Design Index provides systematic PDC bit selection

ADVANCES IN DRILL BIT technology have added a seemingly endless array of features to improve bit performance.

There is little standardization between bit designs, so drilling engineers and supervisors are faced with difficult choices when selecting drill bits.

The development of a systematic method of PDC bit selection was outlined in a paper at the IADC World Drilling 2000 conference in June by **Jim O'Hare** and **Osarumwense OA Aigbekaen Jr** of **KCA Drilling Ltd**.

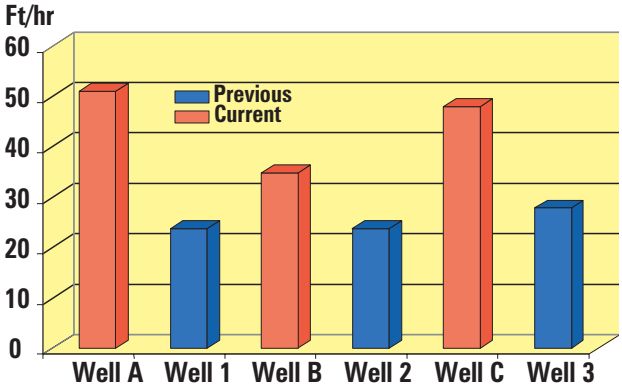
The system is not an "expert system," but a simple methodology that can be readily adapted by engineers to suit their conditions, said the authors.

To use the system, a basic geological model is developed for each hole section. This geological model can be adapted to any area by specifying the main rock types and their percentages in the section to be drilled.

Individual well profiles are specified by the percentages of build, drop and holding tangent, and dogleg severity.

Combining the geological model and well profile enables a set of "ideal" bit characteristics to be generated. This ideal bit design is compared with the drill bits proposed by vendors that are ranked by indices for design, performance and economics.

Figure 1: ROP results using design index



The Design Index takes into account bit characteristics such as the bit profile, number of blades and cutters, cutter size, junk slot area and backrake.

The bit that provides the closest match to the "ideal" design is selected.

The methodology has been geared to fixed cutter PDC bits but is being expanded to include roller cone bits. Although the system was originally developed for extended reach and horizontal wells, it can be applied to any type of well.

The bit selection system has been piloted on several Northern North Sea installations and performance increases have been measured.

HOW THE SYSTEM WORKS

To build a basic geological model, the selection system described by the authors calculates the formation strength which is derived from the porosity, matrix rock sonic travel time, pore fluid sonic travel time, particle grain size factor based on Wentworth's classification of rocks (abrasiveness) and the true vertical depth footage (degree of compaction).

These parameters are all related to the formation.

The value for the formation strength is used to predict a PDC cutter count and cutter size for the section to be drilled.

The other bit design features (blade count, gauge length, junk slot area, profile index, gauge to main cutter ratio and backrake) are built around these parameters.

In summary:

- The number of cutters is derived from the formation strength;
- The cutter size is based on the formation drillability;
- The blade count is based on the number of cutters and the steerability requirements;
- The junk slot area is calculated from the hole cleaning difficulty index;
- The combined profile index is determined from the well profile i.e. % steering, % holding tangent and maximum build and turn required (°/100ft);
- The bit profile is the relation between the depth of the cone and the length of the taper, which characterizes the bit's directional responsiveness;
- The GM ratio is derived from the steerability requirements (% build, turn, drop). It is the ratio of the number of gauge cutters to face cutters, which is a measure of the side cutting action of the bit;
- The backrake angle is also derived from the steerability requirements.

PERFORMANCE

When the vendors' bits have been evaluated and ranked on design they are then evaluated on performance.

The Performance Index compares the offset performance of the proposed bits to the performance of a benchmark bit. The benchmark bit is considered to be the bit with the best performance in the formation or comparable sequence.

The performance parameters taken into account were ROP, footage drilled and dull grading.

These parameters were evaluated taking into account the operating conditions WOB (weight on bit), RPM (rotations per minute) and HSI (hydraulic horsepower per square inch).

According to the authors, the operating conditions were included because the true performance of a bit may not have been realized simply because the operating conditions were different.

This can often be directly related to rig capacity.

The Economic Index evaluates the cost effectiveness of the proposed bits.

A chain of design equations was developed and combined in a spreadsheet to form the Design Index.

STUDY CONCLUSIONS

As a result of this study and dialogues with bit manufacturers, the authors reached the following conclusions.

For rotating assemblies the walk rate (change in azimuth) is most strongly affected by the bit design and the build rate (change in inclination) is most

Figure 2: Profile code guide

Profile Code	Build (Bi)	Hold (Hi)	Walk (left) (Wi)
1	1	9	9
2	4	6	8
3	7	3	7
4	2	8	6
5	5	5	5
6	8	2	4
7	3	7	3
8	6	4	2
9	9	1	1

strongly affected by the bottom hole assembly.

PDC bits which have a long gauge and/or long outer profile (IADC bit profile codes 1, 2 and 3) exhibit a tendency to walk to the left.

As the gauge and profile shortens, the tendency to walk left reduces and may result in right-hand walk with very short profiles and gauges.

Deep coned PDC bits (IADC bit profile types 1, 4, and 7) tend to be directionally stable.

Single cone bits (IADC bit profile types 6 and 9) tend to be directionally isotropic (responsive in any direction).

Spiral gauge pads act to smooth the torque response of a bit, but do not reduce the torque.

Smooth torque response results in reliable tool face settings and improves the hole quality.

The average torque is the same for both spiral and straight gauge pads with the same cutting structure.

The bit's contribution to the average torque value is controlled by the length of the cutting profile, particularly the length of the cutting profile with a radius greater than one half the gauge radius. Bit torque therefore increases with the length of the cutting profile.

The average torque value is lowest with bit profiles tending towards IADC bit profile type 9 and increases with bit profiles tending towards IADC bit profile type 1.

Cutter diameter does not affect torque (at constant ROP).

According to the authors, these guidelines can be used for bit selection based on Profile Codes:

- Select the gauge and profile length to obtain the walk tendencies required by the direction plan in rotary mode or for rotary assemblies. A longer gauge and profile will increase the tendency to walk left;
- Apply deep coned PDC bits (IADC bit profile types 1, 4 and 7) with fully stabilized assemblies to maintain angle and direction in tangent sections;
- Select single (shallow) cone bits (IADC bit profile types 6 and 9) for directional drilling in soft formations with a motor;
- Do not select single cone bits (IADC bit profile types 6 and 9) for pendulum or unstabilized assemblies, as these profiles tend to build angle;
- Select the shortest overall length and a rounded cutting structure for use with a bent housing mud motor;
- Use spiral gage pads for directional motor work;
- Select IADC profile codes 9, 8 or 6 to minimize the average torque value;
- Select cutter size based on formation abrasiveness and strength. as opposed to directional drilling requirements.

Figure 2 shows the respective indices for the IADC profile codes corresponding to these statements.

These indices—Bi, Hi and Wi—are a measure of the bit's tendency to perform these actions. The values range from 1 (least tendency) to 9 (most tendency).

NORTH SEA RESULTS

In one North Sea case study comparing two 8 ½-in. sections, the two sections were drilled in different wells on the same platform. The wells had similar profiles and formation tops.

Both wells were predominantly tangent sections and the formation was readily drillable. Bits with different design specifications were run in each well.

Bit A was initially recommended, based on the success of a previous section drilled on the same platform. The performance of Bit A was used as a benchmark.

Bit B was then chosen using the Design Index methodology. The Design Index method suggested that a more aggressive bit and a deeper cone profile would increase the ROP and improve the bit's ability to hold tangent.

Bit B was chosen over Bit A, which had been the best run on that section to date.

The run with Bit B showed an increase of approximately 10% in average ROP and 6% less steering than planned was required as the bit held tangent better.

The design table for Bit A and Bit B is shown in Figure 3.

Figure 3: North Sea results

Features	Bit A	Bit B
Size	13	13
Cutter count	58	47
Blade count	8	7
Gauge length	3	3
Junk slot area	8.2	10.4
Profile code	6	5
Gauge/main cutter ratio	0.41	0.57
Backrake	19	22

In another case, two successive 12 $^{1}/_{4}$-in. sections drilled from another North Sea platform were compared. These wells had similar profiles and formation tops.

The Design Index methodology was used to select the bit for the second well.

The bit selected using the system more than doubled the average ROP and reduced the cost/ft by approximately 50%.

CONCLUSIONS

The Design Index provides engineers a way to classify and select bits, and an objective method of comparing their performance.

This systematic approach increases the focus on bit selection and drilling performance, and proposes bit attributes to suit individual well conditions.

The system has demonstrated that significant performance and cost benefits can be obtained over "best runs to date".

In addition, the Design Index methodology can be used to further improve bit designs.