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CASING DESIGN FOR HIGH-TEMPERATURE GEOTHERMAL WELL USING THE AFRICAN UNION CODE OF PRACTICE FOR GEOTHERMAL DRILLING: A CASE STUDY OF WELL OW 736A IN OLKARIA, KENYA

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ABSTRACT

Exploration drilling is the key step to verify the existence of a geothermal resource at the end of the exploration phase. All the processes connected to drilling operations should adhere to high standard concerning safety and the use of approved materials since the pressures involved are very high especially in high-temperature geothermal fields. This report presents the casing redesign for well OW 736A in Olkaria geothermal field, Kenya using *The African Union Code of Practice for Geothermal Drilling*. The well was drilled in the year 2014 following mostly the New Zealand code of practice for deep geothermal wells (NZS 2403:1991), now superseded by the New Zealand standard of 2015 (NZS 2403:2015) and adopted by the African Union Standard.

During redesigning of the casing the main factors considered are the lithology of the Olkaria area and wireline logging data, namely pressure and temperature in well OW 736A. Using the methodology of the standard, the redesigned well casing depths were set to 440 m for the surface casing, 790 m for anchor casing and 1470 m for the production casing. The grades, sizes and weights of different casing strings were determined by analysing axial and hoop stresses during casing running, cementing operation and well production operation to make sure that they meet minimum design factors for different scenarios. The final redesigned casings selected for well OW 736A are 20" 94 lb/ft K55 surface casing, 13⅜" 54.5 lb/ft K55 anchor casing, 9⅝" 47 lb/ft L80 production casing and 7" 26 lb/ft L80 perforated liner. The recommended top two segments of the anchor casings, which are normally of higher strength, are of size 13⅜" OD, weight 68 lb/ft and grade T95. The master valve recommended in the redesigned well is ANSI class 1500.

1. INTRODUCTION

Olkaria geothermal field is located within the central segment of the East African Rift system. The well OW 736A which is used as a case in this study is located in Olkaria Northeast which is part of the larger Olkaria geothermal field. The well was drilled to a depth of 3500 m in the year 2014 with a 9⅝" outer diameter production casing. It is a directional well with 20° inclination and a target azimuth of N45°E.

The kick off point is at 500 m with a build up rate of 3° per 30 m (KenGen, 2014). The case study involves redesigning the casing for OW 736A using The African Union Code of Practice for Geothermal Drilling (African Union Standard, 2016). The standard became effective in the year 2016 and is the guideline for designing geothermal wells in Africa.

The minimum casing shoe depth of each cemented casing string or liner as indicated by the African Union Standard has to be the depth where the formation has sufficient effective containment pressure equal to the maximum design pressure expected to be encountered in the next open-hole section. The standard also procedurally indicates how to compute various stresses induced into the casing during running them in the well, cementing operation, well warm up period and production. After the determination of stresses induced in different casing strings, the standard gives recommendations on how to select the casing sufficient to withstand previously mentioned load cases during the entire lifespan of the well. The design part of The African Union Code of Practice for Geothermal Drilling (African Union Standard, 2016) is adopted from the New Zealand Standard (NZS 2403:2015). Most of the wells drilled before 2015 utilised the procedure suggested in the New Zealand code of practice for deep geothermal wells (NZS 2403:1991).

2. GEOLOGY

The Olkaria geothermal area mainly consists of Quaternary volcanic rocks of silicic composition with the youngest being of Holocene age. Outcrops are dominated by comendite rhyolites and pyroclastic rocks while in the subsurface we find trachytes, basalts, rhyolites and tuffs. Geothermal manifestations in the Olkaria field are mainly fumaroles, hot springs and hot grounds. Geothermal exploration in Kenya started in 1950's. Since then the field has been studied extensively and many geothermal wells have been drilled in the area (Mariita, 2009). The stratigraphy of well OW 736A is shown in Figure 1.

0-50 m: Pyroclastics. This zone consists of loose soils and fragments mainly of tuffs, trachytes, lithic material, obsidian, volcanic glass and pumice. Washouts and cavings are likely to be experienced in this zone.

50-450 m: Rhyolite. This zone consists of slightly to massively altered rhyolite and thus the formation is medium hard to hard. At shallow depth within the zone, blocky lavas occur, hence partial or major losses during drilling are expected.

450-900 m: Tuff and basalt. This zone consists of mainly medium soft to medium hard rhyolitic and trachytic tuffs. Basalts occur alternating with tuff layers.

900-2000 m: Trachyte and basalt with minor tuffs. This zone consists of trachyte, basalt, tuff and rhyolite formations occurring in thin layers although trachyte is dominant. This zone is medium hard to hard and partial losses may be experienced.

2000-2700 m: Trachytes. This zone is dominated by trachytic lava flows which are fine grained, apparently non-porphyritic and fairly oxidized. The formation is medium hard and partial losses are expected.

2700-3500 m: trachyte and intrusions. This zone is characterized by trachytes and micro-syenitic, rhyolitic intrusions that are likely to occur intercalated with rock strata. The formation is medium hard to hard and competent. Minor losses may be experienced at fracture or faults zones.

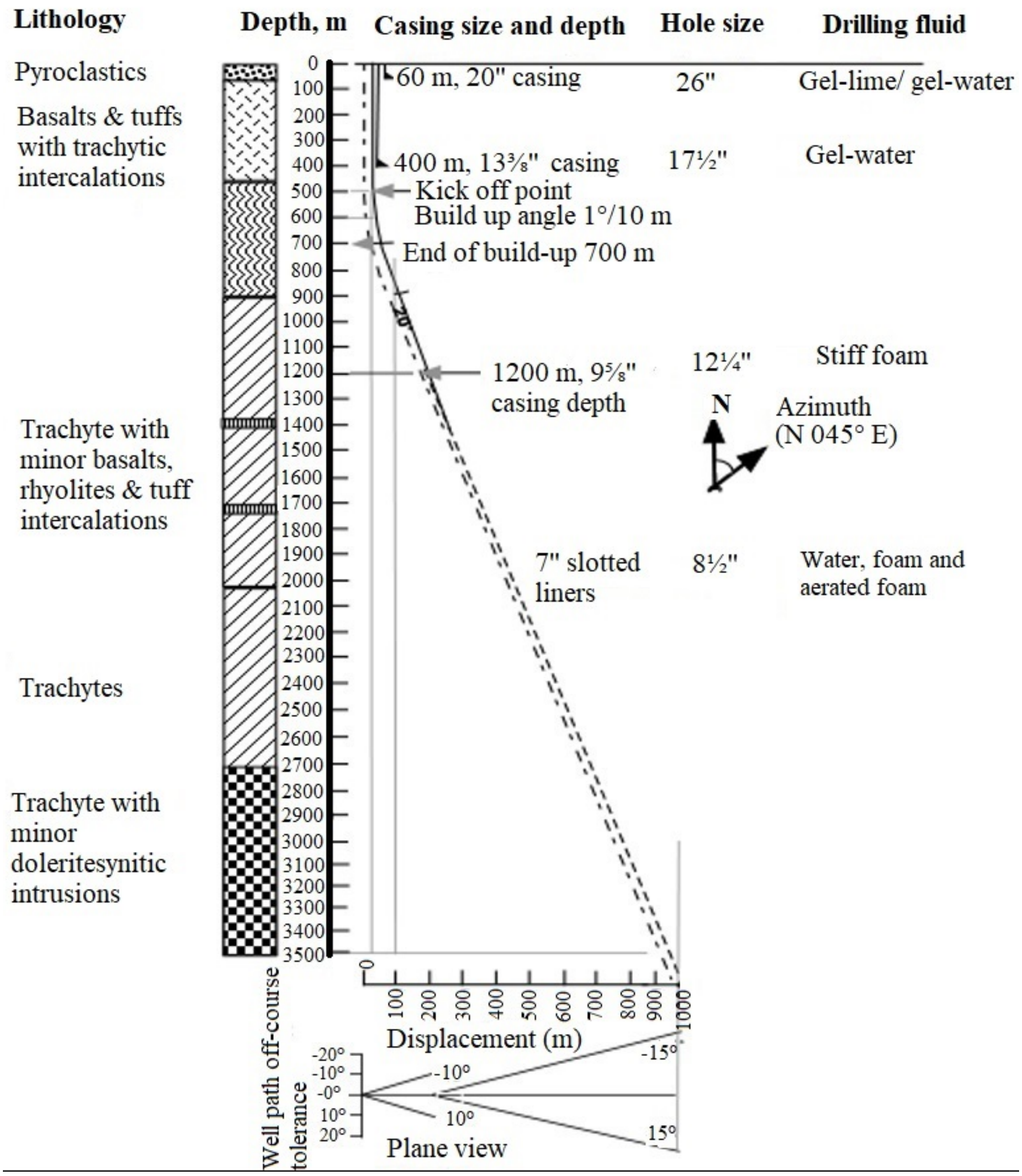

FIGURE 1: Well OW-736A design and geological cross-section (KenGen, 2014)

3. BACKGROUND OF GEOTHERMAL WELL DESIGN

The main objective of drilling is to generate a well in the most convenient way by adhering to all standard procedures. A drilling plan should list and define all activities required to securely complete the well including all related work and cost. The better the formation properties are known from geoscientific surveys, the more budget-friendly the drilling. Reports from neighbouring wells can be essential for predicting the formation behaviour. In order to reduce possible risks, it is essential to generate a large data pool. All engineering assumptions and the drilling program as a whole rely on these data and surveys (Vollmar et al., 2013).

Key aspects to drill and complete a deep geothermal well safely are (Hole, 2008):

- Subsurface rock and fluid conditions;

- Depths of casings and well completion;
- Casing specification and cementing materials and programmes;
- Wellhead specification;
- Drilling fluids, drill string assemblies; and
- The necessary drilling tools and equipment.

3.1 Caliper log

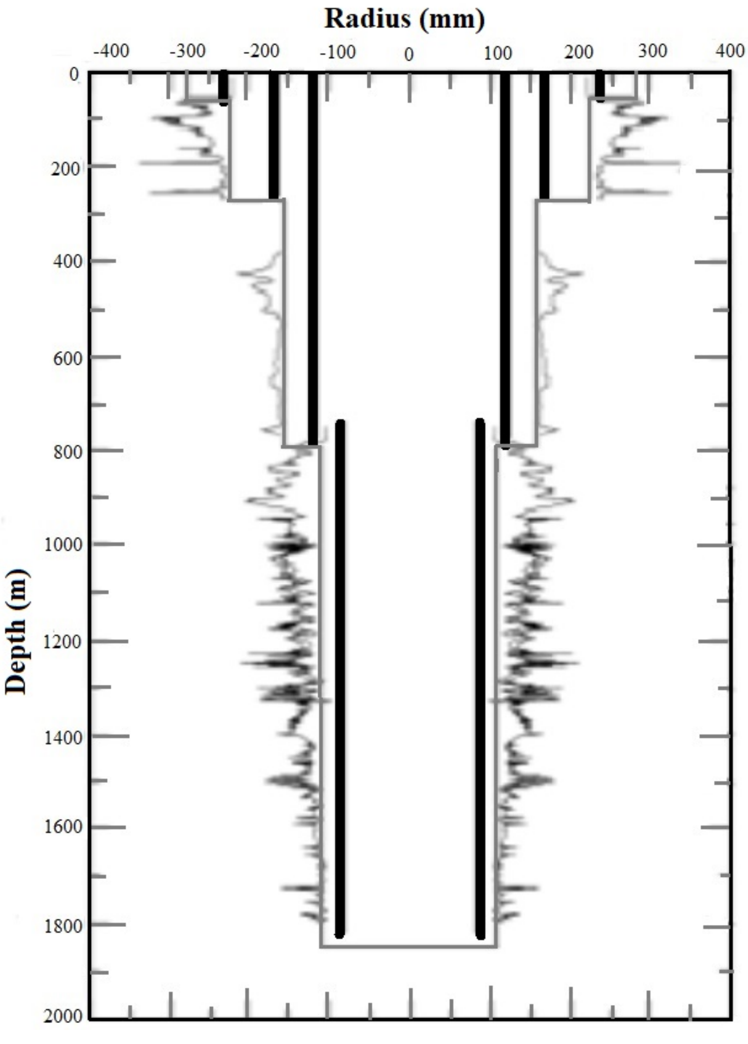

FIGURE 2: Schematic picture of a geothermal well, showing casing (bold lines) and drill bit sizes (soft straight lines) and caliper logs (Steingrímsson, 2011)

Geothermal wells are drilled with a drill bit rotated into the ground, hence it is expected to form a circular hole of a diameter corresponding to the diameter of the drill bit. This is not normally the case since during drilling the drill cuttings created at the bottom of the well are flushed to the surface through circulation of the drilling fluid. This fluid together with cuttings erode the formation as it flows up the hole, creating a larger hole than the drill bit size predicts. The manifestation of this effect varies because the formation is of different hardness ranging from very hard to soft. The washout in unstable formations will be high and caves will appear in the well. The caliper log is the measurement of the diameter of wells to obtain information on their sizes. Figure 2 shows a schematic picture of a geothermal well comparing casing and drill bit sizes to actual caliper logs. It clearly shows that the true diameter of a well was often much larger than the drill bit diameter (Steingrímsson, 2011). This information will be of much help when preparing to run the casing string as the log will indicate clearly if there is any constriction which can hinder lowering the casing into the well. It will also help in estimating the volume of cement needed for each casing string. The caliper logs also provides information about the lithology as washouts indicate the hardness of the formation while cavities indicate drilling through soft sedimentary layers and sandy formations. The log will also show deposition in wells.

3.2 Geothermal well casing

It is generally not possible to drill a well through all of the formations from surface to the target depth in one hole section. The well is therefore drilled in sections, with each section of the well, being sealed off by casing inside of the borehole and cement filling in the annular space between the casing and the borehole before drilling the subsequent hole section. The casing string is made up of joints of casing segments either with threaded or welded connections. According to African Union Standard (2016), the design of the casing strings in geothermal wells needs to take into account conditions anticipated during drilling process itself as well as those anticipated over the lifespan of the well. Specifically, the casing design criteria have to include the following considerations:

- Prevent the collapsing, bursting, buckling, or other deformation of the casing;
- Support drilling and permanent wellheads;
- Safely contain well fluids;
- Control contamination of subsurface aquifers;
- Counter circulation losses during drilling; and
- Protect the integrity of the well against corrosion, erosion, or fracturing.

Each casing string must be carefully designed to withstand the anticipated loads to which it will be exposed during installation, when drilling the next open hole section, and when producing from the well. The loads will depend on types of formation to be drilled, the formation pressures, the temperature profile and the nature of the fluids in the formations. The sizes and setting depths of the casing strings depends on the geological and pore pressure conditions. The minimum casing shoe depth of each casing string according to African Union Standard (2016) has to be set at a depth where the formation has sufficient containment pressure to equal maximum design pressure expected to be encountered in the next open-hole section. The main objective of pressure containment is the prevention of well blowout through either formation, faults, other wells, or underground. A secondary function of pressure containment is prevention of cross-contamination of subsurface fluids.

The detailed specification of sizes, weights and grades of casing which are commonly used has been standardised by the American Petroleum Institute (API). The majority of sizes, weights and grades of casing can be found in the manufacturer's catalogues and in cementing company handbooks. Casings are classified in terms of its size (outside diameter), weight, grade and connection type. Figure 3 shows the most common casing sizes and hole configurations. The dotted lines represent less commonly used configurations. The terms used to explain different casing strings are:

Conductor pipe: This is the first string to be run and its function is to seal off unconsolidated formations at shallow depths.

Surface casing: Its main function is to seal off weak formation to prevent collapse and to anchor blowout preventer for safe drilling in the next open hole section.

Anchor casing: It is used to isolate troublesome formations between surface and production casing setting depths. It also supports blow out preventers during further drilling and also supports the master valve during the entire lifespan of the well.

Production casing: Its main purpose is to isolate the production interval from other formations and act as a conduit to guide the fluid up for production.

Liner casing: This is a perforated casing that is set inside the production section of the well and allows fluid flow into the well.

Buttress threaded couplings are used in high-temperature geothermal wells. It has a high tensile strength while the compressive strength is lower and it is therefore susceptible to leaking when the temperature exceeds 200°C. Several casing manufacturers have developed a coupling where the pipe end butts against a steel shoulder, e.g. Antares, Hydril and GeoConn connections. The three connections have good sealing properties, but the Antares connection is more sensitive to expansion than the other types. GeoConn coupling has been successfully tested with 17.2 MPa internal pressure, 392°C temperature

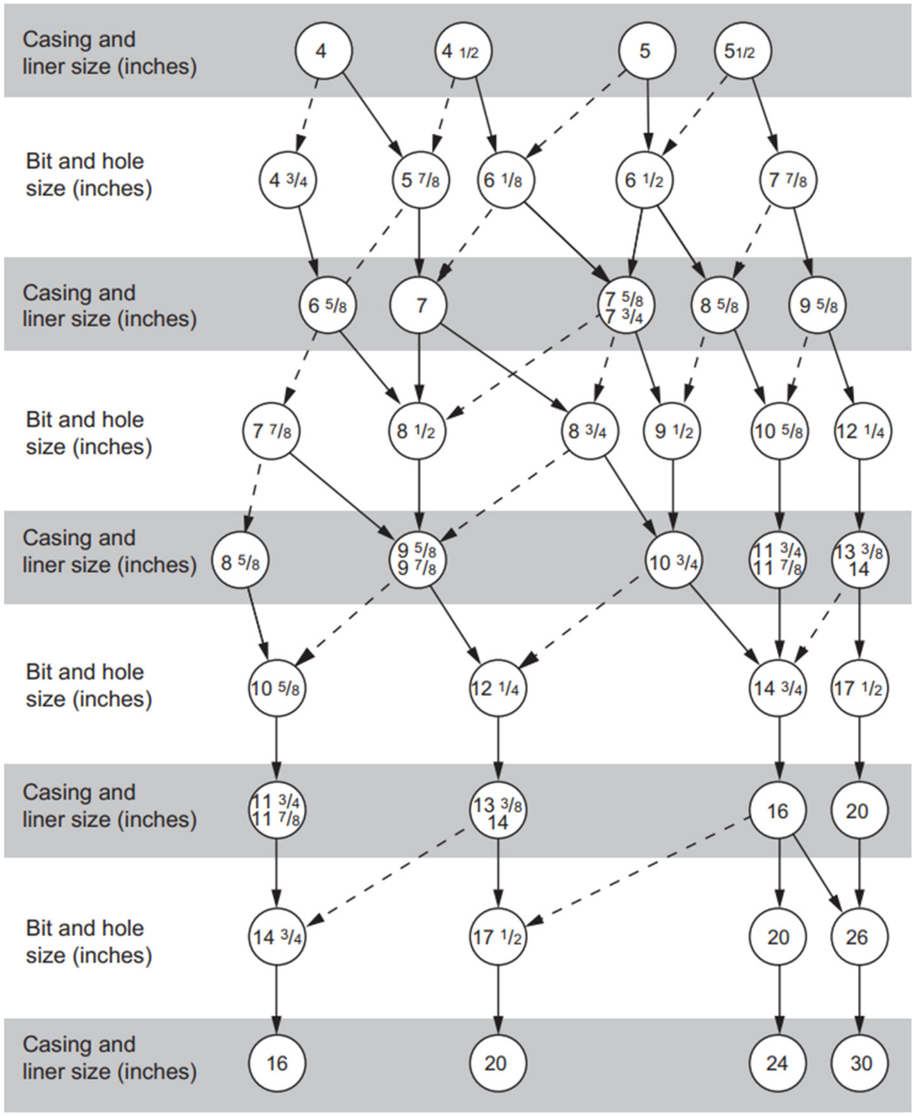

FIGURE 3: Casing sizes and hole configurations (Heriot, Watt University, 2010)

and a corresponding compressive load. Hydril threads withstand an axial load both in tension and compression that exceeds the load capacity of the casing itself. In the Iceland Deep Drilling Project IDDP-1 well, the Hydril 563 connections were chosen for the anchor and production casings whereas buttress thread connections were chosen for the liner (Thórhallsson, et al., 2010).

3.3 Geothermal well cementing

Cementing is used as a seal between casing and the borehole, bonding the casing to the formation. In high-temperature geothermal wells the casings demand uniform cementing over the full casing length so that stress concentration can be avoided. If there are any water pockets between two strings of casing, the casing can collapse when the water expands due to high temperature.

The main function of a cement sheath between the casing and the formation are (Sigurdsson, 2018):

- To support radial and axial loads applied to the casing;
- To support the borehole;
- To provides zonal isolation;

    - Exclude unwanted subsurface liquid;
    - Isolate porous formations from production zone formations;
    - Seal off abnormal pore pressure.
- To protect casing from corrosion; and
- To protect the casing from shock loads when drilling deeper.

During drilling, cementing is also used to condition the well:

- To seal loss of circulation zones;
- To stabilise weak zones (washouts, collapses);
- To plug a well temporarily before re-casing;
- To kick-off side tracking in an open hole or past junk; and
- To plug a well for abandonment or for repair.

When it comes to casing, each cementing job should be planned well to ensure that the right cement and cement additives are used and that a suitable placement technique is being employed. The cement slurry is tested in a laboratory under conditions to which it will be exposed in the wellbore. These tests must simulate downhole conditions as closely as possible. They will help assess the effect of different amounts of additives on the properties of the cement. Properties of cement include thickening time, compressive strength, slurry density, water loss, corrosion resistance and permeability.

There are several cementing methods commonly used:

Single stage cementing: It is the most common type of cementing operation. A determined volume of cement slurry is pumped and is displaced out to the annulus through the casing shoe. The method uses two plugs, a bottom one which displaces the drilling fluid and a top plug which displaces the cement and separates it from the displacement fluid. The bottom plug has a membrane which raptures, allowing cement slurry to flow through. A setback of this method is that the pumped volume cannot be adjusted even if there are no cement returns to the surface.

Multi-stage cementing: This method is used to place cement slurry around the casing in intervals. The first stage is cemented using conventional method, while stage cementing collars designed to allow cement flow into the annulus when they are opened either by use of a plug or hydraulic pressure, are used for stage cementing.

Inner string cementing: This method involves placement of slurry by pumping it through a drill string attached to either the casing shoe or the float collar through a stab-in receptacle. The bottom side of the drill pipe has a stab-in sub with seals to fit in the collar receptacle and the lower part is fitted with centralizers, adapted to the size of the casing being cemented. Mostly used to cement large size casings that run below 1000 m. The disadvantage of this method is time duration to run in and out after cementing for long casing strings.

Reverse circulation cementing: This method involves pumping cement slurry through the annulus, displacing the drilling fluid in the wellbore through the casing. This method reduces the pressure applied to the formation during cementing since the fluid ahead of the cement has a lower density. It also minimises excess cement required for a cementing job since once the cement slurry reaches the bottom, mixing and pumping are stopped. The main challenge of reverse cementing is knowing when competent cement has reached and circulated the bottom of the well.

3.4 Geothermal well control

Well control systems prevent the uncontrolled flow of formation fluids from the wellbore. When the drill bit enters a permeable formation, the pressure in the pore space of the formation may be greater than the hydrostatic pressure exerted by the drilling fluid column. This will lead to formation fluid entering the wellbore and starting displacing the drilling fluid from the hole causing a kick. Failure to control a kick can lead into a blow-out which may cause loss of lives and equipment as well as damage to the environment. Primary well control is achieved by ensuring that the hydrostatic drilling fluid pressure is sufficient to overcome formation pressure (Heriot – Watt University, 2010).

In order to ensure that the crew is safe when drilling the well, blow out preventers (BOPs) must be installed to cope with any kick which might occur. BOPs are basically high pressure valves which are used to seal the top of the well in case of a kick or blow-out. There are two types of BOPs, namely:

Annular preventer: This BOP is designed to seal off the annulus between the drill string and the side hole. It can also seal off an open hole if the kick occurs while the pipe is out of the hole.

Ram type preventer: This BOP is designed to seal off the annulus by closing large rubber faced block of steels together. There are three different types of Ram BOP:

- Blind ram – seal off in open hole;
- Pipe rams – seal off around drill pipe; and
- Shear ram – cut off drill pipe during closing.

The regular type well with 30" conductor pipe, 20" surface casing, 13⅜" anchor casing, 9⅝" production casing and 7" slotted liners with possible depth of 3500 m utilises 29½", 21¼" and 13⅝" sizes of BOP stacks during the entire drilling process. The 29½" 500 psi rated BOP stack is installed after cementing the 30" conductor pipe and is used when drilling the 26" hole section of the well. The 21¼" 2000 psi rated BOP with single ram and annular preventer is installed after cementing the 20" casing and is used to drill the 17½" section of the well. The 13⅝" 3000 psi rated BOP consisting of annular and double gate ram preventers is installed after cementing the 13⅜" anchor casing and is used when drilling the rest of the well (KenGen, 2014).

After completion of the drilling, flanges and valves are designed according to wellhead working pressure de-rating for flanges and valves conforming to ANSI B16.5 and to API 6A (African Union Standard, 2016).

4. CASING REDESIGN FOR WELL OW 736A

The well OW 736A, which is a directional well inclined at 20°, was drilled to a depth of 3500 m in the year 2014. The initial casing design programme for the well relied heavily on the lithology to decide the casing depth. The same well's casing tally is redesigned in this study taking into account the actual well pressure and temperature to determine the depth of each casing string, casing grade, casing material and stress conditions in accordance with the recent African Union Code of Practice for Geothermal Drilling (African Union Standard, 2016).

The casing sizes currently used in Olkaria are 20" 94 lb/ft K55 surface casing, 13⅜" 54.5 lb/ft K55 anchor casing, 9⅝" 47 lb/ft K55 production casing and 7" 26 lb/ft K55 slotted liners. The two top anchor casing segments are normally of higher grade than the rest of the casings and the size used in Olkaria is 13⅜" OD, weight 68 lb/ft and grade K55. All these casings will be taken into consideration in the design process to determine whether they are competent for the redesigned well and if not an alternative thickness and/or grade will be recommended. The conductor pipe size and grade will be designed afresh since it is currently not used in Olkaria.

The drift diameter for recommended casings will be compared to the diameter of the bit used to drill the next section of the hole. The casing, even if considered adequate, will be rejected if its drift diameter is smaller than the diameter of the bit used to drill the next section. The casing drift diameter is computed as shown in Equation 1. Parameters for equations are defined in Nomenclature close to the end of the report. Different drift constants for different casings are listed in Table 1.

$$dd_m = d - dc_m \tag{1}$$

TABLE 1: Drift constants for casings (API 5CT) (Gabolde and Nguyen, 2006; KenGen, 2014)

Product	Casing sizes (")	Constant, dc_m (mm)
Casings	< 9⅝	3.18
	9⅝ to 13⅜	3.97
	> 13⅜	4.76

4.1 Minimum casing depths review

4.1.1 Pressure and temperature with depth

Pressure and temperature logs were taken 11 days, 18 days and 34 days after the well was capped with an ANSI 900 master valve after completion of the drilling process (Figures 4 and 5). Figure 4 shows that the pressure is stable in 2400 m depth at 155 bars in all three logs. Steingrímsson (2013) states that the first response of wells after shut-in is to reach pressure equilibrium with the reservoir which normally takes few days. The well bore fluid heats up. The pressure at the major feed zones is fixed to the reservoir pressure. The water column in the well expands, resulting in rising of the water level during heating and the pressure profiles measured in the well during the heating period will be constant at the depth with the best feed zone known as pivot point.

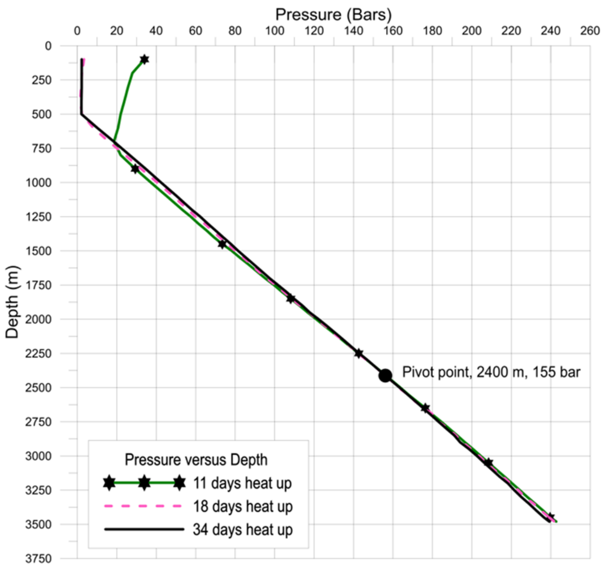

FIGURE 4: OW-736A pressure depth profiles

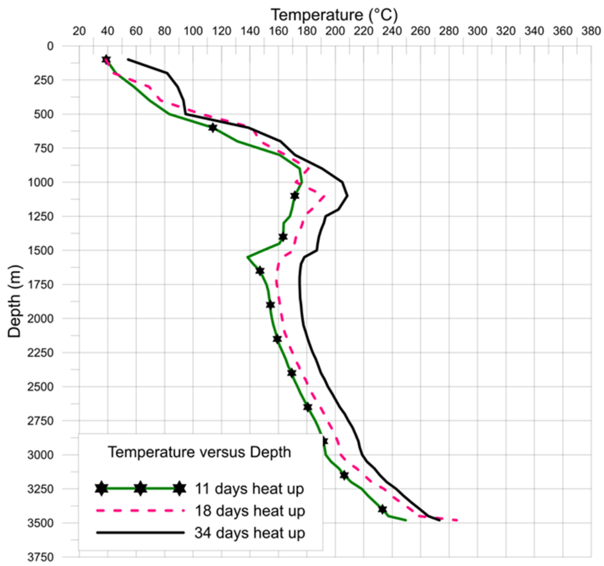

FIGURE 5: OW-736A temperature depth profiles

The pressure profile taken after 11 days of heating (Figure 4) shows high pressures in the top 750 m in comparison to the other logs. This being the first measurement after well completion (in green), there might have been accumulated gas/steam which escaped through the recovery tube during the measurement. Hence, the measurement is stable at lower depth during subsequent measurements.

4.1.2 Boiling point pressure and temperature curves

The boiling point (BP) pressure-depth curve was adjusted to pass through the pivot point in order to obtain a curve representing the boiling pressure against depth in the well in Figure 6. The corresponding BP temperature-depth curve is shown in Figure 7.

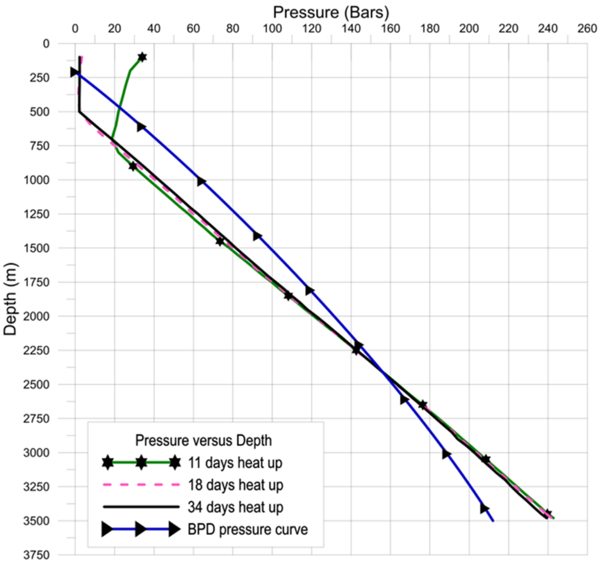

FIGURE 6: OW-736A pressure profiles and adjusted BP pressure curve

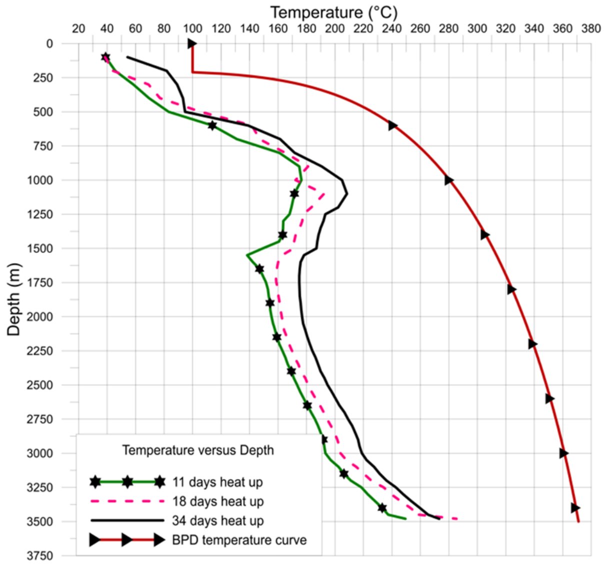

FIGURE 7: OW-736A temperature profiles and adjusted BP temperature curve

4.1.3 BP pressure and effective containment pressure-depth curves

The effective containment pressure (fracture formation pressure) is assessed continuously down to the production casing shoe. It determines the upper boundary for setting of casing strings depth and is estimated using the Eaton Formula (Equation 2):

$$P_{frac} = P_f + \frac{v}{1-v}(S_v - P_f) \tag{2}$$

where

$$S_v = \rho \times g \times h \tag{3}$$

The minimum casing shoe depth of each cemented casing string is calculated to be the depth where the formation has sufficient effective containment pressure to equal maximum design pressure that is expected in the next open hole section. The BP pressure curve and effective containment pressure depth curve were plotted together in order to help setting the minimum casing depth for each casing string. Figure 8 shows the depth setting assuming the fluid column pressure in the well to be constant as indicated in the African Union Standard while in Figure 9, it is assumed that fluid column pressure varies with depth. The final casing string depth settings using static steam column pressure with depth in the well (Figure 9) are used for further analysis.

The casing string minimum depths determined from Figure 8 and Figure 9 are listed in Table 2. A 100 m conductor pipe is introduced since surface casing depth had to be revised from 56 to 440 m. The conductor becomes the actual surface casing and the surface casing becomes an intermediate casing. However, for purpose of clear comparison, the casings will nevertheless be called conductor, surface, anchor and production casing.

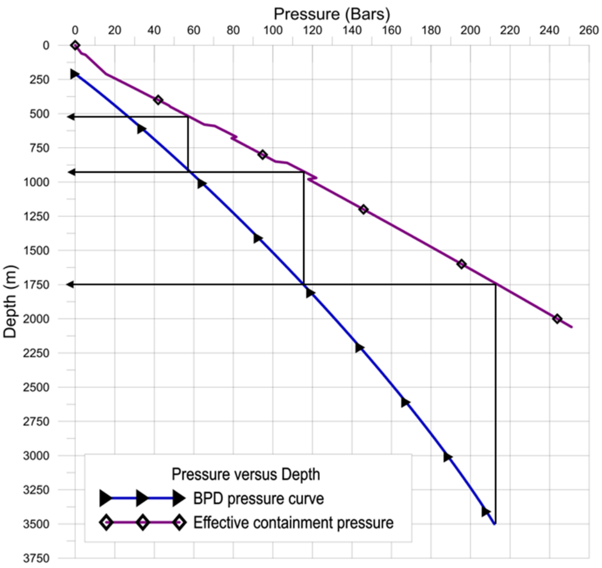

FIGURE 8: Redesigned well OW 736A minimum casing depth setting assuming constant pressure column

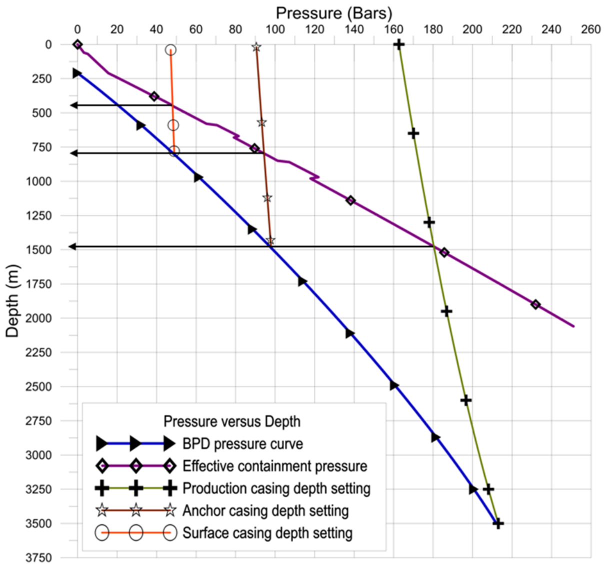

FIGURE 9: Redesigned well OW 736A minimum casing depth setting assuming pressure from static steam column

TABLE 2: Proposed casing string depths

Casing string	Well OW 736 (orig.) casing depth [m] (KenGen, 2014)	Well OW 736 redesigned casing depth [m]	
		Assuming constant pressure with depth (Figure 8)	Assuming varying pressure with depth (Figure 9)
Conductor pipe	-	100	100
Surface casing	56	525	440
Anchor casing	418	920	790
Production casing	1203	1750	1470

4.2 Axial loading before and during cementing

4.2.1 Tensile force when cement is inside the casing and water in the annulus

The tensile force at any depth of the casing is calculated by considering the casing weight in air plus the weight of the casing contents less the buoyant effect of fluid displaced by the casing (Equation 4). The maximum tensile force will be experienced when the content in the casing is cement and the fluid displaced is water. The design for the casing body and casing joints is carried out independently.

$$F_{hookload} = F_{csg\ air\ wt} + F_{csg\ contents} - F_{displaced\ fluids} \tag{4}$$

where

$$F_{csg\ air\ wt} = L_Z \times W_p \times g \times 10^{-3} \tag{5}$$

$$F_{csg\ contents} = \sum \rho_{if} \times L_{if} \times \frac{\pi d^2}{4} \times g \times 10^{-6} \tag{6}$$

$$F_{displaced\ fluids} = \sum \rho_{ef} \times L_{ef} \times \frac{\pi D^2}{4} \times g \times 10^{-6} \tag{7}$$

4.2.2 Maximum bending stress for a directional well

The point of curvature of a directional well is subjected to compressive stress at the inside of the arc and tensile stress on the outside of the arc. The bending stress at the point of curvature adds to the casing stress created by weight, hydraulic loads and thermal loads. The bending stress is computed as below:

$$f_b = 0.291 \times E \times q \times 10^{-6} \tag{8}$$

The minimum design factor is computed as shown in Equation 9 for Sections 4.2.1 and 4.2.2:

$$Design\ factor = \frac{minimum\ tensile\ strength}{maximum\ tensile\ load} \geq 1.80 \tag{9}$$

4.3 Axial loading after cementing

Axial forces imposed after cementing have to be checked for applicability and magnitude both near the top and the shoe of casing string. To calculate the resultant net or total force, each of the loads has to be added to the static force present in the casing at the time of the cement setting. If the stress calculated in Sections 4.3.1 and 4.3.2 exceeds the yield stress, a plastic/strain based design will be required. The design factor due to thermal expansion, which was 1.2 in the New Zealand standard of 1991, has been lowered in the 2015 standard and African Union Standard since casings are likely to reach yield point because of thermal stresses.

4.3.1 Axial load due to temperature increase after cementing

The change in axial force (tension is positive) due to temperature increase with partial longitudinal and lateral constraint is given in Equation 10:

$$F_c = E \times a(T_1 - T_2) \times A_p \times 10^{-3} \tag{10}$$

The resulting force is:

$$F_r = F_p + F_c \tag{11}$$

4.3.2 Axial load due to temperature decrease after cementing

The change in axial force due to temperature reduction when cool fluid is circulated from the surface during drilling, testing or reinjection operations is given in Equation 12:

$$F_t = E \times a(T_1 - T_3) \times A_p \times 10^{-3} \tag{12}$$

At depth, except close to the wellhead, the resulting force is:

$$F_r = F_p + F_t \tag{13}$$

4.3.3 Tension at the top of anchor casing

Tension occurring at the top of any string that anchors a wellhead against the lifting force applied by the fluid in the well is:

$$F_w = \frac{\pi}{4} \times P_w \times d^2 \times 10^{-3} - F_m \tag{14}$$

$$Design\ factor = \frac{anchor\ casing\ tensile\ strength}{lifting\ force\ applied\ by\ the\ fluid} \geq 1.80 \tag{15}$$

4.3.4 Anchor casing lifting force due to thermal expansion of production casing

A lifting force is applied to the anchor casing by thermal expansion of the production casing string where the mechanical design allows it to interfere with parts of the wellhead. The integrity of the anchor casing and the wellhead is protected by ensuring that potential failure would occur elsewhere. The design factor is computed by Equation 16.

$$Design\ factor = \frac{anchor\ casing\ tensile\ strength}{rising\ casing\ compressive\ strength} \geq 1.40 \tag{16}$$

4.4 Axial load of uncemented liners with buckling and bending

The uncemented liners are either hung in tension from the liner top or supported at the shoe in compression. The liners in this case are supported at the shoe and hence should be analysed for helical buckling. The total fibre compressive stress in an uncemented liner that is subjected to axial self-weight and helical buckling is (Equation 17):

$$f_c = L_z \times W_p \times g \times \left[\frac{1}{A_p} + \frac{De}{2I_p}\right] \tag{17}$$

where

$$I_p = \frac{\pi}{64} \times [D^4 - d^4] \tag{18}$$

$$Design\ factor = \frac{minimum\ yield\ stress\ \times R_j}{total\ compressive\ stress} \geq 1.00 \tag{19}$$

The design factor can also contain temperature reduction factor since liners are under high downhole temperature the entire lifespan of the well.

4.5 Hoop stressing – Internal yield

4.5.1 Maximum differential internal pressure during cementing

At the time of cementing the maximum differential internal pressure of the casing string occurs near the shoe or stage cementing ports when the following conditions apply:

- The casing string is filled with cement slurry;
- The annulus either contains a column of water or is subject to formation pressure;
- Constriction within the casing is sufficient to hold the differential pressure.

The maximum differential pressure is:

$$\Delta P_{internal} = \left[L_z\, \rho_c\ - L_f\, \rho_f\right] \times g \times 10^{-3} \tag{20}$$

$$Design\ factor = \frac{internal\ yield\ pressure}{differential\ internal\ pressure} \geq 1.50 \tag{21}$$

4.5.2 Maximum differential internal pressure after cementing

After cementing, the maximum differential internal pressure will occur at the surface. In this study the scenario where steam is present at the wellhead is looked at:

$$Design\ factor = \frac{internal\ yield\ pressure\ \times R_i}{wellhead\ pressure} \geq 1.80 \quad (22)$$

4.5.3 Axial and circumferential tension on casing anchoring wellhead

If the wellhead is fixed to the casing, a biaxial stress condition exists. The combined effects of axial and circumferential tension are calculated as below:

$$F_w = \frac{\sqrt{5}}{2} \times \frac{P_w\, d}{(D - d)} \quad (23)$$

$$Design\ factor = \frac{steel\ yield\ strength}{maximum\ tensile\ stress} \geq 1.50 \quad (24)$$

4.6 Hoop stressing – Collapse

4.6.1 Maximum external pressure after cementing

At a later stage of the casing cementing operation, the maximum differential external pressure occurs near the casing shoe when the casing annulus is filled with dense cement slurry and the casing is filled with water. The maximum differential external pressure is:

$$\Delta P_{external} = \left[L_z\, \rho_c\ - L_z\, \rho_f\right] \times g \times 10^{-3} \quad (25)$$

$$Design\ factor = \frac{pipe\ collapse\ pressure}{differential\ external\ pressure} \geq 1.20 \quad (26)$$

4.6.2 Maximum external pressure during production

During geothermal production, the maximum external differential pressure occurs near the casing shoe when the annulus is at formation pressure ($P_z\ = P_f$) and the internal pressure is controlled by well drawdown. In the worst case the internal pressure at the casing shoe can affect the operating wellhead pressure. The pipe collapse strength is de-rated for the temperature at the shoe.

$$Design\ factor = \frac{pipe\ collapse\ pressure}{differential\ external\ pressure} \geq 1.20 \quad (27)$$

The design factor can also include a temperature reduction factor since the production casing string is under a high downhole temperature the entire lifespan of the well.

4.7 Drilling program for the redesigned well

The drilling programme discussed below is tailor made to suit the conditions in the Olkaria geothermal field. Over the years of drilling in the field, several challenges have let to deviations from the drilling programme. Despite having a drilling programme, there are times when the crew is forced to modify it due to prevailing unique challenges. The sequence of events during drilling are discussed in the drilling programme below.

4.7.1 Drilling 36'' hole and running 30'' conductor pipe

The 36" milled tooth tri-cone bit will be used to drill the conductor pipe hole using mud and low pumping speed to avoid massive washouts. 8" drill collars and a 36" near bit stabilizers should be used to produce a better drift hole. The hole below the expected 30" pipe shoe depth should be at 2 m unless hole cleaning problems are encountered in which case the additional hole should be limited to 4 m. After completion of drilling, the well is circulated to make sure that the well is clean of cuttings before tripping out of hole and running in 30" pipes. Cementing operations should be conducted until the cement slurry is returned to the surface. After the cement has cured for at least 36 hours the landing joint is cut off and a 29½" 500 psi rated BOP stack is installed and tested before further drilling.

4.7.2 Drilling 26" hole and running 20" surface casing

The surface hole has to be drilled using a 26" milled tooth tri-cone bit with high viscous mud and low pumping speed to avoid massive washouts. 8" drill collars and a 26" near bit stabilizers should be used to produce a better drift hole. The hole below the expected 20" casing shoe depth should be at 2 m unless hole cleaning problems are encountered in which case the additional hole should be limited to 4 m. If circulation losses are encountered and cannot be regained with loss of circulation material, drilling should continue blindly with water and high viscosity gel sweeps at every connection or more frequently depending on the hole conditions.

After drilling to the target depth, the hole is conditioned and a high viscosity gel pill is placed on bottom before tripping out. This is followed by running a 20" OD, 94 lb/ft grade K55 casing after which, cementing operations are carried out until cement slurry is returned to the surface. The cement has to cure for 36 hours after which a 21¼" 2000 psi rated BOP with single ram and an annular preventer will be installed and tested to 300 psi for 10 minutes before further drilling.

4.7.3 Drilling 17½" hole and running 13⅜" anchor casing

The intermediate hole should be drilled using a 17½" insert tooth tri-cone bit with water at a flow rate of 4000 l/m. A slick bottom hole assembly consisting of a 17½" bit, bit sub and 8" drill collars will run in hole to drill out cement. The cement will be drilled out with water at low weight on bit and rotary speed in order to maintain low rotary torque. Drilling will be continued to 30 m below the casing shoe and then trip out of hole. Then, a pendulum bottom hole assembly consisting of a 17½" bit, bit sub, 8" drill collars and a 17½" blade stabilizer 20 m above the bit will be run in hole to continue drilling. If loss of circulation return occurs attempt to regain it will be made. If the loss cannot be healed, continue drilling with water and slug the hole frequently with high viscosity mud pills. If hole cleaning is a major problem, change the drilling fluid to aerated water with foam.

After attaining target depth, circulate the well bore to make sure it is clean of cuttings. Then run a 13⅜" OD, 54.5 lb/ft grade K55 casing but the top two joints are 13⅜" OD, 80.7 lb/ft grade L80 casing. This process is followed by cementing until cement slurry is returned to the surface. After 36 hours of cement curing, a 13⅝" 3000 psi rated BOP consisting of annular and double gate ram preventers will be installed and pressure tested to 1000 psi for 10 minutes before further drilling. The installed POB will be used to drill the well up to completion.

4.7.4 Drilling 12¼" hole and running 9⅝" production casing

The production casing hole is to be drilled using a 12¼" insert tooth tri-cone bit. A slick bottom hole assembly consisting of a 12¼" bit and 8" drill collars will be run in hole to drill out cement with water applying low weight on bit and rotary torque. After drilling out cement inside the casing to shoe level, pressure test the shoe track using pipe ram to 200 psi and 1000 psi for 10 minutes each. Drill ahead to 30 m below the casing shoe and then trip out of the hole. Run in hole with a pendulum bottom hole assembly consisting of a 12¼" bit, 8 drill collars and 12¼" blade stabilizer 20 m above the bit to continue drilling to the kick off point and then trip out. Run in hole with an angle building (kick off) bottom hole assembly and kick off directional drilling. The angle should be built at a rate of 3° per 30 m to a maximum angle of 20°. The deviation surveys will be done at the kick off point and every single drilled during build up. After reaching the target inclination and azimuth, pull out and change to angle holding bottom hole assembly and continue drilling. The direction survey will be carried out every 30 m and later 60-90 m depending on the observed dog leg severity and drift on the azimuth angle.

After attaining target depth, the well bore will be circulated to make sure it is clean of cuttings before a 9⅝" OD, 47 lb/ft grade K55 casing is run in hole. The process is followed by cementing operations until cement slurry is returned to the surface. After 36 hours of cement curing blind rams, pipe rams and an annular BOP are tested to 200 psi and 1000 psi for 10 minutes each before further drilling.

4.7.5 Drilling 8½" hole and running 7" slotted liners

The main hole is drilled with an 8½" polycrystalline diamond bit using aerated water with foam. First, a slick bottom hole assembly is run in hole to drill out cement. Next, a pendulum bottom hole assembly is used for further drilling. Down hole temperatures are expected to rise, therefore, the temperature of the ingoing fluid should be maintained at a maximum of 40°C. Temperature control is critical for extending the bit life. The direction surveys are carried out as prescribed under Section 4.7.4. After drilling to target depth the well is circulated to ensure that all cuttings are lifted from the well. The 7" OD, 26 lb/ft grade L80 slotted liners will be run into the hole with two plain top joints and set down at the bottom. The liners are sufficient to cover an overlap of two plain joints inside 9⅝" production casing. Well completion tests will be carried out and a master valve installed.

5. RESULTS

5.1 Axial load before and during cementing

5.1.1 Tensile force when cement is inside the casing and water in the annulus

The axial load considered in this case is with the casing full of cement with a density of 1.69 kg/l, which is typical density of the cement slurry mostly used in Olkaria. The displaced fluid is water with a density of 1 kg/l and a temperature of 25°C. For each casing string it was determined whether it will withstand the load in this scenario and the results are listed in Table 3. The data in the following table and all subsequent tables was computed following the drilling data handbook (Gabolde and Nguyen, 2006) and an unpublished report from KenGen (KenGen, 2014).

TABLE 3: Axial load on casing before and during cementing

Casing size and grade	Casing weight [lb/ft]	Length [m]	$F_{hookload}$ [kN]	Min. pipe yield strength [kN]	Computed design factor	Minimum design factor	Remarks
Conductor pipe, 30" - X52	157.8	100	489.32	6100	12.47	1.80	Adequate
Surface casing, 20" - K55	94	440	1080.38	6590	6.10	1.80	Adequate
Anchor casing, 13⅜" - K55	54.5	790	981.65	3800	3.87	1.80	Adequate
Production casing, 9⅝" - K55	47	1470	1261.99	3320	2.63	1.80	Adequate

The casing joints are also subjected to the same axial load and the design factor is computed as listed in Table 4.

TABLE 4: Axial load on casing joints before and during cementing

Casing size and grade	Casing weight [lb/ft]	$F_{hookload}$ [kN]	Buttress standard tensile strength [kN]	Computed design factor	Minimum design factor	Remarks
Conductor pipe, 30" - X52	157.8	489.32	6100	12.47	1.80	Adequate
Surface casing, 20" - K55	94	1080.38	6580	6.09	1.80	Adequate
Anchor casing, 13⅜" - K55	54.5	981.65	4620	4.71	1.80	Adequate
Production casing, 9⅝" - K55	47	1261.99	4450	3.53	1.80	Adequate

5.1.2 Maximum bending stress for a directional well

Since well OW 736A is a directional well, the production casing will be subjected to both axial and bending forces at points of curvature before and during cementing. The kick-off point is at 800 m depth and the full inclination is achieved at 1000 m depth. The casing was evaluated whether it will withstand forces subjected to it and results are listed in Table 5.

TABLE 5: Axial and maximum bending force at 800 m depth

Casing size and grade	Casing weight [lb/ft]	$F_{hookload}$ [kN]	Bending force [kN]	$F_{hookload}$ + bending force [kN]	Min. pipe yield strength [kN]	Computed design factor	Minimum design factor	Remarks
Production casing, 9⅝" - K55	47	171.70	392.89	564.58	3320	5.88	1.80	Adequate

5.2 Axial load after cementing

5.2.1 Axial load due to temperature increase after cementing

The four strings of casing will be subjected to compressive forces due to temperature increase. It is assumed that conductor pipe, surface casing, anchor casing and production casing were at uniform temperatures of 30, 50, 50 and 50°C, respectively, when the cement is setting. It is also assumed that temperature for conductor pipe, surface casing, anchor casing and production casing will increase to 80, 100, 200 and 250°C, respectively. The resulting compressive force was calculated and listed in Table 6.

TABLE 6: Compressive force in the casing due to temperature increase

Casing size and grade	Casing weight [lb/ft]	F_c [kN]	F_p [kN]	F_r [kN]	Min. pipe yield strength [kN]	Min. yield pipe strength/ F_r
Conductor pipe, 30" - X52	157.8	-4080.77	489.32	-3591.45	6100	1.70
Surface casing, 20" - K55	94	-2375.65	1080.38	-1295.27	6590	5.09
Anchor casing, 13⅜" - K55	54.5	-4097.28	981.65	-3115.78	3800	1.22
Production casing, 9⅝" - K55	47	-4785.71	1261.99	-3916.99	3320	0.85

5.2.2 Axial load due to temperature decrease after cementing

The four strings of casing will be subjected to tensile forces due to temperature decrease. It is assumed that the conductor pipe, surface casing, anchor casing and production casing were at temperatures of 30, 50, 50 and 50°C, respectively, when the cement is setting. It is also assumed that the temperature of conductor pipe, surface casing, anchor casing and production casing will decrease to 25, 30, 30 and 30°C, respectively, when cool fluid is circulated from the surface during subsequent drilling, testing or operations. The resultant tensile force was calculated and is listed in Table 7.

TABLE 7: Tensile force in the casing due to temperature decrease

Casing size and grade	Casing weight [lb/ft]	F_t [kN]	F_p [kN]	F_r [kN]	Min. pipe yield strength [kN]	Min. yield pipe strength/ F_r
Conductor pipe, 30" - X52	157.8	408.08	489.32	897.40	6100	6.80
Surface casing, 20" - K55	94	950.26	1080.38	2030.64	6590	3.25
Anchor casing, 13⅜" - K55	54.5	546.32	981.65	1527.97	3800	2.49
Production casing, 9⅝" - K55	47	478.57	1261.99	2133.44	3320	1.56

5.2.3 Tension at the top of anchor casing

The tension force occurring at the top of the anchor casing was computed and the results are listed in Table 8. The two top segments are always of a higher nominal weight or grade than the rest of anchor casings in the wellbore. The result was used to determine whether the casing is adequate or not.

TABLE 8: Tension force on top two segments of anchor casing

Casing size and grade	Casing weight [lb/ft]	F_m [kN]	F_w [kN]	Min. pipe yield strength [kN]	Computed design factor	Minimum design factor	Remarks
Anchor casing, 13⅜" - K55	68	31.82	1238.53	4760	3.84	1.80	Adequate

5.2.4 Anchor casing lifting force due to thermal expansion of production casing

The lifting force which is applied to the anchor casing by thermal expansion of the production casing string is computed and compared to the design factor as shown in Table 9.

TABLE 9: Lifting force on anchor casing due to production casing thermal expansion

Casing size and grade	Casing weight [lb/ft]	Force due to production casing thermal expansion [kN]	Min. pipe yield strength [kN]	Computed design factor	Minimum design factor	Remarks
Anchor casing, 13⅜" - K55	68	-3916.61	4760	1.22	1.40	Inadequate
Anchor casing, 13⅜" - K55	80.7	-3916.61	5420	1.38	1.40	Inadequate
Anchor casing, 13⅜" – L80	68	-3916.61	6920	1.77	1.40	Adequate

5.3 Axial load of uncemented liners due to buckling and bending

The compressive stress in uncemented liners due to selfweight and helical buckling was computed and is shown in Table 10. It was used to determine the grade of liner which will be adequate for the well design. Connection efficiency for the liners under compression is assumed to be 90%.

TABLE 10: Compressive stress due the liner (length 2050 m) self-weight

Casing size and grade	Casing weight [lb/ft]	f_c [MPa]	Minimum yield stress [MPa]	Computed design factor	Minimum design factor	Remarks
Liner, 7" - K55	26	295.42	379.64	1.16	1.00	Adequate

The liner string design factor contains a temperature reduction factor of 0.8 and is recomputed as shown in Table 11.

TABLE 11: Compressive stress due to liner self-weight,
considering a temperature reduction factor of 0.8

Casing size and grade	Casing weight [lb/ft]	f_c [MPa]	Minimum yield stress [MPa]	Computed design factor	Minimum design factor	Remarks
Liner, 7" - K55	26	295.42	379.64	0.93	1.00	Inadequate
Liner, 7" – L80	26	295.42	552.02	1.35	1.00	Adequate

5.4 Hoop stress – Internal yield

5.4.1 Maximum differential internal pressure during cementing

The maximum internal differential pressure at the shoe during cementing for each casing string was determined and compared to the internal yield pressure. The results are listed in Table 12.

TABLE 12: Differential internal pressure at the casing shoe during cementing

Casing size and grade	Casing weight [lb/ft]	Length [m]	Differentia internal pressure, $\Delta P_{internal}$, [MPa]	Internal yield pressure [MPa]	Computed design factor	Minimum design factor	Remarks
Conductor pipe, 30" - X52	157.8	100	0.68	10.47	15.46	1.50	Adequate
Surface casing, 20" - K55	94	440	2.98	14.50	4.87	1.50	Adequate
Anchor casing, 13⅜" - K55	54.5	790	5.35	18.90	3.53	1.50	Adequate
Product. casing, 9⅝" - K55	47	1470	9.95	32.50	3.27	1.50	Adequate

5.4.2 Maximum differential internal pressure after cementing

The maximum differential internal pressure will occur at the wellhead, that is the anchor casing. Assuming a steam column in the well, the maximum pressure is estimated to be 16.3 bar and maximum temperature 348°C. The temperature reduction factor is 0.8. The computed results for different grade and weight of anchor casings is shown in Table 13.

TABLE 13: Maximum differential internal pressure during well heat up

Casing size and grade	Casing weight [lb/ft]	Wellhead pressure [MPa]	Temperature reduction factor [R_i]	Internal yield pressure [MPa]	Computed design factor	Minimum design factor	Remarks
Anchor casing, 13⅜" - K55	54.5	16.27	0.8	18.90	0.93	1.80	Inadequate
Anchor casing, 13⅜" - K55	68	16.27	0.8	23.80	1.17	1.80	Inadequate
Anchor casing, 13⅜" - K55	80.7	16.27	0.8	28.80	1.42	1.80	Inadequate
Anchor casing, 13⅜" – L80	77	16.27	0.8	39.70	1.95	1.80	Adequate
Anchor casing, 13⅜" – T95	72	16.27	0.8	44.10	2.17	1.80	Adequate
Anchor casing, 13⅜" – T95	68	16.27	0.8	41.10	2.02	1.80	Adequate

The anchor casings measuring 13⅜" 77 lb/ft L80, 13⅜" 72 lb/ft T95 and 13⅜" 68 lb/ft T95 are all matching the design requirements but the casings measuring 13⅜" 77 lb/ft L80 and 13⅜" 72 lb/ft T95 are rejected because their drift diameter is less than the diameter of the bit used to drill the next hole section (bit OD 12¼").

5.4.3 Axial and circumferential tension on casing anchoring wellhead

The biaxial stress condition for anchor casing was computed and used to determine the most suitable as shown in Table 14.

TABLE 14: Biaxial stress condition

Casing size and grade	Casing weight [lb/ft]	Maximum wellhead press., P_w [MPa]	Maximum tensile stress, f_t, [Mpa]	Steel yield strength, [MPa]	Computed design factor	Minimum design factor	Remarks
Anchor casing, 13⅜" - K55	54.5	16.27	301.98	379.78	1.26	1.50	Inadequate
Anchor casing, 13⅜" - K55	61	16.27	265.26	380.13	1.43	1.50	Inadequate
Anchor casing, 13⅜" - K55	68	16.27	235.06	379.22	1.61	1.50	Adequate

5.5 Hoop stress – collapse

5.5.1 Maximum external pressure after cementing

The maximum differential external pressure near the casing shoe when the annulus is filled with cement was computed for each casing string as shown in Table 15. The computed value was used to determine whether the different casing strings were adequate or not.

TABLE 15: Maximum external pressure at the casing shoe

Casing size and grade	Casing weight [lb/ft]	Length [m]	Differential extern. pressure, $\Delta P_{external}$, [MPa]	Pipe collapse pressure [MPa]	Computed design factor	Minimum design factor	Remarks
Conductor pipe, 30" - X52	157.8	100	0.68	1.55	2.29	1.20	Adequate
Surface casing, 20" - K55	94	440	2.98	3.60	1.21	1.20	Adequate
Anchor casing, 13⅜" - K55	54.5	790	5.35	7.80	1.46	1.20	Adequate
Production casing, 9⅝" - K55	47	1470	9.95	26.80	2.69	1.20	Adequate

5.5.2 Maximum external pressure during operation

The maximum external pressure during operation occurs near the casing shoe. The maximum external pressure was estimated to be 18 MPa and it was used to determine whether the production casing is adequate as shown in Table 16.

TABLE 16: Maximum external pressure during operation

Casing size and grade	Casing weight [lb/ft]	Differential external pressure, $\Delta P_{external}$, [MPa]	Pipe collapse pressure [MPa]	Computed design factor	Minimum design factor	Remarks
Production casing, 9⅝" - K55	47	18.00	26.80	1.49	1.20	Adequate

The production casing string design factor contains a temperature reduction factor of 0.8 and was recomputed as shown in Table 17.

TABLE 17: Maximum external pressure during operation, considering temperature reduction factor

Casing size and grade	Casing weight [lb/ft]	Differential external pressure, $\Delta P_{external}$, [MPa]	Pipe collapse pressure [MPa]	Computed design factor	Minimum design factor	Remarks
Production casing, 9⅝" - K55	47	18.00	26.80	1.19	1.20	Inadequate
Production casing, 9⅝" - K55	53.5	18.00	35.40	1.57	1.20	Adequate
Production casing, 9⅝" – L80	47	18.00	32.80	1.46	1.20	Adequate

The production casings measuring 9⅝" 53.5 lb/ft K55 and 9⅝" 47 lb/ft L80 are both adequate but 9⅝" 53.5 lb/ft K55 is rejected because its drift diameter is smaller than the diameter of the bit used to drill the next hole section (bit OD 8½").

5.6 Cement slurry volume

The volume of cement used under each casing string was computed as shown in Table 18.

TABLE 18: Volume of cement slurry

Casing size and grade	Length [m]	Volume [l/m]	Cement slurry vol. [m³]
Conductor pipe, 30″ 157.8 lb/ft X52			
Slurry volume between 30″pipe and 36″ drilled hole	100	200.7	20.07
Slurry volume between float collar and casing shoe	12	426.1	5.11
Slurry volume in the rat hole below the casing shoe	2	656.7	1.31
Slurry excess -100% of open hole volume	-	-	21.38
Total volume cement slurry required for conductor pipe cementing	-	-	**47.88**
Surface casing, 20″ 94.0 lb/ft K55			
Slurry volume between 20″casing and 26″ drilled hole	340	139.8	47.53
Slurry volume between 30″and 20″casing	100	223.46	22.35
Slurry volume between float collar and casing shoe	12	185.3	2.22
Slurry volume in the rat hole below the casing shoe	2	342.5	0.69
Slurry excess -100% of open hole volume	-	-	48.22
Total volume of cement slurry required for surface casing cementing	-	-	**121.00**
Anchor casing, 13⅜″ 54.5 lb/ft K55			
Slurry volume between 13⅜″casing and 17½″ drilled hole	350	64.5	22.58
Slurry volume between 20″ and 13⅜″ casing	440	94.66	41.65
Slurry volume between float collar and casing shoe	12	80.76	0.97
Slurry volume in the rat hole below the casing shoe	2	155.2	0.31
Slurry excess -100% of open hole volume	-	-	22.89
Total volume of cement slurry required for anchor casing cementing	-	-	**88.39**
Production casing, 9⅝″ 47 lb/ft L80			
Slurry volume between 9⅝″ casing and 12¼″ drilled hole	680	29.1	19.79
Slurry volume between 13⅜″ and 9⅝″ casing	790	33.7	26.62
Slurry volume between float collar and casing shoe	12	37.69	0.45
Slurry volume in the rat hole below the casing shoe	2	76.04	0.15
Slurry excess -100% of open hole volume	-	-	19.94
Total volume of cement slurry required for production casing cem.	-	-	**66.96**
Total volume of cement slurry required for the well			**324.23**

6. DISCUSSION

6.1 Minimum casing depths and wellhead for the redesigned well

The wellhead design takes into consideration the maximum pressure and temperature which occur at the wellhead when the well is shut in. Assuming the well contains a column of steam from the bottom to the wellhead, the maximum pressure and temperature at the wellhead are 16.3 MPa and 348°C, respectively. The most suitable wellhead for the redesigned well is determined from the wellhead working pressure by de-rating for flanges and valves conforming to ANSI B16.5 and API 6A (African Union Standard, 2016). The most suitable wellhead for the redesigned well OW 736A is the ANSI 1500 as indicated in Figure 10.

The redesigned well casing depths were set to 440 m for the surface casing, 790 m for the anchor casing and 1470 m for the production casing. The actual casing depths in the well currently are 56 m for the surface casing, 418 m for the anchor casing and 1203 m for the production casing. The redesign using the new African Union code of practice resulted in increased casing depths since it is using the effective containment pressure as upper boundary when setting the depths. The maximum pressure at the wellhead was computed assuming that the wellbore is full of steam from bottom to top. With that assumption, the

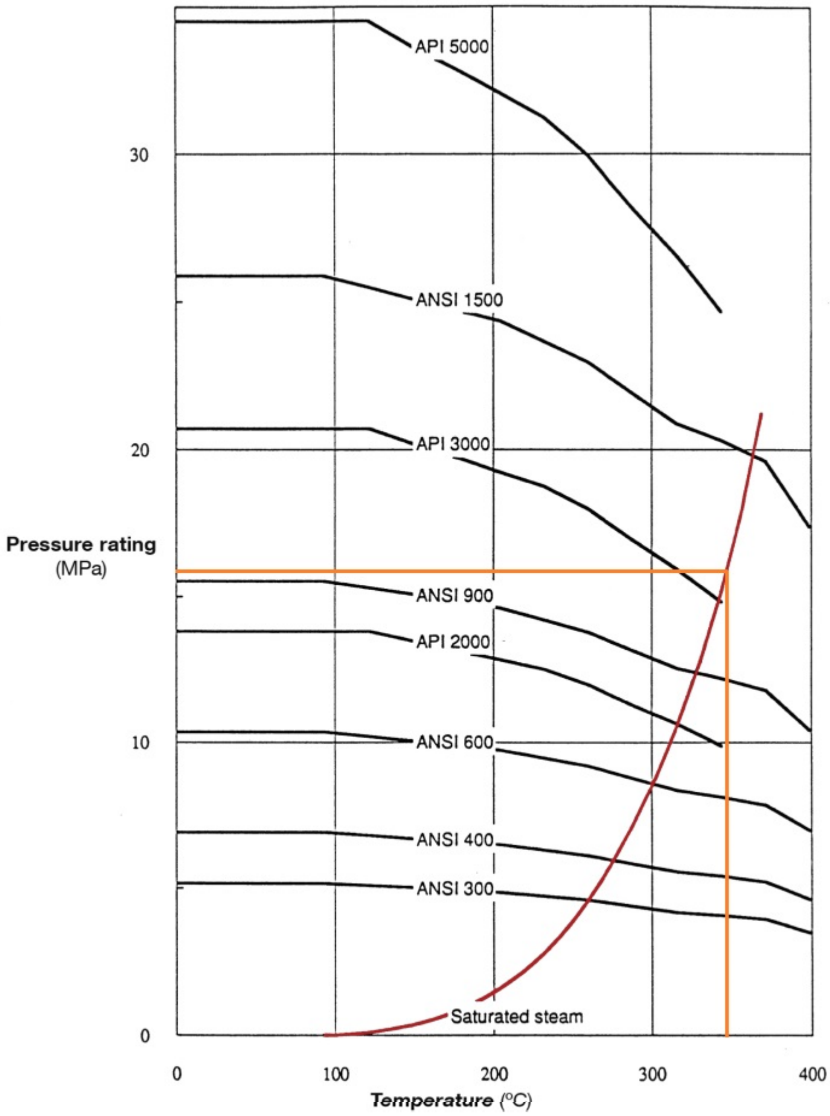

FIGURE 10: Wellhead working pressure de-rating for flanges and valves; the yellow line represents the maximum wellhead conditions (African Union Standard, 2016)

pressure will decrease from the bottom towards the wellhead although the difference is minimal. The previous New Zealand code of practice for deep geothermal wells (NZS 2403:1991) was using overburden pressure as the upper boundary of casing setting and hence resulting in shallow casing depths for previous designs (Ngigi, 2015). The surface casing depth was revised from the original 56 to 440 m which might pose a great challenge to the drilling engineers. Therefore, a 100 m conductor pipe was introduced in the new well design in order to ensure safe drilling of the upper part which is normally very unstable (Murigu, 2017). The previous design of all wells in Olkaria geothermal field did use a conductor pipe but with the introduction of the new standard, the option is inevitable in the future unless conservative safety requirements are relaxed.

6.2 Axial load before and during cementing

6.2.1 Tensile force when cement is inside the casing and water in the annulus

The tensile force acting on the conductor pipe and all casings was computed assuming cement inside the casing displacing fresh water. This scenario was picked for design since it results in maximum axial load during cementing. The design factor computed for the conductor pipe was 12.47, 6.10 for the surface casing, 3.87 for the anchor casing and 2.63 for the production casing in comparison to the minimum design factor of 1.80. The conclusion was that the following casing strings fulfil the requirements of the design: 30" 158.7 lb/ft X52 conductor pipe, 20" 94 lb/ft K55 surface casing, 13⅜" 54.5 lb/ft K55 anchor casing and 9⅝" 47 lb/ft K55 production casing.

The design factor for corresponding buttress standard casing joints was computed and compared to the minimum design factor of 1.80. The computed factor for the conductor pipe joint is 12.47, 6.09 for the surface casing joint, 4.71 for the anchor casing joint and 3.53 for the production casing joint.

6.2.2 Maximum bending stress for a directional well

The production casing is curved from the directional kick-off point to the point of maximum inclination. The production casing is the only casing string which is subjected to bending stress. The curvature point experiences both axial and bending stress during cementing. The design factor for the 9⅝" 47 lb/ft K55 production casing for axial and bending stress was computed to be 5.88 which exceeds the minimum design factor of 1.80.

6.3 Axial load after cementing

6.3.1 Axial load due to temperature increase after cementing

The four casing strings will be subjected to compressive forces due to temperature increase. It is assumed that the conductor pipe, surface casing, anchor casing and production casing are at temperatures of 30, 50, 50 and 50°C, respectively, when the cement is setting. It is also assumed that temperatures for the conductor pipe, surface casing, anchor casing and production casing will increase to 80, 100, 200 and 250°C, respectively.

The resulting compressive force due to the temperature increase for each casing string was computed and compared to the corresponding minimum tensile strength. The resulting compressive force for the 30" 158.7 lb/ft X52 conductor pipe is 3591 kN while the minimum pipe yield strength is 6100 kN. Hence, the pipe will not yield. The resulting compressive force for the 20" 94 lb/ft K55 surface casing is 1295 kN while the minimum casing yield strength is 6590 kN. Hence, the casing will not yield. The resulting compressive force for the 13⅜" 54.5 lb/ft K55 anchor casing is 3116 kN while the minimum casing yield strength is 3800 kN. Hence, the casing will not yield. The resulting compressive force for the 9⅝" 47 lb/ft K55 production casing is 3917 kN while the maximum pipe yield strength is 3320 kN. This casing will exceed the maximum yield stress during operation.

6.3.2 Axial load due to temperature decrease after cementing

The four casing strings will be subjected to tensile forces due to temperature decrease. It is assumed that the conductor pipe, surface casing, anchor casing and production casing are at temperatures of 30, 50, 50 and 50°C, respectively, when the cement is setting. It is also assumed that temperatures for the same casing strings will decrease to 25, 30, 30 and 30°C, respectively, when cold fluid is circulated from the surface during subsequent drilling, testing or operations.

The resulting tensional force due to temperature decrease for each casing string was computed and compared to the corresponding minimum tensile strength. The resulting tensional force for the 30" 158.7 lb/ft X52 conductor pipe is 897 kN while minimum pipe yield strength is 6100 kN. Hence, the pipe will not yield. The resulting tensional force for the 20" 94 lb/ft K55 surface casing is 2031 kN while the minimum casing yield strength is 6590 kN. Hence, the casing will not yield. The resulting tensional force for the 13⅜" 54.5 lb/ft K55 anchor casing is 1528 kN while the minimum casing yield strength is 3800 kN. Hence, the casing will not yield. The resulting compressive force for the 9⅝" 47 lb/ft K55 production casing is 2133 kN while the maximum pipe yield strength is 3320 kN. However, the casing will exceed the maximum yield stress during heat up as described in 6.3.1.

6.3.3 Tension at the top of anchor casing

The resulting force of the tension force occurring at the top of the anchor casing and the lifting force applied by the fluid in the well was computed and compared to the minimum tensile strength. The casings which were considered are the two top casings which anchor the wellhead and are normally of higher grade or weight than the rest of the anchor casings inside the well. The casing for this design is 13⅜" in size, grade K55, 68 lb/ft and the computed design factor was 3.84 while the minimum design factor is 1.80. Hence, the casing fulfils the requirements for the two top casing segments.

6.3.4 Anchor casing lifting force due to thermal expansion of production casing

The lifting force acting on the anchor casing due to thermal expansion of the production casing was computed and compared to the anchor casing minimum tensile strength. The casings considered in this case are the two top casings directly anchoring the wellhead. The computed design factor for the 13⅜" 68 lb/ft K55 casing is 1.22, 1.38 for the13⅜" 80.7 lb/ft K55 casing and 1.77 for the 13⅜" 68 lb/ft L80 casing. All three exceed the minimum design factor of 1.40. The 13⅜" 68 lb/ft L80 casing is recommended to be used for the two top casings anchoring the wellhead.

6.4 Axial load of uncemented liners due to buckling and bending

The compressive stress acting on an uncemented liner due to its self-weight and helical buckling was computed and compared to the minimum yield stress. Connection efficiency in compression was assumed to be 90%. The computed design factor for a 7" 26 lb/ft K55 liner was found to be 1.16 while the minimum design factor is 1.00. Hence, the liner fulfils the requirements.

A second scenario was considered, applying a temperature reduction factor of 0.8 since the expected maximum temperature at the wellhead is 348°C. The reduction factor is not taken into account in the standard but as a matter of fact, the liners will be subjected to high temperatures the entire lifespan of the well. The re-computed design factor for the 7" 26 lb/ft K55 liner is 0.93 and for the 7" 26 lb/ft L80 liner is 1.35 while the minimum design factor is 1.00. In this scenario, the 7" 26 lb/ft L80 liner casing string is recommended for use.

The second scenario is favourable for the redesigned well although the standard does not consider a temperature reduction factor when computing the minimum design factor for this load case. The reasoning is that the liner will be subjected to high temperatures since the well is situated in a high-temperature geothermal field.

6.5 Hoop stress – internal yield

6.5.1 Maximum differential internal pressure during cementing

The maximum internal differential pressure during cementing operation occurs at the shoe. The differential pressure for each casing string was computed and compared to the pipe internal pressure resistance. The computed design factors for the 30" 158.7 lb/ft X52 conductor pipe, the 20" 94 lb/ft K55 surface casing, the 13⅜" 54.5 lb/ft K55 anchor casing and the 9⅝" 47 lb/ft K55 production casing were found to be 15.46, 4.87, 3.53 and 3.27, respectively, while the minimum design factor is 1.50. Hence, all casings fulfil the requirements.

6.5.2 Maximum differential internal pressure after cementing

The maximum differential internal pressure during well shut-in occurs at the wellhead, and therefore affects the anchor casing. Assuming a steam column in the well, the maximum wellhead pressure is 16.3 MPa and the corresponding temperature is 348°C. The temperature reduction factor is estimated to be 0.8. The maximum wellhead pressure being applied to the top two 13⅜" anchor casings was compared to the internal yield pressure considering the temperature reduction factor. The computed design factor for the 13⅜" 54.5 lb/ft K55 casing is 0.93, 1.17 for the 13⅜" 68 lb/ft K55 casing, 1.42 for the 13⅜" 80.7 lb/ft K55 casing, 1.95 for the 13⅜" 77 lb/ft L80, 2.17 for the 13⅜" 72 lb/ft T95 casing and 2.02 for the 13⅜" 68 lb/ft T95 casing while the minimum design factor is 1.80. The anchor casings 13⅜" 77 lb/ft L80, 13⅜" 72 lb/ft T95 and 13⅜" 68 lb/ft T95 are all fulfilling the requirements of the design but the 13⅜" 77 lb/ft L80 and 13⅜" 72 lb/ft T95 casing are rejected because their drift diameter is less than the diameter of the bit used to drill the next hole section (bit OD 12¼"). The 13⅜" 68 lb/ft T95 casing is recommended for use in this case.

6.5.3 Axial and circumferential tension on casing anchoring wellhead

The biaxial stress condition for the anchor casing was determined and compared to the steel yield strength. The computed design factor for the 13⅜" 54.5 lb/ft K55 casing is 1.26, 1.43, for 13⅜" 61 lb/ft K55 casing and 1.61 for the 13⅜" 68.0 lb/ft K55 casing while the minimum design factor is 1.50. The 13⅜" 68.0 lb/ft K55 casing is suitable to be used as top two casings anchoring the wellhead considering the design factor only but a higher grade casing has been recommended in Section 6.5.2.

6.6 Hoop stress – Collapse

6.6.1 Maximum external pressure after cementing

The maximum external pressure occurs immediately after cementing at the shoe of the casing when the annulus is filled with dense cement slurry and the casing is filled with water. The computed differential external pressure for each casing string was compared with the pipe collapse pressure. The computed design factors for the 30" 158.7 lb/ft X52 conductor pipe, the 20" 94 lb/ft K55 surface casing, the 13⅜" 54.5 lb/ft K55 anchor casing and the 9⅝" 47 lb/ft K55 production casing were found to be 2.29, 1.21, 1.46 and 2.69, respectively, while the minimum design factor is 1.20. They all fulfil the requirements.

6.6.2 Maximum external pressure during operation

The maximum external pressure during operation occurs near the production casing shoe. The maximum external pressure was estimated to be 18 MPa and was compared to the pipe collapse pressure. The computed design factor for the 9⅝" 47 lb/ft K55 production casing is 1.49 while minimum design factor is 1.20. Hence, it fulfils the requirements.

A second scenario was considered applying a temperature reduction factor of 0.8 since the expected maximum temperature at the wellhead is 348°C. The reduction factor is not considered in the standard but actually, the production casing string will be subjected to high temperatures the entire lifespan of the well. The re-computed design factor, taking into account the temperature reduction factor, is 1.19 for the 9⅝" 47 lb/ft K55 production casing, 1.57 for the 9⅝" 53.5 lb/ft K55 production casing and 1.46 for the 9⅝" 47 lb/ft L80 production casing while the minimum design factor is 1.20. The production casings 9⅝" 53.5 lb/ft K55 and 9⅝" 47 lb/ft L80 both fulfil the requirements of the design but the 9⅝" 53.5 lb/ft K55 casing is rejected because its drift diameter is less than the diameter of the bit used to drill the next hole section (bit OD 8½"). In this scenario the 9⅝" 47 lb/ft L80 production casing is recommended for use.

The second scenario is describing the actual conditions at the redesigned well better because the production casing string is subjected to high temperatures since the well is situated in a high-temperature geothermal field. The recommendation invalidates previous recommendations on the grade and weight of the production casing.

6.7 Comparison of original and redesigned well

The minimum casing depth determined previously as well as casing sizes, grades and weights recommended in clause 6 is listed in Table 19. The table compares the original OW 736A well, drilled in 2014, and the redesigned well using new African Union Code of Practice for Geothermal Drilling.

TABLE 19: Well details for original and redesigned well OW736A

Description	OW 736A	
	Original well	**Redesigned well**
36" conductor hole		
Hole size (")	-	36
Setting depth (m)	-	100
Casing size (")	-	30
Casing grade	-	X52
Casing weight (lb/ft)	-	157.8
26″ surface hole		
Hole size (")	26	26
Setting depth (m)	56	440
Casing size (")	20	20
Casing grade	K55	K55
Casing weight (lb/ft)	94	94
17½" anchor hole		
Hole size (")	17½	17½
Setting depth (m)	418	790
Casing size (")	13⅜	13⅜
Casing grade	K55	K55
Casing weight (lb/ft)	54.5	54.5
Two top casings supporting wellhead		
Casing size (")	13⅜	13⅜
Casing grade	K55	T95
Casing weight (lb/ft)	68	68
12¼" production hole		
Hole size (")	12¼	12¼
Setting depth (m)	1203	1470
Casing size (")	9⅝	9⅝
Casing grade	K55	L80
Casing weight (lb/ft)	47	47
8½" main hole		
Hole size (")	8½	8½
Setting depth (m)	3500	3500
Casing size (")	7	7
Casing grade	K55	L80
Casing weight (lb/ft)	26	26
Wellhead		
Wellhead (ANSI)	900	1500

7. CONCLUSIONS

Due to formation instability and for well control, it is not possible to drill a well continuously through all formations from the surface to the target depth. Instead, the well is drilled in sections with each section being lined off with a casing which is permanently cemented before the subsequent section is drilled. These casings also act as permanent anchorage of the whole well structure during its lifetime. The design of the casings needs to be taken very seriously, especially for wells located in high-temperature geothermal fields since the pressures and temperatures involved can be very high.

The redesign of well OW 736A was based on The African Union Code of Practice for Geothermal Drilling which became effective in 2016. The only standard which was available previously for geothermal well design was the New Zealand standard of 1991. The redesign resulted in deeper casings since the upper boundary for the casing string setting was revised using effective containment pressure instead of overburden pressure. It is understood that the new design is more cautious to avoid formation breakage which could result in an underground blow out. It should also be noted that strict adherence to classical hydraulic fracturing theory can lead to an impractical number of casing strings at shallow depths.

The analysis of the axial and hoop loads of all casing strings were examined which resulted in the revision of the top two anchor casings from 13⅜" 68 lb/ft K55 to 13⅜" 68 lb/ft T95 casing grades. The top two anchor casings are normally of higher grade than other anchor casings down the wellbore since they are subjected to higher loadings due to high temperature and pressure at the top of the well as the wellhead is placed right on top of them. The production casing string was also revised from a 9⅝" 47 lb/ft K55 to a 9⅝" 47 lb/ft L80 casing grade after a temperature reduction factor of 0.8 at 348°C was introduced. The slotted liner string was revised from 7" 26 lb/ft K55 to 7" 26 lb/ft L80 since the former could not withstand compressive stress due to self-weight and helical buckling after taking into consideration the temperature reduction factor. The length of the liner casing string of 2050 m also contributed to the dismissal of the 7" 26 lb/ft K55 grade.

The recommended master valve for the redesigned well is an ANSI class 1500. It withstands the maximum wellhead pressure of 16.3 MPa and the temperature of 348°C. According to the African Union Standard (2016), conventional design factors are not applicable for casings that are designed to yield. If the casing is expected to thermally yield during operations, it shall be designed to accept limited plastic strain, taking into considerations stress relaxation, cyclic hardening and strain localisation effects. The design factor due to thermal expansion, which used to be 1.2 in the New Zealand standard of 1991, have been dropped in the 2015 N.Z. standard and African Union Standard since casings are likely to reach yield point due to thermal stresses.

The well design process has become simpler and more user friendly with the introduction of the new standard.

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NOMENCLATURE

a	= Coefficient of thermal expansion (°C)
A_p	= Cross-sectional area of casing wall (mm^2), allowing for any slotting
d	= Casing inside diameter (mm)
D	= Casing outside diameter (mm)
dd_{m}	= Casing drift diameter (mm)
dc_{m}	= Casing drift constant (mm)
e	= Eccentricity (mm) = actual (not nominal) hole diameter minus D
E	= Modulus of elasticity (MPa)
f_b	= Maximum stress due to bending (MPa)
f_c	= Total extreme fibre compressive stress due to axial and bending forces (MPa)
f_t	= Maximum tensile stress (MPa)
$F_{buoyancy}$	= Buoyancy force (kN)
$F_{csg\ air\ wt}$	= Air weight of casing (kN)
$F_{csg\ contents}$	= Weight of internal contents of casing (kN)
$F_{hookload}$	= Surface suspending casing that is subject to gravitational and static hydraulic loads (kN)
$F_{displaced\ fluids}$	= Weight of fluids displaced by casing (kN)
F_c	= Change in axial force within casing body due to heating (kN)
F_m	= Net downward force applied by the wellhead (kN), due to its own mass and any pipework reactions (kN)
F_p	= Axial force within casing body at cement set (kN)
F_r	= Resultant axial force within casing body, combining the force at cement set and subsequent thermal forces (kN)
F_t	= Change in axial force within casing body due to cooling (kN)
F_w	= Lifting force due to wellhead pressure (kN)
g	= Acceleration due to gravity (9.81 m/s^2)
h	= Depth below liquid level (m)
I_p	= Net moment of inertia of the pipe section, allowing for perforations (mm^4)
L_{if}	= Vertical length of a section of fluid having the same density – within the casing (m)
L_{ef}	= Vertical length of a section of fluid having the same density – within the external annulus (m)
L_f	= Total vertical length of a fluid column in an annulus (m)
L_z	= Total vertical length of liner or casing (m)
P_f	= Pore pressure (MPa)
$\Delta P_{external}$	= Maximum external differential pressure on casing after cementing (MPa)
$\Delta P_{internal}$	= Maximum internal differential pressure on casing during cementing (MPa)
P_{frac}	= In situ fracture pressure of a formation (MPa)
P_w	= Maximum wellhead pressure (MPa)
P_z	= External fluid pressure at the casing shoe (MPa)
R_i	= Temperature reduction factor (ratio)
R_j	= Connection efficiency in compression

S_v	= Overburden pressure (vertical pressure due to the weight of the overlying formations) (MPa)
T_1	= Neutral temperature (temperature of casing at time of cement set) (°C)
T_2	= Maximum expected temperature (°C)
T_3	= Minimum temperature after cooling well (°C)
W_p	= Nominal unit weight of casing in air (kg/m)
q	= Curvature (degrees per 30 m)
v	= Poisson's ratio
π	= 3.142 (that is to 4 significant figures)
ρ	= Density of underlying rocks in the geothermal field (kg/m^3)
ρ_{ef}	= Density of a section of fluids with constant density within an annulus (kg/l)
ρ_{if}	= Density of a section of fluids with constant density within a casing (kg/l)
ρ_c	= Cement slurry density (kg/l)
ρ_f	= Density of fluid – usually water – in the wellbore or annulus (kg/l).

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