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**Deep Drilling Basic Research
VOLUME 4 — SYSTEM DESCRIPTIONS**

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**Final Report
November, 1988 — August, 1990**

**Maurer Engineering Inc.
University of California, Berkeley**

**Gas Research Institute
8600 West Bryn Mawr Avenue
Chicago, Illinois 60631**

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**DEEP DRILLING BASIC RESEARCH
FINAL REPORT**

VOLUME 4 - SYSTEM DESCRIPTION

MAURER ENGINEERING INC.

**Eric E. Andersen
William C. Maurer**

UNIVERSITY OF CALIFORNIA AT BERKELEY

**Michael Hood
George Cooper
Neville Cook**

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1. Introduction

The first section of this Volume will discuss the *Conventional Drilling System*. Today's complex arrangement of numerous interacting systems has slowly evolved from the very simple cable tool rigs used in the late 1800s. Improvements to the conventional drilling rig have varied in size and impact over the years, but the majority of them have been *evolutionary modifications*. Each individual change or improvement of this type does not have significant impact on drilling efficiency and economics. However, the change is almost certain to succeed, and over time—as the number of evolutionary changes to the system begin to add up—improvements in efficiency and economics can be seen.

Some modifications, defined and described in this Volume as *Advanced Modifications*, have more than just an evolutionary effect on the conventional drilling system. Although the distinction is subtle, there are several examples of incorporated advancements that have had significantly more impact on drilling procedures than would a truly evolutionary improvement. An example of an advanced modification occurred in the late 1970s with the introduction of Polycrystalline Diamond Compact (PDC) drill bits. PDC bits resulted in a fundamental advancement in drilling procedures that could not have been accomplished by an evolutionary improvement in materials metallurgy, for example.

The last drilling techniques discussed in this Volume are the *Novel Drilling Systems*. The extent to which some of these systems have been developed varies from actually being tested in the field, to being no more than a theoretical concept. However, they all have one thing in common—their methods of rock destruction are fundamentally different from conventional drilling techniques. When a novel drilling system is introduced, it is a *revolutionary modification* of accepted drilling procedures and will completely replace current techniques. The most prominent example of a revolutionary modification in recent history was the complete displacement of cable tool rigs by rotary drilling rigs in the late 1920s.

2. Conventional Drilling System

It has taken many years for the methods and equipment used for drilling deep oil and gas wells to evolve to their present state. Many ideas have been tried with varying success during this time, and the result has been a steady improvement in the total number of reservoirs that can be reached. This is in spite of difficulties that may arise because of either the above-ground environment (offshore, inaccessible locations, harsh weather environment), or difficulties encountered underground (increasing reservoir depth, high pressures or temperatures, unstable rock, the necessity to drill deviated wells, etc.). Even though improvements and changes are still possible, it should be recognized that much has been tried already, and the industry has learned from the many experiments attempted in the past. Progress to date, has been steady and evolutionary, rather than revolutionary. This is probably because of the multitude of constraints on the overall system that requires any new introduction to fit with many other components, each one having its own series of requirements. The present state of the art has been achieved as the best compromise between all of these demands. This section provides a brief review of these constraints and the solutions presently used.

2.1 WELL DESIGN

The purpose of an oil or gas well is to access an underground reservoir containing hydrocarbons. To be commercially interesting, the reservoir must be both porous and permeable so the formation fluids can enter the borehole in substantial quantities. If while drilling the well, the borehole pressure is not greater than or equal to the reservoir pressure, an undesirable flow will result, and the well is said to "kick". If the unexpected flow is not controlled and formation fluids escape to surface, the well will "blow out" with potentially disastrous consequences. For this reason, the first requirement in drilling is to match the borehole and formation pressures. This is accomplished by filling the hole with a dense fluid—the drilling mud. The drilling mud is usually composed of natural clays dispersed in water or diesel oil. High-density solids, such as powdered barite, can be added to increase the mud density so that the bottom hole hydrostatic pressure equals the formation fluid pressure (pore pressure).

Often the pressure exerted by reservoirs at different depths in the well are not a linear function of depth, and it is not possible to select a single mud density that will match the pressures in all the reservoirs penetrated (which may contain either water, oil, or gas). If the mud pressure is too low, a blowout will occur, and if too high, the drilling mud may either be injected into the formations around the borehole, reducing formation permeability ("formation damage"), or it may produce massive fracturing with loss of mud into cracks in the surrounding rock ("lost circulation"). Lost circulation is undesirable because not only is there a loss of valuable mud, but the decrease in height of the column of mud in the borehole may cause a sufficient reduction of pressure for blowouts to be provoked in adjacent reservoirs.

Sixty percent of the drilled hydrocarbon well footage is in shales or clays. Because these formations are often mechanically or chemically unstable, the hydrostatic pressure provided by the drilling mud is necessary to maintain a competent wellbore. Salt, often encountered in oil and gas wells, produces similar problems and require adequate mud weight to maintain stability.

2.1.1 Casing and Cementing

For all of the above reasons, it becomes necessary to protect the borehole. This is at present done by placing steel pipe, known as "casing" in the well, and securing it by injecting cement into the gap between it and the rock. Because the internal diameter of the casing is necessarily less than that of the hole it fits, and all subsequent equipment must pass inside the casing, the next section of well is drilled with a smaller diameter.

It is important to realize that a cased hole is not only the desired end result of drilling and completing the well, but is an integral part of the drilling process itself. The completed well must be cased to provide a clean and protected pathway for the production tubing to convey the reservoir fluids to surface, but casing must be run at various depths while drilling the well to protect and support the well bore and to prevent catastrophic blowouts from occurring. Problems of borehole stability frequently increase sharply with time, and the longer the bore is left as an uncased "open hole", the greater the risk of trouble. This effect alone can, under some circumstances, require the early placement of the casing.

2.2 DRILLING EQUIPMENT

2.2.1 Drill Bits

After deciding on the well design, a variety of equipment is needed to drill it. The heart of the system is the drill bit, the tool which actually breaks the rock. Drill bits have many designs, they all destroy the rock in one of two ways: either by a shearing action (drag bits) or by indentation (percussive or roller-cone bits). The direction of tool motion for drag bits is parallel to the rock surface, while for roller-cone and percussion bits the direction of tool motion is normal to the rock surface. In both cases the indenter (typically a sharp wedge or cone) penetrates the rock, and first creates a crushed zone under the tool point. From this crushed zone, further loading generates tensile cracks which spread out from the crushed zone and eventually rise to the free surface, liberating chips of broken rock.

The shearing action of the drag bit is more efficient, but there are two practical problems. The first is that the scraping action of the drag bit causes rapid wear of the tool if the rock is very abrasive, and the second is that the drag tool is essentially loaded as a short cantilever. Thus the forces imposed by the rock on the tool generate tensile stresses on the tool leading edge, and may cause the tool to chip or snap off. A perennial problem in materials science is to find materials which are hard enough to be wear resistant and at the same time have sufficient fracture toughness to resist tensile cracking. Until recently, suitable materials were not available to build drag-type tools for

hydrocarbon well drilling, (with the exception of natural diamond tools, used mostly for coring or for very hard rocks), and so the most commonly used bit was the roller-cone bit. Recently, however, polycrystalline diamond compact (PDC) cutters have been introduced that allow the construction of drag bits capable of drilling very rapidly in soft and moderately hard formations as long as the formations do not contain large quantities of abrasive minerals. PDC bit use is increasing rapidly because they can be capable of drilling at penetration rates several times those of roller-cone bits, particularly in the more ductile formations.

2.2.2 Drill String

The bit is connected to the surface by a "string" of joints of pipe, and to make it drill, it is rotated against the rock, either by rotating the string from surface, or in some cases by the use of a down-hole motor placed a short way above the bit. Down-hole motors are gaining increasing utilization as more and more wells are directionally drilled and bit technology requires higher rotary speeds that are not physically possible with rotation from the surface alone. Down-hole motors help to avoid drill string twist offs by allowing all of the rotational torque to be concentrated near the bit instead of lost through torque and drag on the drill string. Downward pressure on the bit is applied by placing a series of thick-walled pipe sections (drill collars) above the bit. The collars operate in compression, but the remainder of the drill string hangs in tension from the surface. The drill pipe is too flexible to operate in compression, and will fail rapidly in fatigue if not kept straight by the tensile loading.

2.2.3 Circulating System

Once the cuttings have been broken from the hole bottom, they must be transported to the surface. Cuttings are removed from the hole by the mud which is pumped down the inside of the string of pipe, and returned to the surface through the annular space between pipe and hole (or casing). To be capable of carrying the cuttings to surface, the fluid must have sufficient density and viscosity. These properties must be carefully monitored to avoid well control problems (weight) and excessive pressure losses (viscosity). If pumping is stopped for some reason, the mud must be able to suspend the cuttings indefinitely, to prevent them from settling to the bottom of the hole and jamming the pipe, collars, and bit. This is accomplished by developing thixotropic behavior in the mud. When the mud returns to surface, it is passed through a series of cleaning operations designed to remove the cuttings. The mud-cleaning equipment, shown in Figure 2-1,¹ consists of "shale shakers" (vibrating sieves), hydrocyclones, and sometimes centrifuges. After going through the cleaning process, the mud is returned to a holding tank ready to be pumped down hole again.

Figure 2-1. Schematic of a Rotary System

Figure 2-2. Schematic of Example Rig Circulating System

2.2.4 Drawworks, Mast, Rotary Table

As was discussed above, the drill string is suspended from the surface so only the bit and collars operate in compression. The top end of the string is attached to a special section of pipe, called the kelly (see Figure 2-2'). The kelly pipe is square or hexagonal in cross section, and slides, but cannot rotate, inside a circular housing known as the kelly bushing. The kelly bushing has dogs which locate it on, and allow it to be turned by, the master bushing. This is a large thrust bearing set in the rotary table, which is located in the main floor of the drilling rig, and is placed directly above the well. It has a central opening where the drill bit, collars, pipe, casing, etc. are run in and out of the well. By lowering the kelly bushing so that it engages into the master bushing, and by using a motor to turn the master bushing, the kelly bushing, kelly, string, and bit are rotated. Because the kelly can slide downwards inside the kelly bushing, the string and kelly are able to follow the bit as it drills ahead without interrupting the rotary drive.

A swivel is located above the kelly that allows the drilling mud to flow into the drill pipe on its way down to the bit, and serves to decouple the rotating string and kelly from the nonrotating parts above. The swivel hangs from a hook that is suspended by a multiline pulley block and wire rope from pulleys at the top of the drilling derrick or mast (see Figure 2-3'). The wire rope running between the fixed and travelling blocks is let out or reeled in by a winch known as the drawworks. By operating the drawworks, the driller can control the descent of the kelly, pipe and bit into the hole, and can apply the correct weight on bit to make the bit drill satisfactorily.

Figure 2-3. Schematic of Hoisting System

After some time, enough hole will have been drilled for the kelly to run almost all the way through the kelly bushing. At this time another length of pipe must be added to the string (see Figure 2-4¹). By operating the drawworks, the driller lifts the kelly and attached pipe until the top of the highest joint of pipe is visible at the level of the rotary table. The drill pipe is then wedged into the hole in the rotary table by steel wedges called slips, and the kelly is unscrewed and pulled to one side. The kelly is brought over a fresh length of pipe that has previously been placed adjacent to the rotary table in a vertical hole called the mousehole. The bottom end of the kelly is screwed to the new pipe, lifted up, and brought back over the string still hanging in the slips. The bottom end of the new pipe is now screwed onto the top of the string, the slips are released, and the kelly with the lengthened string is run back in hole until the kelly bushing again locates in the rotary table, and rotation is resumed.

Figure 2-4. Making a Connection

2.2.5 Tripping

When it is time to change the bit, run casing, etc., the entire drill string must be removed from the hole. The pipe is usually not broken down into individual lengths by use of the mousehole, but is unscrewed in stands of three pipes, and is racked directly in the derrick (see Figure 2-5¹). This basic process of alternately holding the pipe in the slips so that sections can be added to or removed from the string, and using the hoisting capacity of the rig to lift the remaining part of the string up or down is known as "tripping", and is the second most time consuming activity on the rig after drilling. A trip is necessary every time the bit is replaced, every time casing must be run, and when logging or other operations are necessary.

Figure 2-5. Tripping Out of the Hole

2.2.6 Well Control

Well control is the most important part of well design because of the safety precautions that are necessary, and because of the need to protect the wellbore. The Blow Out Preventer (BOP) and the manifold are the integral pieces of equipment used for well control. These safety devices are attached to the well head, and consist of a series of valves that are used to seal off the annulus of the well in the event of a kick. Various valves are provided, that will either close around the drill pipe without damaging it, crush the pipe flat to seal it in the event of uncontrolled flow up the drill pipe, or shear the pipe completely as a last resort. Once the well is shut in by closing the BOP, the special high-pressure lines on the manifold below the valves allow heavy mud to be brought in to control the well, or to remove the reservoir fluids which have flowed into the well. BOP equipment is essential on all drilling rigs, and any new technology that is introduced must either not interfere with the operation of the BOP system or must replace it with something equally effective.

2.2.7 Other Drilling Operations

Other important operations are also carried out while the well is being drilled, that are not part of the drilling process itself. One of these operations is called well logging. To log a well, a package of instruments are lowered down the hole to make measurements of the properties of the rocks being penetrated. This process provides information on electrical conductivity, sonic velocity, natural radioactivity, and other properties of the rock. From these findings, estimates of the rock

mineralogy, porosity, and the fluids it contains may be determined. If more detailed information is required, particularly data on permeability, it may be decided to extract core samples. If samples of fluids from a hydrocarbon zone are required, various other procedures are followed, ranging from the recovery of small quantities by down-hole devices to full-scale tests where the well is made to flow for a period of hours, or perhaps even days, so that the reservoir engineers can obtain an estimate of the long-term producing capacity of the well.

An undesirable operation that must sometimes be done while drilling a well is called fishing. If something is dropped down the wellbore at any time, or the drill string parts for some reason, the "junk" that remains in the hole must be removed before normal drilling procedures can resume again. A variety of tools ranging from junk baskets to magnets are used to accomplish this task.

2.3 REFERENCE

1. Bourgoyne, Jr., A.T. et al., 1986: *Applied Drilling Engineering*, Society of Petroleum Engineers, Tulsa, Oklahoma.

3. Advanced Modifications

This report covers new developments in drilling technology that have progressed beyond the laboratory experimental stage and are now being tested or implemented into field drilling operations. For the most part, the advanced modifications described herein are not widely applied in industry, but show considerable potential for future development. This review examines new developments in bit design, bit hydraulics, power transmission to the bit, MWD tools, high-pressure jet systems and coiled-tubing drilling. This review describes new developments in MWD logging tools that are enhancing the acquisition of geological and reservoir information while drilling the well. Integration of drilling information and data from a range of sources is allowing advanced management methods to be brought to the rig, and experts in offices and laboratories to participate in drilling decisions. Two advanced management strategies are described in this report.

3.1 ADVANCES IN DRILL BIT TECHNOLOGY

Rock bits cut rock by three different mechanisms as shown in Figure 3-1.

Figure 3-1. Rock Bit Cutting Mechanism (Gill et al., 1985)¹

Roller bits utilize teeth which are pushed into and crush the rock. Drag bits (PDC and TSP) drag sideways across the rock face and cut the rock by a shear mechanism which can generate large cuttings. Small natural diamonds use a grinding action to pulverize the rock into very fine particles. The shearing action of drag bits mechanically removes the broken rock from the rock face, whereas the rock crushed by roller-bit teeth must be removed by the inefficient jetting action of the drilling mud. High differential fluid pressures hamper this jet cleaning action resulting in regrinding of cuttings and reduced roller-bit drilling rates in deep wells.

3.1.1 PDC Bits

The most important recent advance in bit materials has been the introduction of various forms of polycrystalline diamond cutting elements (PDC and TSP) in drag and roller-cone bits. These diamond materials, which have outstanding abrasion resistance, have allowed the reintroduction

of drag bits as a major means of drilling the well, at least in rocks that do not contain large proportions of quartz. Their resistance to shock currently limits applications in hard formations.

PDC bits utilize cutters consisting of a thin layer of small synthetic diamonds bonded to a tungsten-carbide substrate (Eaton, 1975²) as shown in Figure 3-2.

Figure 3-2. PDC Cutter

PDC cutters are utilized in both steel body and matrix bits. Steel-body bits are cheaper to manufacture than matrix bits, but often suffer erosion problems with abrasive muds on long bit runs. Matrix bits are manufactured by infiltrating a molten cobalt/nickel binder (1100°C) into tungsten-carbide powder containing the diamond cutters. Matrix bits are very erosion resistant and are ideal for deep drilling with motors.

The PDC cutters can be mounted on tungsten-carbide studs pressed into steel body bits or brazed directly to matrix body bits (Figure 3-3).

Figure 3-3. PDC Cutter Mounting Technique

Since their introduction, PDC bits have changed the petroleum industry's approach to drilling shales and other soft- to medium-hard rock formations. PDC bits been successful for primary reasons: 1) they utilize a cutting mechanism significantly different from conventional rock bits, 2) they use materials previously not available for drag bit manufacturing, and 3) the utilization of PDC bits has not required changes in the basic conventional drilling system. PDC bits have presented a more

operationally compatible, cost-effective modification to the drilling industry than would a completely revolutionary change.

Despite their success, PDC bits are still in a rapidly evolving development stage with rapid advances being made in cutter materials, bit design, and field optimization of these bits. Continued R & D is needed to fully utilize the potential of PDC cutters.

Although PDC bits are a prime example of a former advanced modification, the technology can no longer be considered a new concept. The emphasis has changed from trying to establish PDC bits as a new innovation to documenting those conditions where they are particularly useful. The use of PDC bits has grown from 5% of all oil-well footage drilled in 1984 to 25% in 1989 (R. Smith, Eastman Christensen, private communication). Improvements in PDC bit design and PDC cutters are still being made, and further advances in bit performance can be expected. Typical is the work of Amoco (Warren, 1988³), where they show that parabolic or bladed designs are superior to the flat-face types in penetration rate and resistance to bit balling, but that they are more likely to be damaged by mechanical overload in hard formations are encountered.

Much of past PDC development work has concentrated on producing bits that resist bit balling and the accumulation of cuttings resulting from high-penetration rates in soft shales. This has led to the development of larger cutters to allow the cutting edges to stand further away from the bit body. Bits with 2-in. diameter diamond cutter disks are now available and 3-in. disks have been made experimentally.

Research has been shown that reducing the grain size of the diamonds from 115 to 1 micron increases the wear resistance by two orders of magnitude (Figure 3-4).

Figure 3-4. Reducing Grain Size Increases PDC Tool Material Wear Resistance (Sneddon, 1987)⁴.

A major obstacle to increasing the application of PDC bits is their reduced performance in hard, abrasive formations. Better resistance to shock and thermal damage is required, although it is uncertain if thermal damage is a primary wear mechanism, or if it only occurs after shock loading has chipped the cutting edge, and allowed a wear flat, with large capacity for frictional heating, to develop (SPE 19571). It is believed that thermal damage in conventional PDC cutters arises from the thermal expansion mismatch between the diamond crystals and the residual intergranular transition metal catalyst that is needed during the fabrication process⁴.

3.1.2 Thermally-Stable Diamond (TSD) Bits

Thermally-stable diamond (TSD) cutters have been developed to overcome the temperature limitations of PDC cutters. TSD cutters (SYNDAX 3) operate effectively at temperatures up to 1200°C whereas PDC cutters (SYNDRILL) degrade and fail rapidly at temperatures above 700°C (Figure 3-5).

Figure 3-5. Effect of Temperature on Granite Drilling Tests

TSD cutters developed by General Electric (Geoset) and DeBeers (SYNDAX 3) have the cobalt binder removed so that they operate at much higher temperatures. The high-temperature capability of these TSD cutters allows them to be cast directly into matrix bits as shown in Figure 3-6.

Figure 3-6. "Matrix Body" TSD Bit

The thermally stable cutters are cast directly into the matrix body as shown in Figure 3-7.

Figure 3-7. Thermally-Stable Cutters (TSP)

PDC cutters fail at high temperatures because the cobalt binder that fills the pore spaces in the diamond matrix expands more than the diamonds, causing the PDC cutters to break apart at high temperatures. TSP cutters are manufactured by leaching out the cobalt in the diamond matrix and leaving the void spaces empty (General Electric) or filled with silicon (DeBeers). Figure 3-8 shows that the coefficient of thermal expansion for silicon is significantly closer to the value of the diamonds than is cobalt, thus eliminating the thermal expansion problem.

Figure 3-8. Thermal Coefficient of Expansion Values

The use of silicon also eliminates the affinity problem between the diamond and cobalt and permits direct attachment of the material to the bit matrix with standard diamond bit matrix materials. TSPs can be used in any number of different configurations because of the variety of sizes and shapes that can be produced with the material.

The TSD matrix bits are ideally suited for drilling the hard sedimentary rocks encountered in deep gas wells. Figure 3-9 shows that these bits can drill in excess of 90 meters (300 ft) before wearing out in granite, an igneous rock that is much harder than the sedimentary rocks normally encountered in deep gas wells.

Figure 3-9. TSD Drilling Data in Granite

Average penetration rate in the hard, abrasive formation was a phenomenal 60 cm/min (118 ft/hr),⁵ a phenomenal rate for this, hard abrasive granite. Observations from these tests included the following:

1. Adequate bit weight is required when using TSD coring bits. Low bit weights result in polishing of the cutters—rendering them useless.
2. High flow rates are required to keep the TSD bit clear of cuttings. This problem was particularly troublesome when laboratory drilling tests were performed in softer formations where penetration rates exceeded 2 m/min (394 ft/hour).
3. Experiments showed that the shape, density, and placement of the cutters controlled the torque, bit weight, and rotary speed requirements of the TSD bits. The optimum shape and exposure of the individual cutters is largely dependent on the formation type.
4. Bit design plays an important role in the capabilities and performance of TSD coring bits.

TSD bits are beginning to find widespread use in difficult oil-field drilling applications. The key to the success is to utilize computer design techniques to match the weight-torque-speed characteristics of the bits to the torque-speed characteristics of the downhole motors to optimize use of the motor power output and to maximize drilling rate and bit life.

PDC and TSD bits have potential for very high drilling rates when used in high-power drilling motors. Figure 3-10 shows cycles where with 8000 lbs bit weight, a natural diamond bit rotated at 50 rpm, drill marble at 10 ft/hr on downhole motors (450 rpm). These natural diamond bits drilled 40 ft/hr compared to 190 ft/hr for PDC bits. This shows that PDC or TSD on advanced drilling motors have potential for very high drilling rates.

Figure 3-10. PDC and Natural Bit Drilling Rates
(Eaton et al., 1975)⁶

TSD coring bits have been tested in South Africa drill reef quartzite—another hard, abrasive formation. Figure 3-11 shows that TSD core bits drilled six times faster and lasted twice as long as impregnated diamond bits.

Figure 3-11. TSD Bit/Diamond Bit Comparisons

TSD cutters have also found use in full-hole boring applications including grout-holes drilled in a large dam project in Turkey by DeBeers. The formation drilled in this application was limestone with varying amounts of chert interspersed. These conditions presented a challenging drilling environment since chert has an average crushing strength approximately twice that of dolomitic limestone. The chert was highly fractured, compounding the stresses imposed on the bits.

TSD bits were successful in this application, drilling two to three times faster than tungsten-carbide roller bits. Figures 3-12 and -13 show that the chert content of the formation affected the performance of the bits, but experience and changes in bit design could be used to limit the chert's influence.⁷ As with other bit types, the chert affected the TSD bits by three basic mechanisms:

1. Impact damage on entering the chert layer.
2. Accelerated abrasive wear in the chert layer.
3. Impact damage in fractured chert.⁷

The design of the TSD core bit was crucial in this field application and in laboratory core bit tests. Various bit runs showed that optimizing drilling parameters was also important, with higher bit weights extending bit life and increasing penetration rates.

Figure 3-12. TSD Bit Performance — ~10% Chert

Figure 3-13. TSD Bit Performance — ~80% Chert

In oil-field applications, TSD bits are used in 1) coring operations, 2) sidetracking bits in horizontal drilling applications, and 3) high-speed downhole motor operations. Use of TSD bits in the oil field is in its infancy and the full use and impact of TSD bits has not yet been realized. There are many areas for fruitful R & D on TSD bits.

A major finding from the TSP experimental work conducted by De Beers was the importance of adequate bit weight. Like PDCs, TSD cutters generate cuttings by shearing the rock, a cutting mode that is very efficient and is the major reason for the high-penetration rates achieved with these bits. If insufficient load is applied to a TSD bit, the cutters do not penetrate the rock sufficiently, and the cutting method reverts to a less efficient crushing and grinding action, resulting in poor penetration rates and premature bit failures.

TSD bits have been very effective in Austin Chalk and other medium strength oil-field formations. Laboratory testing completed by De Beers indicated that TSD bits must be run with improper bit weight, rotary speed, etc. to optimize their use in oil-field drilling.

Experimental studies have shown that TSD cutters have significant potential in hard, abrasive formations. Theory indicates that the shearing rock destruction mode employed by TSD cutters has the potential to provide the most efficient method for penetrating hard, brittle formations, and conditions characterizing most formations commonly encountered in deep oil and gas wells. This suggests that properly designed TSD bits, operated at the appropriate drilling parameter levels, have the potential for significantly improving deep drilling operations.

3.1.3 Roller Bits

Roller bits have undergone continued evolutionary changes since their first use in the oil industry in 1909. Steady improvements in cutter performance have placed increasing demands on the seals and bearings of roller-cone bits. As bearing loads have increased, journal bearings have replaced rollers or balls⁸. This study has shown that increases in bit life have less economic impact than increases in drilling rate, and therefore superior overall performance may be obtained in many formations by the use of high-speed, lower life roller bearing bits. In this context, cone retention is an important safety feature if the bearings fail, and recent work has addressed this issue with the introduction of improved cone-retaining designs.⁹

Journal bearings must be protected from the ingress of mud and rock debris, so seal design has become an important issue, particularly at high bit speeds. Various seals have been tried, and present high performance bits utilize either textured elastomeric or metal-to-metal seals.^{10,11,12}

Figure 3-14. Photomicrograph of Texturized Seal Inside Diameter (10x).
(Salesky and Payne, 1987)

Figure 3-15. Construction of an Advanced Metal-to-Metal Seal
(Kelly and Ledgerwood, 1988).

Roller bits typically utilize roller or journal bearings as shown in Figures 3-16 and -17.

Figure 3-16. Roller-Bit Roller Bearing

Figure 3-17. Roller-Bit Journal Bearing

New synthetic diamond-coated cutters are finding increased use in advanced roller bits because of their improved impact and wear properties (Figure 3-18). These diamond coatings greatly extend cutter life on both roller and percussion bits, especially in hard, abrasive rocks where cutter wear is a major problem.

Figure 3-18. Diamond-Coated Cutters
(Sneddon et al., 1987)⁴

Roller bearings experience fatigue failures and typically do not operate well at high rotary speeds. New diamond bearings being developed for use in roller bits (Figure 3-19) have potential for significantly increasing thrust and speed capabilities of roller bits. The higher speed capabilities are important because of new, high-power downhole motors currently being developed.

Figure 3-19. Roller-Bit Diamond Bearing (Sneddon et al., 1987)⁴

These synthetic diamond improvements could be incorporated into a "superbit" as shown in Figure 3-20.

Figure 3-20. "Superbit" Utilizing Latest Diamond Technology (Sneddon et al., 1987)⁴

As an alternative to sealing the bearing, it has been suggested to operate unsealed diamond bearings in the mud and allowing the mud to polish the diamond surfaces.⁴ Further advances in this area are expected as new techniques of depositing diamond coatings (e.g., low-pressure plasma) become available.

With steady improvements being obtained in both drag bit and roller-cone bit design, a debate has developed as to which method of rock destruction (drag or normal indentation) will ultimately be the most successful. From a rock mechanics point of view, the PDC bit rock removal shearing process is more efficient because 1) the indenting action of a drag bit distributes the stresses in the rock more efficiently, 2) rocks are generally weaker in shear than in compression, and 3) the PDC cutters mechanically removes the cuttings away from the newly exposed hole bottom. The cutter of an indenting roller bit, on the other hand, has limited scrapping action, requiring the rock chips to be removed by the inefficient jetting action of the drilling mud.

From a bit material viewpoint, roller bits have several advantages including 1) indenting action of the roller-bit cutter generates less heat than the shearing action of the drag bit, and 2) the teeth of an indenting roller bit are periodically removed from the rock, and cooled by the flushing fluid.

It is likely that both roller bits and drag bits will remain important drilling tools in both shallow and deep drilling with drag bits dominating in the softer, more ductile rocks, and roller bits proving superior in the harder, more brittle materials.

3.1.4 Advances in Bit Design

This section reviews recent ideas on bit design related to improving the overall running and cutting behavior of the bit. Bit vibrations are often a serious problem in hard formations where impact of the bit on the hole bottom can damage the bit and lead to failure of BHA components and sensitive MWD instrumentation.

PDC bits often do not perform well in hard or abrasive rocks, due to chipping or fracturing of the cutters, and the characteristic pattern of reticulated cracks known as "heat checking" caused by the alternation of frictional heating with quenching by the drilling mud. The quantity of heat generated on a cutter increases with the size of the wear flat,^{13,14} and the rate of damage accelerates as the damage itself increases, therefore very sharp cutters point suffer only minimal thermal damage. Cutter damage is therefore initiated due to chipping and fracturing caused by impacts and bit vibrations. Recent efforts have therefore been directed at reducing bit vibrations.

One novel idea is to build a bit with asymmetric cutters that force a bearing pad on the side of the bit firmly against the side of the hole^{15,16}, thereby reducing "bit whirl" and vibrations. Another approach is to use "hybrid" bits, where PDC cutters are backed by diamond-impregnated studs.^{17,18} The intention is that as the PDC cutters are worn, more of the load is carried by the stud, thereby reducing mechanical and thermal loads on the cutter. As more load is transferred to the studs, a less aggressive cutting structure develops, decreasing the tendency of the bit to vibrate.

Another author¹⁹ proposes a solution to low penetration rates often observed in softer rock that deform elastically under PDC cutters without fracturing. They propose placing a second PDC cutter immediately behind the first, with the object of slicing off a layer of rock as it rebounds elastically from under the first cutter. The second cutter is given a positive rake to ensure cutting the rock and not pressing it down a second time.

3.1.5 Improved Bit Hydraulics

It is important to observe that the power available at the bottom of the hole is in two forms:

1. **Mechanical** — the power transmitted to the drill bit by the rotating drill string or by a downhole drilling motor (typically 20 to 100 kW)
2. **Hydraulic** — the power delivered to the drilling fluid (typically 100 to 300 kW).

The mechanical power is responsible for the rock destruction process and, to a large extent, governs the drilling rate. The drilling fluid serves a number of functions, including removal of rock cuttings from beneath the bit. It is well established that the rate of drilling is affected adversely if this hole cleaning process is not performed effectively. Thus, both the mechanical power and the hydraulic power influence drilling rate. Since the ratio of hydraulic to mechanical power is 5-10, it is apparent that mechanical energy is much more effective than hydraulic energy.

Considerable work has been conducted to improve drilling rates by improving bit hydraulics, including simply increasing the hydraulic horsepower to the drilling fluid. For a given bit weight, this results in an approximately linear increase of drilling rate with drilling fluid jet power until high power levels are reached and the drilling rate levels off. Another successful approach involves minimizing the stand-off distance between the nozzles and the rock face by extending the length of the nozzles.^{20,21,22} It is equally important to avoid a flow regime which will allow the accumulation of cuttings and regrinding of cuttings on the hole bottom.^{23,24,25}

Various more radical methods of improving bit hydraulics have been proposed including: 1) upward-facing ejector nozzles,²⁶ 2) down-hole hydrocyclones,^{27,28} 3) cavitating jets²⁹, and appear not to have progressed beyond the experimental stage.

High-pressure jet drills utilize high-pressure water or mud jets (10,000 to 25,000 psi) to disintegrate the rock (Figure 3-21).

Figure 3-21. High-Pressure Jet Bit

High-pressure jets are often utilized on conventional bits to enhance the mechanical cutting action of these drill bits as shown in Figure 3-22.

Figure 3-22. Jet-Assisted Mechanical Drill Bits

Shell, Exxon, and Gulf conducted extensive oil-field drilling tests utilizing drill rigs modified to operate at pressures of 10,000 to 20,000 psi as shown in Figure 3-23.

Figure 3-23. Oil-Field, High-Pressure Drill Rig (Maurer, 1973)

These field tests demonstrated that high-pressure jet bits can drill many oil-field rocks 2 to 3 times faster than conventional bits (Figure 3-24).

Figure 3-24. Oil-Field, High-Pressure Drilling Tests (Maurer, 1973)

Recent work by Dubugnon (1981) and Hood (1987) shows that the efficiency of high-pressure jet bits can be increased by directing the jets ahead of the drag cutters as shown in Figure 3-25. The high-pressure water enters the fractures ahead of the cutters and reduces the external energy required to propagate the fractures.

Figure 3-25. Jet-Assisted Drag Cutting (Dubugnon, 1981)

High-pressure jet bits drill more effectively when rotated at high speeds. Figure 3-26 shows an example where a conventional PDC jet bit drilled 90 ft/hr when operated on a rotary drill (1000 psi), 260 ft/hr when operated on a high-speed, low-pressure motor (1000 psi), and 1030 ft/hr when operated at 1000 rpm on a high-speed, high-pressure jet motor (9000 psi). This shows the benefit of utilizing high speed motors with high-pressure jet bits.

Figure 3-26. Effect of Speed and Jet Pressure on Drilling Rate (Maurer, 1986)

The drilling rate of the jet bit in Berea sandstone increased rapidly with increased pressure once the pressure exceeded the 5000 psi threshold pressure required to effectively erosion drill this rock (Figure 3-27). This threshold pressure increases with increased rock strength, reaching values of 15,000 to 25,000 psi in some hard rocks encountered in deep wells.

Figure 3-27. Effect of Jet Pressure on Drilling Rate (Maurer, 1986)

High-pressure jet bits are more effective at high-rotary speeds (i.e., on high speed motors) because the depth of cut per bit revolution decreases as the rotary speed increases as shown in Figure 3-28.

Figure 3-28. Effect of Drilling Rate on Depth of Cut (Maurer, 1986)

For example, when drilling at 200 ft/hr, the depth of cut is 0.40 inches at 100 RPM compared to 0.04 inches at 1000 RPM. The reduced depth of cut greatly increases the drilling efficiency and reduces the amount of energy required to remove a unit volume of rock.

Jet bit drilling rates can be increased by increasing the pump horsepower as shown in Figure 3-29. This can result in excessive pumping costs with large diameter bits since one of the major cost items with a high-pressure jet drilling system is the cost of operating and maintaining the high-pressure pumps.

Figure 3-29. Effect of Bit Power on Jet Drilling Rate (Maurer & Helhecker, 1973B)

The hydraulic power requirement can be greatly reduced by reducing the bit diameter, since the hydraulic power required is inversely proportional to bit diameter squared as shown in Figure 3-30.

Figure 3-30. Effect of Bit Diameter on Jet Drilling Rate (Maurer & Helhecker, 1973)

3.2 TOP DRIVES

The top drive is a system that replaces the conventional rotary table and kelly with a motor hanging from the travelling block. The motor is guided by rails situated in the derrick or mast. Between the top drive and the travelling block, a conventional swivel allows circulation of drilling mud into the drill stem. This arrangement has two major advantages. First, drill pipe may be added as complete stands (of three pipes, or 90 ft.), in the same way that it is handled while tripping in a conventional rig. With a top drive system, time is saved and safety increased because the pipe never has to be broken into singles while drilling. Second, circulation can be established through the top drive both while drilling and while tripping. On conventional drilling systems, the kelly must first be attached if it is necessary to circulate while tripping.

Figure 3-31. Typical Top Drive System.
(Adams and Cavanaugh, 1987)³⁰

Top drive improve safety and aid the drilling process. If the well is swabbed and kicks while tripping, valuable time can be saved in closing-in the well since it is not necessary to first pick up and connect the kelly. In addition, the number of manual pipe-handling operations is decreased, reducing crew fatigue and the number of chances for injuries. It is relatively easy to re-establish circulation during tripping, if a sticky point is encountered while tripping either in or out, circulation and rotation may both be started immediately. This allows the driller to drill through the tight spot in either direction, a feature that is helpful when drilling holes at high angles (which are notorious for having problems with sticking pipe), especially in offshore applications where rig costs are high.

Other advantages of the top drive include the capability to core in ninety foot lengths, (instead of the usual thirty-foot single pipe length), and to reciprocate, rotate, and fill casing as it is being placed. The key features leading to the rapid rise in popularity of the modern top drives have been the coupling of the in-derrick drive with an efficient system of pipe handling that includes a make-up and breakout unit, and a drill pipe elevator (Figure 3-32). In this way, a significant step has been taken toward the development of the fully automated rig.

Figure 3-32. Top Drive Pipe-Handling Equipment (Boyadjieff, 1986)³¹

Top drives have found applications in drilling different types of wells. In difficult to drill, moderately-deviated wells, their main advantage has been in "preventing trouble," including avoiding stuck pipe due to differential sticking or hole collapse. There is general agreement³¹ that over time, savings of 10 to 20 percent may be obtained.

Some high-angle wells offshore require the use of top drives to rotate and circulate at all times.³² Top drives have enabled planners to increase the number of highly-deviated wells reaching far from offshore platforms. Although it is unquestionable that significant time will be saved when drilling each well, these well-by-well savings are overshadowed by the enormous savings that may be achieved by developing the field from a lesser number of platforms. Mobil, for example, has investigated high-angle drilling in the Statfjord field,³³ and concluded that it might have been possible to develop the Statfjord field from two, instead of the three concrete gravity platforms actually installed.³⁴ With the cost of such a platform at between \$1.5 to \$2 billion, the savings is obvious. Similar cost reductions have been reported from other fields, including Alaska's Endicott field where the Wall Street Journal reported on September 14, 1984 that two artificial islands would be needed instead of three, and Malaysia's Semangkok field where the Oil and Gas News reported on October 17, 1984 that two platforms could be used instead of three, saving \$53 million.

3.3 DOWNHOLE MOTORS

Downhole motors can drill many formations much faster than rotary rigs because they can rotate drill bits at speeds of 500 to 2000 rpm compared to 50 to 150 rpm for rotary drills. Downhole motors are not new, the first motor patents being granted in the 1880s, and turbine motors being used in the Soviet Union in the 1930s. The Soviets developed and used motors at that time because of the poor quality of their oil-field tubulars. Today, downhole motors are used around the world to perform a variety of different operations.

Because penetration rate is generally proportional to rotary speed, high rotary speeds are desirable. High rotary speeds cannot be obtained by rotating the drill string at high speeds for the following reasons:

1. Drill string durability.
2. Drill rig capabilities.
3. Drill bit durability.
4. Mechanical wellbore erosion.
5. Casing wear.

In addition to higher speeds, downhole motors provide other advantages including:

1. Straighter holes.
2. Higher penetration rates.
3. Reduced washouts.
4. Increased on-bottom time.
5. Reduced casing and drill pipe wear.
6. Reduced bit weight requirements.

3.3.1 Turbodrills

Two types of downhole motors are typically used in oil-field drilling operations: turbine motors and positive-displacement motors (PDMs). Turbine motors have been used in the Soviet Union since the 1930s. The technology was confined to Soviet applications until the late 1950s when turbine motors were used in Europe, and 1960 when they were first used to drill wells in the United States. Today, turbine motors are frequently used in the Soviet Union and Europe, but less than one percent of footage drilled in the United States since the 1960s has been with turbine motors.³⁵ Figure 3-33 shows a schematic of a typical downhole turbine motor.³⁶ The main component of a turbine motor is the stator/rotor assembly (Figure 3-34). Each stator/rotor combination denotes a single stage, and the number of stages contained in a turbine motor determine the torque capabilities of the device.

Figure 3-33. Turbine Motor

Design of single-stage section in turbodrill

Typical cross section of turbine blading showing the flow of fluid through one stage of the unit

Figure 3-34. Turbine Blades

Figure 3-35³⁶ shows typical torque/power/speed curves for a turbine motor. The graph demonstrates that motor torque depends on rotary speed and that the optimum power capabilities of the motor occur within a narrow rotary speed envelope. Turbine motors are complex to operate because of this characteristic. The major difficulty with turbine motors is monitoring their performance during drilling operations since the turbodrill speed cannot be detected from the flow rate or the pressure drop across the turbine.

Figure 3-35. Turbine Performance Curves

To properly monitor the performance of a turbine motor, it is necessary to know the rotary speed of the bit and/or the torque, requiring the use of a tachometer on the rig floor and an experienced driller. The driller must constantly monitor the turbine motor because its operating efficiency can change rapidly. For example, when drilling from a soft formation to a hard formation, the torque will increase for a constant bit weight, resulting in decreased speed, motor power and efficiency. A bit weight adjustment will be required to bring the motor back to optimum operating conditions.

Bit selection is also crucial to optimum performance since the bit must operate within the peak power range of the motor. Roller-cone bits are not suited for turbodrilling because of rapid bearing failure at the high rotary speeds. These problems, coupled with the limited pumping capabilities of most drilling rigs before the mid-1970s, have limited utilization of turbine motors in the U.S.

Positive-displacement motors (PDMs) were first used in oil fields in the early 1960s for directional drilling purposes. The PDM³⁷ motor assembly consists of four basic sections as shown in Figure 3-36:

1. Bypass valve
2. Motor unit
3. Universal joint
4. Bearing assembly.

Figure 3-36. Typical PDM³⁷

The bypass valve (Figure 3-37) bypasses drilling fluid to the annulus when the motor is tripped in and out of the wellbore.³⁸ A piston/spring component is used to cover the valve port when circulation (and higher differential pressure) is initiated.

Figure 3-37. PDM Bypass Valve

The motor section consists of a rotor and stator as shown in Figure 3-38.³⁷

Figure 3-38. PDM Motor Section

PDM stators always contain one more lobe than the rotor (Figure 3-39).³⁹ For example, a 1/2-lobe PDM (single lobe) has a one-lobe rotor, and a two-lobe stator; likewise, a 3/4-lobe PDM (multilobe) has a three-lobe rotor and a four-lobe stator. Motor torque increases and rotary speed decreases as the number of rotor and stator lobes increases, due to the increased displacement of the motor.

Figure 3-39. PDM Motor Configurations

As drilling fluid is pumped under pressure into the cavity between the rotor and stator, the eccentricity of the rotor generates torque on the rotor, causing it to rotate. The rotation of the rotor is transmitted through the universal joint and bearing assembly to the drill bit.

Figure 3-40 shows the torque/power/speed curves for a typical PDM.⁴⁰ Motor torque is controlled by the pressure differential across the motor whereas the rotary speed is controlled by the flow rate. As the pressure drop across the motor increases the motor torque, motor power and efficiency increase. Theoretically, the rotary speed of the motor should remain constant as long as flow rate remains constant; however, at high differential pressures, drilling fluid leakage between the rotor and stator increases, reducing the rotary speed slightly.

Figure 3-40. PDM Performance Curves

PDMs are simpler to operate in the field than turbine motors since motor performance depends on the differential pressure and flow rate. Changes in motor torque can be identified by monitoring the stand-pipe pressure and changes in motor rotary speed can be identified by monitoring flow rate. These features make the operation of positive-displacement motors more attractive than turbine motors, and are responsible in part for their high popularity in the United States.

Downhole motors typically use ball or roller thrust bearings to apply thrust to the drill bit. Wear and fatigue failures of these roller bearings are a major limitation of these motors.

Turbodrills normally use rubber thrust bearings instead of roller bearings due to their high rotary speeds (Figure 3-41). Rubber friction bearings have the limitations that they absorb considerable power and cannot operate at the high temperatures experienced in deep wells.

Figure 3-41. Turbodrill Roller Thrust Bearings

Maurer Engineering⁴¹ developed a geothermal turbodrill for use in Los Alamos National Laboratories hot, dry rock geothermal well at Fenton Hill, New Mexico. All elastomers were eliminated from this turbodrill to allow it to operate at temperatures in excess of 600°F (Figure 3-42). This is the highest temperature downhole drilling system ever developed and demonstrates that motors can operate at the temperatures existing in deep gas wells.

Figure 3-42. LANL Geothermal Turbodrill

New diamond bearings (Figure 3-43) being used in new, advanced downhole motors have several advantages including 1) long life, 2) low friction, 3) high thrust capabilities and 4) high temperature capabilities. These bearings should significantly increase the use of motors in deep drilling and should lead to the development of advanced, high-power motors that will drill 2 to 3 times faster than current motors.

Figure 3-43. Downhole Motor Diamond Thrust Bearing⁴²

3.3.2 Downhole Motors As Advanced Drilling System Modifications

Broad application of downhole motors took place in the 1970s with technical improvements being made continuously since that time. For this reason, major improvements have to be made to qualify downhole motors as a *new* advanced system modification.

Broadening the utilization of downhole motors in deep drilling applications provides important opportunities for motor uses that have not been explored extensively. Downhole motors have been used to drill deep wellbores, but certainly not to the full potential of the technology. One example of motor use in deep wells is an Oklahoma well drilled in the 1980s by ARCO Oil and Gas. The highest cost portion of the ARCO well was the 17½ in. hole section that extended from 4,100 to 14,500 ft. When using conventional roller-cone bits, penetration rates in this section averaged 2.1 (or less) ft/hour, and bit life averaged 66 hours. Positive-displacement mud motors were used in combination with diamond bits to achieve penetration rates averaging 2.6 ft/hour and bit life up to 282 hours. Savings were significant even after the rental cost of the motors was factored in and the relatively short life of the mud motors (approximately 70-80 hours) was considered. ARCO concluded that better performance was achieved with their motor/diamond bit combination because of a smaller hole size (decreased from 17½ to 16 inches), better hydraulics at the bit face because of the diamond bit, and the significant increase in rotary speed. It should be noted that the motors tended to fail well before the drill bits wore out.

The major deficiency of current downhole motor technology is surviving the harsh environment that exists at great depth. High temperatures and pressures are particularly hard on the stator material and the bearing assemblies. Improvements in these two sections of the motor assembly, coupled with increased utilization in the deep sections of wellbores could have a major impact on deep drilling economics. Improving penetration rates by increasing motor power and rotary speed and increasing bit life by using TSD cutters could significantly reduce deep drilling costs. Coupling motor and drill bit design together could also have significant impact on deep well drilling performance.

3.3.3 Slim-Hole Drilling Systems

Slim-hole rotary drilling systems (3 to 4 inch) could significantly reduce deep drilling costs by increasing drilling rates and reducing downhole tool, rig, and casing costs. Reducing the size of the last bit in a 29,000 ft deep Oklahoma well from 7-7/8 to 5-7/16 inches as shown in Figure 3-44 would reduce the casing cost by 36% (Maurer, 1973). In general, slim-hole systems are more portable, resulting in lower transportation costs and the ability to explore for oil in remote areas (e.g., the mountains of Colombia).

Figure 3-44. Deep Oklahoma Well Casing Program

The development of synthetic polycrystalline diamond bits (PDC) and thermally-stable diamond (TSD) bits has greatly enhanced the use of slim-hole drilling because these drag bits contain no bearings and therefore overcome the problem of short bearing life encountered with small diameter roller bits. These PDC and TSD bits are well suited for use in many of the harder rocks encountered in deep gas wells.

Industry experts (e.g., Flack, 1989) have indicated that using slim holes 1 to 2 inches smaller than conventional wells should not restrict production in deep gas wells.

During the 1950s, there was significant interest in slim-hole drilling because of the increasing costs of drilling for oil. Slim-hole drilling technology has been extensively tested in the laboratory and in the field, but has never fully realized its potential by the oil-field drilling industry.

Interest in slim-hole drilling has re-emerged, because operators are being forced to drill deeper for new reserves, resulting in higher exploration costs. As a result, operators are searching for more economical ways to drill and complete deep wells, and slim-hole technology represents a valid solution to high drilling costs.

Slim-hole drilling can reduce deep drilling costs by several means including higher penetration rates since less rock is removed from the hole and reduced casing costs since smaller diameter pipe is used. Additional savings are realized by the use of smaller drilling rigs, smaller mud and cement volumes, and smaller drilling sites.

Drilling slim holes below 10,000 ft can be risky in relatively new drilling areas because of the significant possibility of "running out of hole," (i.e., being unable to run an additional

casing string if unanticipated high-pressure or lost-circulation zones are encountered). Well control is a significant concern in slim holes because even small gas kicks expand rapidly in a narrow annular space, covering a significant portion of the wellbore and arriving at the surface in a very short time. The vast majority of drilling contractors are not equipped to economically drill a slim wellbore. Few oil-field drilling contractors own small drilling rigs because of the perceived limited applications for the technology, and the sporadic utilization of such equipment.

3.3.3.1 OPAB Slim-Hole System

Sweden has limited oil reserves because of the geological stability of sedimentary deposition throughout the history of the region. During the 1970s, exploration results were disappointing, limiting investment in exploration efforts. As a result, Swedish investors searched for an innovative drilling method that would allow exploration to continue.

Figure 3-45 is a photograph of the rig built by Atlas-Copco Craelius for OPAB (a joint venture between the Swedish government-owned Svenska Petroleum Exploration AB (SP) and a group of private Swedish investors).⁴³ This Diamec-700 drilling unit, is fully hydraulic and capable of drilling to approximately 1,500 ft. A later design, the Diamec-1000, is rated to 3,500 ft. The truck-mounted rig weighs only five metric tons and can be operated by a two-man crew. Joints of drill pipe are 10-ft long and the bits used are 2 inches in diameter. If economical oil finds are discovered, the wellbore is re-entered and reamed to 2.4 inches to the top of the producing zone. Rig technology for the system was borrowed from the mining industry, where downsized drilling rigs are the rule rather than the exception. The only significant modifications made to the rig included the addition of a 20 bbl drilling fluid circulating system, and a simple BOP stack to protect the rig and crew in case pressured formations were encountered.

Figure 3-45. OPAB Drilling Rig

The original intent of the investors was to use the downsized rigs strictly for exploration, and to use conventional rigs for reservoir development, thereby maximizing the number of wellbores that could be drilled during exploration operations. However, using conventional rigs was avoided entirely because the versatility of the rig allowed the crew to perform all necessary operations including drilling, acidizing, coring, testing, cementing, and completions. Savings with the downsized drilling rig were substantial. In 1974, a conventional rig was used to drill a 1,600 ft wellbore at a cost of approximately \$148,000, compared to \$21,000 for a similar depth well drilled with the Diamec-700 rig in 1978. In the early 1980s, the Swedes began to market Diamec drilling rigs internationally.

3.3.3.2 Slim-Hole Drilling by BP Exploration

During the mid-1980s, BP exploration drilled six slim holes in the United Kingdom to evaluate the economic and technological merits of slim-hole drilling. Figure 3-46 shows a comparison of the hole and casing sizes for the conventional and slim-hole wells.⁴⁴ BP Exploration used the Microdril MD-3 drilling system marketed internationally by the Swedes.

Figure 3-46. Comparison of Conventional and Slim-Hole Well Plans

The tests showed that slim-hole drilling could be economically successful for a variety of reasons:

1. The small rig reduced site preparation costs by 70% (see Figure 3-47⁴⁴).
2. The 30 bbl drilling fluid system reduced mud chemical costs significantly.
3. The smaller annulus reduced cement volume and costs.
4. The smaller rig reduced fuel oil cost, traditionally, a big expense.

Figure 3-47. BP Exploration Slim-Hole Drill Site

BP Exploration determined that although the technology was adequate, there was considerable room for improvement. Most of the difficulties with the slim-hole rig involved the quality and quantity of tools that could be used in the small diameter wellbore rates. Fishing operations were complicated by the small size of the wellbore, and it was more difficult to run combination logs. The small drill string limited weight on bit to a maximum of 4,500 lb, affecting the performance of the PDC and diamond bits. BP⁴⁴ Exploration noted that wellbore hydraulics, equivalent circulating density, surge and swab pressures, and cementing hydraulics require additional attention since they are dramatically affected by the significant smaller annuli.

3.3.3.3 Slim-Hole Drilling By Conoco Indonesia

In 1985, Conoco Indonesia⁴⁵ drilled and completed 12 slim-hole exploration wells in Irian Jaya, (Figure 3-48 and 3-49). In the past, most drilling in the region was done using helicopter transported rigs ("helirigs") with occasional wells being drilled with river transported rigs. Prior to using the slim-hole rigs, the success of the helirigs prompted Conoco to pursue further reductions in the rig size. The main goals of the new drilling system were to develop a drilling rig that would 1) drill the wells to required specifications, 2) be easily transported by helicopter, and 3) minimize rig-site size. Some of the determining factors included:

1. A 4-3/4 inch core barrel had to be used in the production section.
2. The average total well depth requirement was 3,500 ft.
3. The helicopter portable rig had to break down into 4000 lb sections.

- [illegible]

K.B.S. A

SLIM HOLE WELL DESIGN

TYPICAL WELL

CONDUCTOR AT ± 100 FT
 DRIVEN
9 5/8 IN

8 1/2 IN HOLE

SURFACE CASING AT ± 1500 FT
7 IN H 40 20 LB/FT

6 1/4 IN HOLE

CONTINGENCY LINER
5 1/2 IN J 55 17 LB/FT

4 3/4 IN HOLE

TUBING AT ± 3500 FT
2 7/8 IN J 55 6 1/2 LB/FT

3-36

Use of the slim-hole rig, resulted in significant savings shown in Table 3-1.⁴⁵ In 1955-56, 12 slim-hole wells cost an average of \$2.06 million compared to \$7.67 million for five wells drilled in 1980-81.

TABLE 3-1. Conoco Drilling Programs In Irian Jaya

	<u>1980-81</u>	<u>1983</u>	<u>1985-86</u>
Summary			
Total cost (\$ MM)	38.35	14.03	24.7
Number of wells	5	3	12
Average cost per well (\$ MM)	7.67	4.68	2.06
Drilling			
Total footage (ft)	18962	11740	29170
Average depth per well (ft)	3792	3913	2432
Drilling cost (\$ MM)	2.77	0.96	0.76
Logistics			
Number of lifts for rig move	317	187	100
Average number of days to move	16	9	5
Helicopter	Puma	Puma	S-58T

3.3.3.4 Stratigraphic High Speed Advanced Drilling System (SHADS)

Between 1987 and 1989, Amoco Research developed a slim-hole drilling system called the Stratigraphic High Speed Advanced Drilling System (SHADS). Amoco's approach was different from that of previous investigators because they intended to:

1. Incorporate the technology into a new and innovative exploration approach.
2. Significantly improve the depth capabilities of the slim-hole drilling system.
3. Continuously core from the surface to total depth.

These modifications would significantly extend the capabilities of core drills and should significantly reduce coring costs.

Figures 3-50 and 3-51 show schematics of the continuous wireline coring systems used by Amoco.⁴⁶ The Amoco system was designed to break down into sections weighing no more than 4,000 lbs, similar to the Conoco system. The basic rig, taken from the mining industry, was similar to the Swedish slim-hole drilling system used by BP Petroleum.

Figure 3-50. Typical Mining Continuous Core Drilling System

Figure 3-51. Wireline Coring Assembly

Amoco hoped to impact drilling techniques and economics, and to influence current exploration methods in more hostile environments. The spiraling costs of seismic work and drilling operations in dense jungles, harsh Arctic climates, and isolated mountain passes were the main

motivation for the SHADS project: Amoco hoped that their slim-hole drilling system would directly influence the way major petroleum companies explore for new reserves. Figures 3-52 and 3-53 show how slim-hole and continuous core drilling systems could impact current exploration strategy.⁴⁶ Coring a small diameter wellbore early in the exploration effort, could supplement seismic work and possibly reduce seismic costs.

Figure 3-52. Commonly Used Exploration Procedure

Figure 3-53. Proposed Exploration Procedure

Improving depth capability was an important enhancement Amoco research added to slim-hole drilling technology. Amoco's deepest SHADS rig well was drilled to approximately 10,000 ft., three times deeper than any other slim-hole. The SHADS rig is capable of drilling at rotary speeds in excess of 1,000 rpm; a capability that overcomes decreased bit weight capabilities inherent with slim-hole drilling rigs. Amoco Research conducted extensive studies on well control in small diameter wells and is currently developing an expert well control system to help drillers and drilling engineers monitor drilling conditions.

A reduced-cost, expendable wellbore could save millions of dollars, particularly if the well is dry. By coring the entire length of the wellbore, geologists and geophysicists can examine the various formations as they are drilled. If used properly, analysis of the core generated could dictate the need to drill further exploration wells in the area.

3.3.4 Coiled Tubing Drilling Systems

Coiled tubing rigs which continuously reel 1 to 2 in. diameter steel tubing into wells are extensively used for working over oil and gas wells (Figure 3-54).

Figure 3-54. Coiled Tubing Rig

Coiled tubing rigs are used for various workover operations including 1) squeeze cementing, 2) settling packers, 3) drilling and reaming, 4) stimulating wells, and 5) logging and production testing with logging cables inside of the coiled tabs.

The main advantages of coiled tubing rig are 1) faster tripping time, 2) circulation while tripping, 3) hydraulic power to downhole tools, 4) ability to push logging tools into high angle and horizontal wells, and 5) provide a high-pressure conduit for squeeze cementing and stimulating wells.

A National Science Foundation study being conducted by Maurer Engineering Inc. has shown that coiled-tubing rigs could be used to drill and core to depths of 50,000 feet using titanium tubing and other rig modifications.

3.3.5 Advanced Deep Drilling System

All of the improvements described in this report can be implemented into the advanced deep gas drilling system shown in Figure 3-55.

Figure 3-55. Advanced Deep Gas Drilling System

This advanced drilling system would use coiled tubing to reduce trip time in deep gas wells from 15-20 hours to 3 to 5 hours. It would utilize advanced high-power downhole motors equipped with diamond bearings and advanced rotor/stator systems to deliver 2 to 3 times more power to the drill bit. Advanced synthetic drill bits utilizing the latest thermally-stable-diamond cutters (TSD) could be used to drill 2 to 4 times faster than conventional rotary rigs. Coiled tubing operates at pressures of 7000 to 10,000 psi, so jet-assisted drill bits could also be used on this rig.

Slim-hole motors and bits could be used on exploration wells to produce high drilling rates and reduce casing costs by as much as 50%. Larger diameter motors and bits could be used in larger diameter production wells.

A downhole torque reactor/orienting sub could be added to the advanced rig to allow it to drill horizontal wells (Figure 3-56).

COILED TUBING DRILLING SYSTEM

Figure 3-56. Advanced Deep Horizontal Well Drilling System

The torque reactor sub would grip the borehole wall to provide reactive torque at the hole bottom, thereby allowing directional drillers to orient and guide the bottom-hole drilling assemblies. After drilling the first horizontal hole, the torque reactor could be indexed to drill multibranch horizontal wells in other directions.

All of the know-how and technology exists to put together this advanced drilling system. Development and implementation of this advanced drilling system will require the joint effort of several service companies making the various components needed with this system. GRI could act as the catalyst to have this system put together for deep drilling purposes, and thereby accelerate implementation of this technology by at least five years.

3.3.6 Continuous Drilling with Flexible Drill Stem

Figure 3-57 shows an alternative concept in drilling system that utilizes a continuous flexible drill stem and a downhole motor. This idea, known as "Flexoforage" or "Flexodrilling" was first developed in France in the 1960s.⁴⁷

Figure 3-57. Schematic of the "Flexoforage" or "Flexodrilling" System

This system was investigated extensively by the French from 1960 to 1978. The two main characteristics of this system include:

1. Continuous mud circulation while drilling and tripping.
2. Telemetry and remote control of downhole equipment.

The flexible stem (Figure 3-58) is an armored hose that withstands the different forces of traction, interior pressure, exterior compression, and torsion (due to reaction torque of the downhole motor).

Figure 3-58. Cutaway of Hose

The hose is stored on a drum equipped with a spool regulating device for correct winding of the flexible stem. Drilling fluid flow is affected by a high-pressure rotating joint. Two types of down-hole motors were used, electrodrills and turbodrills. Roller and diamond bits were generally used. Weight on bit was applied by three or four drill collars.

The method was initially used for two applications:

1. A submarine electro-corer for taking cores from the sea-floor (30 meters).
2. A core-drill vessel for investigating ocean floor sediments.

In two later papers, Delacour and Debyser presented modifications to the Flexodrilling program.^{48,49} Advantages of the new method were that trips could be made quickly and easily, and the flexible line between the ship and the sea-bottom served as an inclinometric reference cable for dynamic positioning of the vessel. This minimized the risk of line damage due to ship movement in bad weather. A small displacement surface vessel, similar to the core-drilling vessel used for the ocean floor investigation, was used for the drilling equipment.

All downhole instruments, motors, pumps, and downhole tools for drilling and coring were run at the end of a continuous flexible power-conducting electric cable string that was reeled and unreel quickly and efficiently between the surface and bottom. The string was protected from heave effects by special equipment aboard the surface ship. The downhole equipment consisted of

1) an electrodrill that rotated the drilling bit on the bottom of a coring barrel, 2) an electrically-actuated pump that circulated sea-water down the flexible string during drilling and coring, and 3) sensors and relays for remote controlling the previously mentioned tools. The sensors detected tension, torque, inclination, and pressure.

Between 1960 and 1967, more than a dozen 3000-foot holes were drilled to demonstrate the feasibility of the concept. In 1968, a joint venture was started with the USSR Ministry of Oil Production to develop a 12,000 foot capacity rig. Several holes were drilled, including one to 7,800 ft.⁵⁰ It was found the Flexodrilling could 1) reduce trip time by as much as 60%, 2) eliminate mud conditioning time before and after trips, 3) extend the life of the non-rotating drill stem, and 4) allow constant monitoring of borehole conditions. The main problem encountered was flexible drill stem slippage inside the grippers, necessitating the use of a pneumatically-controlled safety slip attached to the rotary system. Passing connections over numerous sheaves on the rig damaged the flexible drill string adjacent to the couplings (i.e., breaking electric conductors and puncturing the inside leakproof sheath).

The work in the USSR was followed by further development in Holland from 1973 to 1977,⁵¹ including development of two new MWD devices:

1. *Televigile*, which measures weight on bit, torque, internal and annulus mud pressure, and
2. *Azintac*, a directional parameter tool, which gives magnetic azimuth, drift angle, tool face, motor rpm, and borehole temperature.

The authors reviewed twelve holes in two clusters that were drilled satisfactorily and two 1600 ft. wells (35° drift) drilled accurately into a 30 ft. target. Since the tool face readings were constantly monitored, smooth and precise trajectories were maintained. They found that drilling the 1000-ft directional part of the holes could be drilled in 2.9 days compared to 6 to 7 days for normal drilling and that the Flexodrilling system was reliable down to 6,000 ft., but beyond that reliability problems occurred. Extensive differential sticking problems were encountered with the flexo-drilling system since the Flexodrill string could not be rotated.

3.3.7 Casing While Drilling

Many drilling problems occur before the casing is run and cemented in place, because the borehole is unsealed and unprotected. Lack of sealing allows the influx of formation fluids (leading to mud contamination, kicks, or blow out) and the escape of drilling fluid into the surrounding rock, leading to lost circulation, formation damage, differential pressure sticking, and borehole swelling, fracture, and collapse. It would be very useful if a method could be developed to protect the hole wall, even temporarily, immediately after the drill bit has passed, and until a permanent liner can be placed.

Another advantage would be obtained if the usual procedure of setting a series of concentric casings at progressively greater depths could be reduced or avoided. A deep hole, drilled

using conventional techniques, is normally drilled with a much larger starting diameter to accommodate larger surface casing, thus increasing hoisting capability, volume handling systems and deckloading on the rig. If the hole could be drilled with one diameter from the surface to total depth, there would be a substantial reduction in the size of rig, amount of casing used, and drilling cost. A recent project in Norway consisted of casting a polymeric liner utilizes material components pumped in, mixed in situ, and cast in the form of a liner around an inside sliding form (Figure 3-59).

Figure 3-59. Schematic of the "Kolibomoc" (Continuous Lining and Boring Machine) (Littleton, 1987⁵²)

The ideal system would be development of a liner capable of replacing the steel casing, and would thus require a significant wall thickness. Littleton (1987) determined in a 12½ in. borehole liner wall thickness of 2-5 cm. would be required using a 5-6 component polymer having a viscosity of 500 cp at 25°C, and a flexural strength of 150 MPa. The inside sliding form, ("Kolibomac application module") was designed to facilitate the downhole mixing and injection of the mixed material into the annulus surrounding the module. They found that the injected material was successful in plugging the formation, and that the strength of the injected formation increased by a factor of 2-3, a useful effect when applied to unstable formations. They also found that for the 12½ in. wellbore, a collapse pressure of 3,500 psi and a burst pressure of 1,000 psi could be handled by the injected liners. They ultimately concluded that there is enough potential economic gain in the concept to justify further development.

3.4 ENHANCED INSTRUMENTATION

3.4.1 Measurement-While-Drilling (MWD)

Measurement-While-Drilling (MWD) tools transmit drilling data from the hole bottom to the surface while drilling. This is a relatively new, emerging technology widely used as a cost-effective method of drilling directional and horizontal wells, especially in high cost, offshore drilling projects. MWD instruments are located in drill collars near the drill bit at the base of the drill string. The tools measure a range of parameters relating to navigation, drilling mechanics, and formation evaluation. The data may be stored in downhole memory or transmitted to the surface.

MWD tools transmit data to the surface in several ways including:

1. Wireline
2. Mud pulse
3. Electromagnetic waves (Em)
4. Acoustic signals

Wireline systems utilize a wire inside of the drill string to transmit data to the surface while drilling (Figure 3-60). These tools give instantaneous readings, but the wireline creates handling problems.

Figure 3-60. Wireline MWD System

Mud Pulse tools are the most common form of MWD. They transmit data to the surface by sending mud pulses up the mud column in the drill pipe (Figure 3-61). The mud pulses are generated by moving a modular valve into a restrictor ring. The pressure pulses are recorded at the surface with pressure monitoring devices and decoded using sophisticated computer programs.

Figure 3-61. Mud Pulse MWD Tool (Desbrandes, 1985⁵³)

Figure 3-62 shows a mud pulse tool equipped with logging sensors.

Figure 3-62. Examples of MWD Tools. From the Left, Azimuth Measurement, Gamma Ray Intensity and Resistivity, and Neutron Density. (From Teleco and Schlumberger Sales Literature)

An alternate mud pulse system utilizes a rotating disc instead of a valve to produce the mud pulses (Figure 3-63).

Figure 3-63. Mud Pulse Siren System (Desbrandes, 1985⁵³)

The major advantage of mud pulse systems are that they require essentially no changes to the rig or to rig operation. The major limitations of mud pulse systems are 1) slow data rates, 2) depth limitations, especially with heavy drilling muds, and 3) the inability to operate with air drilling systems.

Electromagnetic (EM) MWD systems send electromagnetic waves through the earth to a receiver at the surface (Figure 3-64).

Figure 3-64. Electromagnetic MWD System

The major limitations of EM MWD systems are 1) the inability to transmit from great depths and 2) limited field experience with these tools.

Acoustic MWD systems transmit acoustic signals up the drill pipe (Figure 3-65). The systems have found use in mining applications to depths of 4000 ft and in offshore applications for transmitting data from subsea wellheads to the surface over distances of 3000 ft. These systems have found limited use in oil-field drilling primarily due to transmission distance limitations of 3000 to 4000 ft. Repeaters in the drill string could be used to overcome this limitation.

Figure 3-65. Acoustic MWD System²³

In addition to depth limitations, all MWD tools are limited to maximum temperatures of about 300°F and therefore, cannot be used in many deep, hot wells. Therefore, R & D on MWD tools for deep gas wells should be aimed at overcoming transmission distance and temperature limitations of these tools.

3.4.1.1 MWD Directional Drilling Data

MWD tools provide real time information regarding the course of the borehole (Figure 3-66). In directional drilling, feedback is used as a basis for adjusting the drilling process to accurately steer the borehole along the required trajectory. MWD data are also useful for providing information to the operator on hole problems such as hole sloughing and doglegs.

Figure 3-66. Examples of MWD Tools, From the Left, Drilling Dynamics and Natural Gamma Ray, Resistivity, Electromagnetic, Natural Gamma Ray, and Directional Sub.

The directional measurements include inclination, azimuth and tool face orientation. Toolface orientation allows the directional drillers to orient the bottom-hole tools so that the hole will be drilled along the desired trajectory. A significant advantage of MWD systems is that it allows the operator to take measurements often to achieve good directional control without wasting valuable rig time. The data required to compute deviation and azimuth is automatically sampled and transmitted each time the flow of mud is started, (i.e., after making a connection).⁵⁴ Another important use of MWD is to show orientation of the bent sub, that is increasingly being used with downhole drilling motors. MWD companies suggest using magnetic measurements for borehole deviations less than 5° and using gravity toolface measurements for larger deviations.

Cook et al.,⁵⁵ developed a drilling mechanics tool to measure the dynamic collar forces, accelerations, and fluid pressure forces just above the bit with conventional rotary drilling assemblies and with steerable (bent housing) positive-displacement motors. The spatial orientation (direction and inclination) is measured using magnetometers and accelerometers.

3.4.1.2 MWD Formation Evaluation

MWD Formation Evaluations provide geological data on downhole formations. In recent years, development of new instruments has rapidly narrowed what was previously a huge gap between information available in real time from MWD and post-drilling data from wireline.

The key formation evaluation measurements include resistivity measurements, gamma ray measurements, neutron porosity measurements, and density measurements. MWD real-time data collection enhances decision making, and savings in rig time. In addition, borehole conditions are measured closer to their original state before wellbore alteration has occurred, because of wellbore caving or sloughing, or by the invasion of permeable strata by drilling fluids. The main drawback of MWD logging is that it is expensive and is affected by the hostile drilling environment. Furthermore, because the string rotates while drilling, there can be no pad contact with the borehole wall, and measurements such as dipmeter surveys, and other logging measurements that rely on contact with the hole wall, (e.g., micro resistivity measurements), cannot be made. While these disadvantages impede MWD adaptation, the tools may save rig time expenses by eliminating logging runs and by improving decision-making during the drilling process. In cases where the well caves in before wireline logging tools can be run, the MWD logs may provide the only available data for determining whether to abandon or redrill the well. In wells where the geology is fairly well understood, MWD logging tools can replace wireline.

Correlation between test results from Logging-While-Drilling (LWD) tools and wireline logs in the same hole has shown that LWD logs can be more accurate than wireline because they reflect the state of the hole before borehole erosion, and full invasion by the drilling mud occurs. The ability of the MWD tool to recover information at an early time, and to repeat the measurements each time the tool is run into or out of the hole has allowed the development of a method known as "Time lapse logging." Here, the periodic re-logging of a particular interval can show the progressive invasions of a permeable zone, or the development of wellbore caving.⁵⁶ The biggest impediment to the wider use of MWD logging tools is their high price, but costs will come down as time progresses.

Figure 3-67. Examples of Time-Lapse Logging

The use of MWD to measure the formation resistivity has been extensively documented by various authors. Including Clark, Luling et al.⁵⁷, Fredericks⁵⁸, Wisler⁵⁹, Cobern and Nuckols⁶⁰, Allen and Luling⁶¹, and Koopersmith and Barnett⁵⁶. The main advantages of this tool are 1) its outstanding bed resolution (down to as little as 6 in.), 2) the possibility of use in oil-base muds, and 3) pre-invasion measurements of formation resistivity. Recent advances include storage of data in memory downhole, to be retrieved when the tool is brought up to the surface.

MWD logging gives an accurate estimate of the formation pore pressure while drilling, an important factor in controlling reservoir fluids and preventing blowouts. Lesso and Burgess developed a method to measure the porosity and pore pressure of the formation using rock strength measurements computed from ROP and MWD values of weight on bit and torque.⁶²

Koopersmith and Barnett compared conventional wireline and MWD gamma ray measurements in several Gulf of Mexico and Alaska⁵⁶ wells and found that wireline logs run twelve days after drilling showed that the shale baseline gamma ray count decreased, reflecting increased borehole size, probably due to borehole washout. Because MWD measurements were taken as the hole was drilled, the MWD log clearly exhibits superior bed resolution, and improved bed boundary resolution, in addition to reducing the uncertainty concerning the final measurements.

Neutron sensors indicate formation porosity by measuring the quantity of hydrogen atoms (found principally in water and oil) using neutron bombardment. Roesler et al.,⁶³ found that a

compensated dual neutron porosity log showed excellent vertical resolution and dynamic response of the MWD neutron sensor, and resulted in substantial savings in both direct logging cost and associated rig time when compared to a wireline sidewall epithermal neutron porosity log. Evans et al.,⁶⁴ found that thermal porosity logs made with a MWD Neutron Porosity Sensor were comparable with those obtained from wireline logging techniques. The neutron source was retrievable by conventional wireline/slickline fishing techniques, eliminating the possibility of having to abandon the radioactive source downhole if the drill pipe became stuck. Wraight, et al.,⁶⁵ found that severe borehole washouts limit the accuracy of MWD CDN logs.

3.4.1.3 MWD Drilling Mechanics Tools

MWD drilling mechanic tools measure factors such as bit weight, torque at the bit, and vibrations (Figure 3-68).

Figure 3-68. Schematic of a Drilling Mechanics Sub (Close, 1988⁶⁶)

Operators can use these data to reduce pipe sticking, improve drilling efficiency by maximizing bit performance, detect drilling problems, and eliminate unnecessary trips. Belaskie et al., used downhole data of weight-on-bit and torque to optimize PDC bit performance, provide feedback on directional data and drill string friction analysis.⁶⁷ They used MWD to optimize drilling as follows:

1. Limiting torque while drilling sand to monitor bit wear.
2. Observing torque to detect undergaged bits and locked roller cones.
3. Detecting damage to the mud motors.

Lesage et al., and Falconer et al.^{68,69} concluded that real-time monitoring of friction can be used to detect the onset of drilling problems, provide sufficient time to take remedial action, increase drilling efficiency and avoid getting stuck. MWD data have also been used for other

applications such as detecting bearing tricone bit failures,⁷⁰ and cone locking and loss of cones downhole⁷¹ (Figure 3-69).

Figure 3-69. Illustration of the Detection of Cone Locking (Lesage, Falconer et al., 1988)⁷¹

Close et al.,⁷² measured downhole vibrations with a downhole microprocessor and found that destructive downhole vibrations can be avoided with changes in RPM and WOB.

3.4.2 Automated Rig Operations

Drilling operations require a highly skilled crew of five or six individuals who spend most of their time on the drill floor, working 12-hour shifts. The work is mentally and physically tiring and usually performed in a noisy place without any overhead protection from the environment. Operations vary from routine events to unexpected abnormal events that require process understanding and prompt action.

Automation of rig operations offers the opportunity to remove a good portion of the physically-stressful part of the work so that a smaller crew, environmentally protected, can better cope with the mental requirements of the task. The main components of the robotic system are the brain or the computer, the muscle/skeletal frame or actuator, and the sensors (Figure 3-70).

Figure 3-70: Sketch of an Automatic Drilling Machine (Boyadjieff, 1988)⁷³

Past and present activities associated with automating the drilling process have been related to pipe handling because of the repetitive and physically exhausting nature of the work.

- Boyadjieff⁷³ revived the three types of automatic drilling machines:

ADM - or the Automatic Drilling Machine, which had hydraulic cylinders to hoist the string. A transfer arm moved single pipe lengths from the vertical well position to the horizontal racked position (Figure 3-70).

Iron Roughnecks - they represent true robots in that they were computer controlled, performing their tasks without human intervention. Robotics was applied to the process of connecting and disconnecting drill pipe during a round trip (Figure 3-71).

Pipe-Handling Machines - they were primarily mechanical power tools that were intended to move pipes from the well to the racking area on floating rigs where human muscle power was insufficient (Figure 3-72).

Brugman presented a new generation pipe racking system that combined the functions of traditional powered pipe racking systems and remote-controlled, floor-mounted iron roughnecks into one machine for automated pipe handling (Figure 3-71).⁷⁴

Figure 3-71. Automated Pipe Connecting and Disconnecting Machine

This machine enables a single operator to execute all the pipe tripping operations from the floor to the monkey board while tripping drill pipe into or out of the hole. Instead of using independently controlled racking arms, arm synchronization is obtained mechanically by connecting the arms and their supporting carriages together with tie rods in a four-bar linking arrangement. The entire weight of the drill pipe or collar is supported by the lower arm jaw that is equipped with gripping dies. Below the two arm carriages is a third carriage which houses the operator's cabin, spinning wrench and torque wrench.

The Automatic Pipe Handling Machine (Figure 3-72) has three basic modes of operation from a control system standpoint.

Figure 3-72.- Automatic Pipe-Handling Machine

First, there is the manual mode, where the operator has direct control of all machine movements. Second, the semi-automatic mode, where only the microprocessors can energize an actuator and the machine is dependent on software to interpret switch and sensor inputs and generate appropriate responses. And third, the fully automatic mode that is simply an extension of the semi-automatic mode with all the sequences joined together and all hold/proceed decisions made by the processors.

Price et al., advocate the development of a centralized drill-string supervision system that monitors the relative positions of all main components on the drill floor and in the drill string.⁷⁵ These authors state that combining the most advanced handling and process equipment with a central computer-control system, and ensuring wider technical competence among the operatives make it feasible to control all the drill string, mud, and cementing operations from the same point. The possible benefits of the centralized system include increased safety because of early detection and reaction to abnormal or dangerous situations, significant improvements in the working environment, and improved efficiency.

3.5 ADVANCED MANAGEMENT TECHNIQUES

During the last few years, the increase in number and capability of computer systems has encouraged engineers in all fields of activity to consider using these machines to assist in the management of technical operations. Computer systems are finding increased use in drilling operations including the following:

Technical calculations. Programs are written that deal with problems formulated in terms of physical parameters, and produce outputs that describe the behavior of the specified system.

Data-base management. This is the business of collecting, storing, sorting and retrieving all types of information, ranging from inventories of goods to maintenance of case histories for different operations.

Operations management. Programs of this type typically allow tracking or planning of the progress of operational projects. Such programs may include financial management systems or critical path analyses, etc.

Communications systems. Computer systems are increasingly used to allow rapid and complex communication by spoken word, video, or direct computer-to-computer communication to all parts of the world.

Non-numerical analysis. Typical of this category are the "expert systems" that use a predetermined logical system of "artificial intelligence" to arrive at a "diagnosis" from a given set of inputs. Expert systems may be either "forward chaining" to predict the outcome expected from a specified set of inputs, ("if I do this, this and this, what will happen?") or "backward chaining", to determine the combination of parameters that have resulted in a particular outcome ("I am now stuck; how did this happen ?").

Each of these systems have been applied to oil and gas drilling. Examples of computer utilization in single technical calculations are numerous and are increasingly being made in real time on the rig as drilling proceeds (e.g., continuous monitoring of drilling parameters while drilling,⁷⁶ and continuous monitoring of mud solids^{77,78}).

Lacy et al.⁷⁹ developed a database archived well data as wells were drilled, allowing construction of daily and final reports, and comparison of historical well records. Most oil companies and many drilling contractors now utilize similar data bases.

Operations-management programs have been widely used in the drilling industry; including the early work of Ikoku on learning curve models,⁸⁰ the work of Brett and Millheim on use of the drilling performance curve,⁸¹ and the development of a drilling operations data-base program by Dunn and Payne.⁸²

A notable application of artificial intelligence was in the development of the "Drilling Advisor"⁸³, a system designed to advise drillers on the likely causes of a drilling problem, the set of reasons supporting the conclusion, and a series of recommendations. Lloyd et al. developed an expert system for automatic well control, and it is evident that many other applications will be forthcoming.⁸⁴

In the early 1980s, Millheim and co-workers⁸⁵ developed an "Engineering Simulator" which made all of the technical calculations from all the different drilling processes, (e.g., calculate mud density and rheology), and applied the results as input to a drilling model. This model utilizes a complete description of the drilling process based on input parameters concerning geology, drill rig, wellbore, fluid systems and the drill string.

This "Engineering Simulator" was integrated into a "Drilling Command and Control System," that linked the engineering simulator to a data base and various managerial functions, and operating drilling rigs. The engineering simulator allowed the field operation to be modeled in real time, and to predict and guide the drilling operation. This "Critical Drilling Facility" linked the engineering simulator to the operating rig by a comprehensive video and data transmission system,⁸⁶ allowing the rig crew to access expert guidance from the head office, and the office-based technical and management teams to be aware of the latest developments at the rig site.

Figure 3-73. The Amoco "Critical Drilling Facility" and "Drilling Command and Control System" (Foreman, 1985)⁸⁶

An alternative approach to managing drilling operations, known as the "Management and Drilling System" (MDS), has been developed by the drilling contractor Sedco-Forer. This system is built around the rig as a unit, and the objective is to integrate all rig operations into one system. Sensors and computer terminals at different locations on the rig collect managerial and operational data. For example, managerial data may include stock-keeping information, and the operational information include data collected from ongoing drilling operations or marine information of interest to the barge engineer. All inputs are stored in a central computer and can be accessed from any terminal. The advantage of such a system is that it allows interaction between previously separated functions. For

example, it allows the toolpusher to access a stock-keeping inventory when designing a BHA, or the materials manager to know how many rotating hours have been accumulated on particular section of pipe since it was last inspected. The present system includes a suite of management functions for a marine advisory function. The system also has a set of drilling functions concerning real-time monitoring, and off-line calculations. Real-time monitoring includes optimization of steady-state operations (weight-on-bit, rotary speed, etc.), and the detection of "events" such as a kick, or bit cone-bearing failure. Off-line calculations include comparison of present progress with offset well data, performance prediction, or report preparation.

Opinions vary as to the value of the "rig-centered" versus the "head office-centered" management systems. Certainly, the concept of bringing all the information to a central management location enables one to concentrate a much greater weight of technical and managerial power on any given problem than does the rig-based system, but it can also generate a feeling on the rig that there is a "big brother" back at the head office "second guessing" decisions made at the drilling site. There may also be a feeling that even the most advanced communications technology does not adequately convey to the head office staff the flavor of what is really going on at the rig site.

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4. Novel Drilling Systems

Before discussing the various novel drilling techniques, it is important to understand the characteristics of *novel drilling systems* and the role they have played in the history of oil well drilling. Novel systems are identified by the following criteria:

1. Novel drilling systems use techniques deviating significantly from conventional rotary drilling systems that utilize present state-of-the-art drill rigs, drill pipe, and rock bits.
2. Implementation of novel drilling systems requires significant retrofitting, or complete replacement, of conventional drilling systems because of the revolutionary (rather than evolutionary) approach to improving drilling techniques.
3. The majority of novel drilling systems have not been tested on a large scale and have not been implemented outside the laboratory environment.

Attempts to introduce revolutionary methods of rock drilling that are faster and more efficient is certainly not a new idea. With the first commercial oil wells of the 1860s and 1870s, numerous concepts to improve the drilling process were patented. In fact, some of the 'novel' concepts considered here were first patented between 1850 and 1900, and the drills that today's conventional rotary bits evolved from were first conceived of during the 1830s.

Interest in new drilling concepts has ebbed and flowed several times during the last century. After the activity of the late 1800s, steady improvement was made to the then dominating cable tool rigs until the mid-to-late 1920s. Although the rotary rig was first used for oil-well drilling around 1900, it was considered to be a novel procedure to be used only for drilling soft formations where cable tools were ineffective. Even as the capabilities of rotary rigs improved, the prevailing viewpoint was that cable tools would always be needed because of their superior capabilities in hard rock drilling. This held true until the late 1920s and early '30s when the rolling cutter bit, invented in 1909 by Howard R. Hughes, finally demonstrated the capability of drilling in both soft and hard formations. By the late 1930s, the once novel rotary rigs became the standard to which all other drilling systems would be compared.

During World War II, improvements to the rotary rig slowed, and most novel ideas were focused toward military applications. However, after the war, many improvements in materials and equipment generated for the war effort were implemented on the rotary drilling rigs. During the 1940s and early 1950s these improvements helped the drilling industry penetrate depths greater than 20,000 ft.

The late 1950s and '60s continued to see extensive improvements to the, by then firmly established, rotary drilling rig. By the end of the 1960s, the record well depth with these rigs was in excess of 25,000 ft, and the number of wells drilled each year to depths greater than 15,000 ft had risen from less than ten per year to nearly 400 per year. During this time period, tremendous advancements were made in numerous established technological areas and a number of completely new technologies emerged. Because of the exceptional progress being made, there was broad interest in finding new

applications for devices such as lasers, rockets, and nuclear reactors. This report clearly shows evidence of the interest during the late 1950s and 1960s in applying new technology to the drilling industry.

Comparable to the acceptance of rotary rigs during the early 1900s, the majority of the novel techniques developed during the 1960s continued to be restricted to the laboratory during the 1970s and 1980s. A few new techniques were introduced during these two decades, but nothing compared to the technical advances implemented during the 1950s and 1960s. A literature search conducted on novel drilling techniques revealed that of 304 papers and patents published since 1964, only 82 papers describing novel drilling techniques have been published since 1976. Many of those 82 were actually describing enhancements to conventional techniques already in use. Extensive improvements in drilling rates and the improved performance of conventional rigs has impeded interest in revolutionary changes to the drilling process. The poor economic position of the petroleum industry during the 1980s also contributed to the decline in interest and kept most companies focused solely on survival.

Today, there is renewed interest in investigating the application of novel drilling techniques. The diminishing number of shallow gas and oil-gas bearing formations remaining in the continental United States has created the need to exploit deeper reserves. Because deep drilling is much more expensive and demanding than drilling in the shallower horizons, it may be possible to utilize novel drilling techniques to drill deep oil wells more efficiently and for less cost than current conventional rotary drilling systems will allow. Although some of the novel techniques were not plausible when first introduced, the current state of technology may now permit their application due to improved materials or techniques. The following text presents a variety of novel drilling techniques patented during the last several decades.

Four basic rock breaking mechanisms are utilized by novel drilling techniques, including:

1. Mechanically Induced Stress,
2. Thermally Induced Stress,
3. Melting and Vaporization, and
4. Chemical Reactions.

The following text will consider the various novel drilling techniques based on the rock breaking mechanism utilized.

4.1 MECHANICALLY INDUCED STRESS

Novel drilling techniques that induce mechanical stresses break rock by impact, abrasion, or erosion. Brittle fracture or plastic yielding occurs when the mechanical stress exceeds the rock's tensile or shear strength. Novel drilling systems that utilize this type of rock-breaking mechanism include *abrasive jet*, *cavitating jet*, *explosive*, and *spark*. Each of these techniques will be considered in more detail in the following text.

4.1.1 Abrasive Jet Drill

Abrasive jet drills induce mechanical stress on the rock surface by circulating a drilling fluid containing abrasive materials through high-pressure jet nozzles. Even though the pressure of the jet may not exceed the threshold pressure needed to cut rock, the combination of fluid jets and abrasive materials is able to advance the bit by eroding a kerf, or hole, in the rock surface. Types of abrasive material that have been used include sand (0.8 - 3.2 mm dia.) and steel shot (1.6 - 3.2 mm dia.). A variety of different configurations have been utilized and are described briefly below.

A set of high-pressure, abrasive jets are used in the system shown in Figure 4-1 to cut a kerf along the perimeter of the wellbore. The remainder of the rock is then removed using conventional roller-bit cutters. This system was patented by Bobo in 1963.

Figure 4-1. Abrasive Jet Drill (Bobo, 1963)

A set of high-pressure, abrasive jets are used to cut a pilot hole as shown in Figure 4-2. After the pilot hole has been completed, the jet nozzles are plugged by pushing them into the formation. The sudden pressure increase creates a water hammer that crushes the rock around the pilot hole. The process is then repeated. This system was patented by Atlantic Richfield in 1966.

Figure 4-2. Atlantic Richfield Abrasive Jet Drill
(Cleary, 1966)

A set of wireline retrievable high-pressure, abrasive jets are utilized in the system shown in Figure 4-3. When the jet nozzles wear out (due to abrasive wear), they are pulled from the hole, and replaced, using a wireline. This procedure saves considerable time. The jets are not used in conjunction with any other cutting mechanism. This system was patented by Gulf Oil in 1968.

Figure 4-3. Replaceable Abrasive jet Nozzles (Mori & Schaub, 1968)

A set of high-pressure, abrasive jets are configured in the system shown in Figure 4-4 to cut a core that is then retrieved from the wellbore with a core barrel system. This system was patented in 1969 by Gulf Oil.

Figure 4-4. Abrasive Jet Core Bit (Mori & Schaub, 1969)

Figure 4-5 shows a system of high-pressure, abrasive jets configured to cut kerfs in the rock ahead of a set of loading elements. Utilizing loading elements approach decreases both the volume of rock the jets must remove, and the amount of energy. The system was patented by Gulf Oil in 1970.

Figure 4-5. Gulf Abrasive Jet Bit (Hasiba, 1970)

The system was tested extensively in the field. The major problems experienced with this abrasive jet system included:

1. Extreme nozzle wear. The nozzle entry was subjected to impact wear while the nozzle exit was subjected to abrasive wear.
2. Extreme erosion of the high-pressure equipment. Affected equipment included pumps (packing and valves), swivels, drill pipe, bits, surface mud handling equipment, and surface flow lines.

Before abrasive drills can be utilized economically as a primary rock destruction mechanism, techniques must be found to overcome these significant obstacles. However, abrasive jets and all types of high-pressure jets exhibit the potential to substantially enhance conventional drill bit performances.

4.1.2 Cavitating Jet Drill

In a liquid-circulating system, jet nozzles can be designed to cause pressure at the exit to drop to the vapor pressure of the liquid. The pressure drop causes vapor bubbles to form, and then to collapse on themselves (implode) as the pressure rises further downstream from the nozzle exit. This phenomenon, called cavitation, produces high impact pressures that can be utilized to drill rock at much lower pressures than the threshold pressures required to drill with continuous or pulsed jets. Lower operating pressures are highly desirable because of less stringent requirements on equipment and materials.

Extensive work has been done on cavitating jet bits during the last two decades. Figure 4-6 shows two techniques for producing cavitation in liquid jets, developed and patented in the late 1960s by Hydronautics. The first method uses a turning vane to create turbulence in the fluid as it enters the jet nozzle. This design increases the occurrence of cavitation as fluid exits the nozzles. The second technique shown in Figure 4-6 uses a cylindrical shaped body, centered at the mouth of the nozzle to produce cavitation.

Figure 4-6. Hydronautics Cavitating Nozzles (Koh., 1968)

Figure 4-7 shows an oil-well cavitation drill patented by Mobil Oil (Brooks, 1967). This system utilizes a six-stage turbine to oscillate a piston at speeds up to 10,000 cps to produce cavitation bubbles. This drill is capable of producing cavitation at pressures up to approximately 300 psi — corresponding to a drilling depth of approximately 800 feet. Unfortunately, this limitation prohibits its utilization as a deep drilling technique. Cooke (1968) patented a modification that expands the utilization of this apparatus. By injecting gas into the drilling fluid, the turbine oscillator can produce cavitation at much greater depths. A variety of different drive methods were also developed and patented to improve the depth capabilities of the apparatus.

Figure 4-7. Mobil Turbine-Powered
Cavitation Drill (Brooks, 1967)

The system shown in Figure 4-8 was patented by Mobil (Angona, 1970). This system focuses cavitation bubbles produced by an oscillating piston. A biconical concentrator consisting of two conical frusta joined end to end are used to focus the energy against the rock as shown in Figure 4-9. The flexible connection at the top of the drill (Figure 4-8) allows a deflector to sweep the cavitating jet across the hole bottom. As the drill is rotated, the deflector slides in a groove and sweeps the cavitating jet across the hole bottom in a spiral-like pattern as shown in Figure 4-10.

Figure 4-8. Mobil Cavitation Focusing System (Angona, 1970)

Figure 4-9. Cavitation Focusing Nozzle (Angona, 1970)

Figure 4-10. Bottom-Hole Sweep Pattern (Angona, 1970)

Several observations have been noted during the experimental development of cavitating jet bits. These include:

1. Specific kerfing energy decreases with increased traverse speed and decreased nozzle diameter. This indicates that the most efficient design should include high traverse speeds coupled with small bit diameters. See Appendix A for definition of Specific Kerfing Energy.
2. Specific kerfing energy is higher for cavitating jets than for continuous or pulsed jets because wider kerfs are cut with cavitating jets. However, specific energy is substantially lower for cavitating jets.
3. Cutting rate increases as borehole pressure increases up to a maximum of approximately 1,500 psi and then begins to drop off as shown in Figure 4-11.

Figure 4-11. Cavitating Jet Data (Conn & Radtke, 1978)

4. For a given power level, there is an optimum nozzle standoff distance as shown in Figure 4-12.

Figure 4-12. Effect of Nozzle Standoff on Cavitation
(Lichtarowicz & Sakkejha, 1972)

5. Figure 4-13 shows that a threshold power level must be exceeded before cavitation erosion takes place.

Figure 4-13. Effect of Power on Cavitation Erosion
(Lichtarowicz & Sakkejha, 1972)

Cavitating jet systems do not cause the severe equipment erosion problems inherent with abrasive jet systems. However, because of the pressure limitations of present cavitating jet systems, this type of novel drilling system is a viable candidate for drilling deep wells.

4.1.3 Explosive Drill

Explosive drills induce mechanical stress in the rock by circulating projectiles in the fluid medium, and then detonating them when they contact the rock surface. Explosive drills have

been shown to deliver a significant quantity of horsepower to the workfront, even when the system has not been optimized. The following text briefly describes several of the resulting explosive drills.

In the late 1950s and early 1960s, the Soviets used the explosive drill shown in Figure 4-14 to drill nearly 10,000 ft of hole (approximately 13 inches in diameter) to depths greater than 13,000 ft. The explosive capsules (shown in detail in Figure 4-15) are composed of two liquid chemicals separated by a diaphragm. As the capsule passes through a constriction near the bottom of the drill pipe, the diaphragm ruptures, combining the two liquids to create an explosive mixture. When the capsule leaves the nozzle, the fins spread apart, freeing a percussion pin to impact and fire a detonator when the capsule strikes the rock.

Figure 4-14. Soviet Explosive Capsule Drill (Ostrovskii, 1960).

Figure 4-15. Soviet Explosive Capsule (Raynal, 1960)

In 1962, Jersey Production Research (Robinson) patented the explosive drill shown in Figure 4-16. This drill uses two different types of capsules: jet charges and gauge charges. First, a jet charge is used to create a new pilot hole, and then a gauge charge is used to enlarge the pilot hole to the desired wellbore diameter. As with the Soviet system, the capsules are circulated to the workfront using the drilling fluid. The equipment configuration utilized by Jersey Production Research is shown in Figure 4-17. Figure 4-18 shows schematics of jet and gauge charges. A sand layer (43) is positioned above the jet charge to improve penetration. Both charges are detonated by the increase in hydraulic pressure when the charges seat in the bottom of the drill string.

Figure 4-16. JPR Company Explosive Drill (Robinson, 1962A)

Figure 4-17. JPR Company Explosive Drill (Robinson, 1962A)

Figure 4-18. Explosive Capsules (Robinson, 1962A)

Jersey Production Research (1963) also patented the system shown in Figure 4-19 where encapsulated explosive charges are pumped down the drill string and detonated when crushed by the rock bit. These capsules are designed so that any charges escaping the crushing action of the bit dissolve before reaching the surface.

Figure 4-19. JPR Company Explosive Drill
(Friedman et al., 1963)

In the early 1970s, Sun Oil (Bennett et al., 1971) developed and patented an explosive system that combined a two-cone roller bit with explosive charges. The two-cone design allows the explosive charge to impact the bottom of the hole instead of the perimeter. The change in point of contact enhances the effectiveness of the charge—and thus improves the drilling rate.

The explosive drilling system shown in Figure 4-20 was designed and developed in the early 1980s by Tround International, Inc. This system utilizes a modified tricone roller bit equipped with three machine gun barrels and is designed to improve drilling rates and reduce bit wear. Projectiles, which are fired down the machine gun barrels at high speed, disintegrate upon impact with the rock surface. The force of the impact fractures the rock and enhances the drilling performance of the roller bit. The system has increased penetration rates by 2 to 5 times the rates achieved with standard roller-cone bits. The present model will only operate with systems that circulate air because the gun barrels must be free of any debris, including drilling fluid. This prohibits utilization of the system in deep drilling applications. Tround is attempting to develop high-pressure valves that will open as the bullets pass out of the gun and then close to seal mud out of the guns thereby allowing them to be used in deep mud-filled wells.

Figure 4-20. Tround Terra-Drill (Dardick, 1977)

Certain guidelines must be followed when designing or utilizing explosive drilling systems:

1. A certain stand-off distance is required to protect the nozzle from damage. This distance varies from system to system.
2. An optimum firing rate exists, beyond which the capsules (charges, explosives) will fire sympathetically and not contribute to the rock-breaking process.
3. Increasing the rate of explosions can actually cause penetration rates to decrease because the increased amount of broken rock on the hole bottom cushions the effect of subsequent explosions.
4. Rock strength/drilling rate correlations show little, or no, relationship.
5. Clay has a detrimental effect on drilling rate when using explosive drills. Clay yields plastically and is hard to remove from the hole bottom. This indicates that any formation that behaves plastically will be difficult to excavate using explosive drills.
6. Well depth does not appear to affect explosive drill performance. For this reason, explosive drills are good candidates for deep drilling applications as long as the drilled rock becomes harder without becoming more plastic.

Explosive drills direct a significant amount of power to the rock and this power does not appear to decrease with depth. For this reason, the explosive drill is a viable candidate for deep drilling application. However, the detrimental affect of plastic rock behavior on drilling rates, the

cost to integrate required equipment, the cost of the explosive materials, and safety problems have precluded these systems from becoming commercially viable.

4.1.4 Spark Drill

Spark drills break rock using intense shock waves created by discharging high-voltage capacitors across electrodes. These shock waves produce craters similar to those created by conventional impact bit teeth. One of the earliest novel drilling systems utilizing this technology was developed in the 1950s by the Soviets. Their work resulted in a tangential spark drill (shown in Figure 4-21), and a radial spark drill (shown in Figure 4-22). The tangential spark drill discharges sparks between electrodes around the periphery of the drill. The radial spark drill fires sparks along radii from a rotating center electrode to stationary electrodes on the periphery of the drill. Results from laboratory tests showed that these spark drills require approximately twice as much energy as conventional drills to effectively drill rock.

Figure 4-21. Tangential Spark Drill (Titkov et al., 1957)

Figure 4-22. Radial Spark Drill (Yutkin, 1955)

Figure 4-23. Spark Electrodes (Maurer, 1969)

In 1969, Maurer discharged sparks in air and in water. The results clearly showed that sparks discharged in water produce much greater pressure pulses (up to 1 million psi). Figure 4-23 shows three types of electrodes tested. The results showed three important findings:

1. The mass electrode produced the largest craters,
2. Water saturation of the rock was detrimental to the spark cratering mechanism,

3. Craters were effectively produced with sparks at hydrostatic pressures corresponding to well depths of 20,000 ft.

Figure 4-24 shows a spark drill patented by Mobil Oil in 1970 (Angona). Mechanical cutters are used to cut the gauge portion of the hole and spark discharges are used to remove rock at the center of the hole. The piezoelectric elements used on this drill generate up to 30 kv potentials to produce spark discharges across the electrodes. Dynamic load applied to the piezoelectric elements using the cam mechanism shown in Figure 4-25 generates the required high voltages. The cam is operated by rotating the drill pipe with the bit providing reactive torque to the lower part of the cam.

Figure 4-26 shows a spark-assisted roller bit patented by Jersey Production Research Company in 1964 (Rowley). High voltage sparks are produced between the high voltage electrode and the electrically-grounded roller cones. The high voltage sparks produce intense pressure pulses that assist in disintegrating the rock. Electric power for the sparks can be supplied through high voltage cables in the drill pipe, or by using a downhole mud turbine to power a high voltage generator as shown in Figure 4-27.

Figure 4-24. Combination Mechanical-Spark Drill
(Angona, 1970)

Figure 4-25. Mobil Cam Mechanism
(Angona, 1970)

Figure 4-26. JPR Co. Spark Drill
(Rowley, 1964)

Figure 4-27. JPR Co. Turbine Spark Drill (Rowley, 1964)

In 1970, Shell Oil (Smith) patented the oil-well spark drill shown in Figure 4-28. This drill also utilizes a mud turbine to generate high-voltage electricity for the spark circuit.

In the 1974, Sandia Laboratories (Newsom) began development of the oil-well spark drill shown in Figure 4-29. This system utilized sparks to generate pulsed jets and cavitating jets. The pulsed jets shatter the rock and the cavitating jets remove the broken rock (Figure 4-30). Sandia made several important observations during their tests:

1. It is important to place the sparks as close to the rock surface as possible to be effective,
2. Insulation failure is a major problem in spark drills because of "sparkover," and
3. Spark drilling rates could probably be increased 4- to 10-fold by increasing the pulse rate and the number of electrodes used, but increases of 50- to 100-fold would be required to make the spark drill attractive as an alternative to rotary drilling.

Figure 4-28. Shell Oil Well Spark Drill (Smith, 1970)

Figure 4-29. Sandia Laboratories Spark Drill (Newsom, 1974C)

Figure 4-30. Spark Drilling Mechanism (Newsom, 1974C)

Sandia discontinued work on the spark drill because there was such a large gap between spark and conventional drill bit capabilities.

Several other investigations were conducted in the 1970s showing that spark drills can be used to improve the cutting ability of continuous water jets by interrupting them repeatedly at high speeds. Sandia showed that interrupted water jets operating at 390 psi drilled holes in several rocks that continuous jets and sparks alone would not drill.

Several other observations about the performance of spark drills included:

1. Inductance in a spark circuit lengthens the spark duration and reduces spark pressure. For this reason, the condenser needs to be placed downhole near the bit.
2. To be effective, electrodes must be close to the rock surface.
3. Sparks are more effective when their energy is focused toward the rock.
4. Sparks must be focused in the high fluid pressure environment existing in deep wells to be effective.

After Sandia's experiments with spark drills, little work was done to advance the technology until 1985 when Tetra Corporation started a new project. The reason for renewing work on this rock destruction technique was the tremendous advancements made in electrical hardware technology. Tetra suggested that this progress could permit power delivered downhole to be increased by an order of magnitude greater than the 100 kW systems introduced in the late 1960s. Additionally,

modern systems should be capable of allowing the shock fronts to be focused and steered electronically.

During the project, Tetra tested two pieces of experimental equipment. One of the systems delivered 80 kJ of energy to the electrodes in a water-filled target chamber. Pulse voltages of 1 MV and pulse lengths of 100-200 nanoseconds were employed. Results showed that the rate of drilling a 2.4-in. diameter hole in sandstone or limestone was approximately 29 ft/hr. Tetra calculated that a 7.9-in. diameter hole could be drilled with penetration rates between approximately 24 and 33 ft/hr using the same discharge rate of one spark per second.

Even though significant work was completed, and excellent penetration rates were projected, Tetra noted that significant technical challenges still needed to be overcome before spark drills with reasonable drilling rate capabilities would become commercially available for oil-field drilling. Currently, Tetra is developing a spark drill system for a commercial application outside of the petroleum industry.

4.2 THERMALLY-INDUCED STRESS

Applying heat to rock (700 - 1100°F) causes the different minerals within a formation to expand at different strain rates. This process creates thermally induced stresses in the formation that can fracture and degrade the rock. Novel drilling systems that utilize this type of rock breaking mechanism include:

Electric Disintegration
Flame Jet
Forced Flame (Rocket Exhaust)
High Frequency

Each of these novel drilling techniques is considered in more detail in the following text.

4.2.1 Electric Disintegration Drills

By transmitting a high-voltage, low-frequency electric current into rock, an electric disintegration drill breaks rock by inducing thermal stresses. The thermal stresses are produced by one or more of the following mechanisms:

1. Differential thermal expansion of constituent minerals,
2. Chemical decomposition of rock components,
3. Expansion of gas and moisture, and
4. Phase transition of minerals.

In the early 1960s, Sarapuu used the electric disintegration drill shown in Figure 4-31 to drill limestone, concrete, and other materials. The power transmitted to rock by an electric disintegration drill varies as

$$P = kE^2/r \text{ (watts)}$$

where k = constant depending on the electrode configuration, cm;
 E = electrode potential, v;
 r = rock resistivity, ohm-cm.

Figure 4-31. Electric Disintegration Drill
 (Sarapuu, 1965)

Drilling rates are highest in rocks with low resistivity. Rock resistivities range from 10^{-2} ohm-cm for magnetite to 10^{15} ohm-cm for quartz, indicating that the penetration rate of electric disintegrating drills is highly dependent on rock type.

In the 1970s, Sarapuu developed several versions of the electric disintegration drill for the mining industry—most notably for oil-shale mining. The electrical energy generated by these systems was used to increase the permeability of the oil shale. Unfortunately, the increase was not sufficient for in-situ retorting so nitroglycerin explosives were used to further improve the permeability. Testing of this system was eventually terminated.

During the late 1980s, CEEE, a company located in Connecticut, began promoting a device similar to that developed by Sarapuu. This rock destruction tool is superior to the systems previously designed because it applies short (microseconds) electrical pulses rather than the longer pulse rates (minutes, or even hours) utilized previously.

Although the majority of the work has been for boulder breakage, the results are impressive because successful testing has been performed on sandstone, granite, taconite, and quartzite rocks. Also, CEEE has apparently been able to control the fragment size distribution by controlling the electrical input to the rock. Ascertaining if this technique represents a significant breakthrough will require that the system be tested under field conditions and that the rock destruction technique be attempted on an intact rock face rather than on boulders. Some work has been performed to induce cratering of the rock surface on large blocks of rock.

4.2.2 Flame Jet Drills

Flame jet drills use a combustible mixture of gas and fuel to spall rock. There are two basic types of flame jet drills:

1. The *jet piercing drill* uses fuel and pure oxygen.
2. The *conventional flame jet drill* uses fuel and air or oxygen enriched air.

The lower oxygen concentration of the conventional flame jet reduces the flame temperature and flame velocity. These conditions cause the flame jet to work slower than the jet piercing drill. Despite the slower penetration rate, Browning showed in 1965 that the conventional flame jet requires 50% less oxygen to remove a unit volume of rock, an important factor since oxygen is a major cost of operating jet piercing drills. Browning experimented with various oxidizer mixtures and found that flame jets produced with oxygen/nitrogen oxidizers drilled granite more effectively than those produced with pure oxygen jet piercing drills.

Browning developed the flame jet nozzle shown in Figure 4-32. This nozzle introduces fuel downstream of the combustion chamber causing secondary combustion to occur outside the nozzle. Secondary combustion helps the flame jet produce spalls approximately twice the size of those produced by flame jets without secondary combustion. Browning performed a variety of experiments utilizing different fuel/gas ratios, oxygen/nitrogen ratios, etc. He found that producing stable flames with air or with 50:50 oxygen/nitrogen gas required that the fuel mixture be controlled within much closer limits than when using pure oxygen.

Figure 4-32. Flame Jet Nozzle (Browning, 1965)

Carstens patented a variation of the conventional flame jet drill in 1968 as shown in Figure 4-33. This drill utilizes abrasives such as sand to enhance the capabilities of the flame jet in rocks that do not readily spall.

Browning's later work missing

Figure 4-33. Flame Jet Burner
(Carstens, 1968A)

Although flame jet drills do spall rock, there are a variety of problems with the tool that hinder their use in deep well drilling:

1. Incomplete combustion and other losses cause the effective power output of flame jets to be less than half of that obtainable if complete combustion were realized.
2. Power actually transmitted to the rock is even less because considerable heat is contained in the hot gases leaving the hole bottom. Power is also lost in vaporizing water, and heat conduction to the borehole walls. Jet-piercing drills are only 15-50 percent efficient—transmitting only 100-350 horsepower to the rock.
3. Flame jets are only effective when used on highly spallable rock.
4. Flame jets can only be used in an air or gas-filled wellbore. Because a liquid-filled wellbore is required for well control purposes when drilling deep wells, the flame jet cannot be considered for this drilling application.

4.2.3 Forced Flame (Rocket Exhaust) Drills

The forced flame, or rocket exhaust, drill is similar to the jet piercing drill discussed previously except that nitric acid (HNO_3) is used as the oxidizing agent in place of oxygen. The nitric acid produces a much faster reaction, resulting in higher power output than the jet piercing drill. Shapir developed a rocket exhaust drill in the early 1960s that drilled through quartzite four times faster than a jet piercing drill. The specific energy for the forced flame drill was approximately 30 percent lower, indicating that the nitric acid flame had higher heat transfer efficiency to the rock than the oxygen flame.

Beginning in 1973, Messerschmitt, Bolkow, Blohm (MBB) and Process Engineering International (PEI) began developing a rocket exhaust drill. Their system burns exotic fuels such as hydrazine (N_2H_4) and methyl alcohol (CH_3OH) to produce high-temperature, high-momentum flames. The heart of the system is the burner head shown in Figure 4-34. The patented burner in the drill bit is cooled by the propellants as they flow into the combustion chamber. This unique design reportedly results in a 98% efficient burner that lasts in excess of 100 hours. Previous to this development, burners would last only a few minutes.

Figure 4-34. P.E.I. Potential Combustion Chamber (Munding, 1965)

Drilling tests using PEI's rocket exhaust drill were performed in a variety of rocks as shown in Table 4-1. Note that the rocket exhaust drill penetrated limestone at a rate greater than 45 ft/hr. This formation type does not thermally spall, indicating that the rocket exhaust drill must have eroded the limestone with the high momentum flame. *Tester's later work*

TABLE 4-1. Drilling Rates With P.E.I. Rocket Exhaust Drill

Rock Type	Compressive Strength (MPa)	Hole Diameter (cm)	Drilling Rate (m/hr)
Sandstone 1 (Silica-Based)	73	11.2	92.0
Hematite	300	11.2	35.0
Granite 1	180	11.2	21.0
Basalt 1	192	11.2	18.0
Gabbro	370	13.5	15.0
Taconite	—	12.0	15.0
Granite IX	178	11.2	14.4
Limestone	—	11.2	14.0
Sandstone II (Clay-Based)	63	11.2	10.4

PEI (Baum) patented the water jet assisted rocket drill shown in Figure 4-35 in 1978. High-pressure water jets operating at pressures up to 1,400,000 psi are pulsed through nozzles at the rate of one pulse per second. The water jets assist in removing the rock which is thermally degraded by the rocket exhaust flames.

MBB (Baum and Munding) patented the thermal shocking rocket drills shown in Figure 4-36. As these drills are rotated or oscillated, the rock is thermally shocked as it is alternately heated and cooled, a process which enhances rock spalling and increases drilling rate.

Gulf Research and Development (Messmer) patented the abrasive jet rocket drill shown in Figure 4-37 in 1967. A finely divided abrasive material is disseminated throughout the solid rocket fuel to increase the erosive power of the rocket flame.

Figure 4-35. Jet Assisted Rocket Exhaust Drill (Baum, 1978)

Figure 4-36. Rock Drill Heads (Baum & Munding, 1978)

Figure 4-37. Rocket Exhaust Drill (Messmer, 1967)

Although the forced flame drills considered here performed much better than the conventional flame jet and jet piercing drills, their use is still limited. As with the flame jet drills, an air or gas filled hole is required, eliminating utilization of rocket exhaust drills in deep well drilling. The high cost of the exotic fuels burned by the forced flame drill also limits application to a few special cases.

4.2.4 High Frequency

There are three novel drilling techniques that induce thermal stress to the rock by utilizing high frequency:

High-Frequency Electric Drills
Induction Drills
Microwave Drills

Although none of these methods is currently being pursued as a deep drilling alternative, they are considered in this section for completeness.

4.2.4.1 High-Frequency Electric Drills

Laboratory and field tests have shown that high-frequency electric fields can be used to crush and break rock effectively. A conceptual drawing of a high-frequency electric drill is shown in Figure 4-38. This type of drill breaks the rock by two different heating methods: *dielectric heating* and *resistance heating*.

Figure 4-38. High-Frequency Electric Drill

Dielectric heating is produced by the "friction" between the dipoles switching back and forth. Resistance heating is produced by current flowing through the rock. When high-frequency electric drills are used, both types of heating occur simultaneously.

The dielectric heating power P_d evolved in rock is (Epshteyn *et al.*)

$$P_d = k_1 \epsilon \tan \eta E^2 f \text{ (w/cm}^3\text{)}$$

and the resistance heating power, P_r , is

$$P_r = k_2 E^2 / r,$$

where

k_1, k_2	= constants depending on electrode configuration
ϵ	= dielectric constant
η	= $\pi/2 - \phi$ = loss angle, radians
ϕ	= phase angle between voltage and current vectors, radians
r	= rock resistivity, ohm-cm
E	= electrode potential, v
f	= current frequency, c/s

The dielectric constants for various rocks are shown in Table 4-2. The typical resistivities for a variety of rocks is shown in Table 4-3. The dielectric constant does not vary significantly from rock to rock, but resistivity exhibits a significant range of values.

TABLE 4-2. Typical Dielectric Constants for Various Materials

Material	Dielectric constant	Material	Dielectric constant
Vacuum	1	Marble	8
Lava	4-5	Limestone	8-12
Glass	4-6	Gneiss	8-15
Quartzite	7	Basalt	12
Mica	6-8	Hematite	25
Granite	7-9	Trap rock	19-40

^a Ref.: Epshteyn *et al.*

TABLE 4-3. Typical Rock Resistivities^a

Rock	Resistivity (ohm-cm)
Magnetite	10^{-8} - 10^0
Iron ore (50% Fe)	10^0
Dense limestone	10^4 - 10^5
Slate	10^6 - 10^7
Basalt	10^6 - 10^7
Granite	10^6 - 10^8
Calcite	10^8 - 10^{14}
Feldspar	10^{13} - 10^{14}
Quartz	10^{14} - 10^{16}

^a Ref.: Epshteyn *et al.*

When the high-frequency current is initially applied to a rock, dielectric heating is the dominate source of heating. However, as a conducting channel begins to form in the rock, resistance heating becomes the primary heating source. In 1961, Kravchenko experimented with a high-frequency electric drill that starts heating the rock with dielectric heating. Once the current channel is established, the heating method is switched to resistance heating. This system is advantageous since low-frequency electricity is less expensive to generate.

4.2.4.2 Induction Drills

Figure 4-39 shows a proposed schematic for an induction drill that uses high-frequency magnetic fields to break rock through induction heating. As with the high-frequency electric drill, induction drills heat the rock by two simultaneously occurring modes: *remagnetization losses (hysteresis)* and *eddy currents*. Eddy current heating is inversely proportional to resistivity (analogous to resistance heating) and so the resistivity of the rock determines which heating process dominates.

Figure 4-39. Induction Drill

The induction drill has several drawbacks that impede its utilization. Because hysteresis and eddy current heating vary as the square of current, high currents are required, resulting in excessive resistance power losses. Induction drills are inefficient and supply low power transmission to the rock, resulting in unacceptably low drilling rates. Induction drills are also limited because they are only effective in rocks with high magnetic susceptibility.

4.2.4.3 Microwave Drills

Figure 4-40 shows a conceptual schematic of a microwave drill that breaks rock by heating it with high-frequency (1000-3000 Mc/s) microwaves generated by magnetrons. Similar to the high-frequency electric drill, breakage results from either dielectric heating or resistance heating. The major difference between this drill and the high-frequency electric drill is that dielectric heating dominates when using the microwave drill regardless of the formation of a conducting channel. Testing showed that the microwave drill is more effective when used on saturated rock and when inserted in a hole predrilled with a conventional drill.

Figure 4-40. Microwave Drill

Unfortunately, the microwave drill is also limited by a number of drawbacks including low power output and low efficiency, especially in deep holes. This drill would also have to be used in dry holes since the surrounding liquid would absorb the majority of the microwave

energy. Since drilling deep wells requires a liquid-filled hole for well control purposes, the microwave drill is not a viable option.

4.3 MELTING AND VAPORIZATION

Several novel drilling techniques either melt or vaporize the rock by heating the formation to extremely high temperatures (2000 —4000°F). Novel drilling systems that utilize this type of rock breaking mechanism include:

Electric Arc
Plasma
Nuclear
Laser
Subterrene (Rock Melting)

Each of these novel techniques will be considered in more detail in the following text.

4.3.1 Electric Arc Drills

Electric arc drills are similar to the spark drills presented earlier except for three primary differences:

Electric arcs thermally break the rock whereas spark drills
utilize shock waves to break the rock,
Electric arcs are continuous, and
Electric arcs operate at 10-1,000 v (as opposed to 10-100 kvolts).

The electric arc drill was first conceived by Aarts, who patented the system shown in Figure 4-41 in 1933.

Figure 4-41. Electric Arc Drill (Aarts et al., 1933)

The electrical arc, which is either transferred or nontransferred, is cooled by circulating cooling fluid through the drill head. Transferred arcs have one electrode in the drill and use the rock as the other electrode. Transferred electric arcs are not suitable for drilling most rocks because of their high resistivity. Nontransferred electric arcs are better candidates for drilling rock because they contain both electrodes within the drill head.

In 1949 McCullough patented the electric arc drill shown in Figure 4-42. By transferring the arc to the rock, the rock is melted, vaporized, and then conveyed to the surface where it is removed. As with Aarts system, fluid is used to cool the cable and drill and a surface seal is used to control the formation fluids.

Figure 4-42. Electric Arc Drill (McCullough, 1949)

In 1948, Verte patented an electric arc drill containing a central electrode surrounded by an incandescent shell electrode. The incandescent shell is isolated from the first electrode by a layer of insulation. Brichkin and Bolotov enhanced this design in the mid-1960s by moving the inner electrode as burn-off occurred to maintain a constant distance between the two electrodes (see Figure 4-43).

Figure 4-43. Electric Arc Drill
(Brichkin and Bolotov, 1966)

In 1960, Ledgerwood proposed combining an electric arc with a conventional roller bit, as shown in Figure 4-44. The arc would be used to heat and weaken the formation, and the roller cutters would remove the weakened rock and cut the hole to gauge.

Figure 4-44. Combination Electric Arc-Roller Cone Drill
(Ledgerwood, 1960)

The following observations have been noted during the experimental development of electric-arc drilling systems:

1. Hydrostatic fluid pressure compresses an electric arc, increasing its power concentration and temperature.
2. As hydrostatic fluid pressure increases, the potential required to maintain a constant arc current increases. Although the power output and temperature increase as the potential increases, the electrode burn-off rate also increases.
3. The specific energy required to spall sandstone was 20 times greater in a liquid environment than in an air environment.

These observations indicate the following difficulties with the electric arc drill:

1. Electric arc drills would be very inefficient in fluid-filled wellbores. Even in air, the energy transmission efficiency from the arc to the rock is less than 50%.
2. The burn-off rate in a wellbore 15,000 ft deep would be approximately 9 inches/minute, and
3. Relatively low drilling rates are achieved except in highly spallable rocks.

These problems preclude the utilization of electric arc drills for deep well drilling.

4.3.2 Plasma Drills

Plasma drills are electric arc drills that produce a high-temperature, high-momentum flame by propelling a high velocity (200-8,000 m/sec) monomic gas between the electrodes. Monomic gases such as helium or argon are preferable because they do not undergo dissociation prior to ionization, thus reducing the amount of energy required to achieve high temperatures. Plasma drills began to find increased application for cutting steel and other metals in the late 1950s and early 1960s. Because of their higher power output, interest in developing the capabilities of the plasma drill rather than those of the electric arc occurred during this same time period.

Figure 4-45 shows an oil-field plasma drilling system patented by Murray in 1956. Oxygen and fuel produce a high temperature flame beneath the drill bit. An electric arc is passed

through the flame, further increasing the flame temperature. Water is used to cool the drill head; the resulting steam is used to eject the broken rock from the hole bottom.

In 1961, Karlovitz patented the plasma drill shown in Figure 4-46. The system utilizes an insulated coaxial cable to deliver a.c. or d.c. electrical current to the plasma generator. Two concentric conduits are used to deliver the combustible air-kerosene mixture and flushing air to the bottom of the hole. Rock is melted and removed from the hole bottom by the high momentum plasma flame. Karlovitz also proposed using the 100 kW supersonic plasma drill shown in Figure 4-47. Kerosene and air are burned in a combustion chamber and then further heated with an electric arc. The heated mixture then passes through the diverging nozzle at supersonic velocity. Because the supersonic plasma erodes the rock in addition to melting it, the drilling rate is enhanced.

Figure 4-45. Oil-Field Plasma Drill (Murray, 1956)

Figure 4-46. Plasma Arc Oil Well Drill
(Karlovitz, 1961)

Figure 4-47. Supersonic Plasma Arc Oil-Well Drill
(Karlovitz, 1961)

Figure 4-48 shows a plasma drill patented by Tylko et al. A plasma jet thermally degrades the rock and water emitted from a trailing nozzle then quenches the rock and breaks it into a friable mass. A mechanical reamer then removes the friable mass from the circumference of the wellbore as the device penetrates. Two satellite plasma jets are used to finish the wellbore walls to a smooth glass-like finish, protecting the wellbore from formation fluid invasion.

Figure 4-48. Plasma Drill (Tylko et al., 1966)

Plasma drills possess some of the same problems as electric arc drills. As with the electric arc, low power utilization is a detrimental characteristic of this tool. Although the plasma drill does spall and fuse marble, limestone, granite, and oil shale, drilling rate decreases rapidly after the initial penetration. With limestone and marble, a protective layer is formed as the plasma flame decomposes calcium carbonate to calcium oxide. The plasma cannot fuse the calcium oxide because of the extreme temperature required ($<2,600^{\circ}\text{C}$). For this reason, the high-temperature, high-momentum characteristics of plasma drills should be utilized in conjunction with mechanical cutters. (The plasma drill used to thermally stress the rock, the mechanical cutters used to remove the rock.)

The inability to accurately focus the power output of these devices limits application of the plasma drill. The lack of focus results in wide kerfs, high specific kerfing energy, and wasted power.

4.3.3 Nuclear Drill

Nuclear reactors produce temperatures capable of fusing rock and could be used as drilling tools. In 1965, Adams patented the nuclear penetrator shown in Figure 4-49. This tool would be used to gather geological and seismic data without drilling a wellbore. The tool melts rock and proceeds through the liquefied formation by means of a ballast section on the device. The formation above the apparatus cools and returns to a solid state. At a predetermined depth, the ballast section of the device is released and the equipment then relies on a float to return the penetrator back to the surface.

Figure 4-50 shows a nuclear drill also devised by Adams, but used in a more conventional manner. This device contains the same type of nuclear reactor as did the previous system, but a circulated gas or liquid is used to remove and circulate the fused rock to the surface. As with the

plasma drill, a nuclear drill would work best if used in conjunction with a more conventional mechanical-type cutter. The nuclear drill would be used to spall or weaken the rock and the mechanical cutters would actually remove the rock.

Figure 4-49. Nuclear Penetrator (Adams, 1965)

Figure 4-50. Nuclear Drill

Nuclear drills will not find an application in the petroleum well drilling industry because the size of current nuclear reactors is not compatible with the needed hole sizes. High cost and safety problems are also prominent obstacles.

4.3.4 Laser Drill

Lasers are coherent light beams, focused to produce power densities in excess of 10^{12} w/cm². There are two types of lasers considered here:

- Crystal Lasers — These lasers are excited by intense bursts of light from flash tubes. They are only used in brief bursts to allow dissipation of generated heat (over 99% of the pumping energy is lost to the cooling fluid).
- Gas Lasers — Gas lasers use a mixture of gases to produce different energy levels and are pumped by electron beams, thus allowing continuous laser operation.

Because induction and microwave drills have lower power densities, heat conduction away from the hole bottom is an important consideration. Lasers avoid this difficulty by supplying higher power densities.

Laser technology has revealed details that are important to understand when considering lasers as an alternative drilling method. Some of the findings include the following:

1. Laser energy is either absorbed, reflected, or transmitted through the material being lased. Since most rock is opaque, little, if any, laser energy can be transmitted through the material; between 80 and 95% of the energy is absorbed, and the remainder is reflected.
2. Experimental work has shown that after fusion and vaporization are initiated, laser energy begins to be lost to the generated molten rock remaining on the bottom of the bore.
3. Testing has shown that lasers drill to a certain depth and then cease to penetrate further because power density at the hole bottom is insufficient to continue melting or vaporizing the rock.

4. Where the laser is focused influences the cutting efficiency of the lasing device. As shown in Figure 4-51, lasers focused above or below the rock surface do not cut as deep a kerf as lasers that are focused at the surface of the rock.
5. As laser power increases, specific kerfing energy also increases because energy is lost to superheating and vaporization of the molten rock. As traverse speed increases, less vaporization of molten rock occurs in the kerfs and specific kerfing energy decreases. See Appendix A for an explanation of specific kerfing energy.

Figure 4-51. Effect of Focal Point on Laser Rock Kerfing in Berea Sandstone (Carstens et al., 1972)

By the end of the 1960s a variety of studies and experiments had contemplated laser applications. At the time, it was concluded that lasers would find limited use in the petroleum industry primarily because of low power output. In 1968, a 1 kW laser was among the largest available. This magnitude of power could drill a 1 mm diameter hole at 1500 cm/min. However, the drilling rate when drilling a 20 cm hole would only be about 0.04 cm/min. This data is for a laser drill used to fuse rock; results for a laser used to spall rock showed only slight improvement.

A number of laser drilling systems were patented during the 1970s. In 1972, Stout patented the oil-well laser drilling system shown in Figure 4-52. A large number of radially-spaced laser beams are directed down the borehole using reflectors at the top and bottom of the hole. The reflector at the bottom is rotated, sweeping the laser across the rock surface. A downhole packer seals pressurized liquid nitrogen in the cavity surrounding the drill head. At the surface, a special shield is placed around the laser generating equipment for safety purposes.

In 1975, Keenan patented the oil-well laser drill shown in Figure 4-53. This system contains a downhole mud turbine to generate electricity for the laser and rotate a deflecting crystal used to sweep the laser across the rock surface. Keenan also proposed using high pressure mud jets on this laser drill to assist in breaking and removing the rock.

Figure 4-52. Laser Oil-Well Drill
(Stout, 1972)

Figure 4-53. Laser Oil-Well Drill (Keenan, 1975A)

By 1980, laser technology had achieved tremendous strides forward and laser output power had been enhanced to the 20 kW range. Since then, megawatt lasers have been developed for Starwars and other military applications. Small diameter versions of these high power lasers are needed to produce drilling rates comparable to conventional techniques. If lasers are to find any role in oil-well drilling, it will be to support currently used drilling tools, not as the sole rock removal mechanism. Work in this regard has been focused on enhancing tunneling methods where it has been shown that lasers are capable of doubling or even tripling the penetration rates of conventional drilling tools.

During the 1970s, extensive testing was performed by Los Alamos Scientific Laboratory on a new type of rock penetrating system called a Subterrene. This system utilizes extremely high temperatures (1,800°K) to melt a path through rock.

The original Subterrene penetrator was the *consolidating Subterrene* shown in Figure 4-55 which was designed to penetrate porous materials such as volcanic tuff. As the subterrene penetrates, molten rock is pushed up along the outer perimeter of the drill where it forms a dense, glass-like lining that seals the wellbore from formation fluid intrusion. The body of the consolidating Subterrene is heated to 1,800°K by pyrolite graphite radiant heaters that are insulated from the molybdenum penetrator body by a boron nitride insulator (Figure 4-56). Molybdenum is used in the penetrator body because it retains its strength at high temperatures.

Figure 4-55. LASL Consolidating Subterrene
(Sims, 1973)

Figure 4-56. LASL Consolidating Subterrene (Neudecker, 1973)

The consolidating Subterrene can only be used successfully in porous rock since the melted material must be displaced into the pore spaces to make room for the drill to pass. As the porosity of the rock decreases, the thickness of the glass lining increases, resulting in insufficient space for the drill. Because of this restriction, a modified system called the *extruding Subterrene* was developed for application in less porous rock formations. The extruding Subterrene shown in Figure 4-57 also produces a glass-like lining to form, but since limited pore space does not permit all material to be absorbed by the lining, the excess molten material passes through an opening in the center of the penetrator. As the molten material is extracted through this center opening, it solidifies into small "popcorn-like" particles that are removed by the coolant gas.

Figure 4-57. LASL Extruding Subterrene (Hanold, 1973B)

As shown in Figure 4-58, both the consolidating and extruding Subterrenes have also been constructed as coring devices.

Figure 4-58. LASL Coring Subterrenes (Rowley, 1974)

Figure 4-59 shows the operating procedure of a melt-heating Subterrene. This device utilizes a pyrolytic graphite wafer to start the melting process. After melting is initiated, the wafer begins to oxidize and electrical current flows through the molten rock, producing resistance heating. The 11.8 ft/hr penetration rates achieved with this device were approximately four times greater than

Figure 4-57. LASL Extruding Subterrene (Hanold, 1973B)

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Figure 4-58. LASL Coring Subterrenes (Rowley, 1974)

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those accomplished with conventional Subterrenes. The melt-heating device performs better than the conventional Subterrene for two reasons:

1. The heating power is dissipated directly into the rock. On the conventional device, the power must first flow through the molybdenum body before contacting the formation.
2. The pyrolytic graphite wafer and the resistive heating electrodes work together to produce the higher penetration rates. The wafer initiates the heating process and decreases the resistance of the rock. The two heat sources then combine to magnify the available heat.

Figure 4-59. Melt-Heating Subterrene Operation (Hanold et al., 1977)

- (a). Initial heating in pyrographite wafer, with start of surface melting.
- (b). Electrical current path and heating transfer to melt with oxidation of pyrographite wafer.
- (c). Heating entirely in melt, increased power and rapid penetration rate.

The Subterrene penetrator is not a suitable candidate for drilling deep wells for the following reasons:

1. The consolidating Subterrenes are limited to maximum penetration rates of approximately 3 ft/hr because of limitations in transferring heat to the rock.
2. The 1,800°K temperature is sufficient to melt basalt, tuff, and granite. Unfortunately, this temperature is not adequate enough to melt sandstone, limestone, and dolomite.

If there is any possibility of using the Subterrene as a drilling device, it will be with an improved version of the melt-heating Subterrene. Future research on the Subterrene should focus on this tool.

4.4 CHEMICAL REACTIONS

Chemical drills and rock softeners utilize highly reactive chemicals to dissolve the rock — creating harmless products that are removed from the workface. Figure 4-60 shows a chemical drill that might be constructed for oil-well drilling. Chemical drills have been used to successfully drill sandstone, limestone, and granite in the laboratory using fluorine and other highly reactive chemicals to remove the rock. These reactions produce innocuous products that are blown from the bore. Although these drills have been shown to work, there is little prospect for extensive oil-field application because of high chemical costs and difficulties with handling large volumes of highly reactive chemicals.

Figure 4-60. Chemical Drill (Ledgerwood, 1960)

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Advanced Drilling System - Database

- Source Info

- name of system
- references
- patent(s)
 - individual(s)
 - year(s)
- development status

- Design Info

- A. penetration mechanism
- B. gauge maintenance
- C. hole integrity
- D. communication
- E. cutting removal

Theory
- physics
(first eqns)

Evaluate "type" holes for each system component

- shallow, large dia, soft, wet
- intermediate, soft/hard, wet
- deep, hard, brittle, dry
- ultra, hard, very hot, dry

Appendix B

Specific Energy

Techn. dist.
for system

Performance criteria:

base on 4 requirements of drilling system

- power delivered (J)
- power density (J/cm^2)
- power density rate ($J/cm^2/sec$)

Summary: performance benefits; theoretical perf limits; tech obstacles

- Match rock properties (thermal/elec conduct; dielectric constant; petrographic fabric; mineralogy; grain size) to optimize penetration by a system
 - against physics/chem of ~~rock~~ penetrating mechanism

Specific Energy

Specific energy is a simple method of determining how efficiently a drilling device cuts rock. The equation used to calculate specific energy is as follows:

$$\text{Specific Energy} = \frac{\text{Energy Input}}{\text{Volume Removed}} = \frac{P}{dV/dt} \quad (\text{J/cm}^3)$$

where

P = Power Input (Watts)
 dV/dt = Volume Time Derivative (cm^3/sec)

If the specific energy used by a drilling device is known, the penetration rate for the system can be calculated using the following equation:

$$R = \frac{P}{AE} \quad (\text{cm/sec})$$

where

P = Power Input (Watts)
 A = Hole Cross-Sectional Area (cm^2)
 E = Specific Energy (J/cm^3)

If one drilling tool is used in conjunction with another drilling device (e.g., a novel drilling device used with a conventional mechanical drill), the penetration rate of the combined drilling system equals:

$$R = \frac{1}{A} \left(\frac{P_n}{E_n} + \frac{P_m}{E_m} \right)$$

where, in this case,

n = novel
 m = mechanical

The most practical application of novel drilling devices is to assist mechanical drilling techniques by cutting narrow kerfs in the rock. The kerfs supplement the mechanical drill by significantly decreasing the amount of energy required to cut the rock. The specific energy of a kerfing device is calculated by using the following equation:

$$E = \frac{P}{dws} \quad (J/cm^3)$$

where

- P = Power Input (Watts)
- d = Kerf Depth (cm)
- w = Kerf Width (cm)
- s = Traverse Speed (cm/sec)

Since the primary function of the kerf is to provide a free face to which fractures can propagate, deep, narrow kerfs are much more desirable than shallow, wide kerfs. Specific energy is not a true measure of a kerfing device's performance because it cannot differentiate between a wide, shallow kerf and a narrow, deep kerf. This is illustrated in Figure B-1 where a deep, narrow kerf and a shallow, wide kerf are advancing at the same rate. Even though the specific energies are equal (5,000 J/cm³), the deep kerf at the right would more effectively unsupport the rock.

Figure B-1. Example Kerfing Conditions

To circumvent this difficulty, a parameter called specific kerfing energy is used to more accurately ascertain the performance of drilling devices designed to kerf the rock. The specific kerfing energy is calculated using the following equation:

$$\text{Specific Kerfing Energy} = \frac{\text{Energy}}{\text{Kerf Area}} = \frac{\text{Power}}{\text{Kerf Depth} \times \text{Traverse Speed}}$$

In this equation, the limitations of the specific energy equation are eliminated because only the kerf depth and traverse speed are included. Kerf width is omitted since it is not important to the tool's kerfing effectiveness.

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