Scope

This document describes the entire drilling system and provides guidelines so that the pertinent factors affecting 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.

Purpose

The following procedure covers aspects of running a drill bit from arriving at the rig site through to recommending drilling parameters, run recording and reporting. The procedure can be used as part of the drilling optimization process to ensure a quality service is provided to our customers.

Procedure

Rig Site Protocol
On arriving at the rig site ensure that rig site protocol is adhered to. Each operator/contractor (land or offshore), have their own standards and rules for HSE that must be adhered to. Ensure that both BesteBit and rig site standards are met.

For example, the general rig site protocol for US land is:
- Minimum PPE is a hard hat, steel toe capped rig boots and safety glasses. (Fig. 1)
- Sign in at entrance.
- Reverse park your vehicle.
- Introduce yourself to the oil company representative.
- State why you are there.
- Explain your objectives and how you plan to achieve them.

Fig. 1

Be aware that a number of operators have minimum levels of certification required before being allowed on site. These may include national standards such as UK or Norway offshore survival certificates and medicals; but may also include company specific requirements such as “Stepping and Handling”, H2S and specific safety procedures / orientation courses. Actual certificates or “passports” may be required to be shown before travelling to or on arrival at a given location. Safety certification for some survival courses may also be needed on a land or offshore locations.

Rig and Surface Equipment Evaluation

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, e.g. shale inhibition with water based mud systems.

Evaluate the following equipment:

- Shale shaker (Fig. 2) specification
    - Number
    - Type
    - Screen / mesh size / condition
- Centrifuge equipment

Go through the mud morning reports and review sand content. In particular as this is the best indicator of abrasives being left in the mud. "Solids", as indicated on the report, may include weighting material that is not directly detrimental to the bit.

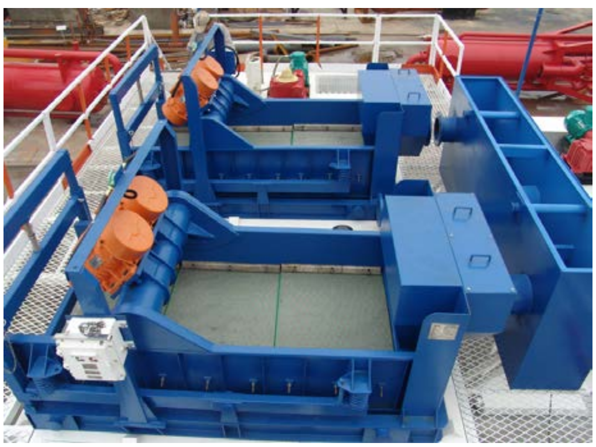


Fig.2

Mud Pumps
A mud pump (Fig. 3) is a reciprocating piston/plunger device designed to circulate drilling fluid under high pressure down the drill string and back up the annulus.

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 (Strokes per Minute).
Information required:

- Pump manufacturer
- Number of pumps
- Type of pump (Duplex, Triplex etc.)
- Liner size and stroke length or volume per stroke cycle (gallons or Liters) Note: some pumps deliver 1 liner volume per cycle (Triplex) others deliver 2 liner volumes (Duplex NB: allow for rod dimension)

Fig. 3

Mud System
The drilling-fluid system (Fig. 4) —commonly known as the “mud system”—is the single component of the well-construction process that remains in contact with the wellbore throughout the entire drilling operation. Drilling-fluid systems are designed and formulated to perform efficiently under expected wellbore conditions.

Some of the basic functions of a drilling fluid are as follows:

- Cleans the hole by transporting drilled cuttings to the surface, where they can be mechanically removed from the fluid before it is recirculated downhole.
- Balances or overcomes formation pressures in the wellbore to minimize the risk of well-control issues.
- Supports and stabilizes the walls of the wellbore until casing can be set and cemented or openhole-completion equipment can be installed.
- Prevents or minimizes damage to the producing formation(s).
- Cools and lubricates the drillstring and bit.
- Transmits hydraulic horsepower to the bit.
- Allows information about the producing formation(s) to be retrieved through cuttings analysis, logging-while-drilling data, and wireline logs.

Minimum information required:
Type (OBM, WBM, POBM, Silicate, etc.)

- Weight
- Solids content /Sand content
- PV/YP

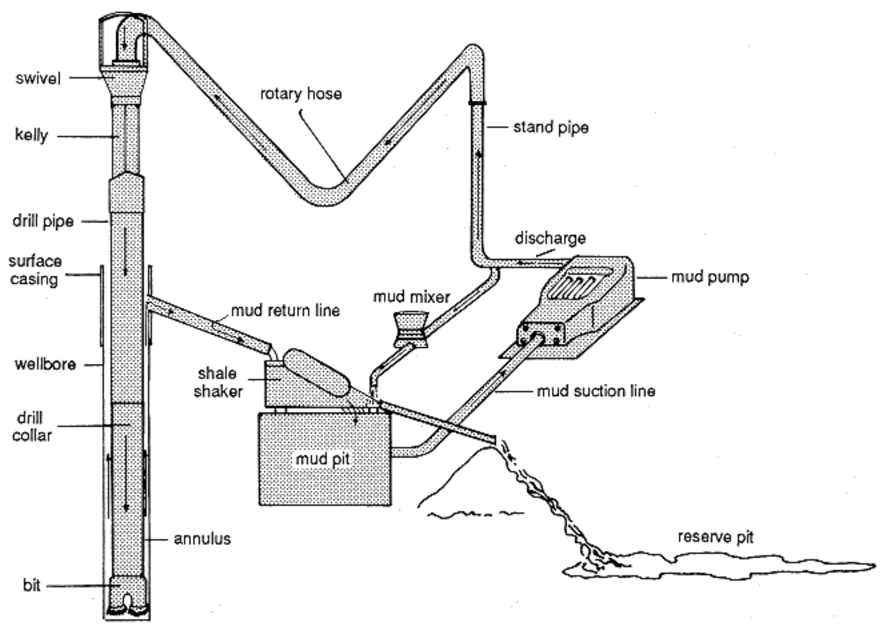


Fig. 4

Lost Circulation Material (LCM)

Lost circulation material is frequently required to plug fractures in the well bore (Fig. 5). If these fractures are not plugged a significant volume of mud can be lost to the formation. In a worst scenario, if there is a rapid loss of mud, which may reduce the hydrostatic pressure that is balancing the formation fluids, then this may lead to a blowout. Mud is also expensive and losses must be minimized. Lost circulation material comes in various sizes and types, e.g.: nut plug, cottonseed husks, cellophane, etc. LCM as well as plugging holes in the well bore can, unintentionally, plug nozzles in a drill bit. If determined that lost circulation material may 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 i.e. the longest LCM must be less than one third the diameter of the smallest nozzle or port.

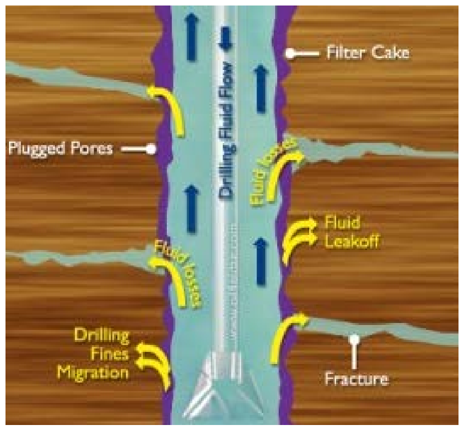


Fig. 5

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 double checked:

- Standpipe pressure
- RPM (Revolutions per Minute)
- WOB (Weight on Bit) and Hookload (Total string Weight)
- Torque
- ROP (Rate of Penetration)
- Differential Pressure

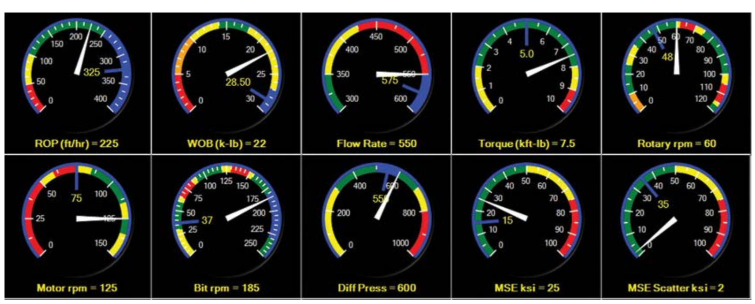


Fig. 6

Bottom Hole Assembly Evaluation

A bottom hole assembly (BHA) is the lowest part of the drill string, extending from the bit to the drill pipe. The assembly can consist of drill collars, subs such as stabilizers, reamers, shocks, hole-openers, bit sub and bit. The bottom hole assembly directly affects drilling performance. The addition of a motor or turbine can significantly increase penetration rate while the addition of stabilizers can affect the dropping, building or turning tendencies of the drillstring. A Rotary Steerable System (RSS) can provide improved directional control compared to that of a motor in some applications, e.g.: extended reach wells, applications where differential sticking of the BHA is problematic, etc.

Useful information:

- Turbine/Motor specifications.
- Revolutions per unit volume pumped for RPM calculation
- Motor bend angle
- Bit to bend distance
- Min / Max flow rates
- Performance charts
- Lobe configuration for motor type, e.g.: high torque/low speed

Stabilizer details can affect both directional tendencies and transmitting weight to the bit (Fig 7), e.g.: stabilizers hanging up. Details required are:

- Size
- Type (Straight or spiral blades, melon)
- Position in the drillstring (including motor stabilizers)
- MWD/LWD details. Find out the specifications for these tools and what data is recording.

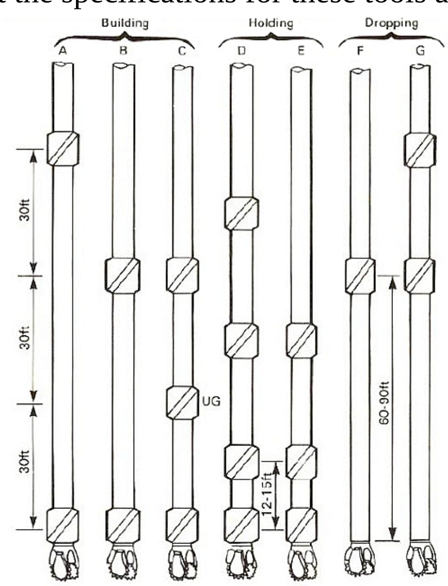


Fig. 7

Useful downhole data is:

- RPM (average, maximum and minimum)
- Torque (average, maximum and minimum)
- WOB
- Pressure
- Lateral Vibration
- Torsional Vibration
- Axial Vibration
- Stick Slip
- Temperature

Well Bore Condition Evaluation

Find out the history of events of the well to date to assess if any incidents have / will affect the run. Gather as much information / ideas from:

- Casing depths
- Log data
- Survey data
- Oil company representative
- Tool Pusher
- Drillers from each shift
- MWD/LWD Engineers
- Mud Logger
- Directional Driller
- Geologist
- Morning reports
- Mud reports
- Directional drillers reports

Preceding Bit Run Evaluation

Find out the details of the preceding bit run. What factors improved/reduced drilling performance.

- What was the condition of the preceding bit when it went in hole? Was it a new bit, rerun, re-tipped?
- Be on the rig floor to witness the preceding bit and BHA being pulled through the rotary table.
- Collect the run details, dull grade the bit and take photos as outlined in the Dull Grading and Dull Bit Photos section.
- 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 (preferably a milltooth) and a junk basket.

- If the previous bit is severely under gauge check the torque and trip records to see if you can determine from what depth the well needs to be reamed. Ensure the new bit reams the section and is not tripped in too far pinching the bit.

Hydraulics and Drill Bit TFA (Total Flow Area)

Hydraulics is the study of fluid in motion. System hydraulics can greatly affect drilling performance and the efficient use of it provides maximum hydraulic energy, power or force to the hole bottom. It is important that both the nozzle and pump liner size are selected to optimize the hydraulics for that application. The pump model and liner size dictate the theoretical maximum stand pipe pressure and flow rate available.

- Flow rate is the volume of fluid flowing in a given length of time. Flow is critical, as it cools and lubricates the cutting structure of the bit. In some applications, drilling with minimal flow rate will cause rapid degradation of the drill bit cutting structure.
- Hydraulic horsepower or HSI is a primary factor for maximizing ROP. HSI is the energy at the bit that lifts the cuttings from the well floor or bit face into the annulus.
- Optimum HSI for any bit type is between 3 and 5 HHP/In2. Matrix bodied bits may go up to 8 HSI but little ROP is gained over 6. An HSI below 3 is not optimized for ROP.
- Flow rate is another important factor. High flow rate helps lift the cuttings to surface.
- Turbulent flow is a flow regime characterized by chaotic property changes. This includes low momentum diffusion, high momentum convection, and rapid variation of pressure and flow velocity in space and time. It is generally achieved around the drill bit. It may be necessary to avoid turbulent flow around the BHA if hole washout is seen as an issue.
- Laminar flow occurs when a fluid flows in parallel layers, with no disruption between the layers and is generally preferred around the drill string to prevent hole damage. In general Laminar flow will minimize the risk of formation damage, whilst turbulent flow gives better hole cleaning and is often the preferred option in high angle and horizontal wells.
- The BesteBit 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. Check the LCM size available to your rig; the smallest nozzle diameter you can use is greater than three times the maximum length of the LCM pieces. (e.g. for an 8/32” nozzle you can use LCM smaller than 0.08” long. 12/32” Nozzles allow 0.12” long).
- Calculate the expected pressure change if one of the nozzles becomes plugged or is lost.

- Large diameter Roller Cone bits, and some 12 ¼" and below if requested, have a center jet. Approximately 17 to 21% of the flow should be taken by the center jet for efficient bit cleaning and ROP. Greater flow to the center jet, such as all 4 nozzles being the same size, reduces ROP as the gauge area has reduced cleaning; below 17% and it may be ineffective at preventing bit balling. In practical terms this normally means select a set of nozzles so that the center jet is 2/32" smaller than the 3 outer nozzles e.g. 3 x 18/32" and a 16/32" center jet.

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 into the 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.
- Check the condition of the bit; if damaged in transit, a rerun or a repaired bit.
- Record bit condition/dull grade
- Photograph the bit as outlined in the Dull Bit Photos section. Take extra shots of damaged/worn area as necessary.
- If the customer wishes to check the gauge of the bit ensure they are using a "GO" gauge of the correct type (FC or RC).
- 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.
- For impregnated bits ensure the blade height in the cone, nose, shoulder and taper are all measured for use in grading later. For Natural Diamond or TSP bits record the stone exposure again for use in grading later.

Making Up the Bit to the Drillstring

Pay attention on how the bit is handled on the rig floor and if it gets damaged record the incident. If there is severe damage it may be necessary to recommend that a different bit is run in hole.

- Witness the bit and BHA being made up to the string and run through the rotary table.
- Ensure the bit is handled correctly on the rig floor and not damaged, e.g.: never place a PDC bit cutting structure directly on the steel decking of a rig floor as this risks damaging cutters, ideally use a wooden or rubber mat.
- Clean and grease API pin / box connection of both bit and drill string (ensure threads and face are well lubricated /"doped".

- Using the BesteBit bit breaker, locate bit in rotary table.
- Lower drill string onto the bit and engage threads.
- Make up by hand if possible or ensure very slow rotation. Never rotate the table unless the bit is too heavy; make up to a straight housing if possible.
- Torque up connection to the specified torque for that API connection, (this can be found on the label that accompanies the bit in the bit box).

Running in Hole

The rig crew will try and trip in hole as fast as possible to return to drilling. Communicate the following points to the oil company representative and the driller.

- Take special attention running through diverters, BOPs, well heads, casing shoes, and liner hangers 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 (50-60 RPM approx.) and low weight on bit, (no more than 4,000 lbs.). In a tight spot the weight is only supported by the cutting structure towards gauge resulting in higher weights on individual cutters, inserts 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, cavings, etc. that may have collected on the bottom of the hole.
- Watch for an increase in torque and / or weight when approaching bottom to identify when the bottom of the hole has been tagged.
- Lift off bottom 6-12” at maximum flow while slowly rotating the bit for 5 mins approx. to clean the bottom of the hole.
- Collect on and off bottom torque, vibration and pressure readings

Note: The above assume no motor or turbine. With either drive type as soon as the pumps are turned on the bit is rotating. If inside casing high RPM, and hence high flow rate, should be avoided as the bit may well be damaged.
On a bent assembly this is even worse as the bit will constantly impact against the casing damaging the cutting structure and perhaps unevenly loading the bearings.
The above instructions for high flow and low RPM must be compromised when reaming and washing to bottom. Flow is needed to remove the cuttings but as the bit is not stabilized by fully engaging the formation at this time caution should be exercised to not increase the RPM too high.
It should also be remembered that when circulating in open hole with a bent assembly the bit has the opportunity after a short time to have cleared a small overgauge hole so as to minimize further gauge impact; if circulating inside casing this opportunity does not exist, so bit damage will continue to occur.

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 (i.e.: 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. For such "problematic" floats or shoes recommend a milltooth roller cone bit. The intended primary bit will then be preserved for the long or difficult drilling section.

PDC, Impregnated and Diamond Drill Bits

- 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 feet (10m) above where the cement is expected. (approx. 50-65 gpm / in of bit diameter)
- Use 50-60 RPM with a rotary assembly and 20-40 RPM with a motor assembly.
- Tag bottom slowly with 3-500 lbs. /in of bit diameter 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 or pumping and increase weight on bit slowly. Do not spud the bit into the float equipment. Once sufficient weight on bit (start with 6- 8,000 lbs. [2,500 – 3,500 kg] and increase as necessary) is applied, slowly increase rotary 10 – 20 RPM at first then to 60-80 RPM. After 5 mins start the pumps, at a low flow rate. Repeat as necessary to drill through the remainder of the plugs. The idea is to cause the rubber to heat up, expand and grip the casing and deteriorate. BUT do not heat to the point of being detrimental to the cutters so do not rotate with the pumps off for more than 5 mins. Heating and cooling the rubber will also weaken the rubber.
- 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 (60cm) 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.
- When using water or salt water to drill out, be aware this usually does not have the lifting capacity to remove large pieces of swarf from the casing or shoe. This may only become apparent when pills or sweeps are used, and then the material will arrive at surface “en-masse” and appear to be far more severe than it actually is.

Rotary Steerable Systems wear pads are back pressure activated:

- Use low flow rate to keep the bit pressure loss as low as possible to stop the pads exerting force against the casing.
- During displacement, if the string is not being rotated, then the flow can be increased without detrimental effect.
- Avoid full flow and pipe rotation without reciprocating the drill string. The reciprocation will stop the casing suffering severe wear in a localized area.

Roller Cone Drill Bits, (Insert and Milled Tooth)

- Wash and ream to bottom with maximum flow rate at least 30 feet (10m) above where the cement is expected.
- Use 50-60 RPM with a rotary assembly and 20-40 RPM 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 3-500 lbs. per inch (60 - 100 kg per cm) of bit diameter 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 (4,500 kg) 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 6-8,000lbs [2,500 – 3,500 kg] and increase as necessary) is applied, slowly increase rotary to 90-100 RPM. 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 (60 cm) 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 cones 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 (1,800 kg) weight and 40-60 RPM 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 / inserts / teeth will be in contact with formation so if weight is added too quickly, particularly in hard formations, they may be overloaded and fail.
- Conduct a drill off test
- 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 (Identified from Drill off test). As a rule PDC bits increase ROP with RPM; Roller Cone bits' ROP plateaus when high RPM prevents optimum penetration.

Making Connections and Restarting Drilling

- Maintain full flow as bit is raised off bottom.
- Return to bottom at half 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.

"Drill-Off Test" Procedures

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. (This method is described twice below as the BesteBit description and BP's primary method).
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 cross-plots of ROP versus WOB created, again for each RPM. (Described below as BP's second method)

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 effected by formation changes. It also has the advantages of being straight forward, gives results quickly and does not impact on rig drilling time. The BP versions of both tests are more complicated and may impact on rig time. 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 (Interval - 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.

The first "Drill-off" test described has been in use for many years and in many locations and is a proven methodology. 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 has been installed into several mud logging systems. Since this software is not always available, more generalized methods for drilling tests are described below, where data is treated using conventional spreadsheet packages.

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. 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, e.g.: 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, e.g.: every 2,000 lbs. (1,000 kg).
- Note down the time taken to drill off each 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. 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.

Interpreting the test results

Review the ROP/WOB cross-plot. 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).

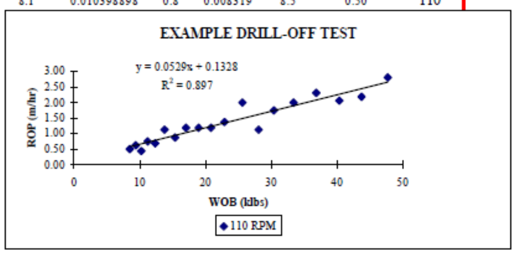
Note that when informing the driller of the chosen optimum WOB, the value from the cross-plot will be the mud loggers' value of WOB. Any discrepancy with the weight indicator WOB will need to be rectified before the driller is given an optimum WOB.

DRILL-OFF TEST

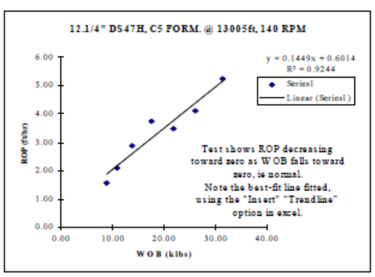
Drillpipe length =	2000	m	Drill off test at (depth):		m
DP modulus =	206	GPA	Date:	10/11/97	dd/mm/yy
Area of DP =	4153	mm*mm	Bit type:	G536GU	12.1/4"
Compliance =	0.0023	m/kn			
Compliance =	0.0104	m/klb			

Raw drill-off test data:

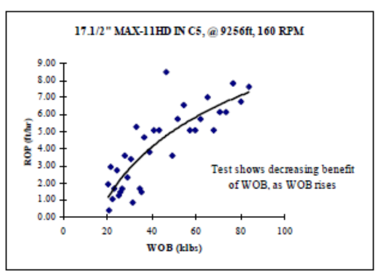
Time step mins	WOB from M.Decker klbs	Calculated compliance m/klb	Delta WOB klbs	Interval drilled m	Average WOB klbs	Calculated ROP m/hr	Test RPM revs/min
1	50	0.010398898					
2	45.5	0.010398898	4.5	0.046795	47.75	2.81	110
3	42	0.010398898	3.5	0.036396	43.75	2.18	110
4	38.7	0.010398898	3.3	0.034316	40.35	2.06	110
5	35	0.010398898	3.7	0.038476	36.85	2.31	110
6	31.8	0.010398898	3.2	0.033276	33.4	2.00	110
7	29	0.010398898	2.8	0.029117	30.4	1.75	110
8	27.2	0.010398898	1.8	0.018718	28.1	1.12	110
9	24	0.010398898	3.2	0.033276	25.6	2.00	110
10	21.8	0.010398898	2.2	0.022878	22.9	1.37	110
11	19.9	0.010398898	1.9	0.019758	20.85	1.19	110
12	18	0.010398898	1.9	0.019758	18.95	1.19	110
13	16.1	0.010398898	1.9	0.019758	17.05	1.19	110
14	14.7	0.010398898	1.4	0.014558	15.4	0.87	110
15	12.9	0.010398898	1.8	0.018718	13.8	1.12	110
16	11.8	0.010398898	1.1	0.011439	12.35	0.69	110
17	10.6	0.010398898	1.2	0.012479	11.2	0.75	110
18	9.9	0.010398898	0.7	0.007279	10.25	0.44	110
19	8.9	0.010398898	1	0.010399	9.4	0.62	110
20	8.1	0.010398898	0.8	0.008319	8.5	0.50	110



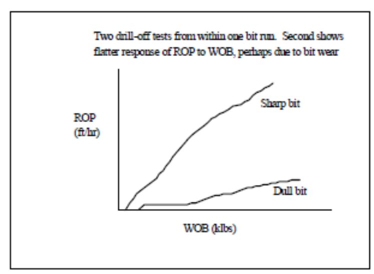
INTERPRETING DRILL-OFF TEST RESULTS



Typical test result; ROP will only be close to zero as WOB approaches zero, and response is linear



Decreasing benefit of higher WOB; perhaps due to imperfect bit cleaning (e.g. in water base mud/shale)



Decreasing response of ROP to WOB; often seen as a PDC bit suffers abrasive wear of the cutters

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:
- All the tool joints worn on the same side suggests lateral vibration.
- BHA balling, (Roughnecks will frequently clean the BHA off and this information will be lost and not recorded).
- 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.
- Roller cone bits and fixed cutter bits have different sized gauge rings. Ensure that the correct gauge ring is used. i.e.: 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 Engineering if necessary and for easy manipulation in a Run Summary Report.
- Ensure good quality close up photos are taken. Number each blade or cone / shirttail 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:
  - Face view
  - Side view
  - Blade by blade or Axial view of each cone (rollercones)
  - All 3 shirttails (rollercones)
  - 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 be written easily. 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 a Run Summary Report.

References

Drillstring Vibration Primer, January 1994, Fereidoun Abbassian, BP Exploration

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 locks the bit in the rotary table as it is screwed onto / made up, or removed from 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 wall of the well down hole rather than being drilled from the bottom of the well.
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.
JIF Jet Impact Force
Kelly The heavy steel drive shaft with a square or hexagonal cross section that locks into 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.
PDC Polycrystalline Diamond Compact.
POBM Pseudo Oil Based Mud.
PPE Personal Protective Equipment.
PSI Pounds per Square Inch, pressure.
RMS Root Mean Square (a method of averaging a signal, the integrated area under a curve).
ROP Rate of Penetration, ft. /hr. or m/h.
Rotary Table Device on the rig floor used to drive / rotate the kelly.
RPM Revolutions per Minute.
RSA Rock Strength Analysis.
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, e.g.: 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 rotate 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, lbs. / tones.

Appendix 1

Bit Run Summary

Clear Form

Salesman: Chris Box Region: South TX

Run Date: 04/30/15

Overall Run Rating: A

Well		Bit		Run	
Operator	U.S Energy	Bit Size (")	8.750	Depth In (ft)	5,633.00
Well Name	Iron Wood B1	Bit Type	TS1653V	Depth Out (ft)	8,037.00
County	Frio	Serial #	229467	Footage (ft)	2,404.00
Lat/Long	28.8475 / -99.384	Nozzles (Qty / Size)	8 / 16	Hours (hr)	32.00
Contractor/Rig	Patterson 238	TFA (IN2)	1.571	ROP (ft/hr)	75.13

Operating Parameters			Mud Properties			Motor Details	
	Min	Max		Min	Max	Make	
WOB (klb)	10.0	25.0	Mud Type	w	w	Model	
RPM	125	145	Mud Wt (sg)	10.4	10.5	Motor Bend	2.3
Flow (gpm)	380	500	PV / YP			Speed (rev/gal)	
Pump Pr (psi)	1,800	2,000	Solids %			Diff Press (psi)	450

Directional Info				Dull Grade	
Run Profile	Curve/Latt	Drive System		I-O-D-L-B-G-O-R	
KOP	6468	Dev (start/finish)	8.0/90.5	Field	0 - 1-WT - G - X - I - N - BHA
Build Rate (/100ft)	10/100	Slide %	0%	Shop	

Additional Comments	
Performance	great
Formations	Eagle ford shale
Directional	built 10/100 great DD said they had no issues with bit, would slide 70+ and rotate 180+ when needed
Dull Condition	great
Offsets	PDC Logic had the first well curve and only averaged 40FPH in curve and BESTE was at 51FPH in curve and 100+ in Latt
Other	Baker started out with 8.75 405 and they could onld get 7 FPH and only got 8 DEV. they POOH and ran this bit to go on and drill the hole curve

FRM-ENG-002 Rev C

Appendix 2

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 "GO"-gauge; if not in tolerance, replace bit. (Check gauge used is PDC GO-GAUGE) - Replace with correct size stabilizer.
Low pressure differential across nozzles or bit face.	- Flow area too large. - Flow rate 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 optimise, 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 rate. - 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. - Pick up 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 ROPs – 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 pipe. - 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.