DRILLING COST REDUCTION BY SIMULATION OF BIT RUN OPTIMIZATION

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ABSTRACT

Computer Drilling Simulator has been used to develop recommendations for the execution of bit runs in a future well. The starting point was to obtain files and bit run records from wells. The files were imported into the simulator to construct the required lithology, and the well was drilled in simulation using the same conditions as had been used for the offset well. WOB, RPM, bit hydraulics and bit types, are the most important parameters affecting rate of penetration and consequently the economics of drilling. The optimization by simulator is the particular set of records that was used, it is found that the hydraulics conditions used in the offset well were probably optimal, but some future improvements might be obtained by decreasing weight on bit and increasing rotary speed, and possibly by using best bit type in the field. In this paper, some first 3465 feet of a reservoir lithology including four bit runs are analyzed so that factors affecting penetration rate are optimized and the lowest possible well cost is achieved. The effects of using other bit types, WOB, RPM and bit hydraulics are simulated in an attempt to determine the optimized parameters, which result in the lowest drilling cost.

Keywords: Bit Run Optimization, Simulation, Weight on bit, Rotary Speed, Bit hydraulics, Oil Well Drilling.

1. INTRODUCTION

The authors' knowledge there have been numerous attempts to use simulators to improve the drilling of hydrocarbon wells (1-5) but none has yet been widely accepted, and, this may partly be because of the complexity of the drilling process. It results, on the one hand, in a requirement to collect a large amount of data before a good simulation can be made of a specific well, and on the other, the need for the operator of the simulator to be highly skilled in using the data to best advantage.

Simulators have, however, been used more successfully in training, (6,7) where it has been found that it is relatively straightforward to illustrate the general principles of drilling operations if there is no requirement that the simulation should exactly match the drilling behavior of a particular well. To bridge this gap, a simulator have used that was originally developed for training purposes and have tuned it to reproduce the drilling behavior in a real well. Once the simulator was tuned, it is used to investigate the effects of re-drilling the well using different operating parameters to see if better results might be obtained under other conditions.

The usual objective when drilling a well is to drill for the lowest overall cost. At first sight, this may seem like a requirement to drill as fast as possible, since many of the costs, such as the rig day rate, wages etc., are time dependent. Weight on bit (WOB), rotary speed (RPM), bit hydraulics and more importantly the type of the bits used, are the most important parameters affecting rate of penetration and consequently the economics of drilling. However, some costs are fixed, for example the cost of the bit, and it may not always be economic to pay a very high cost for a bit that drills somewhat faster, particularly if the other costs are low [1].

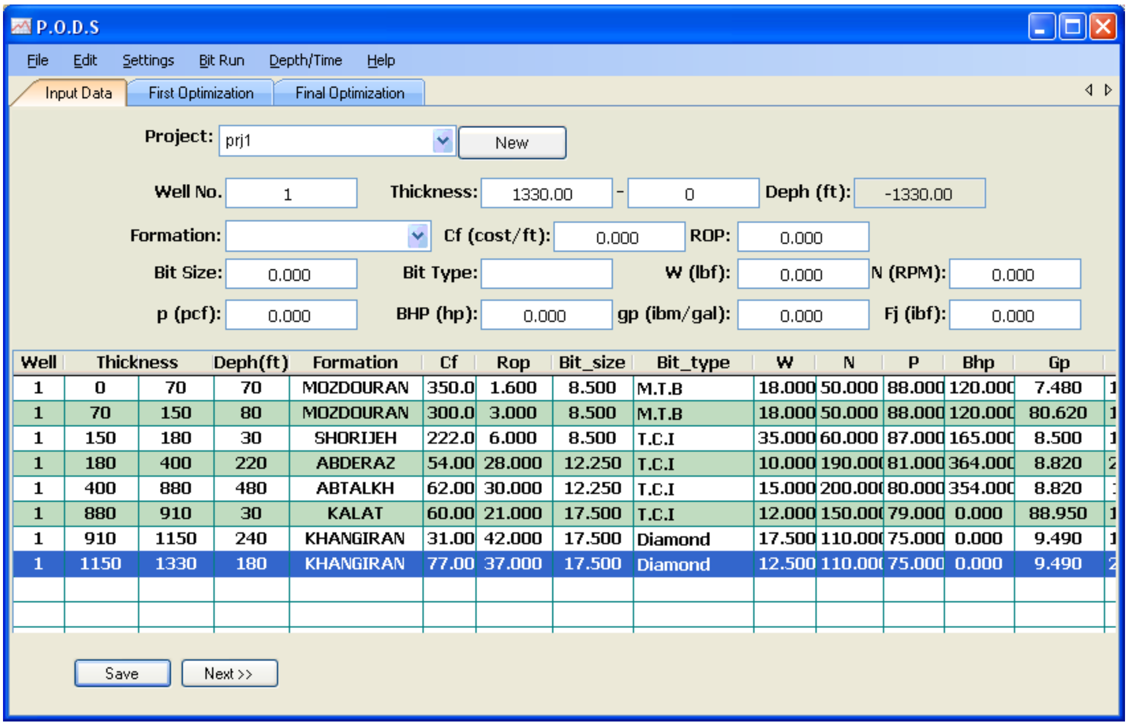
The drilling simulator calculates the cost per foot for each bit run, re-setting the calculation for each new bit. It takes into account the time taken to change the bit, and calculates the time taken to trip into and out of hole. The other costs include the bit cost and the rig day rate (including all the associated overheads) [1].

In this paper, the lithology of case study is analyzed so that the factors affecting rate of penetration are optimized by first optimization & final optimization and the lowest possible well cost is achieved. All bits used in the original drillings process were of tungsten carbide insert type. In the first step, other drilling bit types were examined to see if a better drilling performance is observed. Then, the effect of altering operating conditions (WOB and rotary speed) has been investigated. At the end, it was attempted to get even better results through bit hydraulics optimization.

As a result, it was found that runs number 2, 3 and 4 could yield a lower cost per foot. Optimization of these 4 factors will save about 15% of the original well cost.

2. CASE STUDY

For current study, software contains all of data records from zone holes with various formation type and multiple conditions as drilling history. the average depth in reservoir lithology is 1330 feet & average of bit run is four bit runs , are analyzed so that the factors affecting the rate of penetration are optimized and the lowest possible well cost is achieved. Table 1 shows the lithology of the reservoir where each layer is characterized by its number, depth, thickness, fracture gradient, its drilling softness (S) and abrasively (W), the three logging values of Gamma Ray Activity (GA), Resistivity (Res), Porosity (Por), the fluid type and the pore fluid pressure gradient The lithology was then incorporated into a State file, and a simulation was run using the same operating conditions as had been used in the field. It is found reasonably good agreement between the field and simulator results, which indicated that, although needing adjustment, the simulator was already approximately tuned. This gave confidence that the basic drilling model was reasonably accurate. Figure 1 shows a section from a typical lithology produced in this way.



Well	Thickness		Deph(ft)	Formation	Cf	Rop	Bit_size	Bit_type	W	N	P	Bhp	Gp	
1	0	70	70	MOZDOURAN	350.0	1.600	8.500	M.T.B	18.000	50.000	88.000	120.00	7.480	1
1	70	150	80	MOZDOURAN	300.0	3.000	8.500	M.T.B	18.000	50.000	88.000	120.00	80.620	1
1	150	180	30	SHORIJEH	222.0	6.000	8.500	T.C.I	35.000	60.000	87.000	165.00	8.500	1
1	180	400	220	ABDERAZ	54.00	28.000	12.250	T.C.I	10.000	190.00	81.000	364.00	8.820	2
1	400	880	480	ABTALKH	62.00	30.000	12.250	T.C.I	15.000	200.00	80.000	354.00	8.820	
1	880	910	30	KALAT	60.00	21.000	17.500	T.C.I	12.000	150.00	79.000	0.000	88.950	1
1	910	1150	240	KHANGIRAN	31.00	42.000	17.500	Diamond	17.500	110.00	75.000	0.000	9.490	1
1	1150	1330	180	KHANGIRAN	77.00	37.000	17.500	Diamond	12.500	110.00	75.000	0.000	9.490	2

Figure 1. A Section of a Typical Lithology Produced from an Input Simulator for any Well.

3. DRILLING SIMULATOR

First Optimization

Bit type, bit size, formation type, WOB, RPM and so on is effective parameters on cost of well drilling. These parameters for various holes have entered to the software as records of data. Thus, P.O.D.S simulator contains all of data records from zone holes with various formation type and multiple conditions as drilling history.

The software supplies the best offer for next hole by best effective parameters and maximum ROP and minimum Cost/ft from history drilling. This offer contains required and efficient parameters to minimum drilling cost. For example, note at the two holes parameters.

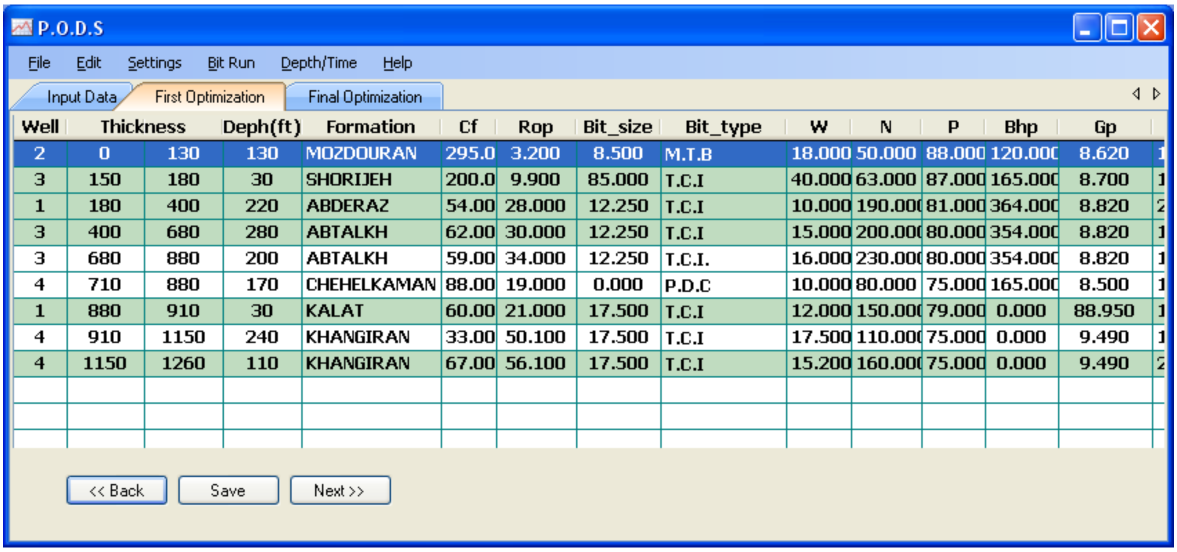
Table 1. Well #1 Parameters.

Thickness	Depth(ft)	Formation	Cf(cost/ft)	ROP	Bit Size	Bit Type	W(Ibf)	N(RPM)	ρ(pcf)
150-180	30	Shorijeh	222	6	8.5	T.C.I	35	60	87
180-400	220	Abderaz	54	28	12.25	T.C.I	10	190	81

Table 2. Well #2 Parameters.

Thickness	Depth(ft)	Formation	Cf(cost/ft)	ROP	Bit Size	Bit Type	W(Ibf)	N(RPM)	ρ(pcf)
130-190	60	Shorijeh	220	8	8.5	T.C.I	40	58	87
190-400	210	Abderaz	56	27	12.25	T.C.I	10	190	81

In Shorijeh formation well 2 ROP is more than well 1 ROP, so the software offers efficient parameters in second hole for this formation, but in Abderaz formation, well 1 ROP is more than well 2 ROP, thus elect first hole parameters for this formation for next drilling. Thus, the software by previous drilling history tries to elect the best efficient parameters in next drilling. For example Figure 2 shows a first optimization for 4 wells in the case study.



Well	Thickness		Deph(ft)	Formation	Cf	Rop	Bit_size	Bit_type	W	N	P	Bhp	Gp	
2	0	130	130	MOZDOURAN	295.0	3.200	8.500	M.T.B	18.000	50.000	88.000	120.00	8.620	1
3	150	180	30	SHORIJEH	200.0	9.900	85.000	T.C.I	40.000	63.000	87.000	165.00	8.700	1
1	180	400	220	ABDERAZ	54.00	28.000	12.250	T.C.I	10.000	190.00	81.000	364.00	8.820	2
3	400	680	280	ABTALKH	62.00	30.000	12.250	T.C.I	15.000	200.00	80.000	354.00	8.820	1
3	680	880	200	ABTALKH	59.00	34.000	12.250	T.C.I.	16.000	230.00	80.000	354.00	8.820	1
4	710	880	170	CHEHELKAMAN	88.00	19.000	0.000	P.D.C	10.000	80.000	75.000	165.00	8.500	1
1	880	910	30	KALAT	60.00	21.000	17.500	T.C.I	12.000	150.00	79.000	0.000	88.950	1
4	910	1150	240	KHANGIRAN	33.00	50.100	17.500	T.C.I	17.500	110.00	75.000	0.000	9.490	1
4	1150	1260	110	KHANGIRAN	67.00	56.100	17.500	T.C.I	15.200	160.00	75.000	0.000	9.490	2

Figure 2. First Optimization for 4 Wells in the Case Study.

Final Optimization

The simulator is a computer program that receives: a description of a series of rock layers (lithology), a description of one or more drill bits, and a set of operating parameters such as weight on bit, bit rotary speed, mud flow rate and other required information, as input. The simulator then calculates the rate of penetration and the rate of wear of the bit. From this information, a plot of drilled depth versus time is obtained [5].

4. ANALYSIS

Cost per Foot Analysis

There is almost always some uncertainty about the best time to terminate a bit run and begin tripping operations. If the lithology is somewhat uniform, cost per foot calculation can be used as a criterion. In this case the best time to terminate the bit run is when the lowest cost per foot is achieved. However, when the lithology is not uniform, this procedure will not always results in the minimum total well cost. In this case, an effective criterion for determining optimum bit run is obtained only after enough wells are drilled in the area to define the lithologic variations. For example it is sometimes desirable to drill an abrasive formation with an already dull bit and then place a sharp bit in the next shale section. Alternatively, it may be best to terminate a bit run in order to place a hard formation bit in an extremely hard abrasive section [3].

Costs are usually broke into two categories: (1) Fixed costs and (2) Variable operation costs [3]. The usual objective when drilling a well is to drill for the lowest overall cost. At first sight, this may seem like a requirement to drill as fast as possible, since many of the costs, such as the rig day rate, wages, etc., are time dependent. However, some costs are fixed, for example the cost of the bit, and it may not always be economic to pay a very high cost for a bit that drills somewhat faster, particularly if the other costs are low [1].Unless the bit run is to be terminated for a specific reason, such as logging or casing the well, the cost of each bit run can be minimized by calculating the cost per foot as the hole gets deeper. This is done by summing the fixed and time-dependent costs and dividing by the total footage drilled during the bit run [4]:

$$\frac{Cost}{ft} = \frac{Bit\ Cost + (Drilling\ Time + Trip\ Time) \times Rig\ Cost\ per\ hr}{Feet\ Drilling\ this\ Bit\ Run} \tag{1}$$

When it is run in hole with the new bit, the cost already incurred of the new bit and spent time to run in hole, but have drilled no distance. Cost per foot is therefore infinite. However, as soon as when begin drilling, the factor "Feet drilled this bit run" begins to increase, and so the cost per foot decreases. As drilling continues, the fixed costs remain constant, but the time related costs increase, as does the footage drilled. Initially, the fixed costs are greater than the time-related costs, but eventually the time-related costs begin to dominate the top line of the expression. In the real situation, the bit gradually wears, and so the number of additional feet drilled per additional hour gets less as time increases. The time-related costs continue to increase steadily, however, and so eventually the cost per foot reaches a minimum and then begins to rise again. It is at this minimum value that reached the minimum cost per foot for the bit run, and should therefore replace the bit.

Finally, note that the Cost per Foot calculation can be used even if the bit run has to be terminated for other reasons. In this case, all that needs to be done is to find the set of conditions that give the minimum cost per foot at the depth where the bit run is to be terminated [1].

Optimizing the Rock Bit Runs

Next investigated whether the bits might have been run with different operating conditions to produce a saving in time or cost. The procedure consisted of a step-by-step approach investigating different parameters in sequence.

Optimization of hydraulics:

The bit runs were repeated using different bit nozzles and different mud flow rates. The data are shown in Table 3. Regarding the mud flow rates (for any particular nozzle size), as long as the maximum pump pressure or flow rate are not exceeded, it is generally true that the more hydraulic power that can be delivered to the hole bottom, the better it is. However, this view neglects the possible adverse effects of excessive flow rate on pump wear and on hole washout. Therefore adopted the view that the best conditions were those that gave high ROP without excessive flow. The values predicted by the simulator coincided in all cases with the values reported from the field. As for the nozzle sizes used, they were all optimal except for run number five, for which it was found that the best set of nozzles was 13/32" (instead of 16/32"). At a flow rate of 550 gpm, these gave an ROP of 20.5 ft/hr, with a bit HSI of 13.6 HP/sq in. The time consumed when using this nozzle size was 64.4 hrs, a saving of 4.5 hrs. The cost dropped to $ 3,264,972 (- $ 9,201).

Optimization of WOB and rotary speed:

The next step consisted of altering the combination of weight on bit and rotary speed to see if some time could be saved in this area. In general, it was found that better results were obtained with lower weight on bit and higher rotary speed, typically in the range of 10,000 – 20,000 lb. WOB with rotary speeds of 130 – 140 rpm. Total savings of more than $90,000 were predicted.

The findings point to the use of higher rotary speed and lower weight, a combination that tends to increase bearing wear over tooth wear, and hence encourages the driller to risk bearing failure and consequent cone loss. Under the optimized conditions, the simulator gave bearing wear values of at most 5, which are in the safe range. Bearing failure is, however, notoriously difficult to predict, and it may well be that experience has taught drillers to err more on the side of caution by reducing rotary speed and instead maintain ROP by corresponding increases in weight on bit.

Optimization of bit types:

Finally the possible advantages of using bits of types are investigated other than the tungsten carbide inserts bits that were used in the field. This is the least certain part of the prediction because had to assumed that the relative rates of penetration could be predicted and wear of different types of bit in the range of formations that constitute the interval to be drilled

Overall, milled tooth bits appear attractive, principally because they have high rates of penetration and were assumed to cost less than half the price of a TCI bit ($2,800 vs. $6,500). PDC bits have generally high rates of penetration, but are expensive (this bits were assumed to cost $25,000). In several cases, they were shown to produce cost savings, but note that the interval contains a substantial proportion of sandstone, and if underestimated the wear rate of the PDC bit in abrasive formations, the recommendation may be in error. Again, a counsel of prudence would probably incline towards choosing a TCI or milled tooth bit, and it should be noted that the real well was in fact a wildcat, so caution would have been in order. Finally, the behavior of natural diamond bits was checked, but, as expected, they are expensive and their rates of penetration are too low to be interesting.

In summary, the estimated savings obtained by optimizing hydraulics, weight on bit and rotary speed using the same (TCI) bits as were used in the field were $94,000. The total saving estimated by substitution of milled tooth bits using optimized conditions were $216.000 while the corresponding value for PDC bits was $165,000. Final optimization show in figures 3-5.

BIT RUN OPTIMIZATION METHOD

All the bits used in the original bit runs were of tungsten carbide insert type. The first 2600 ft of the lithology was drilled using a 17 1/2" bit and mud density of 9 ppg. At the depth of 2600 feet, a 13 3/8" casing was set, mud density was increased to 10.2 ppg and 12 1/4" bit was used. Table 3 shows the 4 bit runs coupled with their resultant cost per foot and overall well cost. As it can be seen, drilling this section takes 163 hours and imposes a cost of about 325000 dollars.

Table 3. Original Bit Runs.

Bit Run #	Bit Type	Bit Size	Depth In (ft)	Depth Out (ft)	Time Taken (hr:min	Mud Weight (ppg)	Nozzles Size (32nds	Mud Flowrate	Rotary Speed	WOB (lbs)	Overal Cost/ Foot	Well Cost ($)	Saving ($)
1	T.C	7 1/2	0	1325	38:12 '	9	15	760-750	100		57	75699	--
2	T.C	7 1/2	1325	2600	70:17 '	9	15	750-730	85		55	1E+05	--
--	**Casing 13 3/8" set at 2600 f**				107:16 '	--	--	--	--	--	94	2E+05	--
3	T.C	2 1/4	2600	2965	118:30 '	10.2	15	675	80		87	3E+05	--
4	T.C	2 1/4	2965	3465	163:12 '	10.2	15	675	120		94	3E+05	--

5. RESULTS AND DISCUSSION

The first step consisted of comparing other bits cost per foot results to find a more economic case. Results are shown in table 4 where, regarding bit types, only the first bit run was recognized optimized. Runs number 2, 3 and 4 could yield a lower cost per foot using milled tooth bits because they have higher rate of penetration and also cost less than half the price of a tungsten carbide bit.

Since Tungsten carbide bits have more bit wear tolerance, they may seem more efficient to be used for drilling harder rocks. However, the distance to be drilled in the fourth section (hard lime stone) is not that long to justify higher cost of the bit.

Table 4, 5 and 6 show the overall well cost and savings made due to optimizations for the studied bit runs. Table 3 compares original and optimized drilling operation in terms of time taken. Having made these optimizations, 55262 $ of the total well cost is saved which is about 15% of the original well cost.

Table 4. Final Optimization of Bit Types.

Bit Run #	Bit Type	Bit Size	Depth In (ft)	Depth Out (ft)	Time Taken (hr:min)	Mud Weight (ppg)	Nozzles Size (32nds)	Mud Flowrate (gpm)	Rotary Speed (RPM)	WOB (lbs)	Overal Cost/ Foot	Well Cost ($)	Saving ($)
1	T.C	17 1/2'	0	1325	38:12 '	9	15	760-750	100	38000	57	75699	0
2	M.T	17 1/2'	1325	2600	69:35 '	9	15	750-730	85	40000	48	125924	17881
	Casing 13 3/8" set at 2600 ft				106:34 '	--	--	--	--	--	87	225947	17881
3	M.T	12 1/4'	2600	2965	117:49 '	10.2	15	675	80	40000	81	239809	18110
4	M.T	12 1/4'	2965	3465	158:35 '	10.2	15	675	120	47000	85	295105	30427

Table 5. Final Optimization of WOB and Rotary Speed.

Bit Run #	Bit Type	Bit Size	Depth In (ft)	Depth Out (ft)	Time Taken (hr:min)	Mud Weight (ppg)	Nozzles Size (32nds)	Mud Flowrate (gpm)	Rotary Speed (RPM)	WOB (lbs)	Overal Cost/ Foot	Well Cost ($)	Saving ($)
1	T.C	17 1/2'	0	1325	36:05 '	9	15	760-750	100	42000	55	73056	2643
2	M.T	17 1/2'	1325	2600	64:18 '	9	15	750-730	120	42000	46	119328	24477
	Casing 13 3/8" set at 2600 ft				102:44 '	--	--	--	--	--	84	219351	24477
3	M.T	12 1/4'	2600	2965	111:05 '	10.2	15	675	130	45000	78	231642	26277
4	M.T	12 1/4'	2965	3465	146:38 '	10.2	15	675	100	62000	81	280084	45448

Table 6. Final Optimization of Bit Hydraulics.

Bit Run #	Bit Type	Bit Size	Depth In (ft)	Depth Out (ft)	Time Taken (hr:min)	Mud Weight (ppg)	Nozzles Size (32nds)	Mud Flowrate (gpm)	Rotary Speed (RPM)	WOB (lbs)	Overal Cost/ Foot	Well Cost ($)	Saving ($)
1	T.C	17 1/2'	0	1325	34:27 '	9	10	456	100	42000	54	71017	4682
2	M.T	17 1/2'	1325	2600	62:23 '	9	10	453	120	42000	45	116935	26870
	Casing 13 3/8" set at 2600 ft				100:01 '	--	--	--	--	--	84	216958	26870
3	M.T	12 1/4'	2600	2965	107:42 '	10.2	12	535	130	45000	76	225340	32579
4	M.T	12 1/4'	2965	3465	141:24 '	10.2	12	533	100	62000	78	270270	55262

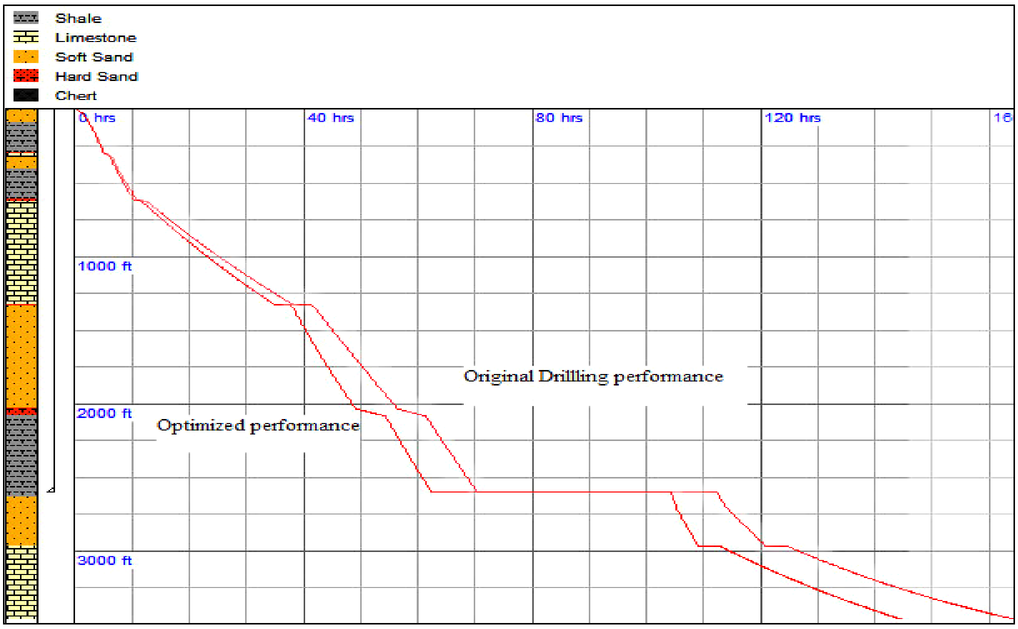


Figure 3: Comparison of the original and optimized drilling

6. CONCLUSION

1. These very preliminary results are intended to demonstrate a general approach to bit run optimization by the use of a drilling simulator rather than to propose a specific set of bits and operating parameters for a particular well. Actual savings will of course depend on the true rig day rate, and costs of bits among other factors. Further, this present level of confidence in the accuracy of the drilling model must inevitably to cautious in adopting the recommendations without due prudence.

2. Nonetheless, the procedure is easy to follow, and it is shown that the technique as being a valuable means of investigating possible drilling scenarios (for example the substitution of PDC bits) that one might hesitate to use in field practice because of the high risks involved. The present approach should at least allow the estimation of the eventual gains or losses. Obviously, as more information can be accumulated concerning a particular field, the predictions can be improved with resulting increase in confidence.

3. The specific well chosen to illustrate the procedure was a hydrocarbon well, but it could equally have been a geothermal well. At the time of writing, however, it was not able to obtain a suitable set of records for a geothermal well. The simulator does, however, have special features that are of interest for simulating geothermal wells, including the simulation and handling of lost circulation (by pumping lost circulation material or using cement plugs), the inclusion of a suite of rocks typical of geothermal wells and the ability to simulate drilling in fractured rock formations.

4. As it is noted, by using this simulator, 15% of the original well cost is saved, which is a considerable amount of money.

7. REFERENCES

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