Rig Selection and Cost Analysis; a Comparison of Top Drive and Rotary Table Drive Rig Systems

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Abstract

Drilling is an industry where everyone knows that time is money. Attention has been focused on improving rotating and handling of drillpipe in order to reduce the non-rotating time. This non-rotating time can be reduced primarily through pipe handling. However, top drive drilling has become among new technologies of the 1980's. Since then, it became one of the biggest changes made to the rotary table method. The aim of this paper is to compare between these two techniques in terms of pipe handling time (connection time and trip time) during the drilling processes. However, it is well known that a top drive system allows rotating full stand; thus, connections are reduced by 2/3 of the number of connections required by a rotary table system. This results a reduced number of connections, and consequently time is saved. On the other hand, the top drive rigs come with higher daily rate costs compared to rotary table rigs. This case study considered nine wells drilled in three different Libyan oilfields. Five wells were drilled using rotary table system, and the remainder wells were drilled through the top drive system. The results show that top drive system is superior in terms of pipe handling time and drilling cost especially in deeper wells. However, top drive rigs become more costly and unviable economically when their daily rental rates exceed by 40% the daily rental rates of rotary table rigs.

Keywords: Rig selection, cost analysis, decision-making, top drive and rotary table systems, drilling connection and trip times.

1. Introduction

The objective of drilling an oil/gas well is to make a hole as quickly as possible subject to the technological, operational, quality, and safety constraints associated with the process. These objectives are frequently conflicting and depend on factors that interdepend; vary with respect to time and location; and are subject to significant market uncertainty. Top drive drilling involves less non-rotating time compared to the conventional rotary table technique.

Cavanaugh and Adams (1988), Tyson and Schuck (1995), Hock (1989) and Hock (1993) wrote expounding the virtues of drilling with permanent top drive versus rotary table system. The main difference between the top drive rig and the conventional rotary table system rig is the position of the drive mechanism. King (1995) summarized the advantages and disadvantages of using permanent top drive for drilling operations as: (1) advantages; a) safety improvements with reduced number of connections, b) improved well control with ability to make up and circulate wile tripping, c) minimized static time in sticky well situations, d) back-ream to clean out tight spots, e) reduced connection time, f) no laying downpipe to wash and ream, g) directional drilling with 93 ft stands as opposed to 31ft singles, h) improved coring and fishing results from utilizing 93 ft stands, and (2) disadvantages; a) cost of top drive unit, b) derrick modifications, c) reduced bottom hole assembly working height, and d) increased maintenance.

Top drive system of drillings has become the predominant method of drilling offshore wells during the last decade. Moreover, the critical parts of onshore wells are drilled by top drive that requires experienced drilling personnel to maintain the system and solve any anticipated or unanticipated problems, Boyadief (1986) and Cavanaugh (1988). However, as top drive system allows rotating full stand and thereby connections are reduced by two thirds of the number of connections required by a rotary table system. Studies have concluded that top drive system is faster, more efficient and therefore less costly than the conventional rotary table drive rig system. This applies to difficult to drill moderately deviated wells, easy to drill deviated or non-deviated wells and highly deviated wells, Cavanaugh (1988). However, this conclusion has not been tested at various depths.

2. Rig selection and drilling cost analysis

Comparing the two drilling techniques, drilling by rotary table requires kelly, kelly bushing, swivel, and rotary table. Top drive drilling system eliminated the use of kelly and kelly bushing. This, consequently, eliminated the need to handle the kelly twice when filling up drillpipe and washing to bottom. The study of cost per foot is useful in defining minimum cost drilling condition. A cost comparison of each bit run on all available wells in the area will identify the bits and operation conditions that yield minimum drilling costs. Drilling engineer provides his/her expected rig costs, bit costs, and assumed average trip time. Then, the bit run cost equation can be used. Preparing cost estimates for a well is the final step in well planning. Time required to drill a well has significant impact on many items in well cost. Cost of footage drilled during a single bit run is the sum of three costs: bit costs, trip costs, and rig operation costs. Bit cost and cost to trip are fixed for a particular bit run, Adams and Charrier (1985). Nevertheless, drilling trip time depends on factors such as: well depth, hole size, surge and swab pressures, bottom hole assembly configuration, hoisting capacity, use of automatic pipe handling system, type of rig, hole problems, crew efficiency and drilling regulations.

2.1 Trip time

Making a trip, in drilling operations, refers to the process of removing the drillstring from the hole to change a portion of the downhole assembly and then lowering the drillstring back to the hole bottom. Normally, the drill bit wear and tear like most any other piece of equipment. Once a bit becomes too worn to drill at an adequate rate or make a full-gauge hole, or if the bearings are thought to be near failure, a trip is undertaken to replace the bit. Nevertheless, a bit removal for the purpose of replacing the bit with a different size in order to start drilling the next section, after casing and cementing jobs, is not considered a trip. Similarly, the removal of the bit for the insertion of the downhole tools such as measurement while drilling, logging while drilling or mud motors break is not considered a trip. Therefore, a trip is solely for replacing the bit due to wear and tear. On the other hand, the connection in drilling terms is the addition and connection of pipes to the drillstring in order to continue drilling the hole deeper. In rotary table drive systems; only one pipe is connected to the drillstring. Nonetheless, the top drive systems require the addition of three connected pipes at once. Thus, drilling rig rental rate costs and time savings rely on the efficiency of the drilling system used.
Tripping speed can be improved by using automation for pipe handling and using an iron-roughneck to make-up or break the connections. Thus the total amount of time that goes into pulling out of the hole, or running in-hole, is less when using the top drive system, especially when the mast can handle three drillpipes at a time (“triples”) with 90 feet long stands. Some masts are only made to handle single lengths of drillpipes (“singles”) and then the tripping time becomes greater. The rotary table rig can pull out of the hole or run in-hole using the “triples”, providing a faster rate of tripping. Also, if an obstruction is encountered while running in-hole while using the top drive, driller can circulate and rotate the bit right away to ream the hole. However, in a rotary table setup, the driller has to pull out one drillpipe and connect the kelly, then run in to circulate and ream the hole and thereafter disconnect the kelly to continue running in-hole, or do it one step at a time which is time consuming.

2.2 Trip time estimation

Adams and Charrier (1985) reported that from the rule of thumb that the trip time is 1 hr/1,000 ft of well depth. Short (1982) shows the trip time is taken as 0.8 hr/1,000 ft to 10,000 ft; and 1.0 hr/1,000ft from 10,000 to 15,000 ft; 1.2 hr/1,000 ft, from 15,000 to 20,000 ft. Adams and Charrier (1985) used Table 1 for trip time estimation in well planning. The table was developed by several operators based on field studies. Schofield et al. (1992) used Equation 1 to calculate trip time. Falcao et al. (1993) indicated that for trip factor (hours per 1,000 ft for round trips below 1,000 ft) top drive system was found to save an average of 25 minutes over the rotary table system's time.

$$t_t = \frac{D}{1000} + 1 \tag{1}$$

Table 1. Average tripping time, Adams and Charrier (1985)

Depth, ft	Hole size, in

	< 8.75	8.75 - 9.875	> 9.875
2,000	1.5	3	4.5
4,000	2.5	4.2	5.75
6,000	3.5	5.4	7
8,000	4.7	6.5	8
10,000	5.8	7.25	9
12,000	7	8.25	10.25
14,000	8.25	9.25	11.5
16,000	9.75	10.25	12.5
18,000	11	11.25	13.75
20,000	11.8	12.25	15

As is known, oil wells are normally drilled by means of a rotating bit suspended at the lower end of a drillstring of drillpipe sections in stands. In order to continue drilling, connections are made to the drillstring. In rotary table the length of the single stand equals 31 ft compared to 93 in case of top drive system. In the simplest case, the cost of a single bit run is the sum of (a) bit cost, (b) tripping cost, and (c) connections cost. In our case study the comparison are based on tripping cost, C_t and connection cost, C_c. These costs are the product of the daily rig rate, C_R. Bit cost is fixed, thus the total cost, C, can be obtained from Equation 2.

$$C = C_R(C_t + C_c) \tag{2}$$

3. Case study

This paper focused on the costs of the rigs daily rates and pipe-handling periods during pipe connections and tripping, for both two drilling techniques. The costs of other drilling activities, however, are considered identical at various drilling footages. Nine wells were considered for analysis and comparison; five wells were drilled using rotary table drive system, one of them is a horizontal well. Whereas the remainder four wells drilled by top drive system, one of them is also a horizontal well. For consistency and in order to obtain accurate results the comparisons are made between wells that are drilled in same field, so they have identical or similar formations. Table 2 illustrates the collected data. Figures 1 and 2 show the percentage of the footage drilled in each section (26, 17½, 12¼, 8½, and 6 inch hole size). The figures demonstrate that the drilled footage by top drive and rotary table are matching for all sections in the wells.

Table 2. Illustrated the data used in the study

Well #	Rig Type	Well Type	Field	Interval	Hole Size, in				
					26	17 1/2	12 1/4	8 1/2	6
A7	TD	Vert.	NC89	Connection time, hr	2	34.5	40.8	18	23
				Tripping time, hr	5.5	98.5	202	180.5	234.5
				Footage, ft	562	4776	7202	1375	1381
F4	RT	Vert.	NC98	Connection time, hr	2	39.5	40.5	32.5	7.5
				Tripping time, hr	31	71.5	142	203.5	155.5
				Footage, ft	522	4699	7309	2106	736
6R1	RT	Vert.	C59	Connection time, hr	5.5	25	73.5	14.5	
				Tripping time, hr	25	44.5	154	97	
				Footage, ft	635	2428	6900	1231	
6R2	TD	Vert.	C59	Connection time, hr	4	10	36	16.5	
				Tripping time, hr	19	45	107	249	

				Footage, ft	564	2447	6466	1783	
A61	RT	Vert.	NC98	Connection time, hr	5	74	48.5	29.5	3.5
				Tripping time, hr	26	117	283.5	166	41
				Footage, ft	806	6737	5054	2045	339
O1	TD	Vert.	NC98	Connection time, hr	3.5	42.5	24.5	32.5	33.5
				Tripping time, hr	21.5	109	124	166	688.5
				Footage, ft	984	6693	5106	1575	2047
2H17	TD	Horiz.	C59	Connection time, hr	5	21.5	51.5	8.4	42.8
				Tripping time, hr	17	31.5	78.5	68.5	285
				Footage, ft	590	2220	6470	836	2910
2H15	RT	Horiz.	C59	Connection time, hr	5	21.5	51.5	8	40.5
				Tripping time, hr	22	39.5	129.5	46.5	349.5
				Footage, ft	552	2439	5703	1442	2061
P2	RT	Vert.	NC98	Connection time, hr	4	27	62	5	59.5
				Tripping time, hr	13.5	55	110	216	712
				Footage, ft	519	4597	5796	971	2616

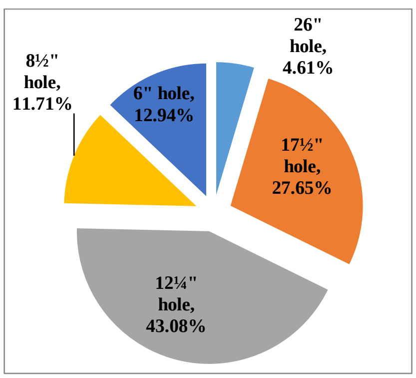

Figure 1. Footage percent for each hole size for the wells drilled by rotary table drive system

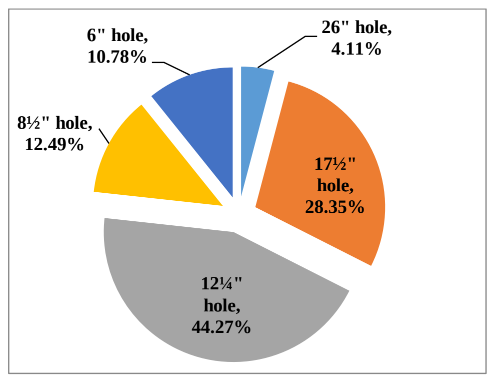

Figure 2. Footage percent for each hole size for the wells drilled by top drive system

4. Results and discussion

Connection time and tripping time spent for drilling each section is presented in Tables 3 and 4. The pipe handling time (total time) is obtained by summing connection time and tripping time. Cost of pipe handling for each section is calculated by using Equation 2. The daily top drive and rotary table rigs rental rates were 1,667 \$/hr and 1,250 \$/hr, respectively.

Figure 3 shows a straight-line relationship between connection time, $t_{c,}$ and depth, D, for both rotary table and top drive drilling systems. Relationship between connection time and depth for the rotary table system is presented in Equation 4. The fitted equation gives correlation coefficient, R^2, of 92.76%. On the other hand, the straight-line between connection time and depth for the top drive drilling system is shown in Equation 5 at a R^2 of 90.71%. The equation can be used to estimate the connection time.

Figure 4 shows a logarithmic relationship of tripping time, t_t versus depth, D. Equation 6 can be used to estimate the tripping time for rotary table drilling system, while Equation 7 can be used to obtain tripping time for top drive drilling system. R^2 values of 94.32% and 92.08% demonstrate the accuracy of the fitted equations for rotary table and top drive drilling systems, respectively.

Table 3. Pipe handling time and cost for top drive system

Top Drive System (Rig rate = 1,667 $/hr)						
Well #	Section	Depth, ft	Connection time, hr	Trip time, hr	Total time, he	Cost, M$/hr
A7	26" Hole	562	2	5.5	7.5	13
	17 1/2" Hole	5,338	36.5	104	140.5	234
	12 1/4" Hole	12,540	77.3	306	383.3	639
	8 1/2" Hole	13,915	95.3	486.5	581.8	970
	6" Hole	15,296	118.3	721	839.3	1,399
6R2	26" Hole	564	4	19	23	38
	17 1/2" Hole	3,011	14	64	78	130
	12 1/4" Hole	9,477	50	171	221	368
	8 1/2" Hole	11,260	66.5	420	486.5	811
O1	26" Hole	984	3.5	21.5	25	42
	17 1/2" Hole	7,677	46	130.5	176.5	294
	12 1/4" Hole	12,783	70.5	254.5	325	542
	8 1/2" Hole	14,358	103	420.5	523.5	873
	6" Hole	16,405	136.5	1109	1245.5	2,076
2H17	26" Hole	590	5	17	22	37
	17 1/2" Hole	2,810	26.5	48.5	75	125
	12 1/4" Hole	9,280	78	127	205	342
	8 1/2" Hole	10,116	86.4	195.5	281.9	470
	6" Hole	13,026	129.2	480.5	609.7	1,016

Table 4. Pipe handling time and cost for rotary table system

Rotary Table System (Rig rate = 1,250 $/hr)						
Well #	Section	Depth, ft	Connection time, hr	Trip time, hr	Total time, he	Cost, M$/hr
F4	26" Hole	522	2	31	33	41
	17 1/2" Hole	5221	41.5	102.5	144	180
	12 1/4" Hole	12530	82	244.5	326.5	408
	8 1/2" Hole	14636	114.5	448	562.5	703
	6" Hole	15372	122	603.5	725.5	907
6R1	26" Hole	635	5.5	25	30.5	38
	17 1/2" Hole	3063	30.5	69.5	100	125
	12 1/4" Hole	9963	104	223.5	327.5	409
	8 1/2" Hole	11194	118.5	320.5	439	549
A61	26" Hole	806	5	26	31	39
	17 1/2" Hole	7543	79	143	222	278
	12 1/4" Hole	12597	127.5	426.5	554	693
	8 1/2" Hole	14642	157	592.5	749.5	937
	6" Hole	14981	160.5	633.5	794	993
2H15	26" Hole	552	5	22	27	34

	17 1/2" Hole	2991	26.5	61.5	88	110
	12 1/4" Hole	8694	78	191	269	336
	8 1/2" Hole	10136	86	237.5	323.5	404
	6" Hole	12197	126.5	587	713.5	892
P2-NC98	26" Hole	519	4	13.5	17.5	22
	17 1/2" Hole	5116	31	68.5	99.5	124
	12 1/4" Hole	10912	93	178.5	271.5	339
	8 1/2" Hole	11883	98	394.5	492.5	616
	6" Hole	14499	157.5	1106.5	1264	1580

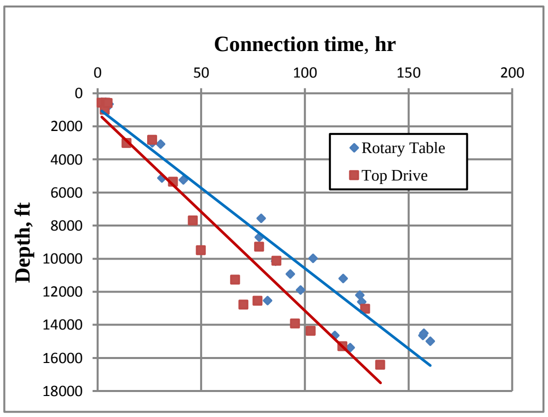

Figure 3. Connection time versus depth

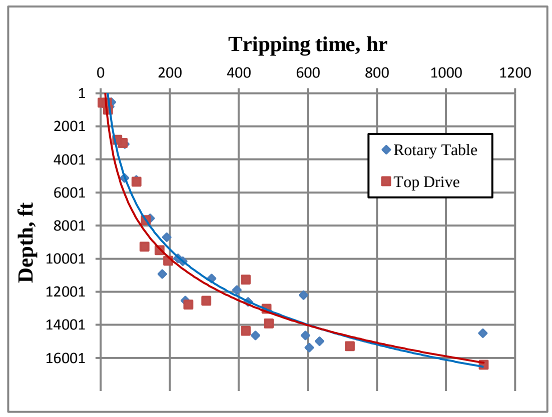

Figure 4. Tripping time versus depth

$$t_c = -9.0827 + 0.0103D \tag{4}$$

$$t_c = -10.02 + 10.02D \tag{5}$$

$$t_t = e^{\left(\frac{D+1259.7}{4156.9}\right)} \tag{6}$$

$$t_t = e^{\left(\frac{D+9559.8}{368.6}\right)} \tag{7}$$

The summation of connection time and tripping time (total time) is plotted versus depth in Figure 5. The plot shows a logarithmic relationship for rotary table and top drive as illustrated in Equations 6 and 7, respectively. The equations can be used to estimate time expected for tripping and connections of drillpipes.

$$t_{total} = e^{\left(\frac{D+13901}{4159.7}\right)} \tag{8}$$

$$t_{total} = e^{\left(\frac{D+11627}{3868.9}\right)} \tag{9}$$

To estimate the pipe-handling cost during tripping, the average of total time for each drilling section was calculated using Equations 8 and 9 then arranged in Table 5. The bar plot in Figure 6 explains the saving time (difference in total time between the two drilling systems). The Figure shows that pipe handling time in rotary table is more than it is for the top drive system. Time saved for each section is shown in Figure 7. It shows that most time saved was in 12¼ and 8½ sections.

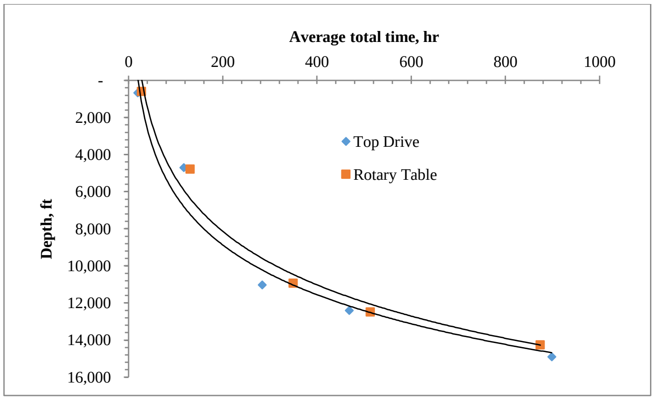

Figure 5. total time (handling pipe time) versus depth

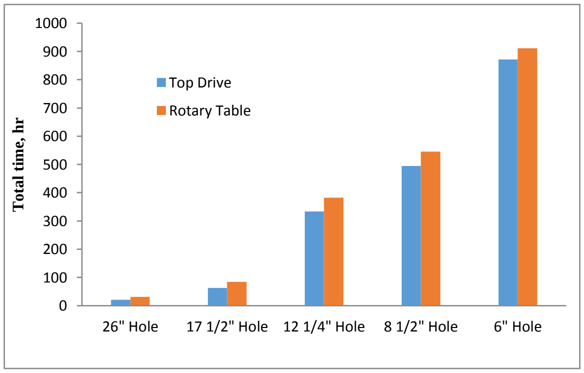

Figure 6. Comparison between top drive and rotary table in terms of total time (pipe handling time)

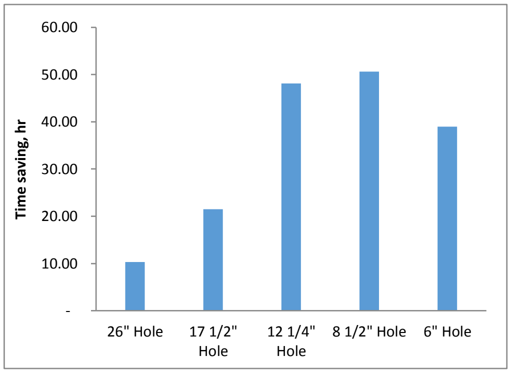

Figure 7. Time saving (difference in total time between the two drilling systems)

Table 5. Pipe handling cost

Top Drive System		Rig Rate =	1667	$/hr
Section	Average Time, hr	Depth, ft	$/ft	M$
26" Hole	19	675	47.849	32
17 1/2" Hole	118	4,709	41.595	196
12 1/4" Hole	284	11,020	42.897	473
8 1/2" Hole	468	12,412	62.911	781
6" Hole	898	14,909	100.426	1,497
Rotary Table System		Rig Rate =	1250	$/hr
26" Hole	28	607	57.268	35
17 1/2" Hole	131	4,787	34.130	163
12 1/4" Hole	350	10,939	39.960	437
8 1/2" Hole	513	12,498	51.347	642
6" Hole	874	14,262	76.623	1,093

Consequently, the sensitivity analysis of the rig daily rate was studied at top drive daily rental rates that exceeds the rotary table system by 5%, 15%, 25%, 30% and 40% at various depths of 650, 5,000, 11,000, 12,500 and 15,000 ft. Table 6 shows the results of the analysis. It can be concluded that, generaly, as the percentage increases the cost of the top drive increases and cost of the rotary table decreases. Moreover, at 5% (daily renatl rate of the top drive that exceeds the rotary table drive by 5%) top drive provides lower cost than rotary table at any wells depth. However, at 15%, 11,000 ft and deeper rotary table offers lower cost. Additionally, at 30%, 5,000 ft and deeper rotary table provides lower cost. Finally, at 40% and higher the ratary table offers lower cost at any depth.

Table 6. Sensitivity analysis of pipe handling cost

	Top drive daily rate exceeds rotary table by *x*%						
Depth, ft	5%	15%	25%	30%	40%	-347%	60%
650	10	7	4	3	-0.5	-20.3	-6
5000	21	12	3	-2	-11	-153	-29
11000	42	-1	-44	-66	-109	-245	-196
12500	43	-21	-85	-117	-181	-527	-308
15000	22	-100	-222	-283	-405	-568	-649

5. Conclusion

This study investigated and compared between top drive and rotary table rigs. A total of nine wells were considered four of which were drilled by top drive rigs and five were drilled by rotary table rigs. The savings or time reductions were substantial with the top drive drilling system. Time saved ultimately leads to significant cost savings which depend on rigs daily rental rates and depths to be drilled. The sensitivity analysis of the pipe handling cost was also presented. The sensitivity analysis results show that at 5%, higher daily rental rate of top drive rigs than rotary table rigs, top drive provides lower overall cost than rotary table at any depth. Besides, at 15%, 11,000 ft and deeper rotary table offers lower cost. Additionally, at 30%, 5,000 ft and deeper rotary table provides lower cost. At 40% and deeper, the ratary table offers lower cost at any depth.

Additionally, three models to eastemate connection time, tripping time and total time are obtainable whit high accuracy.

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Biography

Walid Mohamed Mahmud received his B.Sc. degree in Petroleum Engineering from the University of Tripoli, Libya in 1995, M.E. and Ph.D. degrees in Petroleum Engineering from the University of New South Wales, Sydney, Australia in 1997 and 2004, respectively and an MBA from the University of Southern Queensland, Toowoomba, Australia in 2007. He is currently an Assistant Professor at the University of Tripoli, Libya. He has industry experience as a Business Development Manager and Senior Reservoir engineer at Heinemann Oil GmbH in Austria and Libya. He also gained teaching experience as a lecturer and assistant professor at the Department of Petroleum Engineering, the University of Tripoli. His main general teaching and research interests are fluid flow in porous media, network modeling, two and three-phase relative permeability and reservoir characterization and management. His current research interests include two and three-phase flow, two and three phase relative permeability, numerical network models and drilling cost analysis.

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