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Djibouti Well Design For The Upcoming Wells at Gale Le Goma Site, Asal Region Using The African Code Of Practice.

Mohamed Ali Tabet

Djiboutian Office for the Development of the Geothermal Energy (ODDEG)

PK20, zone Industriel, Raod national N°1

REPUBLIC OF DJIBOUTI

mohamed.ali@oddeg.dj or mota@grogtp.is

Keywords: Well Design Using the African Code of Practice selected a proper Casing grade for extreme salinity and extends the life time of the well.

ABSTRACT

The intention of this paper is to prepare a well design for the upcoming well at Gale le Goma field, located at the Asal region (P-1) by considering experience from pervious well GLG-1 drilled in 2016. Existing well lithology data was referred in order to prepare an updated well design according to the guidelines in the African Union Code of Practice for Geothermal Wells. Asal-3, Asal-6 and GLG-1 are located at the same area and drilled into the same reservoir. Therefore, they have a close lithological relationship with permeability and enthalpy in the Asal geothermal field. In this regard, same lithology will be used to design the upcoming well P-1. The wells encountered highly saline reservoir fluid of 120000 ppm (120 g/L). The planned depth of GLG-1 was 700 m MD and the resulting minimum depth of the production casing was set at 300 m MD with 12-1/4” production section down to 700 m MD. Correspondingly, the surface casing has a minimum setting depth of 60 m MD. The selected casing steel grade was of API 5CT of material grade J-55 for the surface casing and N-80 for the Anchor casing and J-55 for the production casing. In casing design, the casings are selected based on collection of the available data and assessment on expected subsurface conditions from the wellhead to the well target. These include considerations on geological formations, formation pressures, BHT, geothermal fluid properties, e.g. H2S gas presence and salinity. Casing thicknesses and material grades are selected according to calculated design factors (DF) that are required to be higher than minimum design factors defined in the African Union Code of Practice for Geothermal Wells. The selected casings for the upcoming well in Asal are of API 5CT steel grade K-55 for the surface casing and L-80 for the anchor and productions section which has more control on chemical composition than K-55. L-80 casing grade is also beneficial for the extreme salinity in the Asal area that may lead to an excessive corrosion of the casing in the borehole. The planned depth is 1300 m MD and the resulting minimum setting depth of the production casing is 800 m MD. The surface casing has a minimum setting depth of 250 m MD and the anchor casing of a 450 m MD correspondingly. This paper describes assumption that defines an appropriate casing design with emphasis on safe drilling and reduced risk of casing failure in the well. Choosing suitable materials will determine a safe operation and extended life time of the well.

1. INTRODUCTION

Well design is one of the crucial tasks before the drilling phase. Appropriate well design relies on formation pressures and temperatures, lithology and intended hole depth as well as other elements that are essential for the final selection of recommended casing weights and grades. Calculated design factors (DF) are required to be higher than the minimum design factors indicated in the African Union Code of Practice for Geothermal wells 2016. Burst, collapse, and axial loads to the casings during drilling and well operation are considered. H2S gas presence and salinity are considered separately from the stress design. Scaling challenges is one of the critical issue that needs to be taken in to consideration while designing a well. In order to minimize scaling in the well, potential solution is to select a large diameter, e.g. 13-3/8, for deeper production casing where scaling appears. Seven wells have been drilled in the Asal geothermal area. Asal-1 and 2 were drilled in 1975 (BRGM, 1975). Asal-3 and Asal-6 were later drilled in same area in 1989 (Aquater, 1989). The wells have produced extremely saline fluids due to the reservoir condition with saline water from lake Asal area (Mohamed Jalludin, 2009). Combined lithology from Asal-3 and Asal-6 are used as a reference for designing the new well that is planned to be drilled nearby the wells as they encounter the same reservoir and are presumably fed by the same aquifer. The average mass flow rate at Asal-3 has been found to be 40 kg/s at 18 bar and max temperature is 263°C (Virkir-Orkint, 1990), where Asal-6 was not stabilized comparing with Asal-3 well test due to the high scaling occurred (Aquater, 1989). The salinity of around 120000 ppm (120 g/L), more than 3 times higher than the seawater salinity (Elmi, 2005).

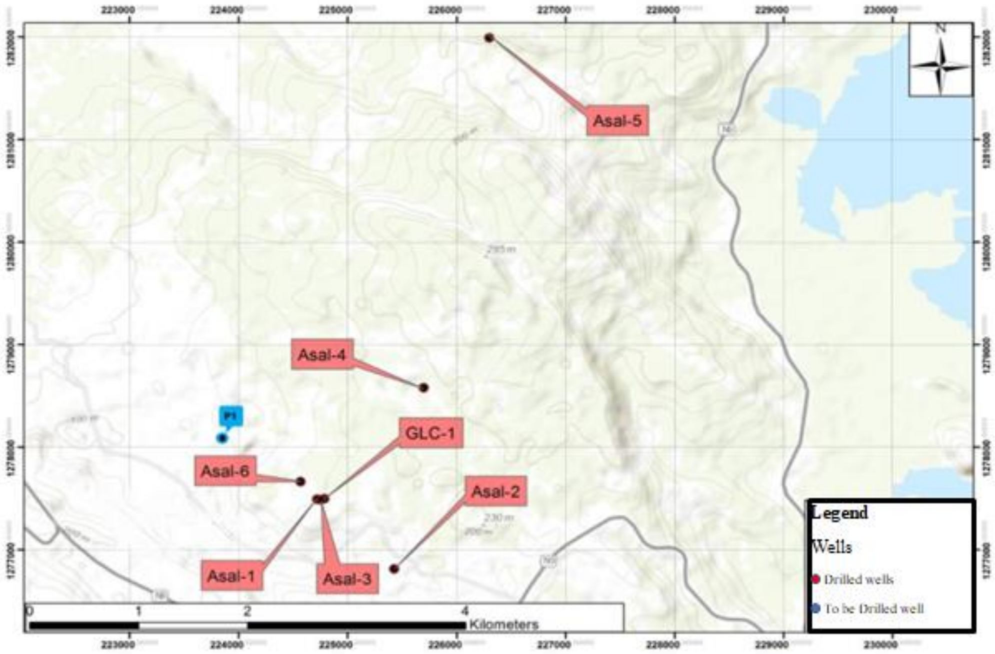


FIGURE 1: Asal wells location and the new well to be drilled (Reproduced from internal report)

2. OBJECTIVE OF THE STUDY

The objective of the current study is to prepare an appropriate well design and upgrade a well design for the first well at Gale Le Goma field (P-1) by considering drilling problems experienced from pervious well GLG-1 in the Asal area and by following requirements of the African Union Code of Practice for a safe drilling and well integrity.

3. GELOGICAL SETTING OF THE ASAL AREA

The Asal Rift is tectonically the most active structure in the zone of crustal divergence in Afar (Figure 2). The Asal area creates a typical oceanic type rift valley, with a highly settled graben structure displaying axial volcanism. The Asal series are relatively complex in structure, because of different series of active volcanism in recent Quaternary times, each with very different characteristics depending on the sites of appearance. Generally, the Asal series are composed of porphyritic basalt formations and hyaloclastites. First 2 wells drilled in 1970 later on, the other 4 wells drilled between 1982-1989. The existence of a shallow crust-melting zone, important seismic activity, the presence of fumaroles and hot springs make it possible to classify this region as a zone with a high geothermal potential (Barberi et al,1980 and Sanguan et al,1990). The salinity of the water of this region is extremely high about 3 times the seawater.

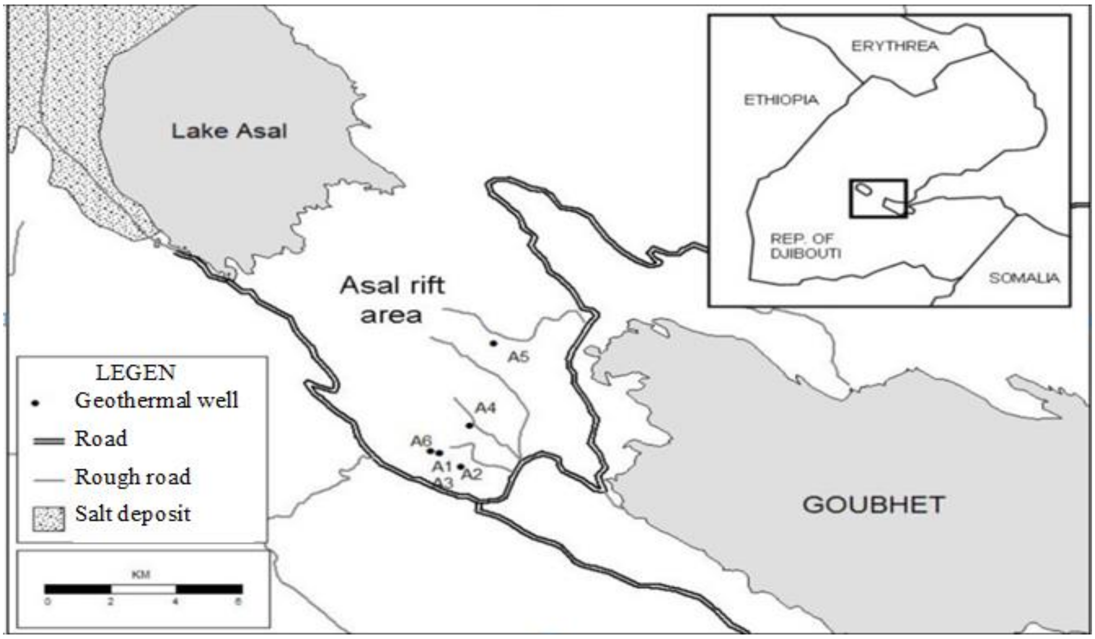


FIGURE 2: Asal geothermal field (Elmi Houssein, 2005)

4. ASAL FIELD AREA AND LITHLOGY LOGGING.

The Asal field a typical oceanic type rift valley, with a very advanced graben displaying axial volcanism. But it's a complex in structure, because of different series of active volcanism in recent Quaternary times, respectively with very different characteristics depending on the sites of appearance. Mostly, Asal series are composed of porphyritic basalt formations and hyaloclastites. The lithological logs of Asal Wells 3, 6 (figure 3) are almost the same with GLG-1 and they encountered the same reservoir and they have a close lithological with a new drilling site. Cuttings were collected every 5m at Asal 3 and 6 where at GLG-1 was collected at every 2 m for being accurate.

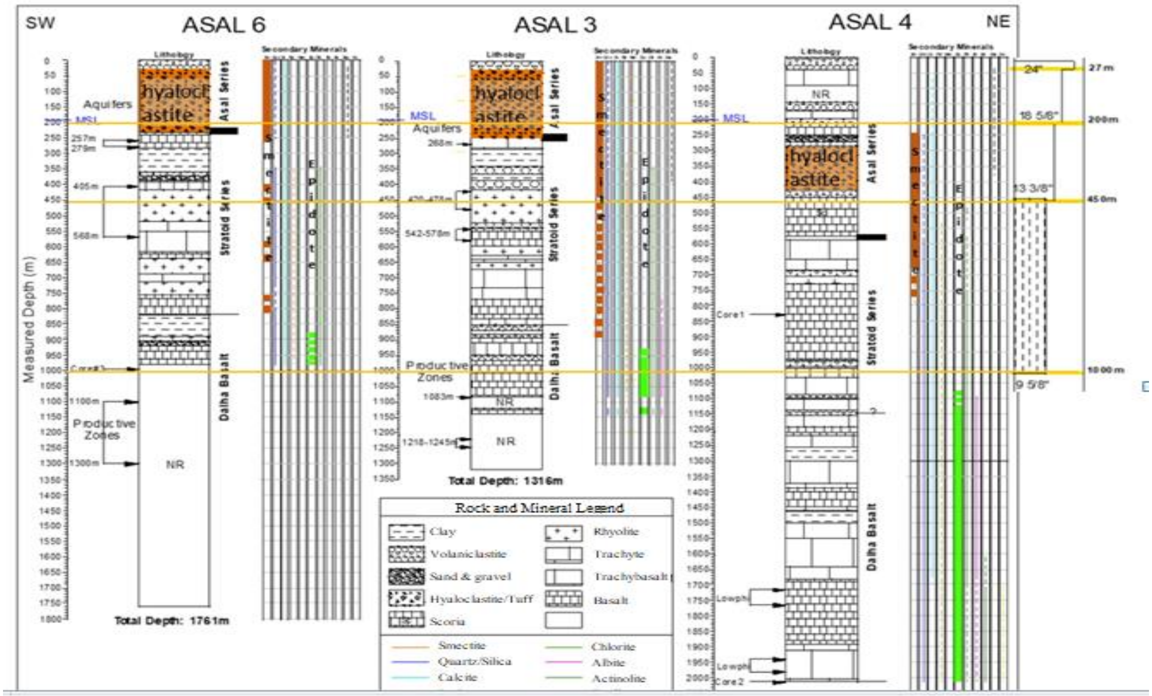


FIGURE 3: Stratigraphy and mineralogy in Asal wells 3, 4 and 6 (Reproduced from Internal report)

5. CASING DESIGN

Main purpose of casing designing is to permit a well to be drilled in safe manner without failure, through providing structural integrity of the well against forces obtruded during drilling, and to fulfil the well objective without necessitating a workover throughout the wells life. The casing design should consider the economic side in a cost effective manner without compromising safety. A proper design for a geothermal well should consider predicted conditions during drilling and operation of the well, which may decrease the lifetime of a well. This is done to assure that the selected casings for the well to be drilled have a substantial leeway of strength to accommodate anticipated stress at all depths throughout the well. Aspects included in African Union Code of Practice for Geothermal Wells (2016) are below:

- Casing failure due to internal and external loads.
- Protect the well against corrosion, erosion or collapse.
- Safe containment of well fluids.
- Anchoring of wellheads during drilling and operation of the well.
- Control against subsurface aquifer contamination.
- Withstand against hydrogen crumbling in environments affluent in H_2S gas.
- Long lifetime to the well.

Main crucial parts in the well design need to be considerable are the casing string. They are contained of numerous pipes steel casings which are run into every well and detained in position by a cement bond formed between the casing wall, well formation or mid of casing strings. The steel casings selected are API spec 5CT and API spec 5L standard. Under the API standards, casings are classified in line with manner of manufacture, grade steel, joint type, and length range and wall thickness. The casing grade determined the strength of casing steel against tensile loads, burst and axial and while the strength against collapse is principally attributed to the wall thickness of the casing (Finger et al, 2010).

6. CASING SETTING DEPTHS

Casing shoe setting depth is based on assumptions on pore pressure and fracture gradient of the rock formation. To determine the minimum casing shoe depth for each depth is by collecting information from nearby wells drilled such geological formation rocks type, temperature and pressure versus depth or by following the casing design process described in the African Union Code of Practice for geothermal drilling (2016) for securely, successfully and steady well.

Design starts from the bottom of the well up to the surface and the setting depths are selected based on pore pressure in this case assumed to be of boiling liquid with depth (BPD curve) for 12% NaCI and calculated fracture gradient. Figure 4 shows a well design for TD of 1300 m with several casing sections and shoe depths of each section and **Eaton equation** used where the fracture gradient is unknown as below.

$$P_{frac} = P_f + \left(\frac{\nu}{1-\nu}\right)(S_v - P_f) \qquad (1)$$

Where:

P_{frac} = Fracture pressure of a the formation [bar];

Pf = Pore pressure [bar];

ν = Poisson's ratio of the rock type (range between 0.1 to 0.4)

Sv = Overburden pressure [bar];

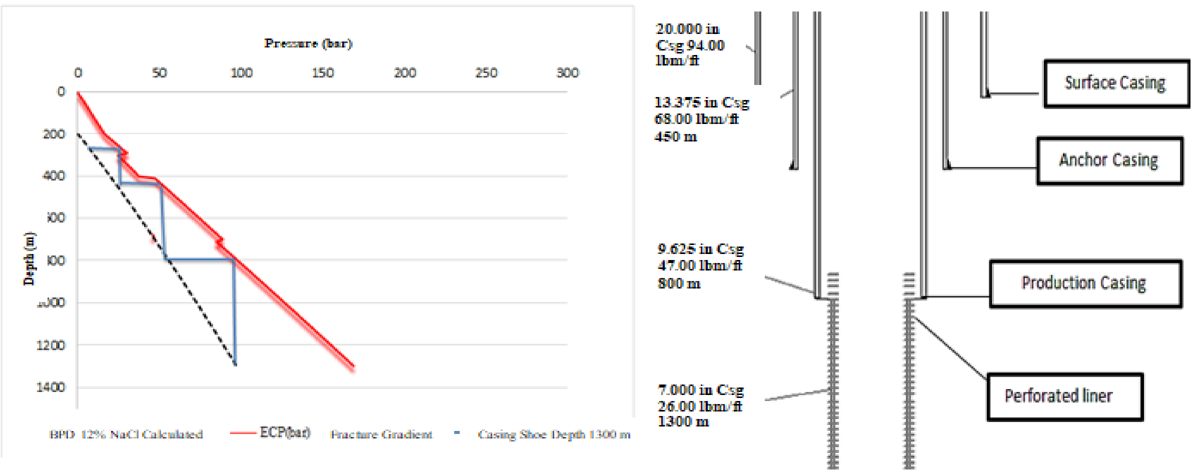
ρ = Density of the rock type [kg/ m^3]

g = Acceleration due to gravity (9.81 [m/ s^2])

h = Depth [m].

Sv = $\rho g h$

The following rock densities such as basalt has an average of 2900 kg/m3, Hyaloclastite of 2500 kg/m3, Pliocenic shale of 2400 kg/m3 and Rhyolite of 2500 kg/m3 (Hathrerton and Leopard, 1964) have been used to calculate the Eaton formula. Poission ratio used range between 0.1 to 0.4 (Gercek, 2006). The max wellhead pressure as calculated uses the xsteam table for saline water 120 g/L to be 97 bar assuming a static column of the steam profile from the bottom of the well and max temperature of 310°C from the water table level at 200m as show in figure 5. The well design sketch and minimum setting depths according to the steam table calculation by following the process described in African Union (2016). The resulting casing shoe depths are 250m, 450m and 800m as shown below, (Figure 4).



Casing shoe 1 Surface casing (m)	250
Casing shoe 2 Anchor casing (m)	450
Casing shoe 3 Production casing (m)	800
Slotted liner open hole (m)	500

FIGURE 4: Well design sketch and minimum setting depths according to the x steam table calculation and the process described in the African Union Code of Practice (2016). Casing shoe depths are 250m, 450m and 800m.

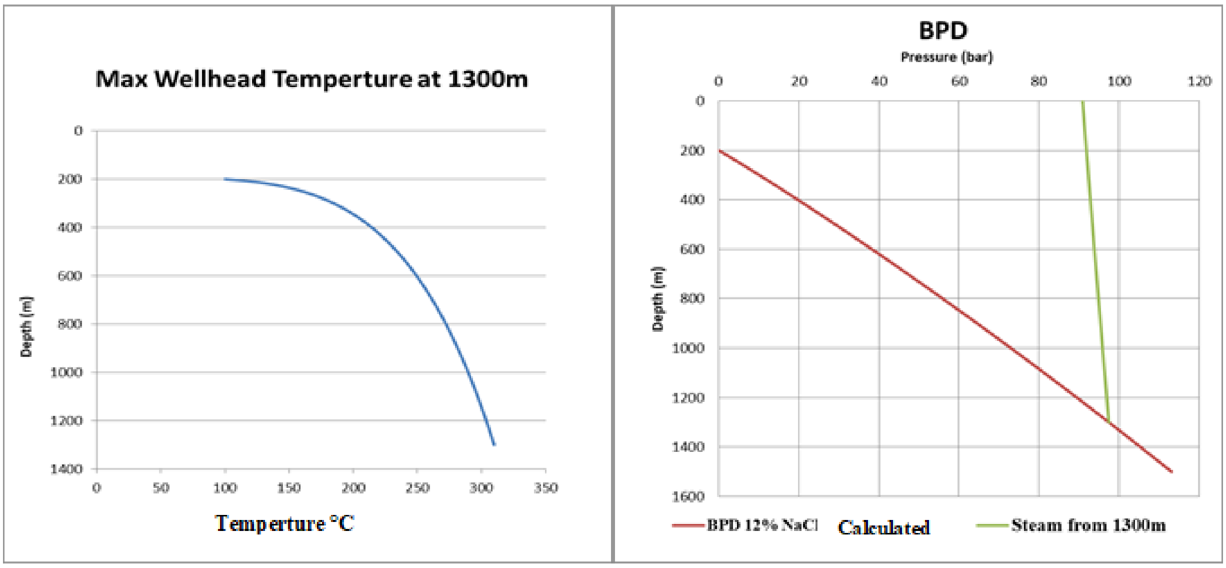


FIGURE 5: The max wellhead temperature and pressure for 1300 m.

6.1 CASING GRADE SELECTION FOR THE NEW WELL

This section it's very important for the proper selections of the casing materials to prevent any failure due to internal and external loads, high salinity and H2S gas be present sore materials need to be select and for safe drilling and long lifetime to the well. Below some description of the different type of grades with different materials compositions of each grade and for the best selection referring to the African Union Code of Practice (2016) and also the DDH. Table 1 indicated the important use of these casing grades where H2S gas might be presented. Table 2 shows the mechanical properties comparing between the K-55 and L-80.

TABLE 1: Casing grades for sour service environment (African Union Code of Practice 2016).

Where gas may be present such H_2S (sour materials)	API SPEC 5CT casing grades
	L-80, K-55, T-95, C-90, H-40

TABLE 2: Mechanical properties comparing between K-55 and L-80.

OD (inches)	**Size**	**Thread**	**Grade**	**Collapse resistance (MPa)**	**Internal yield pressure(MPa)**	**Minum yield strength (MPa)**	**Pipe body yield strength (1000daN)**
20	94	BTC	K-55	3.6	14.5	379	659
20	94	BTC	L-80	3.6	21.1	551	958
13 3/8	68	BTC	K-55	13.4	23.8	379	476
13 3/8	68	BTC	L-80	15.6	34.6	551	692
9 5/8	47	BTC	K-55	26.8	32.5	379	332
9 5/8	47	BTC	L-80	32.8	47.3	551	483
7 slotted	26	BTC	K-55	29.3	34.3	379	185
7 slotted	26	BTC	L-80	37.3	49.9	551	269

TABLE 3: Different of casing grades chemical compositions (DDH, 2014)

Group	Grade	Type	C		Mn		Mo		Cr		Ni	Cu	P	S	Si
			min.	max.	min.	max.	min.	max.	min.	max.	max.	max.	max.	max.	max.
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1	H40	—	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	J55	—	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	K55	—	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	N80	1	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	N80	Q	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	R95	—	—	0,45[c]	—	1,90	—	—	—	—	—	—	0,030	0,030	0,45
2	M65	—	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	L80	1	—	0,43[a]	—	1,90	—	—	—	—	0,25	0,35	0,030	0,030	0,45
	L80	9Cr	—	0,15	0,30	0,60	0,90	1,10	8,00	10,0	0,50	0,25	0,020	0,010	1,00
	L80	13Cr	0,15	0,22	0,25	1,00	—	—	12,0	14,0	0,50	0,25	0,020	0,010	1,00
	C90	1	—	0,35	—	1,20	0,25[b]	0,85	—	1,50	0,99	—	0,020	0,010	—
	T95	1	—	0,35	—	1,20	0,25[c]	0,85	0,40	1,50	0,99	—	0,020	0,010	—
	C110	—	—	0,35	—	1,20	0,25	1,00	0,40	1,50	0,99	—	0,020	0,005	—
3	P110	e	—	—	—	—	—	—	—	—	—	—	0,030[e]	0,030[e]	—
4	Q125	1	—	0,35		1,35	—	0,85	—	1,50	0,99	—	0,020	0,010	—

FIGURE 6: The effect of temperature on different casing grades (African Union Code of Practice 2016 and NZS 2403:2015)

Grade	Temperature (°C)						
	20	100	150	200	250	300	350
	API Yield Strenght (Factor)						
J55-K55	1.00	0.94	0.90	0.90	0.85	0.85	0.70
L80/C90/T95	1.00	0.96	0.92	0.90	0.88	0.85	0.81
	Tensile Strenght (Factor)						
For all grade	1.00	0.96	0.92	0.90	0.88	0.86	0.84
Young Modulus of Elasticity							
All grades	210	205	201	197	194	190	185

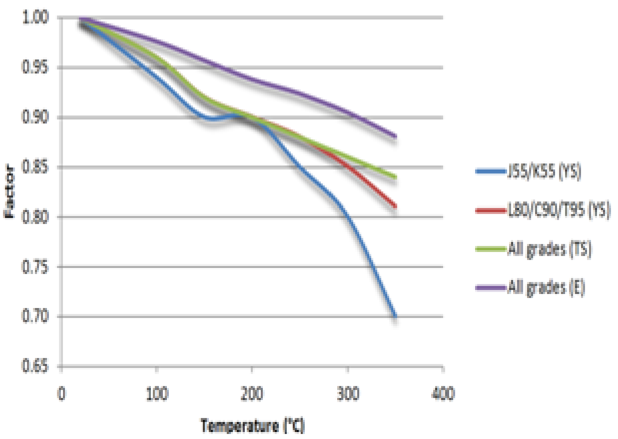


TABLE 4: Casing grades selected for every section for the new well taking in account the salinity issues.

OD (inches)	Size	Thread	Grade	Depth (m)	Comments	Collapse resistance (MPa)	Internal yield pressure(MPa)	Pipe body yield strength (1000daN)	Mandrel Drift dimater (mm)
20	94	BTC	K-55	0-250	This section no need to select a special casing as this use to support the rig	3.6	14.5	659	481
13 3/8	68	BTC	L-80	0-450	Need a grade L80 at least for the First 3 joints of casing pipe assuming about 36m	15.6	34.6	692	311.33
9 5/8	47	BTC	L-80	0-800	Referring to table 5 above	32.8	47.3	483	216.53
7 slotted	26	BTC	L-80	770-1300	Referring to table 5 above	37.3	49.9	269	156.22

6.2 CASING CALCULATION

The proposed calculations are completed after minimum casing setting depth for each section has been determined. Casing stress design is used in order to determine the suitable casing grade, weights, and diameter suitable for a well. The casings are selected for protection against sour environment corrosion, collapse. Additionally, the different casing grade chemical compositions are considered as shown in table 2 and 3. The effect of temperature factor on different casing properties is shown in the above table in Figure 6. Special consideration is needed in the area where extremely saline fluid of 120 g/l is expected, equivalent of three times sea water salinity. Referring to the above Figure 5, the new well covers different section as follow: 20″ surface casing, 13⅜″ anchor casing, 9⅝″ production casing, and 7″ slotted liners and the grade chosen are explained in table 4 for all the casing strings.

The calculation of the casing strength against burst pressure, axial tensile/compressive force, and collapse pressure are essential as it determines the appropriate casing grade selection for the well following the standard design factor table 5. The mechanical properties of the casing strings were taken from the drilling data handbook nine edition (NGUYEN, Gilles GABLODE Jean and Paul, 2014). Based on the calculations done, suitable casing grade and weights will be selected for the 1300 m production well. The design calculations consider that the well is full of steam from the bottom to the surface which represents the worst-case load scenario.

TABLE 5: Standard Design factor (The African Union Code of Practice 2016)

Stress condition	Loader cases	Calculation	Min-Design Factor
Trixial	As per application and caveats in new version 2.10.1.2	$\frac{\text{minimum maerials yield stress}}{\text{minumum total equivalent trixia;stress}}$	1.25
Axial	Tensile force during cementing	$\frac{\text{minimum tensile strenght}}{\text{maximum tensile load}}$	1.8
	Axial load after cementing Compressive strength	$\frac{\text{minimum compressive strength}}{\text{resultant compressive force}}$	Not stated
	Lifting force on anchor casing	$\frac{\text{minimum tensile strength}}{\text{maximum tensile load}}$	1.8
	Thermal load in anchor casing	$\frac{\text{anchor casing tensile strength}}{\text{rising casing compressive strength}}$	1.4
Hoop	Helical buckling due to self –weight plus thermal load (uncemented liner)	$\frac{\text{minimum yield stress} * \text{Rj}}{\text{total cimpressive stress}}$	1
	Internal pressure at shoe during cementing	$\frac{\text{internal yield strength}}{\text{diffrential internal pressure}}$	1.5
	Wellhead internal pressure where wellhead is fixed to casing	$\frac{\text{steel yield strength}}{\text{maximum tensile stress}}$	1.5
	Wellhead internal pressure (shut-in steam/gas as after drilling)	$\frac{\text{internal yield stress} * \text{Ri}}{\text{wellhead pressure}}$	1.8
	External pressure collapse (during cementing)	$\frac{\text{pipe collapse pressure}}{\text{diffrential external pressur}}$	1.2
	External pressure collapse (during production)	$\frac{\text{pipe collapse pressure}}{\text{diffrential external pressur}}$	1.2

7. CASING STRESS DESIGN

The axial stress in casings is caused by three main parameters: the weight of the casing, the temperature (compression and expansion) and restraint due to cement or connection at the wellhead or downhole hanger. African Union Code of Practice (2016) specifies that casing stresses have to be assessed either by calculating each individual stress or calculating the triaxle stress using this standard API TR 5C3. The triaxle stress calculation combines all the stresses acting on the casing. In this report will be calculate each individual stress to obtained the minimum safety design factor as shown in the table (5) above.

The casing strength affecting by the main load which are as follow:

- Burst due to the internal pressure goes beyond the pressure loading inside the casing
- Collapse due to the high pressure acting outside the casing acting higher than the pressure inside
- Compression due to the heating up the well tension due when the well cool down.

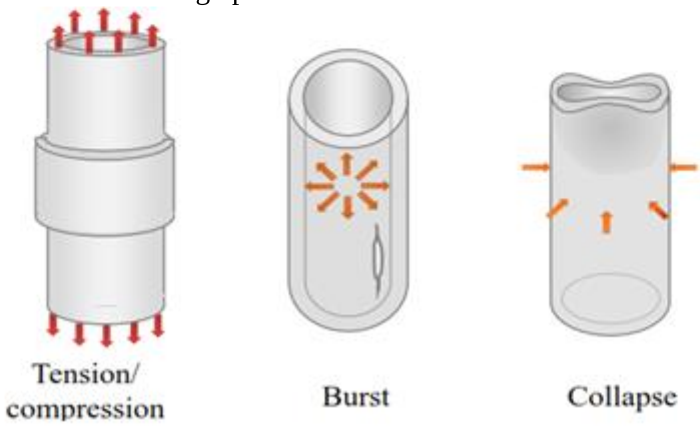


FIGURE 7: Different load affecting casing (Lecture Note 1 casing design GRO-GTP-2021)

7.1 Axial loading before and during cementing

Until the annular cement sets around the casing, the tensile force at any depth includes the weight of the casing in air plus the weight of the casing contents fewer the buoyancy effects due to any fluid displaced by the casing in the well (African Union Code of Practice 2016). **Equation 2**

,

Where:

(2)

$$\text{Fcsg air wt} = LZ.Wp.g$$

$$\text{Fcsg contents} = \sum \rho if.Lif.(\pi d2/4).g$$

$$\text{Fdisplaced fluids} = \sum \rho ef.Lef\ .(\pi d2/4).g$$

As stated by the (African Union, 2016), Buoyancy force (Buoyancy) is the difference between air weight of the casing (Fcsg air wt) and the hook load (Fhookload). It's the applied buoyancy force positive buoyancy acts downward and negative buoyancy acts the way around. **Equation 3**

$$Fbuoyancy = (Fhookload - Fcsg\ air\ wt) = (Fcsg\ contents - Fdispaced\ fluids) \qquad (3)$$

7.2 Axial load after cementing

The axial forces imposed after cementing near the surface and at the shoe of the casing string is necessary. The calculation of the resultant net force is a combination of the static force present in the casing at the time cement is setting and each of the casing loadings. For a case where the stress calculated is exceeded, a plastic/strain based design is required. Change in axial force with tension as positive due to temperature increase and temperature decrease due to the cool fluid circulating nearby the surface during drilling. **Equation 4, 5, 6 & and 7**

Where:

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$$FC = E.\alpha\,(T-1 - T2)\,AP \tag{4}$$

The resultant axial force is =

$$Fr = Fp + Fc \tag{5}$$

$$Ft = E.\alpha\,(T-1 - T3)\,AP \tag{6}$$

$$Fr = Fp + Ft$$

$$\frac{Min\,Tensile\,Strength}{Min\,Tensile\,Load} \geq 1.8$$

Design factor ≥ 1.8

(7)

7.3 Tension at anchor casing due to the lifting force of the fluid

A lifting force is applied to the anchor casing by thermal expansion of the production casing string where the mechanical design allows it to interfere with parts of the wellhead. The integrity of the anchor casing and the wellhead is protected by ensuring that potential failure would occur elsewhere. The design factor is **Equation 8,**

Where:

Design factor ≥ 1.8

$$Fw = \pi/4\ x\ Pw\ x\ d2x10 - 3 -\ Fm \tag{8}$$

$$\frac{Anchor\ Casing\ Tensile\ Strength}{Max\ Tensile\ Load} \geq 1.8$$

7.4 Axial load of uncemented liners with buckling and bending

The uncemented liners are either hung in tension from the liner top or supported at the shoe in compression. The liners in this case are supported at the shoe and hence should be analysed for helical buckling. The total fibre compressive stress in an uncemented liner that is subjected to axial self-weight and helical buckling is **Equation 9:**

Where:

Design factor ≥ 1

$$Fc = LZ\ x\ WP\ x\ g\ x\ \ [(1/Ap) + (De/2lP)] \tag{9}$$

$$\frac{Min\,Yield\ Stress\ x\ Rj}{Total\ Compressive\ Stress} \geq 1$$

7.5 Maximum differential internal pressure during cementing

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

- The casing string is filled with cement slurry;
- The annulus either contains a column of water or is subject to formation pressure;
- Constriction within the casing is sufficient to hold the differential pressure. The maximum differential pressure is: **Equation 10**

Design factor ≥ 1.5

$$\Delta Pinternal = [Lz\, \rho c - Lf - \rho f\,]\, x\, g \tag{10}$$

$$\frac{Internal\ Yield\ Pressure}{Diffrential\ Internal\ Pressure} \geq 1.5$$

7.6 Maximum differential internal pressure after cementing

After cementing, the maximum differential internal pressure will occur at the surface. In this study the scenario where steam is present at the wellhead is looked at: **Equation 11**

(11)

Design factor ≥ 1.8

$$\frac{Internal\ Yield\ Pressure\ x\ Rj}{Wellhead\ Pressure} \geq 1.8$$

7.7 Axial and circumferential tension on casing anchoring wellhead

If the wellhead is fixed to the casing, a biaxial stress condition exists. The combined effects of axial and circumferential tension are calculated as below: **Equation 12**

Design factor ≥ 1.5

$$Ft = [(\sqrt{5}/2)\ x\ (pwd/(D-d)] \tag{12}$$

$$\frac{Steel\ Yield\ Strenght}{Max\ Tensile\ Strength} \geq 1.5$$

7.7.1 Maximum external pressure after cementing

At a later stage of the casing cementing operation, the maximum differential external pressure occurs near the casing shoe when the casing annulus is filled with dense cement slurry and the casing is filled with water. The maximum differential external pressure is: **Equation (13)**

Design factor ≥ 1.2

$$\Delta Pexternal = [Lz\, \rho c - Lz - \rho f\,]\, x\, g \tag{13}$$

$$\frac{Pipe\ Collapse\ Pressure}{Diffrential\ External\ Pressure} \geq 1.2$$

7.7.2 Maximum external pressure during production

During geothermal production, the maximum external differential pressure occurs near the casing shoe when the annulus is at formation pressure (FP) and the internal pressure is controlled by well drawdown. In the worst case the internal pressure at the casing shoe can affect the operating wellhead pressure. The pipe collapse strength is de-rated for the temperature at the shoe. **Equation (14**

Design factor ≥ 1.2 (14)

$$\frac{Pipe\ Collapse\ Pressure}{Diffrential\ External\ Pressure} \geq 1.2$$

8. RESULTS

The design calculations results for the new well are shown below in tables 7-17. This calculation has been done referring to the African Union Code of Practice 2016 guidelines standard. Sour service materials casing grades are selected for this project such K-55 for the surface casing, L-80 for the anchor casing and production section as shown in the resulting Table 6.

TABLE 6: Resulting casing selections for well P-1

Casing size (inches)	20	13⅜	9⅝	7
Grade	K-55	L-80	L-80	L-80
Weight, lb/ft	94	68	47	26
Inside diameter, mm	485.7	315.3	220.5	159.4
Drift diameter, mm	481	311.4	216.5	156.2
Collapse resistance MPa	3.6	15.6	32.3	37.3
Wall thickness, mm	11.1	12.2	12	9.2
Tensile, strength (1000-dAN)	659	692	483	269
Minimum Yield strength, MPa	379	551	551	551
Steel cross section mm^2	17366	12545	8756	4870
Thread type	BTC	BTC	BTC	BTC

8.1 Collapse / burst pressures during cementing

The Collapse pressure calculation designs were done by assuming the annulus to be filled with 1800 kg/m^3 of cement slurry and with water of 1000 kg/m^3 at 30°C inside the casing. Correspondingly, the burst pressure was calculated by considering the annulus to be filled with water 1000kg/m^3 at 30°C and 1800 kg/m^{3}of cement slurry. Results on the collapse, burst pressures and design factors for the different casings are presented in Table 7 and 8.

TABLE 7: External pressure collapse during cementing

Casing size and grade	Casing weight (lb/ft)	Length (m)	Eternal pressure, ΔP (MPa)	Collapse resistance (MPa)	Calculted	Minimum design factor
Surface casing (20″)K-55	94.5	250	1.962	3.6	1.83	1.2
Anchor casing (13⅜″) L-80	68	450	3.532	32.8	4.42	1.2
Production casing (9⅝″) L-80	47	800	6.278	15.6	5.22	1.2

TABLE 8: Internal pressure collapse burst during cementing

Casing size and grade	Casing weight	Length (m)	Internal pressure, ΔPinternal (MPa)	Internal yield pressure (MPa)	Calculated	Minimum design factor
Surface casing (20″)K-55	94.5	250	2.158	14.5	6.72	1.50
Anchor casing (13⅜″) L-80	68	450	3.728	34.6	9.28	1.50
Production casing (9⅝″) L-80	47	800	6.475	47.3	7.31	1.50

8.2 Axial loading before and during cementing

Axial forces generate and performance on the casing string before and during the cementing process starts. Table 9 shows the results on axial forces on casings before and during cementing assuming the worst case, when the internal fluid is water and displaced fluid is cement for the three sections of casings.

TABLE 9: Before and during cementing

Casing	Casing weight (lb/ft)	Internal fluid/ water	Displaced fluid/ cement	Fcsg air wt (kN)	Maximum tensile load (kN)	Yield strength (kN)	Calculated	Minimum design factor
Surface casing (20")	94.0	453.9	893.8	343	-96.9	6581.7	-67.9	1.8
Anchor casing (13⅜")	68	344.33	719.4	446.4	71.30	6912.3	96.95	1.8
Production casing (9⅝")	47	299.38	662.58	548.8	185.60	4824.56	25.99	1.8

8.3 Axial loading after cementing

After cementing the axial loading force may stay positive or changed to negative due to the temperature increase or decrease in the well.

a) Axial load due to temperature increase:

The axial load may arise after cementing job when temperatures increase in the well. Three scenarios have been engaged for casing strings the surface, anchor and production were set at a temperature of 30, 35 and 40°C. Correspondingly and maximum temperature of each casing string has been taken in to consideration. The max temperature at the surface, anchor and production casings were assumed to be 95°C, 127°C and 183°C respectively. The negative sign values indicated at the compressive force means that byoncy force is acting upward. The design factor in the older version of the NZ standard (1991) is 1.2 but in the revised standard (both NZ and AU version), it has been omitted for casings that will thermally yield and a limited plastic strain design needs to be applied as stated in the African Union Code of Practice in clause 2.10.3.4, this is out of the scope of this report. The results Axial force due to rise in temperature are computed in table 10.

TABLE 10: Axial force due to rise in temperature

Surface casing (20")	T-1°C	T-2°C	Compressive force Fc (kN)	Resultant force Fr (Kn)	Min yield strength (kN)	Calculated	Minimum Design factor
	30	95	-3008	3105	6581.7	2.12	1.2
	35	95	-2777	2873	6581.7	2.29	1.2
	40	95	-2545	2642	6581.7	2.49	1.2
Anchor casing (13⅜")	T-1°C	T-2°C	Compressive force Fc (kN)	Resultant force Fr (Kn)	Min yield strength (kN)	Calculated	Minimum Design factor
	30	127	-3243	3172	6912.3	2.18	1.2
	35	127	-3076	3004	6912.3	2.30	1.2
	40	127	-2909	2837	6912.3	2.44	1.2
Production casing (9⅝")	T-1°C	T-2°C	Compressive force Fc (kN)	Resultant force Fr (Kn)	Min yield strength (kN)	Calculated	Minimum Design factor
	30	183	-3570	3385	4824.6	1.43	1.2
	35	183	-3453	3268	4824.6	1.48	1.2
	40	183	-3337	3151	4824.6	1.53	1.2

b) Axial load due to temperature decrease.

The Axial load temperature may decrease after cementing job and cause tension force from the circulation cold fluid in the well. Three scenarios have been engaged for casing strings the surface, anchor and production. Results are computed in table 11.

TABLE 11: Axial force due temperature decrease

Surface casing (20")	T-1°C	T-3°C	Tension force *Ft* (kN)	Resultant force Fr (Kn)	Min yield strength (kN)	Calculated	Minimum Design factor
	30	20	463	366	6581.7	17.98	1.2
	35	20	694	597.	6581.7	11.02	1.2
	40	20	926	829	6581.7	7.94	1.2
Anchor casing (13⅜")	**T-1°C**	**T-3°C**	**Tension force *Ft* (kN)**	**Resultant force Fr (Kn)**	**Min yield strength (kN)**	**Calculated**	**Minimum Design factor**
	30	20	334	406	6912.3	17.03	1.2
	35	20	501	573	6912.3	12.06	1.2
	40	20	668	740	6912.3	9.34	1.2
Production casing (9⅝")	**T-1°C**	**T-3°C**	**Tension force *Ft* (kN)**	**Resultant force Fr (Kn)**	**Min yield strength (kN)**	**Calculated**	**Minimum Design factor**
	30	20	233	419	4824.6	11.51	1.2
	35	20	350	536	4824.6	9.00	1.2
	40	20	467	652	4824.6	7.40	1.2

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

Due to the lifting force by the fluid in the well that may generate a strain at the top of the anchor casing. The well is assumed to be full of steam with a maximum wellhead pressure of 9.7 MPa and with an ANSI class 900 for a safety instead of ANSI class 600 due to extremely high salinity fluid may come-up from the borehole to the surface. Table 12 demonstrates the results calculated.

TABLE 12: Tension force due to lifting force by the fluid on the anchor casing

Casing grade L-80	Casing weight (lb/ft)	Tension force at top, Fw (kN)	Min. Tensile strength (kN)	Calculated design factor	Minimum design facto r
Anchor casing (13⅜")	68	756	6912.3	9.14	1.8

8.5 Thermal expansion of the anchor casing into the wellhead

It is likely that the production casing may rise into the wellhead during the production phase of the well. Therefore, Lifting load could be applied to the anchor casing during production. Results are computed in table 13.

TABLE 13: thermal load expansion (wellhead)

Casing grade L-80	Casing weight (lb/ft)	Anchor casing tensile strength (kN)	Rising casing compressive strength Fw (kN)	Calculated design factor	Minim um design factor	Comments
Anchor casing (13⅜")	61.0 68.0	6216.3 6912.3	756 756	8.2 9.14	1.4 1.4	Suitable

8.6 Helical and buckling for liner casing

The un-cemented liners subject to axial self-weight and helical buckling calculated in Table 14 considering the temperature reduction factor for different grades. Note that **Ri** is the temperature reduction factor for different grades and **Rj** is the connection efficiency in compression.

TABLE 14: The helical buckling of the liner casing (uncemented)

Casing diameter and grade	Compressive stress (MPa)	Ri	Rj	Minimum yield strength (MPa)	Calculated design factor	Minimum design factor	Comments
7" K-55 (26")	382.28	0.7	1	379	0.69	1	Not suitable
7" K-55 (46")	642.11	0.7	1	379	0.41	1	Not suitable
7" L-80 (26")	382.28	0.81	1	551	1.17	1	Suitable

8.7 Internal Differential pressure at the casing shoes

The maximum internal differential pressure of the casing section at casing shoe for the surface, anchor and production are shown in table 15.

TABLE 15: Internal Differential pressure at the shoes casing

Casing diameter	Lz (m)	Lf (m)	Differential internal pressure (MPa)	Internal yield pressure (MPa)	Calculated design factor	Minimum design factor
20" K-55	250	230	2.16	14.5	6.71	1.5
13⅜" L-80	450	430	7.55	34.6	4.58	1.5
9.5/8 " L-80	800	780	6.47	47.3	7.31	1.5

8.8 External Differential pressure at the casing shoes

The maximum external differential pressure of the casing section at casing shoe for the surface, anchor and production are shown in table 16.

TABLE 16: External Differential pressure at the shoes casing

Casing diameter	Lz (m)	Lf (m)	Differential External pressure (MPa)	Internal yield pressure (MPa)	Calculated design factor	Minimum design factor
20" K-55	250	230	1.96	14.5	7.39	1.5
13⅜" L-80	450	430	3.53	34.6	9.80	1.5
9.5/8 " L-80	800	780	6.27	47.3	7.54	1.5

8.9 External Differential pressure during production operation

The maximum external differential pressure arises nearby the casing shoe. The maximum pressure downhole is 9.7 MPa and the design factor is calculated in Table 17 assuming full steam from the bore hole to the surface.

TABLE 17: External pressure collapse during production operation

Casing diameter	Lz (m)	Differential external pressure (MPa)	Pipe collapse pressure (MPa)	Calculated design factor	Minimum design factor
9⅝" K-55	800	9.7	26.8	2.76	1.2
9⅝" L-80	800	9.7	32.8	3.38	1.2

9. DISCUSSION

In this section will discuss the results obtained and the outcome of the design calculations results as shown above in tables 7-17. These calculations have been done referring to the African Union Code of Practice 2016 guidelines standard. Sour service materials casing grades are used such K-55 for the surface casing, L-80 for the anchor casing and production section as shown in the resulting casing selections Table 6.

9.1 Collapse / burst pressures during cementing

The casing strength against collapse were done for the three different section such 20″, 94 lb/ft K-55 surface casing, 13⅜″, 68lb/ft L-80 intermediate casing and 9⅝″, 47 lb/ft L-80 production casing to find out whether this selected grades are strong to resist the pressure exerted during cementing . This was completed by comparing the results found against the minimum design factor specified in the African Union Code of Practice 2016. Results for collapse pressure for the surface casing at 250m was 1.96 MPa with a design factor of 1.83, anchor casing at 450m was 3.53 MPa with a design factor of 4.42, production casing at 800m was 6.28 MPa with a design factor 5.22MPa . Referring to the African Union Code of Practice the minimum design factor is 1.2. These signify that the result obtained is over the minimum design factor which is very much adequate as shown in table 7.

Collapse pressure against burst were done during cementing for the three different section such 20″, 94 lb/ft K-55 surface casing, 13⅜″, 68lb/ft L-80 intermediate casing and 9⅝″, 47 lb/ft L-80 production casing to find out whether this selected grades are strong to resist the pressure exerted during cementing . This was completed by comparing the results found against the minimum design factor specified in the African Union Code of Practice 2016. Results for burst pressure for the surface casing at 250m was 2.16 MPa with a design factor of 6.72, anchor casing at 450m was 3.73 MPa with a design factor of 9.28, production casing at 800m was 6.48 MPa with a design factor 7.31MPa . Referring to the African Union Code of Practice the minimum design factor is 1.5. These signify that the result obtained is over the minimum design factor which is very much adequate as shown in table 8.

9.2 Axial loading before and during cementing

The axial loading results for the surface casing obtained assuming for the worst case, kN when the internal fluid is water and displaced fluid is cement for the three sections of casings as -96. kN hookload and the calculated design factor is -67.9 kN for the surface casing, 71.30 kN hookload and calculated design factor is 96.95 kN for the anchor casing, 185.60 hook load kN and calculated design factor is 25.99 kN. The negative sign means that it's on compressive load acting downward. The minimum design factor is 1.8 as stipulated on the standard which that showed that the calculation design was adequate and over the standard design factor as shown in table 9.

9.3 Axial loading after cementing

The Axial load may arise or decrease after cementing job, when the temperatures increase or decrease in the well. Three scenario have been engaged for different casing strings, the surface, anchor and production were set at a temperature of 30, 35 and 40°C, correspondingly and maximum temperature of each casing string has been taken in to consideration . The max temperature at the surface, anchor and production casings were

95°C, 127°C and 183°C respectively. Results are computed in the table 10 above. The negative sign values indicated at the compressive force means that force is in compressive motions acting downward. The Axial load temperature may decrease after cementing job and cause tension force from the circulation cold fluid in the well. Three scenarios have been engaged for casing strings the surface, anchor and production. The max temperature at the surface, anchor and production casings at the time of cement set were set at 30°C, 35°C and 40°C and the Minimum temperature after cooling well was set at 20 °C respectively. Results are computed in table 11 above. The design factor in the older version of the NZ standard (1991) is 1.2 but in the revised standard (both NZ and AU) it has not been addressed they have assumed that all casing will thermally yield therefore, the limited plastic strain design need to be applied as stated in the African Union Code of Practice in clause 2.10.3.4, this is out of the scope of this report. The results obtained referring to the design factor in the old version 1991 are satisfactory.

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

Due to the lifting force by the fluid in the well that may generate a strain at the top of the anchor casing. The well is assumed to be full of steam with a maximum wellhead pressure of 9.7 MPa and with an ANSI class 900 for a safety instead of ANSI class 600 due to extremely high salinity fluid may come-up from the borehole to the surface. To determine the tension force may occur by the lifting fluid in the well at the top anchor casing, calculations were also done for the 13⅜″, 68 lb/ft L-80 anchor casing supporting the wellhead. The results found min tensile strength is 6912.3 kN and tension force is 756 kN. The design factor calculated in table 12 is 9.14 which indicated is over the standard design factor of 1.8. Therefore the design selected grade is very much adequate and the design is safe.

9.5 Design factor for the thermal expansion of the anchor casing into the wellhead

It is likely that the production casing may rise into the wellhead during the production phase of the well. Therefore, Lifting load could be applied to the anchor casing during production. Two scenarios have been demonstrated to compare between to different casing weigh of grade L-80. Results showed a design factor of 8.2 for the 61 lb/ft casing against the required stipulated minimum design factor of 1.4 and 9.14 for the 68 lb/ft casing against the required stipulated minimum design factor of 1.4. The design factors for both scenarios are suitable as shown in table 13.

9.6 Helical and buckling for liner casing

The 7” un-cemented liner subject to axial self-weight and helical buckling calculated considered the temperature reduction factor for different grades. 2 scenarios have been demonstrated for grade L-80and K-55 for the 7” un-cemented liner. The temperature reduction factor for the K-55 is 0.7 and minimum tensile strength is 379 MPa, L-80 is 0.8 and minimum tensile strength is 551 MPa. The computed design obtained is 0.69 for K-55 and 1.17 for L-80 against the standard design factor 1. This shows that K-55 is not suitable grade comparing to the L-80 based on the calculation obtained in table 14.

9.7 Internal Differential pressure at the shoes casing

The maximum internal differential pressure of the casing section at casing shoe for the surface, anchor and production are calculated for the different casing strings the results found in table 15 above that the casings selected were adequate and there safely beyond the minimum design factor standard of 1.5

9.8 External Differential pressure at the shoes casing

The maximum external differential pressure of the casing section at casing shoe for the surface, anchor and production are calculated for the different casing strings the results found in table 16 above that the casings selected were adequate and there safely beyond the minimum design factor standard of 1.5

9.9 External Differential pressure during production operation

The maximum external differential pressure arises nearby the casing shoe. The maximum pressure downhole is 9.7 MPa and the design factor is calculated in table 17 assuming full steam from the bore hole to the surface. The results obtained comparing between 2 different grades K-55 and L-80 shows that L-80 has high pipe collapse pressure of 32.8MPa against 26.8 MPa for K-55. The calculated design factor obtained for L-80 is 3.38 against the design factor calculated for K-55 as 2.76 both grades over the design standard factor of 1.2. Both grades are adequate grades based on the minimum design factor.

10. CONCLUSION AND RECOMMENDATION

The asal area has a high salinity fluid of 120 g/L within the reservoir, which needs to be taken in to consideration by selecting proper casing grades for sour service to protect against any gases that may be present in the borehole such as H2S gases.

Scaling challenge is one of the critical issues that need to be considered. Especially, in the area where a high degree of salinity fluid may be present. In order to minimize scaling in the well, potential solutions need to be adopted, e.g. by selecting a large diameter such as 13-3/8 inch for the production casing and by a pressure drop control within the well. In addition, well design with a deeper production casing should be considered in order to avoid the deposition zone to be inside the liner and, instead control the scaling to a location where a cleaning operation could be successful.

K-55 has been selected for the top surface and L-80 for the rest of casing sections, due to the extrem salinity fluid which may reduce the life time of the well and productivity. L-80 has more control on composition than K-55 and higher minimum tensile strength of 551 MPa. Referring to the African Union Code of Practice 2016 clause 2.10.1.4 (b), the K55 has minimum yield strength of 379 MPa.

Well design weather for a deep or shallow geothermal well assum an enormous challenges. Therefore, proper selection of API 5CT standard casing grades and ANSI B16.5 or API SPEC 6 A-D standard wellhead necessary required.

Minimum casing depth selection are set based on the pore pressure and fracture gradient, available data from nearby wells drilled such geological formation rocks type, temperature and pressure versus depth or by following the casing design process described in the African Union Code of Practice for geothermal drilling (2016).

Referring to the African Union Code of Practice 2016 clause 2.10.3.4, that conventional design factors are not applicable for casing that is designed to yield. Therefore, if that is the case a call for the limited plastic strain designs mandatory.

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