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CONTROLLED DIRECTIONAL DRILLING IN KENYA AND ICELAND

Thomas Ongau Miyora
GDC South Rift - Geothermal Development Company, Ltd.
P.O. Box 1453-20117
Naivasha
KENYA
tmiyora@gdc.co.ke

ABSTRACT

Directional drilling is the most widely used method for drilling geothermal wells due its various advantages. Drilling multiple wells from the same pad allows for fewer rig moves, less surface area disturbance as well as making it easier and cheaper to exploit the resource being drilled for. Current technology allows the driller to steer the well to the target with high precision and this allows exploitation of resources that would otherwise be difficult or impossible to reach. The study in this report shows that almost 50% of the total time in directional drilling is spent on activities that are not related to actual cutting of the formation by the drill bit. Minimising time spent on these activities will reduce total drilling time per well and, hence, reduce drilling costs. This study highlights the calculations of well trajectory and an analysis of the actual time taken for all activities in drilling of 12 directional wells in Kenya and 14 directional wells in Iceland. The results show that the average depth drilled per day for Iceland is about 56 m, and for Kenya it is about 48 m. The average depth of the Icelandic wells is 2379 m, taking about 41 days to drill, and the average depth for Kenyan wells is 2830 m, taking about 58 days. Comparison of drilling times in Iceland and Kenya indicates that for a well of 2830 m, it will take about 54 days to drill in Iceland while it will take about 58 days to drill in Kenya. These drilling rates are similar, although the difference of 4 days is significant considering the large costs involved in drilling per day.

The government of Kenya has started an ambitious programme to increase its power production from geothermal energy. The capacity of geothermal power in Kenya is estimated to be about 7000 MWe, valued at about USD30 billion. Efficient drilling practices will be required in order to optimise exploitation of its more than 14 prospects. The Geothermal Development Company's ten year business plan indicates that it intends to drill about 500 wells in Olkaria, Menengai, Silali and four other fields and realise at least 2000 MW_e by 2019. Within this period it intends to procure 12 deep drilling rigs with a depth capacity of 5000-6000 m. The rigs should have a capacity to drill deep directional geothermal wells. The study carried out in this report indicates what has been achieved in the past and will act as a benchmark for planning for future drilling, as it addresses good practices that can assist in improving cementing, logging and bit selection. Also, the computer programs generated in this report will be used in monitoring actual drilling to ensure the target is reached within acceptable limits.

1. INTRODUCTION

Directional drilling is a special drilling operation used when a well is intentionally curved to reach a bottom location (Vieira, 2009). Directional wells are drilled in different patterns with the inclined angle of the wells varying from a few degrees to more than 90°. The shapes of the trajectory of directional wells also vary depending on the position of the target to be reached. The government of Kenya, through the Geothermal Development Company Limited (GDC), has started a very ambitious programme of electrical power generation from geothermal. GDC's ten year business plan and strategy is to generate at least 2000 MWe of electricity over the next ten years (2009-2019), and at least 4000 MWe by 2030 through an accelerated development plan (GDC, 2009).

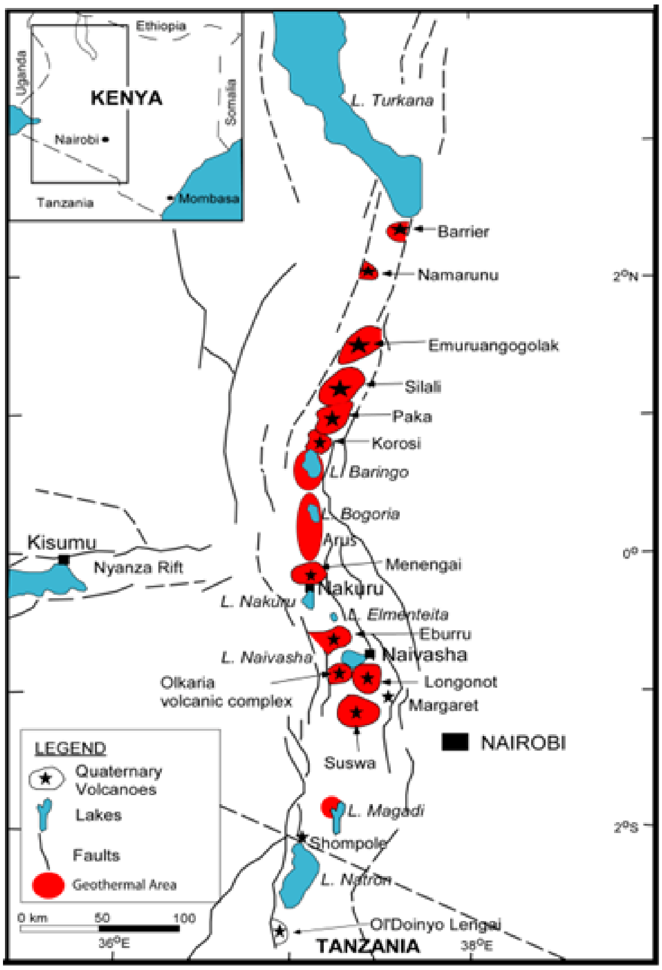

FIGURE 1: Geothermal fields in Kenya (adapted from GDC, 2010)

During this period GDC plans to procure 12 deep drilling rigs for the new fields and hire three more rigs for drilling in Olkaria. There will be extensive exploration and appraisal drilling for all fields to mitigate initial risks. There are plans to undertake early generation by investment in well head generation units which will produce electricity and be connected to the national grid, as a preliminary production before the large-scale power plant.

Directional drilling will reduce the capital investment cost of the wellhead generation unit by making it possible for multiple wells to be drilled on a single pad, hence reducing the temporary pipe-work required for a sizeable unit (Ngugi, 2002). GDC has already acquired two large rigs that are rated with 1,000,000 lbs nominal hook load with a depth rating of 5000-6000 m.

There are more than 14 high potential geothermal fields along the Kenyan rift valley. The estimated generation potential of these fields is more than 7000 MWe (GDC, 2009). Figure 1 shows the location of these fields.

2. LITERATURE REVIEW

2.1 Brief history of directional drilling

Initially all wells were drilled vertically downwards. Directional drilling evolved out of the need to drill wells in other directions. The most common need was a fish in the hole that was impossible to recover. Instead of abandoning the well, drilling around and bypassing the fish was adopted since it was cheaper rather than losing the well. Other reasons that led to the development of directional drilling is the discovery of some crooked holes previously thought to be vertical holes and also the need to drill into more productive areas under adjacent acreage where ownership may have been in question. Almost all oil and gas wells drilled offshore are directional. Geothermal wells, both high- and low-temperature ones, are also very commonly directionally drilled.

The history of directional drilling can be traced back to 1895 when wells were drilled at angles or curved for the purposes of sidetracking equipment stuck in the hole. After the invention of inclinometers and the survey of many wells, which were assumed to be vertical, it was noted that they were actually directional (Vieira, 2009). However, formal directional drilling is thought to have begun in the 1930s in California when a drilling contractor drilled a slanted well from land into a reservoir that was offshore (Vieira, 2009; Inglis, 1987).

The technology of drilling directional wells has dramatically improved since the 1930s when it was first officially documented that a contractor drilled a directional well in Huntington Beach, California (Vieira, 2009) and in southeast Texas where a directional well was drilled to reach a blown out well at a point near the bottom. Fluid was pumped through the directional well into the formation, stopping the blow out (Short, 1993). The general principle of drilling a directional well to a given direction is to point the drilling bit in that direction. This may be achieved by using different tools and equipment which will be discussed later on.

2.2 Types/patterns of directional wells

There are different types of profiles for directional wells. The main profiles commonly adopted for directional drilling in the oil industry are listed below (Figure 2).

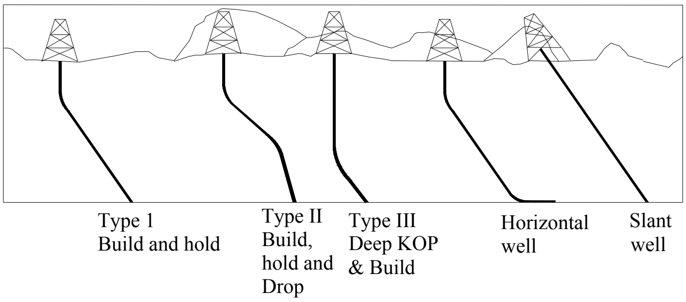

FIGURE 2: Well profiles (based on Inglis, 1987, and Short, 1993)

(i) Build and hold: This type of profile may also be referred to as type I profile or J-profile. It is used for moderately deep wells where the oil bearing rock is in a single zone and no intermediate casing is required. It is the pattern most commonly adopted for directionally drilled geothermal wells. The well has three sections, i.e. the vertical section from the surface to the kick off point (KOP), the curved section where the well angle is built up to the planned inclination and finally the inclined section drilled to the target.

This type of profile is applied when large horizontal offsets are required. The casing is done through and over the curved section of the well trajectory. The angle of inclination varies from 15-55° (Inglis, 1987), but most geothermal wells have an inclination of 20-45°.

(ii) Build hold and drop: This type of profile may also be referred to as type II profile or S-profile. It is similar to type I but the difference comes when the angle of the inclined section is reduced, often drastically, to become vertical as the target is reached.

This type of profile is applied in several cases, such as, when completing a well that intersects multiple producing zones; as a relief well, parallel to a wild well, for the purpose of quenching the reservoir; and finally it is used for accurate bottom hole spacing where many wells are drilled from the same surface location as in offshore drilling (Vieira, 2009).

(iii) Deep kickoff and build: This profile is also referred to as the type III profile. It is used when drilling away from an obstacle such as when sidetracking to drill away from a lost-in-hole fish. Deep kick off poses challenges in that deflection may be less responsive due to hard formations. Due to

great depth, more time is required to trip and change the bottomhole assembly (BHA) for deflecting the well. The angle build up of this profile may be difficult to control.

(iv) Horizontal wells: This type of profile has an angle of inclination reaching 90° within the reservoir. The purpose of this profile is to improve production due to unfavourable factors such as low permeability. Many formations contain oil and gas but produce low volumes from vertical and directional wells because of low permeability. Horizontal wells have increased flow rates because of the increased flow area.

(v) Slant holes: Slant wells start at an angle (30-45°) from the surface and then are drilled by slant-hole rigs. Slant holes are characteristically shallow, reaching depths of about 1200 m (true vertical depth) and 1800 m (measured depth). Slant holes are drilled by first pointing the drill string in the correct horizontal direction toward the target. Then it is raised 30-45° from the vertical. The general design of the pattern and casing strings is similar to other directional holes with allowances made for the angles and tubular compression due to the pull-down system.

2.3 Directional drilling for petroleum

The most common application of directional drilling is in the development of offshore oil and gas reservoirs. This is due to the single site requirement. It is more economical to drill many directional wells from one platform than it is to build a costly platform for each vertical well (Short, 1993). Platforms may take 2-3 years to construct and position which means an equivalent time delay before production can begin. A single large platform can support more than 50 wells (Inglis, 1987).

Modern directional and extended reach techniques may drill into large areas containing oil and gas from one surface location. A vertical well penetrates the reservoir at one point. Directional drilling increases coverage substantially, depending on the angle of inclination. Increased coverage of the reservoir increases production per well (Short, 1993).

2.4 Directional drilling for geothermal energy

Geothermal energy is utilised in certain areas of the world with good geothermal gradients found in some rocks, often associated with volcanic intrusions. The heat is mined from the rocks through drilling. The source rock is generally impermeable except for near-vertical fractures. Extracting heat from this rock requires drilling wells. The wells are directionally drilled to increase the likelihood of intercepting the vertical fractures.

2.5 Benefits of directional drilling

Drilling directional wells will cost about 22-41% more and may increase the cost of a 64 MWe project by 2.8-6% if well productivity does not improve (Ngugi, 2002). In spite of these cost implications, directional drilling is still preferred because of its benefits as discussed below.

(i) Better chances of intersecting near vertical targets

(ii) Side tracking: May be necessitated by a fish in the hole; a re-drill/re-completion where a well was drilled in an unproductive part of the reservoir and did not locate the anticipated target; the hole can be plugged and the well sidetracked towards a new target.

(iii) Drilling to avoid geological problems: This is mostly applicable in petroleum reservoirs. Petroleum reservoirs are sometimes associated with salt dome structures that may be directly in the

path of the well. Drilling through the structure may pose serious corrosive problems later on. In this situation it is prudent to avoid the salt formation by drilling a directional well. In case of a blowout that makes it impossible to cap a well from the rig, relief wells (usually 2) are drilled directionally and controlled to reach targets less than 3 m from the blown out well at the subsurface; this helps kill the blowout.

(iv) Drilling beneath inaccessible locations: This may be a result of manmade or natural obstructions such as buildings, lakes or mountains. Rigging up over these sites is not possible and the only way to reach the resource is by drilling directional wells.

(v) Offshore development drilling: Offshore drilling requires the construction of drilling platforms that are either fixed to the sea bed or floating on the sea. Drilling vertical wells from each platform would not be economically viable. The normal practice is to construct a permanent platform from which more than 50 wells can be directionally drilled (Inglis, 1987).

(vi) Environmental considerations: Directional drilling helps conserve the environment by causing less surface disturbance since several wells can be drilled from the same pad. Vertical wells require a new drilling pad for each well drilled, hence more disturbances. Also, directional drilling makes it possible to use less extensive steam gathering pipe work, thus minimising land requirements.

3. DIRECTIONAL WELL PLANNING

There are many factors to be considered when planning the drilling of directional wells; these are discussed here below.

3.1 Reference coordinates

Directional drilling involves measurements of depth, inclination and azimuth. These measurements have fixed references so that the course of the well trajectory can be calculated. In directional drilling, these references mainly refer to depth reference, inclination reference and azimuth reference.

For depth measurements, they could either be Measured Depths (MD) or True Vertical Depth (TVD). MD is the actual depth along the well bore whereas TVD is the vertical distance from a reference to a point on the well bore. Usually the rotary table is used as the reference. Depths may be given with reference to the Below Rotary Table (BRT) or the Rotary Kelly Bushing (RKB). For inclination measurements, the vertical reference is the direction of the gravitational vector which can be indicated by a plumb bob. Azimuth reference can be one of the following: magnetic north, true geographic north or grid north. These references are discussed in more detail below.

(i) *True geographic north (Meridian direction):* The direction is with reference to the geographical North Pole. In maps, the direction is shown by meridians of longitude.

(ii) *Magnetic north (compass direction):* The compass gives a direction referenced to magnetic north. The position is time dependant and varies accordingly. Correction from magnetic north to true geographic north varies geographically.

(iii) *Grid north:* The earth's surface where drilling occurs is curved but maps represent it as a flat surface. For the purpose of planning a directional well, it is convenient if the curved surface of the earth is projected onto a flat surface on which maps can be drawn. One such system is known as the Universal Transverse Mercator (UTM). This is a projection of the section of the earth's surface that contains the area of interest. When projections are done, there is a distortion of axes such that the

UTM north is offset slightly from true north. Over large distances this offset can bring significant differences and must be corrected for when converting coordinates from one system to another.

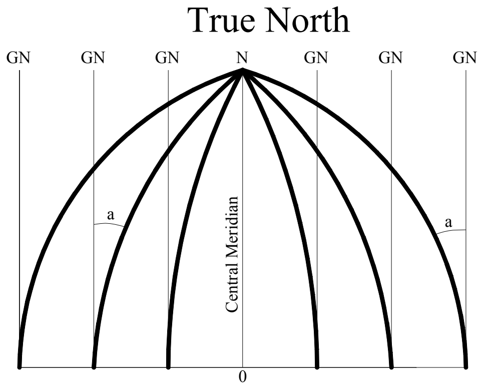

FIGURE 3: Relationship between true north and grid north (Baker Hughes INTEQ, 1995)

The most common method of fixing the position of a point on the earth's surface is to give its latitude and longitude. Latitudes run parallel to the equator and are denoted by a number of degrees 0-90° north or south of the equator. Longitudes are perpendicular to the equator and they pass through the North Pole and South Pole and are denoted by a number of degrees 0-180° east or west of the Greenwich meridian.

The relationship between True North and Grid North is indicated by a convergence angle. This is the angle difference between grid North and True North for the location on the surface of the earth being considered. Figure 3 shows the relationship between true north and grid north. GN refers to grid north and 'a' refers to the convergence angle.

Baker Hughes INTEQ (1995) states that the world is divided into 60 zones under UTM. The division is based on reference meridians which are 6° apart. The zones are numbered 0-60. The zones are further subdivided into grid sectors by latitudes. Each grid covers 8° latitude starting from the equator and ranging from 80°South to 80°North. The sectors are given letters ranging from C to X, excluding I and O. This means that a surface on the earth can be identified by a unique number and letter with reference to a given sector.

Coordinates in UTM are measured in metres. North coordinates are measured from the equator. For the northern hemisphere, the equator is taken as 0.00 m north, whereas for the southern hemisphere the equator is 10,000,000 m north (to avoid negative numbers). East coordinates for each sector are measured from a line 500,000 m west of the central meridian for that sector. In other words, the central meridian for each zone is arbitrarily given the coordinate 500,000 m east (to avoid negative numbers). UTM coordinates are always Northings and Eastings, and are always positive numbers (Baker Hughes INTEQ, 1995). Figure 4 shows how coordinates for a point are given.

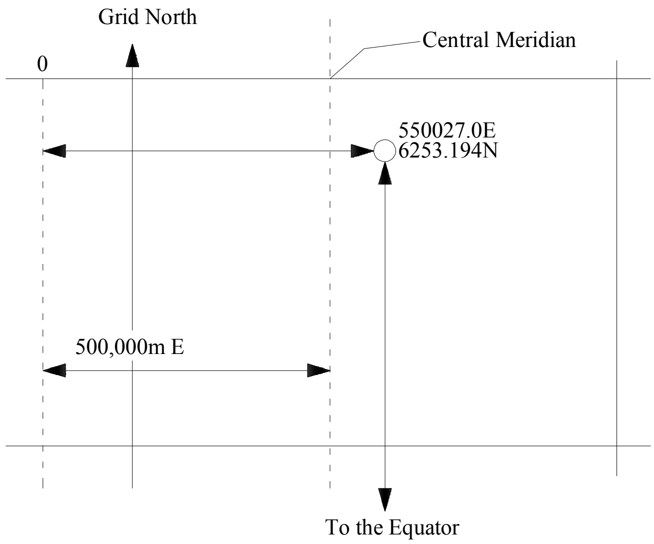

FIGURE 4: Northings and Eastings (Baker Hughes INTEQ, 1995)

3.2 Targeting

The target is the main objective of drilling. The size of the target will determine the cost of hitting the target because of the time spent in reaching it. The smaller the target zone, the greater the number of correction runs necessary to ensure the target is intersected, consequently higher drilling time and cost. To save on time and cost, the geologist or reservoir engineer should give as large a target zone as possible. This will allow the driller to place the well trajectory within the target zone at minimum cost.

3.3 Other adjacent wellbores

Directional drilling requires drilling several wells within the same pad; they may be separated by small distances. In petroleum drilling, the separation distance from one well to another may be as small as 2-4 m. This is due to space constraints and the need to drill as many wells as possible. In geothermal drilling, there may be a need to drill 3-6 wells from the same pad and, in some circumstances, the separation distance from one well to the next may be quite small. Under such circumstances, precise control is required and great care must be taken to avoid collisions under the surface. As each new well is drilled, the separation distance of all adjacent wells must be calculated.

Survey results for the wells can be plotted using a computer program to aid in 3D visualisation of the trajectories. This will help the driller to nudge a well being drilled away from the existing ones, thus avoiding collision. Sometimes this may mean drilling away from the target; when the well is a safe distance away, it may be directed back towards the target.

3.4 Kick off point (KOP)

The KOP is the point on the well trajectory where deviating or sidetracking begins. The KOP should be at least 30 m below the bottom of the last casing in the hole, preferably 60 m or more, especially below surface or shallow intermediate casing. This reduces the risk of excessive casing wear or splitting the casing shoe (Short, 1993). When sidetracking, the KOP should be at least 15 m, preferably 45 m, above the fish. This will prevent drilling back into the fish or re-entering the old hole.

Choosing the point of the kickoff requires knowledge of the type of formations at that point. Very soft formations may increase the difficulty in deviating and building up the angle. Such formations may not have sufficient strength to provide the reaction force on the fulcrum of the directional assembly. Thus, the drill string may partially enter the wall of the hole. Very hard and abrasive formations are difficult to drill. The deviation BHA is less rugged with less weight on the bit. This reduces the action of the bit on a formation, hence increasing the time spent deviating. The use of mud motors allows fast drilling. It is important to avoid very soft, very hard, abrasive or laminated formations. The KOP should be selected for medium soft or medium drillability massive formations when possible (Short, 1993).

3.5 Build-up Rate (BUR)

This is the rate of angle build-up per drilled length. This is usually expressed in degrees/30 m. If the change of angle build-up is too rapid, severe dog-legs can occur in the trajectory. These sharp bends may prevent the drilling assemblies from passing through and cause more wear on the drill string. Too slow a build-up may result in a long interval for the trajectory to reach the required inclination. Commonly used build-up rates range from 1.5 to 2.5° per 30 m (Inglis, 1987).

3.6 Dog leg severity

In directional drilling, a dog leg refers to an abrupt change in the hole angle or direction that causes sharp turns in the well bore trajectory. It is detected by increased torque and drag on the drill string. The size of a dog-leg can be calculated using survey results over 20-30 m intervals, using the following mathematical equation. Gabolde and Nguyen (2006) give the formulas shown in Equations 1 and 2:

$$\beta_n = \cos^{-1}[\cos\theta_n \cos\theta_{n+1} + \sin\theta_n \sin\theta_{n+1} \cos(\varphi_{n+1} - \varphi_n)] \tag{1}$$

where β_n = Dog leg angle at station n; and
θ_n, φ_n = Inclination and azimuth, respectively, at station n.

Dog leg severity is expressed as the change in angle per 30 m drilled.

$$DLS_n = 30\frac{\beta_n}{\Delta L_n} \tag{2}$$

where DLS_n = Dog leg severity for segment n; and
ΔL_n = Segment length between stations n and n+1.

Severe dog-legs cause the drill string to undergo cyclic loading because of the pipe bends containing a dog leg. On the inside of the bend, the wall of the pipe will be under compression and, on the opposite wall, there will be tension. The loading is reversed when the pipe is rotated 180°. This will encourage fatigue and reduce the operational life of a drill pipe.

3.7 Directional well design

There are several parameters to consider when designing a directional well. These are surface coordinates, target coordinates, true vertical depth of target, depth to KOP, and the build-up rate. Geologists usually give the target in terms of inclination and azimuth and allowable margins. The driller will then make the trajectory design for the wellbore to hit the target. Below is a typical calculation. Formulas were derived to generate a computer programme for the visualisation of the trajectory.

Figure 5 shows a directional well profile. The various parameters in the diagram are explained as follows:

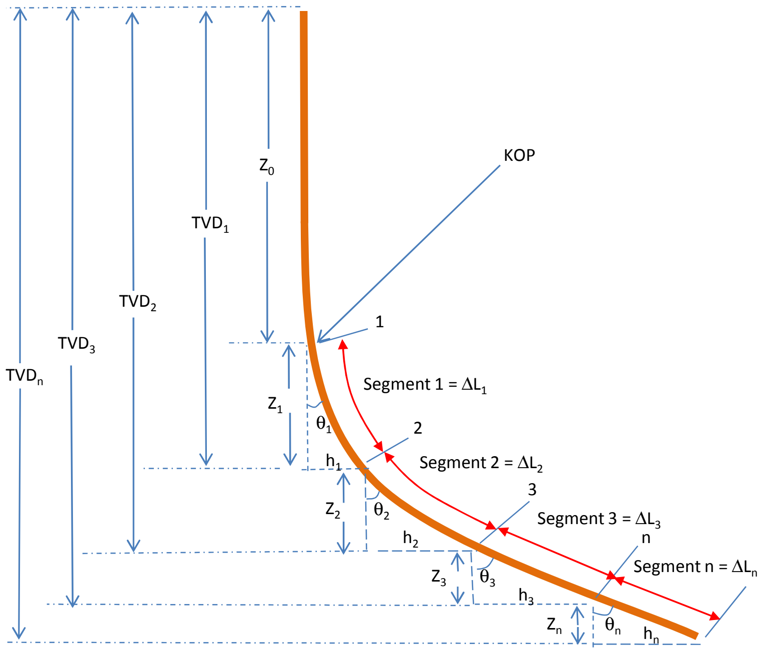

FIGURE 5: A directional well profile

Segment n, ΔL_n = Distance along the trajectory between stations n and n+1;
Z_0 = Vertical depth to KOP;
Z_n = Vertical depth between stations n and n+1;
TVD_n = True vertical depth to station n+1;
h_n = Horizontal distance between stations n and n+1;
H_n = Resultant horizontal distance from the vertical axis to station n+1;
θ_n = Angle of inclination for the well over segment n; and
1, 2, 3, ..., N = Survey stations.

(i) Calculation of true vertical depth (TVD) and horizontal displacement for the segments
The results of a directional survey yield the inclination and azimuth of the trajectory at a given depth. This survey must be analysed to calculate the actual position of the survey station with respect to the surface location. Various kinds of geometrical models have been used, with each model generating a

number of equations. The accuracy of a given model depends on how close it comes to the actual trajectory. For consistency, however, it is important to adopt one model for planning and monitoring wells drilled from the same pad. The geometric models commonly used to analyse and calculate the survey results are the tangential method, the balanced tangential method, the average angle method, the radius of curvature method and the minimum curvature method (Inglis, 1987). In this paper, the method used is the average angle method.

Referring to Figure 5, the first station surveyed is 2. But the angle θ_1 at KOP is 0. Since the angle is gradually increasing, we use the average of two stations, i.e. the upper and lower ends of the segment to calculate the *TVD* for that segment. This makes it more representative for the entire segment. For example, to calculate Z_1 we use the average of θ_1 and θ_2. The well is assumed to be vertical down to the KOP. By trigonometry,

$$Z_1 = \Delta L_1 \cos\left(\frac{\theta_1 + \theta_2}{2}\right) \tag{3}$$

$$h_1 = \Delta L_1 \sin\left(\frac{\theta_1 + \theta_2}{2}\right) \tag{4}$$

This is repeated for each segment. In general, therefore, vertical depth and the horizontal displacement for a given segment n is given as:

$$Z_n = \Delta L_n \cos\left(\frac{\theta_n + \theta_{n+1}}{2}\right) \tag{5}$$

The true vertical depth for the well at a given station will be the summation of vertical depths for the segments up to that station. Thus, for the n^{th} segment, *TVD* will be given as:

$$TVD_n = \sum_{i=0}^{n} Z_i \tag{6}$$

(ii) Calculation of northings, eastings and resultant horizontal displacement

Figure 6 shows a horizontal plane with the main directional axes crossing at the KOP. 2 refers to the first station of survey and 3 to the second station of survey. Parameters are as follows:

φ_n = Azimuth at station n;
n_n = Displacement to the northern direction (northings);
e_n = Displacement to the eastern direction (eastings); and
h_n = Horizontal displacement between two consecutive points of survey.

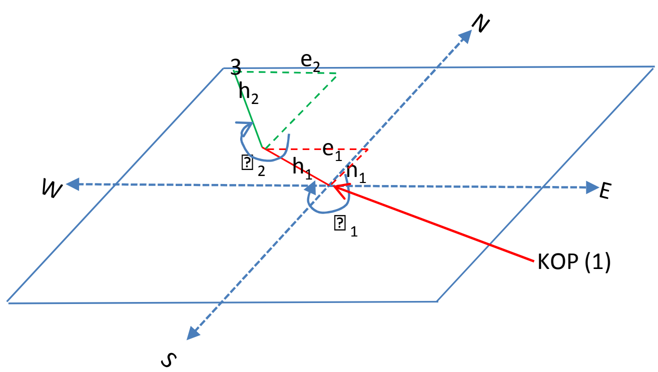

FIGURE 6: Vertical view of the well profile

Consider a well with azimuth φ_1 at the KOP and φ_2 at the first station of survey. The distances shown in Figure 6 are measured from the stations along the main directional axes in the plane. The same case of using the average of the angles between two consecutive sections applies. Using trigonometry, n_1 and e_1 will be given as:

$$n_1 = h_1 \cos\left(\frac{\varphi_1 + \varphi_2}{2}\right) \tag{7}$$

$$e_1 = h_1 \sin\left(\frac{\varphi_1 + \varphi_2}{2}\right) \tag{8}$$

The northing and easting displacements for a given station will be the summation of all displacements behind that point, as shown in Equations 9 and 10. For northings, DN_n refers to the total displacement in the northern direction at station n+1:

$$DN_n = \sum_{i=1}^{n} n_i \tag{9}$$

For eastings, DE_n refers to the total displacement in the eastern direction at station n+1:

$$DE_n = \sum_{i=1}^{n} e_i \tag{10}$$

The resultant horizontal displacement H_n at station n is a vector quantity which has both magnitude and direction. The magnitude is given by Equation 11:

$$H_n = \sqrt{(DE_n)^2 + (DN_n)^2} \tag{11}$$

4. CALCULATIONS AND VISUALISATION OF SELECTED WELLS

In this report, Equations 3-11 were used to generate a computer program in Excel that calculates all the parameters at any given point of the wellbore trajectory, based on survey results. To help in visualising the wellbore trajectory as it was being drilled; graphs were drawn to show the designed/planned trajectory and the boundaries. The drilling of well OW-35A was used as an example. The boundaries define the limits within which the actual wellbore trajectory must stay in order to intersect the target. The program Grapher 7 was used to visualise the wellbore trajectory in both two dimensions (2D) and three dimensions (3D). 2D graphs help visualise the actual trajectory in relation to the planned trajectory and boundary limits. 3D graphs help to visualise the actual trajectory with respect to existing adjacent trajectories. The resultant graphs from the tables generated by the computer programme are shown in Figures 7, 8 and 9. Figure 7 shows a 3D plot of three well bore trajectories near each other, while Figures 8 and 9 show the actual wellbore trajectory of well OW-35A against the planned trajectory and the boundaries.

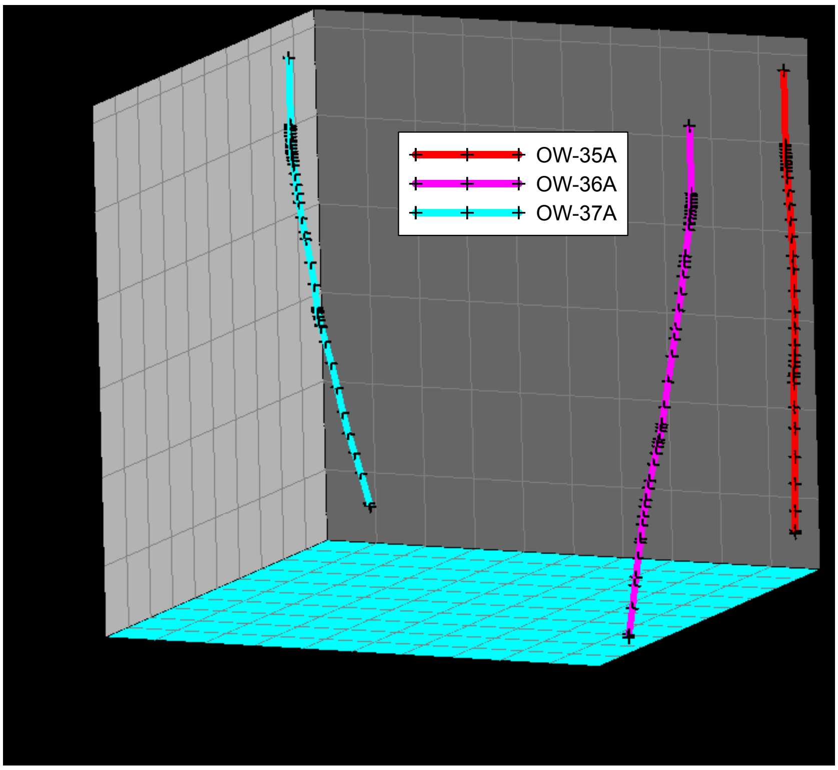

FIGURE 7: 3D view of three wells in Kenya

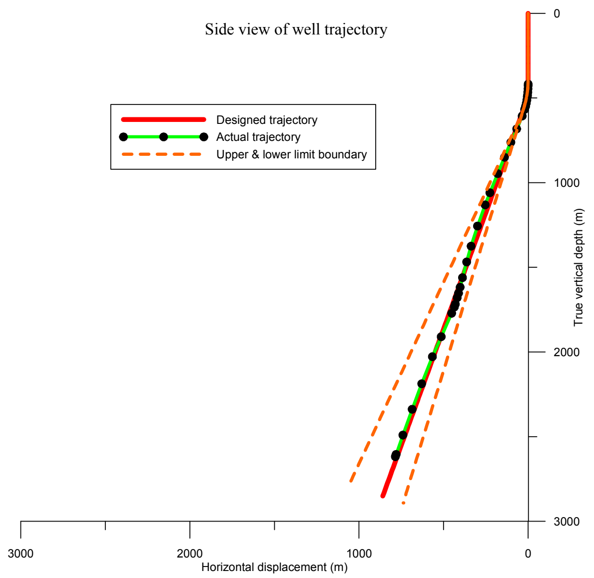

FIGURE 8: Side view of the well profile of the directional well, OW-35A, showing the planned trajectory and boundary limits

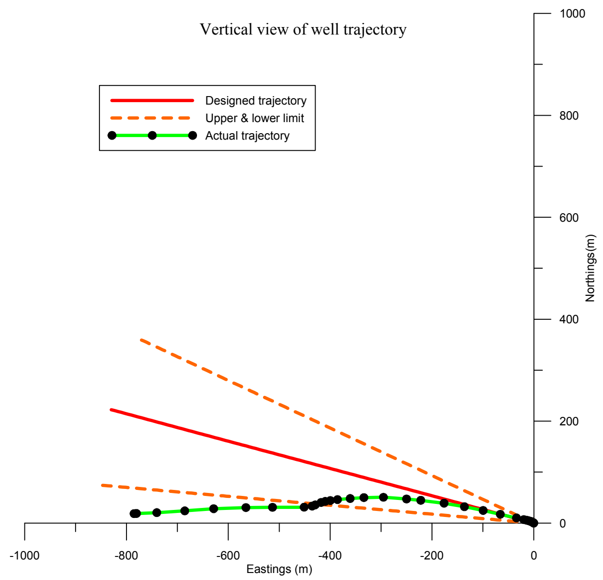

FIGURE 9: Vertical view of the well profile of the directional well OW-35A, showing the planned trajectory and boundary limits

5. EQUIPMENT FOR DIRECTIONAL DRILLING

5.1 Equipment and instruments for changing course

For directional drilling to be possible, tools are needed that will enable a change in the course of the well bore from vertical to the desired direction. The principle is to orient the drill bit in the direction required at the point of kick off. Although the bent sub and the drill bit can be turned at the surface to the right direction of drilling, this needs to be confirmed by surveying after the drill string has been tripped into the hole.

One important aspect to be carefully considered and set is the tool face. The tool face is the direction in which the drill bit tends to drill. It is important to remember that the direction of the tool face is not necessarily the same as the required direction of the well trajectory. There are different types of tools for deflecting the hole. Vieira (2009) identifies the following five factors that determine the choice of a particular tool:

(i) Degree of deflection needed;
(ii) Formation hardness;
(iii) Hole depth;
(iv) Temperature;
(v) Presence or absence of casing; and
(vi) Economics.

In this report, discussion will be limited to two tools for changing the course: the downhole motor and the bent sub.

(i) Downhole motors
Downhole motors can also be referred to as positive displacement motors (PDMs) or mud motors. Downhole motors can be used for drilling both vertical and directional wells. The motors use the pressure and volume of the drilling fluid to rotate the bit. In the past, downhole motors were used in combination with bent subs attached to the top of the motor (Figure 10). Modern mud motors have a bend on the lower end of the motor that allows drilling in "sliding" and rotating mode. In sliding mode, the drill string is locked and does not rotate, thus allowing the bit to build up the angle. In rotation, the whole drill string is rotated, thus adding to the mud motor's speed of rotation. Then the drill bit, facing a different direction, is rotated and thus drills straight.

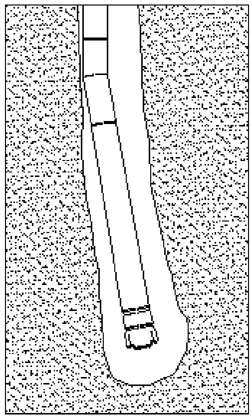

FIGURE 10: Mud motor with a bent sub (Inglis, 1987)

(ii) Bent subs
Deflection of the hole when using a mud motor is achieved by a special sub placed above the motor to create a side force at the bit. The bent sub is a short length of drill collar which is about 0.6 m long. The axis of the lower pin connection is machined slightly off vertical. Figure 11 shows a bent sub (below), orienting sub (middle) and the muleshoe stinger which accommodates the measuring instrument. The pin is inclined to angles that vary from ½ to 3° depending on the rate of angle build up needed. The bent sub causes the motor and the bit to drill in a specific direction depending on the tool face. The amount of deflection is controlled by the amount of offset angle on the pin of the bent sub, the stiffness of the motor and the hardness of the formation.

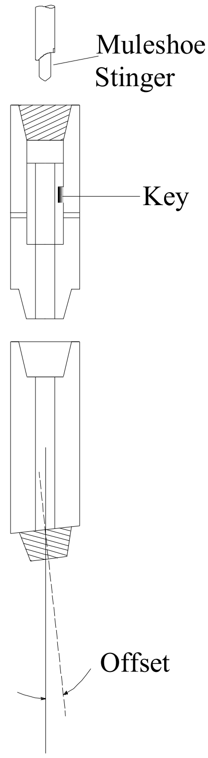

FIGURE 11: Bent sub, orienting sub and muleshoe (mod. from Inglis, 1987)

5.2 Surveying equipment without measuring while drilling (MWD) systems

In directional drilling, it is of paramount importance to know the position of the hole as drilling progresses. Both the drift angle and the direction (azimuth) must be determined at various depths to compare the actual trajectory to the planned trajectory of the well. The information gathered from these measurements will help in monitoring and making appropriate changes to keep the trajectory on course. Inglis (1987) states that the objectives of directional surveying are:

(i) To monitor the actual well path as drilling continues to ensure that the target will be reached;
(ii) To orient deflection tools in the required direction when making corrections to the well path;
(iii) To ensure that the well being drilled is in no danger of intersecting an existing well nearby;
(iv) To determine the true vertical depths of the various formations encountered for geological mapping purposes; and
(v) To determine the exact bottom hole location of the well for the purpose of monitoring reservoir performance and also for relief well drilling.

There are many types of equipment and tools used for surveying, but they can be generally classified into two groups: those with MWD and those with wireline logging tools. MWD systems can be used to survey when drilling is ongoing. The equipment without MWD systems are those that cannot be used when drilling is ongoing. The equipment can be classified as single/multi shots and steering tools. Single-shot surveys can be done during routine drilling operations like just before tripping to change the bit or BHA. If there is a need to take a survey, drilling can be stopped to make single shot surveys and then resume drilling. On the other hand, steering tools or MWD systems furnish the driller with real-time directional data on the rig floor. Some of the tools are discussed below.

(i) Magnetic single-shot: The magnetic single-shot measures both the drift and the compass direction of the wellbore. The instrument barrel of a magnetic single-shot has several components, for example a precision floating compass, a device to superimpose the concentric circles calibrated in degrees with a plumb bob indicator (for measuring inclination). A camera photographs the plumb bob and compass face to record both drift and direction (Short, 1993). The magnetic single-shot cannot record compass directions inside steel pipe or casing because they shield off the earth's magnetic lines of force. It records only in open holes or inside nonmagnetic drill collars. The instrument is checked, the timer is set and the tool is lowered down the drill string on the wireline. Sinker bars may be attached to the instrument to aid its travel through the mud into the baffle plate. After waiting for the camera to operate, the instrument is pulled out of the hole. The recording disk is removed and readings taken from it.

The readings from the magnetic single-shot must be corrected for magnetic declination. This is the difference between magnetic north and true north. The standard practice is to report directions as true bearings. The amount of declination depends on the geographical location. A magnetic single-shot is shown in Figure 12.

(ii) Magnetic multi-shot: The magnetic multi-shot instrument works on the same principle as the single-shot but is capable of taking a series of pictures at pre-set intervals. This is due to a built in film-wound camera with a timer that automatically exposes and advances the film at preset intervals. Using a stop watch, the surveyor keeps track of the depth at which the preset timer takes a shot. Only the shots taken at known depths with the drill string stationary are used in plotting the trajectory. This instrument is used to survey the entire well trajectory while tripping out. The tool must be inside a nonmagnetic drill collar for it to be able to measure direction in the cased hole (Vieira, 2009).

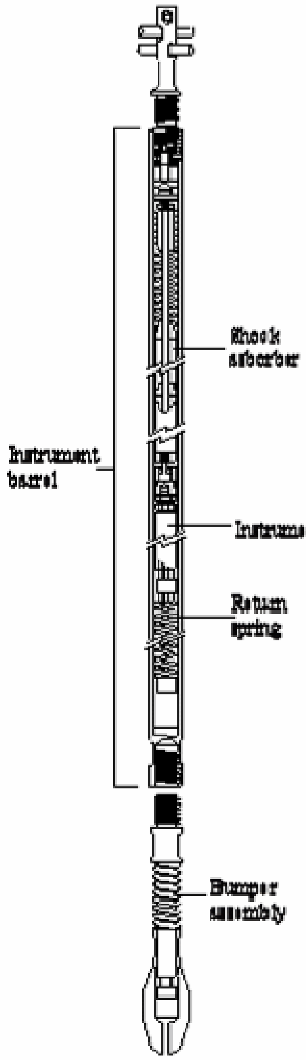

FIGURE 12: Magnetic single-shot instrument (Vieira, 2009)

(iii) Gyroscopic multi-shot: Gyroscopic instruments measure compass directions without using the earth's natural lines of magnetic force. A gyroscopic compass is not affected by the presence of magnetic fields. Gyroscopes can also measure drift angles using regular or modified drift measuring instruments.

The components of a gyroscopic instrument include a spinning wheel driven by an electric motor at 40,000 revolutions per minute (Vieira, 2009). The working principle of a gyroscopic multi-shot is based on its spinning. The direction of the spinning wheel is maintained by its own inertia and the axis of rotation of the wheel is kept in one direction, irrespective of how the other axes are rotated. This property of the gyroscope is used as a reference for measuring the azimuth. Before running the gyro instrument into the well, the gyro must be aligned with a known reference direction which is usually true north. The gyro takes a survey at preset intervals as the tool is run into the wellbore. The survey results are conveyed to the surface via a wireline. The readings do not need to be corrected for declination because they are taken with reference to true north.

The disadvantage of gyroscopic instruments is that they tend to drift gradually out of alignment when an unbalanced force acts upon them. This effect is reduced by taking measurements while running the instrument into the hole. When taking readings, allowance for drift is made with the results.

5.3 Surveying/logging equipment with MWD systems

MWD records measurements on a real time basis while drilling is in progress. Vieira (2009) states that the measured data may be transmitted to the surface by one of the three methods stated below:

(i) Via a wireline;
(ii) Through pressure variations in the drilling mud/fluid (mud pulse); and
(iii) Through electromagnetic or radio waves.

When an instrument uses a wireline to convey survey data to the surface, drilling is usually done with a downhole motor which eliminates the need for the drill string to rotate. There is a provision for the wireline to pass out of the drill string at the side-entry sub. It allows the wireline to pass from the drill string out to the annulus at some point beneath the rig floor. Since the wireline does not interfere with the pipe connection, the instrument need not be pulled out (Inglis, 1987).

The science of measuring at a distance is known as telemetry. In drilling, the three most important parameters for the directional driller are the inclination, the direction (azimuth), and the direction of the tool face. Inclination is measured by accelerometers which can measure the components of the earth's gravitational field. The direction of the hole is measured by magnetometers which can measure the earth's magnetic field. Three types of MWD instruments will be discussed here: the steering tool, mud pulse telemetry and electromagnetic telemetry.

(i) Steering tool: Vieira (2009) defines a steering tool as a wireline telemetry surveying instrument that measures inclination and direction while drilling progresses. Steering tools, as the name suggests, help the driller by providing him with the necessary information to steer the bit in the correct direction. Steering tools are especially important during the critical period of kicking off the well when surveys of the well need to be taken at close intervals.

The tool consists of an electronic probe that is run into the hole on a conducting wireline. It is usually put at the orienting sub just above the bent sub. Because the wireline of the steering tool needs to be stationary, the tool can only be used with a downhole mud motor that turns the bit while the drill string does not rotate. The electronic probe has sensors (accelerometers and magnetometers) that measure hole inclination, azimuth and tool face orientation. The survey data are transmitted as signals from the probe through the wireline to the surface, where a computer converts them and displays the directional data on the screen monitor. The use of steering tools in the market has decreased because of their limitations (used only when the drill string does not rotate) as compared to mud-pulse instruments.

(ii) Mud-pulse telemetry: This instrument transmits signals uphole through the drilling fluid, allowing the driller to obtain real time readings on the monitoring screen while drilling is in progress, including when the drill string is rotating. Vieira (2009) identifies five components in mud-pulse telemetry as follows:

a) Downhole unit that senses direction and inclination;
b) Mud pulse generator, also called a pulser;
c) Surface transducer that decodes mud pressure variations and transforms them into electric signals;
d) Computer that receives the electric signals and interprets them; and
e) Rig floor unit that displays the data.

The mud pulse generator contains a microprocessor that converts the survey data (inclination, direction and tool face orientation) into a series of positive and negative pressure pulses. Positive pulse indicates pressure increase and negative pulse indicates pressure decrease. The pulses are usually transmitted to the surface coded in a binary signal. The mud-pulse telemetry unit inside the hole contains accelerometers and magnetometers for measuring inclination and direction. To avoid magnetic interference, it is placed within the nonmagnetic drill collar.
The downhole unit is powered by a turbine which is rotated by the drilling fluid. The unit can also be powered by batteries. Some mud pulse units contain both batteries and turbine. Measurements are made continuously as drilling goes on, whether there is circulation or not. The data is transmitted to the surface only when there is circulation or circulation resumes. The limitation of mud pulse telemetry is that it cannot transmit data when drilling with air or aerated drilling fluids or when there is no continuous column of drilling fluid.

(iii) Electromagnetic (EM) telemetry systems: EM telemetry can transmit data where mud-pulse telemetry cannot. This is made possible when a two way communication link between the downhole equipment and the surface equipment is established. Data can be transmitted through any formation using low-frequency electromagnetic waves. EM telemetry is especially important when doing underbalanced drilling. Because the EM system does not have moving parts to produce pressure pulses, it is more reliable than mud pulse telemetry.

6. COMPARISON OF DIRECTIONAL DRILLING IN KENYA AND ICELAND – TIME ANALYSIS

The drilling histories of 12 wells from Olkaria, Kenya and 14 wells from Hengill field, Iceland were analysed for comparison. All of these wells were directionally drilled and the casing and bit sizes used were the same.

The Hengill high-temperature field rates as one of the largest in Iceland. It is located 30 km east of Reykjavik. The Hengill volcanic system is composed of crater rows and a large fissure swarm. It is located on the eastern border of the Reykjanes Peninsula, SW-Iceland. The Hengill volcanic system has a 100 km long NE-SW axis, 3-16 km wide, extending from Selvogur in the southwest to Ármannsfell in the northeast. The Hengill central volcano covers an area of about 40 km^2 (Björnsson et al., 1986).

The greater Olkaria geothermal area in Kenya is divided into seven fields, namely Olkaria East (Olkaria I), Olkaria Northeast, Olkaria Central, Olkaria Northwest, Olkaria Southwest, Olkaria Southeast and Olkaria Domes. It is situated south of Lake Naivasha on the floor of the southern segment of the Kenya rift (Figure 1). The wells studied in this report are from the Olkaria I and Olkaria Domes field. Olkaria I has been producing power since 1981 when the first of the three 15 MWe units was commissioned (Lagat, 2004). Olkaria Domes is currently undergoing production drilling. It will eventually be developed as Olkaria IV, where a 140 MWe power plant is scheduled to be developed (Cherutich, 2009).

6.1 Time analysis-raw data

This section deals with raw data and the tables and figures represent the actual work done. The drilling of the wells under study was done in steps; each step is identified by a different casing. The Icelandic naming style for the stages has been adopted for the Kenyan wells. In this report, for Kenyan wells, surface drilling (0–60 m) was called step 0. Table 1 shows the steps of a typical well for both Kenya and Iceland.

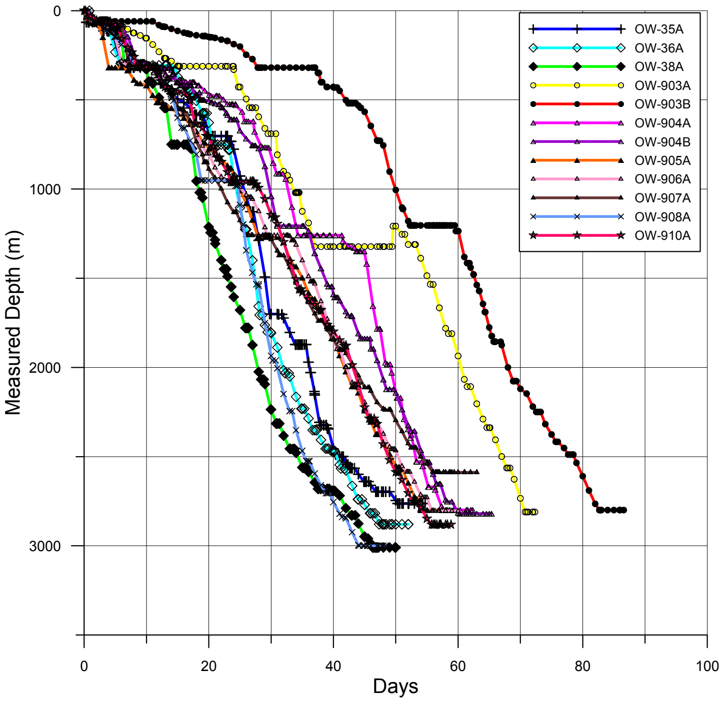

FIGURE 13: Depth vs. days graph for drilled Olkaria wells

TABLE 1: Drilling phases

Kenyan wells		Icelandic wells	
Steps	**Depths (m)**	**Steps**	**Depths (m)**
0	0-60	Predri.	0-90
1	60-300	1	90-300
2	300-1000	2	300-800
3	1000-2800	3	800-2300

For the comparison to be as close as possible, step 0 and pre-drilling times were not included in the analysis except in determination of the average depth drilled per day (ADD/D), which did include step 0 for the Kenyan wells. This is because a smaller rig was usually used for pre-drilling to 80–90 m for Icelandic wells. The wells studied, their depths and the time taken to drill them are shown in Table 2. Figure 13 shows the actual drilling progress (depth versus days) for the Kenyan wells. Wells OW-903A and 903B took the longest time to drill. The reason is that cementing took a long time and there was a gas blowout that delayed drilling.

TABLE 2: Summary of wells studied; pre-drilling for Iceland and step 0 for Kenya are not included.

Icelandic wells				Kenyan wells			
Well no.	**Depth**	**Drilled depth**	**Days**	**Well no.**	**Depth**	**Drilled depth**	**Days**
HE-03	1887.00	1792.00	39	OW-903A	2810.89	2748.39	71.33
HE-04	2008.00	1930.40	45	OW-903B	2800.00	2740.00	76.04
HE-05	2000.00	1904.00	45	OW-904A	2799.31	2731.14	57.08
HE-06	2013.00	1935.00	37	OW-904B	2820.00	2755.20	62.48
HE-13	2397.00	2318.70	44	OW-905A	2800.00	2738.00	56.21
HE-26	2688.00	2596.00	54	OW-906A	2804.49	2742.22	57.23
HE-36	2808.00	2703.00	45	OW-907A	2588.22	2527.72	58.92
HE-51	2620.00	2520.00	34	OW-908A	3000.00	2937.65	45.38
HE-53	2507.00	2438.00	57	OW-910A	2881.73	2819.38	54.75
HE-54	2436.00	2342.00	29	OW-35A	2763.00	2697.61	52.71
HE-55	2782.00	2681.00	37	OW-36A	2880.00	2817.00	48.77
HE-57	3118.00	3023.00	40	OW-38A	3010.00	2949.30	46.92
NJ-24	1928.60	1849.60	35				
NJ-25 c	2098.00	1993.00	28				
Average	**2378.90**	**2287.60**	**40.64**		**2829.80**	**2766.97**	**57.32**

6.2 Normal distribution curve for average depth drilled per day (ADD/D)

The acronym ADD/D is not usually used in drilling. For convenience in this report, it has been adopted since it will be used many times. Average depth drilled per day (ADD/D) indicates the average depth in metres that is drilled in 24 hours. High ADD/D indicates that the well was drilled in a shorter time, hence at lesser cost. A normal distribution curve indicates how spread the ADD/D time is and indicates the average ADD/D for all the wells. The results in Tables 3 and 4 were calculated using Equations 12–14.

ADD/D becomes variable x which is the parameter being studied. The range is the difference between the maximum ADD/D and the minimum ADD/D. It is used in finding the size of the class interval. The mean is the average of the sample taken. Variance and standard deviations (S^2 and S) are statistical parameters found as shown in Equations 12 and 13. The function $f(x)$ is the so-called probability function, which is based on normal distribution giving the same values for mean and standard deviation as calculated from our samples. It is calculated from Equation 14 (Chatfield, 1983):

$$S^2 = \frac{\sum(x-\bar{x})^2}{n-1} \tag{12}$$

$$S = \sqrt{S^2} \tag{13}$$

$$f(x) = \frac{1}{\sqrt{2\pi S^2}}\, e^{-\frac{(x-\bar{x})^2}{2S^2}} \tag{14}$$

where S^2 = Variance;
x = Variable under study;
$\bar{x}$ = Sample mean;
n = Sample size/population;
S = Standard deviation; and
e = Euler's number, a constant given as (2.71828...).

Using Equations 12 to 14, various parameters were calculated for Icelandic and Kenyan wells, presented in Tables 3-6. For Icelandic wells (Table 3) the range is 38.45 (i.e. 80.76-42.31), while for Kenyan wells (Table 5 and 6) the range is 30.87 (i.e. 60.15-37.01).

TABLE 3: ADD/D for the studied Icelandic wells

ADD/D (x)	f(x)
42.31	0.0161
42.77	0.0167
42.90	0.0169
45.95	0.0205
47.60	0.0223
48.07	0.0228
52.30	0.0265
52.70	0.0268
52.85	0.0268
71.18	0.0174
72.46	0.0158
74.12	0.0139
75.58	0.0122
80.76	0.0071

TABLE 4: Frequency of different ADD/Ds, Iceland

Interval classes	Frequency
37-41	0
41-45	3
45-49	3
49-53	3
53-57	0
57-61	0
61-65	0
65-69	0
69-73	2
73-77	2
77-81	1

TABLE 5: ADD/D for the studied Kenyan wells

ADD/D (x)	f(x)
32.34	0.0104
37.01	0.0219
41.14	0.0338
42.77	0.0379
45.15	0.0423
46.90	0.0438
48.07	0.0440
49.08	0.0435
50.50	0.0420
56.31	0.0281
60.15	0.0172
63.21	0.0102

TABLE 6: Frequency of different ADD/Ds, Kenya

Class interval	Frequency
31-33	1
33-36	0
36-39	1
39-42	1
42-45	1
45-48	2
48-51	3
51-54	0
54-57	1
57-60	0
60-63	1
63-66	1

The resulting sample distribution for the ADD/D for Icelandic wells is shown in Figure 14 and the corresponding normal distribution in Figure 15. Similar figures for the Kenyan wells are shown in Figures 16 and 17. For Kenyan wells, the average depth drilled per day is about 48 m and for Icelandic wells it is about 57 m. For Kenyan wells the standard deviation is 9 m, and for Icelandic wells it is 14 m.

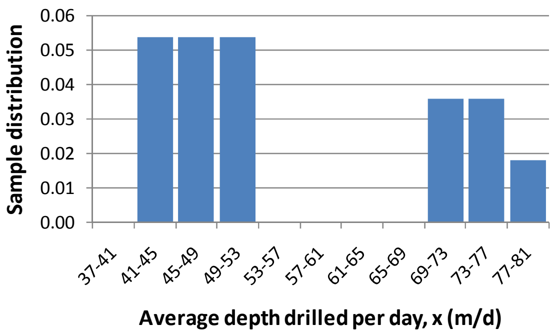

FIGURE 14: Sample distribution for ADD/D for Icelandic wells

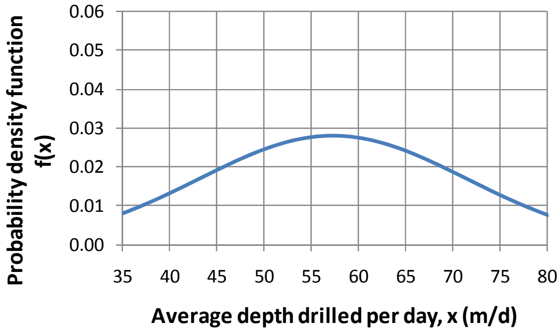

FIGURE 15: Normal distribution for ADD/D for Icelandic wells

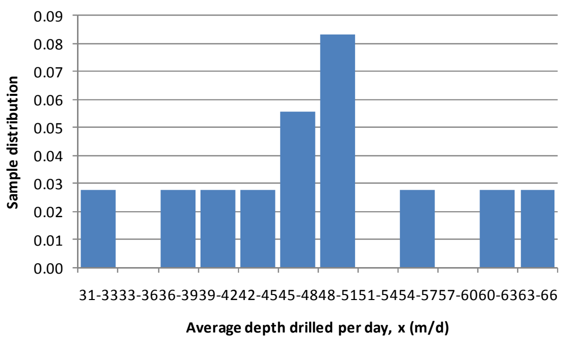

FIGURE 16: Sample distribution for ADD/D for Kenyan wells

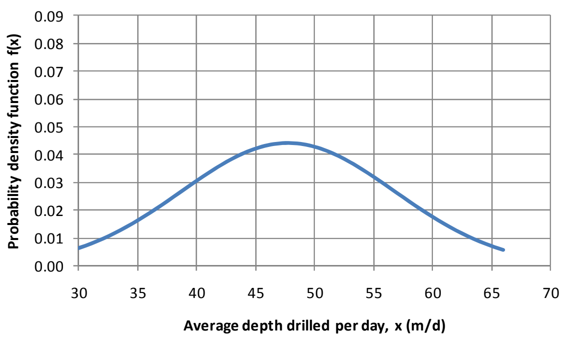

FIGURE 17: Normal distribution for ADD/D for Kenyan wells

Tables 7 and 8 show various activities undertaken during drilling and the time spent doing them. The data for Icelandic wells was adopted from the work of Sveinbjörnsson (2010). Figures 18 and 19 give graphical representations of how the total work time was consumed by various activities during drilling. In order to improve efficiency in drilling, it is important to reduce the time spent on activities other than actual drilling.

TABLE 7: Time analysis (days) for different activities during directional drilling of Kenyan wells

Well No.	Drilling steps	Well depth (m)	Drilling	Casing	Cem.	Cement plug jobs	Stuck	Ream	Fishing	Wait on water	Change bit/BHA	Repair	Hole cleaning	Log.	Other	Total
OW-903A	Step 0	60.5	0.73	0.29	2.08	1.38	0.00	0.00	0.00	0.00	0.00	0.15	0.00	0.00	0.00	4.63
	Step 1	309.4	9.65	1.13	5.21	0.00	0.00	1.00	0.00	0.38	0.50	0.00	0.19	0.00	1.29	19.33
	Step 2	1319.2	10.19	0.50	1.54	1.63	6.25	1.46	0.00	0.25	1.71	0.25	0.17	0.19	1.81	25.94
	Step 3	2810.89	16.88	0.71	0.00	0.00	0.00	0.46	0.00	0.00	3.77	0.63	0.00	2.22	1.41	26.06
		TOTAL	37.44	2.63	8.83	3.00	6.25	2.92	0.00	0.63	5.98	1.02	0.35	2.41	4.51	75.96
		(%)	49.29	3.46	11.63	3.95	8.23	3.84	0.00	0.82	7.87	1.34	0.47	3.17	5.94	100
OW-903B	Step 0	60	2.13	0.13	7.50	0.00	0.00	0.54	0.00	0.00	0.00	0.00	0.04	0.00	0.21	10.54
	Step 1	319.19	16.02	0.50	7.63	0.00	0.00	0.63	0.00	0.00	0.54	0.04	0.15	0.00	0.63	26.13
	Step 2	1204	11.58	0.58	2.08	0.00	0.00	0.88	0.00	0.00	0.75	0.00	0.00	0.21	5.83	21.92
	Step 3	2800	18.65	0.71	0.00	0.00	0.00	0.90	0.00	0.00	3.12	0.25	0.58	3.29	0.50	27.99
		TOTAL	48.38	1.92	17.21	0.00	0.00	2.94	0.00	0.00	4.41	0.29	0.77	3.50	7.17	86.58
		(%)	55.88	2.21	19.88	0.00	0.00	3.39	0.00	0.00	5.09	0.34	0.89	4.04	8.28	100
OW-904A	Step 0	68.17	2.17	0.54	0.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.46	0.00	1.00	4.92
	Step 1	316	2.79	0.83	1.46	0.00	0.00	0.21	0.00	0.00	0.00	0.00	0.08	0.00	1.58	6.96
	Step 2	1259	11.88	0.63	4.29	1.54	0.00	5.17	0.33	0.00	1.21	0.21	0.67	0.25	2.96	29.13
	Step 3	2799.31	10.77	1.29	0.00	0.00	0.00	0.19	0.00	0.00	4.69	0.50	0.13	2.48	0.96	21.00
		TOTAL	27.60	3.29	6.50	1.54	0.00	5.56	0.33	0.00	5.90	0.71	1.33	2.73	6.50	62.00
		(%)	44.52	5.31	10.48	2.49	0.00	8.97	0.54	0.00	9.51	1.14	2.15	4.40	10.48	100
OW-904B	Step 0	64.8	1.54	0.29	0.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.88	3.46
	Step 1	322	4.71	0.54	1.25	0.00	1.21	0.00	0.88	0.00	0.25	0.17	0.33	0.00	1.17	10.50
	Step 2	1206	13.00	1.75	2.46	0.00	0.00	0.38	0.00	0.00	1.88	0.17	0.27	0.52	0.83	21.25
	Step 3	2820	16.75	1.04	0.00	0.00	0.00	0.88	0.75	0.00	4.40	0.75	2.50	2.50	1.17	30.73
		TOTAL	36.00	3.63	4.46	0.00	1.21	1.25	1.63	0.00	6.52	1.08	3.10	3.02	4.04	65.94
		(%)	54.60	5.50	6.76	0.00	1.83	1.90	2.46	0.00	9.89	1.64	4.71	4.58	6.13	100

6.3 Time analysis - processed data

To compare the time spent in each of the activities for the wells, the number of workdays must be normalised with respect to a reference well (Sveinbjörnsson, 2010). The reference well was found by obtaining the average of the parameters under study and using it as a standard. Table 9 shows the reference wells against which the study wells were normalised. The normalising method was adapted from a previous work by Sveinbjörnsson (2010). In order to normalise the work days for each activity in each phase, interpolation is carried out using Equation 15 (Sveinbjörnsson, 2010). This was done for both Kenyan and Icelandic wells.

$$T_i = \frac{Drilled\ reference\ depth}{Actual\ drilled\ depth} \times t_i \qquad (15)$$

where T_i = The normalized number of workdays for activity i; and

t_i = The actual number of days spent on activity i.

TABLE 8: Time analysis (days) for different activities during directional drilling of Icelandic wells

Well No.	Drilling steps	Well depth (m)	Drilling	Casing	Cement plug jobs	Cem. plug	Stuck	Ream	Fishing	Wait on water	Change bit/BHA	Repair	Hole cleaning	Log.	Other	Total
HE-03	1. step	324	4	1	1								1	1		8
	2. step	812	5	1	1								1	2		10
	3. step	1887	8	2							1	2	3	5		21
	TOTAL		17	4	2						1	2	5	8		39
	(%)		43.59	10.26	5.13						2.56	5.13	12.82	20.51		100
HE-04	1. step	305	4	1	1								1	2		9
	2. step	789	4	1	1	4							3	4		17
	3. step	2008	11	1				1					2	4		19
	TOTAL		19	3	2	4		1					6	10		45
	(%)		42.22	6.67	4.44	8.89		2.22					13.33	22.22		100
HE-05	1. step	303	3	1	1								2	1		8
	2. step	802	6	1	1								1	1		10
	3. step	2000	14	2			1	2			1		3	4		27
	TOTAL		23	4	2	0	1	2			1	0	6	6		45
	(%)		51.11	8.89	4.44	0.00	2.22	4.44			2.22	0.00	13.33	13.33		100
HE-06	1. step	310	4	1	1	4							2	1		13
	2. step	813	4	1	1			1					1	2		10
	3. step	2013	5	1									3	5		14
	TOTAL		13	3	2	4		1					6	8		37
	(%)		35.14	8.11	5.41	10.81		2.70					16.22	21.62		100

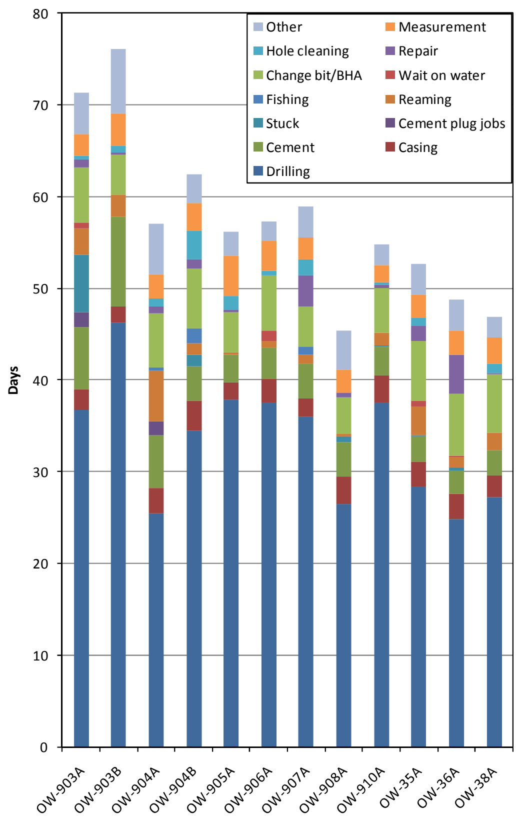

FIGURE 18: Time analysis for different activities for Kenyan wells

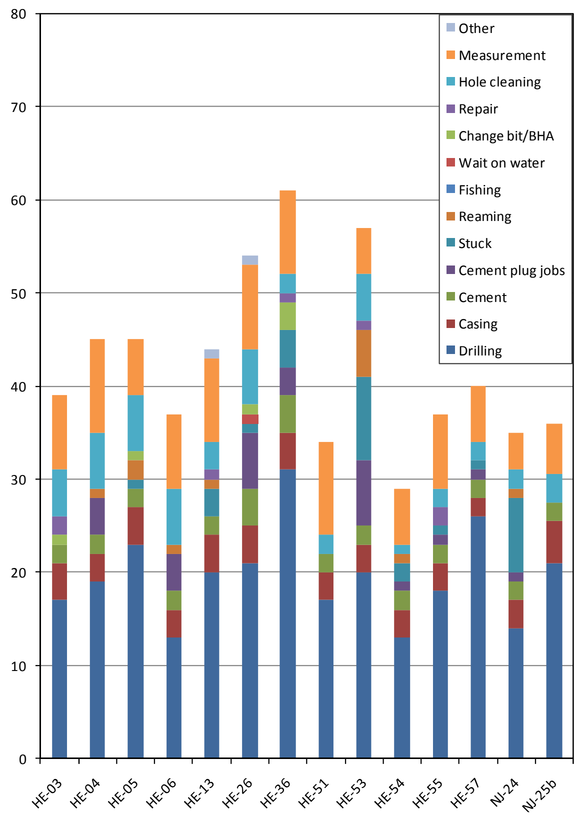

FIGURE 19: Time analysis for different activities for Icelandic wells

TABLE 9: Drilling phases

Reference Kenyan well		Reference Icelandic well	
Steps	**Depth (m)**	**Steps**	**Depth (m)**
1	314.09	1	309.40
2	1073.89	2	854.90
3	2829.64	3	2377.90

Finally, in order to compare Kenyan wells with Icelandic wells, Icelandic wells were normalised into Kenyan wells using the Kenyan well in Table 9 as the reference well. Because there were so many tables generated in the process, the resultant graphs for each phase used as a basis of comparison are shown in Figures 20-27.

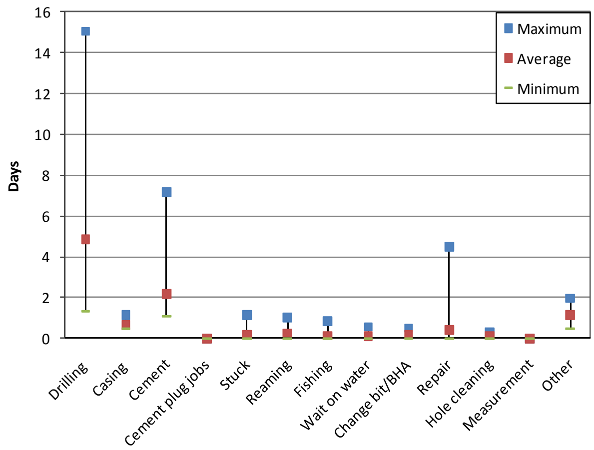

FIGURE 20: Step 1 time analysis for different activities for Kenyan wells

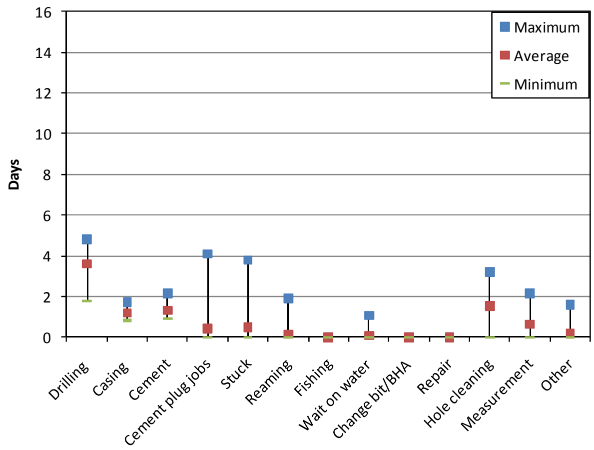

FIGURE 21: Step 1 time analysis for different activities for Icelandic wells

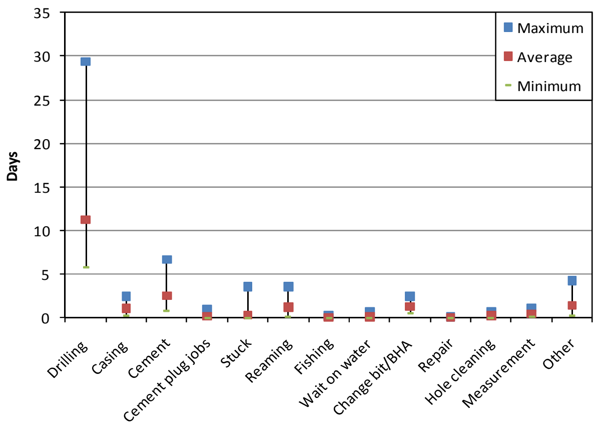

FIGURE 22: Step 2 time analysis for different activities for Kenyan wells

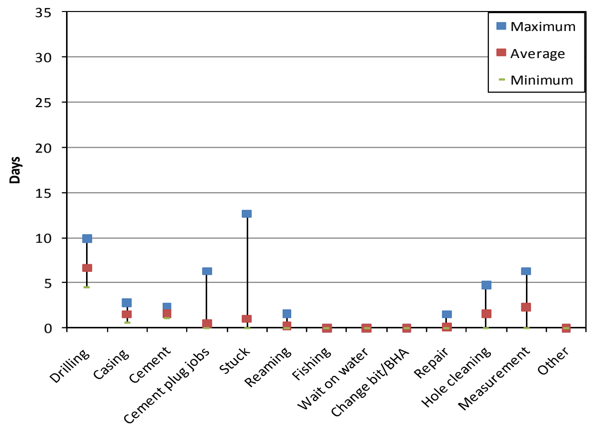

FIGURE 23: Step 2 time analysis for different activities for Icelandic wells

6.4 Discussion

Table 10 shows the percentage of the work time consumed by the different activities during drilling. Based on the time analysis, the following general deductions can be made from the study: The study of 12 Kenyan wells and 14 Icelandic wells shows that about 58% of the work time for Kenyan wells and 45% of the work time for Icelandic wells is spent on actual drilling, i.e. the bit cutting the formation. The rest of the time is spent on other activities that make actual drilling possible, like cementing, and also activities that hamper drilling, for example a stuck drill string or casing. Minimising the time spent on activities other than drilling will improve the efficiency of drilling time

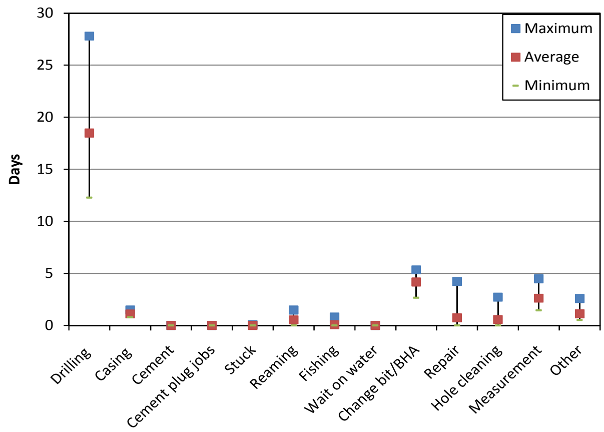

FIGURE 24: Step 3 time analysis for different activities for Kenyan wells

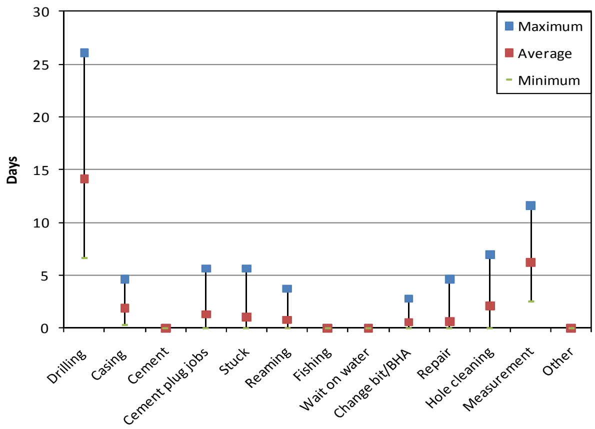

FIGURE 25: Step 3 time analysis for different activities for Icelandic wells

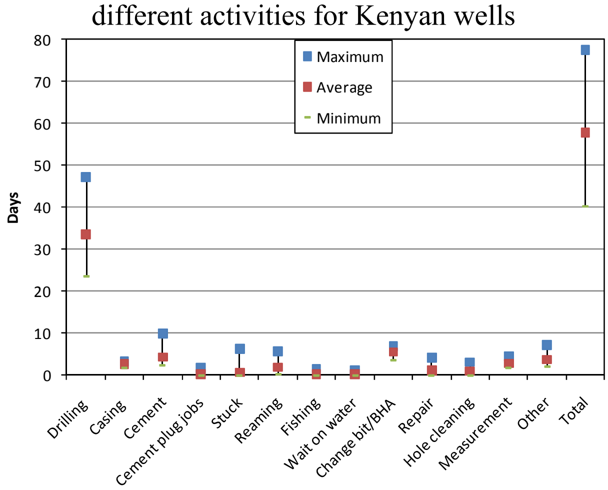

FIGURE 26: Overall time analysis for different activities for Kenyan wells

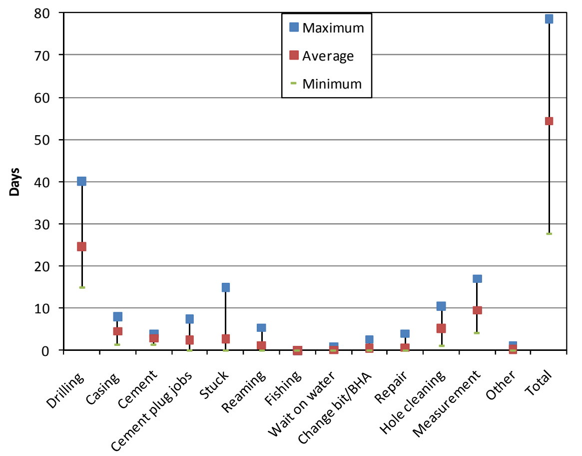

FIGURE 27: Overall time analysis for different activities for Icelandic wells

TABLE 10: Percentage of total time taken by each drilling activity

	Drilling	**Casing**	**Cem.**	**Plug**	**Stuck**	**Ream.**	**Fish**	**WOW**	**bit/BHA**	**Repair**	**Cleaning**	**Meas.**	**Other**
Kenya	57.94	4.42	7.40	0.47	1.26	3.22	0.42	0.37	9.55	2.02	1.66	4.93	6.35
Iceland	45.31	8.33	5.29	4.45	4.99	2.16	0	0.12	0.95	1.16	9.43	17.52	0.28

and eventually lower the drilling cost per well. From Table 2, the average drilling time and well depth are 41 days and 2379 m for Iceland and 57 days and 2830 m for Kenya. Note that the drilling time excludes step 0 (Kenya) and pre-drilling time (Iceland). Analysis of ADD/D as shown Figures 14 and 15 indicates that for Iceland it is about 57 m per day, while for Kenya (Figures 16 and 17) it is about 48 m per day. Figures 20 to 27 show graphs generated after normalising all the wells with reference wells. Each step can be compared with the other for similar activities because they have been put on the same basis as much as possible. Here below, the areas of large disparities for similar activities undertaken in drilling for Kenya and Iceland will be discussed.

(i) Bit or BHA change: Kenya spends ten times more time on a bit/BHA change as Iceland. Most of this time is spent during tripping out to change worn out bits or to run in angle correction BHA. The possible cause could be in the types of bits used. Using long life bits may save on time spent to trip out of the hole in order to change the bit frequently. Tripping to change the angle correction BHA is another possible cause. Adopting measurement-while-drilling technology (MWD) and using a mud motor for a longer time after finishing the angle build up would greatly reduce the

need to trip out in order to run in angle correction BHA. In Iceland, drilling is done using the mud motor for a big portion of the trajectory (until a total loss of circulation is encountered) after building the inclination to the required angle. In Kenya, after building up the angle, the mud motor is changed and there are cases where it is run in for angle correction. This takes a lot of time.

(ii) Well logging: Takes the second largest work time after drilling in Iceland. Iceland spends almost four times as much time for well logging as Kenya. Mostly Kenya does measurements for direction and inclination and well completion tests and well temperature and pressure logs during completion tests. The most common well logging done in Iceland is for temperature and pressure. Calliper logging is done before cementing and cement bond logging (CBL) after cementing. Then there is a full set of lithological logs made in the open hole before running each casing string. Such measurements help get information with which to better understand subsurface conditions. In Iceland, several gyroscopic surveys were made to confirm the MWD readings, due to reversals in polarity of the basalt lavas from different ages.

(iii) Cementing: Cementing wells in Kenya takes almost 1½ times longer than cementing in Iceland. A possible cause for delay is the large amount of backfill cementing done in Kenya when the primary cementing did not fill the annulus space up to the surface. Unlike in Iceland, where plugging of major loss zones is done, Kenya continues to drill blind ahead of major loss zones which eventually takes longer during cementing to fill up. Another possible cause is in the cementing programme. No calliper logging is done to accurately ascertain the capacity of the annulus so it could be that the amount of cement needed to be pumped into the hole during primary cementing is being underestimated.

(iv) Running the casings: The analysis indicates that Iceland takes almost two times longer to run casings in than Kenya.

(v) Stuck: The analysis indicates that the drill string/casing gets stuck more often or longer in Iceland than in Kenya. There could be a close correlation with the time Iceland spends in cleaning the hole to avoid getting stuck.

(vi) Hole cleaning: Iceland takes almost five times longer for hole cleaning than Kenya. It is important to clean the hole to avoid cuttings from accumulating at the bottom of the well which could cause sticking of the drill string and reduce the penetration rate due to regrinding of the cuttings.

(vii) Other activities: This section covers activities that arise to delay the progress of drilling such as accidents, the presence of H_2S, installing well heads and blow out preventers (BOPs). Kenya spends a lot of time in installing well head and BOPs when changing from drilling in one step to another.

6.5 Suggested improvements

Areas of improvement for Kenya include investing in better quality bits to reduce the tripping time needed to change the bits; also an investment in MWD equipment which would reduce the time needed for checking the direction and inclination of the well. Kenya should reduce cementing time by doing calliper logs to help generate a more accurate cementing programme. Besides drilling, the activity that takes the longest time for Iceland to accomplish is well logging. Taking the right set of logs, sufficient for understanding the geology and the reservoir properties, may reduce the time spent in logging. There is need to optimise in the time spent in taking logs to increase knowledge compared to the time spent in acquiring it.

7. SPECIAL PROBLEMS IN DIRECTIONAL DRILLING

Generally, there are many problems encountered while drilling vertical wells, but directional wells are more difficult to drill than vertical wells. This is because everything done by routine in vertical drilling becomes more complex when the well has to be drilled directionally. The problems encountered in directional drilling are related to factors such as the well profile and the reduced axial component of gravity acting along the drill string. The proportion of difficulties in drilling a well is usually reflected in the time taken to complete the well, which has a direct effect on the cost of the well. Vieira (2009) identifies five special problems that occur in directional drilling as:

(i) More hoisting capacity is often needed to raise and lower the drill string;
(ii) Greater rotary torque is needed to overcome friction;
(iii) Mud and hydraulic system requirements are more critical;
(iv) Stuck pipe and equipment failures are more common; and
(v) Casing is harder to run and cement.

These problems are caused by several factors encountered during drilling. These factors are discussed below.

7.1 Tortuosity

An abrupt rate of change in wellbore trajectory is the cause of many problems in directional drilling. Inclination and direction should be changed gradually and be evenly distributed throughout the length of the trajectory. Severe dog legs should be avoided because they may cause key-seating and increase torque and drag. If the drill string has to pass through a severe dog leg, the pipe will make contact with the side of the hole. As the drill string rotates, a small diameter groove in the side of the borehole wall will result. A problem will result during tripping because the large diameter drill collars will get stuck at the keyseat. To free the drill string, the keyseat must be reamed out by a stabilizer or keyseat wiper which is usually installed on top of the drill collars. It is good practice to install a keyseat wiper in the BHA when drilling directional wells where dog-legs can be expected.

7.2 Formation effect

Different types of formations are encountered when drilling. Some formations become unstable either during drilling or some time later. This may cause fragments of the formation to fall into the hole and around the drill collars or the bit. Borehole instability may result from such conditions as the presence of a high percentage of swelling clays (sodium montmorillonite), the presence of steeply dipping or fractured formations, or over pressured shale zones and turbulent flow of drilling fluids in the annulus can cause washouts in soft formations. Most of the problems can be related to shale zones. Most shales will absorb water to some extent, lowering the compressive strength of the rock and allowing it to expand.

Sometimes the formation deflects the bit. Controlling the direction of the trajectory becomes more difficult when drilling through laminar or thin layer formations that are not level. When the formation's angle off the horizontal plane (dip) is less than 45°, the bit tends to drill perpendicular to the layers. If the angle is more than 45° the bit drills parallel to the layers. To overcome this problem, a stiff BHA must be used.

The drill bit also tends to deviate horizontally parallel to tilted formation strata. This effect is called wandering. Even where strata are horizontal, the right-rotating bit tends to walk to the right in inclined holes. This is called bit walk. Stiff BHA may not solve this problem. A more effective method is to use a steering system, discussed under steering tools in this report. If the driller anticipates this problem, he can offset the bit in the opposite direction to compensate for bit wandering and bit walk and then let the bit walk to the final target.

7.3 Differential sticking

To prevent the flow of formation fluids into the well bore, the hydrostatic mud pressure in the borehole must balance or exceed the pore pressure. In a permeable zone, a natural filtration process will take place whereby the fluid content of the mud will invade the formation while the solids will build up on the wall of the bore to form a filter cake. If the filter cake becomes thick, the drill collars may come into contact with it and become embedded. If the positive pressure differential is large (about 1000 psi) it may be difficult to free the pipe. The risk of differential sticking is increased if the pipe is allowed to stay static for a period of time (Inglis, 1987).

8. CONCLUSIONS AND RECOMMENDATIONS

A major project of exploratory and appraisal drilling will soon kick off in Kenya in a number of its geothermal fields, hitherto not drilled into. The majority of the wells drilled will be directional wells. There is a need for proper tools for close monitoring of the well trajectory to ensure that the target is reached. The computer programs generated in this report will be handy in monitoring. The time analysis done here, which includes getting the overall ADD/D and the overall average time taken, will be helpful as a benchmark of what has been achieved, and will be useful in planning for the project. The comparison of Icelandic and Kenyan drilling data is also important; Kenyans can learn from the Icelandic experience and the comparison also points out areas where Iceland can improve.

It is recommended that Kenya invest in long life bits which, although expensive, will reduce the time taken for tripping to change bits and, hence, prove to be more effective. It would also be better to consider drilling with a mud motor after building up the angle in order to reduce angle correction re-runs.

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