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Development Plan for an Advanced Drilling System with Real-Time Diagnostics (Diagnostics-While-Drilling)

J. T. Finger, A. J. Mansure, M. R. Prairie, and D. A. Glowka

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**DEVELOPMENT PLAN FOR AN
ADVANCED DRILLING SYSTEM
WITH
REAL-TIME DIAGNOSTICS
(Diagnostics-While-Drilling)**

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ABSTRACT

This proposal provides the rationale for an advanced system called Diagnostics-while-drilling (DWD) and describes its benefits, preliminary configuration, and essential characteristics. The central concept is a closed data circuit in which downhole sensors collect information and send it to the surface via a high-speed data link, where it is combined with surface measurements and processed through drilling advisory software. The driller then uses this information to adjust the drilling process, sending control signals back downhole with real-time knowledge of their effects on performance. The report presents background of related previous work, and defines a Program Plan for U. S. Department of Energy (DOE), university, and industry cooperation.

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EXECUTIVE SUMMARY

E.1 Overview

Drilling is an essential, ubiquitous, and expensive part of the oil, gas, geothermal, minerals, water-well, and mining industries. Research targets to make the drilling process cheaper and more effective are not obvious, because its technology is very mature. This document proposes a new technology that will improve drilling in two ways: 1) It will reduce the cost of conventional drilling, where "conventional" includes even high-risk, high-cost operations such as off-shore horizontal drilling; and/or 2) It will provide beneficial new capabilities that did not exist before, regardless of cost.

Consequences of reduced drilling cost can be impressive.

- U. S. oil and gas drilling expenditures exceed \$10 billion per year (Oil & Gas Journal, 1/98)
- Drilling costs account for 33% (onshore) to 40% (offshore) of the total costs of finding and developing new natural gas resources. (GRI, 1999)
- Drilling and well completion can account for up to 50% of the capital cost for a geothermal power project. (Pierce, et al, 1996)

Because the industry's breadth of activity is so large, reducing drilling expenditure by even a small fraction pays off with many dollars saved. Cost reduction can take many forms – faster drilling rates, increased bit or tool life, less trouble (twist-offs, stuck pipe, etc.), increased production per well through multi-lateral completions, and others – but the key to each of these improvements is better knowledge at the surface, in real time, of what is happening downhole. This proposal describes a new way – called **Diagnostics-While-Drilling (DWD)** – to gain that knowledge.

The central concept of DWD is a closed information loop, carrying data uphole and control signals downhole, between the driller and the tools at the bottom of the hole. Up-coming data will give a real-time report on drilling conditions, bit and tool performance, and imminent problems. The driller can use this information either to change surface parameters (e.g., weight-on-bit, rotary speed, mud flow rate) with immediate knowledge of their effect, or to return control signals to active downhole components. DWD can reduce conventional drilling costs, even in the short-term, in several ways:

- Improved penetration rate – Operating the bit under optimum conditions will increase its performance and this improvement translates directly into more footage per day or lower cost per foot.
- Increased bit life – Perhaps even more important than penetration rate; increased bit life will mean lower expenses for bit purchase and less time tripping, especially as depths increase. Taken together, doubling penetration rate and bit life have been estimated with Sandia's well-cost model to lower total

well costs by about 21% for a 20,000 foot well, but we will take a more conservative figure of 15%.

- Diminished trouble and tool failures – Downhole trouble, such as stuck pipe or twist-offs, can consume as much as 12% of total drilling time (Tarr, 1999) and could often be prevented with real-time data from the drilling assembly. The well-cost simulation mentioned above showed a total cost saving of 8.4% by eliminating lost circulation, stuck pipe, and twist-offs from a realistic drilling scenario. In addition to this kind of trouble, bits and other downhole tools, especially more vulnerable and expensive ones such as motors and directional drilling hardware, fail regularly. Reducing the number of failures, through real-time knowledge of the tool's operating environment and condition, will cut operating time (tripping) and will reduce service and repair charges for this costly equipment. This failure-reduction saving could be as much as an additional 10% of well cost in expensive, directional wells, but because those are not universal, we will take a total cost saving of 10% for the items in this category.

The near-term savings in drilling cost is taken to be 25%, but advanced technology, which is only dimly visualized now, has the potential to drive this improvement

Figure E.1 – Reduction in electricity cost with drilling improvements by DWD

even further. Some examples of indirect, or long-term, improvements include: better drilling simulators for training; improved learning-curve analysis for multi-well drilling programs; ability to incorporate more detail and variables in drilling optimization studies; and surface-controllable downhole tools (see Section 1 for more detail.)

These direct cost savings in the drilling process are not the only benefits of DWD, however, and an example from the geothermal industry will illustrate the potential.

Example: *Improvements in productivity for each well and a reduction in the number of dry holes may be realized, in addition to the reduced drilling cost. The effect on the price of electricity, considering all improvements, is shown in Figure E.1. In areas where geothermal electricity is marginally competitive, cost savings this important could make the difference between a market's existence and absence. Other cost plots (Figure A.1.1, p. 49) show that electricity from geothermal power plants should vary from 3 to 14 cents/kWh, which is consistent with the current market.*

Rationale for these assumptions and the effect of changes in them are described more fully in Section 1 and in complete detail in Appendix A.1.

E.2 System Description

A DWD system has four functional requirements:

1. Identify information that is useful to the driller.
2. Collect downhole data with appropriate sensors.
3. Use telemetry to bring downhole data to the surface and return control signals downhole.
4. Process surface and downhole measurements to provide real-time information for the driller.

These four criteria require the hardware and software components shown in Figure E.2. Data from all parts of the drilling system, both downhole and at the surface, will be acquired, analyzed, integrated, and displayed for the driller at a rate that is

Figure E.2 - Schematic representation of the Diagnostics-While-Drilling (DWD) system

fast enough to provide him with a realistic feeling of response and that will allow him to take action quickly if a problem is imminent.

Example: The driller will be able to watch a trace of weight-on-bit, measured at the bit. If the bit is bouncing, which is often the case, the driller would try to attenuate this by adjusting rotary speed and/or weight-on-bit at the surface. Research has shown that it is possible to eliminate bit bounce by adjusting these parameters (Heisig et al).

The following components make up the basic DWD system:

- *DWD Tool* acquires data from downhole sensors, conditions it for transmission, and delivers it to the high-speed data link;
- *High-Speed Data Link* carries downhole information to the surface and carries surface control signals back downhole;
- *Drilling Advisory Software* acquires, analyzes, integrates, and displays downhole and surface data in real time to provide the driller with a complete and accurate status of drilling conditions and system performance;
- *Driller* uses traditional methods as well as the Drilling Advisory Software to direct the drilling process;
- *Drill Rig/Drill Pipe* is the primary mechanism through which the drilling process is controlled (weight-on-bit, rotary speed, and mud flow);

Another component that is not part of the initial DWD system but may eventually be extremely important is:

- *Surface-Controllable Downhole Tools (steering tools, shock subs, formation evaluation)* permit the driller to actively control downhole tools with real-time knowledge of the effect of his actions.

E.3 Technical Challenges

Development of the six components for a DWD system appears to face four major technical challenges: the high-speed data link, the drilling advisory software, surface-controllable downhole tools, and advanced downhole sensors.

- The principal challenge is a high-speed data link that will carry data at an adequate rate while remaining transparent to the drilling operation. For geothermal and some deep gas drilling, high temperatures would compromise the electronics for downhole signal processing, so the data link should have a minimum transmission rate of 100 kbits/sec. This is four orders of magnitude above the data rate of conventional measurement-while-drilling (MWD) systems.
- Prototypes currently exist for all the critical elements in Figure E.2, except for the driller's software. Raw data is of little value on the rig floor, so a major task in this project is to work with the driller and determine the best way of processing and presenting the data.

- With an economical high-speed data link to send control signals downhole and transmit sensor data back uphole, a wide range of downhole tools that have not been feasible to this point will become practical.
- Development of advanced downhole sensors with high-temperature, high-shock capability may be evolutionary from existing devices, but may require significant innovation. This will become clearer after the proof-of-concept tests help to refine a list of measurements to be taken and conditions under which the sensors will have to operate.

E.4 Program Plan

The proposed program to develop an advanced DWD system will have four phases, shown in Figure E.3:

- Phase 1 – Project planning and consortium development,
- Phase 2 – Proof-of-Concept testing – assembly of a prototype DWD system, using modified existing downhole components and a hardwired data link, and demonstration of its benefits through field tests,
- Phase 3 – Development of systems needed for cost-effective, commercialized DWD for the geothermal and oil and gas industries, and
- Phase 4 – Research, development and field-testing of enhanced (primarily surface-controllable) tools for DWD applications.

Year	99	00	01	02	03	04
\$ DOE/OGT	300k	2M	8M	8M	10M	12M
\$ Ind., OFA	0k	500k	2M	4M	6M	8M
	Phase 1: Planning					
		Phase 2: Proof-of-Concept ①				
			Phase 3: Optimize DWD ②			
				Phase 4: Enhanced DWD ③		

Figure E.3 - Phasing, cost and milestones for the proposed ADTech Program. Total cost is estimated at \$60.8M over 6 years, split 2/3:1/3 between DOE/OGT and other sources, respectively. Major milestones: ① DWD is proven; ② DWD is commercially available; ③ Enhanced DWD is commercially available.

We will depend on industry to contribute to the cost of Phases 2 and 3 by providing cash and in-kind contributions such as MWD tools and field testing opportunities and facilities. The entire program will be a joint endeavor with industry, universities – including the recently created Well Construction Technology Center – and DOE.

E.5 Rationale

DWD will reduce near-term costs in two ways: improve the drilling process with higher rate of penetration (ROP), and reduce flat – non-productive – time. The drilling industry considers “flat time” to be any time during which the rig is not drilling new hole. Based on one industry survey of a 250-well oil and gas data base, flat time can range from 65 to 83% of a drilling project (Tarr, 1999); reducing it is one of the industry’s principal goals. Each of the top four causes of flat time – non-

scheduled events or "trouble", casing installation, tripping, and formation evaluation – can be reduced by some aspect of DWD technology.

The geothermal and hydrocarbon industries are inextricably linked in their quest to reduce drilling cost. Historically, drilling cost per foot tracks the price of oil very closely (GRI, 1999) because high oil prices encourage more drilling, and market forces drive up drill rig rates. Paradoxically, then, when oil prices go up, geothermal energy becomes more competitive, but drilling for it becomes more expensive because drill rigs cost more. We have tried to accommodate this linkage by involving both industries – and both the Fossil Energy and Geothermal Technology offices in DOE – in planning and implementing DWD development.

Even though geothermal energy is already a substantial contributor to domestic supply (the U. S. geothermal industry is the world's largest), it is a niche market and will remain so even if the goals in DOE's Strategic Plan are met. As such, the geothermal industry alone cannot support a development program of this size, and without this aggressive approach to lower costs, especially for deeper drilling, geothermal energy will not increase its penetration of the world's growing electricity market.

DOE and Sandia have, for more than 20 years, conducted research, development, and demonstration programs to reduce drilling cost through a combination of incremental and revolutionary improvements in drilling technology. Coupling geothermal drilling expertise to the vast technology resources of DOE National Laboratories, Sandia is in an unparalleled position to lead the DWD Program. DOE Office of Geothermal Technology (OGT) funding will catalyze the program and will assure that the technology enhances worldwide development of geothermal energy, but the geothermal, oil, and gas industries also have crucial roles, through their contributions, in making DWD technically viable and routinely used.

E.6 Summary

A Diagnostics-While-Drilling system, either as a stand-alone tool or as a precursor to a smart, semi-autonomous drilling method, has been industry's goal for years, if not decades. The marginal success to date is primarily a result of the cyclic nature of drilling R&D, which rises and falls with the oil market and has been notably volatile for almost twenty years, not any lack of talent or motivation. Many of the issues that we propose to address in this program can also be attacked more effectively now because of advances in associated technologies such as computing power, information processing, expert systems, and improved materials.

We view this program as a necessary step in a revolutionary approach to drilling. It will demonstrate value in a systems approach that leads to both near-term drilling improvements and long-term enabling of new technologies that may be only dimly visualized now. The proposed work is ambitious, yet realistic, and could have an enormous payoff. We should start now to realize this potential.

1.0 BENEFITS OF DIAGNOSTICS-WHILE-DRILLING

1.1 Impact of Drilling on Geothermal Energy Costs

Geothermal energy is an economically viable, clean source of electric power, space heating, and process heating in many parts of the world. To expand its use in more areas, it is essential to reduce the costs of providing geothermal energy and make it more globally competitive.

One of the largest cost components of any geothermal project is the cost of the production and injection wells. Because of the hard fractured rock, high temperatures, and generally underpressured formations in typical geothermal reservoirs, wells are usually very expensive, often \$2-3 million for a 5,000-10,000 ft well. Figure 1.1 shows that even relatively shallow geothermal wells require significant capital investment.

Figure 1.1 For most large geothermal projects, 30-50% of the project's cost is due to the wells: drilling and completion. This figure shows how the fraction of a 40 MW_e project's cost due to drilling and completion varies with well depth for three different reservoir qualities (5 MW_e/well is typical).

Even worse, the capital investment for a geothermal well field is often made several years before the power project begins to produce revenue, creating risk and reluctance on the part of project financiers. The cost of electricity, based on a set of assumptions described in detail in Appendix A.1, has been calculated as a function of well depth and productivity for three kinds of geothermal power plant – flashed steam, binary, and enhanced reservoir (e.g., hot dry rock.) All results are given in the Appendix but, as an example, electricity costs in the flashed-steam plant are shown in Figure 1.2. Clearly, both depth and productivity have major impact on cost of electricity (COE), which ranges from 3 to 9+ cents/kWh. Considering then how DWD might improve the economics of this case, a scenario in which well cost, well productivity, and dry-hole rate are all improved is depicted in Figure 1.3. This demonstrates that in areas where the economics of geothermal energy are marginal,

DWD could make the difference between the existence and absence of a market. Considering all cases analyzed, COE varies from 2.9 to 13.3 cents/kWh, which is consistent with the actual market, and cost reduction is between 2 and 31%.

Figure 1.2 – Cost of Electricity for various well depths and productivities

Figure 1.3 – COE reductions with DWD

For a comparison of geothermal COE with that from other sources, see Appendix A.1, where COE for wind, biomass, solar, natural gas, nuclear and coal are given. It is clear from these numbers that in many cases geothermal is either already competitive, or could be so with the kind of cost reductions shown in this modeling.

Finally, it may well be that most of the “easy” geothermal resources have been discovered and that deeper reservoirs must be tapped to meet the goals of DOE’s Strategic Plan. If costs of deep drilling are not substantially reduced, those goals will remain unmet.

1.2 Impact of DWD on Drilling Costs

Enhanced diagnostic information, combining data from downhole and from surface measurements, will immediately benefit drilling operations in two ways, and will have even greater potential impact in the longer term:

- The rock-cutting process – making hole – will improve with higher ROP and better directional control.
- Non-productive – or “flat” – time will be reduced.
- Development of surface-controllable downhole tools, with capabilities to actively change drilling conditions without tripping, will be stimulated.

Making hole

Better diagnostics and control from surface measurements are already having an impact on drilling costs.

Example: Several rigs drilling in Texas have been fitted with high-performance drawworks brakes and automated control of either WOB or feed rate to give smoother drilling. This produced an average 37% reduction in rotating hours and 34% improvement in bit life (Oil & Gas Journal, 12/98). Other rig manufacturers are also improving instrumentation and adding robotics to their equipment (Warren) and are committed to this trend. Although this current work only includes surface measurements, downhole information added to this kind of system would improve performance even more in a wider variety of drilling.

Drilling performance will improve primarily because the driller will have better, immediate, downhole information about the effect of the changes that he makes in controllable drilling parameters at the surface. This not only means that the bit and other tools will be operating at maximum efficiency, but it will become possible to detect and mitigate or to avoid damage to them.

Example: Poly-crystalline Diamond Compact (PDC) bits usually cut much faster than roller-cone bits, but they are more sensitive to WOB. In directionally drilled wells, the drillstring drag on the wellbore is often too great to accurately know the actual WOB, so PDC bits are unsuccessful because they are either stalled with too much weight or unloaded and not cutting with too little weight. Downhole measurement of WOB would allow use of PDC bits and faster, more economical drilling in highly deviated holes.

We fully expect that PDC bits can be used successfully in hard, fractured formations, which will contribute to reduction of geothermal drilling costs. It is likely, however, that because of their susceptibility to impact damage, success will hinge on the driller's ability to eliminate bit bounce and whirl. DWD will give the driller an ability to use PDC bits for geothermal and deep gas applications by

eliminating the dynamic conditions that damage PDC cutters. If both penetration rate and bit life are doubled, geothermal well costs will be reduced by about 15%.

Reducing flat time

The drilling industry considers “flat time” to be all time that is not spent drilling new hole. It includes tripping, circulating, running and cementing casing, logging, and non-scheduled events (or “trouble”); flat time can occupy 65 to 83% of total time on a drilling project (Tarr). Based on a 250-well database (oil and gas) the top four causes of flat time, with their percentages of total time consumption and the ways that they could be mitigated by DWD, are given below.

- Non-scheduled events (trouble) – 12-25% – more detail below
- Casing installation – 12-21% – better directional control (less dogleg severity), re-design casing during drilling with real-time pore pressure
- Tripping – 10-12% – longer bit life, less tool wear, fewer failures; all reduce number of trips
- Formation evaluation – 5-18% – logging-while-drilling (LWD); reduce or eliminate post-drilling logs

Within the “trouble” category, the top three problems are listed below (note again that the percentages are of total time on the drilling project).

- Stuck pipe, fishing, side-track – 2-12% – real-time knowledge of downhole annulus and pore pressures, along with dogleg severity and formation condition, will reduce stuck pipe; torque, WOB, and other dynamic measurements will warn of conditions that could twist-off the drilling assembly
- Equipment (surface and downhole) problems – 2-9% – better real-time data on operating conditions, probably fed into an expert system, could track key parameters such as pressure and temperature, identifying many imminent failures
- Lost circulation or well control – 1-3% – real-time measurement of downhole pressures would immediately identify a kick or loss zone (the lost-circulation problem is significantly worse in geothermal drilling, but it also gives a measure of productivity)

Combining trouble reduction with improvement in making hole, based on the numbers above, has the potential to lower well costs by 25%. This reduction applies to both oil/gas and geothermal wells, although the DWD cost reduction mechanisms may be different in the two cases.

Surface-controllable downhole tools

While drilling with a given set of downhole tools and without DWD, a driller can control only three parameters: weight-on-bit, rotary speed, and mud pump rate. He then evaluates drilling performance from a combination of indications such as drillstring torque, penetration rate, and even the sounds and vibrations of the rig – measurements made at the surface, often thousands of feet above the bit. Although

conventional MWD systems provide the driller with some downhole data, these usually pertain to static or quasi-static downhole conditions such as hole direction or pressure, and they are transmitted to the surface at very low data rates via mud-pulse telemetry. In contrast, a DWD system would both: 1) provide the driller with a suite of downhole measurements not normally made, at data rates not normally achieved with conventional MWD; and 2) integrate the downhole measurements with surface measurements to give the driller a more complete picture of drill rig status and performance of the downhole drilling assembly.

Example: *Even though nominal weight-on-bit is kept constant, natural resonance in the drillstring can cause such large variations in the actual bit force or individual cutter forces (see Figure 1.4) that the cutter is completely unloaded and thus ineffective. Knowledge of this phenomenon, coupled with new downhole tools, would allow several options: 1) a shock sub with controllable, variable damping could mitigate the force variation; 2) the driller could vary rotary speed or nominal WOB to change the excitation into a more stable state; or, 3) in the ultimate case, a force-generating sub could produce excitation equal and opposite to the drillstring natural frequency and eliminate the force variation completely, much as noise-canceling headphones eliminate loud background noise in high-decibel environments.*

Figure 1.4 – These data were recorded at Sandia's Cutter Wear Test Facility while using PDC cutters to drill through granite. Even for this stiff laboratory system, a ~30 Hz vibration develops which sporadically reduces penetrating force at the cutter (Fp) to zero, even though the WOB measured at the top of the rig appears to remain constant.

1.3 Measurements Made with DWD

The preceding section describes some general applications of DWD and this section lists a number of downhole parameters that would be useful if measured with DWD in real time:

- *Drill Bit Accelerations* – This would detect bit bounce and whirl. A growing body of evidence suggests that bit bounce (where the bit actually bounces off the hole bottom) is very prevalent and very destructive in hard-rock drilling, particularly with PDC bits. Analysis and experiment also indicate, however, that shifting weight-on-bit and/or rotary speed into “pockets” of stability can control or eliminate bit bounce. Varying rock conditions cause the pockets of stability to change, so the key is being able to know when the bit is bouncing and what effect the driller's changes in WOB or RPM are having on the problem.
- *WOB, Torque, and Bending Moment at the Bit* – Downhole values can indicate lithology changes, cutting efficiency, and bit wear, and are the basic measures of bit performance. These are the forces that produce bit accelerations, so monitoring downhole conditions at the surface would be a tremendous advantage to the driller. WOB and torque measured at the top of the drillstring are notoriously inaccurate because of friction between the drillstring and the borehole wall. Because the drill pipe is a long flexible string rather than a rigid object, its motion cannot be completely controlled by boundary conditions at just one end. Better downhole information will stimulate development of advanced active, surface-controllable tools that will create a better drilling environment.
- *Downhole Pressures* – Real-time pressure measurements will improve drilling performance, knowledge of the formation, and safety. Both drill pipe and annulus pressures at the bit would be useful. The differential pressure could be monitored to detect hydraulic problems such as plugged nozzles, drill joint washouts, and mud pump problems. Annulus pressures could be monitored to detect gas or steam kicks or lost circulation. Wellbore fluid levels in geothermal wells with total loss of circulation could be measured while drilling, which can give injectivity or transmissivity of a potential production zone.

Downhole pressure is also critical for under-balanced drilling (static head of drilling fluid is less than formation pore pressure), which has become extremely important in the oil and gas industry, as well as geothermal drilling. The purpose of this technique is to reduce formation damage, but if the downhole pressure is allowed to exceed pore pressure even briefly, benefits of increased production are usually lost and geothermal reservoirs may be damaged.

- *Downhole Temperatures* – Temperature measurements will improve gas- and steam-kick detection, will set criteria for drilling fluids that better withstand geothermal conditions, and will warn when temperature-sensitive downhole tools may be in danger. The temperature also gives better insight to drilling fluid rheology, which is also important for under-balanced drilling.
- *Hole Direction (Azimuth and Inclination) and Tool Face* – These measurements are the ones most commonly made with conventional MWD systems and are essentials for successful directional drilling.

- *Advanced Tool Sensors* – There is great opportunity to gather additional downhole data on tool status, such as drill bit wear, that would be useful for the driller to know in real time. Roller-cone bearing temperatures and PDC cutter temperatures could be monitored as a way to detect bit overload and incipient bit failure.
- *Advanced Formation Sensors* – Many of the measurements now made in separate logging operations could be done while drilling, which would not only save time and money but would be useful to know in real time when a specific target formation is sought. It is also possible that a “look-ahead” capability of sensing pressure ahead of the bit might be added, greatly improving safety and well control.
- *Toxic Gas Detection* – One of the most common gases encountered in both geothermal and oil and gas drilling is hydrogen sulfide (H_2S), which is lethal at concentrations above 300 ppm. Detection of H_2S influx to the wellbore would be a significant advance in rig safety.
- *Seismic Measurements* – Efforts to use the bit as a seismic source in Seismics-While-Drilling have been hindered by lack of characterization for the bit’s excitation. DWD would provide an excellent picture of this forcing function.

1.4 Improved Analysis with DWD

Drilling analysis has suffered for many years from a paucity of data to use in validating or calibrating models. This shortage was caused primarily by lack of sensors to measure data (especially downhole), absence of a data link to transmit information to a recording device, and the primitive nature of analog recording (strip charts, tape, and hand-written readings) that made it inconvenient to transmit, manipulate, and share data among researchers. Better downhole data, integrated with a suite of surface data broader than that normally collected, will have significant advantages in modeling, planning, and managing drilling projects. These applications include:

- Researchers will gain unique data to use in modeling drilling phenomena. This understanding is a first and necessary step in development of “smart” drilling systems.
- More complete and accurate representations of field projects will improve drilling simulators, leading to better training of new drilling crews, particularly for sophisticated directional work (Dubinsky and Baecker).
- Analysis of results for optimization by the Learn Curve Management (LCM) method is a very powerful tool to evaluate drilling methods (Millheim, et.al.) A case study cited in the reference shows that persistent problems in extended-reach wells were identified by this method, with a potential saving of eight days, or 10%, per well (quite significant at offshore day rates of \$200k or more.) Attempts to use this technique, however, are often hampered by lack or inconsistency of data. DWD will not only alleviate this problem but will offer finer resolution of variables to be considered.

- Choosing optimum components for the drilling system is a critical part of planning a drilling operation (Hill and Lee). A great deal of software is available to assist in these choices, but it is often specialized (considers only one aspect of the job, e.g., hydraulics, casing design) or does not account for circular references (e.g., choice of drill pipe for tensile load requirements is affected by the pipe's own weight.) The ability to integrate and iterate these choices would be valuable and drilling advisory software designed for DWD will be inherently useful in this direction. This kind of optimization supports the LCM described above, where much of the experience in drilling several wells in the same area or conditions is sometimes based on a trial-and-error approach.

1.5 Applicability of DWD

DWD will have its greatest benefits where drilling is expensive, which typically means hard-rock and/or directional drilling. In hard rock, drillstring forces and shock are at their greatest, resulting in drillstring vibration and bit bounce. Under these conditions, bits can fail quickly and ROP is often low, so knowing when and how to adjust drilling parameters to keep the bit running smoothly on bottom would be very valuable.

Downhole data could be even more important in generating a database of tool failures that would enable prediction of when a tool should be pulled or could define the operating conditions that give best tool life. In addition to bits, this data would include directional drilling tools, shock subs, and other selected part of the bottom-hole assembly.

Directional drilling has significant applications in geothermal reservoirs because it gives the ability to intersect the maximum number of fractures through which these reservoirs normally produce and because it allows drilling many wells from the same pad, which is often a major expense in typically rugged or mountainous terrain. It is also very widely used in oil and gas reservoirs, especially offshore, because of the frequently laminar nature of the pay zone.

Example: A major oil company has published cost information for one year of their drilling operations – directional wells accounted for 12% of their wells but 36% of their drilling cost. Because this is the environment where DWD would be most useful, clearly the cost benefits would be substantial.

Because of the hole deviation, however, much of the drillstring lies along the wellbore wall and this friction obscures conditions at the bottom of the hole (WOB, bent-sub orientation) when only surface readings are available. This problem is most severe in horizontal drilling and calls for a thruster/director (a tool that clamps to the borehole wall and applies a known force to the bit) in the BHA. Efforts to develop this technology have been mostly unsuccessful, but real-time

knowledge and control at the tool would be a great advantage in making such a device viable.

A special case of directional drilling is multi-lateral completions, where one surface or intermediate casing is run to the wellhead and several holes into the production zone are extended from its bottom. This avoids the need to have a completion with the largest, most expensive casing and cement on each producing leg of the well. In this situation, however, re-entering a specific leg for drilling, completion, or workover activities is often difficult because uncertainty about tool position and orientation. Real-time knowledge and control of downhole operations would greatly simplify these jobs. Multi-lateral completions are becoming increasingly common in oil and gas drilling, and would be appropriate for geothermal wells, especially in rugged areas where site preparation is unusually expensive.

Hard rock and directional drilling occur in geothermal, oil and gas, minerals, and environmental drilling scenarios. The potential cost savings that could accrue from DWD in each of these applications should be enough to secure cooperative research and development commitments from these industries, some of which have already expressed significant interest in the development of DWD-related technology.

Finally, DWD will contribute to simulation and prediction of optimum performance in drilling a given well or set of wells. This is based on existence of such simulators as PayZone, which models drilling situations and analyzes the effect of changing weight-on-bit, fluid flow rate, bit type, lithology, etc. One example (Cooper) of using a simulator showed that rate of penetration in the drilling model was relatively insensitive to rotary speed and weight-on-bit, but that doubling mud flow rate doubled ROP. Coupling downhole information with this kind of simulation will make it more accurate and allow it to include many more variables in the model.

2.0 SYSTEM DESCRIPTION

2.1 Closing the Feedback Loop

The concept behind Diagnostics-While-Drilling (DWD) is a closed-loop system that provides the driller with enhanced feedback on the drilling process. This permits the driller to "tune" the drilling process to maximize performance. A schematic of the concept is shown in Figure 2.1.

Figure 2.1 - Schematic representation of the Diagnostics-While-Drilling system

2.2 System Components

The DWD system consists of the following components:

1. DWD Tool;
2. High-Speed Data Link;
3. Drilling Advisory Software;
4. Driller;
5. Drill Rig/Drill Pipe; and
6. Surface-Controllable Downhole Tools.

(1) The *Diagnostics-While-Drilling (DWD) Tool* acquires data from downhole sensors; conditions it for transmission, and delivers it to the high-speed data link. Sensors mounted on the tool and at other locations on the bottomhole assembly are tied to a data acquisition board and multiplexer in this tool. The amount of signal filtering and processing that is necessary will depend on the speed of the data link

available. The higher the data rate, the less downhole processing is necessary, as more raw data can be sent uphole.

In general, less downhole processing is desirable because of the high cost of hardening downhole electronics for the high-temperature, high-pressure, high-shock geothermal drilling environment. An existing MWD tool without the mud-pulse telemetry component would be a good starting point for designing a DWD tool.

(2) The *High-Speed Data Link* carries downhole information to the surface and carries surface control signals back downhole. To be useful to the driller for real-time analysis and control of drilling performance, the data rate must be high enough to update dynamic information fast enough to give the driller a feeling of response.

(3) The *Drilling Advisory Software* acquires, analyzes, and displays downhole and surface data in real time to provide the driller with a complete and accurate status of drilling conditions and system performance. The software must condense the tremendous amount of data being acquired into simplified, displayed information that the driller can understand and use in real time.

This software can also take data from the interval already drilled or from offset wells, combine it with updated geologic information, and run a continuous background simulation to predict what the current performance should be. If actual performance is substandard, then providing expert advice to the driller will be an important role of the software.

(4) The *Driller* is a very important component of the DWD system. Good drillers have always used the limited information available to manage the drilling process, but DWD would provide a much clearer picture of downhole conditions, allowing the driller to optimize performance.

(5) The *Drill Rig/Drill Pipe* is the primary component through which the driller controls the drilling process. Weight-on-bit (WOB), rotary speed (RPM), and drilling fluid inflow rate are the three drilling parameters that the driller can control at the surface. The drilling process is very sensitive to these parameters; DWD will enable the driller to set them at optimal levels.

(6) *Surface-Controllable Downhole Tools*, such as a variable-damping shock sub to control bit bounce and a bent sub to control borehole direction, will enable the driller to control the drilling process if he is provided with downhole feedback.

Each of these components provides an essential link in the information and control feedback loop created by the DWD system. Absence of any component will prevent enhanced feedback between the downhole tools and the surface.

2.3 Surface measurements

In addition to downhole parameters, the DWD system would use a multitude of surface measurements:

- *Drilling Fluid Inflow and Outflow Rates* – Monitor hydraulic performance and detect lost circulation and gas or steam kicks.
- *WOB and Drilling Torque* – Compare with downhole measurements and use to monitor drillstring drag and wear.
- *Kelly Accelerations* – Detect dynamic behavior at top of the drillstring, controlling the top boundary condition for drillstring analysis.
- *Rotary Speed* – Control many aspects of the drilling process.
- *Kelly Height and Velocity* – Record drillstring position and calculate depth and rate of penetration (ROP).

- *Standpipe Pressure* – Monitor hydraulic drilling performance (pumps, bits, downhole tools) and detect washouts or lost circulation and gas or steam kicks.
- *Inflow and Outflow Mud Temperatures* – Quantify temperature cycling of the drilling fluid, assure use of proper fluid additives, comply with regulatory requirements, and detect heat build-up caused by formation changes, hydraulic work in downhole motors, or other effects.
- *Mud Pit Levels* – Confirm lost circulation and gas or steam kicks.
- *Mud Density and Viscosity* – Monitor drilling fluid quality and correlate with downhole pressure measurements.

With this information provided in real time, the driller would have much better control of the drilling process. At a minimum, he could optimize surface parameters such as weight-on-bit, rotary speed, and inflow rate, but software that constantly analyzes the data, looking for trends, discrepancies, and possible problems, would also give the driller a "heads-up" predictive capability that would allow him to avoid costly mistakes and minimize drilling costs.

2.4 Functional requirements

Specifications for a DWD system are driven by four requirements:

1. Identify the information useful to the driller.
2. Collect downhole data with appropriate sensors.
3. Use telemetry to bring downhole data to the surface and return control signals downhole.
4. Process surface and downhole measurements to provide real-time information to the driller.

Each of these requirements is discussed below; the second and third are so intimately related that they will be considered together.

2.4.1 Identify Information Useful to the Driller

Of the critical elements shown in Figure 2.1 (DWD Tool, High-Speed Data Link, Drilling Advisory Software, and Driller), the element for which prototypes do not exist today is the DWD software that connects to the driller's console. A raw-data stream at 15 kbits/sec or more will bury the driller in numbers and is of no value to him. It must be processed by a data management system into a format that can be absorbed and used.

There are differing philosophies on how to present data to the driller and displays that are radically different from today's may be necessary. If we consider the myriad ways that information technology has affected daily life (e-mail, on-line commerce, electronic data storage) it is not unreasonable that a method of providing information and guidance to the driller will be completely unlike existing interfaces. An important task in this project is to work with a broad spectrum of

drillers, especially younger ones who are more familiar and comfortable with computers, to determine the best way of processing and presenting the data.

The focus of the proposed work is to develop and demonstrate the benefits of a DWD system supported by a high-speed telemetry link. A critical test of the system will be whether the driller can close the loop and drill better using it. While the software is not the primary technical challenge, it is potentially the Achilles' heel if the driller doesn't like the system or is unable to close the loop.

The software that connects to the driller's console must be reasonable in the context of distributed processing. Goals of the system are to:

- accept the data from the high-speed telemetry link,
- synthesize the data into that which should be displayed and/or stored,
- send data to the real-time database,
- process the data to supply reservoir characteristics and diagnostics of drilling dysfunctions, and
- display the appropriate information.

General requirements of the system are that it be:

- capable of real-time data management (i.e., able to process high data rates),
- adaptable to changes in DWD tool and rig network,
- physically and functionally extensible,
- flexible to changes in philosophy, and
- Internet/Intranet accessible.

One concept of the driller's display is a series of stop lights. For a particular diagnostic (e.g., bit whirl), a green light indicates no problem, yellow light alerts that a problem may be imminent, and red light indicates the problem is severe (e.g. bit whirl is damaging the bit or BHA). Clearly, this is the opposite of raw data and requires complete processing and interpretation of the data by the software. This approach does not, after the design phase, give the driller the chance to provide input into the interpretation process. It is similar to the mud-pulse systems now available and may ultimately not be adequate, but should be considered as a candidate for the proof-of-concept tests.

Drillers rely a great deal on the feel-of-the-system, and stoplights don't give much feel. Much of the dynamic data is analogous to the sound and vibrations that the driller is used to sensing, which suggests that the display might have tactile feedback based on information captured through spectra and amplitude plots. Whether either of these two different approaches or something completely different is best will be determined in Phases 2 and 3 of the proposed program. The underlying structure of the data processing needs to be flexible enough to support a variety of display types from stoplights to plots of the data.

Another part of the software development, probably in the later stages, will be incorporation of a drilling simulator related to existing ones (e.g., PayZone) that will assess the drilling system's current performance. Based on data from the hole interval already drilled, or from offset wells, or from estimates by the drilling engineer, the program will run a continuous simulation in the background to predict what the drilling performance (rate of penetration, bit life, hole direction) should be and will compare that to actual values. If performance is below expectations, the drilling process can be examined for possible changes or the modeling assumptions can be reconsidered.

In addition to being used by the driller for real-time control, data from the DWD system will be used by engineers in post-drilling analysis to aid planning of new drilling programs and equipment. This means that the software must be able to replay data and provide plots and correlations of the fundamental data – amplitude and spectra.

2.4.2 Data Processing and Transmission

There are at least two distinctly different approaches to sending the data collected by downhole sensors back to the surface for DWD:

- process the data downhole to evaluate the severity of drilling dysfunction, and send status flags up the data link at a low bit rate, or
- send all the raw data up the link and process it at the surface.

As an example of the first approach, we could establish a dysfunction severity scale of zero to seven, with bit bounce as 3 (moderate), stick-slip as 7 (severe), and bending as zero (mild), and simply transmit those values over the data link. This approach has been used very effectively to fit DWD data into the available bandwidth of mud-pulse telemetry (Heisig, et al). A downhole processor takes a five-second snapshot of the data and algorithms search for patterns in it to assess the severity of dysfunction. The three-bit severity flags can be sent at a low data

Dynamics	WOB	Axial acceleration
"	Torque	Tangential acceleration
"	Bending load	Radial acceleration
Environment	Pressure in drill pipe	
"	Pressure in annulus	
"	Temperature	
Steering	Magnetic field	
Other		

Table 2.1: Minimum measurements to be made by the downhole sub. Shaded data are those that should be sampled at high frequency (1000+ Hz); unshaded measurements can be made less often.

rate, but conventional status information (WOB, torque, rpm, etc.) must also be sent to the driller. The total data-rate required is 21 bits/second, which is higher

Bits per sec	Information transmitted	Refresh time on driller's console	Benefits	Telemetry Technology
4	2 most significant dysfunctions & corresponding average values	8.0 sec.	Basic MWD. After-the-fact information on two drilling problems. Identification of drilling breaks.	Existing Mud pulse (current tech.)
20	All 8 dysfunctions & all 10 average parameters measured at 0.1% accuracy	6.2 sec.	Information on 8 drilling problems and 6 second averages of ten measured parameters. Enables cursory control.	Developmental Acoustic/ Acoustic with repeaters
100	All 8 dysfunctions & all 10 average parameters at 0.1% accuracy & RMS for each parameter at 0.5%	2.0 sec.	Elementary DWD: for real-time feedback control and optimized drilling.	
500	All 8 dysfunctions & all 10 average parameters at 0.1% accuracy & 2 statistics (RMS etc.) for each parameter at 0.1%	0.6 sec.		Existing Wet-connect
15k	Preprocessed (FFT compressed) 1 sec. block raw data at 0.02% accuracy	1.0 sec	Full & accurate DWD allowing post analysis & development of new tools and drilling practices.	Developmental wire/fiber in drill pipe, advanced acoustics
100k	Raw data at 0.001% accuracy	≤0.05 sec		Advanced DWD

Table 2.2: The potential for DWD as a function of telemetry bit rate.

than mud-pulse telemetry can transmit without further compression.

Even if data are refreshed every five seconds, this does not give the driller a prompt report of downhole conditions. Transitions into destructive behavior happen so quickly that significant damage can occur before this data rate would warn of the change. Figure 2.2 shows torque vibrations that build up at the bit when drilling into hard rock. If the driller does not take immediate action, these vibrations will break the cutters of PDC bits and penetration will stop, requiring a trip to change bits. For the driller to be alerted in time to take corrective action, the driller's console should be refreshed at least once a second. What does this mean, then, in terms of the data rate required from downhole?

Table 2.1 reflects a typical suite of downhole measurements that indicate: dynamic state of the bit, general information about the bottomhole environment, and navigation data required from a basic MWD steering tool. The measurements that define the dynamic (i.e., force and acceleration) state of the bit (shaded) are typically high-frequency data and must be sampled at a much higher rate than those that otherwise describe the bottomhole environment (unshaded).

Figure 2.2 - Transition behavior when drilling into hard rock (from SPE 49204, Warren and Oster).

Dynamic data may contain fundamental and important harmonic frequencies up to 300-400 Hz (Leseultre et al., Heisig, et al.), and should therefore be sampled at a frequency of at least 1000 Hz. The environmental and navigation data can be sampled less often, but the sampling rate should be consistent with refreshing the driller's console at least once per second. Eventually, higher sampling rates for the environmental parameters may be useful (e.g., high-frequency pressure data may aid analysis of mud motors), but early efforts will be governed by the driller's response time to the display.

The data rate required to transmit raw data is totally dominated by the shaded portion of Table 2.1. If the six parameters are sampled at a 1 kHz rate, which is required for anti-aliasing, and digitized using 16 bits, a data rate of ~100k bits/sec is required (see Figure 2.3). Using Fast Fourier Transforms (FFT), this signal could be compressed by a factor of about 5 and, although the sensors should be sampled at 16 bits, 12 bits transmitted to the surface could be sufficient. Preprocessed raw data could reduce the transmission rate required to ~15k bits/sec, which is readily achievable with commercial logging cable for proof-of-concept tests. Ultimately, rates in excess of 15k bits/sec will be required to fully support DWD. Trade-offs between data rate and display are shown in Table 2.2, which assumes that eight major drilling dysfunctions can be identified and ten downhole parameters are sampled. The table shows clearly that mud-pulse telemetry at ~4 bits/sec cannot support DWD. Acoustics telemetry has the potential to transmit elementary drilling diagnostic information for cursory control, but full DWD will require a higher-speed link to realize its potential.

2.4.3 Downhole Sensor Tool

DWD measurements fall into four groups, as shown in Table 2.1:

- 1) Measurements needed to characterize the dynamic state of the drill bit and BHA (forces and accelerations) – Three pairs of parameters are needed to fully characterize the dynamic state of the whole bit. The pairs correspond to the three degrees of freedom in motion of the bit and the corresponding forces associated with each of those

motions. Since they are a complete set, they can be used to derive additional information (rotary speed and ROP at the bit) and can be analyzed to determine drilling dysfunction (bit whirl, etc.)

- 2) Measurements to characterize the environment (pressure and temperature) – Pressures within the drill pipe and annulus, coupled with surface measurement of flow rate, allows determination of the hydraulic horsepower available to clean the bit and is also critical in under-balanced drilling. Annulus pressure is useful to determine the potential to fracture the formation or the potential to take a kick, and can aid in analysis of lost circulation. Mud properties are a function of temperature, so temperature is a supplemental measurement needed to analyze and understand dynamic pressure. Temperature is also useful in determining the potential for heat damage to the electronics, bit, and BHA, and is essential for proper compensation of other sensors (e.g., strain gages).

- 3) Measurements to determine orientation – Magnetic field, when combined with gravitational orientation (DC limit of dynamic acceleration measurements), determines the inclination and azimuth of the BHA required for steering.
- 4) Other measurements – The prototype system will address only the minimum requirements for DWD, but many other useful measurements (bit wear, bearing temperature, formation values, etc.) could be made if the telemetry system has extra capacity. It is also very likely that priority of different measurements will change as DWD field experience increases, and new analysis techniques evolve.

Commercial tools that can make the basic measurements are already available (e.g., Heisig, et al.) Although these tools were designed to work with mud-pulse telemetry and store data in memory, they have, for special tests, been interfaced to hardwired telemetry (Baker-Hughes and Radius, Inc., private communication). Using an existing industry sub has the advantages of leveraging DOE's investment, providing a means to benefit directly from industry experience, and is a natural avenue for transferring the benefits derived from this program to U.S. industry.

The requirements of the downhole sub are dependent upon the telemetry system used. For example, if a hardwired telemetry system is used, power can be supplied from the surface, eliminating the need for batteries downhole. The high-temperature geothermal drilling environment dictates that costly, temperature-sensitive components be minimized or eliminated downhole. This important consideration favors the transfer of raw data to the surface for processing over sophisticated downhole processing. Mud-pulse telemetry has driven oil and gas drilling to the latter approach, pushing the processing downhole. Thus, while it is only prudent to begin proof-of-concept work using industry-available downhole subs, initial testing cannot be done in geothermal reservoirs. It must be done either in the upper, cooler part of a geothermal well or at an oil and gas test site. It also means that the technology used in proof-of-concept DWD tests must be adapted to geothermal conditions, a task for which Sandia is well prepared.

2.5 How DWD is Different from MWD

The DWD system as proposed is different from other proposed advanced drilling systems in several respects.

- DWD would function at a higher data rate than MWD. It would also measure additional downhole parameters, particularly drill bit accelerations, for the express purpose of making the drilling process more efficient. Higher data rates than conventional MWD are necessary to provide the driller with the feeling of response he needs to maximize drilling performance.
- DWD is different from existing advanced MWD systems in that DWD would make extensive use of drilling advisory software to analyze and display both downhole and surface measurements in a form that the driller can use to interact with the drilling system.

- DWD is different from "smart" drilling systems and other proposed automated systems in that DWD embraces the driller as an important link in the drilling feedback loop. This does not, however, preclude using automated, expert-system responses to emergency situations in which human reaction time might be too slow.
- DWD has a capability, unlike MWD, of sending information from the surface to the BHA for sophisticated downhole control. This link between cause and effect will be the primary focus of the proposed DWD development program.

3.0 TECHNICAL CHALLENGES

Three major technical challenges have prevented the evolution of DWD systems to date. Both the high-speed data link and the drilling advisory software require technologies that have only recently become available or still await development.

3.1 High-Speed Data Link – The largest technical challenge in the DWD system is the high-speed data link. As described in Section 2.4.2, the data link must have a minimum data rate of 100 kbits/sec to minimize downhole processing and get data uphole with requisite accuracy, but lower rates are acceptable for moderate data compression in proof-of-concept tests. For even the basic requirements, new high-speed telemetry systems ($\sim >100$ bits/sec for processed data and $>15k$ bits/sec for raw data) will be needed to make DWD a reality. The rate of 100 kbits/sec is four orders of magnitude above mud-pulse telemetry used in conventional MWD systems. Acoustic telemetry has the potential for achieving the required data rate with repeaters placed in the drillstring, but the necessary hardware has not yet been developed. Hard-wire methods offer potential, but a cost-effective way of deploying hard wires in routine drilling operations does not yet exist. Despite the lack of progress to date, however, several interesting concepts for achieving a high-speed data link have been proposed.

3.2 Drilling Advisory Software – Developing useful drilling advisory software will also require considerable innovation. The software must acquire, reduce, analyze, interpret, and display data as well as provide expert advice to the driller. The software must use engineering equations and models to examine all incoming data to confirm its integrity, identify trends in the data, determine relationships among the various parameters being measured, and identify any anomalies in those relationships. Computer technology has only recently reached the point where this kind of software could be deployed and run on a routine basis in a drilling environment.

3.3 Surface-Controllable Downhole Tools – New types of surface-controllable downhole tools must be developed to take full advantage of the DWD system. With a high-speed data link to transmit control signals downhole and transmit sensor data back uphole, a wide range of downhole tools that have not yet been feasible will become practical. In some cases, field experience with rudimentary DWD systems will be necessary to define downhole mechanics well enough to design the downhole tools.

3.4 Previous Work

Previous work on telemetry systems produced sophisticated hardware that has not been widely used by industry. This happens when a research project does not demonstrate the real benefit, in dollars and other tangible gains, of using new technology. Consequently, the focus of the proposed program will be to develop and

demonstrate the benefit of DWD systems before moving to an extensive hardware and software development program.

In the 70's, Shell (Denison), Exxon (Robinson et al.), and others built and tested hardwired systems that incorporated conductors into the drill pipe or automated the spooling of wire within the pipe. Arps (1979) has reviewed these systems comparing them to other MWD telemetry systems. The Shell and Exxon systems were technical successes in that they were able to transmit high-rate data. Although they were not successful commercially, they did provide some of the first hard evidence of bit and bottom-hole-assembly (BHA) dynamics proving that downhole behavior is complex. These systems were commercially unsuccessful for a number of reasons. They were cumbersome, increasing costs and trip time. Sensors, computer systems, and knowledge of data processing in real time were not available to fully take advantage of the high-speed telemetry. The information was displayed as acceleration amplitude or spectra rather than degree of dysfunction, e.g., bit whirl. As a result, the information collected was valuable to the research drilling engineer, but not to the driller. Ultimately, the impetus to develop high-speed data telemetry disappeared as mud-pulse telemetry became capable of transmitting steering information to the driller (at that time, steering information was the primary interest of the drilling community).

As the ability to interpret dynamic data and the significance of dysfunction have increased and as new downhole sensors have become available, mud-pulse telemetry has become inadequate. Consequently, development of hardwired systems has continued for market niches, mainly ocean exploration, environmental drilling, and mineral exploration. The development of hardwired systems has also continued as a research tool in oil and gas drilling (Guesnon and Pignard). Nevertheless, these services have not been able to break into the mainstream of MWD due, in part, to the need for better systems to transform dynamic drilling raw data into information useful to the driller. Recently, interest in hardwire systems has renewed as evidenced by a proposal to the Drilling Engineering Association (XL Technology Limited). The proposal seeks support for a comparison of various inside-the-pipe hardwire systems including a cartridge system similar to that patented by Sandia (Norman et al.). The proposal states that new material, especially advanced cables, makes it appropriate to reevaluate the practicality of hard-wire systems.

Besides the benefits of DWD, the geothermal industry needs alternatives to mud-pulse telemetry for air drilling operations which it uses to avoid damage to the geothermal production zone. In these conditions, electromagnetic wave systems (Soulier and Lemaitre) and "wet connector" system (PEI) have been used. Wet connector systems have been proven by the test of time in their segment of the market.

The wet-connect system is of particular relevance to this plan. Off-the-shelf wet-connect system electronics are capable of 300 - 1,200 bits/sec, but could be

upgraded. Thus, a wet connect system has the potential to transmit data at rates required for limited DWD, and could be used for proof-of-concept work to illustrate the benefits of DWD.

In addition to work on high-speed telemetry, there has been significant work toward developing downhole subs that make drilling dynamics measurements (Leseultre et al., Heisig et al., Guesnon and Pignard). Thus, in the initial demonstration phases of DWD, it will be possible to use commercial subs. In general these subs were designed to save data in memory or compress it for use with mud-pulse telemetry, but for the proof-of-concept tests they will be hard-wired to the surface.

3.5 Ongoing Work at Sandia

Sponsored by the DOE/OGT and other DOE programs, Sandia is working on a number of technologies that relate to the DWD program. These include acoustic telemetry, fiber-optic telemetry, environmental drilling MWD, a drilling expert system, PDC bits, high-temperature electronics, and robotics.

3.5.1 Acoustic Telemetry: In contrast to mud-pulse telemetry that transmits data as a sequence of pressure pulses in the mud, acoustic telemetry uses the steel (drill pipe, tubing, or sucker rods) as a wave-guide to transmit stress waves. Field tests have demonstrated that attenuation within drill pipe is low enough to transmit data from the bottom of a well to the surface (Drumheller 1993a & 1993b). Acoustic telemetry can operate when there is no mud in the hole and while making a connection and tripping. It can transmit data at rates higher than mud-pulse telemetry. With repeaters, acoustic telemetry can transmit at rates sufficient for elementary DWD: refreshing downhole status on the driller's console once per second (see section 2.4.2). Elementary DWD requires that dynamic data be processed downhole into dysfunction (e.g., severity of bit bounce) indicators that give a simple rating of dysfunction severity.

Sandia has built and licensed a working acoustic telemetry system for production tubing in oil and gas wells (Drumheller and Knudsen). Current work focuses on practical downhole transmitters for MWD systems. These transmitters are piezoelectric devices that directly convert electrical energy into stress waves, eliminating the need for moving parts. The efficiency of these transmitters is high, minimizing downhole power requirements. Furthermore, acoustic telemetry can readily be used to send messages from the surface downhole allowing the driller control over downhole tools and systems.

A natural improvement to the wet connector system described in Section 3.4 would be a hybrid system that uses acoustic telemetry to replace the top cable (see Figure 3.1). The acoustic transmitter would communicate directly with the surface, eliminating the need for spooling the top cable out-and-in while pipe joints are added. Just as successful demonstration of DWD using a wet connector system

could enable the development of a hybrid cable/acoustic system, successful demonstration of DWD using a hybrid cable/acoustic system could enable the development of a acoustic repeater system eliminating the need for the lower cable.

3.5.2 Circulation Monitoring: To assist in interpreting lost circulation events, a Circulation Monitoring expert System (CMS) is being developed by Tracor under contract to Sandia. CMS is an advanced software system that uses measurements from Sandia's rolling float outflow meter and other mud logging data, including pump stroke counter, to distinguish between lost circulation, kicks, errors in measurements, pump efficiency problems, etc (Harmse et al.). Experience gained in this work will provide insight for designing systems to manage and process data in real-time and display the data in a manner useful to the driller.

3.5.3 Polycrystalline Diamond Compact Bits: Sandia played a major role in the development of polycrystalline diamond compact bits that greatly improved penetration rates and bit life in soft formations, resulting in a significant reduction in drilling costs. Current work is addressing advanced synthetic diamond products for hard-rock drilling for geothermal applications. This is being done through tests at Sandia's cutter wear test facility. Experience gained in monitoring bit performance at this facility will prove invaluable for determining how to process and analyze bit dynamics. Further, Sandia is embarking on a program to compare the performance of PDC bits built by commercial suppliers to determine their potential for drilling geothermal reservoirs. These tests will provide an excellent opportunity for proof-of-concept DWD tests.

3.5.4 High-temperature downhole instruments: Sandia technology has also been built, fielded, and transferred to industry for a number of high-temperature downhole instruments: Precision Temperature/Pressure Measurement Tool, Spectral Gamma Ray Tool, Acoustic Borehole Televiwer, and Steam Sampler Tool. Current work includes testing silicon-on-insulator electronics to 300°C. This experience will be valuable in adapting existing downhole drilling-dynamics subs built for oil and gas applications to high-temperature geothermal and deep gas conditions. These subs will gain much more widespread application once DWD becomes mature enough to (1) take advantage of the information they offer and (2) provide the basis for building controllable downhole drilling equipment.

3.5.5 Fiber-optic MWD: Sandia has tested optical fiber in flowing mud inside drill pipe, showing that fiber can withstand the drilling environment while transmitting data (Holcomb et al.). With sponsorship by the Gas Research Institute, Sandia is currently working on methods to deploy optical fiber for MWD applications. While this work on optical fiber may not be completed in time to be useful for the proof-of-concept demonstration, DWD may create the market pull to justify full development of optical fiber telemetry.

3.5.6 Environmental drilling MWD: Sandia has developed, tested, and is licensing an MWD technology for environmental drilling (Normann et al.). This

system uses a spool of communication cable in the drill pipe; the cable is pulled from the spool as drilling advances. At the surface, the cable is inductively coupled to a pickup coil. This system has been tested in a number of horizontal boreholes to distances of 250 feet (with plans to extend that to 5,000 ft) transmitting data at rates of 2,400 bit/sec. Currently, this system is configured to measure spectral gamma radiation, 3-axis acceleration, inclination, azimuth, and temperature. Consideration is being given to adding DWD measurements. Lessons learned from the environmental MWD program, in particular, how to process and display high-speed information useful to the driller, will be of direct benefit to the DWD program being proposed here.

3.5.7 Robotics: Sandia is a world leader in robotics, with a new ISRC (Intelligent Systems and Robotics Center) and breakthrough developments in micro-machines. As the state of the art in DWD feedback control advances, there is ample opportunity to involve this capability both in downhole and surface equipment.

3.6 Well Construction Technology Center

A recently-signed Memorandum of Understanding between Sandia and the University of Oklahoma (OU) established the Well Construction Technology Center (WCTC), which will be a "virtual laboratory" using people and facilities from both founders to collaborate on science and technology projects related to well construction production. In addition to existing facilities at Sandia and OU, the WCTC will acquire a world-class testing laboratory and core-characterization facility from a leading oil company. Although this partnership is newly formed, it will serve as a model and stimulus for further cooperation between Sandia, universities, and industry.

(a) Single wire System

(b) Wet Connect System

(c) Hybrid Acoustic-Wire System

(d) Acoustic Repeater System

Figure 3 - Possible evolution of telemetry systems: Single wire (a) to wet-connect (b) to hybrid acoustic (c) to acoustic repeater systems (d).

4.0 PROGRAM PLAN

The program to develop an advanced DWD system will have four phases, shown in Figure 4.1:

- Phase 1 – Plan program and develop consortium.
- Phase 2 – Assemble prototype DWD system and demonstrate its benefits through field tests.
- Phase 3 – Development of basic systems needed for cost-effective DWD in the geothermal and oil and gas industries.
- Phase 4 – Continue research, development, and field-testing on enhanced tools for DWD applications.

We will depend on industry to contribute to the cost of Phases 2-4 by providing cash, in-kind contributions of measurement-while-drilling tools, and field testing opportunities and facilities.

Year	99	00	01	02	03	04
\$ DOE/OGT	300k	2M	8M	8M	10M	12M
\$ Ind., OFA	0k	500k	2M	4M	6M	8M

Figure 4.1 - Phasing, cost and milestones for the proposed Program. Total cost is estimated at \$60.8M over 6 years, split 2/3:1/3 between DOE/OGT and other sources, respectively. Major milestones: ① DWD is proven; ② DWD is commercially available; ③ Enhanced DWD is commercially available.

4.1 Program Structure

The program will have a layered structure as shown in Figure 4.2. The **Core Program**, essentially Phases 2 and 3, consists of:

- (1) the proof-of-concept test,
- (2) development of economical, practical high-speed data links,
- (3) development of software and user interface systems for allowing the driller to make use of the high-speed data for optimizing the drilling process, and
- (4) development of the essential MWD tools (vibration, orientation, WOB, torque) needed for the basic DWD system.

These four elements are essential for DWD and must be developed in parallel. They map directly into the physical components of the DWD system presented in Figure 2.1. Over five years, the Core Program will cost a total of approximately \$26.8M, distributed as shown.

It will culminate with the commercial availability of

FY99	FY00	FY01	FY02	FY03
\$0.3M	\$2.5M	\$10M	\$8M	\$6M

profitable DWD technology - a development that is expected to revolutionize the drilling industry and enable development of, and market-pull for, the advanced system described below. A critical milestone on the path to commercial DWD will be validation of DWD's value for improving the drilling process. We believe that this step, which is relatively risky and hence largely federally funded, will be the

catalyst needed to stimulate major industry interest and commitment to the program.

The **Enhanced Program** will ramp up as the Core Program is winding down. During the Enhanced Program, Sandia will develop tools and systems that expand the capabilities shown in the Core Program. This is Phase 4, which will aim for true optimization of DWD and the drilling process. Naturally, full definition of the Enhanced Program will depend heavily on outcomes of the Core Program, but candidate tools would include both devices that provide information about downhole processes, such as:

- logging-while-drilling formation characterization (e.g., seismic, pore pressure, permeability),
- bit condition (e.g., bearing temperature, wear), and
- advanced navigation data functions,

and advanced downhole controllable tools, such as:

- controllable shock subs to reduce vibration for different lithologies,
- surface-directed steering systems, and
- advanced rock cutting systems (e.g., thermal spallation, rock melting, high-pressure erosion).

Ultimately, knowledge gained through developing DWD and its enhancements, and then putting it to use will stimulate development of "*Smart*" drilling systems – autonomous drills with built-in analytical capability that will essentially guide themselves to a predetermined target. We expect to achieve commercial viability of

enhanced DWD technology by the end of FY04. By then, new concepts and "smart" drilling systems will be under development. Over three and one half years, the Enhanced Program will cost a total of approximately \$34M (FY02-\$4M, FY03-\$10M, FY04-\$20M). It will culminate with the commercial availability of enhanced DWD technology.

Finally, Figure 4.2 illustrates how the need for high-temperature (geothermal, deep gas) capability and concepts identified at advanced drilling workshops (Section 5) will crosscut the DWD program. After the proof-of-concept test, DWD hardware must be applicable to geothermal drilling, so all downhole tools and components must be hardened against this harsh environment. Ensuring high-temperature capability will be an important element of the program and will build on Sandia's long-term commitment to high-temperature logging tools. Results from the workshops summarized in Section 5 and in Appendices A.2 and A.3 will also be considered throughout the program. This consensus spans the spectrum of well-construction activities and is included in the plan to remind all researchers that a breadth of opportunities for improvement is available in this program.

4.2 Phase 1: Program Planning

The prerequisite planning for this program is already funded, and is summarized here only for completeness. The planning activity is expected to conclude at the end of FY99, when the DWD Program begins. The principal activities of the planning phase are (1) to develop this plan, (2) to gain support for and comments on the plan from industry and other federal agencies, and (3) to begin a conceptual design of the prototype DWD system for the proof-of-concept test.

A briefing package describing the plan will be developed and then brought to stakeholders' institutions for presentation, review and comment. Our intent will be to get commitments from interested parties regarding their level of interest, their willingness to commit in-kind and/or cash resources, and their willingness to guide the program. Also, and very importantly, we plan to develop a proposal for the Drilling Engineering Association (DEA) to gain support for the proof-of-concept test, Phase 2.

The DEA is an association of drilling service companies, hydrocarbon and geothermal production companies, and other entities (e.g., FETC, GRI) that fosters and tracks cooperative R&D projects. In general, R&D organizations make proposals to the DEA members who then have the option to contribute to the project. Contributors, in turn, gain the rights to all of the products from the R&D activity. We will describe the program to the DEA and attempt to gain their cash and/or in-kind support for the proof-of-concept test. Rig-time, MWD tools, and test facilities are examples of in-kind support that will be solicited and would be extremely valuable.

Phase 1 will cost \$150k.

4.3 Phase 2: Proof-of-Concept Testing

Proof-of-concept tests will demonstrate the usefulness of DWD. The essence of the tests will be comparisons between drilling with and without the prototype DWD in a variety of well-characterized lithologies. Emphasis will be on using high-speed drill-bit data to tune, and eventually optimize the drilling process. Cost-effectiveness, at this point, will not be a priority; rather, we will assemble a system using reliable, mostly existing components to give the best chance of demonstrating the inherent value of the DWD approach. The expected outcome of Phase 2 is an unequivocal demonstration that DWD significantly improves the drilling process.

Many elements of the DWD prototype already exist and can be used in proof-of-concept testing with little or no modification. The software being developed by Sandia and Tracor for circulation monitoring and Sandia's experience with drill-rig instrumentation will guide the development of the data reduction, display, and graphic interface systems. MWD tools such as that developed by Heisig, et al. will be obtained and modified for the MWD sub. The high-speed data link will be chosen from: coaxial cable similar to that used in Sandia's environmental drilling tools, fiber optic, acoustic, or some hybrid. The drill string will be standard drill pipe, and bits will be selected as discussed below. Detailed design, procurement and checkout of the prototype DWD system will be carried out largely in FY00. Testing on actual rigs at one or more sites will be performed in FY01. Tests will be performed in well-characterized lithologies, possibly at GRI's Catoosa facility, Rocky Mountain Oilfield Training Center, or another location with adequate records of drilling performance. Assuming success, a test will be scheduled for a geothermal well in FY01.

The proof-of-concept test will benefit from synergy with Sandia's PDC bit field-test project. This project aims to demonstrate that PDC bits can be used successfully for geothermal drilling in hot, hard formations. A solicitation will be issued requesting bit manufacturers to build prototype PDC bits for geothermal applications (this will be funded out of the conventional drilling program, not as part of the Advanced Drilling Program). Sandia will have a significant role in the design of these bits to ensure that they benefit from knowledge gained under Sandia's Hard-Rock Drill Bit program, then promising prototype bits will be tested in conjunction with a DWD proof-of-concept test. An important feature of these tests will be using force or acceleration measurements with DWD to tune the drilling operation for maximum bit performance – ROP and life – but other downhole data, probably temperature and pressure, will be taken as part of the demonstration.

Total cost of Phase 2 will be approximately \$5.15M.

4.4 Phase 3: DWD Optimization

Given a positive outcome for Phase 2, Phase 3 is the part of the program in which DWD will be refined and optimized, and will move to commercial reality. Referring to Figure 4.1, however, it is clear that the Phase 3 time line overlaps at the beginning and the end with Phases 2 and 4, respectively, so it is best to recognize that the phases serve as logical planning tools but do not rigidly separate tasks that are relevant to more than one phase. The expected outcome of Phase 3 is a commercially viable DWD system that yields dramatically improved drilling performance, but may not yet have been fully optimized. It will, at a minimum, incorporate the technology described below.

Most of Phase 3 will focus on what can be called the information-mode tools: the data link, the software, and the downhole sensors. There is no ranking of importance among these, because all are necessary, but there will be degrees of technical challenge.

4.4.1 High-Speed Data Link – A high-speed link for transmission of downhole data is one of the most desirable tools for improved drilling, and may offer the broadest spectrum of choices in basic technology. Earlier attempts have included: separate hard-wired cables inside the drill pipe; data/power cables incorporated into the drill pipe; electronic transmission through the drill pipe; electronic transmission through the earth; acoustic transmission through the drill pipe; and the currently prevalent method, mud-pulse telemetry. Mud-pulse is relatively simple, but suffers from very severe limits on data rate – only a few bits/second. The other methods offer much higher data rates, but have encountered various difficulties during development attempts.

The choice of data-link technology will be driven by the status of current industry development, Sandia in-house research, and data-rate requirements derived from Phase 2 proof-of-concept testing. The principal advantage we will have in this development, compared to earlier efforts, is the ability to focus the talents and resources of an industry consortium, allied with Sandia researchers and a federally funded budget, on the basic problem; this combination of incentive, ability, and support will be unprecedented. Since there is no fundamental physical barrier to high-speed data transmission up and down a wellbore, there is every reason to expect successful development of this technology.

4.4.2 Analytical and Advisory Software – Data streams from downhole and surface measurements will converge at the software package incorporated into the DWD system. This process presents a subset of technical challenges:

- **Surface rig instrumentation** – Sandia has extensive experience in developing sensors, multi-station displays, and data collection for rig instrumentation. This part of the DWD system should be a relatively straightforward extension of previous work.

- Analytical software – This will be the part of the software package that looks for trends in the data, sets simple alarms (e.g., mud outflow greater than inflow implies a kick), and converts at least part of the data into a format that is more easily stored for permanent retention (e.g., convert 1 Hz fluid temperature data into an average value every 15 or 30 seconds.) This kind of software is also similar to previous work and mainly lacks definition of a data storage format.
- Advisory software – The final form of this part of the software is less well defined, but a contract is already in place to develop what may be its precursor. Using an expert system, this program's capability will range from relatively simple analysis of downhole data (e.g., high accelerations at the BHA indicate bit bounce or whirl) to more sophisticated inferences about drilling performance based on various combinations of surface and downhole data. As an example, the software might look at a situation in which there is significant difference between downhole and surface torque readings, and the navigational measurements show a severe dogleg. The expert system might then warn that there is danger of stuck pipe and might suggest that the driller should pull out of the hole and ream the dogleg with a different bottom-hole assembly.

A great variety of scenarios can be built into this kind of system, but the relevant ones will be defined by work now in progress, results of the proof-of-concept test, and industry input.

4.4.3 Downhole sensors – Many downhole parameters – accelerations, WOB, torque, pressure, temperature, etc. – have already been described as probable quantities to be measured by the DWD tool. Final definition of the measurement list, along with their required resolution and accuracy, will depend on close analysis of the proof-of-concept tests and on clarification of parameters needed for input to the advisory software. It is unlikely, however, that any novel quantity will require measurement, so most of the development work in this task will probably be devoted to hardening conventional sensors against high temperature and high mechanical shock.

Total cost of Phase 3 is estimated to be \$21.5M.

4.5 Phase 4: Enhanced DWD

Much of Phase 4 will be carried out in parallel and in coordination with Phase 3. While Phase 3 was described as development of "information-mode" tools, the enhanced system will move into development of new kinds of sensors and actively controllable downhole tools, and will lay substantial groundwork for smart drilling systems. The direction of this development will be strongly driven by industry input and by constant feedback of Phase 3 results, so it is difficult to give precise descriptions of the specific tools and sensors to be developed, but some high-probability candidates are described below. The expected outcome of Phase 4 is a commercially viable drilling system with an upgraded DWD package that has

significantly greater capabilities and performance than what is available at the end of Phase 3.

Some of the advanced sensors that might be developed in this phase include:

- Formation pressure – Knowledge of either bottom-hole pore pressure or a “look-ahead” to the formation beyond the bit would be of great value in well control, underbalanced drilling, and drilling optimization.
- Bit condition – Bearing temperature in a roller bit, cutter temperature in a PDC bit, or the quotient ROP/WOB could indicate whether the bit is being run under the right conditions or whether it may be almost worn out.
- Drillability – Sonic velocity relates elastic modulus and density of a formation, and has often been used as a measure of drillability, especially for PDC bits. It could also give an immediate signal of entry into a new formation; either criterion might indicate a need for a different kind of bit or different drilling parameters.
- Chemistry – Real-time analysis of drilling or formation fluids would show when corrosive chemicals were present and would give immediate warning to add inhibitors to the mud.
- Cuttings size – The size of cuttings generated by the bit is a key indicator of the bit’s efficient operation, but chip size at the surface is not always accurate because of re-grinding between the drillpipe and wellbore wall. A downhole measurement of chip size would show how well the bit is cutting and could indicate whether the bit was worn or whether a new type of bit might be more effective.

Downhole controllable tools will follow next in the program, although initiation of this task will coincide with the latter stages of sensor development. Some controllable-tool concepts have been mentioned previously, but the opportunity of having active intervention with the drilling process controlled from the surface opens up other exciting potential applications. Some of these include:

- Shock subs – A shock sub, which acts as a shock absorber in the drillstring, could have controllable damping or possibly a controllable spring constant to alter the natural frequency seen by the bit, mitigating mechanical shock on the bit and improving both bit life and rate of penetration.
- Steering tools – A bent sub that could change its orientation and curvature at will, along with improved navigation measurements that gave accurate, real-time well trajectory, would simplify directional drilling, producing a less tortuous and more economical hole.
- Alternative drilling methods – One of the major impediments to many advanced rock reduction methods (electric downhole motors, laser or e-beam drilling, some high-pressure drilling methods) has been the inability to get a reliable power supply downhole. Batteries, power cables, and downhole turbine/generators have all been tried with marginal success but, if the data link turns out to also

have significant power handling capability, some of these alternative drilling methods might become feasible.

- Wellbore lining – Many patents have been granted for ways of lining a wellbore while drilling, but few have been reduced to practice. In all of the methods that involve constructing a liner as the hole is drilled, some relatively complex process must occur near the bit. Again, having real-time knowledge and control of this process might make the difference between a realistic device and wishful thinking.

The need or opportunity for many other kinds of sensors and tools may appear during Phases 2 and 3 but this is an evolving situation that cannot be fully defined now. As before, results of previous work, industry input, and a continuously updated evaluation of the market will drive the program. Industry involvement in research and cost-shared funding will keep us closely tied to realistic objectives and directed toward commercial applications.

Total cost of Phase 4 is estimated to be \$34M.

5.0 RATIONALE FOR THE PROGRAM

5.1 Background

To expand the geothermal contribution to the world's energy supply by reducing drilling costs, the U.S. Department of Energy sponsors the Geothermal Drilling Technology Program at Sandia National Laboratories. Under this comprehensive program, Sandia works with industry to develop and implement new technologies for reducing geothermal well costs. More than thirty projects in seven technology areas are under way to develop improved hardware and software for use in the drilling process. Research, development, laboratory testing, and field testing activities are conducted by Sandia researchers together with over 30 industry partners, university students and faculty, and a number of other contractors. The seven technology areas are:

- Lost Circulation Technology;
- Hard-Rock Drill Bit Technology;
- High-Temperature Instrumentation;
- Wireless Telemetry;
- Slimhole Drilling Technology;
- Systems studies and other Drilling Technology; and
- Advanced Drilling Technology.

The first six areas focus on relatively short-term, incremental improvements in geothermal drilling technology. The program seeks to develop a wide variety of products that can be implemented in the field within the next two to five years using conventional rotary drilling systems and which will reduce drilling costs by a few percent each. The goal of the Program is to develop technologies that together can reduce the cost of drilling a geothermal well by 25%, compared to a historical average of drilling costs in that same area.

The geothermal and hydrocarbon industries are inextricably linked in their quest to reduce drilling cost. Historically, drilling cost per foot tracks the price of oil very closely (GRI, 1999) because high oil prices encourage more drilling, and market forces drive up drill rig rates. Paradoxically, then, when oil prices go up, geothermal energy becomes more competitive, but drilling for it becomes more expensive because drill rigs cost more. We have tried to accommodate this linkage by involving both industries – and both the Fossil Energy and Geothermal Technology offices in DOE – in planning and implementing DWD development.

Under the Advanced Drilling Technology program area, Sandia has been charged with identifying and developing advanced technology that can revolutionize geothermal drilling and reduce geothermal well costs by an additional 25%. This proposal falls within the Advanced Drilling Technology program area.

Even though geothermal energy is already a substantial contributor to domestic supply (the U. S. geothermal industry is the world's largest), it is a niche market and will remain so even if the goals in DOE's Strategic Plan are met. As such, the geothermal industry alone cannot support a development program of this size, and without this aggressive approach to lower costs, especially for deeper drilling, geothermal energy will not increase its penetration of the world's growing electricity market.

The geothermal industry needs both the incremental and revolutionary approaches for reducing drilling costs. Incremental technology improvements can be readily absorbed by the industry with low risk and high probability of success. Revolutionary technology improvements will require major changes in the drilling industry but have the potential for greater impacts on the cost of geothermal power. Revolutionary drilling technology improvements also have a greater likelihood of application to other industries, particularly oil and gas.

5.2 Planning an Advanced Drilling Program

Because of Sandia's experience in drilling research and its ongoing program for developing incremental improvements in conventional geothermal drilling, the U.S. Department of Energy, Office of Geothermal Technologies, funded Sandia in 1997 to initiate planning for an Advanced Geothermal Drilling Technology Program. The task at hand was to:

- Consult with industry on technology needs;
- Evaluate the status of possible revolutionary drilling concepts;
- Identify an enabling technology to provide the basis for a revolutionary drilling system; and
- Write a plan for a DOE program to develop the enabling technology.

Sandia took the following steps:

- We published a systems analysis that examined the myriad advanced drilling concepts that have been proposed and/or developed over the past 40 years (Pierce et al., 1996). These include high-pressure waterjet drilling, spallation drilling, percussive drilling, rock melting, laser drilling, electron-beam drilling, and many other ideas. The report concluded that some of these concepts may have the potential for reducing geothermal drilling costs if significantly improved drilling performance can be achieved, but very few of these concepts have provided the needed improvements under actual field conditions.
- We convened a Workshop on Advanced Geothermal Drilling Systems that brought together drilling technology experts from universities and the geothermal, minerals, and oil and gas drilling industries. The workshop participants considered the drilling process, dividing it into ten essential functions that must be performed for a successful operation. This led to definition of the type and areas of research that should be addressed in an

advanced drilling technology program. Sandia published a detailed report (Glowka) outlining technology development needs in the ten essential functions, and approximately ten categories of new surface tools, downhole tools, and procedures were identified. These new tools and procedures are being further studied by Sandia to determine their potential cost savings, using a comprehensive hydrothermal well-cost model Sandia has developed over the past three years. This workshop is described in more detail in Appendix A.2.

- We convened a second workshop, this time with Sandians from the Geothermal Research Department and other SNL research departments. This workshop considered the results of the industry workshop and studied the following question: Where among these recommendations is the "*silver bullet*" that would meet the program's objective of revolutionizing the drilling industry? The workshop concluded that the silver bullet is a high-speed data link that would provide dramatically faster two-way communication between downhole and the surface. The concept of DWD to implement and take advantage of the high-speed data link was also born during this workshop. We concluded that many aspects of the drilling process could dramatically improve if real-time data could be acquired from downhole, processed in real-time at the surface, and used to guide the drilling process. Further, it was concluded that DWD would enable the development of advanced downhole tools that otherwise might not be developed for lack of a system to ensure their universal benefit. Advancements in no other technology area would provide such a system-wide impact. Appendix A.3 presents a summary of this workshop.
- We consulted with a number of industry experts on the DWD concept and received uniformly enthusiastic feedback. We presented the concept and a rudimentary program plan at a Drilling Engineering Association meeting in November 1998, and received expressions of interest from several industry sources, the Gas Research Institute, and DOE/FETC in cooperating with DOE OGT and Sandia in developing a DWD system.

An essential element of the program, then, was the choice of an enabling technology that would link all ten of the drilling functions and improve all parts of the drilling process. A consensus emerged from the workshops that the single greatest deficit in most of the drilling functions was the lack of real-time knowledge and control of what was actually happening down the hole. By gaining this critical feedback capability, all functions can be optimized for highest efficiency and lowest cost, creating the greatest probability for significantly reducing geothermal well costs. Existence of this capability will also serve as a catalyst for the development of other tools that will take advantage of the real-time data and control.

6.0 CONCLUSION

A Diagnostics-While-Drilling system, either as a stand-alone tool or as a precursor to a smart, semi-autonomous drilling method, has been industry's goal for years, if not decades. The marginal success to date is primarily a result of the cyclic nature of drilling R&D, which rises and falls with the oil market and has been notably volatile for almost twenty years, not any lack of talent or motivation. Many of the issues that we propose to address in this program can also be attacked more effectively now because of advances in associated technologies such as computing power, information processing, expert systems, and improved materials.

A vision for the early part of this program is relatively easy to describe, but there are many branches in its path downstream. Because so much of the later work will be driven by early results in the proof-of-concept test and by data requirements derived from the expert-system modeling, it is impossible to define the exact objectives, schedules, or milestones for the later phases of the program. In each phase of the program, a critical activity will be establishment of criteria for success, or whether to proceed with further work. This should not be considered a defect, however, but a mark of the flexibility with which we approach this task.

It is critical to have industry involvement at every step of this program, not only to be sure that we remain focused on the correct issues for the drilling environment, but to avoid repetition of previous industry work in this field. By making this program as inclusive as possible and soliciting a broad spectrum of industry participation, we should gain access to much information that will be extremely valuable and that would normally be kept proprietary. Industry participation will also make testing prototype tools or components in realistic drilling conditions a great deal simpler and cheaper than contracting this work to a testing laboratory.

We view this program as a necessary step in a revolutionary approach to drilling. It will demonstrate value in a systems approach that leads to both short-term drilling improvements and long-term enabling of new technologies that may be only dimly visualized now. The proposed work is ambitious, yet realistic, and could have an enormous payoff. We should start now to realize this potential.

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Appendix A.1: Estimating Cost of Electricity

This appendix presents the detailed rationale for cost and cost savings assumptions used in calculating cost of electricity (COE) and reductions in COE. A cost model that predicts the COE was developed and exercised over the range of conditions found for geothermal plants in flashed-steam, binary, and enhanced-reservoir (e.g., Hot Dry Rock) applications. The calculations were repeated assuming that DWD technology is available to reduce well costs and improve well productivity.

The results indicate that DWD technology would reduce the geothermal COE by 2 to 31%, depending on well depth, well productivity, and the type of geothermal reservoir. For instance, for a typical 50-MW, flashed-steam geothermal power plant employing 3-MW wells, 6,000-ft deep, the model predicts an electricity cost of 4.9 cents/kWh. With the DWD technology envisioned, the electricity cost could be reduced by nearly 20%, to less than 4 cents/kWh.

Such a reduction in the cost of electricity would give geothermal power a competitive edge over other types of power at many locations across the U.S. and around the world. It is thus believed that DWD technology could significantly expand the role of geothermal energy in providing efficient, environment-friendly electric generating capacity.

The goals of the DWD development program are to:

- Decrease geothermal well costs by 25%;
- Reduce the number of dry geothermal wells by 25%; and
- Increase the average geothermal well productivity by 25%.

Impact on the Cost of Electricity

Cost Model

A spreadsheet model for calculating the cost of electricity produced from geothermal power was developed. The equations used in the model are shown at the end of this Appendix. The model includes two major cost components:

- Debt servicing of capital costs, including well costs, plant costs, and other non-well costs, over 30 years at 13% interest rate; and
- Operating and maintenance (O&M) costs.

The model was run for flashed-steam, binary, and enhanced-reservoir geothermal fields. Well depths ranging from "shallow" at 2,000 ft to "ultra-deep" at 15,000 ft were considered. Well productivities ranging from 3 to 10 MW/well were assumed. A 25% dry well rate was also assumed, which means that for every four productive wells, one dry well was drilled. The calculations were then repeated for a case where DWD technology has been used to reduce well costs by 25%, reduce the dry well rate by 25%, and increase the average well productivity by 25%.

Results

The first results are shown in Figure A.1.1. Note that the electricity costs predicted by the model range from 3.3 to 13.9 cents/kWh. This agrees well with the cost range that actually exists in the geothermal industry today.

Shown in Table I for comparison are reported COEs for various energy sources. These data illustrate the fact that geothermal power is already highly cost competitive with most other forms of power generation. In cases where geothermal power is only marginally cost competitive, it can be concluded that relatively small changes in well costs or productivity can make the difference as to whether geothermal or some other form of energy is selected.

The results shown in Figure A.1.2 indicate that reaching the goals set for the DWD system would reduce the cost of geothermal-produced electricity by 2 to 31%, depending on the depth, productivity, and type of geothermal reservoir encountered. In general, the deeper and less productive a given geothermal resource, the greater the potential benefit of DWD. The predicted cost reductions could provide geothermal power a significant competitive advantage in locations where it is currently marginal.

For instance, if a geothermal reservoir exists at 6,000 ft below the surface and is relatively "tight" so that well productivity is limited to only 3 MW/well, the model predicts the COE to be about 4.9 cents/kWh. This may not be economically competitive if power can be generated in that location for 4.5 cents/kWh with natural gas. With the cost savings promised by DWD, however, the geothermal COE could be reduced by nearly 20%, to 4.0 cents/kWh. Thus DWD could make the difference in getting geothermal selected as the energy source of choice. This is particularly true for deeper, less productive geothermal reservoirs.

Technology	Configuration	COE, ¢/kWh
Geothermal (EPR)	Flashed-Steam	3.3
	Binary	3.9
	Enhanced-Reservoir	10.9
Wind (EPR)	Horiz.-Axis Turbines	
	- Class 4 wind regime - Class 6 wind regime	6.4 5.0
Biomass (EPR)	Direct-Fired	8.7
	Gasification-Based	7.3
Solar Thermal (EPR)	Power Tower	13.6
	Parabolic Trough	17.3
	Dish Engine-Hybrid	17.9
Photovoltaics (EPR)	Util.-Scale Flat-Plate	51.7
	Concentrators	49.1
	Neighborhood	37.0
Natural Gas (UIC)	Gas Turbine, 1984	7.2
	Gas Turbine, 1995	3.1
Oil (UIC)	Oil-Fired Steam, 1984	9.4
	Oil-Fired Steam, 1995	4.3
Coal (UIC)	Coal-Fired Steam, 1984	5.5
	Coal-Fired Steam, 1995	3.0
Nuclear (UIC)	Light-H ₂ O Reactor, 1984	5.6
	Light-H ₂ O Reactor, 1995	3.8

TABLE I – Reported Cost of Electricity (COE) for Several Generating Technologies

Achieving the Goals

DWD has a potential for reducing geothermal well costs by at least 25% through the following effects:

- Improved penetration rates, resulting in more footage per day, or less cost per foot;

- Increased bit life, resulting in fewer trips and bit purchases; doubling penetration rates and bit life would reduce geothermal well costs by about 15%;
- Reduced tool failures through the ability to closely monitor downhole tools and detect incipient problems before they occur; this would reduce the number of trips and service/repair costs, saving at least 5% of the costs of an average geothermal well;
- Reduced hole problems through the ability to closely monitor hole conditions and diagnose events such as lost circulation and gas or steam kicks; this could eliminate problems such as stuck pipe and easily reduce average well costs by 10%; and
- Reduced completion costs, resulting from an improved ability to construct multi-leg completions in geothermal wells; this would reduce casing and cement costs, thereby reducing overall well costs in a given geothermal field by another 5-10%.

Reducing the number of dry wells drilled by 25% would result from the following developments due to DWD:

Figure A.1.2 – % Reduction in the Cost of Electricity for 50-MW Flashed-Steam, Binary, and Enhanced-Reservoir Geothermal Power Plants, Assuming a 25% Reduction in Well Costs, a 25% Reduction in the Dry Well Rate, and a 25% Increase in Average Well Productivity.

- Improved resource detection and real-time drilling course correction to re-drill sections of dry holes and turn them into producers; and
- Fewer hole problems such as stuck pipe and permeability damage that can cause abandonment of a well.

Increasing average well productivity by at least 25% would result from the following capabilities made possible by DWD:

- Multi-leg completions, which could increase well productivity two- or three-fold; made possible by improved directional drilling capability and increased use of surface-controllable downhole tools;
- Improved resource detection and real-time drilling course correction to intercept the maximum resource possible; well productivity should roughly increase in proportion to the length of hole drilled through the productive reservoir rock; and
- Improved underbalanced drilling operations that prevent well permeability damage due to drilling mud and rock chips; made possible by real-time measurement and diagnosis of downhole flow conditions; several-fold improvements in well productivity are possible with properly controlled underbalanced drilling.

Summary

If a Diagnostics-While-Drilling system were available, significant reductions in the cost of geothermal-produced electricity could be obtained. The cost/benefit ratio for developing DWD can be estimated by considering the previous example cited, whereby the COE would be reduced by 0.9 cents/kWh through the use of DWD.

For the single 50-MW power plant assumed in the analysis, this amounts to an annual saving of \$3,517,650, or a 30-yr lifetime saving of \$105,529,500. These accumulated savings are over twice the estimated cost of developing a viable DWD system, and yet they accrue from a single power plant.

Such savings would not only give geothermal projects a competitive edge over other forms of power generation, they would also provide incentive for investors to provide venture capital for the geothermal industry. Both of these effects would help the geothermal industry to significantly expand its role in providing efficient, environment-friendly electric generating capacity.

Equations

The following equations were used to calculate the cost of electricity produced by a 50-MW geothermal power plant.

Plant Size = 50 MW, assumed

Producing Hours/Year = 7817 hours/yr, (EPRI, 1997), accounts for capacity factor

% Debt Amortization/Year = 13.3% = Principal + Interest for 30-yr loan @ 13% interest, 1 pmt/yr

Non-Drilling Plant Cost/kW = \$869/kW for flashed-steam (EPRI); \$1819/kW for binary (EPRI); \$1866/kW for enhanced-reservoir (assumed by doubling the cost of the pumps for a binary plant)
Total Non-Drilling Plant Cost = Non-Drilling Plant Cost/kW * Plant Size (MW) * 1000 kW/MW
O&M Cost/kWh = \$0.0123/kWh for flashed-steam (EPRI); \$0.0112/kWh for binary (EPRI); \$0.0123/kWh for enhanced-reservoir (assumed same cost as for flashed-steam plant)
Well Cost/ft = \$270/ft for 2,000-ft wells (Finger); \$300/ft for 6,000-ft wells (interpolated); \$330/ft for 10,000-ft wells (Ref. 6); \$367.50 for 15,000-ft wells (extrapolated)
Total Cost/Well = Well Depth * Well Cost/ft
No. of Wells (Flashed-Steam & Binary) = # of producers + # of injectors = Plant Size/Well Productivity * (1+% Injectors/100) + 1 spare producer + 1 spare injector = 27 for 3 MW/well; 15 for 6 MW/well; 10 for 10 MW/well
% injectors = # injector wells/# producing wells = 50% assumed; ratios as high as 100% and as low as 10% are common practice
No. of Wells (Enhanced-Reservoir) = # of producers + # of injectors = 2 * # of producers = 2 * (Plant Size/Well Productivity + 1 spare) = 35 for 3 MW/well; 19 for 6 MW/well; 12 for 10 MW/well
Well Field Cost (Flashed-Steam & Binary) = Total Cost/Well * No. of Wells / (1-Dry Well Rate/100)
Well Field Cost (Enhanced-Reservoir) = Total Cost/Well * No. of Wells / (1-Dry Well Rate/100) + Enhanced Reservoir Stimulation Cost/Well Pair * No. of Wells / 2
Dry Well Rate = number of dry wells / total # of wells = 25%, assumed; dry wells are defined as unusable for production or injection; dry well rates as high as 75% occur in some areas
Total Power Project Cost = Total Non-Drilling Plant Cost + Well Field Cost
Debt Amortization Cost/kWh = Total Project Cost / Plant Size (MW) / (1000 kW/MW) / (Producing Hours/Year) * % Debt Amortization/Year
Total Cost of Electricity (COE) = Debt Amortization Cost/kWh + O&M Cost/kWh

The results of Figures A.1.1 were obtained by making the above calculations for well depths of 2,000, 6,000, 10,000, and 15,000 ft and for an average well productivity of 3, 6, and 10 MW/well. Results in Figure A.1.2 were obtained by repeating the calculations assuming: 1) a 25% reduction in the Total Cost/Well; 2) a 25% reduction in the Dry Well Rate; and 3) a 25% increase in average well productivity.

A parametric study was performed to determine the effects of several of the above-listed parameters on the reduction in COE plotted in Figure A.1.2. The most important variables were varied over their plausible ranges and the results plotted in Figure A.1.3. Shown here is the % Reduction in COE due to DWD, plotted as a function of several variables. The

Figure A.1.3 – Parametric Study Results: % Reduction in the Cost of Electricity as a Function of Several Parameters Whose Values are Expressed in % of Their Baseline Values.

variables are plotted in terms of their values relative to their baseline values. The baseline parameter values used were:

Reservoir Type = Flashed-Steam
Well Depth = 6,000 ft
Average Well Productivity = 6 MW/well
Plant Size = 50 MW
Producing Hours/Year = 7817 hours/yr
% Debt Amortization/Year = 13.3%
Non-Drilling Plant Cost/kW = \$869/kW
Total Non-Drilling Plant Cost = \$43,450,000
O&M Cost/kWh = \$0.0123/kWh
Well Cost/ft = \$300/ft
Total Cost/Well = \$1,800,000
No. of Wells = 14.5
% injectors = 50%
Dry Well Rate = 25%
Well Field Cost = \$34,800,000
Total Power Project Cost = \$78,250,000
Debt Amortization Cost/kWh = \$0.0266/kWh
Total Cost of Electricity (COE) = \$0.0390
% Reduction in COE = 13.0%

The Figure A.1.3 results were obtained by varying one variable at a time. For instance, if the Dry Well Rate is assumed to be 300% of its baseline value of 25% (i.e. if 75% of all wells are "dry") while maintaining all other variables at their baseline values, then a 37% Reduction in the COE would result with the use of DWD.

These results indicate that the most sensitive variables in the model are: Dry Well Rate, Average Wellbore Productivity, Well Depth, and % Injectors. The baseline values used to obtain the results shown in Figures A.1.1-3 were selected to be reasonable, moderate values for typical geothermal power plants. Figure A.1.3 shows that the projected COE savings for the baseline case is probably somewhat conservative because it falls within the lower portion of the range of possible values using other parameter values.

The parameter study also shows that the goals set for the DWD technology development program are reasonable and would result in significant reductions in the geothermal COE. Higher goals are not necessary to make the use of DWD economically attractive.

Appendix A.2: Identifying Feasible Alternatives – the Berkeley Workshop on Advanced Geothermal Drilling Systems

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

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

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

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

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

The ten essential functions, and the alternative methods discussed and considered at least potentially feasible for each, are listed below. The numbers within each function are for convenience only and do not imply any rank or priority.

Rock Reduction

1. Drag bits using synthetic diamond or other advanced materials.
2. Low-pressure waterjet-enhanced drill bits.
3. High-pressure waterjet-enhanced drill bits.
4. Percussive hammer bits.
5. Disk-cutter bits.
6. Large-diameter wireline core bits.
7. Casing-while-drilling with a retrievable motor and bit.
8. Replaceable-cutter bits.
9. Rock machining at ultra-high RPM.
10. Hybrid rotary-coring.
11. Hard-rock underreaming.

Downhole Energy Transfer

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

Rock Removal

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

Borehole Stabilization and Fluid Containment

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

Control of Formation Pore Fluids

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

Permanent Borehole Preservation

1. *Advanced wellbore-lining techniques for permanent borehole preservation.*
2. *Cement-lined casing.*
3. *Alternative casing materials.*
4. *Casing-while-drilling.*
5. *Improved methods of emplacing production liners.*
6. *Latex and other advanced cements for corrosive environments.*
7. *Robotics system for running hot liners.*

Sensing, Communication, and Process Control

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

Directional Drilling and Control

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

Production Stimulation

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

Well Maintenance and Workover

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

A.3 Identifying an Enabling Technology – the Sandia Workshop

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

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

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

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