GL00550

Appendix D

Well Design Plan

Appendix D

WELL DESIGN PLAN

D.1 FORMATION CHARACTERISTICS

D.1.1 Introduction

There is a large amount of information available covering the formation properties at the Salton Sea. Much of the data has been made available through the DOE Salton Sea projects, furnished by the geothermal field developers and compiled under the direction of the Lawrence Livermore Laboratory (LLL). The data obtained and published by LLL included temperature profiles, analyses of cuttings, and well test results. Most of the data available are from depths of less than 5,000 feet; however, the Elmore #1 well was drilled to 7,000 feet and the River Ranch #1 well reached 8,000 feet.

Despite the fact that most of the available well data are for shallower wells, when the static temperature for the wells closest to State 2-14 are plotted, along with the Elmore #1 data, they all extrapolate to about 700°F at 10,000 feet. Figure D-1 shows the comparison.

D.1.2 Rock Types

The sediments in the Salton Trough consist of recent sands, silts, and clays at shallow depths, and the deeper rocks are composed of similar, older sediments that have been metamorphosed as a result of high temperatures and pressures at depth. The metamorphic mineral assemblages include common calcitic and silicic phases that are found in other geothermal resources around the world. The metamorphosed rocks are found in inhomogeneous assemblages common to deltaic sediments. These metamorphic rocks are relatively impermeable and brittle, and have low porosity. The tectonic activity in the Salton Trough has resulted in almost continuous epochs of fracturing, cementation, and refracturing in these brittle rocks. The voids and fractures are saturated with a saline brine.

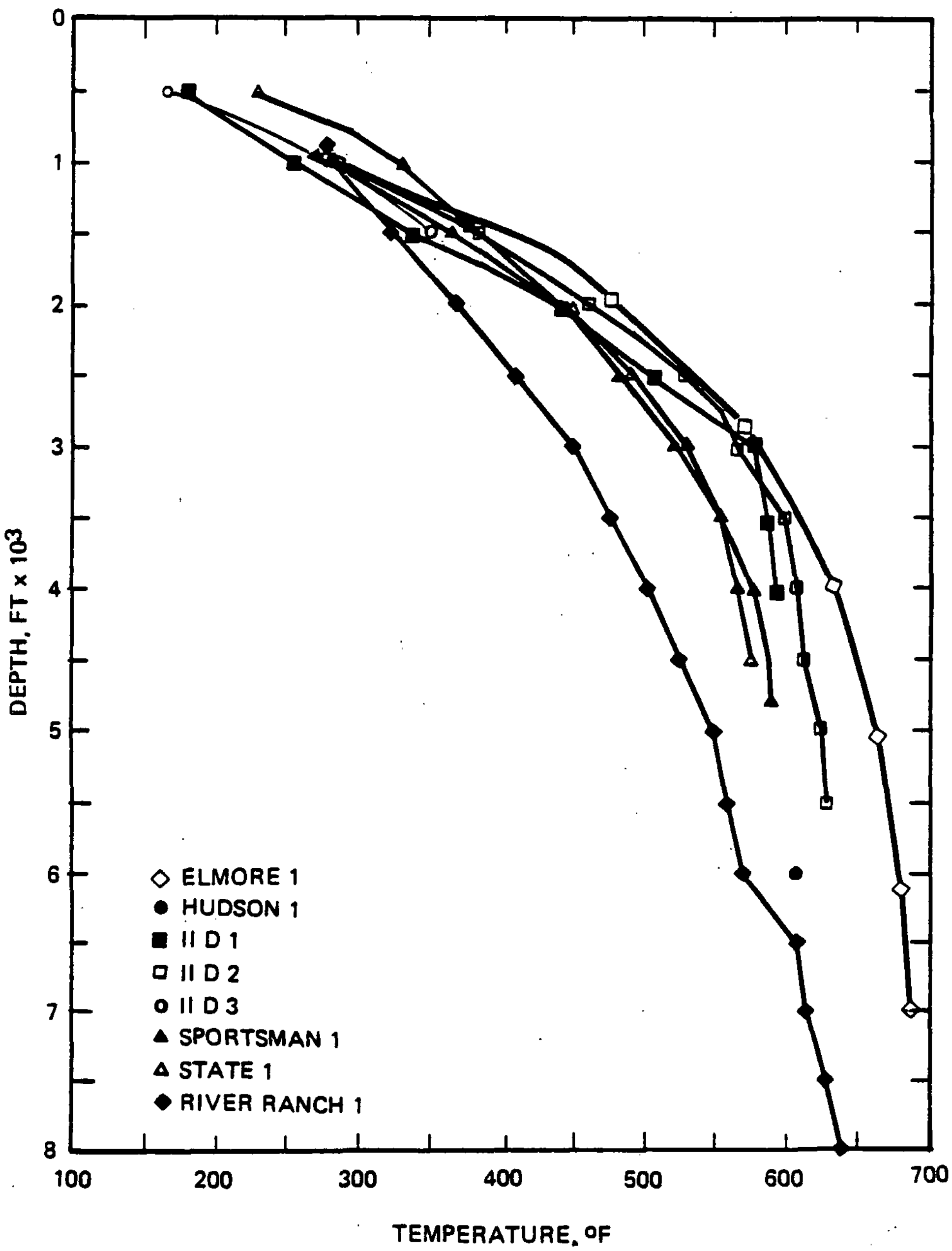

Figure D-1 WELL TEMPERATURE CURVES

The sediments in the stratigraphic column as reported by Austin (1977) are as follows:

Depth, ft	Sediments
0-1,500	Cap rock
1,500-3,000-4,500	Unaltered reservoir rock with high interstitial porosity
3,000-8,100	Hydrothermally altered reservoir rock with relatively low porosity

The cap rock, a partially consolidated clay-silt-evaporite, as described by Tewhey (1977), prevents the upward movement of geothermal fluids and acts as a thermal insulator preventing the loss of heat from the reservoir by radiation or conduction.

The unaltered reservoir rock forms the highly permeable upper reservoir. The brine-induced alteration effects on these rocks are primarily silification and clay mineral reactions which have not affected the porosity and permeability of the reservoir rocks.

The hydrothermally altered reservoir rock is characterized by a gradual transition from clay mineral transformation at the top of the reservoir to replacement of interstitial calcite by epidote in the lower reservoir. The common boundary between the shallower high-permeability reservoir rocks in the upper reservoir and the deeper low-permeability rocks is identified by the first appearance of epidote (Tewhey, 1977). The porosity and permeability have been enhanced in the hydrothermally altered zone by natural fracturing, frequently in the form of micro fractures.

D.1.3 Geothermal Profile

Tables D-1, D-2, and D-3 list key characteristics of the fluid that is most likely to be produced during tests. The maximum temperature and fluid salinity that this well will encounter are by no means certain, and are the subject of current discussion in the geoscientific community.

Table D-1

CHARACTERISTICS OF THE FLUID MOST LIKELY TO BE PRODUCED DURING TESTS

Parameter	Values
Total depth (TD) of well	10,000 ft (3,048 m)
Temperature at TD	Low 360°C (680°F) High 380°C (716°F) Expect 370°C (698°F)
Average production zone temperature	346°C (655°F)
Pressure at TD	4,337 psi (299 bars) (295 atm)
Pressure at average production level (7,000 ft)	3,470 psi
Salinity (average TDS, before flash)	Low 255,000 ppm High 295,000 ppm Expect 265,000 ± 5,000 ppm
Noncondensable gases in total flow	Low 0.05 wt% High 0.50 wt% Expect 0.50 wt%
Composition of noncondensable gases	96 mole% CO_2 4 mole% CH_4, N_2, H_2, H_2S
Average production zone fluid enthalpy	1,277 J/g (549 Btu/lb)

Table D-2

ESTIMATED STEAM FRACTIONS AND SALINITY

Press., psig	Temp., °C(°F)	Fraction of Brine Flashed to Steam	Salinity of Flashed Brine, wt%
Reservoir	346 (655)	0	26.5
550	262 (504)	0.22 ±0.03	34.0
300	231 (448)	0.26 ±0.03	35.8
100	182 (360)	0.33 ±0.03	39.0
0(atm)	108 (227)	0.40 ±0.03	44.2

Table D-3

FORECAST OF CHEMICAL COMPOSITION OF BRINE
AT WELL STATE 2-14

Parameter	Concentration in Reservoir (preflash), ppm
Ca	6,900
Mg	55
Na	73,000
K	21,300
Li	180
SO_4	12
C_1	155,500
B	215
F	15
SiO_2	770
Total CO_2	4800
$H2_S$	16
NH_4	396
Fe (total)	2710
Al	4
Zn	620
Cu	6
Pb	96
Mn	1430
Sr	510
Sn	0.5
Ba	215
Ag	0.9
Rb	110
Cs	17
Br	120
As	12
I	15
Cd	2
Sb	1
Hg	0.005
Au	0.05
TDS	265,000
pH	4 (expect pH about 5 $\pm$ 0.2 after flash to atmospheric pressure and cooling to ambient temperature)

Temperatures, fluid enthalpies, and salinities higher than (or lower than) those listed here may be encountered, particularly at the bottom of the hole. Some estimates of probable ranges are also given in the tables as "Low" and "High" values, but the "High" values could be exceeded. Values labeled "Expect" estimate the average fluid that will be produced and arrive at the wellhead, by flow testing a hole that is open (lined) from about 6,000 feet to 10,000 feet. In the estimate of uncertain parameters, some bias has been given to favoring values for conservative design.

The assumed geothermal profile and hydrostatic profile used in the well design are shown in Figure D-2. The temperature profile is based on measurements made in the Elmore #1 well (Palmer, 1975), which is located approximately 2 miles southwest of the site of the Salton Sea Deep Well (SSDW). The Elmore #1 profile was chosen as the design basis because it exhibits high temperatures at shallow depths and as such represents a worst case condition for the well design.

The maximum temperature measured in Elmore #1 was 680°F at 6,900 feet. The design bottom hole temperature for the SSDW was estimated by extrapolating the temperature gradient in the bottom 2,000 feet of the Elmore #1 well to the anticipated 10,000-foot completion depth of the SSDW. The bottom hole design basis temperature predicted on this basis is 716°F.

D.1.4 Brine Properties

Inspection of chemistry data from the existing wells in the Salton Sea area suggests the salinity of the reservoir fluid is approximately 270,000 ppm (Palmer, 1975). The measured pressures in the existing wells indicate the formation is approximately hydrostatic from the surface.

The salinity and temperature profile, along with brine density data presented by Dittman, was used to calculate the hydrostatic profile. The resulting hydrostatic pressure at 10,000 feet is 4,230 psia.

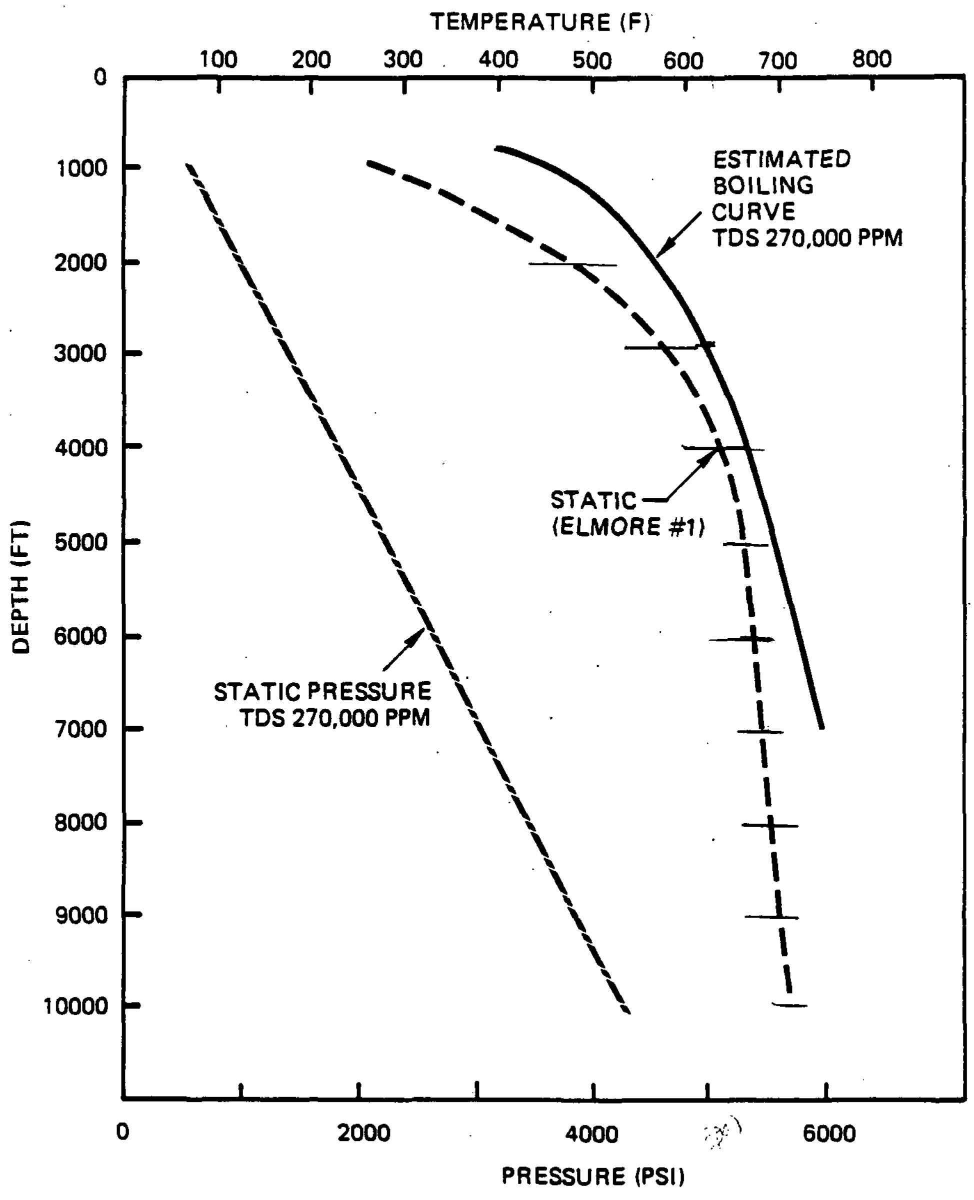

Figure D-2 DEEP WELL DESIGN BASIS
GEOTHERMAL AND HYDROSTATIC PROFILE

Fluid properties were determined using data reported by Haas (1971) for steam-brine mixtures. The saturation pressure for 27 percent salinity brine at 716°F is 2,619 psia. No reliable data could be found in the literature on noncondensable gas content. The effect of gas was assumed to be negligible in estimating the wellbore flowing conditions; however, gas was considered in calculating the design wellhead conditions.

Table D-3 provides a forecast of actual brine composition at the wellhead for State 2-14 provided to Bechtel by GeothermEx, Inc.

D.1.5 Corrosion Potential

The corrosion problems of the brine in the Salton Sea area have been documented. This data shows that corrosion phenomena are very difficult to predict. As a result, the heaviest gauge casing that would pass the required drill bits has been selected.

D.2 DEEP WELL COMPLETION DESIGN

D.2.1 Expected Wellbore Conditions

Materials encountered in the wellbore include 30 to 50 feet of unconsolidated deposits at the surface, consolidated sediments to a depth of approximately 3,000 feet, and metamorphic reservoir rock below. Some zones of CO_2 gas have been reported in the consolidated sediments, generally not above a depth of 700 feet. Anticipated temperatures and pressures at various locations in the hole were previously given in Tables D-1 and D-2.

D.2.2 Wellhead Design

Two criteria were employed in determining the design wellhead condition:

- A steam column in the wellbore at the bottom hole temperature (i.e., 715°F)
- A gas (50:50, H_2S:CO_2) column in the wellbore to the bottom of the cemented casing (6,000 ft) at an assumed average temperature of 500°F

The first criterion results in a maximum design wellhead pressure of 2,200 psia and the second criterion results in a design wellhead pressure of 2,250 psia. Based on these design conditions, the critical wellhead components meeting ANSI 1,500 series service ratings (3,000 PSI) are recommended. This would include, as a minimum, the casing head flange, expansion spool, 3-inch wing valves (double valving), and double 10-inch master valves, as shown in Figure D-3.

D.2.3 Casing Design

The deep well casing design shown in Figure D-4 has been developed to provide a safe and reliable method for drilling and completing the deep well in the difficult environment which has been chosen for the project.

The 30-inch conductor casing will be set to approximately 60 feet. This conductor is necessary to stabilize unconsolidated surface sands and provide a means for returning cuttings to the surface when drilling the subsequent 26-inch hole.

A 20-inch surface casing will be set to provide control of the well when drilling the subsequent protective casing string. In order to provide protection against expected gas kicks from pockets of high pressure carbon dioxide known to exist at depths between 700 feet and 2,000 feet, the 20-inch surface casing will be set to approximately 700 feet. It is possible, however, that shallow high temperature production zones may be encountered before 700 feet. If so, it would be noticed as a sudden increase in mud return temperature. If this occurs the drilling of the 26-inch hole will be terminated and the 20-inch surface casing will be set immediately.

The 17-1/2-inch hole needed for a 13-3/8-inch protective string will be set to 3,000 feet. The selection of depth is made on the assumption that the cap rock extends to no more than 3,000 feet. This assumption is based on evidence from the Elmore #1 and other nearby wells that shows a change from a conductive to convective temperature gradient in the range

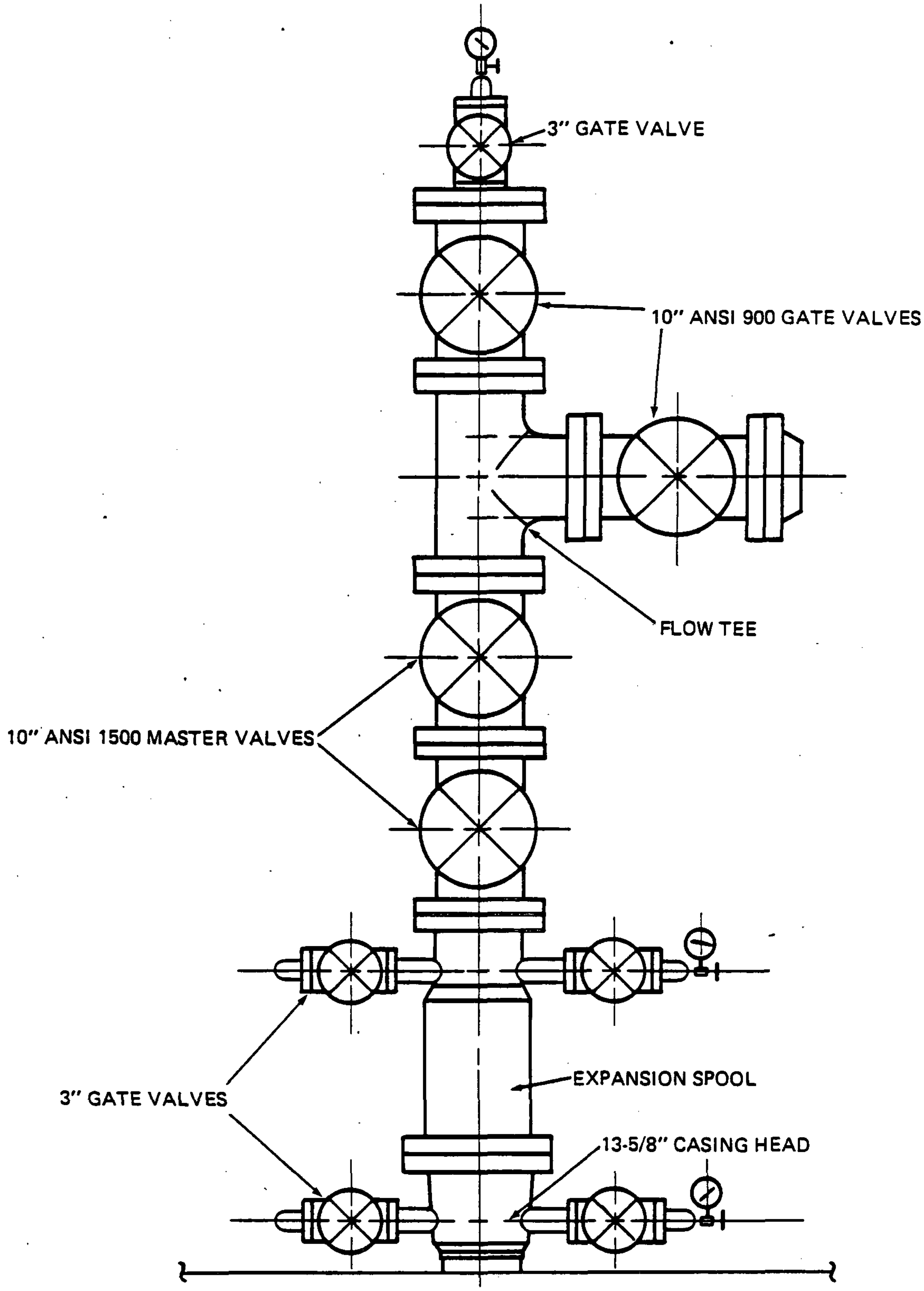

Figure D-3 ANSI 1500 SERIES WELLHEAD FOR DEEP WELL

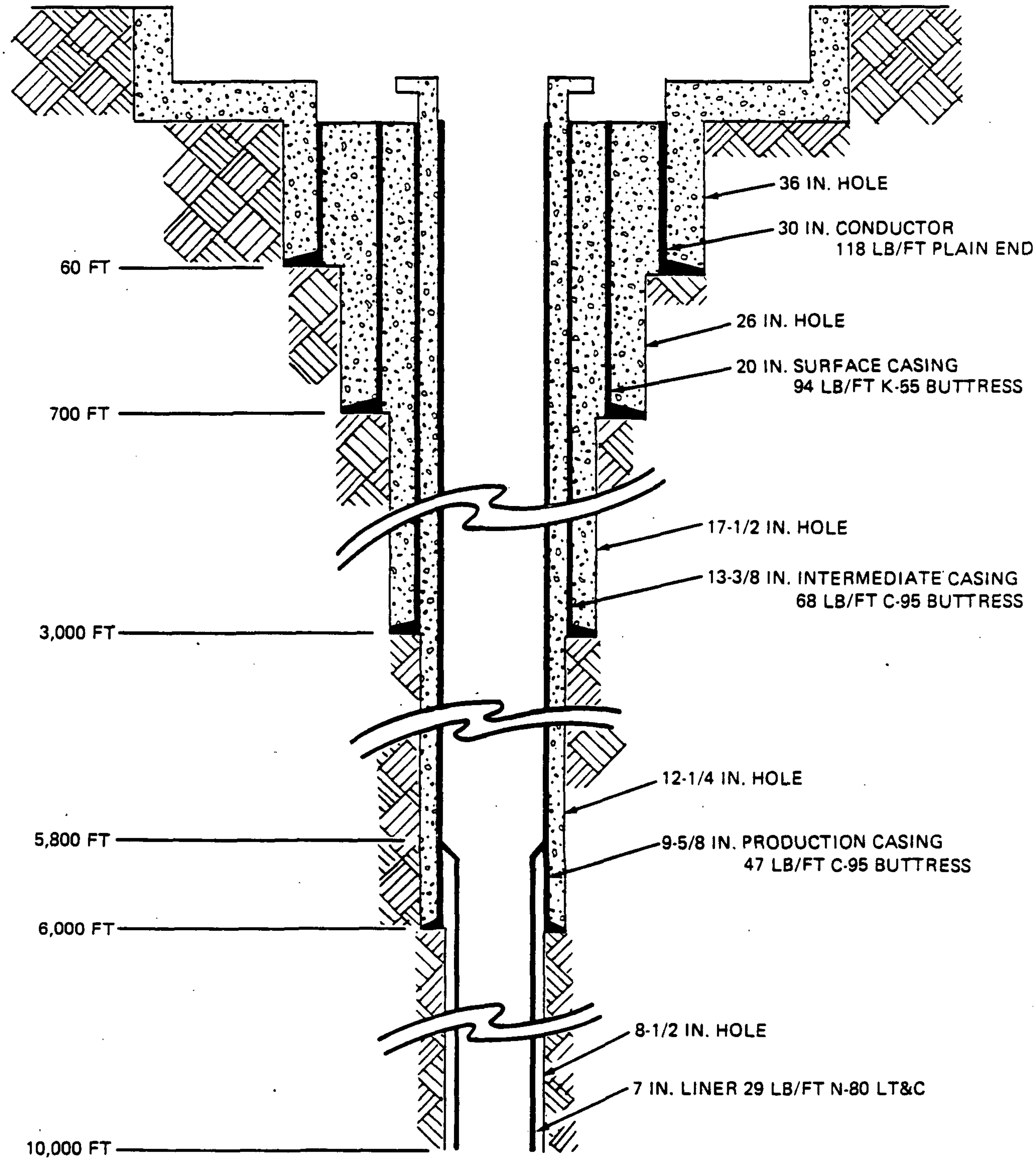

Figure D-4 PRELIMINARY CASING DESIGN FOR THE DEEP WELL

of 2,000 feet. Drilling of this section will proceed with great caution due to the expected presence of gas pockets. In addition to getting past zones of high pressure gas, setting the intermediate string of casing to 3,000 feet is designed to minimize the section of open hole when continuing to drill.

Based on the data from the Elmore #1 well, as shown in Section D.1, the temperature difference between the formation temperature and the boiling point curve closely approach one another in the region between 3,000 feet and 5,000 feet. Spontaneous boiling and discharge could occur if wellbore temperatures are allowed to approach the formation temperature. Setting and cementing the 13-3/8-inch casing to 3,000 feet will ensure control of all of the above problems.

Selection of the 6,000-foot depth for the 9-5/8-inch casing is based on two major factors. The first is the projected bottom hole temperature of 715°F with a corresponding saturation pressure of 2,619 psia. If the well produces from the very bottom hole with no draw-down, the wellbore fluid will begin to flash when the pressure drops below 2,619 psia. Above this point the fluid in the wellbore could be at a pressure higher than he formation fluid. Under these circumstances boiling fluid could escape into the surrounding formation and find its way to the surface. For the formation characteristics in this project that flashing condition occurs above 6,000 feet and thus the choice of a 6,000-foot setting point for the 9-5/8-inch casing.

The additional reason for the 9-5/8-inch casing is the expected wear conditions in the wellbore associated with extensive coring. The repeated interruptions of circulation and regular running of a pipe in and out of the hole could cause deterioration of the borehole wall and promote slipping and/or collapse problems. By minimizing the amount of open hole drilled to the bottom, these risks can be lessened.

Drilling with an 8-1/2-inch bit to the total depth allows the setting of a 7-inch slotted liner for production. It is planned that the slotted liner be hung from approximately 5,800 feet to the bottom of the hole.

The three main conditions that the casing will be subjected to are:

- Emplacement operations
- Well discharging
- Injecting (or circulating) cold fluids

The relevant loading and stress conditions include:

- Collapse. Because of external pressure, the design condition is normally assumed to occur when casing is being run empty into a mud-filled hole. The worst case service condition occurs when the wellbore is hot and empty, such as might occur when stimulating the well by pumping nitrogen through continuous tubing
- Tension. Tension stresses occur owing to string weight, internal pressure, and cooling of the wellbore below the neutral (zero thermal stress) temperature
- Compression. Compression stresses occur when the wellbore is heated above the neutral temperature
- Burst. Stresses due to internal pressure

In most cases, the casing will experience a combined stress condition. For this reason, a biaxial stress analysis was used in determining casing stresses and the maximum energy distortion theory was employed as the failure criterion.

Temperature changes from the casing cement cure temperature in the well may be as high as 500°F. For example, the temperature increase in the near surface between shut-in and flowing or the temperature decrease at 6,000 feet between shut-in and injecting or circulating cold fluids could both approach 500°F. In this case, large thermal stresses will be produced by these temperature changes. They are the determining factor in the casing design. It should be noted that the thermal stress is a function of temperature, elastic modulus, and the expansion coefficient only. Therefore, failure depends on material strength and expansion coefficient rather than on a combination of strength and casing dimensions (e.g., wall thickness).

The thermal stress developed at a given well condition is a function of the cement bonding temperature since this will be the zero stress reference temperature of the casing. The cement bonding temperature is difficult, if not impossible, to predict. For the purpose of this design, it has been assumed that the cement bonding temperature in the near surface would be 200°F, and could be as low as 300°F or as high as 500°F at 6,000 feet.

Another important factor that is particularly relevant to geothermal well design is creep. At high temperatures, steel under stress will undergo significant creep. Creep will relax the stresses in the casing with time. It is extremely difficult to predict what the stress condition may be at a particular time and, more importantly, what it is likely to be when the well condition is abruptly changed, such as when the well is discharged.

There is evidence that corrosion may be severe in this environment; however, the actual severity of the problem in terms of casing serviceability is unpredictable. For this reason, the thickest wall casings that would permit the use of standard 12-1/4-inch and 8-1/2-inch bits without special preparation were arbitrarily selected for the 13-3/8-inch and 9-5/8-inch strings. This approach provides a combination of maximum strength and maximum corrosion protection, since corrosion attack is difficult to accurately predict, especially for the relatively short life needed for the deep well.

The casing material was selected on the basis of the stress calculations under the service conditions outlined in Table D-4. Only API grade carbon steel casing materials were considered. The highest strength considered was C95 (95,000 psi minimum yield), since there is evidence that very high-strength steels are subject to stress cracking in high chloride and hydrogen sulfide environments (Greensip, 1978).

Buttress thread joints were selected for the 20-inch, 13-3/8-inch, and 9-5/8-inch strings. Buttress thread joints offer strengths similar to the pipe body itself and are widely used in geothermal applications.

Table D-4

SUMMARY OF DESIGN OF 9-5/8-INCH, C95, 47-POUND BUTTRESS CASING STRING FOR THE DEEP WELL

Depth, ft	Assumed Cement Bonding Temperature, °F	Operation or Service Condition	Loading or Stress	Design Factor
6,000	500	Wellbore hot, but empty	Collapse	1.54
6,000	-	Running empty into 9.5 lb/gal mud	Collapse	1.52
6,000	300	Flowing at 700°F	Compression	0.96
6,000	300	Injecting at 1,500 psi WHP, 100°F fluid	Biaxial[(a)]	1.85
6,000	500	Injecting at 1,500 psi WHP, 100°F fluid	Biaxial[(a)]	1.06
6,000	500	Wellbore hot, but empty	Collapse	1.54
6,000	500	Flowing at 700°F	Compression	1.96
Surface	200	Running	Weight	4
Surface	200	Injecting at 1,500 psi WHP, 100°F fluid	Biaxial[(b)]	3.5
Surface	200	Flowing with 650°F WHT	Biaxial[(b)]	1.16
6,000	-	Injection after creep relaxation	Biaxial[(a)]	0.87
Surface	-	Flowing after creep relaxation	Biaxial[(b)]	0.66

(a) Internal pressure with axial tension
(b) Internal pressure with axial compression

The inner casing strings could reach temperatures of the order of 700°F when the well is flowing. Published data on the properties of casing at elevated temperatures were reviewed and indicated that yield strength at 700°F is approximately 80 percent of the cold yield for a wide range of casing steels (Snyder, 1980; Nicholson, 1984).

The results of the casing design for the 9-5/8-inch string described above to 6,000 feet are shown in Table D-4. The 13-3/8-inch design (not tabulated) produce similar results since, as explained above, the thermal stresses were similar for both strings and dominated the design. It is important to note that no corrosion allowance was included in the design calculations.

Based on the approach described above, the two selected inner strings are the 9-5/8-inch casing and the 13-3/8-inch casing.

For the 9-5/8-inch casing, the specifications are as follows:

- Specification: API grade C95, 47 lb/ft, buttress
- Wall thickness: 0.472 in.
- Joint area (min.): 10.47 in.^{2}
- Cold yield: 95,000 psi
- Hot yield: 76,000 psi

For the 13-3/8-inch casing, the specifications are as follows:

- Specification: API grade C95, 68 lb/ft, buttress
- Wall thickness: 0.48 in.
- Joint area (min.): 14.46 in.^{2}
- Cold yield: 95,000 psi
- Hot yield: 76,000 psi

The balance of the casing design is as follows:

o	30 in. conductor	0-60 ft, 118 lb/ft, plain end
o	20 in. conductor	0-700 ft, 94 lb/ft, K-55, buttress
o	7-in. slotted liner	5,800-10,000 ft, 29 lb/ft, N80, LT&C

D.2.4 Cementing Program

General. When drilling geothermal wells, highly fractured, incompetent formations with low parting pressures are usually encountered. In the past those conditions, combined with high downhole static temperatures, often exceed the limit of known cement compositions. At the low densities needed to prevent loss circulation thermal cement that would develop useful and stable strength could not be formulated.

Prior to development of high strength microsphere (HSMS) thermal cement one of the best high temperature cementing slurries was Perlite thermal cement. This type of slurry normally has a density of 14 lb/gal, although it can be mixed in weights as low as 12.5 lb/gal. Perlite thermal cements are stable under geothermal conditions, but densities below 12.5 lb/gal are often needed to alleviate loss of circulation and reduce the risk of reaching formation parting pressure. In addition, if a loss of circulation is anticipated, a preflush of FLOWCHEK should be pumped ahead of the thermal cement.

The choice of HOWCO Spherelite (HSMS) cement slurry mixture was made because this lower density cement slurry will permit one stage cementing and this slurry with the Spherelite additive also yields other slurry properties needed for good thermal cement. These include: low fluid loss, zero free water, good rheology and sufficient thickening time. This latest improvement in geothermal thermal cementing has met with a marked increase in the success rate of first stage cementing without loss circulation. Previously, when cementing with Perlite cement, lost circulation would occur in nearly 50 percent of the wells. Since the use of this new thermal cement (on over 100 wells) the success rate has increased to 95 percent. There have been many indications of dramatically improved bonding with this cement. The geothermal/steam wells using this cement are realizing a substantial savings from the reduction in excess cement required.

In conclusion, this cement slurry has a low density, is useful in high temperature applications and meets the high requirements of a thermally stable cement utilizing a low water-to-solids ratio. It has been used successfully in geothermal cementing operations and provides enhanced insulating and physical properties over other cements currently being used. The low water-to-solids ratio enhances bridging properties when water is lost from slurry and provides inherent loss circulation properties. Improved Bond logs are another consistent feature of the cement. The use of Spherelite lowers the density limitation by 3 lb/gal from the lightest thermal cements previously used. This cement can substantially decrease heat loss in the wellbore.

Loss of Circulation Zones. Treatment for loss of circulation must take into account the intended use of the wellbore zone where loss of circulation occurs. If production or samples are required from that zone, the treatment materials must be either removable or degradable. The selection of lost circulation materials, which may include both organic and inorganic materials, must also take into account the drill bit nozzle size and mud rheology. If the problem is not alleviated, a cement plug should be used. The type of cement and additives will depend on the depth, formation properties, and expected temperature.

Cementing of Casing. The cement properties have been estimated in the drilling and casing programs and are listed below. The final design of the cement slurry, the time to wait on cement, the volume of cement, and the cementing operation itself may have to be modified to meet the actual conditions experienced in the well. Casing cementing temperatures recommended are:

- Surface - 200°F
- 3,000 ft - 250°F
- 6,000 ft - 300°F

Casing cement requirements are given in Table D-5.

Table D-5

CASING CEMENT REQUIREMENTS

Casing Size, in.	Cement Requirements
20	1,600 ft^3 API Class G cement mixed with Spherelite (50 lbs per sack of cement) blended with 40% silica flour (use retarder if necessary)
13-3/8	3,000 ft^3 API Class G cement mixed with Spherelite (50 lbs per sack of cement) blended with 40% silica flour, 3% gel, and 0.5% friction reducer. Tail in 500 ft^3 API Class G cement blended with 40% silica flour and 0.5% friction reducer. Retard all cements as required
9-5/8	2,500 ft^3 API Class G cement mixed with Spherelite (50 lbs per sack of cement) blended with 40% silica flour, 3% gel, and 0.5% friction reducer. Tail in 500 ft^3 API Class G cement blended with 40% silica flour and 0.5% friction reducer. Retard all cement as required

D.2.5 BOP and Safety

The selection of proper blowout prevention equipment is particularly important in the drilling of the deep well. In addition to encountering periodic and unexpected high pressures, which is typical of any drilling operation, BOP equipment must also be able to tolerate high temperatures for limited periods of time. As a result the BOP equipment needs to be trimmed for geothermal use and have high temperature rubber sealing elements in order to cope with the high temperatures that could occur during drilling operations.

The blowout prevention equipment required for the various hole depths and anticipated wellbore conditions are described below.

For depths of 0 to 700 feet, the equipment needed is as follows:

- o Hole size 26 in., casing 20 in., 94 lb/ft, K-55 buttress
- o Annular BOP on 30-inch casing, above diverter

For depths of 700 to 3,000 feet, the standard equipment needed, as shown in Figure D-5, is as follows:

- o Hole size 17-1/2 in., casing 13-3/8 in., 68 lb/ft, C-95 butt.
- o 1 ea. 20 in. API Class 3M double hydraulic with pipe and blind rams
- o 1 ea. 20 in. API Class 3M annular blowout preventer
- o CDOG BOPE test required

The additional equipment needed is as follows:

- o 1 ea. 20 in. casing head flange (21-1/4 in.) API 3M
- o 1 ea. 20 in. drilling spool with choke and fill-up lines pitcher nipple (mud flow line)
- o 1 ea. choke manifold setup API 3M or 5M

For depths of 3,000 to 6,000 feet, the standard equipment needed, as shown in Figure D-6, is as follows:

- o Hole size 12-1/4 in., casing 9-5/8 in., 47 lb/ft, C-95 butt
- o 1 ea. 13-5/8 in. API Class 3M double hydraulic BOP with pipe and blind rams
- o Rubber parts to be designed for high temperature
- o 1 ea. 13-5/8 in. API Class 3M annular blowout preventer with high-temperature rubber material
- o Add rotating head 13-5/8 in. 3M, if needed
- o CDOG BOPE test required after installation

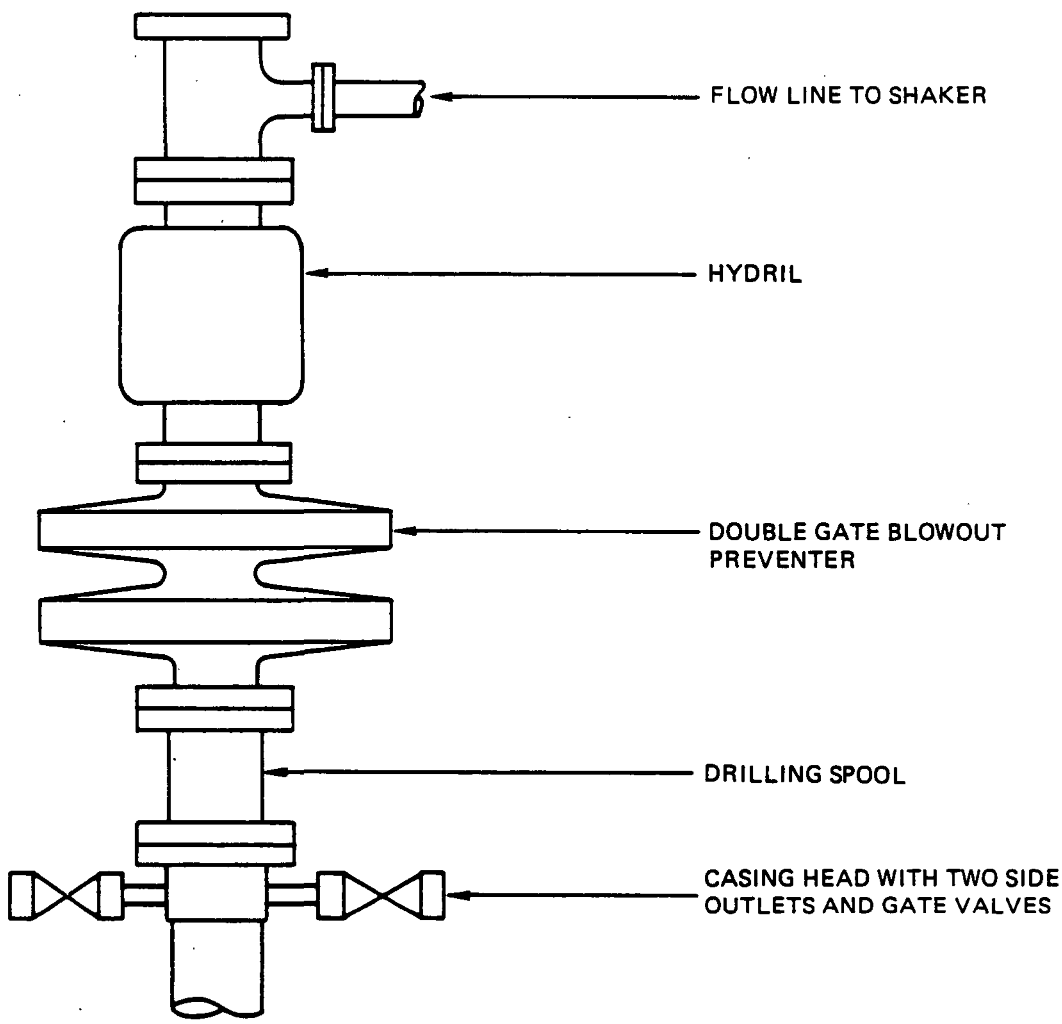

Figure D-5 BOP FOR DRILLING BELOW THE 20-INCH CASING SHOE

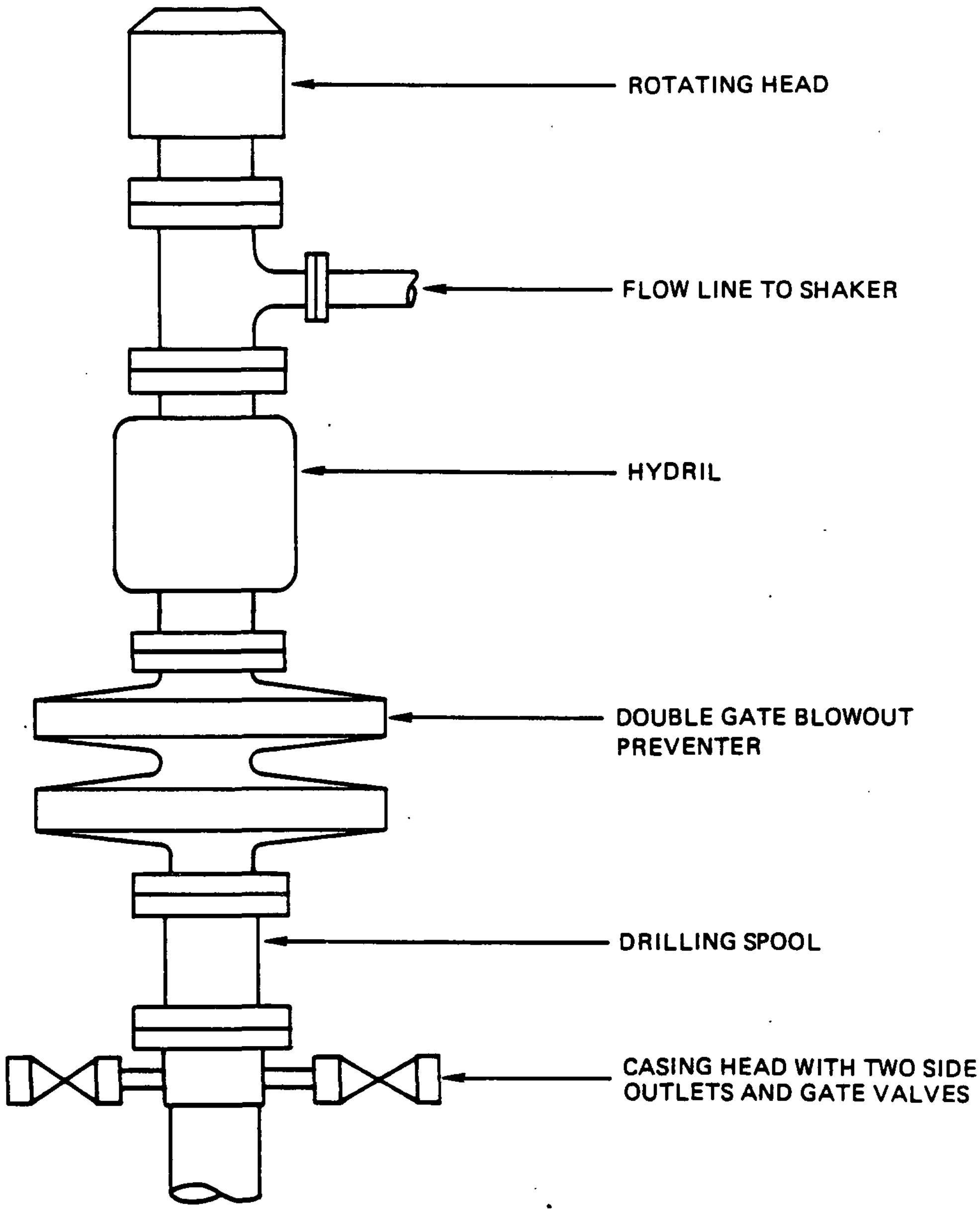

Figure D-6 BOP FOR DRILLING BELOW THE 13-3/8-INCH CASING SHOE

The additional equipment needed is as follows:

- o 1 ea. 13-3/8 in. ANSI 1500 series casing head with 2 ea. 3 in. flanged ANSI 1500 outlets and 4 ea. 3 in. ANSI 1500 slab gate valves (or equivalent)
- o 1 ea. 13-5/8 in. drilling spool with fillup and choke lines ANSI 1500 (13-3/8 in. ANSI 1500 x 13-5/8 in. API 3M)
- o 1 ea. 3 in. flow line to pit (from casing head)
- o 1 ea. pitcher nipple (mud flow line)
- o 1 ea. rotating head class 3M with high-temperature rubber

For depths of 6,000 to 10,000 feet, the standard equipment needed, as shown in Figure D-7, is as follows:

- o Hole size 8-1/2 in. casing 7 in. slotted, 29 lb/ft, N-80 LT&C
- o 1 ea. Class 3M double hydraulic ram type with pipe and blind rams; high-temperature rubber parts required
- o CDOG BOPE test required

The additional equipment needed is as follows:

- o 1 ea. 13-3/8 in. x 9-5/8 in. environmental expansion spool with high-temperature (650°F) rubber sealing materials and 18 in. expansion capabilities
- o 1 ea. 10 in. ANSI 1500 slab gate valve
- o 1 ea. banjo box and rotating head
- o Annular blowout preventer may be added for running 7 in. liner

D.2.6 Coring Approach

The approach to coring incorporates conventional core cutting, using either diamond or polycrystaline bits. Attempts to retrieve core will be limited to 30 feet per attempt, due to the anticipated difficulty with plugging or jamming of highly fractured material in the core barrel. This subject has

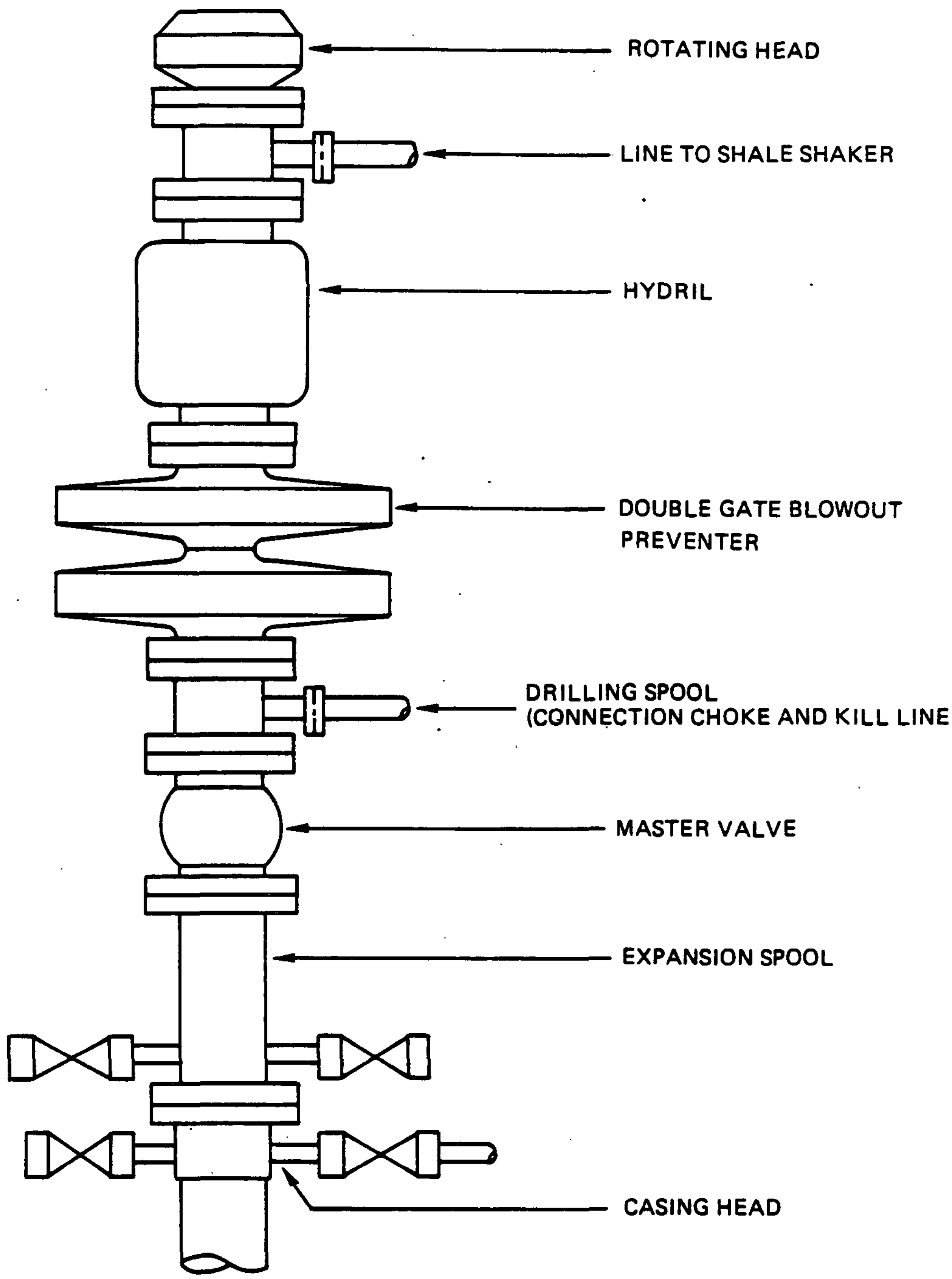

Figure D-7 BOP FOR DRILLING BELOW THE 9-5/8 INCH CASING SHOE

been discussed with geothermal well operators in the Imperial Valley, including Union Geothermal, Chevron Resources, Republic Geothermal and Magma Power Co. The opinion of this group is that coring is difficult, and that coring penetration rates will range from 4 ft/hr to 20 ft/hr, with an average of 5 ft/hr.

Continuous coring with wireline core retrieval, as is frequently practiced in the exploration for minerals, was investigated. This method uses a hole diameter of 3 inches to 5-1/4 inches, and depends on a close tolerance (± 1/4 inch) between the hole and the core bit for directional control. To use this technique in the deep well, it would be necessary to core a section first, and then come back and ream out the hole to the necessary diameter for casing. It is currently unknown if directional control could be maintained after reaming.

Current practice with continuous coring is to allow core bits which become stuck to remain in the hole and then to reduce the size of bit and continue to core through the stuck bit. This does not seem reasonable or safe in the conditions expected for the deep well.

Four companies that are or have been involved with wireline coring were contacted to determine their capabilities and interest. Their response was as follows:

Company	Representative	Comments
Longyear Co.	Gil Speaker, Dick Swayne	Have the capability to core to 10,000 ft, when using a small conventional drilling rig. No experience in large bore geothermal hole. Could possibly do a slim hole, but no coring concept has been developed.
Heath & Sherwood	Bill Hokanson	Has equipment that can be adapted to a large drilling rig for lease. No experience in large bore well.

Company	Representative	Comments
Norton Christensen	Jim Thornton	Had wireline capability for 2 in. cores years ago. No longer active.
Matrix Drilling Products	Jack Power	Interested in adapting 500 ft drill rods and core barrels to drill pipe and power swivel. This would be a first of a kind. No experience in geothermal well.

Based on this analysis, continuous coring with wireline retrieval cannot be judged to be commercially demonstrated in the geothermal environment. As a result, Bechtel and its design subcontractor, Berkeley Group, Inc. recommend the use of conventional coring for the deep well.