# ROAD MAP FOR A 5000-FT MICROBOREHOLE

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## EXECUTIVE SUMMARY

## ABSTRACT

In 1994, Los Alamos National Laboratory (LANL) advanced a concept for drilling deep, small holes with diameters from 2-3/8-in. to 1-3/8-in., for exploration holes, for reservoir monitoring, and for production of shallow- and medium-depth low-productivity reservoirs. This concept for coiled-tubing-deployed microdrilling evolved from theoretical studies and lab tests, to field demonstrations in which 1-3/4- and 2-3/8-in.-diameter holes were drilled to 700-ft deep. This design, developed with input from industrial collaborators and subcontractors, derives primarily from technologies and practices that are both familiar and in some use for drilling larger diameter wells. As a result of our experience, we believe that drilling microholes to depths of 5000 ft can be achieved with relatively modest modification of existing drilling equipment and coiled tubing technology. We prepared a draft Road Map. Industry input is now needed to add a commercial perspective and reality to this Road Map, and to bring potential users and providers into the process. The motivation for developing microhole technology is the potential for a significant reduction of both the cost and environmental impact of drilling. Industry evaluation and participation in a final draft of the Road Map is a prerequisite for moving this effort forward.

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## BACKGROUND

The idea of drilling holes as small as 1-in. diameter in the deep earth is not new. Relatively deep, small-diameter holes as small as 1.175-in. have been drilled using mining coring rigs for at least 50 years. Oil industry attempts to adapt mining core-drilling technology to produce inexpensive slimholes, while technically successful, did not find widespread commercial use because infrastructure costs could only be modestly reduced. However, coiled-tubing-deployed drilling for cleanout and laterals has found some acceptance in petroleum drilling and exploration over the last decade. Major components of a capable infrastructure have already been created for coiled-tubing drilling. Coiled-tubing technology is thus a likely enabling technology for significant cost reductions for wells drilled from the surface.

The combination of coiled-tubing-deployed and microhole-drilling concepts may provide a method to greatly reduce the cost of drilling shallow- and moderate-depth holes for exploration, long-term monitoring, and limited production service. The availability of small sensors and telemetry instrumentation to mine information from microholes changed the paradigm since the slimhole-drilling development reached it peak. The equipment needed to construct microholes that are less than one fourth the diameter of a typical conventional-sized hole can be drilled with equipment that will weigh less than one tenth as much as conventional equipment. The smaller equipment can be handled with less manpower, and a designed-for-purpose, fully automated, coiled-tubing-deployed drilling system would maximize the potential for reducing labor and equipment costs.

There is one obvious roadblock that will tend to deter the commercialization of coiled-tubing microdrilling (or other competing concepts for microdrilling), by independent, small service companies that have historically lead innovations in drilling technology. That is, the inevitable fact that a large number of related services has to be developed in parallel with the basic drilling capability. These include, (but are not limited to): associated drilling support (i.e. sidetracking, directional drilling, underbalanced drilling, formation testing, and fishing), well completion and perforating equipment, logging tools, and instrumented well technology, and artificial lift equipment—all of which can be applied to a microhole size. Without the evolution of a significant number of these capabilities for microholes, microdrilling technology has very limited commercial value.

## MICRODRILLING CONCEPT

The basic microdrilling-rig concept was developed by LANL to achieve a readily automated drilling model that avoids the more complicated and labor-intensive aspects of conventional oil-field drilling, and reduces the size of the rig required for drilling and completing the microbore. The coiled-tubing-deployed drill was selected to provide an inexpensive, reliable, hard-wired, bottom-hole data and control telemetry. The basic, built-for-purpose coiled-tubing-unit (CTU) microrig must be readily adaptable to support low-cost directional drilling and through-tubing micro-lateral drilling from existing wells. The drilling system must also be suitable for drilling with low density, compressible drilling fluids to penetrate depleted reservoirs, and to search for and produce bypassed oil and gas. The CTU design will facilitate quick reel changes in the field in order to support hole-size reduction with a comparable reduction in the tubing diameter.

The basic LANL drilling assembly concept assumes a properly designed, polycrystalline diamond compact (PDC) or thermally stable, polycrystalline diamond (TSD) drag bit will be rotated by a relatively high speed Moineau-principle, positive-displacement (drilling) motor (PDM) that can rapidly penetrate most oilfield rock with low weight-on-bit. A robust, instrumented, near-bit-sensor sub located below the motor will support the automation and control of the bottom-hole drilling assembly. An isolation sub above the motor will protect a less robust telemetry instrumentation sub and the coiled tubing from pulsations and vibrations generated in the drilling assembly.

The coiled-tubing diameter will be sized relative to the bit size to optimize hydraulic power transport and maximize drilling thrust (weight-on-bit) that can be applied by drill stem compression. In order to transport sufficient power to achieve high penetration rates, the microrig hydraulics must operate at relatively high pressure and low flow to minimize power losses. The development of compatible, microsized rotary-drilling motors is a critical element of the drilling system. Very hard rock that cannot be effectively penetrated using PDC bits will require an alternate drill assembly; a rotary percussion system is believed to be the most promising technology for low thrust, hard rock drilling, but commercially available equipment is not well suited for openhole coiled-tubing drilling. Drill-cuttings transport in a very narrow annulus will be a significant challenge that has not been completely resolved for highly inclined, conventional-sized bores using coiled-tubing (slide) drilling.

## WELL CONSTRUCTION AND COMPLETION CONCEPT

To support drilling to 5000 ft, a well-construction concept must include a conductor-pipe surface-casing to isolate fresh water aquifers, intermediate casings if required, and a final production casing (or liner) or a stable openhole to support exploration logging and formation testing. Where feasible, the coiled tubing used to drill the surface, intermediate, and production holes may be expended to serve as the surface and intermediate casing since the drill concept assumes a relatively large ratio of the drill-stem-to-hole diameter. Each size of tubing is converted from drill stem to casing by removing the drilling assembly, and installing a bottom-hole-cementing assembly and casing centralizers clamped to the coiled tubing. The casing is washed to bottom, landed and hung-off in a wellhead, cut off from the remaining reeled tubing, and cemented. The next smaller reel of continuous drill stem is then drilled down to its intended shoe depth and converted to casing in a similar manner to produce a cased hole or openhole completion across the target reservoir or exploration target. To achieve a 5000-ft depth with provision for surface and intermediate casing, drilling of holes as small a 1-3/8-in.-diameter is proposed to keep the rig size for a 5000-ft capability to a minimum. The well designs proposed in the full Road Map do not incorporate the expandable openhole casings and liners that have recently been successfully demonstrated in the field. The expansion of microsized tubing/casing and coiled tubing will increase the potential depth of the microdrilling capability, and decrease the rig-size requirements, in the same way this technology impacts conventional-sized drilling.

Perforators that can be run on small mono-cable wirelines or coiled tubing will be needed, as well as stimulation technology suitable for low-flow treatments. The coiled tubing can be inserted as a tubing string after logging, perforating, and stimulation are completed.

## FIELD DEMONSTRATION RESULTS

The coiled-tubing-deployed microdrilling concept was successfully demonstrated at three sites: the Fenton Hill Demonstration Site near Los Alamos, a site with Basin and Range Dry-Lake-Bed Sediments in support of an industrial sponsor, and the San Ysidro Site in Sandoval County, NM. Based on local outcrops, it was anticipated that the San Ysidro site would provide the first application of the LANL microdrilling system to typical oil-field rocks. As it turned out, the site provided significant challenges including artesian flow, loss of returns, and severe well instability in poorly consolidated sediments, but did not provide strata of relatively hard sandstones and shales that we had anticipated. Where resources were available, most of the drilling problems encountered were mitigated using rather conventional approaches that are commonly applied in conventional-sized holes. All of the demonstrations have been conducted with daylight drilling and shutdowns each night and most weekends. Both the schedule and equipment failures contributed to the bore instability problems encountered. The problem with excessive hole-washouts at the San Ysidro site has not yet been fully mitigated. We believe that the development of a low-flow, high-differential-pressure drilling motor, and continuous drilling operations to penetrate and promptly isolate the problem formations, will mitigate the severe wash out problem we experienced.

Los Alamos presently has the capability to drill 1-3/4-in. and 2-3/8-in. holes up to 800-ft deep in unconsolidated and soft sediments with commercial PDMs where our current limitation is reel size. We can complete the holes with a cemented-in casing in stable formations, and have demonstrated that we can install casing in unstable formations, and seal it in with a bentonite grout.

## TECHNOLOGY NEEDS

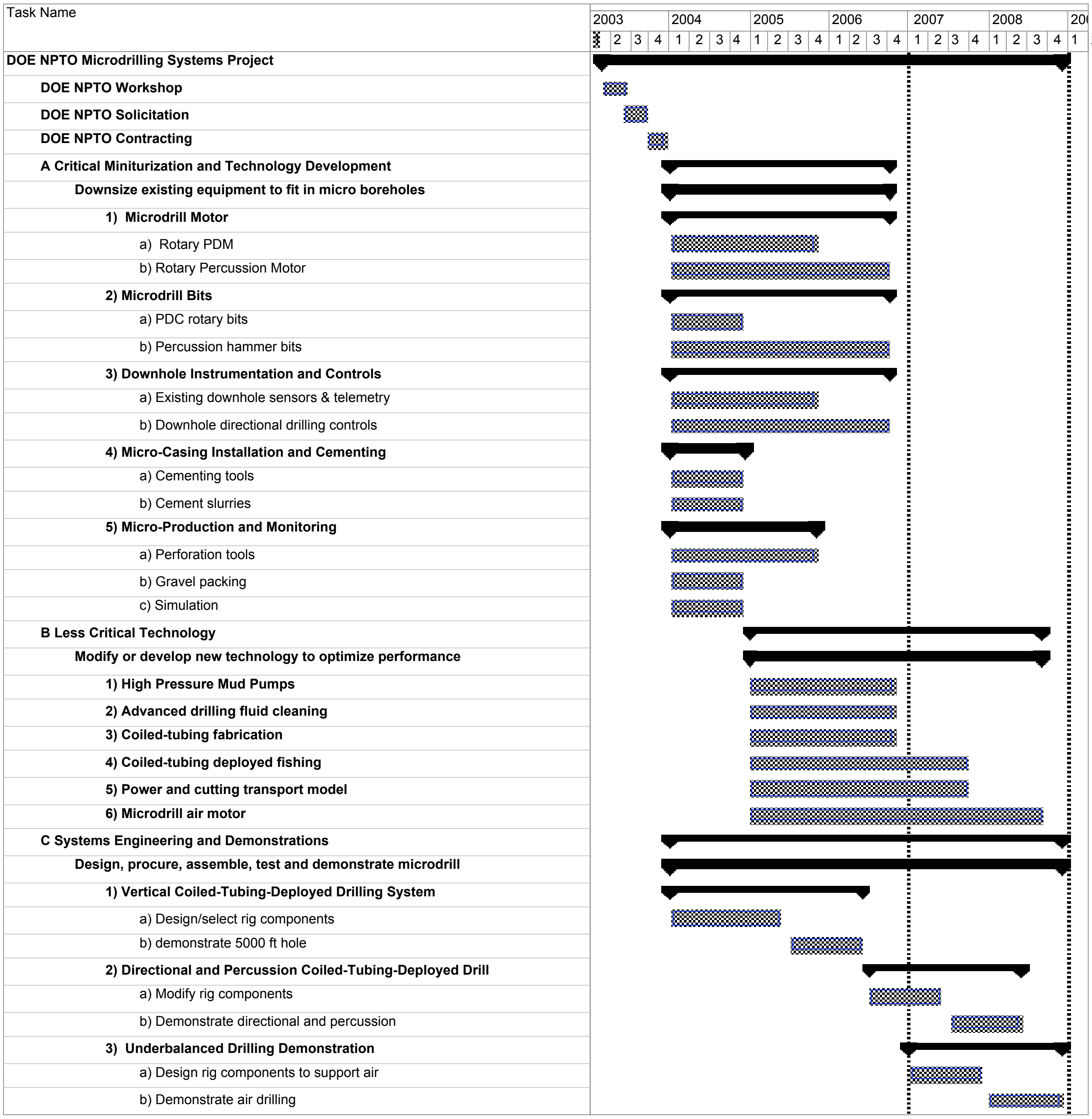
Based on our field drilling experience, a list of modifications needed to improve the original drilling concept was identified. The modifications, described in the full Road Map document, do not require significant new technology development to improve the ability to drill microholes to 1000 ft.

In order to reach a moderate depth of the order of 5000 ft with a low-cost, high-performance, drilling system, some development of new technology (as described in the Road Map) is required. New technology development falls into three areas: (1) optimization of drilling hydraulics, cuttings transport, and bore-wall stabilization; (2) enhancement of drilling motors and rotary percussion hammers with compatible isolation tools; (3) downsizing downhole sensors, instrumentation, and telemetry needed to support automated drilling, real-time steering, and log-while-drilling.

Technology requirements for well logging, reservoir monitoring, and exploration are described in other LANL publications. They are not addressed in detail in the Road Map, but relevant publications are included in the references. Technology requirements for microhole completions include downsizing perforation technology, and downhole cementing equipment for both coupled casing and continuous (coiled-tubing) casing.

## CONCLUSIONS

1. A concept for drilling to 5000 ft in sediments with a coiled-tubing-deployed microdrilling system has been developed and evaluated using modeling, laboratory tests, and shallow field demonstrations. Major components of the technology are familiar and in current use in the drilling of conventional-sized wells and laterals.
2. Some technology development is needed to downsize existing drilling equipment to microhole dimensions, and to develop new equipment for drilling deeper and optimizing the drilling performance at 5000 ft.
3. A $20-million, five-year technology-development program has been outlined in the full Road Map that proposes to demonstrate near-vertical rotary drilling using rental surface equipment and prototype downhole equipment in three years, and evaluates the possibility of expanding to percussion and air drilling using a prototype surface system within five years.




**Initial Plan for Commercialization—**
**A Starting Point for the DOE Workshop on Microdrilling**

# ROAD MAP FOR A 5000-FT MICROBOREHOLE


## ABSTRACT

In 1994 Los Alamos National Laboratory advanced a concept for drilling deep, small-diameter holes for sensor deployment to conduct long-term monitoring. We believed that microsized acoustic sensors, fluid samplers, and other appropriate monitoring instrumentation could be deployed in or near producing reservoirs, and would be economically attractive for long-term, reservoir monitoring. The idea quickly expanded to include exploration holes for formation logging, wireline or drill-stem-deployed logging, and microdrill-stem production testing. More recently, microholes have been considered for production of shallow- and medium-depth gas and shallow oil in special situations. The microdrilling concept has evolved from theoretical studies and laboratory tests of microhole drilling capabilities to demonstrations up to 700-ft deep in soft rock and unconsolidated formations. Deriving from this experience the US Department of Energy in cooperation with industry has begun exploring the feasibility of drilling microholes to 5000 ft for a variety of applications. To this end, Los Alamos National Laboratory has been asked to prepare a Road Map for development of microhole technology.

The Road Map is intended to serve as the guide for developing the technical capability for drilling and completion of 5000-ft deep microholes with an openhole diameter of approximately 1-3/8 in. at total depth before casing and l-in. diameter after casing. We summarize the necessary oil industry support and identify the needs and technical challenges confronting the development of this technology.


## INTRODUCTION

The combination of microdrilling technology and micro-instrumentation provides potentially low-cost, deep wells or through-tubing-produced long laterals for exploration, long-term reservoir monitoring, and production. Microholes sized to provide access for modern downhole instrumentation and an assortment of sensors need be no larger than 1-3/8- to 2-in.-diameter at terminal depth. The maximum cost benefit is assumed to occur with the greatest size reduction as long as the existing drilling and completion equipment infrastructure can be miniaturized using the existing fabrication methods and does not require the major breakthrough technology. Microhole dimensions have a much larger impact on drilling equipment size than slimholes (Fig. 1). Materials, labor, and support equipment to process material and rigup/rigdown the drilling system are greatly reduced with the proposed microhole infrastructure. A coiled-tubing-deployed, mud-motor-powered, PDC-bit rotary-drilling system (Leising and Newman, 1993) was examined to identify any theoretical or practical reasons that deep, small-diameter holes cannot be drilled and completed. Some proof-of-concept, laboratory-scale microdrilling demonstrations were conducted to support the investigation (Dreesen and Cohen, 1997). To date, no fundamental limitation on microdrilling to depths in the range of 5000 to 10,000 ft has been identified. This document is the first draft of the Road Map that defines the technology development necessary to make microdrilling happen. Drilling programs for shallow- and moderate-depth demonstrations will be developed once the final Road Map is completed and demonstration sites are selected. A full suite of acoustic and electromagnetic sensors and sources for deep investigation, and temperature, pressure, and fluid-property sensors for near well examination are either available or can be developed from existing technology. The cost estimates for the logging tools in questions are developed in separate reports (Sinclair 2000 and 2001).

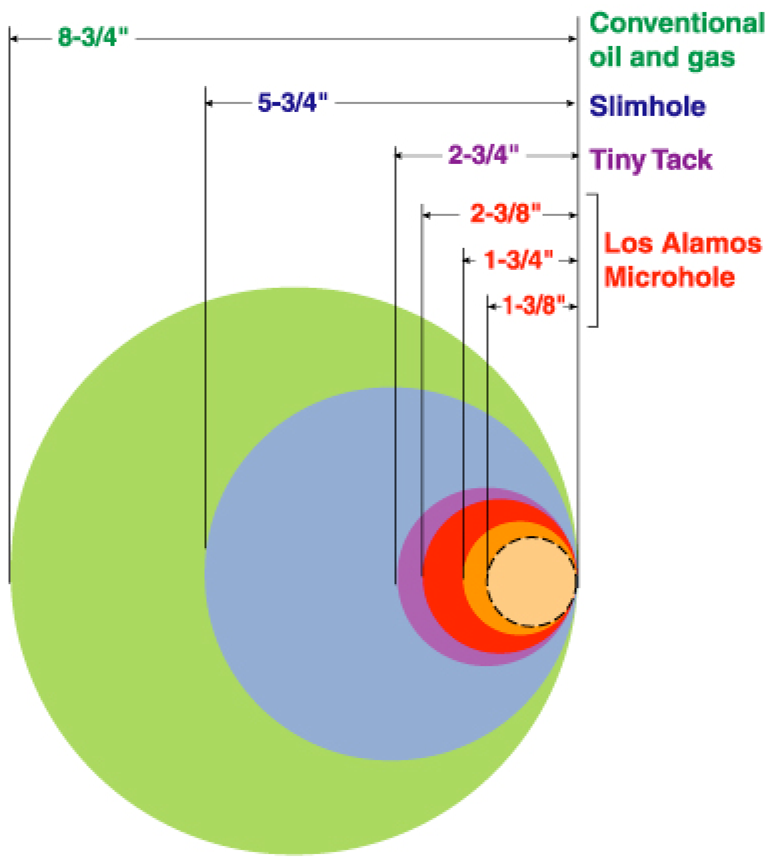



Fig. 1. Bore size illustration compares conventional bottom hole well diameters to slimhole and microhole sizes to emphasize the potential for materials and equipment size reduction through the use of microholes.

## BACKGROUND

The idea of drilling holes as small as 1-in-diameter in the deep earth is not new. Bits that bore a 1.175-in. (29.8-mm) hole to recover a 0.735-in. core are standard bits in a diamond drilling handbook (Heinz, 1985). These bits are run on drill rods with an outside diameter of 1.098 in., using a mining rotary drill (rig). Mining drills use impregnated, or surface-set, diamond-rock cutters, and rely on a narrow annulus, high rotary speed, and low weight-on-bit applied from the rig to produce core in moderate- to high-strength rock. No extraordinary effort to balance the drill rods for high rotary speeds is required because the bore walls and the narrow, fluid-filled annulus, dampen vibrations and preclude destructive resonance that would damage the bit and drill rods. Diamond-rotary core heads that produce small cuttings, a low fluid-circulation rate, and low penetration rate exist and produce the required hole cleaning and lubricity. The mining drill (Heinz, 1985) is well suited for hard- and medium-strength coring, but mining drills adapted for sedimentary drilling and coring (Sinor et al, 1995; Warren et al, 1996) have not found wide acceptance for drilling slim holes in oil field rocks. Concerns about well control, low penetration rates, bit balling in deeper clays and shales, hole stability in softer formations, and depth limitations of drill rods have limited the mining drill's application in oil field drilling.

Coiled-tubing-deployed drilling has found more acceptance in petroleum drilling and exploration over the last decade than the adapted mining drill. As of the year 2001, the coiled-tubing drill has only found a niche due to a shortage of coiled-tubing units (CTU) and the high cost of new CTUs as compared to an abundance of old, fully depreciated drill rigs. The latter are available while the rig counts remain low compared with historical highs.

The acknowledged benefits of coiled-tubing deployed drilling (Byrom, 1999) are:

1. Greatly reduced tripping time for bit or bottom-hole-assembly changes
2. Continuous drilling-fluid circulation while tripping

3. Simple, robust, pressure control during drilling
4. Suitability for highly automated drilling
5. Simple and robust data and control transmission through wirelines installed inside the coiled tubing
6. Low rig-labor requirement compared with conventional tripping
7. Reduced rig size, increased portability, and reduced location size requirement

The deficiencies of coiled-tubing deployed drilling (Byrom, 1999) that applied to the microdrilling are:

1. It requires a hydraulic or electric-powered, downhole drilling motor.
2. Slide drilling (no capability to rotate drill stem) reduces hole cleaning, increases friction between bore wall and drill stem, and limits weight-on-bit that can be applied from the surface. *This is a major problem in highly directional and horizontal drilling. It is not a major difficulty in near vertical drilling or in short directional laterals from a deep, near vertical bore. Very high circulation rates and short tripping (long cycle reciprocation of the drill stem) improve cuttings transport, but drilling performance is reduced due to increased time off of bottom.*
3. High circulating pressure and power loss, as compared with coupled drill stem, while drilling with a significant amount of tubing on the reel unless the flow rate is low and differential pressure drop across the bottom-hole drilling assembly (BHDA) is very high. Motors to support low-flow, high-differential pressure drilling do not presently exit.
4. There is a lack of backup and redundancy related to stuck pipe, fishing technology, and loss of returns during drilling and conventional drilling rigs must frequently be deployed to get out of trouble.

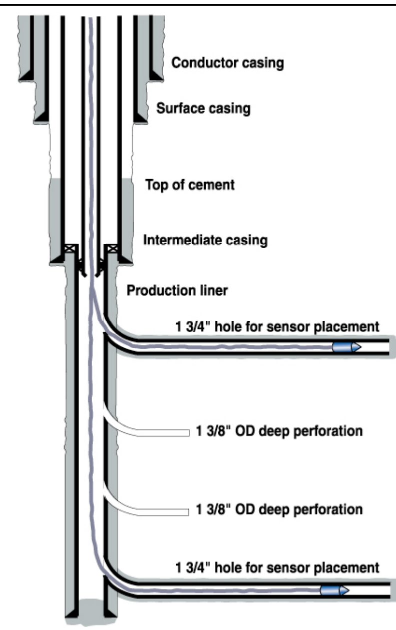



Fig. 2. Though-tubing microlateral and deep perforation concept using micro-drilling technology. The DeepLook Consortium pursued microdrilling as means to place sensors away from the well bore to locate bypassed oil and then drill to and produce bypassed oil from "ultra-deep" perforations produced by microdrilled and microlateral completions.

Based on our analysis of the technical challenges and potential economic benefits of microdrilling we concluded that automation and reduced labor requirements were equally important to the reduction of mass and size of the drilling system in achieving the cost reductions needed to make microdrilling commercially attractive. The principal industry interest expressed in microdrilling has been for: (1) deep well, through-tubing interventions to produce "deep perforations" or openhole-completed, multi-laterals to find and develop production from bypassed oil in prolific reservoirs (Fig. 2), and (2) shallow bores for vertical seismic array deployments and shallow production wells. Coiled-tubing deployment seemed to be a good match for both; therefore, a coiled-tubing-deployed microdrilling system was examined as the primary system for development.

## INITIAL MICRODRILLING RIG CONCEPT

**Rig Concept.** Los Alamos developed a basic microdrilling rig concept to achieve a readily automated drilling system that simplifies the more complicated and labor-intensive aspects of conventional, oil-field drilling, and reduces the size of the rig required for drilling and casing a microbore. The coiled-tubing-deployed drill was selected so that the insertion of a hard-wire, bottom-hole data-acquisition and control telemetry cable inside the drill stem was possible. Figure 3 shows an early concept. In order to support directional drilling and to minimize the bottomhole drilling assembly (BHDA) assembly/disassembly time during trips, weight-on-bit is applied by slack-off of the support of the tubing weight in deep holes, or by surface thrust on the tubing in shallow holes. A relatively large-tubing outside-diameter-(OD)-to-bore-diameter ratio increases the allowable bit thrust that can be applied (Qui, Miska, and Volk, 1998) before buckling occurs. A two-thirds ratio, as opposed to a more traditional one-half ratio in use for conventional drilling systems, achieves an optimum hydraulic power transport to the BHDA based on simple power law simulation of the circulating flow loop (Fig. 4). A continuous, constant OD-tubing drill-stem and short BHDA simplify the blowout-pressure control equipment (BOPE) and reduces the substructure height. The required mast height for handling the BHDA components is dictated by the maximum anticipated drilling-motor length since these are likely to be the longest components that will need to be inserted.

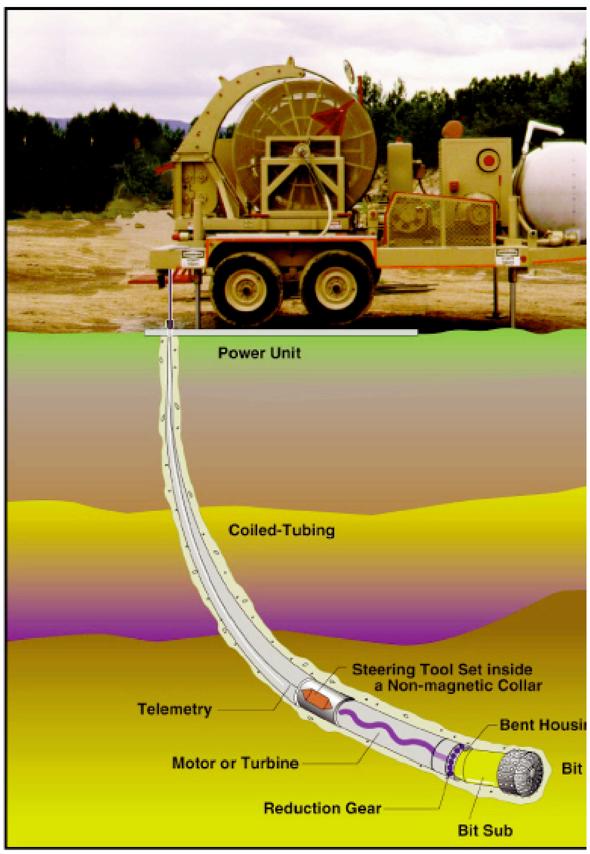



Fig. 3. Early Representation of the Microdrilling Rig and Drilling Assembly Concept

**BHDA Concept.** The basic drilling assembly includes the following components listed from the bit up to the coiled tubing:

1. **A PDC or diamond rotary bit**. The bit is designed for high rotary speed, low weight-on-bit drilling. Rotary percussion bits will be needed to penetrate hard formations, and conglomerates with hard spots (Melamed *et al.*, 2000).
2. **An instrumented, near-bit sub.** The sub includes measure-while-drilling (MWD) inclination and azimuth position sensors, and axial and torsional stress sensors to determine weight-on-bit and torque in the sub housing. The sub includes an electric power source or converter and a two-way radio for telemetry to the main instrument sub located between the motor and vibra-tion isolation sub. An advanced system would include a presently undefined, mechanical positioning system to make the near-bit directional adjustments and a near-bit logging-while-drilling (LWD) subassembly. Advanced second generation MWD measurements would include both the steady state and high frequency dynamic drilling data for downhole diagnostics and control.

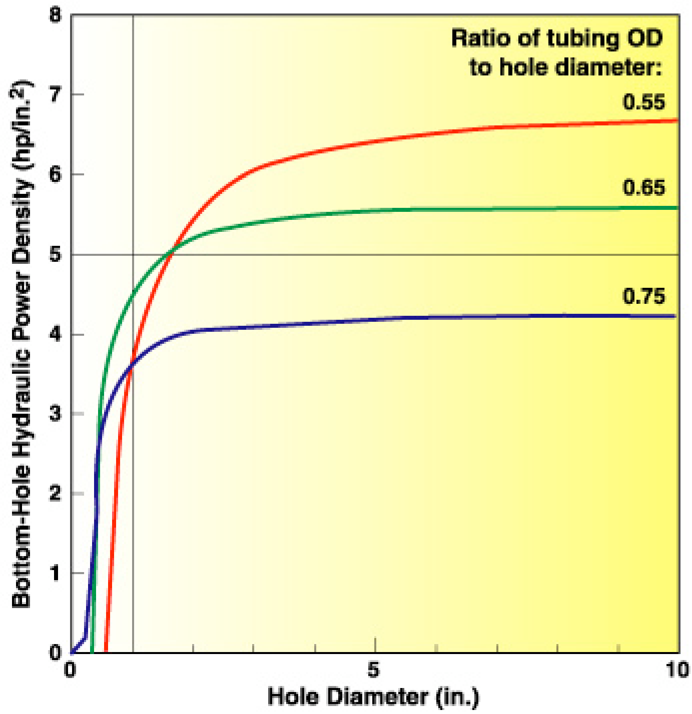


Fig. 4. Hydraulic power transport calculation results that suggest that a 2/3 tubing-to-hole-size diameter ratio optimizes the power to the bit. This calculation was based on a low viscosity mud with power-law fluid rheology.

3. **Drilling Motor.** A Moineau-principle, PDM converts hydraulic power transported down the drill stem to rotary mechanical power. The PDM will be a short, single-lobe, high-speed, low-torque motor designed to operate at low liquid phase flow rates. An advanced, second-generation motor would include a rotary percussion converter, and eventually, a controllable split between rotary and percussion power.
4. **Isolation sub**. This sub will isolate the instrument sub and coiled-tubing from vibration, the rotary motor and bit-induced resonance, and pressure pulsations reflected back from the motor inlet. (Melamed *et al*, 2000).
5. **Safety release sub.** The release sub disengages most of the BHDA, including the motor and isolation tool, to allow recovery of the telemetry sub and coiled tubing, and leaves a fishing neck looking up from the BHDA.
6. **Telemetry sub**. The sub includes two-way radio-telemetry circuit for bit-sub communication and the circuitry needed to send and receive digital data through the cable installed in the coiled tubing. The cable connects the surface data acquisition and control system to the BHDA. An advanced, second-generation telemetry sub would include additional sensors for far-bit MWD and LWD requirements.
7. **Crossover sub.** This sub connects the telemetry sub to the coiled tubing.

**Directional Control**. Trajectory control was one major concern raised by drilling experts during the formulation of the initial concept. A properly designed BHDA with an appropriate transition between the coiled tubing and BHDA (stiffness and diameters) can operate with a low compressive stress (well below the critical buckling stress), and should provide a reasonable straight hole drilling system. The combination of high rotary speed (and high percussive speed) and low weight-on-bit should reduce the tendency to deviate the trajectory. In formations prone to deviate drilling, an active, real-time, trajectory control system with near-bit sensors will almost certainly be required to maintain the desired trajectory. Since this capability is needed for an optimum directional-drilling system anyway, it was included in the initial concept for straight-hole drilling in deviation-prone formations and for directional drilling. It has been assumed that as these capabilities have been demonstrated at conventional and slimhole sizes (Blount, Gantt, Hearn, Mooney, and Smith, 1998), microsized technology is feasible.

**Drilling-fluid Circulation.** Drilling-fluid circulation serves the same function in the microdrilling concept as it does in most traditional slide drilling. These include:

1. cooling the bit,
2. removing cuttings from the hole and cleaning the bit,
3. transporting the cuttings up the drill stem/bore annulus to the surface, and
4. transporting hydraulic power from the surface to the drilling motor.

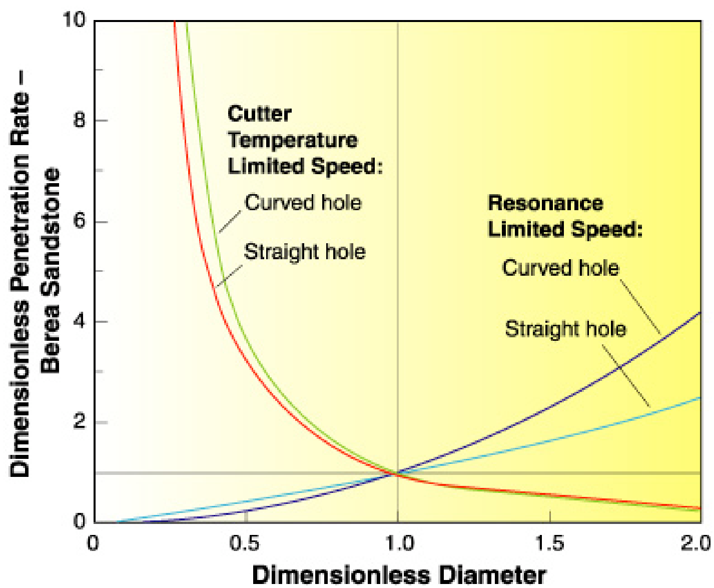



Fig. 5. Los Alamos bit model results that support the concept for a short, very high rotary speed drilling motor to power a drag bit. If resonant speeds can be avoided by keeping the drilling assembly short to make the lowest resonant speed very high, high rotary speed bits should maximize the penetration rates because cutter speeds are relatively low in microbits.

In order to optimize hydraulic power transport, a low-flow-rate circulation system is needed to reduce power losses inside the drill stem and in the annulus. Therefore, an efficient hydraulic-to-mechanical-power converter consisting of a drilling motor or hydraulic rotary hammer must be develop. The converter-bit combination must produce small cuttings that can be readily transported in a small microhole annulus. Three basic conversion systems should be considered:

1. **A soft rock drilling system.** A short, single-lobe drilling motor with only a few stages can be configured to deliver the high rotary speed and the low-to-moderate torque needed to generate high penetration rates with a small depth-of-cut required to produce small cuttings for transport in narrow microhole annulus (Fig. 5.). This motor output must be produced with a rather large pressure drop across the motor compared to present designs. The motor will need sealed bearings that are cooled by the flow through the motor as opposed to flow through a bearing assembly that bypasses the bit. High-pressure nozzles can be fed through the motor to clean the bit and hole bottom. Much of the pressure at the top of the motor will be conducted through the motor to the bit. A large pressure drop in the bit jets will be converted to jet-drilling power, hole- cleaning, or some combination of both to optimize the penetration rate in soft rock.

2. **A hard rock drilling system.** Rotary and percussion drilling can be combined to achieve a low weight-on-bit penetration system. Hydraulic hammers are compatible with a low-flow-rate, high-pressure-drop source. A low-pressure-drop PDM is needed to rotate a percussion drill at sufficiently high rotary speeds to achieve optimum indexing for a high frequency hammer producing small cuttings. A versatile drilling system would include a variable power split between the rotary and percussive modes to optimize the penetration rate in a large variety of rocks. A fully integrated drilling motor would include a PDM, a hydraulic hammer, a hydraulic/mechanical isolation tool at the top of the motor, and a near-bit instrument sub that can survive the percussion loading.

3. **An efficient downhole motor powered with compressible drilling fluids**. An efficient downhole motor powered with compressible drilling fluids is needed to drill under-pressured formations and depleted reservoirs that experience high drilling-fluid losses when drilled with traditional water-based mud (Graham, 1995). Both rotary and rotary-percussion systems need to be adapted to operate efficiently with compressible drilling fluids. It is anticipated that conventional approaches to drilling motors for compressible fluids will produce very poor conversion efficiencies. This technology development will require a novel approach for its solution.

For all of these systems, the flow rate will have to be high enough to keep the cuttings concentration at any point in the annulus well below 5% by volume at the maximum desired penetration rate. High concentrations will result in excessive pressure losses due to particle interactions. Determining the optimum circulation rate to produce the optimum penetration rate is a complex, non-linear optimization problem that will require a computationally sophisticated systems analysis.

## WELL CONSTRUCTION AND COMPLETION

The concept for microwell completions outlined below does not include any use of expanded metal casings to reduce the intermediate casing sizes required to drill to the target depth. There is no theoretical limitation that we are aware of that would preclude the use of this technology in the microhole sizes proposed in this Road Map. The expansion of microsized tubing/casing will increase the potential depth of the microdrilling capability, and decrease the rig-size requirements, in the same way this technology impacts conventional-sized drilling. We anticipate that the application of expanded metal casings to microsizes will not require any breakthrough technology, and would be a logical improvement that evolves quite naturally once the basic microwell completion concepts proposed here are successfully demonstrated. An early concept for completing a 5000-ft-deep microhole with conventional completion technology is shown in Figure 6.

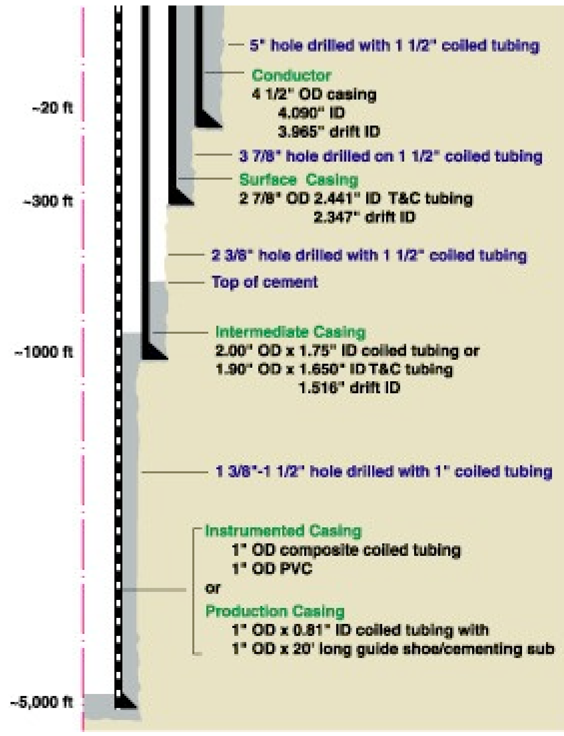



Fig. 6. Early concept for a 5000-ft-deep microhole completion.

**Conductor pipe.** A conductor pipe is installed in an auger-drilled hole that penetrates a few feet of competent rock, or is drilled to 20- to 30-ft deep in unconsolidated soil. The conductor is cemented with a wiper plug displaced with water and landed on a collar at the appropriate height above ground level for initial rig-up of pressure control and circulating equipment.

**Surface and Intermediate Casings.** A concept for installing surface casing, intermediate casings if required, and a final production casing has been developed, but has not been demonstrated in the context of a coiled-tubing-deployed microdrilling. The CTU design will facilitate quick field reel changes. Each string of continuous casing—a standard size coiled tubing with the internal weld bead removed—is reeled onto its own reel and installed on the CTU. Each casing serves as a drill stem before it is installed as a casing. After the casing/drill stem is drilled down to the shoe depth, the BHDA is tripped out, the telemetry cable is removed from the coiled tubing, and a bottom-hole-cementing-assembly (BHCA) is installed. The BHCA includes: a washing/spudding shoe, a float valve, landing joint(s), a wiper plug catcher, and a crossover to connect to the continuous casing. As the casing is inserted, fluted casing centralizers are clamped on to center the casing in the annulus. The casing is washed to bottom, landed and hung-off in a wellhead, and cut off from the remaining reeled casing. A cementing head is installed on the wellhead, and the hole is circulated to condition the mud for cementing. A standard cement job is performed and displaced with a wiper plug and water. While the cement sets up, the reel is replaced with the reel of the next smaller diameter drill stem/casing, and a BHDA is installed on the bottom end of the tubing to drill out the wiper plug and the cemented casing BHCA. The next smaller casing is then drilled down to its intended shoe depth and it is installed in a similar manner.

**Production Tubing.** Cased hole or openhole completions are both feasible as long as the smallest coiled tubing and its BHDA will fit inside the production casing. Long term monitoring can be conducted from wirelines or coiled-tubing-deployed instruments that are installed or inserted and retrieved on a schedule. Mechanical perforators, abrasive jet perforators, or perforators can be downsized and run on small, mono-cable wirelines or the coiled tubing to support sampling of production from cased holes. The coiled tubing can be inserted as a tubing string after stimulation if a tubingless completion is not feasible.

**Stimulation.** Reservoir sampling or production wells may need to be stimulated. For now, it has been assumed that most stimulation methods will be feasible in microholes. Clearly there will be major challenges learning how to adapt stimulation technology for microsized holes and this technology will have to be developed and evaluated.

## INDUSTRY INPUT TO THE INITIAL CONCEPT

**Industry Contractors and Collaborators.** Two contractors have participated in the development of the initial microdrilling concept:

1. **Maurer Technology**. Under contract to Los Alamos National Laboratory, Maurer Technology conducted early drilling laboratory testing of 1-1/2-in. and 1-11/16 in. OD drilling motors, a 54-mm hydraulic hammer, and 1-3/4-in., 46-mm, and 59-mm bits (Dreesen and Cohen, 1997). The proof-of-concept testing program produced: (1) a database on penetration rate versus weight-on-bit and rotary speed for various bits and rocks, (2) motor performance data for the smallest commercial drilling motors then available, and (3) limited drilling performance data for the PDMs and a hydraulic hammer in Berea Sandstone, Carthage Marble (Limestone), and Sierra White Granite. Maurer Technology also developed some concepts for a downhole sub-component that would regulate the weight-on-bit.
2. **Coiled Tubing Engineering Services, L. C.** (CTES, L.C.). Under contract to Los Alamos National Laboratory, CTES ran their coiled-tubing forces and fatigue models to (1) calculate the weight-on-bit that could be applied with surface thrusting for various trajectories, and (2) predict the tubing life under the simulated drilling conditions (CTES, L. C, 1996.). CTES also developed a conceptual design for a coiled-tubing-deployed microdrilling platform. Their concept included an elevated reel that eliminated the gooseneck on the CTU and thus reduced the fatigue cycles to one-third the number of cycles that occur using a gooseneck.
3. **Fleet Cementers** (formally a subsidiary of Plains Energy Services Ltd. of Calgary, Alberta Canada and subsequent to our interaction a subsidiary of Precision Drilling Corporation). Tom

Gipson, President of Fleet Cementers, reviewed and critiqued the microdrilling concept and shared some of Fleet's experience with coiled-tubing-deployed drilling of conventional-sized and slimhole bores. Their experience supports our expectation that drilling with short drilling assemblies and coiled-tubing thrust on the drilling assembly would preclude the need for drill collars.

**Industry Feedback.** Early variations of the initial microhole-drilling concept were presented to many oil and service company representatives, and industry consortia. Concerns expressed about technical and practical aspects of this approach focused on three aspects of the concept:

1. **Market for microholes.** Several industry representatives have indicated that they find the microborehole technically plausible but do not believe that the concept is marketable to the drilling industry. They see a chicken and egg problem that will result in a repeat of the slimhole experience, which has limited slimhole drilling to a small niche of the total oil field drilling business. They cannot see microboreholes as being even a very small niche of the slimhole drilling business. Typically, they cannot imagine a cost savings sufficient to drive the near simultaneous development of the infrastructure required to make microboreholes an attractive alternative to conventional holes.
2. **Drilling performance.** Our economic justification for the microborehole concept has focused on two major benefits: (1) Reduced mass of the system components that reduces the materials required by an order of magnitude and fabrication and mobilization costs by a lesser factor. (2) Reduced labor costs because everything that can be automated will be; the handling of small components will not require more than two people when operations are not readily automated. Some in industry do not seem to place as much value on these cost benefits as we do; most industry input emphasizes high drilling rate as a critical aspect of the microdrilling concept. Without an advanced drilling concept based on an entirely new, or at least different drilling process, we do not believe that a substantial increase in drill rate over representative conventional rates is feasible for deep microdrilling. Just achieving a customary drill rate using a hydraulic-powered drill presents a major challenge for the following reasons:
   (a) As the annular gap between the drill stem and bore is decreased, the maximum allowable drill-cutting particle-size must be decreased proportionally. Therefore, the specific energy to fragment a formation is greater, which increases the hydraulic power that must be transported to the drill motor.
   (b) Flow rates in the annulus must be kept low to assure that pressure losses in the annulus are not excessive (e.g., exceed the allowable maximum circulation density). The volumetric cuttings concentration must be kept well below 5% to maintain a continuous liquid phase and avoid the high pressure loss that occurs when solid particle interactions start to influence annular flow behavior. The combination of low annular flow rates, high penetration rates, and low annular particle concentrations produces a contradiction.
3. **Annular flow**. Our initial hydraulic power transport calculations assumed a power-law fluid and ignored the effect of cuttings transport. Several drilling experts have warned that the friction pressure drop in the annulus will exceed the pressure calculated with simulators even after cuttings transport is included in the model. They are concerned that the equivalent circulating density during drilling will lead to well control problems during tripping, and will cause severe loss circulation problems in normally pressured formations.

## FIELD DEMONSTRATIONS RESULTS

Coiled-tubing deployed microdrill field demonstrations have been conducted at three sites. All of the demonstrations have been conducted with a single daylight drilling tour and long shutdowns each night and most weekends. The selection of bits and bit motor combinations for the formations that were encountered should not be considered as optimal. Typical bottom-hole-assemblies included:

1. A drag bit. Figure 7 shows four bits that were used in the early field demonstrations.
2. A bit sub if needed.
3. PDM runs which included 1-1/2 in. OD, single-lobe and 1-11/16 in. 5:6 multi-lobe motors.
4. A double ball check.
5. A mechanical/ hydraulic release sub set to shear at 4000 to 6000 $lb_f$.
6. A coiled-tubing connector with a slip-grab.
7. A 1-in. OD, 0.087-in. wall, 0.826-in. ID, 0.810 $lb_m$/ft, Grade 70 or 1-in. OD, 0.095-in. wall, 0.810-in. ID, 0.918 lb/ft, Grade 70 coiled tubing.

**Fenton Hill Site.** Two microwells were drilled in welded volcanic tuff at LANL's Hot Dry Rock Geothermal Test Site. The first 1-3/4-in-diameter well was abandoned after a bottom-hole assembly stuck at 110-ft depth while drilling a presumed rubblized zone between ash falls. A second 2-3/8-in hole was drilled to 90 ft following the original well plan. Figures 8 and 9 show pictures of the Los Alamos microdrilling rig and mud system preparing to drill at the Geothermal Test site.

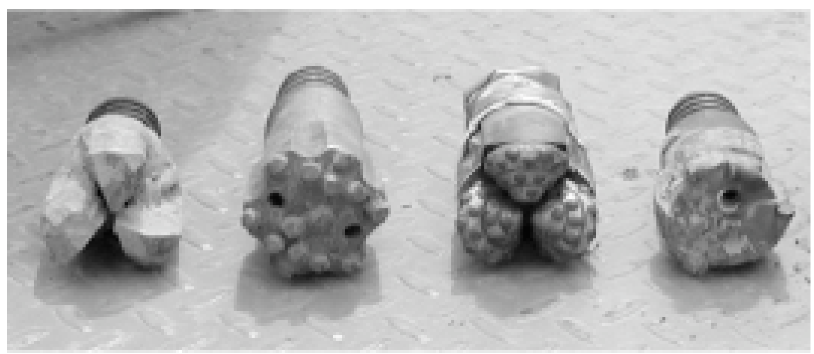


Fig. 7. 1-3/4-in. and 2-3/8-in. bits that were used in the early field demonstrations.

Fig. 8. The Los Alamos coiled-tubing microdrilling rig, (center front), with the mud cleaning system (far left), and the logging van which houses the data acquisition system (far right).

Fig. 9. The Los Alamos mud cleaning system includes a shale shaker, settling tank, and hydrocyclone mud cleaners. The cleaner was manufactured by TriFlo to meet the needs of the trenchless utilities industry It has been upgraded by Los Alamos to improve the performance of the cleaning unit to reduce mud-pump wear.

**Basin and Range Dry-Lake-Bed Sediments.** Four 2-3/8-in. OD microholes were drilled to depths between 315 and 550 ft (Thomson, Hufford, and Dreesen, 1999) in a dry lake area in a western Basin and Range province. A number of deficiencies with the coiled-tubing unit, mud circulation system, and the well plans were identified. The well plans were updated on the second pair of wells and drilling performance was increased. A plan to overhaul the coiled tubing unit and mud circulation system was developed after an evaluation of the 4-well drilling campaign was completed. The overhaul was completed before the next field demonstration. Figure 10 shows a picture of the Los Alamos microdrilling system drilling in lake bed sediments.

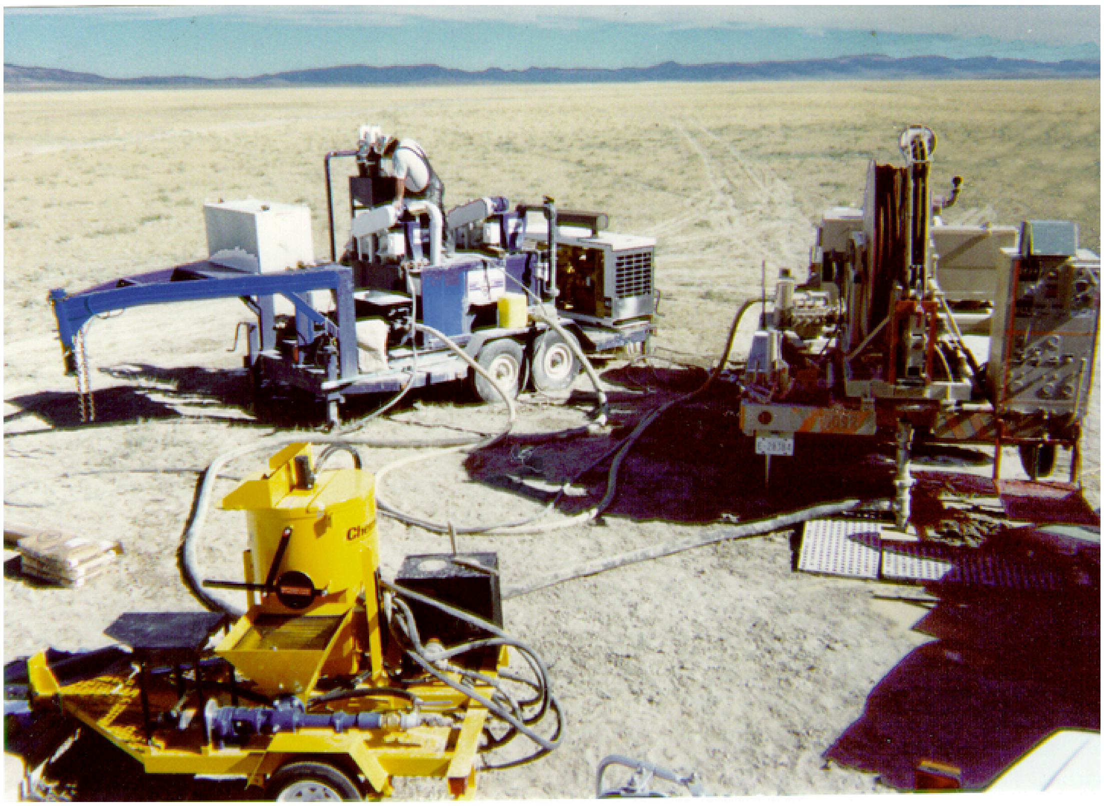


Fig. 10. The Los Alamos coiled-tubing microdrilling rig, far right, with the mud cleaning system, rear left, and contract grout/cement mixer, front right, rigged up to drill in a basin in the Basin and Range Province of the Western United States.

**San Ysidro Site, Sandoval County, NM.** Four 1-3/4-in. and 2-3/8-in. OD microholes were drilled to depths between 182 and 706 ft in soft unconsolidated, or poorly consolidated, blow sand and stream-bed deposits. The first two wells were drilled in a dry wash valley. The first well was abandoned at 182-ft after a hard section precluded future advance. It was deduced that a severe wash out just above 180-ft depth reduced the critical buckling load for the coiled tubing so that insufficient weight-on-bit could be applied to penetrate the hard section. Figure 11 shows a well schematic for the second well drilled at the San Ysidro Site. The second hole encountered a 6-in.-thick, hard section at 189-ft which was penetrated using a rotary percussion drill. Artesian water flows were encountered at 307 ft and 412 ft. This flow increased the annular flow velocity during drilling and contributed to erosion and collapse of the bore wall in an unconsolidated section so that drilling operations were suspended at 599-ft

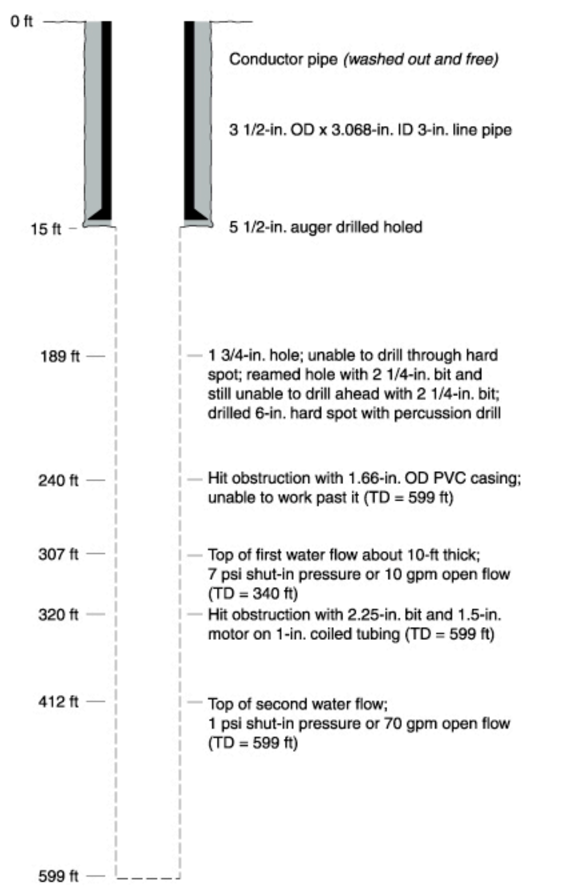



Fig. 11. Well schematic for the second well drilled at the San Ysidro Site.

The second pair of wells was drilled on a ridge overlooking the valley floor in order to ensure that artesian flow would be avoided if the aquifers were penetrated. Even without artesian flow, well collapse occurred due to long formation-soak times that occurred while waiting on mud pump parts. The second hole reached a depth of 706 ft before the deterioration of the bore wall discouraged continued drilling. Figure 12 shows the coiled-tubing unit and mud-system drilling on the ridge at the San Ysidro site. A detailed description of the drilling demonstrations and the successful methods and attempts to complete the wells is included in the Appendix.

## WHAT WE CAN DO NOW

**Hydraulic-powered Rotary Motor Drilling.** Barring budget constraints, Los Alamos presently has the capability to drill 1-3/4-in. and 2-3/8-in. holes up to 800-ft deep in unconsolidated and soft sediments with commercial PDMs. We believe that we will be able to drill 1-3/4-in. holes in medium-hard sediments to 800-ft if we can develop a drilling site in this type of rock without introducing any other drilling complications that we have not yet mastered. We can drill short, hard layers with a rental percussion drilling system that fits in a 2-3/8-in. hole. We can complete the holes with a cemented-in casing in stable formations, and have demonstrated that we can install casing and seal it in with a bentonite grout in unstable formations.

## ADAPTING THE INITIAL CONCEPT BASED ON FIELD OPERATIONS RESULTS

The following modifications or adjustments (identified during the field demonstrations) would improve the performance of the current system:

1. A small auger drill needs to be included in the concept to install a conductor pipe at least 30-ft deep. The auger diameter will depend on the need for an intermediate casing to reach the target depth.
2. Low-flow-rate, high-differential-pressure, drilling motors are needed to reduce the circulation rate and thereby reduce the equivalent circulating density, the annular velocity, and the pump pressure required to circulate the mud.
3. The mud pump's reliability needs to be improved.
   a. The mud-cleaning system needs to be modified to produce cleaner fluid to the mud-pump suction.

b. Mud-pump valve designs and plunger packing glands need to be identified that are better suited for fluids with a fairly low concentration of fine solids.

c. Alternative high-pressure pumping systems need to be evaluated to determine if they may promise a more reliable capability at a reasonable size, weight, and cost.

Fig. 12. Coiled tubing unit and mud system drilling on the ridge at the San Ysidro, NM site.

4. Continuous, 24-hr-per-day drilling is needed whenever potentially unstable formations are exposed to the drilling fluid.

5. Casing installation procedures need to be modified to increase the reliability of the running and cementing operations.

   a. High-pressure-rated, reeled tubulars should be used to enable the casing to be washed to bottom in a bridged hole.

   b. A micro-scale version of conventional high-pressure cementing equipment needs to be developed to support cementing operations.

   c. Foamed cementing technology will very likely be needed to achieve the flow rates required for the effective removal of the drill fluid with bottom-hole-pressures within the allowable equivalent circulation density.

   d. A small clean-out drilling assembly needs to be developed to run inside the smallest coiled-tubing casing/liner.

## MISSING SUB-COMPONENTS AND NEEDED TECHNOLOGY

### Hydraulics and Drilling Fluids

**Hydraulic circulation system.** The basic concept relies totally on hydraulic power transport and conversion to produce microhole drilling and power for driving the bit, hole cleaning, and cuttings transport to the surface. The theoretical calculations for a power-law fluid and low penetration rate drilling (ignoring cuttings transport) indicated that reasonable penetration rates could be achieved to a depth of 5000 feet with a standard-sized, coiled-tubing drill stem and hypothetical drilling motors. Early field results with actual, off-the-shelf, drilling motors that require high flow rates to avoid stalling, showed that the resultant high-equivalent circulating density caused severe loss circulation and wellbore erosion. Special microdrilling motors will be needed to reach even shallow depths in formations susceptible to low pressure fracturing, erosion, and fluid invasion that produces formation instabilities.

**Hydraulic converter technology.** Small PDMs were not developed for openhole drilling; they are used primarily for scale removal and drill out of cement inside tubing. Off-the-shelf motors are designed to operate at high flow rates and standard differential pressure. They typically operate inside tubing and small liners where the high annular velocities needed to produce the required pumping power require high pressure pumps, but are otherwise harmless. Small motor designs are presently constrained by the industry's limited ability to fabricate small stators and rotors. Stators are manufactured using injection-molding methods that have evolved to fabricate much larger stators. Injection molding is not well-suited to production of small stators. The machine tools used to fabricate rotors are also optimized for larger rotors and are marginal when used for the smallest diameter rotors. The dimensional tolerances between the stators and rotors for the small motors are assumed to be of the same order as they are in conventional-sized motors. Therefore, interference between the rotor and the stator is significantly more variable in a small motor, and the conversion efficiency and performance of a small motor is therefore also highly variable. A large interference converts too much hydraulic power to heat in the stator, and a small interference allows too much fluid to leak across the rotor-stator seals, reducing both the pressure drop available for power conversion and the volumetric efficiency of the motor. Because the present market for small motors is very small, there is little incentive for the industry to increase the variety and quality of the small motors. There is even less interest in producing the even smaller motors that will be needed to drill and complete a 1-3/8-in. hole for which there is presently no market.

There are no small PDMs presently designed to operate at low-flow and high-differential pressure. The major technical barrier to the development of micro PDM motors is the fabrication of the rotors and stators. Methods to produce long, small-diameter rotors and stators have been proposed over the years, but it will take a significant investment to evaluate the various methods and demonstrate feasibility.

Hydraulic hammers are far less technically advanced than PDMs. The hammer that was tested in the laboratory (Melamed *et al*., 2000) was unable to produce penetration rates as high as a rotary drill, but probably would out-perform pure rotary drilling in hard rock in a shallow field demonstration on an economic basis, if not on a penetration rate basis. While prototype isolation tools have been designed and tested, there is no accepted performance specification established that assures that the drilling assembly will be protected. Consequently, no equipment is presently available that can be used with any assurance that it will provide the protection needed. Effective isolation tools will be required before rotary percussion drilling can be combined with downhole sensors and controller subassemblies

**Hydraulic modeling capability.** For microdrilling to reach 5000-ft depth, the hydraulic system must be optimized. Accurate simulation provides the most efficient means to achieve a first cut at optimization. Further optimization will require deep demonstrations with realistic flow geometry and drilling fluids. Relying on a field demonstration system to guide the initial attempt to optimize performance is very inefficient because of the large number of potentially controllable variables. This includes: fluid properties, coiled tubing-to-hole-size ratios, depths, penetration rates, and drill cuttings-size distributions that must all be varied in a realistic optimization process.

Published flow versus pressure-drop models start with Newtonian laminar and turbulent pipe flow, and introduce corrections for non-Newtonian fluids, annular flow, eccentricity, skew, and drill cutting concentration and transport. Each correction introduces small errors to the calculated result so large errors cannot be ruled out in predications of annular flow where all of these corrections must be applied. Industry drilling experts have repeatedly warned us that annular pressure losses will exceed calculated losses, and our limited field experience supports that. More accurate models are needed to support the process optimization that will be required. Optimization of rheological parameters and the annular gap to support drilling over a large range of depths, penetration rates, and cutting size distributions will be required.

**Mud Pumps.** High-pressure drilling fluid pumps are almost always a weak link in the oil field drilling system. They require more maintenance and are subject to significantly more unpredictable failures and down time than most other components in a drilling system. The mud pump failures observed in our limited field operations indicate that this will also be true for microsized pumps, and in fact, the small pumps may be more prone to excessive abrasive wear and catastrophic failures than full-sized pumps. The normal tactic to address mud-pump reliability is to have redundant pumps, a large inventory of spare parts on the rig, and sufficient manpower that can be quickly mobilized to overhaul pumps in the field. While this approach is very likely a possible solution for microsized pumps, it is not consistent with a highly mobile system because of:

1. The extra equipment necessary to provide redundancy and the manifolding required,
2. The adverse impact on automation and control requirements caused by the more complex system with higher level diagnostics and trouble shooting, and
3. The extra manpower to service, maintain, and repair pumps in the field.

Conventional mud pumps are triplex plunger or piston pumps. Many alternative pumping systems have been evaluated but none has found a commercial role on drill rigs. There are several alternative-pumping systems feasible in a small pump configuration, that have not proved to be practical in large sizes. These include the following concept pumps:

1. A throwaway version of the centrifugal horizontal pump. This is a submersible pump that has been adapted to high-pressure water injection service. Downhole submersible pumps have been modified to improve their performance in pumping fluids which have some solids in them. When manufactured in large quantities the cost of these pumps is relatively low when compared to other high-pressure pumps. If these pumps can be easily inserted and removed from the pumping-system and their life can be accurately forecast while pumping drilling fluids, then their use may be feasible.
2. A pressure multiplier (intensifier) pump. This is a positive displacement pump that uses relatively large, hydraulic-powered, reciprocating plungers to convert high-flow-rate, low-pressure, clean fluid, hydraulic power to a low-rate, high-pressure, slurry power. They have been used successfully for very high-pressure, high-sand-concentration, hydraulic-fracturing treatments. They require a lot of extra equipment, piping and operational complexity, which has not proven to be justified for traditional, high-pressure drilling pumps. In a microsized pumping system, the extra weight and complexity may be quite realistic if the power fluid can be common with the fluid needed to power the CTU.
3. A barrier type trash pump. These pumps isolate the plunger packing from the slurry with a flexible, low-pressure, highly elastic barrier to separate the working fluid from the fluid around the plunger packing. Unfortunately, these pumps do not address the abrasive wear on the pump valves which is often a more difficult problem than the plunger packing wear.

At this point this list is not complete, and other pumps should be considered before a technology selection for a short list of micropump concepts for evaluation is selected.

**Drilling fluid cleaning.** Regardless of the high-pressure mud pump that is selected, providing the cleanest fluid possible to the pump suction will greatly reduce the effective pumping cost. All high-pressure pumps are vulnerable to accelerated wear when pumping abrasive fluids. Any significant reduction in the fine abrasive content of a fluid will be rewarded with reduced pump maintenance and repairs.

A low-flow-rate, mud-cleaning system is needed that cleans the mud at least as well as the best technology available for full-sized mud systems, and that removes fine abrasives if this can be done with a compact, readily automated system. Based on a brief review of present mud-cleaning technology and our experience with an off-the-shelf cleaning system, we believe that a three-stage hydrocyclone and shaker system will be sufficient. It may be possible to use horizontal separator technology to reduce the quantity of fluid that has to be processed through the first, large particle removal stage. Shaker screens are a weak link in the present technology, and they may have to be replaced or augmented with small settling tanks and sump pumps to recover screen overflow.

## Downhole Drilling Sensors and Controls

**Weight-on-bit and torque sensors.** The capability to make accurate, real-time, bottomhole measurements of weight-on-bit and torque is a critical element of a deep, coiled-tubing-deployed drilling system. Slide drilling inherently generates greater friction between the drill stem and bore wall than rotating drilling, and therefore, surface measurements of drill stem tension and torsion are not a good indication of drilling condition in deep holes.

The best indication of bottomhole drilling conditions would be a continuous measurement of torsion and compression stress in the bit sub. The sensors should provide a steady-state average for basic drill process control and high-data-rate amplitude data for dynamic analysis for advanced drilling process control and bit damage prevention. Measurements above the downhole motor are easier to support than bit-sub measurements, and may be adequate for microrotary-drilling systems in soft-to-medium strength rock. Hard rock and rotary percussion drilling and instrument-protection isolation capability will require near-bit sensors to achieve practical downhole control.

**Downhole weight-on-bit and torque control.** An ideal weight-on-bit control system would provide positioning information to the surface so that drill stem can be inserted as hole is produced and generate a downhole compression stress in a variable length housing as close to the bit as feasible. A downhole torsion control loop will need to generate the torsion in the downhole motor with a rotary speed controller. Selection of the steady-state target output values for weight-on-bit and torsion will be generated manually at the surface by the driller or by automated drilling-control system. A control system would evaluate the downhole, steady-state, sensor data (and dynamic near-bit and downhole sensor data, if available in real time) and automatically develop a drilling rate and bit life optimization tradeoff strategy.

## Downhole Trajectory Sensors and Directional Drilling Controls

**Inclination and Azimuth Sensors.** Accurate, real-time, bottomhole measurement of inclination and azimuth will be needed to feed an active directional control system. Bit sub sensors are critical for timely input to the trajectory control system.

**Deviation and Orientation Positioner.** Two mechanical adjustments must be made to control the direction of the bit. A near-bit housing must be deflected to push the bit off the present hole axis, and the bend developed must be properly oriented to deflect the hole in the proper local azimuth. These actions use the bottom of the drill stem as the local reference point, and the controlled output must be adjusted in real time as the drill stem reacts to the resultant loads.

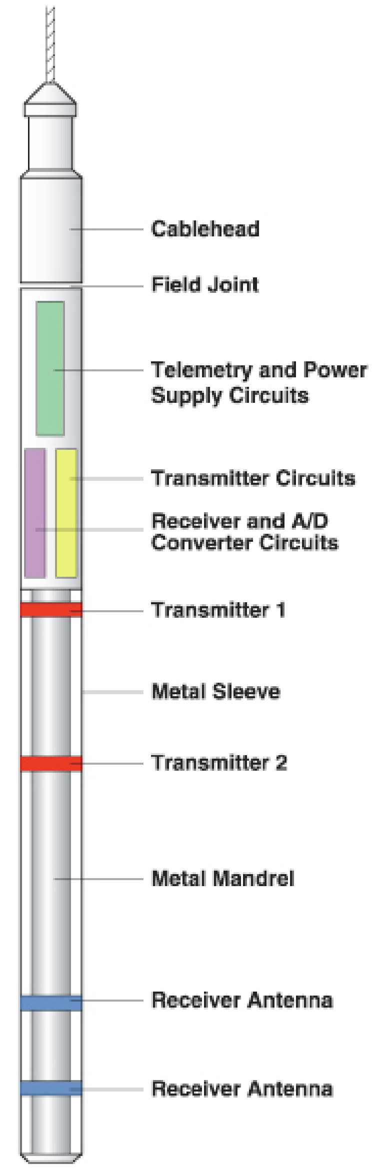



Fig. 13. Schematic of conductivity tool that can be designed as a 1-7/8-in. OD micro-logging in sonde.

### Logging Tools

**MWD/LWD.** Provisions for additional measurements and logging will be site- and job-specific, and will not be addressed here other than to state that the telemetry support and sensor housings need to be included in the final concept.

Wireline logging tools for openhole logging are being investigated under a separate project (Sinclair, 2000 and 2001). Based on the results from this project it appears that microsized formation logs for formation density, electrical resistivity, natural gamma ray, and spontaneous potential are all feasible with tools as small as 7/8-in. deployed on wireline (Fig. 13). Second generation tools that can be run on coiled-tubing in directional holes or as MWD appear to be within reach as well.

### Telemetry

Two telemetry systems will be required:

1. A BHA system that transmits data from the near-bit sub to the instrumentation sub at the bottom of the drill stem. This system can be a two-way radio receiver/transmitter or alternatively, a hard-wire telemetry system, if the drilling motor provides the pass through and space for commutation required.
2. A drill stem telemetry system that transmits data from the instrumentation sub to the surface telemetry system.

## Completion Technology

**CT Completion Equipment.** In order to use drill stem as a CT completion string, microsized equipment is needed to support cementing the tubing, hanging and sealing the tubing into a wellhead, cleaning out the inside of the coiled-tubing, and perforating the coiled tubing for sampling or production. The following equipment will have to be developed to support completion of microholes.

1. Bottomhole cementing equipment. Guide shoe, landing joint, float valve, and wiper plug catchers will have to be downsized to fit on various sizes of coiled-tubing (See the Proposed Drilling Programs.)
2. Centralizers. A wraparound, clamp-on centralizer will be needed to center the casing where zone isolation is required.
3. Tubing hangers. Hangers for small coiled tubing are needed to seal between a wellhead fixture and coiled tubing hung off in tension or compression.
4. Cleanout equipment. A system to drill out cement and wiper plugs in the production casing is needed. This can be the same drilling system used to produce an openhole completion in stable rock below the production casing, or a smaller drilling system that can be run on a smaller coiled tubing that will not be cemented in. The small tubing may be used as a tubing string after the clean out, perforation, and stimulation are completed.
5. Perforations. Methods to run a through-pipe correlation log and perforate a cemented casing must be developed to produce sampling ports and production perforations.

## CONCEPT DESIGN FOR 5000-FT DEEP MICROHOLES

The three concept microwells proposed below are designed for production or reservoir monitoring service. This is assumed to be the most challenging service for a 5000-ft hole. An exploration well will be less challenging because a production casing will not be needed. These microwells are assumed to be near-vertical wells drilled in normally pressured formations with a water-based drilling fluid.

**Three Generic Drilling Programs.** Three generic drilling programs are proposed for production microholes at a nonspecific site. Well Program "A" includes an intermediate casing. Well Program "B" does not. Well Program "C" produces an exploration hole for openhole logging or monitoring in an uncased bore, which is much too small for commercial production of fluids.

**General Objectives:**

| | |
|---|---|
| **TD:** | **< 5000 ft** |
| **PBTD:** | **< 4980 ft** |
| **Depth of production casing:** | **< 5000 ft** |
| **Depth of casing perforations:** | **< 4800 - 4900 ft** |
| **Depth of tubing:** | **< 4750 ft** |

The drilling concept selects holes sizes and coiled-tubing drill stem/casing sizes to produce a 1-in. internal diameter casing at 5000 ft. It is assumed that an auger-drilled hole will be used for the conductor casing and it will be drilled to 20-ft or until 5 ft of hard rock is penetrated.

| Drilling Program A | Production Hole With Intermediate Casing Required | | | |
|---|---|---|---|---|
| **Depth (ft)** | **Hole Size (in.)** | **Casing Size (in.)** | **Function** | **Remarks** |
| 0<br>> 30 | 6.000 | 4.500 Tubing | Conductor Pipe | Auger drilled hole |
| 0<br>< 1000 | 3.750 | 2.875 CT | Surface Casing | CTDMD* |
| 0<br>< 2000 | 2.500 | 2.000 CT | Intermediate Casing | CTDMD* |
| 0<br>< 5000 | 1.750 | 1.250 CT | Production Casing | CTDMD* |
| 0<br>< 4750 | 1.000 | 0.750 CT | Tubing | Open ended or sealed to a packer |

* CTDMD = coiled-tubing-deployed microdrilling with the drill stem converted to casing after the casing depth is reached. The BHDA is replaced with a bottomhole cementing assembly, centralizers, and run to the casing depth and cemented.

| Drilling Program B | Production Hole With No Intermediate Casing Required | | | |
|---|---|---|---|---|
| **Depth (ft)** | **Hole Size (in.)** | **Casing Size (in.)** | **Function** | **Remarks** |
| 0<br>> 230 | 4.000 | | Conductor Pipe | Auger drilled hole |
| 0<br>< 2000 | 2.500 | 2.000 CT | Surface Casing | CTDMD* |
| 0<br>< 5000 | 1.750 | 1.250 CT | Production Casing | CTDMD* |
| 0<br>< 4750 | 1.000 | 0.750 CT | Tubing | Open ended or sealed to a packer |

* CTDMD = coiled-tubing-deployed microdrilling with the drill stem converted to casing after the casing depth is reached. The BHDA is replaced with a bottomhole cementing assembly, centralizers, and run to the casing depth and cemented.

| Drilling Program C | Exploration or Monitoring Hole with Intermediate Casing Required | | | |
|---|---|---|---|---|
| **Depth (ft)** | **Hole Size (in.)** | **Casing Size (in.)** | **Function** | **Remarks** |
| 0<br>< 30 | 4.000 | 2.875 Tubing | Conductor Pipe | Auger drilled hole |
| 0<br>< 1000 | 2.500 | 2.000 CT | Surface Casing | CTDMD* |
| 0<br>< 2000 | 1.750 | 1.250 CT | Intermediate Casing | CTDMD* |
| 0<br>< 5000 | 1.000 | 0.750 CT | Tubing or Monitoring Casing | Open ended or sealed to a packer |

* CTDMD = coiled-tubing-deployed microdrilling with the drill stem converted to casing after the casing depth is reached. The BHDA is replaced with a bottomhole cementing assembly, centralizers, and run to the casing depth and cemented.

**Drilling Mud Program.** It is assumed that the surface casing hole can be drilled with natural mud, that normally pressured sediments are drilled with low solids bentonite mud, and that 2% potassium chloride brine is used as a completion fluid. The calculated dry weight of drilling fluid materials needed, assuming no loss of returns or dumping of mud occurs, is 9633 lb. for Well A and 9633 lb. for Well B. The calculated dry weight of drill cuttings produced is 33,026 lb. for Well A, 17,391 lb. for Well B and 13,589 lb. for Well C.

| **Drilling Mud Program A** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Depth (ft)** | **Hole Size (in.)** | **Drill Stem (in.)** | **In-Hole Volume of Mud ($ft^3$)** | **Proposed Fluid** | **Yield % solids** | **Weight** (lb)** | |
| | | | | | | **Dry Mud*** | **Drill Cuttings** |
| 0 >30 | 6.000 | 6.0-in. Auger | 0 | Air Auger Drill | 0 | 0 | 993 |
| 0 <1000 | 3.750 | 2.875 CT | 34.6 | 8.5 ppg 1 cp natural | 0 | 0 | 6464 |
| 0 <2000 | 2.500 | 2.000 CT | 59.2 | 8.6 ppg 10 cp bentonite | 5 | 6110 | 12,669 |
| 0 5000 | 1.750 | 1.250 CT | 73.9 | 8.6 ppg 10 cp bentonite | 5 | 6505 | 14,077 |
| 0 >4750 | 1.000 | 0.750 CT | 28.0 | 8.5 ppg packer fluid | 3 | 3127 | 0 |
| **Totals** | | | | | | **9633** | **33,026** |
| * Includes a 50 bbl surface system. | | | | | | | |
| ** Assumes 2.7 gm/$cm^3$ rock density | | | | | | | |

| **Drilling Mud Program B** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Depth (ft)** | **Hole Size (in.)** | **Drill Stem (in.)** | **In-Hole Volume of Mud ($ft^3$)** | **Proposed Fluid** | **Yield % solids** | **Weight** (lb)** | |
| | | | | | | **Dry Mud*** | **Drill Cuttings** |
| 0 > 30 | 4.000 | 4.0-in. Auger | 0 | Air Auger Drill | 0 | 0 | 441 |
| 0 > 2000 | 2.500 | 2.000 CT | 14.8 | 8.5 ppg 1 cp natural | 0 | 0 | 2873 |
| 0 < 5000 | 1.750 | 1.250 CT | 73.9 | 8.6 ppg 10 cp bentonite | 5 | 6505 | 14,077 |
| 0 < 4750 | 1.000 | 0.750 CT | 28.0 | 8.5 ppg packer fluid | 3 | 3127 | 0 |
| **Totals** | | | | | | **9633** | **17,391** |
| * Includes a 50 bbl surface system. | | | | | | | |
| ** Assumes 2.7 gm/$cm^3$ rock density | | | | | | | |

| Drilling Mud Program C | | | | | | | |
|---|---|---|---|---|---|---|---|
| Depth<br><br>(ft) | Hole Size (in.) | Drill Stem (in.) | In-Hole Volume of Mud ($ft^3$) | Proposed Fluid | Yield % solids | Weight** (lb) | |
| | | | | | | Dry Mud* | Drill Cuttings |
| 0<br>< 30 | 4.000 | 2.875 Tubing | 0 | Air<br>Auger Drill | 0 | 0 | 993 |
| 0<br>< 1000 | 2.500 | 2.000 CT | 34.6 | 8.5 ppg 1 cp natural | 0 | 0 | 6464 |
| 0<br>< 2000 | 1.750 | 1.250 CT | 59.2 | 8.6 ppg 10 cp bentonite | 5 | 6110 | 12,669 |
| 0<br>< 5000 | 1.000 | 0.750 CT | 73.9 | 8.6 ppg 10 cp bentonite | 5 | 6505 | 14,077 |
| | | | | | | | 0 |
| **Totals** | | | | | | **9633** | **33,026** |

* Includes a 50 bbl surface system.
** Assumes 2.7 gm/$cm^3$ rock density

**Casing Program.** The conductor pipe is constructed with threaded and coupled line pipe. The surface, intermediate, and production casing and production tubing use converted coiled-tubing drill-stem so that the drill stem is retired before it approaches the end of its useful drilling life (Fig. 14A and 14B). All coiled-tubing sizes listed are catalog items, and it is assumed that a standard 70,000 psi minimum-yield-strength steel will provide the load capacity, internal pressure, and collapse and torsional strength required for both the drilling and cemented casing or hung-off tubing functions. The calculated weight of casing materials needed is 13,589 lb. for Well A, 8302 lb. for Well B and 13589 lb. for Well C.

**Cementing Program.** The conductor pipe is cemented with a neat, Type A Portland cement. The surface, intermediate, and production casing are cemented with a lower density and strength, 13.5 ppg, 6% bentonite Type A Portland cement slurry followed by higher strength, 15.6 ppg, “neat” cement to cover the perforated interval and fill the landing joints. The calculated dry weight of cement materials needed is 6363 lb. for Well A, 3600 lb. for Well B, and for Well C.

| Casing Program A | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Depth (ft)** | **Diameters (in.)** | | | **Weight (lb/ft)/ Total (lb** | **Pressure (psi)** | | **Yield lbf \| ft*lbf** | |
| | OD | ID | Drift | | **Yield** | **Collapse** | **Load** | **Torque** |
| 0<br>> 30 | 4.500<br>4 LP A | 4.026 | 3.875* | 10.79/<br>324 | 3160 | | Joint stren | 760** |
| 0<br>< 1000 | 2.875 C | 2.625 | 2.605<br>FLASH-FREE™ | 3.671/<br>1835 | 5840 | 3260 | 75,590 | 4151 |
| 0<br>< 2000 | 2.000 C | 1.782 | 1.762<br>FLASH-FREE™ | 2.201/<br>4402 | 7280 | 5610 | 45,320 | 1694 |
| 0<br>< 5000 | 1.250 C | 1.100 | 0.95*** | 0.941/<br>4705 | 7830 | 6780 | 22,140 | 448 |
| 0<br>< 4750 | 0.750 C | 0.616 | 0.482*** | 0.489/<br>2323 | 11,570 | 11380 | 10,060 | 132 |
| 5000 | **TOTAL OCT WEIGHT** | | | **13,589** | | | | |

* Special drift
** Minimum make up torque for short thread casing connection
*** Calculated value based on specifications for FLASH FREE™ tubing.
FLASH-FREE™ is presently available on tubing sizes of 1.31-in. ID and greater.

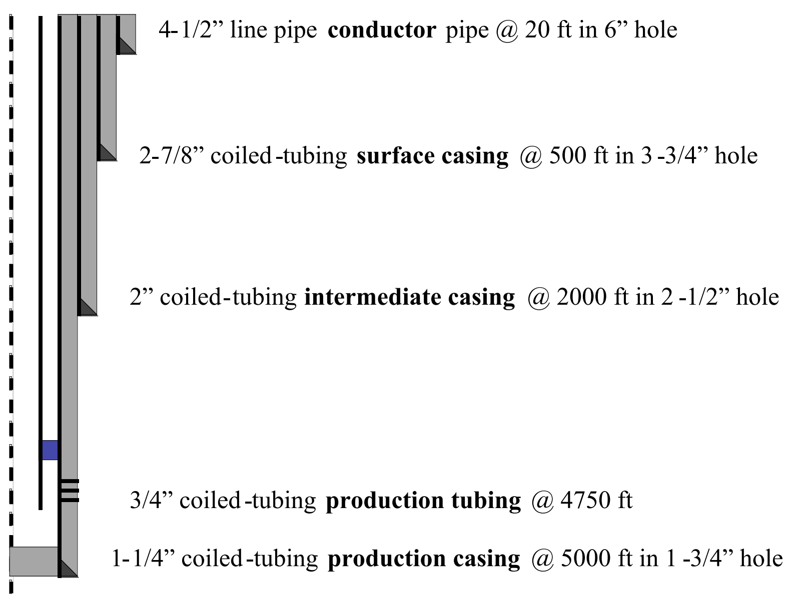



Fig. 14A. Microwell Completion Concept A that includes an intermediate casing string.

| Casing Program B | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Depth (ft)** | **Diameters (in.)** | | | **Weight (lb/ft)/ Total (lb** | **Pressure (psi)** | | **Yield lbf \| ft*lbf** | |
| | OD | ID | Drift | | **Yield** | **Collapse** | **Load** | **Torque** |
| 0<br>> 30 | 2.875<br>2.5 LP A | 2.469 | 2.375* | 5.793/<br>174 | 4240 | | Joint stren | 790** |
| 0<br>< 1000 | 2.000 CT | 1.782 | 1.762<br>FLASH-FREE™ | 1101/<br>4402 | 7280 | 5610 | 45,320 | 1694 |
| 0<br>< 5000 | 1.250 CT | 1.100 | 0.95*** | 0.941/<br>4705 | 7830 | 6780 | 22,140 | 448 |
| 0<br>< 4750 | 0.750 CT | 0.616 | 0.482*** | 0.489/<br>2323 | 11,570 | 11,380 | 10,060 | 132 |
| 5000 | **TOTAL OTC WEIGHT** | | | **8302** | | | | |

* Special drift
** Minimum make up torque for NU tubing thread
*** Calculated value based on specifications for FLASH FREE™ tubing.
FLASH-FREE™ is presently available on tubing sizes of 1.31 in. ID and greater.

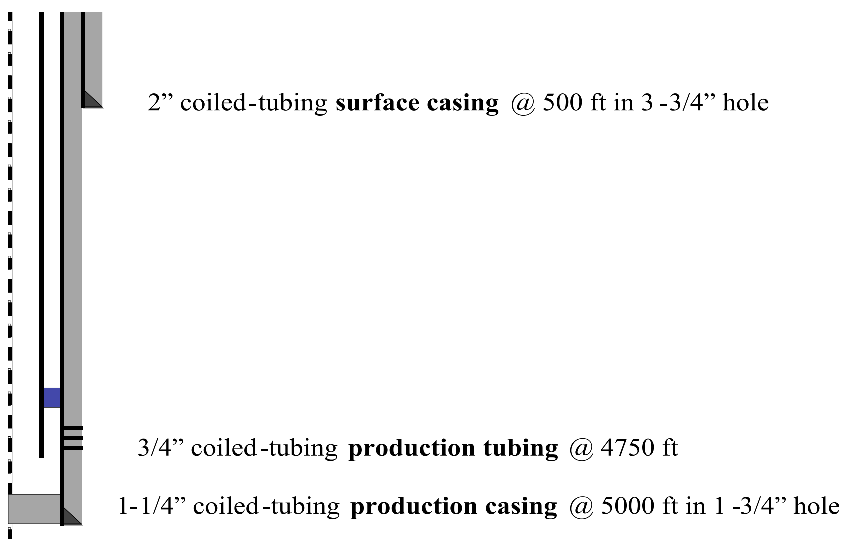



Fig. 14B. Microwell Completion Concept B that does not include and intermediate casing string.

| Casing Program C | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Depth (ft)** | **Diameters (in.)** | | | **Weight (lb/ft)/ Total (lb** | **Pressure (psi)** | | **Yield lb$_f$ \| ft*lb$_f$** | |
| | OD | ID | Drift | | **Yield** | **Collapse** | **Load** | **Torque** |
| 0<br>< 30 | 4.500<br>4 LP A | 4.026 | 3.875* | 10.79/<br>324 | 3160 | | Joint stren | 760** |
| 0<br>< 1000 | 2.875 CT | 2.625 | 2.605<br>FLASH-FREE™ | 3.671/<br>1835 | 5840 | 3260 | 75,590 | 4151 |
| 0<br>< 2000 | 2.000 CT | 1.782 | 1.762<br>FLASH-FREE™ | 2.201/<br>4402 | 7280 | 5610 | 45,320 | 1694 |
| 0<br>< 5000 | 1.250 CT | 1.100 | 0.95*** | 0.941/<br>4705 | 7830 | 6780 | 22,140 | 448 |
| | 0.750 CT | 0.616 | 0.482*** | 0.489/<br>2323 | 11,570 | 11380 | 10,060 | 132 |
| 5000 | **TOTAL OCT WEIGHT** | | | **13,589** | | | | |

* Special drift
** Minimum make up torque for short thread casing connection
*** Calculated value based on specifications for FLASH FREE™ tubing.
FLASH-FREE™ is presently available on tubing sizes of 1.31 in. ID and greater.

| Cementing Program A | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Depth (ft)** | **Calculated Volumes ($ft^3$)** | | | **Cement Volumes ($ft^3$)** | | | **Weight ($lb/ft^3$) \| (lb)** | |
| | Annulus | Landing Joint | Displ. | Slurry | Tail | Displ. | Slurry Density | Dry Weig |
| 0<br>> 30 | 2.6 | 0.1 | 2.6 | 3.2 | 0.1 | 2.4 | 117 slur<br>117 neat | 276 |
| 0<br>< 1000 | 15.8 | 0.8 | 18.0 | 17.8 | 2.7 | 18.0 | 101 slur<br>117 neat | 1240 |
| 0<br>< 2000 | 24.5 | 0.3 | 34.3 | 30.0 | 2.3 | 34.3 | 101 slur<br>117 neat | 1878 |
| 0<br>< 5000 | 40.9 | 0.1 | 32.9 | 44.5 | 5.1 | 32.9 | 101 slur<br>117 neat | 2969 |
| **Totals** | **83.8** | **1.3** | **87.8** | **95.4** | **13.6** | **87.6** | | **6363** |

*

| Cementing Program B | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Depth (ft)** | **Calculated Volumes ($ft^3$)** | | | **Cement Volumes ($ft^3$)** | | | **Weight ($lb/ft^3$) \| (lb)** | |
| | Annulus | Landing Joint | Displ. | Slurry | Tail | Displ. | Slurry Density | Dry Weig |
| 0 > 30 | 1.3 | 0.03 | 1.0 | 1.5 | 0.03 | 1.0 | 117 slur 117 neat | 132 |
| 0 < 1000 | 7.9 | 0.35 | 8.3 | 8.8 | 1.3 | 8.3 | 101 slur 117 neat | 499 |
| 0 < 5000 | 40.9 | 0.13 | 32.9 | 44.5 | 5.1 | 32.9 | 101 slur 117 neat | 2969 |
| **Totals** | **50.0** | **0.5** | **42.1** | **54.9** | **13.6** | **42.1** | | **3600** |
| * | | | | | | | | |

| Cementing Program C | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Depth (ft)** | **Calculated Volumes ($ft^3$)** | | | **Cement Volumes ($ft^3$)** | | | **Weight ($lb/ft^3$) \| (lb)** | |
| | Annulus | Landing Joint | Displ. | Slurry | Tail | Displ. | Slurry Density | Dry Weig |
| 0 < 30 | 2.6 | 0.1 | 2.6 | 3.2 | 0.1 | 2.4 | 117 slur 117 neat | 276 |
| 0 < 1000 | 15.8 | 0.8 | 18.0 | 17.8 | 2.7 | 18.0 | 101 slur 117 neat | 1240 |
| 0 < 2000 | 24.5 | 0.3 | 34.3 | 30.0 | 2.3 | 34.3 | 101 slur 117 neat | 1878 |
| 0 < 5000 | 40.9 | 0.1 | 32.9 | 44.5 | 5.1 | 32.9 | 101 slur 117 neat | 2969 |
| **Totals** | **83.8** | **1.3** | **87.8** | **95.4** | **13.6** | **87.6** | | **6363** |
| * | | | | | | | | |

## THE ROADMAP

**Discussion.** A review of the theoretical work, laboratory-scale, and 0- to 700-ft-deep field demonstrations described above leads us to the following conclusions:

1. The equipment, systems, and services used in the recent field demonstrations will only be suitable for a 5000-ft-deep drilling demonstration in the most ideal drilling site. Such sites may not exist anywhere where drilling 5000-ft holes has significant commercial value.
2. The full value of microdrilling will not be achieved unless the capability to drill the hole sizes proposed in this document is developed. To retreat to working at the size and present performance of the off-the-shelf equipment now available will lead to reduced performance that will quickly push us to the small end of slimhole drilling technology. Only marginal cost-benefits offset by large loss of performance, utility, and capability will be realized. Existing downhole equipment will have to be downsized to 50% of its present size to achieve the microwell designs described previously. Microholes drilled with presently available equipment will be twice the proposed diameter and require approximately four times the mobilization and operating mass that has been estimated above. Either a larger rig crew will be needed to man-handle equipment, or heavy, highly automated handling equipment will have to be mobilized.
3. A large, well planned, technology development program will have to be funded by the oil industry with limited leverage with DOE funding to achieve the 5000-ft deep, microdrilling demonstrations proposed.
4. Microhole technology development can be accelerated through internal investments by the following concerns:
    a. Future microdrilling contractors including oil and gas service companies, oil field, mining, and domestic water drilling contractors.
    b. Future equipment suppliers including oil and gas service companies and mechanical equipment and instrumentation manufacturers.
    c. Future material suppliers including oil and gas service companies and cement and drilling fluid additive suppliers, mining and domestic water drilling service companies.

## NEEDED TECHNOLOGY DEVELOPMENT

Five critical and five less critical technology development initiatives have been identified that are needed to enhance the probability of producing a 5000-ft microhole in a less than ideal environment. Most can be downsized from mature, conventional-sized technology. Basic engineering can be applied to determine the appropriate performance requirements once the geometric scaling parameters are determined. Some technology development is needed to downsize less mature technology. The path to a microdrill design for this technology is uncertain but not expected to require breakthrough developments. Extensive systems analysis will be required to assure that downsized designs are properly scaled to achieve optimal performance. Under each item we have identified target **sponsors** that would plausibly support the effort, a target **subcontractor** that will lead the required development work, and a one-significant-figure **cost estimate** for the development of the first prototypes needed to conduct early demonstrations.

These are technologies that must be demonstrated before microdrilling can move beyond specialty and niche applications. A brief description and detail on each of the technology development items follows. A summary table of the items titled “The Road Map” includes a list of the items, sponsors and contractors, and very rough development time and cost estimates.

**Microdrill motors.** Developments in the microdrill motor area will first require enhancing a mature technology for standard PDMs, and be followed by the development of new downhole hydraulic hammers and compressible-fluid-powered PDMs. These technologies will need to be adapted to the specific performance that microdrilling requires in the specific target rocks. The designs must support high conversion efficiency using both Newtonian and non-Newtonian fluids with some drill solids content. A tradeoff between motor life and mud cleaning performance will have to be optimized in field demonstrations. The diameters shown in drilling programs a, b, and c (below) are the coiled-tubing diameters on which the motors will be deployed, and therefore are minimum values that will have to be specified at the completion of a full systems analysis.

1. **Rotary PDMs.** Micro PDMs must convert low-flow and high-pressure hydraulic power to the torque and speed needed to produce small chips in a very wide range of low and medium strength sedimentary rocks using low weight-on-bit PDC and diamond bits. Theoretical designs are expected to be straightforward for incompressible fluids. The major challenge will be to develop technology to fabricate the rotors and stators to the tolerances needed to produce the high conversion efficiency that will be required for high performance drilling. The following are needed:
   a. The design and fabrication of 3/4-in. motors for cement and wiper plug drilling; sand, scale, and paraffin clean out; and limited duty openhole drilling.
   b. The design and fabrication of 1-1/4-in. and 2-in. motors for cement and wiper plug drilling and heavy duty openhole drilling.
2. **Integrated rotary-percussion motors (IRPM).** IRPMs must convert low-flow and high-pressure hydraulic power to the impact amplitudes and frequencies needed to break medium and high strength sedimentary rocks using low weight-on-bit and integral hammer bits. The IRPM must also produce the torque and rotary speed needed to properly index the percussion bit at low-to-moderate weight-on-bit. In early versions of the IRPM, the rotary speed and frequency may need to be controlled by the common flow rate through each converter. Advanced IRPMs may require independent control to produce an optimum indexing for the rock being drilled. The designs must include a reflector/tubing isolation sub-component that will protect the downhole sensors and telemetry in the instrumentation sub and the bottom of the coiled-tubing drill stem, from both pressure pulsation and the mechanical vibration generated by the converter and the bit/rock interaction. We do not believe that designs for the envisioned integral unit exist, and thus a significant development program will be needed. Developing technology to fabricate the IRPMs to the tolerances required to produce high conversion efficiency may require significant investment. The following are needed:
   a. The design and fabrication of 3/4-in. IRPM for cement and wiper plug drilling; sand, scale, and paraffin clean out; and limited duty openhole drilling.
   b. The design and fabrication of 1-1/4-in., 2-in., and 2-7/8-in. IRPMs for cement and wiper plug drilling and heavy duty openhole drilling.

**Microdrill bits.** Microbit designs must support the efficient production of small chips using the PDMs and IRPMs described above. 3-3/4-in., 2-5/8-in., 1-3/4-in., and 1-in. bits will be needed. The diameters are approximate and will have to be specified at the completion of a full systems analysis. Many of the larger size bits may already exist in a satisfactory design. Most of the smaller bits will likely have to be downsized from larger designs. The following are needed:

1. **PDC rotary bits.** High rotary speed bits with a low threshold thrust designed to penetrate soft and medium strength rocks.

2. **Percussion hammer bits.** Bits designed to operate at high frequency/high rotary speeds and produce small chips at low threshold thrusts in medium and high strength rocks.

3. **Special bits.** Microbits to drill cement and wiper plugs.

**Downhole sensing and control**. Robust, accurate, microsensors and microsized processing and telemetry circuits are needed to control the drilling process. First generation sensors should be sufficiently resilient to operate in the instrumentation and telemetry sub at the bottom of the coiled-tubing and above the drilling motor and isolation sub-component, if present. Second generation sensors should be sufficiently robust to operate in a bit sub between the drilling motor and the microbit.

1. **Existing sensors and telemetry circuits** that perform the following services will have to be resized to fit in micro-housings below the coiled tubing or below the drilling motor:
   a. Drilling process sensors
      (i) drill thrust (weight-on-bit)
      (ii) drill torque
2. **Directional trajectory sensors**
   a. inclinometer
   b. magnetometer/gyro
3. **Telemetry and processing circuits**
   a. Signal conditioning, A/D, and telemetry transmission and reception circuits

**Downhole drilling controls**. Existing sensors and circuits that perform the following services will have to be resized to fit in a microhousing below the coiled tubing or a bit sub between the microbit and drill motor. First generation technology will use downhole measurements to guide surface control of drill-stem insertion to produce weight-on-bit and flow rates to produce the torque and rpm desired. The second-generation technology development will support real-time, downhole drilling process control and steering for directional drilling with near-bit telemetry and control. The following is needed:

1. **Two way radio circuits and antennas**
2. **Motor or valve controller circuits**
   a. Weight-on-bit thrust control
   b. Directional control including:
      (i) Deviation control – variable bent sub and
      (ii) Orientation control – bent sub orientation motor or
      (iii) Combined deviation/orientation sub (array of hydraulic pistons push the bit to one side of the hole while centering the top of the sub to create the bend desired)

**Micro-Casing Installation and Cementing.** The following are needed:

1. **Microsized cementing tools for coiled tubing used for casing**
   a. Wiper plugs for non-flash free and flash free coiled-tubing cementing
      (i) Plug dropping manifold
      (ii) Landing collars /plug catcher
   b. Float valves

c. Casing guide shoes

d. Wrap-around, clamp-on centralizers for coiled tubing

**2. Slurries for small annulus cementing**

a. Low viscosity

b. Low density

c. Longer thickening times to support slower placement

**3. Micro Production and Monitoring.** The following are needed:

a. Microsized well perforation tools for small diameter coiled tubing

(i) Coiled tubing deployed perforators

(a) Abrasive jet

(b) Shaped charged perforator

(ii) Wireline-deployed perforators

b. Gravel packing design, simulations, and field demonstrations.

c. Basic stimulation designs, simulations, and field demonstrations

(i) Perforation breakdown treatments

(ii) Chemical dissolution treatments

(iii) Hydro-fracturing treatments

**Power and cutting transport modeling.** Published models are not very accurate in the turbulent flow regime, and empirical annular-flow correction factors are untested for the proposed microhole-sized experimental data. Experimental data needs to be generated for microsized tubes and annuli to test and validate various commercial and published models. Where models are found to be lacking, new or modified models should be developed and verified. Models accounting for the following are needed:

**1. Hydraulic power transport**

a. Non-Newtonian flow

b. Annular flow

c. Cuttings transports

**2. Pneumatic transport**

a. Newtonian compressible flow

b. Foam flow

c. Annular flow

d. Cuttings transport

## LESS CRITICAL TECHNOLOGY NEEDED

These are technologies that will improve the economics and versatility of microdrilling, but are not needed to accomplish drilling 5000 ft microholes. A brief description and detail on each of the technology development items follows, and a summary table of the items titled “The Road Map” includes a list of the items, sponsors and contractors and very rough development time and cost estimates.

**High-pressure mud pumping.** Demonstrations are needed of a small centrifugal horizontal pump, a pressure multiplier, and other appropriate, high-pressure, mud pumping technologies including sump pumps. Special multiplex pump valves and plunger packing systems should be tested to determine if high pump maintenance costs can be significantly reduced by using nontraditional pumping equipment.

**Advanced drilling fluid cleaning.** Demonstrations are needed of advanced, nonstandard cuttings and drill solids separation technology, beyond an enhanced cleaning system based on present technology. This should be done to determine if high mud-pump maintenance costs can be significantly reduced and drilling motor life is increased using nontraditional separation equipment and configurations.

**Coiled-tubing fabrication.** Development is needed of technology for fabrication of coiled tubing specifically for microdrilling and conversion to cemented casing. To be considered are:

1. **Flash-free coiled-tubing for the smallest sizes**
2. **Telemetry cables**. Installation technology to insert and remove cables in small-diameter, coiled tubing is needed to provide hardwire telemetry for downhole sensors and controllers. (This can be done manually by unreeling the tubing and inserting a stiff wire to pull through a telemetry cable. This method is not very practical for 5000-ft-long cables which must be removed and reinstalled in a smaller tubing each time a drill stem is converted to casing).
3. **Cementing wiper plugs for coiled tubing**

**Coiled-tubing deployed fishing.** While wash-over and fishing operations with mining drill-rig technology has proven to be a viable method of retrieving fish from microholes at shallow depths, it will be far less attractive as the depth of the fish increases, and trip time for the drill rods increases dramatically. Coiled-tubing-deployed fishing technology requirements identified thus far include the following equipment sized to support small-diameter coiled tubing operations, including 3/4-in., 1-1/4-in. and 2-in. tubing. Needed are:

1. **Fishing PDM.** This should be a high-torque, low-rotary-speed motor to slowly rotate fishing tools and wash-over pipe while circulating at a low flow rate.
2. **Flow-though jars and bumper sub.** While small-diameter jars and bumper subs for wireline fishing are available, the inability to circulate fluid through them to wash the fishing tools onto the fish greatly reduces the chance of engaging the fish. Standard drill stem-deployed fishing tools need to be scaled to support fishing on small diameter coiled tubing.
3. **Fishing tools.** A greater selection of overshots, spears, and safety release tools will need to be developed to support small diameter tools.

**Microdrill air motor.** New designs must have high conversion efficiency when using compressible Newtonian air and mist, or non-Newtonian foams with some drill solids content in the continuous liquid phase. This technology will be needed to penetrate highly under-pressured formations and depleted reservoirs. The diameters shown below are approximate and will have to be specified at the completion of a full systems analysis. This work should only be undertaken after a theoretical thermodynamic/compressible flow systems analysis is completed and shows that power transport to 5000-ft in a microhole is sufficient to produce a realistic penetration rate. Needed are:

1. **Rotary, positive displacement, air motor (PDAM) technology.** Micro PDAMs must convert low-flow and high-pressure pneumatic power to the torque and speed needed to produce small chips in a very wide range of low and medium strength sedimentary rocks using low weight-on-bit PDC and diamond bits. Theoretical designs for compressible fluids have been proposed but most have not been fabricated and tested. Using traditional incompressible fluid designs for

compressible fluid service typically reduces the downhole efficiency of the motor by 30 to 50 % and severely reduces the operating torque range between no-load and stall (Graham, 1995). Even greater reductions in efficiency and range were observed for microsized motors (Dreesen, Cohen, Gruenhagen, and Moran, 1999) When the inefficiency of the surface compressors is included, the inefficiency of the compressible fluid system becomes unacceptable and has deterred the use of compressible fluid in slide drilling. Two major challenges are anticipated: (1) designing a compressible fluid PDM that can be fabricated for an acceptable cost, and (2) developing technology to fabricate the rotors and stators to the tolerances required to produce high conversion efficiency. Needed are:

a. The design and fabrication of 0.75-in. motors for cement and wiper plug-drilling; sand, scale, and paraffin clean out; and limited duty openhole drilling.

b. The design and fabrication of 1-1/4-in. and 2.00-in. motors for cement and wiper plug drilling and heavy duty openhole drilling.

2. **Integrated rotary-percussion air hammer (IRPAH) technology.** IRPAHs must convert low-flow and high-pressure pneumatic power to the impact amplitudes and frequencies needed to break sedimentary rocks using low weight-on-bit and integral hammer bits. The IRPAH must also produce the torque and rotary speed needed to properly index the percussion bit. Needed are:

a, The design and fabrication of a 3/4-in. IRPAM for cement and wiper plug drilling, sand, scale, and paraffin clean out, and limited duty openhole drilling.

b. The design and fabrication of 1-1/4-in., 2-in., and 2-5/8-in. IRPAMs for cement and wiper plug drilling and heavy duty openhole drilling.

## MICRODRILLING PLATFORM FOR DRILLING DEMONSTRATIONS

A concept for the coiled-tubing deployed microdrilling platform has not evolved very far because we have yet to perform many of the anticipated different rig operations or operated in deep hole drilling conditions. Yet to be accomplished are:

- Drilling of hard and medium strength rock
- Assembly of longer, more complicated BHDAs
- Drilling underbalanced using compressible fluids
- Drilling with weighted mud systems
- Drilling with more than one diameter of coiled-tubing in the well program
- Converting drill stem to casing and cementing in a coiled-tubing casing
- Directional drilling

Fabricating, debugging, and demonstrating a coiled-tubing drilling unit especially designed to drill 5000-ft microholes is a desirable but not critical part of a initial technology demonstration. It is believed that the first 5000-ft hole microdrilling can be demonstrated using commercial rental CTUs, rental blowout prevention and drilling support equipment, and rental mud pumps and cleaning equipment.

Several deep microdrilling demonstrations relying on rental equipment for most if not all-surface equipment would be beneficial before the final specification of the surface system can be completed. The decision to conduct the drilling demonstration with rental surface equipment or with a prototype CTU and surface drilling system will need to be made once support for the downhole drilling technology is organized and long term technology development is under way. Most if not all of the surface equipment development will very likely have a shorter development time and will be driven by the BHDA equipment selected for development.

| **Road Map<br>Critical Technology Needs That Must Be Met in Order to Drill 5000-Ft Microholes** | | | | |
|---|---|---|---|---|
| **Technology Development** | **Sponser[1]** | **Contractor[2]** | **Time** | **Cost** |
| **A Critical Technology** | **Downsize existing equipment to fit in microboreholes** | | | |
| **1 Microdrill Motor** | | | | |
| a Rotary PDM | E&P | PDM | 2.0 years | $ 2.0 M |
| b Rotary Percussion IRPM | E&P | PDM + HH | 3.5 years | $ 5.0 M |
| **2 Microdrill Bits** | | | | |
| a PDC rotary bits | E&P | RBM | 1.0 years | $ 0.5 M |
| b Percussion hammer bits | E&P | MBM | 3.0 years | $ 1.0 M |
| **3. Downhole Instrumentation and Controls** | Includes drilling process sensors and WOB control and trajectory sensor and directional drilling controller | | | |
| a Existing sensors and telemetry circuits | E&P | LCS and DHI | 2 years | $ 2.0 M |
| b Downhole drilling controls. | E&P | DDS | 3 years | $ 3.0 M |
| **4 Micro-Casing Installation and Cementing** | | | | |
| a Cementing tools | SC | CSS | 1 year | $ 0.5 M |
| b Cement slurries | SC | CSS | 1 year | $ 1.0 M |
| **5 Micro Production and Monitoring** | | | | |
| a Perforation tools | E&P | DILT | 2 years | $ 1.0 M |
| b Gravel packing | E&P | CSS | 1 year | $ 0.5 M |
| c Simulation | E&P | CSS | 1 year | $ 1.0 M |
| **SUBTOTAL-CRITICAL TECHNOLO** | | | | **$19.5 M** |
| **B Less Critical Technology** | **Modify or develop new technology to optimize performance** | | | |
| **1 High Pressure Mud Pumps** | DS | PEM | 2 years | $ 1.5 M |
| **2 Advanced drilling fluid cleaning** | DF | HCS | 2 years | $ 0.5 M |
| **3 Coiled-tubing fabrication** | DS | CTM | 2 years | $ 1.0 M |
| **4 Coiled-tubing deployed fishing** | DS | PDM + FTM | 3 years | $ 2.0 M |
| **5 Power and cutting transport mode** | DOE | Universities | 3 years | $ 2.0 M |
| **6 Microdrill air motor** | E&P | PDM + HH | 4 years | $ 10.0 M |
| **SUBTOTAL-LESS CRITICAL TECHNOLOGY** | | | | **$17.0 M** |
| **CT MICRODRILLING PLATFORM** | | | 2 years | **$3.5 M** |
| **TOTAL DEMONSTRATION HARDWARE COST** | | | | **$40.0 M** |

| | | |
|---|---|---|
| 1 | E&P = major and independent exploration and production with possible inclusion of geothermal and mining companies | |
| | SC = oil field suppliers and service companies | |
| | DS = drilling contractors and coiled-tubing service companies | |
| | DF = Drilling fluid suppliers and field services | |
| 2 | PDM = PDM manufacturers | |
| | HH = hydraulic hammer manufacturers | |
| | RBM = rock bit manufacturers | |
| | MBM = mining bit manufacturers | |
| | LSC = independent and integrated oil field logging service company | |
| | DILT = downhole instrumentation and logging tool developer and packager and consultants | |
| | DDS = directional drilling hardware developer and service provider | |
| | CSS = cementing and stimulation services | |
| | PEM = pumping equipment manufacturers | |
| | HCS = hydro cyclone and separator manufacturers | |
| | CTM = coiled tubing manufacturers | |
| | FTM = fishing tool manufacturers | |

## DRILL SITES FOR DEMONSTRATIONS

Drill sites for microdrilling should be selected to support a demonstration of basic near-vertical drilling in soft to medium strength sediments while technology to drill more challenging trajectories in more difficult environments is still under development. Selection of drilling sites for the first series of deep drilling demonstrations should have the following characteristics:

1. In-fill drilling in a well-characterized drilling environment defined by close offset wells with high quality documentation. A drilling program can then be prepared that has a relatively high chance of being appropriate for the drilling conditions encountered.
2. Normally pressured drilling that is not expected to penetrate under-pressured reservoirs where high permeability and loss of returns is predicted.
3. Soft to medium strength rock that can be drilled at a reasonable penetration rate with modest weight-on-bit using a water-based natural or bentonite mud.
4. No unusual well stability conditions predicted.

## CONCLUSIONS

1. A concept for drilling to 5000 ft in sediments with a coiled-tubing-deployed microdrilling system has been developed and evaluated using modeling, laboratory tests, and shallow field demonstrations.
2. Some technology development is needed to downsize existing equipment and develop new equipment that will be needed to drill deeper and optimize the performance at 5000 ft.
3. A $20 M dollar 5 year technology development program has been outlined that demonstrates near-vertical rotary drilling using rental surface equipment and prototype downhole equipment in 3 years and evaluates the possibility of expanding to percussion and air drilling using a prototype surface system within 5 years.

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## APPENDIX

## FIELD DRILLING DEMONSTRATIONS

**Fenton Hill Site, Sandoval County, NM.** Three microwells were drill at the Los Alamos National Laboratory Hot Dry Rock Geothermal Test Site.

The first well was drilled to 110-ft through welded volcanic tuff with a 1-3/4 in. drag bit. At that depth the BHDA plugged off and was found to be stuck when the coiled-tubing was tensioned. Attempts to pull the BHDA, using the rig leveling jacks and a reel lock, sheared the pins in the release sub leaving the BHDA on bottom. After fishing the motor out of the hole, it was found that the stator rubber had been pumped out of its housing and plugged off in the lower motor (flexible shaft) housing. It is believed that the bit locked up as the limber BHDA drilled into a slightly off axis fracture and the torque-induced pressure surge caused the stator failure. After circulation was lost, cuttings settled around the bit and planted the BHDA.

A second 2-3/8-in. hole was drilled to 90-ft to provide a geophone placement hole.

A third 1-3/4-in. hole was recently drilled to 223 ft where a complete loss of returns occurred. Several attempts were made to seal off the loss zones, and the well was drilled with no return to 262 ft.

**Basin and Range Dry-Lake-Bed Sediments.** Four 2-3/8-in. OD microholes were drilled to depths between 315 ft and 550 ft (Thomson, Hufford, and Dreesen, 1999). On the first two holes it was quickly learned that:

1. A 13-ft deep conductor pipe was not sufficient to prevent fracturing to the surface at the flow rate needed to operate the off-the-shelf PDMs above their stall point.
2. The available drag and tri-cone bits were not suitable for drilling the high clay formation with natural or bentonite mud. It is assumed that bit balling was the cause of the observed poor drilling performance and any technology that would improve drilling performance plagued by bit balling would improve microdrilling performance if the approach was compatible with the microdrilling system.

Deeper conductor pipes and slightly sandier clay on the second two holes resulted in an exemplary demonstration of the microdrilling concept in soft unconsolidated or poorly consolidated, lakebed-deposited shales and clays. The major remaining challenges at the end of the demonstration were:

1. Replace the triplex plunger pump (a high-pressure, triplex water pump), with a pump better suited for pumping drilling mud.
2. Improve the performance of the mud cleaning system.
3. Find bits better suited to drilling high clay formations (or drill with oil base mud).
4. Develop a PDM that converts high-pressure, low-flow-rate circulation to a high speed, high power (torque) output.

Evaluation of the Basin and Range Dry-Lake-Bed Sediment drilling campaign produced a list of rig modifications that were needed to address specific operational deficiencies that were identified. They included:

1. The hydraulic system on the CTU was overheating while drilling with moderate or high weight-on-bit.
2. The coiled-tubing injector was incapable of applying a steady compression load on the coiled tubing to produce a steady compression (weight-on-bit) that is needed for shallow drilling.
3. The reeling system and the controls allowed the coil to swarm during reeling and unreeling.
4. The trailer axles and frame supporting the tubing reel were not structurally sound and the frame cracked in several places.
5. The triplex pump was not well suited for high viscosity fluids and slurries.
6. The direct-drive, gas-engine-powered, triplex pump did not provide the flow rate control needed to conduct openhole drilling.

The redesign and repair of the frame and replacement of the axle corrected the structural concerns. Most of the remaining deficiencies were corrected with a complete redesign of the hydraulic system that included a new hydraulic pump, a variable speed hydraulic motor to drive the mud pump, a greatly enhanced fluid cooler, and compatible reel and tubing injector locks and controllers. The piston-style water pump was replaced with a high-pressure triplex plunger mud pump, but this did not fully eliminate the problems experienced with the water pump.

On each of the four holes, a 1.66-in. OD PVC casing was run and sealed to the annulus with a bentonite grout displaced with a wiper plug and water. The wiper plug locked into a landing collar on the bottom of the casing and the casings were de-watered with compressed nitrogen circulated through a 3/8-in. polyflow tubing. All of the casings were installed without any major difficulty, but the casing on the last two wells refilled with water. The source of the water was either a defective casing-joint below the water table or the wiper plug. To preclude any future wiper plug leak, a landing joint was added between the casing shoe and the landing collar to assure that some cement would remain in the bottom joint below the landing collar. The 1.66 OD casing joints have a buttress thread and an o-ring seal. To preclude a joint leak, extra care is required to assure that each joint is equipped with an o-ring and the o-ring is not damaged as the joint is made up.

**San Ysidro Site, Sandoval County, NM.** Six 1-3/4-in. and 2-3/8-in. OD microholes were drilled to depths between 182 ft and 706 ft in soft unconsolidated or poorly consolidated, blow sand and streambed deposits.

The first two holes were drilled in a valley floor and encountered a thin hard formation in the interval between 182-ft and 189-ft depth. In both wells the hard spot could not be drilled with the rotary drilling assemblies that were available. The first hole was abandoned at 182 ft and the second hole was advanced through 1/2 ft of hard formation using a rental percussion drilling assembly. Considerable damage to the coiled tubing (and possibly to the bore wall) occurred while drilling the short section. After cutting off 178 ft of coiled tubing, rotary drilling resumed and reached a depth of 599 ft before well stability problems made it impossible to advance the hole further. Severe wash outs and hole collapse occurred after two artesian flows were penetrated at 306 and 412 ft. The combination of the flow needed to operate the drilling motor and the artesian flow caused erosion of the bore. The daily drilling routine with overnight shutdowns increased formation exposure time to cross flow and unnatural water until massive hole wash outs and collapse were observed. As the bore diameter increased beyond the bit size the coiled tubing was inadvertently compressed beyond its allowable (critical buckling) load.

The conductor pipe was not set deep enough to control the flow and the conductor pipe was pulled out of the borehole when buckled coiled-tubing was removed from the bore and hung up in the conductor pipe's shoe. Several attempts were made to run and cement-in 1.66-in. OD PVC casing using a conventional rotary mining drill rig and drill rods as a wash-over pipe to reenter the bore and guide the casing to bottom. Casing was run to the bottom of the drill rods and the drill rods were removed on each attempt. However, attempts to cement the casing were plagued with difficulty in establishing full returns prior to pumping cement and partial or total hole collapse when lost circulation material (LCM) or cement was circulated up the annulus. The casing was left full of cement when the last attempt to cement the casing failed to bring significant cement up the annulus. The well was successfully plugged and abandoned using the rotary rig and a coring assembly to wash over the cement-filled plastic casing and to spot cement plugs in the annulus.

The four holes were drilled on a mesa top that was about 100 ft above and one mile to the north of the valley floor wells. The site was selected with the expectation that the elevation would preclude artesian flow if the same aquifers were penetrated by the mesa top wells. 100 ft of 2-7/8 in. OD casing was cemented into 4-in. auger-drilled holes to serve as conductor pipes.

The first well was drilled with coiled tubing to 360 ft with a 1-3/4-in. drag bit when a shear pin failure in the shear release sub left the BHDA on bottom. The hole was reamed to 2-3/8 in. with a drag bit and an overshot and bumper sub (without an internal circulation port) were run on coiled tubing to fish out the BHDA. The first attempts to fish the tool were not successful because the overshot guide was hitting the outside edge of the fishing neck. The hole was temporarily abandoned.

The second well was drilled with coiled tubing to 706 ft with a 2-3/8-in. drag bit when a series of packing leaks and valve failures in the mud pump jeopardized the reliability of the mud pump. The down time waiting on pump parts extended the bore wall soak time to the point that hole stability was becoming a great concern. It was decided to run the 1.66-in. OD PVC and cement it in before the hole collapsed. The PVC was successfully run to TD but attempts to circulate the bore resulted in lost or partial returns and hole collapse when lost circulation material was pumped to reestablish circulation. The casing was successfully pulled to shallower depths to try to establish full circulation and an attempt to cement in the casing at 430 ft resulted in loss of the hole when a total hole collapse shut down the cement pumping just after the lead slurry started up the annulus. The well was successfully plugged and abandoned using the rotary rig and a coring assembly to wash over the cement filled plastic casing and spot cement plugs in the annulus.

A reentry of the first hole on the mesa top was made with the mining rotary rig, BQ drill rods and a 2.345-in. OD by 1.779-in. ID core head. The coring assembly was washed-over the BHDA, and after several miss-runs, the BHDA was trapped in the wash-over assembly by filling it with gravel and the assembly was recovered. The hole was deepened using the mining rotary drilling assembly and the 1.66-in. OD PVC casing was successfully sealed at 383 ft with bentonite grout followed by 13 linear feet of cement run between two wiper plugs to seal the bottom of the casing.

Two additional wells were drilled at the mesa-top site, and each attempt failed to reach 800 ft, which was the length of 1-in. tubing on the CTU reel. A low-molecular-weight polymer mud, and a higher-flow feed-pump for the hydrocyclone mud-cleaner were evaluated on a final well drilled at the San Ysidro site. The results were mixed; the mud cleaner removed ten times the volume of fine cuttings, but the pump pressure to circulate the mud increased. The stalling of the PDM increased substantially.