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Evaluation of High-Pressure Drilling-Fluid Supply Systems

Michael C. McDonald, James M. Reichman, Kenneth J. Theimer
Flow Technology Company
Kent, Washington

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EVALUATION OF HIGH-PRESSURE
DRILLING FLUID SUPPLY SYSTEMS*

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ABSTRACT

A study was undertaken to help determine the technical and economic feasibility of developing a high-pressure fluid-jet drilling system for the production of geothermal wells. Three system concepts were developed and analysed in terms of costs, component availability, and required new-component development. These concepts included a single-conduit system that supplies the downhole cutting nozzles directly via surface-located high-pressure pumps; a single-conduit system utilizing low-pressure surface pumps to supply and operate a high-pressure downhole pump, which in turn supplies the cutting nozzles; and a dual-conduit system supplying surface-generated high-pressure fluid for cutting via one conduit and low-pressure scavenging fluid via the other. It is concluded that the single-conduit downhole pump system concept has the greatest potential for success in this application.

*Work performed under Sandia National Laboratories Contract No. 49-8409 for the U.S. Department of Energy, Division of Geothermal Energy.

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1. Introduction

Laboratory and field tests (Ref. 1) have demonstrated the potential advantages in terms of speed and economy of using high-pressure fluid jets for deep geothermal well drilling. However, fluid-jet drilling at the depths required for this application (to 10,000 feet) has not proven practicable due to a lack of suitable system components, e.g., pumps, swivels, rotary connectors, and hoses.

This deficiency is not readily apparent unless hydrostatic and hydrodynamic effects produced by a column of water contained in 10,000 feet of drill string are considered during component selection. Although hydrostatic pressure increases with depth due to the weight of fluid inside the drill pipe, it is balanced by the weight of the column of mud around the outside of the string. The net result is an insignificant change in relative downhole pressure due to hydrostatic effects. However, the hydrodynamic effect of frictional losses both inside and outside the drill string is extremely important. Due to these losses, fluid for jet cutting and chip removal must be supplied at a pressure much higher than the local hydrostatic pressures.

Flow Industries, Inc. has performed a system feasibility study for Sandia Laboratories based on these considerations. (The system design constraints specified by the contract are listed in Table 1.) The study comprised a review of currently available commercial systems and development of three conceptual designs for both surface and downhole high-pressure drilling systems (15,000 psi maximum). These designs are referred to as "cases" throughout the remainder of this report. Fluid pressure losses due to friction have been calculated and the resulting surface pumping requirements for each case are summarized in Table 2. Where necessary, new components were designed and existing components redesigned to meet the requirements of these cases.

1.1 Case 1 - Single-Conduit Surface Pumping System

The Case 1 system (Figure 1) is the most straightforward and conservative of the three cases in that it relies on the use of a single-conduit drill string and surface components rated at pressures sufficiently high to sustain the total fluid flow, both jetting and scavenging, at the required downhole

Table 1. Contract Performance Requirements

REQUIREMENTS	DOWNHOLE PUMP	SURFACE PUMP	SURFACE SWIVELS	SURFACE HOSE	DRILL PIPE
500°F SOAK	X				X
300°F OPERATE	X				X
212°F OPERATE		X	X	X	
15,000-psi MAX	X	X	X	X	X
300,000-lb TENSION			X		X
50,000-lb COMPRESSION	X				X
30,000-ft-lb TORQUE	X				X
6-in. DIA MAX	X				X
PUMP MUD AND/OR WATER	X	X	X	X	X
200-hr SEAL LIFE	X	X	X	X	X
1,000-hr THROW AWAY	X	X	X	X	X
ON-SITE SEAL REPLACEMENT	X	X	X	X	
SINGLE CONDUIT			X	X	X
100-rpm ROTATION SPEED			X		
NO SINGLE SECTION LONGER THAN 60 ft	X				X

Table 2. Surface Pumping Requirements

	<u>FLOW, GPM</u>	<u>SURFACE PRESSURE, PSIG</u>	<u>HYDRAULIC POWER HHP</u>	<u>CANDIDATE SYSTEM</u>	<u>PUMPING SYSTEM COST, \$1,000</u>
CASE 1: SURFACE PUMP					
CUTTING AND SCAVENGING	200 (1a)	16,500	1,925	GARDNER-DENVER ¹	1,750
CUTTING AND SCAVENGING	200 (1b)	11,500	1,342	GARDNER-DENVER ¹	1,630
CUTTING AND SCAVENGING	200 (1c)	9,000	1,050	GARDNER-DENVER ¹	1,500
CUTTING AND SCAVENGING	200 (1d)	6,500	758	GARDNER-DENVER ¹	1,290
CASE 2: DOWNHOLE PUMP					
DOWNHOLE PUMP SUPPLY	313	4,400	804	GARDNER-DENVER	465
CASE 3: DUAL DRILL STRING					
CUTTING JET (WATER OR MUD)	50	20,000 ²	715	GARDNER-DENVER ¹	490
CHIP SCAVENGING	150	3,300	<u>289</u>	GARDNER-DENVER	<u>255</u>
			TOTAL: 1,004		TOTAL: 745
BASELINE - CONVENTIONAL					
CUTTING AND SCAVENGING	200	3,500	408	HALLIBURTON	291

¹MODIFIED FOR HIGH-PRESSURE SERVICE.

²CASE 3 SURFACE PRESSURE TO OBTAIN 15,000 psi DOWNHOLE AT 10,000-ft DEPTH IS 24,500 psi.

HOWEVER, 20,000 psi WAS SET AS A PRACTICAL LIMIT FOR EQUIPMENT AVAILABILITY. CASE 3

PRICES ARE FOR CUTTING WITH WATER ONLY.

Figure 1. Case 1: Surface Pumping System

working pressure. Four subcases were identified to study the effect of increasing pressure on system costs. The required pressure drop across the nozzles for each subcase is as follows:

- A. Subcase 1a: 15,000 psid
- B. Subcase 1b: 10,000 psid
- C. Subcase 1c: 7,500 psid
- D. Subcase 1d: 5,000 psid

The flow rate for each subcase is 200 gpm.

Friction loss in 10,000 feet of drill string is calculated to be 500 psi and required downhole scavenging pressure is 1,000 psi above hydrostatic pressure. Therefore, the surface pumping pressure required is 500 psi + 1,000 psi = 1,500 psi above the desired cutting jet pressure drop, or 16,500 psi for Subcase 1a, 11,500 psi for Subcase 1b, 9,000 psi for Subcase 1c, and 6,500 psi for Subcase 1d.

1.2 Case 2 - Single-Conduit Downhole Pumping System

The Case 2 system utilizes a single-conduit drill string and low-pressure surface components to supply and operate a downhole high-pressure pump located directly above the bit. The downhole "intensifier" pump converts the energy contained in the high-volume, low-pressure flow to low-volume, high-pressure flow for jet cutting with the spent low-pressure flow used for scavenging (Figure 2). The downhole pump requires either a 200-gpm, 3,000-psid primary flow to produce a 40-gpm, 15,000-psid cutting jet flow and 160-gpm, 1,000-psig scavenging flow (Subcase 2a) or a 200-gpm, 3,750-psid primary flow to produce a 50-gpm, 15,000-psid cutting jet flow and 150-gpm, 1,000-psid scavenging flow (Subcase 2b).

The pressure loss due to friction in 10,000 feet of drill pipe at 200 gpm is calculated at 500 psi. The surface pressure required is, therefore, either 3,000 psid + 1,000 psig + 500 psi = 4,500 psig for Subcase 2a or 3,750 psid + 1,000 psig + 500 psi = 5,250 psig for Subcase 2b.

1.3 Case 3 - Dual-Conduit Surface Pumping System

This case is based on a dual-conduit drill string wherein the total fluid flow is divided into high-pressure and low-pressure portions for jet cutting and scavenging, respectively (Figure 3).

Figure 2. Case 2: Downhole Pumping System

Figure 3. Case 3: Dual Drill String System

The scavenging flow of 150 gpm at 1,000 psig above hydrostatic pressure is supplied by a medium-pressure mud pumping system located on the surface. Fluid pressure losses due to friction in the outer passage of 10,000 feet of drill string at a 150-gpm flow rate are 2,300 psi. Therefore, the total surface pumping pressure requirement for scavenging fluid is $1,000 \text{ psig} + 2,300 \text{ psi} = 3,300 \text{ psig}$.

A high-pressure pumping system supplies either water (Subcase 3a) or drilling mud (Subcase 3b) to the cutting jets. A cutting jet flow of 50 gpm at 15,000 psi supplies the energy required for rapid rock cutting. At a depth of 10,000 feet, a total of 8,500 psi is lost to friction in the drill string's inner passage. Therefore a cutting jet surface pumping pressure of $15,000 \text{ psi} + 8,500 \text{ psi} + 1,000 \text{ psi} = 24,000 \text{ psi}$ is required.

2. State-of-the-Art Review

Mud pumping technology for oil industry applications is highly developed and readily available. This section discusses the relevance of this technology to the geothermal well drilling application.

2.1 Mud Pumps

2.1.1 Drilling Mud

A drilling fluid for deep well drilling operations is commonly referred to as "mud" because of its close resemblance to that material. This mud is circulated via surface pumps through the drill string to the drill bit. Nozzles direct the pressurized mud onto the cutting surface where it may either act as the primary cutting medium or simply help to erode material already loosened by a rotating drill bit. The mud then returns to the surface via the annulus between the drill string and the hole, carrying the entrained cuttings from the drilling process with it. On the surface, the mud is cleaned and conditioned for recirculation.

The muds used for drilling operations are carefully formulated to serve a variety of purposes, some of which are as follows (Ref. 2):

- A. Washing cuttings from the drill bit.
- B. Cooling the drill bit.
- C. Lubricating the rotating drill string.
- D. Balancing high downhole formation fluid pressures by means of their weight.
- E. Reducing loss of circulating fluid into permeable regions.
- F. Controlling the acidity of the drill string's environment and thereby reducing metal corrosion.

The cooling function of the drilling mud is especially important for geothermal drilling operations where downhole temperatures in excess of 500°F may be encountered.

A basic geothermal drilling mud may be composed of Bentonite clay and/or Sepiolite clay suspended in water (Ref. 3). Small percentages of lignite coal are sometimes added to this basic mixture. Also, caustic soda and surfactants may be added to control acidity and reduce hydrodynamic friction, respectively. A typical geothermal drilling mud may weigh 9.5 to 10 pounds per gallon as

opposed to 8.34 pounds per gallon for water alone. At low shear rates, the drilling mud is a viscous, thixotropic, non-Newtonian fluid. As shear rates increase with increased velocity or agitation, the mud begins to behave in a manner more characteristic of a Newtonian fluid with dramatically reduced apparent viscosity. This property helps the mud to suspend solids, which is one of its primary functions.

2.1.2 Positive Displacement Pumps

Positive displacement mud pumps are generally used to circulate the drilling mud for applications where the surface pressure requirement seldom exceeds 3,000 psi. Such pumps must be capable of near continuous, around-the-clock operation with minimum down time. There are a great many pumps available that are capable of satisfying these requirements. The mud pumps most commonly used are of the crank-shaft-driven, reciprocating piston type in multiple cylinder configurations, e.g., duplex, triplex, and quadraplex. (The multiple cylinders tend to smooth the pressure pulses associated with reciprocating pumps.) These pumps contain a "power end" that includes a crankshaft, connecting rods, cylinders, and pistons (or plungers) and a "fluid end" containing check valves and fluid passages.

Although some manufacturers rate their equipment at 4,500 to 5,600 psi for continuous operation (and up to 20,000 psi for intermittent operation), experience shows that pump reliability is greatly reduced at drilling fluid operating pressures in excess of 3,500 psi (Ref. 4). Therefore, a different type of pump, such as the intensifier pump discussed in the following subsection, is needed to produce the higher pressures required for the geothermal well drilling application.

2.1.3 Intensifier Pumps

High-pressure intensifier mud pumps were developed for oil industry applications and are used almost exclusively for oil well cementing, fracturing, and well killing. Therefore, since their duty cycle is short (usually less than 8 hours) and their initial cost high, intensifier rigs are generally rented from service companies, e.g., Halliburton, B.J. Hughes, and Dowell. Within their design limitations, they provide excellent reliability at very high operating pressures. Intensifier and crankshaft pumps are

similar in that they both use reciprocating pistons (or plungers) to pressurize the working fluid and check valves to direct the flow. However, the intensifier pump pressurizes the working fluid by means of a larger low-pressure piston that transfers energy from the primary fluid to a smaller high-pressure piston. The difference in area of the two pistons, expressed as a ratio, represents the factor by which working fluid pressure is increased. (Refer to Subsection 3.3 for a discussion of intensifier pump operating principles.) The primary fluid flow may be supplied either by hydraulic pumps or conventional triplex pumps since the oil or water used to power the intensifier pump is normally pressurized only at 3,000 to 5,000 psi. Theoretically, an intensifier pump can be designed to produce any desired output pressure due to its pressure multiplication capability. However, in practice it is limited by material fatigue. While intermittent pressures to 300,000 psi are possible, 55,000 psi is currently the upper limit for continuous operation (more than 10,000,000 cycles). Figure 4 is a graph of pressure versus flow rate for selected conventional triplex and intensifier pumps.

2.1.4 Pump Availability

Conventional mud pumps with maximum continuous operating pressures above 3,000 psi are available from a number of manufacturers (Table 3). Many of these pumps are rated to 15,000 psi for intermittent operation. However, such operation may be expected to shorten the service life of critical parts, e.g., packings, check valves, and fluid-end housings.

Halliburton Services and Towler Hydraulics manufacture trailer-mounted intensifier pumps for use with drilling mud. The Halliburton Model HT-1000 intensifier pumping unit develops 1,800 hhp at 20,000-psi continuous operation. Halliburton intensifiers are powered by conventional diesel-driven triplex pumps mounted on separate trailers. Towler intensifiers are powered by diesel-driven hydraulic power units. Both Halliburton and Towler intensifiers use long, overlapping strokes to produce very smooth output flows.

Flow Industries, Inc. manufactures a 250-hhp output low-flow, high-pressure intensifier unit designed for use with filtered water. The units are skid-mounted and consist of a double-acting intensifier and an electro-hydraulic power unit. Piston sizes are specifically selected for

- ① Triplex, Halliburton HT-400D, 258 hhp
- ② Triplex, Halliburton HT-400D, 565 hhp, (Intermittant Service)
- ③ Triplex, Gardner-Denver, PZ-7, 495 hhp
- ④ Triplex, Gardner-Denver, PZ-8, 675 hhp
- ⑤ Triplex, Gardner-Denver, PZ-10, 1215 hhp
- ⑥ Intensifier, Towler
- ⑦ Intensifier, Towler
- ⑧ Intensifier, Halliburton, HT-3000, 4400 hhp
- ⑨ Intensifier, Halliburton, HT-1000, 1800 hhp
- ⑩ Intensifier, Flow Tech., 250 hhp (Water Only)
- ⑪ Three Intensifiers in Parallel, Flow Tech., 250 hhp, (Water Only)

Figure 4. High-Pressure Pump Capabilities

Table 3. Mud Pump Manufacturers, Nomenclature, and Specifications

Manufacturer	Pump Type + Trade Name	Pressure, psi	Flow, gpm	Power, hp	Temperature, °F	Applications
B.J. Hughes	Triplex (pacemaker)	15000	160			Oil field cementing Gravel packing services
		15000	210			
		8000	350			
		4600	630			
Worthington Pump	Triplex Quintuplex Septuplex Nonuplex	Up to 40000	Up to 3000	150600		Process Industries Pipelines Petroleum Industry
				1000		
				1600		
				1600		
Wilson-Snyder	Triplex	3180	18-176			
Wilson-Snyder Pumps (hot hydrocarbons)	Triplex Quintuplex	3180	18-176		Up to 600	Hot fuel oil Hot Asphalt Corrosive, abrasive agents
		5000	153-700			
ARAMCO	Triplex 12-P-160	3200-5500	148-700			Land or offshore flush
Cat Pumps Corp.	Triplex Uniflow concept	1000	60			Injection, spraying, hydrostatic testing
		5000	12			
Gardner-Denver	Triplex PJ-8	3118	128	275		Mud pumps
	Quintuplex PZ-7	3556	238	550		
	PZ-8	5381	215	750		
	PZ-9	5530	279	1000		
	PZ-10	5100	400	1350		
	PZ-11	5595	440	1000		
Dowell Schlumberger	Triplex Model PT-02	10500	411	1000		Water (Dirty)
	PD07 Triplex	70000	4600 lb/min.			
Ideco	Duplex-double acting	5556	444	1300		Mud pumps
Dresser		↓	↓	1000		
	Triplex	2000	700	800		

Table 3. Mud Pump Manufacturers, Nomenclature, and Specifications (Continued)

Manufacturer	Pump Type + Trade Name	Pressure, psi	Flow, gpm	Power, hp	Temperature, °F	Applications
Halliburton	Intensifier pumps	9000-20000		1800-4400		Continuous, smooth high pressure supply
	HT-1000, HT-3000					
	HT-400 mud multi purpose	4000	153	275		
Aldrich, Ingersoll- Rand	Triplex	Up to		10 to 2725		
	Quintuplex	7000	15			
	Septuplex	5000	400			
	Nonuplex					
National Supply	Triplex 7-P-50	1515	571	500		Mud Water
	12-P-160	5000	518	1600		
	Duplex					
Oil Well, Division of United States Steel	Triplex					Mud Large variety of pumps
	Duplex					
	A-560-PT	6000	229			
	A-850-PT	5000	310			
	1700-P	4300	475			
Skytop Brewster	Duplex					Mud
	B550F, B750F, B1000F	1200-3800	130-650	775-1000		
	Triplex					
	B1300T, B1600T	2700-5000	235-720	650-1600		
Stewart & Stevenson Tools	Air operated	3000	30	60		Water
	Electric operated					
	Triplex & Duplex					
Valve Control, Subsidiary of Hydrill	Simplex	3000	30	Up to 60		Water, hydraulic
	Triplex					
Wilson Mfg.	Duplex	2000-4250	100-595	600-1300		Mud
Baker Sand Control	Centrifugal Mud Pump					1000 rpm 12 BPM output
NL Rig Equipment	Choke System	10000,15000			300	

each application in order to produce the desired output flow and pressure at a reasonable cycle rate. Integral high-pressure accumulators are provided to smooth pressure fluctuations caused by the piston reversals. These units are currently used for underground mining applications.

The surface pumping requirements of each of the three cases identified for this study have been summarized in Table 2. It may be seen that the requirements of Subcase 1a are beyond the rated performance of both the Halliburton HT-1000 and HT-3000 intensifiers. Subcases 1b, 1c, and 1d requirements, however, may be satisfied by either of these Halliburton intensifiers. Comparing Tables 2 and 3 shows that Case 2 pressure and flow requirements may be satisfied by any of the larger conventional pumps, such as the Gardner-Denver PZ-9. Case 3 high-pressure requirements (Subcase 3a) may be satisfied by water only using three Flow Industries 250-hhp intensifiers in parallel; low-pressure requirements (Subcase 3b) may be satisfied by any of several available triplex pumps.

2.2 Hoses

High-pressure hoses, i.e., those with rated working pressures above 2,000 psi, can be grouped into three general categories as follows:

- A. Hydraulic hoses.
- B. Conventional oil field hoses.
- C. Flexible pipe.

Figure 5 shows the performance of representative hoses from each category with the manufacturer's recommended maximum working pressure as a function of inside diameter. High-pressure hoses are generally hydrotested at 1.5 to 2.0 times the rated working pressure and have safety factors ranging from 2.2 to 4.0, depending on the service requirement.

2.2.1 Hydraulic Hoses

Most hydraulic hoses are manufactured and tested in accordance with the specifications of the Society of Automotive Engineers (SAE). Hydraulic hoses with inside diameters of up to 2 inches (Figure 5, examples 1 through 5) are readily available from several sources, e.g., Dynacraft and Parker. Specialty hoses such as Polyflex (Figure 5, examples 1 and 2) are included in the hydraulic hose category although they may be manufactured with smaller inside diameters and rated for higher pressures.

Representative Examples: $\left(SF = \text{Safety Factor} = \frac{\text{Burst Pressure}}{\text{Working Pressure}} \right)$

- ① Polyflex 4000 ST, SF = 2.2, Hydrotested at $1.5 \times WP$
- ② Polyflex 2000 ST, SAE 100 R9, SF = 2.5, Hydrotested at $1.5 \times WP$
- ③ Hi-Flex "Power Trak", SF = 3.0
- ④ Dynacraft 1066, SAE 100 R11, SF = 4.0, Hydrotested at $2.0 \times WP$
- ⑤ Dynacraft 1064, SAE 100 R10, SF = 4.0, Hydrotested at $2.0 \times WP$
- ⑥ Goodyear Flexsteel 10,000 Rotary and Vibrator, Hydrotested at $2.0 \times WP$
- ⑦ Goodyear Flexsteel 7,500 Rotary and Vibrator, Hydrotested at $1.9 \times WP$
- ⑧ Coflexip Flexible Pipe, Hydrotested at $1.5 \times WP$

Figure 5. State-of-the-Art Hose Performance

Some manufacturers increase hose pressure ratings by reducing the safety factor. For example, hose safety factors of 2.0 to 2.5 may be acceptable for systems with minimal pressure surges and flexing. If a safety factor of 2.0 is acceptable, Polyflex 4000 St and Dynacraft 1-inch inside diameter SAE 100 R11 hose (Figure 5, examples 1 and 2) would be suitable for 10,000-psi service while Hyflex 2-inch inside diameter Power Trak hose (Figure 5, example 3) would be suitable for 7,500-psi service.

2.2.2 Conventional Oil Field Hoses

Goodyear and Uniroyal supply conventional rotary and vibrator hoses for large-diameter, high-pressure oilfield applications (Figure 5, examples 6 and 7). These hoses are designed to provide high-pressure service while surviving the rough handling associated with drill rig work. Although the sales literature does not provide hose safety factors and burst pressures, it does indicate that the hoses are hydrotested at a generous 1.9 to 2.0 times the rated working pressure.

Oilfield hoses are custom fabricated to specific lengths and provided with integral fittings at each end. These fittings are commonly either nipples with API male pipe threads or Victaulic-type grooved ends.

2.2.3 Flexible Pipe

In 1972, Coflexip (a French manufacturing company) developed a flexible pipe for special oilfield applications that require a fluid transport tube combining the high-pressure capability of rigid pipe and the flexibility of conventional hose. Since then, this pipe has come into general use in oil fields around the world for those applications requiring its unique capabilities.

Coflexip flexible pipe comprises a spiral, interlocking steel band that permits limited flexing while providing exceptional hoop strength, double cross-wound bands angled to provide tensile strength, and thermoplastic sheaths to seal the tube, separate the steel layers, and provide an abrasion-resistant outer jacket. The resulting tube is nearly as flexible as comparably sized rotary hose and stronger than double-extra-strength API 5L, Grade B steel pipe.

The smallest flexible pipe presently available has an inside diameter of 2 inches. However, the Coflexip representative in Houston, Texas states that smaller sizes can be made if a market for them develops. The 2-inch inside diameter flexible pipe has a burst pressure of 36,820 psi, or a rated working pressure of 15,000 psi with a safety factor of 2.5. Working pressures to 24,500 psi can be obtained, of course, if a safety factor of 1.5 is acceptable. In that case, however, secondary safety precautions should be taken to avoid injury to personnel and/or equipment damage in the event of a line failure.

End fittings for flexible pipe assemblies are provided in accordance with customer specifications. The connections for the end fittings, which are claimed to be stronger than the pipe itself, leave a 48-inch long rigid portion at each end of the flexible pipe assembly.

Coflexip flexible pipe is, of course, quite expensive. For example, one 80-foot long section with a 2-1/2-inch inside diameter, 15,000-psi working pressure, 48-inch minimum bend radius (working), Weyco union ends, lifting collars, and a stainless steel outer jacket will cost \$41,156 complete, F.O.B. Houston as of January 1981. It is difficult to evaluate the relative worth of this product since no hose currently available has comparable performance characteristics.

2.2.4 Hose Availability

Table 4 lists the high-pressure hoses available for this application together with their sources.

The Case 1 surface pumping (Subcase 1a) pressure requirements will require the use of 2-1/2-inch inside diameter Coflexip flexible pipe at a slightly reduced safety factor. Subcase 1b and 1c requirements, however, are well within the rated capabilities of Coflexip flexible pipe. Subcase 1d and Case 2 requirements can be met using conventional oilfield rotary hose.

The Case 3 high-pressure requirement (Subcase 3a) is far beyond the rated capability of any available high-pressure hose. Coflexip 2-inch inside diameter flexible pipe could satisfy Subcase 3a if a minimum 1.5 safety factor is acceptable. However, it may be better to reduce the nozzle pressure and/or flow requirement and thus the required surface pressure (see Figure 6). For example, a 2-inch inside diameter flexible pipe could transport drilling fluid

Table 4. Hose Manufacturers, Nomenclature, and Specifications

Manufacturer	Type	Specification
Townley Eng. & Mfg.	Series 6000 Slurry hoses	Highly abrasive slurry for mining applications
DayCo	Field hoses & hydraulic hoses	Up to 10,000 psi, up to 3 1/2 in., from -40 to 250°F. Rotary hose, vibrator hose, for mud pump, etc.
The Galer Rubber Co.	Hoses & flex fittings	Rotary & vibratory hoses. High-pressure oil lines, steam, mud and other material. Up to 10,000 psi.
Harrisburg, A Kendaris Industries Company	Rotary & vibratory hoses, couplings	7500 - 10,000 psi.
Coflexip	Flow lines	Up to 15,000 psi test pressure, oil, gas, hydraulic remote, 2-in. ID.
Stratoflex	Hoses and field attachable fittings	No mud - low, medium, high and extra-high. Up to 4000 psi, 120°C, burst = 10,000 psi.
Gay Hose	Hydraulic hose	Up to 5000 psi, burst = 20,000 psi, OD = 35 in., 93°C.
Parker	Paraflex high press. hose with kevlar	250 to -70°F, 27,000 psi.

Figure 6. Dual Drill String High-Pressure Conduit Line Losses

to the tool at an 18,400-psi surface pressure while retaining a safety factor of 2.0. At a 10,000-foot depth, this surface pressure would translate to nozzle pressures and flows of 15,000 psi at 24 gpm, 12,500 psi at 36 gpm, and 10,000 psi at 46 gpm as opposed to the present 15,000 psi at 50 gpm requirement. The Case 3 low-pressure requirement (Subcase 3b) can be satisfied using hydraulic hose.

2.3 Drill Pipe and Tool Joints

Several major drill pipe and tool joint manufacturers were approached for recommendations concerning the use of their products in the conceptual designs presented in this report as Cases 1, 2, and 3. Tables 5, 6, and 7 summarize the recommendations obtained from these manufacturers. It can be seen that Wheeling-Pittsburgh was most responsive in this regard. For the most part, the other suppliers simply recommended their standard drill pipe and tool joints without special considerations. Table 8 comprises a list of manufacturers and their products.

It should be noted that metal failure due to hydrogen embrittlement or sulfide stress corrosion cracking can occur when drill pipe with a yield strength higher than the Grade E encounters sour gas (H_2S) (Refs. 5 and 6). Since Case 1 requires high yield strength pipe due to its high internal pumping pressures, the pH balance of the drilling fluid used for this case must be carefully controlled.

2.3.1 High-Temperature Performance Requirements

None of the manufacturers queried could provide any data concerning the performance characteristics of their drill pipe and tool joints at the specified 500°F soak and 300°F operating temperatures. Also, the API specifications for standard and high-strength drill pipe (API Specifications 5A and 5AX) specify minimum tensile and yield strengths at room temperature only. Therefore, the high-temperature performance characteristics of drill pipe and tool joints must be inferred from existing data on the steels typically used to fabricate them. Figures 7 and 8 show typical tensile and yield strengths for medium carbon and chromium/molybdenum steels at elevated temperatures (Ref. 7). As shown, these materials may be expected to experience yield strength reductions of 5% to 20% at 500°F and 2% to 10% at

Table 5. Case 1: Surface Pumps, Single-Conduit Drill String

CONDITIONS:

10,000 ft	WELL DEPTH (MAX)
30,000 ft-lb	TORQUE (MAX)
50,000 lb	BIT LOAD
* 60,000 lb	DEAD LOAD (DRILLING MUD)
* 15,000 psi	INTERNAL WORKING PRESSURE (ACTUAL PRESSURES VARY WITH PARTICULAR SUBCASES)
6 in.	OUTSIDE DIAMETER (MAX)
* 2-1/2 in.	INSIDE DIAMETER (MIN)
500°F	DOWNHOLE TEMPERATURE (SOAK)
300°F	DOWNHOLE TEMPERATURE (OPERATE)
200°F	SURFACE OPERATING TEMPERATURE

DRILL PIPE RECOMMENDATIONS:

<u>MANUFACTURER</u>	<u>LENGTH, FT</u>	<u>PIPE OD, IN.</u>	<u>NOMINAL WEIGHT, LB/FT</u>	<u>API GRADE</u>	<u>MIN. YIELD, PSI</u>
WHEELING -	1329	4-1/2	16.60	S	135,000
PITTSBURGH	8121	4-1/2	24.60 **	E	75,000
	550	DRILL COLLARS	91.00	-	-
	<u>10,000</u>				
JONES & LAUGHLIN	-	4-1/2	20.00	G	105,000
U.S. STEEL	-	4-1/2	16.60	S	135,000
		5	19.50	S	135,000

TOOL JOINT RECOMMENDATION:

<u>MANUFACTURER</u>	<u>NOMINAL SIZE, IN.</u>	<u>JOINT TYPE</u>	<u>MAX OD, IN.</u>	<u>MIN ID, IN.</u>
HUGHES TOOL	4-1/2	FULL HOLE	6	2-1/2

* IDENTIFIES CONDITIONS UNIQUE TO THIS CASE.

** THIS WEIGHT DRILL PIPE IS NOT CURRENTLY AVAILABLE. SUGGEST
SUBSTITUTING 20.00 lb/ft GRADE X.

Table 6. Case 2: Downhole Intensifier, Single-Conduit Drill String

CONDITIONS:

10,000 ft	WELL DEPTH (MAX)
30,000 ft-lb	TORQUE (MAX)
50,000 lb	BIT LOAD
* 9,000 lb	DEAD LOAD (INTENSIFIER)
* 59,000 lb	DEAD LOAD (DRILLING MUD)
3-5000 psig	INTERNAL WORKING PRESSURE
6 in.	OUTSIDE DIAMETER (MAX)
* 2-3/4 in.	INSIDE DIAMETER (MIN)
500°F	DOWNHOLE TEMPERATURE (SOAK)
300°F	DOWNHOLE TEMPERATURE (OPERATE)
200°F	SURFACE OPERATING TEMPERATURE

DRILL PIPE RECOMMENDATIONS:

<u>MANUFACTURER</u>	<u>LENGTH, FT.</u>	<u>PIPE OD, IN.</u>	<u>NOMINAL WEIGHT, LB/FT</u>	<u>API GRADE</u>	<u>MIN. YIELD, PSI</u>
WHEELING -	1317	4-1/2	24.60 **	E	75,000
PITTSBURGH	3429	4-1/2	20.00	E	75,000
	4704	4-1/2	16.60	E	75,000
	550	DRILL COLLARS	91.00	E	75,000
	10,000				
JONES & LAUGHLIN	-	4-1/2	16.60	E	75,000
U.S. STEEL	-	4-1/2	16.60	E	75,000
		5	19.50	E	75,000
NATIONAL - ARMCO	-	4-1/2	16.60	E	75,000

TOOL JOINT RECOMMENDATION:

<u>MANUFACTURER</u>	<u>NOMINAL SIZE, IN.</u>	<u>JOINT TYPE</u>	<u>MAX OD, IN.</u>	<u>MIN ID., IN.</u>
HUGHES TOOL	4-1/2	FULL HOLE	6	2-3/4

* IDENTIFIES CONDITIONS UNIQUE TO THIS CASE.

** THIS WEIGHT DRILL PIPE IS NOT CURRENTLY AVAILABLE. SUGGEST
SUBSTITUTING 20.00 lb/ft GRADE X.

Table 7. Case 3: Surface Pumps, Dual-Conduit Drill String

CONDITIONS:

10,000 ft	WELL DEPTH (MAX)
30,000 ft-lb	TORQUE (MAX)
50,000 lb	BIT LOAD
* 80,000 lb	DEAD LOAD (INNER STRING)
* 48,000 lb	DEAD LOAD (DRILLING MUD)
3-5000 psig	INTERNAL WORKING PRESSURE
6 in.	OUTSIDE DIAMETER (MAX) }
• 3-1/4 in.	INSIDE DIAMETER (MIN) } PREFERRED
500°F	DOWNHOLE TEMPERATURE (SOAK)
300°F	DOWNHOLE TEMPERATURE (OPERATE)
200°F	SURFACE OPERATING TEMPERATURE

DRILL PIPE RECOMMENDATIONS:

<u>MANUFACTURER</u>	<u>LENGTH, FT</u>	<u>PIPE OD, IN.</u>	<u>NOMINAL WEIGHT, LB/FT</u>	<u>API GRADE</u>	<u>MIN. YIELD, PSI</u>
WHEELING -	2533	4-1/2	16.60	S	135,000
PITTSBURGH	2389	4-1/2	24.60 **	E	75,000
	3429	4-1/2	20.00	E	75,000
	1099	4-1/2	16.60	E	75,000
	550	DRILL COLLARS	91.00	E	75,000
	10,000				
JONES & LAUGHLIN (CONTINENTAL-EMSCO)	-	4-1/2	16.60	E	75,000
U.S. STEEL	-	4-1/2	16.60	E	75,000
		5	19.50	E	75,000
NATIONAL - ARMCO	-	4-1/2	16.60	G	105,000

TOOL JOINT RECOMMENDATION:

<u>MANUFACTURER</u>	<u>NOMINAL SIZE, IN.</u>	<u>JOINT TYPE</u>	<u>MAX OD, IN.</u>	<u>MAX ID, IN.</u>
HUGHES TOOL	4-1/2	FULL HOLE	6	3

* IDENTIFIES CONDITIONS UNIQUE TO THIS CASE.

** THIS WEIGHT DRILL PIPE IS NOT CURRENTLY AVAILABLE. SUGGEST
SUBSTITUTING 20.00 lb/ft GRADE X.

Table 8. Drill Pipe Manufacturers, Nomenclature, and Specifications

Manufacturer	Component	Specifications
RESCO	Collars, round, spiral, square Pipe drill (Hevi-wate) & matching tool joints	4145-H steel heat treated, Brinell hardness 285-341, lengths in API range II 31. OD up to 5 in., ID up to 3 in. - Tensile yield 691,185 lbs., torsional yield 56,495 lb.-ft on 3-in. ID x 5-in. OD - weight 49.3 lb/ft.
Reed Tool	Tool joints Drill pipe Collars (Hi-Flex), double strength	Standard OD up to 7½ in. with 3-in. ID, Yield strengths = 1,925,520 lb. tension, 86,800 lb.-ft torsion. Up to 5-11/16-in. OD with 4.77-in. ID., Yield values = 78,681 lb. tension, 91,280 lb.-ft torsion. Up to 11-1/4-in. OD with 2-3/4 to 4-1/2-in. ID - high grade chromium-molybdenum alloy steel - Spiral grooves - weight up to 318 lb/ft.
SMF International	Collars, spiral, slick (also nonmagnetic) Kelly (square, hex) Thick-wall drill pipe & joints	Yield strength = 100,000 psi tension, BHN = 285-340 - up to 14-in. OD - possible hardfacing - Approx. weight 31 ft. long = 15,450 lb - Integral Collars Up to 6 x 6 in. and 54 in. long - AISI 4145 H alloy steel. Bore up to 3.5 in. Pipe: AISI 1340 modified grade - granular tungsten carbide hardfacing - also nonabrasive chromium carbide hardfacing - tool joints up to 6-1/4-in. OD with 550,000 lb. tensile yield, 40,500 ft.-lb torsion.
United Casing Steel and Pipe	Drill Pipe Tube Connections (five groups) VAM joints (connections) Drill pipe	Up to 5-in. OD - up to 22.5 lb.-ft - yield strength: 712,100 lb tensile, 57,000 lb.-ft torsion. Ex: Metal-to-metal seal, tool joint types, flush or near-flush types (integral - no separate coupling). Up to 4½-in. OD, max 501,000 lb tensile load on P-105 model - coupling torque = 5400 lb.-ft. 6-5/8-in. max OD = max internal press. = 9150 psi - ID = 5.9 in. - other pipes take up to 23,000 psi internal pressure.
Varel Manufacturing	Kelley (square, hex) Collars Joints	Chromium-Molybdenum steel - up to 6-in. OD - spec. SAE4140, 4142, 4145. Up to 11-in. OD Chromium-Molybdenum - spec. API No. 7 - Min. ID = 1 in. Weld-on tool joints - API screw-on tool joints - hardfaced - shrink-on tool joints.
Joy Manufacturing	Kelley (square, hex) Rotary drill pipe substitute	Up to 6-in. N.S., ID up to 3½ in., BHN = 285-341 - yield strength: up to 1,707,000 lb tensile on largest size with 171,774 lb.-ft torsion.
Lone Star Tool	Kelley (square, hex) Drill Collars	BHN = 285-341 Up to 6-1/4-in. OD - AISI 4145.
A-1 Bit & Tool	Drill Collars Mills Drill Pipes Mills	

Table 8. Drill Pipe Manufacturers, Nomenclature, and Specifications
(Continued)

Manufacturer	Component	Specifications
ARAI Iron Works	Drill Pipe	Styles EU, 1EU – up to 5½ in. nominal size – yield strength: 120,000 psi – BHN = 293-341 (wide range), 6-24 lb/ft.
	Tool Joints	AISI 4137H, Cr-Ni-Mo alloy available – hardfaced, 120,000 psi yield.
Breda Fucine (Italy)	Drill Pipe Collars, Kelley	Licensee of Hughes Tool Co.
Curtis Hoover Industries	Drill Pipes Tool Joints	
Drilco, Division of Smith International	Collars	Up to 11-in. OD, 801-8970 lb/31 ft, bore = 1½ – 3 in. BHN 285-341.
	Kelleys (square, hex)	Up to 6-in. N.S.
	Drill Pipe	Heavy wall up to 5-in. N.S., tensile yield = 691,185 lb on 5-in. OD × 3-in. ID, Torque = 56,495 lb-ft, make up torque = 79,400 lb-ft.
Equipetrol	Tool Joints	Internal flush, full hole, up to 5-in. nominal size, shrink fit hardfacing – wide variety.
	Heavy-wall drill pipes	Range II, Range III, 5-in. N.S., 1-in. thick walls, 1,266,000 lb yield, 51,376 lb-ft torque.
	Collars	Up to 11-in. OD, 801-8970 lb/31 ft length.
	Kelley (square, hex) (Wide range)	Up to 6-in. N.S.
Gotco Industries	Tool Joints	For up to 5½ in. pipe, API hole, extra hole.
	Pipe Drill	Up to 5½ in.
Hughes Tool	Drill Pipe	Up to 5½ in. OD with 0.4-in. wall thickness, Grade 5 is strongest with $\sigma_y = 135,000$ psi, $\tau_y = 77,890$ psi.
	Tool Joints	Wide range with maximum makeup torque = 39,600 lb-ft.

Figure 7. Effect of Temperature on API Grade E Steel Drill Pipe Strength

Figure 8. Effect of Temperature on API Grade S Steel Drill Pipe Strength

300°F. These reductions in yield strength are acceptable within the stated design constraints.

2.3.2 Torque Loading Requirements

The 30,000 ft-lb maximum torque requirement specified by the contract design constraints can be satisfied by commercially available drill pipe and tool joints. The Hughes H-90 tool joint provide a torsional yield limit of 39,000 ft-lb; 20.0 lb/ft Grade E pipe and 16.60 lb/ft Grade X pipe provide drill pipe torsional yield points of 36,900 ft-lb and 39,000 ft-lb, respectively. It should be noted, however, that these figures represent room-temperature values only.

2.4 Swivels

A swivel joint is required to transfer fluid(s) from the stationary hoses to the rotating drill string. The swivel must provide a seal capable of withstanding the required internal pressures while operating at a useful speed of rotation. It may also be required to support the entire weight of the drill string. There are at least four types of swivels with one or more features that would be useful in high-pressure geothermal drilling applications. These are as follows:

- A. Piping swivels.
- B. Oil field swivels.
- C. Steam swivels.
- D. Hydraulic swivels.

Refer to Table 9 for a listing of swivel manufacturers and their products.

2.4.1 Piping Swivels

These swivels are used to connect sections of piping where flexibility is required and are often used in place of hoses (Figure 9). Piping swivels are rated to 15,000 psi non-shock cold working pressure. However, they are available only in 2-inch sizes and are designed for light loads and non-continuous rotation.

Table 9. Swivel Manufacturers, Nomenclature, and Specifications

Manufacturer	Type or Trade Name	Specifications
Skytop/Brewster	Models 4-SX, 5-SX . . . 9-SX Power Swivels	Bearing capacity up to 378 tons - max working pressure = 4500 psi - lip-type pressure seal - minimum fluid passage = 3 in. Hyd. power = 7000 psi, 81.5 gpm - stall torque = 3518 lb.-ft. - 100 rpm
Western Engineering & Mfg.	Swivel joints	Up to 6000 psi, max temp. 225°F - up to 6-in. flow passage diam. - swivel joints for 10,000 psi with 1500 psi also available - seals for 450°F are available.
Industrial Export (Romania)	Swivels CH-650, CH-400, etc.	Up to 5000 psi, dead load rating up to 715 tons, 3-in. fluid passage diam.
Joy Mfg.	BAASH-Ross power swivels MR-40/85, PS-130-3	Speed = 300 rpm - Torque = 7400 lb.-ft. possible with 130 ton unit - up to 5000 psi mud pressure. Dynamic load of 77 tons at 100 rpm - spindle bore = 2½ in.
King Oil Tools	Water well swivels Oil field swivels	Up to 500,000 lb. bearing capacity at 20 rpm, min. fluid passage range between 5 to 8½ in. (LW series). Safe depth up to 7500 ft. with 3½ -in. pipe drill, 10,000 ft. with 2-3/8-in. pipe drill.
Lanzagorta International	Swivels CM-TL-120A, CM-TL-650, etc.	Max pressure = 4500 psi, bearing capacity at 100 rpm between 78 to 471 tons - minimum fluid passage up to 3 in.
ARMCO National Supply	National Swivel	Max working pressure = 5000 psi, load rating = 200-650 tons, 3-in. diam. fluid passage.
Bert Industries	Swivel Joint	Up to 450°F, 6000 psi, 3/4-4 in.
FMC	Swivel Joints	Up to 10,000 psi, alloy steel, dynamic seal good for 450°F, elastomeric packing up to 3 in. for high pressure and 8 in. for low pressure.
Gardner Denver	Swivels SW-75 - SW-550	75-550 ton load capacity, 40-471 tons at 100 rpm.
Geograph-Pioneer	Swivel Joints (Western Swivel Joint)	Up to 10,000 psi.
Gray Tool	Swivels, heavy, medium & light duty	500 ton - 3-in. min. passage - API rating at 100 rpm = 234 tons.

Exxon tested a high-pressure swivel seal (15,000 psi) with 50 to 80 hr life time. (This information in Terra Tec report to DOE.)

Extra High Pressure Swivel Joints (STANDARD SERIES)

DESCRIPTION:

Material	Designation	Code Color	Sizes	Maximum Pressure††	Max. Temp. Elastomeric Packings	Max. Temp. Poly-resin Packings
Steel	XH	Red	2"	15,000 psi	225° F.	450° F.

NOTE: Above maximum pressures and temperatures are independent of each other, i.e. max. temp. OR max. pressure NOT max. temp. AND max. pressure.

Made in 8 different styles in 2" size. Material is forged steel with flame-hardened ball races.

APPLICATIONS: Designed and built for extra heavy duty where extreme pressures are encountered.

DIMENSIONS* (Where dimensions are critical, consult factory.)

Component Parts, Page 18

THREADED ENDS

SIZE	B	C	D	E	F	G	J	K	L	M	N	P	Q	R	S	T	V	W	X
2"	6 ⁷ / ₁₆	4 ¹ / ₈	6 ³ / ₈	10 ⁹ / ₁₆	8 ¹ / ₄	3 ¹ / ₄	13 ¹⁵ / ₁₆	4 ³ / ₈	3 ¹ / ₄	6 ⁵ / ₁₆	7 ¹ / ₂	6 ³¹ / ₃₂	10 ⁷ / ₁₆	6 ¹ / ₂	13 ¹³ / ₁₆	10 ⁷ / ₁₆	6 ⁷ / ₁₆	2 ¹¹ / ₁₆	7 ³ / ₈

*See opposite page for dimensional drawings.

WEIGHTS (Approx. in lbs.)

STYLES	20	30	40	50	60	70	80	10
2" Weight, Lbs.	14	21	28	36	29	43 ¹ / ₂	54	47

Figure 9. Extra-High-Pressure Swivel Joints

2.4.2 Oil Field Swivels

Oil field swivels have large bearings to support drill string weight while rotating continuously (Figure 10). However, their maximum working pressures are typically only 3,500 to 5,000 psi (see Table 9). The factors that limit oil field swivel working pressure are as follows:

- A. Washpipe stresses.
- B. Packing capabilities.
- C. Gooseneck stresses.

2.4.3 Steam Swivels

Steam swivels often have multiple passages to allow steam drums to be simultaneously supplied with steam and drained of condensate. These swivels typically have a maximum pressure rating of 250 psi for steam or 300 psi for water.

2.4.4 Hydraulic Swivels

Many hydraulic swivels are provided with multiple passages to connect hydraulic lines to moving, rotating, articulating, and extendible hydraulic machinery. Maximum working pressures are generally 3,000 psi, although some hydraulic swivels are rated to 6,000 psi.

2.5 Downhole Pumps

It has been determined that no presently available downhole pump is capable of satisfying the Case 2 requirements for geothermal drilling. Therefore, the Case 2 downhole pump component requires a new design and development effort (refer to Subsection 3.4).

Figure 10. Oil Field Swivels

3. New Component Designs

3.1 Mud Pumps

Mud pumps used in drilling operations supply fluids both to flush the drill bit and to carry cuttings to the surface. The principal components of a positive displacement mud pump are as follows (refer to Figure 11):

- A. Inlet Check Valve - The inlet check valve opens to allow low-pressure supply fluid to enter the high-pressure cylinder during the piston plunger inlet stroke. It closes to prevent pressurized fluid from entering the low-pressure supply line during the outlet (pressure) stroke.
- B. High-Pressure Cylinder - The high-pressure cylinder contains the fluid admitted during the piston plunger inlet stroke until it has been pressurized and discharged during the outlet (pressure) stroke.
- C. Piston Plunger - The reciprocating piston plunger pressurizes the fluid admitted to the high-pressure cylinder. In the diagram given as Figure 11, the inlet stroke is downward and the outlet (pressure) stroke is upward.
- D. High-Pressure Seals - The high-pressure seals prevent leakage from the high-pressure cylinder by sealing the annulus between the piston plunger and the walls of the high-pressure cylinder.
- E. Piston Drive - The piston drive imparts reciprocating motion to the piston plunger. The piston drive function may be accomplished either mechanically by means of the crankshaft of a triplex pump or hydraulically by means of the hydraulic cylinder of an intensifier pump.
- F. Outlet Check Valve - The outlet check valve opens to permit the discharge of pressurized fluid during the piston plunger outlet (pressure) stroke and closes to prevent a reverse flow of pressurized fluid during the inlet stroke.
- G. Power Supply - The power supply is the engine or motor that powers the entire pumping process via the piston drive.

Figure 11. Positive Displacement Pump Diagram

3.1.1 Pump Reliability

Mud pump reliability decreases as its number of operating cycles increases. This is due to the wear and material fatigue experienced by the individual components during prolonged service.

In any pump, the piston plunger and its seals are the components most subject to wear-induced failure. This is especially true of mud pumps where the working fluid is either drilling mud or unfiltered water. As the piston plunger reciprocates through the seal, particles entrained in such fluids are forced between these components and abrade them until failure occurs.

Check valves and high-pressure cylinders are the most fatigue susceptible pump components. Check valves experience high seating forces due to the large area on which fluid pressure acts to close the valve versus the relatively small seating area that resists the closing force (Figure 12). Therefore, high-pressure cyclic stress on the valve seat can exceed material strength and result in eventual fatigue failure. Also, working fluid particles trapped between the valve and its seat during closing cause high local stresses that contribute to material fatigue.

The cause of high-pressure cylinder fatigue failure is inherent in its function. That is, the cyclic containment of pressurized fluid within the cylinder eventually fatigues the cylinder material to failure. This will occur more rapidly in mud pumps unless special attention is given to high-pressure cylinder design geometries, materials selection, and finished wall smoothness.

3.1.2 New Design

To solve the pumping reliability problems, a method of flushing the plunger seals (Figure 13) and check valve seats (Figures 14, 15, and 16) was devised to prevent wear caused by mud particles. Flow Industries commercial pumps currently last many hundreds of hours pumping clean water at 55,000 psi. Therefore, it seems realistic to expect 200 hours of operation at 15,000 to 20,000 psi if a clean flushing fluid is used. The flushing system, shown schematically on Figure 17, is comprised of two pumps, a reservoir, and a series of orifices to limit flow. The high-pressure pump flushes the plunger seals and check valve seats during the high-pressure (outlet) phase of the mud pump cycle. The low-pressure pump supplies flushing water to the piston

CHECK VALVE
(Shown in Closed Position)

Figure 12. Check Valve Seating Stress Diagram

NOTE:
Cylinder Cap Check Valves
Not Shown

Figure 13. Plunger Seal Flushing Method

Figure 14. Linear Spool Check Valve Flushing Method

Figure 15. Rotating Spool Check Valve Flushing Method

Figure 16. Poppet Check Valve Flushing Method

plungers and check valve seats during the low-pressure (inlet) phase of the mud pump cycle. Check valves are used to prevent high-pressure water from entering the low-pressure side.

3.1.2.1 Piston Seal

The flushing fluid piston seal (Figure 13) consists of a high-pressure seal to prevent seal fluid from leaking out of the pump case, two flushing fluid holes (high and low pressure), a clearance sleeve that directs flushing fluid to the wiper seals, and the wipers seals that prevent particle contamination when the pump is shut down. A weep hole permits high-pressure seal failure to be detected by means of escaping fluid.

3.1.2.2 Check Valves

Three check valve concepts employing flushing fluid on critical surfaces were studied.

The linear spool check valve (Figure 14) operates with a reciprocating motion and would ordinarily have a spring (not shown) to ensure that it remains closed when there is no fluid motion. Seal water is provided in two locations to maintain clean seal surfaces on both sides of the port when the valve is closed. Since this valve must be large enough to permit realistic flow velocities, a great deal of pumping energy is wasted in operating the valves, i.e., poor volumetric efficiency. (Refer to Figure 18 for installation details).

The rotating spool check valve (Figure 15) rotates 180 degrees to alternate inlet and outlet flow in conjunction with high-pressure piston motion. Flushing water is provided to keep the bearing surface clean. This valve is not automatic and must be controlled by an external linkage system connected to the high-pressure piston.

The poppet check valve (Figure 16) is similar in design to an automotive engine valve. Flushing fluid can be piped through the stem to the seals and seat (Figure 19, detail A) or manifolded externally (Figure 19, detail B). Seating force is limited by externally adjustable stops on the valve stems. The wear point on this valve seat is very small and can easily be flushed to prevent particles from damaging the seats while the stops prevent seal over-stressing due to high-pressure loading on the seat.

Figure 18. Rotating Spool Check Valve Flushing System

Figure 19. Poppet Check Valve Flushing Systems

3.1.2.3 Conclusion

Flushing the piston seal and check valves appears to be a feasible method for greatly extending pump life with currently available technology.

3.2 Swivels

3.2.1 Single-Passage Swivels

Custom components are required to modify single-passage oil field swivels for operation at the higher pressures required for this application. Figures 20 and 21 illustrate the means by which a standard Gardner-Denver swivel can be modified for high-pressure service. Other oil field swivel manufacturers have comparable designs that could be modified in a similar fashion.

The first concept, Figure 20, utilizes custom-designed and manufactured high-pressure dynamic seals and incorporates high-pressure fresh water flushing. The load bearing components of the swivel remain unchanged.

The other concept, Figure 21, simply requires an extension of the high-pressure rotating passage to which a high-pressure piping swivel is attached. No flushing water is required since the piping swivel is designed for mud service and is easily replaceable.

3.2.2 Dual-Passage Swivels

The commercially available dual-passage steam and hydraulic swivels are not suitable for the Case 3 dual drill string application. Lack of load bearing capability and low operating pressure ratings exclude these components from further consideration.

A concept for modifying a standard Gardner-Denver oil field swivel for dual passage service utilizes high-pressure dynamic seals and high-pressure fresh water flushing. The low-pressure packing is retained, however, for the outer low-pressure scavenging flow.

3.2.3 Applications

Subcase 1a requires a single-passage swivel with 16,500-psi rating. Since no commercial load-bearing swivels capable of such pressure are available, a modified oil field swivel (Figure 20) would be required.

Figure 20. Single-Passage Swivel Modified for High-Pressure Service With Water Flushing

Figure 21. Single-Passage Swivel Modified for High-Pressure Service Without Water Flushing

Subcases 1b and 1c would require similarly modified swivel designs for either 11,500-psi or 9,000-psi service (Figure 20). The requirements for these subcases could also be satisfied by the combined oil field swivel and piping swivel (Figure 21).

Subcases 2a and 2b would simply require conventional oil field swivels capable of 5000 psi service.

Subcases 3a and 3b will require a dual passage swivel with the inner passage rated for 20,000 psi service. Since commercially available dual-passage swivels are not suitable for drilling service, a modified oil field swivel (Figure 21) would be required.

3.2.4 Conclusion

A modified oil field swivel is needed for high-pressure geothermal drilling in every case except Case 2 (Downhole Pump).

During the high-pressure oil drilling tests conducted by Exxon, then Esso, a special swivel packing was developed that withstood "60 to 200 hours at pressures of 10,000 to 15,000 psi when rotating at 150 rpm."

As illustrated by the design concepts presented in this section, and proven by the Exxon tests, the high pressure swivel is beyond the current state-of-the-art but not beyond the current capabilities of materials and design.

3.3 Downhole Pump

The downhole pumping system supplies high-pressure fluid to the cutting nozzles via a high-pressure pump located inside the drill string just above the cutting nozzles. This system consists of (1) a standard mud processing system, (2) a medium-pressure pumping system (3) a standard single-passage rotary swivel, (4) a standard medium-pressure drill string and drill collars, (5) and a specially designed downhole intensifier pump (Figure 22).

3.3.1 Theory of Operation

The intensifier pump uses fluid at a high flow rate (Q_1) and low pressure (P_1) to actuate a large diameter (D_1) piston that in turn reacts against a smaller diameter (D_2) piston to produce a higher pressure (P_2) at a lower flow rate (Q_2), i.e., $P_1 Q_1 \approx P_2 Q_2$ (Figure 23).

Figure 22. Downhole Intensifier Pump System Diagram

Figure 23. Downhole Intensifier Pump Theory of Operation

However, since a single stroke cannot produce a continuous output of high-pressure cutting fluid, control and check valves are required to produce a reciprocating motion of the low- and high-pressure pistons (Figure 24).

As the piston completes a stroke, the control valve reverses the fluid path to the low-pressure pistons. This reverses the direction of piston motion and high-pressure fluid is produced from the opposite side of the double-acting intensifier pump.

For a given surface pumping system, the area ratio between the low-pressure piston and the smaller high-pressure piston determines the intensifier pump output (Figure 25). Therefore, to achieve a 15,000-psi downhole pressure, 3,000 psi is required at the inlet of an intensifier pump with a 5:1 area ratio (Subcase 2a) or 3,750 psi for a pump with a 4:1 area ratio (Subcase 2b).

The downhole pump uses a 2-inch diameter low-pressure piston and either a 0.894-inch diameter high-pressure piston, (5:1 area ratio, Subcase 2a) or a 1-inch diameter high-pressure piston (4:1 area ratio, Subcase 2b), i.e.,

$$\frac{(2)^2}{(0.894)^2} = 5 \text{ (Subcase 2a)} , \quad \frac{(2)^2}{1^2} = 4 \text{ (Subcase 2b)}$$

3.3.2 Control Mechanism

The intensifier pump control mechanism consists of the following:

- A. The control intensifier (Figure 26, 1) that runs synchronously with the main pump intensifiers.
- B. The shifting rod (Figure 26, 2) connects the control intensifier to the pilot valve.
- C. The shifter (Figure 26, 3) shifts the pilot valve at the end of the stroke.
- D. The pilot valve (Figure 26, 4) controls which side of the main valve is pressurized through ports A_1 and B_1 , i.e., in position 1, A is pressurized and B is drained; in position 2, the opposite occurs.

Figure 24. Intensifier Pump Flow Diagram

Figure 25. Downhole Intensifier Pump Output at Various Piston Ratios

Figure 26. Downhole Intensifier Pump Control Mechanism

- E. The main valve (Figure 26, 5), alternates pressure and drain in its ports A_2 and B_2 as dictated by the pilot valve through ports A_1 and B_1 , i.e., a hydraulic shifter instead of mechanical as the pilot valve.

3.3.3 Pump Requirements

The 200 gpm required from the surface pump is the theoretical value needed to achieve the output flows indicated in Subsection 1.2. In actual operation, the output flows will probably be slightly less than those indicated due to volumetric inefficiencies caused by check valve losses and compression of the working fluid.

3.3.4 Pump Construction

The complete pump assembly (Figure 27) is approximately 100 feet in length and consists of the following:

- A. Top Adapter Sub - Joins standard drill pipe to the pump assembly and directs the fluid flow to the correct location on the shifter section.
- B. Shifter Section - Part of the control valve system that directs fluid to one side or the other of the low-pressure intensifier pistons. The chip scavenging mud is discharged from this section.
- C. Pilot Section - Houses the pilot control valve, shifter rod, shifters, and high pressure inlet check valves.
- D. Pump Section - Series of sections (16) that house the intensifier pumps. Each pump may be removed from the system as necessary for drill string assembly, repair, or to change system performance characteristics. The first intensifier is used to operate the control valve system.
- E. Check Valve Section - Houses the output check valves that supply high-pressure drilling fluid to the nozzles. The check valves prevent reverse flow from the nozzles back into the intensifiers when they are on the intake stroke.
- F. Bottom Adapter Sub - Manifolds the downhole pump output into one conduit and adapts back to 4-1/2-inch API tool-joint threads.

Figure 27. Dual Drill String System Design Concept

Figure 27. (Continued)

Figure 27. (Continued)

Figure 27. (Continued)

A three-component fastening device is used to connect the pump sections. First, a seal plate is sandwiched between joining sections. The seal plate seals various conduits and provides pins to transmit drill string torque. The joints are sealed by means of O-rings on both sides of the seal plates. To make the joint secure, a coupling held in place by a ferrule on the upper section is threaded onto the lower section to pull it up tight against the seal plate. The coupling is designed so that drill string rotation will tighten the joint.

3.3.5 Materials of Construction

Due to the extremely severe downhole environment, special materials will be used on all moving and highly stressed components. The main components as shown on Figure 27 and their initial composition are as follows:

- A. Low-pressure piston - 300 series heat-resistant stainless steel.
- B. High-pressure piston - heat- and wear-resistant titanium carbide or tungsten carbide.
- C. High-pressure cylindrical liner - 300 series stainless steel.
- D. Main body - Medium-strength, heat-resistant, low-alloy steel.
- E. Coupling - same as main body.
- F. Connectors - 15-5PH or other high-strength stainless steel alloy.
- G. Control valves/check valves - tungsten carbide or Carborundum sintered alpha silicon carbide.

3.3.6 Difficulties in Design

The downhole pump is very similar to a standard flow intensifier system (Figure 24). However, the circumstances under which the downhole pump system must function present unique design problems. The problems of lubrication and contamination would seem to be of greatest concern relative to downhole pump reliability. For example, contamination of the control valves could cause failure of the pump if it is severe enough to prevent the valves from shifting. These problems will have to be solved during pump development. The solutions will be based first on more standard hydraulic fluids and then on fluids likely to be encountered in field operations.

3.4 Dual Drill String

A dual drill string has several advantages relative to the single drill string. First, the dual drill string requires only the drilling fluid to be highly pressurized, unlike the single drill string which requires both high-pressure drilling and scavenging fluid. Second, the dual drill string would provide increased operational safety due to the containment of the high-pressure tube within an essentially standard drill pipe. Third, the dual drill string would eliminate some of the complications associated with the use of a downhole intensifier.

3.4.1 Theory of Operation

Figure 28 is a conceptual design drawing for a dual string system. This design incorporates proven high-pressure sealing techniques, a unique coupling concept, and solutions to many of the problems associated with dual drill string systems, e.g., frequent high-pressure tube misalignment, pinched O-rings, and lack of positive sealing.

The dual drill string system concept shown consists of an outer pipe and an inner high-pressure tube. The only difference between the outer pipe and a standard drill pipe is that the female end of the tool joint has been modified to accept a support/spacer lug that is part of the inner high-pressure tube, which is the "new component" portion of the design. One end of the high-pressure tube has a male thread located above the support/spacer lug while the other end is provided with a sliding connector. The sliding connector enables positive connection of the inner high-pressure tubes of two sections before the outer pipe of the lower section is made up to the drill string. The sliding connector is provided with a multiple-seal arrangement consisting of graphite-impregnated teflon seals. The actual connection between two high-pressure tubes is made by means of coned seats. Such a sealing method is currently used at pressures up to 60,000 psi.

3.4.2 Design Problems

As discussed above, the dual drill string concept appears to offer many advantages for geothermal drilling applications. Specifically, it seems to offer the best method of providing small quantities of high-pressure fluid for cutting and large quantities of low-pressure fluid for chip scavenging.

Figure 28. Dual Drill String Components

Dual Drill String Assembly Procedure

Figure 28. (Continued)

However, the design of a dual drill string system presents a number of difficult problems that must be solved in order to make such a system practicable.

The 10,000-psi pressure drop experienced by the 50 gpm of high-pressure fluid as it travels 10,000 feet downhole requires the surface pumping pressure to be $15,000 \text{ psi} + 10,000 \text{ psi} = 25,000 \text{ psi}$. However, presently available hose capable of the 50-gpm flow rate is pressure rated at only 18,000 psi maximum, or 7,000 psi less than the pressure required at the cutting nozzles. Therefore, hoses capable of delivering fluid to the cutting nozzles at both the required pressure and flow rate must be developed.

Tool joints for the dual drill string are another area requiring development. At present, the time required to make up the extra drill pipe connection could triple the overall joint makeup time.

3.5 Economic Comparison

Table 10 compares the costs of the cases identified and described in the preceding sections to determine their economic feasibility for the high-pressure geothermal drilling application. A "first-cost" comparison is deemed sufficient at this time since it is impractical to attempt life-cycle cost predictions for equipment not yet developed, tested, or operated under production conditions. All comparisons are made assuming continuous (around-the-clock) operation. Equipment modifications and/or standby units are required to accomplish this in some instances. Certain concessions were made for the sake of practicality. These are as follows:

- A. Case 2 (downhole pump) total flow rate is limited to 200 gpm to avoid excessive annular flow rates. This means lower high-pressure flow rates downhole.
- B. Case 3 (dual drill string) surface pressures are limited to 20,000 psi by reducing cutting jet flow rates at maximum depths.

Actual vendor quotes are used wherever possible and all costs are list prices as of Spring 1981. OEM discounts and inflation factors are thereby eliminated.

Table 10. Comparative Equipment Costs (in Dollars)

Case	Pumps		Downhole	Hoses (2) 75 to 80 ft Lengths	Swivel	Drill String		Total Equipment	
	Surface Purchased	Rented*				Inner	Outer	W/Purchased Pumps	W/Rented Pumps
1 a	1,750,000	950,000	-	82,000	54,000	-	420,000	2,306,000	1,506,000
1 b	1,630,000	680,000	-	82,000	54,000	-	420,000	2,186,000	1,236,000
1 c	1,500,000	600,000	-	82,000	54,000	-	343,000	1,979,000	1,079,000
1 d	1,290,000	600,000	-	82,000	54,000	-	311,000	1,737,000	1,047,000
2 a**	805,000	470,000	500,000	12,000	24,000	-	334,000	1,675,000	1,340,000
2 b†	1,290,000	600,000	500,000	12,000	24,000	-	334,000	2,160,000	1,470,000
3 a†† LP	260,000	160,000	-	9,000	64,000	220,000	473,000	1,598,000	1,528,000
HP	490,000	520,000	-	82,000					
3 b†† LP	260,000	160,000	-	9,000	64,000	220,000	473,000	1,813,000	1,528,000
HP	705,000	520,000	-	82,000					
Base	291,000	315,000	-	9,000	24,000	-	311,000	635,000	659,000

*Rentals are for 30 days excluding mobilization and crew expenses (to be comparable with purchased costs). Standby units are included on rented pumps for redundancy to get continuous service.

**40 GPM @ 15,000 psi. Extra pump for redundancy.

†50 GPM @ 15,000 psi.

††33 GPM @ 15,000 psi.

For system costing purposes, all equipment is assumed to be at an equal stage of development. Therefore, all design, development, and testing costs are excluded from newly designed equipment such as the following:

- A. High-pressure fluid end for triplex pumps.
- B. Downhole pump.
- C. Swivel modifications.
- D. Dual drill string.
- E. High-pressure flushing systems.

The Case 1 subcases are included to show the effect of increasing pressure on equipment costs. The base case is presented for comparison with a standard, low-pressure, drilling situation.

3.5.1 Pumps

Surface pumping requirements for each case can be satisfied by either rented or purchased equipment. Purchased pumping systems are skid-mounted systems comprising engines, belts, chain or gear drives, and all associated equipment such as inlet and outlet manifolds, charge pump, lube systems, pulsation dampeners, and controls. Pumps operating at pressures above the manufacturer's rating would be modified as described earlier with high-pressure fluid ends, high-pressure seals, and fresh-water flushing systems. Cost of the flushing system is included where used.

Rented pumping systems also include all associated equipment excluding personnel and mobilization costs (normally quoted with rented pumps). Rental costs are for 30 days of continuous operation. Where the equipment is not suitable for continuous operation, standby units are included to insure minimal down time. In this way, reliability is held constant for comparison purposes.

The downhole pump, of course, is a new design. All design, development, and testing costs for this system are excluded.

3.5.2 Hoses

The relative costs of approximately 150 to 160 feet of hose are presented. As can be seen, purchase costs vary by nearly an order of

magnitude (\$9,000 to \$82,000) as the pressure rating increases from 4,000 psi to 20,000 psi. All hoses selected are suitable for drilling service.

3.5.3 Swivel

Standard or modified swivels are selected depending on the service pressure and application. Where modified swivels are required, a fresh-water flushing system is incorporated that uses the same system supplying the modified pump with flushing water. Therefore, the cost of an additional flushing system is not included in the swivel cost. Again, design, development, and testing costs of swivel modifications are not included.

3.5.4 Drill String

Drill string recommendations varied widely from manufacturer to manufacturer. Therefore, in each case an appropriate conservative design was selected for comparison. Modifications to standard drill pipe components are included in the dual drill string (Case 3) costs along with the cost of the inner string.

3.5.5 Total Costs

The costs given here are simply a total of the costs for the equipment studied and are not intended to include all equipment required for high-pressure geothermal drilling. The totals are given two ways: with purchased pumps and with rented pumps. Generally, 30-day rental is less expensive than purchasing. However, rental becomes uneconomical as project length increases or additional projects arise. In fact, since most continuous rental rates are based on revenue that would be generated by the lucrative fracturing and cementing business, long-term rental of oil field pumps rapidly becomes prohibitively expensive.

4. Conclusions

The advantages and disadvantages of the systems presented herein are given in Table 11. The table shows that Cases 1 and 3 (single- and dual-conduit surface pumping systems, respectively) would require the least amount of development time and effort. However, both of these cases have very serious disadvantages relative to system complexity, personnel safety, and rig crew training time. Therefore, despite the apparent advantages of Cases 1 and 3, Case 2 (single-conduit downhole pumping system) actually has the greatest potential for success in the geothermal well drilling application. Its advantages in terms of safety, proven design concept, and fewest system modifications required make it the logical choice for development.

Table 11. System Advantages and Disadvantages by Case

Advantages

Disadvantages

Case 1: Single-Conduit Surface Pumping System

1. Shortest development time	1. Special pumps, hoses, swivels, and pipe required
2. Easily implemented	2. Difficult to seal due to large diameter pipe joints required
3. Lowest development cost	3. Working fluid pH must be carefully controlled to prevent drill pipe failure
	4. Highest operating costs
	5. Most hazardous to operating personnel; safety equipment required

Case 2: Single-Conduit Downhole Pumping System

1. Safest design	1. Highest development costs
2. All components standard except downhole pump	2. Long development time required
3. Intensifier concept already proven in oil field service	3. Working fluid must be carefully filtered
4. Suitable for other well applications	

Case 3: Dual-Conduit Surface Pumping System

1. Easily developed	1. High pressure losses due to fluid friction
2. Low development costs	2. Lengthy joint make-up procedure
3. Drilling can continue if either inner (high-pressure) conduit or nozzles fail	3. Two pumping systems required
	4. Two conduits required
	5. Full 50-gpm flow rate cannot be obtained at greater depths
	6. Hazardous to operating personnel; safety equipment required

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