VAREL PDC BIT OPERATING PROCEDURES

PRE-PLANNING WITH THE CUSTOMER

The first part of a successful job is preplanning with the Operator and drilling service companies. Important factors to be reviewed with the Operator and service companies are expected lithology, length and depth of the interval, drill string drive system, directional objectives, BHA configurations, rig hydraulic capabilities and drilling fluid properties, and casing program. These factors must be understood and planned to achieve the most successful job. Hydraulic calculations must be performed to optimize the bit performance. The bottom hole assembly must be agreed upon to obtain the well objectives. This is especially important when drilling with a PDM.

PREPERATION AT THE JOBSITE

Check Hole Conditions - Did previous bit leave any junk (PDC cutters, inserts, etc.)? If sufficient junk is present, a boot basket trip may be warranted. Was previous bit in gage? If the preceding bit was POOH under gage, then some reaming is to be expected.

Check the Bit - Often you will not know exactly how the bit got to the rig. Debris can get into the bit in transit. Turn the bit upside down and check to be sure it is empty, and that all the nozzle bores are clear. Check to be sure the correct size nozzles are installed. Write down the bit serial number.

Bit Make-Up - NEVER set the bit on a steel surface to make it up. This almost guarantees chipping the cutters. Set it on wood or a rubber mat. Put the bit breaker on the bit and close the gate on the bit breaker. Clean and dope the pin. Lower the drill string to the top of the pin and engage threads. Apply the recommended torque for the API connection. DO NOT over torque the bit.

Tripping In Hole - Go slowly until the bit has cleared the BOP stack. If tight spots were encountered during POOH, they should be anticipated when RIH with the PDC. The PDC is full gage, and may have to be worked or reamed through tight spots. If well has been bridging over in a particular section, anticipate it. Lower the string slowly through any spots in the well that may be restricted. (Hangers, ledges, dog legs, etc.) DO NOT attempt to push the PDC bit through any obstruction. This can potentially damage the cutters or plug nozzles. Wash and ream through obstruction with full pump flow and low RPM. When bottom is close, slowdown in case fill is present. Running the bit into fill without mud flow can plug nozzles.

DRILL-OUT RECOMMENDATIONS

Float Equipment - There is PDC *drillable* float equipment, and then there is PDC *friendly* float equipment. *Drillable* equipment includes such items as aluminum, soft steel, and brass. *Friendly* equipment includes phenolic plastics, epoxy resins, small amounts of machineable aluminum. While both are technically PDC drillable, ***the lower the metallic content of the equipment, the easier it is on the PDC bit***. Cast aluminum tends to break into big chunks under stress, and it can damage PDC bits. Machineable aluminum is less brittle, and seems to drill slowly, but with less chance of catastrophic damage to PDC bits. Brass drills slowly also, but is very soft. The preferred material is non-metallic. It simply works the best for PDC bits.

Cementing Plugs – Follow plug supplier drillout procedure.
Example: Weatherford

Drill Out Procedure - Drill through Float Equipment as per table below. Ensure that cement plug debris is cleared before proceeding to drill out the shoe. Before tagging the Shoe, set the Surface RPM to 50 – 70 RPM and a pump rate that will ensure good cuttings circulation. If using a Motor or Turbine, less control over RPM is possible, so lighter WOB should be used to avoid overloading the shoulder & gauge cutters on PDC Bits Pick up regularly to flush away cuttings. WOB should be kept within the parameters below until past the nose of the Shoe. If required to re-ream the Shoe, pull back inside casing without rotation if possible and ream down only, if back reaming is required keep rotary speeds as low as possible (20-30 rpm) while pulling back.

Recommended drill-out parameters are as follows:

Size	BHA Type	WOB	MAXIMUM WOB	SURFACE RPM
13 3/8"	Rotary Steerable	2 – 8 klbs	10 klbs	70
13 3/8"	Motor	2 – 6 klbs	10 klbs	30-50
9 5/8"	Rotary Steerable	2 – 8 klbs	10 klbs	60
9 5/8"	Motor	2 – 6 klbs	10 klbs	30-50
7"	Rotary Steerable	2 – 8 klbs	10 klbs	50
7"	Motor	2 – 6 klbs	10 klbs	30-50

Note: Exceeding the recommended parameters (particularly WOB) may shear off rather than cut the composite material. These parameters are guidelines; the final parameters used will depend on drilling conditions and any real-time vibration / dynamic considerations.

The primary parameter is the **WOB**. This should, if possible, be kept within the guidelines - the RPM can be varied if and when required.

PDC Bit Break-In - After circulation, lower bit to bottom with full volume. Check actual hydraulics against expected. Record pump pressure and stroke count at drilling volume. Get an off-bottom rotating torque and record it. On rotary, tag bottom with 60-80 RPM, and drill 1 foot at 2-4000 lbs. WOB. On motor, slow pump to minimal bit flow rate, 30 to 60 rpm, and drill with 2-4000 lbs. WOB. Drill about 1 foot to make a new bottom hole pattern. After the 1 foot break-in: a) on rotary, begin to increase to drilling WOB in 2-3000 lb. Increments; B) on motor, bring the pump volume back up to maximum and bring WOB up in 2,000 lb. increments. Refer to the last recorded penetration rate of the previous bit to get a feel for how fast the bit should be drilling in this zone.

Making Connections - After making connection, care should be taken when re-starting the bit. Bring pumps to full drilling volume before tagging bottom. Check the pump strokes and stand pipe pressure. Tag bottom with 60-80 RPM on rotary. On motor, tag bottom with minimal PDC bit flow rate and minimal rotary. After tagging bottom with pumps on increase pump rate to full drilling volume then slowly increase rotary RPM and WOB back to previous levels.

DRILLING WITH PDC BITS IN FORMATION

General Recommendations - PDC bits actually sheer rock. Due to this, a constant feed rate provides superior ROP. If there is an automatic driller on the rig, it should be used in all but fast drilling situations. Adding weight in 5-10000 lb. Increments works on rock bits but usually results in slower ROP with PDC bits.

- PDC bits are very sensitive to formation changes. Watch for torque fluctuations to determine sands rather than drilling breaks.
- If a pump goes down, and minimal flow rate cannot be maintained, control drill the bit at 2/3 of previous ROP or circulate until the pump is fixed. This is usually quicker than trying to clean the bit later.

Drilling Ahead - Determine drilling WOB by observing ROP with various parameters. While more WOB and higher RPM often mean better ROP, either in excess can result in a short bit run. Keep an eye open for cyclical torque; if the rotary is speeding up and slowing down in cycles, slip-stick is likely occurring. Speed up RPM until the cycling stops, and then slowly reduce RPM back to a manageable level.
Bit whirl is not the problem it once was, but still occurs. Usual indicators of bit whirl are: a) ROP under 10 ft/hr for no apparent reason; b) increase in surface torque and drop in ROP; c) high fluctuations in WOB. To stabilize a whirling bit, it is recommended to pick up off-bottom and go through the break-in procedure again. Run a slower RPM and higher WOB to help reduce whirl.

Drilling Hard Stringers - As soon as the hard stringer is encountered, slow RPM down to 60-80. Increase WOB until acceptable ROP is reached or a plateau is reached where more WOB produces no gain in ROP. Maintain these parameters until the ROP begins to increase. When this occurs, resume former drilling WOB first, then increase RPM and optimize parameters again.

Reaming - Reaming is not recommended with PDC bits. The balance on these bits is predicated on the entire cutting structure being on bottom. Bit balance is non-existent when reaming, and bits readily whirl and slip-stick when reaming. If reaming is expected in your well plan, ask for a bit designed to ream and back ream BEFORE the well.

If reaming is required: ream with 40-60 RPM, and no more than 3-5000 lbs. WOB. When drilling directionally, keep the tool face aligned with the well bore curvature. When using a mud motor, use 20 to 40 rpm. Watch for slip-stick and whirl while reaming. Both can occur easily with the cutting structure off bottom.

ALWAYS ream with maximum flow rate. The bit hydraulic design assumes that the bit is on bottom. Off bottom, hydraulic efficiency is greatly reduced.

POOH - Slow down through tight spots. Watch for swabbing, especially with 12-1/4" and larger heavy set bits. They are FULL GAGE, and can swab in wells when mud balance is tight. Take the same care breaking the bit out and handling it as when new. In sticky formations, keep the pumps on at full rate whenever the drill string is moving up for connections and short trips.

TROUBLE SHOOTING

Bit Balling - Bit balling most commonly occurs when drilling smectite shales with WBM. The symptoms indicating balling are an extreme reduction of ROP, torque and increase of pump pressure. If the bit does ball, there are several techniques that can be used to remove the ball:

- **Clean the bit with Mud Flow**: The preferred method is to clean the bit with mud flow. To do this, pick up off-bottom, then lower the bit close to bottom without touching the cutting structure to the formation. Increase the flow rate to the maximum while turning the string at normal rpm. Stay in that position for 10 to 15 minutes. This will allow the fluid to flow and remove the ball.

- **Reduce ROP by reducing WOB**: By reducing the WOB, the depth of cut and ROP can be reduced. As a result, the volume of cuttings generated is reduced. With fewer cuttings the mud can more easily carry the cuttings away from the bit face.

- **Clean the ball off mechanically**: To do this, pick up off-bottom, then lower the bit close to bottom without touching the cutting structure to the formation. Turn the bit at the highest possible rpm with normal flow rates for short periods of time. The idea is to “sling” the ball off. There is a risk that this will cut or wash the hole larger, so this should be done after trying to clean the ball off with mud flow.

- Ultimately, if all methods fail to solve the bit balling problem, a different bit type should be selected that features allowing the bit to clean more easily

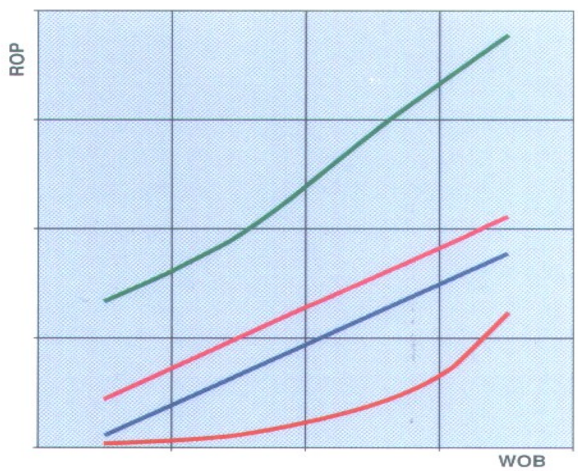
Plugged Nozzles – When a nozzle becomes plugged, you will see an increase in standpipe pressure while flow rate is constant. There are several methods for unplugging a nozzle:

- **Increased flow rate:** Pick the bit up off-bottom, and then lower the bit close to bottom without touching the cutting structure to the formation. Increase the flow rate to the maximum while turning the string at normal rpm. Stay in that position for 10 to 15 minutes. This will allow the fluid to wash away the plug. Sometimes the alternate pumping of low viscosity/ high viscosity mud will clear a plug from a nozzle.

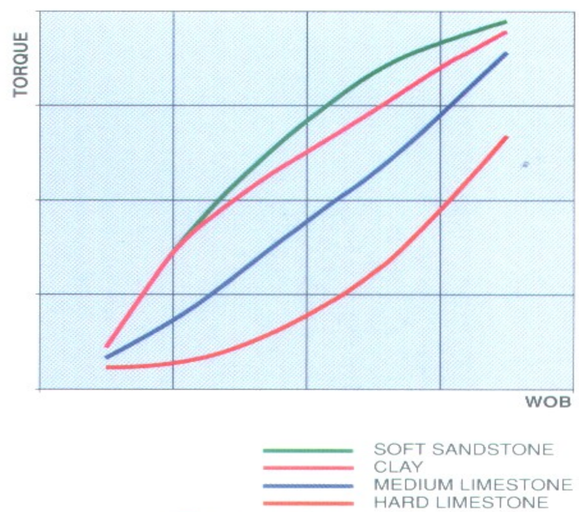
If you unable to clear the plugged nozzle and the rate of penetration are acceptable, the bit should be left in the hole. A bit with one plugged nozzle will often have an acceptable run? Sometimes the plug will clear given time to wash away.

Running parameters
Range parameters listed below are average parameters to maximize the performance of the PDC bit. Some applications may require higher parameters. In some cases, drilling environment may not allow to run the bit with recommended parameters, with an impact on the performance.

WOB
500-2000 (0.25-1t) per inch of bit diameter for soft formations (max 2500 lbs–1.1 t)
1000-2500 (0.5-1.1t) per inch of bit diameter for medium-soft formations (max 3000 lbs–1.4 t)
1500-4000 (0.7-1.8t) per inch of bit diameter for medium formations (max 4500 lbs–2.0 t)
2000-4000 (0.9-1.8t) per inch of bit diameter for medium formations (max 4500 lbs–2.0 t)



ROP/WOB curve



Torque/WOB curve

RPM

Nonabrasive formations – 100 to 180 rpm on rotary
Abrasive – 60 to 80 rpm

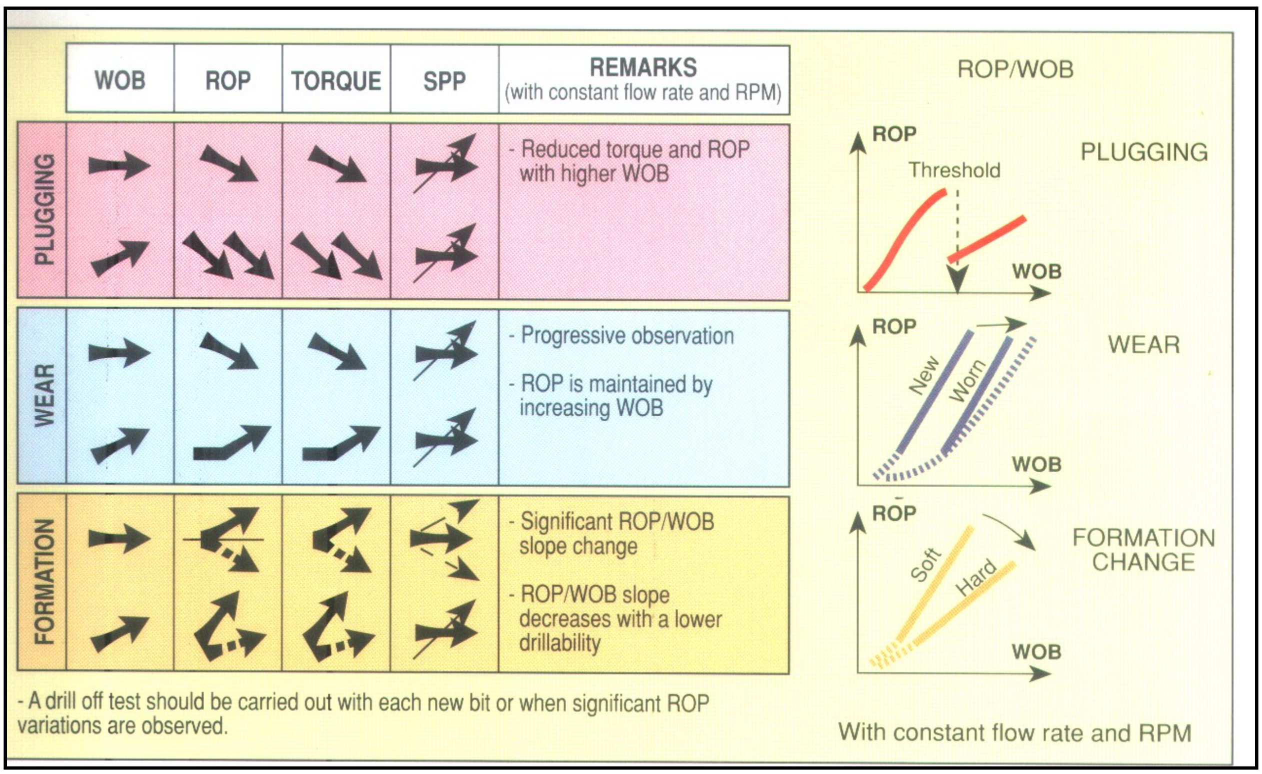
In soft formations, increasing the RPM can increase the ROP. Relative low bit weights are recommended.

Flow Rate	GPM	/ inch of diameter
17"1/2	800-1000 gpm (3000-4000 lpm)	45-57
12"1/4	600-750 gpm (2300-2800 lpm)	50-60
8"1/2	315-400 gpm (1200-1500 lpm)	37-47
6"	160-210 gpm (600-800 lpm)	20-35

HSI

1-5 in OBM
2-7 in WBM

Field analysis



TFA REFERENCE TABLE

Nozzle Size				Number of nozzles					
	1	2	3	4	5	6	7	8	9
7/32"	0.038	0.075	0.113	0.150	0.188	0.225	0.263	0.301	0.338
8/32"	0.049	0.098	0.147	0.196	0.245	0.295	0.334	0.393	0.442
9/32"	0.062	0.124	0.186	0.249	0.311	0.373	0.435	0.497	0.559
10/32"	0.077	0.153	0.230	0.307	0.383	0.460	0.537	0.614	0.690
11/32"	0.093	0.186	0.278	0.371.	0.464	0.557	0.650	0.742	0.835
12/32"	0.110	0.221	0.331	0.441	0.552	0.663	0.773	0.884	0.994
13/32"	0.130	0.259	0.389	0.518	0.648	0.778	0.907	1.037	1.167
14/32"	0.150	0.301	0.451	0.601	0.752	0.902	1.052	1.203	1.353
15/32"	0.173	0.345	0.518	0.690	0.863	1.035	1.208	1.381	1.553
16/32"	0.196	0.393	0.589	0.785	0.982	1.178	1.374	1.571	1.767
17/32"	0.225	0.450	0.675	0.900	1.125	1.350	1.575	1.800	2.025
18/32"	0.249	0.497	0.746	0.994	1.243	1.491	1.740	1.988	2.237
20/32"	0.307	0.614	0.920	1.227	1.534	1.841	2.148	2.454	2.761
22/32"	3.371	0.742	1.114	1.485	1.856	2.227	2.599	2.970	3.341
24/32"	0.442	0.884	1.325	1.767	2.209	2.651	3.093	3.534	3.976
26/32"	0.519	1.037	1.556	2.074	2.593	3.111	3.63	4.148	4.667

MAKE-UP TORQUE

Bit Diameter (inches)	API Connection	Recommended Torque
3-3/4 to 4-1/2”	2-3/8” REG	2400 - 2700 ft/lbs
4-5/8 to 4-7/8”	2-7/8” REG	4600 - 5100 ft/lbs
5 to 7-1/4”	3-1/2” REG	7800 - 8600 ft/lbs
7-1/2 to 9-1/4”	4-1/2” REG	16000 - 17000 ft/lbs
9-7/8 to 14-1/2”	6-5/8” REG	37100 - 40800 ft/lbs
14-3/4 to 18-1/2”	7-5/8” REG	64800 - 66200 ft/lbs

DRILL-OFF TEST PROCEDURE

Drill-off tests are methods for determining the optimum combination of WOB and RPM that yield the highest ROP (within other constraints).

Drill-off tests should be run when:

- Bit Run Start
- Formation change
- ROP change
- Torque change
- Changes in other operational parameters (hydraulics, mud properties, etc.)

1. Maintain constant RPM, build to the maximum practical WOB.
2. Lock the brake.
3. Record the time required to "drill-off" a predetermined weight increment (typically between 2000-5000 lbs.).
4. Continue until 'all' defined WOB are drilled off, and last should be at the same value as first test to be sure that formations didn't change.
5. The shortest time will indicate the optimum weight for that rotary speed.
6. Incrementally increase the RPM and repeat the above procedure. For hard formations or slow ROP conditions, increase the RPM in 5 to 20 RPM increments. For soft formations or high ROP conditions, increase the RPM in 10 to 40 RPM increments. Continue testing until the optimum is determined.

Time to Drill Off (seconds)

	RPM			
WOB KLbs	50	60	70	100
40-35				
35-30				
30-25				
25-20				
20-15				
40-35				

DRILL-ON TEST PROCEDURE

Drill-on tests are methods for determining the optimum combination of WOB and RPM that yield the highest ROP (within other constraints) without time loss.

Drill-on tests should be run when:

- Bit Run Start
- Formation change
- ROP change
- Torque change
- Changes in other operational parameters (hydraulics, mud properties, etc.)

1. Maintain constant RPM, build WOB in increments of 2000 Lbs.
2. Record the time required to drill 3ft of formation.
3. Continue until 'all' defined WOB are tested , and last should be at the same value as first test to be sure that formations didn't change.
4. The shortest time will indicate the optimum weight for that rotary speed.
5. Incrementally increase the RPM and repeat the above procedure. For hard formations or slow ROP conditions, increase the RPM in 5 to 20 RPM increments. For soft formations or high ROP conditions, increase the RPM in 10 to 40 RPM increments. Continue testing until the optimum is determined.

Ex: Time to Drill On 3 ft (seconds)

	RPM			
WOB KLbs	**50**	**60**	**70**	**100**
10				
12				
14				
16				
18				
20				
10				