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Economic Analysis of Multilateral Drilling over Directional Drilling for Olkaria Geothermal Steamfield

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Abstract:
Drilling exploration, production and injection wells is one of the major capital investments required for geothermal energy production. Current practice of drilling geothermal wells in single well penetration increases cost, reduces production due low reservoir exposure and de-accelerates long-term production. Furthermore, there is less flexibity in well selection and monitoring especially when rating a wellhead generator through increase in service to surface equipments costs. This study investigates economic benefits of lateral drilling. This research compared the overall techno-economics for vertical and directional drilling operation from the year 2008 to 2012 at Olkaria Domes, Olkaria East and Olkaria North East. The data were collected through actual field experimental experience, observation and sampling. A total population of 56 wells and a sample size of nine wells were selected within three pads in different fields with each pad hosting three separate wells. Data were analyzed with Drilling Cost Formular (Rabia 2009) and Excel to provide Drilling Cost Predictions. Auto-Desk Inventor and Grapher softwares were used for Cost Sensitivity Analysis. Economic comparison of the two drilling methods shows that, the overall drilling cost of multilateral application at pad #915 saves cost by 26%, pad#44 and pad#733 reduces cost by 28% and 34% respectively in comparison to a single penetration in each pad. It was noted, the overall drilling time of multilateral application reduces by 37% in average for all scenarios. The results indicate, multilateral drilling application at Olkaria Geothermal Steamfield reduces cost by a third that of directional single penetration. Furthermore, the wellhead power output is higher giving less payback period of 2years from 3.5years. The study also shows that, the more the laterals the more cost reduction alongside more output. This study recommends adaption of multilateral practice to save drilling cost by 30%. Economically, increase in well diameter and depth symmetry is recommended in future for more power output and cost reduction.

1. Introduction

1.1. Background

Exploration for geothermal resources in Kenya started in 1950's with mainly geological investigations in the region between Olkaria and Lake Bogoria in the North Rift (Mwangi, 1984) as shown in figure 1. The exploration resulted in the drilling of two wells X-1 and X-2 which encountered high temperatures at depth. The exploration then gained momentum with support of the United Nations Development Programme which saw more extensive geophysical investigations undertaken and additional wells drilled between 1973 and 1980. The geophysical studies included gravity, various resistivity techniques, magnetics and seismics. The activities resulted in the construction and commissioning of Africa's first geothermal power plant at Olkaria with 45 MW capacity between 1981 to 1985 (Langat 2009). Olkaria Geothermal field is a high temperature geothermal resource in the Kenya Rift Valley which has been used for electricity generation since 1981. However, it is estimated that the geothermal potential of the entire area could exceed 800 MWe. A wide range of geophysical surveying methods has been employed at Olkaria over the years including seismology (Maritta and Keller, 1997)., resistivity, gravity, magnetics and electro-magnetics.

1.2. Problem Statement

In Olkaria Geothermal Steamfield, two directional wells OW#912A, OW#912B and one vertical well OW#912 were drilled separately (2008/2012) in the same pad as shown in figure 2. Therefore, this practice of separate single well penetration increases drilling cost and reduces production due low reservoir exposure, de-accelerates long-term production in case of well dominancy factor, increase of surface well equipment and service facility costs. There is also less flexibility in well selection and monitoring especially when rating a wellhead generator. In effect, future plug backs are never laid out causing expensive future redrills.

Figure 1: Three Separate Wells in a Single Point

1.2.1. Specific Objectives

To compare the overall drilling cost for Vertical and Directional wells from the year 2008 to 2012 at Olkaria Domes, Olkaria East and Olkaria North East through sampling in order to determine application of Multilateral drilling in the same field.

i. To calculate the overall drilling costs for three separate pads, each hosting one vertical well and two directional wells at a maximum depth of 3000m.
ii. Interface and analyze the cost, time and output into a multilateral application for each pad.

1.3. Justification

Directional drilling technology have been applied in Olkaria field at a sounded cost. This study of multilateral drilling in the same field seeks to reduce the production cost and increase steam output efficiency. Still, it aims at reducing the drilling time and wellhead equipments during energy production. Finally, the same application will be applied to all dry wells to regain power output and revive payback index.

1.4. Scope of the Study

The study work concentrated in Olkaria Geothermal field and specifically at Domes, North East and East sectors which had been put into commitment. Also, it intends to encourage the geothermal drillers in Africa to make it a more practical option, especially from public to private Renewable Energy Technologist (RET) to apply this drilling technique because it guarantees cost effective drilling alongside shorter payback period.

2. Literature Review

2.1. Multilateral Well Planning Consideration

The following is a partial list of some of the most important considerations in planning a multilateral well: Drilling methods and Junction design alongside considering well control and drilling issues. Also, completion for Multi-lateral requirements and abandonment remains optimal. There are three main drilling techniques are Long radius, Medium radius and Short radius. The drilling assemblies (BHA's) used are typically build-up or drop angle assemblies.

The planning issues to consider when drilling a lateral are associated with hole size and angle, kick off methods considering flow control and isolation. Formation damage and clean-up of the lateral alongside drainage patterns for optimum production (Schuh,1989).

2.2. Well Cost Factors

Well design of a geothermal well is a "bottom-up" process. Location of the production zone determines the well's overall length. The required flow rate determines diameter at the bottom of the hole. The well's profile above the production zone is then set by iteration of the successively larger casing strings required by drilling or geological considerations. Because of the large diameters in geothermal wells. Casing and cementing costs form the largest share of the cost, and eliminating one string of casing would have a major impact (Rabia, 2009). Directional and Multilateral Drilling is usually dictated by geological targets or lease boundaries, which must be included in the well design.

2.3. Factors Affecting Drilling Cost for Directional Wells

2.3.1. Rotary Torque Management

Friction on drill pipes increases with the angle of inclination. Where 90degrees is approached, the string weight is converted from hook load to drag weight. As the string in directional wells lie on the lower side of the wellbore, friction increases resulting in increased torque. For 3000m well deflected at 40degrees, it is common to have 10 and 30 tons of friction while tripping. Mud control is extremely important in decreasing the drag in a directional well (Ngugi, 2002).

2.3.2. Drilling Hazards

Trouble is a generic name for many sorts of unplanned events during drilling, ranging from minor small amounts of lost circulation to catastrophic BHA stuck in the hole and the drill string twisted-off. In some cases, experience in the same or similar reservoirs will give a hint that certain types of trouble are likely especially encountered at OW#915B where the drilling string got stuck and twisted off at a depth of 1734m, after back off the BHA left over had a length of 166m. Therefore, KOP began at 1400m after plug job. Nevertheless, the BHA twisted off at 2842m though the fishing was successful the well was terminated at that point because drilling was behind schedule by 25days, drilling on hard formation hence non-porous and finally the on bottom temperatures had been achieved with outflow temperature of 54 degrees centigrade. Through multi-adoption the risks are reduced by at least 40% since drilling starts below casings.

Furthermore, in-holes that exceed 35degrees inclination, there is a tendency for cuttings to form beds on the lower side of the bore, which increases drag risk of the pipe sticking and pipe failure. In addition, hole angle affects hole cleaning because cuttings removal depends on the vertical component of fluid velocity rather than calculated annular velocity (Ngugi, 2002). Residual cuttings causing high back reaming not only to the reamer but also to the bit shirttail alongside the cutting angle of the cones design setting.

2.3.3. Bit Walk or Lateral Draft

The tendency for the bit to drill a hole curved in the right hand direction is known as bit walk as reflected in figure 5. Which shows the planned trajectory of a directional well OW#38 against its actual trajectory within upper and lower limit. The right hand rotation and increase in bit offset cause it. It may also contribute to the increase in the hole inclination. Evidence exists that increase in bit offset in a specific bit increases the tendency for the bit to walk towards the right and may also contribute to the increase in the hole inclination (Gabolde and Nguyen, 1991). Bits with zero drift are said to check these deviation tendencies. A packed hole assembly is the best method of controlling inclination and direction caused by bit walk. Bit walk however not unique to directional drilling but is also experienced in vertical drilling.

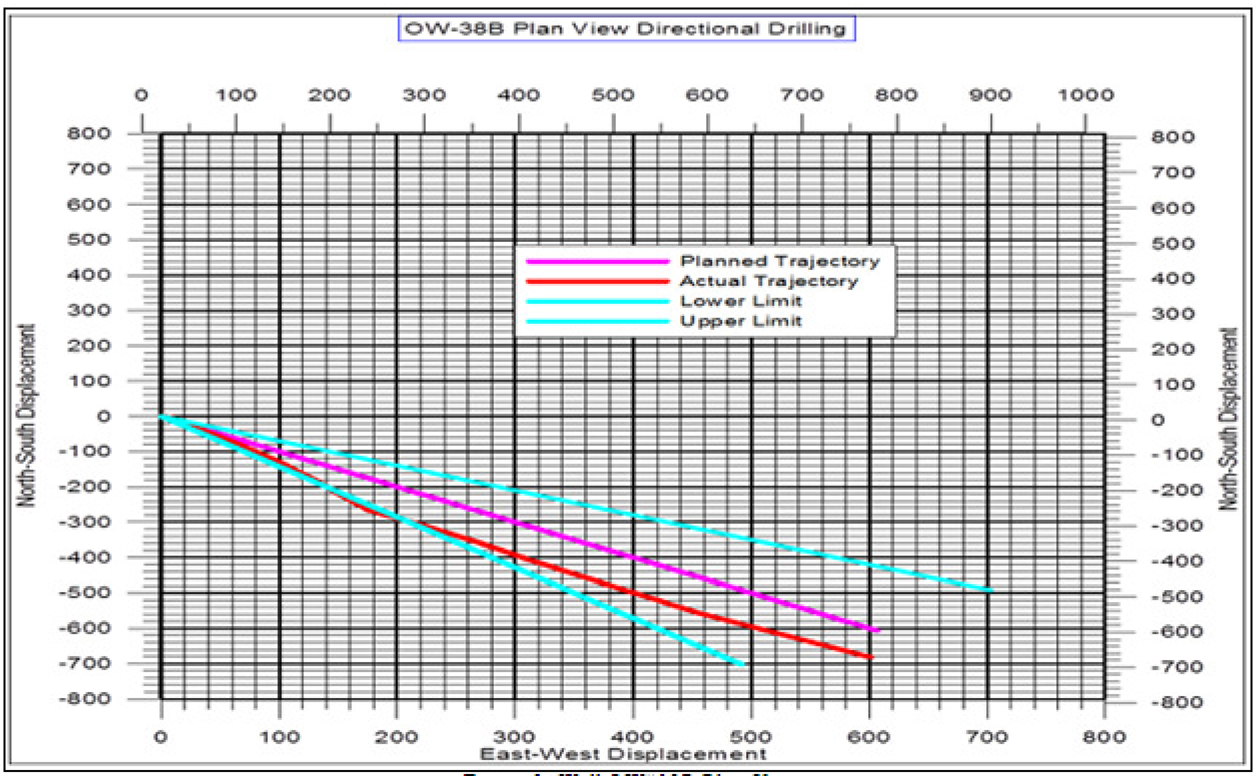

Figure 2: Well OW#38B Plan View

2.3.4. Weight on Bit Variation and Vibration

Weight on bit and vibrations poses challenges especially on directional drilling, where only a fraction of drilling collars weight is transmitted to the bit. BHA drag due to gravity plus tendency of the tool joints ploughs the well bore hence decreases the weight. However, for vertical cases the hole subjects the string to compressive forces that increases tendency of the string to fail (Ngugi, 2002).

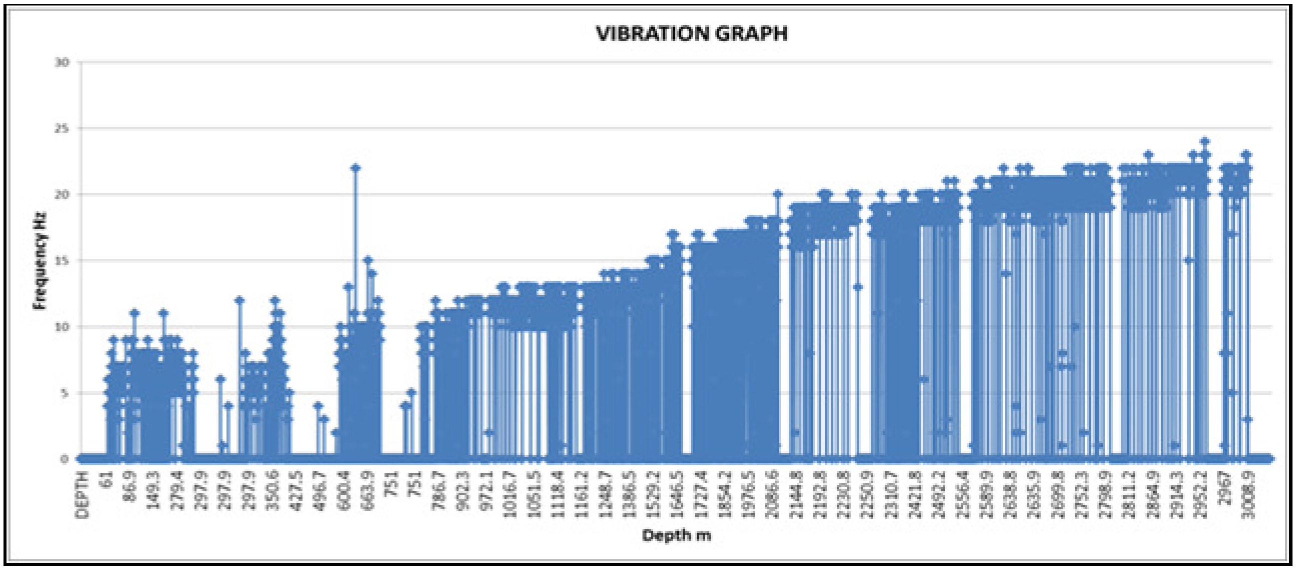

Figure 3: Vibration Profile

Design of a geothermal well is a bottom-up process that requires drilling tools reliability and safety. Figure 3 shows the depth run variations for OW#44A. It is clear that the vibration due to hard formation or lack of drilling shock subs contributed greatly to drilling lugs alongside wait on repair may also be sounded. The run gap in production zone shows less bit life due to high on bottom temperature causing many runs for bit change. Finally, loss of circulation confirms more use of cement and drilling fluid end hence more costs and time especially wait on cement to set. Multilateral application overcomes these challenges where the risk is equated only to bit life.

2.3.5. Rate of Penetration (ROP)

Many of the costs attributed to drilling are time-dependent so it is clear that anything that speeds up the hole advance without compromising safety, hole stability, or directional path is beneficial (Millheim & Chenevert, 1991).

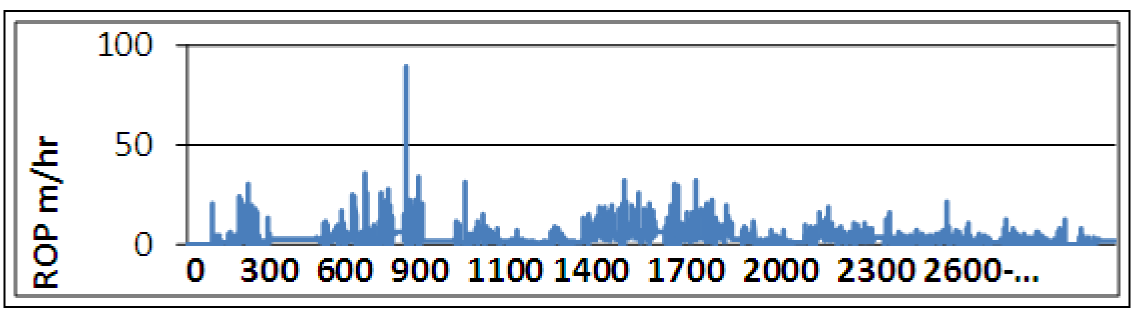

Figure 4: Rate of Penetration Profile

Hard formation contributes to more torque and weight on bit to cut formation hence consuming more fuel and bits. Also, soft formation gives high ROP but increases drilling hazards. In the case of multi analysis this section which contributes to a third total depth the risks are zero.

2.3.6. Stand Pipe Pressure

One of the most important aspects of drilling design is to identify the abnormal pore pressure zone against stand pipe pressure which is usually drawn in to lift cuttings. Figure 8. shows a pressure variation curve from spud in to well completion of a directional well OW#44A.

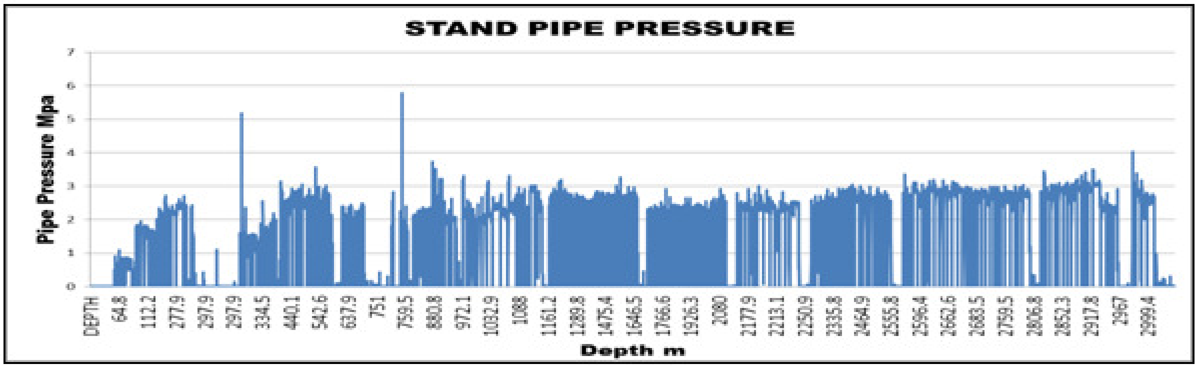

Figure 5: Stand Pipe Pressure Graph

In the case of multilateral, the challenges caused by this factor are overcomed since drilling starts below production casing reducing the risk by 40% (Ngugi, 2002). The gaps shows the frequent of bit change after reaching its life span end. Also, shows the pressure on formation was uniform to accomadate under balancing drilling and better hole cleaning.

2.4. Stratigraphic Section of Olkaria Area

The stratigraphy of Olkaria describes the lithology variation with depth as shown by figure 9. Which shows the different types of formations from surface to targeted depth. The phases of drilling section are captured within different zones as explained below.

- 0-50m PyrocIastics; Loose soils/pyroclastic mainly made up of pumice, obsidian and lavalithic fragments. This zone was soft and with minor cave in.
- 50-300m Rhyolite; The zone consisted of relatively unaltered rhyolitic lava. At shallow depths within the zone blocky lavas were expected and major losses of circulations occured. Washouts and cave inns may also occured.
- 300-400m Trachyte and tuff; Soft and altered zone. The clays swelled and care was taken to avoid clogging the bit.
- 400- 700m Rhyolite; The rock consisted of mainly rhyolite with occasional trachyte Intercalations. The rock was medium hard to hard and competent. Minor losses experienced.
- 700 -1500m Trachyte; The zone consisted of mainly trachyte lava. The rock is competent and weakly altered. Minor or partial losses experienced at fracture zones. Casing was set in this zone.
- 1500-2000m Trachyte and rhyolite; The zone consisted of mainly Trachyte 1 with occasional rhyolite intercalations. The rock was competent and weakly altered
- 2000-2400m Rhyolite; The rock in this zone was mainly trachyte. It was hard and competent. Minor or partial losses experienced at fracture zones
- 2400- 3000m Trachyte; This zone consisted of mainly trachyte with tuff intercalations. Occasional minor syenitic and doleritic dyke intrusives. The formation here was compact and medium hard to hard. Minor or partial losses experienced at fracture or fault zones.

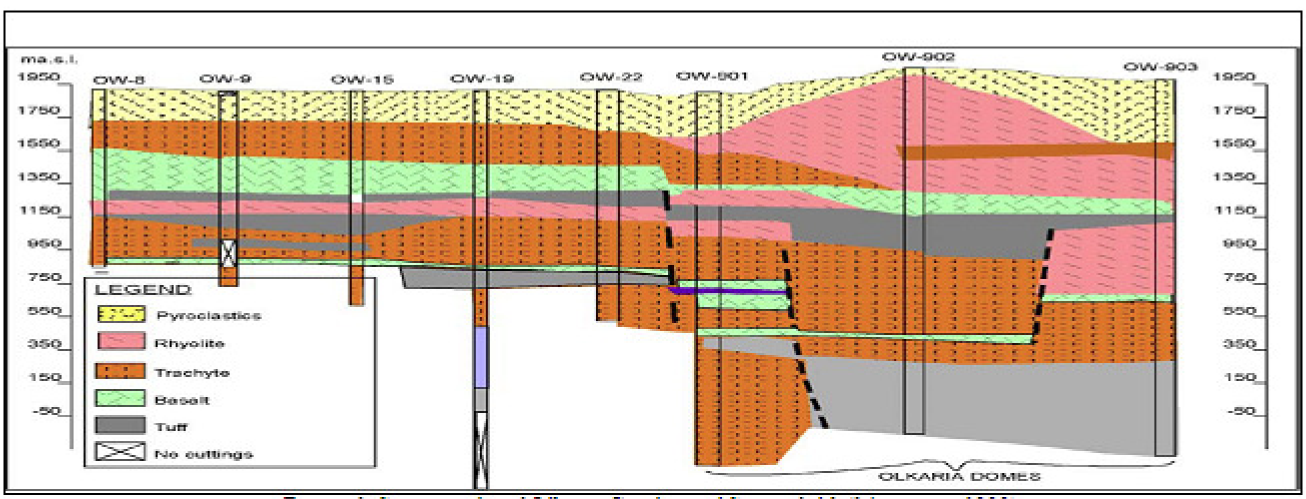

Figure 6: Stratigraphy of Olkaria Geothermal Steam-field (Mungania, 1999)

3. Materials and Methods

3.1. Study Area

The data collected from May, 2013 to Sep, 2013 were specifically from Olkaria Geothermal Field which is divided into seven sectors as shown. and three have been committed to development, namely; OlkariaEast, Olkaria North East, Olkaria South West, Olkaria Central, Olkaria North West, Olkaria South East and Olkaria Domes.

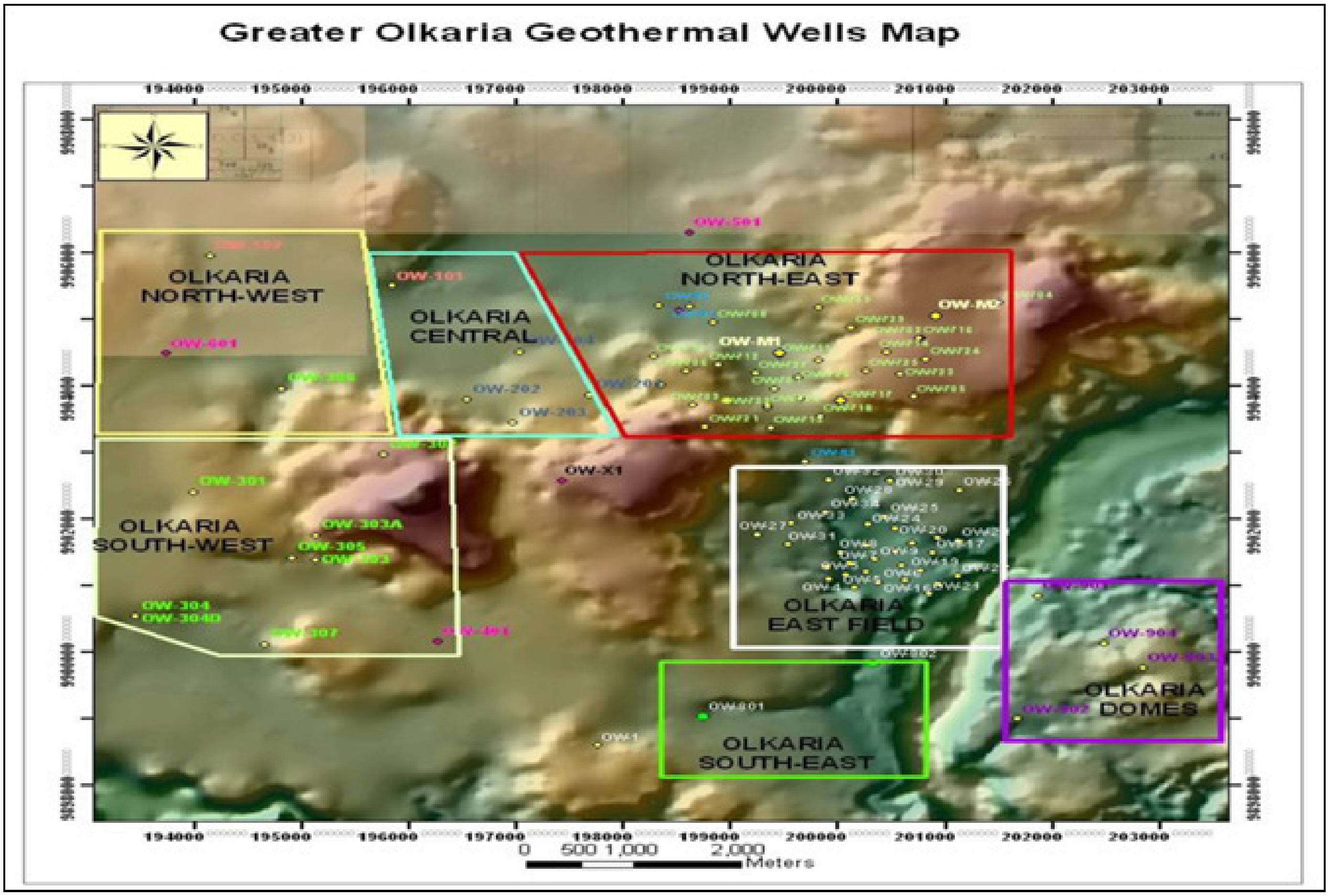

Figure 7: Geographical Wells map for Olkaria Geothermal Steamfield (Ouma 2010)

<u>3.1.1. Sampling</u>

The method used to collect data mainly involved field wells observation experience and sampling. A sample size of 56 wells within seven sectors with only three sectors which have been fully exploited for geothermal resource harness. In this regard, three wells in the same pad from each of the three committed fields giving a total of nine wells were taken from a sample size of 56 wells as shown in table 1. The wells captured in these study are mainly from three pads within three different field sectors of which two are directional and one vertical. From the wells sampled, Domes wells had high output with a total of 35.8MWe, East 23.1MWe and North East 23.7MWe.

SAMPLE						
No.	**Fields**	**Pad**	**Wells**	**Target**	**Depth (m)**	**Output (Mwe)**
1	**Olkaria East**	#44	OW#44A	Directional	3007	7.3
			OW#44	Vertical	3000	7.7
			OW#44B	Directional	3000	8.1
2	**Olkaria North East**	#733	OW#733A	Directional	3000	8.6
			OW#733	Vertical	3000	7.1
			OW#733B	Directional	3000	8
3	**Olkaria Domes.**	#915	OW#915A	Directional	2960	10.5
			OW#915	Vertical	3010	10.8
			OW#915B	Directional	2842	12

Table 1: Sampled wells and their parameters

3.2. Olkaria Wells Design

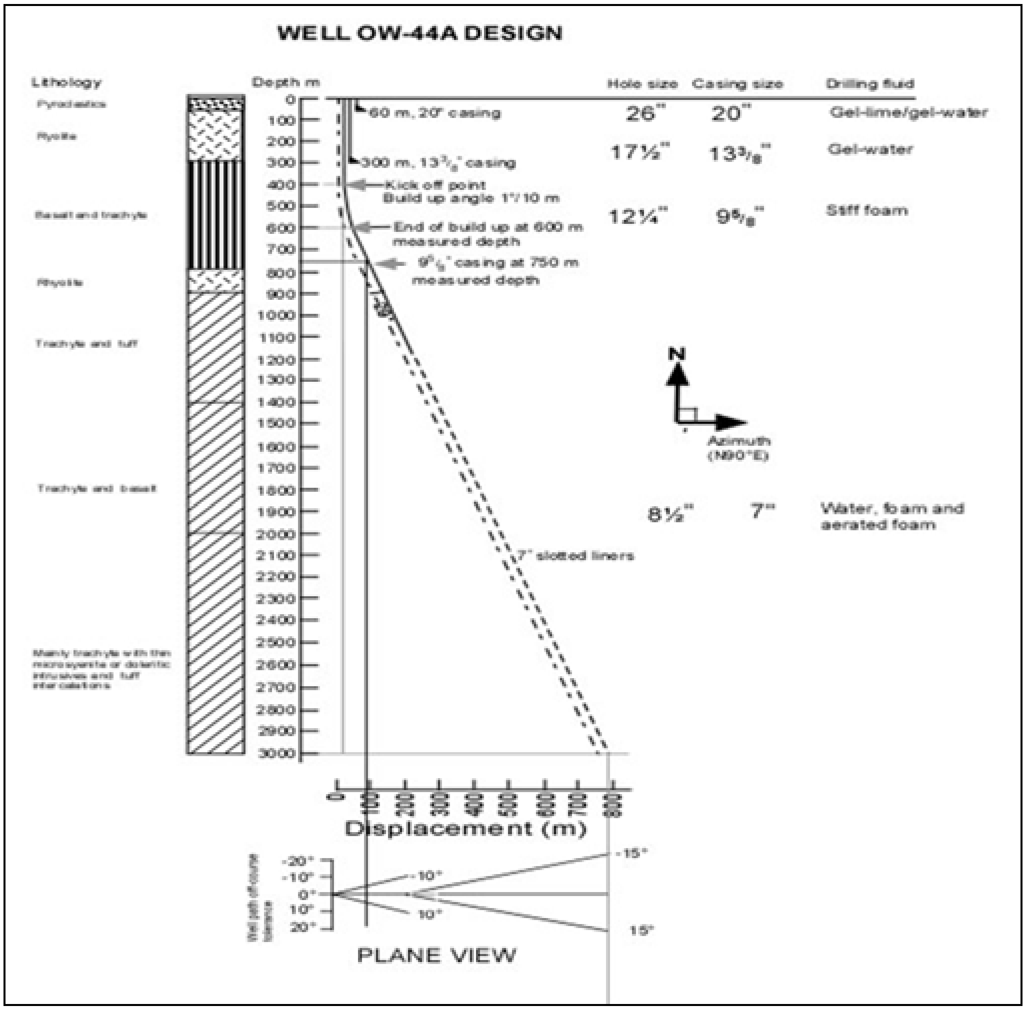

Figure 8: Directional Wells Design for Pad#44

3.3. Multilateral Wells Design and Profile

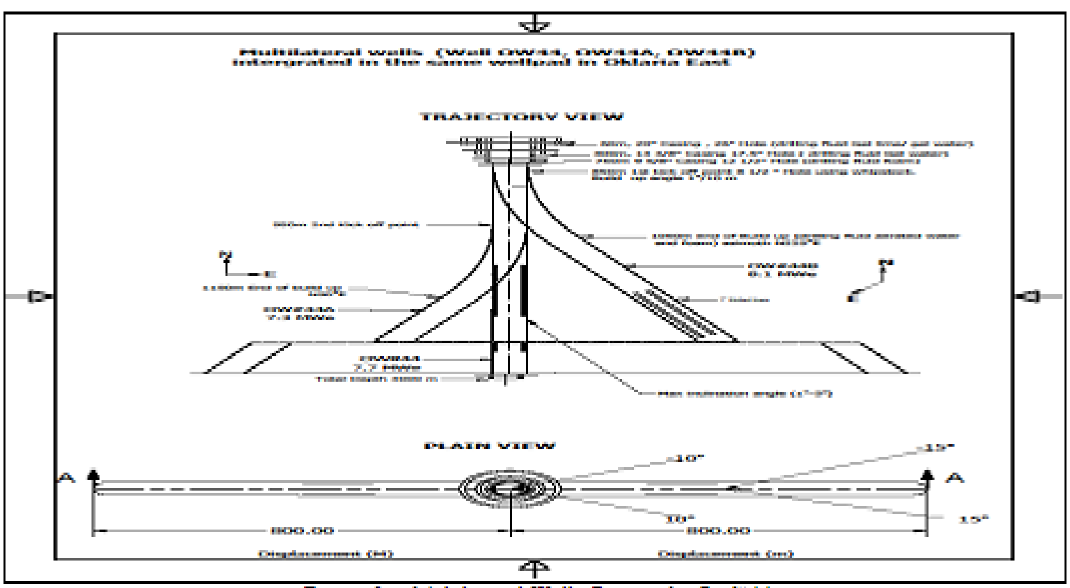

Figure 9a: Multilateral Wells Design for Pad#44

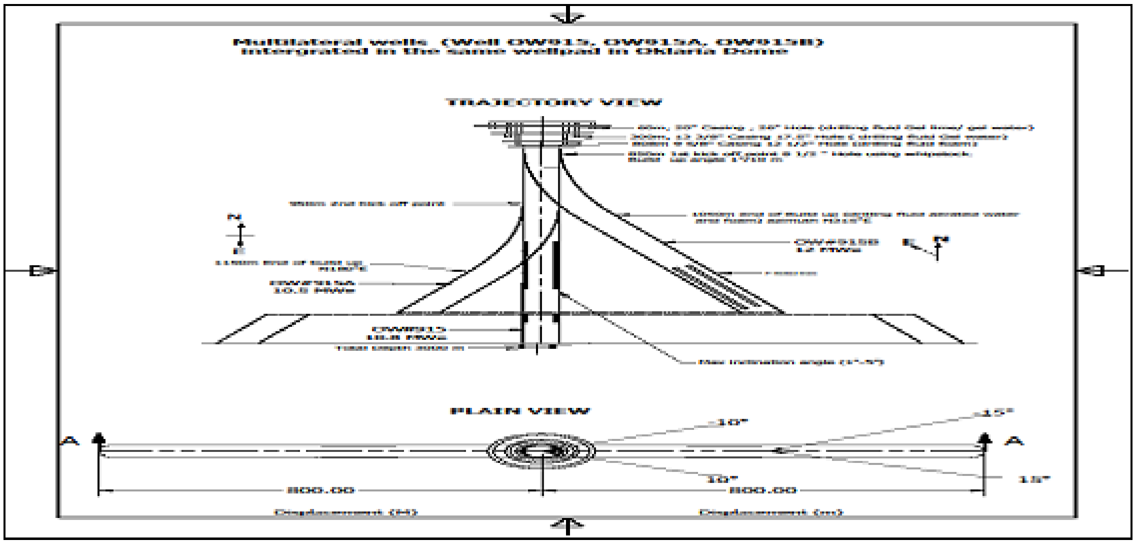

Figure 9b: Multilateral Wells Design for Pad#915

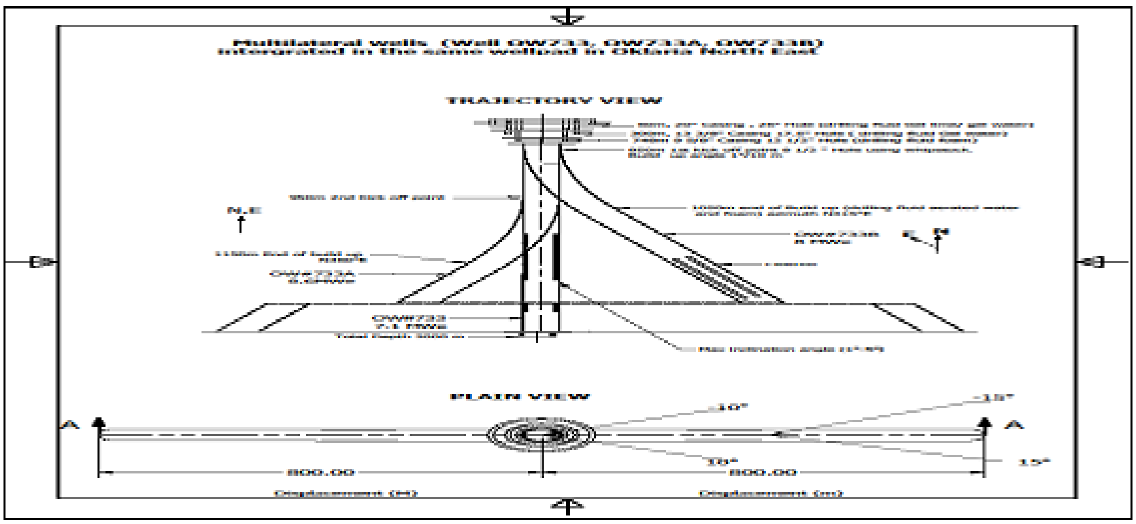

Figure 9c: Multilateral Wells Design for PAD#733

3.3.0. Well Costing

This study compared the overall techno-economics for vertical and directional drilling operation from the year 2008 to 2012 at Olkaria Domes, Olkaria East and Olkaria North East. A total population of 56wells and a sample size of nine wells were selected within three pads in different fields with each pad hosting three separate wells. Analysis of data was done by use of drilling cost formula, cost sensitivity analysis and drilling cost predictions with the help of Excel.

3.3.1. Vertical/Directional Wells Costing

a. Olkaria East Pad#44, Olkaria Domes Pad #915 and Olkaria North East Pad #733

The Overall Total Cost of drilling vertical and directional wells at Pad#44, Pad #915 and Pad #733added up to USD 16,433,660.45, USD15,323,946.4 and USD18,978,123.04 respectively derived from three major cost components i.e. Cost of drilling, Material Cost and Civil Works Cost for three pads respectively (Henneberger, 1995).

Drilling cost had five cost elements, that is, Mobilization and Demobilization cost of the drilling rig and equipment's and actual drilling operation cost. Directional services were on standby for all vertical wells while cementing operation cost was encountered for anchoring three phases of casings from surface to production zone. Final element cost was for inspection of drilling tools.

Materials costs used to complete these well were sub-divided into eight cost elements (Henneberger, 1995); mud materials used to control formation from collapsing and curing the losses plus drilling detergent for improving cutting suspension alongside drilling bits of four different sizes. While cement and additives cost used to anchor three phases of casings from surface to production zone was captured alongside the casings and accessories anchored by the cement during the four phase drilling plus well capping gears after completion. Diesel consumed from spud in to completion and water were also captured.

Civil cost involved four addition elements which were drilling supervisory costs, pad preparation and piping costs, Well profiling and Reservoir Testing cost and finally geological lithology guidance cost (Henneberger, 1995).

3.3.2. Multilateral Wells Costing

a. Olkaria East Pad #44, Olkaria Domes Pad #915 and Olkaria Domes Pad #733

The Total Cost of drilling well OW#44 remained the same (directional case consideration) since it was a primary bore. Pad#44 wells had an overall cost of USD 11,845,732.39, USD11,406,716.09 and USD12,488,709.48 respectively. The total cost of drilling multilateral well OW#44, OW#44A and OW#44B added up to USD 5,332,510.84, USD 3,102,178.57 and USD 3,411,042.98 respectively.

Total cost of drilling multilateral wells OW#915, OW#915A and OW#915B added up to USD4,804,580, USD3,188,461 and USD3,413,675.06 respectively for Pad#915.

Pad#733 wells had an overall cost of USD12,488,709.48 derived from three major cost components. The total cost of drilling multilateral wells OW#733, OW#733A and OW#732A added up to USD 5,585,849.04, USD 3,756,884 and USD 3,145,975.99 respectively. The costs for infrastructure and geological services were never considered because the pad remained the same. Therefore, costing involved two elements for drilling supervisory costs and well profiling and reservoir testing costing.

4.1.0. Total Well Costing and Difference

Evaluation, tabulation and analysis was successfully done for the few sampled wells. The chapter captures the total cost of wells in each pad and cuts out its cost differences in regard to determination and justification of putting the multi application into practice.

4.1.1. Olkaria Domes Pad #915

The table below shows the clear cost comparison of multilateral drilling versus directional drilling at Olkaria Domes pad#915. The cost of drilling vertical wells in both scenarios remained the same since they served as a primary bore. From the data analysis in table 6a, the cost for drilling a directional wells MW#915A & MW#915B was higher than cost for drilling multilateral wells MW#915A & MW#915B. Finally, Total Cost Difference is USD 3,917,230.34]

COST COMPARISON OF MULTILATERAL VS DIRECTIONAL AT OLKARIA DOMES #PAD 915								
Field	Wells	Target	Drilling Cost	Material Cost	Civil Cost	Total Cost (M) USD	Total Cost (D) USD	Cost Difference
	OW#915	Vertical (D)	3,072,889.25	1,158,609.96	573,080.45		4,804,579.65	0
Domes	OW#915	Vertical (M)	3,072,889.25	1,158,609.96	573,080.45	4,804,579.65		
	OW#915A	Directional (D)	3,590,495.39	1,056,769.95	681,893.48		5,329,158.83	2,140,697.45
Domes	OW#915A	Multilateral(M)	2,359,947.07	570,920.96	257,593.35	3,188,461.38		
	OW#915B	Directional (D)	3,281,351.23	1,057,361.48	851,495.23		5,190,207.95	1,776,532.89
Domes	OW#915B	Multilateral(M)	2,545,461.18	610,620.54	257,593.35	3,413,675.06		
OVERALL TOTAL COST (USD)						**11,406,716.09**	**15,323,946.43**	**3,917,230.34**

Table 2a: Cost Comparison for Pad#915

From the graph below in figure 10, the cost of drilling vertical wells to serve as a primary bores remains the same in both drilling scenarios. The study noted that, cost of drilling directional wells increases with increase in depth, time and well numbers. Whereas, the Total Cost Difference will increase with increase in directional wells against increase in multilateral wells. Also, the Cost Difference for drilling vertical wells in same pad remains the same.

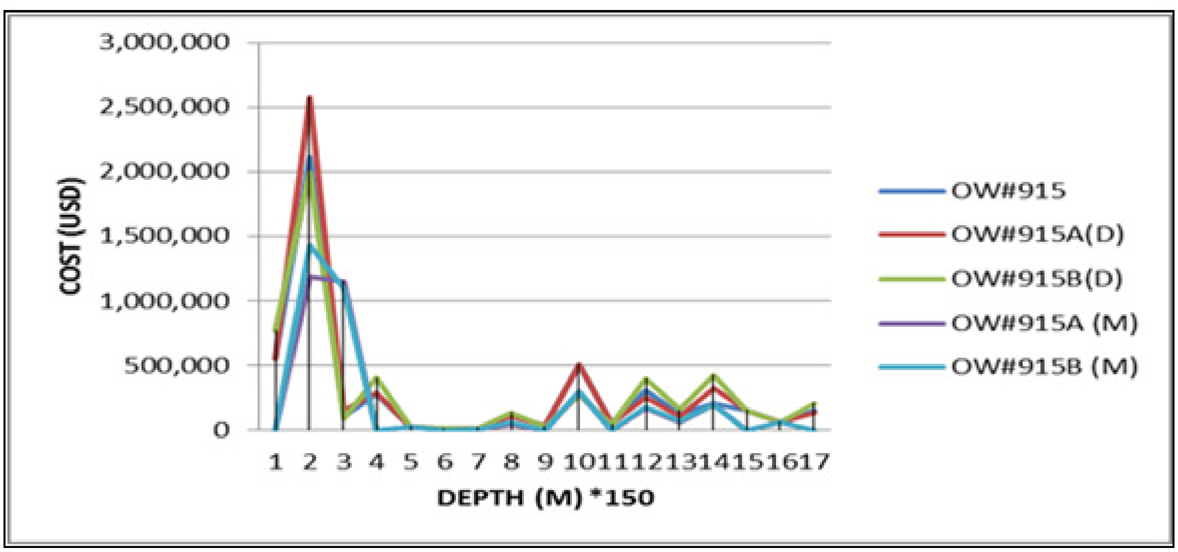

Figure 10a: Cost Comparison for Pad #915

4.1.2. Olkaria North East Pad #733

The table 2b shows the clear cost comparison of multilateral drilling versus directional drilling at Olkaria North East pad 733. The cost of drilling vertical wells in both scenario remains the same since they serve as a primary bore. From the data analysis in table 6b, the Total Overall Cost for drilling a directional wells OW#733A & OW#732A is higher than Total Overall Cost for drilling multilateral wells OW#733A & OW#732A. Overall Total Cost Difference is USD 6,489,413.96

COMPARISON OF MULTILATERAL VS DIRECTIONAL AT OLKARIA NORTH EAST #PAD 733								
Field	Wells	Target	Drilling Cost	Material Cost	Civil Cost	Total Cost (M)	Total Cost (D)	Cost Difference
	OW#733	Vertical (D)	3,808,054.25	1,009,082.86	768,711.92		5,585,849.04	0
N.East	OW#733	Vertical (M)	3,808,054.25	1,009,082.86	768,711.92	5,585,849.04		
	OW#733A	Directional (D)	5,438,475.22	1,214,444.40	1,007,502.42		7,660,422.04	
N.East	OW#733A	Multilateral(M)	2,931,521	512,492.26	312,871.60	3,756,884.46		3,903,537.59
	OW#732A	Directional (D)	3,723,423.09	1,171,549.13	836,880.14		5,731,852.36	
N.East	OW#732A	Multilateral(M)	2,342,594.60	525,380.34	278,001.05	3,145,975.99		2,585,876.37
OVERALL TOTAL COST (USD)						**12,488,709.48**	**18,978,123.44**	**6,489,413.96**

Table 2b: Cost Comparison for Pad#733

From the graph below, the cost of drilling vertical wells to serve as a primary bores remains the same in both drilling scenarios. The case study concludes that, cost of drilling directional wells increases with increase in depth, time and well numbers. Whereas, the Total Cost Difference will increase with increase in directional wells against increase in multilateral wells. Also, the Cost Difference for drilling vertical wells in same pad remains the same.

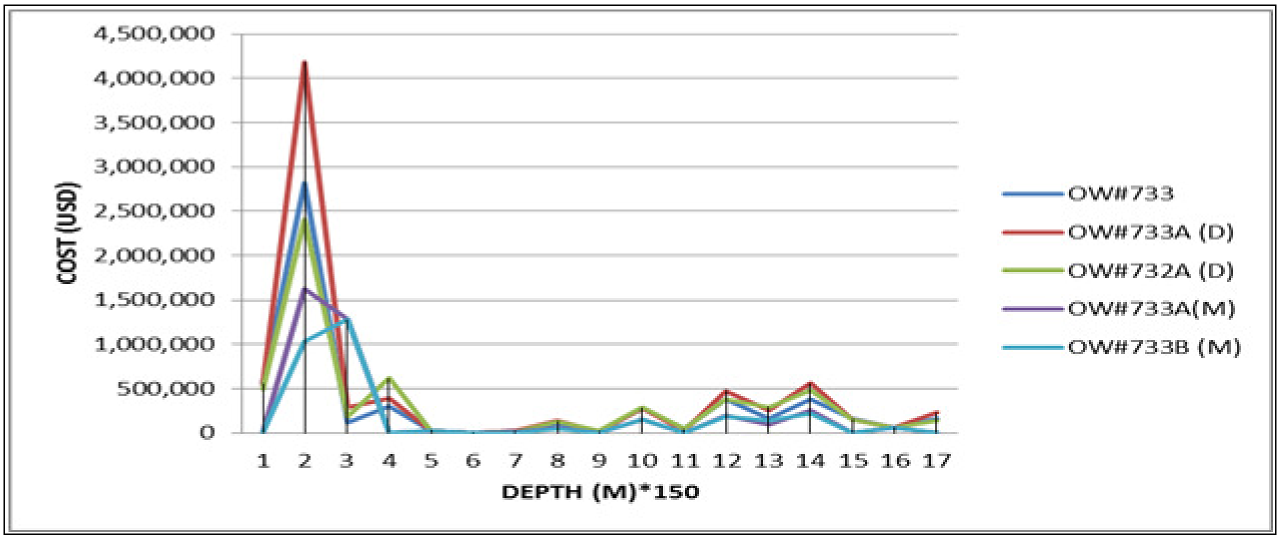

Figure 10b: Cost Comparison for Pad #733

4.1.3. Olkaria East Pad #44

Table 2c shows cost comparison of multilateral drilling versus directional drilling at Olkaria East pad 44. The cost of drilling vertical wells in both scenario remains the same since they serve as a primary bore. From the data analysis, the Total Overall Cost for drilling a directional wells OW#44A & OW#44B is higher than Total Overall Cost for drilling multilateral wells OW#44A & OW#44B. From the data, Overall Total Cost Difference is USD 4,587,928.07

COMPARISON OF MULTILATERAL VS DIRECTIONAL AT OLKARIA EAST #PAD 44								
Field	Wells	Target	Drilling Cost	Material Cost	Civil Cost	Total Cost (M)	Total Cost (D)	Cost Difference
	OW#44	Vertical (D)	3,435,519.25	1,240,494.72	656,496.86		5,332,510.84	
East	OW#44	Vertical (M)	3,435,519.25	1,240,494.72	656,496.86	5,332,510.84		**0**
	OW#44A	Directional (D)	3,751,567.25	1,236,402.04	727,347.11		5,715,316.40	
East	OW#44A	Multilateral(M)	2,634,035.89	555,404.22	221,602.87	3,411,042.98		**2,304,273.42**
	OW#44B	Directional (D)	3,496,850.28	1,189,985.73	698,997.21		5,385,833.22	
East	OW#44B	Multilateral(M)	2,292,780.80	579,660.85	229,736.92	3,102,178.57		**2,283,654.65**
OVERALL TOTAL COST (USD)						**11,845,732.39**	**16,433,660.45**	**4,587,928.07**

Table 2c: Cost Comparison for Pad#44

From the figure, the cost of drilling vertical wells to serve as a primary bores remains the same in both drilling scenarios. The cost of drilling directional wells increases with increase in depth, time and well numbers. Whereas, the Total Cost Difference will increase with increase in directional wells against increase in multilateral wells. Also, the Cost Difference for drilling vertical wells in same pad remains the same.

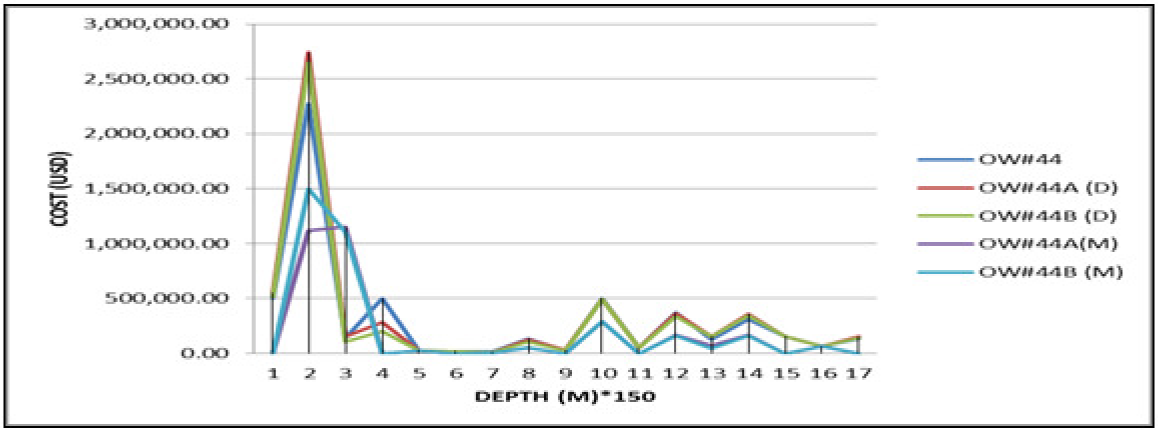

Figure 10c: Cost Comparison for Pad #44

4.2.0. Total Wells Output and Drilling Time

The sampled wells output was tabulated and analyzed alongside total drilling time of each well. These was to give a clear justification of adopting the multi practices over directional application.

4.2.1. Olkaria Domes -PAD#915

The table below shows the collected data at pad#915 in Olkaria domes in terms of drilling trajectory, days, depth and well output alongside the rig name.

Well No.	Field	Target	Drilling days	Total depth	Output (MWe)	Rig No.
OW-915	OLK Domes	Vertical	61	3010	10.8	GWDC-188
OW 915A	OLK Domes	D	55	2971	13	GWDC-116
OW-915B	OLK Domes	D	75	2842	12	GWDC-120
OW-915	OLK Domes	Vertical	61	3010	35.8	GWDC-188
OW 915A	OLK Domes	M	25	2971	35.8	GWDC-116
OW-915B	OLK Domes	M	35	2842	35.8	GWDC-120

Table 3a: Pad #915-Well Output and Drilling Time

From figure 11a, drilling of primary vertical well takes the same time in both scenarios. Drilling directional wells takes more time than multilateral wells due to additional in surface to services operation.

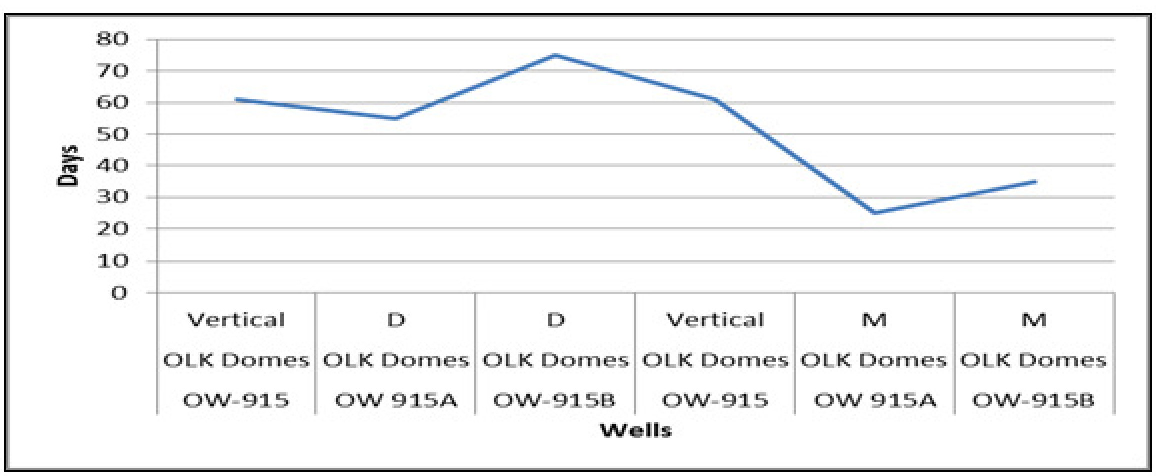

Figure 11a: Pad #915-Drilling Time for Multilateral vs Directional Wells

From figure 11b, the single drilled wells each takes account of its own output while in multilateral primary head account the total output of all lateral conjoins. Hence, multilateral rating remains steady due to self-aquifers and payback period proves to be shorter in regard to their wells production cost against wells output.

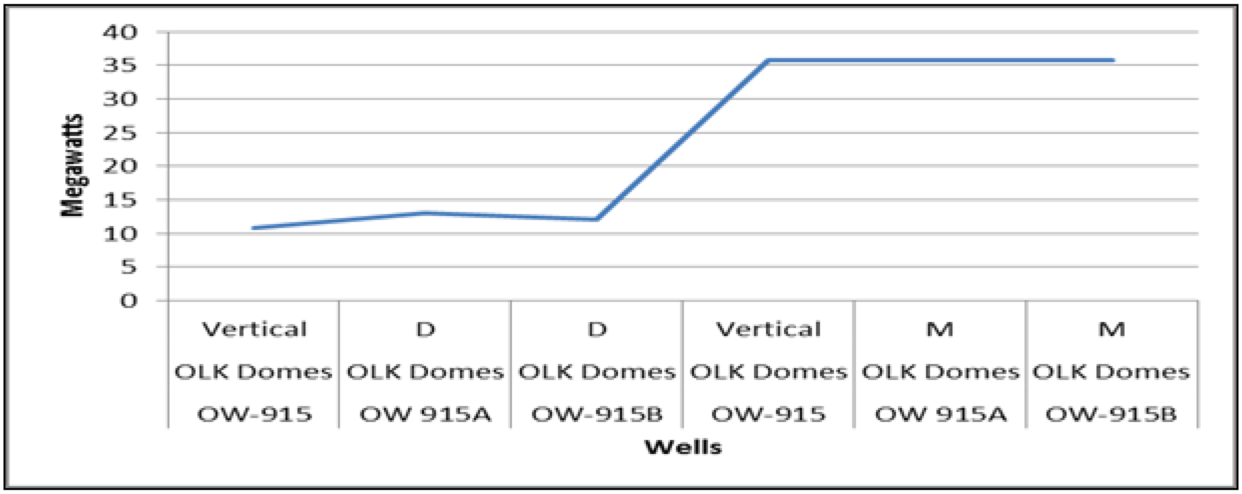

Figure 11 b: Pad #915-Well Output for Multilateral vs Directional Wells

This field sector confirms had the highest on bottom temperature within Olkaria as shown in figure 11c. Drilling on this field needed a lot of care to avoid formation collapsing by applying under balancing drilling. The temperature raised the pressures and gave better hole cleaning. The main disadvantage is that; the bit doesn't survive long on bottom with high temperatures. The well kicks were commonly pronounced as deep drilling progressed.

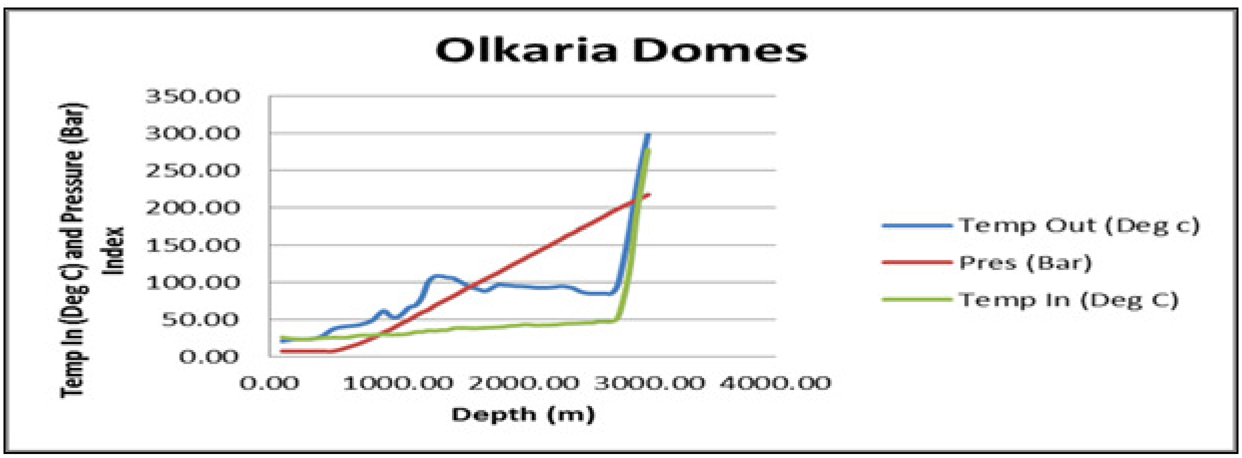

Figure 11c: Olkaria Domes Temperature Profile

Multilateral wells will have a short payback period of 1.5years compared to directional wells which had a high drilling cost in comparison.

PAYBACK PERIOD (YEARS) FOR PAD#915					
Well No.	**Target**	**Output (MWe)**	**Total well cost (USD) and Production**	Year 1	Year 2
OW-915	Vertical	10.8	127198946.4	91290000	182580000
OW 915A	Directional	13			
OW-915B	Directional	12			
OW-915	Vertical	35.8	123281716.1	91290000	182580000
OW 915A	Multilateral	35.8			
OW-915B	Multilateral	35.8			

Table 3b: Payback Period for Pad#915

4.2.2. Olkaria East -Pad#44

Table 4a, shows the collected data at pad 44 in Olkaria domes in terms of drilling trajectory, days, depth and well output alongside the rig name. Minimum depth was 3000m and Maximum 3010m. Overall drilling in the pad with single wells took 191days with maximum wellhead output of 8.1MW. Multilateral scenarios took 121days overall and an average output head of 23.1MW.

Well No.	Field	Target	Drilling days	Total depth	Output (MWe)	Rig No.
OW-44	OLK East	Vertical	61	3000	7.1	GWDC-188
OW-44A	OLK East	D	52	3010	7.3	GWDC-116
OW-44B	OLK East	D	78	3000	8.1	GWDC-116
OW-44	OLK East	Vertical	61	3000	23.1	GWDC-188
OW-44A	OLK East	M	25	3010	23.1	GWDC-116
OW-44B	OLK East	M	35	3000	23.1	GWDC-116

Table 4a: Pad #44-Well Output and Drilling Time

From the figure 12a, drilling of primary vertical well takes the same time in both scenarios as noted from the collected data. Also, drilling of directional wells takes more time than multilateral wells due to additional in surface to services operation.

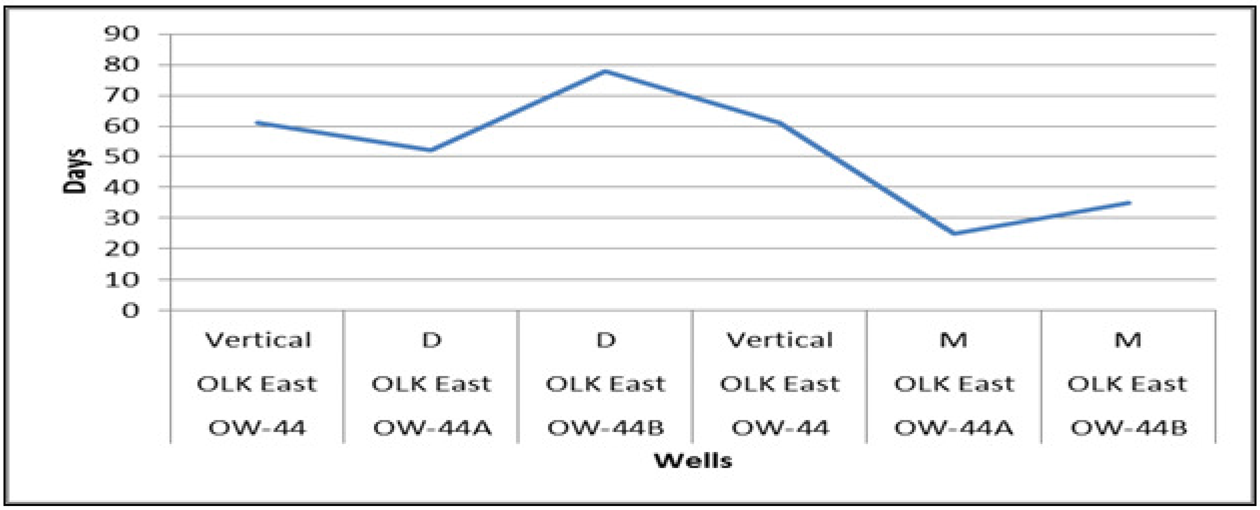

Figure 12a: Pad #44-Drilling Time for Multilateral vs Directional Wells

the single drilled wells account its own output while the primary head accounts the total output of all lateral conjoins in multilateral. Hence the case concurs by, multilateral rating remains steady due to self-aquifers and payback period proves to be shorter in regard to their wells production cost against wells output.

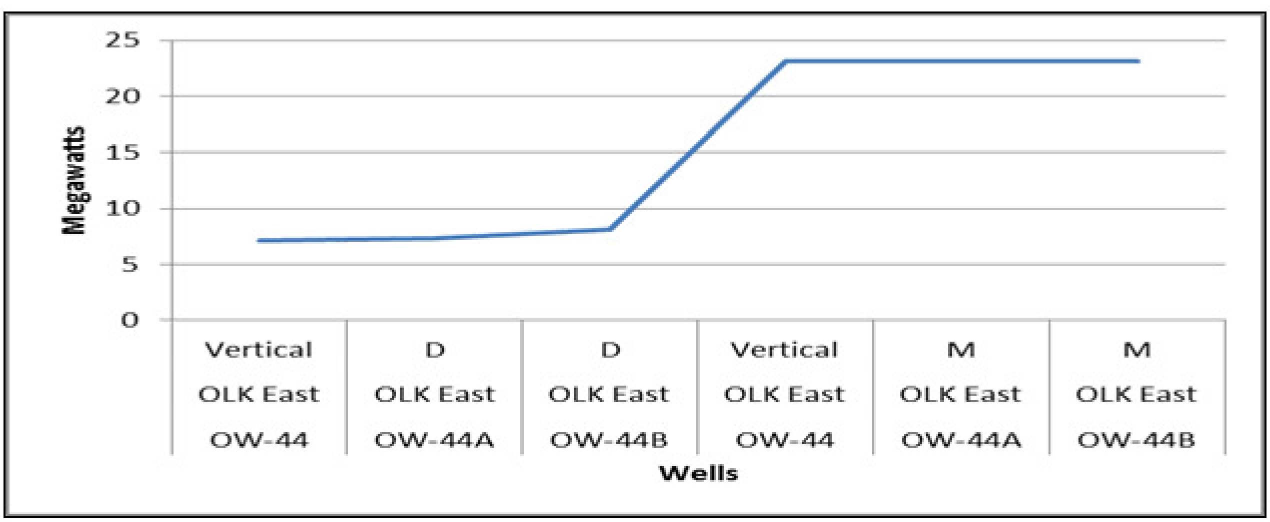

Figure 12b: Pad #44-Well Output for Multilateral vs Directional Wells

This field confirmed to have high on bottom formation pressure hence better hole cleaning as depth increases as shown in figure 12c. Also, the temperature on bottom reduces the bit life and tends to have low cutting criterion as the drilling bit time increases.

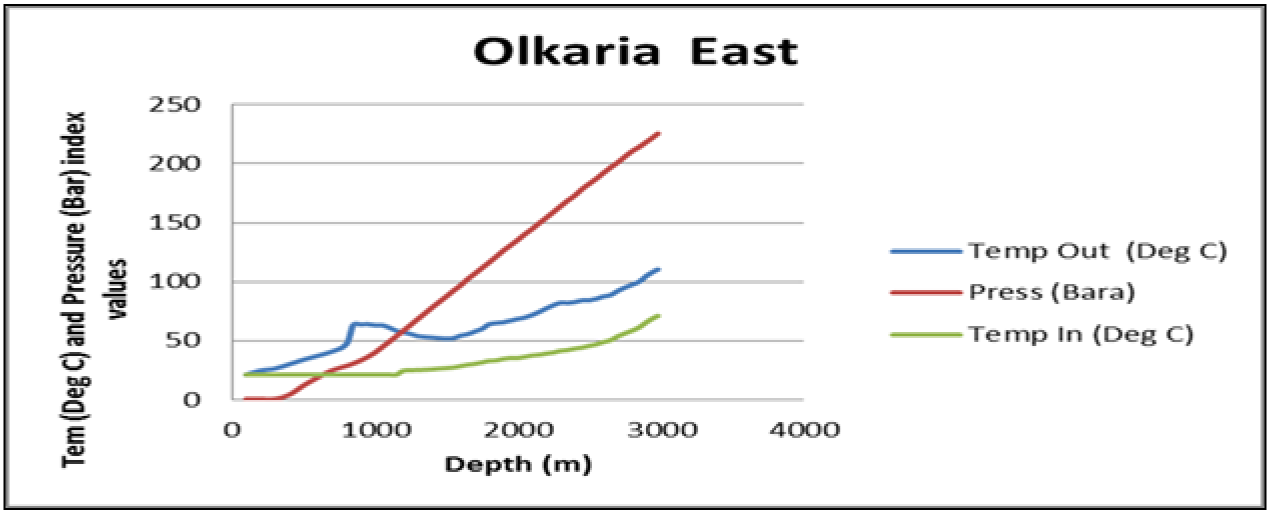

Figure 12c: Olkaria East Temperature Profile

Multilateral wells will have a short payback period of 1.5 years compared to directional wells which had a high drilling cost in comparison as shown in table 8b.

PAYBACK PERIOD (YEARS) FOR PAD#44					
Well No.	**Target**	**Output (MWe)**	**Total well cost (USD) and Production**	Year 1	Year 2
OW-44	Vertical	7.1	88621160.45	58905000	117810000
OW 44A	Directional	7.3			
OW-44B	Directional	8.1			
OW-44	Vertical	23.1	84033232.39	58905000	117810000
OW 44A	Multilateral	23.1			
OW-44B	Multilateral	23.1			

Table 5: Payback Period for Pad#44

4.2.3. Olkaria North East -Pad#733

Table 6a below shows the collected data at pad 733 in Olkaria domes in terms of drilling trajectory, days, depth and well output alongside the rig name.

Wells	Field	Target	Drilling days	Total depth	Output (MWe)	Rig No.
OW 733	OLK N.East	vertical	57	3000	7.1	GWDC-116
OW-733A	OLK N.East	D	84	3000	8.6	GWDC-116
OW-732A	OLK N.East	D	47	3000	8	GWDC-188
OW 733	OLK N.East	vertical	57	3000	23.7	GWDC-116
OW-733A	OLK N.East	M	40	3000	23.7	GWDC-116
OW-732A	OLK N.East	M	25	3000	23.7	GWDC-188

Table 6a: Pad #44-Well Output and Drilling Time

From figure 13a, drilling of primary vertical well takes the same time in both scenarios. Drilling of directional wells takes more time than multilateral wells due to additional in surface to services operation.

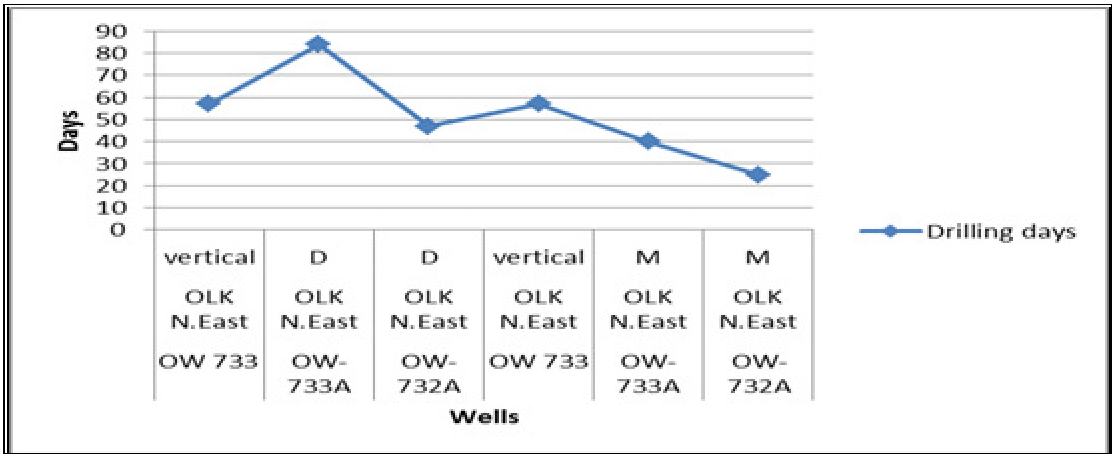

Figure 13a: Pad #733-Drilling Time for Multilateral vs Directional Wells

The study in figure 13b stipulates that, single drilled wells each takes account of its own output while in multilateral primary head account the total output of all lateral conjoins. Hence, multilateral rating remains steady due to self-aquifers and shorter payback period in regard to their wells production cost against wells output.

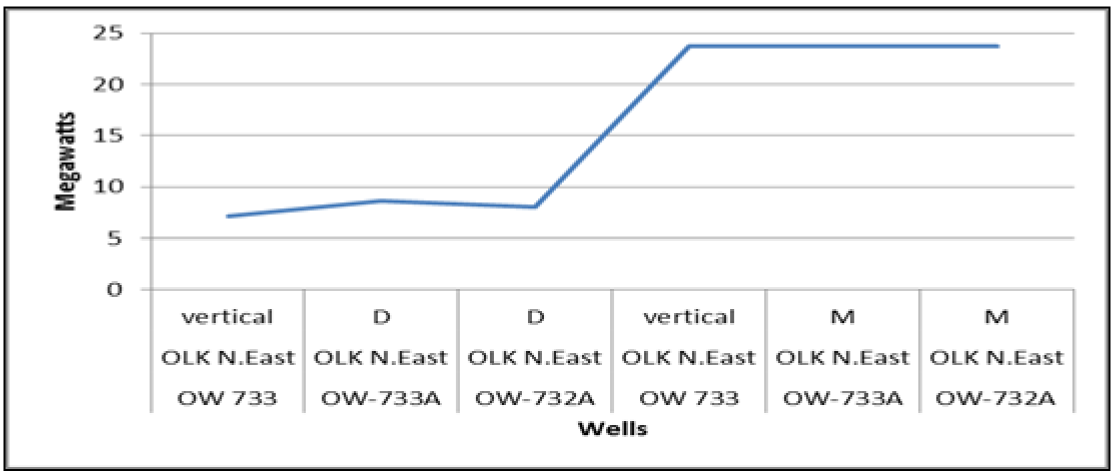

Figure 13b: Pad #733-Well Output for Multilateral vs Directional Wells

The figure 13c, justifies the cause of bit failure which was to the increase in on-bottom temperature as the depth progressed. This analysis confirmed that, as the depth increases the temperature increases hence increase in formation pressure. This formation gives better hole cleaning by lifting cutting though the bit life is diminished by high on bottom temperatures.

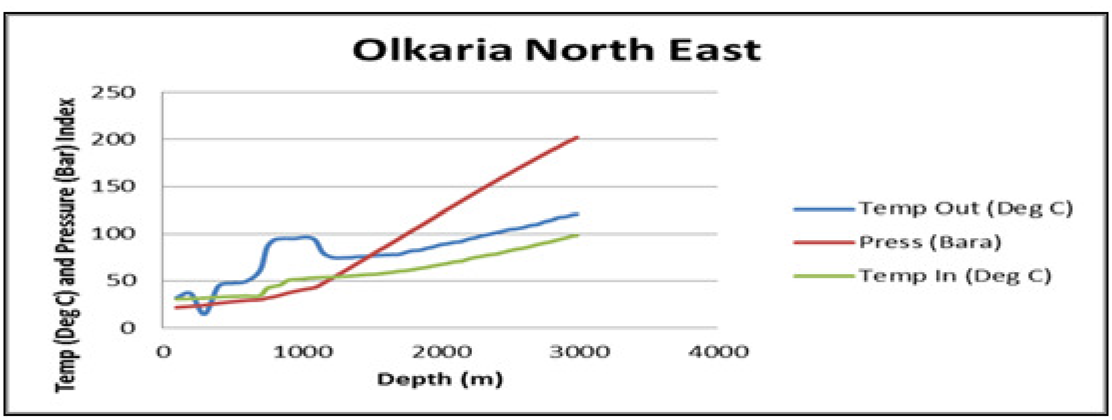

Figure 13c: Olkaria North East Temperature Profile

Multilateral wells will have a short payback period of 1.5 years compared to directional wells which had a high drilling cost in comparison as shown in table 9b.

PAYBACK PERIOD (YEARS) FOR PAD#733					
Well No.	Target	Output (MWe)	Total well cost (USD) and Production	Year 1	Year 2
OW-733	Vertical	7.1	93040623.04	60435000	120870000
OW 733A	Directional	8.6			
OW-732A	Directional	8			
OW-733	Vertical	23.7	86551209.48	60435000	120870000
OW 733A	Multilateral	23.7			
OW-732A	Multilateral	23.7			

Table 6b: Payback Period for Pad#733

5. Conclusion and Recommendations

5.1. Conclusion

The main purpose of this research was to determine the economic viability of drilling multilateral wells over the single drilling of directional and vertical wells as has been the case for the previous drilling application at Olkaria. Research findings confirmed that, adoption of multilateral technique at Olkaria Geothermal Steamfield will actually save cost, work and time as it concurs with the objectives and sets clear solution to the said problem statement.

Over 50 wells have been drilled at Olkaria geothermal field for the last number of years as highlighted by the sample population. This transformation of the geothermal natural resource to steam drive stipulates a lot of capital investment has been laid out to achieve these especially from year 2008 to 2012 as the case puts the limit for 9 wells sampled from three different pads and fields. The data analyzed showed higher costs in drilling directional wells separately caused by general surface to services costs as compared to multilateral adoption.

Generally, the results show that directional drilling increases cost as the number of wells increases whereas the vertical wells had the same costs as to that of multi analysis because they served as a primary bore in either case. After evaluation and analysis of data, it is clear that, maximum cost required for a single lateral well reduces by a third that of directional well. At Olkaria domes Pad#915 reduces well costs from USD 15,323,946.43 to USD 11,406,716.09. Also, Olkaria East Pad#44 reduces from USD 16,433,660.45 to USD 11,845,732.39 and at Olkaria North East Pad#733 the cost reduces from USD 18,973,123.44 to USD 12,488,709.488 respectively.

The minimum time for drilling operation has been achieved through multi analysis and application. The study also confirms that, drilling days at Pad#915 has been from 191days to 121days, Pad#733 reduces from 188days to 122days and Pad#44 from 191days to 121days respectively. Finally, power output in multi applications guarantees shorter payback period of 1.5years inclusive of production machinery.

The costs variations observed were affected by some of uncontrolled factors like geological formation and pressure, cementing practices, bit to tool life, torque management and drilling hazards. Still, the actual cost factors which contributed to increase in directional drilling costs were mobilization and demobilization cost, cementing and casings accessories, drilling materials and civil works. The results suggest that drilling practices for Olkaria field needs to be changed to suit multi-application so as to reduce the actual cost by third and minimize the payback period in the long-run. Furthermore, the results depict that, more cost reduction will be encountered with increase in lateral numbers alongside increase in well output as opposed to directional wells which will increase the cost with increase in single penetration indexes and practices. Since the sky remains the limit, the study highlights future correlation and projections on projects of the same prior to initiation and completion.

5.2. Recommendation

Recommendations based on the research findings are: -

- That all new wells be multilateral to minimize cost.

5.2.1. Future Work

- Increase in wellbore diameter projects better output.
- Use of lateral re-drills to the single dry wells like OW#40, OW#918 and OW#912A.
- Use of top drive over rotary drive below production casings to reduce drilling risks.

5.3. Acknowledgement

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