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RIG SELECTION FOR COST EFFECTIVE DRILLING IN ALUTO LANGANO, ETHIOPIA

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ABSTRACT

Since the beginning of the 1980s, eight exploration wells and 2 appraisal wells have been drilled in the Aluto Langano geothermal field in Ethiopia and two additional wells have been rehabilitated. A 7.2 MW combined cycle steam/binary power plant was installed in May 1998, which is now out of service. Drilling is currently under way to facilitate electricity production of 70 MW. The plan is to drill 3 vertical and 5 directional wells to a maximum depth of 2500 m and to construct a steam gathering and reinjection system. The aim of this project is to examine the technical requirements for a geothermal rig for future drilling at Aluto Langano and provide a transparent account of rig selection for cost-effective drilling. The criteria for the rig selection are described and the minimum required technical rating of the rig equipment is determined. Then rigs on offer for a particular drilling job can be evaluated based on their ratings according to the American Petroleum Institute (API) and ISO standards. The importance of the rig´s instrumentation and automatic data recording system, as well as the quality of the data is also explored.

1. INTRODUCTION

Ethiopia has over 20 geothermal prospects located along the Ethiopian main rift system, which is part of the continental East Africa rift zone. Since the beginning of the 1980s, 16 geothermal exploration wells and 2 appraisal wells have been drilled, and 2 more wells have been rehabilitated. The two rigs used in the past for geothermal drilling were conventional drilling rigs owned by the Ethiopian Geological Survey and the work was supported by international development programs. Figure 1 shows the location of areas where wells have been drilled, as well as other prospect areas. The Electrical Power Corporation has recently acquired two new drilling rigs with top-drive for its geothermal program and started drilling in Aluto Langano in March 2021.

2. GEOLOGY OF ALUTO LANGANO

The Aluto volcanic complex covers an area of about 100 km^2 between lakes Langano and Ziway and rises to an elevation of 690 m above the surrounding Adami-Tullu plain which has an elevation of about 1600 m a.s.l. The broad truncated base and the summit caldera are 6 km by 9 km (with an area of 37 km²) elongated in WNW direction and have formed a basin of internal drainage (Worku Sisay, 2016). Volcanic activity at the Aluto volcanic centre was entirely contained in the Quaternary with earlier sub-lacustrine eruptions. The activity started with a rhyolite dome building phase interrupted by explosive pyroclastic pumice eruptions and a major caldera-forming pyroclastic eruption. The ignimbrite is now exposed on the flanks of the Aluto volcanic massif as pumices ignimbrites and sub-aqueous pumices tuff with minor intercalations of lacustrine sediments.

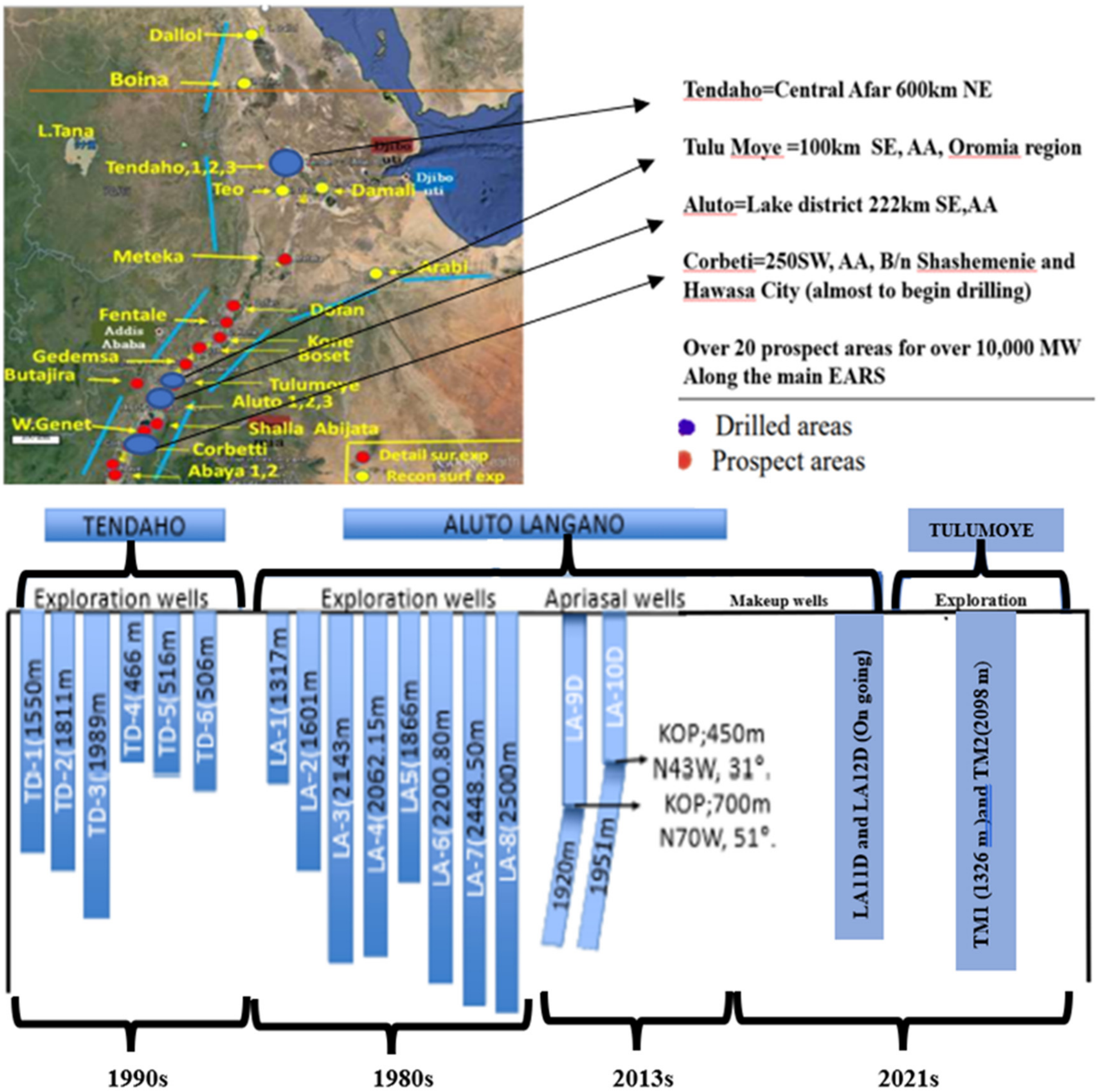


FIGURE 1: Geothermal wells drilled in Ethiopia

2.1 Stratigraphy and lithology

Post caldera collapse rhyolite flows and domes with minor pyroclastic products formed along the NE-SE segment of the Aluto caldera rim on a basement of pumices ignimbrites and older rhyolite. Predominantly rhyolite post-caldera lava and pyroclastics have erupted from numerous craters with all vents being clearly controlled by either the caldera ring fracture or the NNE trending faults of the Wonji Fault Belt (WFB). The northern segment of the centre is characterised by large rhyolite domes and flows, which do not show indications of being structurally controlled. Minor basaltic lavas have erupted from the NNE trending faults east of the Aluto massif and the Aluto caldera is covered by alluvial sediments (Teklemariam and Beyene, 2000).

The geographical location and lithology can have a major impact on cost, schedule, and even well design. A special consideration in some regions is the possibility of encountering hydrocarbon resources, which is not the case in Aluto Langano.

3. RESERVOIR CHARACTERISTICS OF ALUTO LANGANO

3.1 Temperature and pressure

Numerous pressure and temperature logging surveys have been carried out in the existing Aluto Langano wells (LA-1, LA-2, LA-3, LA-4, LA-5, LA-6, LA-7, and LA-8, Figure 2), which were drilled in the 1980's. After checking all the logging data and temperature and pressure profiles, the pre-exploitation conditions (natural state conditions) were determined.

The temperature increases with depth and in LA-10D, it exceeds 300°C at 1500 m. The temperature observed in wells LA-4, LA-5, LA-7, and LA-8 is relatively low compared to that of LA-3 and LA-6. Temperature inversion can be observed at these four wells. This indicates the existence of a main upflow zone of high temperature fluid around wells LA-3 and LA-6. The temperature inversion observed at wells LA-4, LA-5, LA-7, and LA-8 can be explained by the lateral expansion of the ascended hot fluid at relatively shallow depth.

Well	LA-3	LA-4	LA-5	LA-6	LA-7	LA-8	LA-9D	LA-10D
Drilled depth (m)	2114	2062	1867	2203	2448	2500	1921	1950
Elevation (m.a.s.l)	1921	1956	2037	1962	1891	1895	1963	1960
Permeable zones (m)	2000-2121	1445-1800	-	2000-2200	2100-2300	2300-2500	760-1350	920-1760
Maximum T (°C)	322	240	210	335	228	284	308	310
Status of the well	P	P	NP	P	RW	P	P	P
Year of drilling	21/1/83-13/6/83	6/783-23/10/83	15/11/83-11/3/84	24/3/84-2/7/84	12/7/84-21/10/84	26/10/84-13/5/84	12/11/13-01/02/15	25/06/15-02/10/15

FIGURE 2: Summary data of Aluto Langano wells LA-3 to LA-10

Wells LA-1 and LA-2, which were drilled outside of the caldera show relatively low temperatures (50-100°C) and are not encountering the main geothermal reservoir. The Aluto Langano geothermal field is classified as a high temperature geothermal field as the temperature is greater than 200°C at a depth of 1000 m and ranges from 210°C up to 335°C. Pressure interference tests were carried out three times in 2015 during the long-term discharge test of LA-9D and LA-10D to identify interferences between the wells. The hydraulic connections between production wells and the observation wells are as follows: 1) Observed pressure change in LA-10D when well LA-9D started to discharge; 2) Observed change in reservoir pressure in LA-4 when LA-10D was shut-in; and 3) Observed reservoir pressure change in LA-6 when well LA-10D started to discharge. Pressure profiles of the wells show a water level at around 300-500 m. The water levels are relatively shallow, especially the water level of LA-3 which reaches the wellhead. This observation supports the assumption that the main upflow zone is located beneath well LA-3. The reservoir pressure and temperature serve as a basis for the well design, which in turn affects the rig requirements.

3.2 Power potential of Aluto and development

The first 7.2 MW_e (combined cycle: back pressure steam turbine and organic Rankine cycle (ORC) unit) pilot power plant was installed in the Aluto Langano field by the Ethiopian Electric Power Corporation and connected to the national power grid in May 1998. It was started by connecting four production wells, LA-3, LA-4, LA-6 and LA8, and one reinjection well, LA-7 (Teklemariam and Beyene, 2000). The capacity of this geothermal field was assessed to be 30 MWe for 30 years. The pilot power plant has not been in full operation due to problems related to the production wells (e.g. decline of well pressures, scaling, and wellhead valve problems) and problems related to the power plant involving cooling tower fan breakdowns, pentane leakage from the heat exchangers and so on. According to Kebede (2012) and Tassew (2015), the plant has been partially renewed and produced 4 MWe in 2007 using the steam turbine, as the ORC unit is out of service (Figure 3). The plant is no longer in use. In 2015 and 2016, two exploration wells, LA-9D and LA-10D, were drilled with a refurbished rig owned by Ethiopian Electric Power (EEP). These wells are the first directional wells in Ethiopia.

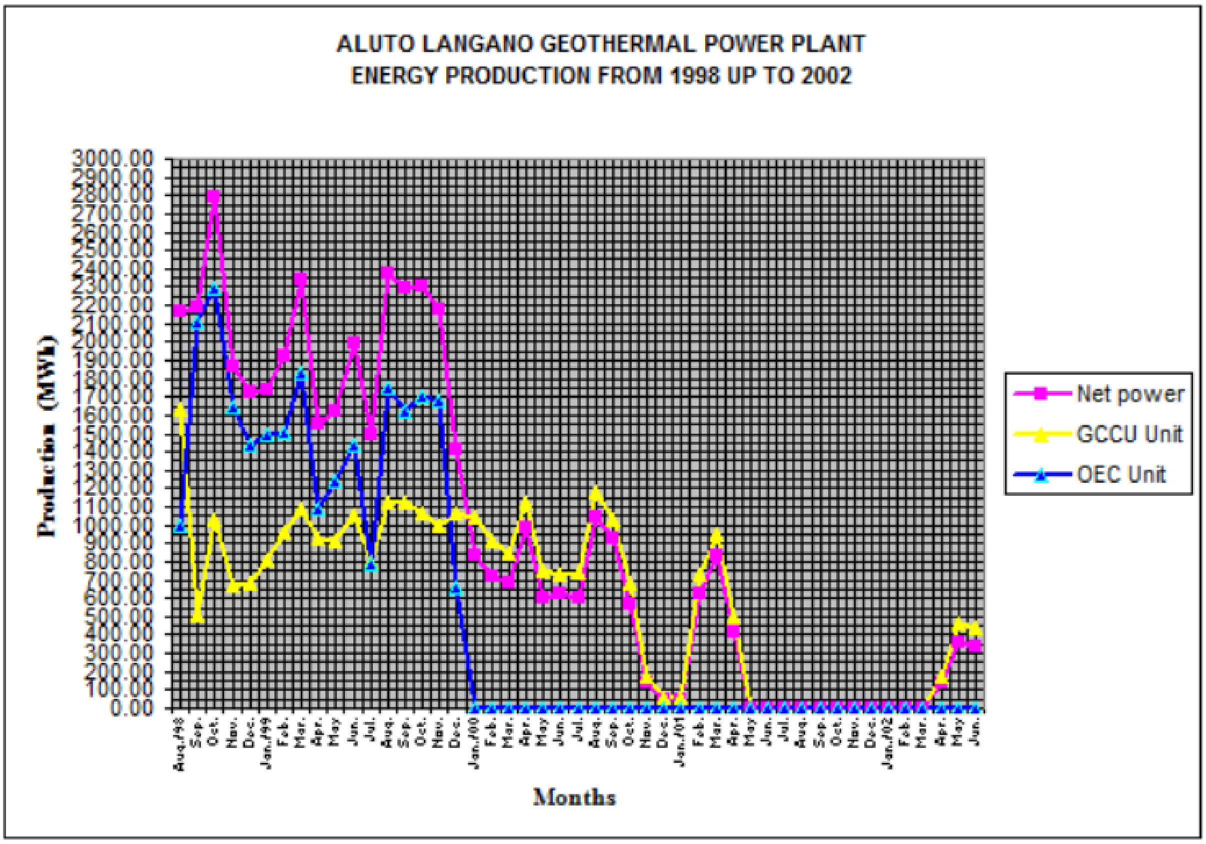


FIGURE 3: Power production of Aluto power plant in MWe (Tassew, 2015)

4. GEOTHERMAL WELLS IN ALUTO LANGANO

4.1 Casing design

The prediction of deep rock and fluid conditions can be subject to considerable uncertainty, particularly during the exploration phase. Conservative assumptions or design factors should therefore be adopted. As more wells are drilled, sufficient data should be assessed to confirm the validity of the well design, or to indicate where further observations or design modifications might be required. Factors to consider are:

(a) Intended purpose;
(b) Targeting: vertical or directional;
(c) Well design: diameters and depths of casing strings;
(d) Design lifetime; and
(e) Operation and maintenance.

For design of high-temperature geothermal wellheads there are two main possibilities: Casing head attached to the production casing or to the intermediate casing (anchor casing) as in Aluto. Aluto Langano geothermal casing programs are as shown in Figure 4. Each casing string and wellhead should be designed to withstand the maximum design pressure for the corresponding hole section. The minimum casing shoe depth for each cemented casing string should be the depth where the formation has sufficient effective containment pressure to equal the maximum design pressure expected to be encountered when drilling the next open-hole section, as prescribed in the *African Union Code of Practice for Geothermal Drilling* (African Union's Regional Geothermal Coordination Unit, 2016).

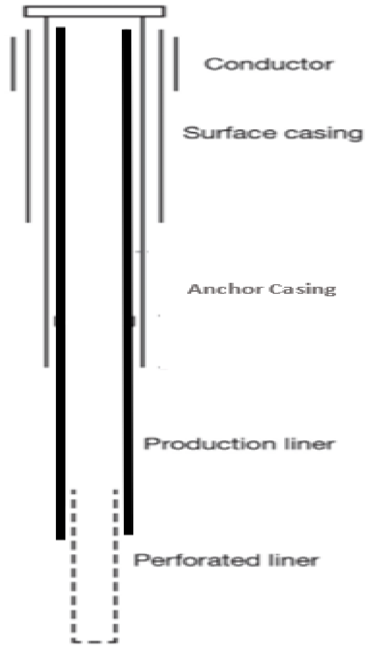


FIGURE 4: Casing program as in Aluto Lagano wells

Due to effects of combinations of pressure and temperature, that may occur at any time or depth during the drilling and operation of the well, it is critical to assess casing stress paying attention to the following aspects:

(a) Room for the linear expansion or contraction of uncemented lengths of casing or liner including potential effects on the liner hanger.
(b) For elastic design, evaluate thermal stresses in fixed sections and to maintain casing and casing connection sealing integrity.
(c) For a strain-based plastic design, adequate sealing integrity at connections.
(d) For a strain-based plastic design, stress concentrations from material property or dimensional variations that can lead to low cycle fatigue or failure.

Most of the criteria used to select a drill rig are derived from well parameters, specifically: Depth, diameter, casing depth, and drill string. That impacts for example the minimum hook load rating of the rig and mud pump sizing.

4.2 Directional drilling

Directional drilling is an important method of drilling which enables drilling into several feed zones. The hole is intentionally drilled off-vertical using special tools, usually starting about 50 m below the previous casing shoe (kick-off-point (KOP)), towards a preselected target using the following techniques and equipment:

(a) Survey methods are used to measure downhole inclination and direction of the hole to be able to calculate the hole position in three dimensions. Examples of survey methods include single-shot or multi-shot surveys, mud-pulse or electromagnetically transmitted signals while drilling (MWD), and gyroscopic surveys.
(b) Non-magnetic drill collars and, possibly, non-magnetic stabilisers are included in the bottom hole assembly (BHA) if magnetic type survey instruments are to be used.
(c) Equipment to direct the drill into the required direction and inclination, and to correct the direction or inclination as drilling progresses. Such equipment includes bent housing positive displacement or turbine-type mud motors, bent sub run above a straight mud motor, or turbine type mud motors and rotary steerable tools (not applied for geothermal drilling yet).

The kick-off point (KOP) is later cased off and care should be taken to avoid damage to the casing during subsequent drilling operations. This may include avoiding the rotation of hard-banded tool joints over intervals inside the casing where there is a change in hole angle or dog-leg, and pumping liquid down the annulus when drilling without returns of circulation. The final well depth needs to be restricted to not exceeding available drilling equipment capacity, e.g. the rotary torque rating of the drill string. The KOP and maximum inclination of recently directionally drilled wells LA-9D and 10D is shown in Figure 5. The trajectory of a deviated well must be carefully planned so that the most efficient trajectory is used to drill between the rig and the target.

When planning, and subsequently drilling the well, the position of all points along the well path (the trajectory) must be considered in three dimensions.

LA-9D LA-10D

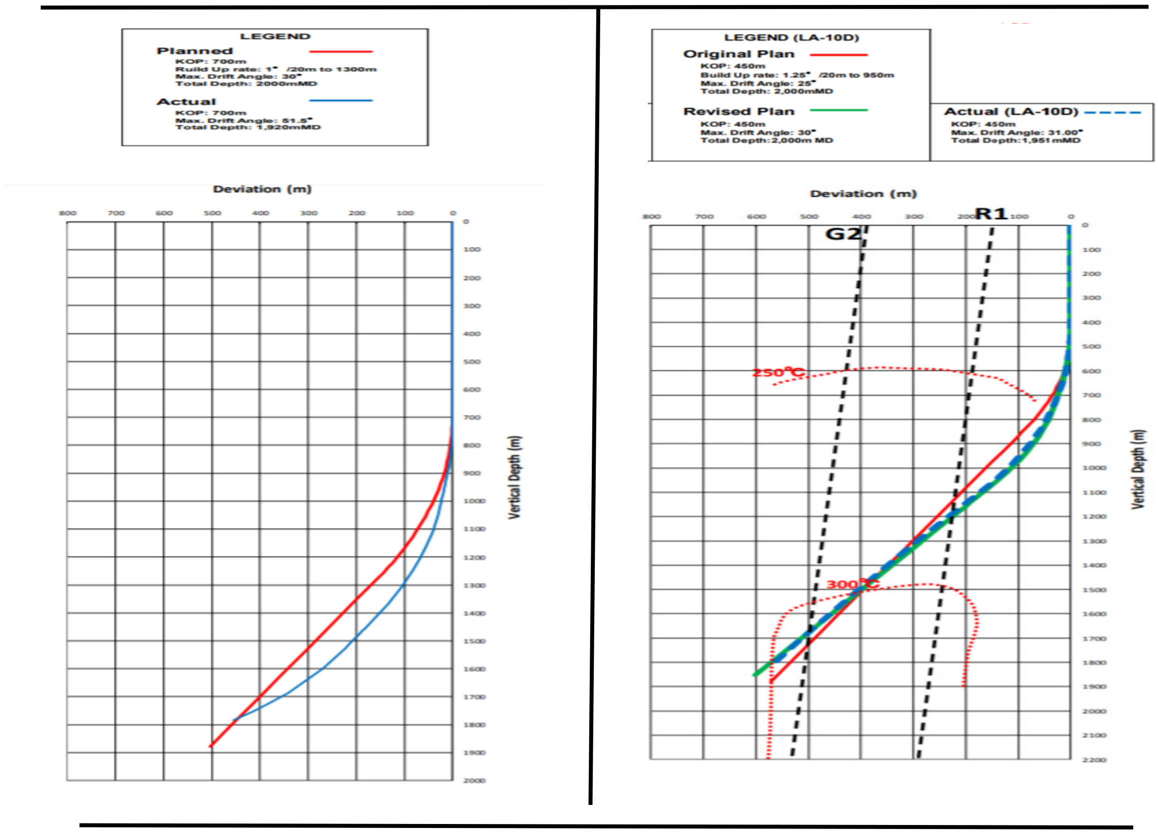


FIGURE 5: Directional drilling trajectory of LA9D and LA10D

4.3 Drilling fluid

Common drilling fluids for geothermal drilling are: Water, water based bentonite mud, aerated water (balanced- or underbalanced drilling) or water with periodic polymer pills. The main function of the drilling fluid is to clean the hole and cool the mud motor and drill bit. The drilling fluid is also important for well control to avoid kicks. As long as the hydrostatic pressure in the column of drilling mud in the well is higher than the fluid pressure in the formation, the formation fluids will be confined in the formation. If the differential pressure of the hydrostatic head becomes negative, the formation fluid invades the hole, displacing the drilling mud. Continued displacement can result in a blowout. Aluto wells have been drilled with water-based mud and with water. Drilling water was treated with soda ash and sodium bicarbonate for pH control to reduce water hardness and prevent cement contamination. One of the issues that caused delays during drilling at Aluto in the past was inadequate supply of drilling water.

4.4 Drilling problems at Aluto Langano

Exploration drilling in Aluto Langano started under a United Nations Development Programme (UNDP) from 1982 to 1985 by drilling wells LA-1 to LA-8 to a maximum depth of 2500 m. A small size rig (100 t hookload) was used for the wells that had a 9 5/8" production casing and a 7" slotted liner. The drilling generally went well (Figure 6).

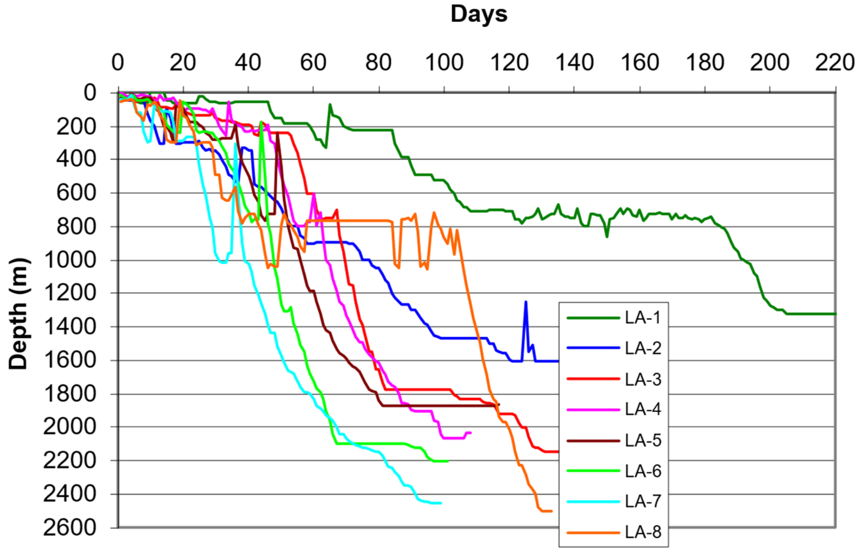


FIGURE 6: Drilling progress curves (depth vs. days) for wells LA-1 – LA-8 at Aluto Langano

Circulation losses: Loss of circulation was encountered shortly after drilling started just below the cellar of LA-9D. This was the result of low-quality foundation grouting at the drill site. Cement plugs were pumped 75 times to help seal this loss. As a result of these losses the original drilling plan with a KOP at 300 m depth was changed to 700 m.

Rig condition: Due to poor condition of the rig engines during the drilling of the LA-10D 12 1/4" hole section, it was decided to run the 9 5/8" casing to 809 m instead of 1000 m depth. During the drilling of well LA-9D and well LA-10D, the desilter and the cooling tower were fed by the same centrifugal pump, which reduced the efficiency of the desilter. Inadequate logistics and major rig maintenance activities during the drilling of wells LA-9D and LA-10D contributed to non-productive time (NPT).

Water supply: During the drilling of LA-9D, inadequate water pond capacities and water pumps were the main reasons for delays.

4.5 Drilling program

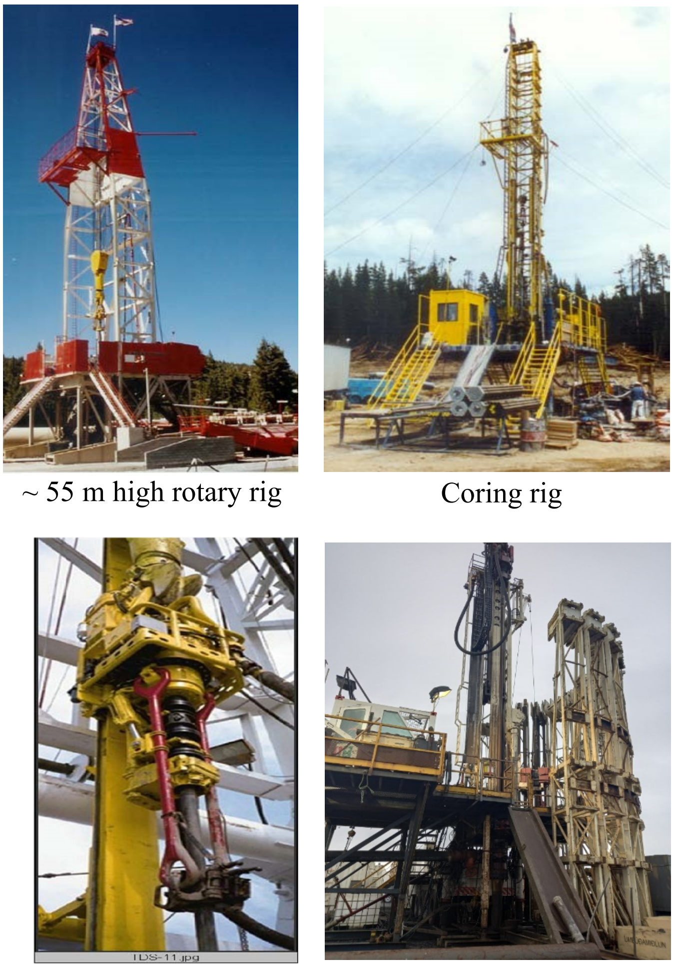
Before drilling operations begin, a detailed well design and drilling programme must be prepared. The well design and drilling programme shall:

(a) Describe the works.
(b) Demonstrate that adequate precautions have been taken to satisfy the provisions of the *African Union Code of Practice for Geothermal Drilling* (African Union's Regional Geothermal Coordination Unit, 2016).
(c) Describe the well control equipment (blow-out-preventers) used during drilling.

The drilling program is issued specifically for each well and consists of the well design, a description of the drilling procedures for each stage, and materials to be used. It is more detailed than the drilling specifications included in drilling tender documents. The final version of the drilling program is sometimes not completed until a few weeks before the operation starts, not with the aim to make major changes in the design but rather to include useful changes in the operational program after consultation with all parties to the drilling project. For this purpose, a meeting is called with the parties involved in the execution of the drilling operations to review the drilling program, also referred to as Drilling Well on Paper (DWOP).

5. RIG TYPES

Drilling is an industry where the final product is a borehole. Geothermal drilling technology is for most parts borrowed from the petroleum industry with some modification to fit the geothermal conditions of high temperature and pressure, drilling in hard, fractured formations and large diameter casing programs. With advancements in technology, rig manufacturers now offer a selection of modern electric or hydraulic rigs with different degrees of automation for the handling of drill pipes and casings. The successful completion of a geothermal well on time and with a good safety margin depends on the efficiency of the rig and the level of skill of the rig crew, together with proper planning and coordination of pre-drilling activities like infrastructure installation and procurement of casings and consumables required for the drilling operation. One step in the preparation is to choose the right type and size of rig (Figure 7) with a good safety margin that fits the drilling program of the wellbore design. Coring rigs are fundamentally different from rotary rigs as they retrieve cores used for minerals exploration. If a large-diameter hole is required, a conventional rotary rig will probably be used which is either a Kelly rig with a rotary table or a top-drive rig. In the early 1980's, a new system "top-drive" in which the drill string was turned by an electric or hydraulic motor hanging directly beneath the traveling block gained commercial acceptance. During the process of planning and designing the well, the diameter will have been decided, which is the primary criterion for whether the well is considered a "slimhole" or a conventional well and, thus, what kind or size of rig will be used.



~ 55 m high rotary rig | Coring rig

Top-drive | Telescopic mast rig

FIGURE 7: Different rig types

5.1 Drill string rotation

The main difference between the top-drive rig and the earlier conventional rig designs with a rotary table drive is the position of the rotary drive mechanism (Figure 8). The top-drive system is situated in the mast and moves with the drill string up and

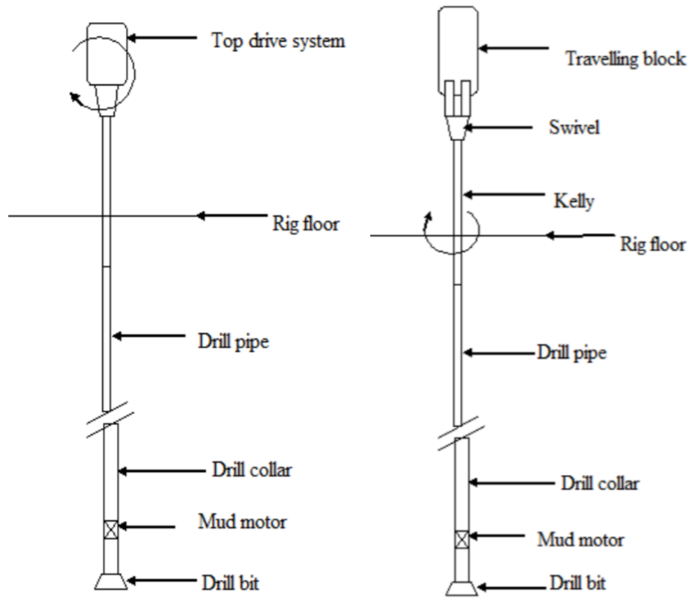


FIGURE 8: The difference between rigs with a top-drive system (left) and a rotary table (right). The drill string design is the same.

down along the mast guide. The top-drive system torque comes from a hydraulic or electrical motor drive. The rotary table drive system is placed on the rig floor and is connected to the drill string with a Kelly (hexagonal pipe).

5.2 Drill string design

Drill string design calculations are made to aid the selection of items from a list of drill string components. The objectives are to:

- Keep the maximum stress at any point in the drill string below the yield strength specified by a design factor;
- Select components and configure assemblies to retard fatigue as much as economically practical.
- Provide equipment that is resistant to hydrogen sulphide if H_2S is expected.

There are many factors that must be considered in the drill string design, such as: Total depth, hole size, mud weight, over pull, bottom hole assembly components, hole angle, pipe weights and grades, corrosive environment, and ability to fish tools out of hole.

Unless mechanical hole sticking is a problem, the largest diameter drill collars consistent with other needs are generally best. Their increased stiffness means more directional and drill bit stability. Also, they will have fewer connections for a desired weight on the bit and therefore a shorter BHA, which can decrease the probability of differential sticking. Larger collar diameter in a given hole also mean less lateral freedom of movement in the BHA. This reduces buckling stress and the rate of connection fatigue. In practice, however, the drill string is often determined by the existing rig inventory. Other factors which come into play are: Fishability considerations, capabilities of the rig handling equipment, directional control requirements, hydraulics, equipment age and condition, desired exterior drill string features (spiral grooves, elevator grooves, or other features).

The first thing to consider while running the drill string design calculation is to check if the drill pipes will be able to sustain the drill collars and BHA loads if the string gets stuck. Also, checking tool joints torsional strength and drill pipes torsional strength is important during the drill string design calculations to ensure that the torque produced during the drilling does not exceed the makeup torque of pipes and tool joints. Field tests have shown that the higher the stiffness ratio in the transition zone, the greater the fatigue build up.

Thread forms with full root radii should be used in all BHA connections to maximize fatigue resistance. Since torsion is transmitted from the top down, BHA connections are usually subjected to lower torsional loads than the connections above. However, if "stick/slip" is occurring, torsional strength should be checked to confirm that it is greater than the expected operating torsion at the BHA. Tool joint torsional strength tables cannot be used directly for this purpose because tool joint and drill collar materials have different yield strengths. However, drill collar connection torsional strength, TS, can be calculated by the following formula:

$$TS = \frac{MUT}{f} \tag{1}$$

where MUT = DC makeup torque; and
f = Decimal fraction of torsion yield strength that forms the basis for the makeup torque value.

The size and placement of stabilizers is often determined by directional considerations. When drilling inclined wells, there are two additional factors that must be considered in drill string design: (1) The frictional forces between the drill string and the hole; (2) The ability to use heavy-weight drill pipe (HWDP) to provide weight on the bit without buckling.

5.3 Energy use of the rig

Energy sources for powering the rig equipment and ancillaries include direct diesel drives, diesel generators, and grid power. The energy consumption during drilling operations accounts for about 10-20% of the operational cost of the rig. Since most of the drilling sites are located in off-grid areas, the rigs must generate their own power using diesel generators. Depending on the size of the rigs they must have three to four 1 MWe generators. This power is mainly used by the drive system, the circulation system, for draw works, and for auxiliary supply. The mud circulation system uses the largest percentage of the energy. Improving the efficiency of the mud circulation system means that power is saved. Hydraulic rigs consume more energy because of conversion losses, for example when converting from AC to DC or from DC to hydraulic. When using aerated drilling, fuel consumption increases further by as much as 50-100% since two to three compressors are added as well as a booster unit. Running the mud pumps is of course still required when using aerated drilling.

Mechanical power: Major drive components are driven by the diesel engine power transmitted through a torque converter and clutches. Direct-diesel power was common on old style rotary table rigs.

Electrical power: Major drive components are run by electrical AC or DC motors. The power can come from the grid or diesel generators on site, and conversion from AC to DC for direct current motors (DC motors) is done by an SCR system, and by variable speed drives (VSD) for synchronous motors (AC motors).

Hydraulic power: Here the rig drive torque is mainly provided via hydraulic power, which is common with the top-drive system rig. The hydraulic pumps are driven by electrical motors.

5.4 Automation

The drill operators are facing more and more challenging geological conditions while also drilling into higher temperatures. In the hydrocarbon industry, advanced drilling methods are being introduced using artificial intelligence. Experienced crews having access to modern rig instrumentation and data acquisition systems have been found to be the most successful in geothermal drilling.

Advanced automation features add to the rig cost and may also add unwanted complexity to maintenance and operations. Top-drives, iron roughnecks (screwing and unscrewing drill pipe joints) and aids for handling drill pipes and casing should, however, be considered for new rigs.

A mud return flow indicator is usually a magnetic or paddle flowmeter in the flow line. It sends a signal to the driller's console where it is reported as "percent of flow" or actual flow. If a well kicks, something has entered the wellbore. This will push mud out of the flow line and will be shown as an increase in flow. So, an increase in flow is the first sign of a kick, and the flow sensor is the first indicator of a kick. The flowmeter is also valuable in monitoring drilling fluid losses. Flow sensor systems are a 'must have' during geothermal drilling.

5.5 Advantage and disadvantage of top-drive and conventional rig drive

A top-drive (Figure 9) is a very important part of the drilling equipment as it rotates the drill string. The top-drive is a combination of electrical and mechanical systems riding below the traveling block and it moves vertically up and down the derrick on one or two guide rails. Top-drives have a variety of advantages and prove beneficial in drilling operations. The top-drive rotates the shaft to which the drill string is attached and decreases the amount of manual work and labour that is involved compared to the conventional Kelly system.

The top-drive has many advantages over the Kelly system regarding functionality, safety and efficiency. The top-drive system is capable of drilling with up to three drill pipes at a time instead of the single drill pipe in a conventional Kelly system.

A top-drive can be installed on almost any mast or derrick rig.

The top-drive method is more economic and involves a lower risk of differential sticking of the drill pipe in the formation. Top-drive systems give drillers enough time to activate or deactivate mud pumps or the rotary while connecting or disconnecting the pipes. It also has been proven feasible for directional drilling and for drilling wells with extended reach.

Torque required for make-up drill pipe and casing connections can be provided by the top-drive.

The usage of top-drives has reduced the risk that was previously involved in the drilling process and increased the safety threshold of drilling by reducing manual labour on site. Most of the time, top-drives are installed, which allow maximum torque and offer better control of the rotation.

The pipe handling equipment uses hydraulic arms to move drill pipes and drill collars to and from the V-door and monkey board, thereby reducing strenuous work and increasing pipe handling safety. The top-drive increases safety by reducing blowout preventer (BOP) wear and allowing the BOP/rotating head to pack off against round tubulars, not a square or hexagonal Kelly. Well control capability is greatly enhanced because it is always possible to circulate drilling fluids, except when breaking a connection to add a drill pipe.

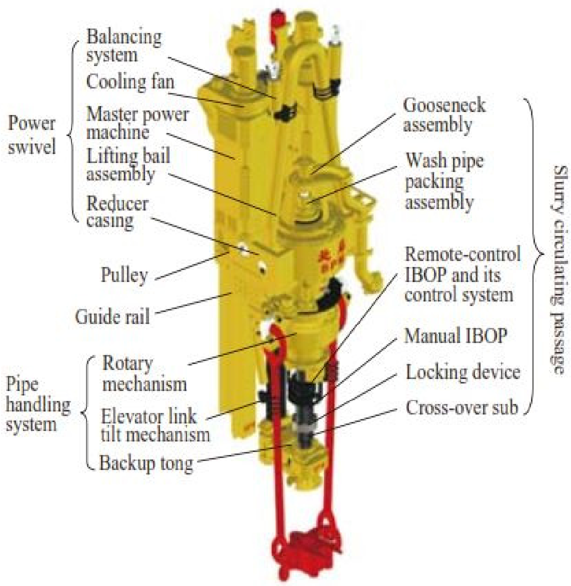


FIGURE 9: Components of top-drive system

Connections can be made at the bottom while drilling directionally, eliminating the need to re-orient the tool face after each connection.

More time can be spent at bottom drilling the hole and less time is needed to make connections, tripping, surveying, reaming and other non-drilling rig functions. Continuous rotation and circulation is possible during full movement of the drill string.

The most important feature of the top-drive is the ability to rotate and pump continuously while reaming in or out of the hole. The circulation is important for geothermal drilling to be able to cool the BHA while running into a hot hole, as well as to prevent the string from getting stuck.

Continuous rotation reduces the chances of getting stuck when removing the string or tripping back into directional wells.

Drilling with stands of two or three drill pipes instead of singles has the following advantages:

- It reduces drilling time when reaming to the bottom in sloughing shales or cleaning the well of fill-in material to bottom.
- It reduces the drilling time during hole-opening and underreaming procedures because the drilling string does not have to be laid down or stands broken down when changing holes sizes.
- It reduces drilling time when reaming an under gauge hole or when reaming full stabilisers into the hole for the first time.
- Multiple wells can be drilled from the same pad without laying down the drill string or breaking down stands while drilling if a skidding system is used for moving the rig between wells.
- It eliminates two of every three connections in reaming operations.
- Continuous spot-coring is feasible without any intermediate connection.
- It substantially reduces directional orientation time after each connection while directional drilling with a downhole motor.

Disadvantages of top-drive systems are as follows:

- The high automation applied in the top-drive system requires a highly skilled and experienced operational and maintenance crew. Hence, when there is a lack of such personnel, the advantages expected from the top-drive system may not be realised.
- It is more susceptible to failure when jarring because of the high strains caused by the impact force from the jar.
- The modern top-drive rig is more expensive than the conventional rig and thus more investment capital is required, which can be out of reach for some companies.
- The top-drive system does not favour the direct job creation motto of the Government of Ethiopia since it tends to need a smaller workforce (Figure 9).
- If the mast of the top-drive is not high enough to allow tripping using triples, then the tripping rate is slower.

Advantages of a rotary table rig:

- Very little strain on rotary system when jarring.

6. RIG SIZE REQUIREMENT FOR ALUTO PROJECT

Geothermal drilling rigs, like oil and gas drilling rigs, have the hookload capacity as the main discriminating factor in rig selection. Hook load capacity becomes important for deep wells. For all drilling rigs, the depth of the planned well and casing program determines the basic rig requirements like hoisting capacity, power system, mud circulation system and the well control system. The use of a compact design saves money by reducing mobilization costs, fuel consumption and makes geothermal resources more cost competitive. Also, environmental concerns such as rig ‘footprint’ make smaller rigs more attractive.

6.1 Hookload capacity

The hookload requirements stem from the weight of casing strings and drill strings (Table 1). Based on future well casing designs, the maximum weight while running the casing is calculated assuming a water level of 300 m. The total weight of the drill string during drilling is calculated as the sum of the weight in water of BHA and drill string. The weight in air from handbooks for the casing and drill pipes is multiplied by the buoyancy factor BF=0.873 to get the buoyed weight in water (Table 1). The total weight in water is multiplied by a safety factor of SF=1.5 to arrive at the minimum hookload requirement for the drill string and a SF=1.2 for running the casing. For directional drilling, the rig should have an additional 20-50 t of hookload for overpull.

TABLE 1: Calculation of weight of casing string and drill string during drilling to determine the rig capacity in tonnes for a 3000 m deep vertical well and a 2500 m directional well

Description	Length m	Weight ppf	Weight in air kg/m	Weight in water kg/m	Buoyed weight in water kg	SF	Weight with SF tonnes
Running casing							
13 3/8" anchor casing	500	68.00	101.19	88.34	44,169	1.20	53
9 5/8" production casing	1,500	47.00	69.94	61.06	91,586	1.20	110
7" liner DP	1,500	26.00	38.69	33.78	50,665	1.20	61
5" DP	1,500	19.50	38.84	33.91	50,861	1.20	61
Liner+DP	3,000			67.68	101,526	1.20	122
Minimum hookload requirement for running casing (t)							**122**
During vertical drilling TD 3000 m							
BHA 7" DC	120	109.00	162.00	141.43	16,971	1.50	25
5" drill pipes	2,880	19.50	38.84	33.91	97,653	1.50	146
Minimum hookload requirement for vertical drilling to 3000 m (t)							**172**
During directional drilling TD 2500 m							
BHA 7" DC	120	109.00	162.00	141.43	16,971	1.50	25
5" drill pipes	2,380	19.50	38.84	33.91	80,699	1.50	121
Overpull (t)							50
Minimum hookload requirement for directional drilling to 2500 m (t)							**197**

As shown in Table 1 the minimum hookload rating for a rig that can drill both types of wells is rounded off to be 200 t. It is worth noting that the tensile strength of the 5" 19.5 lb/ft G105 drill pipe is 193,800 dN which is equivalent to 194 t.

6.2 Hole size of the rotary table

The casing programme affects the rotary table size, hoisting requirements and pump capacity to clean the hole. The main equipment items that are used in the hole are the drill string, the casing, and miscellaneous well surveying instruments such as logging and hole-deviation instruments. The drill string is one of the most important items to consider in the design of the hoisting equipment, although fishing operations may be the largest loads imposed on the derrick. During a drilling operation, the drill bit can frequently become worn, necessitating its removal and replacement, which requires tripping out the entire drill string and then tripping back in with a new bit and possibly new stabilisers as well.

6.3 Mast capacity

The mast is a special unit of welded alloy steel construction, fitted with a track to the top-drive. The floor assembly and the pipe handler are attached to the mast, which is free standing and is of sufficient width and strength to accommodate the top-drive and its related torque. Mud hoses on the mast are fitted with swivel joints.

The mast is the most critical component of the rig and determines the rig's depth limit. The top-drive exerts hook load weight on the crown block. The force (weight) exerted on the crown block is then distributed equally onto the rig mast. The mast should, therefore, be properly designed to carry the largest weight of the drilling string and casing loads exerted on it by these two major loads plus an allowance for fishing operations.

To determine the maximum load imposed on the mast, the mast is cut in half between the crown block and travelling block by an imaginary line. The maximum gross load divided by the number of lines pulling down gives the maximum allowable single line pull. The load on the wireline, expressed in tons of tension, is constant along the line from the drum to the dead line anchor. Thus, the usable maximum static hook load is the number of lines pulling up on the travelling block multiplied by the single line pull. The total dry weight of the entire drill string should not exceed 75% of the static hook load rating. Another "rule of thumb" says that the weight shall not exceed 2/3 of the hook load rating, which corresponds to a safety factor SF of 1.5, as used in Table 1.

The only requirement to the mast height is that it is sufficient to handle single joint or short stands of the drill pipe, but most rigs are designed to handle 2 or 3 joints. Its width can be narrow since automatic tongs, backup tools and air slips do not require the space needed for conventional tongs.

6.4 Mud pump selection and power

The mud pumps draw the drilling fluid in through the suction line from the mud tanks and send it out through the discharge line into the standpipe and down the drill string and back up the annulus until eventually, it is returned to the mud tanks or the mud pit. Prior to equipment evaluation and selection, drilling fluids and hydraulics programmes are prepared. Triplex pumps are preferable over duplex pumps for effective drilling operation (Figure 10). In any case, it is critical that the supporting foundation directly underneath the pump is levelled and strong enough to support the forces and vibrations generated by the pump during operation. Mud pumps should be coupled to a centrifugal charge pump to ensure a good supply of fluid and to maintain constant pressure. Running the pump with insufficient suction pressure due to an incorrectly sized charge pump or poor inlet piping design can cause the pump to run rough and dramatically reduces the life of pistons, liners, valves, and power end components.

6.4.1 Maximum flow rate and pressure requirements

Geothermal wells in Ethiopia are of medium size with a final hole diameter of 8 1/2" and are drilled with water or water-based mud which requires relatively large mud pumps. To determine the flow capacity (l/s) and pressure (bar) requirements of the mud pumps, the drilling programme must be known. This includes hole diameter, hole depth, diameter of drill-pipe, drilling fluids, and all related equipment. When drilling with a down-hole motor, the rotary power is derived from the drilling fluid (extra pressure loss). The pump discharge capacity must be enough to obtain an annular upflow velocity sufficient to remove the cuttings from the borehole. The "rule of thumb" is that for water as the drilling fluid the

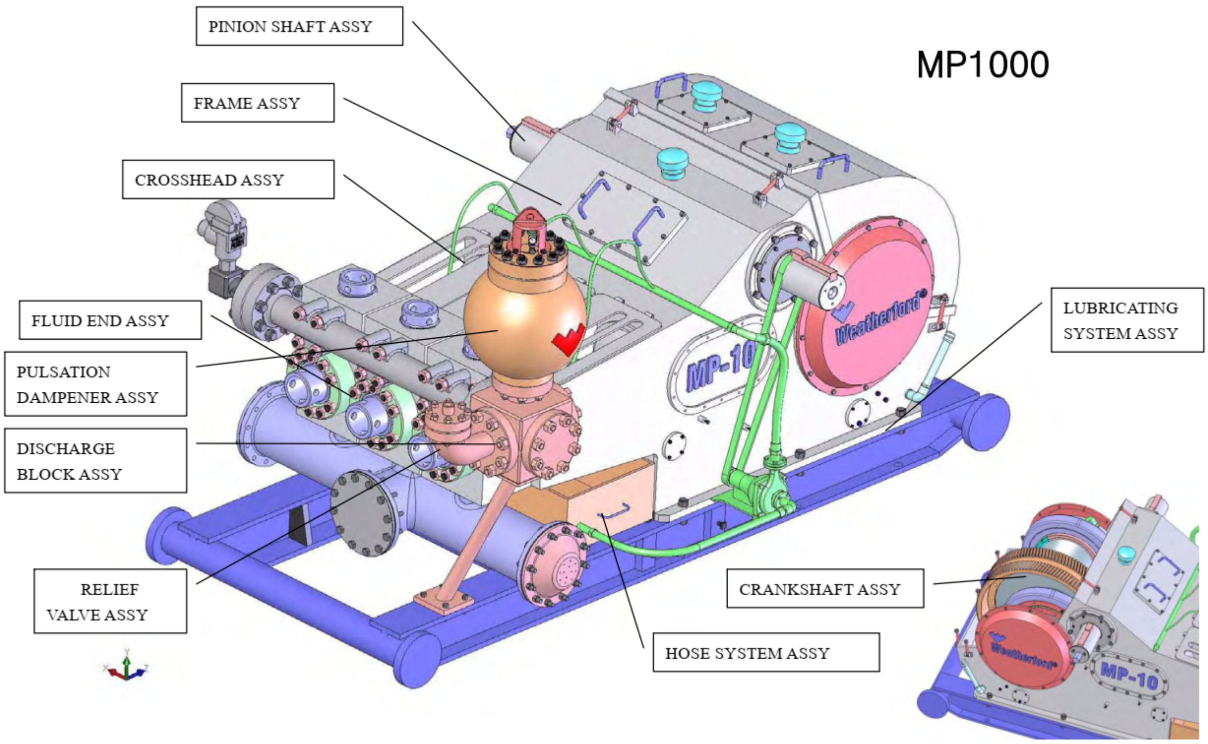


FIGURE 10: Example of single acting triplex mud pump (Weatherford, 2006)

design annular velocity should be 1 m/s and in practice does not go below 0.5 m/s. With drilling mud, the requirements are about half of the water annular flow velocity. When drilling during partial or total losses, this velocity is not reached above the loss, and polymer-pills or mud are used to aid in hole cleaning. The required pump flowrate Q (l/s) is calculated based on the annular volumes and required upflow velocity:

$$Q = (V_h - V_P) \cdot V \tag{2}$$

where V_h = Volume of the well per meter of length (l/m);
V_p = Volume of drill pipe per meter of length (l/m); and
V = Annular velocity (m/s).

Knowing the flowrate Q, the individual pressure drops are calculated from friction loss tables of the surface equipment, the drill pipe, drill collars, and the drill bit. The total pressure losses p (bar) are obtained by summing up the individual losses. Figure 11 shows calculations of pressure loss in the mud circulation system for the well, based on data from the IFP Drilling Data Handbook (Gabolde and Nguyen, 2006). The mud pump pressure rating must be more than 1.5 times the total pressure losses. These pressure losses are comprised of:

$$p = p_1 + p_2 + p_3 + p_4 + p_5 \tag{3}$$

where p_1 = Losses through surface equipment;
p_2 = Losses through drill pipe / drill collars;
p_3 = Losses through the rock bit;
p_4 = Losses between the outer diameter of the drill pipe and drill collar, and wall of the hole; and
p_5 = Losses in the mud motor (when used, e.g. directional drilling).

Calculation criteria for drilling at 3000 m depth:

Description	l/s	l/min
Pumping rate	35	2100
Bit Size	in	8 1/2"
Fluid coefficient	B	1,15

Pressure drop inside drill string:

Drill string description	Size in	Weight lb/ft	Length m	From DDH bar/100m	Press drop bar
Drill pipe	4 1/2"	16,6	2885	2,2	64,4
HW pipe	4 1/2"	41	35	9,5	3,3
Drill collar	6 1/4"	99	80	24,8	19,9
Drill bit	8 1/2"				3,0
Total pressure drop inside drill string (bar)					**90,6**

Annulus pressure drop inside 8 1/2" hole:

Annular space description	String Size	Weight lb/ft	Length m	From DDH bar/100m	Press drop bar
Annulus Pipes	4 1/2"	16,6	2885	0,3	8,0
Annulus HW Pipe	4 1/2"	41	35	0,3	0,1
Annulus Drill collars	6 1/4"	99	80	0,9	0,8
Total pressure drop in annulus (bar)					**8,8**

Cumulative pressure drop: String + Annulus

Total pressure loss (bar)	**99,4**

Engine power required:

kW	**497**
hp	**666**

FIGURE 11: Pump pressure loss calculations for a 3000 m long drill string

6.5 Rig power

6.5.1 Generator maximum power

The generators should also have adequate power for directional drilling. This is because the steerable motor for directional drilling requires extra hydraulic power from the pumping units. The rig power is used principally for three operations:

(a) Rotary table or top-drive system;
(b) Hoisting, draw works; and
(c) Drilling fluid circulation: Mud pumps, mud cooling and cleaning system.

Rig horsepower is the draw works rated power plus the top-drive rated power. The sum of the hook load capacity and the top-drive torque estimation (related to drill pipe strength) gives the minimum requirement for the rig power.

Geothermal reservoirs have high temperatures and pressures; therefore, a high pump flow is necessary to provide sufficient hole cleaning, cooling and to contain the formation pressure. The mud pump should have a discharge of 60 l/s and a pressure of 200 bars for 12 1/4” holes. This requires mud pumps to have a power of 750 kW each. A cooling tower is required for the mud due to the high reservoir temperature. Mud circulation constitutes the highest energy consumption in the rig operation; therefore, improving the efficiency of the mud circulation system saves energy.

6.6 Draw works rated capacity

The draw works power requirements are determined by the rig dynamic load capacity and tripping speed.The main function of the draw works is to reel the drill line in or out and to raise or lower the travelling block which is coupled to the drill string, thus enabling it to run into the hole and out of the hole, or to drill by providing weight on the bit to exert the force. Hydraulic rigs employ a piston inside the mast tube for the purpose of lifting.

6.7 Height of substructure

Geothermal rigs have a high substructure to accommodate the installation of a blowout preventer (BOP) for well control, e.g. to allow for a well shut-in in case of a kick. The blowout stack is commonly fitted with a rotating head on top to divert flow returns and prevent kicks from reaching the rig floor and for diverting when aerated drilling is used. For this reason, rigs normally have a high substructure of 6-10 m.

6.8 Blowout preventer equipment

Primary well control is achieved by ensuring that the hydrostatic pressure exerted by the drilling fluid column in the well is sufficient to overcome the formation pressure. The well control system requirement is to safely permit shutting-in the well at the surface, controlling removal of formation fluid from the wellbore, pumping water or high-density mud into the hole to kill the well, and stripping the drill pipe in or out of the hole.

The well control system is designed to:

(a) Detect a kick;
(b) Close the well at the surface;
(c) Quench or kill the well using drilling fluid; and
(d) Make the well safe.

The basic component of the well control system is the blowout preventer stack, which consists of:

(a) Annular preventer;
(b) Ram preventers, with blind ram and pipe ram;
(c) Spools;
(d) Internal preventers;
(e) Rotating head preventer;
(f) Flow and choke line;
(g) Kill line;
(h) Mud and gas handling facilities; and
(i) Accumulators.

6.8.1 Equipment description

The BOP stack used in geothermal drilling is much smaller and lighter than the high-pressure systems used for geopressured drilling. This depends on the depth of the wells being drilled. Up to 10,000 psi (690 bar) BOPs have been used in deep geothermal drilling but a pressure class of 5,000 psi (345 bar) down to 3,000 psi (207 bar) is usually adequate. If the equipment is coming with rigs that have drilled oil and gas wells, a higher pressure rated BOP can be accepted. The temperature limit of the rubber sealing elements is however only 170°C. The bore of the stack must be large enough to pass the drilling tools, the stack must have a pressure rating against the contemplated worst-case pressures, and it must be strong enough to resist bending moments and impacting forces. Two other restrictions apply to the geothermal BOP stack. First, it must be operational in the temperature environment of geothermal drilling. All stacks are assembled with flanges with metallic seal rings so that, under high temperature, the sealing is not dependent on an elastomer or Viton 0-ring. Exceptions to this are the sealing elements of the rams, annular preventer, and rotating head, which have a stripper rubber. The second restriction to the geothermal stack is its geometry, size and height. The geothermal drilling rig is often small or even a truck-mounted unit. When drilling 2500 m geothermal wells, rigs with 300 and even 450 ton hook load capacity are often used, which have a high substructure to accommodate the BOP stack under the rig floor. Geothermal drilling needs a high-temperature rotating head preventer that can let the drill pipe and collars be stripped in or out of the hole and provide a seal against H_2S gases, thus providing the function of both a rotating preventer and an annular preventer. For this to work a valve is required on the flow-line.

6.8.2 Annular preventer

The purpose of the annular preventer is to close the annulus around drill string components or casings of different diameters. In geothermal wells, the applicability of a particular annular preventer is limited by the temperature limits of the packer element. Generally, when a well kick is imminent, the annular preventer is closed first so the driller does not have to be concerned with the position of the tool joints and the pipe can be moved to avoid sticking. The annular preventer can be closed on the Kelly, tool joints, drill collars, casing, or wire line. It can also close over the open hole, but this is not recommended because of the distortion of the packer. The annular preventer is closed by hydraulic pressure on the closing piston by squeezing a rubber packer element around the pipe.

6.8.3 Diverter system

The purpose of a diverter system is to protect the crew on the rig floor by diverting steam or gas from a shallow kick to the flowline. The most common equipment is a rotating head preventer. Rubber seals around the drill pipe are flexible enough to expand for the larger diameter tool joints to pass. A rotating head preventer is required any time compressed air is used for drilling such as for pressure balance drilling when the drilling water or mud is aerated.

6.8.4 Ram-type blowout preventers

Pipe rams are well suited for their task in geothermal drilling. The sealing rings can be made of Viton material, which resists temperature. The ram sealing area is small and the distortion of the packer area is minimal, so problems with the sealing packer element are significantly lower than with the annular preventer. Care should be taken regarding the specifications of the ram system for geothermal work. The temperature limit for high-temperature elastomers is about 170°C. The rams are not modified to suit the geothermal conditions but it is extremely important to cool the rubber as soon as possible after closing the BOP´s by injecting cold water via the kill line. The purpose of the ram-type blowout preventer is to seal off the annulus of the well (pipe rams) or the open hole (blind rams). When pipe rams are used the pipe is not rotated or reciprocated. While rams were not designed for pipe movement, the pipe can be moved through the rams quite extensively without damaging the packer elements. A stripping technique utilizing pipe rams is quite common. In Iceland, the stripping is usually done with annular BOPs. When used in stripping, the closing pressure of 1,500 psi on the rams is usually reduced to about 800 psi. Pipe rams should be operated hydraulically rather than manually. Manual operation is slow and can become hazardous to both the person under the floor closing the rams and the crew on the floor waiting for ram closure. All ram manufacturers make double-ram units to save space.

6.8.5 Accumulator system

The accumulator system is a 'must' for geothermal drilling and is used for operating the BOPs and can be controlled remotely, e.g. from the drillers console. It allows rapid closing in of the well and, equally important, it allows remote operation of the BOP stack. When using this system for geothermal drilling, it is important to select a proper high-temperature hydraulic fluid since BOP stack temperatures may get high. The accumulator, which has a stored supply of hydraulic fluid under pressure, can shut the pipe rams in six seconds or less on surface-mounted BOP stacks. The pressurized hydraulic fluid in the accumulator acts much more quickly and reliably than a pump system. The system normally consists of a number of steel bottles of fluid pressurized to 3,000 psi. The hydraulic fluid sent to the annular preventer runs through a regulator where it is regulated down to 700 to 1,000 psi and then is sent to the annular preventer. The hydraulic fluid that goes to the pipe rams flows from the bottles to a separate regulator where it is regulated to 1,500 psi and then to the rams. As the bottles are being discharged, a pressure controlled switch starts the pump that recharges the bottles so that the pressure in the bottles stays near 3,000 psi.

6.8.6 Drill pipe safety valves and Kelly cocks

Drill pipe safety valves and Kelly cocks are full-opening ball or plug valves that are used to stop flowback up the drill string if a well kick should occur. These valves would not normally be subjected to extreme pressures or temperatures. However, since they are designed as emergency equipment, they should be able to withstand a worst-case situation. The valves should be checked for high-temperature clearances, greases, and sealing rings. The pressure capability of these valves is very good, but not all manufacturers have high temperature versions for geothermal drilling.

The drill pipe safety valve is usually stored on the floor in a sub that is equipped with handles for quick installation on the drill pipe. The drill pipe safety valve is used to stop flowback up the drill pipe when the Kelly is disconnected. The lower Kelly cock is the same type of valve installed in a sub on the bottom of the Kelly. It is used to stop flow up into the Kelly, so that it can be disconnected or to shut off to relieve pressure of the Kelly, hose, and swivel. The upper Kelly cock is on the top of the Kelly and is used as a secondary valve for relieving pressure of the Kelly, hose, and swivel.

7. RIG INSTRUMENTATION SYSTEM

7.1 Rig parameters recorded

The drill rig will have a minimum set of instruments that are required for monitoring its normal drilling functions, but additional instrumentation and data can be provided by the drilling contractor, the mud logging company (MLC), or an independent service company. This is commonly overseen by the MLC in addition to their primary job, which is recording the geology of the well based on the cuttings brought back to the surface by the drilling fluid. For rigs with a modern data acquisition system, the drilling data is frequently obtained from the rig system. The drilling contractor keeps records of the drill rig's operating conditions and will allow the operator access depending on the contract. A drilling contractor may for example list the measurements shown in Table 2, if available, and it is the well planner's responsibility to decide which are necessary. Some of them are calculated values derived from other measurements.

7.1.1 Loss of circulation or gains

The loss of circulation (l/s) is the difference of what is pumped into the well with the mud pumps via the drill string and what flow is returned to surface through the flow-line. It is important to monitor the fluid losses as it affects the hole cleaning and more importantly identifies where there is permeability and at what depth. In the open hole section large losses indicate good future well productivity – success. Excellent wells will have what is referred to as "total loss of circulation" when the maximum pumped flow is not returned to the surface – all fluid is lost to the formation. There are at least three quantitative methods used to measure the fluid losses.

TABLE 2: Rig instrumentation requirements

PARAMETER	M/C[1]	Graphed	Range	SI units	Sensor location
SENSORS					
Standpipe pressure	M	Yes	0-200	bar	On the standpipe
Flow from MP1 (from SPM)	M	Yes	0-40	l/s	Rotary speed encoder on pump
Flow from MP2 (from SPM)	M	Yes	0-40	l/s	Rotary speed encoder on pump
Flow from MP3 (from SPM)	M	Yes	0-40	l/s	Rotary speed encoder on pump
Total flow from mud pumps	C	Yes	0-80	l/s	Calculated MP1+MP2+MP3
Mud temperature at standpipe	M	Yes	0-100	°C	On standpipe
Mud temperature at flowline	M	Yes	0-150	°C	On flowline
Wellhead pressure	M	Yes	0-150	bar	Side outlet on mud cross
Top-drive position	M	Yes	0-40	m	Measuring line to top-drive and encoder
Rotary torque	M	Yes	0-100	%	Electric power consumption or pressure if hydraulic
Rotary speed	M	Yes	0-150	rpm	Encoder
Weight on bit	C	Yes	0-30	tonne	Cal.: Difference in off-bottom hookload and on-bottom
Hookload	M	Yes	0-300	tonne	Reading from load cell on dead-line anchor
Rate of penetration	C	Yes	0-30	m/h	Calc.: From drill bit advance (m) between time intervals
Total hole depth	C	No	0-3500	m	Calc.: By addition of lengths from tally sheet minus top-drive position
Bit depth	C	No	0-3500	M	- do -
ADDITIONAL SENSORS					
Mud flow out	M	Yes	80	l/s	
Volume of each pit	M	No	30	m^3	
Gain/loss flow	C	Yes	x	%	
Gain/loss active volume	C	No		m^3	
Torque of breakout tongs	M	Yes			

1: M: Measured / C: Calculated.

1. Rig instruments: Two basic measurement devices are used to measure the fluid losses. They are the pump stroke counter (flow in – l/s) along with flow sensor on the flow line (flow out – l/s). Fluid loss = (flow in) – (flow out). The calculated losses are recorded continuously and show relative losses but not exact (l/s) due to inaccuracies in the flow-line sensor.
2. Volume accounting: By stop filling the active mud tanks and measuring the drop in mud level in the tank, the amount (m^3) over a period of 15 minutes, can be determined by volume accounting. Calculation of losses by this method provides the most accurate determination. As it requires manual intervention it is perhaps only made every 4 hr.
3. Mud pump flow with the well full to the brim. The driller can for a spot-check slow down the mud pump until the well is full to the brim (no return flow). The mud pump flow rate can be read directly and is a reasonably accurate method for determination of the fluid losses.

There are other qualitative ways to assess where fluid losses show up: Drop in standpipe pressure, increase in dT of the drilling fluid, visual observation of the drilling fluid flow passing over the mud shakers. These methods also work to monitor fluid gains, more fluid coming out than going in, which is a precursor to a well kick and eventual blow-out.

7.1.2 Mud pit level indicators

The pit level indicator in present usage adds up the volume in each pit and reports the total pit volume or a working pit level. The pit volume indicator is a basic well-control warning instrument. A well kick pushes mud out of the hole and this is recorded by the pit level indicator as an increase in pit level or pit volume. So, one of the warning signs of a well kick is an increase in pit volume. The driller's indicator has an alarm system that calls attention to pit change. The pit volume systems are simple in operation. The height of the mud in each pit is measured. This height is then multiplied by the pit volume in liters per meter of level change. The output of all the pits is then added together and reported on the chart and indicator. On most pit level indicators, the gain or loss of mud is indicated and alarms are provided to show gains or losses exceeding pre-set limits. The mud pit totalizer systems lack reliability and are especially erratic in very hot muds. As with the flow-sensing systems, the accuracy is adequate but the systems are not reliable enough, especially when subjected to heat and steam. They are, however, more reliable than the mud tank volume when the return fluid is being directed to the cuttings pit.

7.1.3 Gas detectors

Gas detectors are quite suitable for geothermal usage, provided they are suitably packaged. Usually solid state 4-gas detectors are sufficient for geothermal drilling. The most important gas to measure is H_2S due to its toxicity at low concentrations. This is why personal alarms are issued to crew working around the well. H_2S detectors and flammable gas detectors are sensitive to moisture, so care needs to be taken when using them for mud-gas or blooie 1ine gas detection. Gas detectors on a rig have two general uses. The mud logger uses a gas detector to detect gas in the mud.

7.2 RigSense

RigSense (RS) is an information management system of National Oilwell (NOV) that consists of multiple computers running rig sense software in a networked environment. The RS server/workstations and the DAQ communicate through the optional network.
Each touchscreen display or human machine interface (HMI) is certified for hazardous areas. Improving rig operations by being conveniently located on the rig floor, the HMI has a simple touch interface that is visible in all lighting and provides continuous rig site data to users. The server and workstation requirements for a RigSense system are as follows.

7.3 Data display and logging

At this stage, there is no standardized assessment of measurement data service quality, but to investigate problems related to rig sensor data quality (and measurement data in general), to propose a systematic process for measurement data quality control and auditing, and to manage and navigate the resulting huge data sets, managing and standardizing are key elements. Currently, real time data is, at best, only checked for completeness.

7.3.1 Data management steps

The main quality management steps consist of:

(a) Data standardization;
(b) Data quality control;
(c) Data quality reporting;
(d) Data compression; and
(e) Data access and visualization.

Data standardization is the first and most crucial step in any automated data analysis procedure.

Different problems need to be addressed to enable data processing. Five of them are discussed in this paper:

(a) Unit definition;
(b) Null values;
(c) Time stamping and time zones;
(d) Depth reference; and
(e) Data identification.

To preserve or enhance data features like accuracy, consistency, reliability, and validity, the data quality management process is divided into three major phases. Phase I is the evaluation of pre-data quality to identify data issues such as missing or incomplete data, non-standard or invalid data and redundant data etc. Phase II is the implementation of different data quality managing practices such as filtering, data assimilation, and data reconciliation to improve data accuracy and discover useful information. The third and final phase is a post-data quality evaluation, which is conducted to assure data quality and enhance the system performance. Safe and efficient performance of such control system heavily relies on quality of the data obtained while drilling and its sufficient availability. Pump pressure, top-drive rotational speed, weight on bit, drill string torque and bit depth are available measurements.

The data analysis is challenged by issues such as corruption of data due to noises, time delays, missing or incomplete data, external disturbances, and lack of calibration of gauges. In order to solve such issues, different data quality improvement practices are applied for the testing. These techniques help the intelligent system to achieve better decision-making and quicker fault detection. The study from the laboratory-scale drilling rig clearly demonstrates the need for a proper data quality management process and for a better understanding of signal processing methods.

7.4 Use of monitoring data to optimize the drilling process and to solve drilling problems

The rig instrumentation systems have built-in graphing functions and other tools to scrutinize the drilling data. All modern rigs have digital recording system for the rig parameters. Iceland Drilling has developed their own rig data acquisition system:

(a) The PC monitor displays on-line and real time data.
(b) The instantaneous readings are in digital form and data from the last 1 hour is graphed.
(c) Every 5 seconds, a data point is stored in a SQL database and can be searched via a SQL script. The ASCII tables are comma delimited and the header file needs to be rearranged to be suitable for direct input either to LogPlot or to EasyView for post processing.
(d) The high-resolution data allows drilling incidences to be analysed, but the main use is for optimizing the drilling process and to identify any precursors to problems.

Data can be exported as data files and with a visualizing software which handles long time series (e.g. EasyView) rig data files can be viewed (drilling parameters, i.e. SPP, ROP, WOB, flow rates and others associated with in the rig). By plotting the parameters and being able to zoom in on selected time periods where the trend deviates from the norm, precursors to drilling problems can be identified. Such "post mortem" analysis is useful in scrutinizing drilling data for lessons learned.

7.4.1 EasyView

EasyView is a software tool that can be used for post processing of drilling data (Figure 12). Statistical characteristics are shown in the "Info Table", which has both a standard and an alternative layout for data acquisition and data evaluation. Calculations can be made using the calculating power of EasyView to analyse any of these parameters. For example, the difference and the average value of two temperatures can be displayed. A histogram is another way of looking at a set of acquired data. It shows the relative frequency of values. Y(x) shows a channel as a function of another channel. For every tab there is a new sheet to fill with information.

Excel files that contain sheets with data in columns can be interpreted, converted and opened by EasyView Pro. EasyView can open ASCII or text format data files. These files should be type txt, asc, csv or skv and have data in columns.

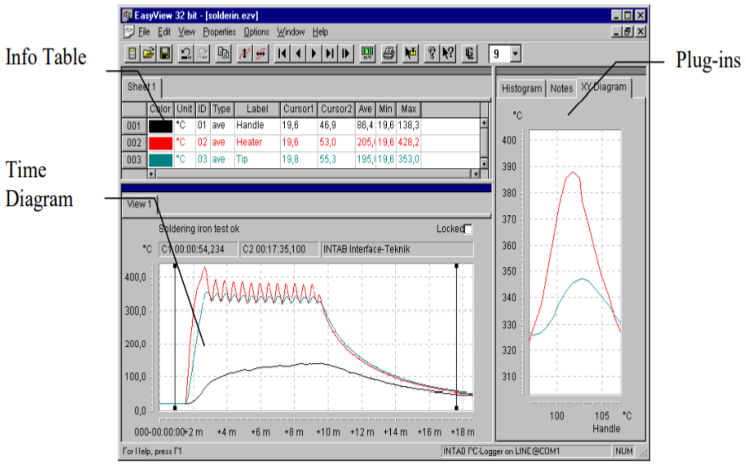


FIGURE 12: A diagram document window of EasyView

8. CONCLUSIONS

Ethiopia can select geothermal drilling rigs from a wide array of rig types that meet similar specifications as described in this report. Since the start of drilling operation in 2019, a mechanical rig was used where the power for major rig components such as the rotary table, draw works and mud pumps was provided through mechanical power transmission. Based on the well design of future wells, the advantage of top-drive over the Kelly drive are substantial. The top-drive system is preferred as a relatively large rig is required to drill into high temperature formation, vertically down to 3000 m or directionally down to 2500 m. The minimum hookload rating of a rig to drill these wells is determined to be 200 t. The swivel head should have a static capacity of at least 200 tons with 350 bars maximum working pressure. The mud pumps should have an output of 60 l/s and be able to pump at 150 bar pressure. The substructure should be at least 6 m of nominal height to be able to accommodate the BOP stack. The draw works, the rotary table and the mud pumps should have a minimum input power of 750 kW each. The opening of the selected rotary table is 27 1/2”. This will allow running the biggest casing and bit size to pass through. In the final rig selection process, many factors not a part of this report must be considered, including the economics and available technology.

Having an instrumentation and data recording system for continuous monitoring of the drilling activities and for later analysis is of great importance. This can improve both time and cost effectiveness of the drilling activities of future drilling projects.

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