

The use of a Drilling Simulator to Optimize a Well Drilling Plan.

by

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Abstract

A 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 LAS (Log, ASCII Standard) files and bit run records from an offset well. The LAS 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. The simulator was tuned so that it reproduced the field drilling records as closely as possible. The tuned simulator was then used to investigate whether different combinations of operating parameters or bit types might give better results in a future well. For the particular set of records that was used, we 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 milled tooth or PDC bits in place of some of the tungsten carbide insert bits that were used in the field.

Introduction

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, to the authors' knowledge, none of these has been adapted to geothermal wells. 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, we have used a simulator 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, we used it to investigate the effects of re-drilling the well using different operating parameters to see if better results might be obtained under other conditions.

Importing Field Data

The Simulator used for the project was based on an earlier model that had been used for training students in Drilling Engineering (6). A new version of the Simulator was constructed that had the capability to import data from field operations. Both simulators operate by taking input generated by a series of editors that specify the governing parameters of the simulator in several

categories (Lithology, Drill bits, Muds, BHAs, Casings, Operational constraints ...). These are combined into a source file, known as a “State”. The State file is used by the simulator itself to generate the drilling response.

In the new simulator, the Lithology Editor was provided with an option that allowed a LAS (Log, ASCII Standard) file to be imported and converted to a lithological column that the simulator could use. LAS files are industry-standard text files that contain log data recorded on a foot-by-foot (or metric) basis. As well as basic log data, they may contain processed data such as estimates of rock strength.

To be of value in generating a drilling response, the lithology needs, at minimum, to record the rock type, its strength and abrasivity. Rock type data are usually available in a typical LAS file, strength data are sometimes given, but abrasivity is usually not posted. The converter has been given a capability to infer rock strength from sonic data following recommendations available in the literature if strength data are not available. However, to estimate abrasivity we have had little guidance. For the present, we have adopted the following formula:

$$\text{Abrasivity} = \text{Constant} \times \text{Quartz content} \times \text{Rock Compressive Strength}$$

We recognize that this is certainly a very coarse approximation, but have decided to adopt the expression until we have more precise information. If the method is used for the simulation of geothermal wells, it is likely that special measures will have to be taken to allow for the fact that many of the rocks encountered in geothermal drilling are very abrasive while at the same time having no free quartz content.

Layer #	Layer Depth	Layer Thickness	Rock Type	Rock Strength	Rock Abrasiv	Pore Press.	Frac. Grad.	Log Por.	Log Res.	Log Gamma	Fluid Type
36	10,273.0	7.0	Sand Soft	4.9	259.6	11.05	12.00	14.4	18.08	66.4	-
37	10,280.0	3.0	Sand Soft	10.3	498.2	11.05	12.00	6.9	35.75	54.6	-
38	10,283.0	18.0	Sand Soft	4.5	220.0	11.06	12.00	15.5	18.85	84.2	-
39	10,301.0	1.0	Limestone	6.6	0.0	11.06	12.00	13.4	15.46	115.5	-
40	10,302.0	186.0	Shale	4.4	39.7	11.08	12.00	4.5	2.13	105.4	-
41	10,488.0	6.0	Shale	6.1	0.0	11.11	12.00	8.4	4.04	99.0	-
42	10,494.0	10.0	Sand Soft	5.2	244.1	11.11	12.00	13.2	8.99	100.0	-
43	10,504.0	1.0	Limestone	5.7	102.4	11.11	12.00	14.4	8.84	104.9	-
44	10,505.0	1.0	Shale	5.6	158.9	11.11	12.00	14.0	8.92	104.6	-
45	10,506.0	7.0	Sand Soft	4.5	192.8	11.11	12.00	13.2	10.02	99.5	-

Layers: 200, Total Depth: 11,501.0

Buttons: New Layer Above, New Layer Below, Delete Layer, Edit Layer, Edit Surface

Figure 1. A section of a typical lithology produced from an imported LAS file.

The converter also has the ability to “block” the data, i.e. to aggregate successive lines of data if their properties are sufficiently similar. In the case of the data used for this paper, we had LAS data logged foot-by-foot from 8,544 to 12,246 ft. This was compressed into 542 layers, making

the average layer thickness about 7 ft. Figure 1 shows a section from a typical lithology produced in this way.

Case study

A set of well records, kindly provided by BP via Baker Hughes Oasis, described a section of an offshore well. The data set included LAS files and the bit run records. We extracted a suite of five bit runs from the data, covering the interval from 8,724 ft to 11,868 ft. All the bits were of 8 1/2” tungsten carbide insert type. The bit run data are shown in Table 1. The corresponding lithological column was derived from a LAS file as described above. It consisted of shale interbedded with streaks of sandstone and limestone from 8,544 ft. to 11,034ft. Below, sand interbedded with shale and limestone streaks was dominant from 11,034 ft to 12,246 ft. The LAS files had no data for the interval from surface to 8,544ft, so we inserted a dummy layer of shale with nominal properties. This was necessary to produce the correct effect of mud and pore pressure at depth. In the present case, the LAS file contained an estimate of rock strength that had been prepared before we received the file, so no calculation of rock strength was necessary. However, we did have to estimate the rock abrasivity using the method indicated above.

Run No.	Make	IADC	Noz.	Depth-	Dist.	Hr's	Rop	Wob	Rpm	Gpm	Mwt	I	O	D	L	B	G	O	R
1	HTC	4/1/05	3x13	8724	185	10.8	17.1	30	70	550	9.7	2	4	WT	H	E	I	NO	CP
2	HTC	5/1/05	3x16	8926	412	18.4	22.4	35	100	610	9.7/10.1	3	3	WT	A	E	I	NO	BHA
3	HTC	5/1/05	3x16	9321	680	30.2	22.5	45	120	580	10.1	2	2	WT	A	E	I	ER	LOG
4	HTC	5/1/05	3x16	10001	544	25.2	21.6	38	93	617	10.1/10.0	1	1	WT	A	E	I	ER	WC
5	HTC	5/1/05	3x16	10545	1323	69.2	19.1	32	90	600	10.0/10.1	6	4	WT	A	E	I	ER	PR

Table 1. The bit run data for the interval from 8,724 to 11,868 ft

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. We 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.

Tuning the simulation

To continue, our first task was to tune the simulator so that it provided a good match to reality. We did this by drilling the well in simulation using the conditions that were used to drill the real well (as shown in table 1) and then tuning the simulation parameters to mimic the field results.

Tuning was done by altering the aggressivity of the bit and its rate of wear. The algorithm that calculates the rate of penetration of the bit contains both the rock strength and the bit aggressivity constant. To adjust the rate of penetration to match the field value, it would of course be possible to adjust either the rock strength or the bit aggressivity. Changing the former would have the

effect of changing the rate of penetration in that rock for all bit types, whereas changing the bit constant changes only the rate of penetration for that particular bit. The same is true concerning wear for the effect of changing rock abrasivity versus the wear constant of the bit. In the absence of any clear indication that we were estimating either rock strength or abrasivity incorrectly, we chose to make the adjustments by changing the bit-specific tuning parameters so as to have the minimum effect on the overall drilling algorithm. Our underlying assumption was therefore that the basic drilling mechanics calculation was correct, and that the adjustments required to match reality were the result of the properties of the individual bits being different from those that had been used to calibrate the simulator when it was first built.

Data:

To reach the depth at which the field lithology began, the well was drilled to 8,724 ft in a 12 1/4" hole with a PDC bit. The 9 5/8" casing was set and the mud density was increased to 9.7 ppg. At this point, the time taken was 82 h 30 min. In the absence of information concerning the rig day rate that was actually applied in the field, we set the value at \$ 50,000 per day, leading to a total cost of \$ 2,842,375. It will be appreciated that this value is arbitrary, and the cost savings reported would have been correspondingly greater or less if the rig day rate had been changed.

1) Tuning the simulator to reproduce the field results

Table 2 presents the five bit runs after tuning the simulator to duplicate the field data. Comparing the values with those in Table 1, we find that we were able to reproduce very similar values of time taken to drill each interval and the state of wear of the bit. The field data report the values of tooth wear for the inner and outer tooth rows (I and O in Table 1), while the simulator reports only an average value. On the other hand, the simulator calculates a specific value of bearing wear while the field data report only bearing effective (E, column B in Table 1) without indicating a fraction of life consumed. However, allowing for these differences, the tuning may be said to have reproduced the field results. The ROP adjustment factors lie in the range 0.3 to 0.92 for the different bit runs, and the wear factors lie in the range 0.1 to 2.0. At present, we are not able to assign any fundamental significance to the magnitudes of these factors. However, we are slightly suspicious of bit run 4, which drilled over 500 ft of an interval that contained a high proportion of sand and yet was given a field grading of T 1, indicating almost no wear.

2) Optimizing the Rock Bit Runs

We 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.

a) 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.

We 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).

b) 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. The results are shown in table 4. 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.

c) Optimization of bit types:

We finally investigated the possible advantages of using bits of types other than the tungsten carbide insert bits that were used in the field. This is the least certain part of the prediction because we had to assume that we could predict the relative rates of penetration and wear of different types of bit in the range of formations that constitute the interval to be drilled

The data are shown in Table 5. 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 (our 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 we have underestimated the wear rate of the PDC bit in abrasive formations, our recommendation may be in error. Again, a counsel of prudence would probably incline us 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 (Fig-2), while the corresponding value for PDC bits was \$165,000.

Conclusions:

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, our present level of confidence in the accuracy of the drilling model must inevitably make us cautious in adopting the recommendations without due prudence.

Nonetheless, the procedure is easy to follow, and we see 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.

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, we were 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.

Acknowledgments

We thank BP and Baker Hughes Oasis for providing the data used in this paper. We also thank Sandia National Laboratories for their funding in support of simulator development.

References

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Well NO.															Dull Factors				F.S.J	Cost(\$) at end of each run
Run #	Type	IADC	Size(")	Noz.	Depth In	Depth Out	Feet	Hours	ROP	WOB	RPM	gpm	PPg	T	B	ROP	Wear			
1	TCI	4-1-5	8.5	3x13	8724	8909	185	10.8	17.2	30	70	550	9.7	3	2	0.30	2.00	10	2864806	
2	TCI	5-1-5	8.5	3x18	8909	9216							9.7							
					9216	9321	412	18.7	22.1	35	100	610	10.1	4	2	0.42	0.25	6.3	2929569	
3	TCI	5-1-5	8.5	3x18	9321	10001	680	30.3	22.5	45	120	580	10.1	4	3	0.45	0.13	5.4	3019889	
4	TCI	5-1-5	8.5	3x18	10001	10046							10.1							
					10046	10545	544	25.5	21.3	38	95	617	10	4	1	0.45	0.10	6.4	3101458	
5	TCI	5-1-5	8.5	3x18	10545	10881							10							
					10881	11868	1323	68.9	19.2	32	90	600	10.1	8	2	0.92	0.10	6.0	3274173	

Table-2

After Hydraulic optimization

Well NO.															Dull Factors				F.S.J	Cost(\$) at end of each run	Saving after optimiz ation
Run #	Type	IADC	Size	Noz.	Depth In	Depth Out	Feet	Hours	ROP	WOB	RPM	gpm	PPg	T	B	ROP	Wear				
1	TCI	4-1-5	8.5	3x13	8724	8909	185	10.8	17.2	30	70	550	9.7	3	2	0.30	2.00	10	2864806	0	
2	TCI	5-1-5	8.5	3x18	8909	9216							9.7								
					9216	9321	412	18.7	22.0	35	100	610	10.1	4	2	0.42	0.25	6.3	2929569	0	
3	TCI	5-1-5	8.5	3x18	9321	10001	680	30.3	22.5	45	120	580	10.1	4	3	0.45	0.13	5.4	3019889	0	
4	TCI	5-1-5	8.5	3x18	10001	10046							10.1								
					10046	10545	544	25.5	21.3	38	95	617	10	4	1	0.45	0.10	6.4	3101458	0	
5	TCI	5-1-5	8.5	3x13	10545	10881							10								
					10881	11868	1323	64.4	20.5	32	90	600	10.1	8	2	0.92	0.10	13.6	3264972	9201	

Table3

After Wob and RPM optimization

Well NO.															Dull Factors				F.S.J	Cost(\$) at end of each run	Saving after optimiz ation
Run #	Type	IADC	Size	Noz.	Depth In	Depth Out	Feet	Hours	ROP	WOB	RPM	gpm	PPg	T	B	ROP	Wear				
1	TCI	4-1-5	8.5	3x13	8724	8909	185	6.67	27.7	15	130	550	9.7	3	5	0.30	2.00	10	2866264	8542	
2	TCI	5-1-5	8.5	3x18	8909	9216							9.7								
					9216	9321	412	13.9	29.6	10	140	610	10.1	3	2	0.42	0.25	6.3	2919708	9861	
3	TCI	5-1-5	8.5	3x18	9321	10001	680	22.7	30.0	15	140	580	10.1	2	2	0.45	0.13	5.4	3004786	15104	
4	TCI	5-1-5	8.5	3x18	10001	10046							10.1								
					10046	10545	544	18	30.2	15	150	617	10	3	2	0.45	0.10	6.4	3085903	15555	
5	TCI	5-1-5	8.5	3x13	10545	10881							10								
					10881	11868	1323	47.1	28.1	20	130	600	10.1	8	3	0.92	0.10	13.6	3228826	45347	

Table4

Optimizing for bit types

Well NO.														Dull Factors				F.S.J	Cost(\$) at end of each run	Saving after optimiz ation	
Run #	Type	IADC	Size	Noz.	Depth In	Depth Out	Feet	Hours	ROP	WOB	RPM	gpm	PPg	T	B	ROP	Wear				
1	MT	short	8.5	3x13	8724	8909	185	5.35	34.6	15	130	550	9.7	3	2	0.30	2.00	10	2849821	14985	
1	FDC	short	8.5	3x13	8724	8909	185	2	92.5	15	130	550	9.7	3		0.30	2.00	10	2865146	340	
2	MT	short	8.5	3x16	8909	9216							9.7								
					9216	9321	412	8.6	47.9	10	140	610	10.1	2	2	0.42	0.25	6.3	2905036	24533	
2	FDC	short	8.5	3x16	8909	9216							9.7								
					9216	9321	412	4.5	91.6	10	140	610	10.1	2		0.42	0.25	6.3	2918555	11014	
3	MT	short	8.5	3x16	9321	10001	680	10.4	65.5	15	140	580	10.1	2	2	0.45	0.13	5.4	2975390	44499	
3	FDC	short	8.5	3x16	9321	10001	680	7.58	89.7	15	140	580	10.1	2		0.45	0.13	5.4	2991722	28167	
4	MT	short	8.5	3x16	10001	10046							10.1								
					10046	10545	544	11.4	47.7	15	150	617	10	3	2	0.45	0.10	6.4	3068453	33005	
4	FDC	short	8.5	3x16	10001	10046							10.1								
					10046	10545	544	5.68	95.8	20	150	617	10	3		0.45	0.10	6.4	3078743	22715	
5	MT	short	8.5	3x13	10545	10881							10								
					10881	11868	1323	23.1	57.3	20	130	600	10.1	6	2	0.92	0.10	13.6	3175196	98977	
5	FDC	short	8.5	3x13	10545	10881							10								
					10881	11868	1323	10.4	127	20	130	600	10.1	6		0.92	0.10	13.6	3170937	103236	

Table5

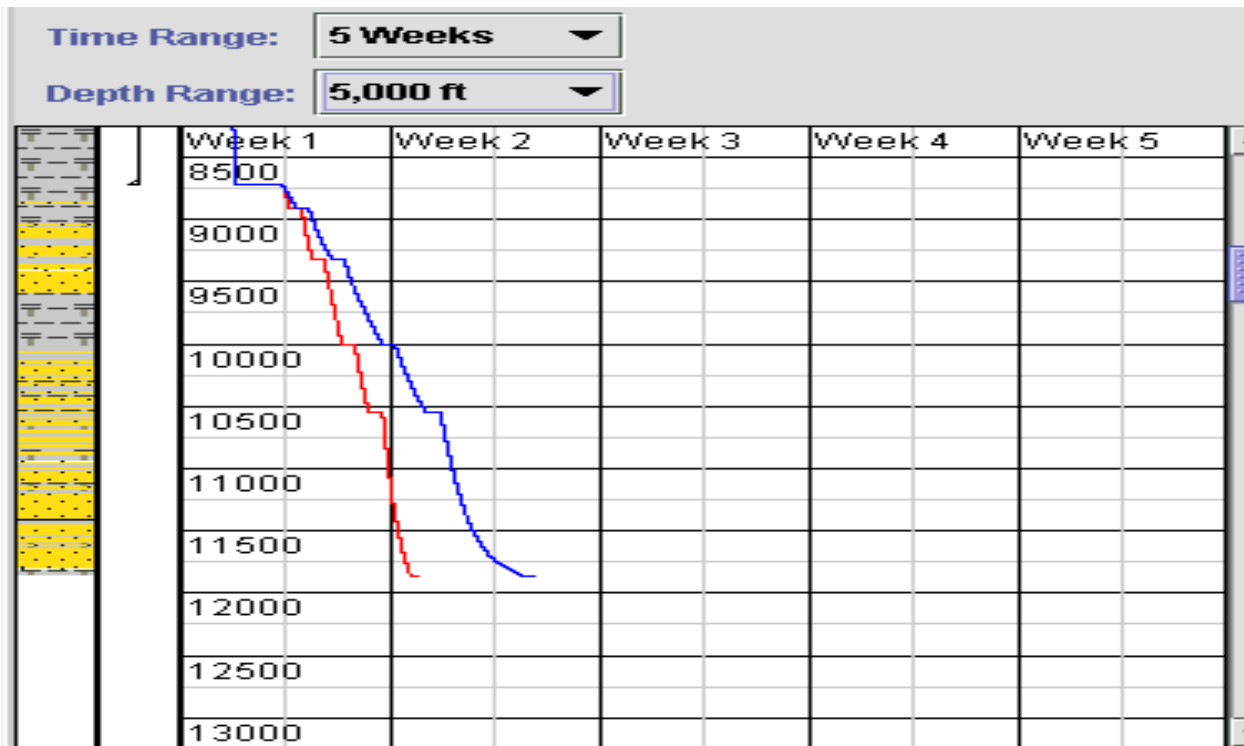


Fig-2: Optimized and the original wells. The optimized well is in red and the original well is in blue.