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Coring in Deep Hardrock Formations

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Coring in Deep Hardrock Formations¹

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ABSTRACT

The United States Department of Energy is involved in a variety of scientific and engineering feasibility studies requiring extensive drilling in hard crystalline rock. In many cases well depths extend from 6,000 to 20,000 feet in high-temperature, granitic formations. Examples of such projects are the Hot Dry Rock well system at Fenton Hill, New Mexico and the planned exploratory magma well near Mammoth Lakes, California. In addition to these programs, there is also continuing interest in supporting programs to reduce drilling costs associated with the production of geothermal energy from underground sources such as the Geysers area near San Francisco, California. The overall progression in these efforts is to drill deeper holes in higher temperature, harder formations. In conjunction with this trend is a desire to improve the capability to recover geological information. Spot coring and continuous coring are important elements in this effort. It is the purpose of this report to examine the current methods used to obtain core from deep wells and to suggest projects which will improve existing capabilities.

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Preface

This document has two main purposes—to describe conventional methods of obtaining core samples from deep wells and to identify a number of engineering projects which will aid in the advancement of current coring methods in hard rock formations. The major premise of this work is that two areas of technology exist which can be combined to produce a highly improved coring system. These technologies are the deep drilling system of the petroleum industry and the deep coring system of the mining industry. Because of drilling depths, formation problems, and wellbore diameters, the petroleum drilling system will undoubtedly be the workhorse for most of the geothermal energy projects, and therefore, the contribution of the mining methods must be viewed as an adaptation or enhancement of the petroleum method.

Economic pressures within the oil and gas industry have not been conducive to the development of optimal drilling or coring tools for hot, hard rock environments. For example, geothermal drilling comprises less than one percent of the market for petroleum drilling equipment. Consequently, for these situations, poor quality core at high cost is the norm. An alternative exists—mining technology. By using this method, continuous and high-quality core can be recovered at a fraction of the cost associated with petroleum methods. Unfortunately, achievable well depths are far shallower, wellbore diameters are much smaller, and formation problems are often “solved” through abandonment of the hole.

Each industry has its own purpose for drilling a well, and this purpose has necessarily specialized and narrowed the development of the technology. The innovation required by new and unusual projects will not naturally arise out of either of these industries. By their own admission, adoption of new tools has been “both disappointing and piecemeal, with a tendency to follow proven practices and avoid the risks of innovation” [1]. Innovation will occur only if it is driven by the engineers, scientists, and public or private investors who support the development of new energy sources. This is the audience for which this report is intended. Consequently, much of this report is devoted to a tutorial designed to familiarize the novice with the drilling processes used by both the petroleum and mining industries.

It must be admitted that to some extent the author also falls into the novice category. The viewpoint of the author is primarily that of an outsider examining the structure of a system. Consequently, some of the comments contained in this work might be interpreted as an overly critical and superficial conclusion about the omissions and inadequacies of drilling technology. That is not the author's intention. Such observations are rather presented as a statement about a situation which has been actively carved out by severe economic and business necessity.

In collecting the information for this report, the author has depended heavily upon a variety of discussions with numerous people in both the mining and petroleum industries. In every case, these people have been extremely helpful and informative. These people included Bill Baker of Smith Tool; Ty Brinker of Thums; Jerry Cerkovnik of Norton Christensen; Gary Clemens of Hycalog Coring Services; Bennie G. DiBona of

Terra Tek; Robert Estes, Steve Radford, Phillip Schultz, and Gordon Tibbitts of Eastman Christensen; Scott Evans of Christensen Mining Products; George Fyfe and Ken Jones of Smith Tool; Aubrey Holt of Datadril; Steven Howard, Stanley Serocki, and Michael Storms of the Ocean Drilling Program; James McPherson of Smith Drilling Systems; Walter Svendsen of Longyear; and George Trautman of Diamant Boart. B. J. Livesay of Livesay Consultants was also of invaluable assistance through numerous discussions and a review of this document.

In addition to the discussions with these people, a workshop was held at Sandia National Laboratories in October 1987. Several of the same people also attended this workshop. A complete list of the attendees of the workshop is given in Appendix A.

The overriding conclusion of all of these people is that any complex energy project which requires extensive drilling and coring will also require a parallel tool development program. The Ocean Drilling Program [2] provides an excellent model of the type of effort which would lead to a major improvement in the capability to collect core from hot, hard rock drilling projects. On a smaller scale certain individual projects can be identified which address underlying needs common to a group of projects. Such a list is included in this work; however, it is a naive assumption to expect that this is a definitive list leading to the ultimate tool. As the workshop concluded, each drilling project is unique and requires specialized tools.

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1 Introduction

At the turn of this century cable drilling rigs were used almost exclusively for drilling petroleum wells. The wells were shallow and located in soft formations in such places as Pennsylvania, West Virginia, and Ohio. Drilling operations were achieved by oscillating a heavy impact tool attached to the end of a steel cable—a system which in principle had changed little since ancient times in China.

On January 10, 1901, things changed. Two men, Patillo Higgins and Captain Anthony Lucas, made history by bringing in the Spindletop well. In an instant this country's oil supply was doubled by a single well. Vast amounts of oil lay under Beaumont, Texas, and new technology was required to efficiently drill these wells. The new problems which had to be faced included drilling to far greater depths and drilling through the hard Texas cap rock. The innovations of the rotary drilling rig and Howard Hughes' roller-cone bit took over.

Today, drilling operations have reached to depths of 40,000 feet, but drilling at these depths is tedious (wells in excess of 20,000 feet are called *ultradeep* wells). Recovery of geological information has improved through the use of new logging tools; however, many operations are still limited by a technology which is still heavily linked to the 90-year-old rotary system [1]. Out of economic necessity, this technology has been specialized to a certain class of tasks normally encountered by production drilling in the oil and gas industry. Several factors have controlled the evolution of these tools. First, oil and gas are generally found in sedimentary formations. These formations usually fall in the soft to middle range of the hardness scale. Consequently, the development of hard-formation tools has been limited. Second, exploration drilling is currently a minor share of oil and gas drilling activity—most wells are drilled within existing fields. Consequently, the development of tools associated with exploration drilling has also been limited.

In the past two decades, innovation in coring technology has arisen from another source—the mining industry. By using the wireline system as a matter of standard practice, coring rigs retrieve continuous core samples from hard crystalline formations. Rates of penetration in hard rock are comparable to those in the petroleum industry, and coring costs are generally at a fraction of those encountered in petroleum industry.

In mining projects, core samples are virtually the only motivation for drilling, and therein lies the shortfall of this technology. Whereas the petroleum industry drills for the purpose of making a usable hole for pumping fluids, the mining industry generally only wishes to examine the core for mineral content and then abandon the hole—often with the drilling string stuck in place. They have devised a system which is based on relatively small wellbore diameters; getting out of trouble and maintaining the well is a secondary priority; and drilling depths are normally limited to relatively shallow regions (less than 5000 feet in this country) which are economically accessible with mining drills.

Today, new types of drilling projects are creating a need for new drilling tools. The expansion of existing geothermal production sites and engineering feasibility studies

for new geothermal production concepts are stretching the state of the art of drilling technology. For these projects, which depend on petroleum drilling equipment, every new well is a challenge. Well depths are often in excess of 6,000 feet; the formations are hot, hard rock; large diameter wellbores are required for production of fluids; and information from core samples are an essential part of the project.

In this report, some of the problems associated with coring in geothermal projects will be examined. Since the drilling methods are based primarily upon petroleum technology, the mining technology will be examined from the viewpoint of its possible contribution to the petroleum drilling process. Because of the lack of market pressure, the petroleum industry has found little incentive to develop tools for coring in hot and hard formations. Also, since oil and gas are normally not found alongside gold and diamonds, geology has helped to produce its own separation between these two technologies. Consequently, some conceptually obvious methods have not been tried.

Unfortunately, not all of the problems can be solved through a combination of these technologies. For example, neither technology seems to have many answers to questions addressing the survival of well-logging tools, polymer components in downhole motors, and drilling mud properties in high-temperature environments.

1.1 How to Read this Report

The plan of this work is to present the reader with an outline of drilling problems and potential solutions, and also to provide a background of information as a context in which these opinions are formed. We start in Section 2 with a summary of the properties of rock and a description of the in situ environment to which deep rock formations are subjected. Following this are two sections which describe the petroleum and mining technologies. Section 5 discusses the differences between the petroleum and mining technologies. Section 6 reviews several projects which attempt to draw from both technologies and develop tools to extract large amounts of core from hard formations. Section 7 examines a list of tools which, if developed or improved, would have a significant contribution to future efforts to obtain core samples from deep, high-temperature, hard crystalline formations. Concluding remarks are given in Section 8. An appendix is also included which summarizes a two-day workshop on coring which was held at Sandia National Laboratories.

1.2 How not to Read this Report

Sections 2 through 5 are primarily a review of various geological concepts, petroleum drilling methods, and mining drilling methods. Readers who are already familiar with the mining and/or petroleum coring systems may wish to skip reading these sections, and proceed directly to Appendix A. The reader can then cover Sections 6 through 8 which contain elaborations on the topics presented in A.

2 The Material—Rock

The ability to drill and core rock at great depths and temperatures obviously requires some knowledge of the properties of rock. These properties affect the types of tools used and their performance. Drill bit life, hole stability, drilling trajectory, and rate of penetration are all linked directly to the behavior of the rock formation. This section reviews a few of the more pertinent factors which directly influence drilling and coring methods.

To the non-geologist the most startling aspect of geology is the variety of names used to describe rock. It is a material which is highly variable, and tools to drill and core rock must be designed with a particular class of rock in mind. However, from an engineer's point of view, the geologists have more names to describe rock than are necessary. The engineer is really interested in the physical properties of rock which relate to its machinability. Many geological classifications which relate to origin of the formation, chemical composition, and morphology are irrelevant. The factors which are important are properties such as yield strength, hardness, fracture distribution, porosity, heterogeneity, thermal diffusivity, and fluid content. Of these, some factors are more important than others, and selection of the most important factors depends upon the type of bit which is used to drill the rock.

Fracture and yield strength seem to be the most important physical properties when roller-cone bits are used to drill hard formations. These bits function by inducing large stresses within the formation as the teeth of the bit are rolled across the surface of the rock. The large axial load on the bit results in a spallation of the formation. If natural fractures exist or if hard inclusions are present, the bit will remove material unevenly from the bottom of the hole. This roughness can eventually cause the drilling assembly, including the rig on the surface, to vibrate violently.

In contrast, if diamond bits are used, surface hardness seems to be the most important physical property. The more readily the surface of the formation can be scratched by diamond, the more effective the drilling action. Constituents in the formation which tend to polish more readily, such as cherts, will also polish the bit and quickly degrade the cutting action.

Rock can also have either a ductile or brittle response. In fact, the same formation can have both responses. The properties of rock are particularly sensitive to the confining pressure experienced by the formation. Over a range of pressure, rock exhibits a brittle-ductile transition. Below this pressure it is brittle, and above this pressure it is ductile. The confining pressure in the neighborhood of a wellbore is also significantly dependent upon the hydrostatic pressure produced by the column of drilling mud in the wellbore. The confining pressure can be altered by changing the mass density of the drilling mud. This change can drive the formation through the brittle-ductile transition and completely alter its drilling characteristics. In the present report, this phenomena will be ignored, since the formations of interest are predominantly brittle.

The in situ rock is subject to natural stresses resulting from the overburden placed on it by the formation above. If the behavior of the rock is adequately described by a fluid model, the stress state is simply a pressure field which depends only on depth. The value of stress associated with this model is called the lithostatic stress. In many cases, the actual stress state can differ significantly from this value. Two factors must be present to produce this deviation. First, the rock must have significant yield strength so that deviatoric stresses can be supported. Hard brittle formations, which are the main concern of this report, exhibit large yield strengths. Second, forces such as horizontal thrust loads must be present to produce a build up of deviatoric components. Many of the drilling sites of concern are near geologically active regions such as boundaries between continental plates. Thus large differences can exist between the various vertical and horizontal components of stress, and because the yield strength increases with pressure, these differences can increase with depth.

Drilling into a highly stressed formation alters the in situ stress state. This causes localized failure of the formation which manifests itself in a variety of ways. Core diskings and borehole breakout are two particularly troublesome problems associated with drilling into hard formations.

Coring produces a long slender cylinder of material from the formation. This is a delicate shape which is subjected only to the hydrostatic confining pressure of the drill mud in the wellbore. If the in situ stresses differ from this hydrostatic value, the process of coring can drastically alter the stress state of the core sample. This can cause failure of the sample, sometimes with an explosive release of energy. Often core samples retrieved from great depths resemble a stack of poker chips—individual chips breaking off as the coring bit advances.

Borehole breakout may occur rapidly or over a longer period of time. The result of this phenomena is to alter the wellbore from the circular cross section produced by the drill bit into an elliptical cross section. The ratio of the major to the minor axis of the ellipse may be on the order of three. This transition is the result of numerous flakes breaking off the walls of the wellbore. The shape and orientation of the evolving cross section is related to the differences between and orientation of the principal components of stress, and also to the shape of the failure envelope of the formation. This spalling action is probably aggravated by thermal cycling induced by the intermittent flow of mud during the drilling process.

The formation can also be damaged by the hydrostatic pressure induced by the column of drilling mud. This can occur when the hydrostatic pressure of the mud column exceeds the actual stress in the formation. This produces local tensile loads near the wellbore and causes fracturing of the surrounding formation. When fracturing occurs, large quantities of mud are lost. If this loss cannot be replaced, the drop in the mud level will reduce the hydrostatic pressure to dangerously low levels. Any naturally occurring gases trapped in the porous structure of the formation can then vent to the surface and cause a *blowout* condition. If the blowout is not contained within a few minutes, the gases may ignite with disastrous results.

The trajectory of the drill bit is directly influenced by two properties of the formation, its heterogeneity and its anisotropy. Gross heterogeneities in material properties occur at interfaces between strata. These interfaces can deflect the trajectory of the drill. Depending upon the relative properties of the two neighboring formations and the angle of their common interface, the drill can be deflected either away from or toward the newly intersected formation.

Anisotropy; that is, directionally dependent properties, are common in rock. Thus, for example, the values of stiffness and strength in the vertical direction can differ significantly from the values in the horizontal direction. This property can also cause the trajectory of the drill bit to deviate. Deflections up to forty degrees from vertical sometimes occur. These deflections can build suddenly, causing what is called a *dogleg*, or they can build slowly over hundreds of feet.

Thermal diffusivity plays an important role in situations where high temperatures are encountered. This property is a measure of the resistance of the rock to localized cooling. Rock has a low thermal diffusivity. Thus, for example, a block of rock in comparison to a block of metal can be cooled more easily at the surface and still retain a hot interior. The low thermal diffusivity of rock makes it feasible to cool a wellbore by circulating mud through it, even when molten rock is encountered.

Finally, the amount and chemical composition of the natural fluids within the pores of the formation influence drilling performance. The primary concern in geothermal projects is the presence of hydrogen sulfide. Beside being extremely toxic, this compound reacts with steel resulting in corrosion and hydrogen embrittlement. Embrittlement makes steel far more susceptible to the development of fatigue fractures by cyclical loads.

3 Petroleum Drilling Practices

3.1 The Drill Rig

The work horse of the petroleum industry is still the rotary drilling rig. In this system, the drill bit is attached to a series of thick-walled pipes called drill collars, see Fig. 1. The drill collars in turn are connected to the drillpipes which are much lighter and considerably more flexible than the drill collars. The drill collars and pipe come in two lengths, either 30 or 45 foot. The 45-foot sections are normally used on offshore drilling platforms. The very top section of pipe has a square cross section. It is called the kelly, and it fits into a square hole in the rotary table. This table, which is mounted into the floor of the drilling rig, rotates the drillstring which is composed of the bit, collars, pipe, and kelly. The drillstring is supported at the top by the hoist works and the derrick.

The weight of the entire drillstring is far greater than that necessary to drive the rotating bit into the formation. Consequently, the hoist works are used to pull back

Figure 1: The Rotary Drilling Rig

on the string during drilling operations. The actual weight applied to the bit usually varies between 40,000 and 70,000 pounds. As a result, the lower part of the string is in compression, and the upper part is in tension. The location of the transition point between tension and compression is usually kept in the drill-collar section of the string unless heavy weight drillpipe is used.

This makes the entire system appear like a large heavy pendulum with a large part of the weight concentrated in the drill-collar section. Often the drill bit may be several inches greater in diameter than any other component of the string. In such cases this pendulum effect tends to keep the bit traveling in a vertical direction. However, due to the rotation of the bit and the geological formation properties, the actual trajectory of the borehole deviates from vertical or is at best helical about the vertical axis.

Sometimes several stabilizers which have nearly the same diameter as the bit are placed in the drill-collar assembly. This stiffens the bottomhole assembly and, given proper placement, tends to maintain the existing trajectory of the wellbore. Drilling strategies make use of both these techniques to keep the well trajectory near vertical while maximizing the rate of penetration of the formation.

Regardless of the drilling strategy, clearances between the wellbore and the drillpipe are large. This is to accommodate high flow volumes in the circulation of the drilling mud. Tight clearances, which are accompanied by high flow velocities and large pumping pressures, are avoided. High flow velocities have the undesirable effect of either washing mudcake off the walls of the wellbore or washing out soft formations. Because of these large clearances, excessive rotational speeds which result in vibration of the string are not feasible. Rotation rates are normally about 100 rpm.

The cuttings produced by the drilling process are removed from the bottom of the hole by pumping mud down the hollow center of the drillpipe and collars to the bit. This mud then returns to the surface by way of the annulus between the drillstring and the wellbore. Typical flow volumes are on the order of 250 to 450 gallons per minute. The mud also exerts a hydrostatic load on the formation which prevents naturally occurring fluids in the formation from escaping to the surface.

The drilling process is controlled by the operator on the floor of the drill rig. He has several indicators by which he can judge and control drilling performance. They are the weight on the bit, the rate of penetration, the torque at the drive table, the rate of rotation, the flow rate of the mud, and the vibration of the drillstring. Given that the drill bit is usually thousands of feet below the surface, some of this information can be misleading.

For example, the weight on the bit is not a direct measurement. It is computed by subtracting the load on the hoist works from the total weight of the drillstring. If the string is sticking in the wellbore, the actual weight on the bit can be significantly different. By the same reasoning, the torque reading is not the torque on the bit. The standard procedure is to operate with only limited and possibly misleading information. Direct measurement of information at the drill bit and telemetry of this data to the surface is extremely complicated and expensive.

Currently, two types of power systems are used for turning the bit from the surface

and driving the mud pumps. The oldest is with direct drive by diesel engines. The newer system uses diesel units to power electrical generators which in turn power electric motors. With the electrical system, the operator has far greater control of drilling and pumping speeds. For example, it is quite easy to advance the pumps a single stroke with this system. The energy consumption on a large drill rig is on the order of a half megawatt. Most of this energy is used to drive the mud pumps.

Top-drive units are replacing some of the standard rotary systems [3]. With this system, rotation is achieved with an electrical motor attached to the top of the drill-string. The advantages of this system are not related to drilling performance, but rather to pipe-handling advantages between and during the drilling stages.

As the hole is being drilled, an additional section of pipe must be connected to the string every thirty feet. On a standard rig, this connection involves a complicated process to remove the kelly, add the new section of pipe, and reattach the kelly. The top-drive unit has a set of elevators and a break out system to assist in the handling, connecting, and torquing of the new pipe sections. This has significant impact on the overall drilling rate.

The speed at which a string can be withdrawn or *tripped* completely out of the hole can also be improved with a top drive. Here the advantages accrue because the string can be easily rotated and the mud can be circulated during the tripping process.

Consequently, the top-drive unit is gaining acceptance because it partially automates the pipe-handling process. Total automation would seem to be a natural next step. Automatic drilling machines, introduced into the industry more than 20 years ago, are available today [4]; however, they have not had significant impact on the market.

3.2 Drilling Fluid and Circulation Systems

Either mud or air is circulated down the center of the drillstring and up the annulus between the string and the wellbore. This fluid must serve several purposes. It must clean, cool, and lubricate the drill bit, carry away the cuttings generated by the drilling process, and provide sufficient hydrostatic pressure to contain the formation gases.

The petroleum industry typically uses both oil-based and water-based mud as the drilling fluid. They depend upon control of the viscous properties of the mud to be low enough for maintenance of circulation with reasonable pump pressures, but at the same time to be high enough to carry the cuttings to the surface. Caking properties are also important. Caking helps in the deposition of a coating on the wall of the wellbore which is necessary to inhibit the loss of fluid into the surrounding formation. At the bit, the mud is also forced through nozzles with the resulting jets being used to clean the teeth on the bit.

After the mud returns to the surface from the well, the cuttings are removed using screens and settling ponds. Samples of these cuttings are examined to ascertain the characteristics of the formation being drilled.

In the geothermal industry, after the production zone is reached and the well is

cased to that depth, formation gases often do not pose as serious a problem as that encountered in oil and gas drilling. For example, in the Geysers area near San Francisco, when these wells enter the hot production formation, they are drilled with air circulation. Typical flow rates are 3000 scfm. Use of air prevents contamination of the formation by the drilling fluid. Use of mud is also impractical since geothermal wells are drilled into formations which have very high permeability to liquids. These wells also have the added problem of high temperatures. Typically, these temperatures approach 500 F in the production zone. Water-based muds lose much of their beneficial properties at 250 F, [5] and [6].

Loss of circulation is a term applied to situations where the return of fluid to the surface is less than the amount pumped down the hole. For the petroleum industry, loss of circulation indicates a potentially dangerous situation. When mud is lost into the formation and not replaced, the mud level in the wellbore will drop and the hydrostatic pressure in the wellbore will also drop. Eventually the formation gases will escape, causing a blowout. Additives which cause the mud to gel and cake onto the surface of the wellbore are placed into the mud to reduce these problems. However, the primary method of controlling loss of circulation is to control the mud density. The mass density is kept at the minimum value to contain the formation gases. This value is usually low enough so that the hydraulic pressure will not exceed the fracture limit of the formation. If this condition is not achievable, the well must be cased, with the casing cemented into place.

3.3 The Drillstring

The drillstring is one of the most expensive components of the rotary drilling system. The drillstring is divided into two major sections, the drill-collar section and the drillpipe section. Along its total length, the drill-collar section has a uniform cross section. It is a uniform thick-walled tube with threaded connections every 30 or 45 feet. These connections are the weakest part of the collar assembly. Typically, drill collars weigh about 150 pounds per foot of length, although this number can vary from 20 to 350 pounds per foot. The collars provide the weight necessary to drive the drill bit into the formation. The total collar assembly weighs a fraction more than the required maximum drill bit load.

Above the drill collars is the drillpipe section. This is a far lighter and more flexible assembly. A typical weight for drillpipe is about 16 pounds per foot of length. Drillpipe also comes in either 30 or 45-foot lengths. They are threaded together with connections called tool joints. The tool joints have a cross sectional area which is four to five times larger than the main body of the pipe. Because of this design, the weakest part of the drillpipe assembly is located within the main body of the pipe and not the threaded connections. Also because of its flexibility and buckling characteristics, drillpipe is never allowed to support a compressive load.

The inside diameter of the drillstring is roughly 3 inches, while the outside diameter can be as large as 7.5 inches. This has important implications with regard to the design

of coring equipment. This will be discussed in later sections.

Because of the knuckles created by the tool joints, wear caused by abrasion with the formation and well casing is usually localized at the tool joints. During the normal useful life of a section of drillpipe, the cross sectional area of the tool joint will decrease about 30 percent. Sometimes when a dogleg in the well is encountered, the main body of the pipe wears a slot into the wall of the wellbore at the inside of the turn. This is called a keyseat. The pipe can slide through this slot, but the tool joints cannot. Keyseats cause severe problems when the drillstring is withdrawn from the hole.

The majority of drill collar and pipe is made from steel. Aluminum has found only a small application.² Each section of drillpipe is composed of two types of steel. The main body uses a common grade of carbon steel which is heat treated to one of several specifications. The tool joints are made from a higher grade of tool steel and are welded to each end of the main body. These components are designed to withstand abuse which occurs as much during assembly and disassembly of the drillstring on the rig floor as it does during actual drilling operations within the well.

With one exception, large clearances are maintained in the annulus between the drillstring and the wellbore. The exception is when stabilizers are used. These are short sections of the drill-collar assembly which contain helical ribs of steel with coatings of ultra-hard material. The ribs make contact with the wall of the wellbore, and as their name indicates they stabilize the rotation of the drillstring. This stabilizing action improves the performance of the drill bit by holding it on the center line of the hole. The trajectory of the drilling process is also maintained by using several of these devices placed along the length of the lower section of the drill-collar assembly. Optimal performance of the stabilizer requires a wellbore with a circular cross section and proper diameter. Proper stabilization of the bit is critical when core is being cut.

3.4 Drill Bits

Drilling in the petroleum industry is achieved almost totally with full-faced bits. These bits make contact with the entire cross section of the bottom of the hole. Coring bits which leave a central core that extends into the center of the drillstring are seldom used. Both types of bits use one of three different types of cutters. They are the roller cone, the polycrystalline diamond compact (PDC), and the natural diamond.

The roller-cone bit dominates in this industry. Three cones are used to create a full-faced bit, see Fig. 2. A variety of different tooth materials and patterns is used depending upon the hardness of the formation which is being drilled. Soft-formation bits use large teeth milled into the cone. The axis of rotation of each cone is skewed to produce a combination of rolling and sliding. Drilling is achieved by crushing and tearing the material from the bottom of the hole.

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²The Soviet project on the Kola Peninsula makes use of an aluminum drillstring primarily to reduce weight. This is currently the deepest hole in the world. Even using aluminum, the drillstring weights between 400 and 500 metric tons [7] and [8].

Figure 2: The Roller-Cone Bit.

Hard-formation bits use smaller teeth or button inserts. Less skew is used, and the motion of the cone approaches a simple rolling action. Drilling is achieved solely by impact and crushing.

The bearing seals in the roller-cone bit are temperature sensitive. Maximum operating temperatures are about 350 F. The geothermal industry reports that bit life is the most difficult problem to overcome in their drilling operations. This is a substantial concern, since drilling costs account for 30 percent of the cost of producing electricity by this method.

The effort behind the development of the roller-cone bit has been long and extensive. The process of manufacturing these bits is a combination of technology and the machinist's art. As a full-faced bit, they will cut through the widest range of formation hardnesses encountered by the industry and with high rates of penetration. In contrast, as a coring bit, development of the roller-cone system is limited. Coring brittle, hard rock is difficult when using a tool which operates primarily as a crushing device.

Both PDC and natural diamond bits operate on a different principle. They are drag cutters. Cutting is achieved by scraping and smoothly penetrating into the rock. The PDC bit uses penny-shaped disks of polycrystalline diamond mounted on a tungsten-carbide stud, see Fig. 3. As the bottom edge of the disk is drawn across the rock face, small pieces break off in a manner which produces a self-sharpening effect. These are a new generation of bits which are still evolving. They are used for soft formations, and have only limited success as a coring bit.

Natural diamond is the hardest known substance. It would be reasonable to expect that this industry would use this material to drill the hardest formations; however, this

Figure 3: Polycrystalline Diamond Compact Bit.

is not the case. Natural diamond bits are used for soft to moderately hard formations. These bits are manufactured by casting stones into a tungsten-carbide matrix. Cleaning is very important when using these bits. Numerous flow paths are molded into the face of the bit to allow for passage of the drilling mud. This type of bit has a reputation for highly inconsistent performance. It is not unknown for them to be damaged after only a foot or two of drilling.

As Section 4 will show, this experience with natural diamond bits is in sharp contrast to that of the mining industry where they typically drill hundreds of feet in very hard formations. The reason for this difference in performance resides with the manner in which these bits are used. Natural diamond is temperature sensitive and brittle. In order to cut properly, impact must be avoided and the cutting element must be drawn across the rock surface at a velocity and contact pressure which avoids vibration and excessive heating. When full-face bits are used, this is impossible. The cutting elements in the center are always moving at a very slow velocity, even when the circumferential elements are moving too fast. In general, because of the clearances and balancing of the drillstring, the rate of revolution of the bit is always too low for effective cutting with natural diamond bits.

This situation is not completely alleviated even when a coring bit is used. Since the coring bit does not have a full face, the variation in velocity between the inside-diameter cutting elements and the outside-diameter elements is smaller. However, because the petroleum industry uses thick kerfs on their coring bits, the variation is still significant and degrades the performance of the tool.

3.5 Coring Methods

Conventional coring is an expensive operation in the oil field. Usually only short core samples (10 to 60 feet) are recovered at specified depths in the drilling program. This is achieved by tripping the drillstring out of the well and attaching a hollow core barrel and coring bit to the bottom end of the string. The string is placed back into the hole, and the core is cut. The string is then removed again to recover the core sample, remove the barrel and core bit, and rebuild the drilling assembly. Typically, core recovery costs are about \$1000 per foot.

Two types of core barrels are used, see Fig. 4. The oldest type is simply a single hollow tube which rotates with the drillstring. This either results in relative motion between the stationary core sample and the rotating barrel or the core is twisted off. The newer type of barrel has two hollow tubes. The inner tube is attached to the outer tube through bearings and thus can lock onto the core sample without twisting it off. With these systems, the diameter of the recovered sample is about 2 to 3 inches less than the diameter of the wellbore.

A new innovation in coring capability within the oil field is the wireline coring system. An outer core barrel and coring bit are attached to the bottom of the drillstring. After the string is tripped back into the hole, the inner barrel is floated down the center of the drillstring. Upon hitting bottom, the inner barrel latches into position, and the drillstring is rotated to cut core. When the inner barrel is filled or when the inner barrel sticks, it is retrieved by lowering a wireline down the center of the drillstring. The wireline attaches to the top of the inner barrel and causes the latch to release. The inner barrel is then fished back out of the well by rewinding the wireline. Another inner barrel can then be floated into position.

Since the inner core barrel and sample must be able to drift through the center of the drillstring, core diameters are even smaller than with conventional systems. Also coring bits used with this system must have wider kerfs to make up for this diameter difference. The ratio of the inside diameter to the outside diameter of the bit is about 2/9, [9].

One of the key elements in the design and successful use of the core barrel is the core catcher. This is a lock ring located near the bottom of the inner barrel. Its function is to provide a one-way direction of travel for the core sample. It allows for entry of the sample into the barrel, but inhibits movement and breaks off the sample at the base as the core barrel is removed from the hole. If this device malfunctions, the core can slip back out of the barrel. The core sample can also be twisted off prematurely. A large percentage of the sample can be lost.

Another important factor in the operation of the coring system is stabilization. Poor stabilization can result in excessive vibration and damage of the sample. Typical recovery rates in hard formations are about 40 percent; that is, if 10 feet of hole is cored, 4 feet of core is recovered. Improper stabilization is blamed for most of the loss. This situation is aggravated in formations which breakout to produce elliptical boreholes. Stabilizers do not work in these situations.

Figure 4: Core Barrels.

Side-wall coring devices are also available. These tools remove core samples from the wall of the borehole. They are lowered by wireline into the hole after the drillstring has been removed. In some of the tools a coring cutter is explosively launched into the wall and then retrieved. The resulting samples are usually of poor quality. In another tool, see [10] a motor is used to rotate a diamond coring bit and core barrel into the formation wall. Short, one-inch diameter samples are recovered.

3.6 Directional Drilling

The need for directional drilling (other than straight down) occurs most frequently on offshore drilling platforms or on artificial islands. In these cases it is easier to drill the well from the platform or island to the formation rather than relocate the rig over the formation.

Another occasion for directional drilling occurs when the lower portion of a well has a sharp dogleg or is blocked with "junk" resulting from equipment failure. In these cases, the bit is pulled back to a higher elevation. It is then deflected into the sidewall, and drilling proceeds along a path which avoids the problem.

Two devices are commonly used to achieve the required change in direction. They are the whipstock and the downhole motor. The whipstock is simply a metal wedge which is dropped into the borehole ahead of the drillstring. If necessary, it is aligned to deflect the bit in the proper direction—north, south, etc. Drilling then proceeds as before, and the whipstock forces the bit into the opposing sidewall.

The downhole motor is a far more sophisticated tool. With the exception of the Soviet Union, positive displacement mud motors are almost universally used—the Soviets use mud turbines. A positive displacement mud motor or Moineau motor is shown in Fig. 5. The flow of mud axially along the central shaft causes it to rotate. The pattern of motion is complex, causing the centerline of the shaft to both rotate and translate about the centerline of the motor stator. A flexible coupling is used to transform this complex motion into simple rotation for turning the bit. This is called a positive displacement motor, since unlike a turbine, the amount of rotation of the drive shaft is directly proportional to the amount of mud forced through the motor.

When these motors are used for directional drilling, the bit is attached to the lower end of the motor and an elbow with approximately 1 or 2 degrees of bend is attached between the motor and the rest of the drillstring. Mud is then pumped through the motor while the drillstring is advanced into the hole without rotation from the surface.

These motors are expensive to use. They can double the cost of drilling. The stator of the motor is a polymer which is cast into a steel case. This polymer component as well as the main thrust bearing which transfers the load from the drill collars to the drill bit must be rebuilt after about 100 hours of operation. The polymer stator also limits use of these tools to temperatures below 250 F.

Figure 5: The Positive Displacement Motor.

4 Mining Drilling Practices

4.1 The Coring Rig

The mining industry's primary motivation for drilling is to retrieve core samples and examine them for mineral content. A rotary drilling system is also used in the mining industry. A diamond coring bit is attached to a thin-walled tube called a drill rod. Drill rods come in 10-foot lengths which are threaded together to form a drillstring. At the surface, the drillstring is rotated with a hydraulic drive which is powered by a diesel engine. The hydraulic unit not only rotates the string, but also applies an axial load to the string forcing it into the formation. Typical loads on the coring bit are about 10,000 pounds. The diesel engine and the hydraulic unit are mounted to the floor of a drilling platform. A hoist works and derrick are also mounted on the platform, see Fig. 6. Typical hole diameters range from 2 to 5 inches. The drillstring is rotated at about 1000 rpm, and clearances between the drill rod and the borehole wall are small in order to reduce vibration. Several reamer shells are placed in the drillstring a short distance above the bit. These shells are used to ream the hole out to the specified diameter to further insure proper operation of the drilling system.

Mud is pumped down the center of the drillstring, past the face of the coring bit, and up the annulus between the wall of the hole and the drill rod. Typical flow rates are about 20 gallons per minute. The lubricating qualities of the mud are important to reducing sticking and vibration of the drill rod.

Core is cut continuously in this operation. It is collected in an inner coring barrel, similar to that shown in Fig. 4. After 10 feet of coring, the drillstring is stopped, and a wireline is used to retrieve the inner barrel and core sample. A new inner barrel is dropped down the center of the string and drilling proceeds for another ten feet. Thus the volume of material removed from the borehole is about twice the volume of material actually cut by the bit.

The drilling operator has little real-time information to indicate drilling performance. Normally, rotation rate is not measured. Instead the operator listens to the diesel engine for a "measure" of torque and speed. Rate of penetration is available and is watched carefully. The flow of mud into and returning from the well is also monitored. Finally the amount and quality of the retrieved core is an indicator of drilling performance.

The trajectory of the drill bit can be controlled to a certain extent by altering the drilling speed and the rate of penetration. The types of reamer shells, clearance between the hole and the drill rod, and the sharpness of the drill bit also can be used to control direction.

In this country drilling experience is limited to about 5000 feet maximum depth; however, systems are available to drill to 10,000 feet. In South Africa coring rig drives have also been mounted onto small petroleum drilling platforms. These systems have drilled to between 15,000 and 20,000 feet in highly uniform geological formations.

Figure 6: The Coring Rig.

4.2 Drilling Fluid and Circulation Systems

Mining projects are normally drilled into crystalline rock formations which do not have an abundance of natural gases. Losing a well because of a blowout condition is not a primary concern. Thus the muds used in these wells are not designed to contain formation gases. Instead the mud provides lubrication between the rods and the wellbore, and it provides for cleaning of the bit and removal of the cuttings. High temperatures affect drilling operations primarily by destroying the lubricating qualities of the mud. At 700 F, these properties are completely eliminated.

Loss of circulation of the mud into the formation is frequent and a condition which does not necessarily cause concern. Drilling can continue for hundreds or even thousands of feet after return circulation has been completely lost.

Because of the small clearances between the rods and the wellbore, high mud velocities can be achieved with small flow volumes—about 5 to 15 gpm. Since diamond bits are used, the cuttings are also fine and more easily removed by lower flow velocities. Since the formations are hard, washing out the formation through circulation of the mud is also a problem of minor importance.

4.3 The Drillstring

The drillstring is composed of ten-foot sections of drill rod ranging between 1-3/4 and 6 inches in outside diameter. When the rods are threaded together (usually with a hand-held wrench), the outside diameter is constant along the length. The inside diameter decreases only slightly at the threaded joints. The weakest point in the string is at the thread connections. Drilling depths are limited by the ability of a connection to support the total weight of the string. The walls of the rods are relatively thin; for example, a 5-inch diameter rod has about a 1/2-inch thick wall at the tool joint and a 1/4-inch thick wall in the main body.* This allows for larger diameter core samples, and thinner kerfs on the coring bits.

The rods come in a range of sizes. A drilling project is started with a large size. Drilling proceeds to a specified depth or until the rods stick in the hole. These rods are then left in place as well casing, and the next smallest size of rod is assembled and lowered through the center of the first string. This can be repeated over again, since each step down in size nests into the previous string.

Rods are constructed from drawn 4130 seamless tubing. Some have variable wall thickness. This type of tubing is sensitive to hydrogen embrittlement. When used at elevated temperatures, fatigue fractures become a serious concern.

The threads are machined into the tubing, and alignment and balance are carefully controlled. When rotated rapidly, the assembled string is subject to bending mode vibrations. The manufacturer of the string usually supplies an analysis which indicates the rotational speeds where vibration is a problem.

4.4 Coring Bits

The mining industry makes nearly exclusive use of diamond coring bits. Because of the thin-walled drill rod, the kerf on these bits is relatively small. The inside diameter is about $2/3$ of the outside diameter [9]. Thus the tangential velocity between the diamonds and the formation, called the cutting speed, is relatively uniform across the bit face. High rotational speeds and low bit loads also contribute to the success of this type of bit.

Two types of diamond bits are used, the surface-set type and the impregnated type. The surface-set bits are constructed in a manner which is similar to the methods employed for diamond bits in the petroleum industry, see Section 3.4. The impregnated bits use small diamond grit which is uniformly distributed in a matrix material. A 2535 grit, which is about 2400 stones/carat, is the most popular grade. As drilling proceeds, the matrix material wears away and continually exposes new cutting elements to the formation.

The impregnated bit is becoming very popular. It comprises about 80 percent of the product of some bit manufacturers, and it accounts for 97 percent of the last 25 million feet of core cut in the Canadian mining industry.

The impregnated bit is routinely capable of drilling hundreds of feet through hard granitic formations. Penetration rates are on the order of 10 feet per hour. The operator must take care to avoid overheating or polishing the bit face. Impregnated bits are particularly sensitive to the effects of polishing. When these bits are used, the operator usually varies the thrust load on the bit in order to maintain a constant rate of penetration. If the penetration rate falls to zero, the bit will polish the formation and itself.

Temperatures below 1600 F do not seem to present serious problems to these bits. The diamonds are temperature sensitive and begin to carbonize at 900 F. However, this process can be slowed considerably by adding carbon dioxide to the drilling mud. Impregnated bits in combination with jet nozzles for injecting cool drilling fluids at the bit face were used several years ago by Sandia National Laboratories to drill into molten rock at the Kilauea Iki lava lake in Hawaii [11].

4.5 Coring Methods

The wireline coring system, developed by this industry, is used exclusively. Diamond coring bits and tight clearances which provide good stabilization produce high quality samples.

The gage of the hole is carefully maintained with sharp coring heads and reamer shells. The hole is often reamed open by slowly feeding the rotating bit and shells through the hole on a second run. The relatively thin-walled rods and the small clearance between the rods and the formation allow the diameter of the core sample to be about $2/3$ of the diameter of the wellbore. In addition to reducing the amount of rock which must be cut away, this also allows small kerfs which optimize bit performance.

Figure 7: Core Jamming.

Core jamming is a problem. The classic situation is illustrated in Fig. 7. The sample either has a natural or an induced fracture and wedges itself into the barrel. When this occurs, the advance of the coring system is arrested, and the inner barrel must be withdrawn. One type of core barrel is available which has an impact device attached to it. The hammer action counteracts the wedging action and allows the advance of the core barrel to continue [12].

5 Contrast Of Drilling Practices

The most apparent difference between the coring rigs used by the mining industry and the drilling rigs used by the petroleum industry is size. The top of a coring rig usually does not stand much taller than the floor of a petroleum rig. In terms of volume of equipment on the site, the petroleum system is at least 100 times larger than the mining system. Why?

One obvious reason is that petroleum equipment is used to drill holes that are about twice as large in diameter and twice as deep. Full faced bits are used instead of coring bits. Consequently, more than 10 times the amount of material is drilled out of the hole in an oil field project. Also additional equipment is required to control the formation gases which are not normally a problem in mining operations. The oil field system must also deal with complicated casing and well completion programs. But putting all of this together still does not completely explain the size difference.

In the oil field, one of the reasons equipment is big and heavy is because people

think that it has to be big and heavy. Equipment is over designed. To some extent this view is also prevalent on coring rigs, but not to the same degree. The mining industry's lighter equipment is partially connected to its operating philosophy. The equipment is designed to operate at high rotational speeds and cut rather than pulverize the formation.

To a large extent the differences in drilling methods are also controlled by the types of natural formations which are encountered. The petroleum industry must deal with much softer formations which contain large amounts of formation gases. One result of this is that mudcake must be formed and maintained on the walls of the wellbore. This requires large clearances between the drillstring and the wall of the well. These requirements do not allow rapid rotation of the drillstring. This puts severe limitations upon the use of diamond bits.

The mining industry usually drills in hard crystalline rock. They are not often concerned about washouts or blowouts. The softer formations drilled by the mining industry are usually at the top of the hardness scale of most oil field projects.

The different views held by these two industries with regard to the diamond bit is also significant. The mining industry's viewpoint is expressed in the *Diamond Drilling Handbook* [13], which states that "For exploration drilling the mining industry worldwide uses almost exclusively diamond coring tools." Thus for them the diamond bit is the only tool to use for hard brittle formations.

In contrast the petroleum industry's viewpoint as expressed in *Applied Drilling Engineering* [14] is that "Diamond bits perform best...in nonbrittle formations that have a plastic mode of failure for the stress conditions present at the bottom of the hole." Furthermore, it is not a tool of first choice. It is used only when absolutely necessary.

This difference of viewpoint stems not only from the differing rotational capabilities of the equipment, but also from the methods used to thrust the bit into the formation. The oil field uses the weight of drill collars and pulls back on the assembly with a hoist and mechanical brake. They operate at about 100 rpm and between 40,000 and 70,000 pounds load on the bit. The mining operation uses a hydraulic feed which can be controlled with greater accuracy. They operate at about 1000 rpm and 10,000 pounds load on the bit. The diamond bits require this speed and control.

The petroleum industry drills wells to extract fluids from the formation, and the mining industry drills wells to obtain core samples. Consequently, the capabilities to obtain core by mining techniques are far in advance of the petroleum methods. Ninety-five percent recovery of core samples using wireline methods is typical. Often, the sample recovered from a diamond coring operation has the appearance of a sample which was machined in a laboratory.

Coring with roller-cone bits cannot produce these results. The oil field system recovers more on the order of 30 to 50 percent of the footage traveled by the core bit. In hard rock formations, the bits seem to do a good job of breaking off the core before it enters the barrel. Some advances are being made to improve this situation; however, even when core is collected, the roughness of the surface of the sample significantly

degrades the ability of the core catcher to latch on to it.

In a few situations these differences between diamond coring and roller-cone coring are irrelevant. At extreme depths the in situ stresses are so high that the sample shatters as it is being cut. This is the situation with the deep Kola well [7]. In this case the core barrel simply catches the pieces which are released as the roller-cone coring bit advances.

Unfortunately, while the coring capabilities of mining equipment are superior, the depth and diameter limitations are severe. The ability to maintain directional control of the wellbore is also limited when compared to the oil field. It is not unknown for a well to uncontrollably deviate more than 25 degrees in 100 feet. Devices similar to whipstocks can be used, but due to the low flow rates of the mud, mudmotors are not used.

6 Hybrid Drilling Systems

The object of a hybrid drilling system is to couple the capabilities of diamond coring tools with the depth, diameter, and directional drilling capabilities of the oil field system. To date the most ambitious effort in this area has come from the **Ocean Drilling Program** at Texas A & M University [2]. The hard rock coring system developed by this project uses a small mud motor as its key element, see Fig. 8. The coring bit, core barrel, and mud motor form a unit which can be wirelined through the main drillstring. This drillstring is composed of modified conventional drillpipe. The inside diameter is slightly larger than normal to allow for passage of the mud motor. A roller-cone, hole-opening bit is placed at the end of the drillstring. Thus the roller-cone bit can be rotated with the drillstring at roughly 70 rpm, while the diamond coring bit can be rotated by the mud motor at approximately 125 to 250 rpm. In addition, the drillstring acts as a stabilizer for the core barrel and bit.

A large volume of liquid is pumped down the drillstring to drive the mud motor. After the flow exits the motor it enters a piston and cylinder assembly or "fluid spring" which hydraulically drives the coring head into the formation. The flow is then divided through a pressure relief valve. A small portion of it is forced past the coring bit while most of the flow returns up the wellbore.

This design recognizes the importance of using higher rotational speeds and low thrust loads with the diamond coring system; however, there are some drawbacks. First, the rotational speeds of the coring head, while higher than normal petroleum drilling speeds, are still low for mining-style bits. Second, there is no way of determining when the core barrel is filled. There are methods being considered to correct this. Third, except when the fluid spring collapses completely, there is no direct way of sensing or controlling the rate of penetration of the coring bit. Thus polishing of the bit face cannot be recognized and avoided. Fourth, the system relies heavily upon the capabilities of the roller-cone, hole-opening bit.

Due to lack of market pressure, this type of roller-cone bit has not been developed to the same degree as full-faced bits. Experience with using hole-opening bits shows that

Figure 8: The Ocean Drilling Project's Hard Rock Coring System.

this type of bit tends to suddenly jam into the formation. This is suspected to occur when a portion of the shoulder which is being drilled by the bit suddenly collapses. The roller cones fall into the cavity. This results in the twisting off of part of the drillstring. This project has experimented with several alternative hole-opening bit designs. Both four and six roller cones have been used. Also reversing half of the roller cones has been tried. At present this hybrid system is still under development, and little is known about its ultimate performance capabilities.

Another attempt at testing a hybrid drilling principle was carried out at the Cajon Pass Project under the direction of Deep Observation and Sampling of the Earth's Continental Crust, Inc. (DOSECC) [15]. In this project several companies which produce mining style core bits were contracted to produce two sizes of large-diameter, wide-kerf, diamond-impregnated coring bits. The larger bit had an outside diameter of 8.5 inches and an inside diameter of 5.375 inches. The dimensions for the smaller bit were 6.5 and 4 inches, respectively. The bits were rotated in one of two ways, either with a large mud motor mounted to the end of a petroleum drillstring or by rotation of the drillstring itself. Not surprisingly, the bits which were rotated by the drillstring were damaged immediately and made only one or two feet of core. The bits which were run by the mud motor at speeds up to 400 rpm were still usable upon removal from the well. Estimates of the their potential life were in excess of 100 feet [16].

The final example of a hybrid system has been used successfully by the mining industry on one or two occasions to increase drilling depth capabilities. This system uses both drill rod and drillpipe to make up the drillstring. The drillpipe is used in the upper section of the wellbore. Petroleum-style tool joints and large clearances are employed.

The drillpipe is dynamically balanced to allow surface rotation at high rates. The weight on the bit is achieved with drill collars. The lower section of the well is drilled with mining-style rods and impregnated diamond bits. The surface rig is a small petroleum workover rig which is fitted with a hydraulic drive unit.

Several things are suggested from the experience obtained in these projects. First, the current technology of diamond coring bits requires cutting speeds which are beyond the rotational capabilities of conventional petroleum equipment. Second, the sizes of bits used in the mining industry (6 inches or less) are not necessarily a limitation. Larger diameter bits with wider kerfs are possible. Third, the mud motor is an effective way to produce the rotational speeds required by mining style bits.

7 Technology Development

Two technologies exist which can be exploited to achieve the goal of economic recovery of large quantities of core samples from deep, hard, high-temperature formations. The petroleum industry has developed capabilities to drill large diameter and deep holes. Given sufficient funding of the project, they can also carefully control the trajectory of the drilling operation. The mining industry can economically recover high quality core

samples even in high-temperature formations. All that needs to be done is to bring these two capabilities together.

That is not a simple task. By the nature of these projects, trying even some obvious ideas becomes complicated and expensive. Thus very few efforts to develop hybrid systems have been undertaken, and those have not dealt with the problems of high temperatures.

In Section 6 two types of hybrid systems were discussed. The first system involves fitting a downhole motor to a petroleum system with the goal of providing rotation rates and bit loads which are compatible with impregnated diamond coring bits. The second system involves modification of the petroleum-style rig and drillstring to provide high rotation rates and improved feed control. It is not clear which is the superior approach. The choice in the future will surely depend upon the specific drilling project. In general, each drilling project has its own special problems. Specialized tools and on-site innovation are always required. These tools are built from components, and for the average drilling project, most components are there. However, for the special projects which fall within the topic of this report, many components are missing.

This section presents a list of components which are not available or which need improvement. Each subsection presents a technology development project which could have significant impact on a large number of future geothermal drilling projects. The list with accompanying discussion is presented in no particular order of importance. Any allusion to completeness is not intended.

7.1 Stabilizers

Stabilization of the core barrel and the coring bit is critical to the process of obtaining high quality core samples. In hard brittle formations, vibration and gyration of the bit and barrel will break off the sample and possibly induce jamming of the sample in the barrel. In highly stressed formations the sample is even more delicate, and the wellbore is more unstable.

Current petroleum stabilizers and mining reaming shells rotate with the drillstring. They work in holes with proper diameter and circular cross section. When the gage of the hole is lost or when breakout due to stress and thermal effects causes the cross section of the wellbore to become elliptical, the function of the conventional stabilizer degrades significantly.

It is not obvious that use of downhole motors to rotate the core bit will improve this situation. Positive-displacement mud motors are grossly out of dynamic balance. This is inherent in the complex rotating and translating pattern of the drive shaft. Thus the problem may be even more severe than when rotation from the surface is used.

One possible solution to this problem is to use a non-rotating stabilizer. The pressure from the mud pumps could be used to radially expand arms or movable splines against the wall of the wellbore. As the bit advances, these components would slide vertically against the formation.

A comprehensive examination of the dynamic loads generated during coring operations is required, and innovative designs need to be generated and tested. Because complexity is introduced into the system with each new design in the form of additional bearings and seals, the effect on the reliability of the total system must also be examined.

7.2 Impregnated Coring Bits

The crushing action employed by roller-cone bits does not produce quality core samples. Typically the sample is fragmented or has a rough surface which compromises the function of the core catcher.

The surface set diamond bits used by the petroleum industry also have poor capabilities. The reasons apparently are related to the wide kerfs which are required by the core barrel-drillstring assembly, the poor control of load and advance of the bit, and the limits on the maximum rotational rates when surface rotation is employed. Typically one diamond is first damaged on the bit face. This results in a domino effect which successively damages the trailing diamonds located along a constant radius. A ring region is formed in which all the cutting elements are destroyed.

In contrast, the mining industry is turning more and more to coring with impregnated diamond bits. When a diamond element is damaged, it is abraded away and a fresh cutting element is exposed. The function of these bits is linked to the properties of the matrix material which contains the diamond grit. Quantitative understanding of the precise role played by the matrix is still evolving; however, it seems clear that matrix properties can be manipulated to produce large diameter-wide kerf bits which will operate at reduced rotational rates approaching the rotational capabilities of the petroleum drill rigs [17].

Laboratory testing of impregnated bit designs is needed. This would improve our understanding of the mechanisms which affect the performance of current bit designs; that is, the complex interaction between the matrix material, diamond grit, and geological formation. Experimentation with new matrix materials to achieve tools which operate at both a lower and a wider range of speeds would be possible. This would lead to designs for larger diameter bits with wider kerfs which are more compatible with the petroleum methods of drilling.

Because the outside diameter of the bit moves faster than the inside diameter, matrix properties of wide-kerf bits are always a compromise. One possible way around this problem is to investigate the use of matrix materials with properties that vary radially across the face of the bit.

A program to experiment with the use of these bits on petroleum rigs is also needed. This would include the use of a retrofitted hydraulic feed system on a small petroleum platform, and a drillstring which has been dynamically balanced, see Section 7.3. This system would allow higher rotational rates and better control of penetration rate.

7.3 Drillstrings

The drillstring is one of the most important and expensive components of the drilling system. Both the mining and the petroleum industries use drillstrings that are designed for specialized tasks. These tasks are discussed in Sections 3 and 4. The specialized task of drilling and coring large-diameter, deep wells into high temperature formations differs from these conventional requirements. This job is best done with a specialized drillstring designed specifically for this purpose.

The use of mining-style drillstrings is limited to about 10,000 feet. Beyond this depth, the drillstring simply cannot support its own weight. The mining industry's efforts to extend this depth requires them to partially abandon their usual design and adopt a string which is more like a petroleum design in the upper section of the hole. Larger tool joints are used to overcome the stress-concentration effects at the threads.

Petroleum-style drillstrings, strictly from an engineering point of view, are over designed. They are designed to survive abuse. Usually only visual inspection methods are used to examine the pipe. The standard inspection techniques, eddy current and magnaflux methods, for locating cracks due to fatigue and hydrogen embrittlement are not trusted. These strings are also designed for soft, not hard, formations. This means that large clearances between the wellbore and the drillstring are employed to reduce the mud-flow velocities and accommodate the flow of dense, high-viscosity mud.

When drilling occurs in hard formations where control of formation gases and washouts are far less of a problem, the cuttings are smaller and can be removed with lighter, less viscous muds flowing at greater velocities. Tighter clearances between the wellbore and the drillstring allow a significant increase in the inside diameter of the drillstring. Consequently, larger samples and larger downhole motors can be wirelined through such a string. The design of the coring bit is also affected in that coring bits with smaller kerfs can be used.

Some projects proposed for extremely hot environments (1000 F) will require high flow rates and thermally insulated drillpipe [18]. In one respect, this may prove to be an advantage. The use of insulation will increase the depth capability of the drillstring by increasing its buoyancy. An 1/8-inch of insulation on an aluminum drillstring can increase its apparent strength-to-weight ratio by 50 to 100 percent, depending upon the density of the drilling mud in the well.

Trade-offs which recognize the advantages and limitations of other metals such as aluminum and titanium in comparison to steel must be considered in new designs. Furthermore, the role of hydrogen sulfide and hydrogen embrittlement of alloy steel must be more clearly understood. There is argument over whether or not elevated temperatures stimulate or inhibit the embrittlement process.

Unfortunately, the depths and the cooling requirements of these projects do not allow the tight clearances and low flow rates employed by the mining industry. To achieve higher rotational rates, dynamic balancing of petroleum drillstring will have to be employed. Balanced drillstrings can probably be rotated at 500 rpm.

By analyzing and testing several new drillstring designs, the best overall coring and

drilling strategies will be defined. Determining the feasible rotation rates, insulation capabilities, field inspection procedures, and pipe dimensions will help to better understand system trade-offs. The choice between using a wirelined downhole motor and core barrel versus high-speed surface rotation of an oversized impregnated bit is integrally connected to careful study of this problem.

7.4 Downhole Motors

Downhole motors are a key element in the development of hybrid coring systems. For drilling or coring at extreme depths (greater than 20,000 feet), motors may be an integral part of all operations. Currently, two type of motors are in use—the positive displacement motor (PDM) and the turbine.

In western countries, with the exception of the North Sea, the PDM is the most used of the two. Two reasons contribute to this. First, the speed of the drive shaft is low and directly accommodates the use of roller-cone bits; and second, the speed is directly proportional to the mud-flow rate. Thus, this motor does not need a transmission or a tachometer. Unfortunately, because of the large amount of polymeric material used in the PDM, it cannot operate above 250 F. It is believed that a PDM could be built to operate at higher temperatures; however, this has not been tried.

Commercially available turbines use polymer seals and have the same temperature limits as PDMs; however, straightforward design modifications of the bearings could easily raise this temperature limit to 500 F [19]. The main impediment to the acceptance of the turbine is the high rotational rates and the lack of positive control on the rotational rate. Most turbines operate at too high a speed to be used with roller-cone bits. However, this is not a drawback to using turbines with impregnated bits which require high speeds.

Drilling projects in high-temperature formations will require downhole motors not only for coring operations, but also for directional drilling capabilities. Overcoming the temperature limitations of the turbine seems a far easier task than upgrading the polymer components of the PDM.

7.5 Stress Phenomena in Wellbores

Wellbore breakout is a critical problem in many wells located in brittle and highly stressed formations. In tectonically active regions, the in situ stresses may reside at or near the yield point of the formation. Drilling will then severely alter the natural state of stress and result in failure of the formation in the neighborhood of the wellbore. This usually results in the development of an elliptical cross section to the wellbore. This situation has occurred in both the Kola well and the Cajon Pass well. In the later case, a 6-1/4 inch drill bit resulted in an elliptical hole with dimensions of 6-1/2 by 17 inches. Breakout occurred simultaneously with the passage of the drill bit. Breakout can also occur over a longer period of time. In either case, the results can significantly

inhibit or even halt the progress of the drilling project by severely limiting the ability to stabilize and control drilling direction.

Breakout usually occurs along the direction of minimum principal stress in the plane perpendicular to the wellbore trajectory. At this point the formation experiences the maximum differential or shear stress. During failure of the formation, the deformation of the formation in the neighborhood of the wellbore localizes into bands. The formation assumes a layered appearance similar to the skin of an onion.

Understanding the mechanics of this process is important. Factors such as wellbore trajectory and mud density can directly influence breakout. Potentially, the phenomena itself is an indicator of the in situ stress state.

The low thermal diffusivity of rock also plays an important role in this process. A small amount of circulation of cooling fluid in the wellbore can produce significant localized cooling of the formation. Because circulation is not always maintained in the well; for example, during tripping of the drillstring, the wall of the wellbore is subject to thermal cycling. This results in cyclic stresses which aggravate breakout.

A combination of theoretical modeling, laboratory experiment and field simulation of wellbore breakout could answer many questions central to the success of the drilling project and the maintenance of the well after completion. Modeling should include development of constitutive models for failure and shear banding phenomena as well as finite element analysis of three dimensional stress effects. Laboratory experiments should be directed towards studying the influences of confinement, temperature, and formation anisotropy.

7.6 Hole Openers

One important strategy for continuous coring in large diameter holes is to initially core ahead with a small mining-style bit and then hole open with a roller-cone bit, see Section 6. Hole opening bits are dangerous tools to use. The danger is compounded in brittle formations.

During hole opening the drilling bit rests on the flat shoulder. The inside diameter of the shoulder is that of the coring bit, and the outside diameter is the final diameter of the hole. Roller-cone bits are normally used. Their action can result in sudden collapse of a portion of the shoulder. This can cause the bit to suddenly stick and twist off. If a non-circular hole is drilled by the coring bit, or if the hole opening bit walks off center, the situation can be worsened.

The design problem involves producing a bit which is less likely to generate the situation leading to sticking and which can survive sticking without twisting off. A few modifications of roller-cone bits have been tried, see Section 6; however, the problem deserves more attention. Once again, given the nature of these hard and brittle formations, impregnated bits may be a better choice provided the rotational rates and bit-load control can be achieved by surface rotation. Studies of this type are best done with laboratory drilling mills and testing on rock samples in which shoulder collapse can be induced at will.

7.7 Side-Wall Coring

A variety of methods have been tried to extract core samples from the wall of a well. The wall saw is one of these devices [9]. Two circular abrasive saws extend into the formation from differing angles until they meet. They then travel down the wall of the well, and saw a triangular wedge of material out of the formation. Experience with this type of tool indicates that it sticks about 85 percent of the time.

Explosively driven core barrels are also used, [20] and [21]. In soft formations, these devices recover poor quality samples—usually rubble. In hard formations, this tool has little chance of success.

Coring tools which rotary drill into the wall of the wellbore with small diamond coring bits also exist, [22]-[24]. They take relatively small core samples (about 1-inch diameter), and are temperature limited by their bearing seals and electrical components. Experience with these devices indicates reliable recovery of quality core samples.

Several improvements can be made to these devices. First the temperature capability can be improved to about 400 F by replacing polymer seals and protecting electrical components and motors. Second, the sample size can be increased to about 2.5 inches in diameter and 2 inches in length.

7.8 Measurement While Drilling

It is clear that real-time recovery of data collected at the bit during drilling and coring will significantly improve the economics and success of most types of drilling operations [1] and [26]. Compared to drilling a well, cutting and recovering a quality core sample is a far more complicated task. When using conventional coring methods, the process depends upon the stabilization of the core barrel, the rate of penetration of the formation, the rotational speed of the bit, the sticking or lack of sticking of the core sample in the barrel, the extent to which the barrel has been filled, and the proper operation of the core catcher. Usually any knowledge of the conditions at the bottom of the hole has to be indirectly inferred from information at the surface.

When the slender drillstring reaches several miles or more into the earth, rotational speed and rate of advance of the hoist works are only related to bit rotation and rate of penetration in some average sense. The vibration of the string cannot be correlated to a poorly stabilized core barrel; the weight on bit is a poor, inaccurate measurement of core sticking; and the indication that the core catcher has not worked is only obtained after the string is withdrawn from the hole without the core sample. All of this is added to the usual concerns about determining and controlling the trajectory of the hole.

This is the situation with conventional methods of coring. If hybrid systems are developed, the direct measurement of these parameters and the telemetry of this information to the surface becomes even more important. For example, with mud turbines there is no direct correlation between mud flow rate and turbine speed. Also with these systems, the relationship between the rate of advance of the hoist works and the rate of penetration of the bit is lost.

With the usual limitations that high temperatures place upon the use of electronics, these diagnostics can be readily measured. Accelerometers can measure stabilization effectiveness; acoustic pulse-echo methods can measure core sticking, rate of penetration, and the amount of core within the barrel; and tachometers and dynamometers can measure rotation and torque. The critical problem is not measurement but rather a method for telemetry of this information to the surface.

One type of telemetry system is commercially available from several sources—the mud pulse system. It transmits data as a series of pressure pulses in the mud column within the drillstring. It has two major limitations. First, it cannot be used during air drilling operations. This excludes its use for a major percentage of geothermal drilling projects. Second, it has extremely low data transmission rates—about 2 to 4 bits per second.

Two possibilities exist as alternative methods of transmission. They are the wireline method and the acoustical method. The wireline method is relatively straightforward, but limited in use to those situations in which wireline coring methods are employed. The concept is simply to leave the wireline in position during coring operations, and to use it as an electrical conductor for data transmission. It is normal to rotate the drillstring even if a downhole motor is employed. Consequently, provision must be made to also rotate the wireline spool.

The acoustical method is more complex. It relies upon the metal drillstring as a transmission medium. Research into this method has occurred over several decades with only limited success. The primary contributor to this work has been **Sun Oil Company** [27]. They have not been able to produce an operating system, and have abandoned their project. **Exxon Production Research** has also worked in this area [28]. They have developed an operating system which can communicate both up and down the drillstring. Their system operates at very low frequencies; and, consequently, has the same data-rate limitations as the mud pulse devices.

Recent work at **Sandia National Laboratories** on this concept has uncovered a method whereby acoustical transmission rates can be increased at least tenfold. The method relies on understanding the transmission characteristics of the drillstring and advanced signal processing methods which are commonly employed in public telephone networks.

8 Conclusions

This report reviews the drilling and coring techniques used by both the mining and petroleum industries. The motivation for this work has been to investigate new methods for recovering large quantities of high-quality coring samples from geothermal production-drilling and engineering-development projects.

One aspect of this work seems clear, the mining-style, impregnated-diamond coring bit produces the best results in hard, high-temperature formations. If used properly, this type of bit performs on a level with the hard formation roller-cone bits both in

rate of penetration and total distance drilled. However, the impregnated bit requires rotational speeds and drilling-rate control which are not within the capabilities of conventional petroleum drilling practices. In addition, it is clear that the current slim-hole drilling practices of the mining industry do not provide sufficient well diameters, depths, or deviation control for these projects.

The solution to this problem is to modify the petroleum drilling system and make it more compatible with the requirements of the impregnated bit. At the same time it also seems possible to develop impregnated bits which will operate at the lower rotational rates which are currently available on petroleum rigs.

Two possible hybrid systems seem to be possible. In the first, the operational capability of the petroleum system would be increased by using a dynamically balanced drillstring and a hydraulically operated feed control. Core samples would be cut with surface-driven, impregnated diamond bits designed to operate at lower speeds and with wider kerfs. Improved stabilization and measurement-while-drilling techniques would be used to obtain the optimal control of the coring process.

The second system relies upon a high-temperature downhole turbine. A large-diameter drillstring and improved hole-opening bit would produce the final gage of the wellbore, while the core sample would be cut with an impregnated bit driven by a small high-speed turbine. Again stabilization and measurement while drilling would play an important role in successful recovery of core samples.

Both ideas require significant improvements in the tools of the current technology. A list of projects has been presented which will move us toward new coring capabilities.

Table 1: Sandia Coring Workshop Attendees

Name	Affiliation
Douglas Drumheller	Sandia National Laboratories
James Dunn	Sandia National Laboratories
John Eichelberger	Sandia National Laboratories
Scott Evans	Norton-Christensen Mining Division
Mel Friedman	Texas A& M University
John Finger	Sandia National Laboratories
John Huddy	Huddy Incorporated
Al Jagler	Gearhart Industries
James Langford	Security Division—Dresser Industries
B. J. Livesay	Consultant
B. J. Mitchell	Colorado School of Mines
Art Parks	Consultant
Heino Rhode	Eastman-Christensen
John Rowley	Los Alamos National Laboratory
Mike Storms	Ocean Drilling Program—Texas A& M University
Richard Traeger	Sandia National Laboratories
Bruce Walker	Terra Tek
Russ Veddow	Longyear

A The Sandia Coring Workshop

On October 6–8, 1987, a workshop was sponsored by Sandia National Laboratories in Albuquerque, New Mexico. The purpose of this workshop was to discuss various aspects of coring technology with experts from the petroleum and mining industries. Several geologists were also in attendance to give their opinions on core sample requirements. A list of the attendees is given in Table 1.

The structure of the workshop was divided into two major sections. The first section consisted of formal presentations by each of the industrial and university representatives. Table 2 is a list of speakers and the topics which were presented in the first section of the workshop. These talks provided a setting for the second section of the workshop.

The second section consisted of panel discussions motivated by a series of drilling scenarios—hypothetical drilling problems. The topics of discussion were:

- What are the depth and temperature limitations of mining wireline systems? Can this system go to 12,000 feet and 300 C? Can hole diameters greater than 6 inches be achieved?
- Is mining-style coring followed by hole opening a viable strategy for a hybrid

Table 2: Coring Workshop Presentations

Speaker	Topic
Friedman	Scientific needs of coring in granitic bodies
Eichelberger	Scientific needs and geological situation of the Magma-Long Valley area.
Storms	Ocean Drilling Program hard rock coring system
Jagler	Side wall coring system
Finger	Insulated drill pipe for high temperature application
Langford	Roller cone technology
Walker	Surface set diamond bit technology
Huddy	Impregnated diamond bit technology
Storms	Drill pipe for coring applications
Rhode	Downhole motors
Rhode	Core barrels
Rhode	Pressurized coring and oriented coring
Park	Coring monitoring instrumentation
Park	Oil-field style coring systems

mining-oil field drilling system?

- Can the hard rock system developed by the Ocean Drilling Program be extended to depths of 24,000 feet and temperatures of 300 C to 500 C?
- What is the best coring strategy for the proposed magma well in Long Valley, California?
- When drilling in hard crystalline formations, is continuous coring an economic drilling technique in comparison to conventional oil-field methods?

As the reader might expect, the answers to these questions are complex and not completely understood. In most cases, the answers are also specific to a particular drilling situation. The main body of this report is devoted to a presentation of the information obtained from this discussion.

With the caveat that simplification can be misleading, the conclusions of the participants of the workshop can be summed up as follows:

- The Ocean Drilling Program is an approach to a special set of coring problems. Even though the hardware developed in that program may not be adaptable to many other coring problems, the general approach used by them to develop a total system should serve as a model for any future project.

- The temperatures and depths of geothermal projects are extreme. Each project is unique. Specialized tools will be required and an engineering development program should be funded as an adjunct to the drilling project.
- Mining wireline coring can achieve 15,000 to 20,000 feet. Drilling bits are capable of drilling into formations with temperatures above 500 C; however, wireline core barrels are limited to much lower temperatures due to their polymer components. Directional control is poor. Hole diameters are less than 6 inches.
- Roller-cone coring bits cannot recover as high a quality core as that recovered by the impregnated bit.
- It is believed that impregnated bits can be developed which have diameters of 8 inches, wide kerfs, and operating speeds down to 70 rpm.
- Hole opening in crystalline rock is a risky operation. Twist offs are common.
- Granitic formations often have unstable noncircular wellbores. Stabilization is difficult. Stabilization is the key to quality core recovery.
- Drilling and core recovery at these depths will require extensive use of down-hole motors. Positive displacement mudmotors will not meet the temperature requirements of most geothermal projects. Turbines will be required.
- Real-time information obtained from measurement-while-drilling systems is invaluable in improving overall system performance.
- As an alternative to conventional oil-field or mining coring, side-wall coring systems are available which in many cases would provide suitable core samples.
- Coring is usually more expensive than conventional drilling.

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