COMPARISON OF DRILLING IN HIGH TEMPERATURE FIELDS IN OLKARIA, KENYA AND KRAFLA, ICELAND.

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ABSTRACT

This report is divided into two parts. The first one is an account of drilling activities observed by the author while on a six weeks practical training in the Krafla field in northern Iceland. These are on inner string (stab-in) cementing, directional drilling and fishing in a deviated hole. The second part compares and contrasts the drilling practices of the Olkaria geothermal field in Kenya with those of Krafla. The emphasis is more on explaining the different approaches rather than criticising them, as an outright comparison would be deceitful. This is because the approaches can vary from one area to another one depending on the formation, level of water table, position of production acquifers, etc.

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1 INTRODUCTION

1.1 Scope of work

This work is the result of a six months fellowship awarded to the author by the United Nations University to study drilling technology at the UNU Geothermal Training Programme at the National Energy Authority of Iceland.

The training started with five weeks of introductory lectures on the status of geothermal development in the world, borehole geology, geochemistry, geophysics, discharge measurements, drilling technology, casing design and cementing, and reservoir engineering. These provided a good background on later lectures on the low and high temperature geothermal utilisation and its application in industry. They also certainly helped in showing how to integrate the various disciplines when planning for geothermal projects.

Because of the need in the specialised course on drilling technology to integrate both theoretical and practical training, and the fact that the rig operations could not be modified to the needs of the trainee due to the high operating costs, there was a flexibility in the course structure. This allowed for movement to the field whenever something of importance was taking place on the rig.

During the practical training period, which followed the lectures, there was a one week excursion and a few separate trips to the main geothermal fields in Iceland where seminars on case histories were given. These also included visits to industries where geothermal energy is utilised. The author spent altogether about six weeks on the Jotunn drill rig in the Krafla high temperature area. The last two months or so of the training were spent in a literature survey and in the preparation of this report.

2 DRILLING PRACTICES OBSERVED IN KRAFLA

2.1 Cementing of the 9 5/8" casing in well KJ 19

Cementing of casing strings in geothermal wells serves several purposes. The most critical, however, are (Smith, 1976): a) to prevent the mixing of fluids from the various acquifers in the formation, b) to prevent corrosion of casings by the fluids, c) to bind the casing firmly to the formation, and d) to provide safety during further drilling.

The most common defect in otherwise good cementing jobs is to have water pockets trapped by cement in the annulus between two casings. When the well heats up, the water builds up pressure as part of it turns to steam and this may be enough to cause a casing collapse. This may lead to a low output from the well if reaming, which is both time consuming and expensive, is not successful.

The high temperatures involved in most geothermal fields have also a significant effect on the cement quality after it has set (Smith, 1976). Some cement compositions show a deterioration in compressive strength when subjected to the well conditions. This may eventually lead to the cracking of the cement which then allows mixing of hot and cold fluids in the well. Obviously this should be avoided as it may lead to the quenching of an otherwise good well. A good cementing operation, therefore, requires the filling of the annulus properly with the right cement composition.

Depending on the expected final depth and geological conditions, the production casing (9 5/8") depth is between 600 m and 700 m in most wells in the Krafla field. Well KJ19 was drilled to 654m on 26/5/82. After a downhole temperature run was done, a caliper probe was put into the well to obtain the diameter of the well and check for any caving-in of the formation. This probe has three arms that are spring-loaded so that the instrument is centralised in the well (Stefansson and Steingrimsson, 1980). Movement of the arms is transmitted to a plotter inside the logging truck. The probe is calibrated before and after running into the hole. Further downhole measurements are done with probes for resistivity, natural gamma, neutron-neutron, and a casing collar locator, CCL (Stefansson and Steingrimsson, 1980).

Preparations are then made to run in the 9 5/8" casings. The guide shoe is screwed into the first casing and the float collar placed in the 3rd joint from the bottom. The actual locations of the centralisers around the casings depend very much on the quality of the well. A crooked one requires the centralisers to be placed close to each other while this may not be necessary when the hole is relatively straight. However, a typical programme in Krafla places two centralisers in the first casing, one in the next, and subsequently one after every three casings.

API N80 grade steel casings (43.5 lb/ft) a with buttress thread were used in KJ19. These have a higher strength than J55 or K55, which are more commonly used in geothermal fields, but they are not as corrosion resistant.

After the running in of casings, a free-pipe sonic cement bond log is taken (Stefansson and Steingrimsson, 1980). This is used as a reference to show 0 % cement behind the casing. Cementing the annulus should, in theory, indicate 100 % cement behind the casing. This, however, cannot be achieved in practice and more often than not, the quality is between 50-90 %. The sonic bond logging is done when well temperatures are below 100°C. This is because of temperature limitations of the electronics and the rubber within the instrument (Fig. 1). The quality of the received signal is poor when the probe is not properly centralised in the well. To improve this, centralisers are used which have diameters equivalent to the size of the particular casing string. The transmitter has a transducer fara ←

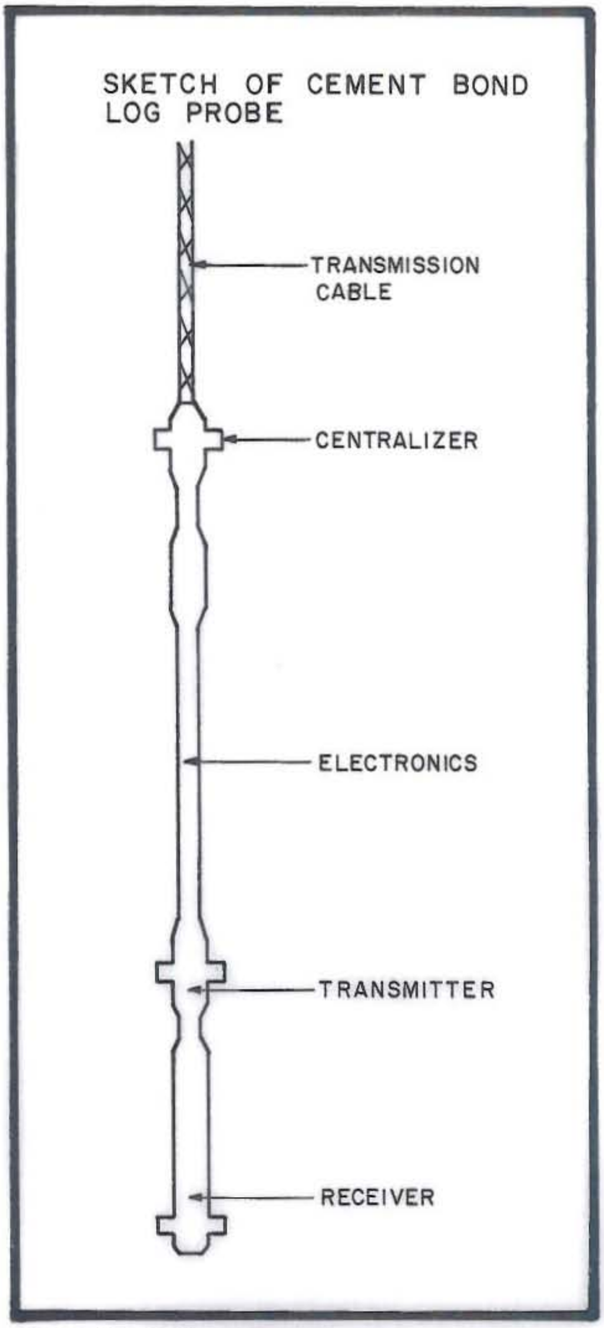

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Figure 1. Sonic cement bond log probe.

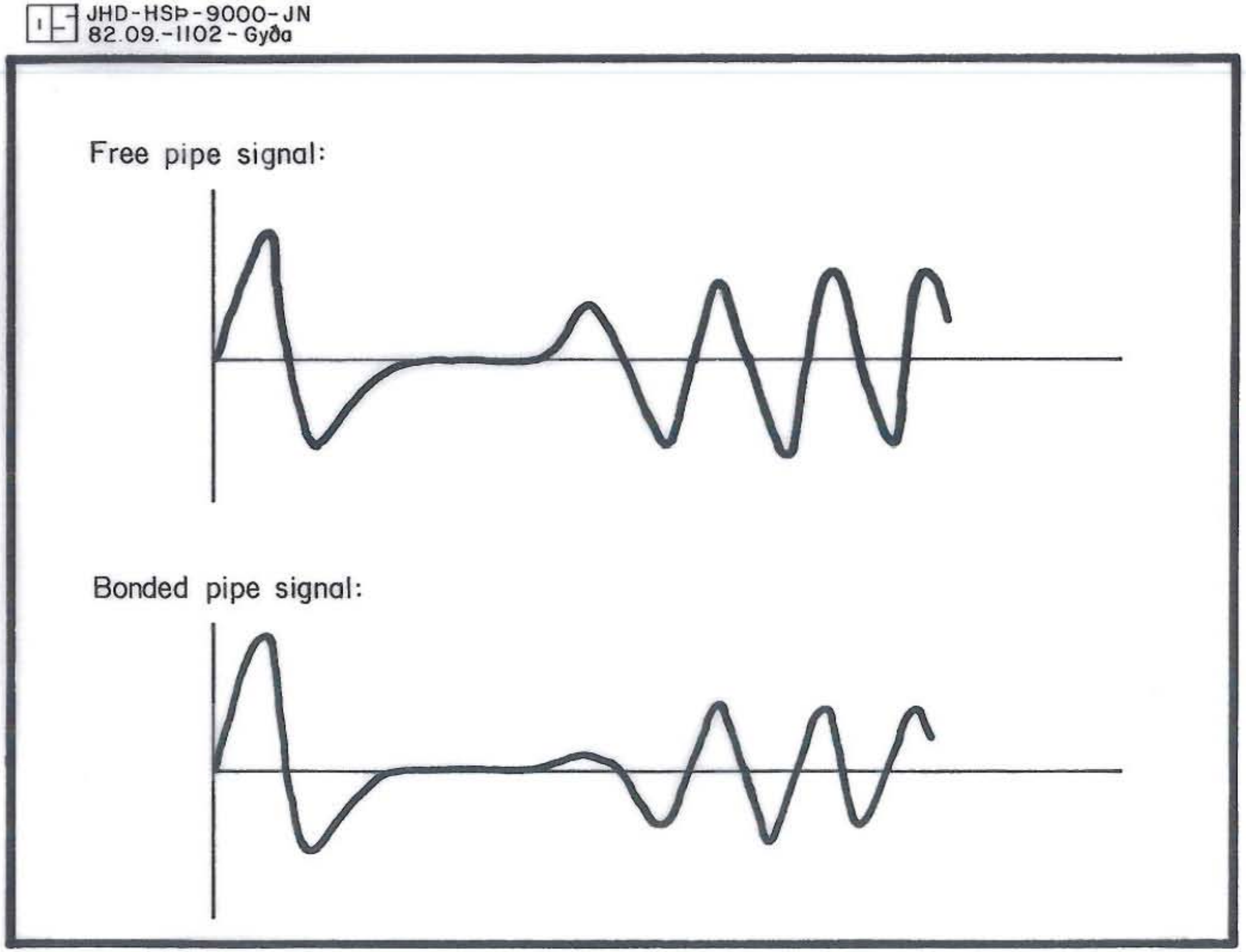

Figure 2. Sonic cement bond log signals.

which is activated by an electric current from the logging truck. A sonic signal is sent to the casing and formation. When there is good bonding of cement behind the casing, the transmitted signal is virtually absorbed and only a small portion can be detected by the receiver.Conversely, when the cementing is poor, the first signal received is bigger. This is observed with ease when the signal is displayed on an oscilloscope screen, or a plotter. Fig. 2 illustrates the free and bonded pipe signals. After completion of the sonic log, preparation for the cementing of the casing string start.

If a loss of circulation is experienced during drilling, the first task before cementing is to try to seal off these zones and, if possible, obtain circulation from the annulus. In KJ19 a calcium chloride solution was pumped into the well and forced up the annulus by water followed by a sodium silicate solution. When these solutions mix in the formation, calcium silicate is precipitated as a gelly substance and this blocks fissures that allow circulation loss to the formation. Excess calcium chloride may, in addition, accelerate the setting of the cement slurry in the fissures.

When a return of water from the annulus was obtained, cement slurry of 1.6 specific gravity was pumped into the annulus (the method employed is described later). A water loss additive (Halliburtonś Hallad 22A) was put into the water prior to the mixing with the cement. The cement composition was:

portland cement (API class G)	100.0 kg
silica flour	40.0 kg
perlite	8.5 kg
bentonite	2.0 kg

(i.e. 150.5kg of mixture/100kg of neat cement)

water ratio: 100L water/100kg of neat cement.

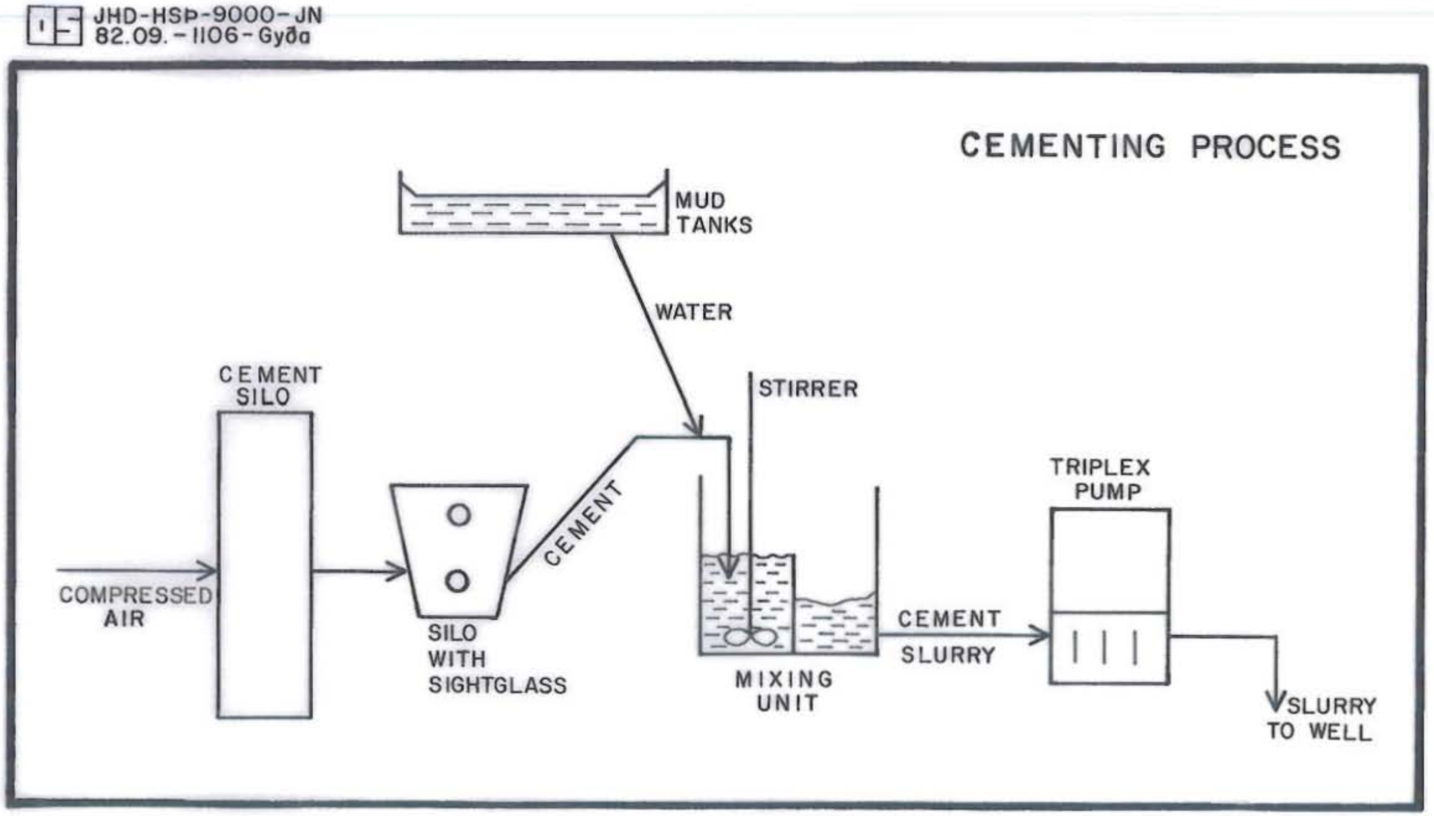

Figure 3. Cementing process.

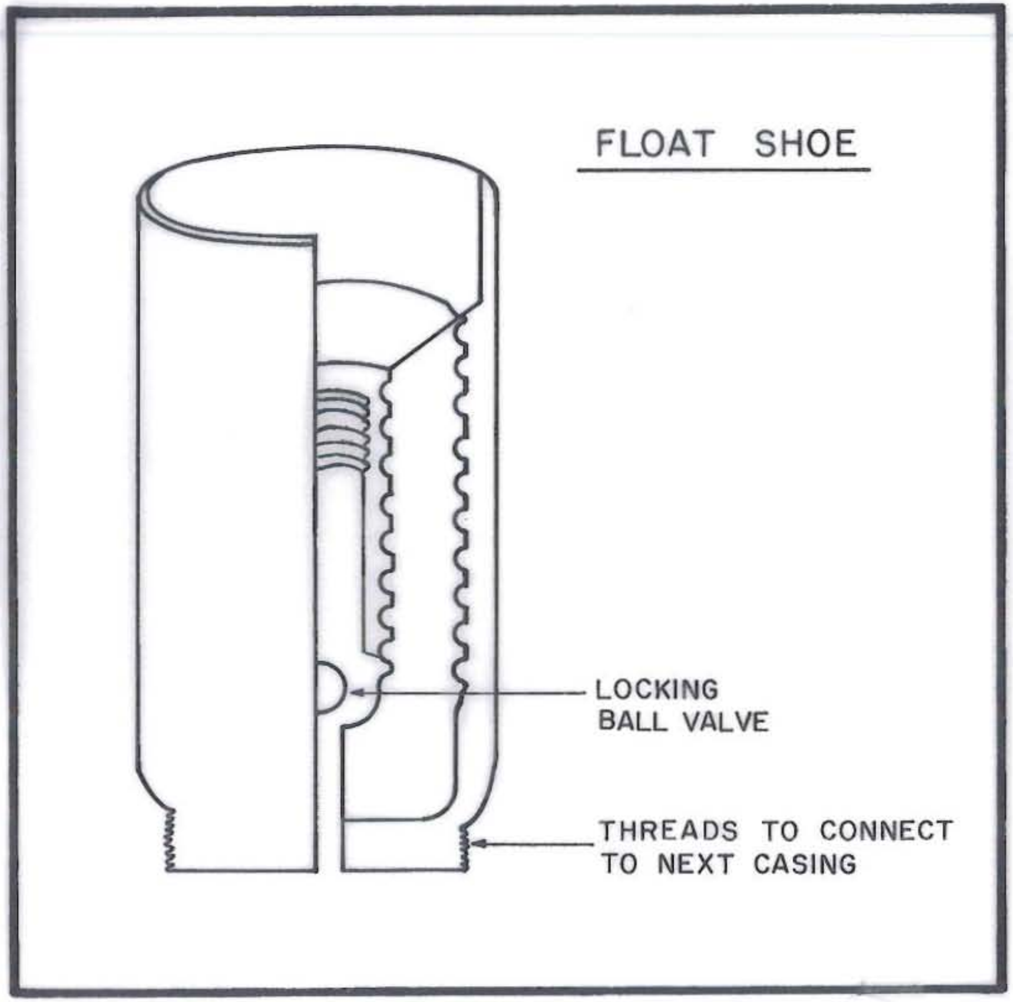

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Figure 4. Float shoe

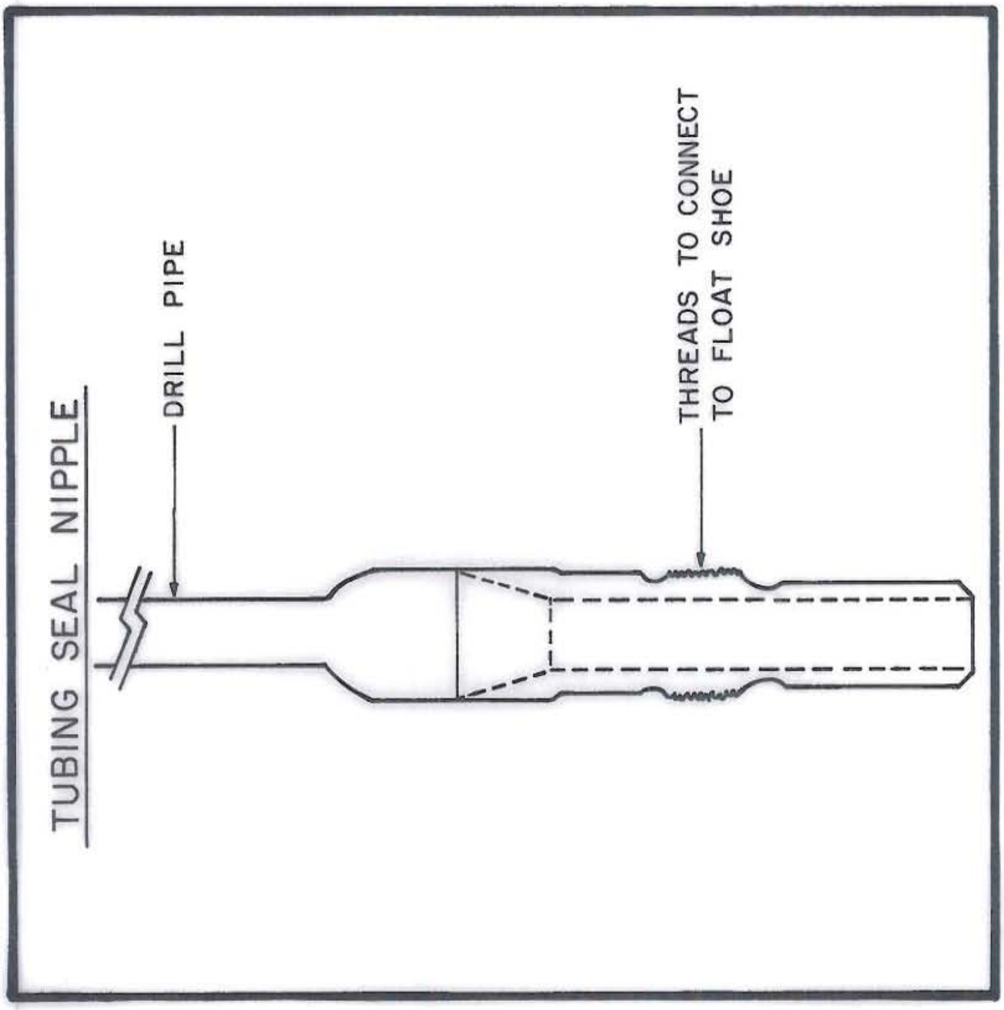

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Figure 5.

The inner string (STAB-IN) cementing method was used (see Fig. 3, 4 and 5). The technique employed here is to pump the cement slurry through the drill pipes which are coupled to the float collar (Tang,1981). Because of the smaller size of the pipes, the slurry takes a shorter time to reach the guide shoe and hence up the annulus than with the conventional method of pumping through the casing and displacing it with a plug. Pumping can also continue until return is obtained, if there is no loss to the formation.

However, after cement had been pumped for 90 minutes a back pressure was experienced, most likely due to the setting of cement in the annulus. The operation was therefore halted and the pipes disconnected from the float collar and flashed with water. A sonic bond log taken about twelve hours later indicated the top of the cement to be around 170 m from the top. The casing was perforated at this depth by firing ten charges 15 cm apart. It is important to have the holes as close as possible to the top of the cement so as to avoid trapping of water above the cement top. Water is then pumped through the casing to check for circulation through the annulus. This did not produce any results and another perforation was done 7 m above the previous one. This time a return of circulation was obtained when water was pumped through the casing.

A cement slurry was then pumped through the casing. The water column below the perforated holes acts as a plug to the cement slurry forcing it up the annulus through the holes. A return of specific gravity 1.59 was obtained indicating the annulus space was full of the cement slurry. About 60 tons of cement were used during the whole operation.

A sonic bond log was taken after drilling out the cement in the casing. This was done to ascertain the quality of the cement behind the casing. The results of this log may be slightly affected by the vibrations caused when drilling out the cement left in the casing.

2.2 Drilling of the deviated section in KJ 20

A directionally drilled well costs approximately 25% more than a straight one of the same depth (the latter being the true vertical depth). It therefore follows that before a decision to drill a deviated hole every effort is made to clearly define the target so that a reasonable drilling programme can be made.

In KJ 20 the aim was to traverse a fracture to the northeast of the site which was believed, geologically, to be either vertical or inclined at a maximum of 15° from the vertical. The tentative plan was therefore to strike this fault just below 900 m, if it was vertical or at around 1800 m if it was inclined at 15° to the vertical (see Fig. 6). It is also worth mentioning that permeability in the field is believed to be fracture controlled and hence more permeability was expected with a deviated hole than in the previous straight ones.

After a broad plan as outlined above is made, several other details have to be decideed on before drilling commences. Among the most important to be addressed to are:

a) KOP (kick off point);
b) the maximum tolerable temperature in the well for the safety of downhole motors and instruments;
c) the angle build-up rate after kick-off;
d) the drill string arrangement during and after build-up;
e) the mud motor to use for kick-off;
f) the required capacity of slush pumps;
g) directional surveying.

As this was the first time directional drilling was carried out in Iceland a Working Group was formed to make a contingency plan for the drilling operation. The group consisted of staff members of the State Drilling Contractors, the National Energy Authority, the State

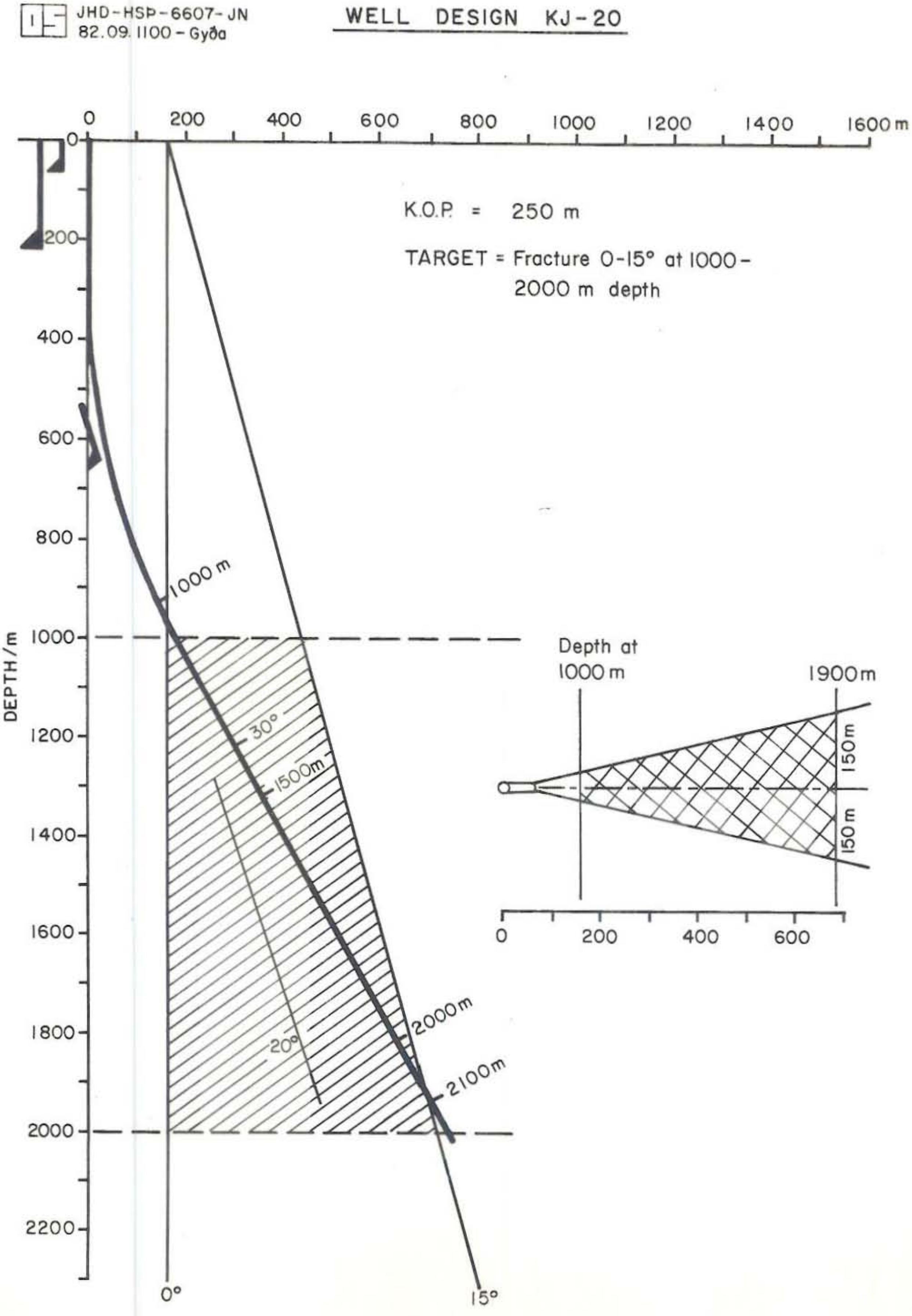

Figure 6. Directional drilling plan for well KJ-20.

Electric Power Works (who operate the Krafla power station), a directional drilling specialist from USA and a local engineering consultant. The group recommended the following well design for KJ 20: Drill a straight hole to 250 m and then kick off at that depth with a 12 1/4" bit using a positive displacement mud motor (PDM, Dynadrill). The maximum build-up angle in the 12 1/4" hole to be 20° with build-up done partially by the PDM and partially by a build-up drill string arrangement. This part of the hole to be drilled to a measured depth of 650 m. Afterwards drill with a 8 1/2" rock bit to a proposed final depth of 2150 m. The maximum build-up angle in this part of the hole below 1000 m to be 30° using a build-up string assembly. After that, to drill with a locked-in string assembly down to the final depth.

In actual drilling, however, several factors inherent in the process dictate continous modifications necessary to remain within limit of the initial target. The major ones are "bit walk" and reactive torque of the mud motors (Servco, 1980). Others, like weight on bit, drillstring rotation and position of stabilizers are adjusted depending on the way the hole is progressing. Once the KOP has been selected the initial deflection is initiated using a mud motor with a bent sub above it. The sub is accurately machined so that its bottom part is 1-3° from the vertical. A mud motor is connected to its bottom accurately aligning the toolface to the direction desired once it is inside the well. This should be adjusted to accomodate the reactive torque in the motor as mentioned earlier.

There are several methods for orienting the toolface (Servco, 1980) such as:

a) The mule shoe.
b) MMO (magnetic method of orientation).
c) Teleorienter.
d) Electronic wire line.

In KJ 20 the mule shoe method was used. This is a direct mechanical alignment of the tool. The survey instrument used to find the direction has a keyway (shaped like a mule shoe) which locks to a pin in the bent sub. The pin is in the exact direction of the toolface and hence when a survey picture is taken the direction can be readily found out. In practice, several string adjustments and corresponding orientation surveys have to be done before drilling begins.

In recent years application of downhole motors is becoming common practice in directional wells. Although the classical whipstocks continue to be used for deflection they have several disadvantages over the mud motors; the main one, however, being the fact that, when used, only an undergauge hole can be made, necessitating more trips for hole-opening. In the relatively soft formations deviation can be easily achieved with a jet bit (Servco, 1980). The latter has a relatively large side nozzle and deflection is mainly achieved by spudding.

A special characteristic of downhole motors is that they utilise the hydraulic potential of the drilling fluid (turbodrills will not function with air as the fluid) to turn the drilling bit attached to their bottom. Consequently, the drill string is stationary when they are in use. A positive displacement motor (Dynadrill) was used for deflection in KJ 20. While this has a relatively low speed compared to the turbodrill which results in a longer bearing life when drilling, its stator is made of an elastomer which degrades rapidly when temperatures exceed 120°C. This is one of the factors to consider when deciding the KOP.

Because the motor can only allow a fixed quantity of fluid within it (325 gpm for the 6 1/2" dynadrill) the resulting annular velocities are not sufficient to remove cuttings from the hole. Drilling mud is therefore mandatory for efficient hole cleaning when using the motor.

Turbodrills are also used for deflection, but because of their relatively high speeds (about 600 rpm) which on the other hand results in greater penetration rate, their bearing life is shorter, and mostly, conventional rock bits are unsuitable when using them. However, they will operate at relatively higher temperatures than the PDMs. It is therefore obvious that the choice of which motor to use will depend on the particular circumstances encountered and/or required in the field.

The Dynadrill in KJ 20 was used from 255 m for 65 m. After that drilling continued with a locked-in assembly at an inclination of approximately 18° to the vertical. Directional surveys were taken every one stand (about 30 m) with a Gyro single shot instrument.

The 9 5/8" casing was run and cemented at a measured depth of 650 m. The cementing procedure is similar to the one described in chapter 2.1. The only difference in KJ 20 was that a cement dispersant and retarder (Halliburtonś HR 12) was added to the water prior to mixing with the cement. The total volume of neat cement slurry required, allowing a 100% factor, was 24900 liters.

After completion of the CBL (sonic cement bond log), drilling resumed with an 8 1/2" bit and a locked-in string assembly. Measurements for inclination were taken by a Totco inclinometer every one stand. A light weight (10,000-14,000 lbs) was maintained on the bit so that the angle build-up would be quite small, about 0.5° per 30 m. The speed on the rotary was also maintained relatively low at around 70 rpm. The targeted inclination of 30° was achieved at 1151 m. After drilling a further 350 m, a trip was made to change the bit and add an extra string stabiliser to make the string stiffer, in order to stop any further angle build-up.

Drilling fluid leakage to the formation was evaluated every 40 m. This is a simple procedure. The return from the well is directed to one of the mud tanks and the time to fill a known height is found out. From this data one can calculate the return in litres per second. Knowing how much the pump is discharging, one can easily find the loss to the formation.

Drilling was maintained to 1822 m when, unfortunately, there was a twistoff of the string at about 130 m from the surface. Fishing operations were then started; these are described in chapter 2.3.

In deviated holes, circumstances arise when one has to increase (build-up), decrease, or hold up the inclination to the vertical. The initial dogleg, however, has to be initiated by a mud motor or the other tools mentioned earlier. Two fundamental principles are used to increase and decrease the angle (Servco, 1980). These are:

(a) The fulcrum principle: This is used to increase the angle. The drill string is made with the bit followed by a full gauge stabiliser and several drill collars. As can be seen from Fig. 7 the weight of the string acts as a downward force with the stabilizer as the fulcrum. This makes the bit tend to drill to the high side of the hole and thus increasing the angle.

(b) The pendulum principle: In this case the stabilizer is connected above a D/C (drill collar) which is joined to the bit. The stabilizer thus acts as a pivot and the weight of the D/C makes the bit drill on the low side of hole, thereby decreasing the angle eventually.

By a combination of these two principles one can easily deduce a string combination that neither builds nor decreases the angle. That is, from the bottom we have a drill bit, near bit stabilizer, 1 D/C, string stabilizer, several D/Cs, and then the rest of the string. This is the socalled locked-in assembly and maintains a constant angle while drilling. A more detailed string design for the various cases is shown in Tables 1 and 2, and the gyroscopic directional surveys are shown in Table 3.

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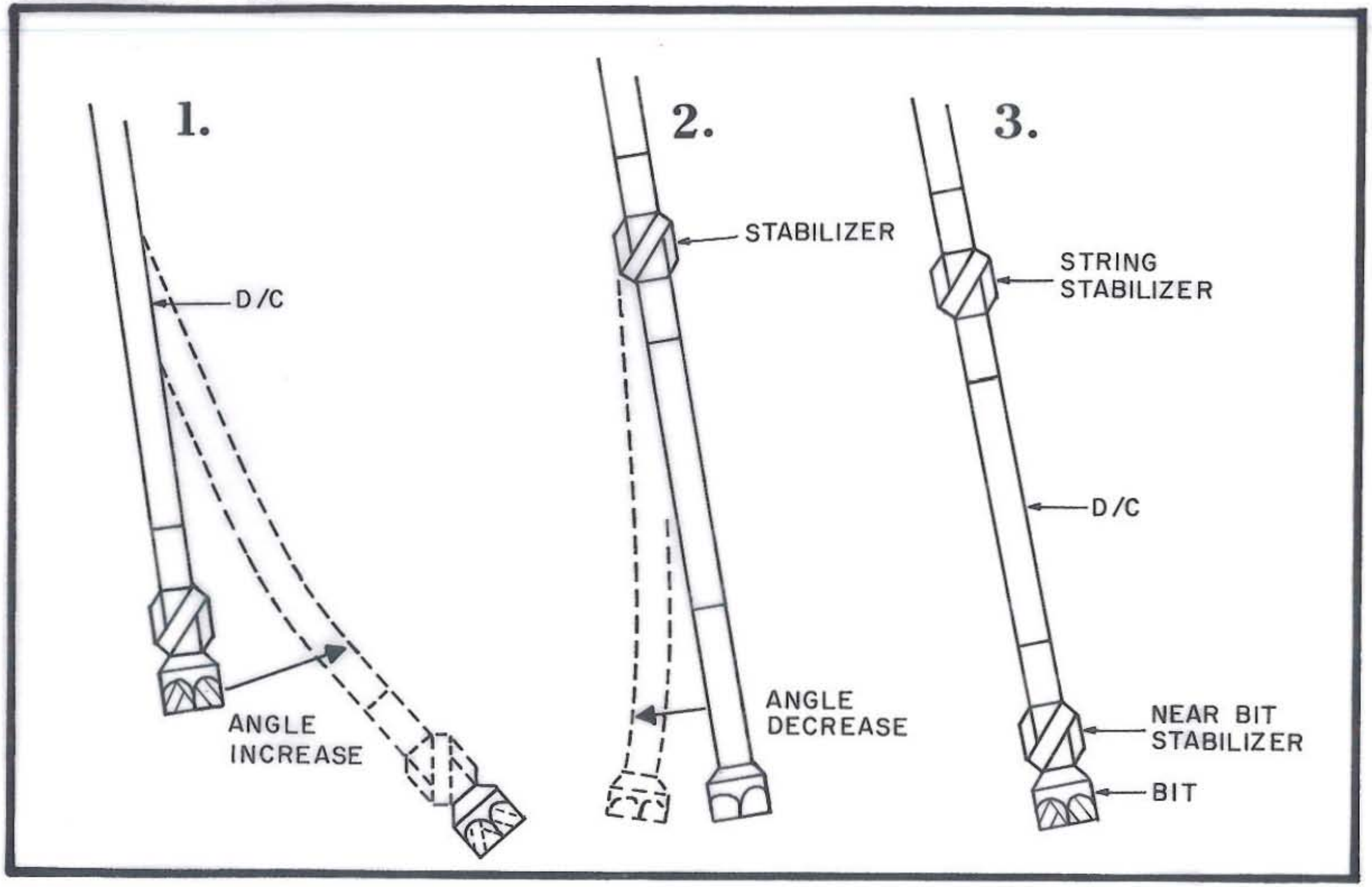


Figure 7. String design for increasing, decreasing and maintaining angle.

Table 1. String design for the 12 1/4" hole in well KJ 20

1. Kickoff assembly:

(i)	12 1/4" bit antifriction bearing (milled teeth)		
(ii)	Cross-over sub	6 5/8" API Reg.	box down
		4 1/2" API Reg.	pin up
(iii)	Dynadrill mud motor	6 1/2"	
		4 1/2" API Reg.	box down
		4 1/2" API Reg.	box up
(iv)	Bent sub	4 1/2" API Reg.	pin down
		4 1/2" API Reg.	pin up
(v)	Cross over sub	4 1/2" API Reg.	box down
		5 1/2" H-90	box up
(vi)	Collars 7 1/4" conventional and then the normal string up.		

2. Angle buildup assembly:

(i)	12 1/4" bit conventional		
(ii)	Near bit reamer	6 5/8" API Reg.	box down
		6 5/8" API Reg.	pin up
(iii)	Cross over sub	6 5/8" API Reg.	box down
		5 1/2" H-90	box up
(iv)	Collars 7 1/4" conventional 4 pcs.		
(v)	12 1/4" string stabilizer		
		5 1/2" H-90	pin up
		5 1/2" H-90	box up
(vi)	Collars 7 1/4" conventional 3-6 pcs. etc.		

3. Locked-in assembly:

(i)	12 1/4" bit conventional	
(ii)	Near bit reamer	(same as before)
(iii)	Cross over sub	(same as before)
(iv)	Collar 7 1/4" conventional	one piece
(v)	12 1/4" string stabilizer - as before	
(vi)	Collars 7 1/4" conventional 7-9 pcs. etc.	

Table 2. String design for the 8 2/2" hole in well KJ 20

1. Angle build-up assembly:

(i)	8 1/2" bit			
(ii)	Near bit reamer	4 1/2" API Reg.	box down	
		4 1/2" API Reg.	pin up	
(iii)	Cross over sub	4 1/2" API Reg.	box down	
		5 1/2" H-90	box up	
(iv)	Collars 7 1/4" conventional	4 pcs.		
(v)	8 1/2" string stabilizer			
		5 1/2" H-90	pin down	
		5 1/2" H-90	box up	
(vi)	Collars 7 1/4" conventional	3-6 pcs. etc.		

2. Locked-in assembly:

(i) 8 1/2" bit conventional
(ii) Near bit reamer - as before
(iii) Cross over sub - as before
(iv) Drill collar 7 1/4" conventional 1 piece
(v) 8 1/2" string stabilizer - as before
(vi) Collars 7 1/4" conventional 7-9 pcs. etc.

Table 3. Gyroscopic directional survey in well KJ 20 (selected readings):

Measured depth m	Vertical depth m	Inclination degrees	Dogleg severity /30m	Direction degrees
0	0.00	0.00	0.00	0.00
120	120.00	0.53	0.34	356.90
240	269.96	4.20	0.28	28.10
270	269.96	4.20	3.54	28.10
300	299.77	8.50	4.41	18.80
360	358.77	12.05	1.68	11.30
480	474.25	18.27	0.58	9.40
600	588.39	17.95	0.17	10.50
720	701.97	20.55	1.07	11.03
840	812.57	24.67	0.84	13.30
960	920.27	27.33	0.36	13.20
1050	999.84	28.38	0.39	11.57
1200	1130.56	30.37	0.52	12.91
1320	1233.36	31.33	0.48	13.75
1380	1284.21	31.88	0.57	14.22
1440	1335.12	31.83	0.59	14.77
1500	1385.96	31.87	0.94	14.17
1620	1486.88	33.63	0.47	14.27

2.3 Fishing operations in well KJ 20

There are numerous downhole problems that can be confronted while drilling. Undoubtedly, among the very worst, is to be confronted with a fishing operation. While the art of fishing has gradually improved over the last 30 years or so, the uncertainity and downtime involved, which of course translates into money, makes it one of the most hated cores on the rig. True, some fishing operations may require just one trip with a spear or overshot to be completed, but some continue for days, and as each round trip is made without success, a sense of despair develops among the personnel, even though no one wants to admit it. Actually it is advisable to be optimistic as there is some stroke of luck involved, although experience is also necessary. Of course to be able to start, the right fishing gear is needed together with essential data like allowable pull on the mast, drill pipe yield strength, depth to top of fish, etc. However, fishing should not be an endless test of ideas. Accurate costs should be maintained to allow comparison with other alternatives like sidetracking, or, say, buying a new drill string.

Fishing in deviated holes is, as would be expected, a bit more complicated than in a straight one, especially if it is below the KOP. Then it is not possible to give a direct axial pull up to the bit and the possibilities of keyseating arise.

The parting of the string in KJ 20 occurred in a drill pipe approximately 130 m from the top. Thus afer removing the free pipe, the next step was to trip in with an overshot (Fig. 8) having a basket grapple capable of holding the 5" outer diameter (OD) of the drill pipe (D/P). Because the overshot had a fishing-lip type skirt, the string had to be rotated carefully before reaching the top of the fish so that the latter could be directed towards the grapple. By putting a mark on the kelly when the top of fish is reached, the driller can know when the overshot has completely entered the fish. It is preferable after this not to turn the rotary, and obtain movement by releasing the brakes until it is no longer possible. Then start turning the rotary table slowly while noting the torque increase. That, together with an increased weight on string (when fish is heavy) are good indicators of when fish is held (Bowen Tools, 1974). However, when the fish is light, e.g. 5 m of D/P, it might be difficult to note the increased torque or weight (the weight indicator is in 000's of lbs). In this case the depth to the top of fish is noted. When it is held by an overshot, this should be slightly lower by an amount equivalent to that within the overshot.

In KJ 20, after holding the parted string, it was pulled up 385 m from the bottom when it got stuck. The initial assumption was that a keyseat had been formed preventing movement of the string below the D/Ps. Fishing operations were therefore performed with an effort to correct this. Because the overshot was now part of the string and any big downward blows might make it release the fish, it was necessary to back-off (disconnect) the string somewhere above the stuck point so that a different string assembly could be made, with a bumper sub to give big blows that, hopefully, will release the string.

To decide where to back-off, however, the length of free pipe above the stuck point had to be found out. There are several methods to calculate this. All of them however, require finding the differential extension of the drillpipe when an extra pull (below the yield point!) is applied over and above what is required at the stuck point. Then the following formula (Institut Francais du Petrole, 1978) applies:

$$L = \frac{2.675 \times W \times l}{P' - P}$$

Where L = length of free pipe (m)
W = weight per metre of pipe (kg/m)
l = differential stretch (mm)
$P' - P'$ = differential pull (000´s daN)

In this way the stuck point was calculated to be at 1245 m.

Initially, the conventional method to back-off a frozen string was used when adjusting the string assembly. This involved the application of an axial tensional force on the string equivalent to the weight (taking into consideration the buoyancy factor in water) of pipe above the joint to be opened (i.e. making it a neutral point), and then the application of an anticlockwise motion on the rotary while observing the number of turns. The maximum allowable number of turns which can be given to a particular pipe under a given axial tension varies with the grade being used and hence this has to be known initially to avoid failure (Institut Francais du Petrole, 1978). Understandably, however, this method will not give the desired results when there is another joint that was made up with a lower make-up torque than the recommended one; the weak joint will of course back-off first. To overcome this problem in KJ 20, a prima cord (explosive) was used to produce a big shock on the joint to be opened after applying the neccesary tension and number of turns. This has a close analogy to applying blows with a hammer to a nut when trying to open it, and resulted in a high degree of accuracy when backing-off the string.

While reconnection after back-off may be a tricky job when one remembers it is done downhole, it is nevertheless a fairly practical operation when one considers several facts. In KJ 20, for example, when connection was to be made inside the casing (9 5/8") the maximum clearance possible, when the tool joint is lying against the casing, is 3 1/4" (tool joint was 6 3/8" OD). It is therefore impossible for the connecting D/P to pass the top of the box of the pipe to be connected. Nevertheless, when this operation has to be done in an open hole more care is required because a pipe joint could be inaccessible when inside, say, a washover of the formation. In this case, therefore, back-off should be in an area where the formation is definitely hard. Also, in deviated holes, it should be as far away from the KOP as is practical. One definite advantage when connecting in open hole in KJ 20 was that the hole diameter was 8 1/2" and therefore assuming no washover of formation the maximum clearance was about 2".

Several back-offs were performed in KJ 20. The first, at 595 m, was to include a bumper sub to provide a shock effect at the stuck point. When this failed to produce any results, another backoff was done at 605.8 m so as to add more weight on top of the sub to give a bigger blow to the frozen string. The sub had a stroke of 24". Success was not forthcoming, however, even after working the string with the sub for over 6 hours. The probable failure of improvement was felt to be lack of transmission of the full blow to the stuck point. As the stuck point was in the inclined section of the hole only a component of the force applied vertically would effectively reach the stuck point. It was therefore decided to back-off at 1196 m. This was way down the inclined section and penetration rates from the geolograph charts indicated the formation to be hard. No improvement was observed, however, even after working the string for 4 hours.

A decision was therefore made to back-off at yet a lower depth, 1257 m, and include an oil jar in the string together with 6 D/Cs to provide weight for a bigger blow. And to wipe out the keyseat, a keyseat reamer was added. Thus, once reconnected, the string was of the following format:

1 D/P open-ended (pin down)
Bumper sub
Oil jar
Cross (X) over sub
6 D/Cs
Keyseat reamer
D/Ps to kelly

Because all the water pumped down was entering the formation, the oil in the jarring tool had to be allowed to cool after working the string for some time - about 30 minutes for one hour of working. The maximum pull was maintained at around 316,000 lbs (the yield point for the same D/Ps when new is 394,000 lbs). Only marginal movement (3") was observed after working the string for about 3 hours.

A fifth back-off was then decided at 1376 m, which was 1 D/P above the sub joining the frozen drill collars (D/Cs) to the D/Ps. When tripping in, the string could not enter freely and therefore it was rotated slowly as it approached the top of the fish. Probably because of this, the first D/P was broken before making a connection, and about 3 m remained downhole. To bypass this fish, arrangements were made to try to make a connection with 5 D/Cs at the beginning of the string. Tripping in below 45 m depth was not possible, however, as some obstacle prevented this. Initial analysis with a spotlight and binoculars indicated the obstacle to be hanging inbetween the space left by the casings in a coupling. A photograph taken with a special downhole camera confirmed this. The obstraction was believed to be a piece of plate off the kelly bushing. Fortunately, the problem was easily removed by a washover. Later, a trip was made with the D/Cs to try to make a connection. It was not possible, however, to go below 1376 m where the D/P was broken. When a trip was made with an overshot to grab the broken piece of D/P, no success was achieved. The only alternative was to mill it.

A stiff string assembly consisting of bit, stabilizer, 1 D/C, stabilizer and the rest of string, was therefore made and the milling bit covered with a hard face material. Milling was done to about 1 m above the top of the stuck string, with only one round trip being made to add more material on the bit. Later a trip with a junk basket (8 3/8" OD) was made to pick the cuttings made by milling. For some reason, however, nothing was trapped in the basket.

A 8 1/4" overshot with a 5" basket grapple was then taken downhole. About 1.6 m of the broken D/P was caught by the milled tooth of the overshot. Another 0.6 m together with the X-over sub remained in the hole. These were positioned in such a way that no washover (with 8 1/4" OD wash pipe) was possible below their top.

A trip was then made with a tapered tap to try to screw it into the fish. A piece of D/P, 0.8 m long with a tool joint, was fished out. It had been half way milled along its axis. The tool joint shoulder had a cut that was made when trying to washover. It was now possible to understand why washing over was not possible below the fish.

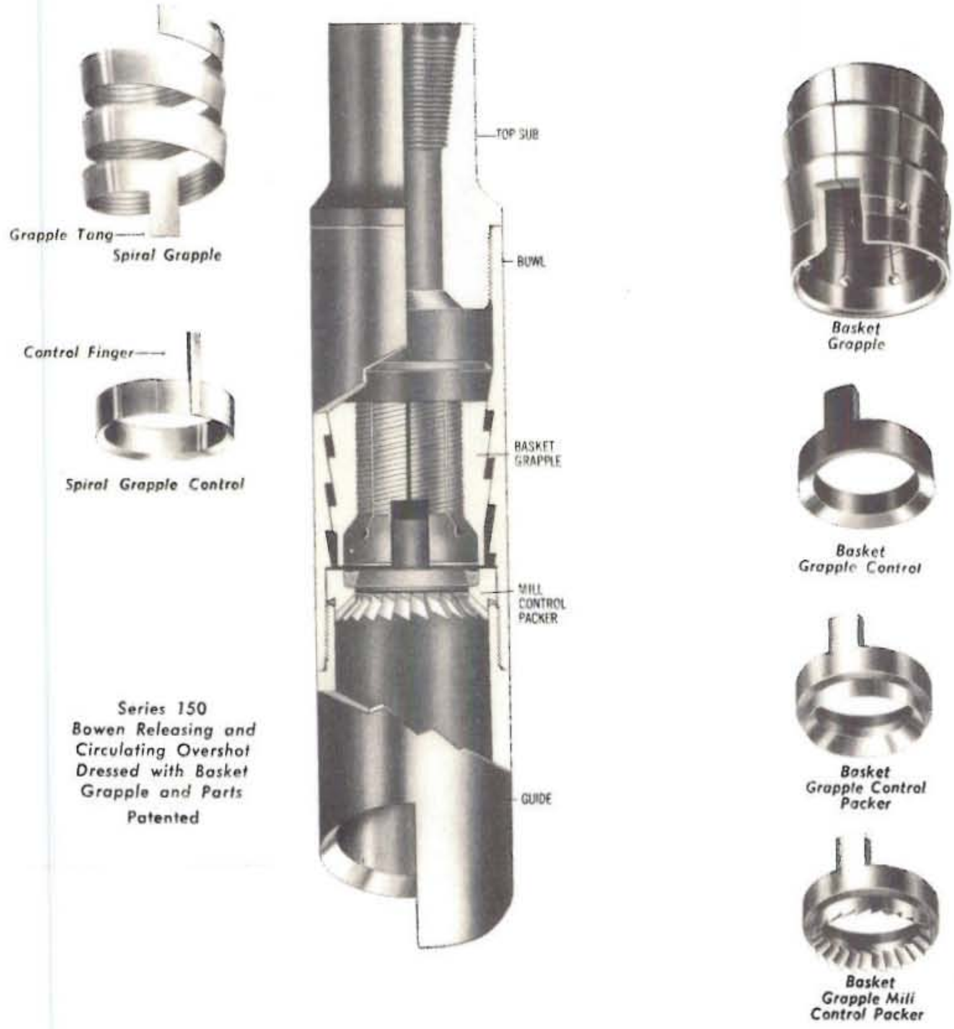
Efforts were now directed towards the remaining sub. A trip with an overshot, having a 6 5/8" spiral grapple, was not fruitful. The general opinion then was that the sub was at the side of the main hole. So a connection was tried with D/Cs but this was not fruitful either. Indeed it was possible to go some length below the expected top of the frozen string. This suggested that its top might to some extent be lying alongside the formation in such a manner that made a connection impossible. By now, the possibilities of sidetracking were seriously being considered. Before that, however, a 2 3/16" tapered tap was run into the fish.

This was what saved the day (or the 17 days if we want to be serious). Connection was made at 1437 m and 9 turns of the rotary produced close to the maximum make-up torque of the joints. When pulling was tried, the hook load shot up to 300,000 lbs, indicating that the frozen string had been caught. And although movement was possible, the string was not quite free. It was decided to continue pulling out slowly. Correspondingly, the hook load started getting slowly to the expected values as the string passed above where the keyseat reamer had reached and into the 9 5/8" casing. About 12 hours were taken to pull out as no one wanted to risk shearing the threads of the tap now that connection was made. When this was completed, the hole was reamed to the drilled depth of 1822 m and the 7" slotted liner set without any problem. Because this was a deviated hole, the reaming string assembly had a locked-in set up, i.e. 8 1/2" bit, near bit stabilizer, 3 D/Cs, string stabilizer, 2 D/Cs, X-over sub and then the rest of the string.

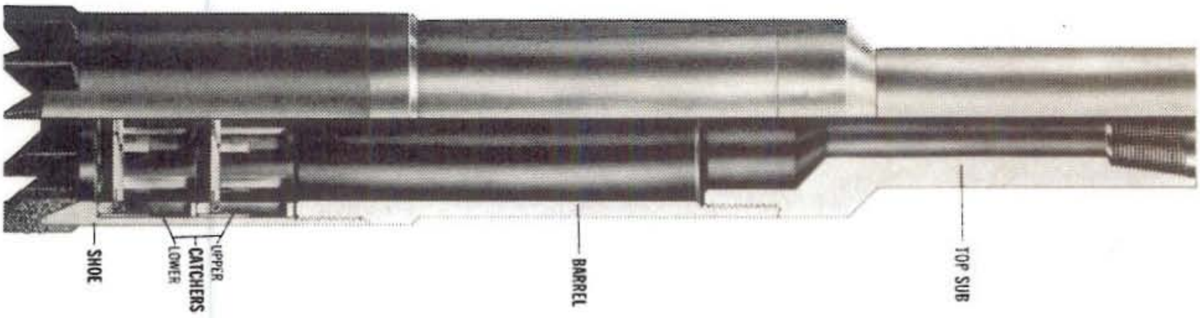
The whole fishing operation had taken 17 days. However, because the drilling was 7 days ahead of schedule when the string broke, the effective downtime due to the fishing was only 10 days beyond the initial drilling schedule for the well.

Figure 8.

(a) Releasing and circulating overshot (Bowen Tools, 1972):



(b) The Junk basket (Bowen Tools, 1972).



(c) Tapered Tap (Bowen Tools, 1972).

3 COMPARISON OF DRILLING PRACTICES IN OLKARIA AND KRAFLA

3.1 Introduction

Because of the abundant geothermal surface manifestations in the Olkaria field and several other areas (Lake Bogoria-formerly lake Hannington, Eburru, etc.) in the Rift Valley in Kenya (Fig. 9), there has been a keen interest to utilise this energy for electrical power production (Thompson and Dodson, 1963), especially after the energy crises of the early seventies.

The first exploratory well in the Olkaria field (X1) was drilled in 1956 with a cable tool (percussion) rig. The formation consisted mainly of loose pyroclastic material. This greatly hindered drilling operations and the hole was abandoned at 502 m, the last 130 m or so drilled with a rotary rig. Another attempt, also partly with a rotary rig, at a site north-east of the first one, resulted in a 942 m deep well. These boreholes did not indicate an underlying geothermal resevoir that would be economically exploitable for power generation (Noble and Ojiambo, 1976). There was therefore a lull in drilling activities until around 1970. The sudden rise in oil prices and the limited hydropower available necessitated another look at other alternative sources of energy.

With the technical and financial assistance of UNDP, the East African Power and Lighting Co. Ltd, EAPL, (a quasi-government company responsible for power generation and distribution in Kenya) embarked on an ambitious exploration for geothermal energy. Reconnaisance work was carried out in three fields, Eburru, Olkaria and Lake Bogoria. Olkaria was selected for drilling (Healy et al., 1972; Noble and Ojiambo, 1976). The first deep well in Olkaria (OW1, 1003 m) was completed in 1973. By 1976 five more appraisal wells had been drilled and these confirmed the existence of a geothermal reservoir which could be economically exploited. All the drilling was contracted to Foramines, a

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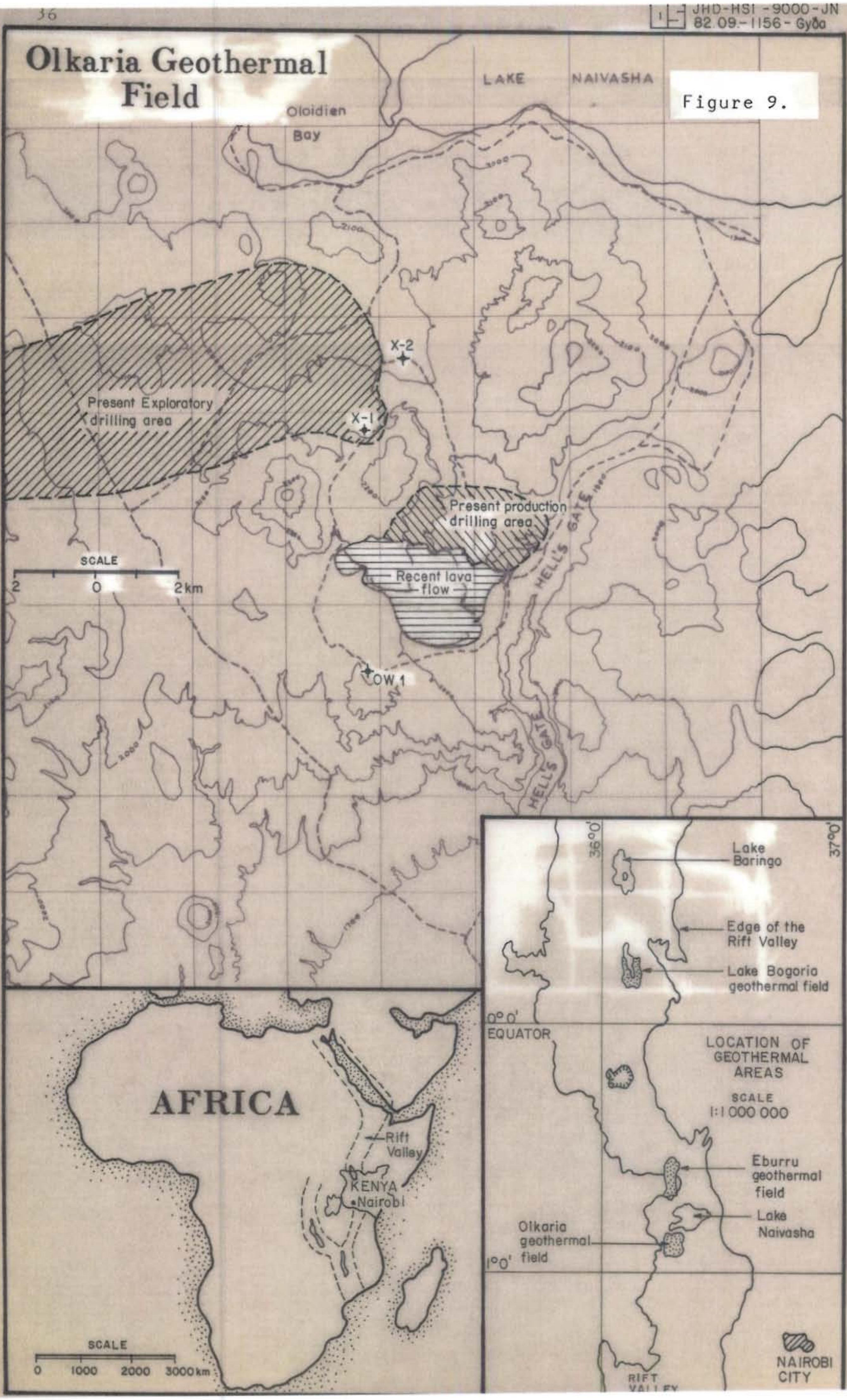

Figure 9.

French company, under the supervision of a UNDP manager. Indigenous people formed the bulk of the drilling crew.

In early 1978, the Kenya Power Company, a government body managed by the EAPL Co. Ltd., signed a contract with GENZL of New Zealand for a full-scale production drilling programme in the Olkaria field and for the training of the local people so that they can eventually man the drilling operations. By November 1981, 21 wells had been drilled in the area. All but one (OW 19), were drilled with an Ideal T12S rig. OW 19 was drilled with a National C370 rig purchased by KPC in late 1980. Presently, the old rig, T12S, is used in production drilling while the C370 rig is used in exploratory drilling on the outskirts of the present production area. The first 15 MWe unit in Olkaria was put on line in June 1981 and the second 15 MWe unit is expected on line in November 1982.

In contrast to Kenya drilling for geothermal energy in Iceland is a relatively old affair. The first geothermal wells in Iceland were drilled in 1928 (Ragnars and Benediktsson, 1981). Since then, a wealth of experience has been accumulated, even though prior to 1960 much emphasis was on drilling in low temperature areas. The combined length of boreholes has already exceeded 400 km (Ragnars and Benediktsson, 1981). There are five major rotary rigs (Gardner Denver 700 E, 3600 m; Oilwell 52, 2000 m; Failing 3000 CF, 1400m; Wabco 2000, 800 m; Mayhew 1000, 400 m), several small rotary rigs and cable tool rigs. The drilling is done by a government company, the State Drilling Contractors which is a division of Orkustofnun, the National Energy Authority. Most of the development for electrical power generation has been in the Krafla field in the northern part of the country. The steam drilled, however, has other industrial applications like drying of diatomite, production of salt, wool cleaning, etc. The installed capacity for power generation in Iceland in 1982 is 41 MWe, but for direct utilization 960 MWt (Fridleifsson, 1982).

3.2 Equipment

The rigs operated in Olkaria and Krafla are basically the same, the only major exception being the presence of air compressors in the former to facilitate air drilling. These, together with a triplex plunger pump are used when drilling below the production casing (9 5/8") shoe. However, it is worth noting some features on the Jotunn rig used in Krafla which give it a definite advantage over both Olkaria rigs: (i) the major equipment (rotary table, drawworks and both mud pumps) are driven by electrical DC motors and these require minimal maintenance and can be selected to suit the drilling operation by a flip of a switch at the driller's console, (ii) the presence of a power tong increases speed and safety while drilling instead of throwing a chain, and (iii) one stand consists of three D/Ps. This simply means that to go 60 m, for example, requires making one connection on the Jotunn and two on the Olkaria rigs. Operations with the latter are therefore slower.

Until late 1980 there was only one rig (Ideal T12S, depth capacity 1700 m) drilling in the Olkaria field. Then the KPC purchased a National C 370 rig with a capacity to drill 2500 m. At the time of writing, it has completed drilling two wells, the first one to almost its full rated capacity at 2484 m. Because some parts arrived late and others failed in operation, even though covered by the manufacturerś warranty, the wells took a considerable time to complete (Kenya Power Company, 1982a). For this reason, and the fact that the crews had not got used to the equipment (a number of them were still under training), I do not consider the time taken to drill those two wells as representative of the rig. I have therefore used drilling data from the older rig when comparing the drilling practices in Olkaria and Krafla.

The following is an attempt to tabulate the significant differences in the drilling equipment used in the Olkaria field with those of Krafla as the equipment has a direct effect on the efficiency of the drilling operations.

	Gardner Denver 700 E (3600m)	Ideal T12S (1700m)
(a)	Drawworks: Gardner Denver.	Drawworks: Ideal Oweco.
(b)	Swivel: Gardner Denver S-30 300 ton capacity.	Swivel: Ideal type L 3547 with 65 ton capacity.
(c)	Rotary table: 22 1/2".	Rotary table: 20 1/2".
(d)	Slush pumps driven by DC motors.	Slush pumps driven by GM V12-71 diesel motors.
(e)	Mud/water tanks have a capacity of 80 ton.	Mud/water tanks have a capacity of 52 ton.
(f)	Power tong: Foster type 97-2 3/8"-10 3/4".	
(g)	-	Cooling tower rated at 800 gpm (size 6.4m x 2.1m x 2.1m).
(h)	Blowout preventers:	Blowout preventers:
	2 Cameron - hydraulic.	1 Shaffer double gate - hydraulic.
	1 Hydril - annular.	1 mechanical BOP - 20".
	1 rotating head BOP.	1 rotating head BOP.
	80 gallon control system.	114 US gallon control system.

(i)	-	Triplex plunger injector pump with a GM 2-71 diesel motor.
(j)	-	Air compressor (1000 cfm at 250 psi) with GM V12-71 diesel motor.
(k)	1 stand: 3 D/Ps.	1 stand: 2 D/Ps.

3.3 Site selection and preparation

But for exploratory wells, which are sometimes sited to indicate the extent of a field (Kenya Power Company, 1982c), production wells are sited with one or more of the following factors in mind:

(a) low resistivity anomaly
(b) lithological and structural features
(c) indication of acquifers at depth
(d) appropriate well spacing
(e) results of previous wells
(f) location of the power station
(g) topography
(h) access to a reliable water supply

After a site has been selected the ground is cleared with a grader or bulldozer. In Olkaria, a 6" thick layer of murram is added on top and compacted with a roller. Because of the nature of the top soil in Olkaria, no definite advantage has been found with site grouting. In Krafla a layer of gravel and volcanic scoria is put on the site to make a stable platform for the rig. The size of the sites, however, are almost similar, at about 60m x 90m.

The only noticeable difference in the cellars is their depth. In Olkaria they are about 1.3 m deep. In Krafla, about 3 m. This is because in the latter there are commonly two master valves instead of one as in Olkaria.

3.4 Casing programme

A casing programme is heavily dependant on the lithology and the levels of the various acquifers in the formations to be drilled. Most important is to have enough length of casing to prevent a blowout during further drilling (Karlsson, 1978). As an example it can be mentioned that it was for this safety reason that a production casing was sunk to 948 m in well OW 19 in Olkaria where the final depth was proposed to be 2500 m. It is likely that this may have effectively cased off the steam zone which lies approximately at 600-800 m. Still, it would have been prudent to have a shorter casing length and risk a formation failure while drilling to the final depth.

The production and anchor casings are similar (with ODs of 9 5/8" and 13 3/8" respectively) but sunk to different depths (see Fig. 10) for the reasons outlined above. The slotted liners are usually 7" OD and sunk in a 8 1/2" open hole. Sometimes 7 5/8" liners are used in Krafla.

It is almost standard in Iceland to drill the first 60 m of a hole with a cable tool (percussion) rig. The surface casing is sunk simultaneously with the drilling. Some minor differences should therefore be expected. The major one, however, is that an 18 5/8" surface casing is sunk into a 22" hole. In Olkaria, a 20" casing is sunk into a 26" hole.

3.5 Pre-drilling

As already noted, it is customary in Iceland to drill the first 60 m with a cable tool rig. In Olkaria, the whole well is drilled with a rotary rig. This poses the question of whether it is more cost effective spudding a well with a rotary or a cable tool rig. Several factors may influence this decision (Krogh, 1982):

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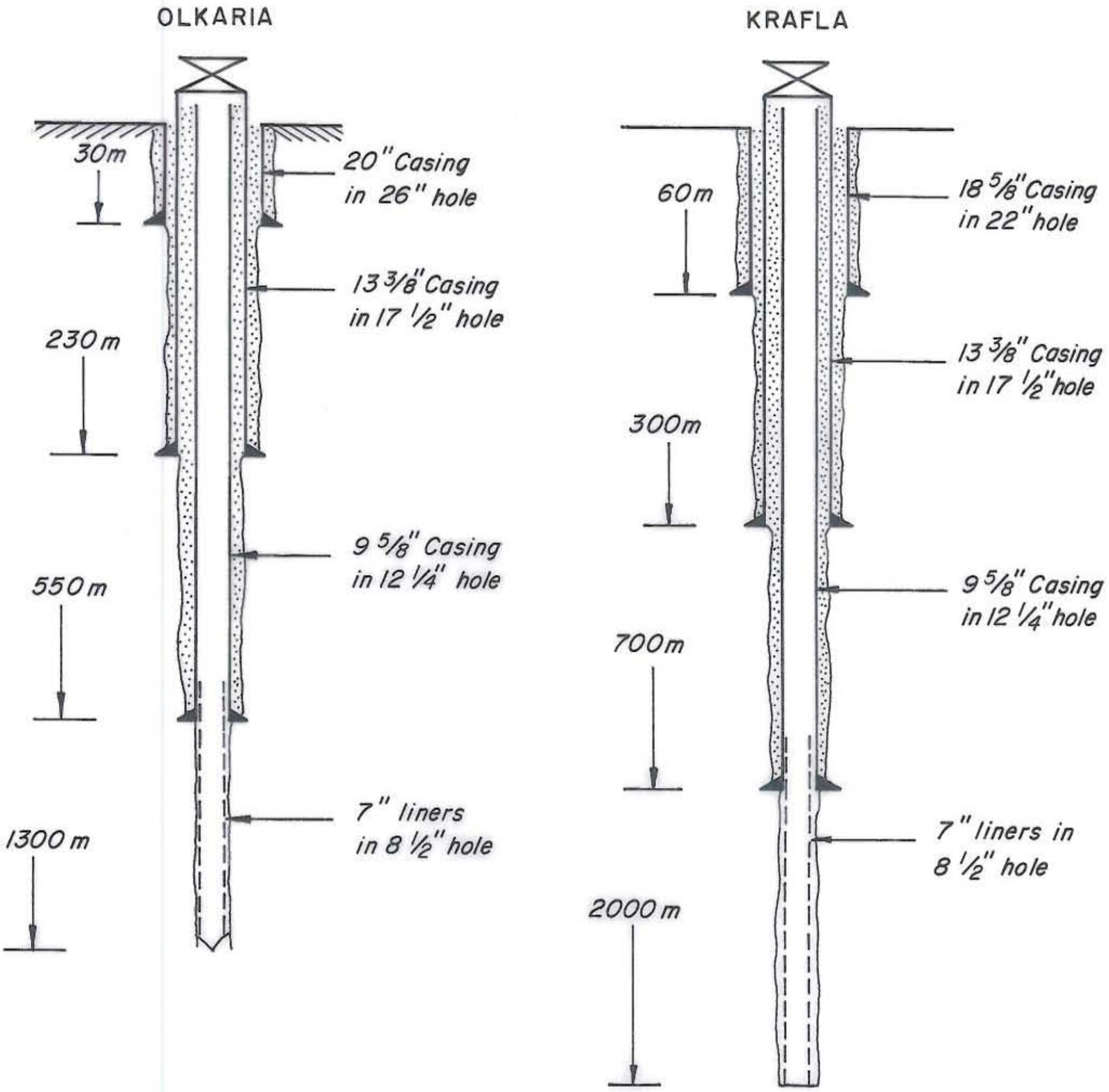
Figure 10.

TYPICAL CASING PROGRAMMES



a) size of the rotary table;
b) the drilling fluid;
c) nature of the formation;
d) weight on bit;
e) slush pump capacity;
f) depth to the water table.

Unfortunately, no reasonble cost comparison is possible as relevant data is unavailable. Suffice to note that (a) the daily cost of a cable tool rig is approximately 10% that of a rotary rig, (b) a rotary rig is about ten times faster than a percussion rig, and (c) with a rotary rig, it is not possible to put the full weight on the bit in the first 30 m or so. Consequently, if the top layers are hard, considerable strain on the rig and may, in the long run, increase rig maintenance, spare parts and down time. Of course, when the formation is soft, this problem is non-existant. In addition, because the cable tool rig is able to run the casing simultaneous with the drilling, caving-in of the formation and circulation loss can be controlled.

It can therefore be seen that the decision on the spudding rig depends on a great many factors. The choice may have to be made for a particular area and possibly for each well. Still, until good data is at hand, it is safe to conclude that for conditions such as in Olkaria a cable tool rig is not superior to a rotary rig for pre-drilling especially as it would have to be purchased or hired.

3.6 Drilling programme

Below the surface casing, the drilling procedures are essentially similar, albeit with minor modifications to suit the different formations. A typical programme after cementing the surface casing in Olkaria is as follows. A 12 1/4" hole is drilled to 230 m and opened to 17 1/2". Then a 13 3/8" casing is run and cemented in place. The joints have a buttress thread and the guide shoe is screwed into the first casing. The float collar is placed in the second joint. The 12 1/4" hole is continued to around 550 m when a 9 5/8" casing is run and cemented in place. The joints also have a buttress thread. Both the anchor (13 3/8") and production (9 5/8") casings are made of API grade J55 steel and are 54.5 and 36 lb/ft respectively. From 550 m the hole is drilled to about 1300 m using a 8 1/2" bit. Then a 7" slotted liner is set into the open hole, with at least one blind liner above the production casing shoe. The liners are also of API grade J55 steel and, usually, 20 lb/ft. The slots, which are 152 x 12mm, are gas cut. There are 20 such slots in a meter of liner.

This is not very different from the procedure in Krafla where the 13 3/8" casing is set into a 17 1/2" hole that is drilled to 300 m. The 12 1/4" hole is drilled to anywhere between 700 m and 1100 m depending on the level of the cold water reservoir. A 9 5/8" casing is also cemented in place. Further drilling is continued with a 8 1/2" bit down to 2000 m and then cased with 7" slotted liners. The slots are also gas cut, each 70 mm x 20 mm. There are 30 slots to one metre of liner. The two casing strings together with the liner are made of API grade J55 steel and have buttress thread joints. They are 68, 43.5 and 26 lb/ft respectively.

In rotary drilling, common brands (Hughes, Smith, Security, etc.) of rock bits are used in both places and these give reasonable drilling times under the various formations. When using bits having sealed bearings, it is adviceable to keep the hole at low temperatures to avoid damaging the seals.

3.7 Drilling fluids

This is the one area where there is a distinct difference between the normal practice in Olkaria and Krafla.

The functions of a good drilling fluid are mainly to carry the cuttings from the hole, cool and lubricate the bit, form a filter cake around the well, control formation pressure, and to support part of the drill string. To be able to achieve these, the fluids should have both physical and chemical properties that can be widely varied to suit the particular requirements (Dresser Industries, 1972). Especially important are density, viscosity, and annular velocity while drilling.

Water is commonly used as the drilling fluid in Iceland (Jonsson, 1976). While this is preferable because it does not have to be purchased it may create several problems. Of special interest is its low density and viscosity which reduces its carrying capacity. This may result, without due care, in poor hole cleaning which eventually can lead to a stuck drill string. To overcome this, reliable slush pumps should be at hand with capacities to give the water an annular velocity of as high as 1 m/s. Only when there is a total loss of circulation to the formation, drilling mud or ʹflow-checkʹ is used to try to regain circulation. Loss of circulation is also sometimes controlled by injection of sawdust, cement plugs or gel.

In contrast, drilling mud is used in Olkaria wells down to the production casing shoe depth. Because this has a higher density and viscosity than water, good hole cleaning is possible without the need of high annular velocities (Chilingarian and Vorabutr, 1981); 0.5 m/s is generally sufficient. The viscosity is increased by addition of bentonite. Caustic soda is used to raise the pH of the mud to prevent corrosion of the drill string. Loss of circulation is controlled with cement plugs, gel and circulation loss material. If there is a total loss, then water is used as the drilling fluid.

Below the production casing shoe depth, foam is used as the drilling fluid. Even though additional equipment is necessary, this is offset by the resultant high rate of penetration (Dresser Industries, 1976). The equipment includes a compressor capable of delivering about 400 cfm at 600 psi, a plunger injector pump for injecting soap into the air, a rotating head to divert the return to the blooie line, and, preferably, a jet sub in the string to help when unloading the well. Other factors that can be argued against foam drilling are (a) the high annular velocities encourage caving-ins and erosion of the drill string, and (b) extra expense is incurred on purchase of soap. Still, the low formation pressures require a light fluid column in the drill string to encourage circulation return. The higher density of water would encourage circulation loss. Mud cannot anyway be used as it would seal off the potential production zones. Only when it is not possible to unload the well is drilling with water opted for. This was done in OW 19 when unloading the water column below 1850m was not possible. Drilling was continued to the final depth with water.

3.8 Cementing

The cementing method used in Iceland was described in chapter 2.1. The essence of cementing casing strings was also explained there and will therefore not be repeated here.

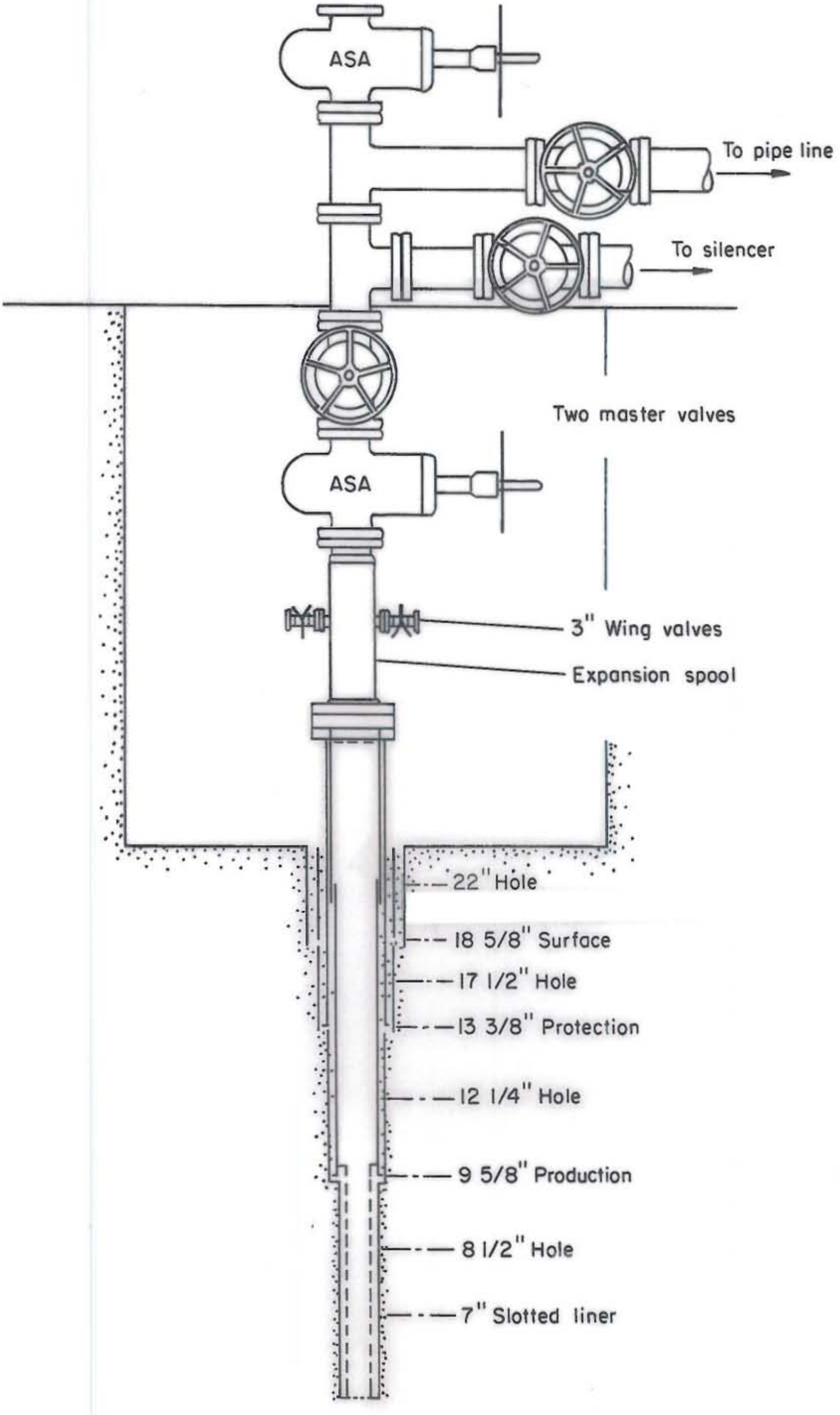
Every cementing job starts with the calculation of the volume to be cemented. This is normally the volume behind the casing and open hole. The volume between the float collar and guide shoe is also added. To cater for losses to the formation, a safety factor is also included. This depends very much on the experience in the area. In Olkaria it can be as high as 100%.

Prior to pumping the cement slurry, the hole is flushed with water. If a return is obtained from the annulus, it may be indicative of a potentially good job. Usually this does not happen. Therefore, after installation of the cementing head, which contains the top and bottom plugs, a calculated amount of cement slurry is pumped into the casing preceeded by the bottom plug which prevents contact of the slurry with water. The plug eventually rests on the float collar and, because of the heavy slurry column, ruptures, allowing the slurry to go up the annulars via the guide shoe. When the required amount of slurry is pumped, it is chased with a calculated volume of water with the top plug acting as a buffer between the slurry and the water. When this is done, a full weight cement slurry return should, hopefully, be observed. If and when this is not possible, the annulus is filled with slurry through a 1/2" high pressure pipe until a return is obtained. The top of the pipe is placed just above the set cement to exclude trapping of air in-between the annulus. The cement takes about 12 hours to set.

3.9 Wellhead equipment

In recent years it has become common practice in high temperature fields in Iceland to have two master valves (ASA) in the completed wells (Fig. 11). This is a precautionary measure encouraged by well KJ-4 in Krafla which blew its top in 1976. Only one master valve, WKM ANSI series 600 (900 in OW 19), is used in the completed wells in Olkaria. But for minor leaks in some valves, they have given satisfactory performance in all the wells drilled.

Figure 11.



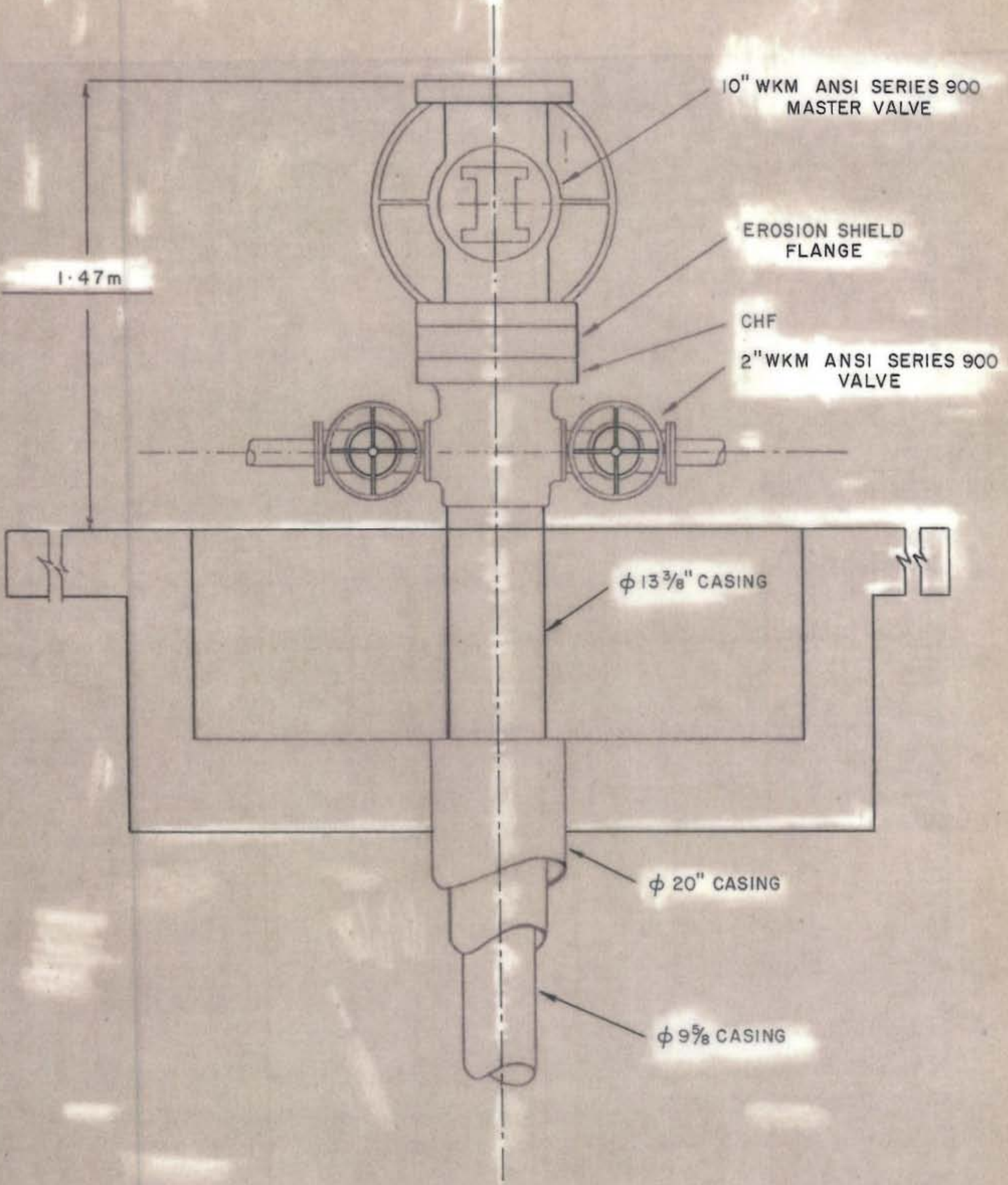
SCHEMATIC DIAGRAM OF KRAFLA COMPLETION

Figure 12.

OLKARIA

PRODUCTION WELLHEAD ARRANGEMENT

WELL No. 19



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3.10 Management of drilling operations

There are many problems that can occur while drilling. These may be caused by equipment failure, stuck string, blowouts, circulation loss, casing collapse, and several other factors. Thus, while it might be virtually impossible to eliminate all these problems in every well, there are several ways to minimise their occurrence.

In the planning stages of a drilling project, a reasonble target should be set preferably with the costs included, for the various stages of drilling. The actual time taken is analysed against this target. If actual costs are excessively above this, then a definite solution should be taken to remedy the problem. For example, when fishing a drill string, the costs can indicate when purchase of a new drill string or sidetracking becomes a better choice, cost wise, to continued fishing. In the case of equipment failure, it should be borne in mind that the downtime costs of a normal rotary rig can be at least US$ 5000 per day. A continuous cost assessment during a drilling operation can thus be a useful guideline in decision making and highly advantageous financially.

In high temperature drilling, the risks of a blowout are high. Its control may very much depend on the availability of a reliable water supply. This is a factor that is sometimes overshadowed by the drilling requirements until the problem occurs. Similar cases include fishing operations and casing failure. When these problems arise, contingency plans for resque operations have to be planned for in advance and some equipment may have to be purchased so as to have it at hand if a particular problem arises.

Cases from KJ 19 and KJ 20 in Krafla are included as examples (Fig. 13 and 14) to show how the planned and actual times can vary. Actual depth/time graph from well OW 21 (Kenya Power Company,1982b) is also provided.

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PLAN FOR THE DRILLING OF WELL KJ-19 IN KRAFLA

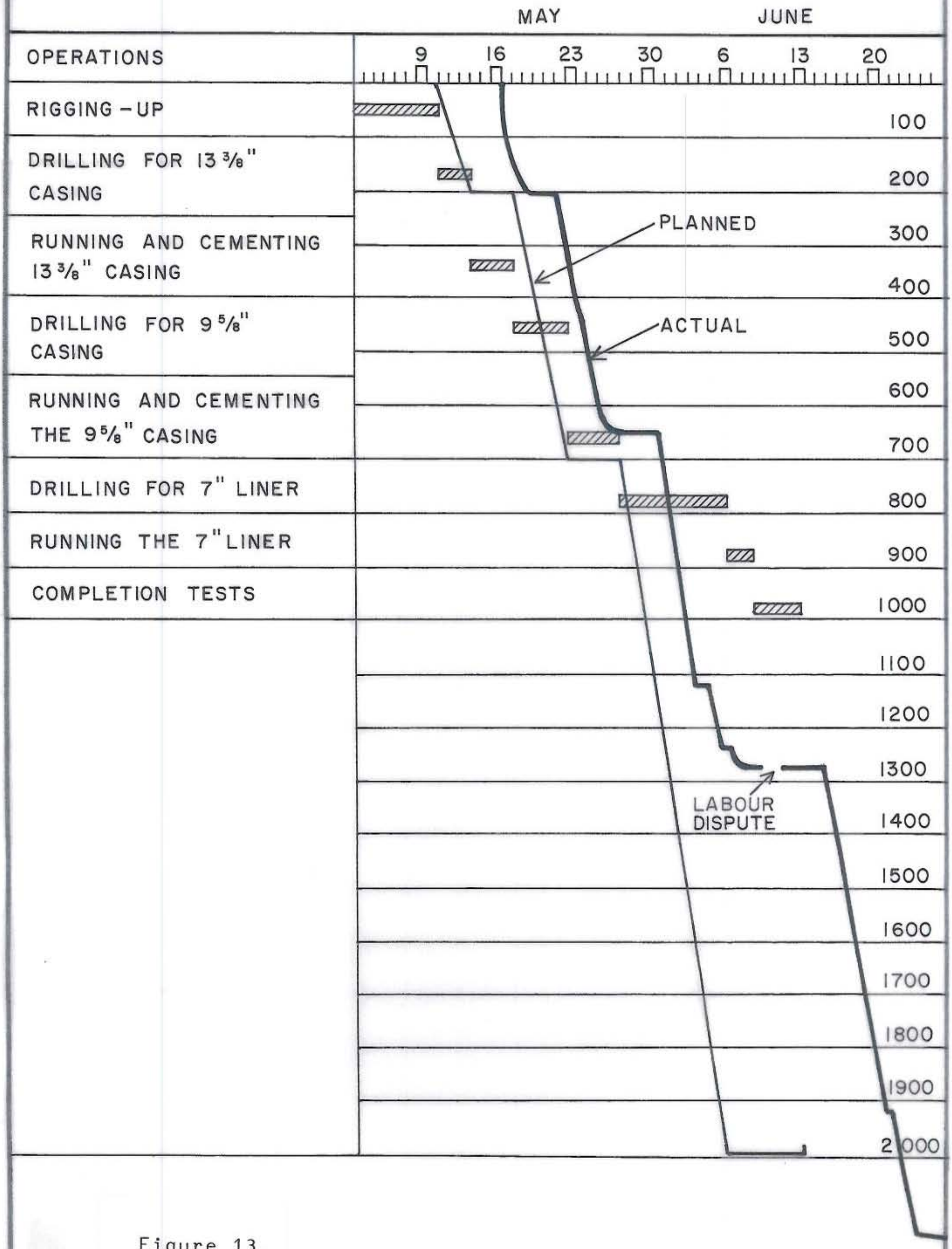

Figure 13.

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PLAN FOR THE DRILLING OF WELL KJ-20 IN KRAFLA

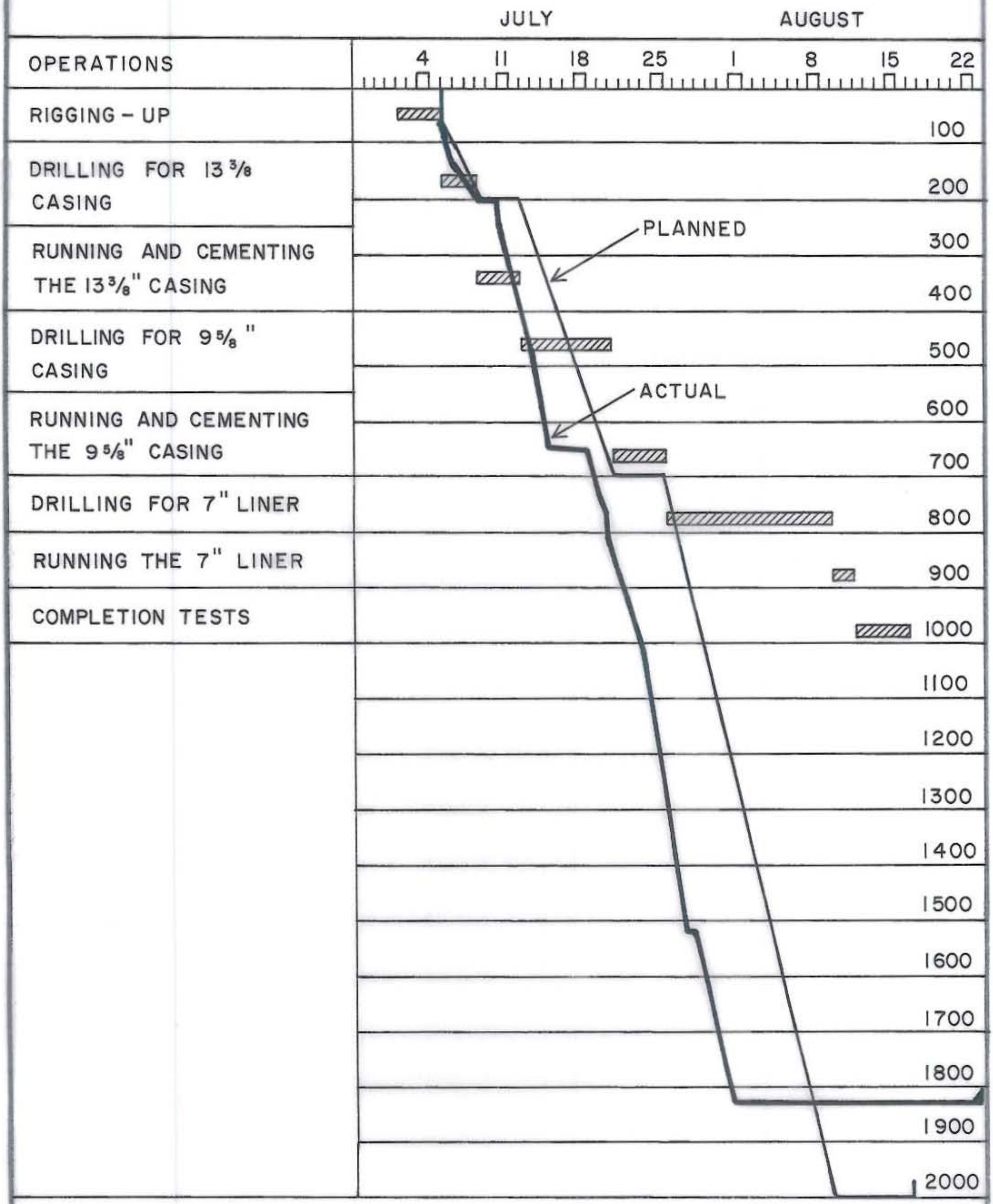

Figure 14.

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DRILLING OF WELL OW-21 IN OLKARIA

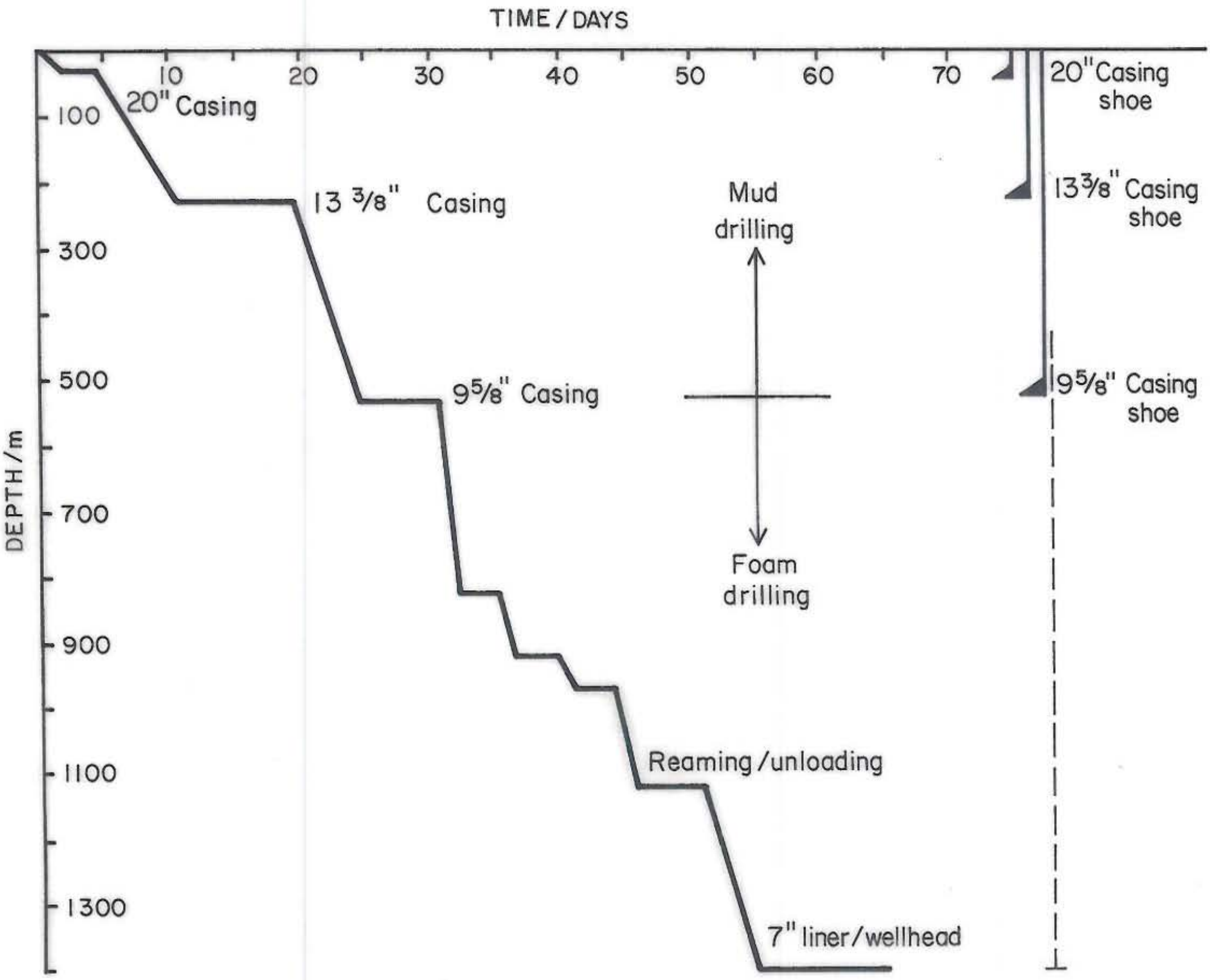

Figure 15.

4. CONCLUSIONS

While it might be easy to give merits, and otherwise, of some drilling practices in high temperature fields, it is difficult to say which ones are definitely superior to others. This is because the approaches vary very much with the area, and sometimes, even in a particular well. For example, pre-drilling with a cable tool rig where the top formations are hard may have a long-term advantage over spudding with a rotary rig. But then, if the formations are soft, the rotary rig is certainly better. Similarly, using water as a drilling fluid reduces the drilling costs considerably. However, high annular velocities would be required and, becauce of its low carrying capacity, good hole cleaning may not be possible, especially in soft formations. Mud and aerated foam may be superior to water in some ways but, unfortunately, increases the drilling costs.

As regards cementing, the Stab-In method described in chapter 2.1 may, in the authorś opinion, be superior to the conventional one of pumping the cement slurry directly into the casing. It is faster and there is no limitation to the amount to be pumped as long as setting of the cement slurry does not occur. If the annulus is not filled, however, both methods require a reliable tool to identify the depth to the top of the set cement. The sonic cement bond log (CBL) is perhaps among the best of such tools.

Other conclusions that can be drawn from the report are:

a) Flushing the open hole with calcium chloride and sodium silicate solutions prior to cementing can help in regaining circulation where a loss has been encountered.
b) When planning a directional well the target should be well defined in order to minimise costs when selecting the downhole motors, KOP, hole inclination, survey instruments, etc.

c) Because there is an element of uncertainity involved when fishing, continuous costs should be maintained so as to assess them against other alternatives like sidetracking, purchasing of a new drill string, etc.
d) When deciding on a casing programme, safety during further drilling is important as the casing costs are lower than losing the whole well.
e) If and when problems arise during drilling, support tools like downhole camera , impression block, caliper log, sonic bond log, temperature probe, etc. may be of help when defining and correcting the cause.

Nevertheless, the management approach should be the same everywhere. This is because its objective is to keep the drilling costs per metre as low as possible.

ACKNOWKEDGEMENTS

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