250 kHz in the preliminary characterization test plan. The HSTU was attached to the wet connector pin assembly and tested through the cable on the wireline truck. The data through the complete communication link closely resembled the captured HSTU 250 kHz waveforms recorded at the wireline shop.

The HTSU was lowered into the borehole and latched into the drillpipe at the test depth of 1196 feet. This was a test simulation and the purpose was to check the reliability of the wet connect system process. An effect that is easily remedied is the tendency of the female wireline connection to pack off with grease and pipe dope as it is lowered into the drillstring. This necessitates circulating the pipe clean before running the wireline. The "pickup and setdown" distance of the mating wet connectors was set for approximately 10 ft. The wireline device is lowered at a velocity of approximately 60 ft/min to give enough momentum to successfully latch together and complete the electrical circuit from the downhole to surface. The connection procedure went through a minimum of 5 cycles, each time verifying a good signal condition. This 250 kHz data was then recorded and is shown in Figure C-3.

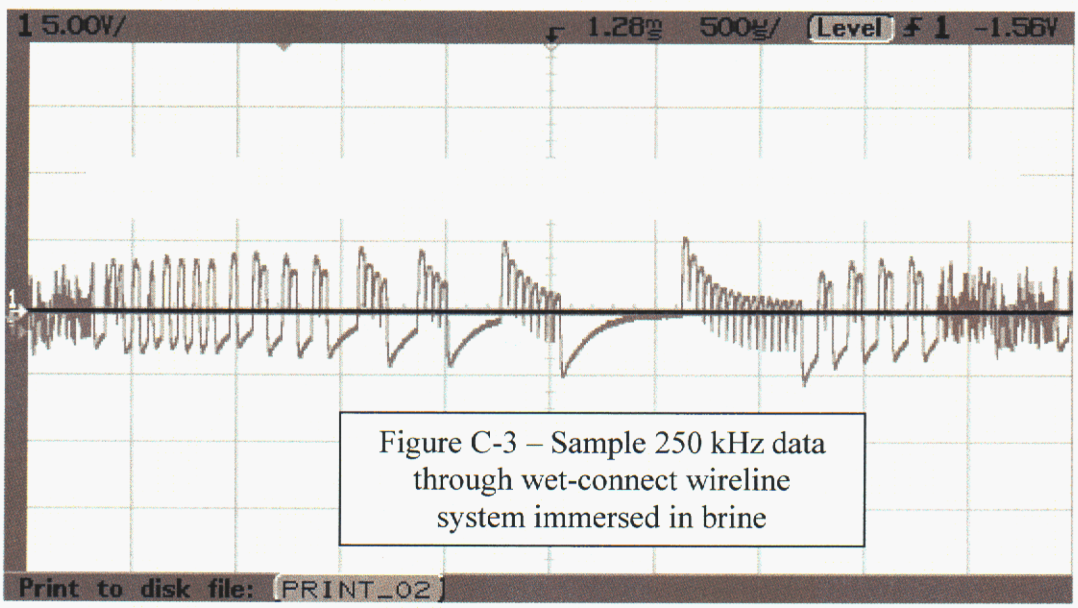

Figure C-3 – Sample 250 kHz data through wet-connect wireline system immersed in brine

After circulating a brine solution for the preliminary tests, the salt concentration was increased to a maximum fluid weight of 9.6 ppg, a very saturated brine solution, with the

HTSU set up to run all night. The next day the received signals still looked very similar to the original signals when starting transmission. We then began drill string rotation at approximately 5 rpm and made a number of reconnections in the wet connect system. Rotary speed was increased to 15 rpm and the telemetry system still performed as expected. Signals at this condition are shown in Figure C-4.

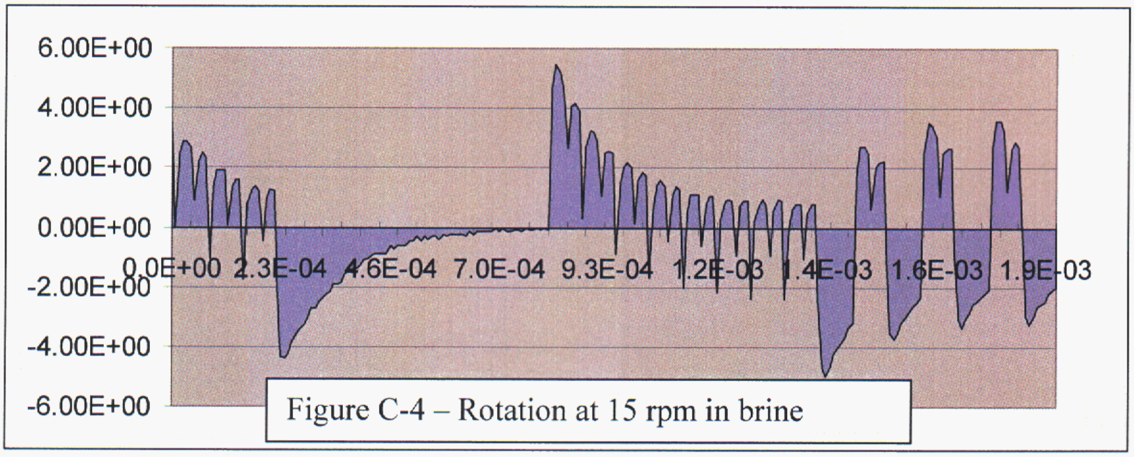

Figure C-4 – Rotation at 15 rpm in brine

Rotary speed was stepped to 30 rpm, 60 rpm, and 100 rpm. The signal was monitored at each rate, and at each rate the received signal was adequate.

Disconnecting the latched wet connect assembly required a "pull off" of 1900 lb on the wireline. The HTSU was tripped out of the hole and reconfigured for a transmission rate of 500 kHz. The transmitted signal, with drill pipe rotation at 15 rpm, is still very good quality and a sample is shown in Figure C-5 (compare with C-4, at half the data rate).

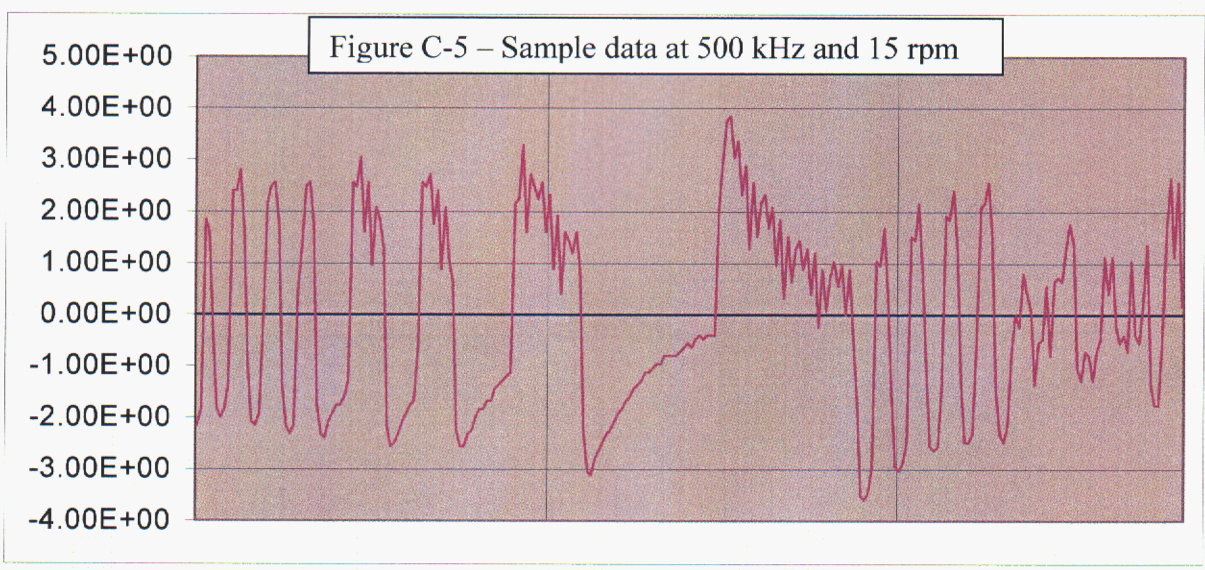

Figure C-5 – Sample data at 500 kHz and 15 rpm

Summary: The test was successful in showing that signals were not degraded or distorted by the wet-connect components, compared to an uninterrupted wireline of the same length.

With this same test configuration – the HTSU transmitting data and an oscilloscope to examine the received signal – simulations indicate that the data rate through this wireline could probably be extended to 500 kHz, or with a data rate of 125k-baud, the transmission length could be at least 7000 feet. These calculated values are contingent on the design of the surface demodulator, signal-to-noise ratio, and sensitivity.

In the data system used for the POC and CRADA tests, however, different downhole and surface electronics were used for the bi-phase encoded data stream, and transmission length with this system is probably limited to around 3000 feet. For this reason, the next-generation telemetry system will use frequency-based encoding (FSK = frequency shift key) that should extend line length capability to 15,000 feet; in simplest terms, the next system will be FM instead of AM.

Appendix D
Vibration and Laboratory Drilling Tests

I. Vibration Testing

This preliminary testing used Sandia's vibration facility to shake the measurement sub in three axes, at both random and steady-state conditions (Figure D-1). These tests had three principal objectives: to verify that the internal accelerometers in the sub accurately measure the input acceleration from the shaker table; to identify any sensitive or resonant frequencies in the sub; and, to dynamically exercise the tool as a low-level survival test simulating drilling conditions. Test parameters were: random vibration, swept from 10-500 Hz at 2 g rms (which gives 6 g peaks); and a 100 Hz sine wave dwell at up to 10 g for 5 minutes each axis. These relatively low acceleration levels were determined by the capacity of the vibration facility. Running the random sweep first identified resonant frequencies, and the dwell frequency was then chosen to be 100 Hz, which is between high amplifications at 55 and 125 Hz.

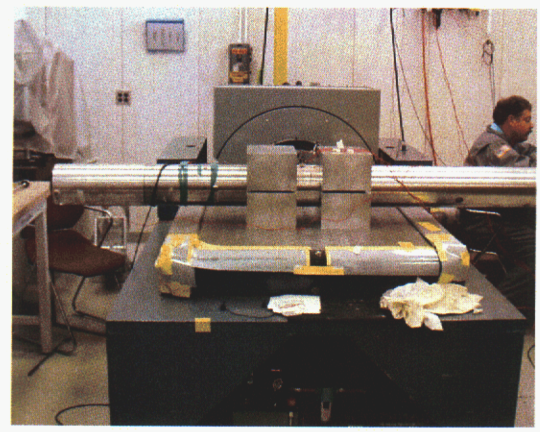

Figure D-1 – DWD measurement sub on vibration table

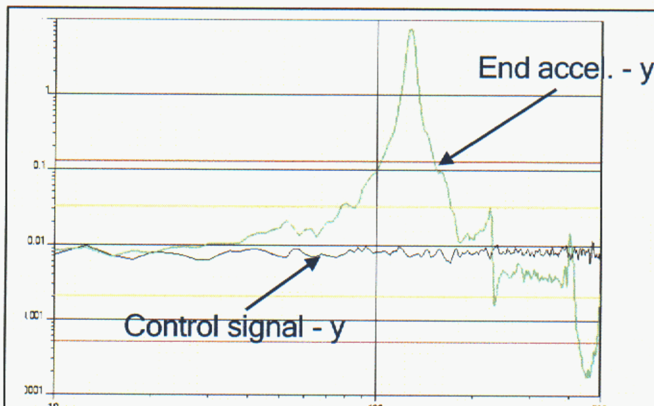

Figure D-2 – Amplification of control signal at end of measurement sub

Control accelerometers were mounted at the clamping blocks (Fig. D-1) and at the end of the tool to measure any amplification; not surprisingly, there was a pronounced difference in readings between these in several cases. It was also clear that, with this mounting configuration, excitation along one axis excited vibration in a transverse axis. For example, Figure D-2 shows the difference between the control signal and the acceleration at the end of the tool for transverse excitation (note that acceleration scale is logarithmic). Cross-excitation is shown in Figure D-3, in which the tool is being shaken along the "z" (longitudinal) axis but, probably because of a couple between the driven axis and the tool's center of mass, there is noticeable signal from the vertical accelerometer at the mounting block and even more from the accelerometer at the end of the sub.

Accelerometer outputs from the measurement sub correlated well with the input calibration levels, and long-duration (30 minutes/axis) random vibration did not produce any serious component failures. During discussion of vibration testing with the Technical Advisory Committee, there was some question as to whether the test levels were high enough to be realistic, and there was comment that other companies normally performed vibration tests at 30 g levels. Test levels at Sandia were limited by the shaker capacity, and data from earlier drilling at Catoosa indicated that 5-10 g acceleration levels were typical.

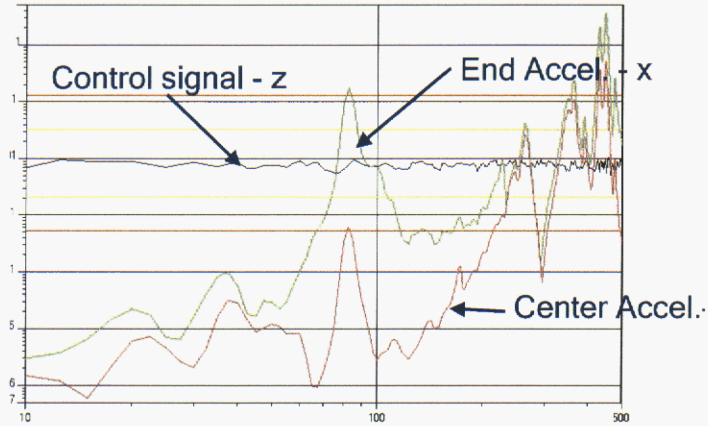

Figure D-3 – Comparison of accelerations in orthogonal axes (excitation is along "z" axis, response is on "x" axis)

II. Laboratory Drilling Tests

Testing at the ReedHycalog drilling laboratory in Houston provided a fairly realistic simulation of drilling with a "rig" (Figure D-4) that can rotate the DWD sub with a bit attached and can drill rock while circulating fluid. There were four principal objectives for the tests:

- Verify DWD measurements (rotation, etc.) not previously made
- Test ability to identify bit whirl or other dysfunctions using data display
- Check tool's operation in a semi-realistic environment
- Compare measurement sub values with laboratory drill rig values

Figure D-4 – Laboratory drill rig at Reed-Hycalog

These tests confirmed the functionality of all DWD transducers and provided comparison of torque, weight on bit, and rotary speed measurements between the laboratory instrumentation and that in the tool. We acquired baseline data with a roller-cone bit drilling in both sandstone and granite, and then drilled with different PDC bits in sandstone. Dynamic bit response ranged from very smooth and stable drilling to pronounced bit whirl, depending on the combination of bit and operating conditions. We also exercised the tool fairly vigorously, with WOB up to 50k lb in granite and rotary speeds up to 150 rpm in sandstone. The ability to examine the drilled rock after the test was also very revealing in correlating the smoothness of the borehole with data indications of bit whirl (Figure D-5).

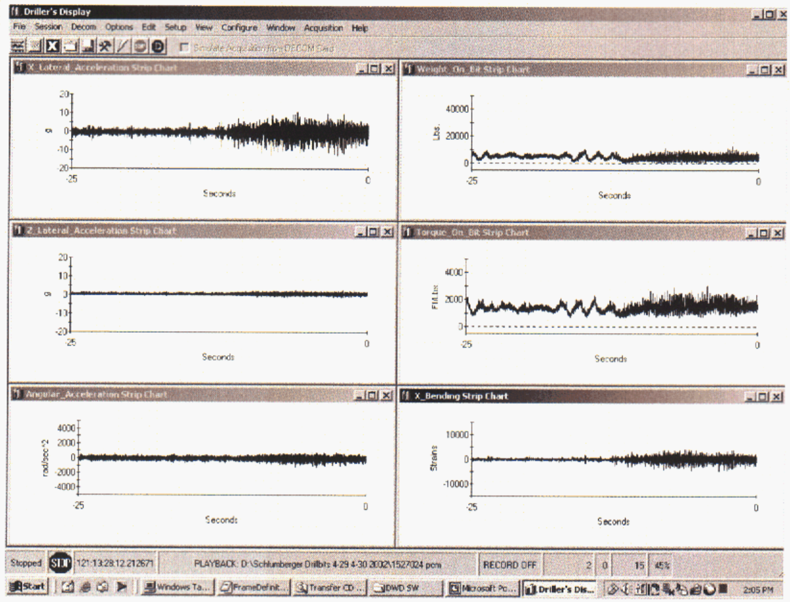

Figure D-6 – Data display showing inception of bit whirl

The basic surface display can be configured to show any combination of the measurements taken by the downhole sub, but some combinations are clearly more useful than others. To identify bit whirl, for example, an early version of the DWD display shown in Figure D-6 (containing x, z, and angular acceleration, as well as torque, WOB, and x-bending) combined the sort of measurements that would be expected to change significantly with bit whirl (in contrast to pressure, for example, which would not). Another promising diagnostic is cross-plotting either x- and y-bending or x- and y-acceleration as a vector sum; an example of bending before and during bit whirl is shown in Figure D-7.

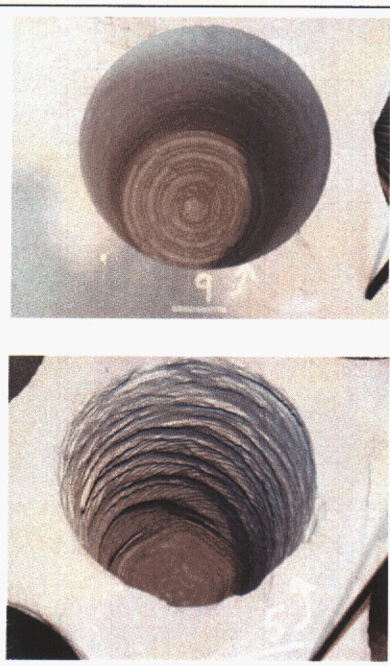

Figure D-5 – Holes produced by smooth drilling (above) and bit whirl (below)

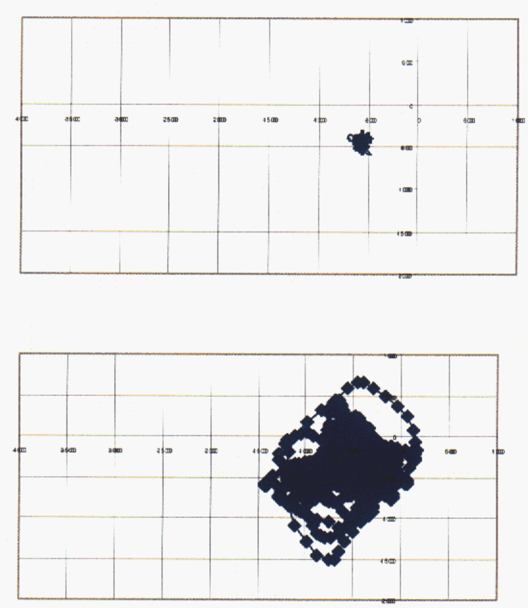

Figure D-7 – Cross-plot of bending before (above) and during (below) bit whirl

Appendix E
Bit Damage and Life Observations During POC Tests

(i) First hard-rock interval: ~1106 – 1320 ft

Phase 1: Only 3 cutters exhibited visible wear or damage. All three of these were on the bit face; one near the center and the remaining two near the periphery. Damage was most severe for the cutter nearest the center of the face; see Figure E-1. In this case, a fragment was missing that included a portion of the diamond table and the substrate, all the way back to the mounting stud. The second damaged cutter, which was set back just inside the periphery of the bit face, showed slight wear and minor chipping on the cutting edge. The third damaged cutter evidenced slight wear and no chipping.

Phase 2: Only one face cutter, which was near the bit periphery, showed damage; all remaining face and gage cutters had no measurable wear or damage. A portion of the diamond table and substrate were missing on the damaged cutter; see Figure E-2.

Figure E-1: Damage to centrally located face cutter on PD5 bit after drilling first hard-rock interval during Phase 1.

Figure E-2: Damage to peripheral face cutter on PD5 bit after drilling first hard-rock interval during Phase 2.

(ii) Second hard-rock interval: ~1320 – 1420 ft

Phase 1: This drilling interval encompassed the notably hard section of formation known as "The Wall." As seen in Figure E-3, seven face cutters incurred significant damage, and three face cutters developed slight wear. The remaining face and gage cutters showed no measurable damage or wear.

Phase 2: As seen in Figure E-4, eleven face cutters suffered significant fracture damage. No noteworthy cutter wear was observed. The gage cutters had no measurable wear or damage.

Figure E-3: PD5 bit condition after drilling second hard-rock interval, including "The Wall," during Phase 1.

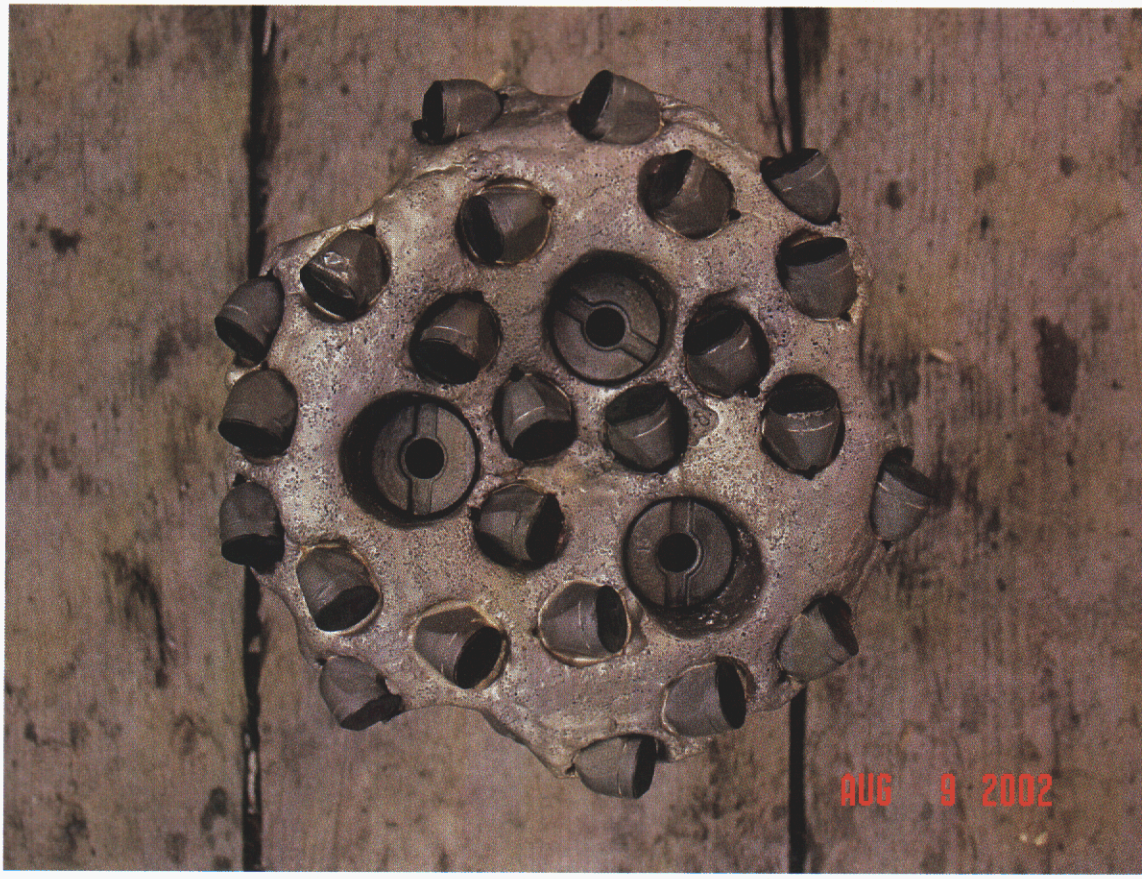

Figure E-4: PD5 bit condition after drilling second hard-rock interval, including “The Wall,” during Phase 2.

(iii) Third hard-rock interval: ~1420 – 1492 ft (Phase 1); ~1420 – 1542 ft (Phase 2)

Phase 1: This drilling interval was terminated when bit failure was suspected due to erratic drilling conditions and an inability to advance the hole despite a significant increase in WOB. Referring to Figure E-5, numerous cutters showed substantial fracture damage, as evidenced by missing portions of cutter diamond tables, substrates, and mounting studs.

Phase 2: The third drilling interval for Phase 2 ended at an indicated depth of 1542 ft when the bit was tripped out of the hole for inspection before re-entering the hole for the final day of DWD and PDC-bit testing. As seen in Figure E-6, fifteen face cutters showed substantial fracture damage with some wear, and three additional cutters evidenced measurable wear. Fracture damage to at least four of the cutters was major. Only very minor wear was sustained by the gage cutters.

Figure E-5: PD5 bit condition after termination of Phase 1 drilling at a depth of 1492 ft in the third hard-rock interval.

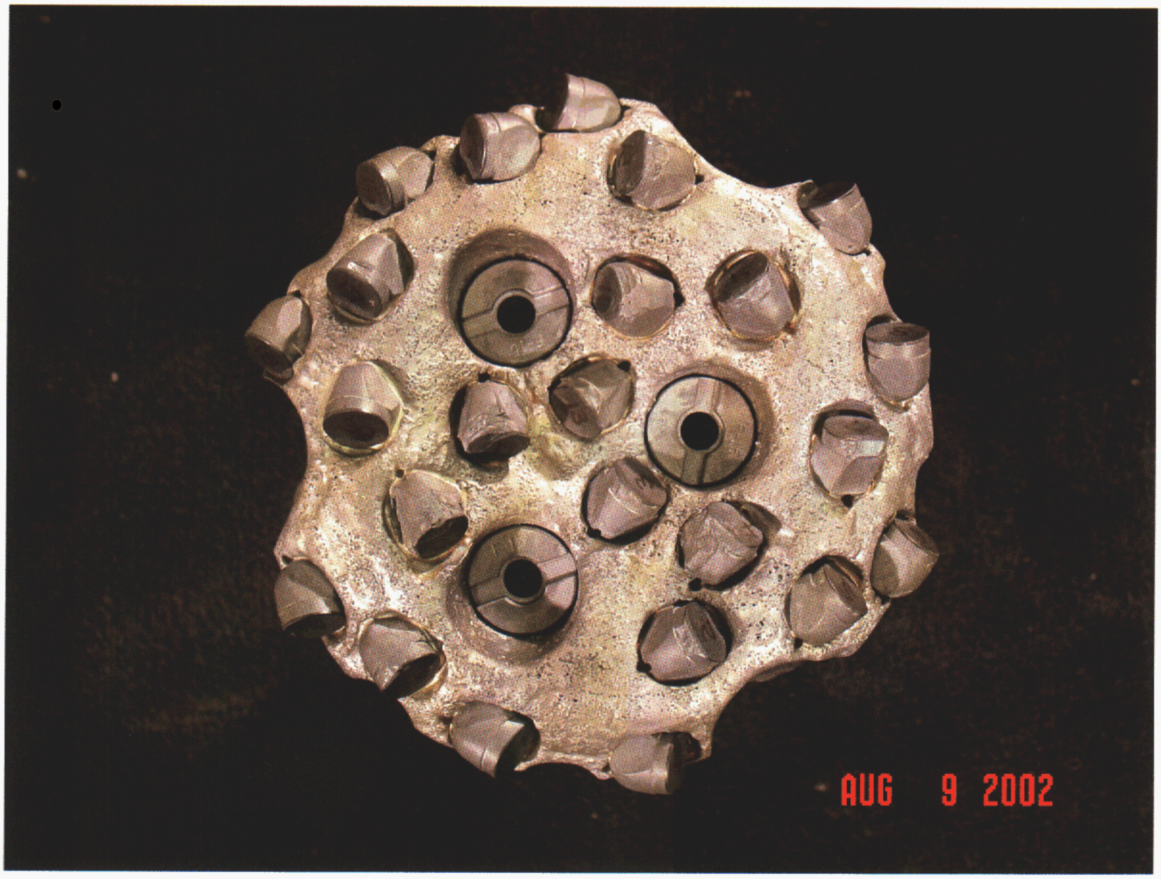

Figure E-6: PD5 bit condition after drilling third hard-rock interval, to 1542 ft, during Phase 2.

(iv) Fourth hard-rock interval: ~1542 – 1631 ft

Phase 2: The fourth, and final, drilling interval for the PD5 bit during Phase 2 ended at an indicated depth of 1631 ft when all available rig time was exhausted. At this point, the bit had passed through the extremely abrasive Misener sand formation, and numerous face cutters (~15) had developed substantial wearflats (see Figure E-7). One cutter near the center of the bit face had sheared off at the base of the support stud, and two other center cutters were very heavily damaged. As before, only minor wear was noted for the gage cutters. Despite the observed wear and impact damage, the PD5 bit was still maintaining an excellent ROP (about 70 ft/hr) when testing was terminated.

Figure E-7: PD5 bit condition after drilling fourth hard/abrasive interval, to 1631 ft, during Phase 2.

Appendix F
Development of DWD Concept–
Workshops on Advanced Drilling

At the request of the U.S. Department of Energy, Office of Geothermal Technologies, a group of sixteen experts was convened in Berkeley, California, on April 15-16, 1997, to discuss advanced geothermal drilling systems. The objective of the workshop was to develop one or more conceptual designs for an advanced geothermal drilling system that meets the following criteria:

1) The system would perform all the necessary functions for drilling a model geothermal well.
2) The system would reduce the cost or economic risk of drilling a geothermal well and/or improve the lifetime productivity of the well, thereby reducing well cost/unit heat.
3) The system would contain one or more key components that do not currently exist but might be developed with DOE funding.

During the workshop, the process of constructing a model geothermal well was divided into ten essential functions. The group reached consensus on conventional technology used for each function and problems commonly encountered in the function, and then identified and evaluated alternative methods of performing each function. Those methods considered feasible, or at least worth further investigation, were identified and methods considered impractical or not potentially cost-saving were eliminated from further discussion. In general, the recommendations were made with the agreement of all the workshop participants.

Several general or systems-level conclusions and recommendations were made:

1. *Any viable drill bit for cutting hard rock requires the use of mechanical cutters to cut a round hole and maintain gage.*
2. *More extensive use of software should be made in the geothermal drilling process.*
3. *The use of robotics in geothermal drilling should be undertaken where possible.*
4. *The use of very large upper-well sections with multiple lower legs (i.e., multi-lateral completions) should be considered as a way to reduce the number of times that upper-hole problems need to be addressed in a given field.*
5. *The industry needs to develop better ways to analyze and handle the risk of putting expensive tools downhole.*
6. *The industry needs to maintain awareness of technological advances in other fields (e.g., robotics, microelectronics, materials, and oil and gas drilling).*
7. *Institutional and logistical constraints should be addressed to reduce well costs.*

The ten essential functions are listed below, along with the alternative methods discussed and considered at least potentially feasible for each of them.

<u>Rock Reduction</u>

1. *Drag bits using synthetic diamond or other advanced materials*
2. *Low-pressure waterjet-enhanced drill bits*

3. *High-pressure waterjet-enhanced drill bits*
4. *Percussive hammer bits*
5. *Disk-cutter bits*
6. *Large-diameter wireline core bits*
7. *Casing-while-drilling with a retrievable motor and bit*
8. *Replaceable-cutter bits*
9. *Rock machining at ultra-high RPM*
10. *Hybrid rotary-coring*
11. *Hard-rock underreaming*

Downhole Energy Transfer

1. *High-temperature fluid motors*
2. *Coiled tubing*
3. *Downhole electric motors*
4. *Composite drill pipe or tubing*
5. *Insulated drill pipe*
6. *Aluminum drill pipe*
7. *Downhole pressure intensifier for high-pressure waterjet drilling*
8. *Percussive mud hammer*
9. *Compact rigs and automated pipe handling*
10. *High-temperature pipe recovery tools*
11. *Diesel exhaust scrubbing for use as a non-corrosive drilling fluid*

Rock Removal

1. *High-temperature drilling fluids, including temperature-stable drilling foams*
2. *Large-diameter wireline coring*

Borehole Stabilization and Fluid Containment

1. *Advanced wellbore-lining techniques for achieving mechanical integrity and outflow sealing*
2. *Open-hole packers for improved lost-circulation cementing efficiency*
3. *Alternative cements for lost circulation control*
4. *Polymer foam for lost circulation control*
5. *Removable production-zone plugs*
6. *Improved underbalanced drilling techniques*
7. *Lightweight drilling muds*

Control of Formation Pore Fluids

1. *Advanced wellbore lining techniques for achieving inflow sealing*
2. *Improved underbalanced drilling techniques*
3. *Removable production-zone plugs*

Permanent Borehole Preservation

1. *Advanced wellbore lining techniques for permanent borehole preservation*
2. *Cement-lined casing*
3. *Alternative casing materials*

4. *Casing-while-drilling*
5. *Improved methods of emplacing production liners*
6. *Latex and other advanced cements for corrosive environments*
7. *Robotics system for running hot liners*

Sensing, Communication, and Process Control

1. *Temperature-hardened logging tools*
2. *High-temperature MWD/LWD systems*
3. *Advanced rig instrumentation and software*
4. *Better target definition*

Directional Drilling and Control

1. *High-temperature downhole motors*
2. *High-temperature variable-angle bent sub*
3. *Directional thrusters/retractors/directors*
4. *Steerable percussion hammer*

Production Stimulation

1. *Wellbore designs that maximize flow from the reservoir*
2. *Advanced fracture stimulation methods*
3. *High-temperature downhole motors for multi-leg completions*
4. *Hard-rock underreaming*
5. *High-temperature perforators*
6. *Thermal-shock fracturing with cold water*

Well Maintenance and Workover

1. *Ultrasonic scale removal*
2. *Electromagnetic scale control/removal*
3. *Tornado frac to rubblize scale*
4. *Chemical additives to reduce silica scale*

Given the ten essential drilling functions, and feasible alternatives for them, compiled in the Berkeley workshop, the Geothermal Research Department still faced the critical task of identifying a key technology that would pull together and improve all these functions in a revolutionary drilling system. The Sandia Workshop was convened to address this question.

Emphasis on a systems approach differed from almost all previous work on advanced drilling, because that work focused on the rock reduction process, i.e., the drill bit. Although efficient rock reduction remains an important element of improved drilling, effective drilling also requires that the other nine functions of the drilling process operate optimally. Even the best drill bit will not significantly reduce overall well costs if it is not compatible with or does not enhance the operation of the complete drilling system. An essential element of the program, then, was the choice of an enabling technology that would link all ten of the drilling functions and improve all parts of the drilling process. After considerable discussion, a consensus emerged that the single greatest deficit in most of the drilling functions was the lack of real-time knowledge and control of what was actually happening down in the hole. By gaining this critical feedback capability, all functions can be optimized for highest efficiency and lowest cost, creating the greatest probability for significantly reducing geothermal well costs. Existence of this capability will also serve as a catalyst for the development of other tools that will take advantage of the real-time data and control.

The Diagnostics-While-Drilling system is based on "Sensing, Communication, and Control", one of the ten essential functions, and is identified as the enabling technology that will facilitate the development and use of other downhole and surface tools, including improved drill bits, to greatly enhance drilling performance. Advancements in no other technology area would provide such a system-wide benefit. The Sandia workshop also identified the high-speed data link, the drilling advisory software, and surface-controllable downhole tools as the key components that must be developed to make the DWD system a reality.

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