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KPI BENCHMARKING—A SYSTEMATIC APPROACH

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Abstract

Performance improvement creates value. For the driller, this means achieving a better performance with each new hole. But what defines a "better" performance? It is common practice to use a few offset wells as a benchmark of expected performance, but this up-front effort to establish key performance indicators (KPIs) requires specialized resources and a significant financial commitment normally justified on only the largest projects. Others, begun without establishing clear benchmarks, often leave untapped value behind.

There are many features and benefits of a systematic approach to benchmarking drilling performance. KPIs are established and statistically analyzed for central tendencies and convergence, which together serve as benchmarks. A database is created and is readily accessible for effective offset analysis. The KPIs, with their associated probabilities, can be used to generate risk-based authorizations for expenditures (AFEs).

This method paves the way for a probabilistic approach to planning new wells. It also serves as a yardstick for measuring the performance of ongoing operations and provides consistent, fact-based data for selecting the optimal approach for each well.

Several case studies demonstrate the use of this database. These studies illustrate the ability of the database to combine drilled surveys, lithology information, and drilling data from offset wells to establish formation-specific directional tendencies before a well is planned. This ability to correlate drilling parameters facilitates the process of drilling optimization. The combined knowledge of formation tendencies and drilling parameter optimization forms a solid foundation for selecting the right technology for the right well.

It is a truism that any performance that cannot be measured consistently cannot be improved. The systematic creation and application of a drilling performance database provides the clear benchmarks by which performance can be measured and constantly improved.

Introduction

Project Management Book of Knowledge defines three areas for measuring the success of a typical project: cost, time, and quality. These areas are also very much applicable to drilling. A drilling project is considered successful when it is drilled within the constraints of budget and schedule and conforms to the specifications for subsequent completion and production operations. The tightening economic situation puts a squeeze on the cost constraints. Budget constraints easily translate into time constraints, as trades are based on day rates. Performance improvement therefore becomes the art of reducing the time and cost to drill a well without compromising the quality of the wellbore.

How is performance monitored today?

The drive for improvement leads to performance monitoring done at various levels. Traditional end-of-well reports, daily reports, and bit records are used, along with state-of-the-art methods that offer a much higher granularity. Advancements in information technology have positively affected the drilling industry such that every rig in Western Canada is wired with an electronic system to capture operating parameters in real time. Consequently, an abundance of electronic drilling data is captured in various databases. Few people use this abundance of data in a systematic manner to establish benchmarks and gauge their performance against those benchmarks, as there is no industry-wide application to facilitate the process. Commonly available spreadsheet tools are less efficient with high data volumes.

When a well is being drilled, various pieces of information are generated. An end-of-well report captures information such as well name, location, dates, and depths for each run, tools used for each bottomhole assembly (BHA) and their corresponding sizes, and the bits used for each run and their dull grade. A directional service provider will typically generate his/her own report of as-drilled surveys versus the well trajectory plan. The geological operations team generates its own report of formation tops encountered during the course of drilling. The electronic data system captures data in real time and stores it in its own database. Drilling tools employed downhole are often equipped with sensors that record useful information on downhole operating dynamics. Even though all this information from various sources becomes part of a well file, it is seldom looked at in unison. Establishing benchmarks based on real offset data becomes a daunting task, which is hard to justify, especially in a high-volume, low-tier market.

How does a database relate all the information?

A database was designed to relate relevant bits of data across the various disciplines. The various components of data that populate the database include details of BHA, operating parameters, formations drilled, well plans, as-drilled surveys, electronically captured surface parameters, and shocks and vibrations data. The drilling KPIs are calculated using the electronic drilling data broken down into individual bit runs and are then stored in the database.

The database relates the information at two levels:

1) Well level whereby each well is identified with a job number—the well level binds location information with formation tops, well trajectory plans and surveys, electronically captured data from surface systems, and downhole tools.

2) Bit run level whereby each run is identified with a run number—the BHA components, run parameters, performance parameters, bit details, and mud systems information are bound to the run number. This level also facilitates the process whereby streams of surface and downhole-captured electronic data are broken down to what is relevant to an individual run and analyzed for KPIs. The run-specific KPIs are also bound to the run number and their data streams.

The two-tier approach for binding all information provides the framework required to run queries.

KPIs

A method of analyzing performance from electronically captured drilling data has been described in detail in the paper AADE-07-NTCE-50 (Hammad, 2007). Drilling data is analyzed line by line for determination of rig state. The patterns formed by variations in bit depth and hole depth are used to identify trips. The rig states aggregated over the duration of the bit run provide useful KPIs such as rate of penetration (ROP) in sliding and rotating, survey time, connection time, reaming time, trip time, and slide percentages. This method provides the foundation for establishing the KPIs. A brief explanation of some of the KPIs is provided here for clarity:

Rotary ROP is the ratio of cumulative rotary distance to cumulative rotary time.

Sliding ROP is the ratio of cumulative sliding distance to cumulative sliding time.

Slide distance per 100 m is the ratio of the cumulative slide distance to the cumulative distance in a bit run normalized to 100 m of bit run.

Time in hole per 100 m is the accumulation of time from the point where bit was within a certain threshold distance off-bottom while tripping in to the moment in time where bit was tripped out to the same threshold distance. That accumulated time is normalized to 100 m lengths of interval. The threshold is taken as 50 m.

Drilling time per 100 m is accumulated the same way as time in hole per 100 m, but it accounts for only the on-bottom drilling time.

Flat time per 100 m is accumulated the same way as time in hole per 100 m, but it accounts for only the off-bottom nondrilling time. Flat time includes time spent on activities such as connections, surveys, orienting, reaming at connections, and circulation prior to trip out.

Trip time per BHA is the round-trip time and is calculated by aggregating the time when the bit is off-bottom by greater than 50 m. It includes the time spent in wiper trips and hole conditioning while off-bottom.

Applications of database

A user interface enables queries across the database for various attributes such as location, hole size, depth, time, BHA component, bit type, formation name, inclination, and azimuth. The execution of a query yields information back to the user at bit run level. For all bit runs that satisfy the specified attributes, the following information is returned in separate tables:

- run summary table
- well plans
- as-drilled surveys
- formations drilled during the run
- KPIs
- lessons learned during that run.

Two flags are added to the run summary table to highlight the longer runs drilled with better ROP. Intuitive color coding of the flags readily differentiates between average, better, and poorer BHA runs. An example of BHA run summaries with color coding is presented in Fig.1.

This allows drilling engineers to swiftly access the run details of the best runs in the area of interest. With one click of mouse, he/she can access the BHA components, the formations that were drilled by the BHA, and comparison of directional performance in the form of T-plots. Formation data and directional information play a key role in determining the applicability of that information to the well being planned.

Various graphical displays are available for correlations. These include shocks and vibrations data from the measurement-while-drilling (MWD) tools and drilling parameters from a surface system. Depth logs of shocks and vibrations data provide insight into the response of BHA in the various formations with varying drilling parameters.

ROP_Flag	Run_Length_	Well_BHA_No	Job_No	Date_In	Date_Out	Depth_In	Depth_Out	Hole_Size
		PC 6-19 Dr Ferrier BHA No. 1	40011618 ...	3/22/2005 12:00 AM	3/30/2005 7:26 AM	630	2897	200
		PC ET AL 8-11DR FERRIER 1-11-40-8 BHA No. 3	P0062	10/12/2007 7:54 AM	10/18/2007 6:04 PM	624	2003	200
		PC ET 5-1DR FERRIER 8-2-40-8W5 BHA No. 4	P0066	10/14/2007	10/20/2007	618	2044	200
		PC ET AL 8-11DR FERRIER 8-11-40-8 BHA No. 3	P0067	10/25/2007 4:57 AM	11/1/2007	618	2155	200
		PC et al FERRIER 5-1DR 1-2-40-8W5 PRECISION 422 BHA...	P0061	10/28/2007	11/2/2007	628	1738	200
		PC ET AL 3-12DR FERRIER 7-12-40-8 BHA No. 5	P0065	11/11/2007	11/17/2007	618	2133	200
		PC ET AL 3-1DR FERRIER 3-1-40-8 BHA No. 3	P0064	11/11/2007 4:03 AM	11/18/2007 6:36 AM	620	2008	200
		PC ET AL 3-12DR FERRIER 3-12-40-8 BHA No. 5	P0063	11/27/2007	11/29/2007	619	1220	200
		PC ET AL 10-15DR FERRIER 9-15-40-8 BHA No. 3	P0068	11/27/2007 7:46 PM	12/3/2007 12:26 PM	627	2054	200
		PC ET AL 3-12DR FERRIER 3-12-40-8 BHA No. 6	P0063	11/29/2007	12/7/2007	1220	2182	200
		PC ET AL 10-15 FERRIER 15-15-40-8 PRECISION 422 BHA...	P0070	12/12/2007	12/18/2007	630	2217	200
		PC ET AL 11-1DR FERRIER 11-1-40-8 BHA No. 4	P0069	12/13/2007	12/18/2007	620	2162	200
		Petro Canada Ferrier 7-1-40-8W5m BHA No. 1	08CGT0122...	7/13/2008 12:56 AM	7/17/2008 2:47 PM	622	1980	200
		PC Ferrier 3-11-40-8W5 BHA No. 1	08CGT0208	7/24/2008 11:21 AM	7/25/2008 5:58 PM	619	1104	200
		PC Ferrier 3-11-40-8W5 BHA No. 2	08CGT0208...	7/25/2008 7:18 PM	7/28/2008 2:48 AM	1104	2198	200
		Petro Canada Ferrier 12-11DR 5-11-40-8W5M BHA No. 1	08CGT0209	8/2/2008 3:47 PM	8/6/2008 3:52 AM	618	2193	200
		PC et al Ferrier 5-1 Dr 5-1-40-8 W5M BHA No. 1	08CGT0207...	8/11/2008 5:53 PM	8/14/2008 4:27 AM	617	2199	200
		PC et al 16-2 DR 102 Ferrier 09-02-40-08 BHA No. 1	08CGT0212	8/19/2008 9:15 AM	8/22/2008 6:19 AM	616	2192	200
		PC et al Ferrier 12-14 DR 5-14-40-08 W5M BHA No. 1	08CGT0210...	8/28/2008 4:28 AM	8/30/2008 7:04 AM	616	1984	200
		PC et al Ferrier 14-14 DR 14-14-40-08 W5M BHA No. 1	08CGT0211	9/4/2008 2:30 AM	9/7/2008 11:39 PM	617	2170	200
		PC et al Ferrier 4-31 DR 3-31-39-07 W5M BHA No. 2	08CGT0213...	9/29/2008	10/1/2008	615	2184	200

Figure 1. BHA run summaries highlighted by intuitive color coding.

Correlation plots provide valuable information on selection of drilling parameters with the view of optimizing drilling in various formations with a variety of bits and BHA types. Tripping loads provide a direct indication of wellbore friction that can be expected for the given profile and can be used together with the model outputs for deducing friction factors.

Benchmarking of KPIs

One of the outputs generated from a database query is a table of KPIs associated with bit run that satisfy the specified criteria. This dynamically generated table is used for benchmarking of KPIs.

A list of values for each KPI is extracted from the table and analyzed for central tendency and convergence. Statistical mean is used for central tendency and standard deviation (SD) is used to indicate convergence. The mean and SD are used to identify outliers which are filtered out to generate a reduced list of values. For this reduced list, the mean, SD, median, modes, probability density function, and cumulative probability are determined once more. This mean, together with probabilistic information, serves as the benchmark for a KPI. An example KPI is presented Fig. 2.

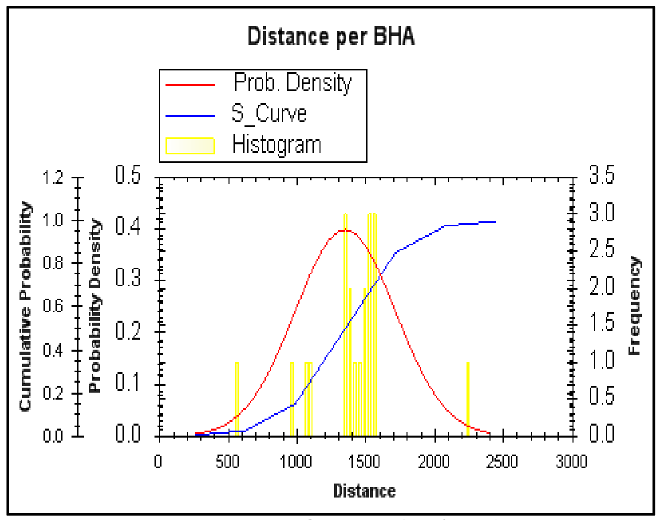


Figure 2. Example of KPI benchmarking.

Case Histories:

The following case histories pertain to the use of database for quantifying the benefit of using rotary steerable systems (RSS). It compares the calculated benefit with the actual performance.

<u>1—Bougie wells</u>

The subject wells were drilled in the North East British Columbia. At the planning stage, the performance analysis of motor wells predicted significant potential time savings. Depending on the formation the ratio between sliding and rotary, ROPs ranged from 0.3 to 0.5 with 15% sliding on average in the tangent section. The sliding was fairly tortuous resulting in a flat time of 11.4 h for every 100 m of drilling. The drilling of the tangent section with motor took 290 h, which included two extra trips. For the sake of quantifying the RSS benefit, it was assumed that the two trips were avoidable and therefore were stripped out of the time calculation. It was calculated that a motor could potentially drill this interval in 224 h, as shown in Fig. 3.

Formation	BHA #	MD_From, m	MD_To, m	ROT_ROP, m/hr	Slide_ROP, m/hr	Slide %	Rot_Time, Hrs	Slide_Time, Hrs	Drill_Time, Hrs	Flat Time per 100m, Hrs	Flat Time, Hrs	Trip Time, Hrs	Total Time, Hrs
Drilling with Motors													
Banf	5	2009.6	2217.4	9	3.62	0.15	19.63	8.61	28.24				
Exshaw	5	2217.4	2220.5	15.3	7.96	0.15	0.17	0.06	0.23				
Kotcho	5	2220.5	2231.7	8.16	4.11	0.15	1.17	0.41	1.58				
Trout%River	5	2231.7	2260.4	10.33	6.51	0.15	2.36	0.66	3.02				
Kakiska	5	2260.4	2293.1	4.15	1.06	0.15	6.70	4.63	11.32				
Red%knife	5	2293.1	2660	11.9	3.96	0.15	26.21	13.90	40.10				
Red%knife	5	2660	2720	11.9	3.96	0.38	3.13	5.76	8.88				
Red%knife	5	2720	2766.9	11.9	3.96	0.15	3.35	1.78	5.13				
F%Simpson	5	2766.9	2820.4	9.65	2.39	0.15	4.71	3.36	8.07				
Muskwa	5	2820.4	2837.5	9.07	5.71	0.15	1.60	0.45	2.05				
Otter Park	5	2837.5	2850	9.14	3.37	0.15	1.16	0.56	1.72				
Summary	5	2009.6	2850						110.35	11.42	95.97	18	224.32
Drilling with RSS													
Banff	4	1918.4	1958.3	2.83	2.63	0	14.10	0.00	14.10				
Banf	4	1958.3	2217.4	9	3.62	0	28.79	0.00	28.79				
Exshaw	4	2217.4	2220.5	15.3	7.96	0	0.20	0.00	0.20				
Kotcho	4	2220.5	2231.7	8.16	4.11	0	1.37	0.00	1.37				
Trout%River	4	2231.7	2260.4	10.33	6.51	0	2.78	0.00	2.78				
Kakiska	4	2260.4	2293.1	4.15	1.06	0	7.88	0.00	7.88				
Red%knife	4	2293.1	2660	11.9	3.96	0	30.83	0.00	30.83				
Red%knife	4	2660	2720	11.9	3.96	0	5.04	0.00	5.04				
Red%knife	4	2720	2766.9	11.9	3.96	0	3.94	0.00	3.94				
F%Simpson	4	2766.9	2820.4	9.65	2.39	0	5.54	0.00	5.54				
Muskwa	4	2820.4	2837.5	9.07	5.71	0	1.89	0.00	1.89				
Otter Park	4	2837.5	2850	9.14	3.37	0	1.37	0.00	1.37				
Summary	4	1918	2850						103.73	3	27.96	15	146.69

Figure 3. Bougie well benefit calculation.

A simple KPI analysis suggested that the same section could be drilled with RSS in 147 h. The analysis was based on eliminating sliding and its associated inefficiencies. Benchmarking of previous RSS performance suggested that for every 100 m of drilling, flat time averages out to 3 h. Drilling the well with RSS offered a potential savings of 80 h of rig time.

The results of drilling are presented in Fig. 4. The blue line is the time depth curve for the well drilled with RSS. The light blue curve reflects the bit depth for the same well. The red and orange curves reflect the hole depth and bit depth, respectively, of the well drilled with motors. With RSS, it was possible to drill the interval and trip out in

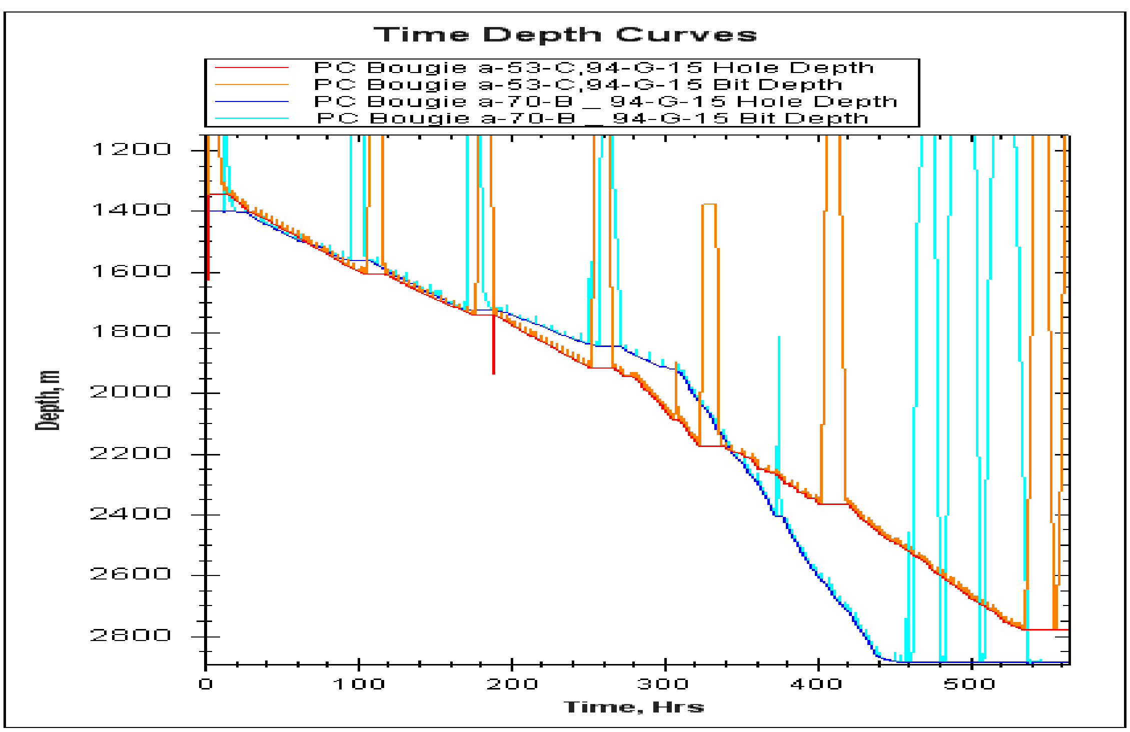


Figure 4. Bougie time depth curves: RSS (blue) versus motors (red).

160 h. This time included two wiper trips and 15 h of sample catching to verify the correct formation zone. Only 2.9 h were spent in flat time for every 100 m of drilling. The actual performance came within a close range of time calculated from benchmarked performance.

2—Ferrier project

The PetroCanada Ferrier project required drilling eight J-shaped wells. In 2007, 10 wells were drilled in this area. The drilling group was fairly satisfied with their drilling performance, but was concerned with wellbore tortuosity. The completions program for these wells called for rod pumps. The client was concerned with the adverse effects of well bore tortuosity on their completion system. The Drilling Engineering Center was invited to suggest a solution to wellbore tortuosity without compromising the overall drilling performance. Savings in drilling time was seen as a secondary benefit. To cap the financial risk, the client requested a lump-sum-amount-per-well pricing model for the project.

The Western Canada Drilling Engineering Center undertook a study of the past drilling performance. The main objectives were:

-trajectory design for reduced well bore tortuosity
-identification of opportunities for improving drilling performance
-providing the basis of a mutually agreeable lump sum amount per well.

Drilling engineers, completions engineers, and suppliers of rods teamed up to determine a trajectory that was suitable to meet the directional objective with reasonable rod stresses. Historical data from previous wells was used to calibrate models for tortuosity. After comparing the build sections with motors with that of RSS using continuous inclination data from MWD tools, the client readily recognized RSS as the right tool for improving tortuosity.

Drilling engineers then jointly looked at the performance improvement opportunities. PetroCanda shared the drilling data captured by their data acquisition system , and the drilling engineering center used the algorithms developed in-house to discern meaningful KPIs from that data. Those KPIs as agreed with PetroCanada were:

-Rotary ROP: 15 m/h
-Flat time per 100 m: 4.5 h/100 m
-Slide distribution per 100 m: 17%
-Time to drill hole section: 150 h (actual average)

The offset data and its relevant KPIs are presented in Fig. 5. It was recognized that ROPs would be better with an RSS, and expected drilling time with RSS was based on the following parameters:

-Rotary ROP: 21 m/h
-Flat time per 100 m: 2 h/100 m (suggested from existing benchmarks)

With these parameters, time to drill the hole section was calculated as 107.7 h. Using USD 23,000/d for RSS, the lump sum for the section was calculated as USD 118,000.

It was also noted that the previous wells had been drilled with insert bits even though the formations in that area lended themselves to drilling with polycrystalline diamond compact (PDC) bits. The concerns with directional control, coupled with high flat times, were the main reasons stopping PCs from utilizing PDC bits.

Based on offset data, it was recommended to use an RSS BHA with a PDC bit below a mud motor. PetroCanada put these recommendations to practice and drilled eight Ferrier wells from July to September 2008. The results were outstanding. PDC bits, coupled with RSS, improved the ROP by more than 200% with average at 47 m/h. RSS helped in keeping the flat time below 2 h/100 m of drilling. PetroCanada was able to drill its production hole sections in an average of 55 h compared to 150 h with motors and insert bits. Figure 6 illustrates the actual drilling performance.

Conclusions
Benchmarking of KPIs helps in establishing a baseline against which drilling performance can be measured. It is important that the benchmarks are established from data which correctly reflects the expected drilling environment.

Glossary of terms

KPIs: Key performance indicators

ROP: Rate of penetration

BHA: Bottom hole assembly

SD: Standard Deviation

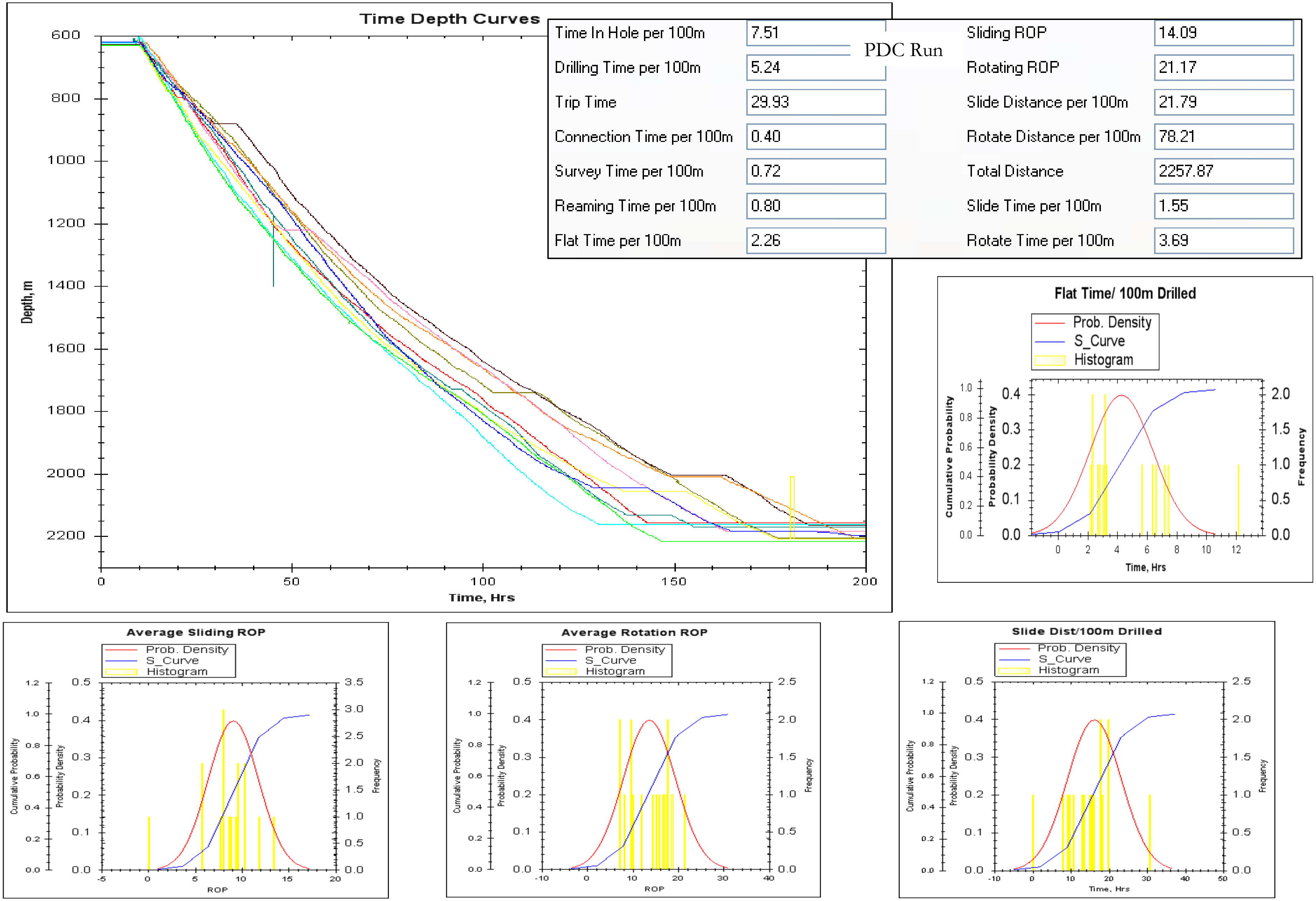
RSS: rotary steerable system

PDM: Positive displacement motor

ROP: Rate of penetration

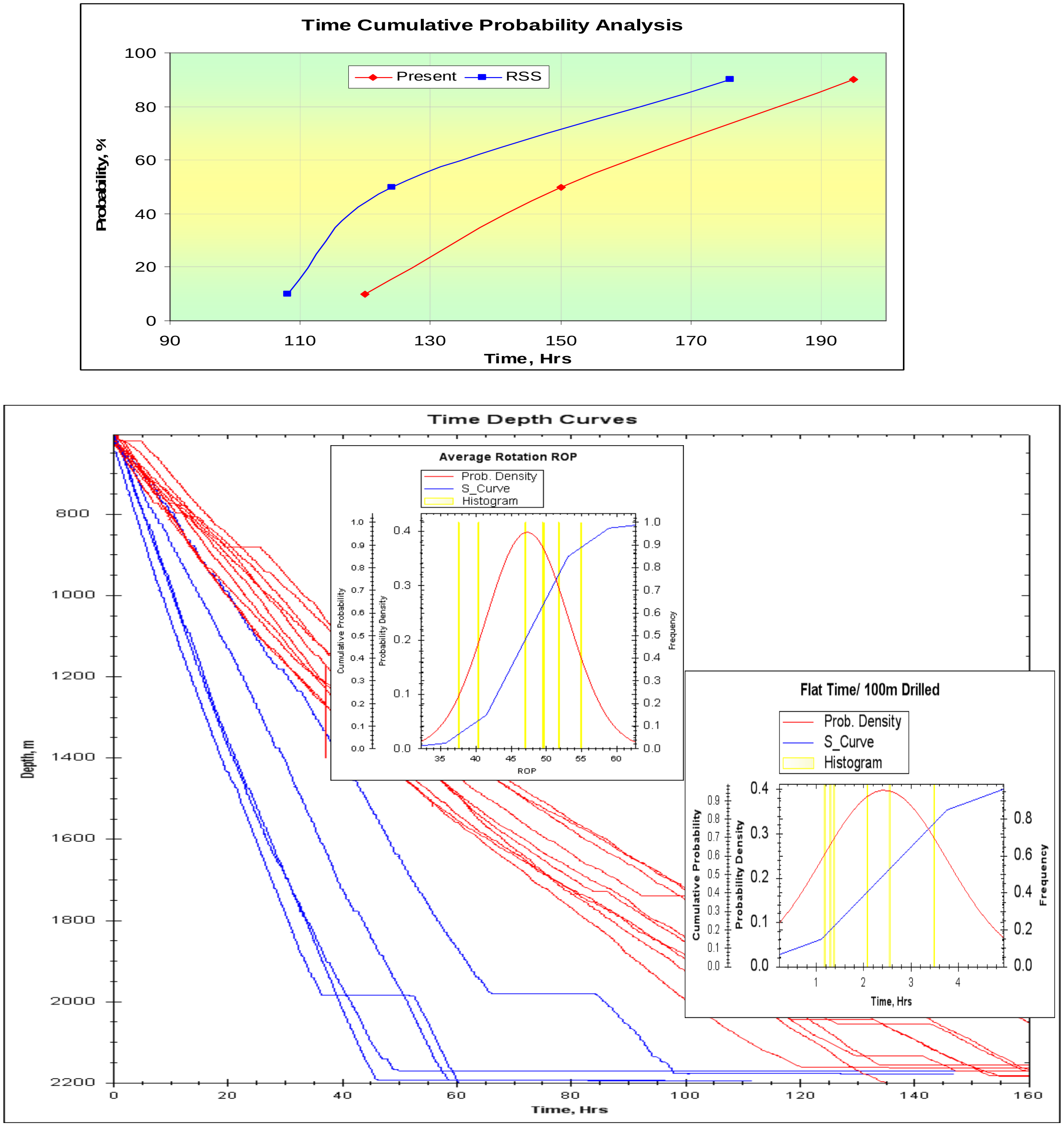
MWD: Measurement while drilling

References
S Hammad Zafar, Schlumberger and Brenda Slaney, PetroCanada Oil and Gas, Screening Tool for Rotary Steerable Candidate Selection, AADE-07-NTCE-50, Houston, April 10-12, 2007



Time In Hole per 100m	7.51	Sliding ROP	14.09
Drilling Time per 100m	5.24	Rotating ROP	21.17
Trip Time	29.93	Slide Distance per 100m	21.79
Connection Time per 100m	0.40	Rotate Distance per 100m	78.21
Survey Time per 100m	0.72	Total Distance	2257.87
Reaming Time per 100m	0.80	Slide Time per 100m	1.55
Flat Time per 100m	2.26	Rotate Time per 100m	3.69

Figure 5: Ferrier project- offset data and KPIs.



Average		
Expected Rot ROP	21	m/hr
Flat Time	2	Hrs/100m
Trip Time	12	Hrs/100m
Interval Length	1650	m/hr
Time for the section	123.5714	Hrs/100m
	5.14881	days
PD Svc Rate	23	K$/day
Lump Sump Price	118.42	$
Best Case		
Expected Rot ROP	25	m/hr
Flat Time	1.8	Hrs/100m
Trip Time	12	Hrs/100m
Interval Length	1650	m/hr
Time for the section	107.7	Hrs/100m
	4.49	days
Worst Case		
Expected Rot ROP	15	m/hr
Flat Time	2.5	Hrs/100m
Trip Time	24	Hrs/100m
Interval Length	1650	m/hr
Time for the section	175.25	Hrs/100m
	7.30	days

Time to drill 200mm Section			
Probaility	90	50	10
Present	195	150	100
RSS	176	124	108

Cost to drill 200mm section			
Probaility	90	50	10
Present	569 K$	438 K$	292 K$
RSS	557 K$	427 K$	388 K$

Figure 6. Ferrier project probabilistic analysis and actual performance.