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The Downhole Replaceable Drill Bit -- Progress Report and Program Plan

M. Max Newsom, Jack A. St. Clair, Richard F. Ashmore, Henry M. Dodd, Jr.

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SAND76-0227
Unlimited Release
Printed June 1976

THE DOWNHOLE REPLACEABLE DRILL BIT --
PROGRESS REPORT AND PROGRAM PLAN

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ABSTRACT

The significant progress in the development of the downhole replaceable drill bit which had been completed by the end of January 1976 is reviewed. A long-range program plan is included to indicate the level of effort required to bring this system to commercial production.

Printed in the United States of America

Available from
National Technical Information Service
U. S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161
Price: Printed Copy \$5.50, Microfiche \$2.25

4.28

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ACKNOWLEDGMENT

This work was sponsored by the Division of Geothermal Energy, ERDA. Mr. Morris Skalka of that organization is project manager.

Highlights

The feasibility of the downhole replaceable bit (DHRB) and the economic viability of this concept have been extensively investigated during this period. A full-scale working model of the downhole magazine, fluidic sensing system, and cutting surface cycling mechanism has been completed. Two fixed-head cutting surface prototypes, based on roller cone technology, have been developed and tested by the Reed Tool Company, Houston, Texas. The results of this test series indicated the following:

- The size of the roller cone cutters and journal bearings must be reduced by about a factor of two over a tricone bit to fit the space and form allowed in the DHRB.
- The penetration rate of this prototype was comparable to that of a conventional mill-tooth roller cone bit until structural failure of the prototype occurred (40,000 pounds total load).
- Since penetration rate is a linear function of bit load, the penetration rate of the DHRB prototypes was not competitive with a standard tricone bit and therefore the drilling economics were not favorable.

Models have been developed that will allow drilling-cost comparisons on competitive drilling systems. The results of these studies, coupled with the test results at Reed, have led to a series of redesigns to investigate new, high-penetration-rate cutter systems in the DHRB configuration. These designs utilize the G. E. "Compax" diamond cutter, either with or without roller cones. Conceptually, these designs should offer higher penetration rates, simplified cycling mechanism designs, and significantly reduced drilling costs. If this program is continued, the next phase will be to build and test prototypes of these cutters to verify the expected performance in the laboratory. If the results are favorable, field test prototypes could be quickly constructed for field demonstration tests. Limited funding in FY 76 stopped this effort on March 1. With constant-level funding for Sandia drilling technology programs as now projected by ERDA/DGE, this program will be cancelled. If additional funding can be provided in FY 77, this program can be rapidly moved to the field demonstration phase.

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THE DOWNHOLE REPLACEABLE DRILL BIT -- PROGRESS REPORT AND PROGRAM PLAN

Introduction

This report reviews the significant progress and associated developments which were completed in the downhole replaceable bit (DHRB) program to the end of January 1976. A program plan is also included to indicate the level of effort and time that will be required to advance this concept to the point of transferring the technology to private industry for commercial production.

The future exploration and development of the geothermal resources of the United States will require a high level of drilling activity. Much of this drilling will be through formations as difficult as extremely hard igneous and metamorphic formations and some holes will be drilled to great depths. Current drilling technology has been developed for the softer oil- and gas-bearing sedimentary formations. Even drilling in these is expensive (see Figure 1) and increases almost exponentially with depth. Since the difficulty of drilling increases with rock strength, as shown in Figure 2, drilling for geothermal reserves will be much more costly than for hydrocarbon reserves. Costs per foot for current geothermal development drilling is averaging a factor of 2 to 4 higher than petroleum drilling, while hard-rock drilling is often a factor of 15 or more higher.

Figure 1. Average U. S. Petroleum Well Costs

LABORATORY DATA - ATMOSPHERIC PRESSURE

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Figure 2. Effect of Bit Loading on Penetration Rate

Rotary drilling, the technique most commonly used today, has been continuously improved since it was first developed at the turn of the century. While great strides have been made in rig power, depth capability, bit life and penetration rate, this work has been centered on recovery of oil and gas reserves. Comparatively little attention has been directed to the harder, hotter crystalline formations. To assure that future geothermal energy reserves can be economically exploited, new and more economical methods of drilling holes into harder formations must be found. This goal is the basic thrust of the program described in this report.

System Description

"Tripping" of the drill pipe (to the surface) to replace worn or broken drill bits is one of the major cost items in rotary drilling. In a recent review of the drilling costs for 21 wells drilled in various parts of the country,¹ the percentage of the total time devoted to trips ranged from 3.8 to 31.5 percent with an average value of 15.8 percent. Since time is money in a drilling operation, there has been a continuous effort in the drilling industry to reduce trip time. One approach to this problem is to replace the bit without making a trip, but past efforts along this line have generally required oversize drill pipe and have not proven to be economical for a variety of reasons. The downhole replaceable bit (DHRB) addresses this problem by storing a number of cutting element assemblies in the bit with the necessary mechanism to cycle a new cutter into place as the old one wears out. It is not necessary to trip the system until the entire magazine of cutting heads has been expended. This bit is designed to be compatible with existing rotary drilling rigs without modification to the rig equipment or drill pipe. This concept would not only lower the cost of drilling the hole, but would enhance the safety of the drilling operation.

The drill bit consists of four major parts (Figure 3):

- The Torque Tube. Transmits the drilling weight and torque to the cutter head, forms the external surface of the drill bit, and has the connection for attaching the drill bit to the drill string.
- The Yoke. Forms the supporting structure for the drill bit, contains the cam path which guides the cutter heads from the new bit storage area into the cutting position and back into the used bit storage area; also contains the drilling fluid passages and houses the drilling fluid pulse-counting mechanism.
- Pulse Counting Mechanism. This device monitors the flow of the drilling fluid and counts the number of times the drilling fluid flow is stopped and started. When the proper number of pulses are recorded, the device unlocks the yoke from the torque tube allowing the cutter heads to be cycled.
- Cutter Heads. The rock-cutting mechanism which includes the cones, bearings, compax, supporting structure, and the cam follower which guides the cutter heads in the cam path.

The system is designed to work as follows:

A cutter head is in the drilling position on the lower end of the drill bit and drills the rock in the conventional manner with torque and pressure applied by the drill stem. When the cutter head dulls and the head is to be exchanged for a new cutter head, the drill stem is lifted a minimum of 10 feet off the bottom of the hole and rotation is stopped. The drilling fluid flow is then stopped and started three times. The pulse (Flow Sensor) counter counts the fluid flow starts and stops and on the third cycle releases the locks which lock the yoke to the torque tube. When the fluid flow is again started, the drilling fluid forces the yoke out from the torque tube.

Figure 3. Downhole Replaceable Bit

As the yoke is forced outward, locks which retain the cutter in the drilling position are released. Further motion of the yoke engages an indexing hook with an indexing bar in the chain which links the cutter heads together. Since the indexing hook is attached to the torque tube, the cutter heads move relative to the yoke, causing the cutter head in the drilling position to follow the cam path into the used cutter head storage area. A new cutter head follows the used cutter head as the chain moves into the drilling position. At this point, a valve is opened releasing the pressure of the drilling fluid on the yoke and a stop positively locates the cutter head in the drilling position.

The drilling fluid flow is then stopped and the drill stem lowered to the hole bottom. This forces the yoke back into the torque tube and resets the entire mechanism. Fluid flow is resumed, rotation of the drill pipe started, weight applied to the cutter head and drilling is resumed.

A maximum of twelve cutter heads can be stored in the drill bit. Savings in the cost of drilling the well depend on life and penetration rate of the individual cutter heads plus the saving in trip time, which for deep holes is significant.

A full-scale model was fabricated (Figure 4) which demonstrates the feasibility of the downhole cutter head changing mechanism. Some significant changes were made to the design as a result of the model fabrication. The resulting design was thought to be sufficiently complete so that the total effort would be directed to development of a cutter head for the device. When an adequate cutter head is developed, effort will then be expended to complete the design of the changing mechanism.

Figure 4. Downhole Replaceable Bit Model

Objectives, Impact, and Program Strategy

Objectives

The primary objective of the downhole replaceable drill bit program is to reduce the footage costs of hard-rock drilling by increasing the net downhole life of the bit system, thereby reducing the number of trips required. A second objective that must be met is to maintain or increase the instantaneous penetration rate compared to conventional bits. Both of these factors are significant contributors to overall drilling time, and therefore costs. In addition, a design is envisioned that can provide these improvements over a wide range of borehole diameters. A basic assumption in this program is that the replaceable bit must be directly compatible with existing rotary drilling rigs, drill pipe, drill collars, and liquid circulation systems. Power is delivered to the rock face by a combination of static loading and rotation of the bit. The drilling fluid pressure is used to cycle the replaceable cutter head when needed.

The minimum drilling rate and life performance that must be met by a downhole changeable bit to be economically competitive with a conventional tricone bit can be approximated by a parametric investigation of the drilling cost equation. The conventional footage cost equation is generally presented as

$$F_c = \frac{C[L_c + T] + B_c}{R_c L_c}, \text{ or} \quad (1)$$

$$= \frac{C}{R_c} + \frac{nT + nB_c}{t}, \quad (2)$$

where subscript c denotes conventional bit, and

F = cost/foot

C = rig rate

R = penetration rate

L = bit life in hours

t = interval thickness

n = number of bits required to drill t feet

T = average trip time over interval t

B = cost per bit.

From cost and drilling performance data acquired on a given well drilled conventionally, a comparative study can be made that will establish the minimum performance standards that a changeable bit must meet to be economically competitive. Further, the sensitivity of these minimum standards to the many drilling cost variables can be studied. The economic break-even drilling rate for the replaceable bit (R_r) compared to the conventional bit can be expressed by (see Eq. (14) in a later section):

$$R_r = \frac{1}{L_r F_c} \left[C(L_r + T/m) + B_r \right] , \quad (3)$$

where subscript r denotes replaceable bit, and m equal the number of changeable cutting surfaces required to drill the interval t.

Three examples have been developed and are shown in Figures 5, 6, and 7. The following assumptions were made in these examples for conventional rotary drilling:

- The interval to be drilled is between 10,000 and 20,000 feet.
- The formation hardness of the three examples is assumed to be one each medium, medium-hard, and hard.
- The number of conventional bits (n) required to drill this interval (t) is

$$n = \frac{t}{R_c L_c} , \quad (4)$$

where R equal the penetration rate (feet/hour) and L equal bit life (hours).

<u>Formation</u>	<u>R</u> <u>(ft/hr)</u>	<u>L</u> <u>(hr)</u>	<u>n</u>
Medium	10	120	8.33
Medium-Hard	6	80	20.83
Hard	2	30	166.7

- Bit cost (conventional) = \$2010 = B.
- Trip time average = 12 hours = T.

The assumptions for the changeable bit include:

- Cost per cutting surface = \$1770.
- Number of changeable bits in the magazine = 12.

The following trends can be seen in Figures 5, 6, and 7: To be economically competitive under the assumptions that were made, the drilling performance of the changeable bit must lie to the right and above the curves for a constant rig cost. It can be seen that very little penetration rate can be sacrificed for increased downhole life. For example, in the medium-hard formation with a penetration rate of 6 ft/hr conventionally and a rig rate of \$200/hour, break-even life performance for the changeable bit at the same penetration rate is 46 percent. If downhole life is increased to 70 percent, the bit must drill at a rate of 5.6 ft/hr to break even. If, on the other hand, rate can be increased to 8 ft/hr, life can be reduced to 18 percent of the conventional bit for economic break-even.

Figure 5. Break-Even Drilling Rate, Medium Formation

Figure 6. Break-Even Drilling Rate, Medium Hard Formation

Figure 7. Break-Even Drilling Rate, Hard Formation

The sensitivity of bit cost to rate is shown in Figure 8 which plots break-even drilling rate vs bit costs and rig rate in the medium-hard formation. These curves assume a 30 percent life ratio for the changeable bit cutting surface. It can be seen that drilling economics are a weak function of bit costs if rate can be maintained or improved. For a \$800/hr rig and a 6-ft/hr penetration rate, the changeable bit could cost \$2400 per cutting surface for a total bit cost of \$28,800 to break even.

The broad goals of this development program, as well as the criteria to measure bit performance, can be developed from this type of analysis. It is clear that the DHRB must maintain an instantaneous penetration rate that is equal to the rate of a tricone bit. The life, per cutting surface, can be traded off to maintain or improve rate which implies that each element can be worked harder, sacrificing life over some limits to improve rate.

Figure 8. Break-Even Drilling Rate vs Bit Costs, Medium-Hard Formation

Impact

The impact that a high-performance bit can have on reducing geothermal drilling costs may perhaps best be visualized by a hypothetical example. The following assumptions are not based upon any experimental data nor are they supposed to represent a particular DHRB design. Rather, they illustrate the potential cost savings if a DHRB can achieve a significant drilling rate increase at the expense of individual bit life, then recover the lost bit life by having multiple bits downhole.

- A deep well is to be drilled into hard, dense basement rock. Final depth is to be 12,000 feet. The first 2000 feet are through sedimentary formations and will be drilled conventionally.
- A comparison will be made of the costs for drilling the last 10,000 feet conventionally and with a high-performance bit. It is assumed that mud, casing, cement, logging, and other incidental costs are constant for both drilling techniques.
- Drilling costs are determined from the equations on drilling economics presented in a later section of this report.
- Twelve changes of cutting surface are provided by the DHRB and the life of each cutting surface is 30 percent of the life of a conventional bit.

The following parameters are also assumed:

	<u>Conventional Bit</u>	<u>DHRB</u>
Penetration Rate, R (feet/hour)	6	10
Bit Life, L (hours)	33.3	(10)(12) = 120
Depth Per Bit, D (feet)	200	100(12) = 1200
Number of Trips, n	50	9
Rig Rate, C (\$/hour)	400	400
Cost Per Bit, B (\$)	2,000	(12)(2000) = 24,000
Interval to be Drilled, t (feet)	10,000	10,000
Average Round Trip Rate, ν (hour/ft)	.001	.001

The footage costs, F_c , for drilling this interval conventionally, from Eq. (9), Page 31, are

$$F_c = \$90.69 \text{ or } \$906,900 \text{ total for the interval.}$$

The costs, F_r , for drilling this interval with the higher performance DHRB, from Eq. (11), are

$$F_r = \$62.33 \text{ or } \$623,300 \text{ total for the interval.}$$

This represents a net saving in excess of \$280,000 on one hole. The footage cost is reduced by 31 percent. If 20 development wells are drilled in the assumed reservoir, it represents a savings of \$5,672,000. Another important factor is the amount of time saved. In this example, drilling time was cut from 84 to 44 days. Since rigs are in short supply, this time savings can be very important to timely reservoir development. The major impact of this program will be in reduced drilling costs and time which will have a significant impact on the overall costs of both geothermal exploration and development.

Strategy

Assuming technical success in this program, it is our opinion that the easiest way to assure timely commercial takeover of the DHRB is to involve the appropriate industrial companies from the outset. This must be supplemented by a continuing effort to keep potential suppliers and users informed of both progress and setbacks as they occur.

We feel very strongly that combining the technology of a national laboratory with the practical experience and industrial base of private industry will allow rapid progress to be made in programs of this type at minimum costs. Companies that have been active participants in the DHRB program include Reed Tool Company, General Electric Company, Reed/Terra-Tek Drilling Research Lab, and Maurer Engineering. In addition, the results of this work are being broadly disseminated by our participation in national conferences and technical meetings, and by journal articles, press releases, and countless briefings to visitors to the Laboratories from all segments of industry and government. This approach seems to be working very well and, if the technical program succeeds, the appropriate industrial firms will have the necessary information and background experience to proceed in short order with commercial applications of this concept.

Laboratory Drilling Tests

Concurrently with the development of the downhole changing mechanism, negotiations were being conducted with the Reed Tool Company for development of a cutter head for this device. Participation by Reed in this effort was highly desired so that their tricone technology could be applied directly to this design. These negotiations resulted in a mutually funded contract to develop a cutter head, based on roller cone technology, which could be adapted to the space and form available in the DHRB.

The Reed Tool Company's design of the cutter head incorporated three cones, two to cut the hole gage and one to remove the rock from the center of the bore (Figure 9). Because of space limitations, the gage cones were about 1/2 the diameter of the cones in a regular tricone drill bit with the bearing journals in the same proportion (Figure 10).

Figure 9. Prototype DHRB Cutter Head

Figure 10. Experimental DHRB Bit Beside Standard Tricone Bit

The center cutter was not a true cone but a tapered cylinder with a doubly supported journal. This arrangement makes possible the carrying of a heavy load in the center, but increases the drag of the cutter. Reed used production tricone materials, design concepts, and expertise wherever possible in the design and fabrication of two cutter heads.

The two experimental cutter heads were tested on Reed's drilling simulator. To permit a direct comparison to the performance of tricone drill bits, two control drill bits were run as part of the evaluation:

Reed Y-21G - Milled tooth rock bit

Expected Life:

Danbe Marble - 250 feet

Texas Pink Granite - 60 feet

Reed Y-34 - Milled tooth rock bit

Expected Life:

Danbe Marble - 300 feet

Texas Pink Granite - 125 feet

The test parameters and results are summarized in Table I and shown graphically in Figures 11 and 12.

TABLE I
Test Parameters and Results of Reed Prototype Tests

Rock-Danbe Marble (5000 psi compressive strength)
60 rpm, Bit dia. = 7-7/8 in.

Bit Type	Weight (lb)	Penetration (in./rev)	Rate (ft/hr)	Depth (in.)	Remarks
Sandia No. 1	5,000	.033	9.9	1.2	At 40,000 pounds the gage journals broke, no wear on teeth
	10,000	.082	24.6	2.0	
	20,000	.139	41.7	3.6	
	30,000	.189	56.7	11.2	
	40,000	-	-	18.0	
Reed Y-21G	5,000	.025	7.5	.5	No wear on bit
	10,000	.077	23.1	1.7	
	20,000	.144	43.2	2.8	
	30,000	.204	61.2	5.2	
Texas Pink Granite (23,000 psi compressive strength), all other parameters the same.					
Sandia No. 2	5,000	.007	2.1	.7	Center cutter cored out, gage cutters 1/8 worn, bearings good.
	10,000	.018	5.4	.9	
	15,000	.032	9.6	1.5	
	15,000	.022	6.6	7.8	
				10.9	
Reed Y-31G	5,000	.007	2.1	2.0	Teeth 1/4 to 1/2 worn, bearings good--projected life is 18 to 24 feet in the rock vs expected life of 60 feet.
	10,000	.019	5.7	1.2	
	15,000	.031	9.3	1.6	
	20,000	.046	13.8	2.3	
	30,000	.078	23.4	4.4	
	30,000	.081	18.3	14.8	
	40,000	.084	25.2	23.7	
	50,000	.127	38.1	25.4	
				75.4	
Reed Y-34	10,000	.017	5.1	1.4	Teeth 1/4 worn, bearings good-- projected life is 28 to 30 feet vs expected life of 125 feet. The tooth wear is noticeable in the reduction of drill- ing rate on reruns of drilling pressure.
	20,000	.026	7.8	1.5	
	30,000	.046	13.8	2.4	
	40,000	.074	22.2	3.0	
	50,000	.105	31.5	4.2	
	60,000	.133	39.9	4.0	
	30,000	.044	13.2	7.4	
	40,000	.061	18.3	24.3	
	50,000	.081	24.3	20.0	
	60,000	.101	30.3	21.6	
				89.8

Figure 11. Downhole Changeable Bit Drilling Rate -- Danbe Marble

Figure 12. Penetration Rate Tests on Texas Pink Granite (22,600 psi compressive strength) Bit Speed - 60 rpm

Test Results

As can be seen in Table I, the projected life of the control bits in the Texas Pink Granite is considerably less than expected. This could be caused by harder than usual rock samples or by variations in drilling parameters but it does show the value of running control bits in testing of this type to provide direct comparisons rather than comparing expected performance.

Sandia Bit No. 1 drilled comparatively well in the Danbe Marble to bit loads of 40,000 pounds. At this load the journals failed and testing was discontinued. The failure of the bit (Figure 13) was due to insufficient journal strength in the gage cutters. Posttest calculations indicated that these journals had about 20 percent of the strength of a standard tricone journal. The data show, however, that if the journal strength could be increased, the bit would equal the penetration rate of a regular tricone drill bit. It must be recognized, however, that if the tooth depth were decreased to increase journal size, the teeth would bottom out and penetration rate would become constant at a rate less than a tricone.

Figure 13. Prototype DHRB No. 1 After Test

Sandia Bit No. 2 (Figure 14) failed early in the Texas Pink Granite test because of excessive drag in the center cutter. This resulted in rapid wear of the cutting structure. A failure of this type is more pronounced in the harder rock.

Figure 14. Prototype DHRB No. 2 After Test

Test Conclusions

The results of these tests and posttests analyses conducted at Sandia indicate that a DHRB using roller cone technology would not be economically competitive with the conventional tricone bits. This is primarily because of the strength limitations of the smaller journals which limit applied bit load and penetration rate. It is our opinion that, if this design is to be successful, a cutting surface must be found that will equal the penetration rate of the standard bit.

Hybrid Bit Design

After the tests of the prototype series, design effort was begun at Sandia to determine if the causes of failure could be overcome. After some study it was found that the optimum use of cones, with an acceptable amount of drag for cutting the rock, would result in a cutter head which would have 40 to 50 percent of the strength of a standard tricone bit. This means the penetration rate would also be about 40 to 50 percent of a heavily loaded tricone, as penetration rate is roughly a linear function of bit weight. Investigation then turned toward what alternative type of cutting mechanism might meet the requirements of high penetration rate and adequate life. These searches indicated that a hybrid design using roller cones in conjunction with the new G. E. man-made diamond "Compax" cutters might be one possibility. Another possible variation of interest would be an all "Compax" cutter head.

The "Compax" cutter (Figure 15) is a disk of tungsten carbide faced with man-made industrial diamonds, then brazed to a stud of tungsten carbide. G. E. has been evaluating the Compax as a rock-cutting tool and has an ongoing program to evaluate the Compax in a rock drill.

Figure 15. General Electric "Compax" Cutter Element

While spectacular results have sometimes been observed, G. E. has experienced several problems in tests of this unit. One of the basic problems has been the braze joint between the Compax cutter and the supporting stud. The Compax diamond cutting surface is destroyed when exposed to temperatures in excess of 650°C. This requires the use of a low-temperature braze which results in low bond strength. Sandia's metallurgical department, in conjunction with the process development shops and G. E. Carboloy, is investigating ways to improve the strength of

this braze joint. Initial results indicate it may be possible to bond the junction by diffusion bonding using nickel in lieu of the brazing material, to greatly improve strength of the junction. This effort is continuing and will be reported separately.

Another problem encountered by G. E. in the use of Compax is the breakage of the cutters and supporting studs in the drilling environment. We feel that this problem could be minimized if the cutting load per Compax was uniform and each one removed a limited or controlled maximum amount of rock per revolution. This amount is thought to be 0.3 cubic inches for a 0.33 inch diameter and 0.5 for a 0.52 inch Compax (the only two sizes of circular discs they make). Another problem is the need to prevent excessive penetration of the Compax during fluctuations in the bit loads and formation hardness in the drilling operation.

The uniform load can be achieved by careful layout of the cutter head. The excessive penetration can be eliminated by incorporating penetration limiters in the design of the cutter head. The penetration limiters could be modified cones or thrust pads on the drill face.

The use of cone cutters as the penetration limiter is very attractive and they can be used to remove rock and also (due to penetration of the teeth) give an increasing amount of resistance as bit load and depth of penetration increases. The problem again, though, is the journal strength of the cones. A hybrid design was developed which used cones to cut the hole gage and Compax to remove the center rock (Figure 16). This design was analyzed and was determined to be capable of carrying 94 percent of the linear load of a tricone in bending. It was capable of carrying 61 percent of the tricone load in shear. This should be acceptable as the shear loads are not thought to be high.

Based on this design, a request for information was sent to both Reed Tool Company and Smith Tool to determine their interest in participating in the joint design of a prototype bit. Both companies expressed interest in developing the cone cutters and indicated they might be interested in a mutually funded development contract. They did object to the patent and background patent clauses in our standard contract format. The Sandia Purchasing organization is working with both suppliers to determine if a mutually agreeable solution to this problem can be reached.

While these negotiations are continuing, the design analysis has continued. The gage roller cones of the hybrid are estimated to have 1/4 the life of the Compax cutters. To provide a balanced system, the cutter head has been designed so that the cone assemblies could be replaced when the drill bit was withdrawn from the hole. The total life of a cutter with three rebuilds is estimated to be 1.33 times the life of a tricone drill bit at the same penetration rate. The maximum number of cutter heads which can be stored in the DHRB body is twelve. At the estimated life of a cutter head (1/3 that of a tricone), three less trips would be required to drill an equal footage of hole. The projected costs of the hybrid DHRB were provided for the economic analysis discussed in the following section. In addition results using the economic analysis technique indicate that the cost savings accrued for the three trips would approximately offset the increased bit costs for the DHRB in 10,000 to 15,000 foot deep holes. In deeper holes the DHRB would become more attractive. For these reasons, the study of alternate design approaches is continuing.

Figure 16. Hybrid Bit Design No. 1

The predicted penetration rate of the Compax element is extremely attractive if breakage can be prevented. The predicted penetration rate is 1.5 to 2 times that of a tricone drill bit with less weight applied to the drill bit. This feature could result in less hole deviation during drilling, and the increase in drilling rate would greatly reduce drilling costs.

As a first approach, an all-Compax cutter head with passive pads to limit the penetration is being studied. This effort is in the initial stage and will be pursued as funds are available.

A second approach being investigated is another hybrid cone/Compax design (Figure 17). In this design cone cutters would be used to remove rock from the hole center and to prevent excessive penetration. Preliminary analysis indicates that this configuration will result in increased journal strength (greater than or equal to tricone journals), increased life of the cone cutters (less rock to remove), and increased journal life (slower cone rpm due to short radius).

Compax cutters would be used to cut the hole gage and remove approximately 80 percent of the rock from the hole. This configuration may also eliminate the need to fold the cutter head during the exchange cycle, greatly simplifying the mechanism. An additional advantage of this configuration is the possibility of using the larger 0.52 inch diameter Compax, which is considerably stronger in bending strength.

The combination of stronger journals, increased cutter life, use of 0.52-inch diameter Compax, and the elimination of the folding requirement not only could result in a simpler, stronger drill bit, but offers the promise of significant increases in both penetration rate and downhole life. As a result, effort on this design is being increased; and if future results continue to indicate improved performance, this design will be substituted for the gage cone design presently being discussed with both the Reed and Smith tool companies. Assuming that the results of ongoing analysis are favorable, the next step would be the fabrication and testing of prototype cutters.

Studying Drilling Economics

The fundamental purpose of all efforts to improve well-drilling bits must be to reduce the total cost associated with sinking a well. Included in the total cost and of importance here are expenses incurred while the bit is actually drilling and expenses incurred while "tripping" the bit for replacement. Thus, improvements in either of these areas have the potential to reduce total costs, provided the improvement in one area does not seriously degrade performance in the other. For example, increasing the lifetime of a bit may mean fewer trips for changing them; but if increased life is obtained at the expense of drilling rate, drilling costs may actually increase dramatically. Earlier studies² have demonstrated this when competitive bits are of the same single-bit type. However, certain new drilling concepts are not governed by the same cost equations, which means standard approaches for comparing footage costs³ may not be valid.

.4 in³ / rev. Max. vol. rock per compax
 .15 in max radial spacing
 5° compax rake angle
 3° compax cant angle

Figure 17. Center Cone/Compax Cutter Head (.330 dia. Compax)

The basic economic reason for any downhole replaceable bit is to reduce footage costs by decreasing or eliminating the need for multiple trips to the surface to change worn bits. An incidental advantage of this concept would be the reduced wear on drill pipe connections since fewer disconnects and hookups would be required. On the other hand, any drill bit that can change cutting heads without tripping must be mechanically more complex than its conventional counterpart and, therefore, probably more expensive as well. Also, if the drill bit is lost downhole, the larger size and weight of a replaceable system may make fishing more difficult and costly. While some of the above factors are of secondary importance and are not included in the subsequent economic analysis, all these factors and probably others as well must be considered before a new bit can be considered commercially competitive.

The DHRB system typically has 12 cutting heads which can be cycled downhole. It is in many ways similar to the conventional tricone bit having tungsten carbide insert teeth. All performance and cost comparisons for the DHRB system will be made with appropriate tricone bits designed for drilling in specified geological conditions, from medium to hard dense formations.

Governing Equations -- Consider a well-drilling operation with rig operating costs of C dollars per hour drilling at a depth D below the surface. A new geological formation of thickness, t, has just been encountered and a change in drill bit will be necessary. The problem, of course, is to choose the type of drilling bit that will minimize the cost per unit depth associated with drilling through this new formation. For a conventional single bit system the total time, A_c , spent drilling in the new stratum is

$$A_c = \frac{t}{R_c} + \sum_{i=1}^n \nu_i \left[D + (i-1) R_c L_c \right] \quad (5)$$

where

R_c = conventional bit drilling rate, ft/hr

n = number of round trips required (also number of conventional bits used)

ν_i = tripping rate, hr/ft, at depth $\left[D + (i-1) R_c L_c \right]$ (note this is a round-trip rate)

L_c = conventional bit life, hours.

The first term in the equation is the total time spent actually drilling while the second term is the time spent making n round trips, each trip starting at a depth $R_c L_c$ deeper than the previous trip.

However, the cost per foot to drill through the stratum must consider the bit costs as well as the time spent operating the rig; so the footage costs, F_c , can be found from the relation

$$F_c = \frac{CA_c + nB_c}{t} \quad (6)$$

where

C = rig costs, \$/Hr, and

B_c = conventional bit price, \$.

The above relation can be further simplified by making the following assumptions that are consistent with the conditions under which the conventional and replaceable bit systems are to be compared. First, the tripping rate ν is known to vary slowly and can be considered a constant in almost all situations. Next, if the summation term in A_c is expanded using the identity

$$\sum_{i=1}^n (i - 1) = \frac{n(n - 1)}{2}, \quad (7)$$

and n is assumed to be large, so that $n - 1 \approx n$,

A_c simplifies to

$$A_c = \frac{t}{R_c} + n\nu \left(D + \frac{1}{2} n R_c L_c \right). \quad (8)$$

Finally, noting that $n \approx \frac{t}{R_c L_c}$, the footage costs become

$$F_c = \frac{C \left[L_c + \nu \left(D + \frac{t}{2} \right) \right] + B_c}{R_c L_c}. \quad (9)$$

Note that the $(D + \frac{t}{2})$ term is simply the approximate average depth from which the n trips are made. Neglecting the $\frac{t}{2}$ term yields the standard equation for footage costs used in many previous studies, where νD is the round trip time (T in reference 2, t in reference 3).

Now if a drilling system exists whereby bits can be replaced rapidly downhole, the number of round trips should be drastically reduced. Assuming there are enough bits, m , to drill completely through the stratum of thickness, t , then only the initial installation trip requiring time νD is necessary. The total time spent drilling is then approximately (assuming $m \gg 1$)

$$A_r = \nu D + m(L_r + p), \quad (10)$$

where

L_r = replaceable bit life, hours,

p = time required to cycle to new bit,

and the footage costs analogous to Eq. (9) above are

$$F_r = \frac{C \left[L_r + p + \nu D/m \right] + B_r}{R_r L_r}. \quad (11)$$

Note that the rig costs C are assumed to be the same for either drilling system. Also the cycle time p is typically very small compared to $L_r + \nu D/m$ and can usually be neglected.

Equation (11) was derived under the assumption that a sufficient number of replaceable bits, m , is carried to drill through the stratum of thickness, t . If the replaceable system is designed for a maximum of M bits, then $m \leq M$ if Eq. (11) is to be considered valid. On the other hand, it is certainly possible that t is large enough or the stratum is hard enough so that $\frac{t}{R_r L_r} > M$ in

which case the above equation could not be applied directly. However, in this case t could be subdivided into a number of substrate, and Eq. (11) can be applied repetitively with $m = M$ (except for the last strata where $m < M$). Then an average footage cost, $\bar{F}_r$, can be found and compared with the conventional F_c found from Eq. (9).

Equations (9) and (11) form the basis for all subsequent cost analyses, and the potential advantage of a replaceable system is readily apparent in the second equation: namely, the m replaceable bits reduce the effective tripping time by a factor of m when compared to the conventional case. Whether or not this advantage will reduce overall footage costs depends upon what changes must occur in the other variables in order to achieve the replaceable capability; and that, of course, is the purpose of the economic portion of this report.

When comparisons are being made between hypothetical and existing systems, it is often desirable to know how changes in inputs influence the output (footage costs in this case), especially when there may be gross uncertainties in some of the inputs. A sensitivity analysis using variational calculus is one technique for quantifying the relative contributions of the input parameters. In this study we are concerned with ranking the relative contributions of the following: drilling rate, R ; bit life, L ; bit cost, B ; rig costs, C ; drilling depth, D ; stratum thickness, t ; and replaceable bit cycle time, p , and number of bits, m . By taking the various partial derivatives of F_c and F_r in Eqs. (9) and (11), then dividing by the original functions, the following variational forms are obtained. For the conventional case:

$$\begin{aligned} \left(\frac{dF}{d}\right)_c &= K_1 \left(\frac{dR}{R}\right)_c + K_2 \left(\frac{dL}{L}\right)_c + K_3 \left(\frac{dC}{C}\right)_c + K_4 \left(\frac{dD}{D}\right)_c \\ &+ K_5 \left(\frac{dt}{t}\right)_c + K_6 \left(\frac{dB}{B}\right)_c, \end{aligned} \quad (12)$$

where the K 's are sensitivity coefficients defined, for example, as

$$K_1 = -1.0,$$

$$K_2 = -\frac{1}{1 + \frac{L_c}{\nu(D + t/2) + B_c/C}},$$

and the other K 's are of the form $K_i = \pm \frac{1}{1 + x_i}$, $x_i > 0$.

For the replaceable case:

$$\begin{aligned} \left(\frac{dF}{F}\right)_r = & K_1' \left(\frac{dR}{R}\right) + K_2' \left(\frac{dL}{L}\right)_r + K_3' \left(\frac{dC}{C}\right) + K_4' \left(\frac{dD}{D}\right) \\ & + K_5' \left(\frac{dm}{m}\right) + K_6' \left(\frac{dB}{B}\right)_r + K_7' \left(\frac{dp}{p}\right) , \end{aligned} \quad (13)$$

where

$$K_1' = -1.0 ,$$

$$K_2' = - \frac{1}{1 + \frac{L_r}{p + \nu D/m + B_r/C}}$$

and again the other K's are of the form $K_i' = \pm \frac{1}{1 + x_i'}$, $x_i' > 0$.

Each coefficient tells how much the footage cost is incrementally changed when one of the variables is increased by some small amount. Specifically, the incremental change in the variable is multiplied by its sensitivity coefficient (K) to obtain the effect on footage costs. For example, a small (say 5%) increase in the conventional or replaceable drilling rate (R_c or R_r) causes a corresponding 5 percent decrease in F_c or F_r , since $K_1 = K_1' = -1.0$. Note that the drilling rate sensitivity coefficient (K_1 or K_1') is always the largest coefficient in absolute value since for all other K's, $|K| < 1$. This fact should not be surprising for the conventional bit since this result has been previously reported.

Finally, one other manipulation of Eqs. (9) and (11) can be quite useful, particularly when minimum performance criteria are needed to define the conditions under which the new bit concept will be competitive. This generally means defining what combinations of drilling rate, R_r , and bit life, L_r , yield economically competitive footage costs. Economic breakeven occurs when the replaceable bit footage costs, F_r , can be reduced to the point that they just equal the conventional costs, F_c . Thus, equating the right hand sides of (2) and (4) yields the breakeven relation

$$\frac{R_r}{R_c} = \frac{L_c}{L_r} \frac{C[L_r + \nu D/m] + B_r}{C[L_c + \nu(D + t/2)] + B_c} \quad (14)$$

Thus we have the following methods available for footage cost comparisons: Equations (9) and (11) allow a direct quantitative cost comparison between conventional and replaceable systems; Eqs. (12) and (13) yield the sensitivity of these footage costs to changes in input variables; and Eq. (14) defines the minimum replaceable bit performance requirements for the system to be cost competitive.

The validity of the economic comparison presented here is strongly dependent upon the accuracy of the performance estimates for the replaceable bits. Since experimental data are generally not available, these estimates may be incorrect by significant amounts. However, they do represent the best available estimates at the time of this report and as such serve as a performance index to indicate in what particular environments the DHRB has the best chances for commercial success.

Bicone System Economics -- The replaceable bicone design is to be compared with conventional tricone bits having tungsten carbide insert teeth and a sealed journal bearing roller system. Drilling conditions range from medium through hard dense rock with bicone and tricone designs chosen to match the drilling conditions. Initial design requirements for the bicone system included attempting to match the tricone drilling rate, then lowering footage costs by having 12 bits downhole to greatly lengthen the time between trips. If successful, such a strategy should yield increasing savings as depth increases (i. e., longer tripping time), as rock hardness increases (i. e., more trips), and as stratum thickness increases (also more trips).

Table II summarizes the nominal performance characteristics of the two types of bits. The values for the bicone system are those which were initially considered to be realistically obtainable: specifically, matching the conventional bit drilling rate while having about 1/3 the bit life. Results based on more detailed analyses will be presented later. Table II also represents the most favorable drilling conditions in terms of stratum thickness; namely, the maximum thickness is exactly that required to wear out all 12 of the replaceable bits. The effects of thicknesses less than these values will also be discussed. The conventional bit performance values and bit prices given in the table are typical for tungsten-carbide insert bits.³

Of the so-called nominal conditions given in Table II, the rig cost, C, is certainly going to be the most highly variable. It can range from less than \$50 to more than several thousand dollars per hour, depending upon geographic location, depth capability, well conditions, and other factors. For this reason most results will be presented either with C as the independent variable or with several curves representing different values of C. Figures 18a through 18c summarize drilling cost per foot, F, as a function of C for the tricone and bicone systems, using the nominal bit performance values of Table II. Recognizing that drilling rate, R, is the single most important variable, it would be expected that R would be maintained even if bit life had to be reduced somewhat. Therefore, results for a bicone bit life of 1/6 the conventional bit life are presented along with the nominal 1/3 and an optimistic 1/2 life values. Figure 18a is for a hard dense stratum at 18,000 feet having a thickness of 240 feet. Typical land-based rig costs for wells this deep are estimated at between \$150 and \$300 per hour while offshore costs would be \$500 per hour or higher. These areas are indicated on the figure and it can be seen that with the 1/3 bit life ratio the bicone system would not be cost-competitive for land-based operations but would be for offshore rigs. Also note that any significant reduction in bit life would make the replaceable system too expensive over the entire range of rig costs shown.

TABLE II
Nominal Design Drilling Conditions for
Bicone/Tricone Comparison

		Formation Type		
		Medium	Medium-Hard	Hard Dense
Depth (ft)		18000	18000	18000
Maximum Thickness (ft)		4800	1920	240
Conventional Tricone	Drilling Rate, ft/hr	10	6	2
	Bit Life, hrs	120	80	30
	Bit Cost, \$	2010	2010	2010
	Rig Cost, \$/hr	200	200	200
Replaceable Bicone (12 bits)	Drilling Rate, ft/hr	10	6	2
	Bit Life, hrs	40	26.67	10
	Bit Cost, \$	2000	2000	2000
	Rig Cost, \$/hr	200	200	200

Figure 18b shows similar results for a medium-hard stratum with a thickness of 1920 feet at the same drilling depth. Note the decrease in footage cost caused by the increase in drilling rate and bit life. Also the effects of changes in bit life are considerably reduced. However, the basic result is still the same: bicone footage costs for the nominal case of 1/3 the bit life are greater than conventional costs for values of C less than about \$400/hour. Finally, Figure 18c gives the results for drilling in a medium stratum. This case becomes rather unrealistic about stratum thickness because a 12-bit bicone system would drill through 4800 feet before wearing out, and homogeneous strata this thick are rarely if ever encountered in the petroleum industry. However, the trend set in Figures 18a and 18b of decreasing footage costs, decreasing effect of bit life changes, and cost crossover occurring above land-based rig costs is continued in this figure. But since a single tricone is capable of drilling through 1200 feet of this material, it would appear a replaceable system has little utility in this softer material, and subsequent results will be limited to the medium hard and hard dense strata (results for a geothermal well with $t = 10,000$ ft in fairly hard strata were presented earlier).

The preceding figures serve to illustrate the footage cost trends when comparing the conventional and replaceable bits, but they cannot quantify the relative importance of the individual variables nor allow an order ranking of the variables' contributions. For this it is necessary to apply the sensitivity analysis represented by Eqs. (12) and (13). Table III summarizes these effects by showing the percentage change in footage costs, F , caused by a 10 percent change in each of the cost variables. Sensitivity coefficients are listed for rig costs of 50, 200, and 800 dollars per hour. A negative coefficient means that a 10 percent increase in the cost variable causes the percentage decrease in footage costs shown. Also, the sensitivity coefficients for drilling depth, D , and bit number, m , in the replaceable system are equal in magnitude but opposite in sign. For brevity they are shown on the same line in the table, but it should be remembered that m has significance only for the bicone system.

TABLE III
Percentage Changes in Footage Costs Caused by a
10 Percent Change in Cost Variables

Stratum	Cost Variables	Conventional Bicone Rig Costs (\$/hr)			Replaceable Bicone Rig Costs (\$/hr)		
		50	200	800	50	200	800
Hard Dense	Drill Rate	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0
	Bit Life	- 6.4	- 4.4	- 3.5	- 8.0	- 5.3	- 2.8
	Rig Cost	5.2	8.1	9.5	2.2	5.3	8.2
	Bit Cost	4.8	1.9	0.5	7.8	4.7	1.8
	Depth and - Bit Number	1.6	2.5	2.9	0.2	0.5	0.8
	Stratum Thickness	0.01	0.02	0.02	-	-	-
	Bit Cycle Time	-	-	-	0.05	0.18	0.18
Medium Hard	Drill Rate	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0
	Bit Life	- 4.0	- 2.3	- 1.7	- 6.1	- 3.0	- 1.3
	Rig Cost	7.0	9.0	9.7	4.1	7.4	9.2
	Bit Cost	3.0	1.0	0.3	5.9	2.6	0.8
	Depth and - Bit Number	1.0	1.3	1.4	0.2	0.3	0.4
	Stratum Thickness	0.05	0.07	0.07	-	-	-
	Bit Cycle Time	-	-	-	0.04	0.07	0.08
Medium	Drill Rate	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0
	Bit Life	- 3.2	- 1.7	- 1.3	- 5.1	- 2.2	- 0.9
	Rig Cost	7.7	9.3	9.8	5.1	8.0	9.4
	Bit Cost	2.3	0.7	0.2	4.9	2.0	0.6
	Depth and - Bit Number	0.8	0.9	1.0	0.1	0.2	0.3
	Stratum Thickness	0.10	0.12	0.13	-	-	-
	Bit Cycle Time	-	-	-	0.03	0.05	0.06

Next, consider the effect of drilling through strata whose thicknesses are less than $MR_r L_r$, i. e., situations where all 12 of the replaceable bicone bits are not needed. Figures 19a and 19b show footage cost variables for changes in stratum thickness for hard dense and medium-hard rock respectively. Again, the nominal values listed in Table II are used and three rig costs (50, 400, and 800 dollars per hour) are included. The value of 400 was chosen here because it is close to the crossover points seen in Figures 18a and 18b. Note that once L_r and R_r are fixed, there is a unique linear relationship between t and m , enabling both variables to be shown along the abscissa. In both cases the increase in bicone footage costs as stratum thickness decreases is readily apparent. In the two lower rig-cost situations (50 and 400 dollars/hour), the bicone system is simply not cost-competitive at thicknesses less than maximum. In fact, for the \$50/hour case it is never competitive. On the other hand, at \$800/hour the bicone system is competitive as long as more than five bits are needed (i. e., thicknesses of about 100 feet for the hard dense case and 800 feet for the medium-hard case). Thus, the only potential use for the bicone system appears to be on the more expensive (e. g., offshore) rigs, assuming the nominal performance estimates are fairly accurate.

Finally, it may be of considerable importance in the present situation to define exactly what improvements in the bicone system would make it competitive over a broader range of rig costs and strata thicknesses. The performance of the bicone bit relative to the tricone bit could only be improved by increasing drilling rate, increasing bit life, or decreasing bit costs. Table III indicated that other considerations such as number of bits and bit cycle time offer little potential for cost savings. In addition, there is no reason to believe a replaceable bit system would reduce rig costs at all; thus, R_r , L_r , and B_r are the only possibilities. At first, it might appear that B_r might be significantly lower than B_c since there are only two cones requiring insert teeth and sealed bearings. However, the costs of the cycling mechanism and spare storage cartridge must be averaged over the 12 bits, and this cancels any potential savings.

It now appears that a bit life of 1/3 conventional bit life is the most that can be expected for the present design. This leaves only improvements in drilling rate as a possibility for reducing footage costs. Unfortunately, at the present time it appears that rates equal to conventional rates may be difficult to achieve.

At this point, the most useful result is a presentation of what must be achieved by the replaceable system in order for it to be competitive; the actual mechanical design changes that would achieve these improvements is not suggested here. By using the breakeven relationship, Eq. (14), it is possible to define what bicone drilling rates must be achieved to realize a competitive situation. Figure 20 summarizes these rate requirements for both medium-hard and hard dense strata, where stratum thickness and rig costs vary. Note the thickness varies from about 0 to 300 feet for the hard dense case and from about 0 to 2000 feet for the medium-hard case. From the stress analyses and tooth/bearing life estimates mentioned above, a best estimate was derived for drilling in a medium-hard stratum of 5.4 feet/hour (assuming a 6 ft/hr conventional rate). This estimate is shown on the figure and it is apparent that even at the very expensive rig cost rate of \$2000/hr

the 12-bit bicone system is not competitive with the conventional tricone. However, the required improvements can be easily picked off for various combinations of rig costs and stratum thicknesses. While Figure 20 is valid only at a depth of 18,000 feet, it does illustrate the trend that would be expected at any other depth and shows how Eq. 14 can be applied.

Figure 19a. Cost Crossover Points in Terms of Bit Number or Stratum Thickness, Hard Dense Stratum ($D = 18,000$ ft)

Figure 19b. Cost Crossover Points in Terms of Bit Number or Stratum Thickness, Medium-Hard Stratum ($D = 18,000$ ft)

Figure 20. Bicone Drilling Rates Required to Achieve Breakeven Drilling Costs ($D = 18,000$ ft)

Compax System Economics -- Results for a DHRB system employing Compax cutting elements in place of the bicone head are summarized in Figures 21a and 21b for hard dense and medium-hard strata. While the bicone performance parameters discussed previously could be restricted to a fairly narrow range of values, the performance of the Compax element is too uncertain at this time to draw a specific comparison. Instead, the figures show the "best case" (bottom dashed line) and "worst case" (top dashed line) from current performance estimates as follows:

	Hard Dense		Medium-Hard	
	Best	Worst	Best	Worst
Drilling Rate, R_r (ft/hr)	25	3	75	10
Bit Life, L_r (hr)	30	8	80	20
Bit Cost, B_r (\$)	4000	6500	4000	6500

These values are compared with the previously stated tricone bit values; i.e., for hard dense, $R_c = 2$, $L_c = 30$; for medium-hard, $R_c = 6$, $L_c = 80$; $B_c = \$2010$ for both. Drilling depth is 18,000 feet through a hard dense stratum 250 feet thick and a medium-hard stratum 2000 feet thick. These thicknesses do not exceed the capabilities of a single DHRB system, even if it performs at the "worst case" level.

It must be emphasized that any potential footage cost savings cannot all be attributed to the use of the DHRB system. A portion may be due to the performance changes associated with the Compax cutters as opposed to the tricone bit. In order to obtain a rough quantitative feel for the relative importance of the DHRB concept in the examples of Figure 21, additional broken curves are shown. They represent the cost performance of a single Compax head having the "worst case" values given above and drilling in a conventional way (i. e., a trip to the surface for each bit change). The relative improvement associated with the DHRB concept can be seen to be quite significant, particularly at the higher rig cost values. However, at the other extreme using the "best case" situation, the corresponding broken lines would fall directly on the dashed lines. This is because the drill rate and bit life are high enough that the example stratum thicknesses can be drilled by a single Compax bit, eliminating the need for a DHRB system. Thus, if the Compax cutters prove to be competitive, their use in a replaceable bit system will depend not only on the performance of the Compax but on the rig costs, drilling depth, and strata conditions as well.

Figure 21a. Cost Performance of a DHRB Compax System, Hard Dense Stratum (D = 18,000 ft, t = 250 ft)

Figure 21b. Cost Performance of a DHRB Compax System, Medium-Hard Stratum (D = 18,000 ft, t = 2000 ft)

Conclusions from the Economic Analysis -- The preceding results give a somewhat mixed picture of whether the bicone bit can be economically competitive with its conventional single-bit counterpart. The trend in well depth and rig costs is favorable to the replaceable systems, but it is very doubtful that these factors alone can make the proposed bicone bit cost-competitive and work has stopped on this approach.

The dilemma in use of the bicone bit is perhaps best illustrated by Figure 20. Particularly in medium-hard rock the bit must either be used to drill only through very thick (greater than 1500 feet) strata using very expensive rigs or somehow achieve drilling rates significantly higher than the tricone bit. The first alternative would appear to restrict the use of the bicone bit to a small number of drilling sites, making the value of commercial development somewhat dubious. The second alternative requires mechanical design changes which may simply be impossible. However, in hard dense strata the picture is considerably less bleak, with thickness requirements not exceeding 200 to 300 feet.

The drilling conditions in which the present replaceable bicone bit would be economically competitive are very restricted, at best. Only in very deep holes being drilled by very expensive rigs would it be even marginally acceptable. This, however, does not mean that this kind of replaceable bit concept is necessarily bad. But it does indicate a need exists for either modifying the bicone cutters or replacing them so that a drilling rate at least slightly greater than the conventional tricone can be achieved.

Depending upon the outcome of experimental Compax tests, the Compax system may well offer the needed performance improvements to achieve an economically competitive DHRB. However, it is certainly premature to say that the Compax concept will be any panacea for the DHRB system; further information is needed to narrow the broad range of possible performance seen in Figure 21.

Finally, the governing equations and comparative techniques have been developed for determining the relative performance of conventional and replaceable bits. These techniques not only can be used now for evaluating other proposed replaceable systems, but in the future they could be used in the field to choose the most economic bit at any depth and under any drilling conditions.

Regardless of the fate of the DHRB system, the need to consider economic breakeven curves (such as Figure 20) early in a design program should be apparent. Such an approach defines minimum performance objectives for the new system and can also indicate the drilling environments in which the system should be competitive.

Program Plan to Commercial Production

The basic study of the Compax and other improved cutting surfaces that may be applied to high-performance drill bits is being sponsored by the Division of Fossil Energy, ERDA. This work includes improved materials studies, improved joining techniques, and studies of more economical ways to fabricate advanced drill bits using these cutting elements. This work is being coordinated with the General Electric Company and ERDA/DGE in an effort to maximize technology development at minimum cost to ERDA. The technology that is developed in this program can be applied to the DHRB if this program continues.

The question of program continuation rests on projected ERDA/DGE future funding levels. The most recent guidance that this laboratory has received indicates that we can expect the same funding levels for FY 77 and FY 78 that we received in FY 76 for our DGE drilling programs. Sandia Laboratories has had four advanced drilling development programs underway for ERDA/DGE in the past. These include the DHRB, the chain drill, the terra-bit, and the spark drill. It is not possible to maintain four viable development programs at the funding levels we anticipate in the future and for this reason the DHRB will be cancelled so that the other programs can be completed in a timely manner.

A program plan to commercialization has been developed in this section, however, and can be accomplished by the Sandia/industry team if funds become available. The overall program plan is divided into five tasks that will lead to field demonstration deep-drilling tests in the fourth quarter of FY 78 and transfer of this technology to the private sector in the first quarter of FY 79.

To speed the technology transfer, the drilling industry will be heavily involved in each phase of this program as they have been since its inception. Their advice and active participation will be solicited and every effort will be made to keep our industrial contacts informed on the progress of this program. A milestone schedule (Table IV) and detailed budget (Table V) are included in this report and the task descriptions follow.

Task 1 - Cutter Head Development

The immediate job to be accomplished in this task is the development of an economically viable cutter head for the drill bit. The most economical approach is to involve industry wherever possible, particularly where their expertise and facilities are applicable (i.e., roller cones and Compax cutters). An additional benefit of this approach is that the transition from the development program to commercial production will be expedited.

To implement this approach, the question of patents and background information will need to be resolved. The Sandia Purchasing organization is presently working with the possible suppliers to identify and resolve these problem areas. The fact that Reed Tool and Smith Tool companies have indicated a willingness to share the costs of portions of the program is encouraging and indicates a mutually agreeable solution may be found.

TABLE IV
DHRB Program Schedule

Task	CY 1976												CY 1977												CY 1978													
	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D		
I. Cutter Head Development																																						
A. Design																																						
1. Gage Cone/Compax																																						
2. Center Cone/Compax																																						
3. All Compax																																						
B. Fabrication																																						
1. Center Cone Compax																																						
2. All Compax																																						
C. Test & Evaluation																																						
1. Center Cone/Compax																																						
2. All Compax																																						
D. Selection of Final Head																																						
II. Laboratory Prototype Development																																						
A. Design																																						
B. Fabrication																																						
C. Assembly																																						
D. Laboratory Test																																						
E. Evaluation																																						
III. Field Demonstrations																																						
A. Design Modification																																						
B. Field Test & Evaluation																																						
IV. Finalize Program																																						
A. Final Report																																						
B. Tech Package																																						
C. Industry Conference																																						
Costs by Fiscal Year (\$ x 10 ³)	FY 76			76A			FY 77			FY 78			FY 79																									
	121			50			447			320			50																									

* - Economic study indicates this approach will not yield sufficient advantage--fabrication canceled.

** - Decision Points

TABLE V
DHRB Program Budget

	<u>FY 76</u>	<u>FY 76A</u>	<u>FY 77</u>	<u>FY 78</u>	<u>FY 79</u>
A. Man-Years					
1) Scientific	1.5	2.0	3.0	2.0	1.0
2) Other Direct	<u>1</u>	<u>1.0</u>	<u>1.0</u>	<u>1.0</u>	<u>0</u>
Total Direct	2.5	3.0	4.0	3.0	1.0
B. Funding					
Operating Costs (10 ³ dollars)					
1) Loaded Salaries	96	37	202	148	25
2) Subcontracts, Travel, Direct Charges	<u>25</u>	<u>13</u>	<u>245</u>	<u>172</u>	<u>5</u>
Total Operating Costs	121	50	447	320	30

It is essential to evaluate the drilling configurations as rapidly and economically as possible. This can best be accomplished by fabricating the initial drilling prototypes as fixed-head drill bits (Figure 22) for evaluation. The fabrication is simplified and this type of unit can be readily tested on existing equipment available in industry.

The design of both a center-cone hybrid and an all-Compax configuration will be completed and a drilling economic study based on anticipated performance and costs of these bits will be conducted. The completion of this work will mark a key decision point. One or both of these configurations may be taken to the fixed-head hardware stage based on the results of this analysis. One or two industrial contracts will be let to fabricate the fixed-head units. An industry cost-sharing option will be pursued at this point. When hardware is received the prototypes will be tested in a wide variety of rocks at the Reed/Terra Tek Drilling Research Laboratory (DRL) in Salt Lake City. Comparative drilling rates as a function of rpm and bit load will be established as well as bit life. The data acquired will be used to finalize the cutter head design and update the drilling economic study. This task will be completed in April of 1977 at a total cost of \$97,000.

Task 2 - DHRB Prototype Development

When a drilling configuration is shown to have the penetration rates, load-carrying capability, and life required to yield a definite improvement in the laboratory, three full-scale prototypes will be constructed. The models will incorporate the latest design(s) which result from the cutter head effort. One model will be evaluated by DRL to obtain initial performance data. The other two models will be used in field evaluation tests (Task 3). The laboratory tests will be conducted to:

Figure 22. Fixed-Head Test Bit

- Demonstrate the adequacy of the DHRB design in the laboratory drilling environment
- Determine optimum hydraulic performance and life
- Determine bit life and penetration rate as a function of drilling variables
- Acquire data for field test planning.

The result of this test series will confirm the feasibility of the DHRB design. Design deficiencies that may exist will be detected and corrected on the field drilling prototypes. Bit companies and drilling contractors will be invited to observe this test series and will be provided the data at the completion of the series. This task will be completed in April of 1978 at a total cost of \$450,000.

Task 3 - Field Demonstration Tests

The full field tests should begin in July 1978. Commercial drilling companies will be asked to run this bit in hard, deep formations in wells then being drilled. It is assumed that this testing can be accomplished at no charge to ERDA other than normal day rates for any drilling delays incurred by running these prototypes. Informal commitments have been received from several drilling companies to test on this basis. It will be advantageous to select a site in which information on penetration rate and life of conventional bits has been acquired so that a meaningful direct comparison of performance can be made. A wide segment of the drilling industry will be invited to observe this demonstration program. The results of the field tests should convincingly demonstrate the economic advantages of the DHRB in deep, hot, hard-rock drilling. The field demonstration will be completed in October 1978 at a cost for this task of \$300,000.

Task 4 - Program Completion and Technology Transfer

To wrap up this development effort and transfer the technology to the drilling industry, a technology transfer package will be prepared. This package will include the final report that summarizes the results of this program, a detailed drawing and specification package, process control, materials, and parts lists that are adequate to put this system into production. This package will be presented at an industry-wide conference called to discuss this program and will be made available to all interested parties. Sandia's manufacturing development engineers can also be made available to interested companies for more detailed assistance if necessary. This task will complete this program in December 1978. Task 4, it is estimated, will cost \$50,000.

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