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Repair, Sidetrack, Drilling, and Completion of EE-2A for Phase II Reservoir Production Service

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REPAIR, SIDETRACK, DRILLING, AND COMPLETION OF EE-2A FOR PHASE II RESERVOIR PRODUCTION SERVICE

by

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ABSTRACT

Hot Dry Rock (HDR) geothermal energy well EE-2 at Fenton Hill, New Mexico, was sidetracked and redrilled into the HDR Phase II reservoir after two unsuccessful attempts to repair damage in the lower wellbore. Before sidetracking was begun, six cement slurries were pumped to plug the abandoned lower wellbore and to support the production casing where drilling wear was predicted and where sidetracking was to occur. This work and the redrill of EE-2A were completed in November 1987. Specifications were prepared for a state-of-the-art tie-back casing, which was procured, manufactured, and delivered to Fenton Hill in May 1988. The well was then completed in June 1988 for hot-water production service by cementing in a liner and the upper section of production casing and installing and cementing a tie-back casing string.

I. INTRODUCTION

The world's first hot dry rock (HDR) geothermal energy system was constructed by the Los Alamos National Laboratory (LANL) at Fenton Hill, New Mexico, in 1977 and is referred to as the Phase I system. It was created by drilling a hole from the surface into the granitic rock to a depth of approximately 3000 m (10,000 ft) at a bottom-hole temperature of 195°C (383°F), producing hydraulic fractures centered at a depth of 2600 m (8500 ft), and then directionally drilling a second hole to intersect those fractures. Water was injected into and then produced from the man-made reservoir at temperatures and thermal power rates as high as 175°C (347°F) and 5 MWt, respectively. The system was enlarged in 1979 by additional hydraulic fracturing and then operated successfully for almost a year. Complete results of these early reservoir tests are provided by Dash et al.[1]

Construction of a larger, hotter, HDR system was initiated in 1979 to extend the technology to the temperatures and rates of heat production required to support a commercial power plant. It is referred to as the Phase II system. Two new holes about 50 m (150 ft) apart at the surface, EE-2 and EE-3, were drilled directionally; EE-2, the deeper well, to a vertical depth of 4390 m (14,400 ft) and EE-3 to a vertical depth of 3970 m (13,025 ft).

EE-2 was drilled to a measured total depth (TD) of 4660 m (15,289 ft) in 1981 as the intended reservoir stimulation (reservoir creation) and injection well for the Phase II HDR demonstration. Damage to the 339.7-mm (13-3/8-in.) intermediate casing during and following its installation required premature installation of a 244.5-mm (9-5/8-in.) production (injection) casing at a depth of 3529 m (11,578 ft).[2] The production casing was worn thin over several intervals during milling operations that occurred before the well reached TD.

Fracturing deep in the well through a cemented-in liner[3] failed to establish a reservoir connection to well EE-3,[4] and most of the open hole below the production casing was abandoned with the placement of sand plugs up to 3658 m (12,000 ft) and later up to 3550 m (11,646 ft). Fracturing below the casing shoe through casing packers and tubing protected the casing from fracturing pressures that were two to three times higher than had been predicted, based on the Phase I reservoir stimulation.[1] A wellhead failure occurred after the largest injection of 21,000 m^3 (5.6 million gallons) in 1983.[5] Later the tubing-casing annulus was inadvertently blown down during repair of the wellhead.

We believe this blowdown caused the production casing to collapse near the top of the reservoir that had just been created. In any event, damage to the well resulted in leaks that connected (through the uncemented production casing annulus) the well to subhydrostatic aquifers just above the basement rock at 730 m (2400 ft).

The first attempt to repair the well in 1984 isolated the aquifer but left the well connected to a low-pressure reservoir (similar to Phase I) at a depth of 2850-3100 m (9400-10,200 ft). A reservoir connection was achieved during the 1985 redrill of EE-3A into the EE-2 reservoir,[6] but continued deterioration of EE-2 during its first production service prevented wireline logging into the Phase II reservoir. However, production from the reservoir had not been reduced, and a 30-day flow test of the reservoir[7] in 1986 used EE-3A for high-pressure injection and EE-2 for low-pressure production service.

A second repair attempt in 1986 found EE-2 in much worse condition than had been predicted, and the repair was quickly terminated. The condition of the casing was reevaluated following a cement bond log (CBL) and a 64-arm caliper log. The condition of EE-2 above the 3204-m (10,512-ft) collapse was reasonably good. Figure 1 is a schematic of the EE-2 wellbore following the second repair attempt. Costs for several repair and redrilling options were reestimated, and a detailed plan was prepared to sidetrack and redrill EE-2.

EE-2 was plugged with cement to the top of the damaged region in the first stage of the redrilling program. Additional cement was placed in the annulus outside the production casing to

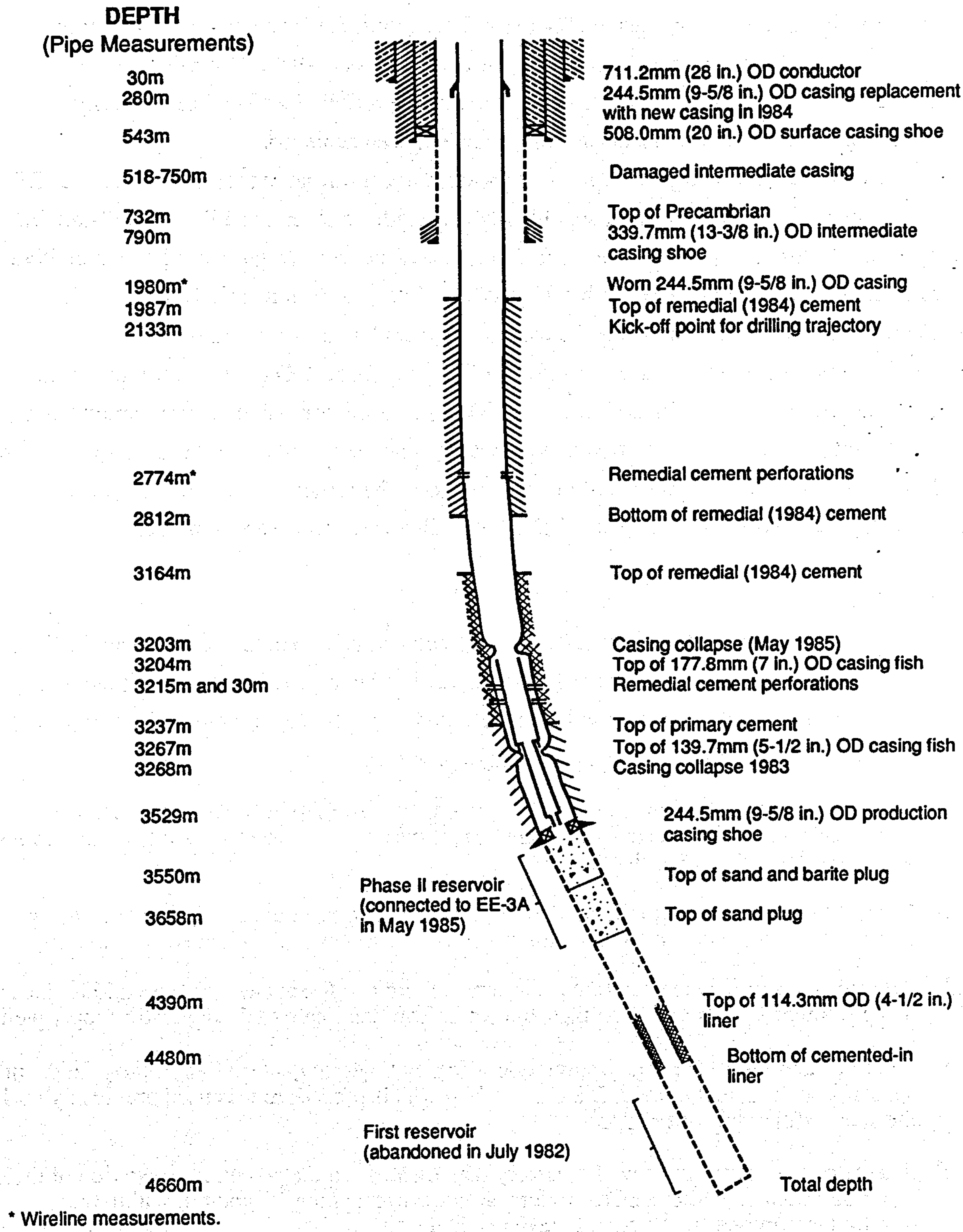

Fig. 1. EE-2A schematic of the well configuration at start of repair and sidetracking.

assure separation of the old and new wellbores and to support the production casing during redrilling. Sidetracking and redrill were completed in November 1987. Operations were suspended after a short reservoir test demonstrated that the redrilled well had successfully penetrated the reservoir and an adequate connection had been achieved.

A specification for surplus casing was prepared and a formal request for quotations (RFQ) was distributed. The procurement of suitable high-strength, sour service 177.8-mm (7-in.) OD casing from surplus stockpiles was not successful, so new casing was purchased at competitive prices using the same specification with a May 1988 delivery at Fenton Hill. Detailed well completion plans were prepared while the casing was manufactured and shipped.

When rig operations resumed in May, a 177.8-mm (7-in.) OD liner was cemented-in, additional cement was placed in the top 275 m (900 ft) of annulus outside the production casing, and 177.8-mm (7-in.) OD tie-back casing was installed and cemented to the surface. In this report the 244.5-mm (9-5/8-in.) OD casing will be referred to as the production casing and the subsequently installed 177.8-mm (7-in.) OD casing will be referred to as the tie-back casing.

II. PLANNING

Los Alamos staff and consultants prepared a detailed plan to plug back, cement the 244.5-mm (9-5/8-in.) casing annulus, sidetrack EE-2, and drill and complete EE-2A. The plan was reviewed by an additional consultant and then presented to a U.S. Department of Energy (DOE) review panel. After revision, the plan had 10 major activities:

(1) Plug the damaged wellbore below the casing collapse at 3200 m (10,500 ft) with cement and with back-up cementing above that point so that the damaged wellbore and the redrilled bore would be isolated from each other.

(2) Cement the annulus behind the production casing to minimize the possibility of a casing failure during the redrilling and to contribute to the success of the planned sidetracking.

(3) Set aside cement for the operations in a reserved silo and formulate and test various slurries using samples from the reserve silos and water from the Fenton Hill domestic supply well.

(4) Sidetrack and redrill using an optimum low dogleg trajectory, a sepiolite drilling fluid, and special low-drag directional drilling assemblies. This procedure was used previously during the successful redrill of EE-3A.[6]

(5) Select drilling targets and a well trajectory that maximized the potential penetration of the reservoir based on earlier seismic (microearthquake) mapping[8-10] and fell within the constraints imposed by the outside review panel.

(6) Build up the pressure in the reservoir through injection into EE-3A during the redrilling in an attempt to prevent the loss of drill cuttings into the reservoir and cause inflow to occur as the reservoir was penetrated by EE-2A. A complete geological and drilling fluid log was specified to assure that the well path was penetrating the reservoir. A postdrilling reservoir flow test was developed to verify successful reservoir penetration.

(7) Perform a complete set of casing stress calculations to assure that casings of suitable strength and wall thickness were installed as liner and tie-back string and to optimize the installation procedure.

(8) Develop a procedure to cement the annulus outside the production casing from 274 m (900 ft) to the surface that would avoid the requirement to cement lost circulation intervals below 520 m (1700 ft). This cemented annulus would reduce the stress in the surface and intermediate casings to acceptable levels and thereby eliminate the need for a wellhead expansion spool.

(9) Install an open-hole, cemented-in liner using technology that was successfully tested in earlier liner installations at Fenton Hill.

(10) Initiate procurement of the tie-back casing as recommended by the outside review panel and plan to cement the tie-back casing to the surface, subject to the existing economic constraints.

A detailed technical specification was prepared for the purchase of approximately 3000 m (10,000 ft) of 177.8-mm (7-in.) OD casing to be used as a tie-back string. This specification was primarily intended to purchase new, previously manufactured (surplus) casing that was believed to be available. The specification was prepared to assure that the casing purchased met the special strength and material requirements that had been identified in earlier well completion work in the Fenton Hill Phase II reservoir.[11]

An 11.5-mm (0.45-in.) thick-wall, moderate-strength casing was needed with controlled hardness of steel for service in a known stress corrosion cracking environment. Surplus casing would be prescreened based on mill certification documentation, general appearance, and evidence of proper handling and storage since the time of manufacture. Tentative award of the procurement would be made based on price if the casing met the technical specification. Final acceptance would be accomplished with a thorough qualification procedure. Destructive testing of a small sample of joints to check mechanical properties and metallography would, if satisfactory, be followed by a complete nondestructive test (NDT) inspection of the casing. The NDT specified exceeded American Petroleum Institute (API) requirements. Final award of the procurement would be negotiated following the NDT.

Premium thread connections were specified, and rethreading was allowed. The specifications and qualification procedure also allowed for the possibility that the surplus casing bid would not be acceptable and that new casing would have to be manufactured, which in fact occurred.

III. CONTRACTS

LANL buyers in the Materials Management Division assisted with the procurement of major services and hardware. The award of these contracts was based on HDR Project staff evaluations of submitted cost and technical proposals. The drilling contract provided for the procurement of reimbursable services and hardware on a third-party basis through the drilling contractor. HDR staff with Materials Management Division oversite used this arrangement to acquire required day-to-day specialty services and equipment.

A. Drill Rig

Big Chief Drilling Company Rig #47 was originally contracted to redrill EE-3A in 1985. The contract was extended and the rig was skidded to EE-2 for the second repair of EE-2. The contract was extended a second time so the rig could be used to redrill and complete EE-2A.

Rig #47 is capable of drilling deep gas wells to 9000 m (30,000 ft). It has a draw works, mast, and substructure rated for 6600-kN (1.5 million-lb) pull (see Table I for detailed description). This capability was larger than specified in the original EE-3A drilling rig specification, but the rig's large capacity had proved valuable several times during the redrill of EE-3A. It was decided to save the cost of demobilizing rig #47 and mobilizing another rig by extending the contract with Big Chief.

TABLE I. DESCRIPTION OF BIG CHIEF RIG #47

	Metric	Customary
Mast (Pyramid type)		
152x30 (ft) rated at	7.1×10^6 N	1.6×10^6 lb_f
Substructure (Pyramid) setback,	3.5×10^6 N	0.8×10^6 lb_f
with hanging load of	6.7×10^6 N	1.5×10^6 lb_f
Draw works (Gardner Denver 3000E)		
Power (electric), 3 each	746 kW	1000 hp
Drilling line	44 mm	1-3/4 in.
Traveling equipment	6.7×10^6 N	750 ton_f
Pumps, 2 each (Gardner Denver PZ-11)		
Power (electric), 2 motors	746 kW	1000 hp
Stroke	279 mm	11 in.
Liners	140 mm	5-1/2 in.
Rotary table (Gardner Denver)	952 mm	37-1/2 in.
Blowout preventers		
Cameron type U	279 mm	11 in.
Working pressure	34.5 MPa	5000 psi
Power supply, type SCR Ross-Hill		
Caterpillar, 3 each, D-399 diesel	970 kW	1300 hp

The drilling contractor provided single-ram, double-ram, and annular blowout preventers. A rotating head was installed to provide maximum safety during drilling and other operations in the Phase II reservoir that is capable of short but prolific production of carbon dioxide gas with up to 150-ppm concentration hydrogen sulfide. A gas buster was installed to salvage drilling fluids when they were in use.

A drilling fluid (mud) cooler was fabricated from DOE surplus liquid-liquid heat exchangers obtained from the East Mesa binary turbine demonstration project. It was connected to the conventional circulating system. The air-contactor type mud cooler, which was used on the EE-3A redrill, was also installed as a supplemental and backup cooler, but it was used as little as possible to minimize the oxygen content of the mud. A mud mixing and storage plant was installed adjacent to the rig's mud tanks to reduce the amount of rig time expended mixing and conditioning mud.

B. Other Contracts

In addition to the drill rig contract, contracts for other major well services were competitively awarded. These included (1) engineering support and rig supervision, Lithos (formerly Well Production Testing); (2) cementing services, Dowell-Schlumberger; (3) high-pressure pumping services, BJ Titan; (4) chemicals and drilling fluid additives, NL Baroid; and (5) geologic and drilling fluid (mud) logging services, Epoch Well Logging.

Two sole source hardware procurements were justified by prior efforts to develop HDR support equipment that was compatible and met technical requirements: (1) a high-temperature/high-pressure open-hole stimulation packer, Baker Service Tools (formerly Lynes, Inc.)[12] and (2) a packstock packer to mate to a LANL-owned whipstock (surplus from the EE-3A redrill), Grant-AZ-Drilex.

C. Third-Party Procurements

Other services and hardware were procured using the third-party agreement with the drilling contractor. The larger third-party procurements were made following evaluation of informal technical and cost proposals. The reviews were made by the LANL drilling team, which included Earth and Space Sciences Division staff and consultants. Some of the larger procurements included (1) directional drilling services, Directional Investment Guidance; (2) drilling motors, Grant-AZ-Drilex; (3) reamers and stabilizers, Spidle; (4) directional wireline services, AMF Scientific Drilling; (5) high-temperature wireline logging and perforating, Oilwell Perforators; (6) low-temperature wireline logging and perforating, Welex; (7) rental equipment, e.g., miscellaneous drill string, handling, and supplemental blowout prevention and safety equipment, Land and Marine; (8) expansion joints to support open-hole packer operations, Baker Service Tools (formerly Brown Oil Tools); (9) wellhead equipment, Food Machinery Corp. (formerly OCT); and (10) wellhead valves, Foster WLG.

IV. WELL OPERATIONS

Most well services, materials, and hardware were furnished from Farmington, New Mexico, 280 km (170 miles) from the Fenton Hill site, from Midland-Odessa, Texas, 1125 km (700 miles), or from Casper, Wyoming, 1290 km (800 miles). Daily planning was required not only to assure that appropriate services and hardware were mobilized to be available as needed but also to keep standby costs at a minimum. Consultants and staff updated a projected schedule of upcoming activities as each major activity was completed. The schedule, drill plan, and detailed procedures that had been prepared for the more complex activities were monitored to identify and alert appropriate service companies and LANL support staff for each activity.

The most significant activities are discussed with a technical perspective in the following sections. Appendix A is a brief summary of daily operations that can be used to place specific activities into sequence.

Rig supervisors, provided by the engineering support contractor, directed well operations. The engineering support contractor also provided a drilling office manager who (1) compiled, edited, and distributed drilling plans and detailed procedures; (2) administered third-party procurements, informal RFQs, rentals, shipping, and receiving; (3) maintained field cost estimates; and (4) performed accounting and budgeting functions.

The rig was operated on an oil field day-work contract, and Big Chief provided an on-site tool pusher on a 24-hour-per-day basis. The drilling staff (LANL and Lithos) received twice-daily reports, made a daily on-site review of operations and plans, and provided on-site supervisory and technical support for the more complex operations.

The Fenton Hill site staff, consisting of LANL technicians and contract staff provided by a site support contractor, supplied support services: (1) fresh water and rig water supply; (2) pit water treatment, flocculation, settling, and clarification; (3) drilling mud storage and disposal; (4) on-site drill pipe and casing movements; (5) auxiliary pumping service; and (6) machine shop and welding support.

A LANL logging team ran high-temperature noncommercial logs in EE-2A in support of cementing and reservoir evaluation that included gamma-ray/temperature, gamma-ray/three-arm caliper, and sonic televiewer. Table II is a complete list of wireline logging and completion services, including commercial and LANL logs.

Routine services supporting rig operations included (1) drill pipe pickup/laydown and casing services; (2) blowout preventer tests; (3) H_2S safety services; (4) drill pipe, drill collar, and casing inspection; (5) welding, machine shop, and fabrication; (6) trucking, hot shot, and motor freight; and (7) premium thread casing makeup services.

TABLE II. SUMMARY OF LOGGING AND WIRELINE OPERATIONS ASSOCIATED WITH THE REDRILL AND COMPLETION OF EE-2A

Date	Description of Log or Activity	Company[a]	Depth Interval Top-Bottom (ft)
11/26/86	Casing profile caliper log	Dia-Log	0-10,500
11/26/86	Casing minimum ID caliper log	Dia-Log	0-10,600
3/19/87	Cement bond/gamma log	OWP	6000-10,495
3/20/87	Casing inspection log	OWP	100-10,495
9/10/87	Kuster slick line temp survey	LANL	10,435
9/12/87	Perforate 9-5/8-in. casing 4 shots/ft	OWP	10,221-10,225
9/12/87	Kuster slick line temp survey	LANL	10,200
9/14/87	Kuster slick line temp survey	LANL	9050-9875
9/15/87	Perforate 9-5/8-in. casing 4 shots/ft	OWP	9546-9550
9/19/87	Spud sinker bars into section mill	Big A	9688
9/27/87	3-arm caliper of milled section	LANL	9600-9820
9/28/87	Temp/casing collar locator	LANL	0-7000
9/28/87	Perforate 9-5/8-in. casing 4 shots/ft	OWP	9470-9476
10/01/87	Kuster slick line temp survey	LANL	800-3500
10/08/87	Orient whipstock	SDI	9685
10/14/87	Temp/casing collar locator	LANL	0-12,025
10/18/87	Gyro (single-shot verification)	SDI	10,150
10/27/87	Fluid sampler	LANL	10,700
10/27/87	Temperature	LANL	0-10,907
11/11/87	Multishot at TD	DIG	9600-12,360
11/14/87	Maximum casing ID	Dia-Log	0-9650
11/15/87	Gamma/temp	LANL	0-12,350
11/15/87	3-arm caliper	LANL	9700-12,350
11/16/87	Gamma/temp	LANL	9700-12,350
5/17/88	Gamma/3-arm caliper	LANL	9600-12,294
5/18/88	Borehole acoustic televiewer	LANL	0-10,000
5/23/88	Gamma/casing collar locator	Welex	0-1200
5/24/88	Kuster slick line temp survey	LANL	500-9350
5/25/88	Gamma/casing collar locator - locate RA frac balls	Welex	0-2502
5/25/88	Perforate 9-5/8-in. casing 2 shots/ft	LANL	885-889
5/27/88	Kuster slick line temp survey	LANL	0-500
5/28/88	Cement bond log	Welex	0-1000
5/28/88	Perforate 9-5/8-in. casing 4 shots/ft	Welex	210-212
6/03/88	Kuster slick line temp survey	LANL	200-8600
6/07/88	Kuster slick line temp survey	LANL	500-9000
6/08/88	Kuster slick line temp survey	LANL	100-5000
6/09/88	Cement bond log/casing collar locator/gamma	OWP	0-10,624
6/16/88	Kuster slick line temp survey	LANL	9000-10,650
6/16/88	Temperature log	LANL	0-12,187
6/17/88	Kuster slick line temp survey	LANL	9000-10,600

[a]Wireline/logging contractors used:
Big A Well Service, Farmington, New Mexico
Dia-Log Company, Odessa, Texas
DIG - Directional Investment Guidance, Inc., Midland, Texas
OWP - Oil Well Perforators, Casper, Wyoming
SDI - Scientific Drilling Int'l (AMF), Midland, Texas
Welex (a division of Halliburton), Farmington, New Mexico.

V. SIDETRACKING AND DRILLING

The production casing section was milled following the first three plug-back cementing operations described in Section VII of this report. The milled section was plugged with sand and cement, and the cementing of the production casing annulus above 1975 m (6480 ft) was completed. The milled section was then drilled out and a packer-anchored whipstock (packstock) was installed. Sidetracking proceeded, and the well was drilled from 2964-3767 m (9725-12,360 ft) with two reservoir production tests; one conducted at a drilled depth of 3356 m (11,009 ft) and another at TD, 3767 m (12,360 ft).

A. Section Milling and Setting a Packer Whipstock

Four A-Z International section mills were used to cut an 18.3-m-long (60-ft) section from 2953-2972 m (9688-9748 ft). The production casing was not centralized at this depth, and we believe this contributed to the intermittent rapid wear of the tungsten carbide(TC)/soft matrix Zitco™ cutting wings. Cut-rite™, Zitco™, and other TC cutting materials wear rapidly during contact with Fenton Hill gneiss or granodiorite.

Mill runs were also complicated by our inability to retract the knives at the end of the mill runs. Reciprocation of the mills, spotting fresh water, high viscosity mud sweeps, and, in one case, a sand line jarring assembly were used during attempts to retract the knives. Deficient drilling fluid properties at the high bottom-hole temperature [the geothermal gradient temperature is 194°C (380°F) at this depth] provided inadequate cuttings removal and resulted in backflow when circulation was stopped.

Both cuttings and backflow may have contributed to the difficulty in retracting the knives. Some drill pipe was bent because of reciprocation with high rotary speeds while attempting to close the cutting wings.

A sand plug was placed in and over the lower production casing (stub) below the milled section; a hard cement plug was placed in the rest of the section and extended up 52 m (170 ft) into the casing. After the cementing procedure at 1975 m (6480 ft) was completed, the cement in and above the milled section was drilled out with a rock bit.

A "dummy" whipstock locator assembly was run but could not be worked through the milled section, presumably because of the presence of a nest of steel cuttings. After a bit and reamer run, the locator was rerun but failed to set properly on the lower casing stub. A final 1-ft cut was made with the fifth section mill to dress off the stub. A final locator run successfully tagged the stub. After the "dummy" was dismantled, the locator was made up between the packer and the whipstock in the packstock assembly (Fig. 2).

The packstock was run on drill pipe, located on the lower casing stub, and oriented with the face of the stock 0.785 rad (45°) left of the high side of the bore. A Scientific Drilling Int'l (SDI) high-temperature-service 204°C (400°F) steering tool was used to orient the stock.

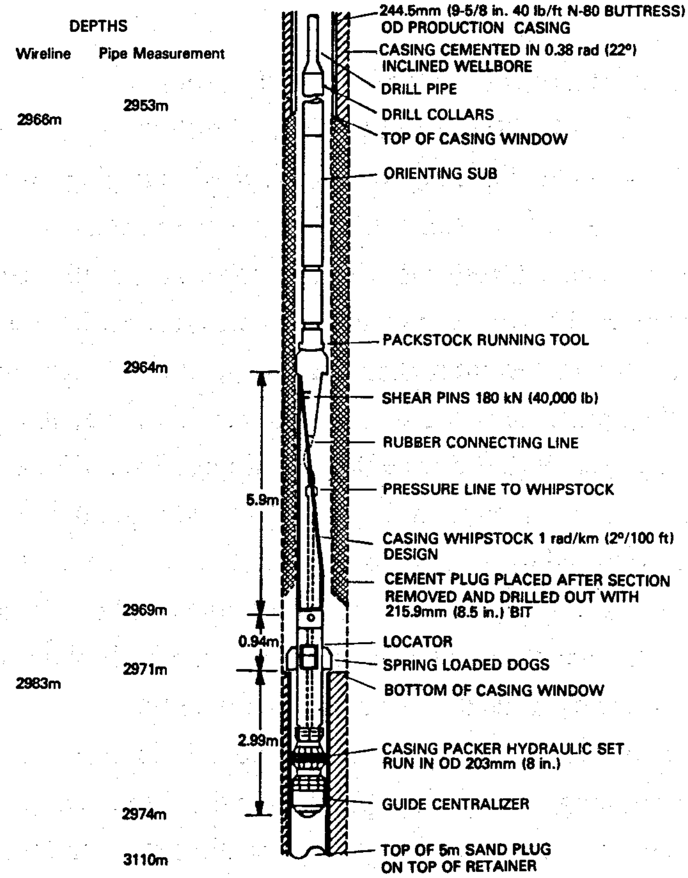

Fig. 2. Production casing window, cement plug, and packstock configuration.

Sidetracking was accomplished with 2 limber drilling assemblies, BHA numbers 1 and 2 of the 22 bottom-hole drilling assemblies used in the drilling of EE-2 (14 rotary, 2 milling, and 6 drilling motor assemblies) listed in Appendix B.

B. Drilling

The drill plan was based on the successful redrilling operation at well EE-3A in 1985. The major features of the plan were (1) elimination of drill pipe twistoffs with large-diameter, moderate-strength drill pipe; (2) accurate directional drilling and longer bit runs with carefully designed BHAs and bit selection; and (3) higher penetration with good hole cleaning using a sepiolite base drilling fluid.

1. Drill String. A 127.0-mm (5-in.) API premium or better drill string, including 2530 m of 29.0-kg/m (8300 ft of 19.5-lb/ft) Grade E, 2500 m of 38.1-kg/m (8200 ft of 25.6-lb/ft) Grade X-95, and 172 m of 74.4-kg/m (565 ft of 50-lb/ft) Grade E heavyweight drill pipe (all with NC 50 tool joints), was available for drill string design. Stronger, lightweight pipe was not used because of its susceptibility to stress corrosion cracking (SCC).[13] The large-diameter pipe was used to

keep bending stresses low and prevent fatigue failures in the high dogleg areas of EE-2 above the kick-off point (KOP).

About 640 m of 29.0-kg/m (2100 ft of 19.5-lb/ft) drill pipe had rough hardbanding for open-hole service and 378 m of 29.0-kg/m (1240 ft of 19.5-lb/ft) and 186 m of 38.1-kg/m (610 ft of 26.5-lb/ft) pipe had smooth hardbanding, which was used in doglegs to minimize wear on the already worn production casing.[14] The drill string weight was kept as low as possible to minimize the wear rate on the casing and yet keep 445-kN (100,000-lb) overpull capacity, based on 80% tensile strength of new pipe. The drill string pipe order was rotated three stands (triples) within each pipe grade on every trip to prevent concentration of wear and fatigue over a short part of the drill string. Pipe-handling procedures and specifications are described in Appendix C.

2. Bottom-Hole Assemblies and Directional Drilling. The trajectory needed to reach the selected drilling targets (Fig. 3) called for a slight left turn and angle-building assemblies to separate the wellbores, followed by angle-holding assemblies in the middle region, followed by dropping assemblies. It was hoped that only one motor run would be required, but the rotary assemblies had a strong left-hand walk in the upper part of the well followed by a shift to right-hand walk once the required right-hand turn had been completed.

The rotary assemblies used three-point and six-point roller reamers to (1) minimize reaming off of bottom (and the resulting casing wear), (2) provide the required directional characteristics in lieu of integral blade stabilizers that wear rapidly in crystalline rock, and (3) reduce the BHA wear and hole drag by providing standoff for the drill collars.

A 171.5-mm (6-3/4-in.) OD, 6-m-long(20-ft) Drilex™ D675 positive displacement motor (PDM) and 0.026 or 0.035 rad (1-1/2° or 2°) bent subs were used on all of the motor runs. The drill plan called for a maximum dogleg severity of 1 rad/km (2°/100 ft),[15] so the five successful motor runs were staggered between rotary runs. Turn rate increased with penetration on the motor runs and great care was needed to pull the assemblies before the maximum allowed dogleg was exceeded. On two occasions the dogleg reached 2 rad/km (4°/100 ft) when motors were run 9-18 m (30-60 ft) too far.

One washout occurred in the drill collars. This was attributed to rotary bending and stress fatigue in the connection in the higher than planned dogleg at 3155 m (10,352 ft). A replacement string of collars was run. The drill collars and heavyweight drill pipe were inspected twice (trip checked with black light). Each inspection found one cracked box.

Nonmagnetic collars were run on all drilling BHAs. Magnetic compass single-shot surveys were run on every connection near the KOP and every second or third connection until the rat hole was drilled below the reservoir. There, surveys were run every fourth connection. A multishot gyro survey was run after drilling to 3093 m (10,149 ft) to assure that the azimuth readings from the single shot were accurate. The multishot location was within 3.5 m (11-1/2 ft) of the single-shot bottom-hole location. A magnetic multishot survey was run at TD and showed a bottom-hole location within 5.5 m (18 ft) of the single-shot projection (Appendix D). EE-2A penetrated the drilling targets selected based on microearthquake locations[8-10] that also met the target criteria of the DOE review panel, which had suggested that the wellbore should be within a 15.2-m (50-ft) radius of the open-hole wellbore of EE-2. Figures 3 and 4 show that all objectives were achieved.

3. Bits. A bit, drilling, and fluid parameters record is shown in Appendix E. The two primary bits used were the Hughes Tool Co. and Smith Tool Co. TC insert bits for hard abrasive formations, IADC class 7-3-2, with roller bearings for air drilling. The air ports through the bearings were plugged and jets were installed to optimize the drilling hydraulics.

Four journal-bearing insert bits were run for comparison purposes. These bits were IADC class 7-3-7 with special gauge protection on one of the bits. They were one and one-half to two times more expensive than the air bits. Although the bearings showed little to no wear, the cone and insert structures were worn out with less total penetration than was obtained with the air bits.

4. Drilling Fluids and Hydraulics. A lightweight, low solids, fresh water sepiolite and bentonite mud treated with lignite, caustic, and Torq-Eze™ was used for section milling and drilling. Normal desired fluid properties were a mud density of 1040 kg/m^3 (8.7 lb/gal), plastic viscosity of 0.0025 Pa·s (25 cp), yield point of 8.6 Pa (18 lb/100 ft^2), and pH of 10+. Appendix E lists typical fluid properties achieved during each bit run.

Experience on EE-3A had shown that the excellent hole cleaning achieved with a fairly high viscosity mud significantly improved total penetration and drill rate with a rotary drilling assembly. Bit jets were sized to maintain an annular velocity in excess of 0.760 m/s (150 ft/min), and bit hydraulic power was usually maintained near the optimum. Hydraulics has been found to play only a minor role in increasing instantaneous penetration rate. An overall drill rate of 29 m/day (95 ft/day) (Fig. 5) was achieved in the crystalline rocks with hole cleaning that extended bit runs and reduced reaming time. As was the case during the EE-3A redrill, the wear on drilling assemblies and the maintenance costs, as compared with previous drilling efforts at Fenton Hill,[2,4] were reduced, and fishing for parted strings was eliminated.

The relatively simple drilling fluid system became more difficult to maintain as the new wellbore penetrated the Phase II reservoir. Flow from the reservoir was encouraged to protect it from becoming plugged with drill cuttings and dehydrated mud. The first fractures penetrated near the top of the reservoir were prolific producers that caused more severe dilution of the mud than had been expected, and the high CO_2 concentration in the reservoir fluids required large caustic treatments to keep the pH in the desired range (10-11). The treatments caused high gel strengths and difficulty in degassing the mud.

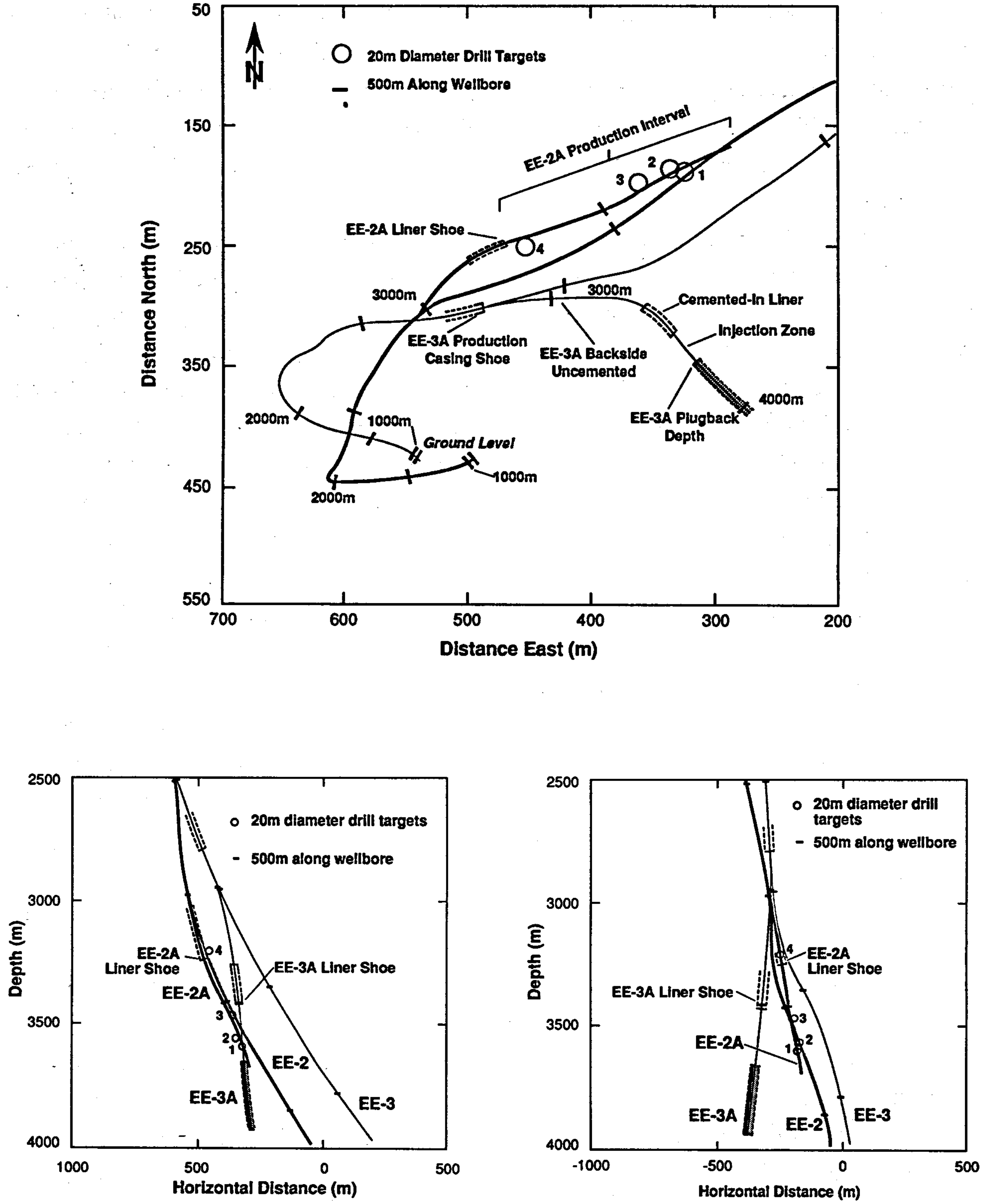

Fig. 3. EE-2A targets and drilled trajectory.

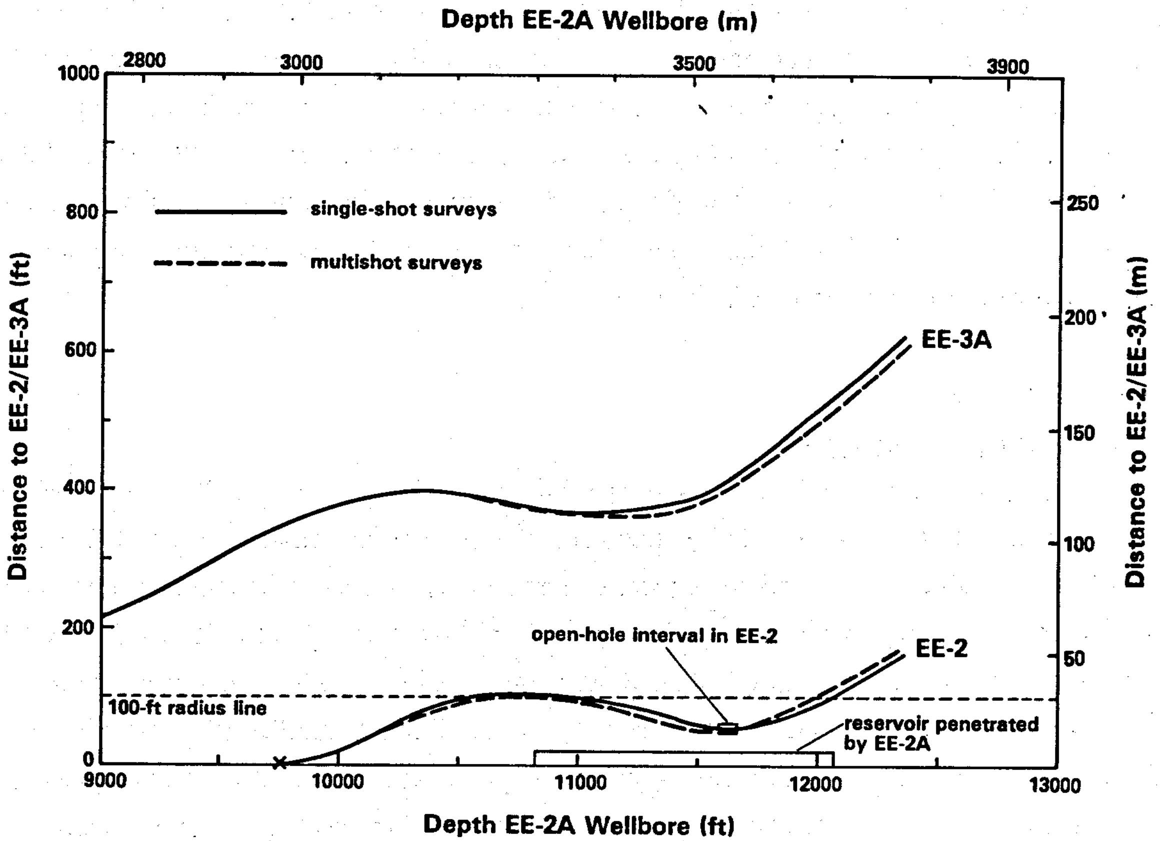

Fig. 4. Wellbore separation distances for the actual EE-2A drilled trajectory.

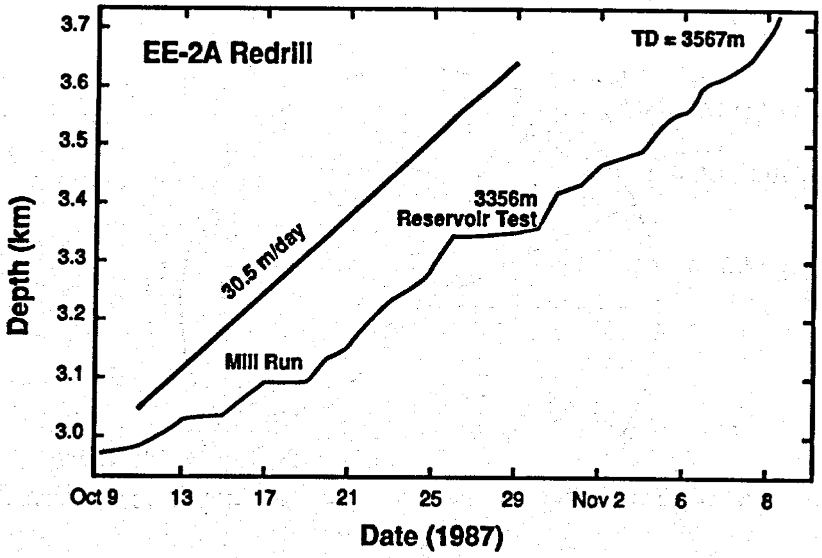

Fig. 5. EE-2A drill depth chronology.

5. Drilling Results. Although minor problems occurred with directional drilling and drilling fluids, the drilling was completed within budget and time estimates. A successful drilling fluids program, described in the previous paragraphs, contributed to an overall average penetration rate of 3.17 meters per hour (10.43 ft/hr) at an average cost of $618 per meter ($188/ft). Table III-B in Section IX contains a comparison of costs and maximum, minimum, and average penetration rates achieved during drilling off the whipstock, rotary drilling, and motor drilling. Figure 6 shows the time spent on various redrilling operations.

VI. WELL COMPLETION

A. Casing Stress Calculations

The well design is based on the successful liner installation deep in EE-2 and the principles of geothermal well design presented by Nicholson,[16] Dench,[17] and Snyder.[18] The 177.8-mm (7-in.) OD casing wall thickness and grade were selected based on stress calculations for an open-hole liner and tie-back casing to surface. A 177.8-mm (7-in.) OD, 52.1-kg/m (35-lb/ft) C-90 VAM (T&C premium connection) casing had been purchased in 1984 for a liner that was not run. It was suitable for the open-hole liner. A 177.8-mm (7-in.) OD, 47.6-kg/m(32-lb/ft) C-95 Nippon NSCC (T&C premium connection) casing string was purchased for the tie-back casing based on a specification that allowed several combinations of weights and grades to satisfy the calculated maximum stress.

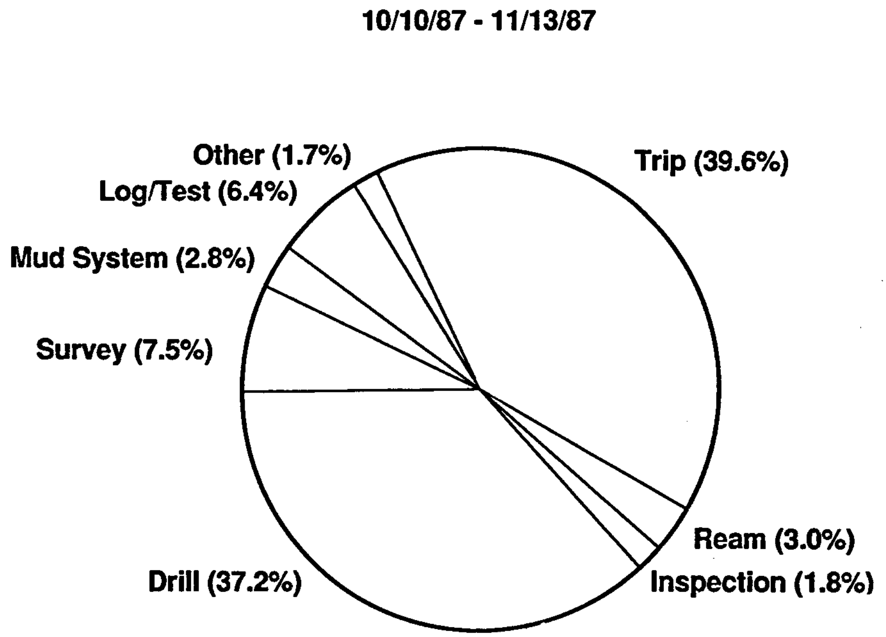

Fig. 6. Time distribution of EE-2A drilling.

Both the liner and tie-back string were designed for high-pressure fracturing and injection and production service.[11] To achieve the flow rates desired between EE-3A and EE-2A, additional stimulation of EE-2A may be needed. Stimulation of the well may require injection at pressures up to 41 MPa (6000 psi) above hydrostatic and a bottom-hole cool-down to 32°C (90°F). During production, a surface temperature of 221°C (430°F) at surface pressures ranging from 3.4 to 39.6 MPa (500 to 5750 psig) is projected. The higher pressure is a shut-in pressure with the well hot and the reservoir acting as a closed system with full injection pressure, 34.5 MPa (5000 psig), on EE-3A.

Additional comprehensive stress calculations were later run for the 177.8-mm (7-in.) OD liner and tie-back casing and the uncemented production casing using a recently developed computer code. The code was developed using the methods presented by Lubinski,[19] Lindsey,[20] and Mitchell.[21] It enabled numerous deviations from the planned procedure to be analyzed to determine the casing stresses that would result. Three major conclusions resulted from the code runs:

(1) A liner hanger on the top of the liner would not increase the calculated stress in the liner as long as the liner was completely cemented. The liner hanger was used.

(2) The liner, if left uncemented or poorly cemented across the milled section in the production casing, would develop high bending stresses under the assumed conditions. To prevent fallback of cement in the event of a float equipment and wiper plug failure, a 1980-kg/m^3 (16.5-lb/gal) drilling mud displacement was used to fill the liner as the cement was displaced into the liner annulus.

(3) Tie-back and production casing stress calculations were made for a well configuration where the cement top outside the 177.8-mm (7-in.) casing was set at 730 m (2400 ft) to match the 244.5-mm (9-5/8-in.) cement top obtained in the predrilling cementing (see Section VII-C). The casing loads calculated for the 177.8-mm (7-in.) and the 244.5-mm (9-5/8-in.) OD casings were acceptable, but the resulting loads that were transferred through the wellhead to the intermediate and surface casings were too high. Unless it was assumed that compression loads imposed by the production and tie-back casings during production were divided evenly between the intermediate and surface casings, the 8-year-old surface casing could be exposed to tension loads exceeding its new rated yield strength. Three ways to reduce the stress on the surface casing were considered:

(a) The tie-back and production casings could be decoupled from the fully cemented casings with a wellhead expansion spool.

(b) The production casing could be cemented from some reasonable depth above 520 m (1700 ft) to the surface and the tie-back casing could then be cemented to the surface.

(c) The production casing could be cut off above 538 m (1766 ft), the upper casing removed, the lower casing hung and packed-off to the intermediate casing with a casing patch-liner hanger-packer assembly, and the tie-back casing could then be cemented to the surface.

A plan to build an annular plug on an existing screw-in sub in the production casing at 274 m (900 ft) was devised, and the production casing was cemented from the plug to the surface. This is described in more detail in Section VII-E.

B. Liner Hardware

The 177.8-mm (7-in.) OD liner was installed and cemented with the hardware shown in Fig. 7. The liner equipment was manufactured from AISI 4140 steel with a 550-MPa (80,000-psi) minimum-yield-strength heat treatment. All pressure connections were VAM™ threads.

(1) Liner float shoe: a taper was cut in the inside of the bottom of a standard float shoe to provide a wireline reentry bevel on the bottom of the liner after drillout. The antirotation blades on a shoe were rounded off so that the shoe would traverse ledges in the hard granite wellbore. Two all-metal dart type floats were specified.

(2) Landing collar: a standard aluminum insert collar was run two joints above the shoe to stop and latch-in the liner-wiper plug following the cement.

(3) Liner: 380 m (1250 ft) of Algoma casing, 52.1 kg/m (35 lb/ft), grade Soo-90, range III, with VAM threads and beveled collars was run with 15 Turbulator™ centralizers spaced out to provide maximum centralization and facilitate rotation of the liner.

(4) Liner hanger: the acme thread and O-ring seal above the roller-bearing assembly in a standard single-cone rotating/reciprocating liner hanger was replaced with a VAM connection (with a metal-to-metal seal).

(5) Cementing polished bore receptacle (PBR): a full ID PBR was specified to mate to a high-pressure and high-temperature seal unit on the liner setting tool.

(6) Liner-setting sleeve: a standard sleeve with a left-hand acme support thread and a 3-m-long (10-ft) tie-back extension was run on top of the liner.

(7) Liner-setting tool: the setting tool with a Molyglass™ seal unit spaced out to seal in the PBR and a high-temperature service, Viton™ liner-wiper plug shear-pinned to a short tubing joint extending into the liner hanger was attached to the liner and pressure tested to 48 MPa (7000 psi).

Geothermal grade Kopr-Kote™ thread lubricant was used to make up the liner casing. The attempt to rotate and cement the liner is described in Section VII-D.

C. Tie-Back Casing Hardware

A 2896-m-long (9500-ft) string of 177.8-mm (7-in.) OD, 47.6-kg/m (32-lb/ft), C-95 NSCC casing was purchased to serve as the main string in the tie-back casing. NSCC, a proprietary Nippon Steel casing connection, is a premium threaded and coupled buttress connection with a metal-to-metal internal flank seal. Six joints of 177.8-mm (7-in.) OD, 52.1-kg/m (35-lb/ft), Algoma Soo-90 VAM casing were run on the bottom; four joints were run on top of the tie-back casing to provide a stiffer, thicker wall casing in the critical, highly stressed regions.

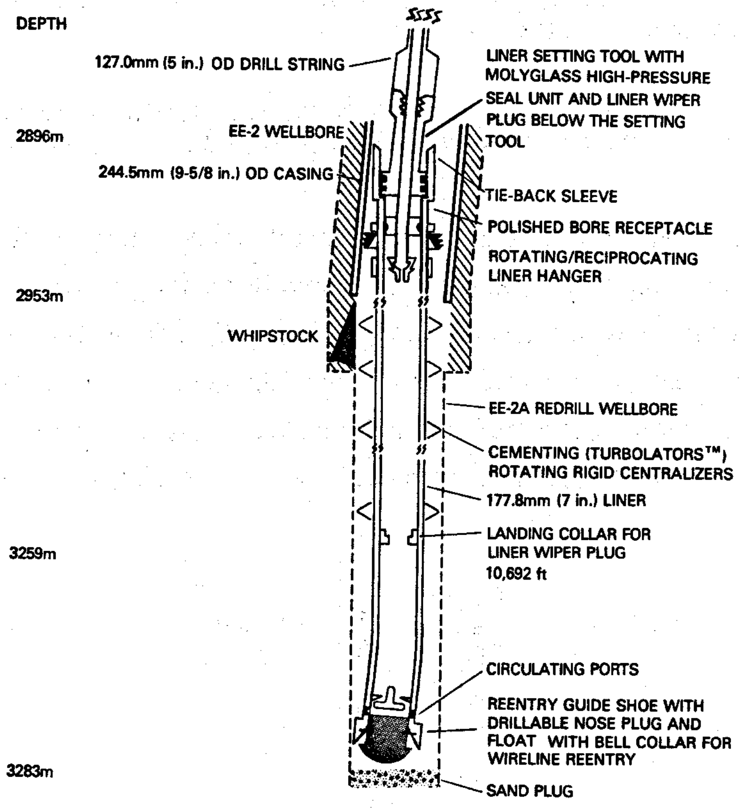

Fig. 7. Liner cementing hardware.

The tie-back casing was installed and cemented-in with a single stage placement, as described in Section VII-F. The following tie-back hardware was manufactured from AISI 4140 steel with a 550-MPa (80,000-psi) minimum-yield-strength heat treatment and proprietary Grade C-95 tube stock with premium threaded connections as listed below.

(1) Tie-back stem: a 3.4-m-long (11-ft) tie-back stem with three Molyglass™ (chevron style) seal units was configured as shown on Fig. 8. The lower seal was intended to be a debris seal to keep cement out of the tie-back sleeve during cementing. The middle seal was a test seal that allowed a pressure test of the tie-back stem before cementing. The top seal was the primary seal that would be activated by shearing the seal protector sleeve and stinging fully into the tie-back sleeve after displacement of the cement.

(2) Landing collar: a standard aluminum insert collar was run two joints (Algoma VAM) above the shoe to stop the liner-wiper plug following the cement to prevent overdisplacement.

(3) Crossover: a VAM pin by NSCC pin crossover pup joint was run four joints (Algoma VAM) above the landing collar.

(4) Casing: 2770 m (9100 ft) of Nippon Steel casing, 47.6 kg/m (32 lb/ft), Grade C-95, range III, with NSCC threads and standard collars was run with 65 rigid centralizers spaced out to provide maximum centralization.

(5) Crossover: a VAM pin by NSCC pin crossover pup joint was run below four joints of Algoma VAM and a cementing crossover joint and cementing head on the rig floor.

The pressure test of the tie-back stem indicated that it was not stung-in. Steel line measurements and casing string weight indications showed that a sting-in had occurred and, in that case, the tie-back stem could be cemented and shut-in to prevent flow-back if the top seals did not function. If a sting-in had not occurred, junk on top of the liner was the most likely explanation. A collar locator log of the tie-back sleeve and stem and removal of the casing, if necessary, to inspect the tie-back stem were ruled out because of predicted risks and limited

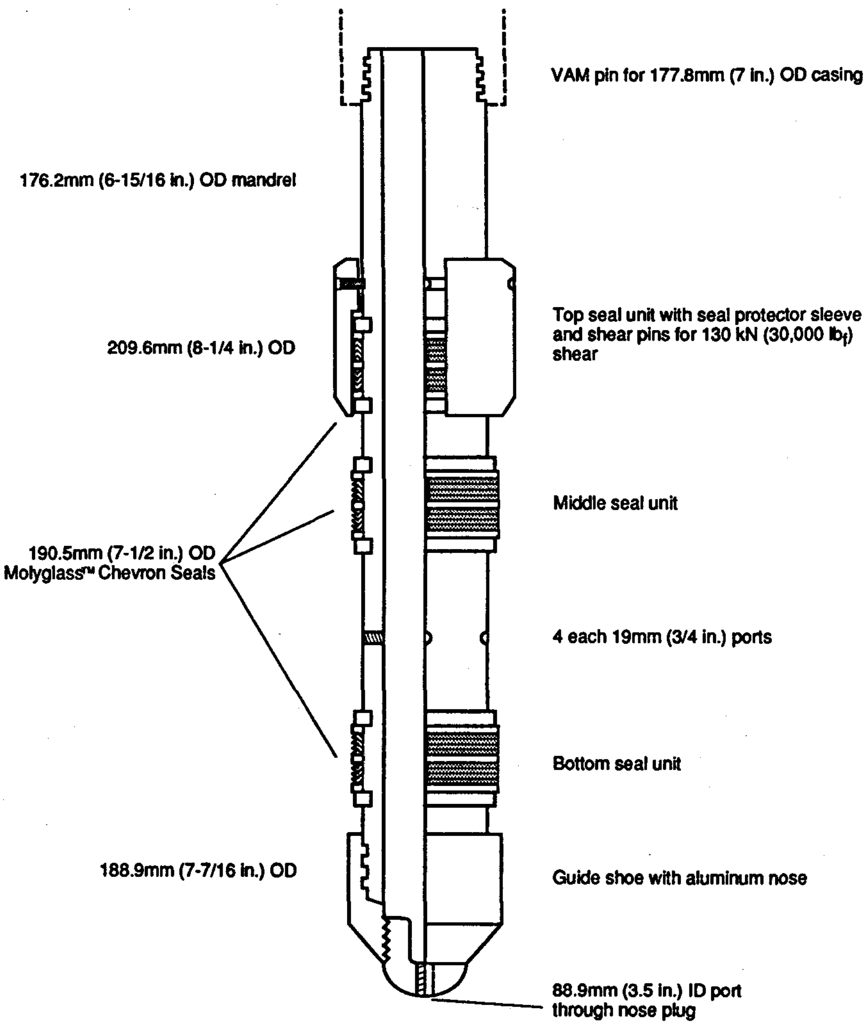

Fig. 8. Tie-back stem.

contingency funds. The tie-back casing was cemented through the tie-back stem. After placement, the ports in the stem could not be isolated with a 667-kN (150,000-lb) reduction in string weight to sting-in and set-down to shear the seal protector sleeve. The collar log on the CBL confirmed that the stem was resting on top of the tie-back sleeve and was not stabbed-in before cementing. Figure 9 shows the final bottom-hole well completion.

After cementing, the tie-back casing was pretensioned to the near optimum axial load to equalize the anticipated thermal stress load during both high-temperature production and low-temperature, high-pressure injection. Stress calculations discussed previously were used to prepare the tensioning procedure. After an attempt to seal off the tie-back stem by shearing the seal-protector sleeve, the string weight was increased to 890 kN (200,000 lb) while the cement at

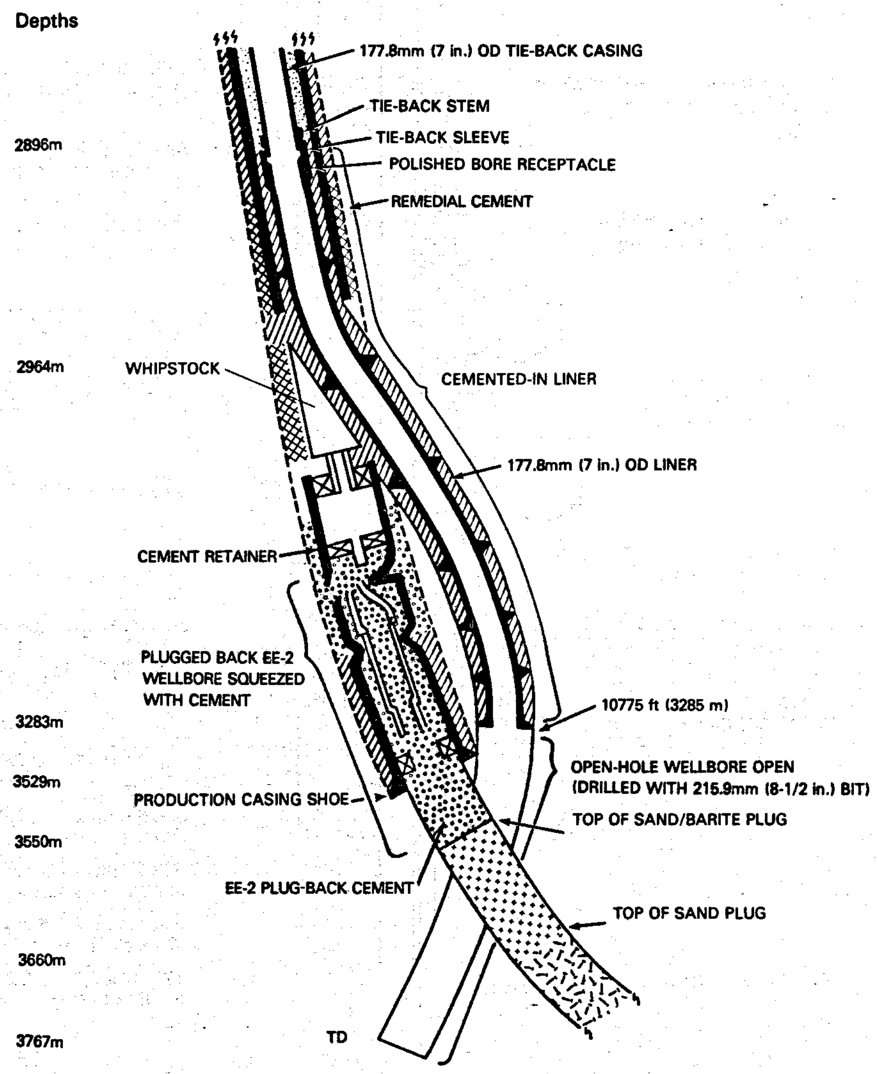

Fig. 9. Final EE-2A schematic of the lower wellbore configuration.

the bottom of the casing was setting up. A slick line temperature survey was run, and final calculations were made to determine the optimum tension for the casing. The casing was landed in a new casing spool with 1450-kN (325,000-lb) tension.

A 179.4-mm (7-1/16-in.), API 10,000-psi (68.9-MPa), working pressure (WP) master valve was installed over the 177.8-mm (7-in.) casing. The casing pack-off consisted of an Aflas elastomer primary seal and an omega style, spring-energized, metallic, secondary seal contained in the bottom of an API 10,000-psi (68.9-MPa), WP tubing spool with 52.4-mm (2-1/16-in.) side outlets and valves. Figure 10 shows the final wellhead configuration.

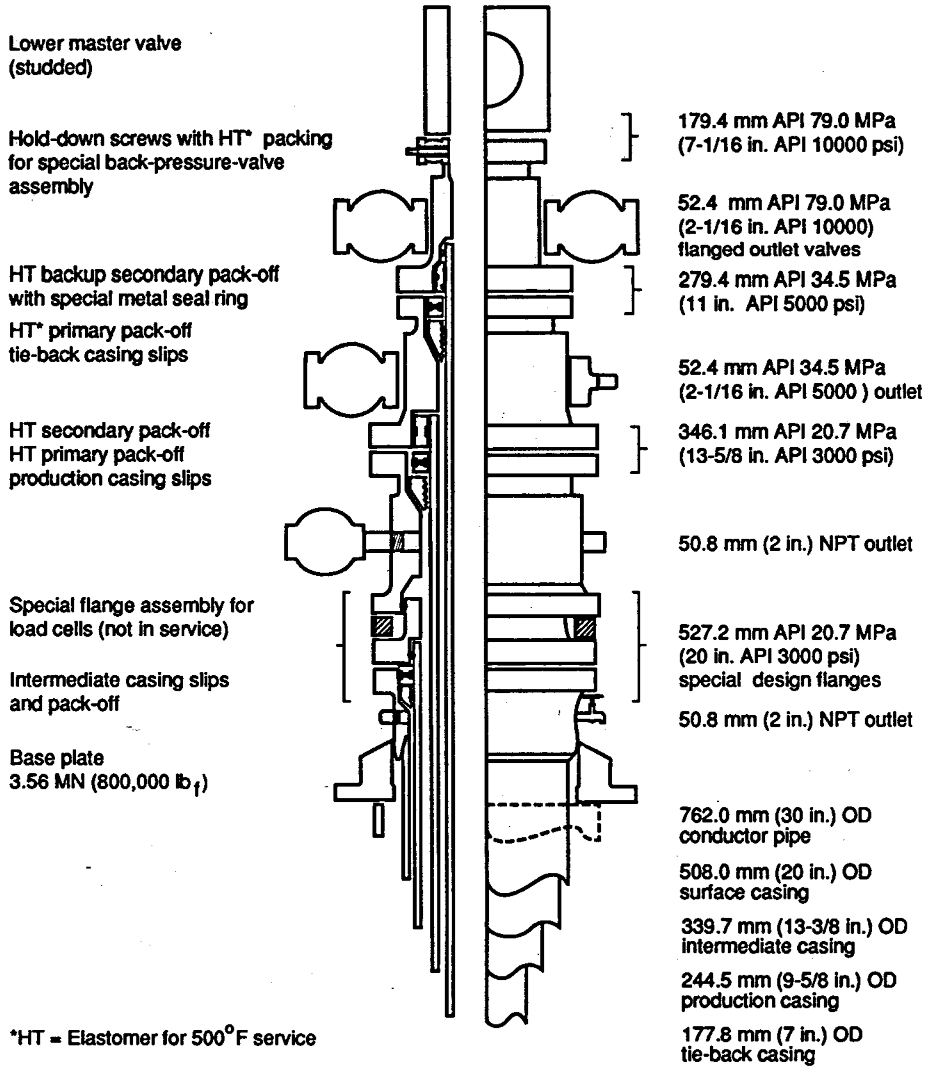

Fig. 10. Final EE-2A wellhead assembly.

VII. CEMENTING

Five cementing operations requiring seven batch-mixed slurries were conducted before EE-2 was sidetracked. After drilling the sidetracked hole, four additional cement placements were conducted during the installation of the open-hole liner and tie-back casing. Appendix F-1 lists the cementing procedures.

The large number of planned procedures required that excellent communication between the cementing service company, Dowell-Schlumberger (DS), and Los Alamos staff and consultants be maintained throughout the planning, cement testing, and operations.[22] Detailed procedures were completed. Cooling and thermal recovery projections were run on the LANL wellbore heat transfer (WBHT) code and the Geotemp2 code, developed by the Sandia National Laboratories. Cement testing was conducted by DS based on the temperature projections and planned cement placement times. Appendix F-2 summarizes the cement formulations; Appendix F-3 lists the cement slurry properties and test results.

API Class H and G cements and 300 mesh silica flour were stored in reserved silos in Farmington, New Mexico. Cement testing was conducted with samples from the reserved silos and water from the Fenton Hill site domestic water well. Typically, a slurry batch mixing time of 2 to 3 hours and a thickening time of 3 to 4 hours were specified. Zero operating free water and no particle segregation or channeling were also specified but not always achieved.

In the formulations that were tested for the predrilling cementing operations, free water was excessive in the lightweight slurries using Class H cement and perlite. A formulation using a California perlite (Perfalite™) and Class G cement was eventually developed with nil free water. In the testing for tie-back casing 6 months later, a suitable Class H cement and Perfalite™ formulation was developed.

To maintain the strength of the cement during 220°C (430°F) production operations, 45% silica flour was specified for high-strength cements and 35% silica flour for lightweight perlite cements. These silica concentrations were intended to provide a CaO/SiO_2 ratio of one, which should result in forming the best phases (xontolite, tobermorite, and calcium silicate hydrate) for high-temperature strength maintenance.[22]

Before cementing, the well was cooled with circulation through or injection into the region to be cemented. The cooling circulation rate and pressure were selected to suit the rig's pumps. This freed the cementing contractor's pumps for batch mixing. The duration of cooling was specified to achieve approximately 95% of maximum cool-down based on WBHT simulations.

Cement, silica flour, and gel (except for prehydrated gel) were weighed and blended in Farmington and then transported to Fenton Hill. All soluble additives were carefully weighed and added to the mix water at Fenton Hill. The slurries were normally mixed "heavy" and then thinned with additional mix water to obtain the proper density.

Cementing procedures were conducted to keep dilution and contamination of the cement to a minimum.[23] Redundant pumping equipment and piping were rigged up to assure that cement placement would be completed in the planned time. Displacement volumes were corrected for thermal expansion[24] and shutdowns were specified to prevent overdisplacement of the cement if wiper plugs failed to latch and seal.

CBLs with an amplitude, transit time, and microseismogram display were run following the cementing procedures. Because the slurries were normally highly retarded, the bond logs were usually run at least 10 days after the cementing. Collar-locator and gamma-ray correlation logs were run simultaneously. Appendix F-4 summarizes the bond log results.

A. Plug Back of Damaged EE-2 Wellbore

Three cementing procedures had been planned to provide certainty, within budget constraints, that the redrilled wellbore would be hydraulically isolated from the reservoir through the damaged wellbore. The drill string, two Baker Service Tools (BST) Model "K-1"™ tubing set cement retainers, and a BST Model "B" Retrievamatic Hurricane Plug™ packer were used for a plug back and two annular cement placements.

Both the retainers and the packer used a proprietary ethylene/propylene/diene/methylene (EPDM) elastomer packer element and O-rings and were set using drill pipe measurements. They were set in cemented casing, where possible, based on a recent CBL. The retainers and packer were tested with a 10-MPa (1500-psi) backside pressure test and operated with a 20-MPa (3000-psi) drill pipe pressure limit with a 7-10-MPa (1000-1500-psi) backside pressure.

Oil Well Perforators made perforations using conventional 34-g 218°C (425°F) Harrison charges in a 127-mm-diameter (5-in.) hollow-steel carrier perforating gun. There were no misruns and all charges fired. Special effort was made to correct wireline depth measurement to drill pipe measurements by tagging drill pipe set retainers with the perforating gun or by running collar locator logs out of open-ended drill pipe near the planned perforating depth. Wireline depths varied from 11 m (36 ft) to 6 m (19 ft) deeper than pipe measurements at 3178 m (10,428 ft) and 1928 m (6326 ft), respectively.

First, the damaged wellbore below 3204 m (10,512 ft) was plugged (procedure 1a in Appendix F-1) with 5.25 m^3 (33 bbl) of cement slurry displaced to a retainer at 21 L/s (8 bbl/min) and injected below the retainer with a decreasing rate (Fig. 11). The final displacement pressure was 14.1 MPa (2040 psi) with an injection rate of 0.6-L/s (0.25-bbl/min).

Second, the cement placement in the production casing annulus through perforations at 3115-3117 m (10,220-10,224 ft) (procedure 1b in Appendix F-1) used two 5.6-m^3 (35-bbl) slurries of cement displaced to a retainer at 14 L/s (5.4 bbl/min) (Fig. 12). The first slurry was overdisplaced when it was certain that a high-pressure squeeze would not be achieved [injecting 2 L/s (0.75 bbl/min) at 13 MPa (1900 psi)]. The second slurry was displaced to the retainer and

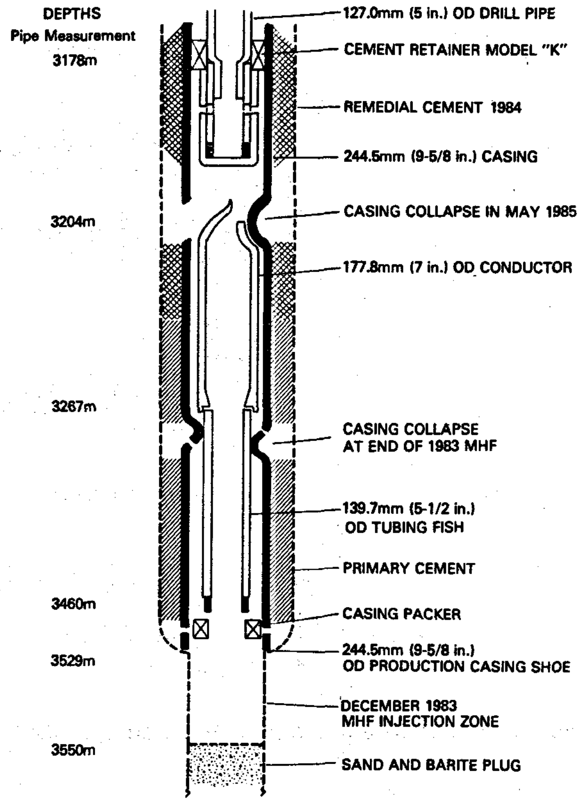

Fig. 11. Plug back of lower EE-2A wellbore.

injected into perforations at 0.6 L/s (0.25 bbl/min) and 15.2 MPa (2200 psi). The 11 m^3 (70 bbl) of cement pumped should have filled the void or unbonded annular volume shown on the most recent CBL.

Following 24 hours of waiting on cement (WOC), a slick line temperature log was run in an unsuccessful attempt to locate the top of the cement based on heat of hydration. A CBL (amplitude display only) was then run and showed a transition from bonded to free casing from 2925-2980 m (9600-9780 ft). A later CBL run at the end of drilling showed a gap in the cement from 2920-2960 m (9580-9710 ft). Apparently the earlier log run in poorly set cement was improperly calibrated because of the assumption that the cement was set and had achieved moderate strength.

Third, a 4-m^3 (25-bbl) slurry of cement was displaced to the packer at 8.5 L/s (3.2 bbl/min) and injected into the perforations at 2910-2911 m (9546-9550 ft) (procedure 1c in Appendix F-1) at 4.5 L/s (1.7 bbl/min) with pressure increasing from 16.9-17.2 MPa (2450-2500 psi) (Fig. 13). Following a 2-hour shut-in, the first attempt to bleed off the pressure and release the packer resulted in flow back of cement. The well was finally bled off after a 7-hour shut-in.

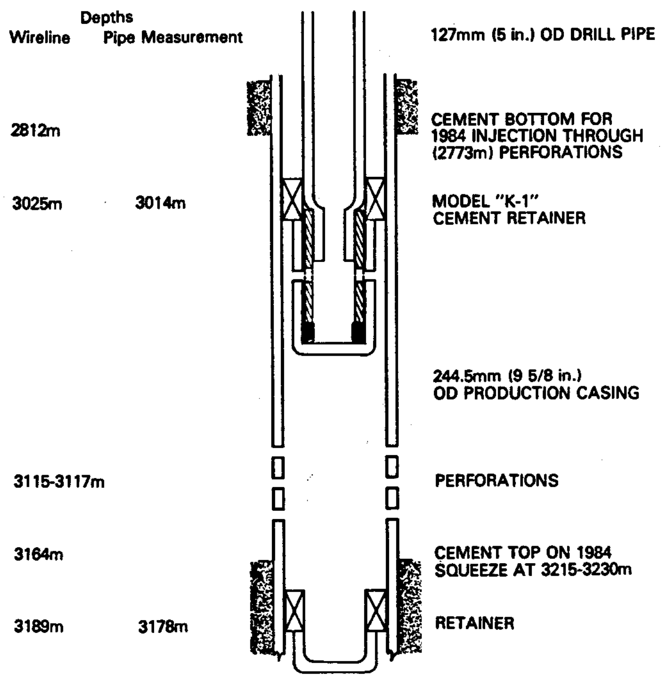

Fig. 12. Cementing the production casing annulus at 3115 m.

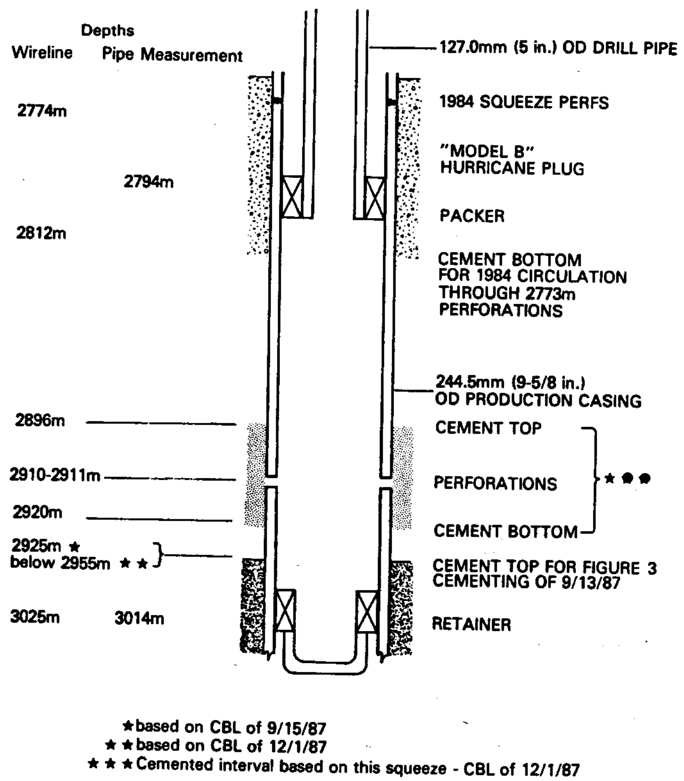

Fig. 13. Cementing the production casing annulus at 2910 m.

The lightweight cement formulation for the next procedure was not ready because of the excess free water in the formulations tested. The section for the whipstock in the production casing was milled and then temporarily plugged with a hard cement plug while the lightweight formulation was modified and tested in the laboratory.

B. Whipstock Plug

After milling an 18-m-long (60-ft) section in the production casing below 2953 m (9688 ft), a 20/40 mesh sand plug was placed in the casing below the milled section, extending 2 m (5 ft) into the bottom of the section. A balanced plug placement through the drill string was used to fill the top 17 m (55 ft) of the milled section, extending 50 m (170 ft) into the casing above the section (procedure 2 in Appendix F-1). The cement plug was intended to prevent potential junk from entering the milled section where the junk would be difficult to remove; i.e., any parts of the drillable cement retainer to be used during cement placement above the milled section.

The plug was to be drilled out with a 215.9-mm-diameter (8-1/2-in.) bit just before the whipstock was to be set, and the remaining plug in the 311-mm (12-1/4-in.) drilled diameter section was intended to provide some support for the whipstock during sidetracking as shown on Fig. 2.

C. Support of Production Casing during Drilling

As recommended by the outside review panel, a cement placement to fill the 244.5-mm (9-5/8-in.) production casing annulus from the existing cement top at 1987 m (6520 ft) to the surface was attempted. Unsuccessful attempts to seal off lost circulation zones from 520-730 m (1700-2400 ft) during the original drilling of EE-2 had placed more than 25,000 sacks of cement in this interval. A successful cementing campaign would probably require at least 6 cement placements extending over 14 full-cost operating days. The estimated cost was $250,000 with no contingency included or 12.5% addition to the total projected redrill and completion cost. This was unacceptable, and the job planned was a best reasonable effort based on economic constraints.

Much of the casing was worn, based on earlier caliper and wall thickness logs run in November 1986 and March 1987 (see Table II), and its calculated collapse resistance was low. A cementing procedure was devised that allowed the cement to be pumped down the casing instead of down the drill pipe and through a packer. The cement was displaced with 1138-kg/m^3 (9.5-lb/gal) fresh water mud to provide an additional safety margin should a loss of well pressure occur when the cement placement was completed (procedure 3 in Appendix F-1).

A modified Model "K-1" retainer with a check valve instead of the standard drill string operated valve was set 40 m (125 ft) above casing perforations at 1972-1974 m (6470-6476 ft). It was used as a string float to place and prevent back flow of the cement (Fig. 14). Equipment to conduct the cement and wiper plugs through the blowout prevention equipment (BOPE) was assembled as shown on Fig. 15. A top liner-wiper plug was shear-pinned to the bottom of two

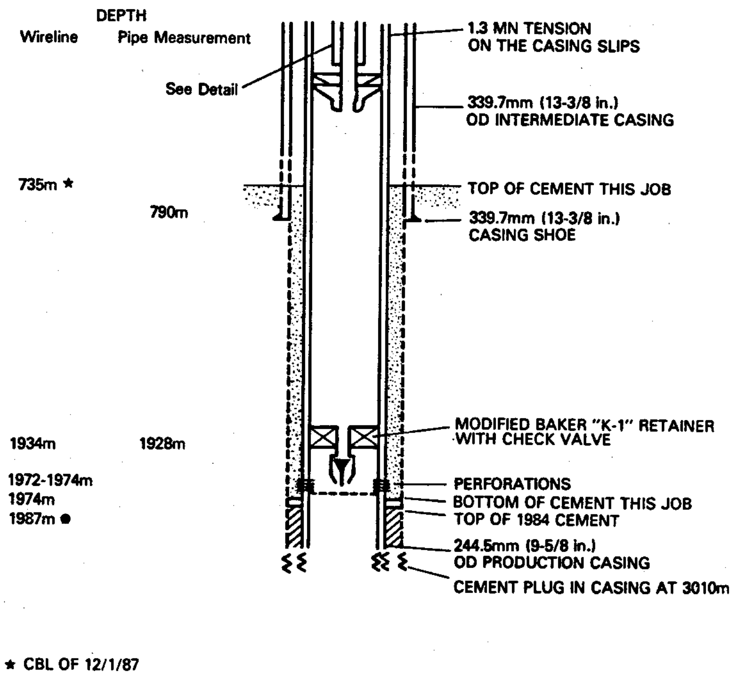

Fig. 14. Cementing the production casing annulus at 790-1975 m.

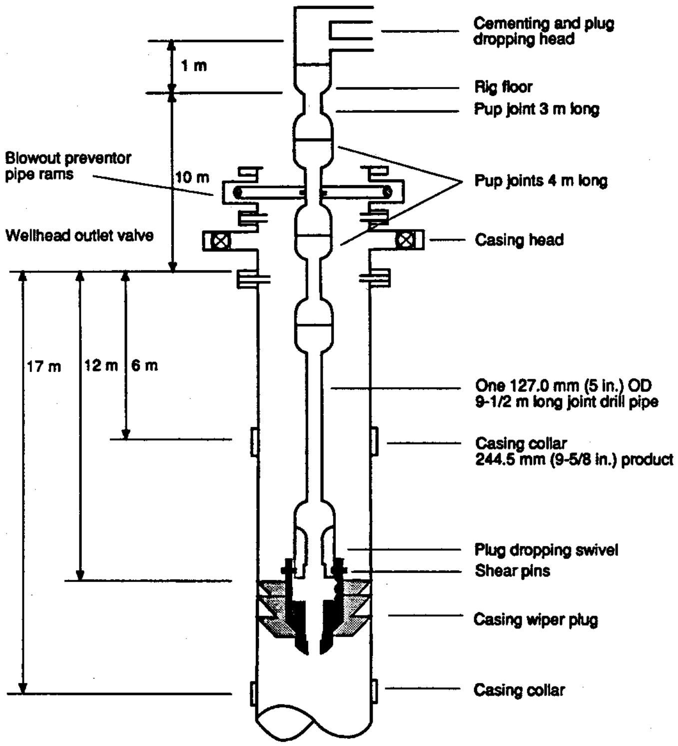

Fig. 15. Surface hardware for cementing through blowout preventers.

joints of drill pipe that were inserted through the BOPE. A plug-dropping (cementing) head was installed on top of the drill pipe, and a drill pipe dart was loaded into the head. The head was manifolded to the rig's mud pump manifold and to the cementing contractor's lines.

The well was cooled for 1 hour by circulating at 19.9 L/s (7.5 bbl/min) without returns. A 6.4 -m^3 (40-bbl) preflush slurry of 1260-kg/m^3 (10.5-lb/gal) pozzolan water was circulated during cooling to clean the annulus and, hopefully, seal off the lost circulation zones. A cement slurry consisting of 76.5 m^3 (481 bbl) of lightweight and 3.82 m^3 (24 bbl) of high-strength cement was pumped and displaced with 75 m^3 (470 bbl) of mud. The slurry volume provided 3% excess based on the calculated annular volume. The final pumping pressure was less than 1.4 MPa (200 psi), and there were no returns during the displacement. The casing was opened to atmosphere, and the well was on a vacuum. A slick line temperature log run 23 hours after shutdown showed a cement top at 730 m (2400 ft), and this was later confirmed on a CBL.

The 15.9 m^3 (100 bbl) of lead slurry was batch mixed; 60.5 m^3 (381 bbl) was mixed on the fly and pumped into a 7.95-m^3 (50-bbl) batch mixer. The mixing rate was approximately 15.9 L/s (6 bbl/min), so an 8-minute residence time in the mixer was provided to even out the mixing variations.

D. Cementing-in the Liner

Operations were suspended after drilling the sidetrack hole, EE-2A, to a TD of 3767 m (12,360 ft) and evaluating the new production path to assure a good connection to the reservoir had been reestablished. Additional funding was needed to purchase 177.8-mm (7-in.) OD casing for the tie-back string recommended by the outside review panel. When operations resumed, the open-hole gamma-ray/temperature, gamma-ray/three-arm caliper, and sonic televiewer logs were run in the interval below the whipstock. The open hole was then filled with sand (see Appendix G) to cover the production interval while an open-hole production liner was cemented-in from 3283-2896 m (10,770-9500 ft).

A 177.8-mm (7-in.) OD, 52.1-kg/m (35-lb/ft), Soo-90 VAM liner was designed as described in Section VI-B (Fig. 7). The liner was run on the 127.0-mm (5-in.) OD drill string and a liner-setting tool that allowed either rotation or reciprocation of the liner during cementing. The liner was successfully rotated at a low torque (approximately the same torque needed to rotate the drill string set at the same depth on an earlier torque measurement) when it was first hung off in the production casing. After circulating through the liner and cooling the well at 22 L/s (8.5 bbl/min) for 1 hour, a slick line temperature log was run to verify well temperature simulation runs. Cooling was resumed for 4 hours based on the verified temperature simulation. A retarder concentration of 0.6% was selected for the slurry, and batch mixing of the slurry was begun.

A second rotation check before cementing showed that the liner could not be turned at the allowed torque limit. It was feared that the cooling had caused spallation of the borehole wall and formation of a bridge on the liner. The bridge, if substantial, could have also prevented reciprocation of the liner and interfered with resetting of the liner hanger. An attempt to reciprocate or rotate the liner during cementing was not made.

A 1.6-m^3 (10-bbl) pad of retarded water (leftover mix water) preceded the 8.7-m^3 (55-bbl) cement slurry (procedure 4 in Appendix F-1). A drill pipe dart was dropped and followed by 0.08 m^3 (1/2 bbl) of cement, which was the volume of cement in surface hard lines, and 0.12 m^3 (3/4 bbl) of retarded water. The slurry was displaced with 6.4 m^3 (40 bbl) of 1990 kg/m^3 (16.6 lb/gal) mud followed by 22.9 m^3 (144 bbl) of water. The mud was almost enough volume to equalize the pressure on the floats and the liner-wiper plug catcher. It thereby provided a backup for them to prevent backflow of the cement when the drill string was released from the liner.

A calculated displacement volume of 30.7 m^3 (193 bbl) and a density correction for the projected temperature and pressure resulted in a theoretical displacement volume of 29.4 m^3 (185 bbl). A rapid pressure increase occurred after 28.5 m^3 (179 bbl) of displacement. When the displacement rate was reduced from 10.6-1.4 L/s (4-0.50 bbl/min), the pressure broke back and then increased a second time. The displacement was shut down at 29.3 m^3 (184 bbl) as the pressure increased rapidly toward the pressure limit set by the procedure, 20.7 MPa (3000 psi).

When the drill pipe was vented back to check the floats, it was on a vacuum. It is assumed that the pressure increases were the result of the previously mentioned spallation bridge being circulated up into the milled section by the high-density cement. Pressure increases would have occurred when the bridge hit the top of the milled section and the liner hanger. Displacement volumes at the time of the increases support this explanation.

E. Surface Cementing in the Production Casing Annulus

It was necessary to cement the 244.5-mm (9-5/8-in.) OD casing to the surface to reduce the potential loading on the 508-mm (20-in.) casing (see Section VI-A). Cost constraints precluded another series of attempts to plug and fill the zones from 520-730 m (1700-2400 ft) using conventional cementing. Review of unconventional cementing and applicable lost circulation materials did not offer any nonexperimental method to seal this zone.

A method was devised to set an annular plug at 274 m (900 ft) in which a 298.5-mm (11-3/4-in.) OD screw-in sub was located at 280 m (920 ft) (see Fig. 16). It had been installed when the top 275 m (900 ft) of casing had been replaced during the 1984 workover. By dropping 19-mm (3/4-in.) OD rubber ball perforation sealers down the 244.5-mm (9-5/8-in.) OD casing annulus, a bridge was built up on the sub that was 28.6-mm (1-1/8-in.) larger diameter than the casing collars. Balls tagged with an Ir-192 radioactive (RA) tracer were dropped and logged with a gamma-ray detector to assure that most of the balls were falling all the way to the screw-in sub and that none were getting past the sub. Over 600 ball sealers and 0.2 m^3 (5 gallons) of pea gravel [enough to form a 0.45-m-long (18-in.) annular plug] were dropped over a 12-hour interval. Then

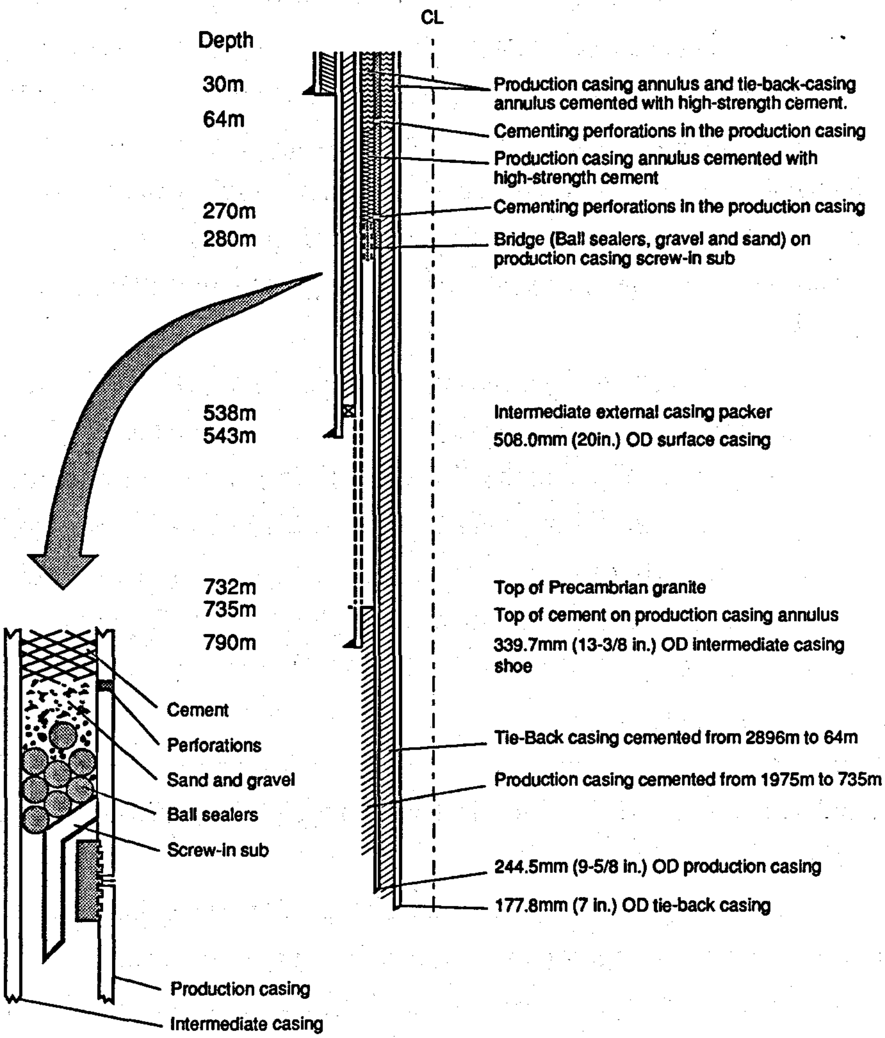

Fig. 16. Final EE-2A schematic of the upper wellbore configuration.

0.6 m^3 (160 gallons) of pea gravel and 20/40 mesh "frac" sand were mixed into a 0.01-0.03-L/s (3-10-bbl/min) stream of water, which was run into the annulus. At one point, gravel was added too rapidly and appeared to bridge off high in the annulus. After pumping on the bridge, it appeared to break when the pressure above the bridge was released. Additional RA ball sealers were dropped and logged. Many of the frac balls were located at a depth of approximately 49 m (160 ft). After perforating 10 m (30 ft) above the screw-in sub, an attempt to break circulation above the perforations was successful, proving that a bridge had been formed on the screw-in sub. Some of the bridges that formed above 280 m (920 ft) were broken up and circulated out.

A solid rubber wiper plug was pushed and located below the perforations with the drill string. A liner wiper plug was installed using the same hardware and procedure that was used during the previous cementing at 1975 m (6480 ft) (see Fig. 15).

An 11.4-m^3 (71.5-bbl) slurry of high-strength cement was mixed and pumped down the 244.5-mm (9-5/8-in.) OD casing (procedure 5 in Appendix F-1). Just as the displacement started, the cement slurry hit the perforations and the pressure increased to 7.6 MPa (1100 psi). The pressure broke back, and the displacement was pumped at 6.6 L/s (2.5 bbl/min) until the slurry reached a calculated depth of 40 m (130 ft) and the pressure rapidly increased to 8.6 MPa (1250 psi), the maximum allowable pumping pressure. Several attempts to resume pumping and complete the displacement were not successful. Consequently, the job was terminated with no circulation of cement.

A CBL was run that showed a clean cement top at 65 m (215 ft). It was decided to perforate the production casing at 64-65 m (210-212 ft) and cement the 244.5-mm (9-5/8-in.) annulus during the same operation that the 177.8-mm (7-in.) OD casing annulus was cemented.

Both the perforations at 282 m (926 ft) and 65 m (212 ft) were made by Welex using special shallow penetration 10-g Big Hole™ charges in a 79.4-mm-diameter (3-1/8-in.), hollow steel carrier perforating gun. There were no misruns; all charges fired and there was no indication that the charges penetrated the 339.7-mm (13-3/8-in.) OD or 508-mm (20-in.) OD casing.

F. Cementing-in the Tie-Back Casing

The drillout of the production casing, the cleanout of the top 335 m (1100 ft) of the liner, and a fluted mill run to dress off the tie-back sleeve on top of the liner were completed before running the tie-back casing.

A tie-back stem (Figs. 8 and 9) was run on bottom, and a cementing head was installed on top of the tie-back casing. The tie-back stem did not sting in properly and the casing was cemented with the tie-back stem tagging the top of the tie-back sleeve, which is described in more detail in Section VI-C.

Breaking circulation through the tie-back casing at 40 L/s at 8.3 MPa (15 bbl/min at 1200 psi) revealed a leak in the cementing head. Two attempts to repair the leak were unsuccessful, and the head was replaced. The second head also leaked but was successfully repaired. When cement mixing preparations were completed, the tie-back string was circulated for 3 hours at 40 L/s (15 bbl/min) while batch mixing of the lead and tail slurries was completed.

A 1.4-m^3 (9-bbl) pad of retarded water preceded the bottom plug. A shutdown was required to insert the bottom plug into the casing and load the top plug into the cementing head. A 33.9-m^3 (213-bbl) lightweight lead slurry and the 15.9-m^3 (100-bbl) high-strength tail slurry were pumped (procedure 6 in Appendix F-1).

Flow line returns were lost several times during the pumping of cement. To assure that the tie-back stem was not closing and sealing off, the 177.8-mm (7-in.) OD casing was raised several feet with the rig's casing elevators. Flow line returns did not resume, but flow resumed later and was lost again. It is assumed that the cement outran the pumped slurry so far that it back-flowed on the two occasions that flow ceased.

The cement slurry was injected into the tie-back casing. During a short shutdown, the top plug was dropped and followed by 0.08 m^3(1/2 bbl) of cement, which was the volume of cement in surface hard lines, and 0.12 m^3 (3/4 bbl) of retarded water. The slurry was displaced with 1.6 m^3 (10 bbl) of retarded water followed by 36.7 m^3 (231 bbl) of water.

Cement was circulated out of the 177.8-mm (7-in.) OD by 244.5-mm (9-5/8-in.) OD (first) casing annulus; shortly thereafter, cement was circulated out of the 244.5-mm (9-5/8-in.) OD by 339.7-mm (13-3/8-in.) OD (second) casing annulus through perforations in the production casing at 64 m (210 ft) just as the planned displacement volume was reached (Fig. 16). The tie-back casing was lowered and set down on the liner in an attempt to close and seal the tie-back stem to the liner. Approximately 1.6 m^3 (10 bbl) of water was then bled back, confirming that the tie-back stem had not sealed off. The rig pumps were used to clear the perforations at 64 m (210 ft) and circulate the first and second annuli through the perforations to clean out the lightweight, low-strength cement.

G. High-Strength Cement for Top Annuli

The tie-back casing was tensioned as described in Section VI-C. As soon as this was complete, a 4-m^3 (25-bbl) unretarded slurry was mixed and circulated through the perforations in the production casing by pumping down the second annulus (Fig. 16). The cement became too thick to pump just as the first cement returns were circulated. The cementing lines were removed and cleaned with diluted cement recovered in the flow lines (procedure 7 in Appendix F-1).

H. Results of Cementing Operations

Cementing operations were very successful. The placement procedures provided sufficient contingencies and flexibility to allow all jobs to be completed without any major problems. Injection and production tests conducted in EE-2A have shown no evidence that the plug back and isolation of the old wellbore were not accomplished. Bond logs showed that the remedial cementing of the production casing and cementing of the liner and tie-back casing achieved better placement and higher cement strength than had been predicted. These results are summarized in Appendix F-4.

The attempted squeeze cementing of the production casing annulus below 2812 m (9225 ft) left large voids between the well bonded annular plugs. The bond log showed some uncemented casing below 2920 m (9580 ft) and between the upper squeeze at 2910 m (9546 ft) and the cement placed in November 1984 at 2774 m (9100 ft) (Fig. 13). The voids are attributed to the difficulty of squeezing low-permeability fractured rock. Natural joints or fractures have been opened between 2865-3109 m (9400-10,200 ft), based on injection temperature logs following the massive hydraulic fracture in 1983. It was assumed that even with three or four more squeeze injections into the voids, the size of the voids would be significantly reduced but the voids would not be eliminated. The financial constraints on the project precluded this undertaking.

The good bond obtained over most of both lightweight cement slurries is indicative of high compressive strengths and little or no channeling. Poor centralization of the production casing and the highly retarded, lightweight cement used on both the production and tie-back casing may have contributed to the intermittent poor cement bond on the CBLs.

The bond log of the production casing showed a small void between the 1987-m (6520-ft) top of the 1984 cement and the cement circulated in at 1974 m (6476 ft) (Fig.14). It also showed two 6-m-long (20-ft) intervals of poor bond at 1608 m (5275 ft) and 1647 m (5405 ft) and a cement top at 735 m (2410 ft). A 6-m^3 slurry of 1260-kg/m^3 (40 bbl of 10.5-lb/gal) pozzolan water and over 31.8 m^3 (200 bbl) of cement was placed in the subhydrostatic aquifer at 735 m (2410 ft), just above the top of the Precambrian rock.

The bond log of the tie-back casing showed minimal bond between 899-902 m (2950-2960 ft) and several regions between 381-1579 m (1250-5180 ft) where intermittent poor bond occurs (Appendix F-4). It also showed two poorly defined cement tops from 389-259 m (1250-850 ft) and from 49 m (160 ft) to the surface. Because cement was circulated on both of the cement jobs (procedures 6a and 7 in Appendix F-1), the lower top is believed to be the top of the well set and cured cement and the upper top is thought to lie under channeled and diluted cement, both having insufficient strength to indicate any bond at the time the log was run.

The safety factors for retardation of the cement were based on several premature sets that occurred in earlier cementing in wells EE-2 and EE-3A. The long set times that resulted probably contributed to some separations and segregation of the cement. Staged cementing might have significantly reduced separation problems, but the higher risks, costs, and additional requirement for cement formulation testing exceeded our resources. Cement strength and bond strength will probably increase with time. The cement voids, if they exist, should not cause future problems based on stress calculations of the thick-wall, high-strength 177.8-mm (7-in.) casing.

VIII. RESERVOIR AND CASING EVALUATION

The reservoir evaluation and protection plan called for EE-3A to be pressurized and the reservoir to be inflated to 15.2 MPa (2200 psi) above the hydrostatic pressure as EE-2 penetrated the reservoir. As flow and CO_2 were detected by the mud loggers' flow monitoring equipment, the top of the reservoir was located. When additional major flowing fractures were penetrated, the mud log and geochemistry log located many of them by detecting changes in flow, pH, CO_2, and other ion concentration changes.

A 2-day logging and flow testing operation was conducted after the top 60 m (200 ft) of the reservoir had been penetrated, so the upper reservoir, 3290-3550 m (10,800-11,000 ft), and the total reservoir, 3290-3675 m (10,800-12,050 ft), could be compared without high-cost and higher-risk open-hole packer operations.[12] After drilling to 3356 m (11,009 ft), the drilling mud was displaced with water and the drill pipe was removed. Temperature logs, a bottom-hole fluid sampler, and flow tests were run over a 2-day interval. Drilling was resumed after displacing the well with drilling mud.

EE-3A injection pressure was reduced several times as more fractures were intercepted to achieve a balance between protection of the reservoir and dilution of drilling fluid and increased drilling costs. By the end of the redrill, the EE-3A pressure had been reduced to less than 2.8 MPa (400 psi) above hydrostatic.

More than 90 m (300 ft) of rat hole drilled below the lowest indication of reservoir flow provided a large volume for rock spalls and sand fill below the producing interval.

After reaching TD at 3767 m (12,360 ft), the well was again displaced with water. A final 2-day logging and flow testing operation was conducted, including (1) a CBL of the production casing, (2) a 64-arm maximum ID (wear measurement log of the production casing), (3) the multishot magnetic directional survey, and (4) a short flow test of the entire producing interval.

The casing ID caliper log showed moderate wear of the casing over the entire length, but the effort to protect the previous high wear areas with reduced string weights and smooth hardbanded pipe was apparently successful. The lack of decomposed drill pipe rubbers and their reinforcing straps contributed to an excellent wireline logging environment and to high quality caliper logs on the first attempt. The steel straps and rubber had jammed the caliper tools and hung up other logs during the EE-3A redrill.

A longer, more comprehensive production and tracer test was conducted in December that included (1) temperature/gamma-ray logs, both background and RA tracer gamma ray; (2) a three-arm caliper/ gamma-ray log, and (3) a 7-day flow test of the entire penetrated reservoir with a 6.6-L/s, 20.7-MPa (2.5-bbl/min, 3000-psi) injection into EE-3A. Two RA bromine tracer injections into EE-3A were conducted with surface monitoring of EE-2A for both tests and downhole RA logging for the second test. Temperature and RA logs showed the same production interval that the mud logs predicted. A well completion was subsequently designed based on a producing interval from 3284-3673 m (10,775-12,050 ft) (Fig. 17).

After the completion of EE-2A with the installation of the 177.8-m (7-in.) OD liner and tie-back string, a final production, injection, shut-in, and flow back testing sequence was run. This assured before the drilling rig was released that the productivity of the open-hole wellbore below the liner had not been damaged by the sand back or the cleanout of the sand placed to protect the open hole during the cementing of the liner.

Two days before beginning the sand cleanout below the liner, injection into EE-3A was initiated to increase the reservoir pressure to 6.9-13.8 MPa (1000-2000 psi) above hydrostatic

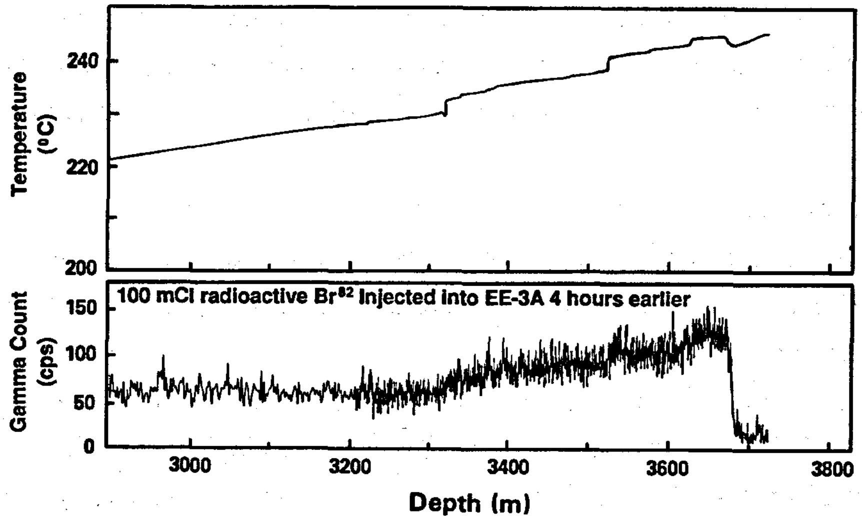

Fig. 17. Production temperature and gamma-ray (tracer) logs of EE-2A open hole below the production casing window at 2953 m.

pressure. This caused flow into EE-2A as the sand in the open hole was penetrated and helped keep sand out of the fractures. The production heated EE-2A during the cleanout and accelerated the set of cement in the first annulus. Once cleanout was complete, EE-2A was vented, a slick line temperature log was run, and the drill pipe was removed. A 10.3-MPa (1500-psi) pressurized CBL was run while injecting approximately 1.3-2.6 L/s (0.50-1 bbl/min) into the EE-2A open-hole bore. After flowing the well back, a cleanout run was made with the drill pipe in before the well was shut-in for 2 days.

After tripping into the hole and laying down drill pipe, a flowing temperature log showed that all production intervals detected before well completion (Fig. 17) were still productive. A 185-m^3 (1150-bbl) cool-water stimulation was conducted at a maximum rate of 40 L/s at 29.3 MPa (15 bbl/min at 4250 psi) injection pressure. Following a 9-hour shut-in, the pressure had declined to 3.3 MPa (480 psi). There was some concern that flow was leaving the wellbore between the tie-back casing and liner. Consequently a short injection was conducted with the rig's pumps, and slick line temperature logs were run with no conclusive evidence of a leak.

IX. OPERATING COSTS

A. Sidetracking and Redrilling

Itemized costs for all cementing, section milling, sidetracking, drilling, and reservoir evaluation from September 8 to November 16, 1987, are summarized in Table III-A. The per-unit costs shown in Table III-B reflect all expenses associated with drilling (drilling fluids, tubular

TABLE III-A. SUMMARY OF OPERATIONAL COSTS FOR CEMENTING, SIDETRACKING, AND DRILLING OF EE-2A
September 8, 1987, to November 16, 1987

Item	Cost($)
Contract rig day rate (69-1/8 days)	436,300
Fuel	42,200
Drilling fluids	63,100
Cementing materials and service	120,500
Retainers and plugs	20,300
Section milling	21,400
Mud logging	58,000
Supervision	122,000
Drill bits	53,000
Reamers and stabilizers	27,200
Rentals:	
Mud system	18,400
BOPE	14,000
H_2S alarm system	4800
Downhole tools (scrapers, mills, etc.)	4500
Other	4200
Directional drilling:	
Supervision	22,100
Tools (motors, non-mag DCs, etc.)	20,500
Wireline	43,700
Logging and perforating	41,600
Transportation	25,100
Drill pipe pickup/laydown	6500
Inspection service	9000
Miscellaneous services	12,200
Miscellaneous purchases	21,100
TOTAL	1,211,700

TABLE III-B. EE-2A DRILLING STATISTICS

	Penetration Rate					
	Maximum		Minimum		Average	
	m/hr	(ft/hr)	m/hr	(ft/hr)	m/hr	(ft/hr)
Overall						
803 m (2635 ft) with 20 bits						
Penetration rate	9.8	(32)	0.6	(2)	3.17	(10.43)
Penetration per bit	97.5	(320)	0.3	(1)	40.16	(131.75)
Cost - $618/m ($188/ft)						
Drill off Whipstock						
12 m (40 ft) with 2 bits						
Penetration rate	1.2	(4)	0.6	(2)	0.87	(2.86)
Penetration per bit	7.0	(23)	5.2	(17)	6.10	(20.00)
Cost - $2527/m ($770/ft)						
Directional (Motor) Drilling						
189 m (620 ft) with 6 bits						
Penetration rate	9.8	(32)	1.8	(6)	3.81	(12.50)
Penetration per bit	64.3	(211)	0.3	(1)	31.51	(103.37)
Cost - $639/m ($195/ft)						
Rotary Drilling						
602 m (1975 ft) with 12 bits						
Penetration rate	8.8	(29)	1.8	(6)	3.19	(10.45)
Penetration per bit	97.5	(320)	1.5	(5)	50.25	(164.85)
Cost - $531/m ($162/ft)						

TABLE IV. COST SUMMARY OF OPERATIONS AND HARDWARE FOR EE-2A COMPLETION
May 16, 1988, to June 17, 1988

Item	Cost($)
Contract rig day rate (31-1/2 days)	187,100
Fuel	15,100
Cementing materials and service	97,900
Retainers and plugs	9400
Supervision[a]	41,500
Drilling fluids	4300
Drill bits and mills	2500
Liner and tie-back casing[b]	285,500
Premium thread service	3800
Liner and tie-back hardware[b]	31,100
Wellhead equipment and service	56,900
Rentals:	
Drill string/handling tools	12,700
BOPE	8400
H_2S alarm system	2800
Other	4200
Commercial logging and perforating[c]	26,100
Transportation	10,800
Pickup/laydown service	20,500
Miscellaneous services	10,700
Miscellaneous purchases	4600
TOTAL	835,900

[a]Contract supervision only; no LANL costs are included.

[b]Actual cost was lower than what is shown. Surplus 177.8-m (7-in.) casing, liner hardware, and centralizers from a previous campaign were used in the string. Costs shown include an estimated value of surplus materials.

[c]No LANL logging costs are included.

inspections, mud logging, and the rig operation base rate, which includes all supervision, rentals, fuel, etc.). Not included in the rotary and directional drilling costs are two runs associated with suspected junk in the hole where no actual penetration was made. This "trouble" cost is, however, reflected in the overall cost per meter (ft).

B. Completion Costs

An itemized breakdown of completion costs in Table IV indicates what actual costs could realistically be expected for a deep hot dry rock completion. Actual costs were slightly lower in the completion of EE-2A because of surplus equipment that was used.

X. CONCLUSIONS

The EE-2 plug back and repair of EE-2 and the drilling and completion of EE-2A were completed on schedule and within the optimum cost estimates using primarily standard oil field services and high-temperature-rated equipment. This demonstration and previous EE-3A drilling results show that HDR drilling should no longer be viewed as high risk and overly difficult. With good planning, sufficient lead time to order the proper equipment, and most importantly, excellent rig supervision to assure careful judgments and adjustments to changed conditions, a drilling project in a difficult drilling environment similar to Fenton Hill can be undertaken with moderate risk. However, further research, development, and tests of HDR well technology are suggested. Accomplishments and needs are listed below.

1. Eleven cement slurries were placed without any serious disruptions. Bonding was better than expected, but remedial cementing in the fractured reservoir was just as difficult as cementing in naturally fractured oil field rocks. Cementing procedures were necessarily complicated and involved a great deal of planning. WBHT code runs, numerous laboratory tests, and several field planning meetings were required. This effort would not be practical in many commercial ventures. Sufficient retarding of the cement for safe placement resulted in long WOC times and a misleading CBL for perforating, and it precluded completion of the cementing work as planned. Improved retarders with more time dependence and less temperature dependence are needed to simplify high-temperature cementing.

2. Packer, retainer, and perforating operations were nearly perfect, but problems can be expected in the future if temperatures exceed 260°C (500°F).

3. Section milling to cut the 12.3-m (60-ft) segment of the production casing was difficult and risky. A redesigned mill modified specifically for crystalline rock and high-temperature drilling fluids might reduce the risk.

4. The drilling itself was the least risky operation. Available drilling fluids, BHA equipment, and bits are suitable for the Fenton Hill environment. Development of a journal-bearing bit with a cutting structure similar to that of a mining bit would extend bit life. Temperatures above 260°C (500°F) would probably cause problems with the drilling motors, drilling fluids, and directional survey and steering tools. Much of the difficulty with the well trajectory, such as higher than planned dogleg severity and unexpected azimuth drift, should be overcome with additional experience in this drilling environment.

5. Reservoir evaluation was less expensive and the results more meaningful than in any previous drilling campaign, partially because of developments in microseismic studies. Improvement of the caliper log and completion of the high-temperature, high-resolution televiewer are needed for future HDR evaluation.

6. The well completion in EE-2A represented a consensus of both hydrothermal and HDR technology. A reasonable attempt, given the economic constraints, was made to prevent additional failures in the underdesigned 244.5-mm (9-5/8-in.) casing. Perhaps this effort will prove successful, but it is premature to make that claim at this time.

7. Hydrothermal completion technology offers no solution to the two major HDR well completion problems: a) how to provide for multiple-completion, high-pressure zone isolation for reservoir stimulation and for long-term injection in a high-temperature crystalline rock at an acceptable cost and risk and b) how to prevent unacceptable loss of reservoir fluids around cemented-in casings and liners? Should the role of the two Phase II wells, EE-2A and EE-3A, be reversed, the present completion will not allow multiple-zone isolation nor backside monitoring that might be desired in an injection well. It is yet to be verified that the problem of flow bypass around cemented-in liners has been solved by total cementing of casings and liners. Possibly the problem is only removed from view.

ACKNOWLEDGMENTS AND DISCLAIMER

The authors gratefully acknowledge the many oil field service companies and equipment suppliers that supported the operations at EE-2A. The supervisors and crew of Big Chief rig #47 contributed greatly to the success of the drilling and completion operations. We especially appreciate the efforts of Vurtis H. McDowell, Tommy Hufford, and Thomas Turner, the independent consultants who supervised the rig, drilling fluids, and cementing operations. The efforts of DS Services' Denver laboratory staff and the Farmington District cementing crews were evident in the successful completion of the complex cementing program. William Turner, an independent consultant, provided invaluable support in preparing specifications for and providing quality assurance of the tie-back casing

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APPENDIX A

SUMMARY OF DAILY OPERATIONS
REMEDIAL CEMENTING, SIDETRACK, REDRILL, AND COMPLETION OF EE-2A

Abbreviations:

bbl - barrel (42 gallons)
BHA - bottom-hole assembly
BOPE - blowout prevention equipment
bbl/min- barrels per minute
BPV - back pressure valve
CBL - cement bond log
CCL - casing collar log
circ - circulate
OWP - Oil Well Perforators
perf - perforate
perfs - perforations
POH - pull (drill pipe) out of hole
RA - radioactive
TD - total depth
TIH - trip (drill pipe) in hole
WOC - wait on cement (to set)

Date	Operations
09/08/87	Change out rams and test BOPE.
09/09/87	Pick up 5-in. drill string, 8-1/2-in. bit, and (9-5/8-in.) casing scraper.
09/11/87	Set Baker 9-5/8-in. K-1 cement retainer at 10,428 ft, inject into formation to cool well.
09/12/87	Pump 33 bbl cement and displace thru retainer to plug off lower wellbore, pull out of retainer and circ, test casing to 1500 psi - leaked off to 1000 psi in 45 seconds, perf 10,221-10,225 ft, pump thru perfs and run temp tools.
09/13/87	Set Baker K-1 retainer at 9889 ft, inject into formation w/rig pumps to cool well and establish rate, pump 36 bbl cement and displace thru perfs to plug off lower casing annulus, no squeeze, pump into formation, attempt second squeeze w/38 bbl cement, pull out of retainer and circ.
09/14/87	Build volume and condition mud, run Kuster temp survey to predict cement setup time.
09/15/87	Build mud system, run CBL, perf 9546-9550 ft, set Baker Retrievamatic cementer at 9166 ft, inject into formation to cool well and establish rate.
09/16/87	Pump 25 bbl cement and displace to fill void behind 9-5/8 in. casing, hold pressure to allow cement to set, POH w/packer.
09/17/87	Drill out cement to 9889 ft, displace drilling mud into hole.
09/18/87	Begin section milling, mill #1 - 9688-9697 ft, circ hole clean, attempt to POH - cutter arms not retracted, circ high vis sweep and attempt to close cutter arms.

Date	Operations
09/19/87	Continue circ and work mill cutter arms, mill 9697-9699 ft, work cutter arms, set slips on drill pipe in spider on annular preventer, break off kelly, run sinker bars on wireline - ram into piston in section mill to retract cutter arms, POH.
09/20/87	Run section mill #2, attempt to break circ - pipe plugged, found mill plugged w/iron, make 8-1/2-in. bit run to retainer at 9889 ft.
09/21/87	Complete bit run, run section mill run #2, mill 9700-9706 ft.
09/22/87	Mill #2 - 9706-9735 ft, attempt to close cutter arms, circ.
09/23/87	Circ and work cutter arms closed, POH.
09/24/87	Mill #3 - 9735-9746 ft, work cutter arms closed.
09/25/87	Run mill #4, re-mill 9739-9746 ft, mill to 9747 ft, make 8-1/2-in. bit run.
09/26/87	Could not work bit past 9755 ft, make junk mill and basket run, drill and wash out 9755-9885 ft.
09/27/87	Displace mud from hole w/water and store, run LANL 3-arm caliper log through window, TIH open ended, rig up cementers and circ to cool well.
09/28/87	Circ, sand back to 9717 ft, wash out sand to 9742 ft, pump 17.4 bbl cement top plug and displace, POH 6 stands, drop wiper plug and circ, POH to 6300 ft, run LANL CCL, TIH to 7100 ft, place high vis pill below 6475 ft, POH, perf 6470-6476 ft, attempt to circ thru perfs - no flow from annulus, TIH w/9-5/8-in. casing scraper.
09/29/87	Make bit and casing scraper run to 6420 ft, set K-1 retainer at 6326 ft, POH w/setting tool, rig up cementers, pump 900 bbl water thru perfs to cool well, pump 481 bbl lightweight cement and 24 bbl tail slurry and displace volume of cement pumped to fill 9-5/8-in. x 13-3/8-in. annulus to surface.
09/30/87	Rig down cementers and WOC, test BOPE.
10/01/87	Run Kuster temp survey and WOC, make 8-1/2-in. bit run to top of cement at 6326 ft, pressure test casing to 1500 psi - no leak off, drill out cement and retainer to 6351 ft.
10/02/87	Drill out retainer, TIH to cement top at 9520 ft, displace water w/mud, circ, pressure test casing to 1500 psi - leaked to 1450 psi in 10 min, drill out cement to 9718 ft.
10/03/87	Drill out cement to 9748 ft, wash out sand to 9875 ft, circ and condition mud, make bit and casing scraper run to 9660 ft.

Date	Operations
10/04/87	Run locator sub and dummy packstock - could not work past 9688 ft, TIH w/bit and roller reamers.
10/05/87	Ream 9631-9768 ft, run locator sub and dummy packstock, could not locate casing stub.
10/06/87	Modify dogs on locator sub, run locator sub and dummy packstock - could not locate casing stub, run section mill #5, ream 9737-9747 ft, mill 9747-9748 ft, circ and work cutter arms in.
10/07/87	Run locator sub and dummy packstock, locate on top of casing stub, run whipstock/packstock assembly.
10/08/87	Orient and set whipstock, make bit run w/BHA #1.

Date	Depth (ft)	Footage Drilled	Redrilling Operations
10/09/87	9725-9727	2	Start to drill off whipstock.
10/10/87	9727-9754	27	Drill off whipstock, survey, run BHA #2.
10/11/87	9754-9779	25	Drill to 9765 ft, survey, repair rig, drill ahead.
10/12/87	9779-9835	56	Drill to 9804 ft, survey, drill to 9735 ft, survey, run BHA #3.
10/13/87	9835-9924	89	Ream 9690-9835 ft, drill to 9892 ft, survey, drill to 9924 ft, survey twice, run drilling motor #1.
10/14/87	9924-9946	22	Orient motor w/steering tool, drill to 9946 ft, bit stuck, work free, POH, inspect drilling tools and found cracked box on drill collar.
10/15/87	9946-9960	14	Run BHA #4, ream 9727-9951 ft, make 5-ft-depth correction, survey twice.
10/16/87	9960-10,051	91	Run drilling motor #2, orient w/steering tool, and drill ahead.
10/17/87	10,051-10,149	98	Run BHA #5, ream 9954-10,051 ft, drill to 10,055 ft, survey, drill to 10,118 ft, survey, drill ahead.
10/18/87	10,149-10,151	2	Survey, POH to 9014 ft, pump-in test held 1650 psi, TIH, circ and condition mud, run drilling motor #3, drill ahead.
10/19/87	10,151-10,151	0	Motor stalling, bit markings showed junk in hole, run gyro survey, make junk mill run.

APPENDIX A (cont)

Date	Depth (ft)	Footage Drilled	Redrilling Operations
10/20/87	10,151-10,281	130	Run drilling motor #4, orient and drill ahead.
10/21/87	10,281-10,358	77	Drill to 10,358 ft w/motor, run BHA #6, ream 10,151-10,164 ft.
10/22/87	10,358-10,478	120	Ream to bottom, survey twice, drill to 10,415 ft, survey, drill to 10,478 ft, survey, POH to 9268 ft, pump-in test held 1420 psi.
10/23/87	10,478-10,620	142	Run drilling motor #5, orient and drill ahead.
10/24/87	10,620-10,689	69	Drill w/motor to 10,689 ft, run BHA #7.
10/25/87	10,689-10,821	132	Ream 10,450-10,689 ft, drill to 10,716 ft, survey twice, drill to 10,811 ft, survey, drill ahead.
10/26/87	10,821-11,009	188	Drill to 10,904 ft, survey, drill to 11,009 ft, survey, clean mud system.
10/27/87	11,009-11,009	0	Displace hole w/water, POH, repair rig, shut in and monitor pressure buildup, inject and flow well, run fluid sampler and LANL temp log.
10/28/87	11,009-11,009	0	Inject 1.5 bbl/min @ 1700 psi while logging, vent down well, run BHA #8, displace hole with mud.
10/29/87	11,009-11,014	5	Circ and condition mud, ream 10,841-11,009 ft, apparent junk in hole, pump high vis pill and fiber sweep, bit showed no iron marks.
10/30/87	11,014-11,039	25	Run BHA #9, drill to 11,021 ft, circ and condition mud, drill to 11,029 ft, pump pressure drop (bit washout), ran BHA #10, drill ahead.
10/31/87	11,039-11,257	218	Drill to 11,103 ft, survey, drill to 11,198 ft, survey, drill to 11,257 ft.
11/01/87	11,257-11,296	39	Drill to 11,292 ft, survey, run BHA #11, ream 11,147-11,292 ft, drill ahead.
11/02/87	11,296-11,409	113	Drill to 11,342 ft, survey, drill to 11,405 ft, survey, drill ahead.
11/03/87	11,409-11,455	46	Run drilling motor #6, drill ahead.
11/04/87	11,455-11,497	42	Drill ahead, run BHA #12.

APPENDIX A (cont)

Date	Depth (ft)	Footage Drilled	Redrilling Operations
11/05/87	11,497-11,661	164	Ream 11,460-11,495 ft, survey, drill to 11,557 ft, survey, drill to 11,652 ft, survey, drill ahead.
11/06/87	11,661-11,715	54	Repair swivel, run BHA #13, drill ahead.
11/07/87	11,715-11,886	171	Drill to 11,728 ft, survey, drill to 11,790 ft, survey, drill to 11,886 ft, survey.
11/08/87	11,886-11,936	50	Drill ahead, inspect drilling tools, run BHA #14.
11/09/87	11,936-12,014	78	Ream 11,919-11,936 ft, drill to 11,996 ft, survey, drill ahead.
11/10/87	12,014-12,161	147	Drill to 12,129 ft, survey, drill ahead.
11/11/87	12,161-12,360	199	Run BHA #15, drill to 12,259 ft, survey, drill to TD, drop multishot survey.
11/12/87	12,360	0	Run bit, pipe plugged, POH and unplug, displace mud from hole and circ.

Date	Completion Operations
11/13/87	Run bit and casing scraper to 9660 ft, install corrosion inhibitor, lay down drill pipe.
11/14/87	Finish laying down drill pipe, store mud and clean pits, run max casing ID log to 9650 ft, set bridge plug and remove BOPE.
11/15/87	Install master valve, remove bridge plug and install lubricator, run LANL gamma/temp and 3-arm caliper logs.
11/16/87	Complete logs, furlough rig till 5/16/88.
05/16/88	Activate rig, run LANL gamma/temp log.
05/17/88	Run LANL gamma/caliper log.
05/18/88	Run LANL acoustic televiewer, set bridge plug, install new 9-5/8-in. casing spool, install BOPE.
05/19/88	Retrieve bridge plug, test BOPE, pick up 3-1/2-in. drill pipe and stand back.
05/20/88	Pick up 8-1/2-in. bit and 5-in. drill pipe.

Date	Completion Operations
05/21/88	Circ and wash to 12,356 ft. TIH w/1500 ft open-ended 3-1/2-in. drill pipe on 5-in drill pipe, tag bottom and circ.
05/22/88	Sand back to 10,740 ft, wash out sand to 10,775 ft.
05/23/88	Pick up and run 1250 ft 7-in. 35 #/ft VAM C-90 casing and liner assy, drop RA frac balls in 9-5/8 x 13-3/8-in. casing annulus and locate with Welex gamma log.
05/24/88	Run Kuster temp survey, circ and record cooldown, hang liner w/bottom at 10,770 ft, circ to cool well, pump 50 bbl cement and displace behind liner, POH w/setting tool, plug 9-5/8 x 13-3/8-in. annulus w/frac balls and gravel, make 8-1/2-in. bit run.
05/25/88	Drill cement 9269-9299 ft, build bridge in casing annulus w/gravel and sepiolite, drop RA frac balls and locate with Welex gamma log, perf 9-5/8-in. casing 885-889 ft, circ thru perfs, pressure test annular bridge to 500 psi.
05/26/88	Make 8-1/2-in. bit run, wash and drill 9269-9499 ft, push 9-5/8-in. wiper plug to 900 ft, pump 70 bbl cement and displace into 9-5/8 x 13-3/8-in. annulus thru perfs - pressure up before complete displacement, shut in, WOC.
05/27/88	Make 8-1/2-in. bit run, drill cement 522-523 ft, run Kuster temp survey to locate cement top, run 8-1/2-in. bit and drill thru cement 523-920 ft.
05/28/88	Tag liner top at 9499 ft and circ, run Welex CBL, perf 9-5/8-in. casing 210-212 ft, circ thru perfs, make 5-3/4-in. bit run and drill out liner.
05/29/88	Clean out liner to 10,608 ft, run 9-5/8-in. casing scraper to liner top, lay down 5-in. drill pipe.
05/30/88	Pick up fluted mill and 3-1/2-in. drill pipe.
05/31/88	Mill out tie-back receptacle, remove 11-in. BOPE.
06/01/88	Pick up tie-back stem and run 7-in. 32 #/ft NSCC C-95 casing tie back, attempt to sting into tie-back receptacle.
06/02/88	Circ to cool well, pump 223 bbl lightweight cement and 100 bbl tail slurry, displace to cement in tie back, pump water down 9-5/8 x 13-3/8-in. annulus thru perfs at 212 ft and up 7-in. annulus, WOC.
06/03/88	Pump thru perfs, run Kuster temp survey to measure buildup, cement 9-5/8 x 13-3/8-in. and 7 x 9-5/8-in. annuli w/17 bbl slurry, install and test 7-in. BOPE.
06/04/88	Make 5-3/4-in. bit run, drill out cement to 9407 ft.
06/05/88	Pick up new bit and drill out to 9530 ft, pressure test tie-back seal to 4000 psi, drill out cement to 10,749 ft.

Date	Completion Operations
06/06/88	Drill out shoe w/5-3/4-in. flat bottom mill. pressure test liner to 2500 psi, drill out cement to 10,812 ft. wash out sand to 11,592 ft.
06/07/88	Wash out sand to 12,360 ft. circ hole clean, run Kuster temp survey.
06/08/88	Pump into EE-3A with rig pumps to develop flow in EE-2A to increase temp and set cement, run Kuster temp survey, make 5-3/4-in. bit run, tag ledge at 12,186 ft, circ reservoir to heat well.
06/09/88	Run OWP CBL/gamma log, run 5-3/4-in. mill - plugged, POH.
06/10/88	Run 5-3/4-in. mill to TD and circ hole clean.
06/11/88	Clean pits, release rig to standby secured status.
06/13/88	Reactivate rig, run 5-3/4-in. bit to TD and circ.
06/14/88	Lay down 3-1/2-in. drill pipe. run LANL temp log, set bridge plug, remove BOPE.
06/15/88	Replace 7-in. casing spool. install BOPE, retrieve bridge plug, set BPV. remove BOPE. install frac valves. retrieve BPV, pump 1160 bbl water at up to 4120 psi at 12 bbl/min with BJ Titan.
06/16/88	Run Kuster temp survey, set BPV, install 7-in. BOPE, retrieve BPV, run LANL temp log.
06/17/88	Pump 373 bbl water into formation w/rig pumps, run Kuster temp survey, remove BOPE, release rig for demobilization.

APPENDIX B
BOTTOM-HOLE DRILLING ASSEMBLIES USED IN EE-2A DRILLING

BHA No.	Depth Out(ft)	Footage Drilled	Bottom-Hole Assembly	Vertical Deviation (end of run)	Remarks
1	9742	17	Bit #1 (0.8), bit sub w/float (3.0), XO (1.8), 2 jts 5-in. 25.60 #/ft DP (63.4), XO (2.6), 6 ea 6-1/4-in. DCs (174), XO (2.7), 12 jts 5-in. HWDP (377).	12.0	Slick assembly to drill off whipstock.
2	9765	23	Bit #2 (0.8), bit sub w/float (4.0), IBS (3.9), XO (1.8), 2 jts 5-in. 25.60 #/ft X-95 DP (63.4), XO (2.6), 6 ea 6-1/4-in., DCs (174), XO (2.7), 12 jts 5-in. HWDP (377).	13.5	Slick build assembly to drill by whipstock.
3	9835	70	Bit #3 (0.8), bit sub w/float (1.2), 3 pt RR (5.7), 6-1/4-in. NMDC (30.9), 6-1/4-in. DC (28.3), 6 pt RR (8.6), 13 ea 6-1/4-in. DCs (366), XO (2.7), 15 jts 5-in. HWDP (470).	13.5	Slight build assembly.
4	9924	89	Bit #4 (0.8), bit sub w/float (1.2), 3 pt RR (4.3), baffle plate, 6-1/4-in. NMDC (30.9), 6-1/4-in. DC (28.3), 6 pt RR (8.6), 13 ea 6-1/4-in. DCs (366), XO (2.7), 15 jts 5-in. HWDP (470).	14.8	Slight build assembly.
5	9946	22	Bit #5 (0.8), Drilex motor (20.8), float sub (1.2), 1-1/2° bent sub (1.3), orientation sub (2.0), XO (2.7), 1 ea 6-1/2-in. NMDC (30.9), 12 ea 6-1/4-in. DCs (341), XO (2.7), 15 jts 5-in. HWDP (470).	15.0	Stuck on bottom - worked free.
6	9960	14	Bit #rr5 (0.8), bit sub w/float (1.2), 3 pt RR (5.8), baffle plate, 6-1/4-in. NMDC (30.9), 6 pt RR (8.6), 6-1/8-in. DC (28.1), 3 pt RR (5.7), 14 ea 6-1/8-in. DCs (397), XO (2.7), 15 jts 5-in. HWDP (470).	15.0	Hold assembly.
7	10,051	91	Bit #6 (0.8), Drilex motor (20.8), float sub (1.2), 1-1/2° bent sub (1.2), orientation sub (2.0), XO (2.7), 1 ea 6-1/2-in. NMDC (30.9), 15 ea 6-1/4-in. DCs (425), XO (2.7), 15 jts 5-in. HWDP (470).	15.0	Azimuth correction and slight build.
8	10,150	99	Bit #7 (0.8), bit sub w/float (1.2), 3 pt RR (5.3), 6-1/4-in. NMDC (30.9), 6-1/4-in. DC (28.1), 6 pt RR (8.6), 6-1/4-in. DC (28.8), 3 pt RR (5.7), 13 ea 6-1/4-in. DCs (368), XO (2.7), 15 jts 5-in. HWDP (470).	16.5	Slight build assembly.

APPENDIX B (cont)

BHA No.	Depth Out(ft)	Footage Drilled	Bottom-Hole Assembly	Vertical Deviation (end of run)	Remarks
9	10,151	1	Bit #8 (0.8), Drilex motor (23.8), float sub (1.2), 1-1/2° bent sub (0.9), orientation sub (2.0), XO (2.7), 1 ea 6-1/2-in. NMDC (30.9), 15 ea 6-1/4-in. DCs (425), XO (2.7), 15 jts 5-in. HWDP (470).	16.5	Motor stalled-junk in hole. Pulled for mill run.
10	10,358	207	Bit #9 (0.8), Drilex motor (23.8), float sub (1.2), 1-1/2° bent sub (0.9), orientation sub (2.0), XO (2.7), 1 ea 6-1/2-in. NMDC (30.9), 15 ea 6-1/4-in. DCs (425), XO (2.7), 15 jts 5-in. HWDP (470).	18.8	Azimuth correction and build.
11	10,478	120	Bit #10 (0.8), bit sub w/float (1.2), 3 pt RR (5.7), 6-1/2-in. NMDC (31.0), 6-1/4-in. NMDC (30.9), 6 pt RR (8.6), 6-1/4-in. DC (28.1), 3 pt RR (5.7), 10 ea 6-1/4-in. DCs (287), XO (2.7), 15 jts 5-in. HWDP (470).	20.5	Washed out DC -removed from string.
12	10,689	211	Bit #11 (0.8), Drilex motor (23.42), float sub (1.2), 2° bent sub (1.0), orientation sub (2.0), XO (2.7), 2 ea 6-1/2-in. NMDCs (61.8), 11 ea 6-1/4-in. DCs (315), XO (2.7), 15 jts 5-in. HWDP (470).		Lay down DCs. Pick up replacement collars.
13	11,009	320	Bit #12 (0.8), 6 pt RR (9.1), 6-5/8-in. NMDC (27.1), 6 pt RR (8.6), 6-1/2-in. NMDC (31.0), 6-9/16-in. DC (30.6), 3 pt RR (5.7), 8 ea 6-1/2-in. DCs (241), XO (2.7), 18 jts 5-in. HWDP (565).	25.8	Hold assembly.
14	11,014	5	Bit #13 (0.8), 6 pt RR (9.6), 6-1/4-in. DC (8.7), 6 pt RR (9.6), 6-5/8-in. NMDC (27.1), 3 pt RR (4.7), 6-1/2-in. NMDC (31.0), 3 pt RR (5.6), 9 ea 6-1/2-in. DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	25.8	Apparent junk in hole.
15	11,029	15	Bit #rr13 - SAME AS ABOVE.	25.8	No iron marks on bit - reran.
16	11,292	263	Bit #14 (0.8), 6 pt RR (9.6), 6-1/4-in. DC (8.7), 6 pt RR (9.6), baffle plate, 6-5/8-in. NMDC (27.1), 3 pt RR (4.7), 6-1/2-in. NMDC (31.0), 9 ea 6-1/2-in. DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	26.3	Hold assembly.
17	11,409	117	Bit #15 (0.8), bit sub w/float (3.0), baffle plate, 6-5/8-in. NMDC (27.1), 6 pt RR (8.6), 6-1/2-in. NMDC (31.0), 6 pt RR (9.6), 9 ea DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	25.3	Drop assembly.

APPENDIX B (cont)

BHA No.	Depth Out(ft)	Footage Drilled	Bottom-Hole Assembly	Vertical Deviation (end of run)	Remarks
18	11,497	88	Bit #16 (0.8), Drilex motor (23.8), float sub (1.2), 1-1/2° bent sub (1.0), orientation sub (2.0), XO (2.7), 2 ea 6-1/2-in. NMDCs (58.0), 9 ea 6-1/2-in. DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	23.8	Azimuth correction.
19	11,660	163	Bit #17 (0.8), 3 pt RR (5.4), 6-5/8-in. NMDC (27.1), 6 pt RR (8.6), 6-1/2-in. NMDC (31.0), 3 pt RR (4.6), 9 ea DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	24.0	Hold assembly.
20	11,936	276	Bit #18 (0.8), 3 pt RR (5.4), 6-1/4-in. short DC (8.7), 6 pt RR (8.8),6-5/8-in. NMDC (27.1), 6 pt RR (9.6), 6-1/2-in. NMDC (31.0), 9 ea 6-1/2-in. DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	23.3	Hold assembly.
21	12,161	225	Bit #19 (0.8), bit sub (2.9), 6-5/8-in. NMDC (27.1), 6-1/4-in. short DC (8.7), 6 pt RR (8.6), 6-1/2-in. NMDC (31.0), 6-1/2-in. DC (30.6), 3 pt RR (4.6), 8 ea 6-1/2-in. DCs (242), XO (1.7), 18 jts 5-in. HWDP (565).	21.5	Drop assembly.
22	12,360	199	Bit #20 (0.8), 6 pt RR (9.1), baffle plate, 2 ea 6-1/2-in. NMDC (58.0), 3 pt RR (5.7), 3 ea DCs (91.7), 3 pt RR (4.6), 3 ea 6-1/2-in. DCs (91.1), XO (1.7), 18 jts 5-in. HWDP (565).	23.0	Slight drop assembly.

Numbers in (xx) are lengths in feet.

Abbreviations:

XO = crossover sub	HWDP = heavyweight drill pipe	RR = roller reamer
DP = drill pipe	IBS = integral blade stabilizer	NMDC = nonmagnetic drill collar
DC = drill collar	pt = point	#rr = bit number rerun

APPENDIX C

DRILL PIPE HANDLING PROCEDURES FOR EE-2A DRILLING

The following procedures minimize additional wear damage on the 9-5/8-in. casing, fatigue damage, and downhole drill string failures:

1. All drill pipe rotated inside the 9-5/8-in. casing must have "smooth" hardbanding or no hardbanding.

2. Drill pipe protectors (rubbers) will not be used. They decompose at projected circulation temperatures leaving rubber and reinforcing steel straps that foul logging and other wireline operations.

3. A wear bushing will be installed in the 9-5/8-in. casing head during all drilling.

4. Drill pipe specifications are as follows:

	19.50 # - GRD E	25.60 # - X-95
Actual weight	21.34 #/ft	28.62 #/ft
Makeup torque	20,000 ft/lb	32,300 ft/lb
Tool joint (TJ) dimensions	6-3/8-in.x 3-3/4-in.	6-1/2-in.x 3-in.
Tube ID	4.276-in.	4.00-in.
Torsional yield TJ	44,600 ft/lb	62,400 ft/lb
Torsional yield tube	32,230 ft/lb	66,070 ft/lb
Tensile yield TJ	1,128,460 lb	1,619,520 lb
Tensile yield tube (new)	311,400 (395,600)	535,000 (671,520)
Collapse	7070 psi	14,510 psi
Burst	8690 psi	15,200 psi
Slip max load	304,000 lb	450,000 lb

a. Drill pipe and heavyweight pipe have 4-1/2-in. IF connections.

b. Drill collars and reamers have 4-1/2-in. XH connections.

5. Generally the drill string will have about 5300-5700 ft of 19.50 #/ft Grade E on the bottom of the string.

   a. The remaining drill pipe will be 25.60 #/ft X-95.

   b. Maximum pull at surface will be limited to 280,000 lb at the top of the 19.50 #/ft Grade E.

   c. Max surface pull = (25 #/ft) x (length of 25.60 #/ft X-95) + 280,000 lbs + wt of blocks + wt of kelly.

   d. Toolpusher and LANL supervisor are to be consulted before exceeding these limits.

APPENDIX C (cont)

6. The minimum BHA weight for drilling will be 45,000 lb.

7. Four (4) stands of heavyweight will be run above the drill collars.

8. Special hardbanded 25.60 #/ft X-95 drill pipe will be run through the dogleg section from 500-700 ft while drilling.

9. Coarse hardbanded 19.50 #/ft Grade E will be run only in the granite open-hole section.

10. Drill pipe and heavyweight are to be rotated on each trip as follows:

    a. Bottom three (3) stands of 25.60 #/ft are to be rotated on top of string and change "break" on tool joints.

    b. Bottom three (3) stands of 19.50 #/ft Grade E are to be rotated to top of Grade E section and change "break" on tool joint. (Avoid running coarse hardbanding in casing.)

11. Maintain record of total rotating hours on drill pipe and drill collars. (Note daily cumulative in log book.)

12. All BHA components are to be inspected after 150 rotating hours. All drill pipe is to be inspected after 200 rotating hours.

13. Pump pressures are to be monitored for washouts.

14. Corrosion rings will be run in the bottom and top stands of drill pipe.

APPENDIX D

EE-2A SINGLE-SHOT SURVEY DATA

No.	MEAS. DEPTH	CRSE LEN.	DRIFT	VERT. CRSE	TOTAL DEPTH	VERT. SECTION	DRIFT DIR.	DOG SEV.	COURSE COORDS. NORTH	COURSE COORDS. EAST	TOTAL COORDS. NORTH	TOTAL COORDS. EAST	OLD TOTAL COORDS NORTH	OLD TOTAL COORDS EAST
0	9745		12.00		9653.02	250.88	45.5				412.8	-170.8	-1014.67	-1774.26
1	9830	85.0	13.50	82.90	9735.92	269.40	37.0	2.82	14.12	12.28	426.9	-158.5	-1000.55	-1761.98
2	9886	56.0	14.25	54.36	9790.29	282.81	32.0	2.52	11.07	7.59	438.0	-150.9	-989.49	-1754.39
3	9918	32.0	14.75	30.98	9821.27	290.82	29.0	2.81	6.90	4.06	444.9	-146.9	-982.58	-1750.33
4	9954	36.0	15.00	34.79	9856.07	300.04	31.0	1.58	8.00	4.62	452.9	-142.3	-974.58	-1745.71
5	10049	95.0	15.00	91.76	9947.83	324.62	31.0	0.00	21.08	12.66	474.0	-129.6	-953.50	-1733.05
6	10112	63.0	16.00	60.71	10008.54	341.42	38.0	3.36	13.83	9.55	487.8	-120.1	-939.67	-1723.50
7	10144	32.0	16.50	30.72	10039.26	350.34	37.0	1.79	7.10	5.45	494.9	-114.6	-932.57	-1718.05
8	10245	101.0	17.25	96.65	10135.91	379.57	38.0	0.79	23.26	17.85	518.2	-96.8	-909.31	-1700.20
9	10352	107.0	18.75	101.81	10237.73	411.86	52.0	4.27	23.10	23.33	541.3	-73.5	-886.21	-1676.87
10	10409	57.0	19.75	53.81	10291.54	429.36	53.0	1.84	11.44	14.91	552.7	-58.6	-874.77	-1661.96
11	10471	62.0	20.50	58.21	10349.75	449.47	52.0	1.33	12.99	16.92	565.7	-41.6	-861.79	-1645.04
12	10609	138.0	22.25	128.55	10478.30	494.97	63.0	3.16	26.75	42.34	592.5	0.7	-835.03	-1602.69
13	10706	97.0	24.50	89.06	10567.37	526.52	72.0	4.34	14.56	35.51	607.0	36.2	-820.48	-1567.19
14	10800	94.0	25.00	85.36	10652.73	556.88	73.0	0.69	11.83	37.53	618.9	73.7	-808.65	-1529.66
15	10894	94.0	25.50	85.02	10737.75	588.26	70.0	1.46	12.73	38.01	631.6	111.8	-795.92	-1491.64
16	10999	105.0	25.75	94.67	10832.43	624.76	69.0	0.47	15.90	42.53	647.5	154.3	-780.01	-1449.11
17	11075	76.0	26.00	68.38	10900.81	651.59	69.0	0.32	11.89	30.96	659.4	185.2	-768.13	-1418.15
18	11171	96.0	26.25	86.19	10987.00	685.79	69.0	0.26	15.15	39.46	674.5	224.7	-752.98	-1378.68
19	11262	91.0	26.25	81.61	11068.62	718.14	70.0	0.48	14.09	37.70	688.6	262.4	-738.88	-1340.99
20	11338	76.0	26.00	68.23	11136.85	744.51	72.0	1.20	10.90	31.64	699.5	294.0	-727.99	-1309.35
21	11400	62.0	25.25	55.90	11192.75	765.50	71.0	1.39	8.50	25.43	708.0	319.5	-719.48	-1283.92
22	11489	89.0	23.75	81.01	11273.77	796.14	62.0	4.51	14.60	33.79	722.6	353.3	-704.88	-1250.13
23	11551	62.0	23.50	56.80	11330.57	818.03	60.5	1.05	11.95	21.78	734.6	375.0	-692.93	-1228.35
24	11646	95.0	24.00	86.95	11417.53	852.19	59.0	0.82	19.28	33.05	753.8	408.1	-673.66	-1195.31
25	11705	59.0	24.00	53.89	11471.43	873.76	59.0	0.00	12.36	20.57	766.2	428.7	-661.30	-1174.74
26	11767	62.0	23.75	56.69	11528.12	896.41	58.0	0.76	13.11	21.40	779.3	450.1	-648.19	-1153.34
27	11863	96.0	23.75	87.87	11615.99	931.30	59.0	0.41	20.20	32.97	799.5	483.0	-627.99	-1120.37
28	11999	136.0	23.00	124.83	11740.83	979.59	60.0	0.62	27.39	46.49	826.9	529.5	-600.59	-1073.89
29	12126	127.0	21.75	117.43	11858.27	1022.28	62.0	1.15	23.45	42.27	850.4	571.8	-577.14	-1031.62
30	12249	123.0	22.25	114.04	11972.31	1062.97	60.0	0.73	22.34	40.29	872.7	612.1	-554.80	-991.34
TD	12360	111.0	22.25	102.73	12075.04				21.01	36.40	893.7	648.5	-533.79	-954.94

(Projection based on prior survey.)

APPENDIX D (cont)
EE-2A MAGNETIC MULTISHOT DATA

No.	MEAS. DEPTH	CRSE LEN.	DRIFT	VERT. CRSE	TOTAL DEPTH	VERT. SECTION	DRIFT DIR.	DOG SEV.	COURSE COORDS. NORTH	COURSE COORDS. EAST	TOTAL COORDS. NORTH	TOTAL COORDS. EAST	OLD TOTAL COORDS NORTH	OLD TOTAL COORDS EAST
0	9745		12.00		9653.02	250.88	45.5				412.8	-170.8	-1014.67	-1774.26
1	9777	32.0	13.25	31.23	9684.25	257.79	30.0	11.24	5.51	4.21	418.3	-166.6	-1009.16	-1770.05
2	9871	94.0	14.00	91.35	9775.60	279.92	33.0	1.09	18.87	11.58	437.2	-155.0	-990.30	-1758.47
3	9966	95.0	14.25	92.12	9867.73	303.10	32.0	0.36	19.55	12.45	456.8	-142.6	-970.74	-1746.01
4	10060	94.0	14.75	91.01	9958.75	326.54	40.0	2.19	18.98	13.82	475.7	-128.7	-951.76	-1732.19
5	10154	94.0	15.50	90.74	10049.49	350.93	38.0	0.97	19.06	15.42	494.8	-113.3	-932.70	-1716.76
6	10248	94.0	17.00	90.25	10139.74	376.89	45.0	2.62	19.62	17.45	514.4	-95.9	-913.08	-1699.31
7	10343	95.0	18.00	90.60	10230.35	404.44	51.0	2.16	19.06	21.23	533.5	-74.7	-894.02	-1678.08
8	10437	94.0	21.00	88.59	10318.95	434.28	51.0	3.19	19.74	24.38	553.2	-50.3	-874.28	-1653.70
9	10531	94.0	22.00	87.47	10406.42	466.26	58.0	2.92	19.93	28.03	573.2	-22.3	-854.34	-1625.67
10	10626	95.0	22.00	88.11	10494.53	496.97	68.0	3.93	16.10	31.60	589.3	9.3	-838.24	-1594.08
11	10720	94.0	25.00	86.19	10580.73	527.06	71.0	3.43	13.07	35.11	602.3	44.4	-825.18	-1558.96
12	10814	94.0	24.50	85.36	10666.10	558.27	70.0	0.69	13.13	37.10	615.5	81.5	-812.04	-1521.86
13	10909	95.0	25.00	86.27	10752.37	589.82	71.0	0.68	13.27	37.49	628.7	119.0	-798.77	-1484.37
14	11003	94.0	25.25	85.10	10837.48	621.28	71.0	0.26	12.99	37.74	641.7	156.8	-785.78	-1446.64
15	11097	94.0	26.00	84.75	10922.23	653.31	71.0	0.79	13.24	38.44	655.0	195.2	-772.54	-1408.20
16	11191	94.0	26.00	84.48	11006.72	685.56	72.0	0.46	13.07	39.08	668.0	234.3	-759.47	-1369.12
17	11286	95.0	25.75	85.47	11092.19	718.00	71.0	0.52	13.15	39.32	681.2	273.6	-746.31	-1329.81
18	11380	94.0	25.50	84.75	11176.95	749.82	72.0	0.53	12.90	38.55	694.1	312.1	-733.41	-1291.26
19	11474	94.0	23.75	85.47	11262.42	781.78	64.0	4.00	14.56	36.27	708.6	348.4	-718.86	-1254.99
20	11569	95.0	23.25	87.12	11349.55	815.03	59.0	2.16	18.05	33.27	726.7	381.7	-700.81	-1221.72
21	11663	94.0	23.50	86.28	11435.84	848.41	60.0	0.49	18.93	32.13	745.6	413.8	-681.89	-1189.58
22	11757	94.0	24.00	86.03	11521.87	881.99	61.0	0.68	18.64	32.95	764.3	446.8	-663.25	-1156.63
23	11852	95.0	23.75	86.87	11608.75	916.09	60.0	0.50	18.93	33.47	783.2	480.2	-644.31	-1123.17
24	11946	94.0	23.75	86.03	11694.79	949.67	61.0	0.42	18.64	32.95	801.8	513.2	-625.67	-1090.22
25	12040	94.0	21.25	86.83	11781.62	981.57	60.0	2.69	17.70	31.31	819.5	544.5	-607.98	-1058.90
26	12229	189.0	22.25	175.54	11957.17	1043.68	61.0	0.56	34.47	60.96	854.0	605.5	-573.50	-997.95
27	12323	94.0	23.00	86.77	12043.94	1074.80	66.0	2.19	16.10	32.35	870.1	637.8	-557.40	-965.60
28	12346	23.0	23.00	21.17	12065.11	1082.33	66.0	0.00	3.66	8.21	873.8	646.0	-553.75	-957.39
TD	12360	14.0	23.00		12078.01	1086.94	66.0	0.00	2.22	5.00	876.0	651.0		

(Projection based on prior survey.)

APPENDIX E

BIT RECORD, DRILLING PARAMETERS, AND TYPICAL MUD PROPERTIES FOR EE-2A DRILLING

BIT#	MFG	TYPE	JET SIZES 1	2	3	DEPTH OUT	FTGE	HOURS RUN	FT/HR	WEIGHT 1000#	RPM	VERT DEV.	PUMP PRES	PMP SPM	DULL CODE T-B-G
1	SEC	H8J	13	15	15	9742	17	5.25	3.24	6-8	40	13.50	1300	123	5-6-I
2	HTC	HH77	14	15	15	9765	23	9.00	2.56	15	44	13.75	1300	122	4-5-I
3	STC	7GA	12	12	16	9835	70	9.00	7.78	35-40	40	13.50	1500	120	1-4-I
4	STC	7GA	12	12	13	9924	89	8.00	11.13	40-45	45	14.75	1800	120	2-4-1/16
5	STC	7GA	13	13	13	9946	22	0.75	29.33	20-40	MM		1475	96	
RR5	"	"	13	13	13	9960	14	1.00	14.00	40	50	15.00	1700	110	2-4-I
6	HTC	HH77	13	13	13	10051	91	9.50	9.58	20-25	MM		1600	98	4-5-I
7	HTC	HH77	13	13	13	10150	99	8.00	12.38	45	60	16.50	1750	120	5-5-I
8	STC	7GA	13	13	13	10151	1	0.25	4.00	3-4	MM		1750	120	5-2-I
9	STC	7GA	13	13	13	10358	207	16.00	12.94	20-25	MM		1700	98	6-6-I
10	STC	F7	14	14	0	10478	120	8.75	13.71	45	60	20.50	2150	115	2-2-1/16
11	STC	7GA	13	13	13	10689	211	13.00	16.23	20-22	MM		1600	98	2-5-I
12	HTC	HH77	14	14	0	11009	320	26.00	12.31	40	60	25.50	2125	115	8-8-3/8
13	HTC	HH77	14	14	0	11014	5	1.00	5.00						RERAN
RR13	"	"	14	14	0	11029	15	3.00	5.00		60	25.50			WASHOUT
14	STC	F7	14	14	0	11292	263	23.25	11.31	30-40	60	26.25	1950	115	4-2-1/8
15	HTC	HH77	13	13	12	11409	117	14.25	8.21	30-40	60	25.25	1400	115	4-5-I
16	HTC	HH77	13	13	12	11497	88	9.50	9.26	45	MM	23.00	1500	97	4-5-I
17	STC	F7L	13	13	13	11660	170	16.00	10.63	30-40	65	24.00	1600	120	6-4-1/8
18	HTC	ATJ77	11	11	14	11936	276	27.00	10.22	40	60	23.25	1600	120	8-8-3"
19	STC	7GA	12	12	13	12161	225	22.00	10.23	40-45	60	21.50	1550	110	6-7-1/8
20	STC	7GA	12	12	13	12360	199	17.75	11.21	44	60	23.00	1600	110	7-7-1/16
RR9	STC	7GA		OUT		12360	0								

HTC = HUGHES TOOL CO.
SEC = SECURITY TOOL CO.
STC = SMITH TOOL CO.

MM = MUD MOTOR

JET SIZES ARE MEASURED IN 1/32-in. DIAMETER

DULL CODE MEASURES TOOTH AND BEARING WEAR ON A SCALE OF 1-8. GAUGE WEAR IS IN INCHES.

APPENDIX E (cont)

TEMP		MUD WEIGHT		PLAS. VISC.		YIELD POINT		GEL STRENGTH		FUNNEL VISC.		SOLIDS %		LUBRICITY		pH		HOURS CIRC.	BIT#
OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN		
112	80	8.7	8.7	14	14	6	3	1/12	1/7	47	37	3	3	N/A	N/A	10.5	10.5	1:30	1
120	100	8.8	8.8	16	13	7	4	1/18	1/13	42	39	3	3	.24	.26	10.0	9.8	2:40	2
156	149	8.9	8.8	15	14	5	7	2/28	2/24	45	43	3	3	.37	.36	9.8	10.0	3:30	3
142	115	8.8	8.7	12	13	4	6	1/19	1/21	43	42	4	3	.32	.32	10.5	10.5	3:30	4
155	141	8.8	8.8	13	14	8	7	1/13	1/16	47	46	3	3	.32	.32	10.0	10.0	6:00	5
154	130	8.8	8.8	20	20	19	13	1/31	1/26	67	52	3	3	.31	.32	10.0	10.0	3:00	RR5
146	133	8.8	8.8	18	15	12	9	1/25	1/18	74	52	3	3	.31	.32	10.0	10.0	8:00	6
157	128	8.8	8.8	22	22	14	12	1/30	1/23	62	50	3	3	.31	.31	9.5	9.5	8:30	7
149	118	8.9	8.9	22	20	13	11	2/32	2/20	83	47	4	4	.32	.32	9.5	10.0	19:00	9
149	121	8.9	8.9	22	20	7	5	1/23	1/16	76	42	4	4	.36	.34	10.0	10.0	9:30	10
135	120	8.9	9.0	21	20	16	13	2/28	1/21	56	49	5	5	.39	.37	10.0	9.5	16:00	11
151	121	9.0	9.1	28	26	27	18	4/37	3/28	72	52	5	6	.34	.32	9.5	9.5	23:00	12
155	134	8.6	8.6	13	15	7	11	4/28	4/34	47	55	3	3	.36	.36	7.9	9.1	5:30	14
153	128	8.7	8.6	10	11	6	6	4/58	4/42	52	47	3	2	.36	.36	8.8	9.2	4:30	15
170	143	8.8	8.8	7	7	13	11	7/72	4/48	75	52	3	3	.34	.34	9.8	10.0	4:00	16
156	126	8.7	8.6	9	13	4	11	1/23	3/48	38	62	3	2	.36	.35	9.3	9.5	5:30	17
172	126	8.6	8.6	8	10	4	6	3/16	3/33	39	44	2	2	.40	.38	8.0	9.2	34:00	18
152	120	8.6	8.6	8	11	4	11	3/22	4/34	40	50	2	2	.38	.37	9.4	9.8	16:00	19
164	138	8.8	8.7	13	11	13	12	4/51	4/49	52	48	3	3	.36	.38	10.2	10.0	11:30	20

NOTE: THE TIMES LISTED FOR HOURS CIRCULATING ARE FROM THE TIME OF FIRST BREAKING CIRCULATION TO TIME OF MUD REPORT.

APPENDIX F-1
CEMENTING PROCEDURES

SLURRY PROCEDURE No.	DESCRIPTION	REFERENCED FIGURE	PROJECTED TEMPERATURE BHST(a) °C	(°F)	BHCT(b) °C	(°F)	CEMENT VOLUME CALCULATED m^3	(bbl)	PUMPED m^3	(bbl)
Predrilling - September 1987										
1a(c)	Plug 244.5-mm (9-5/8-in.) casing below 3180 m (10,420 ft).	2	210	(410)	149	(300)	8.44	(53.1)	5.25	(33.0)
1b	Plug 244.5-mm (9-5/8-in.) casing annulus from 3165-2810 m (10,380-9225 ft).	3	206	(403)	149	(300)	10.24	(64.4)	11.13	(70.0)
1c	Plug 244.5 mm (9-5/8-in.) casing annulus from 2924-2810 m (9590-9225 ft).	4	198	(388)	149	(300)	3.24	(20.4)	3.97	(25.0)
2	Temporary plug in window cut in 244.5-mm (9-5/8-in.) casing from 2954-2972 m (9688-9748 ft).	6	197	(287)	149	(300)	3.56	(22.4)	2.77	(17.4)
3a	Fill 244.5-mm (9-5/8-in.) casing annulus above 1860 m (6100 ft).	5	127	(260)	113	(235)	77.9	(490)	76.5	(481) (d)
3b	Fill 244.5-mm (9-5/8-in.) casing annulus above 1980 m (6500 ft) with high-strength tail slurry.	5	127	(260)	113	(235)			3.82	(24.0)
Postdrilling - May and June 1988										
4	Cement-in 177.8-mm (7-in.) open-hole liner from 3920-2900 m (10,770-9500 ft).	11	216	(420)	(e)		43.4	(273)	8.11	(51.0)
5	Fill 244.5-mm (9-5/8-in.) casing annulus above 282 m (926 ft).	12	40	(104)	38	(100)	8.76	(55.1)	11.4	(71.5)
6a	Cement-in 177.8-cm (7-in.) tie-back casing from 2900 m (9500 ft) to surface.	13	182	(360)	(f)		44.8	(282)	33.9	(213) (d)
6b	Cement-in 177.8-mm (7-in.) tie-back casing from 2900 m (9500 ft) to surface with high-strength tail slurry.	13	182	(360)	(g)				15.9	(100)
7	Circulate high-strength slurry into 177.8-mm (7-in.) by 244.5-mm (9-5/8-in.) casing annulus and 244.5-mm (9-5/8-in.) by 339.7-cm (13-3/8-in.) casing annulus.	12	25	(77)	25	(77)	2.66	(16.7)	2.7	(17.0)

(a) Bottom-hole static temperature.
(b) Bottom-hole circulating temperature.
(c) Two batch-mixed slurries of 5.5 m^3 were placed.
(d) Downhole volume corrected for projected crushing of Perfalite.
(e) Formulations for 149°C (300°F), 177°C (350°F), and 207°C (405°F) were tested.
(f) Formulations for 149°C (300°F) and 177°C (350°F) were tested.
(g) Formulations for 93°C (200°F), 149°C (300°F), and 177°C (350°F) were tested.

APPENDIX F-2

CEMENT FORMULATIONS

SLURRY PROCEDURE (No.)	CEMENT API CLASS	SILICA FLOUR D66 (%BWOC)(a)	BENTONITE D20 (%BWOC)	DISPERSANT D65 (%BWOC)	RETARDER D28 (%BWOC)	EXTENDER (VARIOUS) (%BWOC)	PERFALITE (PERLITE) By Vol.	MIX WATER (%BWOC)
1a,b,c	H	45	0.75	0.25	0.7	--	--	55.3
2	H	45	0	0.7	0.6	--	--	43.0
3a	G	35	2.0(b)	0.5	0.3	0.44 D75	1:1	101.2
3b	H	45	0.75	0.3	0.2	--	--	55.3
4	H	45	0.75	0.75	1.6	0.80 L10	--	49.0
	Various retarder concentrations tested –				0.6 0.5 0.3			
5	G	45	0	0.25	0	(c)	--	58.1
6a	H	35	1.75	0.75	0.5	--	1:1	82.3
	Various retarder concentrations tested –				0.4 0.35 0.3			
6b	H	45	0.75	0.75	0.5	--	--	49.0
	Various retarder concentrations tested –				0.3			
7	H	45	0	0.25	0	--	--	57.6

(a) BWOC = by weight of cement.

(b) Prehydrated for 48+ hours.

(c) Last 2.7 m^3 (17 bbls) slurry accelerated with 1% calcium chloride.

APPENDIX F-3
CEMENT SLURRY PROPERTIES AND TEST RESULTS

SLURRY	DENSITY		YIELD		MIX	THICKENING TIME				FREE	COMPRESSIVE TESTING						
					TIME	RETARDER	TIME(a)	TEMP		WATER	TIME	TEMP		PRESSURE		STRENGTH	
No.	kg/m^3	(lb/sk)	l/sk	(ft^3/sk)	hours	%BWOC	h:mm	°C	(°F)	ml	hours	°C	(°F)	MPa	(psi)	MPa	(psi)
1a,b,c	1920	(16.0)	44.5	(1.57)	2	0.7	4:13	149	(300)	0(b)	12	177	(350)	34.5	(5000)	22.4	(3250)
					heat-up rate °/min -			3.06	(5.5)		24	''	''	''	''	25.9	(3750)
											48	''	''	''	''	29.3	(4250)
											72	''	''	''	''	29.6	(4300)
											96	''	''	''	''	29.6	(4300)
2	2040	(17.0)	39.6	(1.40)	2	0.6	2:56	149	(300)	N/A	12	177	(350)	34.5	(5000)	32.4	(4700)
					heat-up rate °/min -			3.06	(5.5)		24	''	''	''	''	36.2	(5250)
											48	''	''	''	''	42.7	(6200)
											72	''	''	''	''	43.4	(6300)
											96	''	''	''	''	43.4	(6300)
3a (c)	1530	(12.8)	68.8	(2.43)	1	0.3	4:53			0(b)	12	127	(260)	34.5	(5000)	7.3	(1060)
(d)	1590	(13.3)	66.0	(2.33)	heat-up rate °/min -			2.7	(4.8)		24	''	''	''	''	8.6	(1250)
											48	''	''	''	''	9.1	(1325)
											72	''	''	''	''	9.5	(1375)
											96	''	''	''	''	9.7	(1400)
3b	1920	(16.0)	45.0	(1.59)	2	0.2	2:57			0(b)	12	127	(260)	34.5	(5000)	22.1	(3200)
					2	0.2(e)	2:39				24	''	''	''	''	26.2	(3800)
					heat-up rate °/min -			2.7	(4.8)		48	''	''	''	''	32.1	(4650)
											72	''	''	''	''	35.8	(5200)
											96	''	''	''	''	37.6	(5450)

(a) Time to reach 100 Bc (Bearden unit of consistency), not including designated mixing time, with heat-up rate indicated.
(b) No particle gelling or channeling.
(c) As mixed properties.
(d) Properties after exposure to 31 MPa (4500 psi).
(e) Duplicate test.

APPENDIX F-3 (cont)

SLURRY	DENSITY		YIELD		MIX TIME	THICKENING TIME				FREE WATER	COMPRESSIVE TESTING						
						RETARDER	TIME(a)	TEMP			TIME	TEMP		PRESSURE		STRENGTH	
No.	kg/m^3	(lb/sk)	l/sk	(ft^3/sk)	hours	%BWOC	h:mm	°C	(°F)	ml	hours	°C	(°F)	MPa	(psi)	MPa	(psi)
4	1980	(16.5)	42.8	(1.51)	2.5	1.6(b)	4:10	207	(405)	0(c)	24	216	(420)	20.7	(3000)	83.0	(12035)
											48	''	''	''	''	73.4	(10650)
											72	''	''	''	''	53.4	(7750)
						0.5	2:43	179	(350)	0(c)	24	177	(350)	20.7	(3000)	0	(0)
											36	''	''	''	''	13.1	(1900)
											48	''	''	''	''	30.9	(4475)
						0.3	2:04	149	(300)		(c)						
5	1890	(15.8)	45.9	(1.62)	N/A	N/A	N/A	N/A		N/A	N/A	N/A		N/A		N/A	
6a (d)	1610	(13.4)	60.9	(2.15)	2.5	0.5	4:45	177	(350)	0.2(c)	24	182	(360)	20.7	(3000)	17.6	(2550)
(e)	1680	(14.0)	58.0	(2.05)		0.4	2:28	177	(350)	(f)	48	''	''	''	''	18.6	(2700)
						0.4	7:00	149	(300)	(f)	72	''	''	''	''	20.5	(2975)
						0.35	6:15	149	(300)	(f)	72	129	(265)	20.7	(3000)	No set	
						0.3	2:45	149	(300)	(f)	96	''	''	''	''	10.3	(1500)
					heat-up	rate	°/min -	4.4	(8.0)		120	''	''	''	''	13.4	(1959)
					2.5	0.5	2:02	177	(300)	(f)	288	93	(200)	20.7	(3000)	No set	
					heat-up	rate	°/min -	4.4	(8.0)								
6b	1890	(16.5)	42.2	(1.49)	1.5	0.6	3:20	177	(350)	0.8(g)	24	177	(350)	20.7	(3000)	30.3	(4400)
											48	''	''	''	''	31.9	(4625)
											72	''	''	''	''	31.9	(4625)
						0.35	3:33	149	(300)	0.7(g)	24	149	(300)	20.7	(3000)	33.1	(4800)
											48	''	''	''	''	35.2	(5100)
											72	''	''	''	''	35.2	(5100)
7	1970	(16.4)	42.2	(1.49)	N/A	N/A	N/A	N/A		N/A	N/A	N/A		N/A		N/A	

(a) Time to reach 100 Bc (Bearden unit of consistency), not including designated mixing time, with a 3.06°C/min (5.5°F/min) heat-up rate.
(b) With 0.08% L-10.
(c) No particle gelling or channeling.
(d) As mixed properties.
(e) Properties after exposure to 31 MPa (4500 psi).
(f) No compressive testing performed.
(g) No sedimentation or gellation observed.

APPENDIX F-4
CEMENTING RESULTS

SLURRY PROCEDURE No.	DATE	RESULT OF PLACEMENT	CEMENT BOND LOG DATE	m DEPTH	(ft)	AMPLITUDE	COMMENTS
1a	9/12/87	Cement placed as planned below retainer at 3178 m (10,428 ft). Cement injection pressure 10-14 MPa (1450-2040 psi).	N/A	N/A	N/A	No opportunity for CBL	Cement plug and retainer leaked during pressure test of 244.5-mm (9-5/8-in.) casing. Subsequent injection and production testing indicate that EE-2 was successfully plugged.
1b	9/13/87	Two 5.5 m^3 (35 bbl) slurries pumped thru perforations at 3115-3117m (10,221-10,225 ft).	N/A	3045-3165	(9990-10,380)	Same as above	
			9/15/88	2975-3020	(9760-9900)	80±10%	Bond log run 12/1/87 showed that the 9/15/87 log was misleading or inaccurate.
		First injected at 8-13 MPa (1200-1900 psi) and over-	9/15/88	2940-2975	(9640-9760)	0-80%	
		displaced. Second injected at 10-15 MPa (1500-2200 psi).	9/15/88	2810-2940	(9225-9640)	No bond	
1c	9/16/87	Cement injected thru perforations at 2910-2911m (9546-9550 ft). Slurry injected at 14-17 MPa (2050-2450 psi).	12/1/87	2960-3165	(9710-10,380)	No CBL	
			12/1/87	2920-2960	(9580-9710)	No bond	
			12/1/87	2895-2920	(9500-9580)	80-99%	
			12/1/87	2810-2895	(9225-9500)	No bond	
2	9/28/87	Cement spotted thru drill string using balanced plug technique.	N/A	N/A	N/A	N/A	Good hard cement was drilled out leaving a hard in-gauge cement sheath to set the whipstock in.
3a,b	9/29/87	Cement circulated thru perforations at 1972-1974 m	12/1/87	1975-1985	(6480-6520)	50%	Gap between 1984 and 1987 cement.
		(6740-6776 ft). Displaced w/1140 kg/m^3 (9.5 lb/gal) mud.	12/1/87	1650-1975	(5420-6480)	90-100%	Top of high-strength cement at 1860 m (6100 ft).
		Final pump pressure 1.3 MPa	12/1/87	1585-1650	(5200-5420)	30-99%	
		(190 psi). No circulation of	12/1/87	1160-1585	(3800-5200)	70-99%	
		water or cement during	12/1/87	760-1160	(2500-3800)	90-100%	
		cooling and cement placement.	12/1/87	735- 760	(2410-2500)	0-100%	Top of cement.

APPENDIX F-4 (cont)

SLURRY PROCEDURE No.	DATE	RESULT OF PLACEMENT	CEMENT BOND LOG DATE	m DEPTH	(ft)	AMPLITUDE	COMMENTS
4	5/23/88	Displaced with 6.4 m^3 (40 bbl) of 1940 kg/m^3 (16.2 lb/gal) mud followed by water. Pressured up to 18.6 MPa (2700 psi) and broke back as lead slurry hit top of window in 244.5-mm (9-5/8-in.) casing and again at top of liner.	6/9/88	3245-3285	(10,640-10,770)	N/A	Logging tool set down and hung up at 3243 m (10,640 ft).
			6/9/88	2895-3245	(9500-10,640)	95-100%	
5	5/26/88	Circulate with full returns thru perforations at 270-271 m (885-889 ft). Pressure increased to 8.6 MPa (1250 psi) 2.2 m^3 (14 bbl) before placement was completed.	5/22/88	270-285	(890-928)	30-50%	Ball sealers and gravel.
				240-270	(790-890)	90-100%	
				200-240	(660-790)	60-100%	
				135-200	(445-660)	30-100%	
				80-135	(255-445)	70-100%	
				65-80	(215-255)	45-90%	Collar at 62.8 m (206 ft).
				0-65	(0-215)	No bond	
6	6/2/88	Full circulation with excess returns followed by two short periods of no returns. Cement circulated on both inner and outer annuli.	6/9/88	2835-2895	(9300-9500)	98-100%	
				2815-2835	(9230-9300)	70-95%	
				2370-2815	(7770-9230)	90-100%	
				2235-2370	(7325-7770)	80-100%	
				2205-2235	(7240-7325)	60-100%	
				1950-2205	(6400-7240)	90-100%	
				1390-1950	(4560-6400)	40-100%	Calculate top of high-
				1040-1390	(3420-4560)	90-100%	strength cement at
				365-1040	(1200-3420)	30-100%	1845-1965 m (6050-6450 ft).
				900-905	(2945-2965)	0-30%	Cement may not have been
				360-900	(1175-2945)	20-100%	hot enough to set up.
7	6/3/88	Reverse circulation with diluted cement returns on inner annulus. Cement became too thick to pump.	6/9/88	50-65	(160-215)		
				0-50	(0-160)		

APPENDIX G

PROCEDURE TO SAND BACK EE-2A FROM 12,360-10,775 ft

1. Run in hole to total depth w/1500 ft of 3-1/2-in. drill pipe on bottom of string. Put red-band joint on bottom of drill pipe

Drill Pipe Size and Grade	Weight (lb/ft)	Length (ft)	Capacity bbl/ft	Volume (bbl)
3-1/2-in. G-105	15.50	1500	0.00658	9.87
5-in. Grade E	19.50	4500	0.01776	79.72
5-in. X-95	25.60	6360	0.01555	98.90
				188.49

2. Circulate at 375 gpm for 1-1/2 hours or until gas is cleared up. Rig up Dowell while circulating. Dowell should have 20 lb/1000 gallon guar gel mixed in storage tanks. Rig up Dowell to Big Chief's 3-in. stand pipe (service line) with drill pipe and from rig pumps to drill pipe. Rig up fresh water supply line to Dowell from rig.

3. Sand plugs are to be pumped in 100-bbl stages. Set back kelly and rig up Dowell pump-in sub. Pump 10 bbl water. Mix and pump 100 bbl sand and gel water with 3 lb/gal sand.

Volumes:

4200 gal x 3 lb/gal =

Weight of sand = $\dfrac{12{,}600 \text{ lb sand}}{107 \text{ lb/ft}^3} = 117.75 \text{ ft}^3$ fill.

Capacity of hole = $\dfrac{117.75 \text{ ft}^3}{0.3941 \text{ ft}^3\text{/ft}} =$ 298 ft of fill.

4. After pumping sand and gel, switch to rig pump and displace with 169 bbl water.

   3.4 gal/stroke = 0.081 bbl/stroke.

   169 bbl/0.081 bbl/stroke = 2086 strokes.

   Displace at 100 spm.

   Knock off Dowell lines on pump-in sub - pull 15 stands - pick up kelly and circulate for 45 min.

5. Set back kelly and run in hole and tag sand. Pick up 15-20 ft and run another plug. Adjust diplacement depending on where sand is tagged.

6. Continue sanding until above 10,775 ft. Wash out sand until top of sand plug is at 10,775 ft.