PLANNING AND DRILLING OF A GEOTHERMAL WELL.

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ABSTRACT

This paper deals with the planning and drilling of a geothermal well. For this purpose well KJ-22 in the Krafla geothermal field in Iceland is taken as a practical example to discuss both cases. The first three chapters deal with planning, and the fourth chapter with drilling.

In the discussion on well planning, priority is given to the most critical aspects, such as the casing design, the bit programme, the cementing programme, the drilling fluid programme, the blow-out preventer system and the drilling programme. The discussion on well drilling includes a discription of the drilling activities that were carried out at well KJ-22 in the Krafla geothermal field. The analysis throws light on the nature of geothermal well planning and drilling problems.

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1 INTRODUCTION

1.1 Scope of work

This report is the result of a 6 month training which was awarded to the author by the United Nations University Geothermal Training Programme at the National Energy Authority of Iceland (NEA) in Reykjavik and the University of Iceland, for the study of geothermal drilling technology.

The training started with a 6 week lecture course on various aspects of geothermal science and engineering. The training continued with 4 weeks of lectures, mainly on drilling and planning of geothermal wells, followed by 4 weeks of practical training on a geothermal drilling rig used at well KJ-22 at Krafla.

The author was also given an opportunity to participate in a field excursion to the main high- and low-temperature geothermal fields in Iceland, including visits to the various geothermal industries and power generating stations. The author also attended two weeks of lectures mainly on casing design, followed by one week of practical training on small size rigs.

The 6 months were devoted both to preparing this paper and to attending the various lectures which are relevant to geothermal drilling.

It is the author's belief that this training will be valuable in his work after he returns to Ethiopia.

1.2 Well planning

Well planning deals with most practical aspects of drilling and cost of well. It covers also the entire phase of drilling, because good well planning requires all the available information on drilling and a complete knowledge of the drilling activity.

A competent well plan should include decisions on the casing programme, the bit programme, drilling mud programme, cementing and grouting technique, water supply system, site preparation and selection of drilling equipment. With full understanding of this, one can prepare well specifications meeting the objectives; Poor planning may result in extra costs and long waiting for materials, and even in the destruction of the hole and the drilling equipment in case of uncontrollable blow-outs.

As drilling cost outweighs all other exploration expenses, careful planning of minor and major details is needed. No matter how small the savings, they may add up to a very large sum. However, good planning keeps in balance the effort and the saved amount.

In this paper the most critical well planning parameters are discussed, such as casing design, bit programme, cementing programme, blow-out prevention system and drilling programme for well KJ-22.

1.3 The target area

To make a good plan for a well it is important to know the anticipated down-hole conditions. These are mainly the reservoir parameters (temperature and pressure), type of aquifer, geological conditions at depth and the target of the well. In the case of well KJ-22 it is assumed that the main aquifer is fracture dominated. The fractures trend north-south and are inclined 3-5° from the vertical (see Fig. 1.1). The probability of intersecting many fractures with a straight hole drilling method is low. Hence, directional drilling is the best way of intersecting these fractures.

As is shown in Fig. 1.1, well (KJ-22) is sited in order to intersect many fractures.

The depth of the hole is determined by economic and reservoir factors, though the general aim is to cut as many fractures as possible. For this reason, the maximum depth of KJ-22 was planned to be 2,000 m with an inclination of 30 degrees to the vertical in a N73degW direction and a true vertical depth of 1,830m. In this paper for the casing design for the KJ-22, the true vertical depth is superimposed on the boiling curve (Fig 2.1).

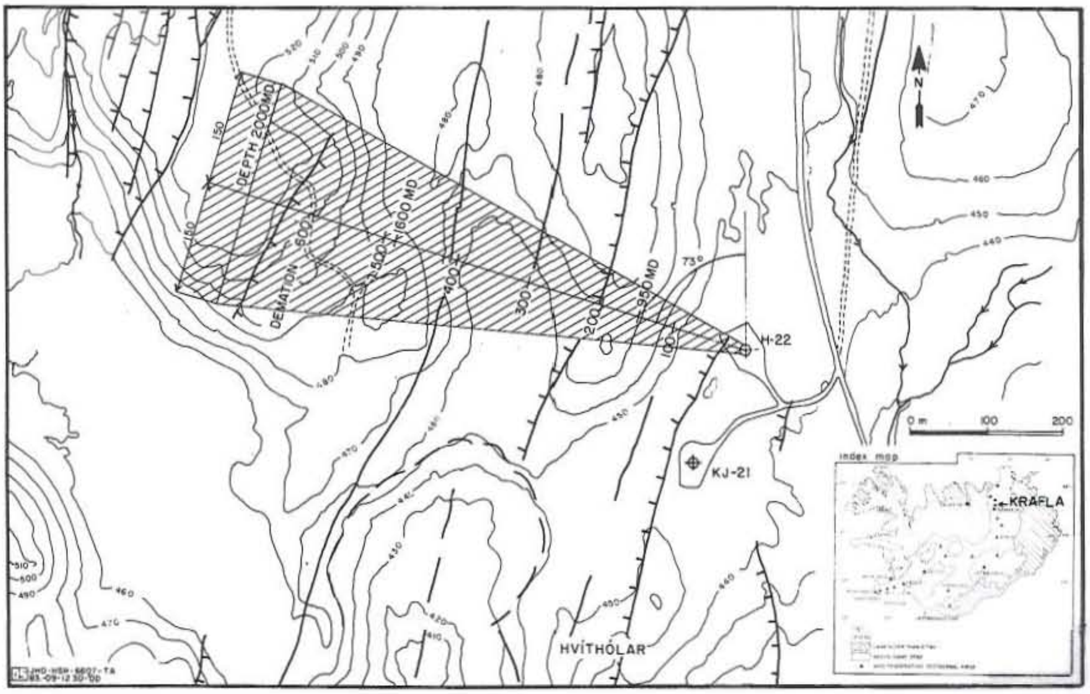

Fig. 1.1 Index map and location map of well KJ-22, also showing the target area and the north-south faults in the vicinity (from RARIK, 1983).

2 GEOTHERMAL CASING DESIGN

2.1 Introduction

The design of the casing is a critical part of geothermal well design. Casing design ensures a longer life of the well, and a successful drilling activity. Casings are designed primarily to satisfy the safety and economic requirements. However, some compromising is needed to balance these two without sacrificing essential safety. Geothermal casings are designed to fulfill requirements during drilling, running and cementing of the casing and for the operating life of the well. The effects of axial thermal stress and internal pressure are analysed for the life of the well. The tensile load, burst and collapse pressure are analysed for the operation conditions during drilling. However, the former one is the most critical for the geothermal well casing design. Due to this fact, geothermal casing depth, grade of steel, type of joint and well head equipment are selected, based on the temperature and pressure anticipated in the formation.

Although the casing depths are primarily determined by minimum safety based on the boiling water condition of the field, there are other criteria which have to be taken into account. These are the starting point of boiling in the well and the formation condition. A solid ground is needed for a casing shoe. In this paper, the casing design for KJ-22 is used to illustrate the calculation procedures. The casing design procedures in question are mainly those described by Dench (1970) and Karlsson (1978). For calculating the burst and the collapse resistance of the pipe, as well as for calulating the joint strength, the API Bull. 5C3 (1974) is used. The API Bull. 5C2 (1975) gives the performance properties of casing and tubing.

Finally, the specifications for KJ-22 and the results found in this paper will be compared.

2.2 Purpose of casing

As was mentioned before, casings are mainly needed for safety and for conducting steam and water. To satisfy these conditions, three strings of casing are worked out in this paper. These are production casing, anchor casing and surface casing.

The purpose of the production casing is to screen off the upper cold aquifer; to provide means of controlling blow-outs; to provide a transmission line for steam/water; and to protect the hole from collapsing.

The purpose of the anchor casing is to provide means of controlling blow-out; to prevent caving of hole during drilling; and to anchor the well-head equipment.

The purpose of the surface casing is to control blow-out; to prevent collapse of the hole; and to prevent corrosion.

2.3 Determination of casing depth

2.3.1 Minimum casing depth

The minimum safe casing depth is determined by the pressure and the temperature expected in the hole. For design of exploration wells, it is generally assumed that the temperature and pressure at depth follow the boiling-point curve.

The maximum expected pressure in the well is obtained by the method given by Karlsson (1978). When a flowing well is shut off the pressure variation in the wellbore ignoring inertia effects, is given by the equation

$$dp/dz = g\rho_m, \qquad (1)$$

where ρ_m = steam/water mixture density, g = acceleration of gravity, z = vertical co-ordinate axis, positive down. The relationship between ρ_m and p for steam is approximated by the equation

$$\rho_m = \alpha \cdot \exp(\beta_p) \qquad (2)$$

in the interval $p_o/2 < po$, where p_o is the well bottom pressure. The factors α (kg/m3) and β (bar^{-1}) are chosen so that equation (2) gives the correct value for $p = p_o$ and $p = p_o/2$. The solution to equation (2) is then

$$\exp(-\beta p) - \exp(-\beta p_o) = g\alpha\beta(H-z) \qquad (3)$$

For safe design the steam/water pressure in the wellbelow the casing must be lower than the overburden pressure of the formation. It is assumed that the density of the formation is uniform, $\rho_f = 2000$ kg/m^3, resulting in a simple procedure for determining the casing depth as illustrated below.

<u>Production casing.</u> The total depth of well KJ-22 is 1830m resulting in a bottom hole temperature of 334°C and a pressure $\rho_o = 135$ bar, assuming saturation conditions at all depths (Figure 2.1).

In order to determine the factors α and β in equation (2) the borehole fluid properties are read from steam tables as follows:

Pressure, bar		135	67,5
Specific volume, m3/kg,	v_f	1.588×10^{-3}	1.343×10^{-3}
	v_g	-	28.505×10^{-3}
Specific enthalpy, kJ/kg	h_f	1551.8	1254.4
	h_g	-	2776.5

Assuming isenthalpic flow the dryness fraction of the steam/water mixture at $p = p_o/2 = 67.5$ bar is

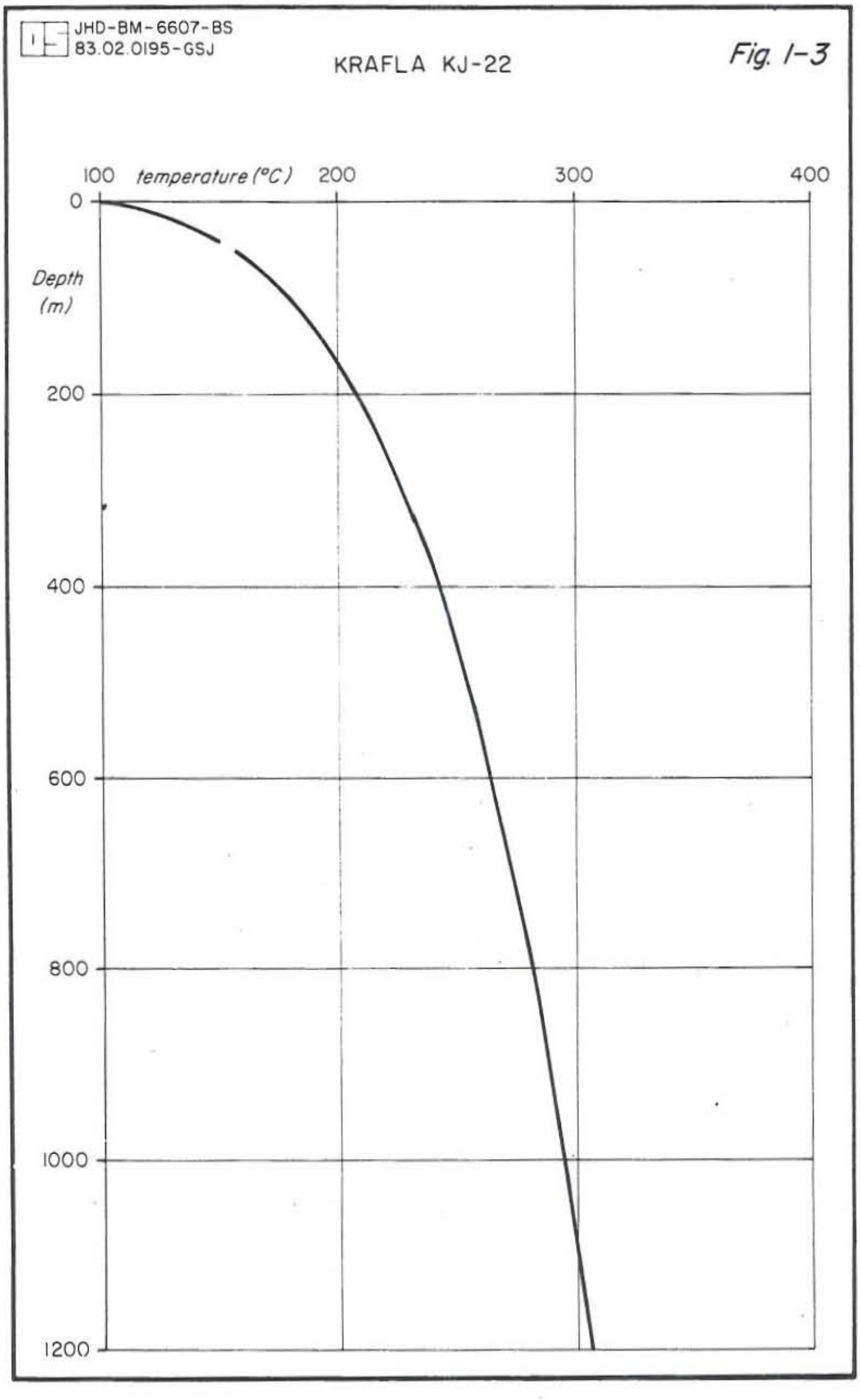

Fig. 2.1 Boiling point curve.

$$x = \left[h_f(p_o) - h_f(p_o/2)\right]/h_{fg}(p_o/2) = 0.1954 \quad (4)$$

The density of the water at p_o = 135 bar and the steam/water mixture at $p_o/2$ = 67,5 bar is then:

$$\rho(p_o) = (1.588x10^{-3})^{-1} = 629.72 \ kg/m3$$

$$\rho(p_o/2) = (1.343x10^{-3} + 0.1954x28.505x10^{-3})^{-1}$$
$$= 144.66 \ kg/m3$$

The value of the factor β is easily determined from the equation

$$\rho(p_o)/p(p_o/2) = \exp(\beta p_o/2) \quad (5)$$

and then the value of α is easily found by equation (2). The results are as follows:

$$\alpha = 33.23 \ kg/m3$$
$$\beta = 0.0218 \ bar^{-1}$$

The minimum casing depth is determined by setting the overburden pressure (p_{ov}) equal to the pressure in the well (p_w):

$$p_{ov} = \rho_f \cdot g \cdot z = p_w \quad (7)$$

where z is the minimum casing depth, (m); ρf is the density of the formation, (assumed = 2000 kg/m3); and g is the acceleration of gravity = 9.81 (m/s^{-2}).

By substitution of (7) into equation (3) the following expression is obtained:

$$\exp(-0.004277z) - \exp(0.0218 \cdot 135)$$
$$= 9.81 \cdot 33.23 \cdot 0.0218x10^{-5}(1830-z)$$

or

$$\exp(-0.004277z) + 7.1065x10^{-5}z = 0.1828 \quad (8)$$

This equation is solved by trial and error as shown in Table 2.1, resulting in a minimum casing depth of 440m.

Anchor casing. The minimum anchor casing depth is determined following the same procedure as with the production casing, but now the design is based on the depth of the production casing, i.e. H = 440m. The corresponding bottom hole pressure, based on saturation conditions, is po = 38 bar. Following the same procedure as before, the following values are found for the factors α and β:

$$\alpha = 10.545 \text{ k/m3}$$
$$\beta = 0.1140 \text{ bar}^{-1}$$

By trial and error calculations as shown in Table 2.2, the minimum anchor casing depth is determined to be 135 m.

Surface casing. The minimum surface casing depth is based on the anchor casing depth of H = 135 m. The corresponding bottom hole pressure, based on saturation conditions, is p_o = 13.0 bar. The values of α and β are

$$\alpha = 3.0048 \text{ kg/m3}; \qquad \beta = 0.4364 \text{ bar}^{-1}$$

By trial and error calculations (Table 2.3) the minimum surface casing depth is found to be 50 m.

2.3.2 Other factors which determine casing depth

Other factors which may affect the determination of casing depths are:

a) Type of reservoir: In a two distinct reservoir system, the depth of the casing decides which reservoir is going to be tapped, b) Chemical deposition is a common problem, especially calcite scaling. It will worsen if boiling takes place inside the liner. In that case, the severity of scaling can be reduced by extending the length of the production casing below the boiling point. c) If caving is a problem below the minimum casing depth, it may be

Table 2.1 Determination of minimum production casing depth

(1) z, m	400	420	430	440
(2) exp(-0.004277z)	0.1807	0.1659	0.1590	0.1523
(3) $7 \times 1065 \cdot 10^{-5} \cdot z$	0.0284	0.0298	0.0306	0.0313
(4) (2)+(3)	0.2091	0.1957	0.1896	0.1836

Table 2.2 Determination of minimum anchor casing depth.

(1) z, m	125	130	132	134	135
(2) exp(-0.02237z)	0.0610	0.0546	0.0522	0.0499	0.0488
(3) $1.1793 \times 10^{-4} z$	0.0147	0.0153	0.0156	0.0158	0.0159
(4) (2) + (3)	0.0757	0.0698	0.0678	0.0657	0.0647

Table 2.3 Determination of minimum surface casing depth

(1) z, m	45	48	49	50
(2) exp(-0.08562z)	0.0212	0.0164	0.0151	0.0138
(3) $1.2864 \times 10^{-4} z$	0.0058	0.0062	0.0063	0.0064
(4) (2) + (3)	0.0270	0.0226	0.0214	0.0202

neccessary to extend the casing. d) If a reservoir investigation reveals that cold water is flowing below the anchor casing, the length of anchor casing has to be extended in order to protect the production casing from a thermal shock.

2.4 Sizes of casings

The most commonly used casing sizes are 18 5/8", 13 3/8", 9 5/8" and 7".

The limiting factors in selecting casing sizes are: a) The desired production rate depending on the reservoir condition. b) Number of casing strings that have to be run. c) Drilling cost. d) Available rig capacity.

2.5 Casing design calculations

Casing failure in geothermal fields is most likely to happen after completion of the well. The most critical casing failure can be traced to thermal expansion (Karlsson, 1978). Casing failure may also be classified in terms of four modes of failure which will be discussed later in this chapter (Dench, 1970).

2.5.1 Effect of temperature on properties

In the ASME Boiler and Pressure Vessel Code (1974), the design stress intensity, S_m is defined as the smaller of the following stress values:

$$S_m = 2\sigma_y/3$$
$$S_m = \sigma_u/3 \qquad (11)$$

where σ_y = reduced yield strength at working temperature, and σ_u = ultimate tensile strength.

At elevated temperature up to 350°C it is assumed that the ultimate tensile strength of the casing is unchanged, whereas the relationship between yield strength and temperature is given by (Karlsson, 1978):

$$\sigma_y/\sigma_{yo} = 1 \qquad T < 80°C$$
$$\sigma_y/\sigma_{yo} = 1 - (T - 80)/640, \qquad T > 80°C \qquad (12)$$

where σ_{yo} is the minimum yield strength in cold conditions, and T is the working temperature, (°C).

2.5.2 Stress caused by internal pressure

Tangential and radial stresses in the pipe wall caused by internal pressure are shown in Figure 2.2. According to the ASME code (1974) the analysis is based on the average value of the principal stresses through the shell thickness. These average values are:

$$\begin{aligned} &\text{Axial stress:} && \sigma_1 = 0 \\ &\text{Tangential stress:} && \sigma_2 = pD_i/2t_{min} \qquad (13) \\ &\text{Radial stress:} && \sigma_3 = p/2 \end{aligned}$$

where p is the internal pressure; D_i is the internal diameter of casing; and t_{min} is the minimum casing wall thickness.

The stress intensity S_p is found as the largest of the three values

$$\begin{aligned} S_{p1} &= |\sigma_1 - \sigma_2| \\ S_{p2} &= |\sigma_2 - \sigma_3| \qquad (14) \\ S_{p3} &= |\sigma_3 - \sigma_1| \end{aligned}$$

which for the present case gives

$$S_p = (D_i/t_{min} + 1)\cdot p/2 \qquad (15)$$

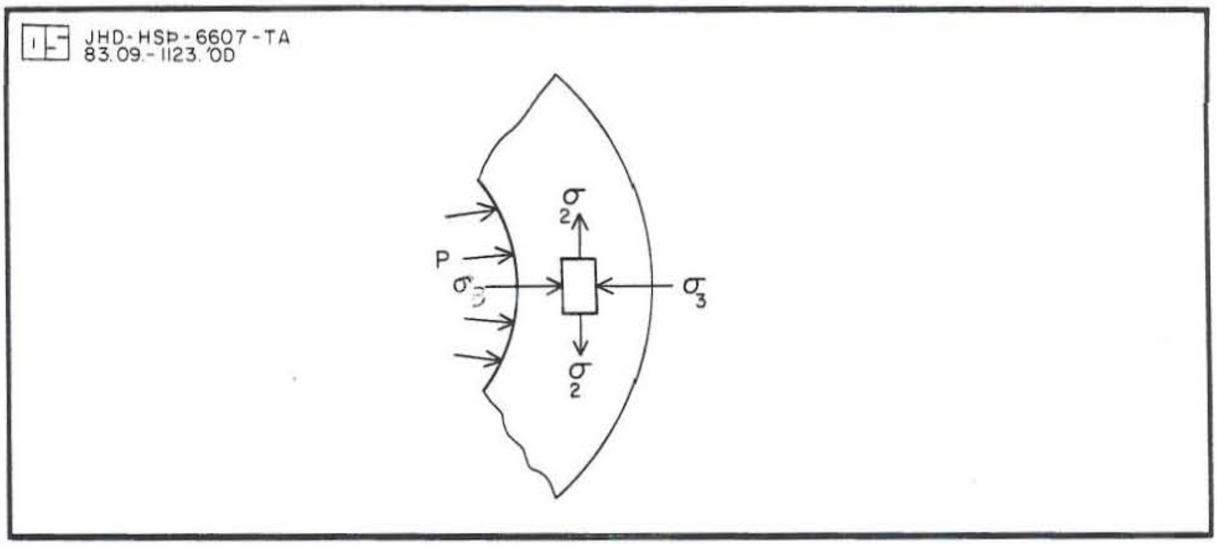

Fig. 2.2 Principal stresses in casing wall due to internal pressure.

For safe design the code specifies $S_p < S_m$ from which condition the minimum wall thickness is found as

$$t_{min} = D_i/(2S_m/p - 1) \qquad (16)$$

Seamless API casing is manufactured within a 12.5% tolerance on wall thickness. In addition a corrosion allowance of 1.6 mm is added to the calculated values of wall thickness. The necessary wall thickness based on internal pressure is therefore

$$t = t_{min}/0.875 + 1.6 \qquad (17)$$

2.5.3 Axial thermal stress

The axial thermal stress caused by heating a pipe which is prevented from expanding is given by the expression

$$\sigma_1 = E\alpha\Delta T \qquad (18)$$

where E = 2.0x105 N/m2, modulus of elasticity for steel;

α = 1.2×10^{-5} m/m °C, thermal expansion coefficient for steel; and ΔT is the temperature rise from initial temperature of pipe, taken as 40°C.

For safe design the ASME Code (1974) specifies

$$\sigma_1 < 3S_m \tag{19}$$

where S_m is design stress intensity at the average temperature.

2.5.4 Evaluation of stresses in casing

In this section the calculated values for stresses caused by internal pressure and thermal loads are tabulated for the various strings of casing. From these tabulations (Tables 2.4. through 2.8) it is possible to identify the limiting stress and temperatures for the casing in question.

All the Tables 2.4 through 2.8 are arranged in the same way. The uppermost shaded area (lines 3 and 4) indicate S_m as the lower value, $2\sigma_y/3$ or $\sigma_u/3$. The second shaded area shows the limiting temperature based on internal pressure and the lowermost shaded area shows the limiting temperature due to thermal loading.

Production casing The following grades and weights of casing are considered for the production casing:

Grade	J-55		C-75		N80
Weight lbs/ft	36.0	40.0	40.0	43.5	43.5
D_i, mm	226.6	224.4	224.4	222.4	222.4
t_{nom}, mm	8.94	10.03	10.03	11.05	11.05
σ_{yo}, N/mm^2	380		517		551
σ_u, N/mm^2	517		655		689

Table 2.4 Stress calculations for production casing - grade J 55

T(tC)	200	220	240	260	280	300	320	340
σ_y(N/mm^2)	308.3	296.5	284.6	272.8	261.0	249.1	237.2	225.4
$\sigma\sigma_y$/3(N/mm^2)	205.5	197.7	189.8	181.9	174.0	166.1	158.2	150.2
σ_u/3,(N/mm^2)	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3
S_m,(N/mm)	172.3	172.3	172.3	172.3	172.3	166.1	158.2	150.2
p,(N/mm^2)	1.554	2.319	3.344	4.692	6.414	7.443	11.285	14.599
S_p(36 lb/ft),(N/mm^2)	29.3	42.1	60.7	85.1	116.3	135.0	204.7	264.8
S_p(40 lb/ft),(N/mm^2)	25.4	36.4	52.5	73.7	100.8	116.9	177.3	229.4
σ_1=2.4AT (N/mm^2)	384.0	432.0	480.0	528.0	576.0	624.0	672.0	720.0
3S_m*(N/mm^2)	517.0	517.0	517.0	517.0	517.0	517.0	517.0	517.0

*The design stress intensity for thermal stress is based on mean temperature

Table 2.5 Stress calculations for production casing - grade C 75

T (tC)	200	220	240	260	280	300	320	340
σ_y(N/mm^2)	419.9	403.7	387.7	371.5	355.3	339.1	323.0	306.9
$\sigma\sigma_y$/3(N/mm^2)	279.9	269.2	258.4	247.7	236.9	226.1	215.4	204.6
σ_u/3,(N/mm^2)	218.3	218.3	218.3	218.3	218.3	218.3	218.3	218.3
S_m,(N/mm^2)	218.3	218.3	218.3	218.3	218.3	218.3	215.4	204.6
p,(N/mm^2)	1.554	2.319	3.344	4.692	6.414	7.443	11.285	14.599
S_p,(40 lb/ft)(N/mm^2)	24.4	36.4	52.5	73.7	100.8	116.9	177.3	229.4
S_p,(43.5 lb/ft)(N/mm^2)	21.7	32.4	46.6	65.4	89.5	103.8	157.4	203.6
σ_1=2.4AT(N/mm^2)	384.0	432.0	480.0	528.0	576.0	624.0	672.0	720.0
3S_m*,(N/mm^2)	655.0	655.0	655.0	655.0	655.0	655.0	655.0	655.0

* The design stress intensity for thermal stress is based on mean temperature

Table 2.6 Stress calculations for production casing - grade N 80

T, (°C)	200	220	240	260	280	300	320	340
σ_y,(N/mm^2)	447.8	430.6	413.4	396.1	378.9	361.7	344.5	327.2
$2\sigma_y/3$,(N/mm^2)	298.5	287.1	275.6	264.1	252.6	241.1	229.7	218.2
$\sigma_u/3$,(N/mm^2)	229.7	229.7	229.7	229.7	229.7	229.7	229.7	229.7
S_m,(N/mm^2)	229.7	229.7	229.7	229.7	229.7	229.7	229.7	218.2
p,(N/mm2)	1.554	2.319	3.344	4.692	6.414	7.443	11.285	14.599
S_p(43.5 lb/ft),(N/mm^2)	21.7	32.4	46.6	65.4	89.5	103.8	157.4	203.6
$\sigma_1=2.4\Delta T$, (N/mm^2)	384.0	432.0	480.0	528.0	576.0	624.0	672.0	720.0
$3S_m$*(N/mm^2)	689.0	689.0	689.0	689.0	689.0	689.0	689.0	689.0

*The design stress intensity for thermal stress is based on mean temperature

Table 2.7 Stress calculations for anchor casing - grade H 40

T, (°C)	200	220	240	260	280	300	320	340
σ_y,(N/mm^2)	223.9	215.3	206.7	198.1	189.5	180.8	172.2	163.6
$2\sigma_y/3$,(N/mm^2)	149.3	143.5	137.8	132.1	126.3	120.6	114.8	109.0
$\sigma_u/3$,(N/mm^2)	138.0	138.0	138.0	138.0	138.0	138.0	138.0	138.0
S_m,(N/mm^2)	138.0	138.0	137.8	132.1	126.3	120.6	114.8	109.0
p,(N/mm2)	1.554	2.319	3.344	4.692	6.414	7.443	11.285	14.599
S_p(48 lb/ft),(N/mm^2)	4.393	6.556	9.454	13.265	18.131	21.042	31.904	41.271
$\sigma_1=2.4\Delta T$,(N/mm^2)	384.0	432.0	480.0	528.0	576.0	624.0	672.0	720.0
$3S_m$*,(N/mm^2)	414.0	414.0	414.0	414.0	414.0	414.0	414.0	414.0

*The design stress intensity for thermal stress is based on mean temperature

Table 2.8 Stress calculations for anchor casing - grade J 55

T,(°C)	200	220	240	260	280	300	320	340
σ_y,(N/mm^2)	308.3	296.5	284.6	272.8	261.0	249.1	237.2	225.4
$2\sigma_y/3$,(N/mm^2)	205.5	197.7	189.8	181.9	174.0	166.1	158.2	150.2
$\sigma_u/3$,(N/mm^2)	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3
S_m,(N/mm^2)	172.3	172.3	172.3	172.3	172.3	166.1	158.2	150.2
p,(N/mm2)	1.554	2.319	3.344	4.692	6.414	7.443	11.285	14.599
S_p(54.5lb/ft),(N/mm^2)	3.684	5.497	7.926	11.122	15.201	17.642	26.749	34.603
S_p(61lb/ft),(N/mm^2)	3.169	4.728	6.817	9.566	13.074	15.173	23.006	29.761
$\sigma_1=2.4\Delta T$	384.0	432.0	480.0	528.0	576.0	624.0	672.0	720.0
$3S_m$*,(N/mm^2)	517.0	517.0	517.0	517.0	517.0	517.0	517.0	517.0

*The design stress intensity for thermal stress is based on mean temperature

Inspection of Tables 2.4 through 2.6 shows that in all cases the axial thermal stress represents the critical loading. By linear interpolation the limiting temperature for the production casing is found to be:

Grade of casing	J 55	C 75	N 80
Limiting temperature, (°C)	255	313	331

<u>Anchor casing</u> The following grades and weights of casing are considered for the production casing:

Grade	H 40	J 55	
Weight, lbs/ft	48.0	54.5	61.0
D_i, mm	323.0	320.4	317.9
t_{nom}, mm	8.38	9.65	10.92
σ_{yo}, N/mm^2	276	380	
σ_u, N/mm^2	414	517	

Inspection of Tables 2.7 and 2.8 shows that the axial thermal stress represents the critical loading as was the case for the production casing. By linear interpolation the limiting temperature for the anchor casing is found to be:

Grade of casing	H 40	J 55
Limiting temperature, (°C)	212	255

<u>2.5.5 Failure mode analysis</u>

Four different casing design criteria were suggested by Dench (1970). The necessary checking will be carried out according to these criteria for all API casings previously analysed in this paper.

<u>First mode of failure</u> If water is trapped in the annulus between two casings under cold conditions (during cementing), it will expand with temperature until the pressure exceeds either the collapse strength of the inner

casing or the burst strength of the outer casing. A good design ensures that the outer casing fails before the inner casing does.

The formulas for calculating the burst and collapse strength of API casing are presented in API Bulletin 5C3 (1974). The minimum collapse pressure is determined by one of four formulas, each applicable for a given range of diameter to thickness ratio. For the grades and thicknesses of the production casing considered in Tables 2.3 through 2.5, two of the these four equations apply. These are the following:

Plastic collapse: $$p_p = \sigma_{yo}(A/(D/t) - B) - C \qquad (20)$$

Transition collapse: $$p_t = \sigma_{yo}(F/(D/t) - G) \qquad (21)$$

where p = minimum collapse pressure; σ_y = the minimum yield strength of pipe; D/t = diameter to thickness ratio, and A,B,C,F,G = formula factors which vary with casing grade.

The values of yield strength and formula factors for the various grades are as follows:

Casing grade	σ_y N/mm2	A	B	C N/mm2	F	G
J 55	380.0	2.990	0.0541	8.3	1.990	0.0360
C 75	517.0	3.060	0.0642	12.4	1.985	0.0417
N 80	551.0	3.070	0.0667	13.5	1.998	0.0434

The formula for calculating the burst strength is also presented in API Bulletin 5C3 (1974):

$$p_i = 0.875 \times 2\sigma_{yo}/(D/t) \qquad (22)$$

where P_i is the minimum internal pressure causing yield of pipe wall and other symbols are the same as before.

The calculated values of bursting pressure of anchor casing and collapse pressure of production casing are presented in Table 2.9.

In order to compare the bursting strength of the anchor casing (p_i) and the collapse strength of the production casing (p_c) a failure factor (FF) is defined as the ratio between the two values.

$$FF = p_c/p_i \qquad (23)$$

A value of the failure factor greater than 1.0 will indicate that the collapse resistance of the production casing is greater than the burst strength of the anchor casing. For added safety a combination of the two casings giving FF > 1.125 will be considered adequate.

The failure factor for the various anchor and production casing combinations is shown in Table 2.10. The shaded region indicates the combinations which satisfy the requirements of FF > 1.125.

<u>Second mode of failure.</u> The second mode of failure is due to the axial compressive stress caused by a change in temperature. If the axial thermal stress exceeds the joint strength, failure may occur in the joint of the casing string.

For the analysis of this mode of failure it will be assumed that each section of casing is firmly acnhored at two points (couplings, Fig. 2.3). Experimental results from New Zealand are used for selecting the types of casing joints (Dench, 1970). In these experiments, the joint efficiency for different kinds of joints, such as round thread joints, buttress thread joints and extreme line joints was established for compressive loading.

Table 2.9.(a) Bursting pressure of 13 3/8" anchor casing

Casing grade	σ_{yo} N/mm2	Weight lb/ft	D/t	pi bar
H-40	276.0	48.0	40.54	118.7
J-55	380.0	54.5	35.20	188.3
		61.0	31.11	213.8

Table 2.9 (b) Collapse pressure of 9 5/8"production casing

Casing grade	Weight lb/ft	D/t	Collapse formula	Collapse pressure, (bar)
J-55	36.0	27.35	Transition	139.3
	40.0	24.37	Plastic	176.5
C-75	40.0	24.37	Transition	205.0
	43.5	22.12	Plastic	258.9
N-80	43.5	22.12	Plastic	262.8

Table 2.10 Failure factors for the various combinations of anchor and production casings.

9 5/8" production casing		13 3/8" anchor casing H-40 48.0 lb/ft	J-55 54.5 lb/ft	J-55 61.0 lb/ft
J-55	36.0 lb/ft	1.17	0.74	0.65
	40.0 lb/ft	1.49	0.94	0.83
C-75	40.0 lb/ft	1.73	1.09	0.96
	43.5 lb/ft	2.18	1.38	1.21
N-80	43.5 lb/ft	2.21	1.40	1.23

The experiments showed that the round thread joint failed after jumping several threads; the buttress thread joint failed due to pipe end bulging, but no such effect was observed for the extreme line joint. The latter is, however, a lower strength joint than the buttress joint because of its smaller critical cross-sectional area outside the last engaged thread (Dench, 1970).

The efficiency of casing joints, defined as the ratio between the joint failure load and the product of pipe cross sectional area and tensile strength of the pipe material, is given in API Bulletin 5C3 (1974) for tension only. The New Zealand experiments indicated that the round thread joints have compression strengths roughly 25% greater than their tensile strengths calculated by the Clinedienst formula used in API Bulletin 5C3 (1974) and tabulated in API Bulletin 5C2 (1975).

The joint efficiency for buttress thread joints in compression is presented in graphical form by Dench (1970) and reproduced here as Figure 2.4. The buttress thread joint strength is given by the relation:

$$P_j = E \cdot \sigma_u \cdot A_p \qquad (24)$$

where P_j = joint strength; E = joint efficiency (Fig. 2.4); σ_u = minimum ultimate strength of the pipe; and A_p = cross-sectional area of the plain end pipe.

The allowable axial compressive stress (σ_c) in the pipe is given by the simple relation:

$$\sigma_c = P_j / A_p = E \cdot \sigma_u \qquad (25)$$

The allowable compression stress calculated for the various grades and weights of casing are presented in Table 2.11. All the values are for buttress thread joints except the first line (H-40a) which is for round thread joints. This is included since the API specifications indicate that the H 40 casing is not available with buttress thread joints.

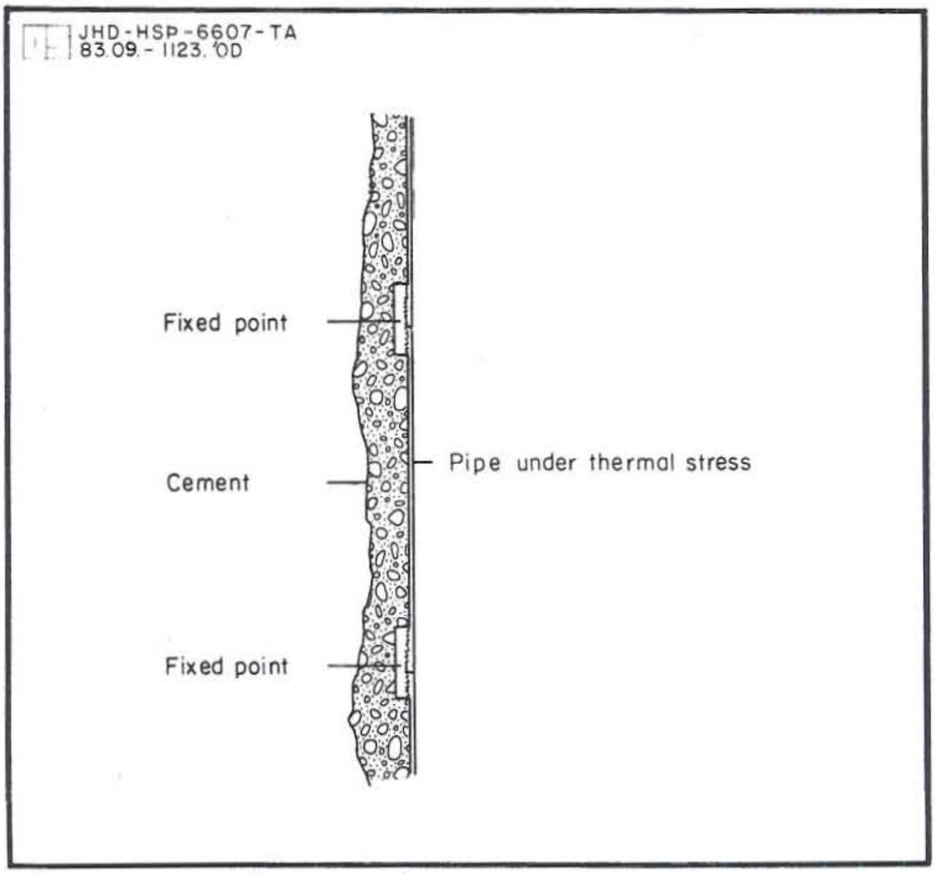

Fig. 2.3 Anchoring of casing in cement.

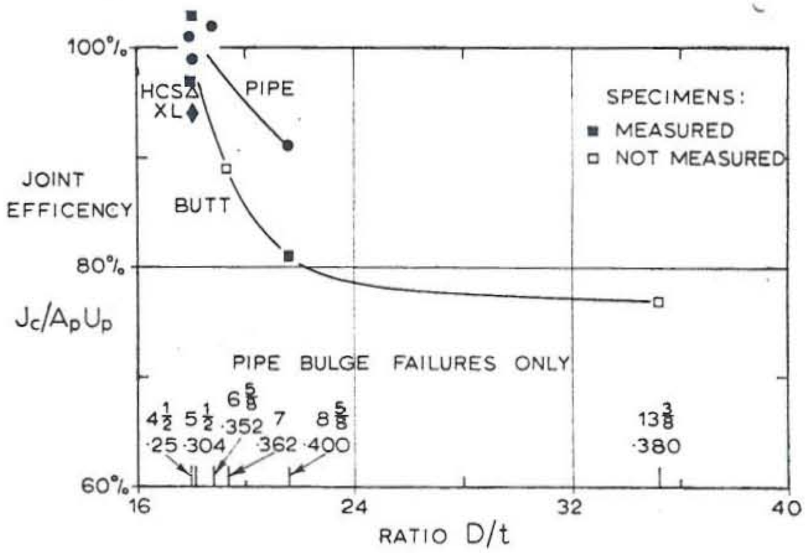

Fig. 2.4 Buttress thread joint efficiency for compressive loads (from Dench, 1970).

The last column in Table 2.11 shows the maximum axial thermal stress (σ_t) calculated from equation (18) and assuming the following maximum temperature:

Anchor casing: T_{max} = 204°C
Production casing: T_{max} = 254°C

The shaded areas indicate which grades and weights of casing are safe to use based on the joint strength. It is seen that the H-40 pipe is not suitable for the anchor casing and the J 55 pipe is not suitable for the production casing.

<u>Third mode of failure.</u> The third mode of failure may occur when axial tensile stressing due to cooling exceeds the casing joint strength. The equation for joint strenth given in API Bulletin 5C3 (1974) shows that the joint efficiency for tensile loads is higher than the efficiency for compressive loads given in Table 2.10. The latter is therefore critical for joint design and therefore this mode of failure need not be considered further.

<u>Fourth mode of failure.</u> This mode of failure is caused by the differential movement at the wellhead caused by the axial expansion of the wellhead equipment and the casing. That problem can be solved by an appropriate wellhead design as shown in Fig. 2.5 or by using a special expansion spool.

It is assumed that the top section of the production casing, a length of possibly 50 - 100 m, is free to expand as the well is producing. This expansion is given by the equation

$$\Delta L = \alpha \cdot L \cdot \Delta T \qquad (26)$$

where ΔL = expansion of the free end of production casing;

Table 2.11 Allowable compressive stress (σ_c) due to joint strength and compression with thermal stress in anchor and production casing. All joints are buttress thread joints except the first line which is for round thread joint.

Casing size	Grade	Weight lb/ft	D/t	Joint Eff.%	σ_c N/mm2	σ_t N/mm2
13 3/8"	H-40a	48.0	40.54	-	164.3	393.6
	H-40b	48.0	40.54	76.5	316.6	393.6
	J-55	54.5	35.20	76.8	397.2	393.6
		61.0	31.11	77.3	399.7	393.6
9 5/8"	J-55	36.0	27.35	77.7	401.8	513.6
		40.0	24.37	78.4	405.4	513.6
	C-75	40.0	24.37	78.4	513.5	513.6
		43.5	22.12	80.0	524.0	513.6
	N-80	43.5	22.12	80.0	551.6	513.6

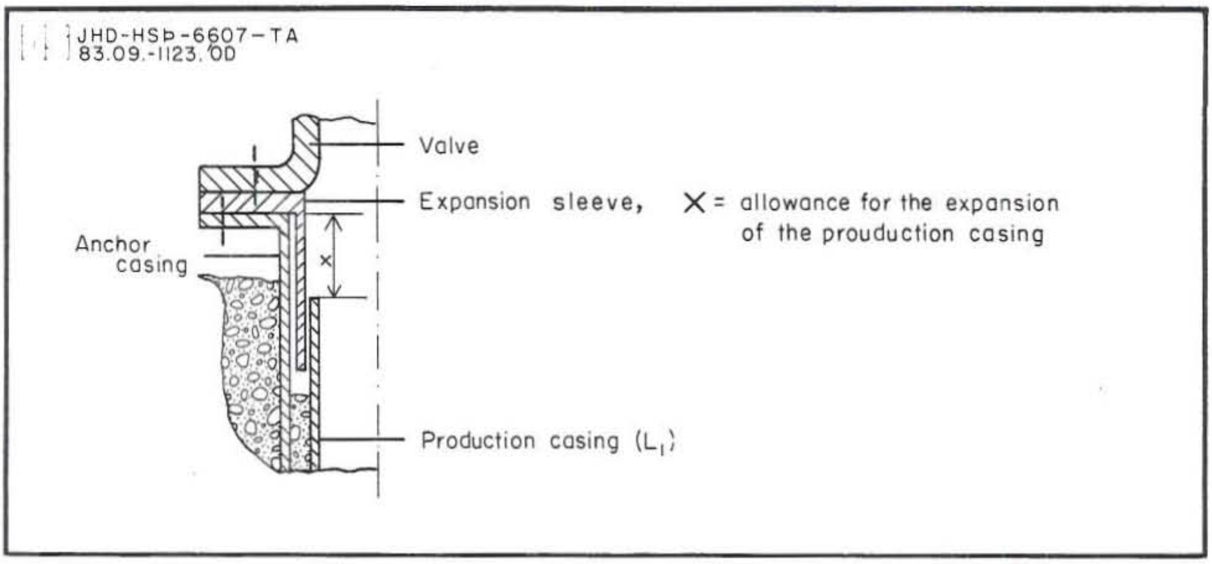

Fig. 2.5 Expansion sleeve arrangement at wellhead.

α = expansion coefficient for steel, ($1,2 \times 10^{-5}$ m/m°C); L = length of free end of production casing, (m); and ΔT = differential temperature at wellhead (°C).

For safe design, the allowance for expansion (X on Fig. 2.5) should be greater than the calculated casing expansion (ΔL).

2.5.6 Casing loading during running and cementing

Failure of casing due to excessive tensile stresses or due to burst or collapse pressure may occur in a long pipe. The tensile loading occurs while the pipe is being run when the entire string is suspended from the top. The joints represent the most critical regions for this type of loads. Table 2.12 shows these loads for all casing strings under consideration as well as their joint strength, and it appears that this tensile loading is not critical in the given range of hole depths.

Table 2.12 Suspended weight of casing strings.

Casing size	Grade	Weight lb/ft	Type of joint*	Casing lenght m	Weight of casing string in air MN	Weight of casing string in water MN	Joint strength MN
18 5/8"	H-40	87.5	RT	60	0.077	0.067	2.49
	J-55	87.5	RT	60	0.077	0.067	3.36
13 3/8"	H-40	48.0	RT	180	0.126	0.110	1.43
	J-55	54.5	BT	180	0.143	0.125	4.04
		61.0	BT	180	0.160	0.140	4.56
9 5/8"	J-55	36.0	BT	500	0.263	0.229	2.84
		40.0	BT	500	0.292	0.255	3.18
	C-75	40.0	BT	500	0.292	0.255	4.12
		43.5	BT	500	0.318	0.277	4.52
	N-80	43.5	BT	500	0.318	0.277	4.78

*RT:round thread; BT:buttress thread

The burst and collapse loading may occur during the cementing operation. The burst pressure may be caused by a malfunctioning float valve in the casing shoe or by quick setting cement. Both of these may cause excessive pump pressure which may easily lead to bursting of the pipe. If it is assumed that the pipe is filled with cement slurry with water in the annular space around the pipe the pressure differential is given by the equation

$$p_i = gh(\rho_s - \rho_w) + p_p \qquad (27)$$

where p_i is the pressure differential, (inside - outside); h is the hydrostatic head; ρ_s is the density of cement slurry; ρ_w is the density of water; and p_p is the pump pressure.

The collapse pressure may be reached near the bottom of the casing string when cementing is carried out by the inner string method. It is assumed that the annular space is filled with cement slurry, the pipe is filled with water, the pressure differential across the pipe wall (outside - inside) is given by the same formula as before:

$$p_c = gh(\rho_s - \rho_w) + p_p \qquad (28)$$

Evidently the risk of burst or collapse is increased as the length of casing string being cemented is increased. The burst and collapse pressures are evaluated below for the longest casing string, the production casing, with a length of 500 m. The density of cement slurry is 1610 kg/m3 (G-class cement, see Chapter 4) and as suggested by Dwiggins (1983) the collapse pressure is increased by a 12,5% safety factor. The resulting pressures are

$$p_i = 9.81 \cdot 500(1610 - 1000)x10^{-5} + p_p = 29.92 + p_p \text{ bar}$$
$$p_c = 29.92x1.125 + p_p = 33.66 + p_p \text{ bar}$$

where the pump pressure pp is in bars.

The burst and collapse strength of the various grades and weights of production casing is tabulated in Table 2.13, showing also the allowable pump pressure according to the above expressions. It is seen that the danger of reaching burst or collapsing pressures is low due to the short length of casing.

2.5.7 String analysis for liner

For an uncemented liner, the effect of axial thermal stress on the joint and on the body of the liner, is not as severe as it is in a cemented casing, because 100% expansion is allowed.

Axial compressive load exists only if the liner stands in the hole, but tensile load normally exists as the liner is hung. It is not practical to allow the liner to stand in the hole. In order to avoid the axial compressive force effect, it is sufficient to leave enough space for expansion and for the downfall of sand to the bottom of the hole.

Figure 2.6 shows the slot arrangement used in the wells at Krafla (VIRKIR, 1983). In general, geothermal liners are either perforated with circular holes or slots. In case of a torch cut slotted liner, the stress concentration factor is greater than that of the circular machine cut one, in which case stress corrosion cracking may be encountered. Since only slot cutting equipment is available at Krafla, the liner for KJ-22 is designed for slot cuts.

The lenght of the slotted 7" liner for KJ-22 is determined as follows:

a) Overlap length of liner: 10-15 m; b) Allowance for downfall : 2-5 m; c) Depth of hole below the 9 5/8" casing shoe = 1500 m; d) Length of the 7" liner = 1510 m.

Table 2.13 Burst and collapse strength of 9 5/8" production casing (from API Bulletin 5C2, 1974)

Grade	Weight lb/ft	Burst p_i bar	Burst Allowable p_p bar	Collapse p_c bar	Collapse Allowable p_p bar
J-55	36.0	242.7	212.7	139.3	105.6
	40.0	272.3	242.4	177.2	143.5
C-75	40.0	371.6	341.7	205.5	171.8
	43.5	408.9	378.9	258.6	224.9
N-80	43.5	436.4	406.5	262.7	229.0

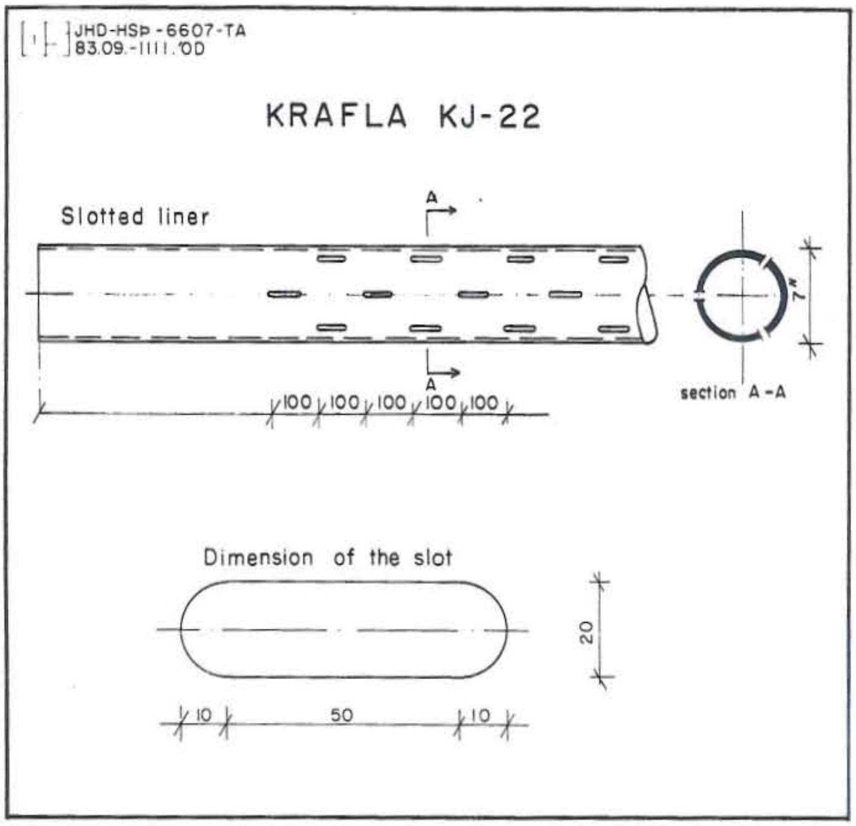

Fig. 2.6 Slotted liner for Krafla KJ-22.

The API J 55 casing was chosen for the liner because this grade of casing has a good corrosion resistance compared to the higher rated casing grades.

The tensile stress in the suspended liner is evaluated by assuming that the liner is hanging freely, the buoyancy force is neglected, and the weigth of couplings is neglected. Using the plain end weight of the pipe will compensate only partly for the lighter slotted pipe and the buoyancy forces so that the evaluated stress will be higher than actually encountered. The minimum cross sectional area of the pipe will be based on a minimum thickness evaluated from equation (17) with t representing the nominal value. The critical cross sectional areas will be across the slots and the stress is then given by:

$$\sigma_t = W \cdot L \cdot g / A \qquad (29)$$

where W is the weight of liner per unit length, plain ends; L is the suspended length of liner; g is the acceleration of gravity; A is the cross sectional area scross slots; and σ_t is the tensile stress.

The calculated stresses as well as the joint strength for round thread couplings are presented in Table 2.14. It is seen that with a safety factor of 1.8 as suggested by Dwiggins (1983) the maximum tensile stress in 26.0 lb/ft casing, σ_t = 319.4 N/mm^2 is well within the tensile strength of J 55 casing, σ_u = 517.0 N/mm^2.

The round thread joint strength is also found to be considerably above the maximum pull at the top of the suspended string.

The suspended liner will be elongated from two effects: (1) axial thermal expansion and (2) the tensile load due to the weight of the pipe. The axial thermal expansion alone will be about 5,3 m for a hole temperature of 334°C. This enlongation must be accounted for when the liner length is

Table 2.14 Tensile stresses in suspended slotted liner, 7"OD,J-55, 1500 m long round thread couplings

Nominal weight lb/ft	Wall thickness nom mm	min mm	Weight plain ends	Amin slotted mm^2	Suspended weight kg	Tensile stress σ_t, N/mm^2	$\sigma_t \cdot 1.8$ N/mm^2	Maximum pull MN	Joint strengt MN
26.0	9.19	6.64	38.19	3167	57285	177.4	319.4	0.56	1.90
29.0	10.36	7.67	42.74	3632	64110	173.2	311.7	0.63	2.19
32.0	11.51	8.67	47.19	4078	70785	170.3	306.5	0.69	2.46

deterined so that with the downfall effect taken into account, a minimum open hole length of 10-11 m should be left below the 7" liner.

2.5.8 Selection of casing

In a developed field, the available temperature and pressure data of the nearest hole is the basis for selecting the grades of casing. However, in case of well KJ-22, the neighbouring well (KJ-21) was only drilled to 1200 m, which is not deep enough for comparison. For this reason, the criteria for temperature and pressure for well KJ-22 are those described in Chapter 2.3.

Taking into account the geological formation factors, an allowance of 60 m is given for the production casing, 45 m for the anchor casing and 10 m for the surface casing. Hence, the production casing can be run between 440 and 500 m, the anchor casing between 135 and 180 m and the surfacecasing between 50 and 60 m. The maximal temperature and pressure for the given depths are:

at 500 m: T_{max} = 254°C, p_{max} = 43 bar,
at 180 m: T_{max} = 204°C, p_{max} = 17 bar,
at 60 m: T_{max} = 160°C, p_{max} = 6 bar.

Production casing. It was found in section 2.5.4 that the limiting temperature for all three casing grades considered, J-55, C-75 and N-80, is higher than T_{max} = 254°C expected at 500 m depth. The J-55 grade, however, is rejected by the second mode of failure analysis see Table 2.11.

Anchor casing. In section 2.5.4 it was found that the limiting temperature for the two anchor casing grades considered, H-40 and J-55 is higher than T_{max} = 204°C expected at 180 m depth. The joint strength of H-40, however, is not sufficient to meet the thermal stress expected as shown in Table 2.11. The H-40 is apparently not available with buttress thread joints, but even if they were, their strength is not sufficient. It is, however, possible to weld the pipe together instead of using screwed joints in which case the H-40 could be used.

Combination of production casing and anchor casing. Assuming that welded H-40 pipe may be used for anchor casing the possible combinations of production casing and anchor casing are presented in Table 2.15 (see also Table 2.9).

Table 2.15. Possible combinations of 9 5/8" production casing and 13 3/8" anchor casing.

9 5/8" casing		13 3/8" casing					
Grade	Weight lb/ft	Grade	Weight lb/ft	Grade	Weight lb/ft	Grade	Weight lb/ft
	40.0		48.0	-	-	-	-
C-75							
	43.5	H-40	48.0	-	-	-	-
N-80	43.5		48.0	J-55	54.5	J-55	61.0

Surface casing. According to the API Bull. 5C2 (1975), the 18 5/8" surface casing is available in grades: H-40, J-55, and K-55, all available of the same weight, 87.5 lb/ft.

The previous calculations have shown that the joint strength is the limiting factor for all casing grades. For the API casing 18 5/8", the buttress thread joints are available for J-55 and C-75 but not for H-40, whereas round thread joints are available for all grades.

The joint strength for the 18 5/8" surface casing in tension is given in API Bulletin 5C2 (1975). Experimental values on compressive joint strengths made in New Zealand (Dench, 1970) indicate values for round thread joints 25% higher than given for tensile strength and for the buttress thread joints for this casing with $D/t = 42.8$ the joint efficiency is found to be about 76.0% (see Figure 2.4). All these joint strength values are tablulated in Table 2.16.

The maximum temperature for the surface casing was estimated at $T_{max} = 160°C$. Assuming a heating range of 150°C the axial thermal compression force on the surface pipe joints is found to be 5.78 MN. This is within the joint strength of the buttress thread joints but exceeds that of the round thread joints.

It is a common practice in Iceland that the surface pipe is welded together, in which case the H-40 is sufficiently strong.

2.5.9 Wellhead equipment.

The wellhead equipment may be selected by the following two criteria:

No gas in well. If there is no gas accumulation at the top of the well in shutdown condition the conditions at the wellhead are calculated by equation (3) by setting $z = 0$. For the KJ-22 depth of $H = 1830$ m the wellhead pressure is

Table 2.16 Joint strength for 18 5/8" surface casing.

Casing grade		H-4	J-55		K-55	
Joint type		RT	RT	BT	RT	BT
Joint strength MN	Tension	2.49	3.36	5.91	3.53	6.35
	Compression	3.11	4.20	6.31	4.41	7.99

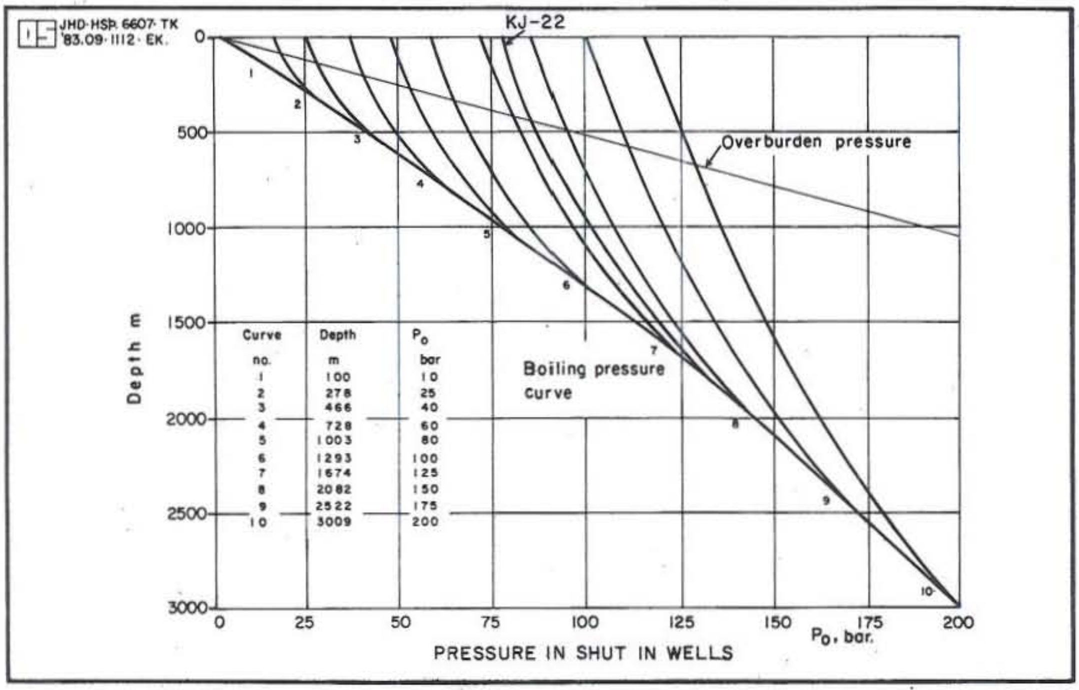

Fig. 2.7 Pressure in shut-in wells. (from Karlsson, 1978).

p_W = 77 bar at a temperature of T_W = 293°C (see Fig. 2.7). By the ANSI B16.5-1968 standard the wellhead equipment of ANSI 900 pressure rating is recommended.

Gas accumulation in well. Geothermal wells in Iceland usually produce gas which accumulates at the top of the well when it is shut in. If the well is shut in for any length of time the gas will displace the water out of the production casing until its surface is at the production casing shoe. The pressure at that level will then be equal to the pressure in the formation, and neglecting the weight of the gas column this will be the pressure at the wellhead. The temperature at the wellhead in this condition may be assumed to be the same as the surrounding air.

Assuming boiling curve conditions at the casing shoe pressure at 500 m is about 49 bar. This pressure in cold condition calls for wellhead equipment of ANSI 300 pressure rating.

It is seen that the first criterion is more severe so wellhead equipment of ANSI 900 series should be selected.

2.5.10 Comparison - actual casing programme

It is of interest to make a comparison of the actual casing programme for KJ-22 with the casing found suitable in this paper. This comparison is presented in tabular form in Table 2.17. The table lists the casing of lowest grade and lightest weight determined in this paper.

It is found that the actual programme called for higher grade and heavier pipe for both anchor and production strings. By comparison with Table 2.10 it is doubtful that the anchor/production pipe combination fulfills the requirement of a weaker burst strength of the anchor pipe than the collapse strength of the production pipe.

Table 2.17. Comparison of casing programmes - this report and actual programme for KJ-22

Casing string	Size OD	This report Depth m	Grade	Weight lb/ft	Joints	Actual programme Depth m	Grade	Weight lb/ft	Joint
Surface	18 5/8"	60	H-40	87.5	Welded	50	-	87.5	Welded
Anchor	13 3/8"	180	H-40	48.0	Welded	220	J-55	68.0	BT
Production	9 5/8"	500	C-75	40.0	BT	550	N-80	43.5	BT
Slotted Liner	7"	1500	J-55	26.0	RT	1500	J-55	26.0	-

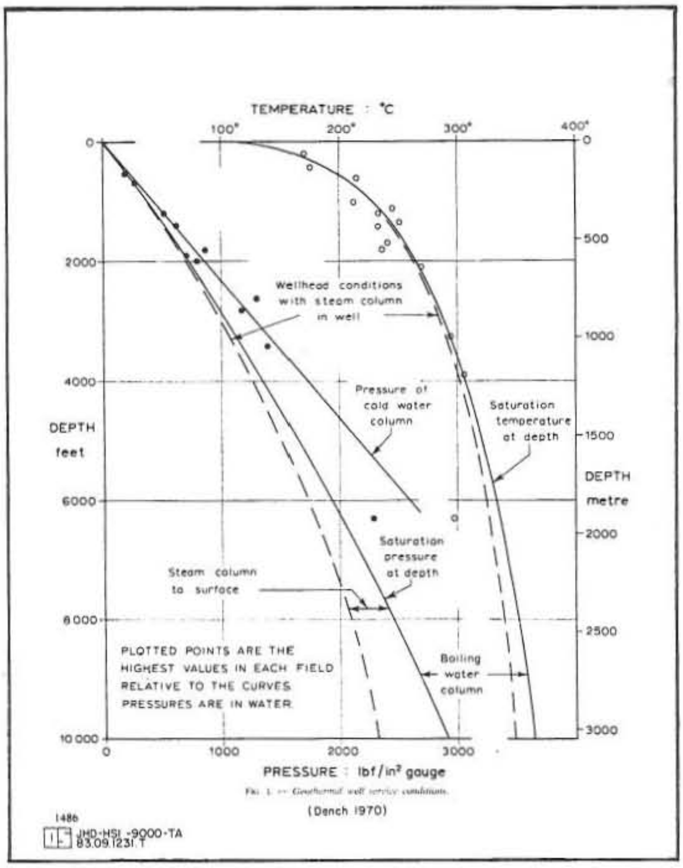

Fig. 2.8 Geothermal well service conditions.

3 A BRIEF DISCUSSION ON FIVE WELL DESIGN PARAMETERS

3.1 Bit programme

The bit programme is an important factor in well planning. Size and type of bits as well as previous bit records and cost of drilling are the key considerations in a bit programme. A brief discussion of these factors follows.

Size of bit. The size of drill bit is based on the casing programme and on the desired cement wall thickness, at least 1 1/2" is recommended (Stanley et al., 1983). Table 3.1 is based on such criteria. Similarly, Table 2.2, is also worked out based on the casing programme and the clearance between the cased hole and the standard bit size is determined.

Drilling can be carried out using the following three methods:

1. Drilling with a full size bit,

2. Drilling with a small size bit and a hole opener. After drilling with a small size bit, the hole is opened to full size using a hole opener.

3. Simultanuous drilling and opening of the hole. This can be done at the same time, using a hole opener and a small size bit as a pilot.

As drilling experience in Iceland shows, each of these methods has been found to have its own advantage and disadvantage. The second one takes a much longer time than the first one. The third method is troublesome, because the hole assembly jerks in drilling through hard formations.

Selection of bit. Generally, bits are selected based on past bit records, geological conditions and cost calculations. According to the International Association of Drilling Contractors (IADC), rock bits are classified as milled tooth bits,or insert bits,formationseries and features such as bearing type and type of gage protection.

Bit record. It has been a common practice, that the best bit for a specific field is selected on basis of past bit records, expected lithology and cost calculations. The record and old bit evaluation may help determine how long a new bit should be run. Usually, an old bit with low wear is run to a shallow depth.

Table 3.1 Bit size selection

Casing size	Recommended hole size	Available bit size
Surface casing	21 5/8"	22"
Anchor casing	16 5/8"	17 1/2"
Production casing	11 5/8"	12 1/2"
Liner	-	8 1/2"

Table 3.2 Bit size selection in KJ-22

Casing outer diameter(in)	Nominal weight lb/ft	Clearance mm
18 5/8"	78.5	-
13 3/8"	61.0	9.3
9 5/8"	43.5	5.3

3.2 Cementing programme

A good cementing work guarantees a long lifetime for a well. Cementing in a high temperature geothermal well serves the following purposes:

1. To protect the casing from corrosive ground water which contains dissolved oxygen.

2. To support the casing.

3. To hold the casing in a specific position.

4. To prevent fluid migration.

Bad cementing can have damaging effects on the hole. Possible causes of failures of casing are the following:

1. Water trapped in the annulus between two casings during cementing can collapse the inner string of the casing or burst the outer string. This effect was discussed in Chapter 2.

2. An uncentralized casing may leave portions of the casing uncemented. This can lead to casing failure.

3. Badly cracked cement allows fresh ground water to pass through and get in touch with the casing (production casing). This may result in a serious casing corrosion and may eventually lead to a blow-out.

Factors that affect cementing can be listed as follows:

a) A loss zone may cause unsuccessful cementing as return of cement to the surface is not achieved; b) Beyond a certain length of casing, it is difficult to achieve successful cementing work. If the static pressure from the cement column is high, it may not be possible to make the slurry return in one move, as it may be forced into a weak formation; c) Quick setting of cement. This may be caused by a high temperature, a high dissolved solids content of the mixing water, or an excessive amount of accelerator. Once the cement starts setting, it is impossible to drive it out. Therefore the next step usually is cementing through perforations (see Chapter 4.3.2.); d) Slow setting may happen if cementing is carried out in a cold aquifer, especially the cementing of the surface casing.

3.3. Drilling fluid programme

Drilling fluids are used for the following purposes: a) to clean cuttings from the bottom of the hole; b) to prevent the wall of the hole from caving; c) to prevent the entry of formation fluid; d) to cool the drill bit; and e) to lubricate the down-hole assembly.

The most common drilling fluid types used in geothermal fields are water, mud, air and foam. In all cases, the drilling fluid is chosen on the basis of field conditions. This is to say, whether the geothermal fields are vapour dominated or water dominated.

Vapour dominated reservoirs are drilled with air or water. The vapour pressure of a steam reservoir is less than the hydrostatic pressure exerted by a column of water (Rehm et al., 1978). Liquid dominated reservoirs are on the other hand drilled with mud or water. However, due to the sealing effect of the mud, its use is not recommended in drilling the production part of the well.

In the case of the Krafla geothermal field, water is the first choice for any depth except in special circumstances. By drilling with water, some advantages can be obtained. These are mainly: a) Negligible cost compared to other drilling fluids, especially mud; b) Sealing of aquifer is prevented; c) Wear on pumping equipment is limited; d) Mud conditioning equipment such as cooling tower, desilter, degasser, mud mixing pumps and stirrers is not used;

e) Quick removal of cuttings and a fast penetration rate; and f) Good cooling of drill bit and long life of drill bit seals and bearings.

When using drilling mud, the following properties have to be monitored at definite time intervals:

a) The specific gravity of the drilling mud is measured using a simple device called "mud balance." The result of this measurement helps to recognise whether the well pressure is in balance with the formation fluid pressure; b) The viscosity is measured using a Marsh funnel or a viscosimeter. The resultof this measurment helps to determine the carrying capacity of the mud and the pressure loss; c) The temperature of the drilling fluid entering and leaving the well is measured using a thermometer. The information obtained from this measurement may call for the use of a cooling tower; d) The pH of the drilling fluid can be measured with indicators. The results of the pH measurement are used to adjust the addition of chemicals to the mud; e) The sand content is measured using a special screen set. The result of this measurement helps to recognise improper desanding of the mud that may lead to high wear rates. Improvement or change of equipment may be required depending on the content measured; f) The filter cake is measured using a special filter press with filter paper. The result of this measurement helps to estimate the mud wall thickness and sealing effectiveness.

Besides, it is necessary to know the important mud additives (mix). These are usually bentonite (major constituent), barite (weighting material), chemicals such as caustic soda (NaOH, for adjusting pH), and tannin (for thinning the mud).

3.4 The blow-out prevention system

Geothermal blow-outs are caused by unbalanced pressure between the hole and the formation. When the hole pressure is lower than the formation pressure, the flow of fluid in the formation will be directed towards the hole. Eventually, it may reach the surface and blow out.

Geothermal blow-outs can be controlled with blow-out preventers, good casing design, and appropriate drilling fluid to kill the well (Chapter 3.3). A safe well design never allows drilling without installation of blow-out preventers.

Selection of blow-out preventers (BOP) for the Krafla geothermal well is given below:

a) Surface casing installation (18 5/8" casing)

Master valve, ANSI 300 valve series. Annular BOP, ANSI 600 series, size 21 1/4". This BOP is designed to close against any shape that comes through it.

b) Anchor casing installation (13 3/8" casing)

Master valve ANSI 900, size 12" (12 1/4" opening)

Pipe ram BOP, ANSI 900, size 12". This can close against the drill pipe only.

Blind ram BOP, ANSI 900, size 12". This can close against an open hole only.

Annular BOP, ANSI 900, size 12". Designed to close against any shape that passes through it.

Rotary BOP, ANSI 900, size 12". Used while drilling with air or foam.

Both annular BOP and the ram type BOP are activated by oil or water and are remotely controlled. This configuration is shown in Fig. 3.1.

3.5 The drilling programme

3.5.1 Factors in directional programmes

When a well is to be directionally drilled in order to reach a desired target area, one must consider many complex factors and make a comprehensive drilling plan. Casing design has been discussed in previous chapters, and the directional plan made for KJ-22 is shown in Figure 4.30.

3.5.2 Drilling time

This is the approximate time that a drilling process takes to reach a certain depth. It is possible to estimate drilling time by examining past drilling data for a specific field. For this reason, data of four drilled wells from the Krafla field are given in Table 3.4 below. The progress chart for well KJ-22, both planned and actual is shown in Fig. 4.31.

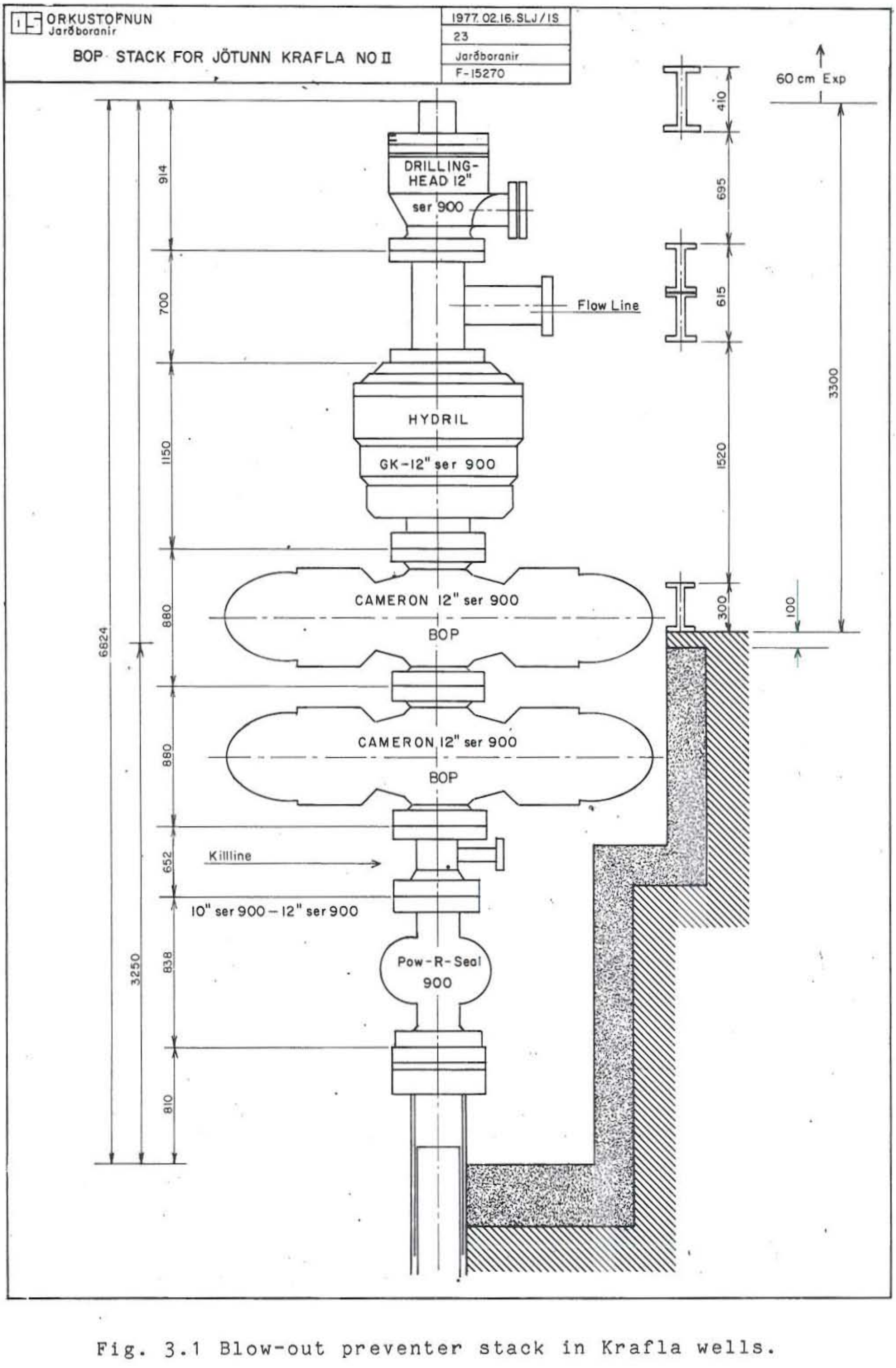

Fig. 3.1 Blow-out preventer stack in Krafla wells.

Table 3.3 BOP installation for KJ-22

Installation	BOP		Size (in)
Surface casing	–	–	–
Anchor casing	Master valve	ANSI.900	14
	Cameron BOP pipe rams	ANSI.900	12
	Cameron BOP blind rams	ANSI.900	12
	Rotating BOP	ANSI.900	12

Table 3.4 Drilling time data from past drilled wells in Krafla geothermal field.

Hole size(mm)	Max.depth(m) and working days	Well KJ-18	Well KJ-19	Well KJ-20	Well KJ-21
17 1/2	Casing shoe (m) Time (days)	206 2D 3RCC	203 2D 2RCC	212 3D 3RCC	293 3D 3RCC
12 1/4	Casing shoe (m) Time (days)	674 4RCC	654 5RCC	650 4RCC	1200 4RLCO
9 5/8	Well bottom (m) Time (days)	2215 22RLCO	2150 7RLCO	1823 22RLFCO	1200 –
7	Total drilling time (move in + drilling + completion)(days)	55	53	52	24

R = running of casing; CC = cementing of casing; CO = completion; L = logging; F =fishing.

4 DRILLING IN THE KRAFLA GEOTHERMAL FIELD

4.1 Introduction

KJ-22 is the second deep well which has been drilled directionally in the Krafla geothermal field. The main reason for such drilling is to increase the output of the well (optimum production). The well was inclined in order to cut near vertical parallel fractures which are located west of KJ-22.

Drilling of KJ-22 to 43m depth was done by a cable tool drilling machine. As shown in Fig. 4.1 and Table 4.1, the drilling rate was very slow, but the operation is simple and it saves expensive rotary rig time. This has been a common practice in Iceland for a long time. After the desired depth was reached, surface casing was run and cemented prior to moving in the rotary rig. According to the original well plan, the intermediate casing should have been run to 200 m and cemented. The kick off point depth (KOP) for directional drilling should have been around 350m and the production casing should have been run to 550m (see Fig. 4.2). Unfortunately this could not be done due to uncontrollable problems that were encountered in the 17 1/2" hole. The drilling programme was modified; i.e. an intermediate casing was run to156 m and cemented, a production casing was run to 564 m in the straight partof the hole and the KOP was made at 576 m. The whole process was completed by drilling a 1878 m deep hole with a maximum inclination of 37.9°N73°W direction.

4.2 Drilling of the 17 1/2" hole

Drilling started on May 29, 1983, with the biggest drilling rig (Jotunn) available in Iceland. On the first day of drilling, a depth of 65m was reached, but problems started to appear such as loss of circulation, collapsing, and caving. That made it impossible to go beyond 65 m.

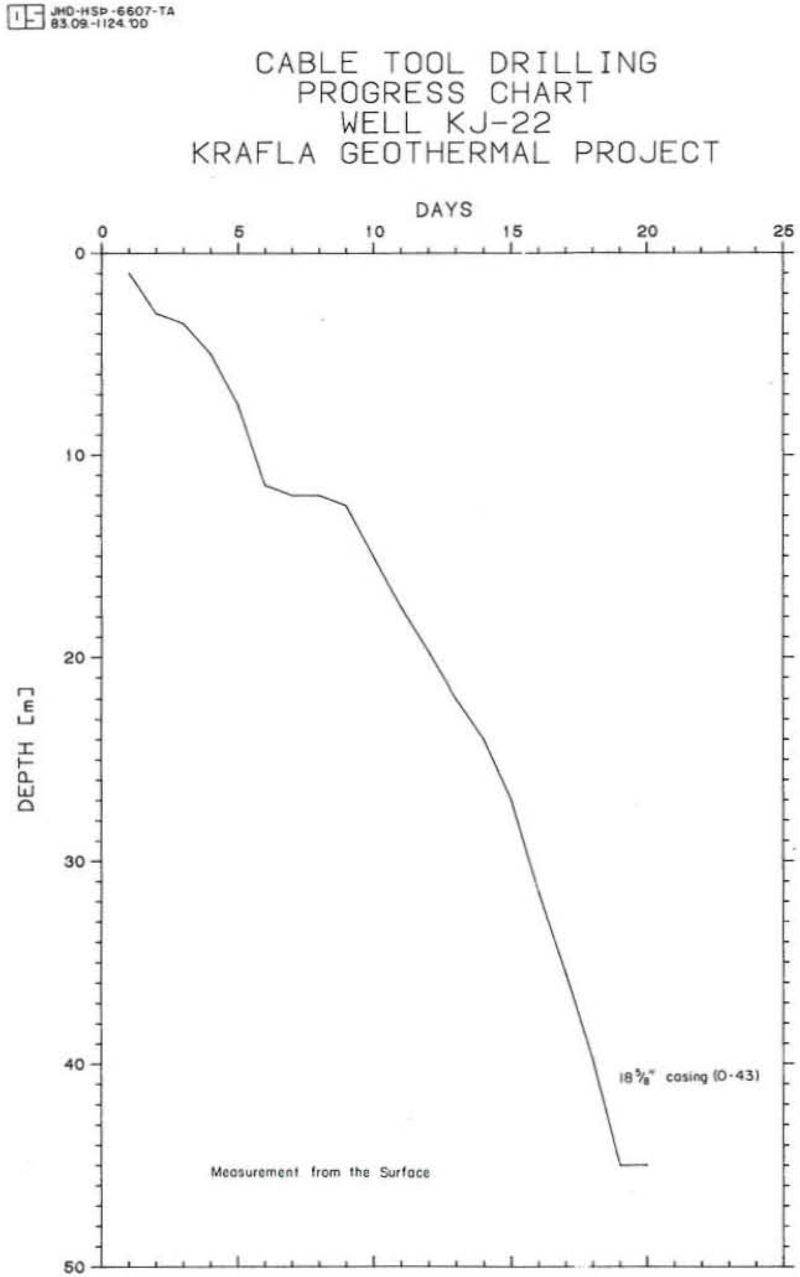

Fig. 4.1 Cable tool progress chart for KJ-22.

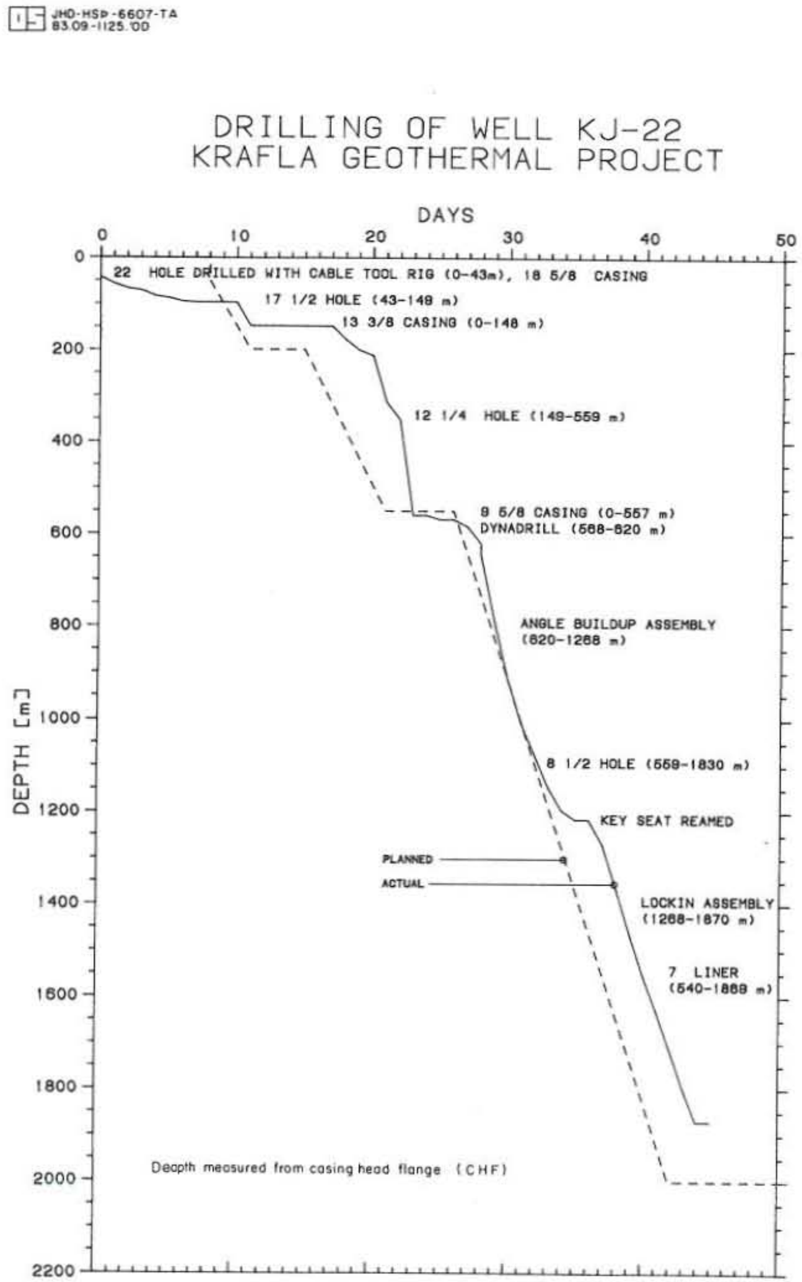

Fig. 4.2 Planned and actual drilling progress chart.

Table 4.1 Cable tool drilling data (depth measurements are taken from the top of cellar)

Working day	Drilled depth	Working hours	Working day	Drilled depth	Working hours
1	1.0	10.5	11	17.5	13.0
2	3.0	13.0	12	19.7	13.0
3	3.5	2.0	13	22.0	11.0
4	5.0	13.0	15	24.0	11.0
5	7.5	13.0	15	27.0	24.0
6	11.5	13.0	16	31.5	24.0
7	12.0	6.5	17	35.5	24.0
8	12.0	7.0	18	39.8	24.0
9	12.5	7.5	19	45.0	24.0
10	15.0	13.0	20	45.0	4.0

The maximum loss of circulation recorded was 40 l/s. In fact the loss of circulation alone would not have been a problem if it had not been associated with collapsing.

To determine the approximate size of the cave and its location, a caliper log was made. Besides information on the condition of the well, a caliper log can be used to calculate the approximate amount of cement that will be squeezed into the loss zone. In KJ-22 the first caliper log was run to 65 m. The maximum wash-out was 32" at 58 metres (see Fig. 4.3). Based both on drilling observations and on the caliper log results, it was decided to cement the cave, but it was found difficult to force the drilling string into the sand. This cementing job required 16 tons of cement. After waiting for 16-20 hours until the cement got a reasonable strength, the cement was drilled out. As drilling was in progress, the same problem happened for the second time and further drilling was not possible beyond

91 m. For the second time, the log showed that the first cemented part was not stable and that some parts had been washed away. The circulation loss detected was 25-30 l/s.

The cementing job was carried out right after the second caliper log. Before the cementing work started, it was decided to pump loss of circulation material, i.e. calcium chloride and sodium silicate. The right procedure of pumping these chemicals is discussed in the next paragraph. Cement required for this job was 14 tonnes with 2-3% calcium chloride ($CaCl_2$) added as an accelarator. As before the result was negative, as further drilling was difficult. This demanded additional caliper log and cementing work (see Fig 4.3). Figure 4.4 shows the cement technique used.

This job was carried out using 5 1/2" drill pipes as a pumping line, and it was lowered into the sand and gravel as close as possible to the bottom of the hole.

4.2.1 Procedure for sealing loss of circulation with sodium silicate

1300 litres of calcium chloride (10%) were pumped through the drill pipe followed by 600 litres of water (spacer) and 200 litres of sodium silicate (Na2SiO3) followed by 400 liters of water (displacer). The chemicals and water were pumped at a very slow rate so that turbulence would not be created in the hole to avoid a mix of the chemicals around the drill pipes. By this technique, the chemical reaction hopefully takes place outside the hole. When these two chemicals are combined or get in contact, a reaction will take place and a solid jelly substance will be formed of calcium silicate that blocks the loss channel.

$$Na_2SiO_3 + CaCl_2 \rightarrow 2NaCl + CaSiO_3$$

Calcium silicate ($CaSiO_3$) is an effective sealant. The sealing was observed by monitoring the water level in the hole. The first monitoring results gave a rise of the water

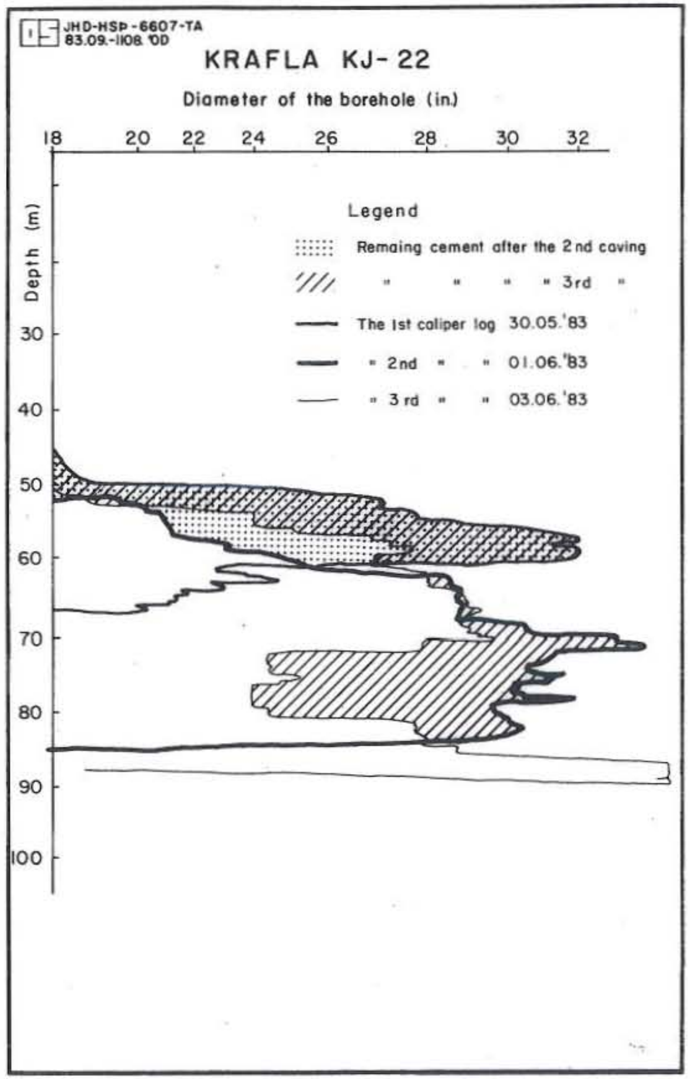

Fig. 4.3 Results of the first 3 caliper logs demonstrating the caved cement and the remaining cement after the second and third collapse (from Gudmundsson et al., 1983a).

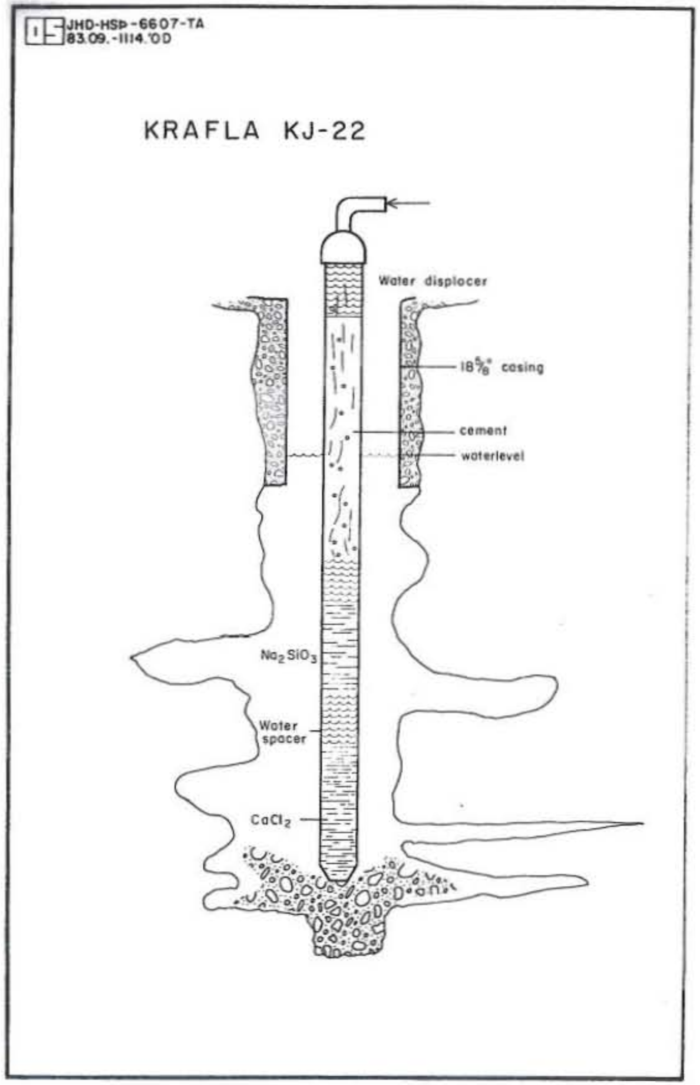

Fig. 4.4 Placement technique used to block loss of circulation

level by two metres after the whole process of pumping ceased. This increment of water level in the pipe (dp) was a good indication of that the reaction was starting to take place. This effect was controlled by lowering the water level close to the original level. The mix had thus taken place at the right place. Care should be taken not to lower the level of water in the hole with a full force. If full force is used every thing that was pumped will be shifted and the effort will be ineffective.

After pumping the loss of circulation material, cement was placed in two steps; (a) 7-8 tonnes of cement were pumped and allowed to set and subsequently 10 tonnes of cement were pumped in.

After waiting for the cement to set, drilling started, and the rate of penetration in the cement was reasonably low. This low penetration rate was an indication of good cementing.

For a specific grade of cement, waiting time depends on temperature, the amount of retarder or accelerator in the slurry, and the quality of water. Because so many factors are involved, it is not possible to give the exact waiting time. For this reason, the trial method was used, which includes the following steps: a) Lower the bit at the end of the cementing job, b) Wait for a short time, c) Check the strength of the cement by lowering the bit in rotation and applying the bit weight, d) Depending on the check observation (penetration rate) wait or continue drilling.

In some cases, this trial/error method works very well, as it saves valuable rig time. However, it is impossible to know the exact time at which the cement gets the required strength. In the cited case, the waiting time was 8 hours, and excessive bit weight was avoided. In spite of all this care, the same problem repeated itself as the bit approched the formation. A big back fill in the hole occurred which was estimated to be 12 m.

Loss of circulation during drilling was 40 l/s. Observation during drilling showed that broken pieces of cement appeared with the cuttings while the bit was drilling in the formation. This showed that the cemented section was not stable.

For the fourth time the hole was surveyed, and the results are shown in Fig 4.5. This time, the cave was cemented first by pumping 2000 litres of sodium silicate followed by 800 litres of water (spacer). After that, lightweight cement slurry (three tonnes of cement) was pumped down into the hole at a slow rate. Two hours later the same thing was repeated, because the slurry and loss of circulation material seemed to have been lost.

Before running the down-hole assembly for drilling, some modifications were made. As was mentioned earlier, drilling observation indicated breaking of the cemented part and the caliper log indicated a big cave (Fig 4.5). The apparent reason given for this was the action of the stabilizer as the cement was being drilled out. As before, the cement was drilled out, but it was not possible to go deeper into the formation (below 93 m). In order to determine the approximate size and shape of the hole, the 5th caliper log was run (Fig. 4.5). According to the logging result, the hole seemed not too bad because the cave did not extend into the cemented zone. The 5th cementing job was carried out using 16 tonnes of cement and 2-3% calcium chloride. Since the loss was not substantial, there was no need to pump loss of circulation material.

The cement was drilled out after it had gained the desired strength. This time, as in all the former cases, it proved difficult to drill in the formation. The bit was taken out at 106 m. The 6th caliper log and the down hole assembly indicated that there were eleven metres of back fill in the hole. The cementing work was carried out for the 6th time. This time, unlike all previous cases, it was possible to lower the drill pipe into the cuttings on the bottom at 104 m. The work required 13 tonnes of Portland cement with 2-3% calcium choride added. The cement was drilled out within a few hours. For the first time, unlike the other five cases, it was possible to drill into the formation. The first crew (8 hours) drilled to a depth of 137 m. The size of cuttings at this depth was smaller than the cuttingsobserved between 50-100 m. The reason for this was some change in the formation between 100 - 110 m, with some silica and zeolite cementing the fractures. Below 150m the formation was totally altered.

After this little loss was recorded, and the penetration rate was fast. A maximum depth of 198 m was achieved after 36 hours of continuous drilling. At this stage the whole length of the hole was reamed up and down using one reamer on top of the first dill collar. Right after the reaming process caliper and temperature logs were run for better information. The bottom hole temperature was 33°C. The result of the caliper log showed that the hole was wide enough to run the desired casing size (13 3/8") (Fig. 4.6). On the other hand, caliper log information shows only the diameter of the well, but not whether the hole is straigth or crooked.

4.2.2 Running of the 13 3/8" casing

Before running the casing the length of each pipe was measured and numbered. Four centralizers were attached at definite intervals. Even though centralizers are the cause

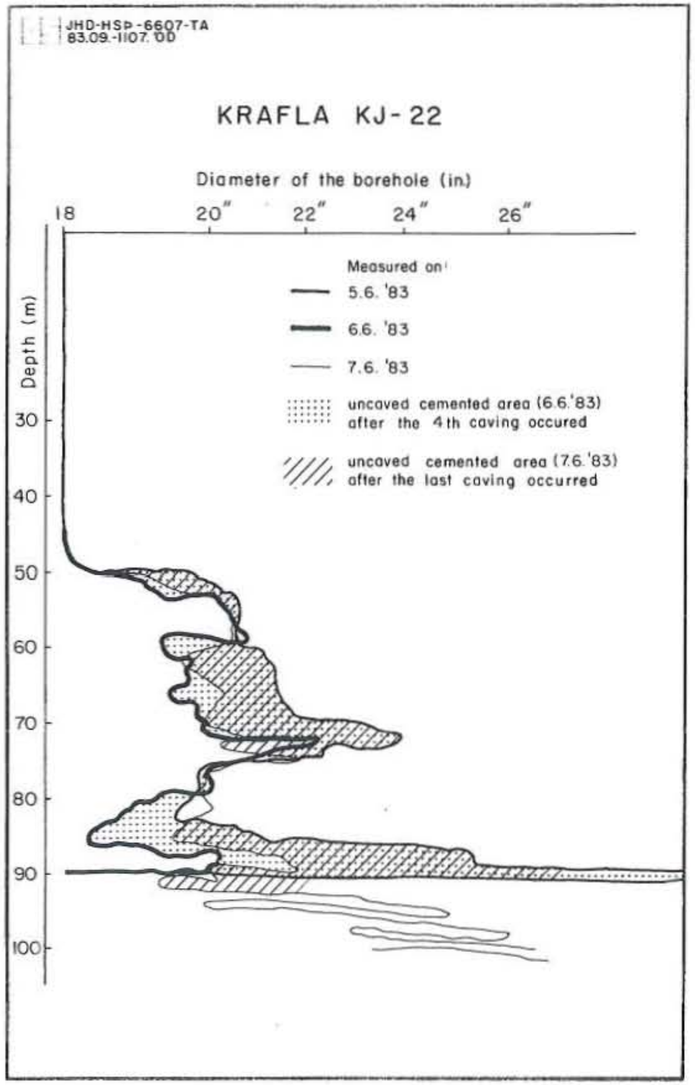

Fig. 4.5 Results of the four caliper logs, demonstrating the caved cement and the remaining cement after fourth and fifth collapse (from Gudmundsson et al., 1983a).

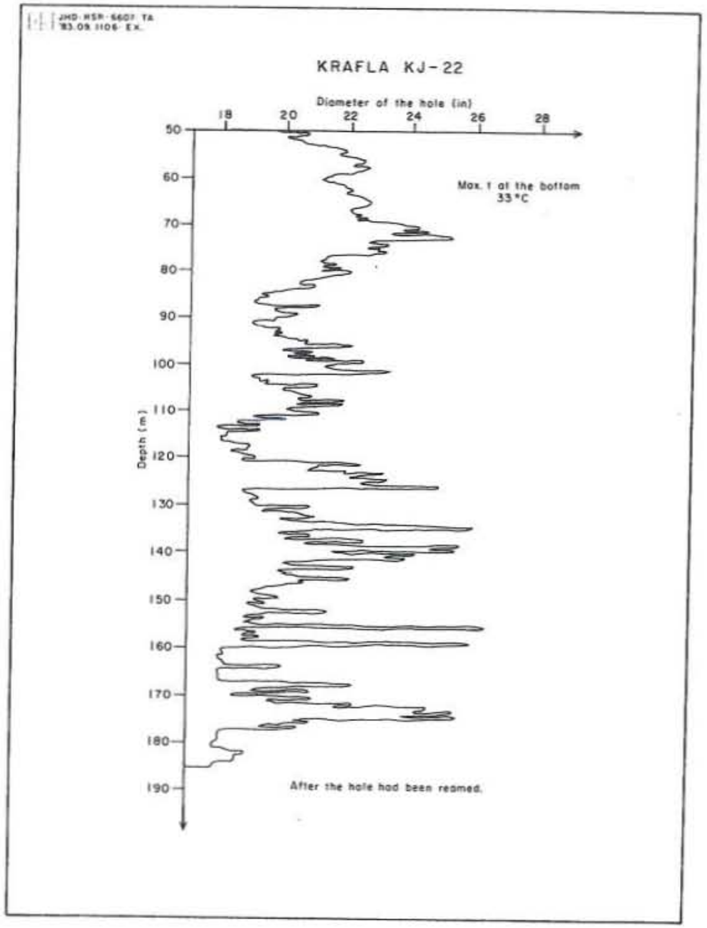

Fig. 4.6 Caliper log before running the 13 3/8" casing (from Gudmundsson et al., 1983a).

of some problems while running casings, a well centralized casing results in a successful cementing job and guarantees a longer lifetime of the well. As no obstacles were observed, the running of 13 3/8" casing started, but the process took much longer time than expected because of all the problems that had been encountered in the hole. While the running work was carried out, the casing got stuck at several depths, but the drillers were able to free them by hammering (lowering the whole length of casing at high speed). This way of hammering helped at several points above 130m, but this was not possible below that. The casing got stuck at 160 m. Neither hammering nor any other method that was tried could make the casing go lower.

The whole length of the 13 3/8" casing was taken out, and it was found that one of the four centralizers was missing. To see what was happening to the hole, the last caliper log was run (see Fig. 4.7). From this log it was possible to see that it was hard to run the instrument beyond 126 m. There were two possible conclusions to be drawn: a) The hole might have been filled with down-fall while running of the casing, and b) the hole might have been blocked.

Opening of the hole was tried by drilling the mass that had blocked it. Continuous drilling was possible to a depth of 156 m. The drilling result proved that the hole was not blocked, but rather filled by sand and gravel that had collapsed from the wall of the hole.

Why was it not possible to run the casing? Why did all this happen? To answer this, three possibilities can be considered:

a) Collapse during normal running. No hole has a uniform and straight wall surface. Due to this, the hole could have collapsed while the casing was run. It is known that this hole had a weak zone that could easily collapse. As running of casing cannot assure 100% casing centralization, the hole may have collapsed before the hammering.

b) The hole may have collapsed before the casing was run, due to instability of the formation material. The collapse may have blocked the hole with a mass of rocks at some depth (130 m), where hammering had been carried out.

c) Unstabilized bit. As mentioned before, the hole was drilled without stabilizers in the assembly. The unstabilized bit has much more freedom to drift in any direction and in most cases to the softest part of the rock. If so, the hole will be crooked, and it will be very difficult to run the casing. If this was the case it is possible to draw a second conclusion: that the casing had a solid ground to stand on, provided it was fully centralized. As it was not possible to pull the casing free, hammering was tried several times, finally with caving resulting.

Later a decision was made to rerun the 13 3/8" casing to the maximum possible depth instead of cleaning the hole and re-drilling. Hence, the 13 3/8" casing was run and cemented to 156 m.

4.2.3 Cementing of the 13 3/8" casing

Before cmenting the 13 3/8" casing, certain parameters were calculated, such as the amount of cement, water requirements and pumping time. Calculation of the amount of cement required is done by the general equation: Cs = c x L, where: Cs = cement slurry (litres) and c = capacity of annulus (litres/meter) and L = length (m).

To make this calculation, the following data are required: a) Drill pipe size 5 1/2", 19.5 lb/ft, internal and external upset. Grade E. b) Casing size 13 3/8", 61 lb/ft, Grade K55. c) Hole size 17 1/2".

<u>The theoretical volumes</u> that need to be calculated are shown numbered in Fig. 4.8. They are as follows:

(1) Volume capacity of drill pipe (5 1/2", 19.5 lb/ft): 9.16 l/m x 130m = 1190 l.

(2) Annular volume between 13 3/8 casing and 18 5/8" casing: 68.94 l/m x 42m = 2895 l.

(3) Annular volume between 13 3/8" casing and open hole: 64.4 l/m x 113.65m = 7319 l.

(4) Volume of cement inside the 13 3/8", 61 lb/ft casing: 79.37 l/m x 12.40. = 984 l.

(5) Volume of cement below the floatshoe (17 1/2" hole) 155.2 l/m x 0.5 = 77 l.

The sum of items 2 - 5 is 11276 litres. Due to the non-uniform shape of the hole, 100% excess of the calculated value is estimated to be used. Hence the total slurry needed is = 22,552 liters.

The calculated value of the specific gravity (sp.gr.) for Portland cement plus silica plus gel is 1.8 g/cm3. The cement yield is 85.6 l of slurry/100 kg for sp.gr. = 1.8. Hence the total cement needed will be 22552 l x 100kg/85.6 l = 26.3 tonnes.

Water requirements are 53.7 l/100 kg: Wn = 29.13 x 53.7 litres/100 kg = 1564.3 litres.

<u>The pumping time</u> depends on the pumping rate. Assuming 600 litres of cement slurry pumped per minute, the total pumping time = 24.935 litres x min / 600 litres = 42 min.

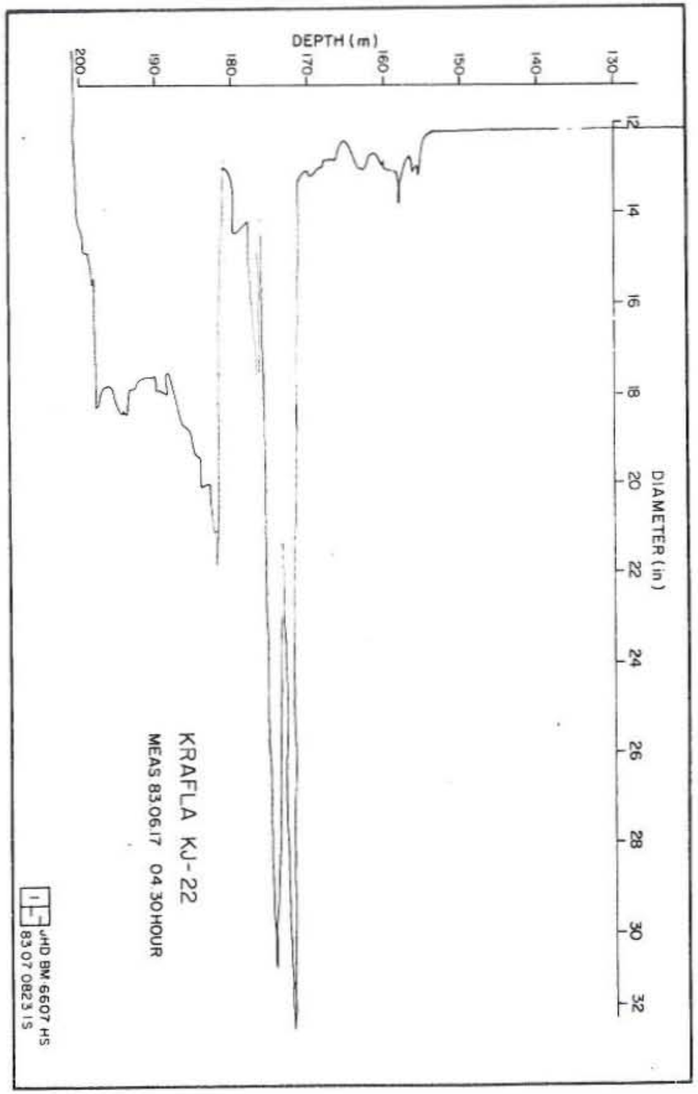

Fig. 4.7 Final caliper log
(from Gudmundsson et al., 1983a).

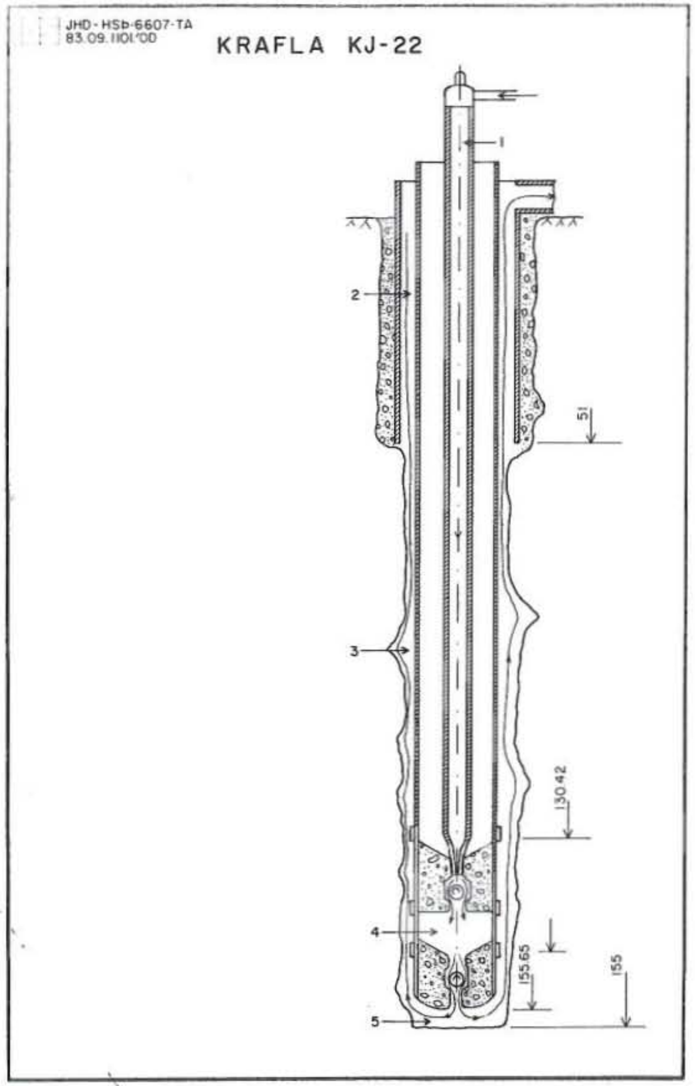

Fig. 4.8 Inner string cementing method used
for 13 3/8" casing.

Cement in storage must be in excess of what is calculated before a cementing job is started. Two types of mix were used. Mix 1 consisted of: Portland cement (73%), silica flour (25%), gel (1.6%) and retarder (0.4%).

Mix 2 consisted of G Class cement (66.7%), silica flour (26.7%), gel (1.3%) and perlite (5.3%).

Pumping: During circulation of water, return was maintained, and it was not found necessary to pump any loss of circulation material. But after pumping of slurry started, loss of return was detected. The pumping continued for 45 minutes without cement being returned to the surface. Thus the cementing was unsuccessful as the full length of the casing was not cemented. The actual cement usage was 28 tonnes of Mix 1 and 11 tonnes of Mix 2. Volumes of Mix 1 was 23,520 litres and 11,297 of Mix 2 for a total of 34,817 litres, which is roughly 170% excess.

There are two possible causes for this. The slurry may either have been forced into the formation, especially into the problem zone, or the capacity of the hole with its many cavities may have been larger than expected.

Before taking any major action, a cement bond log (CBL) was made to detect the top of cement. In this particular well (KJ-22) the cement was allowed to set for about 6 hours. After 7 hours, the CBL was run to 127.5m (top of the float collar). But this gave no conclusive result (Fig. 4.9). The 2nd and 3rd CBL were run after 13 and 18 hours intervals respectively. The results, however, were negative in both cases. As one can see from the cement mix, the slurry was excessively retarded, i.e. 0.1 tonne of retarder for the hole, which had a bottom hole temperature of only 33°C. An accelerator should rather have been used. The unwanted retarder and the low hole temperature affected the setting time to a great extent. To counterbalance the effect of retardation, 40 tonnes of hot water at 55°C were circulated in the well for 2 hours. Ten hours after the circulation had been stopped the 4th CBL was run and it

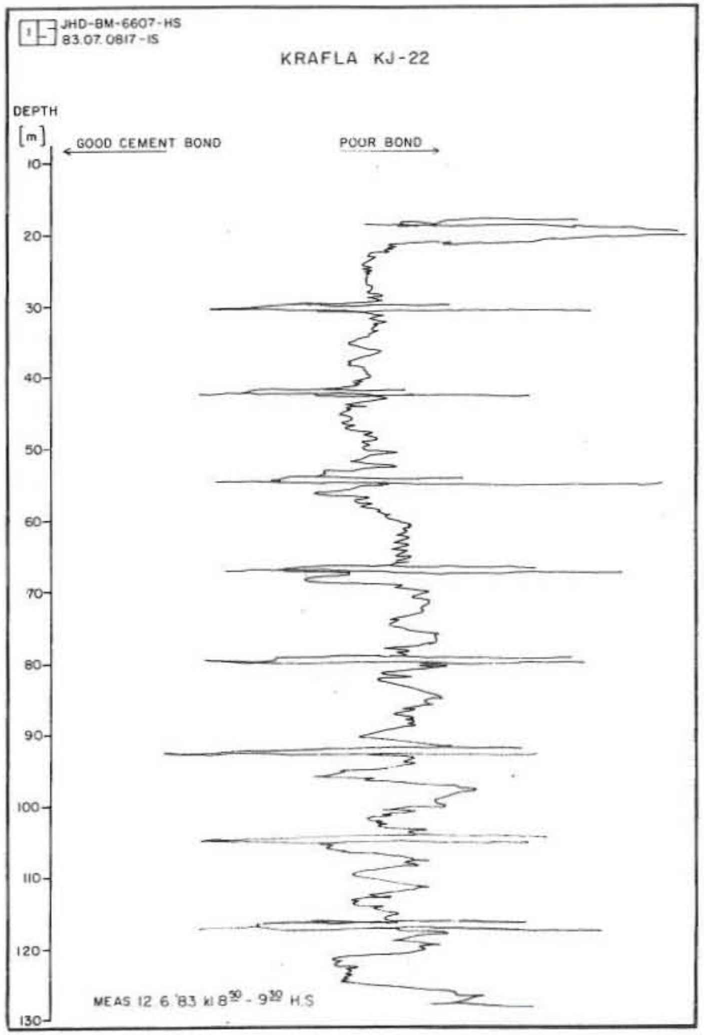

Fig. 4.9 The first cement bond log
(from Gudmundsson et al., 1983a).

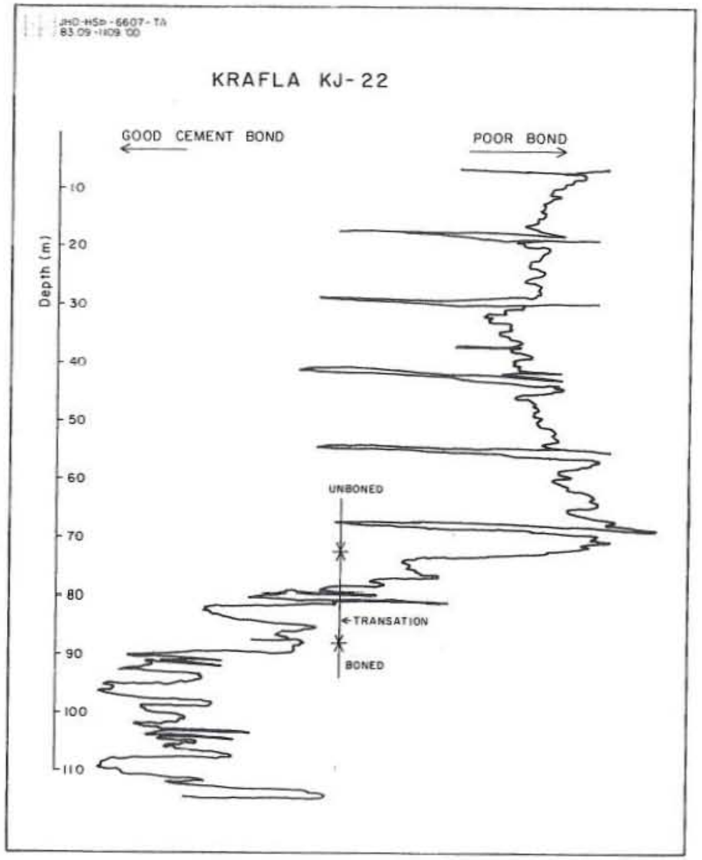

Fig. 4.10 The fourth cement bond log
(from Gudmundsson et al., 1983a).

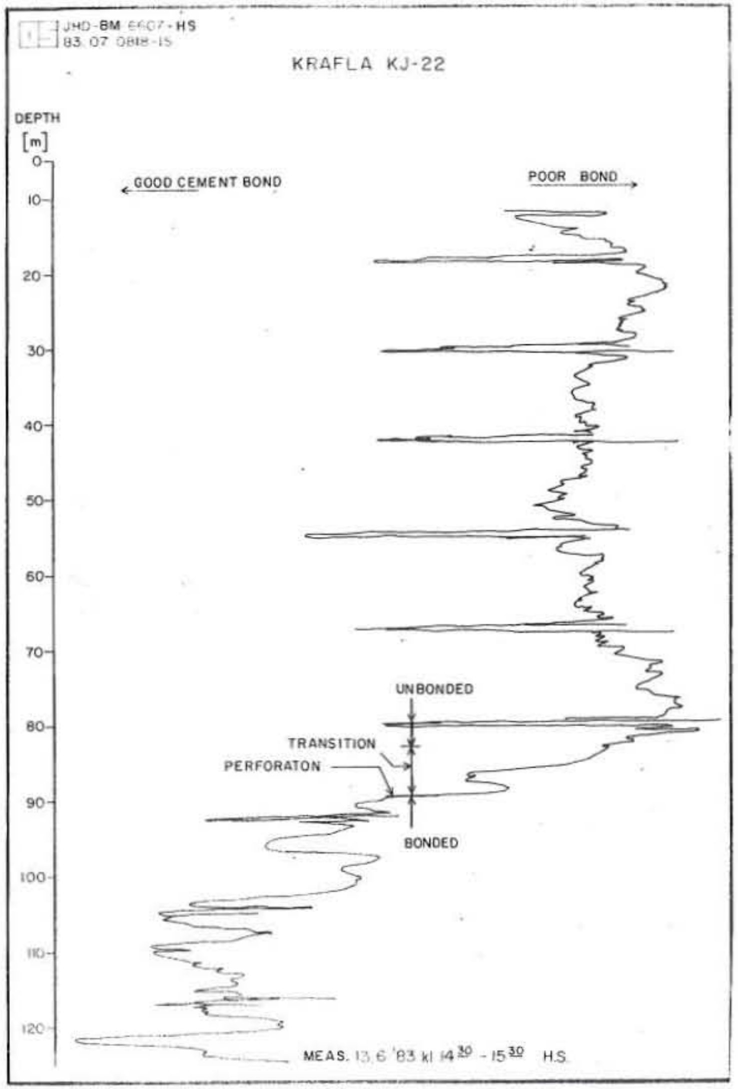

Fig. 4.11 Final cement bond log (from Gudmundsson et al., 1983a).

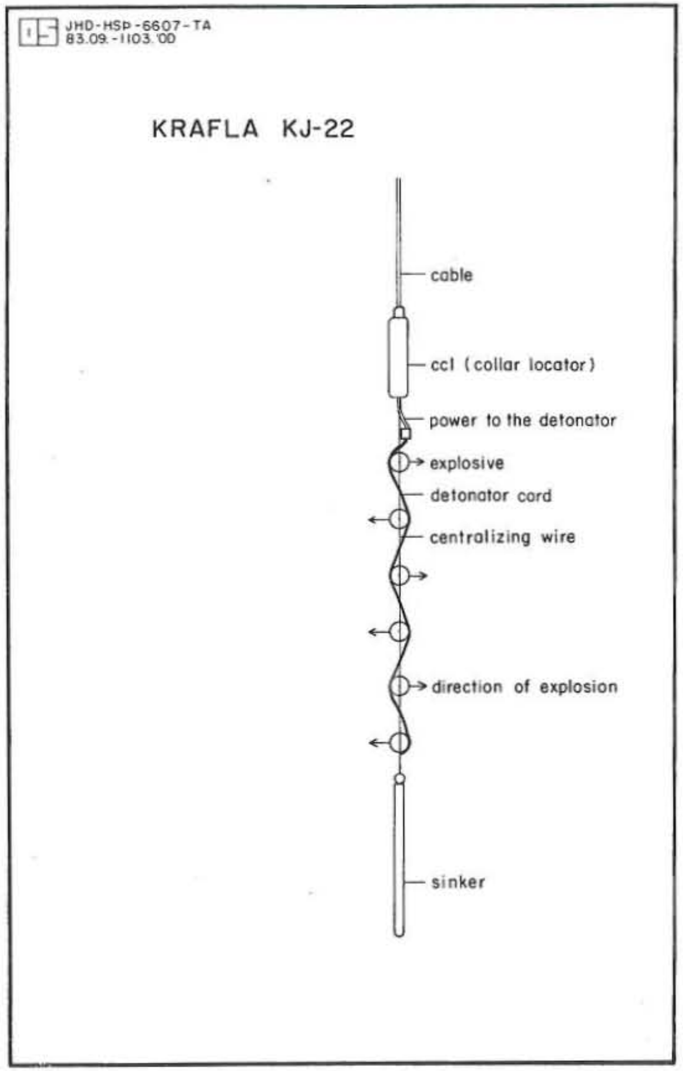

Fig. 4.12 Arrangement of explosive charges for casing perforation (after Gudmundsson et al., 1983a).

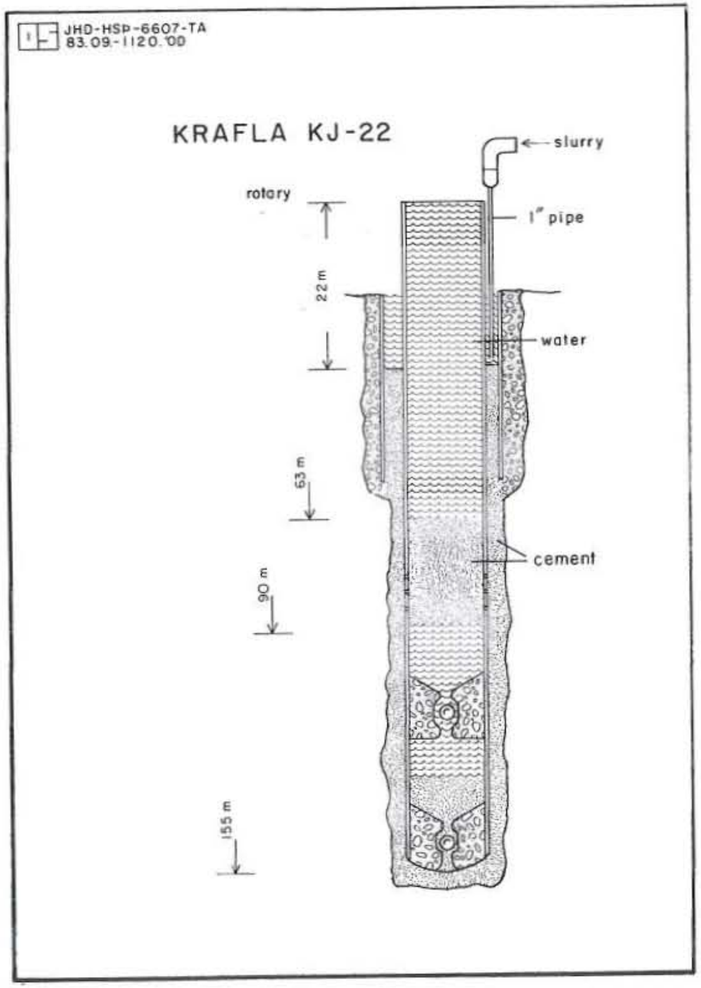

Fig. 4.13 Cementing of the annulus.

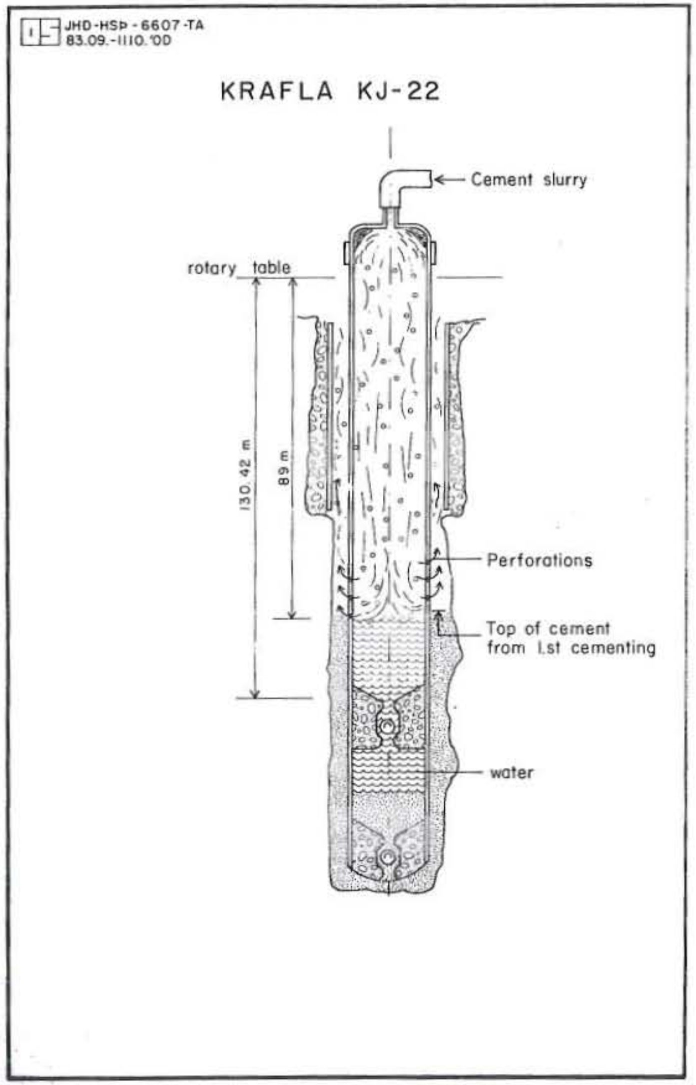

Fig. 4.14 Cementing through perforations in the casing (squeeze cementing).

showed, that the cement slurry had started to set (Fig. 4.10). After 13 hours, the 5th CBL was run based on the results (Fig. 4.11) and a decision was made to perforate the casing. The arrangements of explosives, detonator and casing collar locator (CCL) was made and the perforation was carried out successfully. Fig 4.12 shows the explosive arrangement. The perforation was checked by circulating water down through the 13 3/8" casing and up the annulus (see Fig 4.13).

The uncemented part of the casing was cemented using G-class cement (silica flour, perlite) and 2-3% $CaCl_2$. A proper mix of slurry (sp.gr. = 1,61) was pumped through the 13 3/8" casing up the annulus. (see Table 4.3) The total amount of cement used in this job was 12.9 tonnes.

After the cement set, the level was measured in the annulus, and it was found to be 22 m from the rotary. This unbonded part of the hole was filled with a proper mix of slurry using a 1" steel pipe extending to the top of cement in the annulus. The work required 12 tonnes of Portland cement and 2-3% accelarator. Fig. 4.14 shows the technique used.

Table 4.2 The 2nd cementing data for 13 3/8"casing

Time hours	Specific gravity	Slurry re-circulating pump pressure (bars)	RPM of slurry pump	Water jet pressure (bars)	Returns	Remarks
17.30	1.53	25	1540	7.58	water	
17.32	1.64	47	-	-	-	
17.34	1.65	46	-	-	-	
17.38	1.61	42	-	-	-	
17.40	1.63	45	-	-	-	
17.43	1.65	45	-	-	-	
17.45	1.61	45	-	-	-	
17.48	1.72	45	-	-	-	
17.50	1.58	46	-	-	-	
17.53	1.62	46	-	-	-	
17.55	1.61	45	-	-	-	
18.00	1.62	45	-	-	-	
18.00	1.62	46	-	-	-	
18.07	1.16	Return slurry specific gravity				slurry pumping stopped
18.09	1.16	Return slurry specific gravity				

4.3 Drilling of the 12 1/4" hole

Drilling continued in the 12 1/4" hole after the casing float collar and the casing shoe had been drilled out. Just below the casing shoe, during drilling in the formation, the hole collapsed (Fig. 4.15). The cave was cemented by forcing the string into the cuttings. This was done mainly to cement the cuttings for better cleaning of the hole. It was very hard to drill as cuttings did not come out of the hole. In order to overcome this problem, the drilling fluid was changed from light mud to heavy mud. In this way a depth of 208 m was reached within a few hours. At this point, fragments of a lost centralizer were found that was lost while running and taking out the 13 3/8" casing.

After this process, the hole collapsed for the second time. The same method as before was carried out, with the exception that hot water was now used for mixing the cement (hot slurry). The hot water was taken from the nearby well (KJ-21) at 60°C. This was done to accelerate the setting time of the cement.

The next phase of this hole (155 m to 567 m) was drilled using heavy mud. (specific gravity 1.16).

Before running the 9 5/8" casing, a temperature log was carried out through the drilling string, and the temperature build-up at the bottom of the hole was monitored for a short time (30 minutes). From the down and uphole logging the rate of temperature build-up in the well was roughly estimated (Fig. 4.16). The monitoring of the temperature buildup of the hole is helpful in judging whether the string can be pulled out without the risk of a blow-out.

4.3.1 Cementing of the 9 5/8" casing

Before discussing the cementing of the well it is worth mentioning the specifications of casing hardware and cement materials used in KJ-22. Specifications of the casing: N80,

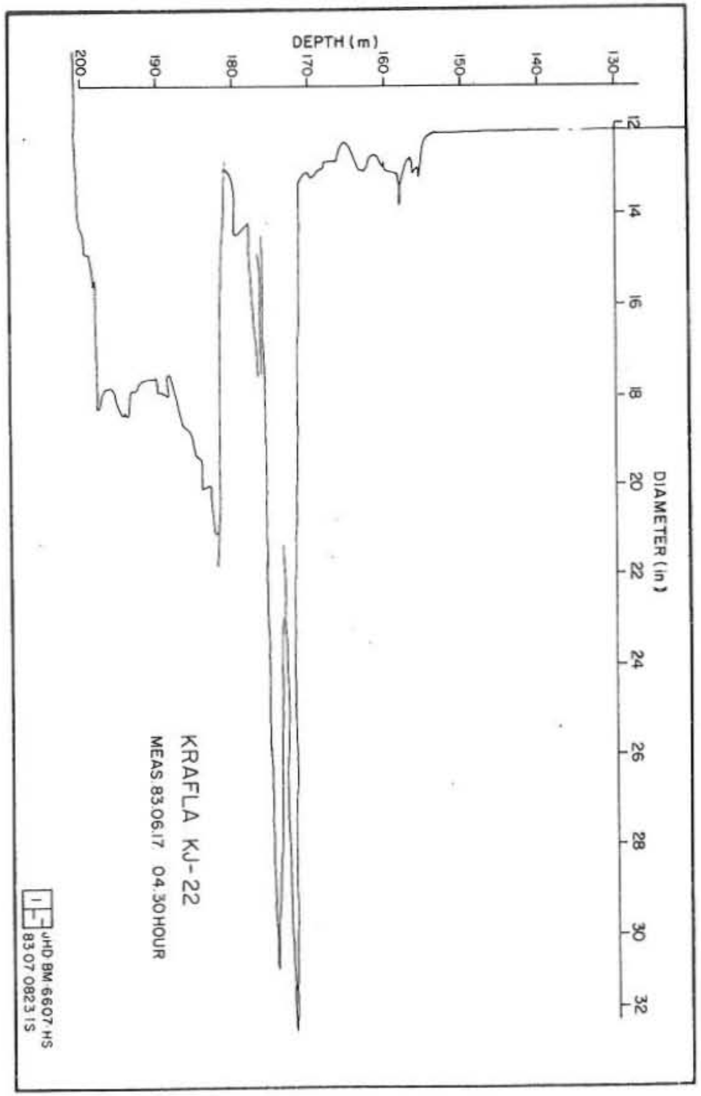

Fig. 4.15 Caliper log for 12 1/4" hole (from Gudmundsson et al. 1983a).

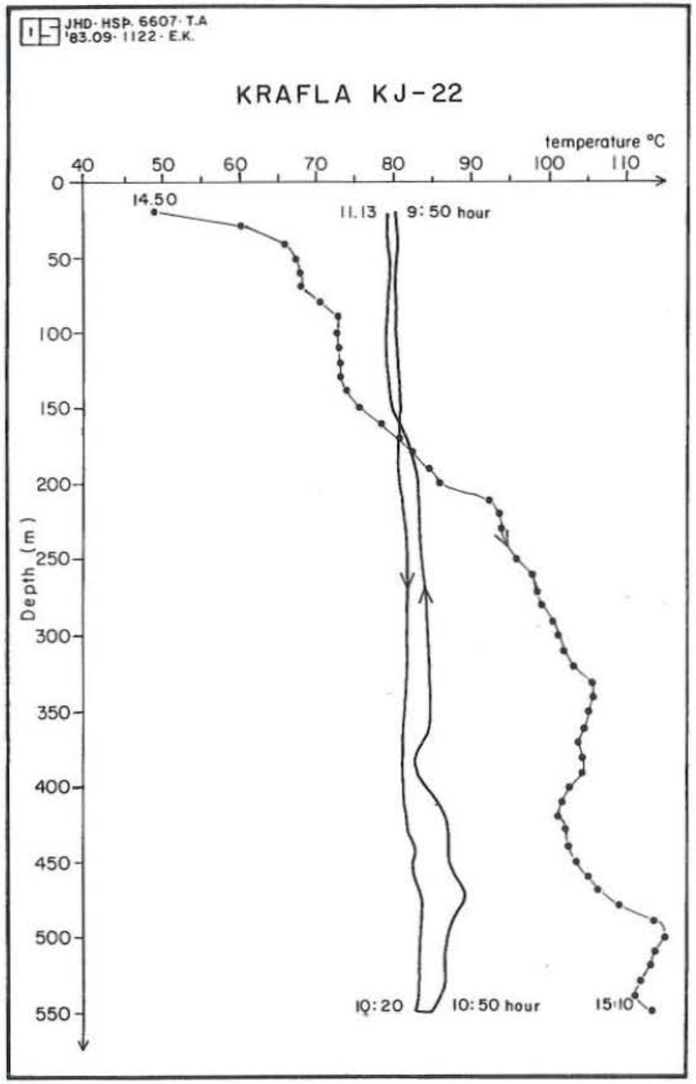

Fig. 4.16 Temperature log before cementing of the 9 5/8" casing (from Gudmundsson et al., 1983b).

9 5/8", 43.5 lb/ft, buttress thread. Total length of casing 564.87 m. Specification of the float collar: 9 5/8" Baker model "B" duplex cement float collar. 43.5 lb/ft/buttress box/pin. Specification of casing shoe: 9 5/8" Baker cement float shoe with 9 5/8", 61 lb/ft buttress box.

When planning the cementing job, it is important to consider the available cementing equipment. Figure 4.17 shows the equipment for preparing the cement mix storage of the cement in silos and pumping of the slurry. The equipment for the cementing and for the dry cement mixing and slurry mixing units are shown in Fig. 4.18 and Fig. 4.19 respectively.

The running procedures for the casing is as follows:

a) Run the 9 5/8" casing to 564 m. b) Run the stab-in connector at the lower end of the drill string and connect the string to the float collar in the 9-5/8" casing. c) Fill up the casing with water. d) Circulate cold water until the recommended return temperature is obtained (< 30°C). e) Check for any leakage that may be caused by improper function of the stab-in connector seal. This can be detected as water level rises inside the 9 5/8" casing.

The cement usage for the inner-string method is estimated as follows: a) the numbers 1 - 5 are as indicated in Fig. 4.20.):

1.	9.16 l/m x 539.43 m	=	4941 l
2.	30.98 l/m x 155.65 m	=	4822 l
3.	22.90 l/m x 409.22 m	=	9371 l
4.	38.95 l/m x 25.44 m	=	990 l
5.	76.04 l/m x 2.13 m	=	175 l
		Total	20300 l

The total estimated slurry = 2 times the calculated amount = 40600 liters.

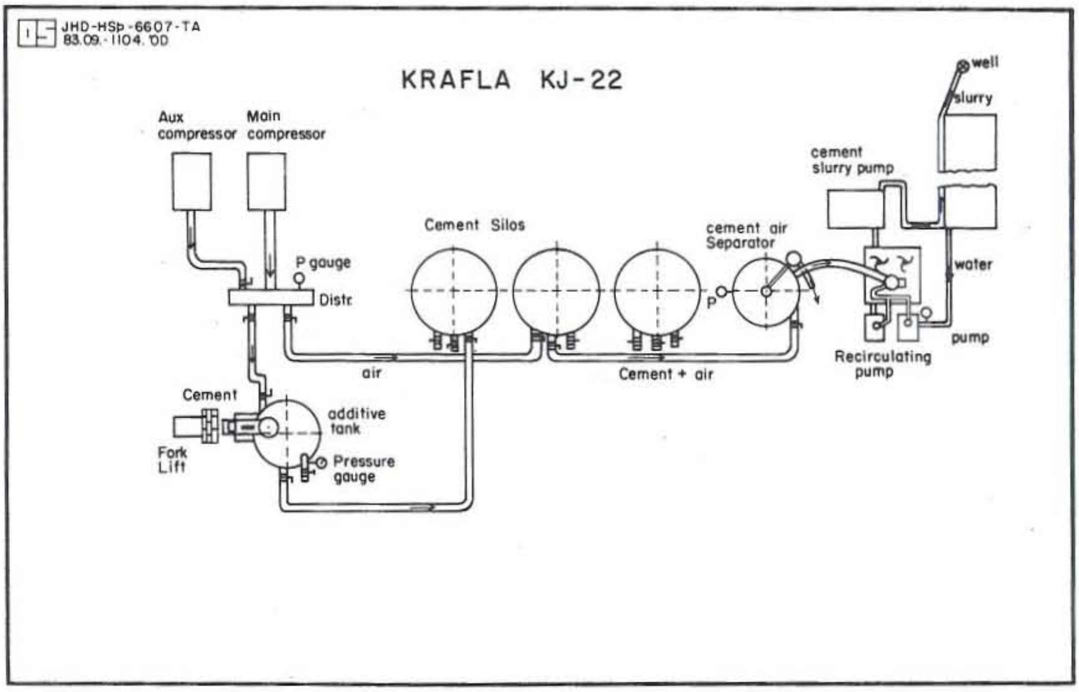

Fig. 4.17 Cement storage and transport.

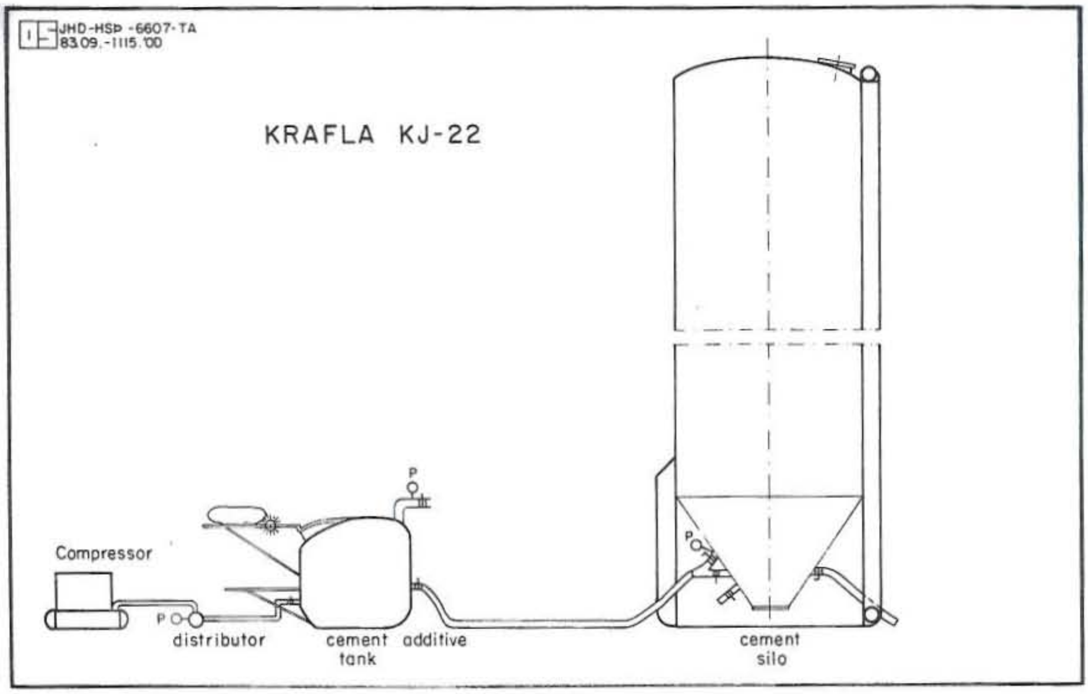

Fig. 4.18 Cement dry mix equipment.

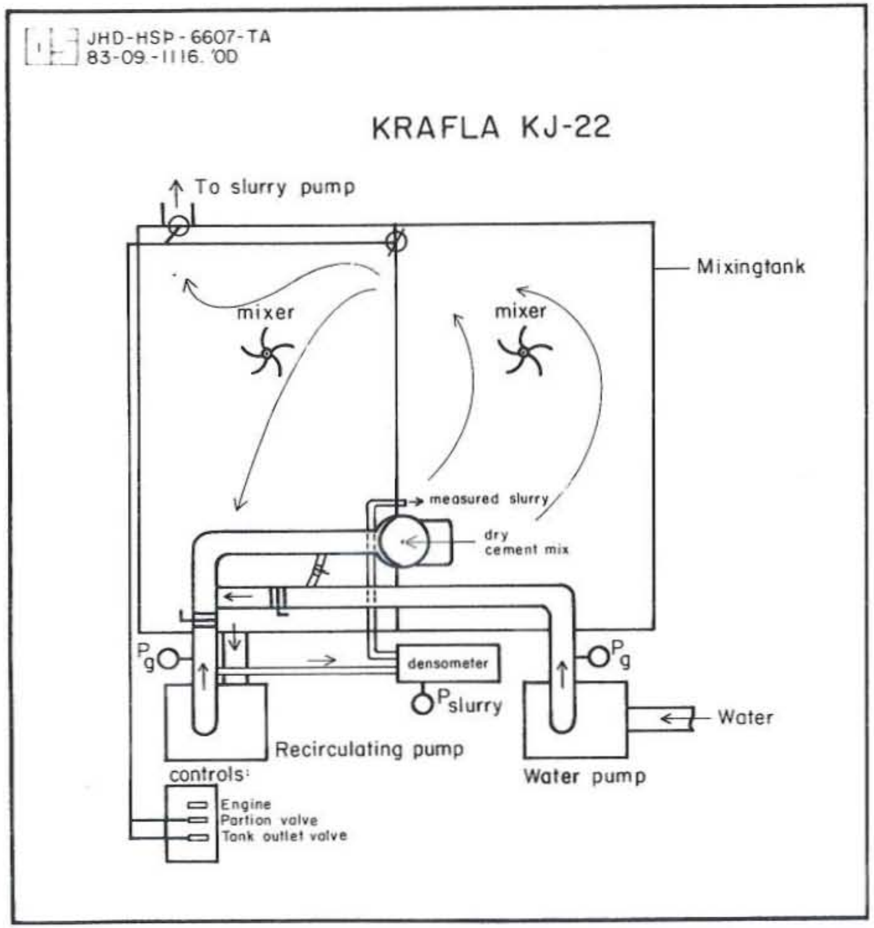

Fig. 4.19 Cement pumping equipment.

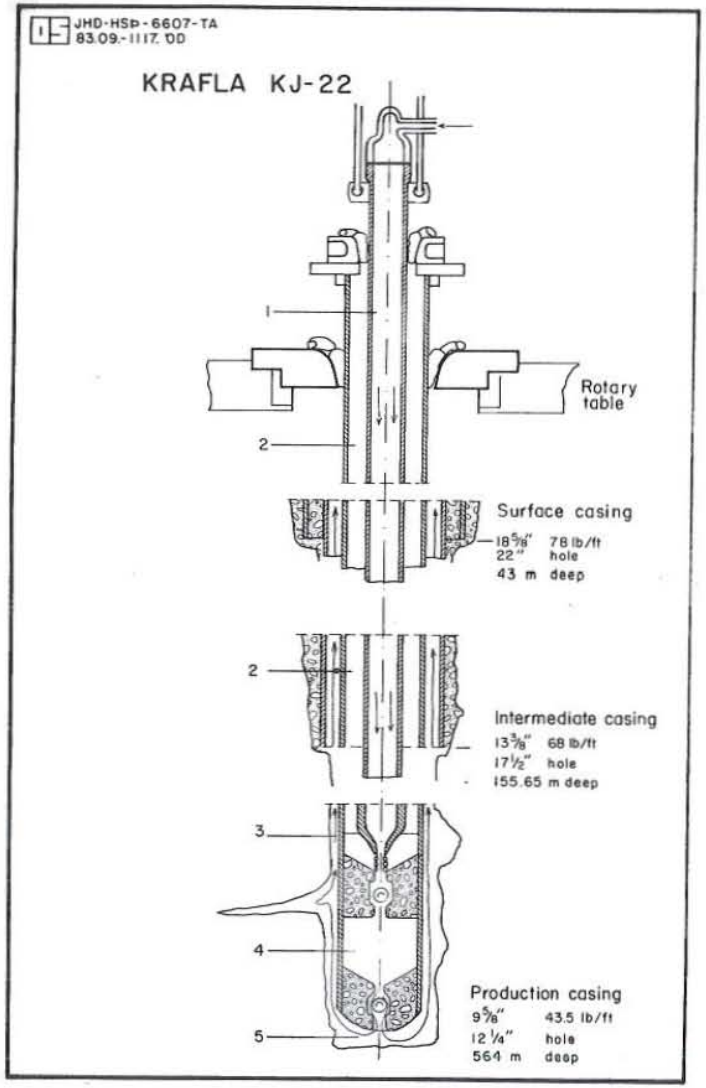

Fig. 4.20 Inner string cementing technique
for 9 5/8" casing.

This is the calculated amount of cement slurry that will be pumped. The actual quantity of cement to be used is heavily dependent on the specific gravity (sp.gr.) of the slurry. The cement that was used for KJ-22 was a G-class cement mixed with silica flour, perlite and other additives like retarder and bentonite. The existence of perlite in the cement makes the mix light sp.gr. 1.6 as compared to 1.8

As can be seen, G-class cement + silica + perlite is advantageous in two ways: a) it is resistant to high temperature, due to the presence of silica flour; and b) it gives a light cement column and reduces the risk of breaking the formation. The specification of the G-class cement givenby the manufacturer for the 1.61 sp.gr. slurry was as follows: cement yield = 1027 l/tonnes; water required = 66,45% by weight of cement. Hence the calculated value of cement is 40600 liter x tonne/ 1027 liter = 39,53 tonnes of cement. The water required: 26.3 m3.

<u>The pumping time.</u> As said before, because of high temperature and a high solids content of the mixing water, one should know the pumping time in advance, as there may be an early setting of the cement. In order to minimize this risk, it is advisable to pump as fast as possible. A risk connected with high pumping rate is however the fracturing of the formation, which may cause loss of slurry into weak formations that do not stand the frictional pressure and pressure exerted by the cement column. It is thus wise to compromise as regards the pumping rate.

The estimated pumping rate was 800 l/min, and the total pumping time would thus be 40600 l x min / 800 l = 51 min. The cement required in this particular job was 38.8 tonnes G-class cement and 25 kg of tannin. The tannin was mainly used as thinner to preflush the mud layer which had been formed on the wall of the hole during drilling. As was mentioned earlier, this part of the hole was drilled with heavy mud, which may form a thick wall cake that results in a poor cement job.

4.4 The directionally drilled hole

This is the part of the hole which taps the reservoir between 567 and 1878 m. According to the geoscientific information, the hole is targeted to intersect the north-south (NS) trending vertical and parallel fractures inclined approximately 3° - 5° (see Fig. 1.1).

After the setting of the production casing, the hole was drilled straight with a 8 1/2" bit, to a depth of 576 m. At this depth a moderately soft formation was detected, and deviation of the hole was then started to the desired direction, using the Dyna-drill and a 2.5° bent sub. According to the tentative drilling programme the kick-off point (KOP) was intended close to 350 m.This was planned mainly because of the following four resons: a) To reach the target area at as small an inclination of the hole to the vertical as practicable. As the plan for KJ-22 showed, it was intended to use 1.5° bent sub at a shallow KOP (350 m). However, as the plan was changed, a 2.5° bent sub was used at the KOP (576 m) see Fig. 4.30. b) To minimize or avoid the risk of high temperature effect on the Dyna-drill, as it is sensitive to temperature. If the working temperature exceeds 120°C there is a risk of destroying the rubber stator. c) The trip time for a deep KOP is greater than for a shallow KOP. This is especially significant if there is a need to change the bit or downhole motor several times. d) The shallower the KOP the easier it will be to pull out the string and less danger of key seating. The danger of key seating is similarly reduced by starting deviation at a shallow depth, and increasing the angle more gradually. In case of fishing being required, it can be handled more economically and with less effort.

Due to the problem of caving below the anchor casing shoe, the shallow KOP was changed to a deep KOP at a depth of 576 m in the straight hole. The whole deviating processof KOP can be summarized as follows: a) The hole was filled with mud which was circulated until the right properties were obtained. The mud was used mainly for safety reasons, as the circulation rate through the downhole motor is less than is required for conventional water drilling. b) The drilling string was taken out of the hole and replaced by the KOP assembly. c) The drilling fluid was circulated until return was obtained with the downhole assembly in tension. d) By removing the kelly, a directional survey was made through the drill pipe. e) According to the information from the surface read-out instrument, the direction was corrected by a slight turn of the rotary table. f) The instrument was taken out, and the rotary table was locked. This was done to prevent any effect of mechanical torque on the drilling assembly. g) Drilling was carried on by keeping an eye on the pump pressure and strokes per minute of the pump. The bit weight indicator was also used to monitor the drilling process.

4.4.1 The deviated hole assembly

Fig. 4.21 shows the kickoff point assembly. A journal bearing tungsten carbide insert bit was used in the straight hole, as has been found effective over a long time of Icelandic geothermal drilling. If subjected to a very high rotational speed such a bit has a very short lifetime due to the journal bearing. It can similarly not withstand high impact loads. This type of bit is thus not suitable for a downhole motor where high rotational speed and low bit weigths are required. For this reason, a milled toothed bitwith roller bearings is better suited for the Dyna drill. The operational parameters for the Dyna drill, are shown in Table 4.3 -4.4.

The Dyna drill is a positive displacement motor which can be operated either with mud or air (Smith Int. Inc., 1977). The use of the Dyna drill avoids the rotation of the downhole assembly except the bit and in some cases the cross-over sub if there is any. The rotation of the bit is produced by the drilling fluid passing through the downhole motor. The rotational speed (N) is proportional to the pump rate (Q). Torque (T) and the pressure drop (dP) are also important parameters which one should take into

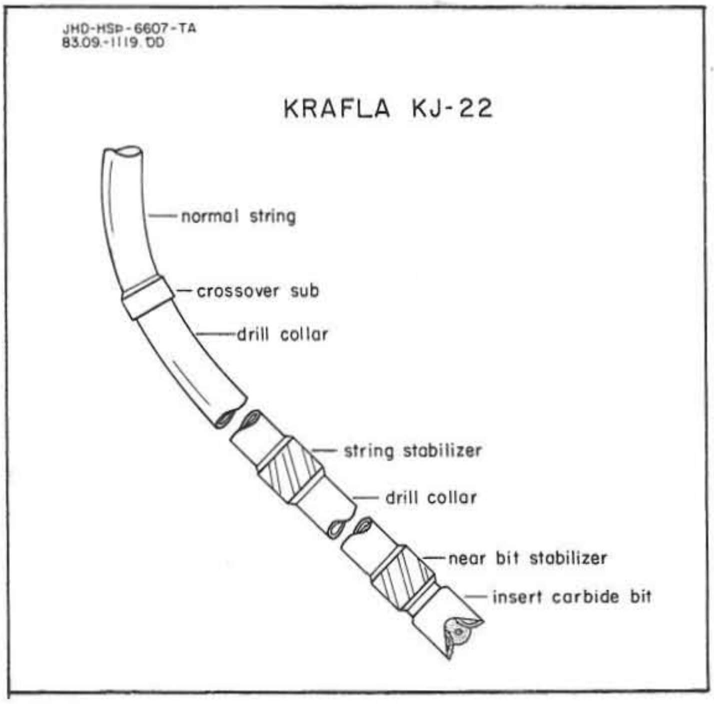

Fig. 4.21 Kick-off point assembly.

Table 4.3 DYNA-DRILL opration parameters

Tool size	Hole size	No. of stages	Pump rate l/min	Bit RPM	Differential pressure, psi		Available torque ft/lbs
					Motor	Bit	
61/2" DELTA 500	8 3/8"- 9 7/8"	3	(946- 1325)	(292- 433)	360	(150-500)	810

account. The torque produced while drilling and the pressure drop through the motor depend on each other. The right application of weight on the bit and the pump pressure also plays an important role. If excessive weight is applied, the bit could reach a stagnation point and the gauge pressure will increase rapidly. This is the sign of an incorrect operation.

For well KJ-22, the Dyna drill was used only between 576m to 628m and the angle built at that maximum depth was 7.6°. In short, the Dyna drill was used to drill 52 m whichtook 6.5 hours.

Under normal conditions the bent sub gives approximately the desired inclination of angle per certain unit length. A 2.5°/m bent sub was used in KJ-22. The angle which had been made previously (7,6°), was to give the right direction to the angle build-up assembly. The use of any of the specialized device such as the Dyna drill and the bent sub was avoided in building up further. This assembly consists only of the normal or conventional down hole drilling assembly (see Table 4.6). But the techniques applied in this assembly and in the straight hole assembly are not identical.

In the angle buildup assembly, the major role is played by the stabilizers and the drill collars (see Fig. 4.22). The rest is a matter of technique and a question of the number and size of stabilizers and drill collars needed.

The assembly to maintain the angle is more or less the same as the conventional downhole assembly (see Table 4.7). As indicated in Fig. 4.2, some delay from the tentative drilling plan occurred due to a key seating problem. As was discussed before, key seating is usually caused by a rapid angle drop or a rapid angle build-up. At 600 m where the key seating problem appeared, the dog leg severity was 5.59/30 m. The cause of this problem was found to be a thin hard formation of basalt at 600 m sandwiched with a big mass of tuff and breccia.

Table 4.4 KICK-OFF-POINT assembly

Part name	Size	Type	Description
Bit	6 1/2"	Y-21	Milled toothed roller bearing
DYNA-DRILL	6 1/2"	Delta 500	
Bent sub	6 1/2"		2 1/2° bent
Cross-over sub	6 1/2"		
Drill-collars (4pcs)	OD 6 1/2" ID 2 1/4"	API spec.7	
Cross-over sub	6 1/2"		
Normal string	OD 5"XH ID.4.276"	E,19.50lb/ft	
Kelly	5 1/4", 40'		Square cross section

Table 4.5 Angle build up assembly

Part name	Size	Type	Discriptions
Bit	8 1/2"	HPSM	Journal bearing tungstun carbide-insert
Near bit stabilizer	8 1/2"		
Cross-over sub	6 1/2"		
Drill-collars (1pc)	OD: 6 1/2" ID: 2 1/4"	API spec.7	
String stabilizer	8 1/2"		
Drill-collar (6pcs)	OD: 6 1/2" ID: 2 1/4"	API spec.7	
Normal string	OD: 5"XH ID: 4.276"	E,19.50lb/ft	
Kelly	5 1/4",40'		Square cross-section

The key seating problem was solved by a continuous rotation of the downhole assembly, while pulling up at the same time. In both cases, the key seat reamer was not used; rather, the action of breaking the key hole took place by the 6 1/2" crossover sub (X/O sub).

4.4.2 The directional survey for KJ-22

The directional surveys in this well were carried out with a drop shot inclinometer and single and double shot gyro surveys. While kicking off the hole, the single shot gyro survey was used to control the hole direction. In order to collect the downhole data, the measuring tool was run down through the drill string to the bent sub, where the mule shoe on the tool and the mule shoe key on the bent sub were engaged. All information required such as the measured depth, the inclination of the hole, azimuth, true vertical depth, latitude, and the departure were obtained by a surface recording system computer printout. (Sperry-Sun, 1981)

Beyond the KOP (628 - 1878 m) a drop shot inclinometer (TOCTCO) was used. For the last part of the hole, after the KOP, it was assumed that the direction of the hole was not changing. Hence, N73°W was taken as a constant value for all depths below the KOP. Together with the well completion test, a multi shot gyro survey was conducted as a final directional survey of the well. After obtaining the data from the directional survey, certain calculations can be carried out using four different computation methods. These are: 1) The tangential angle method; 2) The average angle method; 3) The balanced tangential method; 4) The radius of curvature method. Of these four methods, the second one will be discussed in this chapter (see Fig. 4.23 and Table 4.8).

The well servey computations are done as follows (using average angle method):

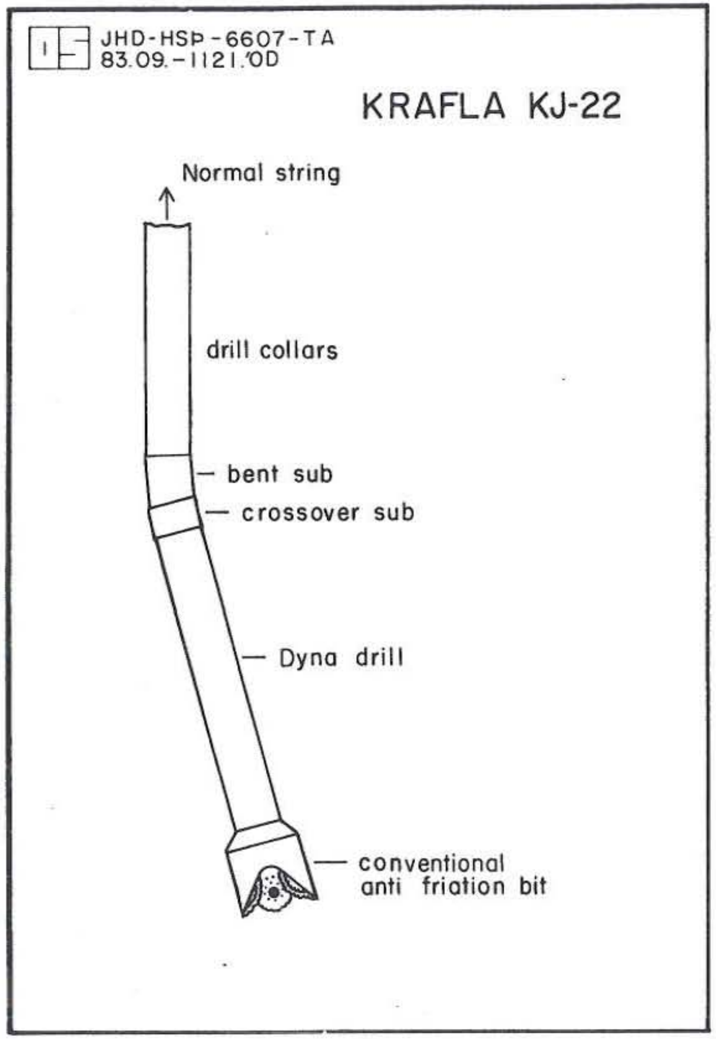

Fig. 4.22 An angle build-up assembly.

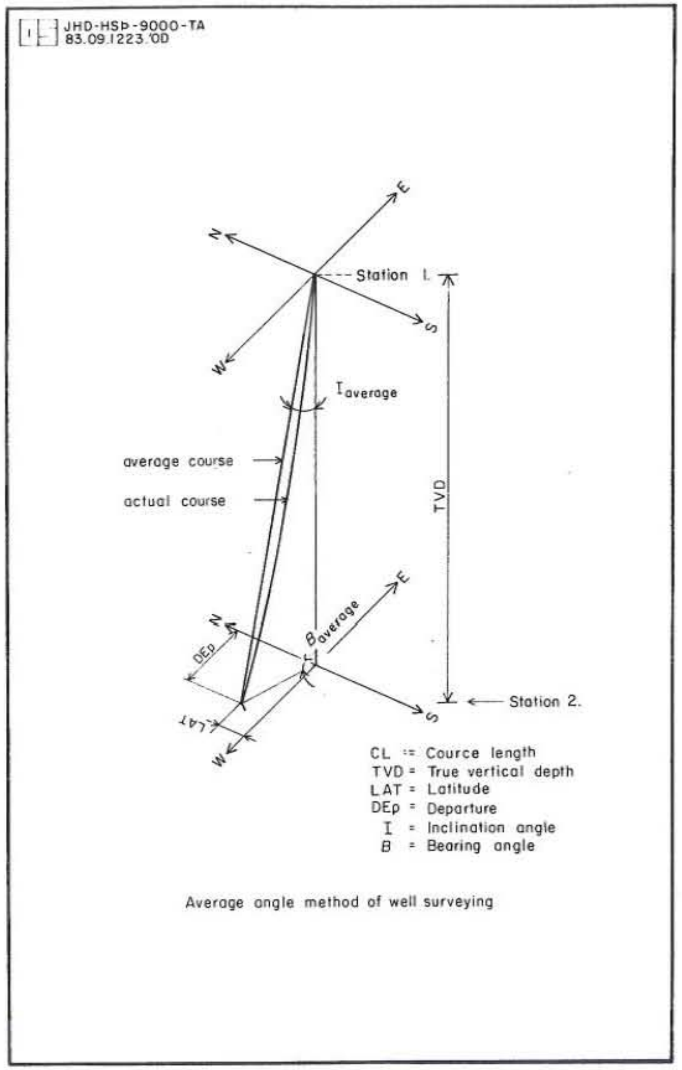

Fig. 4.23 Simplified sketch for directional survey calculation using the average angle method.

Table 4.6 Angle maintaining assembly

Part name	Size	Type	Description
Bit	8 1/2"	F-4	Journal bearing tungstun carbide-insert
Near bit stabilizer	8 1/2"		
Cross-over sub	6 1/2"		
Drill-collars (1pc)	OD: 6 1/2" ID: 2 1/4"	API spec.7	
String stabilizer	8 1/2"		
Drill-collars (7-9pcs)	OD: 6 1/2" ID: 2 1/4"	API spec.7	
Cross-over sub	6 1/2"		
Normal string	OD: 5"XH ID: 4.276"	E,19.50lb/ft	
Kelly	5 1/4",40'		Square cross section

Table 4.7 Directional survey result (Calculated using average angle HP-41 programme)

MD (m)	IN deg	AZ deg	TVD (m)	LAT (M)	DEP (m)	VS (m)	DLS deg/30m
550	0	0	550.00	0	0	0	0
560	0.97	268.0	560.00	0	0.14	0.13	2.91
579	1.16	343.7	579.00	0.28	0.53	0.59	2.08
598	4.10	283.0	597.97	0.89	1.18	1.13	5.80
619	7.60	281.0	618.85	1.36	3.36	3.61	5.01
647	9.30	283.6	646.53	2.26	7.52	7.85	1.87
685	10.20	288.0	683.96	4.05	13.82	14.40	0.92
741	12.14	285.0	738.88	7.16	24.32	25.35	1.08
798	14.00	287.0	794.39	10.72	36.76	38.29	1.01
851	15.70	-	845.56	14.75	49.95	52.08	0.96
912	18.00	-	903.87	19.99	67.08	70.00	1.13
968	19.00	-	956.98	25.19	84.08	87.77	0.54
1020	21.00	-	1005.84	30.39	101.09	105.55	1.15
1072	23.20	-	1054.00	36.13	119.85	125.17	1.27
1120	25.20	-	1097.74	41.91	138.76	144.95	1.25
1170	27.20	-	1142.55	48.39	159.97	167.13	1.17
1225	27.80	-	1191.18	55.90	184.53	192.81	1.12
1300	28.60	-	1256.99	66.42	218.94	228.79	0.30
1400	30.50	-	1343.67	81.00	266.63	278.66	0.30
1500	31.80	-	1428.85	96.31	316.72	331.04	0.60
1600	33.80	-	1512.40	112.38	369.27	385.99	0.40
1700	36.20	-	1593.98	129.29	424.57	443.82	0.70
1800	37.90	-	1673.41	147.05	482.68	504.58	0.50

TVD_2 = $CL_2 \cdot \cos Iavg$

LAT = $CL_2 \cdot \sin Iavg \cdot \cos Bavg$

DEP_2 = $CL_2 \cdot \sin Iavg \cdot \sin Bavg$

DLS = dog leg severity

cosD = $\cos Ic \cdot \sin I2(1-\cos Bc)$

Iavg = $(I_2 + I_1)/2$

Bavg = $(B_2 + B_1)/2$

where I_1 = Inclination of the first section; CL= course length; I_2 = Inclination of the second section; TVD = True vertical depth; B_1 = Angle of direction of the first section; B_2 = Angle of direction of the second section; LAT = Latitude; DEP = Departure; Bc = The change of direction over the interval; Ic = The change of inclination over the interval; D=The total angular change.

The planned and actual directional programmes are shown in Fig. 4.24.

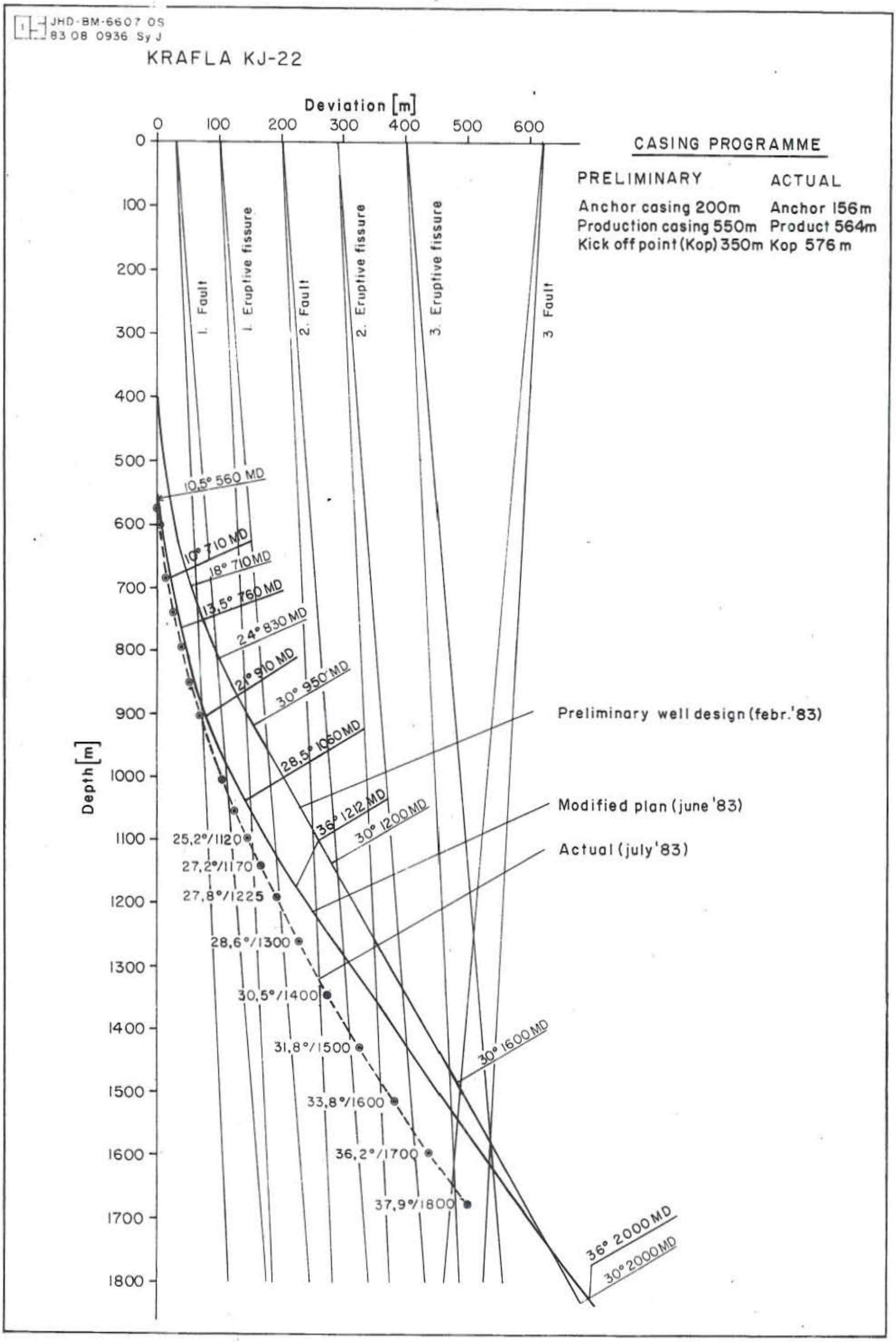

Fig. 4.24 Planned and actual directional programme
(from Gudmundsson et al., 1983c).

5 DISCUSSION

In planning a geothermal well, it is possible to make decisions on many things, such as the capacity of the rig and the accessories, depth and types of casings, type of drilling fluid etc. Many things are decided on in the planning stage, but the actual situation may force these decisions to be changed. For instance, the exact depth of casing cannot be determined beforehand. It can vary within certain limits, based on the actual conditions. The wellhead equipment and the casings are designed for the maximum expected pressure and temperature. It is assumed that these will be experienced during shut-in period after discharging. As problems differ from place to place, even within a single geothermal field, there should be ample room for flexibility in drilling plans.

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