PDC Drill Bit Running Procedures Guideline for Field Engineers

Introduction

While drilling a well, crucial decisions are made on the basis of what is believed to be happening down hole. There are a large number of factors that can effect drilling performance from the drilling rig itself and associated surface equipment to the down hole equipment; from run parameters and formation type to their consequential effect on drillstring dynamics and bit life. It is the purpose of this document to improve the understanding of the entire drilling system and provide guidelines so that the pertinent factors effecting drilling performance can be identified and managed. With better identification and understanding of drilling problems informed decisions can be made to improve drilling performance and significantly reduce the drilling costs for our customers, the operator.

These guidelines cover aspects of running a drill bit from arriving at the rig site through to recommending drilling parameters, run recording and reporting. The guidelines can be used as part of the Drilling Optimization Process, the Plan, Execute & Evaluate Cycle to ensure a quality service is provided to the client.

Whilst in the position of Drilling Optimization Specialist for BP, Martyn Fear developed two formalized drill-off test procedures for optimizing drilling parameters for maximum performance.

Other reference material utilized was a Drillstring Vibration Primer written by Fereidoun Abbassian also of BP.

Evaluate the rig and surface equipment to become familiar with the maximum and minimum parameter variables that are available. An understanding of the limitations of the equipment can help in developing a realistic and practical solution to a drilling problem.

Solids Control Equipment

Poor solids control equipment can cause the following problems-

- Ineffective or too few shakers can limit the speed at which cuttings can be removed from the mud system. If this is the case penetration rate may need to be limited.
- If the solids are not removed from the mud effectively the mud can become very erosive. Erosive mud can reduce bit and downhole tool life resulting in shorter run lengths.
- If the solids content becomes too high this can reduce the effectiveness of the mud, eg shale inhibition with water based mud systems.

Evaluate the following equipment-

- Shale shaker specification
    a. o Number
    b. o Type
    c. o Screen/mesh size
- Centrifuge equipment

Mud Pumps

Mud pumps drive the mud around the drilling system. Depending on liner size availability they can be set up to provide high pressure and low flow rate, or low pressure and high flow rate. Analysis of the application and running the Drill Bits hydraulics program will indicate which liners to recommend. Finding the specification of the mud pumps allows flow rate to be calculated from pump stroke rate, SPM. Information required-

a. o Pump manufacturer
b. o Number of pumps
c. o Liner size and gallons per revolution

Mud Condition

Drilling mud has two fundamental functions. The primary function is to keep the well bore in good condition by managing the formations, eg: balancing pore pressure, inhibiting shale reaction, etc. The secondary function is to aid the drilling process, eg: transporting cuttings to surface, cleaning and cooling the drilling bit, etc. For maximum drilling performance the mud system must be maintained in good condition. Minimum information required-

a. o Type (OBM, WBM, POBM, Silicate, etc)
b. o Weight
c. o Solids content
d. o PV/YP

Lost Circulation Material

Lost circulation material is frequently required to plug fractures in the well bore. If these fractures are not plugged a significant volume of mud can be lost to the formation. Mud is expensive and losses must be minimized. Lost circulation material comes in various sizes and types, eg: nut plug, cottonseed hulls, cellophane, etc. LCM as well as plugging holes in the well bore can plug nozzles in a drill bit. If determined that lost circulation material will be required, ensure that the size and type is known so that drill bit nozzles can be selected that will allow LCM to pass through with a minimal risk of plugging.

Surface Parameter Gauges

Surface parameter gauges are the primary tools for evaluating and setting drilling parameters. Consequently it is critical that all gauges are operational and calibrated. The following gauges and recording instruments need to be checked-

a. o Standpipe pressure

b. o RPM
c. o WoB
d. o Torque
e. o Geolograph (depth measurement)
f. o Rig Floor Parameter Display/Monitor
g. o SPM

Bottom Hole Assembly Evaluation

The bottom hole assembly directly effects drilling performance. The addition of a down hole drive mechanism (motor or turbine) can significantly increase penetration rate while the addition of stabilizers can effect the dropping, building or turning tendencies of the drillstring. A rotary steerable system can provide improved directional control compared to that of a motor in some applications, eg: extended reach wells, applications where differential sticking of the BHA is problematic, etc.

Useful information is-

- Turbine specification.
  a. o Revolutions per unit volume pumped for RPM calculation, (due to the mechanical operation of a turbine the calculated rpm is theoretical and is not necessarily actual rpm)
- Motor specification.
  a. o Performance charts
  b. o Lobe configuration for motor type, eg: high torque/low speed
  c. o Revolutions per unit volume mud pumped for rpm calculation
- Stabilizer details can affect both directional tendencies and transmitting weight to the bit, eg: stabilizers hanging up. Details required are-
  a. o Size
  b. o Position in the drillstring (including motor stabilizers)
- MWD/LWD details. Find out the specifications for these tools and what data each is collecting. It is easier to ask/get the data if it is known that it is being collected. Down hole data is better than surface data for problem identification, monitoring and curing, eg: down hole vibration data. Useful downhole data is-

a. o RPM
b. o Torque, (average, maximum and minimum)
c. o WoB
d. o Pressure
e. o Vibration

Preceding Bit Run Evaluation

Find out the details of the preceding bit run. What factors improved/reduced drilling performance and can the lessons learnt be utilized in the planned run?

- Find out the condition of the preceding bit when it went in hole, ie: new bit, rerun, re-tipped, etc.
- Be on the rig floor to witness the preceding bit and BHA being pulled through the rotary table. This is the only way of ensuring maximum information is collected on the dull condition of the bit and the BHA, ie: sometimes bit/BHA balling is removed and not recorded.
- Collect the run details, dull grade the bit and take photos as outlined in the Dull Grading and Dull Bit Photos section. If a detailed run report is required this information may be critical.
- If it is planned to run a PDC bit and the preceding bit is pulled out of hole with severe damage; lost cutters or cones; or severely under gauge, the hole should be conditioned with a roller cone bit and a junk basket. (PDC bits are generally not recommended for long intervals of reaming or cleaning out junk).

Drill Bit TFA (Total Flow Area) Calculation

System hydraulics can greatly affect drilling performance, eg: HSI and cuttings removal for high RoP, cutter cooling for drill bit life, etc. It is important that both the nozzle and pump liner size are selected to optimize the hydraulics for that application. The limiting factor may be available rig power. The drilling rig motor that drives the mud pumps, combined with the pump liners sets the maximum stand pipe pressure and flow rate available.

- Flow is the critical medium that cleans, cools and lubricates the cutting structure and bit, (critical for unsealed roller cone bits). In some applications, drilling with minimal flow rate will cause rapid degradation of the drill bit cutting structure.
- HSI is a primary factor for maximizing RoP. HSI is the energy at the bit that transports the cuttings from the bit face into the annulus.
- Flow rate is another important factor. High flow rate helps lift the cuttings to surface.
- Turbulent flow is generally achieved around the drill bit.
- Laminar flow is generally preferred around the drill string to prevent hole damage.
- The DDI Hydraulics program should be run to optimize the hydraulics for either maximum HSI or maximum flow rate depending on the application requirement.
- If there is the possibility of pumping lost circulation material, small jet sizes should not be run as the risk of plugging them is high. As a general rule, nozzle sizes under 12/32nds should not be run.
- Calculation of expected pressure change if one of the nozzles becomes plugged or is lost.

Preparing the Bit to be Run in Hole

These are final checks to ensure that the correct bit with the correct nozzle sizes is run hole and recorded accordingly.

- Record bit type, size and serial number.
- Ensure there is no debris inside the central feed bore and the individual feed bores that could potentially plug a nozzle.
- Ensure the bit is jetted with the correct size nozzles as indicated by the Drill Bits TFA calculation.
- If either damaged in transit, a rerun or a repaired bit.
    a. o Record bit condition/dull grade
    b. o Photograph the bit as outlined in the Dull Bit Photos section. Take extra shots of damaged/worn area as necessary.
- If a motor is to be tested in the casing recommend using a dull bit rather than the bit required to drill the section. This eliminates the risk of damaging the bit planned for the section in the casing.

Making Up the Bit to the Drillstring

Ensure that the bit is not manhandled on the rig floor and if it is damaged record the incident and damage appropriately. If there is severe damage it may be necessary to recommend that a different bit be run in hole.

- Witness the bit and BHA get made up to the string and run through the rotary table.
- Ensure the bit is handled correctly on the rig floor and not damaged, eg: never place a PDC bit cutting structure directly on the steel decking of a rig floor as this risk damaging cutters, ideally use a wooden or rubber mat.
- Clean and grease API pin/box connection of both bit and drill string.
- Using the DDI bit breaker, locate bit in rotary table.
- Lower drill string onto the bit and engage threads.
- Either make up by hand or slow rotation.
    - Torque up connection to the specified torque for that API connection, (this can be found on the Product Report that accompanies the bit in the bit box).

Running in Hole

When tripping there is little that a Field Engineer can influence. The rig crew will try and trip in hole as fast as possible to return to drilling. It is worth noting the following points and communicating them to the oil company representative and the driller.

- Take care running through diverters, BOPs, well heads, casing shoes, etc.
- Approach tight spots slowly as striking ledges can damage the bit cutting structure.
- When reaming tight spots pump at maximum flow rate, rotate the string with low rotary speed (50-60rpm approx) and low weight on bit, (no more than 4,000lbs). In a tight spot the weight is only supported by the cutting structure towards gauge resulting in higher weights on individual cutters, insets or teeth than is normally the case. Hence, to prevent cutting structure damage low weight should be recommended.
- On the final stand/kelly wash the hole at full flow to bottom and rotate the string at low rotary speed to prevent plugging a nozzle or balling the bit with cuttings, carvings, etc that may have collected in the bottom of the hole.
- Watch for an increase in torque and weight when approaching bottom to identify when the bottom of the hole has been tagged.
- Lift off bottom 6-12” at maximum flow while rotating the bit for 5 minutes approx to clean the bottom of the hole.

Drilling Out the Wiper Plugs, Cement, Shoe and Float Assemblies

Different types of drill bits and bottom hole assemblies have different drill out procedures. When designing a drill out float assembly for PDC applications, 'PDC friendly' equipment will ensure a successful run (ie: more plastic and rubber components make for an easier drill out). Liner running tools and float equipment that require an activating ball to set or close the liner hanger or float valve can cause problems during drill out. These balls (typically made of brass) can damage the bit resulting in slower penetration rates and failure to complete the desired interval. Aluminum landing collars can also be problematic. Aluminum in the dart, landing collar, float collar and float shoe can plug the junk slots of the bit impairing bit cleaning/cooling and hence bit performance.

PDC (including Steering Wheel and BiCentrix), Impregnated and Diamond Drill Bits

- Natural diamond impregnated and surface set diamond drill bits will take 25-50% longer than PDC drill bits to drill out casing shoe assemblies.
- Ensure there is no metal or junk in the hole.
- Do not use Automatic Driller.
- Wash and ream to bottom with maximum flow rate at least 30' above where the cement is expected.
- Use 50-60rpm with a rotary assembly and 20-40rpm with a motor assembly.
- Tag bottom slowly with 4,000lbs maximum weight on bit and look out for green/wet cement.
- If the bit does not drill off, reciprocate the drill pipe. Do not stay on bottom if bit is not drilling.
- Use as little weight as possible, do not exceed maximum recommended weight on bit.
- If the wiper plugs begin to rotate, it may be necessary to tag bottom without rotation and increase weight on bit slowly. Do not spud the bit into the float equipment. Once sufficient weight on bit (start with 6-8klbs and increase as necessary) is applied, slowly increase rotary to 60-80rpm. Repeat as necessary to drill through the remainder of the plugs.
- Monitor penetration rates and adjust weight on bit as necessary.
- In difficult drill out applications allow the weight to reduce/drill off naturally and evaluate penetration rate. Repeat this process until a more consistent drilling pattern is established.
- Raise the bit 2 feet off bottom and circulate once the plugs are drilled and midway through drilling the float collar assembly, (repeat as often as dictated by Hole conditions/bit performance).

- Reducing or stopping the flow rate may cause the bit junk slots to pack-off. Use extreme caution when reducing flow rates during drill out.
- On semi-submersible and drill ships where the rig may heave, use the compensator to prevent spudding the bit. Rig heave can complicate a successful drill out and can cause bit balling.

Roller Cone Drill Bits, (Insert and Milled Tooth)

- Wash and ream to bottom with maximum flow rate at least 30' above where the cement is expected.
- Use 50-60rpm with a rotary assembly and 20-40rpm with a motor assembly, (ensure correct motor has been selected as very high speeds do not suit some roller cone bits).
- Do not use Automatic Driller.
- Tag bottom slowly with 4,000lbs maximum weight on bit and look out for green/wet cement.
- If the bit does not drill off, reciprocate the drill pipe. Do not stay on bottom if bit is not drilling.
- Use as little weight as possible increasing to 10,000lbs if required, do not exceed maximum recommended weight on bit.
- If the wiper plugs begin to rotate, it may be necessary to tag bottom without rotation and increase weight on bit slowly. Do not spud the bit into the float equipment. Once sufficient weight on bit (start with 68,000lbs and increase as necessary) is applied, slowly increase rotary to 90-100rpm. Repeat as necessary to drill through the remainder of the plugs.
- Monitor penetration rates and adjust weight on bit as necessary.
- In difficult drill out applications allow the weight to reduce/drill off naturally and evaluate penetration rate. Repeat this process until a more consistent drilling pattern is established.
- Raise the bit 2 feet off bottom and circulate once the plugs are drilled and midway through drilling the float collar assembly, (repeat as often as dictated by Hole conditions/bit performance).
- Reducing or stopping the flow rate may cause the bit cutters to pack-off. Use extreme caution when reducing flow rates during drill out.
- On semi-submersible and drill ships where the rig may heave, use the compensator to prevent spudding the bit. Rig heave can complicate a successful drill out and can cause bit balling.

Bedding/Breaking the Bit In

- Approach bottom with maximum flow rate.
- Slowly set the bit on the hole bottom with no more than 4,000lbs weight and 40-60rpm to establish the bottom hole pattern.
- Extra care should be taken following a coring run due to the possible ‘stump’ left on the bottom of the hole.
- If the bit does not drill ahead increase weight until it does.
- Maintain as low weight as possible until the bit has drilled at least its own length. Until the bit has cut its own bottom hole pattern only some of the cutters will be in contact with formation so if weight is added too quickly, particularly in hard formations, these cutters may be overloaded and fail.
- Increase weight on bit to target weight on bit, (do not exceed recommended maximum for the bit). As a general rule, the optimum weight for a PDC is less than half that for a roller cone bit.
- Increase rotary speed up to target RPM.

Making Connections and Restarting Drilling

- Maintain full flow as bit is raised off bottom.
- Return to bottom with 50% of the target drilling rotary speed and full flow rate to wash and clean the hole.
- Return to bottom gently. Dropping the string too rapidly can cause the bit to tag bottom violently and damage the cutting structure.
- Increase weight on bit to target weight on bit taking care to avoid stick-slip or other detrimental vibrations.
- Increase RPM to target RPM.

General Drilling Parameters for 'Clean' Formations

Clean formation refers to a homogenous formation that is not interbedded and is 100% one lithology type. These types of formations are rare as some shales for example include a certain sand and limestone content. However, selecting parameters that suit the primary lithology will generally optimize drilling performance.

- Soft clean shales
    a. o Increasing rotary speed generally improves penetration rate, (usually RPM has a greater effect on RoP than WoB).
    b. o There is minimal risk of damaging the cutting structure in this lithology.
- Hard clean chalk/limestones
    a. o Penetration rate is maximized by increasing cutter point loading to fracture the formation. High weight is recommended with low rotary speed to allow the cutters to bite into the formation.
    b. o Bits may suffer impact damage. If the formation is clean (ie: no sand content) the cutters should suffer minimal abrasive wear.
- Hard sandstones
    a. o Penetration rate is maximized by increasing cutter point loading so high weight is recommended.
    b. o To ensure the cutters can get a bite, low rotary speeds are preferred.
    c. o Bits may suffer both impact damage and abrasive wear. Low RPMs will reduce abrasive wear.
    d. o Low rotary speeds will also reduce penetration rate so a reasonable compromise must be reached.

Drilled Cuttings Analysis

Regularly collect and analyze the cuttings coming over the shakers to confirm the formation lithology being drilled. It must be remembered that cuttings coming over the shakers take time to reach surface. This time can be calculated and the cuttings related to their drilled depth and those drilling parameters. Reviewing the cuttings shape and size can indicate drilling efficiency, ie: rock flower is very inefficient.

Torque

- Rotary torque is an indicator of what is happening at the drill bit. For example-
    a. o PDC high torque -the bit is likely to be digging or if there is low RoP the torque could be being generated from the BHA and not the bit.
    b. o PDC low torque -the bit could be skidding in a hard formation, the cutting structure could be dull or the bit could be balled up.
    c. o Roller cone medium torque -the bit is likely to be digging.
    d. o Roller cone high torque -the bit could have locked cones, if this is the case the torque will reduce as the inserts/teeth wear down.
    e. o Roller cone low torque -the cutting structure could be dull or balled up.
- In soft formations torque may indicate the bit is on bottom before the weight on bit gauge does. In such formations the torque gauge may be the best surface measurement by which to drill.
- The torque could be considered to be too high when it starts to slow down surface rotary speed.
- The torque is too high when it stalls the motor, rotary table or the top-drive.
- Homogenous formations should produce a smooth constant torque signal.
- Interbedded formations will produce torque changes as the bit and/or the BHA moves in and out of formation beds that have different rock strength and 'drillability'.
- If downhole torque measurements are available they can be used in combination with surface measurements to gain a more accurate representation of what is happening in the well bore.

Weight

- As a drill bit cutting structure wears more weight will be required to achieve the same RoP in a homogenous formation.
- PDC wear flats, worn inserts and worn milled tooth teeth will make the bit drill less efficiently.
- Increase weight in increments of 2,000lbs approx.

- In general, weight should be applied before excessive rotary speed so that the cutting structure maintains a significant depth of cut to stabilize the bit and prevent whirl.
- If downhole weight measurements are available they can be used in combination with surface measurements to gain a more accurate representation of what is happening in the well bore.

Rotary Speed

- Total bit rotary speed is equal to the surface rotary speed plus the down hole motor/turbine rotary speed.
- Rotary speed is not limited when running PDC drill bits.
- High rotary speed should be avoided in abrasive formations to prevent rapid abrasive wear.
- High rotary speed should be avoided if the drill bit starts to whirl.
- Rotary speed may be limited due to drill pipe or drive limitations.
- Some rotary speeds can initiate drill string resonance (high levels of vibration) and should be avoided. Either increase or decrease RPM to avoid operating in drill string harmonic frequencies.
- High rotary speeds in hard formations may reduce RoP as the cutters are unable to 'dig in'.
- The rotary speed that maximizes RoP without causing other drilling problems is likely to be the 'right' one.

Flow Rate

- Flow rate greatly effects hole cleaning. Generally high flow rates provide better hole cleaning than low flow rates as they are better able to return cuttings to surface due to increased annular velocity.
- Flow rate greatly effects bit cleaning. Generally high flow rates provide better bit cleaning than low flow rates by increasing hydraulic energy at the bit.
- If a motor is in the hole increasing flow rate will increase the rotary speed developed by the motor. of Increasing motor speed must be considered carefully as it can greatly affect drilling performance-
    - In clean shale increasing motor speed increases bit speed that will generally increase penetration rate without damaging the bit cutting structure or other downside.
    - In hard abrasive sandstone increasing motor speed increases bit speed that will generally increase penetration rate momentarily. However the higher rotary speeds will tend to increase the wear rate of the bit cutting structure that will reduce penetration rate and ultimately bit life.

  - Increasing motor and consequently bit speed can change the directional tendency of the bottom hole assembly with a bigger effect on building/dropping tendency than azimuth. The compromise between instantaneous penetration rate and sliding corrections must be considered.
- High flow rates can cause formation damage especially in highly fractured formations so excessive flow rates must be avoided.

Simple Drill-Off Test Procedure

The following simple drill off test has been used since drilling started. It is simple to conduct, has little or no impact on rig time and the results are immediately apparent. All that is needed is a watch with a second hand, a tally book and a pen. Basically, at three different rotary speeds weight is applied to a given level and the brake chained down. The weight is then allowed to drill off.

- Talk to the driller to describe and explain the series of tests to be performed.
- Select three rotary speeds to be tested, eg: 80, 120 and 160.
- Apply the lower rotary speed and increase the weight to the maximum recommended in the bit operating notes.
- If the formation is known to be soft a lower weight should be selected to avoid bit balling.
- If the maximum weight is not achieved before high torque levels or vibration occur then select a lower weight.
- Chain the brake down and allow the weight to drill off.
- Note down the weight on bit that the brake was locked and list below weights in decreasing value, eg: 2klbs.
- Note down the time taken to drill off a weight interval as listed. The least time taken in seconds to drill off indicates the weight that will give the highest penetration rate at that rotary speed.
- Test the other two rotary speeds in the same way.
- Attention should be made to any vibrations experienced throughout the tests, see InSight. Check with time based MWD shock data to see if unstable drilling conditions existed at any particular weight and rotary speed combination.
- Select on the basis of the drill-off tests and shock data the optimum combination of weight and rotary speed.
- Frequently increasing weight will increase penetration rate, however if vibration occurs (axial, whirl or torsional) drilling efficiency is poor resulting in lower penetration rate. When this occurs higher penetration rate can frequently be achieved by reducing the weight to minimize the inefficient vibrations.

Summary

Drill-off tests are essential to identify which factors are limiting ROP on a particular bit run, and the levels of WOB and RPM that will give best ROP for the constraints acting during that bit run.

This section describes how to perform a drill-off test, and how to treat the resultant mud logging data to yield clear drilling parameter relationships to ROP, so that the best WOB and RPM can easily be chosen.

There are two types of drilling test available to relate WOB and RPM to ROP :

1. A "drill-off" test, where the WOB is built to a selected level, the brake locked, and the bit allowed to drill-off as the string extends under its own weight. RPM and flow rate are held constant as the bit drills off, and the drill off is then repeated at different rotary speeds. ROP is calculated from the rate of WOB decay as the bit drills off, and plotted versus WOB for each RPM
2. A "drillability" test, where pairs of WOB and RPM are chosen, and a certain depth increment drilled at each pair. Average values of WOB, RPM and ROP are then taken for each interval, and crossplots of ROP versus WOB created, again for each RPM.

The first type of test is generally preferred, because a range of WOB and ROP data is gathered while the bit drills off over only a very small interval. Thus the results are less likely to be affected by formation changes. The second type of test is however useful when prevailing ROP is very high, because insufficient (time-based) data can be gathered if the bit drills-off rapidly at high WOB during the drill-off type of test. The second type of test guarantees acquisition of a minimum amount of (foot-based) data irrespective of ROP.

Both types of test may be limited as to the maximum applicable weight on bit, either by motor stalling when a motor is in use, by weight below the jars, or by torque cycling if the soft torque system is not perfectly in tune. In addition, varying surface RPM when a motor is in use may be of little value, since small changes in surface speed make little difference to bit speed with a motor in use. Motor speed will probably need to be constant since a flow rate stipulation will be in effect for hole cleaning.

Both types of test have been run in BPXC wells since 1993, and have proven useful and relatively easy to perform. The most laborious step involves treating the mud logging data to reduce the contribution of errors in the ROP measurement. To aid this, BP's methods have been built into drill-off test software which is currently being installed onto Exlog and Geoservices mud logging systems. Since this software is as yet incomplete and not validated, a more generalized method for drilling tests is described next, where data is treated using conventional spreadsheet packages.

Optimising Drilling Performance

Optimizing drilling performance is frequently interpreted as maximizing penetration rate. However, this is not always the case as in some applications drilling performance will be optimized by maximizing run length and reducing the number of trips. In these applications, an example of which is interbedded formations, the goal is to protect the cutting structure so it may be necessary to compromise penetration rate for run length.

A diligent driller that performs frequent drill off tests for drilling parameter optimization will always drill further and faster than the driller who “sets and forgets”. Parameter optimization can significantly reduce cost per foot. Points to note are-

- Be on the rig floor at all crew changes. This is critical to ensure optimum drilling parameters are maintained, to update the new driller of the current drilling/rig issues and of any drilling parameter testing in progress.
- If running a motor, try setting the automatic driller to run off motor differential pressure rather than weight on bit. This generally corrects the weight faster, consequently the weight will be applied more consistently and better performance achieved.
- Conduct a series of drill-off tests at various weights (eg: 2-5,000lbs increments), rotary speeds (eg:5-10rpm increments) and flow rate (to change down hole RPM if a motor is in the hole although care is required as flow rate changes will also effect bit HSI and hole cleaning) to find the optimum drilling parameters to achieve satisfactory penetration rate or to minimize bit/BHA damage.
- Formation changes can result in a penetration rate change, eg: if the RoP reduces and reasonable torque is still generated the formation is likely to be harder so the rotary speed should be reduced and weight increased. If this generates too much torque, weight should be reduced and rpm increased.

- Monitor mud weight. As mud weight increases, RoP generally decreases. When closer to balanced drilling (where the mud pressure equals the formation pore pressure) RoP generally increases.
- Maintaining good notes is very important for optimizing drilling performance over an entire run. It also aids understanding/problem solving if the drilling becomes problematic. If this is completed in a spreadsheet down hole rpm, etc can easily be calculated and plotted to watch for trends, see Figure 1.
- Parameter readings are more accurate if read directly from the gauges (Martin Decker for WoB, the stand pipe gauge for pressure, etc) than those displayed on the rig floor monitor or geolograph. The rig floor monitor and the geologragh can be inaccurate unless they are frequently recalibrated as hole is drilled.

Date	Time	Rotary /Slide	Depth (ft)	RoP (fph)	WoB (klbs)	RPM Surface	RPM Motor	RPM Total	Torque On Bottom	Torque Off-Bottom	Pump 1 Strokes per Minute	Liner Size	Gallons per Stroke	Flow (gpm)	Pump 2 Strokes per Minute	Liner Size	Gallons per Stroke	Flow (gpm)	Total Flow (gpm)	Stand Pipe Pressure (psi)	Comments

Figure 1: Spreadsheet for recording and calculating drilling parameters.

<u>Drill-off Test Method 1 – Locked Brake Test</u>

<u>Planning and supervising the test</u>

1. Choose the WOB to drill off from/to. Choose upper limit noting torque cycling, motor stalling, weight below jars, and bit limit (from catalogue). Drill-off over as wide a range as possible within these constraints.
2. Choose the three rotary speeds to be applied (if a rotary BHA). Choose as wide a range as possible, e.g. 80, 140 & 200 RPM (a lower maximum may be applicable with a tricone bit).
3. Notify the mud logging unit that a test is to be performed.
4. Ensure that the WOB is simultaneously zeroed by the driller and the mud logging unit immediately before the test. Note the reference hookload (string weight) values (from the mud logging display <u>and</u> the Martin Decker gauge), while rotating off bottom at the same RPM and SPM as will be used during the drill-off test.
5. With the middle RPM value, build the WOB up to the desired maximum, lock the brake, and allow the bit to drill-off at constant RPM/SPM. Lower the desired maximum WOB and restart the test if torque cycling is severe.

6. Repeat step 5 with the highest and lowest RPM, and lastly with the middle RPM (this last repeat drill-off will give some idea if the formation remained constant, and if the data quality is good).
7. Return to normal drilling. Instruct the mud loggers to process the drill-off test data.

Processing of the data by the mud loggers

During the test, the logging system should run a time database and chart recorder, gathering the following data at an interval not longer than every 30 seconds: time, block height, hook load, instantaneous WOB, RPM, average torque, sigma torque, flow rate in, pump pressure. These data will be used for the computations described here.

• Calculate a value for the axial stiffness (compliance) of the drill pipe (ignore the HWDP and drill collars). The formula is :

C = L/E (Fdp1/Adp1 + Fdp2/Adp2), in which

C = compliance (m/kn)

L = total length of drill pipe (m). Exclude HWDP and drill collars

E = young's modulus for steel (gpa)

Fdp1,2 = fraction of drill pipe length for pipe of size 1 and 2 (e.g. 5" and 6.5/8" pipe)

Adp1,2 = cross-sectional area of pipe of size 1 and 2, (e.g. 5" and 6.5/8" pipe) (sq.mm).

Example values are :

E = 206 gpa for drillpipe

Adp = 5354 sq.mm for 6.5/8" drillpipe (average of body and tooljoint)

Adp = 4153 sq.mm for 5" drillpipe (average of body and tooljoint)

Fdp1 = 1 if the drillpipe is all of 1 size

Fdp1 = 0.4 if 40% of the drillpipe length is of 1 size, with 0.6 (60%) of the other size.

Note that to convert C to ft/klb, multiply C (m/kn) by 14.5939.

- From the acquired chart or time database data, identify the start and end of each drill-off interval
- From each drill-off interval, read the following data into a spreadsheet : time, hookload, instantaneous WOB, pump pressure (the latter if a motor BHA only).
- Within the spreadsheet, perform the following calculations for each line of data :

Delta time = time spacing between data points (secs)

Depth change = C * (Inst. WOB - previous inst. WOB) (feet)

ROP = Depth change * 3600/delta time (ft/hr)

Avg. WOB = (Inst. WOB + previous inst. WOB / 2) (klbs)

- Crossplot average WOB (x axis) versus ROP (y axis), for each RPM. Label or code each curve for the RPM value.
- If the plot is noisy (e.g. attachment 11), repeat the calculations by selecting only intermittent data points, i.e. by expanding delta time (all four of the above calculations must be repeated).
- Repeat the last step with longer time increments until clear ROP/WOB relationships appear. Avoid using excessively long time increments, since the character of the ROP/WOB relationship will be suppressed. A delta time of 1-4 mins will normally suffice; use the lowest that gives a clear plot.
- Deliver the crossplot to the Drilling Representative or Assistant.

An example of the spreadsheet calculations is shown on the attachment (note that on the attachment example, WOB was calculated from the difference between reference hookload and instantaneous hookload, because the raw WOB data was unreliable. Note also how two separate sets of ROP and AVG. WOB were computed using different delta times).

Interpreting the test results

Review the ROP/WOB crossplot. Use the examples on attachments to aid identification of excessive drag or bit dulling. Choose the optimum WOB and RPM noting any excess torque cycling at high WOB/low RPM, and any WOB/RPM constraints for required BHA directional behavior. If possible, choose the lowest WOB and RPM that gives maximum ROP (if additional loads are applied without any extra ROP, this will only shorten bit life).

Note that when informing the driller of the chosen optimum WOB, the value from the crossplot will be the mud loggers' value of WOB. Any discrepancy with the Martin Decker WOB will need to be rectified before the driller is given an optimum WOB.

Drill-off Test Method 2 – Drillability Test

Planning and supervising the test

1. Choose the three or four WOB values to use during the drillability test. Choose the highest WOB noting torque cycling, motor stalling, weight below jars, and bit limit (from catalogue).
2. Choose the three rotary speeds to be applied at each WOB (if a rotary BHA). Choose as wide a range as possible, e.g. 80, 140 & 200 RPM (a lower maximum may be applicable with a tricone bit).
3. Notify the mud logging unit that a test is to be performed.
4. Start the test early enough in the drilling of a stand so that making a connection will not be necessary before the test is completed.
5. Ensure that the WOB is simultaneously zeroed by the driller and the mud logging unit immediately before the test. Note the two reference hookload (string weight) values (from the mud logging display and the Martin Decker gauge), while rotating off bottom at the same RPM and SPM as will be used during the drilling test.
6. With the first WOB value, drill 5 ft with each of the three RPM's. Abort the test at highest WOB if torque cycling is severe, and restart with lower WOB. Ensure the driller works to maintain as constant WOB as possible.
7. Repeat step 6 with the other WOB values.
8. Return to normal drilling. Instruct the mud loggers to process the drill-off test data.

Processing of the data by the mud loggers

During the test, the logging system should run a time database and chart recorder, gathering the following data at an interval not longer than every 30 seconds: time, block height, hookload, instantaneous WOB, RPM, average torque, sigma torque, flow rate in, pump pressure. These data will be used for the computations described here. If any problems exist with these data, conventional depth database data can be used.

- From the time database or chart recorder data (former is preferred), identify the start and end of each period of constant WOB and RPM
- Calculate an accurate average of WOB and RPM for each period when these parameters were held constant
- For each period of constant WOB and RPM, calculate an average ROP from the change in block height, and the duration of the period.
- Repeat the calculations for each period of constant WOB and RPM.
- Crossplot average ROP (y axis) versus average WOB (x axis), for each RPM.
- Deliver the crossplot to the drilling Representative or Assistant.

An example of part of a time database data set from this type of drilling test is shown. The final ROP/WOB crossplot is shown. Two RPM's were used at each WOB in this case.

Interpreting the test results

Review the ROP/WOB crossplot. Use the examples to aid identification of excessive drag or bit dulling. Choose the optimum WOB and RPM noting any excess torque cycling at high WOB/low RPM, and any WOB/RPM constraints for required BHA directional behavior. If possible, choose the lowest WOB and RPM that gives maximum ROP (if additional loads are applied without any extra ROP, this will only shorten bit life).

Note that when informing the driller of the chosen optimum WOB, the value from the crossplot will be the mud loggers' value of WOB. Any discrepancy with the Martin Decker WOB will need to be rectified before the driller is given an optimum WOB.

General

- Drillstring vibration is inevitable.
- Low levels of vibration can be harmless.
  - Severe downhole vibrations can be problematic and can cause the following-
    a. o Drillstring failure, washout/twist off
    b. o Premature bit failure
    c. o Poor directional control
    d. o Damage to well bore, hole enlargement
    e. o Rotary drive stalls, top drive/rotary table
    f. o Motor stalls
    g. o Motor failure, bearings/stator
    h. o MWD failure
    i. o Stabilizer/tool joint wear
    j. o Reduced penetration rate
  - Primary drillstring excitation forces are-
    a. o Bit/formation interaction
    b. o BHA/borehole interaction
    c. o Downhole motor/turbine
    d. o Rotary drive type
- The response of the drillstring to excitation forces is complex.
- The complexity of vibration is due to the physical coupling between the bit and the drillstring and the coupling of vibration mechanisms.
- Identify if the rig is equipped with a rotary feedback system ("soft torque") and whether it is activated.

Types of Vibration

  - There are three types of vibration-

a. o Axial, motion along the drillstring axis.
b. o Whirl, eccentric rotation of a component about a point other than its geometric centre that can generally be recognized/seen as lateral vibration (side to side motion). This can relate to both the bit and the bottom hole assembly.
c. o Torsional, motion causing twist/torque/stick-slip.

- These types of vibration can co-exist and produce symptoms that belong to more than one vibration mechanism. This can make the detection process iterative for identification and cure.

Drillstring Resonance

- Drillstrings have their own natural frequencies for vibration relating to rotary speed.
- Excitation frequencies close to the natural frequency of the drillstring will cause the drillstring to resonate, (vibrate laterally and/or torsionally).
- A resonating drillstring can be highly damaging to bit/BHA components.
- Rotary speeds that induce and sustain drillstring resonance should be avoided.

Axial Vibration

General

- Severe axial vibration leads to Bit Bounce.
- Vibration range is 1-10Hz, (1Hz is equal to 1 vibration cycle per second).
- Most frequently occurs when drilling with roller cone bits in hard formations.
- Occasionally occurs with PDC drill bits in hard formations.
- Caused by weight on bit fluctuations. Extreme WoB variance can cause the bit to lose contact with the bottom of the hole and then impact back to bottom.
- The three cones of a roller cone bit will generate a tri-lobe pattern causing the bit to be axially displaced three times per bit revolution.
- Can be caused by formation change.

Detection

- Large surface vibration.
- Axial movement of pipe at surface.
- Large weight on bit fluctuations.
- High levels of axial vibration from MWD tools.

Consequences

- Bit damage including cutting structure/bearings/seals.
- Reduction in penetration rate.
- Short run lengths.
- BHA washout.
- MWD failures.

Cures and Control

- Destroy tri-lobe bottom hole pattern by either-
    a. Changing drilling parameters.
    b. o Lifting off and returning to bottom with lower weight and lower rotary speed.
- Run a shock sub in the BHA.
- Running shock subs with PDC bits is not recommended as they can lead to bit ‘chatter’ (high frequency vibrations) that can chip and prematurely fail PDC cutters.

Bit Whirl

General

- The eccentric rotation of the bit about a point other than its geometric centre.
- Whirl is a self perpetuating motion.
- Types of whirl-
    a. o Forward whirl, the centre of rotation rotates in the same direction as the drillstring. Causes flat spots on stabilizers and tool joints.

b. o Backward whirl, the centre of rotation rotates in the opposite direction to the drillstring. Is more violent than backwards whirl and can cause severe cutting structure damage.
c. o Chaotic whirl, the whirl rotation moves between forward and backward whirl.

- Can generally be recognized/seen as lateral vibration (side to side motion).
- Whirl induces high frequency lateral/torsional vibrations in the range 10-50Hz, (10Hz is equal to 10 vibration cycles per second).
- Causes a dramatic increase in impact loading on the bit cutting structure causing rapid failure.
- Motors with bent housings can cause whirl.
- Can be initiated by formation change.
- Frequently seen while reaming.
- BHA whirl can induce bit whirl and vice-versa.

Detection

- Can be difficult to detect at surface.
- Generally seen at high RPMs and low WoBs.
- Increased surface and downhole torque.
- High frequency downhole lateral/torsional vibration.
- Increase in MWD shock counts.
- Reduction in penetration rate.
- Over gauge hole.
- Cutter impact damage, generally over the shoulder and gauge areas of the bit.

Consequences

- Bit damage, cutting structure damage generally over the shoulder and gauge areas of the bit.
- Reduction in penetration rate.
- Short run lengths.
- BHA washout.
- MWD failures.
- Motor failures.

Cures and Control

- Reduce rotary speed and increase weight on bit.
- Ream at lower rotary speeds.
- Destroy bottom hole whirl pattern by either-
    a. o Changing drilling parameters.
    b. o Lift off bottom and attempt to restart drilling without initiating whirl, try high WoBs and low RPMs
- Run anti-whirl or SteeringWheel bit.
- Run higher torque and lower speed motors so that higher weights can be applied.
- Run roller reamers instead of stabilizers.

BHA Whirl

General

- The eccentric rotation of the BHA about a point other than its geometric centre.
- Whirl is a self perpetuating motion.
    - Types of whirl-
        a. o Forward whirl, the centre of rotation rotates in the same direction as the drillstring. Causes flat spots on stabilizers and tool joints.
        b. o Backward whirl, the centre of rotation rotates in the opposite direction to the drillstring.
        c. o Chaotic whirl, where the bit moves between forward and backward whirl.
- Can generally be recognized/seen as lateral vibration (side to side motion).
- Initiated by friction between stabilizers/tool joints and the well bore leading to gearing of the BHA around the hole.
- Whirl induces high frequency lateral/torsional vibrations in the range 5-20Hz, (5Hz is equal to 5 vibration cycles per second).
- A stabilizer passing a ledge or through a formation change can initiate BHA whirl.
- Mud properties greatly affect BHA whirl as the mud is the lubricant that reduces friction between the stabilizer/tool joint and bore hole wall.
- Bit whirl can induce BHA whirl and vice-versa.

Detection

- Can be difficult to detect at surface.
- Increased surface torque.
- High frequency downhole lateral/torsional vibration.
- Increase in MWD shock counts.
- Localized wear on stabilizers and tool joints.
- Damage to stabilizer blades.

Cures and Control

- Change drilling parameters, reduce rpm and raise WoB.
- Increase mud lubricity, eg: pump a pill.
- Run roller reamers or non rotating stabilizers.
- Run non rotating drill pipe protectors.
- Lift off bottom and attempt to restart drilling without initiating whirl, high weights and low RPMs should facilitate this.

Torsional Vibration

General

- Severe torsional vibration leads to stick-slip.
- Stick-slip vibration range is below 1Hz, (1Hz is equal to 1 vibration cycle per second).
- Stick-slip is the rotary acceleration and deceleration of the drillstring. The bit can stop rotating momentarily at regular intervals causing the drillstring to windup and the torque to increase. The drillstring will then brake free and accelerate the bit to high rotary speeds with minimal torque.
- Stick-slip motion is often accompanied during its slip phase by lateral vibration of the BHA.
- Most common with PDC drill bits and can cause severe and rapid damage to their cutting structures.
- Can be formation dependent.
- Can be caused by the interaction of-

a. o the bit and formation.
b. o the BHA and the bore hole, eg: stabilizers ‘digging in’ to a soft formation.
c. o the drillstring and the bore hole, (eg: high well bore tortuosity).

- Can be caused by the drive system characteristics.
- Generally occurs at low rotary speed and high weight on bit.

Detection

- Can be detected at surface by both torque (Max – Min Torque > 20% Mean Torque) and rpm variance.
- Increased surface mean torque.
- Rotary drive stalls, (rotary table or top drive).
- Increase in MWD shock counts.
- Downhole rpm can range from zero to up to 2-3 times surface rpm.
- Bit impact damage, cutting structure damage generally seen over the nose of the bit.
- MWD tool failure.
- Reduced penetration rate.
- Over torqued connections, washouts and twist-offs.
- Connection back-off due to backward rotation.
- Downhole memory data acquisition and analysis.

Cures and Control

- Change drilling parameters, increase rpm and reduce WoB.
- Increase flow rate for increased motor RPM and increased lubricity/reduced friction due to improved hole cleaning.
- Run rotary drive system (rotary table or top drive) in higher gear.
- Run a soft torque system. This consists of a top drive or rotary table feedback mechanism that regulates surface torque fluctuation by altering rotary speed thus enabling more uniform bit rotation. The system must be regularly tuned to take account of changing parameters including depth and formation.
- Increase mud lubricity, eg: pump a pill.
- Run a motor to decouple the drill bit from the drillstring and to increase bit RPM.
- Run roller reamers or non rotating stabilizers.

- Lift off bottom and attempt to restart drilling without initiating stick-slip, high RPMs and low weights should facilitate this.

Vibration Coupling

• Vibration mechanisms can be coupled since some can trigger others, for example-

a. o Bit whirl can be triggered by high bit speeds generated during stick-slip motion.
b. o Stick-slip can generate lateral vibration of the BHA as the bit accelerates during the slip phase.
c. o Large lateral vibration of the BHA into the well bore can cause bit bounce.
d. o Bit whirl can induce BHA whirl and vice-versa.
e. o Bit torsional vibration can induce BHA torsional vibration and vice-versa.

Vibration Monitoring

General

- It is essential to establish what vibration mechanism is occurring downhole in order to prescribe the correct remedial actions.
- Corrective actions for one may exacerbate another, eg: the corrective actions for bit whirl are directly opposite than those for stick-slip.

Tool Inspection

- The nature of damage to downhole drilling components can often be a direct indication of the vibration source and mechanism. For example-
  a. o The location of bit impact damage could suggest bit whirl or stick-slip, (shoulder and gauge for whirl, nose and face for stick-slip).
  b. o Flat spots on tool joints are evidence of forward whirl.
  c. o Damage to stabilizer blades is an indication of BHA whirl and lateral vibration.

Mud Logging Data

- Mud logging data can provide the following surface measurements-
  a. o Mean torque.
  b. o Max/min torque.
  c. o RPM
  d. o WoB
  e. o Flow rate
- This data gives a good indication of whether stick-slip is present, ie: separation between max and min torque is indicative of stick-slip type vibration.
- To improve accuracy, set the chart recorder speed between 0.1-0.3 ft/min.

MWD Data

- MWD data can serve as an invaluable real time monitoring system.
- An increase in the number of lateral shocks above a threshold value (usually set at 25g's) provides a direct indication of severe BHA lateral vibration.
- Schlumberger D&M, Baker Hughes Inteq and Sperry-Sun provide MWD tools with shock measurements.
- Other down hole measurements that give a true indication of whirl or stick-slip at the bit are-
  a. o RMS torsional vibrations.
  b. o RMS axial vibrations.
  c. o RMS lateral vibrations.
- Gamma ray can indicate if any of the vibration mechanisms are related to lithology, ie: correlate formation changes to vibration changes.
- If a rock strength analysis is completed (both gamma and sonic required as minimum) it may indicate if rock strength is inducing the vibration mechanisms.

LWD/Wireline Log

- Calliper data indicates hole oversize and provides evidence for either bit or BHA whirl.

High Frequency Surface Measurements

- High frequency surface measurements of axial and torsional vibration can help indicate bit whirl, especially in shallow and non-deviated wells.
- Baker Hughes Inteq can provide these measurements.

Downhole Recording

- In deviated wells, it is not usually possible to detect high frequency events such as bit whirl from surface measurements due to dampening and attenuation of lateral vibrations.
- Downhole recording of the vibration data can be analyzed for subsequent wells.
- Schlumberger (DRT) and Sperry-Sun can provide downhole vibration measurement recording tools.

Factors Related to Bit Run Termination

Economics

• Frequently assess the run economics for the benefit of the operator, for example-

a. o At a formation change, it may be more economical to replace an insert bit with a faster PDC bit even though the insert bit still has many operating hours left.
b. o It may be more economical to pull a bit early to achieve a shorter trip and then complete the section with a longer final run.

Worn Cutting Structure

- Cutting structures wear out, (PDC/insert/milled/impreg/diamond).
- A worn cutting structure requires more weight to achieve the same penetration rate as a new/green cutting structure, ie: RoP generally decreases.
- If the gauge area of the cutting structure wears first the bit can become a ‘wedge shaped plug’ that fits tightly in the hole. This can cause high on-bottom torque even with low weight on bit, very low penetration rate and often

accompanied by an increase in SPP. Under gauge bits can also cause the stabilizers to hang up and cause general BHA damage.

- As an impregnated or surface set diamond bit wears the standpipe pressure will increase due to a reduction of the flow area. This is due to a reduction in blade height due to wear.
- As a PDC bit wears, for a given weight on bit, torque generally reduces as the cutting structure is no longer as aggressive.
- Severe PDC wear can result in the blades being worn down to the bit body/nozzles. Consequently, a significant increase in SPP will be seen as the flow is restricted due to contact of the bit face and the formation.

<u>Worn/Failed Bearings on Roller Cone Bits</u>

- If it is thought that the bearings have failed the bit should be immediately pulled. Failed bearings can deteriorate rapidly and result in losing a cone downhole. This is a very serious and expensive failure for the oil company due to lost time fishing.
- There are various symptoms that suggest a bearing failure, for example-
    a. o Torque changes: spikes, character or overall level not related to parameter or formation changes.
    b. o RoP changes: not related to parameter or formation changes. The RoP can increase temporarily as the skew angle of a cone increases with a failed bearing.
    c. o Directional responsiveness change: loss in control of toolface.
    d. o MWD signal quality deteriorates as the vibration from the bit masks the signal.

<u>Bit Balling</u>

- Usually occurs when drilling soft sticky formations with WBM.
- Some formations, predominantly shales react with water swelling considerably and becoming sticky.
- Montmorillonite content is the most significant factor with respect to formation hydration and bit balling.
- Montmorillonite changes to illite with time and temperature.
- Kaolinite does not hydrate and react with water.
- The order of claystones with greatest to least balling tendency is-
    a. o Montmorillonite
    b. o Mixed layer, montmorillonite and illite

c. o Illite
d. o Kaolinite

- Swollen and sticky cuttings can adhere to the bit clogging up waterways, junk slots, individual cones and possibly the entire bit.
- Severe balling results in total clogging up of the cutting structure so that the string weight is transmitted to the formation via the balling material rather than the cutting structure. Consequently, penetration rate is dramatically reduced.
- Balled formation can also plug the annulus so that no cuttings can be returned to surface. This results in an increase in SPP and possible risk of losing mud into the formation.
- Balled bits are generally characterized by-
    a. o Reduced rotary torque
    b. o Reduced penetration rate
    c. o Increased SPP
- If it is thought a bit is balling up lift off bottom immediately. Drilling with a balled bit can only exacerbate the problem by forcing more material to plug the bit or annulus further. This tightens/compresses the material and makes it heavier and more difficult to transport back to surface.
- Methods for un-balling a bit are-
    a. o Increase flow rate to the maximum for at least 5mins.
    b. o Spin the bit as fast as possible to ‘fling’ the material off.
    c. o Lift and drop the string rapidly to ‘shake’ the formation off, (take care not to surge the hole and damage the formation or drop the bit on bottom and damage the cutting structure).
    d. o Pump a pill, (eg: Nut Plug) to try and wash the material off.
    e. o A combination of the above.
- When returning to bottom after un-balling a bit use maximum flow rate and high rotary speed. Tag bottom gently as there may be huge chunks of balled material that need to be cut up. If weight is added too quickly the bit may just push into the balled material and become immediately balled again.
- Where balling is expected the risk of occurrence can be reduced by limiting penetration rate. This means that a reduced and more manageable amount of cuttings can be transported away from the bit face and annulus to surface.

Lost Nozzle

- A lost nozzle will cause a sudden decrease in pump pressure. Calculation will indicate the expected pressure drop.
- Pressure may continue to decrease gradually in an erosive environment due to the nozzle feed bore washing out and increasing in size/cross sectional area.
- If penetration rate is not significantly reduced drilling can continue but may result in cutting structure damage due to drilling on tungsten carbide nozzle components.
- In softer formations, a lost nozzle may be pushed into the hole wall and cause minimal cutting structure damage.
- If a nozzle is lost HSI is reduced so there in an increased risk of bit balling and reduced RoP.

Plugged (Blocked) Nozzle

- Nozzles can be plugged by a variety of materials. Some examples are-
    a. o Formation
    b. o Lost circulation material
    c. o Motor stator rubber
- A plugged nozzle will result in increased SPP.
- If penetration rate is not significantly reduced drilling can continue.
- If multiple nozzles are plugged and there is a severe deterioration in RoP it should be attempted to un-plug the nozzles or pull the bit out of hole.
- Methods for un-plugging a bit are-
    a. o Increase flow rate to the maximum for at least 5mins.
    b. o Lift and drop the string to ‘shake and surge’ the plugging material free, (take care not to surge the hole and damage the formation or drop the bit on bottom and damage the cutting structure).
- A bit with plugged nozzles has an increased probability of balling in softer formations and accelerating cutter wear in abrasive formations.

Downhole Motor or Turbine Failure

- A down hole motor or turbine failure will dramatically reduce penetration rate.
- SPP pressure fluctuations are likely to occur as the failure develops.
- A reduced pressure differential (the difference between on and off-bottom pressure) over the motor or turbine is likely to be seen.

- Depending on the failure, even if the rotary drive is rotating the string, there is a high probability that the bit will not be turning. This is because the motor or turbine may not be able to transmit any torque to the bit.
- Catastrophic motor failures can be caused by repeated motor stalling.
- Motor and turbine failures can be caused by bit whirl, stick-slip, BHA lateral vibration, etc.
- At surface, motor bearing wear can be estimated/measured by examining the play in drive shaft.

Dull Grading

- Witness the bit and BHA being pulled out of hole as evidence for run analysis can be collected. Take photos if necessary. For example-
    a. o All the tool joints worn on the same side suggests forward whirl.
    b. o BHA balling, (Roughnecks will frequently clean the BHA off and this information will be lost and not recorded).
    c. o Bit balling, (Roughnecks will frequently clean the bit off and this information will be lost and not recorded).
- Dull grade the bit using the IADC system, (dull grading manuals for each drill bit type can be found on the SLB website).
- Roller cone bits and fixed cutter bits have different sized gauge rings. Ensure that the correct gauge ring is used. ie: if an in-gauge PDC bit is measured with a roller cone gauge it will appear to be under gauge.

Dull Bit Photos

- Use a digital camera so that the photos can easily and quickly be e-mailed to the Product Centers, DEC or Optimization Engineer if necessary and for easy manipulation in a Run Report.
- Ensure good quality close up photos are taken. Number each blade with a marker pen to aid photo analysis at a later date.
    - Take the following photos to ensure the full dull bit condition is recorded-
        a. o Face view
        b. o Side view
        c. o Blade by blade

d. o Close ups of any extraordinary cutting structure damage, body junk damage, etc

Run Reporting

- If good notes are maintained throughout the run a good report can easily be written. It is good practice to write the report as the run is progressing so relevant points are highlighted and not forgotten.
- On the report it is important to record the run objectives and observations, dull bit observations and finally recommendations for how performance can be improved or good performance maintained consistently.
- Record the 'drillability' of each of the different lithologies drilled.
- Record mud and BHA details.
- See Appendix 2 for an example of an Optimization Run Report.

Drilling Terms

Annulus	The space between the drill pipe and hole wall or casing inside surface.
BHA	Bottom Hole Assembly.
Bit Breaker	The steel plate that locates the bit in the rotary table while it is screwed onto/made up to the drillstring.
BOP	Blow Out Preventer, a series of valves that close to seal in the well and prevent it blowing out.
Cavings	Formation that has fallen out of the well bore wall down hole.
Drill Collar	Heavy drill pipe used in the BHA to add weight.
Fishing	Attempting to recover an item out of the well bore to surface.
GPM	Gallons Per Minute.
HSE	Health, Safety and Environment.
HSI	Hydraulic horsepower per Square Inch.
Kelly	The heavy steel drive shaft with a square or hexagonal cross section that locks in the rotary table and is connected to the drillstring to transmit torque.

LCM	Lost Circulation Material.
LWD	Logging While Drilling.
MWD	Measurement While Drilling.
OBM	Oil Based Mud.
RMS	Root Mean Square (a method of averaging a signal).
RoP	Rate of Penetration, fph/mph.
Rotary Table	Device on the rig floor used to drive/rotate the kelly and support the drillstring.
RPM	Revolutions Per Minute.
RSA	Rock Strength Analysis.
PDC	Polycrystalline Diamond Compact.
POBM	Pseudo Oil Based Mud.
PPE	Personal Protective Equipment.
PSI	Pounds per Square Inch, fluid pressure.
Sliding	While directionally drilling with a motor, the rotary drive is switched off so the drillstring does not rotate and is 'slid' downhole
SPM	Strokes Per Minute.
SPP	Stand Pipe Pressure.
Spudding	Burying the bit face into material, eg: the hole bottom or casing shoe assemblies.
TFA	Total Flow Area, the sum of the cross-sectional areas of the exits of all nozzles in the bit.
Toolface	The direction the motor is orientated to in hole while sliding.
Top Drive	A torsional motor used to drive the drill string. Usually installed on the bigger rigs and can provide more power than a kelly drive.
WBM	Water Based Mud.
WoB	Weight on Bit, klbs/tonnes.

DiamondDrillingIndustries

Common Problems Affecting PDC, Natural and Thermally Stable Diamond Bit Performance

COMMON PROBLEM	PROBLEM CAUSE	PREFERRED ACTION
Difficulty going to bottom.	-Previous bit under gauge. -New bottom hole assembly. -Collapsed casing. -Out of drift. -Bit oversized. -Stabilizer oversized.	-Ream with roller cone bit. -When reaming to bottom, pick up and ream section again. If difficulty remains, check stabilizers. -Roll casing with smaller bit. -Use bi-centre bit or reduce bit size. -Gauge bit with API gauge; if not in tolerance, replace bit. -Replace with correct size stabilizer.
Low pressure differential across nozzles or bit face.	-Flow area too large. -Flow area too low. -Different drilling parameters than designed for. -Washout in drill string.	-Increase flow rate and correct on next bit. -Increase flow rate/strokes. -Change liners. -Attempt to optimize, on next bit change flow area. -Check bit pressure drop, drop soft line, trip to check pipe and collars.
High pressure differential across nozzles or bit face.	-Flow area too small. -Excessive flow rate. -Diamond too small for formation. -Bit partially plugged (formation impaction) -Formation change. -Ring out. -Downhole motor stalled.	-Reduce flow rate, on next bit change flow area. -Reduce flow area.. -If ROP acceptable, change on next bit. -If ROP unacceptable, pull bit and use bit with correct diamond size. -Check off bottom standpipe pressure. Let bit drill off, circulate full volume for 10 minutes while rotating. Check off bottom pressure again. -Pick up, circulate, resume drilling at higher RPM, reset, drill-off test. -On - and off-bottom pressure test, pull bit. -Refer to manufacturer's handbook.
Fluctuating standpipe pressure.	-Drilling through fractured formation. -Formation breaking up beneath bit. -Stabilizers hanging up. -Equipment failure.	-If ROP acceptable, continue. -If ROP acceptable, continue. -Check equipment. -Try combination of lighter weight and higher RPM. -Check over pull. -Check stabilizers on next trip. -Repair equipment.
Bit won't drill	-Bottom not reached. -Stabilizers hanging up or too large. -Formation too plastic. -Establishing bottom hole pattern. -Core stump left. -Bit balled	-Check tally. -Check torque, over pull. -Check pressure – increase flow rate, decrease / increase bit weight, RPM. -Can take up to an hour. -Attempt to carefully drill ahead with low bit weight. -Back off and increase flow rate, then slug with detergent or oil.

Slow RoP	-Not enough weight on bit; hydraulic lift. -RPM too low/high. -Plastic formation. -Change in formation. -Overbalanced. -Diamonds flattened off. -Cutters flattened. -Pressure drop too low. -Wrong bit selection.	-Increase weight on bit; -Increase/decrease rotary. -Reset drill off -Reset weight -Reset drill off. -Accept ROP. -Pull bit. -Compare beginning and present drops – new bit may be required. -Increase weight. -Pull bit. -Increase flow rate – new bit may be required. -Pull bit.
Excessive torque	-Excessive weight on bit. -Slow RPM. -Stabilizers too large. -Collars packing off. -Bit under gauge.	-Reduce weight and RPM. -Increase rotary. -Decrease weight -Check bottom hole assembly; stabilizers should be 1/32” to 1/16” under hole size. -Increase flow rate and work. -Pull bit.
Bit Bouncing	-Slip-stick action. -Broken formation. -Pump off force.	-Change rotary weight combination. -Reduce rotary speed and weight. -Increase weight. -Decrease volume.