COST AND EFFECTIVENESS OF GEOTHERMAL DRILLING

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ABSTRACT

For geothermal power projects about 40-50% of the total investment cost lies in drilling of the production and reinjection wells and the steam supply system to the plant. Current geothermal project costs for conventional flash-steam plants are about 4,000 USD per kilowatt (kW) of power. Roughly half of the well cost comes from materials and infrastructure and the other half is from the rental of rigs and services (day rates). Drilling of each hole to 2,000-2,500 m may take anywhere from 32 to 60 days. The cost of wells does thus critically depend on the effectiveness of drilling, that is to say the number of working days. The paper describes an analysis of the drilling performance of 77 high-temperature geothermal production and reinjection wells in the Hengill geothermal area in Iceland drilled from 2001 to 2011, and assesses the statistical level of risk. The study compares workdays in drilling holes of two different casing programmes, and two trajectories of vertical or directional drilling. The production casing was either of a regular diameter of 244.5 mm (9⅝") or a large diameter of 339.7 mm (13⅜"). The workdays were normalized to a reference well of four sections, Section 0 of initial drilling to 90 m, Section 1 to 300 m, Section 2 to 800 m, and Section 3 to 2,235 m depth (Figure 3). The workdays used to drill each of the sections of the hole were broken down and analysed for seven different activities. The average and standard deviation for each of the four well sections was calculated and the findings used for the model calculations. For large diameter holes an average of 45 days was required, but 47 days for holes of the regular programme. No difference was found for vertical or directional trajectories.

The Monte Carlo method was applied to obtain a statistical estimate of the number of workdays and the cost of a reference hole to 2,235 m with large casings and directionally drilled. The cost estimate is based on assumed prices for services and material, but not on the actual cost which was not made available for the study for commercial reasons. The actual drilling contract for Hellisheiði was based on meter rates (not day rates) and sharing of the risk when problems are encountered. The cost figures presented in this study reflect what the cost may be, but not the contract. The estimated cost was found to be \$4,318,000 with a standard deviation σ of \$451,000. The cost lies with 95% confidence between \$3,517,000 and \$5,262,000. About 31% of the holes encountered drilling problems which led to higher drilling costs. The additional cost due to drilling problems was estimated on the basis of workdays that were required to solve the problem beyond the average number of workdays required in the respective section. In most cases the difficulties were due to a loss of circulation or collapsing geological formations where the drill string got stuck. The additional cost due to these problems was though low in most cases. It exceeded 1 σ in 23% of the 77 drilled holes, 2 σ in 13% and 3 σ in only 8%. The majority of holes were thus drilled according to the original schedule, demonstrating that the perceived high risk of drilling such holes is less than commonly thought.

The Injectivity ((kg/s)/MPa) is determined at the end of drilling by logging the pressure response to different rates of pumping water onto the well. These results are compared to the final well output obtained later by flow testing. Such estimates of future production are valuable for deciding

whether to drill deeper, drill a sidetrack or to apply well stimulation before moving the drilling rig off the well. The average generating capacity amounted to ~5.7 MW of electricity per well, but surprisingly there was not a significant difference in the mass flow output that could be related to the trajectory nor the well diameter.

1. INTRODUCTION

After successful development of the Nesjavellir Field in the Hengill Geothermal Area (commissioned 1990, generating 120 MW_e of electricity and 300 MW_t of hot water), Reykjavík Energy decided to explore other prospects in the area. In the years 2001–2011 the company drilled 55 exploratory and production wells as well as 17 reinjection wells in the Hengill Area, and 5 make-up wells in the Nesjavellir Field. The Hellisheiði Geothermal Plant, about 20 km east of Reykjavík, was commissioned in four stages 2006-2011. It generates 303 MW_e of electricity and 133 MW_t of hot water for district heating. This intensive drilling period in the same geothermal area provided a unique source of data to obtain statistical estimates of the cost and effectiveness of geothermal drilling. A first attempt to analyse this data was undertaken by Sveinbjornsson (2010). The following paper reports the main topics of that reference, with emphasis on the frequency of problems which lead to excessive additional cost. The number of working days to complete each of four depth sections of the well was analysed and the time broken down to show how much was spent on drilling, tripping, casing, cementing, logging, repair etc. The results were then grouped according to which well design was used and technology applied. Cost calculations in this study are based on assumed prevailing prices for services and material, as the real cost was not made available. The drilling was done by Iceland Drilling Co. (Jarðboranir ehf) after international tendering, where the cost is based on performance, i.e. price per meter of hole drilled, and unit costs for material. In the case of problems the cost is shared, and then day rates come into play. The majority of the wells were drilled with modern drilling rigs, up to four at the same time, all-hydraulic with a top-drive and the large ones with automatic pipe handling. The time breakdown in this study was worked out from the geological daily reports prepared by Iceland GeoSurvey (ÍSOR) as the daily reports of the rigs are confidential.

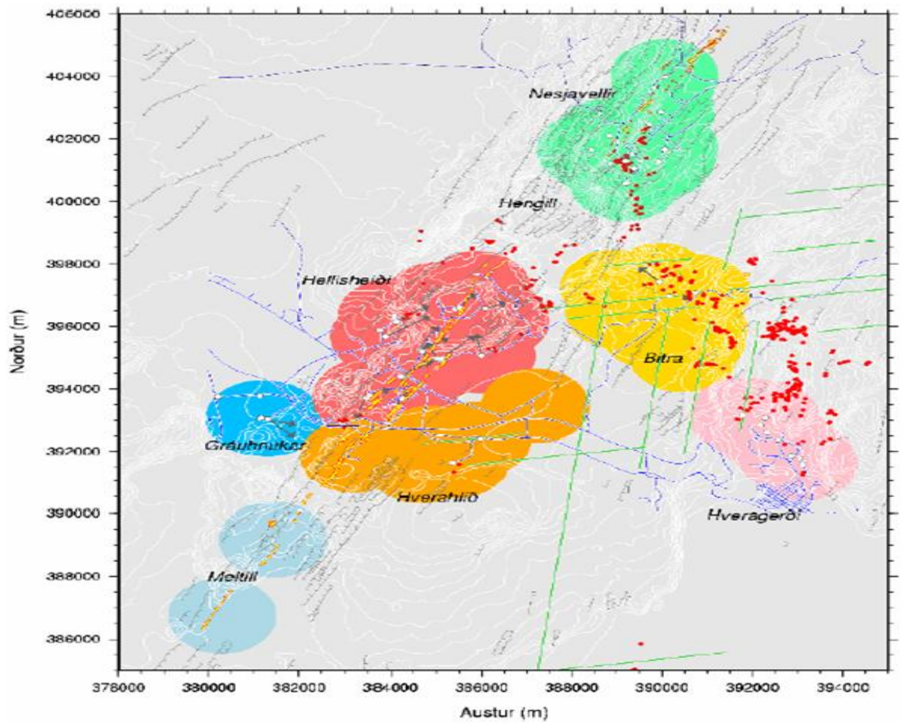

Fig. 1. Prospective fields in Hengill Geothermal Area. Figure from Reykjavik Energy. The Nesjavellir Field is green. Most of the wells drilled in the years 2001–2011 were in the Hellisheidi, Grauhnukar and Hverahlid Fields. Location of those wells and the formation temperature at depth are shown in Fig. 2.

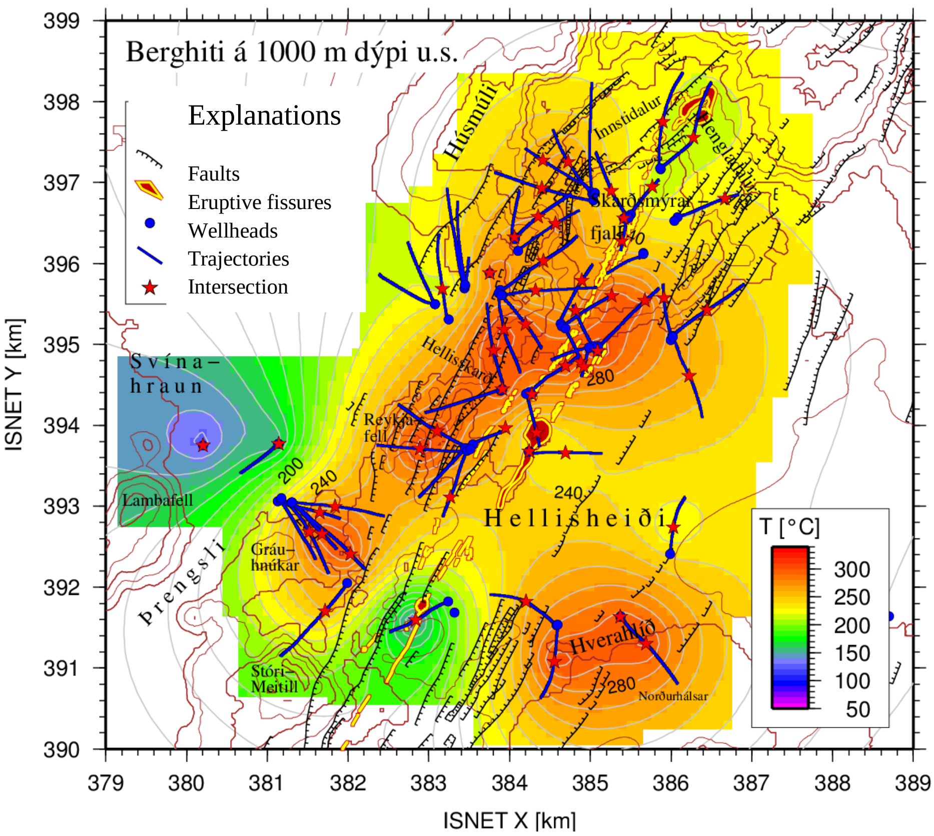

Fig. 2. Formation temperature in the southern half of Hengill Area at 1,000 m below sea level. Blue dots and lines indicate wellheads and trajectories of directional wells. A red star on the trajectory indicates where the well reaches the depth of the map. Figure from Gunnarsson, Reykjavik Energy (2012).

2. DRILLING IN THE HENGILL AREA

A recent description of the conceptual model of the Hengill geothermal system was given by Franzson et al. (2010). Fig. 1 shows the drill fields of the Hengill Area. Most of the wells analysed were drilled in the fields of Hellisheidi, Grauhnukar and Hverahlid (Fig. 2).

Two types of casing designs for high temperature wells were used in the Hengill Area. The wells were either drilled vertical or directional. The most common type is that of a directional well with a "large diameter" casing program. The initial drilling (Section 0) is by a small rig with a 26" bit down to 90 m for a 22½" surface casing, followed by Section 1 drilled by a larger rig with a 21" bit to 300 m for the 18⅝" anchor casing. Inclined drilling starts with a kick-off point (KOP) in Section 2, where the inclination is gradually built up by 2.5–3.0° per 30 m. The section is drilled with a 17½" bit to 800 m for 13⅜" production casing. The open hole in Section 3 is drilled with a 12¼" bit to a depth of 1,800 to 3,300 m for 9⅝" slotted production liner. The other design is narrower and called the "regular diameter" casing program. The sections are the same but the diameters 18⅝" of the surface casing, 13⅜" anchor casing, 9⅝" production casing, and 7" slotted production liner. Fig. 3 shows the design of a vertical well of regular diameter and a directional well of large diameter.

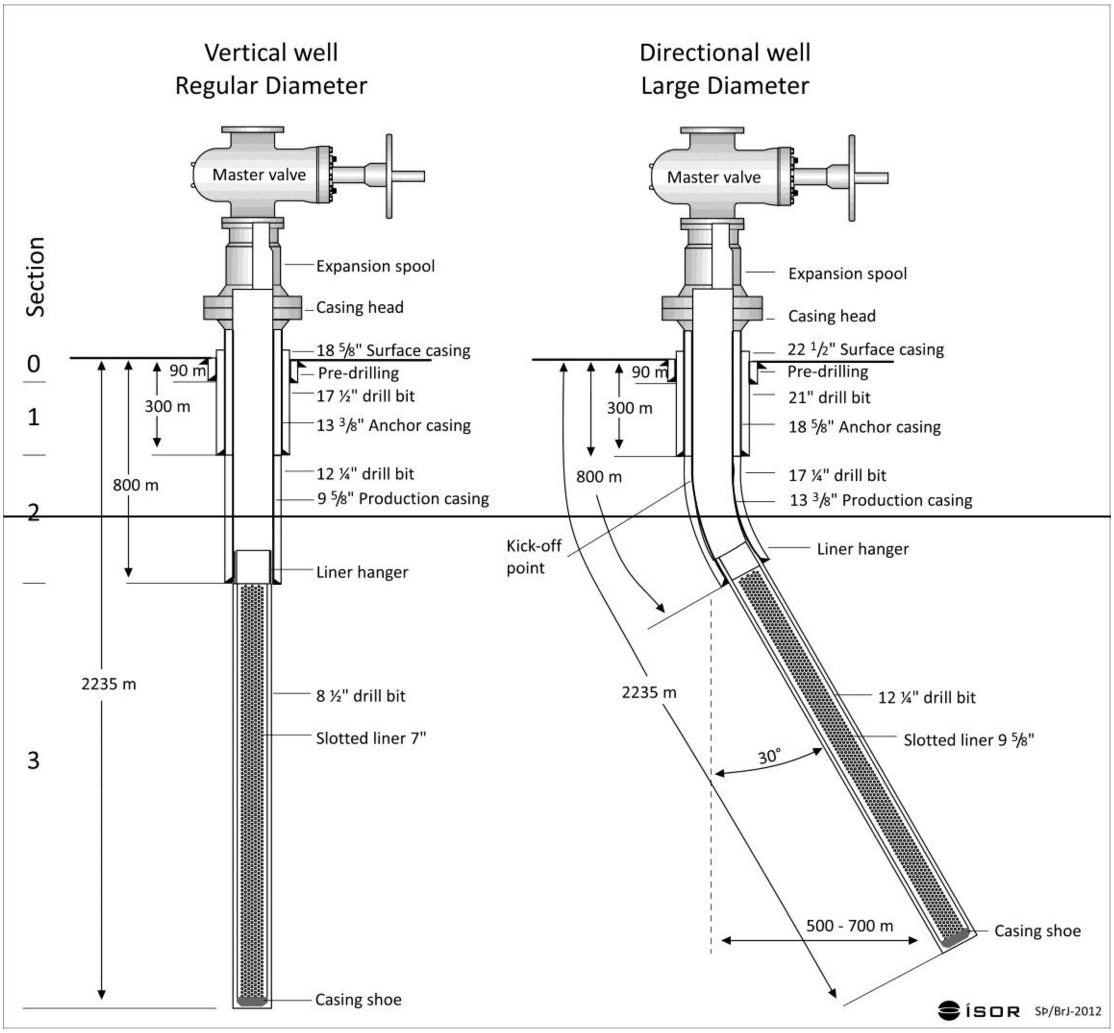

Fig. 3. Design of a vertical well of regular diameter and a directional well of large diameter. The well is divided into four sections, numbered 0-3, according to the depth interval drilled. The figure shows the depth intervals, on the left, for the reference well. The same section numbers are used in the tables.

Fig. 4. A drilling rig on site at Hellisheiði (200 t hook load capacity). Photo Jarðboranir.

Seven drill rigs were used in the drilling. Two small rigs with a hook-load capacity of 50 tons were used in the initial drilling (pre-drilling) to 90 m depth. An intermediate rig (100 t) was used mostly for the shallower sections and four larger rigs (179–300 t) were used in all sections, but preferably in the deepest ones.

The initial drilling was performed with air hammer and foam or tricone bits with tungsten carbide inserts, using mud and water as circulation fluids. Rotary drilling techniques with tricone bits were applied in Section 1 from 90–300 m. depth, but in Section 2 from 300–800 m depth a mud motor was used to rotate the bit and a MWD (Measurement While Drilling) tool inserted in the drill string to monitor direction (Azimuth) and inclination of the well. In Section 3 below the 800 m production casing until total depth no mud was used but drilling was carried out with only water as long as there were no circulation losses, but in most wells then switched over to aerated water by compressed air for pressure balance.

3. TIME ANALYSIS OF DRILLING DATA

To compare the drilling time for different wells, the respective numbers of workdays were normalized for a reference well of that design and the average depth of the group which was 2,235 m. The frequency distribution of workdays for each section is asymmetric with the most frequent value lower than the average. An example of this distribution is presented in figure 5 for the workdays in drilling Section 3 from 800-2,235 m in 46 large diameter directional wells. The data is best fitted by a Beta-PERT distribution, defined by the lowest, most likely and the highest value observed.

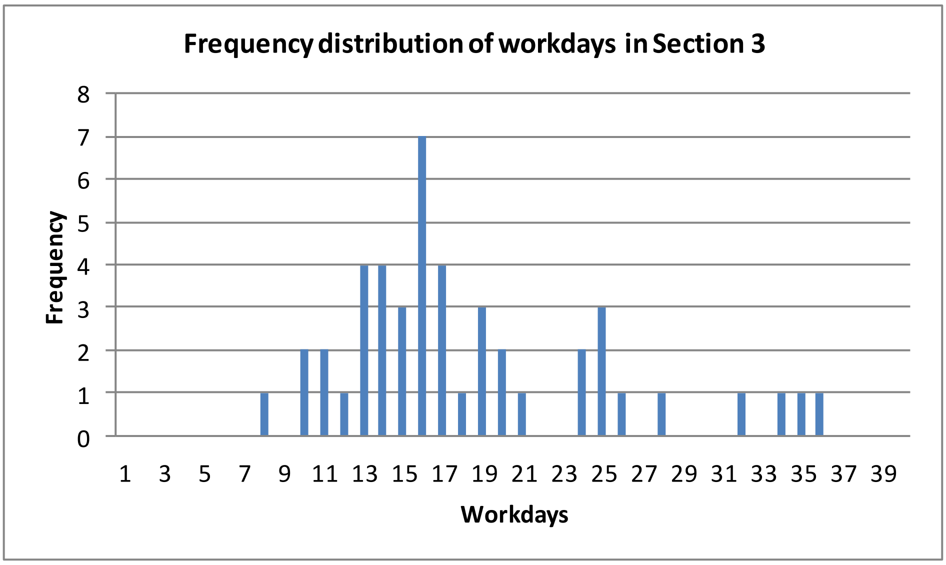

Fig. 5. Frequency distribution of normalized workdays in drilling Section 3 from 800-2,235 m in 46 large diameter directional wells. The data is asymmetric and best fitted by a Beta-PERT distribution.

Table 1. shows the lowest, most likely and highest values of normalized workdays in drilling the four sections of directional large diameter wells. Average and standard deviation are calculated for the respective Beta-PERT distribution.

Wells			Workdays total			Beta-PERT		
Section	Drilled (m)	Number of wells	Lowest	Most likely	Highest	Average (days)	St. deviation (σ)	(%)
0	0-90	38	3	4	14	5.5	1.8	33
1	90-300	44	4	8.5	29	11.2	4.2	37
2	300-800	46	6	9	20	10.3	2.3	23
3	800-2,235	46	8	16	36	18.0	4.7	26
Total	**2,235**					**45.0**	**6.9**	

Table 1. Normalized workdays for large diameter reference wells.

The number of wells varies as fewer reports were available on the sections of initial drilling and drilling for the anchor casing than the sections of drilling for the production casing and the productive open hole. Figure 6 below shows the distribution of the resulting reference class for the total of workdays in drilling of large diameter wells. The input to the simulation is from Table 1. With 95% confidence the workdays lie between 32.1 and 60.1 days. The average for the empirical data of the total is 45.0 days.

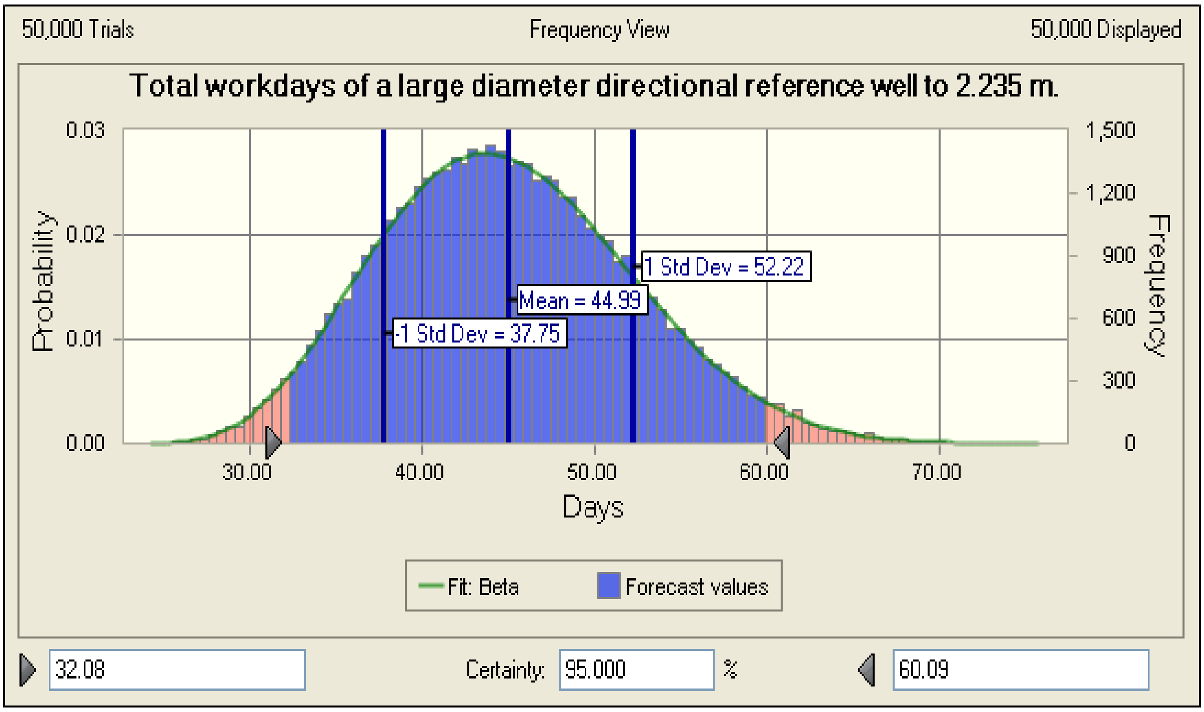

Fig. 6. Distribution of total workdays of a large diameter directional reference well to 2,235 m, from Monte Carlo simulation.

The workdays were also analysed for each section of drilling and the time used for different activities such as actual drilling, running and cementing casing, delays due to drilling problems, logging, installation of wellhead (BOPES), repairs of equipment, and other reasons for delays. The results of that analysis are shown in Table 2.

Holes			Workdays	Percentage in different activities						
Section	**Drilled**	**Number**	**Average**	**Drilling**	**Casing**	**Probl.**	**Logging**	**Compl.**	**Repairs**	**Other**
	(m)	**(n)**	**(d)**	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**
0	0-90	38	5,5	47,0	28,1	9,5	0,0	11,0	1,7	2,7
1	90-300	44	11,2	36,6	26,3	10,0	9,9	12,5	2,9	1,7
2	300-800	46	10,3	46,6	21,7	5,1	11,2	11,0	3,9	0,6
3	800-2,235	46	18,0	54,4	5,8	11,1	15,8	7,5	4,8	0,6

Table 2. Percentages of total workdays used in different activities of drilling a directional, large diameter reference well.

Besides the analysis for the reference well of the directional “large diameter” type it is of interest to compare the number of workdays for directional and vertical wells of the “regular” program which have casing diameters of 18⅝" surface, 13⅜" anchor, 9⅝" production casing and a 7" slotted liner. The results are shown in Tables 3 and 4. The number of wells varies according to the number of each type drilled and the availability of reports. The average and the standard deviation are calculated assuming a Beta-PERT distribution for the workdays. The total workdays for the large diameter directional wells are 45.0 days compared to 45.8 days for much fewer vertical wells.

Workdays for large diameter wells Depth 0-300 m			
Diameter (")	Number of wells	Workday average (d)	St. Dev. (s)
Section 0: 0-90 m			
26	38	5.5	1.8
Section 1: 90-300 m			
21	44	11.2	4.2

Directional Depth 300-2,235 m			
Diameter (")	Number of wells	Workday average (d)	St. Dev. (s)
Section 2: 300-800 m			
17½	46	10.3	2.3
Section 3: 800-2.235 m			
12¼	46	18.0	4.7
Total workdays			
		45.0	6.9

Vertical Depth 300-2,235 m			
Diameter (")	Number of wells	Workday average (d)	St. Dev. (s)
Section 2: 300-800 m			
17½	5	9.8	0.8
Section 3: 800-2.235 m			
12¼	7	19.3	3.7
Total workdays			
		45.8	5.9

Table 3. Workdays for large diameter directional and vertical wells. The first two sections to 300 m are drilled vertical and then the rest of the well, Section 2 and 3, are either drilled directional or vertical.

Workdays for regular diameter wells Depth 0-300 m			
Diameter (")	Number of wells	Workday average (d)	St. Dev. (s)
Section 0: 0-90 m			
21	25	5.8	2.2
Section 1: 90-300 m			
17½	25	8.3	2.0

Directional Depth 300-2,235 m			
Diameter (")	Number of wells	Workday average (d)	St. Dev. (s)
Section 2: 300-800 m			
12¼	17	10.7	2.0
Section 3: 800-2.235 m			
8½	17	18.7	3.0
Total workdays			
		43.5	4.7

Vertical Depth 300-2,235 m			
Diameter (")	Number of wells	Workday average (d)	St. Dev. (s)
Section 2: 300-800 m			
12¼	6	12.2	2.8
Section 3: 800-2.235 m			
8½	5	22.0	6.3
Total workdays			
		48.3	7.5

Table 4. Workdays for regular diameter directional and vertical wells.

The directional regular diameter wells take 43.5 days on average but fewer vertical wells 48.3 days. Considering the numbers in each group and the respective standard deviations the difference in total workdays is not significant. It is of interest to note that for directional wells the average for 17 narrower program wells is 43.5 days compared to 45.0 days for 46 wells of the large diameter program.

4. COST ANALYSIS

The cost structure in this paper is such that there is a day rate for the drilling rig and crew and also for the many services engaged such as for cementing, directional drilling, drilling mud, logging etc. These daily costs vary according to the technology requirements of the equipment, geographic area, and prevailing market conditions. The unit material costs on the other hand reflect the commodity prices for steel, cement, fuel oil etc. and their overall cost is therefore more predictable as the usage quantity can be calculated. On top of this the remoteness of the site and proximity to supplies and services affect these costs. A small drill rig is used for Section 0 to 90 m (initial drilling), but the Sections 1, 2 and 3 are drilled by a larger rig.
The estimated cost of drilling the reference well of the large diameter program was calculated on the basis of the number of workdays required for each section of the drilling, using a weighted average of the day rates for different activities. A breakdown of cost for different sections is shown in Table 5.

Item of cost	Time		Material		Total	
	($)	(%)	($)	(%)	($)	(%)
Site and moving in of rigs					490,000	11.3
Section 0: 0-90 m	219,048	69.2	97,648	30.8	316,696	7.3
Section 1: 90-300 m	634,031	79.5	163,417	20.5	797,448	18.5
Section 2: 300-800 m	633,154	60.7	410,379	39.3	1,043,533	24.2
Section 3: 800-2,235 m	1,202,106	72.0	468,628	28.0	1,670,734	38.7
					4,318,411	*100*

Table 5. Breakdown of cost for a large diameter directional reference well to 2,235 m.

5. VARIANCE IN THE TOTAL COST

To obtain an estimate of the variance in total cost Monte Carlo simulations were carried out using probability distributions for the uncertainties in the number of workdays, the unit costs of material, and day rates for the drilling rigs. Figure 7 shows the distribution for the total cost of the reference well of the large diameter directional program. Note that here the cost of the drill site, cellar and water supply, as well as the cost of moving rigs in, are included. The average obtained for the simulation is $4,317,588, compared to the total cost of $4,318,410 obtained in Table 5. The standard deviation was found to be $451,229. The cost lies with 95% confidence within the limits $3,517,000 and $5,262,000. Sensitivity analysis shows that the number of workdays causes most of the uncertainty, 58.4% in Section 3, 28.3% in Section 1, and 11% in Section 2. Graphs for accumulated probability indicate that in 30% cases the cost exceeds $4,541,000 and in 30% cases the cost will be lower than $4,055,000.

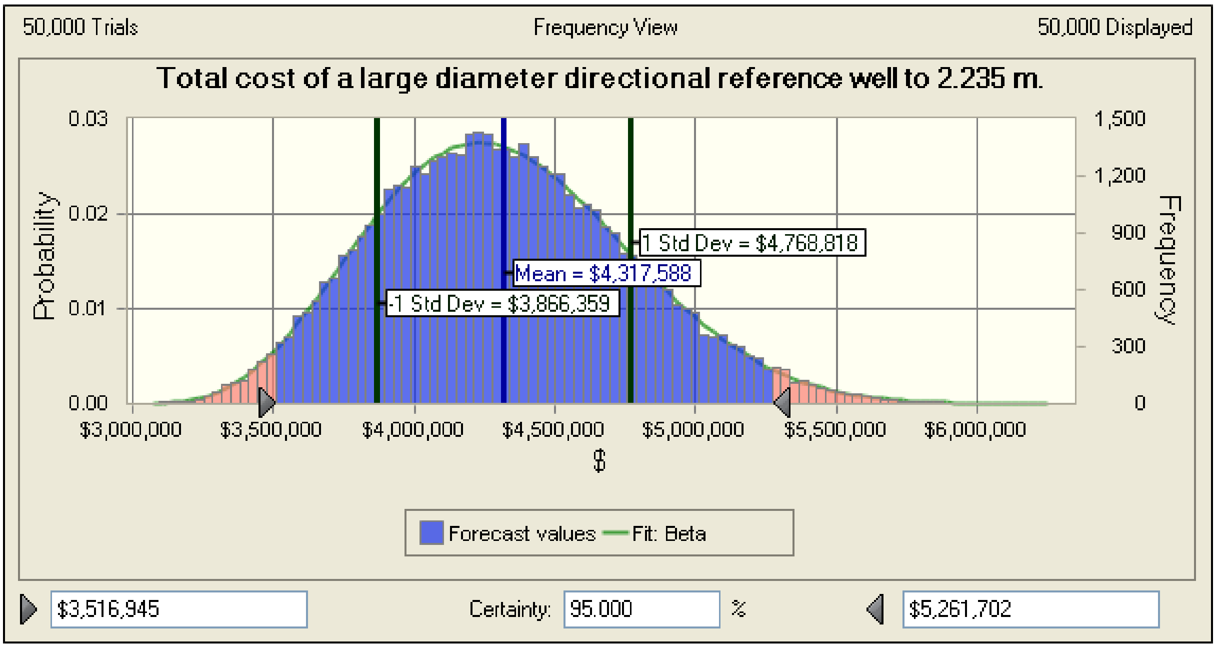

Fig. 7. Total cost of the large diameter directional reference well to 2,235 m.

6. DRILLING PROBLEMS

Although most wells were drilled according to the original schedule, some wells encountered difficulties resulting in workdays exceeding considerably the average for the respective activity. The drilling reports were examined to find the cause of the excess workdays. Most common were problems due to loss of circulation or collapsing geological formations where the rig got stuck. The time analysis identified such problems in 24 wells or 31% of the 77 wells drilled. The additional cost was though low in most cases.

Problems due to geological formations were the primary cause of problems in 18 of the 24 wells. They led to other problems such as difficulties in running the casing in 3 wells and excessive cement loss into the formation. In 5 wells the rig got stuck and had to cut the drill string by explosives, loosing the bottom hole assembly, collars and part of the drill pipes in the well. This occurred twice in one well. Four wells were sidetracked due to a stuck drill string and 2 because of a wrong direction. Two wells were abandoned because of collapse and a stuck drill string. Repairs of top drive of drill rigs were necessary in drilling 4 wells, sometimes due to excessive strain in attempts to free a stuck string. In 2 wells the section of initial drilling had to be divided into two steps due to overpressure in shallow boiling aquifers.

The additional cost due to drilling problems was estimated on the basis of workdays that were required to solve the problem beyond the average number of workdays required in the respective section. Also taken into account was the cost of cement, bentonite and other supplies in excess of what is accounted for in a reference well. Sections that were abandoned by sidetracking were counted as additional cost in workdays and material used. Thirdly the cost of lost equipment and drill string in the hole that could not be recovered, was counted as lost in hole charge. Figure 7 shows the cost above the average, for the 24 problem wells.

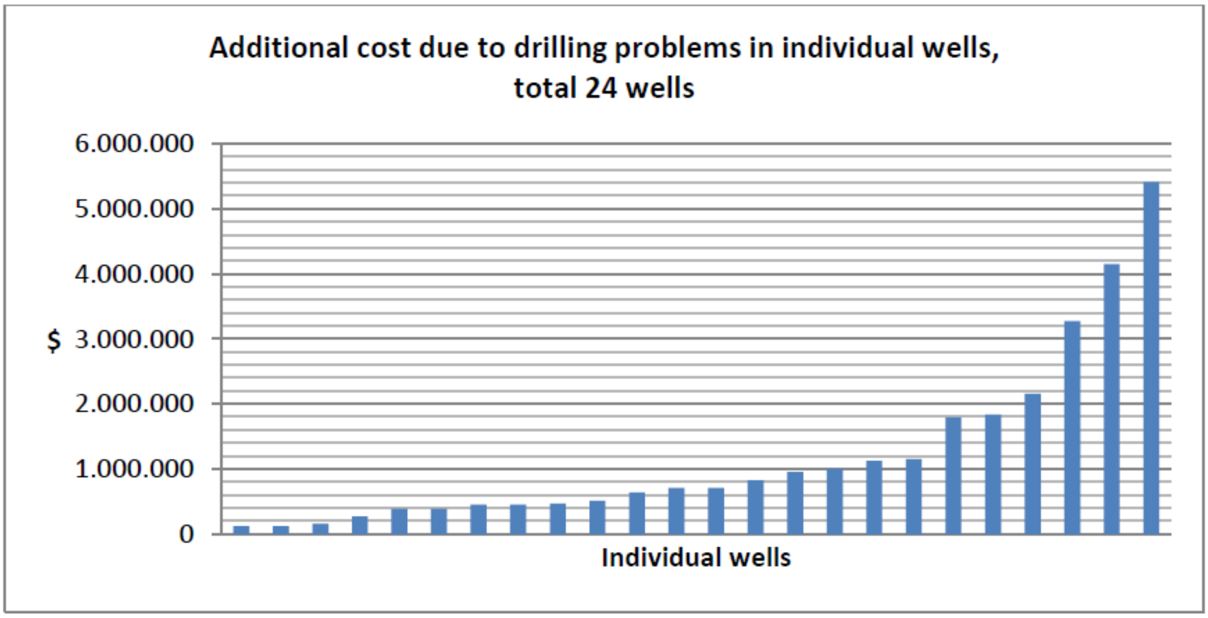

Fig. 7. Additional cost due to drilling problems in individual wells, total 24 wells.

Considering the standard deviation σ of $450,000 for the reference well, 18 of the wells have an additional cost less than 3 σ.
To obtain a view in terms of the σ the additional cost was divided by the σ and the frequency calculated as percentage of the total wells drilled. Fig. 8 shows the result.

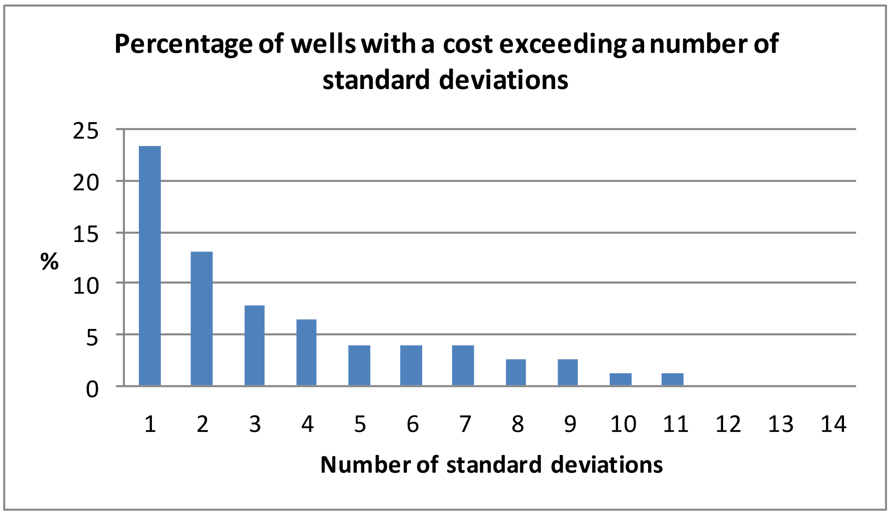

Fig. 8. Percentage of the total of drilled wells with additional cost due to drilling problems larger than a multiple of the standard deviation σ of the reference well.

For 77 wells drilled the additional cost was larger than one σ in 18 wells or about 23%. It exceeded 2 σ in 10 wells or 13% and 3 σ in 6 wells or nearly 8% of the total. This distribution can be of aid in estimating additional risk due to such problems on top of the risk included in the statistical distribution of the reference well.

7. POWER OUTPUT OF WELLS

The overall economics of a geothermal power project is strongly influenced by the power output per well, or how much can be reinjected, which is also considered in evaluating the drilling effectiveness. Table 6 shows the power output per drilled geothermal production well and per productive well in the Hellisheiði Field of the Hengill Area. It is of interest to note that the difference between the regular and large diameter wells appears insignificant.

Diameter	Drilled production wells	Productive wells	Power per drilled well (MWe)	Power per productive well (MWe)
Large diameter	38	33	5.8	6.7
Regular diameter	15	13	5.7	6.6
Total	*53*	*46*	*5.8*	*6.7*

Table 6. Power output of drilled production wells in megawatts (MW_e) of electricity that can be generated.

The data bank could be used for other comparisons such as vertical vs. directional wells, drilling with water only or managed pressure drilling by aerating the water. Only 7 of the large diameter and 5 of the regular diameter wells in the Hengill Area were however drilled vertical. A comparison with vertical wells is therefore not reliable.

For success metrics, comparisons were made between the Injectivity at the end of drilling and the confirmed total mass flow of the well. The Injectivity ((kg/s)/MPa) is determined at the end of drilling by logging the pressure response to different rates of pumping water onto the well, each step lasting a few hours. It serves as the first indicator of the well productivity. Fig. 9 shows a log/log-graph of total mass flow (kg/s) of wells at 8 bar-g drawn against Injectivity (kg/MPa*s). The range of mass flow lies between 10-100 kg/s and the Injectivity between 20-350 (kg/MPa*s). The figure clearly indicates a linear relation but the data points are scattered due to different enthalpy of the mass flow which depends on the temperature of the major feedpoint of each well.

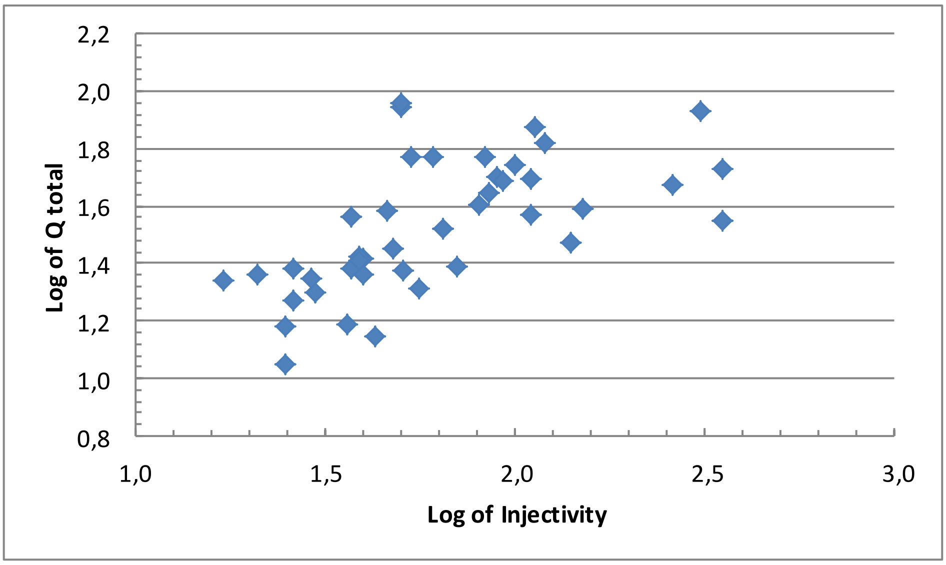

*Fig. 9. A log/log graph of total mass flow (kg/s) of wells at 8 bar-g drawn against Injectivity (kg/MPa*s).*

The results indicate that to obtain reliable predictions of yield on the basis of the Injectivity one must also consider reservoir conditions and enthalpy of the expected discharge. Such predictions would be valuable for decisions, whether to deepen a well or redrill the last section as a sidetrack or “fork”.

8. CONCLUSIONS

The results of this analysis of cost and effectiveness of geothermal drilling clearly indicate that the the perceived high risk in this kind of drilling is less than commonly thought. The standard deviation of the total cost of a well is about 10% of the average cost. Only 6 wells, or 8% of the total 77 wells drilled, had costs exceeding 3 standard deviations. The risk lies mainly in the nature of the geological formation, problems due to loss of circulation or collapsing walls where the rig gets stuck.
No significant difference was found in the time required to drill holes of the wider 13⅜" production casing or the regular narrower casing of 9⅝" diameter. No difference either was found in the time used to drill vertical or inclined directional holes. The difference in power output between the regular and large diameter wells also appears insignificant.

9. ACKNOWLEDGEMENTS

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