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Field Experiences With Computer-Controlled Drilling

J.F. Brett* and T.M. Warren,* Amoco Production Co., and D.E. Wait, Consultant

*SPE Members

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ABSTRACT

This paper describes the mechanical, electrical, computer, and software systems of a prototype computer controlled drilling rig. The rig has operated under computer control for over three years on a project investigating optimized turbine control. In addition to describing the advantages and the basic computer control features of the rig, this paper presents the practical problems for computer controlled drilling and suggests possible solutions to these difficulties.

In the past, several attempts at full computer control of the drilling process have been made, but all have ultimately proven to be short lived. Recent advances in the power and reliability of sensors and computer control hardware, as well as reductions in their cost, have brought computerized rig control closer to reality. However, some important hurdles remain.

It is the authors' experience that most of the hurdles lie on the electrical and mechanical side of the system. Computer hardware and software capabilities have improved to the point that almost any function can be economically programmed. However, problems with sensor reliability and calibration, and actuation still exist. Each of these problem areas is discussed in this paper.

In summary, the purpose of this paper is: (1) to describe the use of a computer controlled rig, (2) to describe the problems the authors have experienced during three years of computer controlled drilling, (3) to present possible solutions to these problems, and (4) to discuss the future for field use of computer controlled drilling.

References and illustrations at end of paper.

INTRODUCTION

The computer controlled rig discussed here was one element of a project aimed at reducing costs in drilling slower formations (those that drill at less than about 25ft/hr). The rig has been used in dozens of experimental wells to drill more than 40,000 feet under complete computer control. This effort should be distinguished from recent efforts to automate/computer control the tripping process. The computer controlled rig discussed here does have a mechanized tripping system, but no attempts were made to automate the process. Rather, the effort focused on computer control of the drilling process itself (i.e., when the bit was actually drilling ahead). Consequently, the points made here will specifically apply to computerization of the drilling process. To the extent that the environment and requirements are similar, however, many of the points made here may also apply to computer automated tripping systems.

There have been many notable attempts at computerization of the drilling process.¹⁻¹⁴ Generally, these past attempts combined fine control of the weight and rotary with drilling models to prevent hydraulic flounder and to minimize cost per foot. It was intended that by taking the human out of the control loop, there would also be increased reliability, improved vigilance, safer operation, and faster response to anomalous situations. All of these projects have been short lived, and the closest that most drilling operations come to automation is the use of a pneumatic automatic driller. Current automation project^{15,16} are mostly directed at automating the tripping process.

The short lives of these past drilling control projects is curious, especially in light of the fact that most of the literature seems to indicate that these projects held great promise. Here we sit ten or twenty years later wondering what went wrong. Computers are used at the rig site to monitor and

collect data, and to plan operations, but computer controlled drilling rigs certainly are not prevalent. Why did these projects fail? Was the computer, electrical, or mechanical hardware too expensive or unreliable? Did the economic benefits prove to be too small? Was the problem that the available field personnel did not have the proper training to operate or repair the equipment? The list of questions could go on and on. Without post analyses of these projects we will never be able to assess the chances for success of future projects. Further, progress towards the goal of automation is harmed because, without knowledge of the real cause of past failures, the industry as a whole is unable to efficiently redirect effort.

This paper describes a computer controlled drilling project that succeeded in achieving most of its technical goals, but was nevertheless economically unviable. It is hoped that this paper will add to the body of literature by providing a critical analysis of this project, and will allow future researchers to realistically identify the pitfalls and, the possible benefits of computer controlled drilling.

Project Economic Justification

This project began with the goal of significantly reducing the cost per foot required to penetrate slower drilling formations. Figure 1 shows that, depending on the region, between 50 and 80% of Amoco's total rotating hours occur at less than 25 ft/hr. Although, most of the footage is drilled at much higher penetration rates, most of the time and money is spent drilling relatively slowly. Because of this, efforts aimed at improving drilling efficiency would be best directed at increasing the penetration rate in slower drilling situations.

Given the economic incentive to improve these penetration rates, a project was begun to study ways that this might be accomplished. One possible solution identified was the use of drag bits on high speed motors. Figure 2 shows why the use of drag bits on high speed motors was considered as an alternative. Clearly, very high penetration rates are possible with drag bits on turbines and, significant cost per foot reductions would be possible, if bit life could be made sufficiently long. Indeed, by the time the project was started, drag bits on turbines had already significantly reduced the cost per foot required in some areas.^{17,18} So, based on the premise that the cost per foot could be significantly reduced, a project was initiated to determine the best way to achieve penetration rate increases in harder formations using turbines and drag bits.

One of the first steps in the project was to verify that cost savings were possible. Using the 1987 performance information for every one of Amoco's runs, the penetration rate required for a successful high speed system was determined. The Amoco data set includes every bit run by the company in North America and, because Amoco is active in most geologic areas, is assumed to be representative of the industry.

The study started by eliminating from the 6400 bit data set all those bits larger than 12.25", or

those that had runs of less than 40 hours - this left 3800 bits. The high speed system was not targeted at large diameter bits, and bit runs of less than 40 hours were assumed not to be candidates for a high speed system (i.e., drilling out casing, coring, clean out runs, etc.). Of the 3800 bits, 1900 bits had an average penetration rate less than 25 ft/hr. These 1900 bits accounted for 65% of Amoco's total rotating hours.

This data set was used to quantify the performance that would be required from a successful high speed system. The actual cost per foot for each bit run was calculated using actual rotating hours, footage, bit, and spread costs. The penetration rate that would have been required by a bit operated on a high speed system (given a bit cost of \$18k, a system cost of \$350/hr, and bit life of 80 hours) to either break even, or to save 20 to 40% was determined. Figure 3 shows the results. The figure shows that a penetration rate increase of 170% would have reduced the cost per foot by at least 20% in 80% of Amoco's 1987 bit runs (in 12-1/4" hole and smaller), and 40% in 60% of the runs. If the high speed system cost could be reduced, or if the bit and system life could be lengthened, then the incremental gains in penetration rate needed to achieve the same savings could be lower. In any event, if the penetration rate increases seen under high speed operation in the lab could be consistently realized in the field, then significant cost per foot reductions seemed possible.

What the analysis did not show, however, is that to be considered completely successful the high speed system also had to increase the penetration rate in a broad range of formations. The high speed drilling system had to be robust enough to successfully penetrate intervals that would ball normal PCD or diamond bits, be adaptive enough to drill through ratty formations without damaging the bit, and be tough enough to drill very hard formations or inclusions. Turbines and drag bits had achieved the greatest success in uniform formations. To achieve peak performance under a wide range of drilling situations would require new bits and motor operation techniques. The bit development section of the high speed project is discussed by Warren and Behr,¹⁹ Brett et al,²⁰ and Warren et al²¹ in another set of papers. The attempts to optimally control the motor via computerization of the rig is discussed below.

Computer Control Strategy

The entire justification for even considering computer control centered around the nature of the turbine itself. Figure 4 shows the typical response of a turbine. For a particular bit, a turbine's penetration rate is nearly proportional to its output power. The problem is that the output power is very sensitive to the operating conditions (flow rate, and weight on bit), AND to the formation being drilled. This means that, unless the formation is very uniform, it is not possible to attain peak performance out of a turbine by maintaining a constant weight on bit.

Figure 5 shows turbine speed fluctuations during 28 feet of field drilling with a nearly constant weight on bit. In this formation, the bit/motor combination was almost never operated at

peak power (~1200 RPM for this particular tool). Had the weight on bit been increased, the turbine would have stalled every time it hit a soft streak. Had the weight been reduced, the turbine would have only drilled more slowly. Without a technique to quickly sense the bit rotary speed and to correct the weight on bit, it would not be possible to gain maximum benefit from the use of a turbine.

It is not as difficult to keep positive displacement motors (PDMs) near peak power, because the power output is not as strong a function of weight on bit. For this reason, high speed PDMs (near 800 RPM) were also considered as candidates for a high speed system. In ratty formations however, a significant percentage of a PDM's available power can still be unused if the weight on bit is not continuously varied.

One other reason why continuous automatic control was envisioned as necessary is that many flat faced PDC, thermally stable, or natural diamond bits have balling problems at high rates of penetration. Given the goals of the project, bit balling is almost as bad as bit failure. Although the design was for slower drilling intervals, (i.e., <25 ft/hr) the system also had to be able to penetrate fast intervals without balling.

It was hypothesized that by continuously controlling the weight on bit it would be possible to: (1) Increase the penetration rate by operating a downhole motor very close to peak power even in ratty formations, and (2) limit the penetration rate in fast streaks to levels that would allow the bit face to remain clean. Further, it was hypothesized that operator error could be reduced, and that possible problems could be diagnosed earlier with computerized automatic control. Diagnostic tools were envisioned to include automatically conducted pump-off tests,²² continuous comparison of the actual with predicted response of the circulating system, drillstring torque tension analysis,²³ and possibly realtime dynamic analysis of the drill string.²⁴

This basic strategy for actually implementing the control system is summarized in Figure 6. A rig with a hydraulic feed was required so that the hoist could be dynamically raised as well as lowered. It is not possible to quickly lower the weight on bit in slow drilling situations with conventional brake controlled feed mechanisms. To keep the motor operating at peak power, it is often necessary to reduce the weight on bit. A hydraulic mechanism would allow dynamic control (both positively and negatively) of the weight on bit. Rig instrumentation would have to be accurate and reliable enough to allow continuous control, and the span of control required was such that digital implementation of the control scheme was more viable than conventional analog techniques. This all meant that the rig had to be computer controlled. The next section of this paper discusses the details of a computer controlled rig constructed in 1986-1987 to test the hypotheses outlined above.

Computer Controlled Rig Description

There are three parts to any control system, actuation, instrumentation, and the control algorithm. To use the human analogy, actuators (how the

system affects reality) are like the muscles; instruments (how the system perceives reality) are like the senses; and the control algorithm (how the system decides to act on reality) is like the mind. All control systems have these three elements - including the system where a man controls the hoist position with a draw works and a brake. Deficiencies in any one of the areas will cause the system to fail.

When it comes to optimally controlling a downhole motor, conventional rigs are deficient in at least two of the three areas. The actuation is deficient because the hoist cannot either quickly add or remove weight from the bit. The instrumentation is deficient because the driller normally does not know the power output of the tool. Given proper instrumentation and actuation it was at least possible that a driller could process information quickly enough to control the hoist and thus provide nearly optimal downhole motor control. It was also possible that the control job could be done better and more reliably under computer control. One of the goals of the project was to determine if a human could control the system given sufficient actuation and instrumentation.

The remainder of this section describes a rig built specifically to determine the economic viability of rigs with the actuation, instrumentation, and control necessary to operate down hole motors under optimum conditions.

Actuation

Figure 7 shows a general view of the computer controlled rig that was built for this project. Warren and Canson²⁵ describe the capabilities of the rig in some detail. But briefly, the rig has a 100kip manual, servo, or computer controlled hydraulic hoist capable of drilling to 3500' with 5" aluminum drillpipe, 40 kips of drill collars, and 40 kips overpull. The rig stands back singles using a semi-automatic pipe handling system. Rotary power is provided by a 150RPM-6000 ft/lb power swivel, which is also computer controlled. The power for the rig (excluding the mud pump) is provided by a single 450HP diesel. A pump drive splits the power on demand between the hoisting system, the power swivel, and the pipe handling system. The rig has a closed loop solids control system, and a single 1200HP triplex mud pump.

The hoist actuation system (shown in Figure 8) is hydraulic, and on the surface is similar to snubbing units and other hydraulically controlled rigs. However, the system is unusual for two reasons. First, all control signals are electric to facilitate computer control. So even under manual control, the driller does not physically move valve handles. Second, the hoisting ram is controlled by a high precision servo valve while drilling. The valve's rated flow is too low to move the hoist fast enough for efficient tripping. But without the valve, responsive and accurate control of the ram would not be possible. A larger capacity valve was installed in parallel to provide acceptable tripping speeds.

The rotary power is provided by a power swivel that functions normally except for: (1) like the

hoist, even when operated in manual mode, the control signal to the pump is electric; and (2) a feature has been added that allows the swivel to be held against reactive torque or to turn fractions of a revolution one way or the other. This feature has been found to be especially useful for orienting while directional drilling with a motor. Figure 9 shows a schematic of the rotary system.

Hydraulics are not new to the oil patch, and this was not the first hydraulically controlled rig. All in all, the actuation system for the high speed rig, (while certainly not standard for a drilling rig) was based on technology that had been proven in other fields. A critique of how well the actuation system functioned is included in the findings section of this paper.

Instrumentation

Table I describes the sensors used to instrument the experimental rig. The sensors can be divided into three main types: (1) rig "health" sensors that allowed the computer to monitor the status of the rig and determine that the rig was functioning as expected, (2) drilling data sensors that were used to monitor the, drilling situation but were not directly controlled by the rig; and (3) direct control sensors that monitored parameters to be placed under computer control. All the surface sensors, and conditioning equipment used for the project are commercially available.

Besides the surface sensors, a proprietary turbine tachometer and wireline MWD system was also used. The MWD provided information concerning operating conditions (weight, torque, acceleration) directly above the bit at a .6 Hz update rate,²⁰ and could be used while rotating. The turbine tachometer gave an average reading of the turbine speed about every five seconds. A secondary goal of the project was to determine whether downhole instrumentation was required to optimally operate downhole motors.

There are four major differences between the surface instrumentation system used for the project and those available from commercial drilling data logging services. First, the hoist was instrumented with high bandwidth strain gauges. This, along with high bandwidth strain gauge torque, and hoist acceleration channels allowed study of the dynamic conditions at the surface. Second, many sensors (i.e., oil temperature, accumulator pressures, et cetera) allowed the computer to monitor the rig itself. If any of these sensors deviated from appropriate bounds (which could depend on the operating conditions), the computer would issue a warning. Third, more care was given to sensor calibration than is normal in drilling situations. This was particularly true for the hookload and torque sensors. The hookload was periodically calibrated with a test jig against a dead pull. An analog system also was constructed to compensate for changes in the hookload with hoist position due to the weight of the kelly hose. When the hookload was properly calibrated it was not unusual to accurately measure to within 1100lbs. To calibrate the torque, an instrumented brake produced a known load under rotation. For every sensor, a linear regression coefficient

was used to evaluate calibration quality and detect instrumentation problems.

Perhaps the biggest difference between conventional rigs and the instrumentation system used for the project was that the instrumentation was designed to be the only system of sensors used by the rig. There was no conventional weight indicator, torque, or rpm gauge, et cetera. This necessitated that critical measurements be made with redundant sensors. Table I lists the redundant sensors, and shows that every effort was made to make the redundant sensor of a completely different type than the primary sensor.

Control

There are three different basic types of control used on the experimental rig: (1) analog control, (2) procedural computer control, and (3) algorithmic computer control. During normal operation each of these forms of control can function simultaneously. Figure 10 summarizes the control scheme.

As shown in Figure 10, the analog control loops bypass the computer altogether. Commercially available servo controllers are used to control the rotary speed, and either the hookload or hoist position. The rotary speed control uses an integral control scheme for zero steady state error, while the hookload or hoist position controller uses simple linear feedback control. The analog control is necessary so that the computer will not be burdened with the demands of relatively high bandwidth, and so that when operated manually, the weight on bit can be servo controlled. Figure 11 shows that the no load frequency response of the hoist system is about 15 rad/sec (2.3 Hz).

The procedural computer control routines control the rig during start up, calibration, shutdown, and emergency situations, and one of several formatted drilling tests. During startup, for example, the computer performs a number of calculations (predicting hookload, standpipe pressure, and the hydraulic pressure required to support the string), measures the zero point of tarred parameters and takes appropriate action if the calculated value is out of bounds. The computer then lowers the bit to bottom and begins drilling. An emergency control task runs while drilling and monitors key parameters. If any of the parameters are out of bounds while drilling a warning is issued, or the bit is automatically picked up and drilling halted if appropriate.

The formatted drilling tests include standard drill-off tests (the hoist position is locked and the bit allowed to drill-off), slackoff tests (used to determine diamond bit total flow and pump off areas),²² and a pseudo-drill off test where (instead of allowing the bit to drill off) the weight on bit is automatically decremented for each data point by the desired amount. These formatted tests allow consistent and routine bit performance analysis. For example, Figure 12 shows the results of a computer performed pumpoff test. The rig was programmed to conduct these tests after every connection as the bit was being set on bottom. This allowed the total flow and pump off areas of the bit

to be measured at 30 foot intervals. This information could be interpreted to diagnose the state of the bit, as discussed in reference 22.

While the analog and procedural computer control features of the rig add functions not available under conventional control, the real purpose of the rig was to test the possibility of operating a downhole motor (turbine or PDM) at closer to peak power. The penetration rate of a specific bit varies nearly directly with applied power. If it were possible to increase the power produced by the motor, then the penetration rate would also increase. Figure 5 shows that is difficult to continually operate a turbine at peak power. It is not as widely known that PDMs suffer from similar problems. The control algorithms implemented and tested have the purpose of controlling the weight on bit so that other relevant parameters (turbine RPM, downhole torque, surface torque, or standpipe pressure) are almost constant. In this manner, the power output of a motor can remain closer to the peak, and the penetration rate can increase.

Appendix I describes the control algorithms in some detail. Briefly, the computer would use either integral or adaptive control schemes to vary the weight on bit so that the controlled parameter was held constant. Figure 13 shows an example where an adaptive routine was used to vary the weight on bit applied to a high speed PDM so that the torque would remain at a set level about 20% under the stall torque of the tool. If the weight were to remain constant, the average torque would be lower. The findings section of this paper includes more discussion of the performance of the control algorithms.

Project Findings

The single most important finding of this project is not the subject of this paper, but rather was the discovery of a fundamental cause of PDC bit failure. Brett et al,²⁰ and Warren et al,²¹ describe a phenomena called "bit whirl" that explains why PDC bits are usually unsuccessful when operated at high speeds. Even if motors were continually controlled at peak power, it was more economical to run a sharp PDC bit on conventional rotary than to use a high speed motor through ratty formations because of the damage caused by bit whirl. Readers are referred to the papers cited above for a more complete discussion.

During the course of numerous drilling tests, however, the surface computer control system described above was extensively tested, and is still used as a test drilling rig. A number of points specifically pertaining to computer control can be made. These findings are summarized below and may prove useful to future researchers who attempt to control a drilling rig with computers.

Actuation

Hydraulics is not a new technology, and is used with very high reliability in many other industries. Our experience, however, is that successful operation of electro-hydraulic systems in the drilling environment requires a higher level of training among maintenance personnel, and a very high level

of care given in the design stage to very simple (but very important) principles of hydraulic cleanliness. With those caveats we can say that electro-hydraulically powered drilling rigs work, can easily be adapted for computer control, and be made to accomplish much finer control than conventional systems. Hydraulic systems also have (like electrical systems) the advantage that a single power source can supply any one of a number of different components without transmissions.

The fundamental problem with hydraulic systems is dirt. If the system is properly designed and cleanly maintained, then it is possible for hydraulics to operate reliably almost indefinitely. The problem is that drilling rigs are among the worst possible environments for cleanliness. On larger rigs, the problem is compounded, because hydraulic lines must be routinely broken during rig moves. We have found that most of our problems occur following moves when lines are broken. This may account for the fact that most successfully operated hydraulic systems in dirty environments are completely closed. Earth moving equipment, and truck mounted drilling rigs are two examples of systems where hydraulics operate successfully in spite of dirty environments. In both cases it is not normally necessary to ever open the system. Further, the servo valves required to control the hoisting system with a high bandwidth are especially susceptible to contamination.

Proper design can mitigate the effects of contamination. Judicious and liberal placement of filter elements throughout the system is one useful technique. Liberal use of filters also has the advantage of helping to contain any damage to only one part of the system. The best way to prevent contamination, however, is to make sure that dirt never enters. Ideally the system would be designed so that it could remain completely closed. Since this may not be possible, the system should be designed so that a minimum of hydraulic lines ever need be broken. Lines that must be broken should have self sealing quick disconnects. Filter elements should be placed downstream of any line (even a high pressure line) that needs to be broken for a move.

Other factors that need to be given careful consideration are the proper heating and cooling requirements of the hydraulic fluid, and the proper hydraulic piping. Oil temperature is so important that it is not unreasonable to have dual redundant cooling systems. (This is also one area where the vigilance of computer control can pay off because human operators can easily overlook climbing hydraulic temperature). We also found that short runs are more suitably made with hoses than pipe because they are less susceptible to vibrations, and when a leak does occur it is more easily repaired.

There are two other technical considerations more fundamental than those mentioned above. First, active control of the hoist position requires considerably more power than controlled feed. This would be true no matter how the hoist position is actuated - mechanical, electrical, or hydraulic. When drilling on a conventional rig, the hoist control system need only sink energy (i.e., with the brake). However, while drilling with active control (i.e., being able to add or decrease weight), more

power is required because the hoist system must both source and sink energy. For shallow rigs with small hookloads (like the rig described here) this is not a major concern. Power requirements can begin to present a concern, however, with active control of high hookloads. Second, hydraulic hoisting and rotary systems are subject to pressure transients higher than is normal for other hydraulic systems. These transients cause reliability problems even if the static load is well within the pressure rating of the system.

The final problem we have found to occur on hydraulically controlled rigs, is that a more highly trained crew than normal is required for proper maintenance. This can be accomplished by either adding a hydraulics technician (which increases manpower costs), or by increasing training and the responsibilities of the existing crew. Our experience is that most of the manpower commonly available in the drilling labor market does not have the experience necessary to properly maintain hydraulic systems. Most competent drillers can develop a good understanding of hydraulic systems, but the on-the-job training period required is something like 3-4 months. This means that for reliable operation and quick repair of damaged hydraulic components and one of several things must happen. Either: (1) a qualified hydraulics technician must be available to perform routine maintenance and repairs, (2) the work force must be stable enough to allow the benefits from on-the-job training to be realized (i.e., a crew must stay with the specific rig for a long enough period); or (3) intensive hydraulics system training must be available for any new workers. Organizationally, we have found it easiest to hire a qualified hydraulics technician. This increases manpower costs.

Instrumentation

Electronic sensors are commonplace in the drilling industry. However, there is one major difference between the sensors used for a computerized rig project and those used to monitor drilling conditions. If sensors used to monitor drilling conditions fail or loose calibration, the rig can still function and drilling continue. If sensors used in a computer control loop fail, then in the best case the rig will not work, and in the worst case serious damage to the bit, drill string, or rig itself will result. Under computer control situations, sensors become as important for operation of the rig as the prime mover.

Another difference between common oil field sensors and those used for computer control is that the degree of accuracy required by the computer sensor is much higher. On a conventional rig, if the weight indicator is off by as much as 10%, then there is not really much harm done. The weight on bit might be higher or lower than thought, but the rig will still function. However, inaccuracies in the control parameter measurement will cause a systematic error in the system set point. The reason this error is worse than in typical drilling situations is that the power peak for high speed down-hole motors (especially for turbines) can be quite steep. A set point inaccuracy of 10% may mean a decrease in penetration rate of 25%. For these reasons instrumentation for a computer controlled rig

must be both more reliable and more accurate than that of a conventional rig.

The prospects of achieving reliability equal to that of a conventional rig are constrained by probability theory. If a conventional rig's hoisting system experiences a breakdown once every 100 days, and it is desired that a computer controlled rig achieve the same level of reliability then EVERY component of the computer controlled rig will have to be significantly more reliable than those used in the conventional rig. Given the same prime mover, the components shown in Figure 8 replace the hoist, the components in Figure 11 replace the driller, and the sensors wiring, and conditioning equipment replace the weight indicator.

A simple example illustrates the point. If there are ten major components in a conventional hoisting system, and those component's combined reliability is .99 (i.e., one failure every 100 days of operation), then the individual elements of the system must be able to function without failure for nearly 1000 days. If a twenty component computer controlled system is to achieve the same reliability, then the components (on average) will have to function for nearly 2000 days without failure. The problem is even worse if five of the 20 components have a failure rate of 1 in 1000 days, then the remaining component's reliability must have only one failure in 3000 days. The point is that to achieve equivalent system reliability, a computer controlled rig has more vital components, the reliability of each component must be significantly increased.

An increased reliability level need not necessarily be a problem. Electronic instrumentation can function with a very high degree of reliability in the right environment. A drilling rig, however, is not naturally in the right environment. We have found several points absolutely critical. First, it is critical that the wiring be completely isolated from moisture. Second, like the hydraulics, a minimum number of disconnects should be designed into the system so problems will not develop after moves. Third, wiring needs to be designed so that sensor and control wiring is hardened (and preferably located in places where it is impossible to smash). Finally, redundancy of critical sensors is a must.

To solve these problems attention must be given to the details. For example, conduit should be replaced by steel pipe in any place that could possibly be subject to damage. It is reasonable to consider pressurizing the entire wiring system to keep it dry and to provide an early indication of any leaks. Also, the wiring design must be an integral part of the overall rig. We have not found instrumentation reliability problems to be with the sensors themselves, rather the problem is with making the sensors function reliably in a less than optimum environment.

Along these lines, sensors critical to operation of the rig should be redundant. Preferably, the sensors should use different techniques to measure the same parameter. Redundancy allows calibration problems to be noticed early, and can prevent serious problems due to sensor failure. Redundancy is important for another reason. Failures of properly designed components on conventional

rigs are not normally catastrophic. There is usually some kind of forewarning (like the a gradual loss of power, a noise, or reduced performance). Electrical control and instrumentation failures, however, are often sudden. Redundant sensors (along with a control scheme to stop operation when the sensors do not agree) can help reduce the chances of serious problems due to catastrophic instrument failure. Finally, maintaining instrumentation on a computer controlled rig presents problems similar to those experienced with hydraulic maintenance. An experienced instrumentation technician must be available to repair and trouble shoot any problems that develop.

Control

As mentioned above, the initial justification for computer control of drilling parameters was optimum operation of downhole motors. The system described here could successfully operate motors at much closer to peak power than a conventional rig, but we also found that this control was not necessary to achieve the objectives of the project (i.e., reduce drilling costs in slower drilling formations). We have found that sharp, non-whirling bits offer greater promise.^{20,21} So, the most basic finding of the control system portion of this project is that while almost any envisioned control algorithm can be successfully implemented on a drilling rig, the algorithms we tested were not able to make turbine/drag bits operate significantly better than non-whirling PDC bits. We also found that the reliability problems experienced with the computer system were not nearly as bad as those with the instrumentation or actuation systems.

Besides the project specific findings, there were a number of more general items that related to computer automation in the drilling situation. Most of these stemmed from the requirement to have a human monitor the process, yet not be directly responsible for control of the system. Complete computerized control is more than a small step from computerized data logging (as is commonly used in the industry). The fundamental difference is that under computer control the human is removed from the loop.

There definitely is a tension between requiring a human to be alert enough to assure that the computer control process is functioning properly, and removing primary control from the human so that no direct intervention is required. On one hand, a well functioning computerized system might function flawlessly 99% of the time. Under these circumstances it is very easy for the human monitoring the system to become inattentive. This inattention can lead to serious problems during the 1% of the time when active human intervention is required. On the other hand, if human intervention is required 100% of the time, the benefits of the computer's speed and tirelessness are lost.

The computer can be programmed to automatically identify when some things are not right (i.e., the weight on bit calculated by the redundant systems do not match, or when the oil temperature in a certain motor is too high) and stop drilling completely. But unless the program is sophisticated enough to identify EVERY possible problem (i.e., it looks like

it is time for a core point, the bit is wearing out, or there is a strange noise in the transmission), then human supervision will still be required.

In any event, the point of computer control is to supplement the abilities of humans - not to replace them. As such, it is important that the warnings registered by the computer be significant virtually all the time. If not, an operator can easily become immune to the warnings and miss important problems. Also, the "bandwidth" of numerically displayed data is too low to allow the operator to see things like stand pipe pressure, hookload, or torque fluctuations. This deficiency can be mitigated by displaying the RMS value, along with the DC measurement of the relevant signal. With the RMS value, the operator can then get an indication of the magnitude and severity of any vibrations. Alternatively, a digital or analog realtime plot or spectral distribution could give the operator a better understanding of any vibrations. Even with these, however, the operator often cannot see the character of the vibrations. For this reason, an operator should be within sight of the drill floor.

Besides the test rig described here, we have operated a lab rig with computer control capabilities for five years. Basically, the lab rig acts like a robot and can be programmed to conduct lab drilling tests in any way desired. We have found, however, that lab drilling is so varied that it is easier and more flexible to tell a skilled human operator how to conduct the test than it is to program the procedure into the computer control system. A similar point can be made for computer control of a field rig. Unless every desired control sequence (i.e., openhole reaming procedures, reaming procedures before and after connections, drill-off tests, kick off procedures, emergency procedures, ...) is programmed, human intervention of some kind will be required. If a critical mass of these procedures are not available under computer control, then many benefits of computer control are lost.

CONCLUSION

This paper is one of the few of dozens on the subject that expresses anything negative about computer controlled drilling. Yet, the negative tone of this paper is not meant to denigrate the possibilities for drilling automation. We believe that it is possible to instrument, and control a drilling rig with almost any control scheme imaginable using off-the-shelf actuators, sensors, and computer systems.

However, our experience also shows (and we contend that the plethora of failed drilling automation projects supports the contention), that ECONOMICALLY computer controlling the drilling process is not an easy task. We have found a number of factors that prevent economic application of computer control: (1) The raw number of different components in an automated system is increased, the average reliability of each component in the automated system must be much greater than that of the conventional system, (2) A higher level of technical expertise is required to properly maintain an automated drilling system, this requirement most likely means that manpower costs on a computer controlled rig will be no

lower (and quite possibly higher) than on a conventional rig; (3) the requirement that the rig be periodically moved means that hydraulic and electrical systems are subject to contamination (this conclusion does not necessarily apply to offshore rigs), (4) the unfavorable environment of the drilling rig means that normal lab or manufacturing instrumentation techniques will not give adequate reliability; (5) The economic objective of the project could be achieved by means more reliable than computer control, and (6) because capital costs, and hourly operational costs of an automated rig will probably be higher than a conventional rig, the economic benefits of automation (i.e., increased productivity) must be demonstrable and quantifiable.

These conclusions do not mean that drilling automation can never be economic. Many, many difficult technical tasks have been perfected by the industry in the last twenty years, MWDs, top drives, iron roughnecks, dynamic positioning, computerized drilling data collection, to name only a few. Each of these technologies initially faced problems. The point is that unless the problems are recognized and dealt with, the industry will forever be making the same mistakes. We hope that this paper has identified at least some of the hurdles yet to be overcome, and will assist future drilling automation endeavors.

NOMENCLATURE

n = The current execution's time step.

ROP(n) = Rate of penetration measured at time step ' n ' (ft/hr).

CON(n) = Control parameter measurement at time step ' n '; units depend on parameter being controlled (torque-ftlbs, pressure-psi, rotary speed - RPM).

CONcmd = Control parameter commanded value; units depend on parameter being controlled (torque-ftlbs, pressure-psi, rotary speed - RPM).

WOBout = Weight on bit commanded to the hoist control sub-system (lbs).

WOBmax = Maximum desired weight on bit (lbs).

WOBmin = Minimum desired weight on bit (lbs).

WOB(n) = Actually measured weight on bit for time step ' n ' (lbs)

SIGN = Control parameter vs. WOB sign relationship; a positive relationship between the control parameter and WOB would require a sign of +1 (i.e., torque), an inverse relationship between the control parameter and WOB requires a sign of -1 (i.e., turbine RPM).

$K(n)$ = Calculated proportionality between the controlled parameter and the applied weight on bit.

$K^+(n)$ = Estimate of the next step's linear relationship between the controlled parameter and the applied weight on bit.

ϵ = Difference between the desired and actual value of the control parameter.

α = Control loop gain constant.

α_{down} = Control loop gain constant for upward motion.

α_{up} = Control loop gain constant for downward motion.

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APPENDIX I Rig Control Algorithms

The control algorithms were implemented in such a way that the user could select the penetration rate, surface torque, downhole torque, turbine RPM, or stand pipe pressure (to maintain a constant PDM torque) as parameters for control. The weight on bit would then be adjusted to maintain the parameter constant in the face of changes in lithology and bit characteristics. Control would often require that the controlled parameter be a tarred value properly adjusted for zero load conditions. In practice, at the beginning of each joint to be drilled a zero point was determined for the control parameter. The zero point was used as a reference to determine the change in each parameter attributable to weight on bit. The sections below outline the three realtime algorithms used to control the portion of the measurement related to changes in weight on bit. All of the algorithms implemented are standard control system techniques.²⁸

Integral Control

The simplest control scheme implemented and tested during the project was integral control of the desired parameter. The scheme uses a Z-plane equivalent (forward rectangular rule) of conventional integral control. First, the error (ϵ) between the desired (CON(n)) and commanded value (CONcmd) for a particular parameter is determined with proper consideration given to maintaining the correct sign relationship (Eq. 1). Most control parameters (surface and downhole torque, PDM standpipe pressure) increase with weight on bit. Since turbine speed, however, decreases as weight is applied consideration of the sign relationship is necessary. The weight on bit required to move the controlled parameter closer to its command value is then determined consistent with pure integral control (Eq. 2). The time rate constant α controlled the speed of response, and its value depended on both the desired system gain, and the time between samples. The indicated weight on bit is then controlled to be lesser of either the weight determined by the control algorithm, or the maximum desired weight on bit set by the operator (Eqs. 3).

$$\epsilon(n) = (\text{CONcmd} - \text{CON}(n)) * \text{SIGN} \quad (\text{Eq. 1})$$

$$\text{WOB}(n) = \alpha * \epsilon(n) + \text{WOB}(n-1) \quad (\text{Eq. 2})$$

$$\text{If } \text{WOB}(n) > \text{WOBmax} \text{ then } \text{WOBout} = \text{WOBmax} \quad (\text{Eq. 3a})$$

$$\text{Elseif } \text{WOBout} = \text{WOB}(n) \quad (\text{Eq. 3b})$$

Adaptive Control

A second control algorithm used parametric identification to implement an adaptive control technique. After the difference (ϵ) between the desired and commanded value is determined (Eq. 4), the linear relationship ($K(n)$) between the weight on bit and the control parameter is calculated for the specific time step (Eq. 5). Next, a prediction (K^*) of the relationship between the weight on bit and the control parameter for the next time step is

determined (Eq. 6). The dynamic response of this prediction is controlled by a constant (α), the value of which depends on the time step between updates and the desired gain of the parametric identification loop. The desired weight on bit (WOB(n)) is then determined as shown (Eq. 7). The weight on bit actually commanded is then the lesser of the maximum desired weight on bit selected by the operator, or the value determined by the control scheme (Eqs. 8).

$$\varepsilon = (\text{CONcmd} - \text{CON}(n)) * \text{SIGN} \quad (\text{Eq. 4})$$

$$K(n) = \text{WOB}(n) / \text{CON}(n) \quad (\text{Eq. 5})$$

$$K^+(n) = (1 - \alpha) * K(n) + \alpha * K^+(n-1) \quad (\text{Eq. 6})$$

$$\text{WOB}(n) = (K^+(n) * \varepsilon) + \text{WOB}(n) \quad (\text{Eq. 7})$$

$$\text{If } \text{WOB}(n) > \text{WOBmax} \text{ then } \text{WOBout} = \text{WOBmax} \quad (\text{Eq. 8a})$$

$$\text{Elseif } \text{WOBout} = \text{WOB}(n) \quad (\text{Eq. 8b})$$

Adaptive Rate of Penetration Limiter

The final algorithm programmed for the project is an adaptive scheme that can either run separately or concurrently with any other control algorithm. When this algorithm functions, the weight on bit commanded by other control schemes can be overruled if the actual penetration rate exceeds a limit set by the operator. If the algorithm functions alone, it will control the weight on bit independently. The purpose of the limiter is to control the penetration rate to below levels that are known to present a bit balling hazard. The description below assumes independent operation of the algorithm.

The algorithm begins by calculating the difference (ε) between the penetration rate limit (ROPmax), and the actual penetration rate determined for the latest time step (ROP(n)), (Eq. 9). Follow-

ing that, a calculation is made to determine the linear relationship ($K(n)$) between the penetration rate and the applied weight on bit (WOB(n)), (Eq. 10). The next steps determine if the calculated linear relationship for the time step is higher or lower than the last estimate of the relationship ($K^+(n-1)$). The estimator gain (α) is then selected to one of two values (α_{up} or α_{down}) depending on whether or not weight is to be added or taken off the bit (Eqs. 11). By selecting two different estimator gains it is possible to have the hoist slowly add weight to the bit, or quickly pick up if necessary. Once the control gain is determined, a prediction of the next linear relationship ($K^+(n)$) between the weight on bit and the rate of penetration is made (Eq. 12). The weight desired by the algorithm (WOB(n)) (Eq. 13), and finally the commanded weight (set to be between limits set by the operator) are then determined (Eqs. 14).

$$\varepsilon = \text{ROPmax} - \text{ROP}(n) \quad (\text{Eq. 9})$$

$$K(n) = \text{ROP}(n) / \text{WOB}(n) \quad (\text{Eq. 10})$$

$$\text{If } K(n) > K^+(n-1) \text{ then } \alpha = \alpha_{up} \quad (\text{Eq. 11a})$$

$$\text{Elseif } K(n) \leq K^+(n-1) \text{ then } \alpha = \alpha_{down} \quad (\text{Eq. 11b})$$

$$K^+(n) = ((1 - \alpha) * K(n)) + (\alpha * K^+(n-1)) \quad (\text{Eq. 12})$$

$$\text{WOB}(n) = (\varepsilon / K^+(n)) + \text{WOB}(n-1) \quad (\text{Eq. 13})$$

$$\text{If } \text{WOB}(n) > \text{WOBmin} \text{ and } \text{WOB}(n) < \text{WOBmax} \text{ then } \text{WOBout} = \text{WOB}(n) \quad (\text{Eq. 14a})$$

$$\text{Else if } \text{WOB}(n) < \text{WOBmin} \text{ then } \text{WOBout} = \text{WOBmin} \quad (\text{Eq. 14b})$$

$$\text{Else if } \text{WOB}(n) > \text{WOBmax} \text{ then } \text{WOBout} = \text{WOBmax} \quad (\text{Eq. 14c})$$

Table 1 - Sensor Description

Analog Input Instrumentation

Parameter	Transducer Description	Conditioner Description	Sampling Frequency (Hz)	Classification
HOOK LOAD (PT)	two 0-3000 psi pressure (4-20mA)	two process signal ¹ and summing module ⁴	5	Direct Control
HOOK LOAD (SG)	two 0-50 kip strain gages (4-20mA)	two process signal ¹ and summing module ⁴	5	Direct Control
WOB (PT)	conditioned unfiltered hookload signal	summer module ⁴ and signal conditioner ³	1	Direct Control
WOB (SG)	conditioned unfiltered hookload signal	summer module ⁴ and signal conditioner ³	1	Direct Control
ROTARY SPEED	magnetic pickup (0-3V)	frequency to voltage ²	5	Direct Control
HOIST POSITION	15 turn potentiometer (4-20mA)	process signal ¹ and isolating transmitter	5	Direct Control
ROTARY TORQUE	0-5000 psi pressure (4-20mA)	process signal ¹	5	Direct Control
PUMP PRESSURE	0-5000 psi pressure (4-20mA)	process signal ¹	5	Direct Control
TORQUE (SG SUB)	strain gage (4-20mA)	process signal ¹	5	Direct Control
TURBINE TACH.	CALCULATED	none	5	Direct Control
UNFILTERED WOB	conditioned unfiltered hookload signal	two process signal ¹ and summing module ⁴	0.1	Direct Control
FLOW RATE (MAG)	magnetic pickup (0-5V)	frequency to voltage ²	5	Drilling Data
FLOW RATE (SC)	magnetic pickup (0-5V)	frequency to voltage ²	1	Drilling Data
BIT DEPTH	CALCULATED	none	5	Drilling Data
TORQUE VIBRATION	strain gage (4-20mA)	process signal ¹ and AC transmitter	5	Drilling Data
SG HOOKLOAD VIB.	strain gage (0-5V)	AC transmitter	5	Drilling Data
ACCELEROMETER Gs	accelerometer (4-20mA)	process signal ¹	5	Drilling Data
ACCEL. VIBRATION	conditioned accelerometer signal	AC transmitter	5	Drilling Data
NET FLOW RATE	CALCULATED	none	1	Drilling Data
PIPE DRAG	CALCULATED	none	5	Drilling Data
BIT VOLUME	reed switch (0-5V)	single turn potentiometer	0.1	Drilling Data
FLOW OUT	single turn potentiometer (0-5V)	signal conditioner ³	0.1	Drilling Data
MUD TANK TEMP.	resistance temp. detector (4-20mA)	current to voltage convertor and signal conditioner ³	0.1	Drilling Data
MUD RETURN TEMP	resistance temp. detector (4-20mA)	current to voltage convertor and signal conditioner ³	0.1	Drilling Data
WOB ZERO	10 turn potentiometer (4-20mA)	process signal ¹	0.1	Drilling Data
HOIST POS SERVO	15 turn potentiometer (4-20mA)	process signal ¹	-	Drilling Data
DETROIT RPM	magnetic pickup (0-5V)	frequency to voltage ²	5	Rig Health
BY-PASS FLOW	magnetic meter (4-20mA)	process signal ¹	1	Rig Health
RAM HYD. SUPPLY	0-5000 psi pressure (0-5V)	signal conditioner ³	0.1	Rig Health
ROT. CHARGE PRE.	0-200 psi pressure (0-5V)	signal conditioner ³	0.1	Rig Health
ACCUMULATOR PRE.	0-5000 psi pressure (0-5V)	signal conditioner ³	0.1	Rig Health
RPM SERVO ERROR	servo (0-5V)	none	0.1	Rig Health
WOB SERVO ERROR	servo (0-5V)	none	0.1	Rig Health
VALVE B PILOT	0-5000 psi pressure (0-5V)	signal conditioner ³	0.1	Rig Health
HYD. RES. TEMP.	resistance temp. detector (4-20mA)	current to voltage convertor and signal conditioner ³	0.1	Rig Health
MUD CHARGE PRESS	0-500 psi pressure (0-5V)	signal conditioner ³	0.1	Rig Health

Digital Input Instrumentation*

Parameter	State Description	Sampling Frequency	Classification
SLIPS OUT	0=SLIPS IN / 1=SLIPS OUT	10	Direct Control
COMPUTER ENABLE	0=SHUT-DOWN / 1=RUN	10	Direct Control
COMPUTER CONTROL	0=OFF / 1=ON	10	Direct Control
RAM LOCK	0=UNLOCKED / 1=LOCKED	10	Direct Control
AB SERVO SELECT	0=A / 1=B	10	Direct Control
SG/PT WOB SWITCH	0=SG / 1=PT	10	Direct Control
ROTARY LOCK	0=UNLOCKED / 1=LOCKED	10	Direct Control

Analog Output Instrumentation*

Parameter	Units	Classification
WOB (PT)	LBS	Direct Control
WOB (SG)	LBS	Direct Control
HOIST POS SERVO	FEET	Direct Control
RPM	RPM	Direct Control
WOB ZERO	VOLTS	Direct Control: 6.1

Digital Output Instrumentation*

Parameter	State Description	Classification
WOB/POS FEEDBACK	0=WOB / 1=POSITION	Direct Control
COMP/MANUAL WOB	0=MANUAL / 1=COMPUTER	Direct Control
COMP/MANUAL RPM	0=MANUAL / 1=COMPUTER	Direct Control
RAM LOCK	0=LOCKED / 1=UNLOCKED	Direct Control
TAPE RECORDER	0=OFF / 1=ON	Drilling Data

- The process signal conditioner is a 4-20 mA to 0-5 V convertor with .2, 2, 200, 2K Hz selectable low-pass filtering, and zero and gain adjustment.
- The frequency to voltage conditioner is a frequency to voltage convertor with zero and gain adjustment.
- The signal conditioner is a 0-5 V to 0-5 V convertor with 2 or 2K Hz low-pass filtering, and zero and gain adjustment.
- The summing module is a three 0-5V input channel device with sum and difference capabilities.
- Digital inputs use standard digital switches, various electrical switches, and solid-state 24V relays.
- Analog outputs are used as set-points to commercially available analog servo controllers and as inputs to commercially available data displays. The WOB position feedback servo uses linear control and the RPM servo uses integral control.
- 6.1 WOB zero is used to send a zero reference signal to the WOB summer module signal conditioner.
- Digital outputs use solid-state 24V relays and various electromechanical relays.

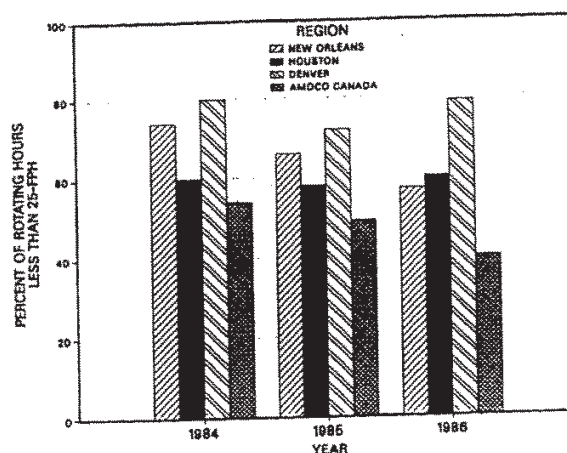


Figure 1 - Percentage of Rotating Hours Less than 25 ft/hr

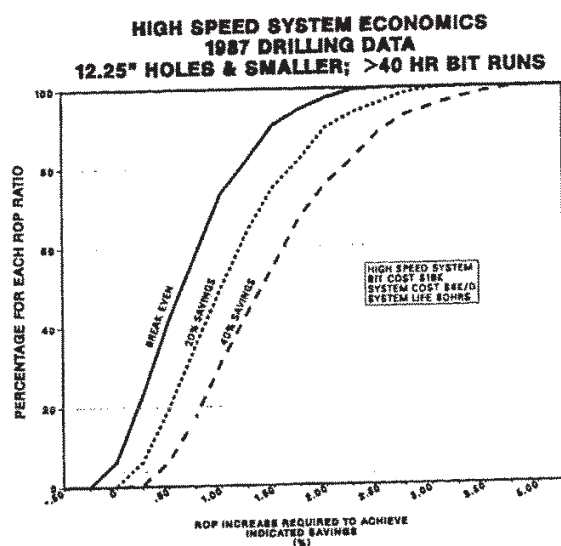


Figure 2 - Penetration Rate Requirements for Success

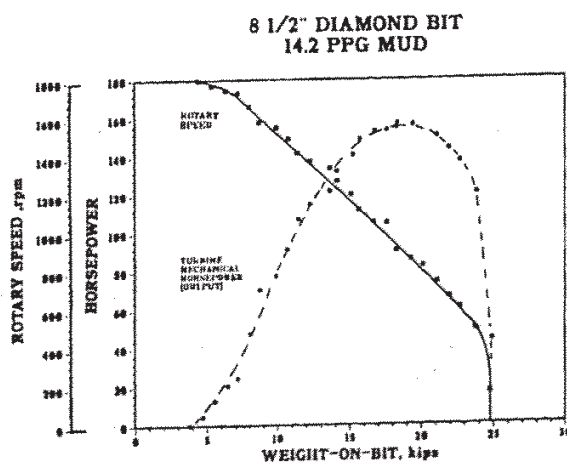


Figure 3 - Turbine/Drag Bit Drilling Performance

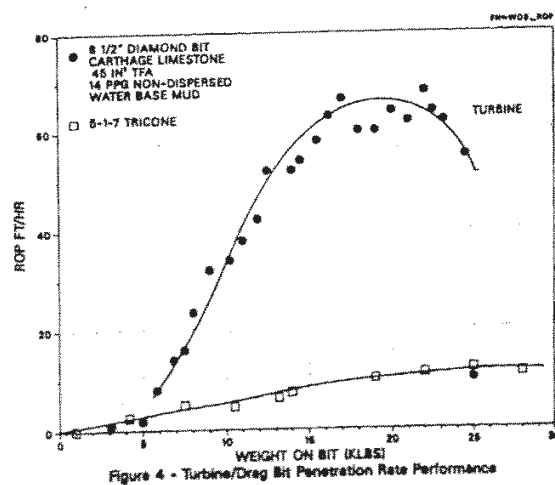


Figure 4 - Turbine/Drag Bit Penetration Rate Performance

DM-5A TURBINE SPEED FLUCATIONS 1435'-1466'

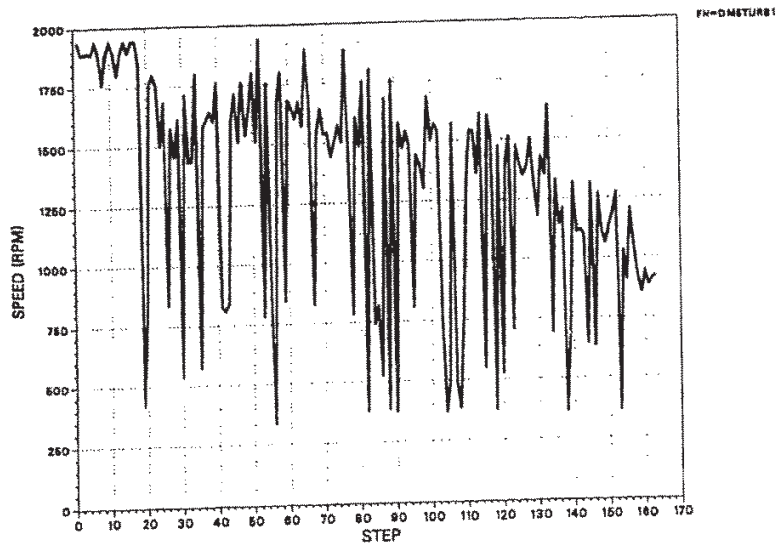


Figure 5 - Typical Turbine Speed Fluctuations

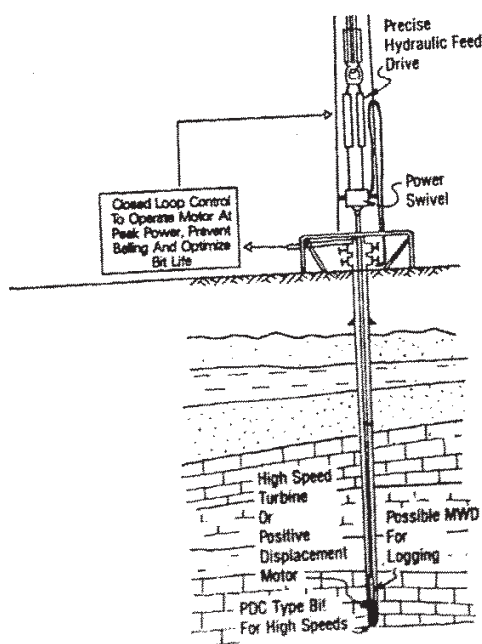
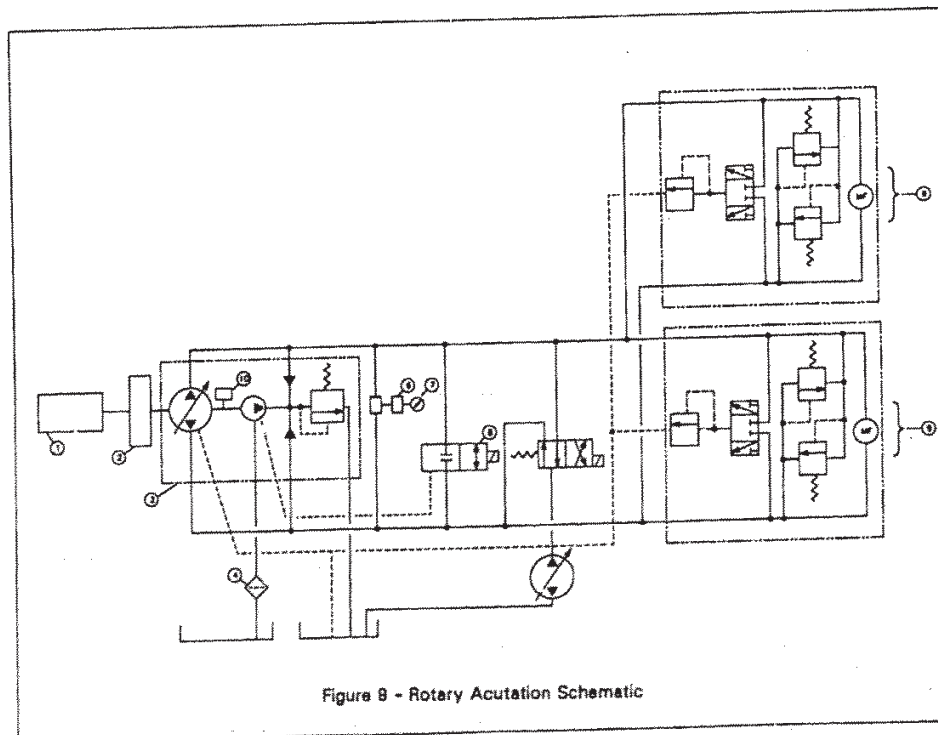
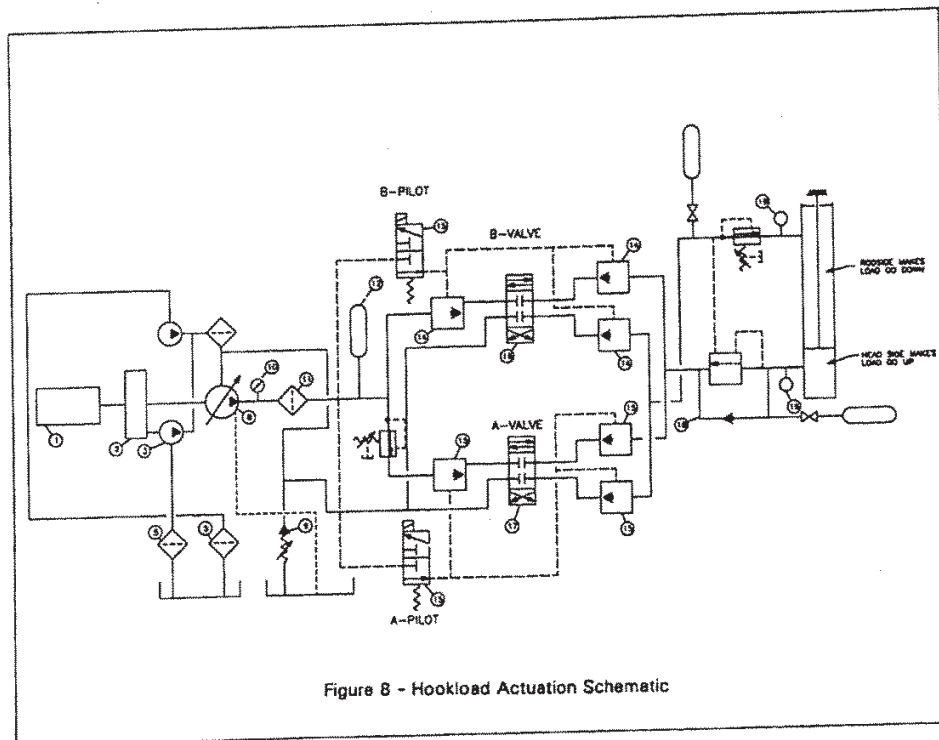


Figure 6 - Closed Loop Drilling System Schematic



Figure 7 - General Rig View



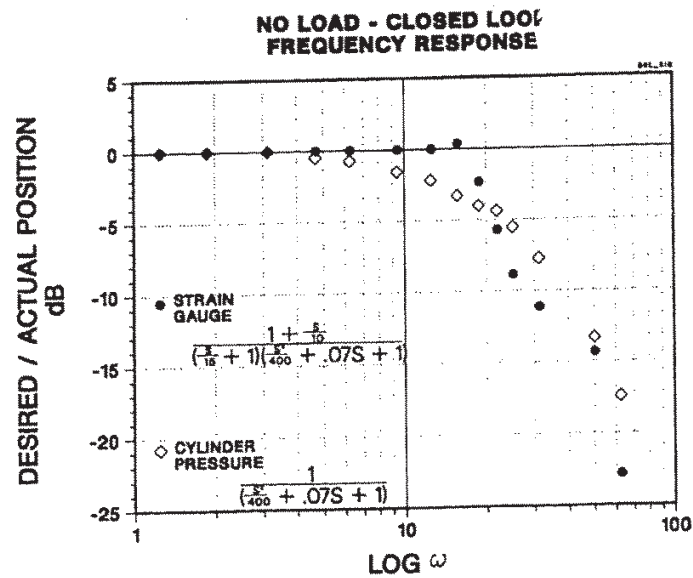


Figure 10 - Hookload Frequency Response Measurement

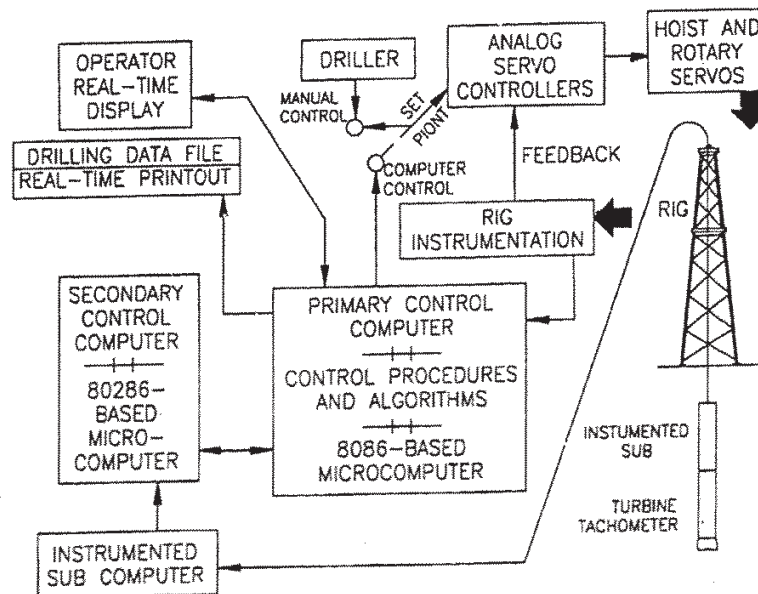


Figure 11 - Computer Control Schematic

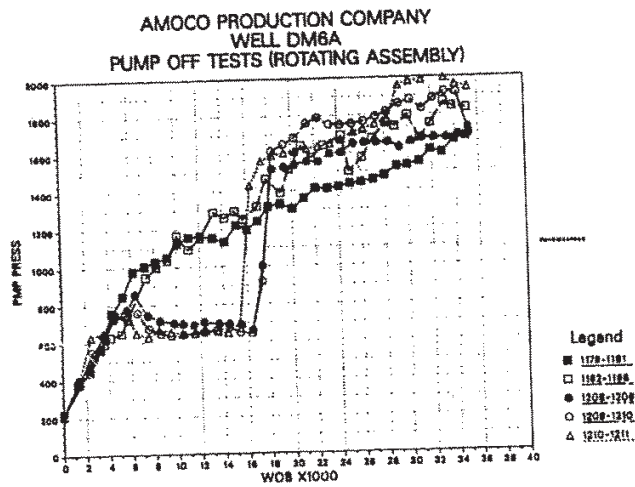


Figure 12 - Pumpoff Test Results

TORQUE ALGORITHM FROM WELL DM #6A

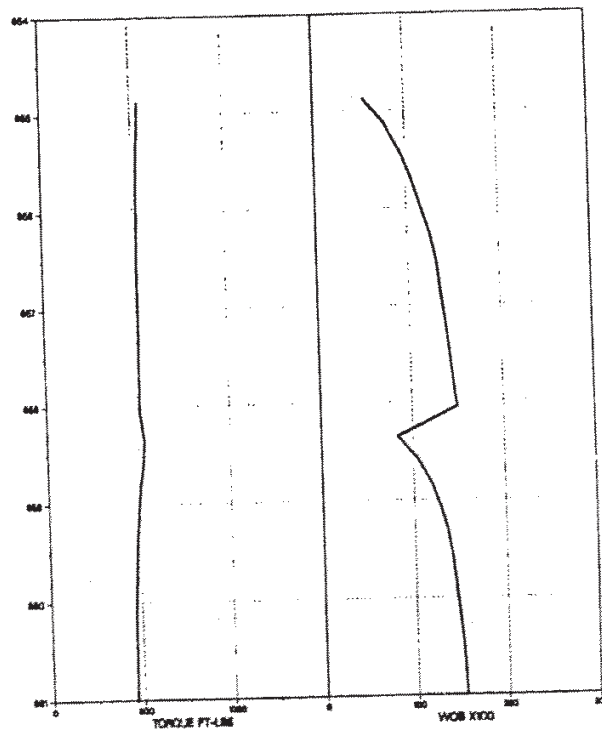


Figure 13 - PDM Torque Control Algorithm Performance