UNITED NATIONS UNIVERSITY
UNU-GTP
Geothermal Training Programme

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Reports 2016
Number 29

THE BASIS FOR WELL DESIGN AND DRILLING PROGRAMME FOR GEOTHERMAL EXPLORATION IN KINIGI, RWANDA

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ABSTRACT

The western branch of the East African Rift System is expected to flourish in geothermal resources as it is the case on the eastern branch. However, unlike the eastern branch, these resources are not yet developed. Even though exploration has been undertaken recently in countries like Rwanda and Uganda several setbacks were encountered and the worst was the deep exploration drilling in Karisimbi, Rwanda in 2013-2014. An intensive geoscientific exploration process is being performed and ultimately drilling will be carried out and therefore, a drilling programme specific to the area needs to be prepared. The African Union has provided the code of practice, the African Union Code of Practice for Geothermal Drilling, to guide engineers in the design of drilling programmes and this report is about the basis of the design of the casing programme, the cementing programme and the mud programme for future Kinigi exploration drilling. The casing programme is made up of 3 cemented strings of casings, namely: surface casing (100 m), anchor casing (450 m) and production casing (1230 m). A slotted liner is hung from the production casing from 1200 m depth down to the bottom at 3000 m. The choice for the design of the 3000 m deep well at Kinigi is based on minimum design factors and possible worst load scenarios.

Drilling fluids play a key role for the success of the drilling process, and well cleaning together with well stability are top considerations. Poor selection of drilling fluids either in quality or in quantity may result in well collapse, a stuck drill string or worse. While designing the drilling fluids programme for exploration wells in Kinigi, a number of factors has to be considered including the formation pressure, temperature, and expected loss zones in the well. Apart from those technical consideration, the cost also must be considered because some fluids e.g. the air drilling package required for pressure balance drilling with aerated drilling fluids is expensive. The design for the cementing programme focused mainly on the estimated volume of cement slurry necessary for the annular volume to be cemented plus the excess of 150%. Therefore, the estimated volume of the slurry is 180 m^3 per well and considering the planned density of the slurry of 1.87 kg/l, the amount of dry cement required for each well is estimated at 250 tonnes. The success of getting a sound cement around the casing at the end of the cementing process was the priority and the inner string cementing method was chosen. The slurry pumping and displacement time also were explored and the calculated pumping time is less than 3 hours per well.

1. INTRODUCTION

The western branch of east African rift system is expected to flourish in geothermal resources as it is the case on eastern branch. However, unlike the eastern branch, these resources have not yet been developed, even though exploration drilling has been attempted recently in countries like Rwanda and Uganda. Several setbacks were encountered and the worst was the deep exploration drilling in Karisimbi, Rwanda in 2013-2014.

The eastern branch of the Africa rift system is being exploited successfully with Kenya putting on grid hundreds of MWe from successfully drilled wells and Ethiopia having built its first pilot plant. As geological conditions have been shown to be different on the western branch, it is necessary to anticipate the conditions and produce a drilling programme suitable for drilling of exploration wells in that area. The main aim of this work is a contribution to the establishment of a drilling programme specifically designed according to the conditions and lithology of the area based on the available data.

Geothermal exploration in Rwanda started in 1982 and continued during the following years until 2008 when conclusions of the various studies were indicating a geothermal system with temperatures over 200°C in the Karisimbi volcano, and 150-200°C near Lake Karago with a heat source at about 5 km depth. All surveys indicated that the drilling at Karisimbi would intersect a hot reservoir which turned out to be the opposite, unfortunately. Nevertheless, results related to the lithology of the area will be pursued in this work while calculating basic formulations and designs for a drilling programme for the Kinigi area which is to the east of Karisimbi.

Kinigi geothermal area is not chosen randomly, instead it was ranked as the best prospect by a new complementary survey prepared for Rwanda Energy Group (REG) by the Japan International Cooperation Agency (JICA) in March 2016. Furthermore, the Geothermal Risk Mitigation Facility (GRMF) sanctioned an award to the exploration drilling proposal which was prepared and submitted by the Rwandan Energy Development Corporation which is in charge of exploration and development of geothermal resources. In 2015, JICA prepared a geothermal master plan in which they ranked Kinigi as the most promising area among other prospects in Rwanda, with potential energy close to 60 MWe at the confidence level of 50%.

This United Nations University – Geothermal Training Programme (UNU-GTP) document will focus specifically on the Kinigi area but it can be adapted and used in the region of the western branch of the Africa rift system as well. Basically, drilling programmes are documents subject to modifications once firm data is obtained to replace earlier assumptions made before wells were drilled and to address new challenges encountered in the field.

In the Kinigi area, the heat source is expected to be at 5 km depth (JICA, 2014), therefore, it is necessary to drill exploration wells up to 3 km deep in order to prove the existence or absence of the resource. A target depth of 3000 m will guide the choice of the rig, the materials to be used as well as the parameters to be used throughout the drilling process. The wells will be drilled in 4 sections; namely surface casing, anchor casing, production casing and the production section with a slotted liner. The first three sections are cased and cemented back to the surface while the last one is open and allows the geothermal fluid to flow in the well to the surface. The depth for every section is determined by a number of factors including: well safety, environmental protection, and eventually, success of production and well testing. This document will summarise all basic calculations which govern the design of the drilling programme and associated programmes including the mud programme, cementing programme, casing programme etc. The aim of this paper is to have a good understanding of design calculations as part of selecting a casing programme and preparation of the drilling programme document, and to know how changes may affect the whole process and especially the success and/or the cost of the well drilling.

2. BACKGROUND OF GEOTHERMAL EXPLORATION IN RWANDA

2.1 Methods used for geothermal exploration in Rwanda

For geothermal resource development, exploration is a compulsory step. Different methods are used for the exploration process including geoscientific methods like geology, geochemistry, geophysics, drilling etc. Like elsewhere in the world, geothermal resource exploration in Rwanda went through all procedures and steps since the launching of the survey series initiated by BRGM (French Bureau of Geology and Mines) in 1982.

That survey included a geochemical reconnaissance survey at different sites like Mashyuza (Bugarama), Gisenyi, Kibuye, Ntaresi and Musanze. At the conclusion of the survey, Gisenyi and Bugarama were identified as potential sites for geothermal development with an estimated reservoir temperature beyond 100°C. A new survey was conducted by Chevron in 2006 at the hot springs of Bugarama and Gisenyi using geothermometry and the results indicated low to moderate temperature. The most promising prospects in Rwanda were identified as Bugarama, Gisenyi, Karisimbi and Kinigi (Figure 1).

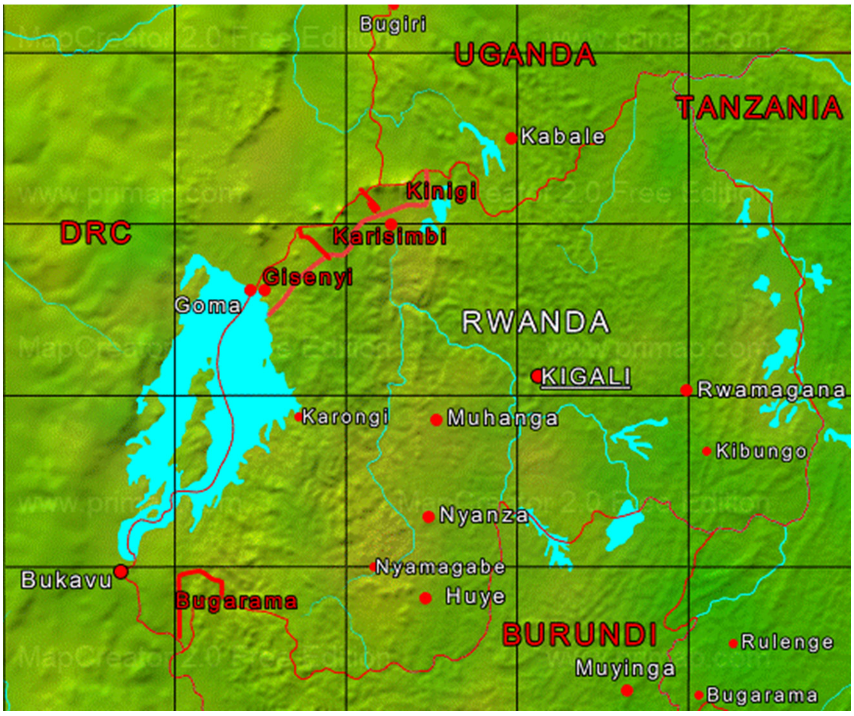


FIGURE 1: Location map of geothermal areas in Rwanda (Namugize, 2011)

In 2008, the Germany Institute for Geosciences and Natural Resources (BGR) collaborated with Kenya Electricity Generating Company (KenGen), Iceland GeoSurvey (ÍSOR) and the Institute for Technology and Renewable Energies (ITER) to conduct geochemical, geophysical and soil gas surveys in Gisenyi, Karisimbi and Kinigi. They concluded that (BGR, 2008):

(1) A geothermal system with a temperature over 200°C is located south of Karisimbi volcano;
(2) The temperature of the geothermal system near Lake Karago is 150 to 200°C; and
(3) The depth of heat source in these geothermal systems is about 5 km.

In 2009, KenGen conducted additional surface surveys (geophysical and geochemical) and an environmental impact assessment south of Karisimbi volcano. In a workshop held in Kigali in February 2010, a geothermal conceptual model based on those results and drilling targets for three wells were discussed.

In 2010, KenGen conducted geophysical (MT and TEM), geochemical (soil gas: CO_2, mercury and Radon) and hydrogeological surveys. They concluded that the geothermal system is possibly distributed to the regions around the southern slopes and trends to the southeast through the town of Mukamira toward Lake Karago. Therefore, it was recommended that the exploration wells should be drilled directionally ranging between 2,000 and 3,000 m in depth to intersect as many structures as possible.

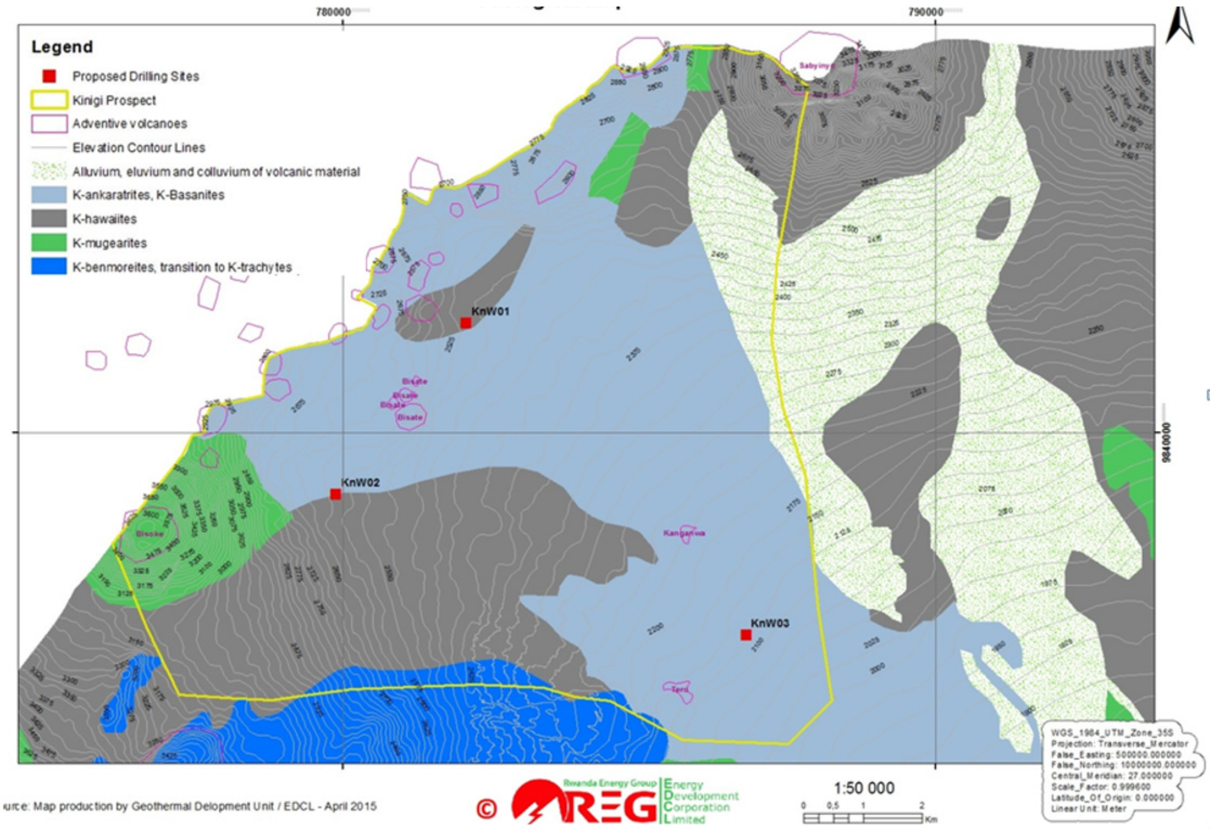


FIGURE 2: Geological map of Kinigi prospect modified from (EDCL, 2015)

From 2011 to 2012, IESE (Institute of Earth Science and Engineering) conducted additional geological, geochemical and geophysical (MT, TEM and CSAMT) surveys as part of a microseismic and heat flow study with boreholes at Kinigi, Gisenyi and Karisimbi. As a result, a geothermal conceptual model regarding geological structure and geothermal fluid flow was elaborated and targets for three vertical exploratory wells were proposed to confirm the reservoir.

In April 2012, the first validation workshop was held in Kigali with different stakeholders in order to verify previous survey results and enable the elaboration of a geothermal conceptual model of the area around Karisimbi and the targeting of three exploratory wells. However, the geophysical analytical results were thought to be insufficient. In January 2013, another validation workshop was held by UniServices, Geothermal Development Company (GDC), Reykjavik Geothermal (RG), KenGen and EWSA to verify the re-analysed results.

The outcome can be summarized as follows:

1) The resistivity model around Karisimbi volcano consists of a high resistivity layer (recent volcanic), a low resistivity layer (may be the clay cap) due to hydrothermal alteration of low-temperature clays and a higher resistivity layer (reservoir) due to a higher degree of hydrothermal alteration;
2) There is a deeper low resistivity layer (heat source) which becomes shallower toward Karisimbi volcano and dips sharply to the south; and
3) Drilling targets were confirmed: future drilling should be directional toward Karisimbi volcano targeting the NW and NE trending interpreted fractures and go to a depth of 3,000 m.

The first exploratory well was drilled in Karisimbi (KW01) starting July18th, 2013 and reached the target depth of 3,015 m on October 23rd, 2013. The second exploratory well (KW02) was drilled from December 14th 2013 until March 22nd 2014 and was stopped at 1,367 m . The data from these two wells showed that the area was rather cold (a gradient of 30°C/km) and with low permeability. Among the lessons learned is to carry out additional surveys prior to new exploration drilling.

Among the additional surveys, a gravity survey was carried out in Kinigi area by JICA and concluded that the heat source of the geothermal system is related to the Quaternary activity of the Sabinyo volcanoes (JICA, 2014).

2.2 Geology of the Kinigi area

The geology of Kinigi area as shown on the map (Figure 2) is dominated by the upper tertiary to quaternary volcanic rocks which originated from the explosive volcanism of the Karisimbi, Bisoke, Sabyinyo, Gahinga and Muhabura volcanoes (EWSA, 2014). The volcanic rocks in Kinigi area are dominated by pyroclastites of different ages and trachytes. They are probably related to a caldera collapse phase and also indicate magmatic differentiation while latites indicate silica-rich melts from local upper crust (Rogers et al., 1998).

The latites from Sabyinyo and trachytes from Karisimbi are results of fractional crystallization. The abundant pyroclastites which also occur in shallow ground water boreholes up to a depth of 100 m are expressed as volcanic ashes, lapilli and volcanic bombs (Rogers et al., 1998).

High temperature, pressure and gas content were the main engines of explosivity, possibly in the upper mantle. This together with the recent whole rock chemistry studies by Shalev et al. (2012) support the theory that magmatic differentiation could be the heat source for the geothermal system.

The rocks around Kinigi were dated to be between 100,000 and 200,000 years old in the case of the latites and the K-basanites less than 100,000 years **(**Rogers et al., 1998**)**.

Most of the cold, warm and mineralised springs occur in lowlands generally at the boundary of the volcanic and the basement rocks and along NS tectonic features in the Kinigi area. Cold springs, generally with high flow rate, are sourced by the porous volcanic rocks and open faulting systems. The very high permeability and rainfall would mask any geothermal manifestations like fumaroles (EDCL, 2015).

Based on the geology, hydrogeology, geochemistry, active volcanism and geophysics there are three possible hydrogeological models for the Kinigi area (EDCL, 2015):

(1) Thermal fluids may ascend below the volcanic zone and move to the south east along fault zones at the contacts of the different strata.
(2) Geothermal fluids may ascend via near vertical channels along the northeast trending fault zones between Bisoke and Sabinyo volcanoes with many cones that could be associated with hot intrusive rocks. This geothermal system may be discharging to the south east along the fault zones towards the tepid springs in the basement.
(3) The model relates to the heat source provided by a mafic-magmatic heat source (associated with demagnetised zones with low magnetic anomaly) that could be related to the mineralisation in the NE trending tungsten belt. In this model, the discharge is still expected to be to the south east along the regional NW faults and at the contacts of the lava flows.

However, it is uncertain which hydrogeological model is correct but all the three models are applicable to this area (EDCL, 2015).

The main outcome of all efforts was a recommendation in favour of an exploration drilling in the area targeting the interpreted high permeability zones to assess the geothermal potential. The geothermal system between the Bisoke and Sabyinyo volcanos appears to be controlled by a near orthogonal set of fault zones. The main up flow of the system appears to be between Bisoke and Sabyinyo along the NW and NE trending fault zone.

From the experience of Karisimbi drilling we know that from the surface to 3000 m depth, the lithology of the area is characterised by the following different rock types: the top 60 m are basanite rock, from 60 to 1000 m Hawaiite and basanite rocks can be found, while the layer from 1000 m and deeper is made of granite rocks (Table 1). The geophysical surveys show a resistivity structure with a low resistivity anomaly interpreted as a mafic-magmatic heat source at a depth of 5000 m. Unaltered and un-fractured basement rocks, granites and fresh volcanic rocks have very high resistivity (Figure 3).

TABLE 1: Comparison of rock type discoveries from Karisimbi drilling and the estimate for the entire region (EWSA, 2014)

Depth (m)	KW01 rock type	KW02 Rock type	Estimate of the area lithology
0-56	K-basanite	Basanite	Basanite
56-156	Scoraceous basanite	Basanite and scoria	Basanite and scoria
156-180	Scoria of K-basanite	Basanite	Basanite
180-212	K-Hawaiite and K-basanite	Basanite	Hawaiite and basanite
212-325	Scoria of Hawaiite	Basanite	Hawaiite and basanite
325-334	K-Hawaiite	Basanite	Hawaiite and basanite
334-960	None	Scoria, Hawaiite, pyroclastic deposits, mugearite, Granite	Hawaiite, scoria and granite
960-3015	Granite	Granite (to bottom at 1367)	Granite

Figure 4 shows the resistivity map of the Kinigi area and Table 2 shows the potential energy in Kinigi area as estimated by JICA, 2014.

2.3 Design alternatives for geothermal wells

The geothermal well design includes the casing programme, i.e. the size of the borehole, casing diameters and depths, connections and type of steel. The design is influenced by the expected formation temperature and pressure, subsurface rock type and needed minimum temperature for the intended exploitation scheme.

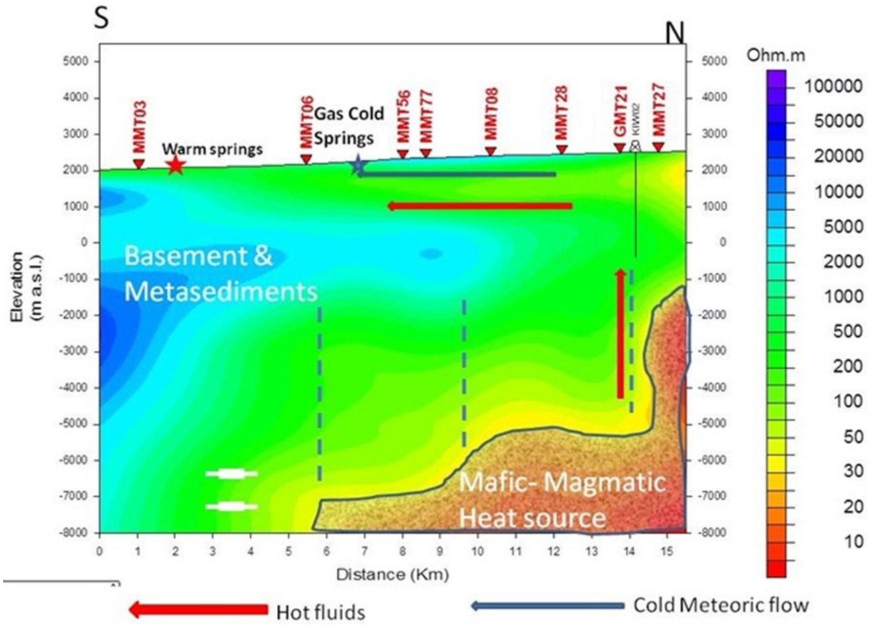


FIGURE 3: NS resistivity cross section showing a deep low resistivity interpreted as a mafic-magmatic heat source that is shallower to the north than the south (EDCL, 2015)

Secondary factors influencing the drilling programme are the availability of drilling rigs and drilling materials like drilling fluids, a drill string assembly, cementing materials and other necessary drilling tools and equipment.

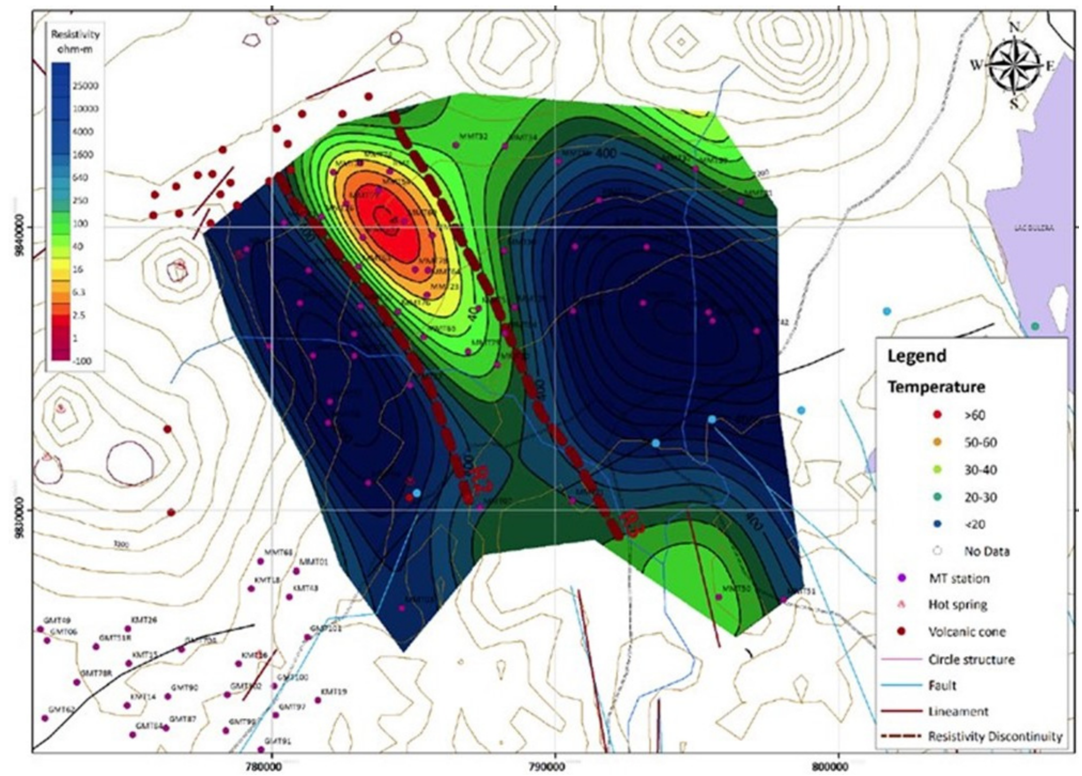
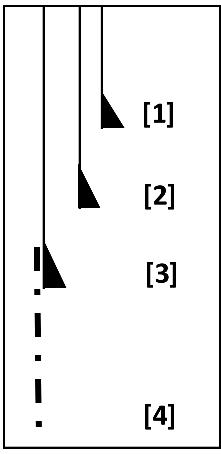


FIGURE 4: Estimated geothermal resource area extent in Kinigi prospect;
resistivity map at 3000 m (JICA, 2014)

TABLE 2: Summary of resource evaluation for 5 prospects of Rwanda (modified from JICA 2014)

Field name	**Potential energy (MWe) at 80% confidence level**	**Potential energy (MWe) at 50% confidence level**
Kinigi	32.6	58.6
Bugarama	6.6	15.1
Gisenyi	1.9	3.7
Karago	2.5	4.9
Iriba	3.7	7.2
Total	**47.3**	**89.5**

A typical geothermal well has 3 types of cemented casings with various diameters set at different depths: surface or conductor casing, anchor or intermediate casing, and production casing (Hole, 2008a). In the open hole section there is a slotted liner. In a hot water or two phase field with boiling conditions the maximum temperature is assumed to follow the boiling point depth curve (BPD). The pressure at depth and the boiling point is dictated by the water column (saturation pressure). Only a few reservoirs are filled with steam (vapour dominated). The casing depth must be set in order to seal off unwanted fluid with not high enough temperature, which for high-temperature wells is about 200°C. The rock competence and loss of circulation may also influence the casing depth. This rock competence often lies between the theoretically derived fracture gradient and a theoretical overburden pressure. This hypothetical situation of BPD in a 2,500 m deep well would require the production casing shoe being set at a depth of 800 m, the anchor casing shoe at 300 m depth and the surface casing shoe at around 60 m according to the African Union Code of Practice for Geothermal Drilling (African Union, 2016). The diameters for geothermal exploration wells are chosen considering the desired fluid flow and the annular clearances for the cementing of concentric casings. Generally, geothermal wells may be classified into four categories according to the casing programme diameter selection: regular, large, slim and cored (Figure 5).



CASING DIAMETER IN DIFFERENT GEOTHERMAL HOLES					
No		[1]	[2]	[3]	[4]
Name		Surface	Anchor	Production	Liners
Large holes	(inches)	26"	20"	13-3/8"	9-5/8"
	(mm)	660,4	508	339,73	244,48
Regular holes	(inches)	20"	13-3/8"	9-5/8"	7"
	(mm)	508	339,73	244,48	177,8
Slim holes	(inches)	13-3/8"	9-5/8"	7"	4-1/2"
	(mm)	339,73	244,48	177,8	114,3
Cored holes	(inches)	11-7/8"	8-5/8"	6-5/8"	4-1/2"
	(mm)	295,28	219,08	168,28	114,3

FIGURE 5: Possible casing programme for geothermal wells

3. WELL DESIGN

The African Union Code of Practice for Geothermal Drilling (African Union, 2016) indicates steps and requirements to be followed for well design in order to safely drill a successful and stable well. This code is based on the New Zealand Code NZS 2403:2015 and the steps include determination of expected geological formation, anticipated subsurface conditions, e.g. temperature versus depth, pressure versus depth, interval of lost circulation and anticipated problem zones, targeted well depth and wellhead location.

3.1 Anticipated subsurface conditions in Kinigi area

The volcanic area of Kinigi geothermal prospect is characterized by many caves, unconsolidated rocks and boulders in the top 100 m section. The water table is expected to be deeper or located between 200 and 300 m depth. This water level estimate for the first drill site in Kinigi is projected from the elevation of the nearest water body (Rugezi swamp) which is at 2050 m a.s.l. (Hategekimana and Twarabamenye, 2007) while the elevation of the drill site in Kinigi is at 2300 m a.s.l. The Karisimbi drilling showed the water level at 400 m with the well site elevation being 2622 m a.s.l. (EWSA, 2014). The elevation of the nearest water body (lake Kivu) was at 1460 m a.s.l.

A number of drilling challenges are expected during the drilling operation of the Kinigi area and the most likely include total loss of circulation, very low rate of penetration (ROP), difficulties in cleaning the hole and trouble during cementing or running the casing.

It is important to identify alternative actions in order to overcome these challenges and this report suggests some possible solutions; for instance the use of air hammer drilling technology for the surface casing (top 100 m), the use of Icelandic policy for loss of circulation and methods of cementing losses, procedures for casing cementing, how to maintain a clean hole when drilling blind (no circulation returns) and so on.

This programme is for exploratory wells which is the term used for the first 2-3 wells in a new field, therefore no data is available to support the prediction of important parameters, e.g. pressure and temperature vs. depth. For that reason, we assume that the subsurface fluid pressures are the hydrostatic values for a column of water at the boiling point (BPD) below the ground water level with no artesian condition (Africa Union, 2016). The assumptions for maximum subsurface temperature values follow saturation conditions for a column of boiling water below the same level defined by the pressure (Table 3).

TABLE 3: Standard hydrostatic pressures (gauge) and BPD temperatures for a column of pure water with no dissolved gas with water table at 200 m (African Union, 2016)

Hole depth	Hydrostatic fluid Pressure at 20°C	Hydrostatic fluid pressure at BPD	BPD temperature
(m)	(MPa)	(MPa)	(°C)
200	0.00	0.00	100
210	0.10	0.09	119
220	0.19	0.19	132
240	0.39	0.36	149
260	0.58	0.54	162
280	0.78	0.72	172
300	0.98	0.89	180
350	1.47	1.32	196
400	1.95	1.75	208
500	2.93	2.57	227
600	3.91	3.37	242
700	4.89	4.16	254
800	5.87	4.93	264
1000	7.82	6.43	281
1200	9.78	7.87	295
1400	11.70	9.26	306
1700	14.70	11.27	321
2200	19.60	14.40	339
2700	24.50	17.30	354
3200	29.30	19.90	365

3.2 Casing design

The target is to reach the low resistivity layer between 3 and 5 km as interpreted by JICA (2014) and thus the planned vertical depth for Kinigi exploration wells is 3000 m. While drilling deep wells, safety dictates that the wellbore pressure be maintained between the natural occurring pressure of the formation fluids and the maximum wellbore pressure that the formation can withstand without fracturing (Bourgoyne et al., 1986). The knowledge of how formation fluid pressure and fracture pressure vary with depth is extremely important for safe drilling of deep geothermal wells and serves as the basis for determination of minimum casing depths (Hole, 2008a).

In order to understand subsurface fluid pressure in a given area, ground elevations and previous geological processes must be considered. The pore pressure in a highly porous formation at depth, such as in a geothermal reservoir, is the same as the hydrostatic pressure which depends only on the depth and fluid density. With greater depth the porosity decreases due to high geostatic loads and the formation pore pressure increases but the hydrostatic equilibrium is maintained as the pores do not become geopressured.

For the formation pore pressure data to have the greatest utility, it must be available as early as possible. However, direct measurement of formation fracture pressure is only possible after a well has been drilled in the area. Therefore, general assumptions have to be made for the very first wells, which include the pore pressure following the boiling point depth (BPD) curve and the fracture pressure being equal to the overburden pressure. The older version of the New Zealand standard (NZS 2403:1991) considers only the overburden pressure, which depends on the soil density and that criteria has been in use for 30 years. The new version, NZS 2403:2015 (New Zealand Standards, 2015), which the AU standard is based on considers however the pore pressure following the BPD curve and the formation fracture pressure is considered instead of the overburden pressure. A comparison of results for calculations made based on both the African Union, 2016 code of practice and the old version of the New Zealand standard (1991) (NZS 2403:1991) will be given further in this section.

Conventional practice for drilling deep wells requires the setting of successive, separate casing strings as the well gets deeper. The length of each string is determined by several factors, including rock properties (fracture gradient, sloughing, swelling, unstable, or unconsolidated formation), formation fluids (pore pressure much less or much greater than drilling fluid pressure) and well control considerations (Finger and Blankenship, 2010). Therefore, the minimum casing shoe depth for each casing string is calculated to be at the depth where the geological formation has sufficient effective containment pressure (fracture pressure or overburden pressure) equal to the maximum design fluid pressure expected to be encountered in the next open hole section (African Union, 2016).

The basis of the maximum fluid pressure to be encountered in the open hole is a steam filled well from the total depth of that section where the starting pressure at bottom of the well is at the BPD curve hydrostatic fluid pressure (African Union, 2016).

Nevertheless, the actual casing shoe depth may be adjusted slightly deeper either to target the competent formation, to avoid the problem zones or to avoid any other conditions requiring more attention. The actual depth of the production casing shoe is very much dictated by the formation temperature which should be above 200°C in order for the wells to sustain stable self-flow. For the "regular" casing programme different hole sizes and casing shoe depths for different strings are presented in Table 4. Details on the casing design calculations will be given in the casing programme section.

TABLE 4: Well plan and planned casing shoe depths for Kinigi exploration wells

Casing sections	Minimum shoe depth (m)	Hole diameter (inches)	Casing diameter (inches)
Surface	100	26	20
Anchor	450	17-1/2	13-3/8
Production	1230	12-1/4	9-5/8
Liners	3000	8-1/2	7

The formation fracture pressure in Kinigi area is not yet known. For this reason the formula of Eaton (1969) was used and later different depths for casing shoes were determined as shown in Figure 6. Thus, the hydrostatic pressure in the BPD curve serves as the lower margin of the minimum casing shoe as observed in Figure 6, while the maximum (containment pressure or formation fracture pressure (African Union, 2016)) serves as the upper margin. The old version of the New Zealand standard (NZS 2403:1991) stipulates to use the hydrostatic pressure at 20°C as lower margin and the overburden pressure curve as upper margin.

$$P_{frac} = P_f + \frac{V}{1-V}(S_V - P_f) \tag{1}$$

The overburden pressure $p(z)$ (Bourgoyne et al., 1986)) is calculated according to the formula below:

$$p(z) = p_0 + g\int_0^z \rho(z)\mathrm{d}z \tag{2}$$

where $\rho(z)$ is the density of the overlying rock at depth z, g is gravity and p_0 is the datum pressure or pressure at the surface.

The new African Union Code of Practice for Geothermal Drilling (2016) stipulates techniques to be followed while designing the casing programme and Figure 6 shows the theoretical minimum depth of casing shoes for Kinigi exploration wells.

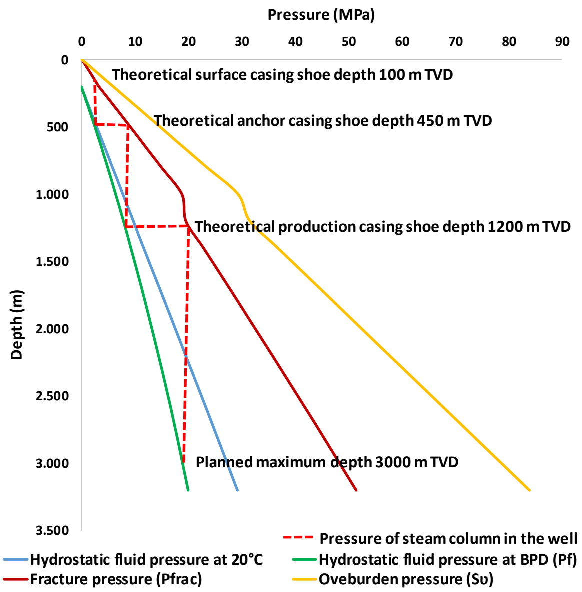


FIGURE 6: Minimum casing shoe depth for Kinigi area calculated using AU (2016) code of practice

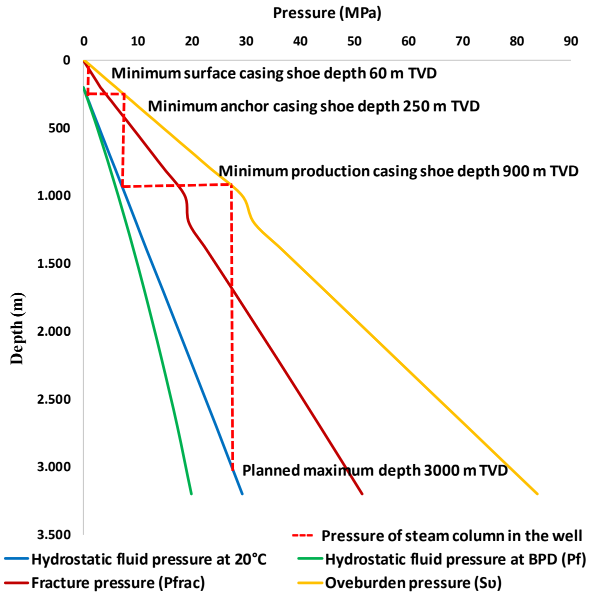


FIGURE 7: Comparative casing shoe depth set as stipulated by the NZS 2403:1991 code of practice (New Zealand Standard, 1991)

For comparison, results obtained by the method of the old New Zealand standards (NZS 2403:1991) for Kinigi area are shown in Figure 7. It is clear that this old method would set the minimum casing shoe depth at the slightly shallower levels. For instance, the production casing shoe would have been set to a depth of approximately 900 m, the anchor casing shoe to 250 m and the surface casing shoe to 60 m.

Comparing the results of the two methods, the old version of the New Zealand standard (NZS 2403:1991) set cemented casing strings at shallower depths and that can play a part financially (the cost of casing and materials) and also technically because short casing strings are more resistant to loads but their minimum setting depths are likely to be above the cold aquifer and thus would produce cooler fluids. Nevertheless, both methods, the NZS 2403:1991 code of practice and this new African Union code of practice, set minimum casing shoe depths theoretically and each has advantages and disadvantages.

3.2.1 Tackling anticipated drilling challenges in the surface casing section (0-100 m)

Considering the anticipated subsurface conditions in the Kinigi area which are volcano boulders, hard and unconsolidated rocks and total loss of circulation, alternatives to conventional rotary drilling are explored in order to see if any of them can help to overcome or alleviate these challenges. In such formations, it is advisable to apply percussion drilling because this technology presents advantages compared to rotary drilling. Air hammer technology (DTH) is probably the most versatile percussion drilling method available because it can be used in medium to hard rock formations where rotary drilling has been slow. Its benefits are directly linked to the increased rate of penetration (ROP) at the shallow depth where the weight on bit (WOB) is still low where it can even be five or seven times faster than conventional rotary drilling (Bar-Cohen and Zacny, 2009). Large fluid losses in the cavities expected are less of a problem by drilling with foam.

The use of DTH hammer does not require large rigs and sometimes pre-drilling or pre-holing for the surface casing is done before the large rig is brought in. Another advantage is the low water consumption which is only to prepare drilling soap to create the required foam to bring out the cuttings. However, every technology has its own pros and cons and air hammer drilling also has some drawbacks associated with pneumatic drilling including its use at increased drill depth, hole deviation, dust etc. (Thompson, 2010).

3.2.2 Tackling anticipated drilling challenges in the anchor casing section (0-450 m)

Anticipatively, this section will be characterised by big caves and total loss of circulation. Drilling with air hammers (DTH) is a possibility worth considering as the water table is low. If that does not succeed it is easy to switch over to conventional rotary drilling with mud or water. For large losses sweeps of foam at every joint will be applied but if the loss is not healed after 10-30 m then a cement plug job will be required as a solution. Large loss zones have been proven to be difficult to heal and a novel method used in Iceland may need to be applied. A mixture of sand and cement from a ready-mix truck is placed in the well using concrete pumps from the construction industry.

Cementing the anchor casing, with expected caves and loss zones, will require much care in planning and application of the most suitable method. A common method is to cement in the conventional way by pumping through the casing and up the annulus but only enough to reach the loss zone and then revert to a top-job to fill the annulus. A full reverse circulation of cement technique (RCC) has several advantages compared to conventional practices (Wreden et al., 2014). While using this technique, the fluids are pumped into the annulus of the well and water returns are taken through the casing. Benefits of this technique include: lowering bottom-hole placement pressure, reducing cement retarder concentration, lowering the time for cement placement etc. (Davis et al., 2004). Scenarios of different methods and calculations of slurry quantity to be used will be presented in the section on the cementing programme.

3.3.3 Tackling anticipated drilling challenges in the production casing section (0-1,230 m)

This is the most troublesome section where different drilling challenges are expected, e.g. loss of circulation, hole instability, risk of stuck drill string, low ROP and hole cleaning. Cementing this section is also very problematic but the cementing programme section will describe alternative methods to use. Issues related to well cleaning in the production casing section was observed in Karisimbi (EWSA, 2014) and in Kinigi, there is high expectation of facing similar nightmares. The section on drilling fluid will put more light on fluid to use, lag time for the travel of casing and so on.

3.3.4 Tackling anticipated drilling challenges in the slotted liners casing section (0-3,000 m)

The main drilling issues to be expected in this particular section is low rate of penetration (ROP) due to an extended granitic layer, hole cleaning etc. Other issues may be dealt with by improved drilling parameters but the granitic layer cannot be drilled with a tricone bit for more than 100 m before wearing out. Unless the permeability is greater and the formation temperatures higher the formation will be similar to the one observed at Karisimbi (EWSA, 2014). Because of the Karisimbi results there is a possibility that the basement formation in the Kinigi area is also made of granite and drilling into the basement will not result in a productive geothermal well, but only drilling will tell.

4. CASING PROGRAMME

A casing string is designed from the bottom to the top and from the innermost casing to the outside ones (Hole, 2008a). In general, casing sizes are chosen taking into consideration a number of factors, e.g. expected down hole pressure, economical objectives, pumping capacity, prevention of collapse or burst, buckling or any other deformation, support drilling and permanent wellheads, control contaminations from aquifers, counter circulation losses during drilling and protection of the integrity of the well against corrosion, erosion or fracturing (African Union, 2016).

In order to choose the right steel grade for the casing string, one has to be very careful considering the fact that casing was initially designed for the petroleum industry where parameters like fluid pressure, casing weight and tensile loads have to be taken into account. In geothermal wells, the most severe service is high temperature loading (Hole, 2008a).

In this section, generic case methods for calculation of the design or safety factors of the casing string will be used. All calculations will be defined to find the minimum design factor below which every casing string is at high risk of damage and the maximum design line above which every casing string is an economical waste because of much unnecessary investment. Therefore, any casing design between the two lines is considered to be safe but field data update will be necessary to make precise decisions between the two limits. Figure 8 shows theoretical casing strings for geothermal exploration wells in Kinigi with depth of casing shoes, diameter of various casings and the cementing job.

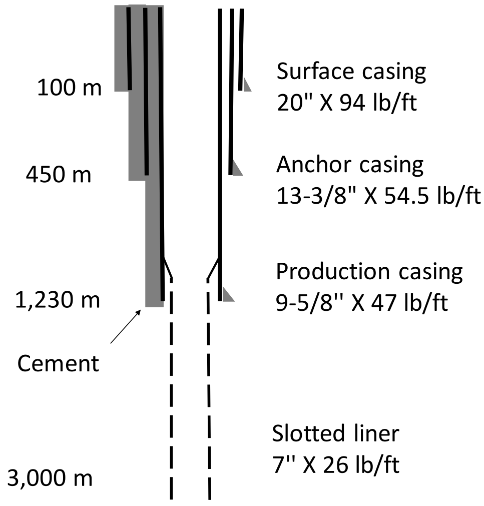


FIGURE 8: The proposed casing program for exploratory wells in Kinigi

4.1 Casing design factor calculation formulas as per the African Union code (2016)

The casing design factors are calculated in order to ensure that the casing will withstand all anticipated stresses. Among those stresses we include: radial and circumferential stress, uniform axial stress due to all sources except bending, axial bending stress for a Timoshenko beam and torsional shear stress due to a moment aligned with the axis of the pipe (African Union, 2016).

The axial stress in casings is caused by three main parameters: the weight of the casing, the temperature (expansion and contraction) and restraint due to cement or connection at the wellhead or downhole hanger. African Union (2016) stipulates that casing stresses have to be assessed either by calculating each individual stress or calculating the triaxial stress using API TR 5C3 or equivalent methods. The triaxial stress calculation combines all the stresses acting on the casing. The scope of this report will be limited to the method which uses the calculation of each individual stress. While checking the axial stress, it is paramount to separate two sets of conditions, namely before and after cementing the casing (Hole, 2008a).

4.2 Axial stress conditions

4.2.1 Axial loading before and during cementing the casing

Before the cement sets in the annulus around the casing, the tensile force at any depth includes the weight of the casing in air plus the weight of the casing contents minus the buoyancy effect due to any fluid displaced by the casing in the well (African Union, 2016).

$$F_{\text{hookload}} = F_{\text{csg air wt}} + F_{\text{csg contents}} - F_{\text{displaced fluids}} \tag{3}$$

and

$$F_{\text{csg air wt}} = L_z \times W_p \times g \times 10^{-3} \tag{4}$$

$$F_{\text{csg content}} = \sum \rho_{\text{if}} \times L_{\text{if}} \times \frac{\pi d^2}{4} \times g \times 10^{-6} \tag{5}$$

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

Negative $F_{hookload}$ means that the casing is floating and steps should be taken to hold the casing down against this floatation. Buoyancy force ($F_{buoyancy}$) is the difference between air weight of the casing ($F_{csg\ air\ wt}$) and the hook load ($F_{hookload}$) (African Union, 2016):

$$F_{buoyancy} = F_{hookload} - F_{csg\ air\ wt} = F_{csg\ contents} - F_{displaced\ fluids} \tag{7}$$

The buoyancy force is considered to be applied as a point load at the depth within the casing that is holding differential pressure either at the float collar, float shoe or at the surface (Hole, 2008b). Thus, prior to cement setting the tensile force applied at any point in the casing under hydraulic and gravitational loads is defined as:

$$F_p = [L_z W_p - (L_z - L_w) A_p / n] g \tag{8}$$

Nevertheless, the above tensile force does not include any stress which may be due to bending.

In non-vertical hole, the maximum bending stress induced is:

$$f_b = 0.291 \times E \times q \times D \times 10^{-6} \tag{9}$$

This stress is applied both as additional compressive stress and additional tensile stress. These additional stresses have to be added to the casing stress created by weight, hydraulic loads and thermal loads (African Union, 2016).

Where the axial loadings before cementing can occur simultaneously they have to be added together and the resultant maximum axial load checked against the minimum tensile strength of the casing. The design factor applied to this is 1.8 and is given by the following formula (African Union, 2016):

$$\text{Design factor} = \frac{\text{minimum tensile strength}}{\text{maximum tensile load}} \tag{10}$$

4.2.2 Axial loading after cementing the casing

According to African Union 2016 code of practice, axial forces imposed after cementing have to be checked for applicability and magnitude near both the shoe and the top of the casing. And to calculate the resultant net force, each of the loadings have to be combined with the static force present in the casing (F_p) at the time of cement setting. Hole (2008b) suggests that thermal stress can be calculated using the coefficient of thermal expansion and estimated temperature difference but it is worth to consider that due to cement constraints, the casing is forced back to the original length by axial compression (modulus of elasticity). Stress from thermal expansion, for example a temperature change of 150°C, can be calculated as follows (Hole, 2008b):

$$\begin{aligned} \text{Unit extension} &= \text{strain} = \text{coefficient} \times \text{temperature change} \\ &= 12 \times 10^{-6}\ °C^{-1} \times 150°C = 1.8 \times 10^{-3} \end{aligned} \tag{11}$$

$$\text{Stress} = \text{modulus} \times \text{strain} = (200 \times 10^3) \times 1.8 \times 10^{-3} = 360\ \text{MPa} \tag{12}$$

The total axial stress in a cemented string varies with depth and with the difference in temperature at any time between the time when the casing was fixed in position (neutral temperature value) and the temperature at any subsequent time (Hole, 2008b). Stress relaxation will occur if the steel is loaded at high temperature over a long period of time. Further stresses also may be induced if the geological formation in the place is faulting or moving by subsidence (Hole, 2008b). The compressive force due to temperature rise in the situation of partial longitudinal and lateral constraint is given by:

$$F_c = C_t (T_2 - T_1) A_p \tag{13}$$

$$C_t = E \times a = 200 \times 12 \times 10^{-6} = 2.4\ MPa\ per\ °C \tag{14}$$

The tensile loading as calculated for the pre-cementing time remains in the casing even after cement set. Therefore, the resultant axial force F_r on the casing after cement set and heating is given by (African Union, 2016):

$$F_r = F_c - F_p \tag{15}$$

The design factor is given by:

$$\text{Design factor} = \frac{\text{minimum compressive strength}}{\text{resultant compressive force}} \tag{16}$$

The minimum strength refers to the lesser of the strength of the pipe body or connection. In any means the design factor may not be less than 1.2 (African Union, 2016).

One of the main causes of casing failure is rapid cooling of the well, therefore cooling of a hot hole for any reason whether subsequent drilling activities, pumping tests or reinjection must be done in accordance with a strict well quenching and cooling programme thus allowing the stress to be uniformly distributed over the full length of the casing (Hole, 2008b). As the temperature rises it causes a compressional force. Cooling exerts tension to the casing, therefore the axial tension is calculated ignoring any relaxation of stress with time due to temperature reduction caused by circulation of cooling fluids. This axial tension is given by the following formula (African Union, 2016):

$$F_t = E \times a \times (T_1 - T_3) \times A_p \times 10^{-3} \tag{17}$$

At every other depth except the wellhead, the resultant force is given by (African Union, 2016):

$$F_r = F_p + F_t \tag{18}$$

The tensile axial loading of the top section of the casing due to lifting forces applied by the fluid to the wellhead is given by the formula below (African Union, 2016):

$$F_w = \left(\frac{\pi}{4}\right) \times P_w \times d^2 \times 10^{-3} - F_m \tag{19}$$

The design factor for all axial tensile and compressive loading may not be less than 1.2 (African Union, 2016).

4.2.3 Axial loading with buckling and bending

The perforated liners in the production section are not cemented and thus radially neither supported nor constrained. However, instead they must either be hung in tension on a liner hanger just above the production casing shoe or sat at the bottom of the hole with their top part sitting freely inside the production casing shoe (Hole, 2008b). In the case of the liner sitting at the bottom of the hole, it is subjected to axial self-weight compression and helical buckling and therefore must be analysed for extreme fibre compressive stress. Hole (2008b) provided the following formula for calculating this compressive stress in liners:

$$f_c = L_z \times W_p \times g\left[\frac{1}{A_p} + \frac{D \times e}{2I_p}\right] \tag{20}$$

The ratio of the hole diameter to the pipe diameter (eccentricity) determines the amount of bending and thus the bending stresses. The eccentricity e is around 1.5 times the bit diameter depending on the formation integrity and the design factor which has to be always less than 1.2 and is given by African Union (2016) as:

$$\text{Design factor} = \frac{\text{minimum yield stress } \times R_j}{\text{total compressive stress}} \tag{21}$$

R_j is the connection joint efficiency and should not exceed 1.0, but when the listed joint efficiency exceeds 1.0 it is ignored in the formula above (Hole, 2008b).

The ability of a casing string to resist loads is governed by the steel grade (which prescribes its strength), the type of connections, and the loading condition at the neutral temperature state. Since high strength steels are susceptible to corrosion due to H_2S in geothermal, API Grade K-55 and L-80 grade steels are typically utilized, manufactured according to API 5CT (API, 2005). Regarding connections, geothermal service requires a square thread form or shouldered connections to transfer the full axial loading of the pipe body. API buttress threads and various proprietary square threaded connections have been found to be suitable (Hole, 2008a).

4.3 Radial stress conditions

Hoop or circumferential loadings are applied primarily by internal or external fluid pressure. The ability of tubulars to resist differential pressures take into particular consideration the pressure that occur before and during cementing operations, and well fluid pressure in the static condition or when producing or reinjecting (Hole, 2008c). The African Union (2016) code of practice stipulates that hoop stresses which are exerted to the casing from any source have to be considered. Among the sources of hoop stress, there is pressure difference between inside and outside casing before and during cementing, well fluid pressures in static conditions or when producing or injecting, temperature changes with restraint on movement, heating of a confined liquid and dynamic loading.

4.3.1 Internal yield bursting

The casing design must ensure that adequate safety margins exist against internal yield or burst which could result from high internal fluid pressure due to a range of situations that occur during and after the cementing of casing. Those situations include but are not limited to: surface pressure plus a static fluid column, thermal expansion of trapped liquid, well pressures generated from the formation and any combination of the above (African Union, 2016). The maximum differential burst pressures usually occur near the casing shoe or stage cementing collar ports and will apply in one of the cases below:

- The casing is filled with high density cement slurry;
- The annulus is either completely filled with water back to the surface or partially filled with water as controlled by formation pressure; and
- A restriction within the casing, such as a blocked float valve or a cementing plug which will hold the differential pressure.

This last scenario is not a likely situation but it is possible, and it must be looked at as a worst case scenario. The differential burst pressure in this case is the hydrostatic pressure inside the casing at the casing shoe caused by the cement slurry plus any applied pumping pressure minus the hydrostatic pressure in the annulus at the casing shoe caused by the head of water in the annulus (Hole, 2008c).

$$\Delta P_{internal} = [(L_f \rho_c - L_f \rho_f)] \times g \times 10^{-3} \tag{22}$$

The design factor is given by the formula below and may not be less than 1.5:

$$\text{Design factor} = \frac{\text{casing internal yield pressure}}{\text{differential burst pressure}} \tag{23}$$

Once the cement has been successfully displaced to the annulus and the well completed, the maximum differential internal pressure will occur at the surface. Two scenarios are possible:

1) With steam at the wellhead, the design factor will be given by the formula below and may not be less than 1.8 (African Union, 2016):

$$\text{Design factor} = \frac{\text{casing internal yield pressure} \times R_i}{\text{maximum wellhead pressure}} \tag{24}$$

2) With cold gas at the wellhead, when the stress corrosion tensile limit of the steel should be used to determine the appropriate yield strength (African Union, 2016).

If the wellhead is fixed to the casing, a biaxial stress condition exists. The combined effects of axial tension and radial burst stress caused by the lifting force of the wellhead pressure has to be calculated with the following expression (African Union, 2016):

$$f_t = \frac{\sqrt{5}}{2} \times \left(\frac{P_w \times d}{D - d}\right) \tag{25}$$

The design factor is given by:

$$\text{Design factor} = \frac{\text{steel yield strength}}{\text{maximum tensile stress}} \tag{26}$$

The top section of the anchor casing from the surface to around 25 m depth also requires design compliance with the ASME Boiler and Pressure Vessel Code (Hole, 2008b).

4.3.2 Hoop stressing – collapse

The casing design has to ensure an adequate safety margin against pipe collapse due to external pressure from entrapped liquid expansion, applied pressure during pumping, and/or static pressure from a dense liquid column such as cement slurry. Typically, the maximum differential external pressure occurs near the casing shoe when the annulus is filled with dense cement slurry, and the inside of the casing is filled with water (African Union, 2016). The maximum differential external pressure is:

$$\Delta P_{external} = [L_z \rho_c - L_z \rho_f] \times g \times 10^{-3} \tag{27}$$

The design factor which may not be less than 1.2 is given by:

$$\text{Design factor} = \frac{\text{casing external collapse pressure}}{\text{net external pressure}} \tag{28}$$

Hole (2008b) emphasized that large diameters and especially thin walled surfaces and intermediate casings are the most vulnerable to this mode of failure.

During 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 approach the operating wellhead pressure. The design factor is (African Union, 2016):

$$\text{Design factor} = \frac{\text{pipe collapse pressure}}{\text{differential external pressure}} \tag{29}$$

4.3.3 Thermal expansion of trapped fluid

Since the bulk modulus of thermal expansion of water is not constant, particularly at low temperatures and pressures, the effect of heating water in a confined space is best calculated by reference to steam tables, using a constant specific volume. However, at temperatures above 100°C, the resulting pressure rise due to change in temperature approximates to 1.6 MPa/°C (Hole, 2008b).

For instance, the rated collapse pressure of 9-5/8" 47 lb/ft Grade L-80 casing is 32.8 MPa. Assuming an event where a volume of water is trapped between an outer casing and the 9-5/8" casing, the collapse pressure of the 9-5/8" casing would be reached with a temperature rise of less than 20.5°C, although a large volume of trapped water would be required to deform the pipe until failure (Hole, 2008b).

If the temperature rises from a nominal neutral temperature of 80°C to a formation temperature of 240°C which is the typical case, the maximum pressure being possibly built up from the thermal expansion of a trapped volume of liquid between casings exceeds the strengths of normal casings strings resulting in either burst or collapse (Hole, 2008b).

Due to the importance given to the integrity of the production casing string, it is desirable that any failure should occur in the outer string. For this reason, the final pair of cemented casings has to be designed in the way that the collapse resistance of the inner string should exceed the burst resistance of the outer string with a design factor greater than 1.2. This factor is calculated by the following formula (African Union, 2016):

$$\text{Design factor} = \frac{\text{production casing collapse strength}}{\text{outer casing burst strength}} \tag{30}$$

The added resistance to 'burst' provided by the cement sheath is to a degree countered by the secondary stressing effects of the thermal axial compression, which tends to reduce the resistance to burst and increase the resistance to collapse. For the purposes of design calculations and in the interests of conservative design, this support provided by the cement sheath is ignored (Hole, 2008b).

4.4 Casing design calculation results for Kinigi exploratory wells

4.4.1 Axial loading before and during cementing

While running the casing and cementing just before the cement set, axial forces (tensile) develop and apply to the casing string. The drilling fluid in the well is basically a mixture of water and mud, let's assume the case of hot water at 50°C and apply a buoyancy factor due to its density. The density of the drilling fluid in the well is assumed to be 988 kg/m^3. Table 5 below shows the calculated design factor for the casing programme in Kinigi exploratory wells. All results are based on assumptions which must be updated when the data from drilled wells will be available. It is clear that the axial forces increase with the length of the casing and the safety factor also slightly decreases.

TABLE 5: Axial forces on casing string before and during cementing

CSG Grade K55	lb/ft	Length (m)	$F_{csg\ air\ wt}$ (kN)	$F_{csg\ contents}$ (kN)	$F_{displaced\ fluids}$ (kN)	$F_{hookload}$, F_p (kN)	Min. tensile strength (kN)	Cal DF	Min DF
20"	94	100	137	180	196	120	11,375	94.5	1.8
13-3/8"	54.5	450	358	352	395	314	6,556	20.9	1.8
9-5/8"	47	1,230	844	444	546	742	5,735	7.7	1.8

4.4.2 The axial loading after cementing

Axial load after the cement set may rise due to temperature increase or when cold water is pumped into the well. An increase in temperature results in compressive forces while a decrease of temperature results in tensile forces. Apart from these two possible forces, eventual bending of the borehole also exerts force on the casing string.

Table 6 shows assumptions made on temperatures, both the initial neutral considered to be in the well at the time of cement set (T_1) and the expected maximum (T_2) which might vary at the bottom of every casing. The thermal expansion is assumed to be 13×10^{-6} and the negative sign (-) shows that these are compressive forces. Results show that the higher the temperature the higher the risk. In the production casing for instance the safety factor reaches the threshold when T1 and T2 are assumed to be 80 and 227°C, respectively.

TABLE 6: Axial forces on casing string after cementing due to rise in temperature

CSG GRADE K55	lb/ft	E (GPa)	a (°C^{-1})	T1 (°C)	T2 (°C)	Ap (m^2)	Compres-sive force, Fc (kN)	Resulting force, Fr (kN)	Min compressive strength (kN)	Cal DF	Min DF
20"	94	210	13x10^{-6}	30	120	0.017	- 4,147	-4,146	-6,582	1.6	1.2
13-3/8"	54.5	210	13x10^{-6}	50	160	0.010	- 3,006	-2,691	-3,793	1.4	1.2
9-5/8"	47	210	13x10^{-6}	75	220	0.009	- 3,466	-2,724	-3,318	1.2	1.2

Table 7 shows tension forces resulting from a cooling fluid circulating in the hole either during drilling, testing or reinjection. Assuming that the cooling fluid is at ambient temperature of 25°C, the bottom hole temperature is assumed to be 30°C, 50°C and 75°C for respective casing strings from the surface. Results show that casing strings are robust for the assumed temperature changes. However, if the initial temperature T1 is assumed to be 120°C and the temperature of the cooling fluid T2 20°C the production casing safety reaches the minimum values.

TABLE 7: Axial forces on casing after cementing due to cooling fluid or decrease in temperature

CSG Grade K55	lb/ft	E (GPa)	a (°C^{-1})	T1 (°C)	T2 (°C)	Ap (m^2)	Compres-sive force, Fc (kN)	Resulting force, Fr (kN)	Min compressive strength (kN)	Cal DF	Min DF
20"	94	210	13x10^{-6}	30	25	0.017	237	237	11,375	32	1.8
13-3/8"	54.5	210	13x10^{-6}	50	25	0.010	683	998	6,556	6.6	1.8
9-5/8"	47	210	13x10^{-6}	75	25	0.009	1,195	1,937	5,735	3.0	1.8

After the well has been completed, the wellhead is supported by the anchor casing. Therefore, the lifting forces may be exerting to the casing string due to fluids in the well. Table 8 shows calculated forces under the maximum working pressure tolerable to the wellhead fitting (20.7 MPa) with such casing diameters as suggested by the African Union 2016 code of practice. The weight of the wellhead considered here is six tons for the Christmas tree. Tests were made with 4 tons and 8 tons which proved that the greater the weight, the higher the downward forces and thus the smaller the safety factor. Additionally, the maximum wellhead working pressure must be considered carefully since great pressure reduces the safety factor.

TABLE 8: Tension on top of the casing anchoring the wellhead

CSG Grade K55	lb/ft	P_w (MPa)	d (m)	Xmass tree weight (Tonnes)	F_m (kN)	Tension force at top F_w (kN)	Min tensile strength (kN)	Cal DF	Min DF
13-3/8"	54.5	20.7	0.32	4	39	1,629	6,556	4.02	1.8
				6	59	1,609	6,556	4.07	1.8
				8	78	1,590	6,556	4.12	1.8

4.4.3 Radial stress conditions

After drilling the well to the target depth, slotted liners are run to allow geothermal fluid to flow through the well to the surface through the production casing. Liners are often hung in the production casing, therefore they are subject to compressive forces due to axial self-weight and helical buckling. Table 9 below shows the calculated compressive forces as f_c (kN) and the calculated design factor is also shown from top, middle and bottom of the liners. Hanging the liners inside the production casing reduces the compressive forces exerted at the bottom and thus increases the design factor. For instance, if the bottom of liners was set to 1750 m the calculated design factor (DF) would be 2.78 instead of 2.70 at 1800 m. Values for the moment of inertia are calculated as for a hollow cylinder and the eccentricity is assumed for the worst case where the liner is lying aside which is given by hole inside diameter (ID) minus liner outside diameter (OD).

TABLE 9: Compressive stress in the un-cemented liner due to axial weight and helical buckling

lb/ft	Layers	Depth of liner L_z (m)	W_p (kg/m)	g (m/s^2)	A_p (m^2)	D (mm)	e (mm)	I_p (kgm^2)	f_c (kN)	Min yield stress (MPa)	Cal DF	Min DF
	Top	10	38.7	9.81	0.005	177.8	38	1,986	779	379	486	1.0
26	Middle	900	38.7	9.81	0.005	177.8	38	1,986	70,147	379	5.4	1.0
	Bottom	1,800	38.7	9.81	0.005	177.8	38	1,986	140,293	379	2.7	1.0

Table 10 shows the maximum burst pressure for all casing strings from surface to bottom. For each casing the burst pressure and design factors are calculated for three different points, the bottom, middle and top 10 m of the casing. Assumptions are made for the case of the casing being filled with cement slurry of 1.87 kg/l density and the annulus is filled with water at 50°C and of 0.988 l/kg mean specific volume.

TABLE 10: Maximum differential burst pressure of casing near shoe or stage cementing ports

CSG Grade K55		Length of casing L_z (m)	Slurry density ρ_c (kg/m)^3	Fluid column in casing L_f (m)	Density of water ρ_f (kg/m^3)	g (m/s^2)	Differential burst pressure Δpi (kPa)	Internal yield pressure (MPa)	Cal DF	Min DF
	Top	10	1,870	10	988	9.81	86.5	14.5	167.6	1.5
20"	Middle	50	1,870	50	988	9.81	432.6	14.5	33.5	1.5
	Shoe	100	1,870	100	988	9.81	865	14.5	16.8	1.5
	Top	10	1,870	10	988	9.81	86.5	18.9	218.4	1.5
13-3/8"	Middle	225	1,870	225	988	9.81	1,947	18.9	9.7	1.5
	Shoe	450	1,870	450	988	9.81	3,894	18.9	4.9	1.5
	Top	10	1,870	10	988	9.81	86.5	32.5	375.6	1.5
9-5/8"	Middle	615	1,870	615	988	9.81	5,321	32.5	6.1	1.5
	Shoe	1230	1,870	1230	988	9.81	10,642	32.5	3.1	1.5

Table 11 shows collapse pressure and design factors for all cemented casing strings taking into consideration the top 10 m, the middle and the shoe of the casing as reference points. Assumptions made here are the casing being filled with water at 50°C (988 kg/m^3 specific volume) while the annulus is filled with cement (1870 kg/m^3 density). Assumptions in the worse scenario would be that the annulus is empty due to total loss of circulation and the casing is full of cement (inner-casing cementing is reported in appendix). Of course that scenario is placed above the water table and the internal differential forces increase dramatically but stay far below the internal yield so that the design factor is still safe.

During production operation, the worst condition that can occur are when the internal pressure at the casing shoe is approaching the wellhead pressure (P_z=P_f) or if the fluid inside the casing is pure steam. Table 12 below shows the calculated design factors for such a scenario and shows that the casing safety factor is 6.3. Assumption are made for the case of a wellhead operating at a pressure of 5 MPa but even though that pressure would be reduced to zero the casing can still hold because the calculated design factor should be 2.6 in such a case.

TABLE 11: Hoop collapse pressure during cementing

CSG Grade K55		**Length of casing L_z (m)**	**Slurry density ρ_c (kg/m^3)**	**Density of water ρ_f (kg/m^3)**	**g (m/s^2)**	**Differential pressure on casing Δ_{pex} (kPa)**	**Collapse pressure (MPa)**	**Cal DF**	**Min DF**
20" 94 lb/ft	Top	10	1,870	988	9.81	86.5	3.6	41.6	1.2
	Middle	50	1,870	988	9.81	432.6	3.6	8.3	1.2
	Shoe	100	1,870	988	9.81	865	3.6	4.2	1.2
13-3/8" 54.5 lb/ft	Top	10	1,870	988	9.81	86.5	7.6	90.1	1.2
	Middle	225	1,870	988	9.81	1,947	7.6	4.0	1.2
	Shoe	450	1,870	988	9.81	3,893.6	7.6	2.0	1.2
9-5/8" 47 lb/ft	Top	10	1,870	988	9.81	86.5	26.8	309.7	1.2
	Middle	615	1,870	988	9.81	5,321	26.8	5.0	1.2
	Shoe	1230	1,870	988	9.81	10,6642	26.8	2.5	1.2

TABLE 12: Hoop collapse pressure during production calculated for 13-3/8” casing with P_z=P_f.

BPD curve Pressure (P_f) (MPa)	**Min wellhead operating pressure (MPa)**	**Differential external pressure (MPa)**	**Casing collapse pressure at shoe (MPa)**	**Cal DF**	**Min DF**
9.26	5	22.6	26.8	6.3	1.2

5. DRILLING FLUIDS PROGRAMME

In order to specify and select drilling equipment (mud pumps and compressors), drilling fluids and hydraulics programmes, the programme needs to be prepared for each well section according to the bit sizes and depths. The programmes should consider at least the following aspects:

- The types of drilling fluids used and their properties;
- Minimum annular velocities necessary to ensure adequate removal of cuttings from the well;
- Pressure losses in the drill string and hole (for example, through the drill string, bit jets, annulus);
- Differential pressures between the circulating fluids in the well and the fluid pressures in the formations;
- Hydraulic horsepower requirements; and
- Ability to cool and quench the well.

The drilling fluid programme design aims to serve the following functions: cleaning the hole of cuttings, cooling the bit, lubricating the drill string, maintaining the stability of the borehole, helping to collect geological information, controlling the formation pressure, protecting the drilled formation from damage, supporting partial weight of the drill-string or casing, and transmitting hydraulic power to the bit and mud motor (African Union, 2016).

Successfully drilling a geothermal well is a critical task for both the service provider and the project developer. Many factors are involved and the focus of this chapter is on the use and importance of drilling fluids. Normally, each drilled section of the well is independent with regards to behaviour, drilling parameters and fluid specifications. Drilling fluids play a key role for the success of the drilling process and well cleaning and well stability are the most important aspects. Poor selection of drilling fluids both in quality and quantity may result in well collapse, a drill string getting stuck or even worse.

While designing the drilling fluids, a number of factors have to be considered, including the formation pressure, temperature and expected loss zones in the well. Apart from those technical consideration, the cost must be considered also because some fluids like air drilling package and foam seem to be more expensive.

5.1 Drilling fluid properties and reporting

Drilling fluid properties determine fluid behaviour in and outside the borehole. Simple field tests for viscosity and density help to understand the behaviour and to generate the mud report which includes additive inventory and cost among others. Appreciating the properties and changes that take place helps to predict the situation of the well (Chemwotei, 2011).

Basically, all drilling fluids have the same properties, only the magnitude varies. These properties include density, viscosity, gel strength, filter cake, water loss, pH value and electrical resistance. For the exploration in Kinigi, normal water based bentonite drilling fluid is planned to be used in the drilling programme. Each drilling section namely surface, anchor and production will have specific mud properties. The slotted liners section will be drilled with aerated water and sweeps of foam or hi-vis polymer pills.

5.2 Hole cleaning

The aim of hole cleaning is the transportation of all cuttings from the hole in a sufficient and fast way in order to avoid severe drilling challenges like, e.g. high torque which may lead to stem snapping, a stuck pipe which may lead to the loss of the stem, hole pack off, damaged formation, excessive over pull during trips and slow rate of penetration (Dayan, 2014). The well design sets 4 different drilling sections and each will be drilled with different bit size. The fluids to be used for each section are summarised here below.

5.2.1 The drilling fluid to be used while drilling the surface casing

This section is drilled with a 26” inch bit from surface to 100 m depth and the drilling fluid to be used is air with foam. The air hammer drilling (DTH) is the preferred drilling technique because of the challenges, which are expected in this section. The amount of drilling detergent needed for this section per well is estimated at 1000 l with reference to the Karisimbi drilling experience (EWSA, 2014) which used foam and a conventional tricone bit.

5.2.2 The drilling fluid to be used while drilling the anchor casing

This section will be drilled using bentonite based mud. Calculations shown in Table 13 estimate the amount of dry bentonite needed in tons and in total mud volume and the cartoon in Figure 9 shows how volumes were estimated.

TABLE 13. Estimated amount of bentonite required to drill 17-1/2” hole from 100 to 450m with 1.05 mud density

	Length (m)	**Capacity (l/m)**	**Amount (m^3)**
Mud tanks (~1/5)			30
20" csg. 94#/ft	100	185.32	18.5
17 1/2" bit	450	155.2	54
Theoretical volume			103
Excess, open hole 200%			109
Total slurry volume			211
Bentonite 5% by weight (T)			**11**

5.2.3 The drilling fluid to be used while drilling the production casing

This section is the longest to be drilled with mud in this programme. Figure 10 and Table 14 show mud volume and dry bentonite amount required for the process. The total amount of dry bentonite estimated for these two sections is 23 tons. We take into account the experience of KW01 where around 37 tons of bentonite were used to drill the whole well, even in the slotted liner section (EWSA, 2014). This estimation is pretty reasonable.

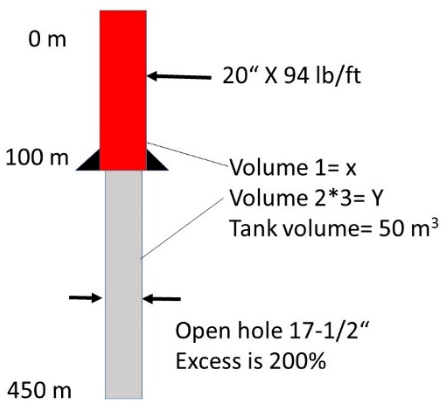


FIGURE 9: Estimated volume of mud required for anchor

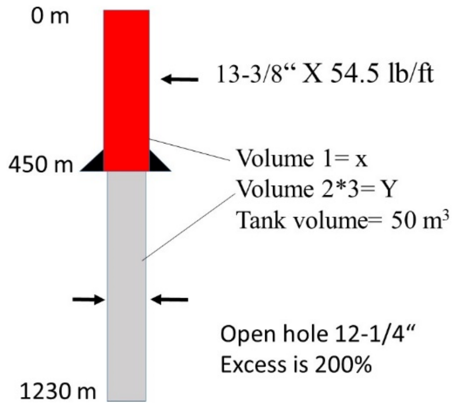


FIGURE 10: Estimation of volume of mud required for production

TABLE 14: Estimated amount of bentonite required to drill 12-1/4" hole from 450 to 1230 with 1.05 mud density

	Length (m)	**Capacity (l/m)**	**Amount (m^3)**
Mud tanks (~1/5)			30
13-3/8" csg. 54.5#/ft	450	80.64	36
12 1/4" bit	780	76.04	59
Theoretical vol.			126
Excess, open hole 200%			112
Total slurry volume			244
Bentonite 5% by weight (T)			**12**

5.2.4 The drilling fluid to be used while drilling the slotted liners section

In this section hole cleaning became very challenging while drilling KW01. At that point, even bentonite-based mud was used to attempt cleaning the hole (EWSA, 2014). Under normal circumstances that should be avoided because the mud cake could seal off the permeability which is highly needed for the well discharge and production. This is considered to be the reservoir section and every loss of circulation is considered as a good sign for future feed zone. To use mud could in some ways seal off the feed zones or at least reduce permeability. For the purpose of this drilling programme, no bentonite will be used in this section, instead aerated water and foam will be used and if that is not enough, sweeps with hi-vis polymers need to be considered as a contingency plan. Figure 11 and Table 15 show the calculation of the expected volume of drilling fluid in this section, the slowest lag time estimated may not be more than 35 min for a fluid to complete the trip to the total target depth of 3000 m.

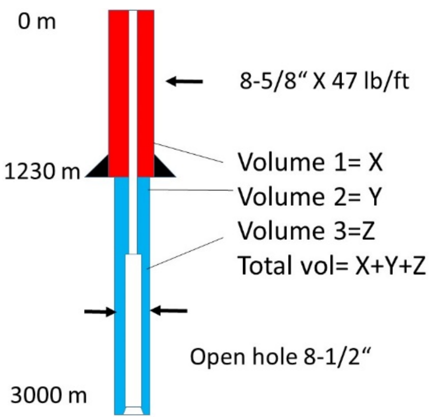


FIGURE 11: Lag time estimation for the slotted liner section

TABLE 15: Estimation of lag time for the last well section

	Length (m)	**Capacity (l/m)**	**Amount (m^3)**
9-5/8" x 47 #/ft, 3 1/2"DP	1230	24.9	31
8 1/2" hole, 5" DP	1597	23.3	37
8 1/2" hole, 6 3/4" DC	173	13.5	2
Total	**3000**		**70**
Pumping rate	35	l/s	
Lag time	35	min.	

6. CEMENTING PROGRAMME

According to African Union (2016), the cementing programme shall be designed and undertaken in a manner which is most likely to ensure that the total length of annulus outside the casing is completely filled with a good quality of cement from the bottom of the respective well section to the top. Therefore, the main objective of any casing cementing is to ensure that the total length of the annulus is filled with sound cement that can withstand long term exposure to geothermal fluids and temperatures (Hole, 2008c).

6.1 Cement slurry design and composition

Cement slurry design depends mainly on well information from logs and drilling operation. That information includes but is not limited to: temperature measurements, calliper logs and cement bond logs (Khaemba, 2014). Designing a cement slurry for a geothermal well requires careful choice of cement, fluid loss additives, dispersants, silica flour, extenders, bentonite, mica flakes, friction reducers, retarders or accelerators, defoamers and mix water.

A number of properties have to be considered before the slurry is pumped into the annulus: slurry density, yield (m^3/mT), thickening time, fluid loss (m^3/h), free water (%), test temperature, compressive strength and filtration. Standardized test are carried out in a cement lab either on site or at the cementing service provider.

The cement slurry appropriate for geothermal wells has to be either mixed from neat cement or from blended cement. Portland cement manufactured accordingly to API specifications like API class A or API class G are commonly used.

The high temperature environments of geothermal reservoir systems require the in-blending of additional materials to ensure longevity of the cemented casing (Hole, 2008c). The use of blast furnace slag with class A Portland cement blended in the ratio of 30:70 provides a highly corrosion resistant cement with enhanced mixing and pumping properties. Additives other than silica flour are retarders, friction reducers, fluid loss control agents, and free water additives like Wyoming bentonite, and mica (Hole, 2008c).

6.1.1 Hole and casing volume calculations

Calculation of the total cement slurry volume requires to break the hole into a series of volume components including: casing volume (interval between the float collar and top), shoe track (interval between casing shoe and float collar), rat hole (interval between total drilled depth and casing shoe basically 2-3 m), casing-open hole annulus (volume between new casing and the open hole; just from new casing shoe depth up to the casing shoe of the previous casing) and finally casing-casing annulus (the volume of the annulus where two casings fit one inside the other) (Hole, 2008c). Therefore, the total volume of the slurry to be pumped including the excess which varies from 100% to 150% due to well conditions is given by the formula:

$$\begin{aligned}\text{Volume} = \text{shoe track } &+ (\text{rat hole} + \text{casing open hole annulus}) \times (1 + \text{excess}) \\ &+ \text{casing casing annulus}\end{aligned} \tag{31}$$

6.1.2 Cementing equipment

For cementing the casing, a number of equipment is important and a distinction can be made between in-hole and surface equipment. In hole equipment also known as casing accessories (Hole, 2008c) is equipment specifically designed to enable the cement placement procedure to be carried out. The float collar is fitted to the casing shoe, which has a non-return valve in order to allow the flow of the slurry throughout the casing but prevents the flow from the well back into the casing at the end of the job. A float collar is fitted either between the first and second casing joint or between the second and third. It also has a non-return valve to ensure one-way flow of the slurry from casing to the annulus (Hole, 2008c). Other in hole equipment like casing centralisers, travelling plugs, string centralisers and tag-in adaptors for inner-string cementing are of great importance, too. On the surface, there is a cementing head for the casing or to connect to the drill pipes. Other important equipment is at the surface, including bulk pressure silos, cement mixing and pumping system just to name a few.

6.2 Cementing techniques

Casings in geothermal wells, unlike in oil and gas, are run back to the surface and are fully cemented back to the surface. This is mainly due to the high thermal stress imposed to the casing which requires a uniform cementation over its full length (Hole, 2008c). There are a number of techniques used for pumping the cement slurry into the annulus. In this section, three of them (casing cementing, inner string cementing and reverse circulation cementing) are discussed outlining the advantages of each method with regards to the situation in Kinigi and expected challenges.

6.2.1 Casing cementing

This technique involves pumping the cement slurry into the casing via a cementing head connected to the top of the casing and then at the end displacing the cement slurry from the casing into the annulus (Hole, 2008c). Travelling plugs are used to separate the cement slurry from the fluid in the casing and the displacement fluid. This technique can be carried out either in one stage or it can be done in two stages. This report will focus only on the single stage cementing as shown in Figure 12.

The procedure involves the casing string with all the required cementing accessories such as float collar,

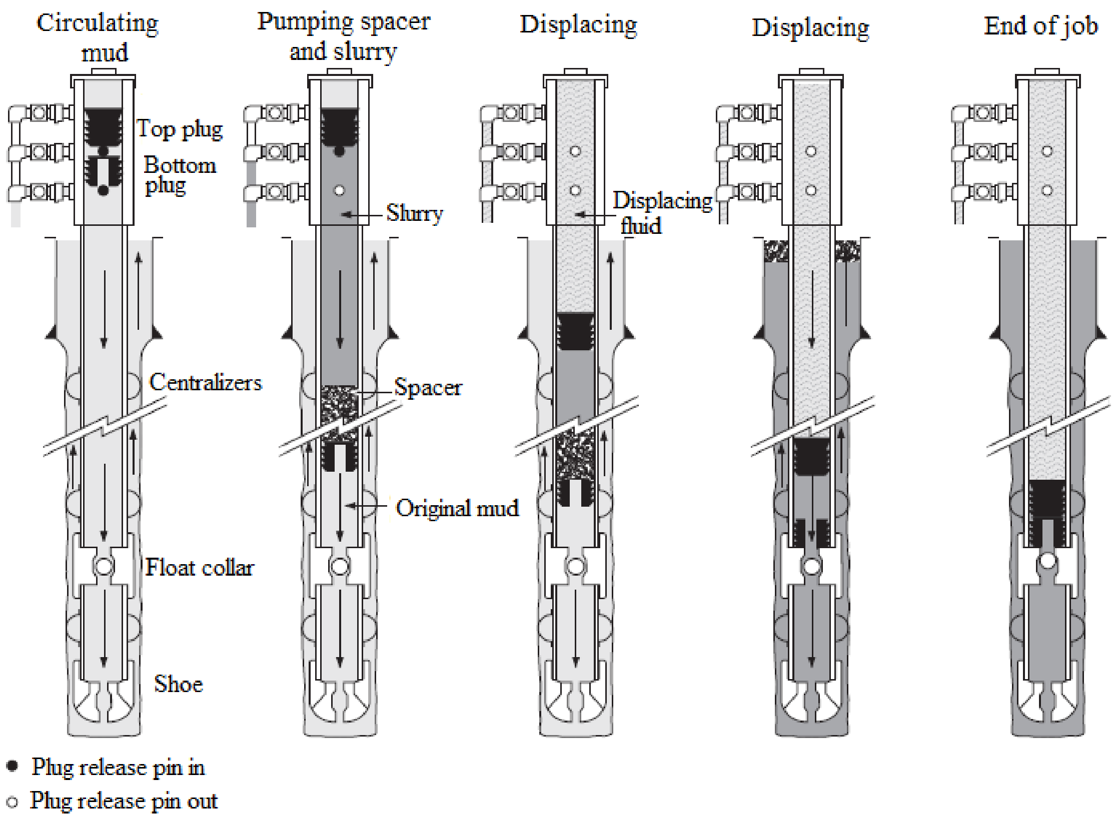


FIGURE 12: Through casing cementing single stage (Bett, 2010)

guide/float shoe and centralizers. The cementing head must be connected at the top of the casing so that cement plugs can be placed in the cementing head and released at the right moment (Khaemba, 2014).

For the success of the procedure of cementing, the well is cooled and cleaned by circulating water prior to slurry pumping. Then the bottom plug is released to wipe the casing clean and form a barrier between the spacer and the drilling fluid in the casing, followed by a spacer and then cement slurry (Khaemba, 2014). Once the bottom plug reaches the float collar, the diaphragm in the plug ruptures, allowing the spacer and slurry to flow through the plug, around the shoe and then up the annulus. The top plug is released at the end and displacing fluid is pumped. Once the plug reaches the float collar, it lands on the bottom plug and stops the displacement process.

6.2.2 Inner string cementing

When the casing has been run to depth, washed to bottom and the annulus has been circulated sufficiently, the casing is set in the rig rotary table and the inner cementing string is picked up; ran into the casing, and stabbed into the float collar receptacle (Hole, 2008c).

This technique allows large diameter casing to be cemented through and it provides a number of advantages including the reduction of the risk associated with cement slurry setting within the casing by reaching the annulus faster, no need for large diameter plugs, reduction in cement contamination, reduction of cement setting high up in the casing, reduced displacement time, and additionally, it allows the cement slurry to be pumped until returns are obtained on the surface (Khaemba, 2014). Possibly, only one backfill job is required, unlike the unlimited number of the ones done in Karisimbi KW01 (EWSA, 2014). Should large loss zones exist and cement returns are not seen at the surface, then the BOP is closed and the cement is immediately squeezed out of the casing/casing annulus with water to maintain an open path for reverse cementing (top-job).

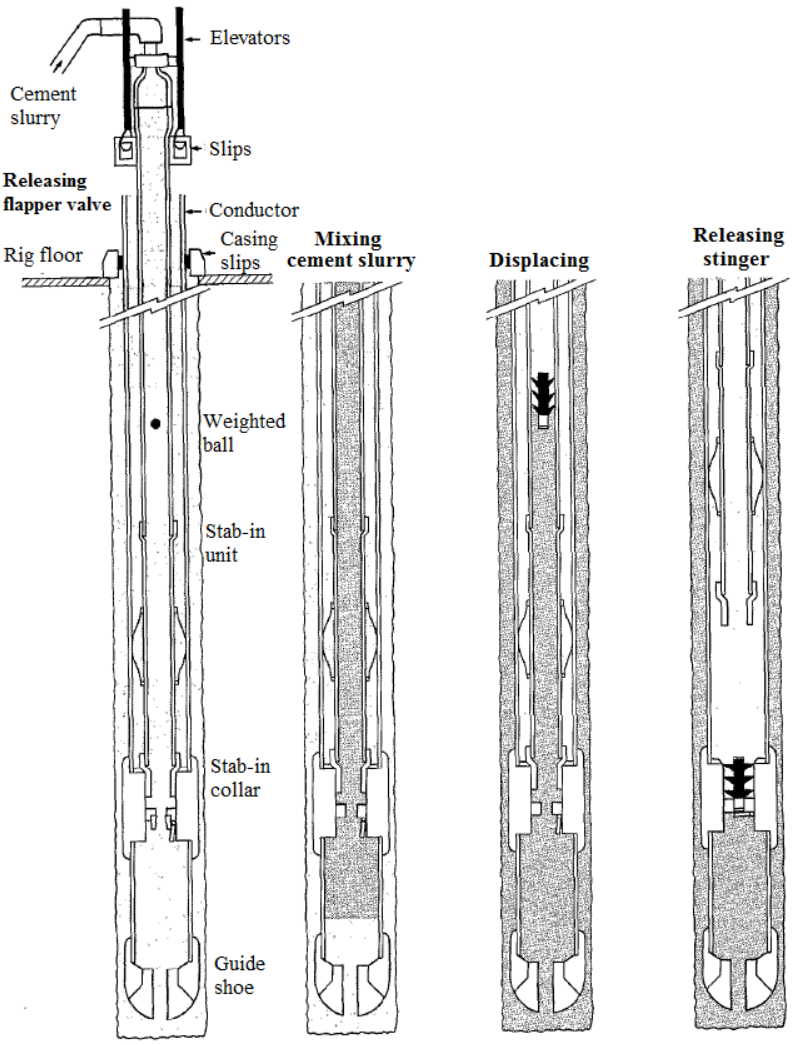


FIGURE 13: Cementing technique using inner string method (Bett, 2010)

Once the inner string is made up on the lower end with a sealing adapter and is stabbed into the float collar in order to seal the receptacle of the inner string adapter (Figure 13), sufficient water is circulated in the system to ensure that the stinger and annulus are clear of any debris and the well is cooled enough (Khaemba, 2014).

A variation of the inner string method is commonly in use in wells with large losses. First, a part of the calculated slurry volume is pumped to reach up to the loss zone via the inner string. Then the rest of the slurry is pumped down the annulus via the kill line with the annular BOP closed. The cement may not reach the surface or sink a little, then it is a simple matter to fill up the annulus later as there is no water in the casing/casing annulus above the top of cement.

6.2.3 Reverse circulation cementing

This technique is mainly used in wellbores where loss of circulation has been encountered while drilling. The slurry is pumped down the annulus and at the same time the drilling fluid flows back up through the casing. Therefore, the float, differential fill up and wellhead equipment must be modified. This technique can provide advantages including the reduction of hydraulic horse power of cement slurry pumping equipment since gravitational flow works in favour of the slurry flow, reduction of the fluid pressure (equivalent circulating density-ECD), shorter slurry thickening time and shorter execution time since no displacement is required. However, this method has one main disadvantage which is the difficulty in ensuring a good cementing at the shoe (Hole, 2008c).

6.3 Calculated scenarios for the cementing of Kinigi exploration wells

Calculations presented in Table 16 show that under the same environmental conditions and while pumping the same amount of slurry the reverse method requires the shortest pumping time, then the inner string method with slightly longer pumping time, but the plug method requires considerably longer pumping time. The candidate cementing methods for Kinigi exploration are the plug method or inner string method if there are no losses at the time of cementing and a variation of the inner string method is preferred for the expected caves and loss of circulation sections. For the later method, the slurry is first pumped via the drill string and then the rest is immediately placed as a "top-job". The reverse circulation cementing method may be considered for long production casing strings but not as a first option due to the uncertainties of good cementation at the casing shoe.

TABLE 16: Comparison between cementing techniques provided same volume of slurry and conditions

Methods	Materials	Surface casing	Anchor casing	Production casing
Inner string	Cement (T)	54	85	97
	Slurry volume (m^3)	41	65	73
	Time (min)	35	57	70
	Pump rate (l/min)	1,200	1,200	1,200
	Displacement (m^3)	0.7	4	11
In-casing	Cement (T)	54	85	97
	Slurry volume (m^3)	41	65	73
	Time (min)	45	83	100
	Pump rate (l/min)	1,200	1,200	1,200
	Displacement (m^3)	14	34	46
Reverse	Cement (T)	54	85	97
	Slurry volume (m^3)	41	65	73
	Time (min)	34	54	61
	Pump rate (l/min)	1,200	1,200	1,200
	Displacement (m^3)	-	-	-

Calculations show that 240 tons of dry cement is required for one well. The Karisimbi experience shows that for well KW01 the cement used was around 250 tons of dry cement (EWSA, 2014). As shown in EWSA (2014) cementing and WOC at KW01 took more than 15 days. Considering the day rate drilling contract that means high cost and by reducing the cementing time, especially for many backfills, by modifying the placement procedure, the cost can be reduced. Three analysed cementing methods require the same amount of dry cement and slurry volume but there is a difference in pumping time where the reverse circulation cementing uses significantly less time. Nevertheless, both inner string and reverse circulation cementing show almost similar advantages with regards to pumping time and the choice between the two will be dictated by other conditions like loss of circulation during drilling for example. Taking all parameters into account, the inner-string cementing method, with or without the variation of the "top-job", could be the most suitable method for the Kinigi exploration wells.

The cement of API class G is the preferred because it can be used with accelerators and retarders to cover a wider range of well depths and temperatures. Laboratory testing of the cement and water samples in special equipment is required to properly support the cementing plans.

7. PERMANENT WELLHEADS

The African Union (2016) suggests components of the permanent wellhead to include:

- The outer flanges of the master valve directly exposed to the fluid in the top of the well; and
- The bottom of the CHF (casing head flange) attaching the wellhead to the casing, plus any spools or other components included between these items.

The preferred wellhead configuration is for two side valves of at least three inches (Figure 14). It has to conform to API Spec 6A or API Spec 6D and needs to be designed to comply with maximum pressure conditions and temperature exposure possible at the surface under static or flowing conditions (Hole, 2008b).

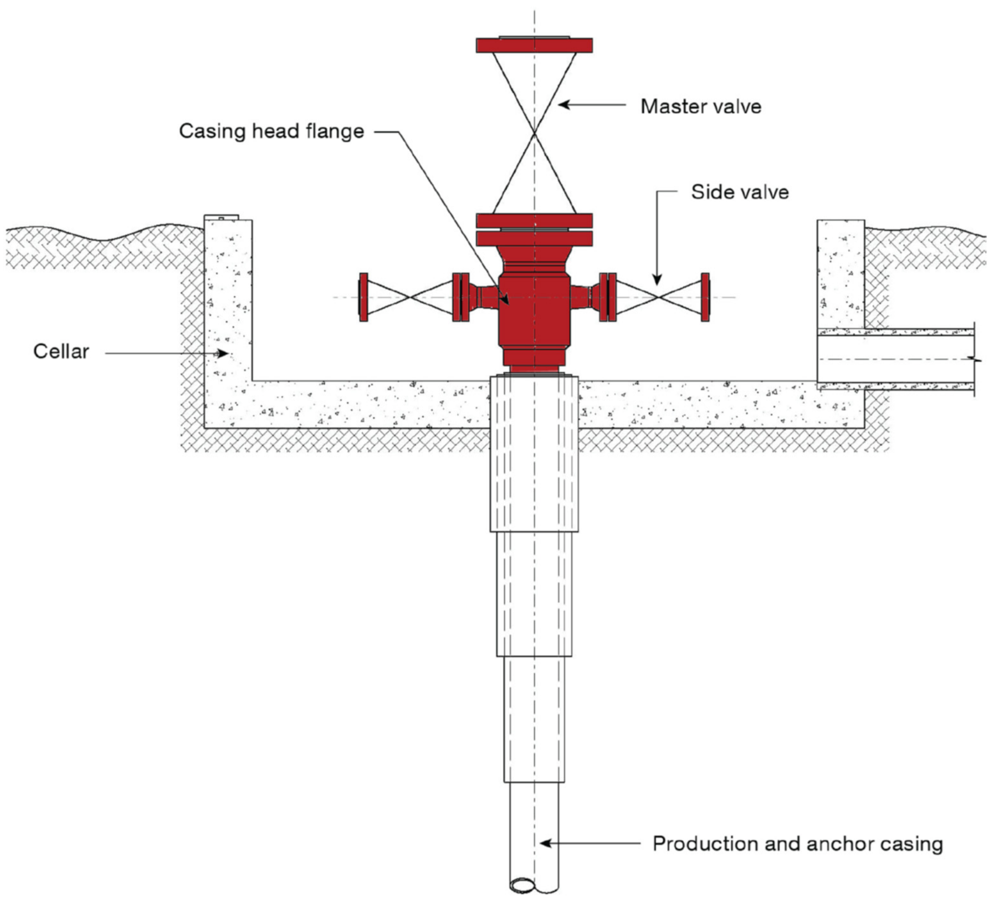


FIGURE 14: Typical permanent wellhead (African Union, 2016)

The fluids at the wellhead may vary from water, steam (either saturated or superheated), cold gas or a mixture of these fluids. In some circumstances, pressure and temperature conditions may be equal or close to downhole ones because of fluids in the well (Hole, 2008b).

7.1 Wellhead materials

Material used in wellhead components has to be suitable for use under all expected service temperatures and pressures. The pressure ratings are de-rated as temperature increases in accordance with ANSI B16.5 and API 6A (Hole, 2008b).

7.2 Wellhead design factors

According to African Union (2016), the wellhead design factor for the permanent wellhead has to include provisions for corrosive environment, it needs to minimise the rise and fall of the wellhead during operation and orientation of wellhead equipment relative to waste sumps and attachment of surface pipework to the wellhead components needs to be guaranteed.

With the assumption that the top 25 m of each casing string will expand freely through their expected temperature range, the wellhead has to provide service without interference from projecting components anchored to other casing strings. The CHF has to be connected to the anchor casing by casing threading for sizes and API pressure ratings as set out in the Table 17. However, if the design pressure exceeds these values, it is advised to connect the wellhead using a weld-on CHF.

TABLE 17: Recommended pressure limits for threaded CHFs (AU, 2016)

Casing size	Pressure rating
4-1/2" to 10-3/4"	Up to 5000 psi (34.5 MPa)
11-3/4" to 13-5/8"	Up to 3000 psi (20.7 MPa)
16" to 20"	Up to 2000 psi (13.8 MPa)

If welding is used to connect the CHF to the casing, it should be conducted using a procedure appropriate to the materials. If H_2S is expected to be present in the fluids, welding should comply with ANSI/NACE MR 175/ISO 15156. All welds have to be inspected and tested for defects including the ability to seal against an applied pressure equal to the maximum design pressure that the section will be exposed to (AU, 2016).

7.3 Wellhead valves

The entire wellhead including the master valve, expansion spool and CHF should allow for a clear bore diameter (1/8" or 3 mm) larger than any tool expected to run into or through the valve. The sealing should be accomplished by metal-to-metal seals. Figure 15 shows working pressure derated for flanges and valves conforming to above cited standards.

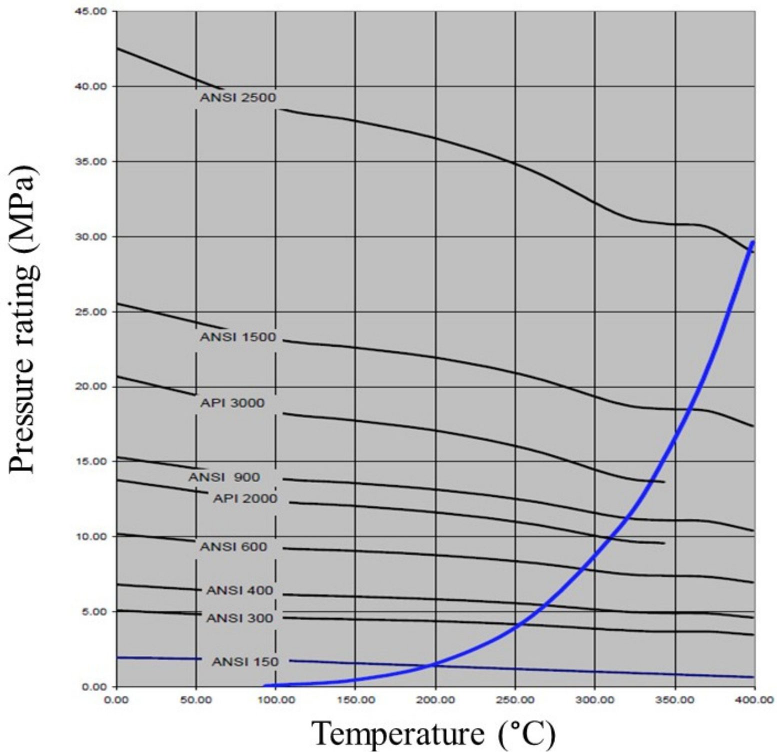


FIGURE 15: Wellhead working pressure derated for temperature modified from Hole (2008b)

8. WELL CONTROL PROGRAMME

Well control aims at preventing the flow of formation fluids into the wellbore during drilling and thereby avoiding spontaneous boiling that may lead to a kick. When the drilling process reaches a fractured or permeable layer where the pore pressure is higher than the static head of the drilling fluid, there is an inflow into the wellbore, which may results in a kick, which must be controlled. Failing to control a situation like that may result in disaster, which will at least cost money and in the worst case can even cost lives (Finger and Blankenship, 2010).

Some geothermal fields have pore pressure, which is greater than the hydrostatic column (e.g. Tiwi in the Philippines and parts of Salton Sea in California, USA) at shallow depths, usually due to high temperatures. However, most geothermal fields are under-pressured (the pore pressure is lower than the fluid pressure in the wellbore), therefore, influx may occur if there is a reduction in wellbore pressure due to either circulating hot fluids from deeper depths to the surface or loss of circulation (Finger and Blankenship, 2010).

8.1 Blowout preventer BOP

The apparatus used to control a kick is called blowout preventer (BOP) or blowout prevention equipment (BOPE). It comprises 5 types of devices to shut off the wellbore and prevent fluid flow out: rotating heads, annular preventers, pipe rams, blind rams and shear rams. The basic function of each is to shut off the wellbore but they operate in slightly different ways.

8.1.1 The rotating head or rotating BOP

This device forms a seal around the drill pipe that rotates with it. This is enabled by encasing the drill pipe seal and bearings in a sealed housing. The main purpose of this device is to keep hot fluids from reaching staff on the rig floor and can handle pressure up to 10.3 MPa.

8.1.2 Annular preventer

This is either an inflatable bladder or an elastomer that is forced into a conical cavity by a hydraulic piston; either way, the flexible element seals around drill pipe, casing, drill collars, or irregularly shaped component of the drill string.

8.1.3 Pipe rams

These are two sliding gates, each with a semi-circular cut-out that come together from each side of the drill pipe. The hole in the centre fits and seals around the outside diameter of the drill pipe.

8.1.4 Blind rams

These are also sliding gates, but there is no hole in the centre. They are used when the drill pipe is outside of the hole.

8.1.5 Shear rams

A last resort, the sliding gates have sharp, hardened, overlapping edges and are designed to sever anything hanging in the wellbore. If these are used, anything cut by them falls into the hole and becomes fish. Most of geothermal BOP stacks do not include shear rams when drilling, although they can be an important part of workovers that involve removing damaged casing from the wellbore.

8.2 Blowout preventers per well sections

The Kinigi area is not expected to have any kind of shallow high-temperature fluids which might cause a kick in the surface section drilling process. Therefore, no BOP stack is provided for this section. However, for the anchor casing, production casing and slotted liners sections BOPs are provided and they will be tested to different ranges of pressure. Table 18 below shows sizes of BOP stacks per section and the eventual pressure test it undergoes before drilling resumes. Each BOP stack connected to the casing CHF is required to fit the two cylinders, for instance the 21-1/4" BOP has a CHF of 20" since it is connected on the top of 20" casing. Figure 16 shows a typical BOP stack arrangement for a drilling process carried out with water or mud but not aerated fluid. For drilling with foam and to increase safety, a rotating head preventer is installed above the annular. The flow line connects to the rotating head so a razor is not required.

TABLE 18: BOP stack size per section and pressure test required

Section	**Size of hole (inches)**	**OD casing (inches)**	**BOP stack size (inches)**	**Pressure test (PSI)**
Anchor casing	17-1/2	13-3/8	21-1/4	500
Production casing	12-1/4	9-5/8	13-3/8	1000
Slotted liner	8-1/2	7	9-5/8	2000

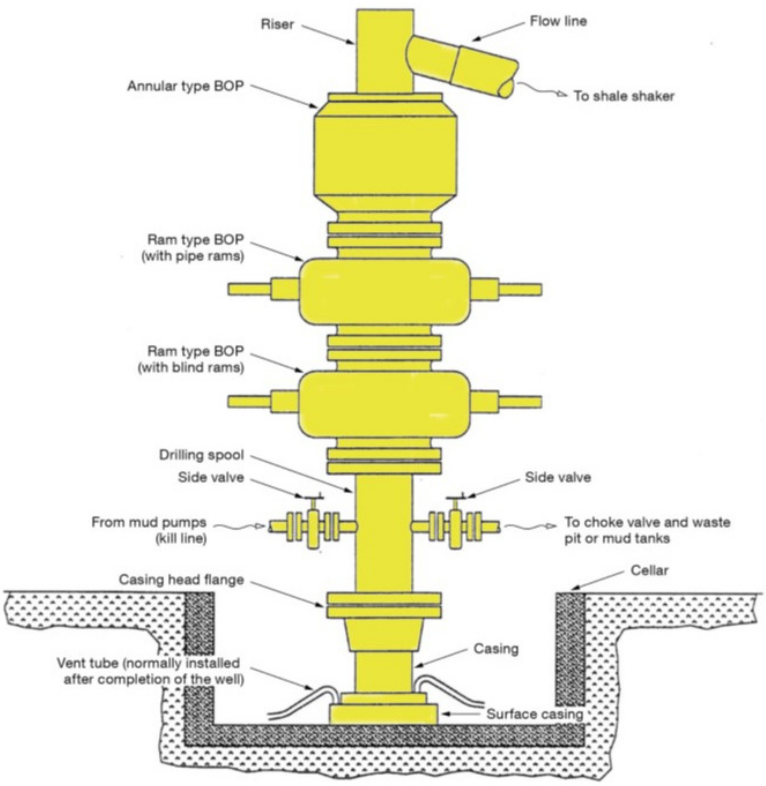


FIGURE 16: Typical drilling wellhead for use while drilling with water or mud (non-aerated)
(African Union, 2016)

9. WELL COMPLETION AND WELL TESTING PROGRAMME

At the conclusion of drilling the last section and running the slotted liner, the inner cemented casing needs to be logged in order to confirm casing condition and provide a baseline record for subsequent condition monitoring (African Union, 2016). Well logs and tests carried out on geothermal wells can include pressure and temperature surveys, and pressure measurements taken at depth of primary permeability while pumping water at stepped and variable flow rates. Well logging and testing can be done during drilling as well as after the drilling operation is completed. After the well has heated up, it may build up wellhead pressure on its own and once opened will self-flow or it may have to be stimulated to flow. The most common stimulation methods are by air compression where the water level is depressed to a level with high temperatures and then rapidly released or by air lift pumping via an air-line and using compressed air for the lift.

10. CONCLUSIONS

Exploration drilling in Kinigi prospect area around 12 km to the east of Karisimbi will be referenced to the previous experience because some of the environmental and drilling conditions are expected to be similar.

In the well, three drilled sections will be cased and cemented back to the surface; namely surface, anchor and production casing sections. The slotted liner section will be open and the liners will be hung in the production casing. Based on the AU code of practice for geothermal drilling, the surface casing minimum depth is set at 100 m, the anchor casing at 450 m and the production casing shoe at 1230 m in order to exclude cold inflows. The total planned depth is 3000 m targeting a deep geothermal reservoir estimated between 2 and 5 km in Kinigi area.

Apart from the surface section, which will be drilled with foam and air hammer in order to overcome the challenges expected to be present in that layer, the other cemented casings sections will be drilled with mud while the last open-hole section for the slotted liner will be drilled with aerated water and foam or water and hi-vis polymer pills.

Cementing the casing will be done preferably using the inner-string method. Calculations made including excess of 150% show a requirement of 180 m^3 of cement slurry and 250 tons of dry cement at 1.87 kg/l of slurry density per well. By selecting a placement procedure according to the condition of the well prior to cementing the total time is expected to be considerably reduced.

This study focused on well design, casing tally and safety for the eventual mechanical loads, cementing programme and mud programme design. But other components of a drilling programme like bottom hole assembly, corrosion and erosion stress on casing due to assumed chemistry of the reservoir and so on must be assessed in further research works.

It is highly recommended that prior to exploration drilling in a new field the well design and drilling programme is established from the available data and assumptions before engaging in contract for drilling services or materials.

ACKNOWLEDGEMENTS

Allow me to use this opportunity and express my gratitude to everyone who supported me throughout the course of this geothermal training programme. I am thankful for their aspiring guidance, invaluably constructive criticism and friendly advice during the project work. I am sincerely and specifically thankful to the people listed down here for particular reasons.

On my list the first person to thank is Mr. Lúðvík S. Georgsson, Director of UNU-GTP. Sir, you and your team will always be highly ranked in my memory because of many things but the one which touched my heart the most is a well-structured and organized way of working. You handle everything in simple and calm manner that I wish to practice in my life. I would like to express my gratitude to my supervision team: Mr. Gunnar Skúlason Kaldal, my direct supervisor and Mr. Sverrir Thórhallsson, co-supervisor, for the continuous support of my personal development and related research, for your patience, motivation, and immense knowledge. Your guidance helped me in all the time you have been there for me and the hard work you made it simple as if my life was dedicated to meet good people like you.

My wife Jeannine and children Ange, Mediateur and Darcy, you are the real sign of the benediction from God in my life and your immense love and support is the source of energy which helps me to strive and achieve goals always. I will always love you more. The Managing Director of EDCL Mr. Emmanuel KAMANZI and Mrs. Uwera Rutagarama, Manager for Geothermal Development, you are my best bosses and good friends ever, please receive here my little sign of honour and gratitude.

All of you good people from all over the world we met here at UNU and you helped me during this time, I will always remember you. I really thank you.

Prima facea, I am grateful to the Almighty God for the good health and wellbeing that were necessary to complete this training.

NOMENCLATURE

P_{frac} = In situ fracture pressure of a formation (MPa);
P_f = Pore pressure (MPa) and is assumed to be the boiling point pressure;
V = Poisson's ratio values are averaged from the values of Gercek (2006);
S_V = Overburden pressure (vertical pressure due to the weight of overlying formations (MPa));
$\rho(z)$ = Density of the overlying rock;
z = Depth;
$F_{csg\ air\ wt}$ = Air weight of casing (kN);
$F_{csg\ contents}$ = Weight of internal contents of casing (kN);
$F_{displaced\ fluids}$ = Weight of fluids displaced by casing (kN);
$F_{hookload}$ = Surface force suspending casing that is subjected to gravitational and static hydraulic loads (kN);
ρ_{if} = Density of a section of fluids with constant density within a casing (kg/l);
ρ_{ef} = Density of a section of fluids with constant density within an annulus (kg/l);
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_z = Depth of casing (m);
L_f = Height above casing shoe of cement column inside casing (m);
W_p = Unit weight of casing (kg/m);
D = Casing outside diameter (mm);
d = Casing inside diameter (mm);
g = Acceleration due to gravity (9.81 m/s^2);
F_p = The tensile force at the surface from casing weight (kN);
L_w = Depth of water level in well (m);
A_p = Cross sectional area of pipe (mm^2);
n = Mean specific volume of hot fluid (m^3/kg);
f_b = Maximum stress due to bending (MPa);
E = Modulus of elasticity (MPa);
q = Curvature of deviated hole (° per 30 m);
F_c = Compressive force due to heating (kN);

F_r	=	Resultant axial force (kN);
T_1	=	Neutral temperature (temperature of casing at the time of cement setting) (°C);
T_2	=	Maximum expected temperature (°C);
a	=	Coefficient of linear thermal expansion (°C^{-1});
F_t	=	Tensile force due to cooling (kN);
T_3	=	Minimum temperature after cooling well (°C);
F_w	=	Lifting force due to wellhead pressure (kN);
P_w	=	Maximum wellhead pressure (MPa);
F_m	=	Net downward force applied by the wellhead due to its own mass and pipe work reactions (kN);
f_c	=	Total extreme fibre compressive stress due to axial and bending forces (MPa);
e	=	Eccentricity (actual hole diameter minus D) (mm);
I_p	=	Net moment of inertia of the pipe section, allowing for slotting or perforating (mm^4);
R_j	=	The connection joint efficiency;
$\Delta P_{internal}$	=	Differential on casing during cementing (MPa);
L_f	=	Total vertical length of fluid column in an annulus (m);
ρ_c	=	Cement slurry density (eg 1.87 kg/l);
ρ_f	=	Density of water in annulus (kg/l);
R_i	=	Temperature reduction factor (ratio);
F_t	=	Maximum tensile stress (MPa);
P_w	=	Maximum wellhead pressure (MPa);
$\Delta P_{external}$	=	Differential pressure on casing during cementing (MPa).

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APPENDIX I: Assumed pressure on which the casing design is based

Depth below water level	Hydrostatic pressure at 20°C	Hydrostatic pressure at BPD (P_f)	BPD temperature	Hole depth from surface	Expected rock type	Average Poisson ratio (υ)	Overburden pressure ($S_υ$)	Fracture pressure (P_{frac})	Density of the overlying rock ρ(z)
m	MPa	Mpa	°C	M			MPa	MPa	(wet) ($X10^3$ Kg/m^3)
		0		0	Basanite	0.35	0.08	0.04	2.98
		0		50	Basanite	0.35	1.54	0.83	2.98
		0		150	Basanite	0.35	4.46	2.40	2.98
0	0	0	100	200	Basanite	0.35	5.92	3.19	2.98
10	0.10	0.09	119	210	Hawaiite	0.35	6.22	3.39	2.98
20	0.19	0.19	132	220	Hawaiite	0.35	6.51	3.59	2.98
40	0.39	0.36	149	240	Hawaiite	0.35	7.09	3.98	2.98
60	0.58	0.54	162	260	Hawaiite	0.35	7.68	4.38	2.98
80	0.78	0.72	172	280	Hawaiite	0.35	8.26	4.78	2.98
100	0.98	0.89	180	300	Hawaiite	0.35	8.85	5.17	2.98
150	1.47	1.32	196	350	Hawaiite	0.35	10.31	6.16	2.98
200	1.95	1.75	208	400	Hawaiite	0.35	11.77	7.15	2.98
300	2.93	2.57	227	500	Hawaiite	0.35	14.69	9.10	2.98
400	3.91	3.37	242	600	Hawaiite	0.35	17.62	11.04	2.98
500	4.89	4.16	254	700	Hawaiite	0.35	20.54	12.98	2.98
600	5.87	4.93	264	800	Hawaiite	0.35	23.46	14.91	2.98
800	7.82	6.43	281	1,000	Hawaiite	0.35	29.31	18.75	2.98
1000	9.78	7.87	295	1,200	Granite	0.33	31.51	19.51	2.67
1200	11.70	9.26	306	1,400	Granite	0.33	36.75	22.80	2.67
1500	14.70	11.27	321	1,700	Granite	0.33	44.60	27.69	2.67
2000	19.60	14.40	339	2,200	Granite	0.33	57.70	35.73	2.67
2500	24.50	17.30	354	2,700	Granite	0.33	70.80	43.65	2.67
3000	29.30	19.90	365	3,200	Granite	0.33	78.65	48.84	2.67

APPENDIX II: Minimum design factors (AU, 2016)

Stress condition	Load case	Minimum DF
Triaxial	As indicated in the AU code point 2.10.1.2	1.25
Axial	Tensile force during running and cementing casing	1.8
	Fluid lifting on anchor casing	1.8
	Thermal load on anchor casing (where applicable)	1.4
	Helical buckling due to self-weight plus thermal load (uncem. liner)	1
Hoop	Internal pressure a shoe during cementing	1.5
	Wellhead internal pressure (shut-in steam/gas after drilling) where wellhead is fixed to the casing	1.8
	External pressure collapse (during cementing)	1.2
	External pressure collapse (during production)	1.2