In the name of God

Drilling Engineering -1

Designed for PUT Undergraduate Program

PART-1

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1. Overview of Drilling Operation

- Introduction
- Drilling Personnel
- The Drilling Proposal and Drilling Program
- The Drilling Process (Making a hole)
- Offshore Drilling
- Drilling Economics

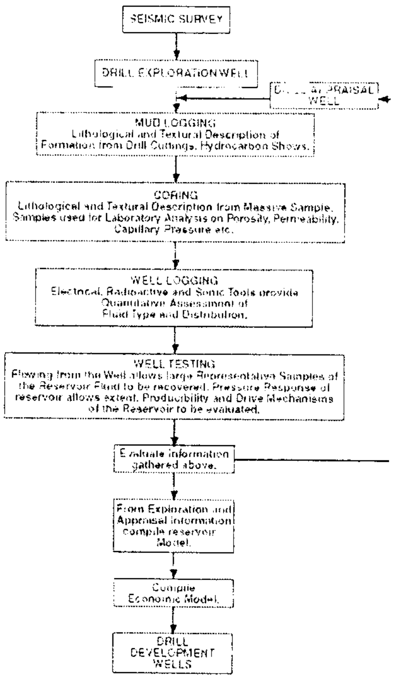
Introduction

- **Drilling License** (Prior to applying for a production licence the exploration geologists will conduct a 'scouting' exercise in which they will analyse any seismic data they have acquired, analyse the regional geology of the area and finally take into account any available information on nearby producing fields or well tests performed in the vicinity of the prospect they are considering. The explorationists in the company will also consider the exploration and development costs, the oil price and tax regimes in order to establish whether, if a discovery were made, it would be worth developing.

The life of an **oil or gas fileld** can be sub-divided into the following phases:

• **Exploration Phase**: The length of phase will depend on the success or otherwise of the exploration wells.(one or many exploration wells)
• **Appraisal Phase:** If an economically attractive discovery is made on the prospect then the company enters the **Appraisal** phase of the life of the filled. More seismic lines may be shot and more wells will be drilled to establish the lateral and vertical extent of the reservoir.
• **Development Phase:** Economic Production from the field
• **Maintenance Phase:** (work over, Gas or water injection IOR)
• **Abandonment Phase:** At some point in the life of the field the costs of production will exceed the revenue from the fi eld and the fi eld will be abandoned .

Role of drilling in field development



Well Classifications

Onshore — Offshore

Exploration

Appraisal / Delineation

Development

Production (Oil, Gas) | Observation | Injection (Gas, Water, IOR)

Infill | Re-drills + Recompilations | Relief

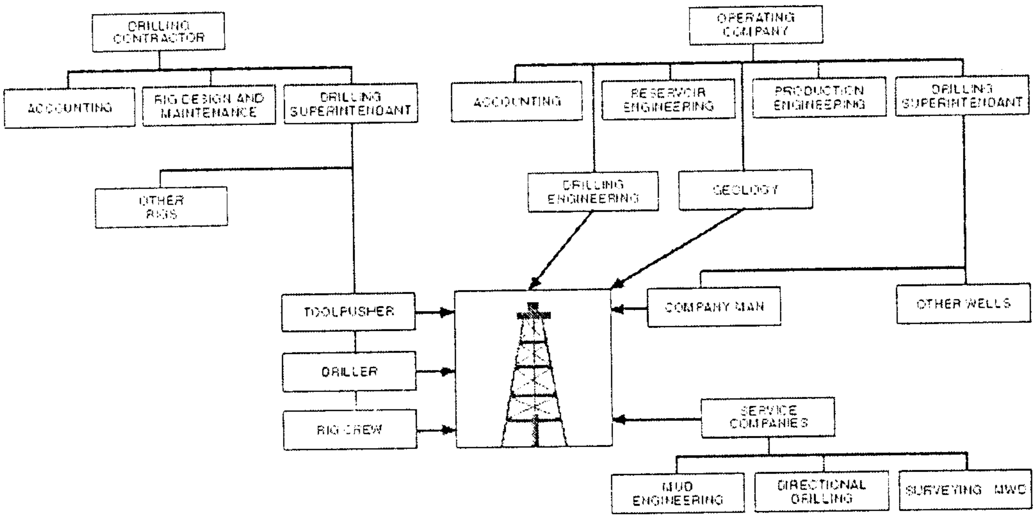
Drilling Personnel

The **drilling contractor** owns and maintains the drilling rig and employs and trains the personnel required to operate the rig.
During the course of drilling the well certain specialized skills or equipment may be required (e.g. logging, surveying).These are provided by **service companies** . These service companies develop and maintain specialist tools and staff and hire them out to the operator, generally on a day-rate basis.

The **operator** will generally have a representative on the rig (sometimes called the **"company man"**) to ensure drilling operations go ahead as planned, make decisions affecting progress of the well, and organize supplies of equipment. He will be in daily contact with his **drilling superintendent** who will be based in the head office of the operator. There may also be an oil company ***drilling engineer*** and/or a **geologist** on the rig.

The drilling contractor will employ a **tool pusher** to be in overall charge of the rig. He is responsible for all rig floor activities and liaises with the company man to ensure progress is satisfactory. The manual activities associated with drilling the well are conducted by the drilling crew. Since drilling continues 24 hours a day, there are usually 2 drilling crews. Each crew works under the direction of the **driller** . The crew will generally consist of a **derrick man** (who also tends the pumps while drilling), 3 **rughnecks** (working on rig floor), plus a mechanic, an electrician, a crane operator and **roustabouts** (general labourers).

Drilling Personnel



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Drilling Personnel

The oil company who manages the drilling and/or production operations is known as the **operator**

There are many different management strategies for drilling a well but in virtually all cases the oil company will employ a **drilling contractor** to actually drill the well. The drilling contractor owns and maintains the drilling rig and employs and trains the personnel required to operate the rig.

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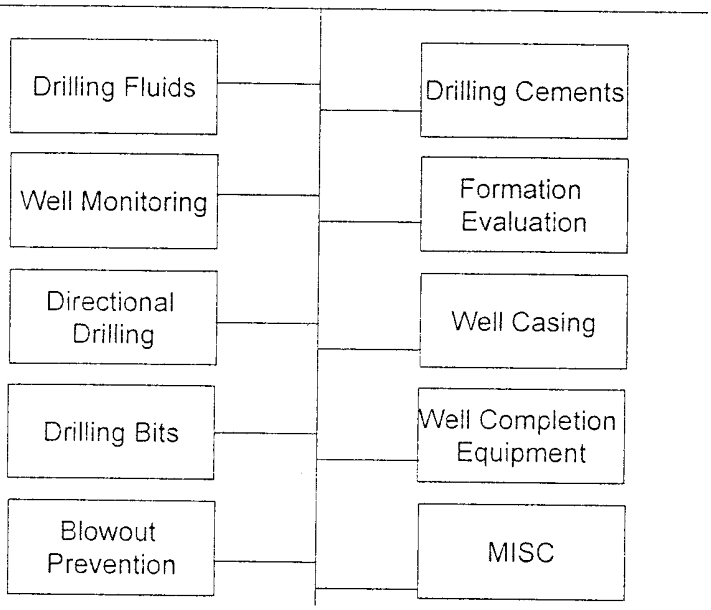
Drilling Service Companies



Drilling Proposal and Drilling Program

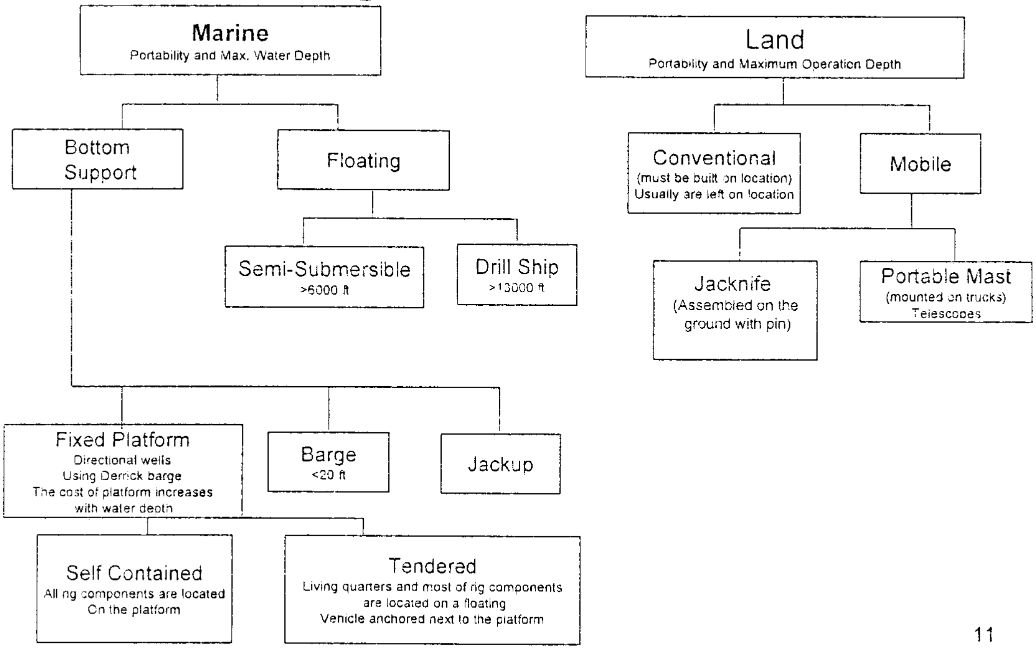
Geological Forecast:

- Objective of the Well
- Depth (m/ft Sub-sea), and Location (Longitude and Latitude) of Target
- Geological Cross Section
- Pore Pressure Profile Prediction

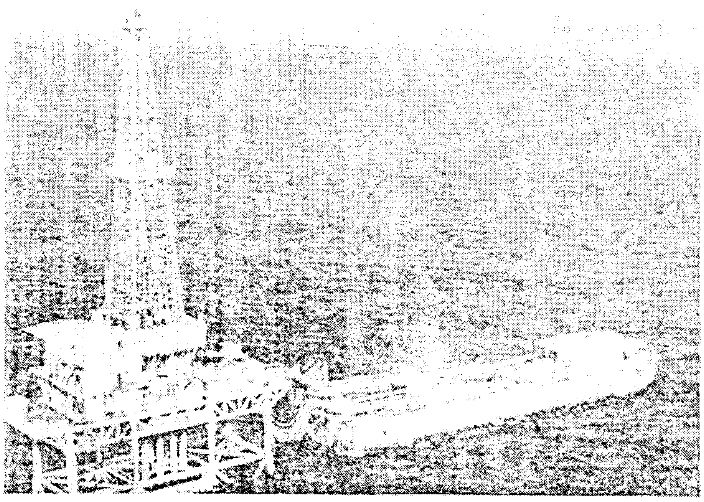
Drilling Program:

- Drilling Rig to be used for the well
- Proposed Location for the Drilling Rig
- Hole Sizes and Depths
- Casing Sizes and Depths
- Drilling Fluid Specification
- Directional Drilling Information
- Well Control Equipment and Procedures
- Bits and Hydraulics Program
- Completion program

Rig Classifications

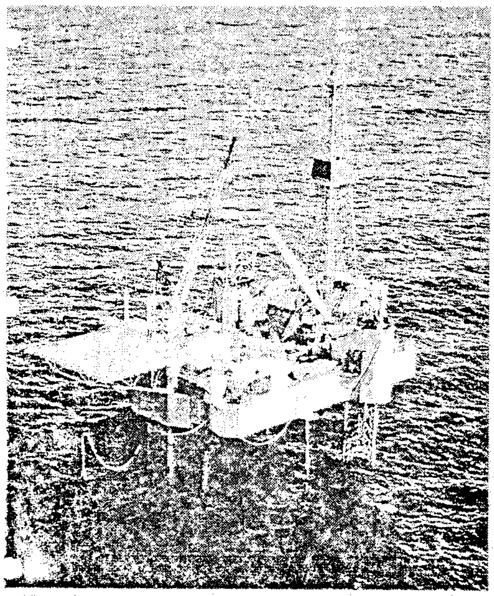


Tendered



A tendered platform rig.[12]

Jackup rigs



NOBEL DRILLING'S CECIL FORBES — A JACK-UP RIG

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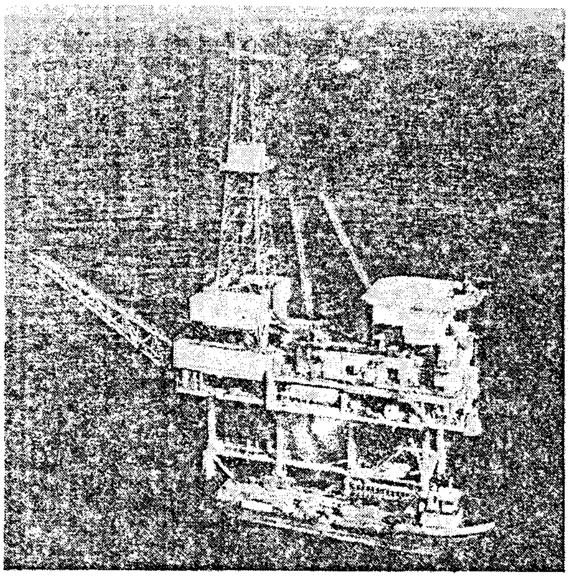
Self contained



– A self-contained platform rig on location in the Eugene Island area, offshore Louisiana.

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Selecting a Drilling Rig

- Main factors:

1- Loading "Capacity" or strength of Derrick

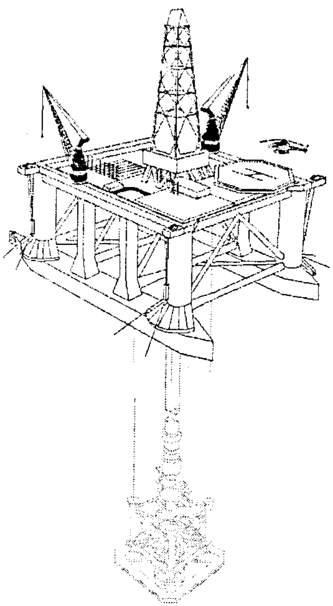
2- Lifting capacity o hoisting equipment i.e. draw-works, cable strength, number of lines in pulley arrangements

3- Mobility expected

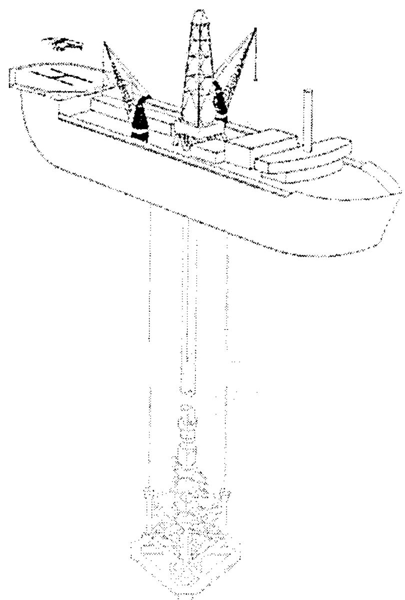
4- Climate conditions, wind strength, rain fall

5- Type of substructure required.

Offshore Drilling

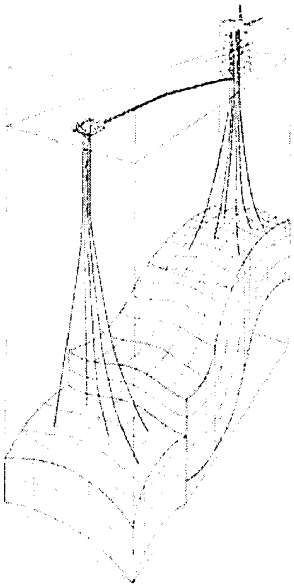


Semi-Submersible Rig (3500 ft)

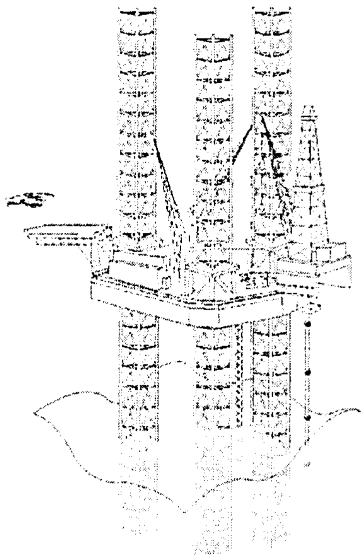


Drilling Ship (very deep water, 7500 ft)

Offshore Drilling

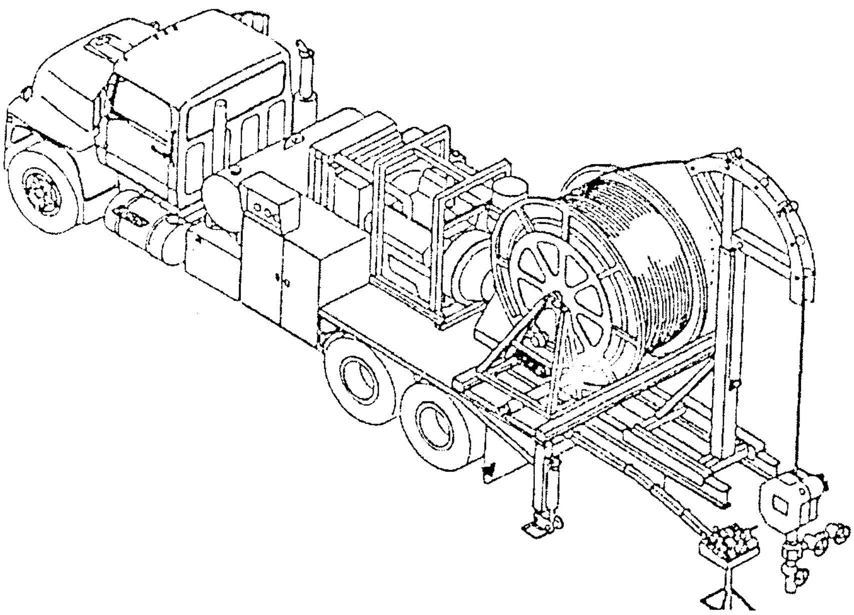


Fixed Platform

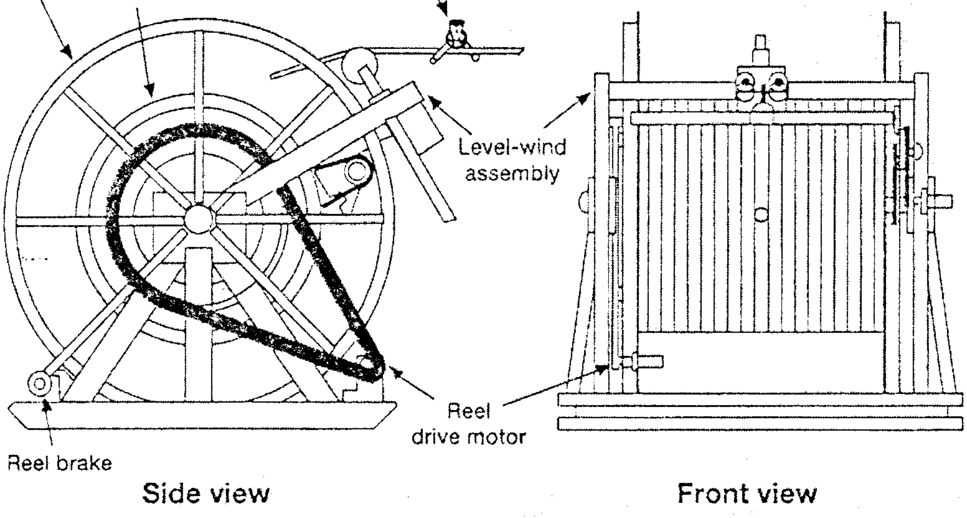


Jack-Up Rig (350 ft)

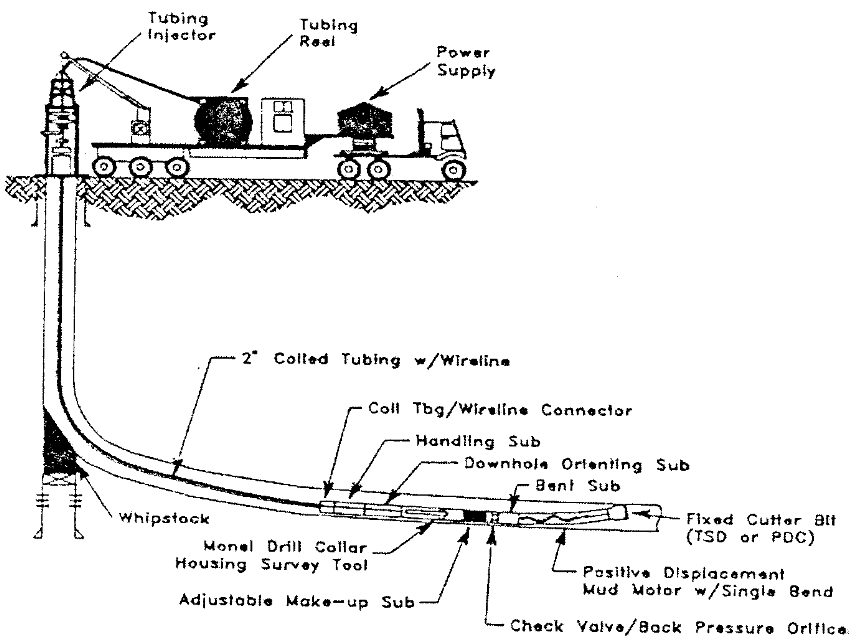
Truck-Mounted Coiled Tubing Reel Assembly



Coiled Tubing Reel Assembly



Coiled Tubing Drilling



The Drilling Process

- The operations involved in drilling a well can be best illustrated by considering the sequence of events involved in drilling the well shown in Figure:

-not possible to drill the whole well in one sizebecause of geological and formation pressure problems which are encountered whilst drilling.
The drilling engineer must assess the risk of encountering these problems,

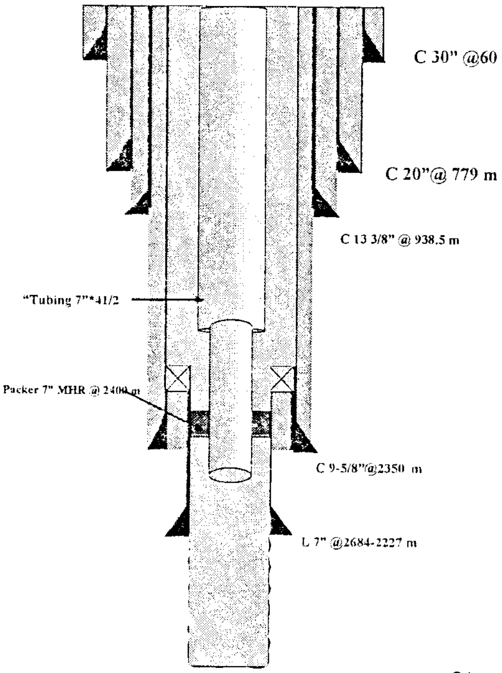
-Hole conditioning

-Wireline logging

-Coring

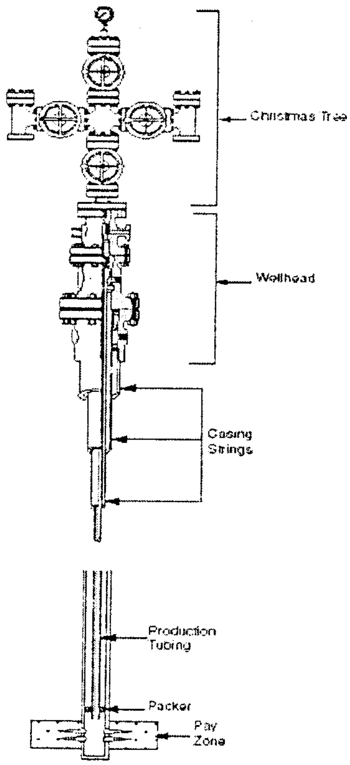
-DST

-Completing the well



Well Completion

- Bare feet Completion
- Slotted Liner
- Cemented liner
- Perforated liner
- Dual completion
- Urban completion
- Gas / Water injector Completion



Drilling economics

- Before a drilling programme approved it must contain an estimate of the overall cost involved.

-25%- 30% of the total development costs for an offshore field

-Some costs are related to time and therefore are called **time-related costs.** (drilling contracts, transport, accommodation)

-Many of the consumable times (e.g. casing, cement) are related to depth and therefore are often called **depth- related costs**.

-Some of consumable items are fixed (e.g. Wellhead): **Fixed costs.**

	Cost ($ million)
Platform structure	230
Platform equipment	765
Platform installation	210
Development drilling	475
Pipeline	225
Onshore facilities	50
Miscellaneous	120
Total	2075

Estimated development costs (Brae Field)

Drilling economics

Breakdown of Well Costs	($'000)	(%)
Wellhead	105	1.1
Flowline and surface equipment	161	1.7
Casing and downhole equipment	1465	15.5
Sub-total	1731	18.3
Drilling contractor	2061	21.8
Directional drilling/surveying	319	3.4
Logging-testing/perforating	603	6.4
Mud processing/chemicals	858	9.1
Cementing	288	3.0
Bits	282	3.0
Sub-total	4411	46.7
Transport	1581	16.7
Equipment rental	391	4.1
Communications	120	1.3
Mobilisation	686	7.3
Power and fuel	225	2.4
Supervision	300	3.2
Sub-total	3303	35.0
Total well cost	$9,445,000	

Drilling Economics

An operator and contractor have some different objectives:

Operator

Obtain well to fulfill requirements (provide information, access the reservoir at minimum cost)

Contractor

Maximise profit from drilling the well

• The operator does not directly make money out of drilling a well, (benefit is solely from the information obtained and/ or the potential for extra hydrocarbon recovery)

• The drilling contractor's only business is (usually) drilling wells

Drilling Economics

Drilling Contracts:

Contact Type	Effect on Operator	Effects on Contactor
-Day rate	* Full risk * Total control	* No risk * No incentive for speed or maintenance
- Day rate + Maintenance Bonus	* Full risk * Total control	* No risk ·Incentive for maintenance *No incentive for speed
- Day rate + Footage Bonus	* Full risk * Total control	* No risk * Incentive for Efficiency
-Footage	* Less risk * No control	* More risk * More incentive for Efficiency
-Turnkey	* No risk * No control	* Full risk * Full control

Well Costs

Well costs for a single well depend on:

1. Geographical location: land or offshore, country
2. Type of well: exploration or development, HPHT or sour gas well
3. Drillability
4. Hole depth
5. Well target(s)
6. Profile (vertical/ horizontal /multilateral)
7. Subsurface problems
8. Rig costs: land rig, jack-up, semi-submersible or drillship and rating of rig
9. Completion type
10. Knowledge of the area: wildcat, exploration or development

The total well costs for a development drilling programme comprising several wells depend

Drilling Time Estimate

The time spent on a well consists of:

• Drilling times spent on making hole, including circulation, wiper trips and tripping, directional work, geological sidetrack and hole opening.

• Flat times spent on running and cementing casing, making up BOPS and wellheads.

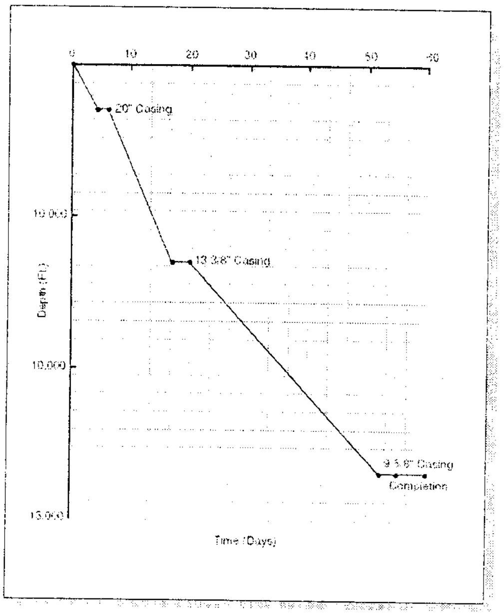
• Testing and completion time.

• Formation evaluation time including coring, logging etc.

• Rig up and rig down of rig.

• Non-productive time, (NPT)

Drilling Economics



Time breakdown for a North Sea well (fixed platform)		
	HOURS	%
Drill	552.0	41.9
Trips/Lay Down Drill Pipe	195.0	14.8
Directional Surveys	104.0	7.9
Core/Circ. Samples	91.5	6.9
Guide Base/Conductor	60.0	4.6
Wash/Ream/Clean Out Borehole	59.0	4.5
Lost Time	49.5	3.8
Run Casing/Tubing/Packer	37.5	2.8
Nipple down, up/Run Riser	37.0	2.8
Log/Set Packer/Perforate	26.5	2.0
Test Bops/Wellhead	25.0	1.9
Rig Maintenance	20.5	1.6
Circ. & Cond. Displace Mud	20.5	1.5
Fishing/Milling	20.0	1.5
Cement/Squeeze/WOC	18.0	1.4
Rig Down/Move/Rig Up	2.5	0.2
TOTAL	1318.5hrs (55 days)	100.0

Drilling cost

$$C_f = \frac{C_b + C_r(t_b + t_t)}{D} \qquad \frac{\$}{ft}$$

C_f = drilling cost, \$/ft

C_b= cost of bit, \$/bit

C_r= fixed operating cost of rig, \$/hr

t_b= total rotating time, hrs

t_t= trip time (round trip), hrs

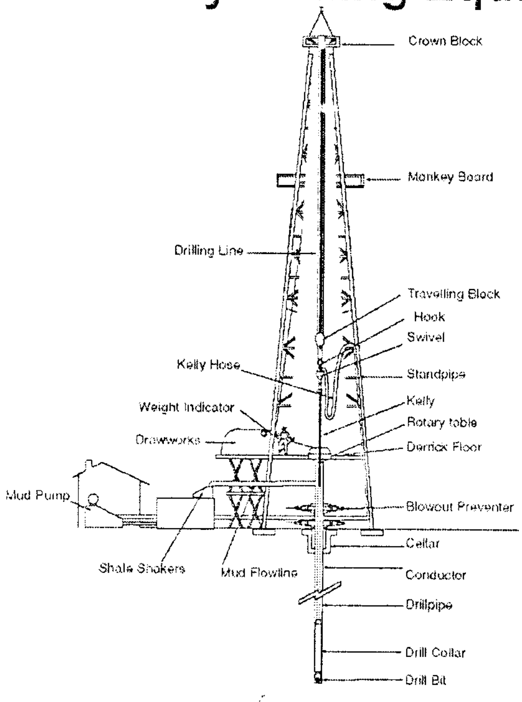
D = footage drilled with bit, ft

2. Rig Components

Objectives:
Describe the six major sub-systems of a drilling rig and the function of each system.

1. Power System
2. Hoisting system
3. Circulating system
4. Rotary system
5. Well control system
6. Well monitoring system

Rotary Drilling Equipment



2.1 Power System

- Steam power at older rigs

Most of power system is consumed by the hoisting and fluid circulating systems.

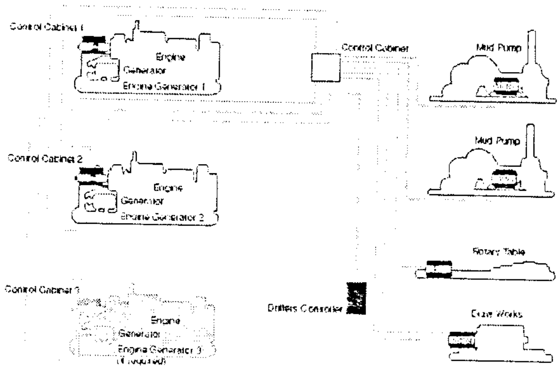
The hosting and circulating systems are not used simultaneously.

Total power requirements for most rigs are from 1000 to 3000 hp.

Diesel Engines:

1)The diesel-electric type

2)The direct derive (compound: gears, chains, belts, clutches etc) [Advantages: eliminating the need for aligning the compound, less noise]



Electricity is supplied to electric motors connected to the **drawworks, rotary table** and **mud pumps.**

2.2 Hoisting system

The hoisting system is a large pulley system which is used to lower and raise equipment into and out of the well. In particular, it is used to raise and lower the drillstring and casing into and out of the well.

The principal components:

1)The derrick and mast

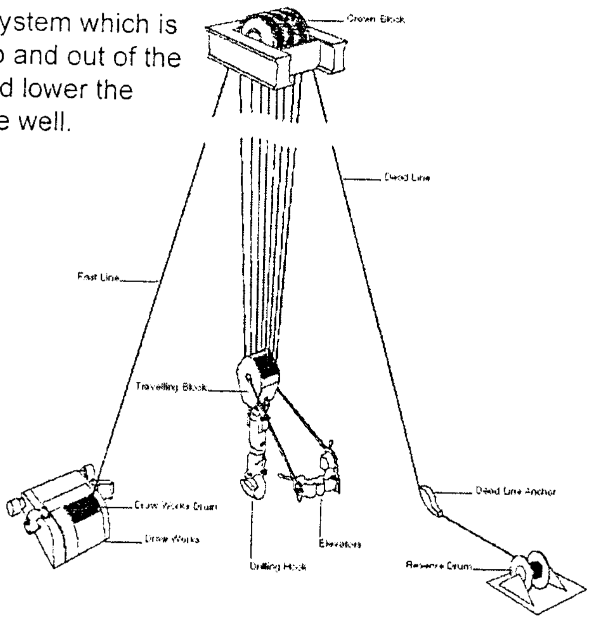
2) The block and tackle (the crown, the travelling block & the drilling line [fast and dead line])

3) The drawworks

Two routine functions:

1) Making a connection

2) Making a trip



Derrick

The derrick is a steel framework of lattice construction whose function is to take the weight of the drill string. (140 ft)

- To support the rig floor, providing space for equipment and workers
- To provide space under floor for special large valves called BOPs

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Types of Derricks

- **Triple:** has the capacity of pulling 90' stands of pipe
- **Double:** has the capacity of pulling 60' stands of pipe
- **Single:** has the capacity of pulling 30'stands of pipe (one
- 30-ft joint)

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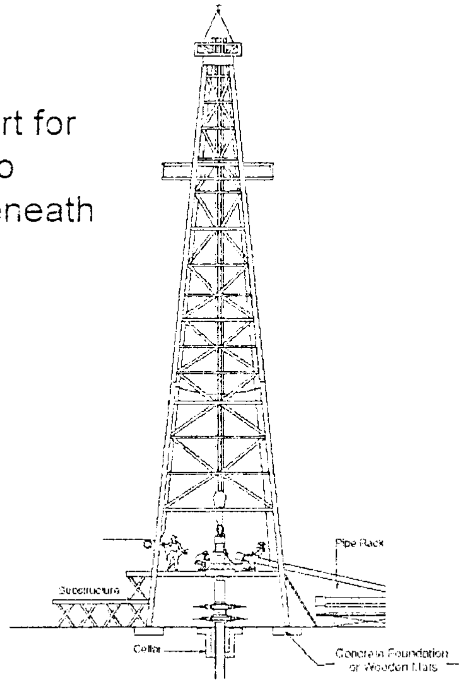
Substructure

The substructure provides the support for the derrick and derrick loading. It also provides the necessary clearance beneath the rig floor for the preventor stack.



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The block and tackle

The principal function of the block and tackle is to provide a mechanical advantage which permits easier handling of large loads.

The block and tackle is comprised of:

- The crown block
- The travelling block
- The drilling line

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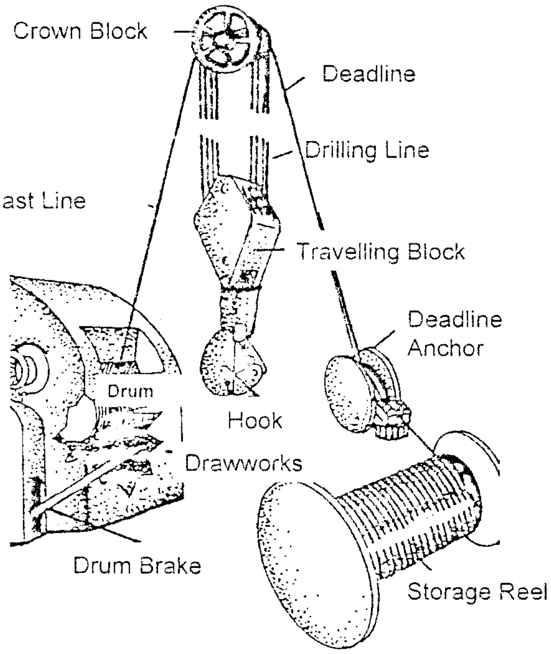
The block and tackle



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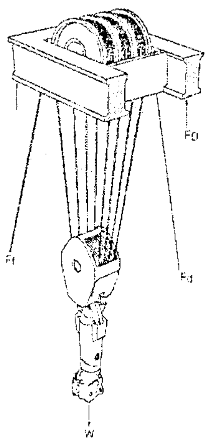
Crown Block

A series of sheaves affixed in the top of the derrick used to change the direction of pull from the drawworks to the traveling block.

The mechanical advantage M of a block and tackle is the load supported by the travelling block, W, divided by the load imposed on the drawworks, F_f:

$$M = \frac{W}{F_f}$$



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The Travelling Block

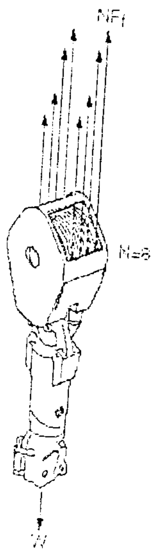
The tensile load (lbs.) on the drilling line, and therefore on the fast line, F_f and dead line F_d in a frictionless system can be determined from the total load supported by the drilling lines, W (lbs.) and the number of lines, N reeved around the crown and travelling block:

$$F_f = F_d = W/N$$

$$M = \frac{W}{F_f} = \frac{W}{W/N} = N$$

The input power P_i of the block and tackle is equal to the drawworks loads F_f times the velocity of fastline, v_f.

$$P_i = F_f v_f$$



Free body diagram of traveling block

The Travelling Block

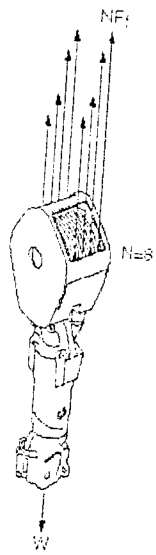
The output power of, or Hook power P_h is equal to the travelling block load W times the velocity of travelling block, v_b:

$$P_h = W v_b$$

$$v_b = v_f / N$$

In a frictionless system :

$$E = \frac{P_h}{P_i} = \frac{(NF_f)(v_f / N)}{F_f v_f} = 1$$



Free body diagram of traveling block

The Travelling Block

There is however inefficiency in any pulley system. The level of inefficiency is a function of the number of lines . An example of the efficiency factors for a particular system is shown in Table below.
The tensile load on the drilling line and therefore on the fast line will then be :

$$F_f = \frac{W}{EN}$$

For a four sheave, roller bearing system

Number of Lines, N	Efficiency, E
6	0.874
8	0.841
10	0.81
12	0.77
14	0.74

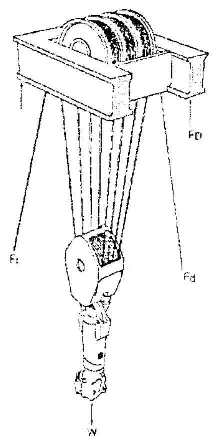
The load on the deadline will not be a function of the inefficiency because it is static.

The block and tackle

Total load applied to the derrick, F_D:

$F_D = W + F_f + F_d$

$$F_D = W + \frac{W}{EN} + \frac{W}{N} = (\frac{1 + E + EN}{EN})W$$



Example

A drillstring with a buoyant weight of 200,000 lbs must be pulled from the well. A total of 8 lines are strung between the crown block and the travelling block. Assuming that a four sheave, roller bearing system is being used.

a. Compute the tension in the fast line
b. Compute the tension in the deadline
c. Compute the vertical load on the rig when pulling the string

a. The tension in the fast line :

$$T_F = \frac{200,000}{8 \times 0.842}$$

$$T_F = 29691 \text{ lbs}$$

b. The tension in the deadline

$$T_D = \frac{200,000}{8}$$

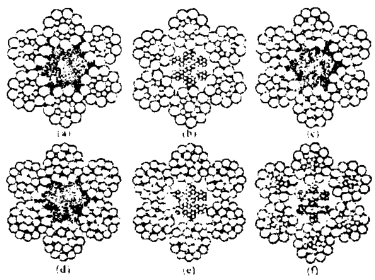
$$T_D = 25000 \text{ lbs}$$

c. The vertical load on the rig when pulling the string

$$\text{Total} = 200000 + 29691 + 25000$$
$$= 254691 \text{ lbs}$$

Drilling line

The drilling line is basically a wire rope made up of strands wound around a steel core. Each strand contains a number of small wires wound around a central core.



(a) 6 x 19 Seale with fibre core; (b) 6 x 19 Seale with independent wire rope core; (c) 6 x 21 filler wire with fibre core; (d) 6 x 25 filler wire with fibre core; (e) 6 x 25 filler wire with independent wire rope core; (f) 6 x 25 Warrington Seale with independent wire rope core.

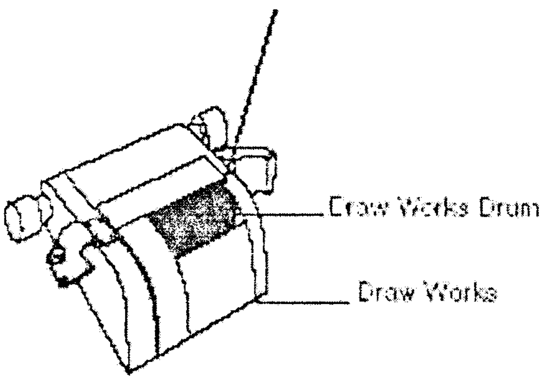
Drawworks

The principal function is to convert the power source into a hoisting operation and provide braking capacity to stop and sustain the weights imposed when lowering or raising the drill string.

A. The drum
B. The cathead
C. Brake system [mechanical break, hydraulic or electrical]
D. System of speed changes (transmission systems)

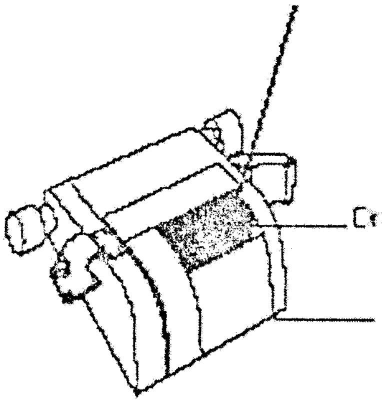
Drum

The drum is housed in the drawworks and transmits the torque required for hoisting and braking. It also stores the drilling line required to move the traveling block the length of the derrick.



Cathead

The cathead is a shaft with a lifting head that extends on either side of the drawworks and has two major functions. It is used in making up and breaking out tool joints in the drill string. It is also used as a hoisting device for heavy equipment on the drill floor.



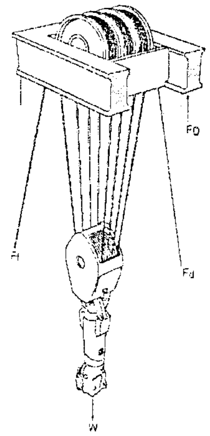
Hoisting System

The procedure for carrying out hoisting design calculations are as follows:

- Determine the deepest hole to be drilled
- Determine the worst drilling loads or casing loads
- Use these values the select the drilling line, the derrick capacity and in turn the derrick

Hook

The hook is located beneath the traveling block. This device is used to pick up and secure the swivel and kelly.



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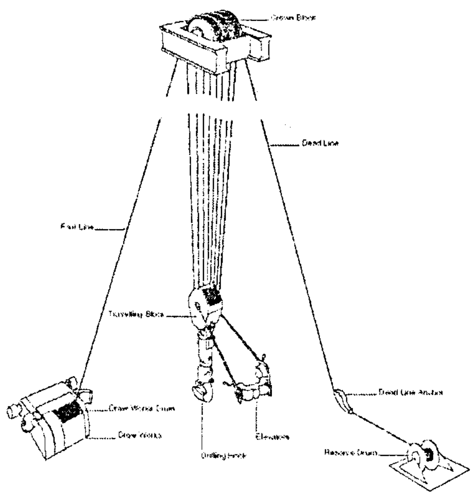
Elevators

The elevators are used for latching on to the tool joint or lift sub of the drill pipe or drill collars. This enables the lifting and lowering of the drill string while making a trip. The elevators are connected to the hoisting system (traveling block) by means of bails.



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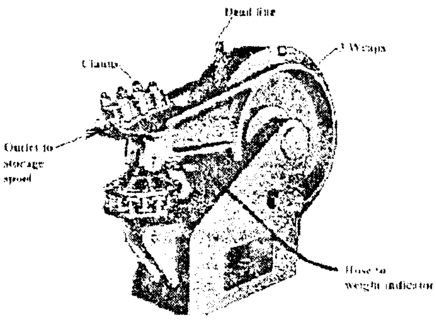
Sandline

The sandline is a small drawworks system. The line is generally used for running surveys or fishing for lost surveys. These units are usually integral parts of the drawworks.

Dead Line Anchor

Dead Line Anchor: anchors the last line coming from the crown block and also stores drilling line on a reel. This allows new lengths of line to be fed into the system to replace the worn parts of the line that have been moving on the pulleys of the crown block or the travelling block.

- The worn parts are regularly cut and removed by a process called: **Slip and Cut Practice**. Slipping the line, then cutting it off helps to increase the lifetime of the drilling line.



2.3 Circulating System

The principal purposes of circulating fluid are to:

1) Clean the bottomhole
2) Cool the bit
3) Flush cuttings from the hole
4) Support the walls of the well so that they do not cave in
5) Prevent the entry of formation fluid into the borehole

Mud:

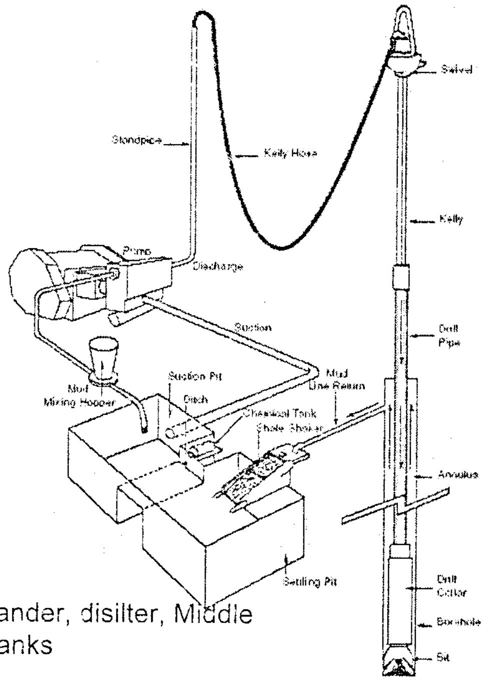
-A mixture of water, clays, weighting material and chemicals

- Mixed in mud pits and then circulated downhole by slash pumps

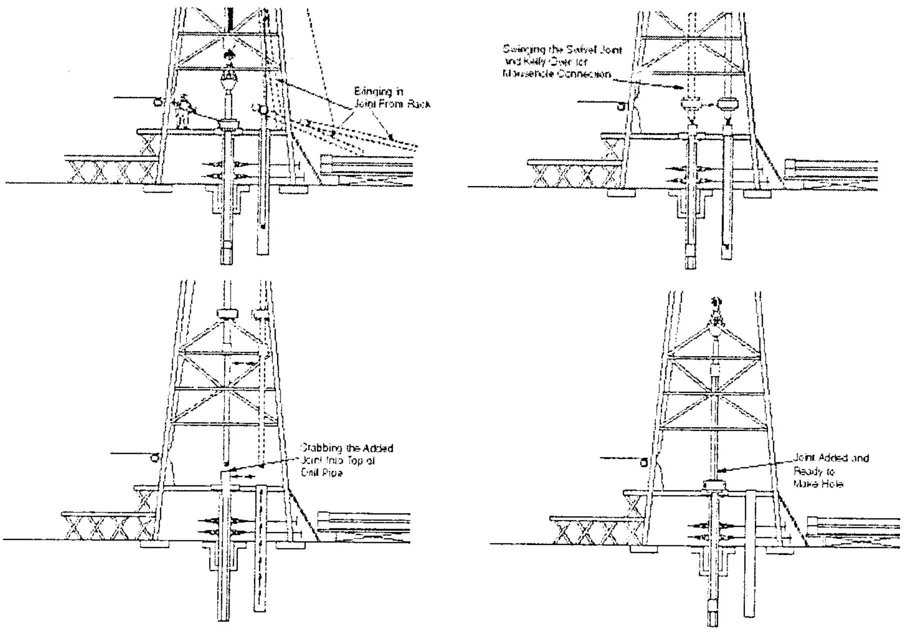
- Is pumped through standpipe, kelly house, swivel, kelly and down the string.

- Then is directed through flow line and solid removal equipment.

Shale shaker, degaser, sand trap, desander, disilter, Middle tank, suction tank, Mixing or Reserve tanks



Making a connection



Circulating System

- Swivel: Whilst drilling rotation is applied to the drilling string and to prevent the rotation being exerted on the travelling block
- Kelly: is a square or hexagonal shaped steel tube., transmit the toque, sustains very high tensile loads, rotating whilst being lowered through rotary table (chrome molybdenum steel)
  Length: depends on average DPs length: 42' (for 30' DPs); 56' (for 40' DPs)
  Size: 3", 3.5", 4.5", 5"
  - Kelly cocks: is a valve installed to isolate the Kelly from high well pressure or back flow.
  - Kelly saver sub

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Mud Pumps

Mud pumps are used for circulating the drilling fluid down the drill pipe and out of the annulus. These are high-pressure and high-volume pumps. They can be double-acting duplex pumps or single-acting triplex pumps.

A.The double-acting duplex pump hasfour pumping actions per pump cycle.

B. The single-acting triplex pump has three pumping actions per pump cycle.

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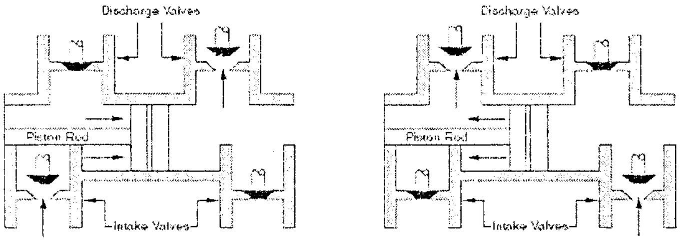
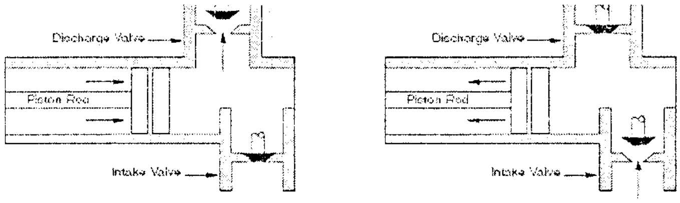
Positive Displacement Type Pumps



Duplex pump (Double acting) - Land Rigs

Pump on the up-stoke and down-stroke



Triplex pump (Single acting) - Offshore Rigs

Pump on Up-stroke only

Have two cylinders, are lighter, Smoother discharge and lower maintenance cost

Positive Displacement Type Pumps

-At least two pumps on each rig

-Advantages of using PDM pumps:

- -Pump fluid containing high solid contents
- -Operate over a wide range of Pressure and flow rates
- - They are reliable
- -Simple to operate and easy to maintain

Flow rate and discharge pressure:

The flow rate and pressure delivered by the pump depends on the size of sleeve (liner) that is placed on the cylinders of the pumps

Power: $HHP = \frac{PQ}{1714}$

Where,

HHP= Horsepower

P= Pressure (psi)

Q= Flow rate (gpm)

Since the power rating of a pump is limited (generally to about 1600 hp) and that the power consumption is a product of the output pressure and flowrate, the use of a smaller liner will increase the discharge pressure but reduce the flow rate and vice versa. It can be seen from the above equation that when operating at the maximum pump rating, an increase in the pump pressure will require a decrease in the flowrate and vice versa. The pump pressure will generally be limited by the pressure rating of the flowlines on the rig and the flowrate will be limited by the size of the liners in the pump and the rate at which the pump operates.

Positive Displacement Type Pumps

Mechanical Efficiency E_m: related to the operation of the prime movers and transmission system (~0.9)

Volumetric Efficiency E_v: depends on the type of pump being used (0.9-1)

The Overall Efficiency# $E_m \times E_v$

Duplex Pumps

The theoretical displacement on the forward stroke:

$$V_1 = \frac{\pi d^2 L}{4}$$

d= liner diameter

L= stroke length

On the return stroke

$$V_2 = \frac{\pi (d^2 - d_r^2) L}{4}$$

d_r= rod diameter

Duplex Pumps

Taking account of the 2 cylinders, and the volumetric efficiency Ev the total displacement (in gallons) of one pump revolution is:

$$2(V_1 + V_2)E_v = \frac{2\pi(2d^2 - d_r^2)LE_v}{4}$$

The pump output can be obtained by multiplying this by the pump speed in revolutions per minute. (In oilfield terms 1 complete pump revolution = 1 stroke, therefore pump speed is usually given in strokes per minute) e.g. a duplex pump operating at a speed of 20 spm means 80 cylinder volumes per minute. Pump output is given by:

$$Q = \frac{(2d^2 - d_r^2)LE_vR}{147}$$

where,
Q = flow rate (gpm)
d = liner diameter (in.)
d_r = rod diameter (in.)
L = stroke length (in.)
R = pump speed (spm)

Triplex Pumps

In triplex pumps the piston discharges in only one direction, and so the rod diameter does not affect the pump output. The discharge volume for one pump revolution is:

$$= 3V_1E_v = \frac{3\pi d^2LE_v}{4}$$

Again the pump output is found by multiplying by the pump speed:

$$Q = \frac{d^2LE_vR}{98.03}$$

where,
Q = flow rate (gpm)
L = stroke length (in.)
d = liner diameter (in.)
R = pump speed (spm)

Example

Calculate the following, for a triplex pump having 6 in. liners and 11 in. stroke operating at 120 spm and a discharge pressure of 3000 psi.

a. The volumetric output at 100% efficiency

b. The Horsepower output of the pump when operating under the conditions above.

a. The volumetric output at 100% efficiency

$$Q = \frac{6^2 \times 11 \times 1.0 \times 120}{98.03}$$

$$= 485 \text{ gpm}$$

b. The Horsepower output of the pump when operating under the conditions above.

$$HP = \frac{3000 \times 485}{174}$$

$$= 849 \text{ hp}$$

Advantages of Triplex Pumps

- More power can be delivered using a triplex pump since higher pump speeds can be used.
- The efficiency of a triplex pump can be increased by using a small centrifugal pump to provide fluid to the suction line.
- Triplex pumps are generally lighter and more compact than duplex pumps of similar capacity, and so are most suitable for use on offshore rigs and platforms.

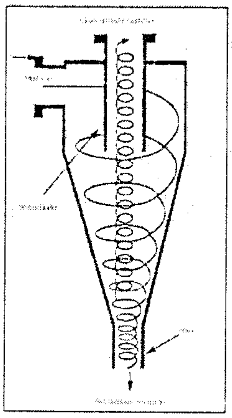
Shale Shaker

The shale shaker is a contaminant removing device. It is used to remove the coarser drill cuttings from the mud. This is generally the first solids-removing device and is located at the end of the flow line. The shale shaker is composed of one or more vibrating screens though which mud returns pass.

Desander & Desilter

The desander and desilters are for contaminant or solids removal purposes. These devices separate sand-size particles from the drilling mud. Both devices operate like a hydrocyclone. The mud is pumped in at the top of the cyclone. This causes the mud stream to hit the vortex finder which forces the mud down the cyclone in a whirling fashion towards the apex of the cyclone. The heavier particles are forced outward faster than the smaller particles. The heavier particles on the outside of the whirling fluid are deposited out of the apex while the much smaller particles follow the path of the liquid and reverse their path in the center and flow out of the cyclone through the vortex finder.

Hydrocyclone



Degasser

This vessel is used for gas contamination removal. It consists of a vessel which has inclined flat surfaces in thin layers and a vacuum pump. The mud is allowed to flow over the inclined thin layers which helps break out entrained gas in the mud. The vacuum pump reduces the pressure in the vessel to about 5 psia which extracts the gas from the mud. This device is about 99% efficient.

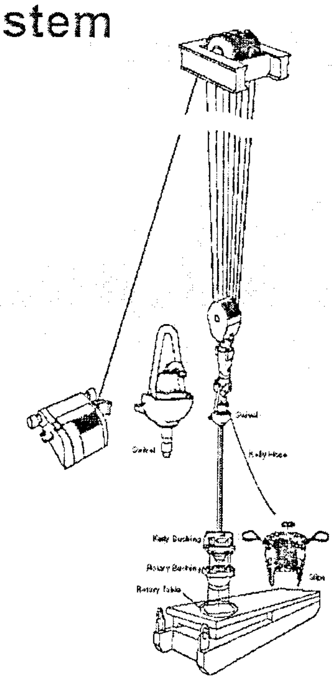
2.4 Rotary System

Rotary table: clockwise & anticlockwise rotation, RPM controlled from the drilling console

Master Bushing

Kelly Bushing

Slips



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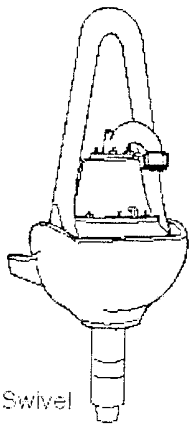
Swivel

The *swivel* is positioned at the top of the drillstring. It has 3 functions:

- Supports the weight of the drill string
- Permits the string to rotate
- Allows mud to be pumped while the string is rotating



Swivel

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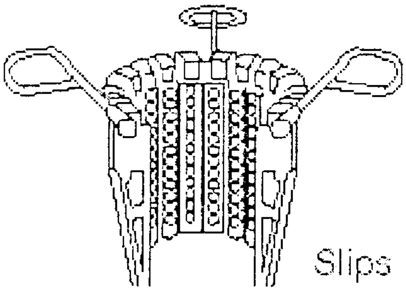
Kelly

The square or hexagonal member at the upper most part of the drill string (immediately below the swivel) that passes through a properly fitting bushing known as the kelly bushing or drivebushing. The drive bushing transmits rotary motion to the kelly which results in the turning of the drill string.

Slips

Slips are used to suspend pipe in the rotary table when making or breaking a connection. Slips are made up of three tapered, hinged segments, which are wrapped around the top of the drillpipe so that it can be suspended from the rotary table when the top connection of the drillpipe is being screwed or unscrewed. The inside of the slips have a serrated surface, which grips the pipe .



Kelly Bushing / Drive Bushing

That bushing which fits inside the rotary bushing and transmits rotary torque to the kelly.

The torque from the rotary table is transmitted to the kelly through the four pins on a device which runs along the length of the kelly, known as the **kelly bushing**. The kelly bushing has 4 pins, which fit into the post holes of the rotary table. When power is supplied to the rotary table torque is transmitted from the rotating table to the kelly via the kelly bushing. The power requirements of the rotary table can be determined from:

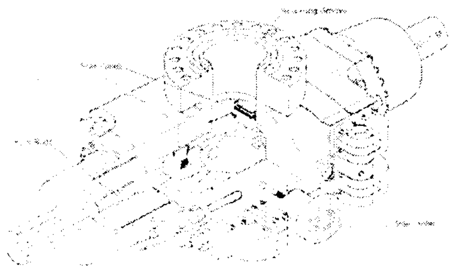
$$P_{rt} = \frac{\omega T}{2\pi}$$

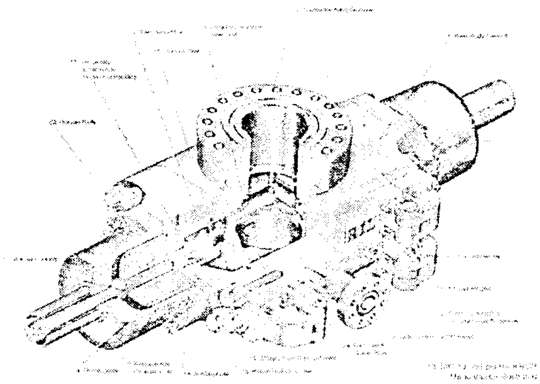
where,
P_{rt} = Power (hp)
ω = Rotary Speed (rpm)
T = Torque (ft-lbf)

Rotary

Transmits the rotary motion or torque from the power source to the drive bushing.

2.5 Well Control System





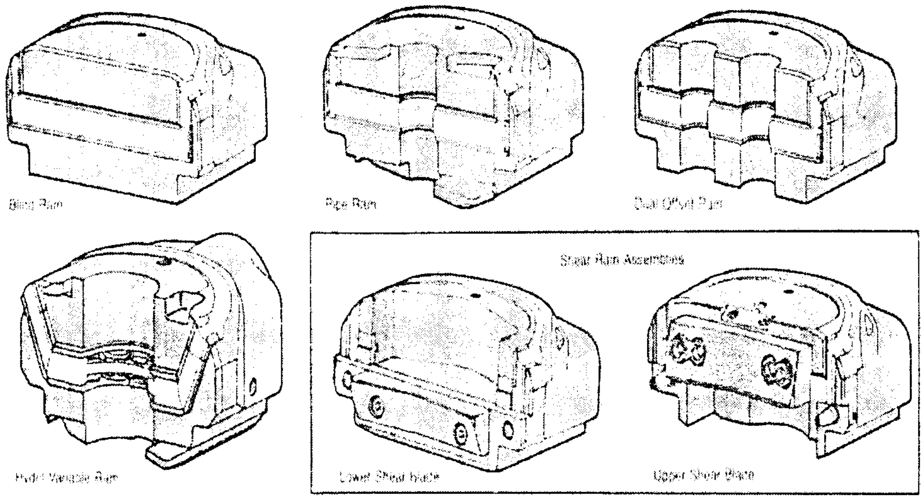
Ram Preventers

This type BOP is used mainly as a backup to the bag-type preventer or for high-pressure situations.

A.The pipe rams have two rams on opposite sides that close by moving towards one another. The rams themselves have semicircular openings which match the diameter of pipe being used. Each different size pipe requires correctly sized rams.

B. If a tapered string is being used to drill a well, such as a 5" drill pipe and a 3-1/2" drill pipe, then two ram-type preventers must generally be used. This type preventer cannot allow the pipe to be worked through it.

Ram Preventers



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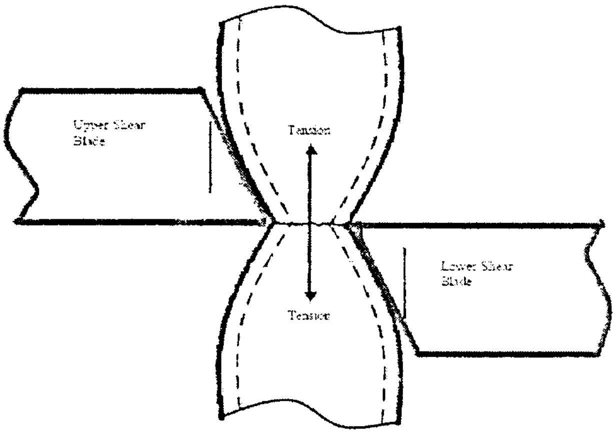
Ram Preventers



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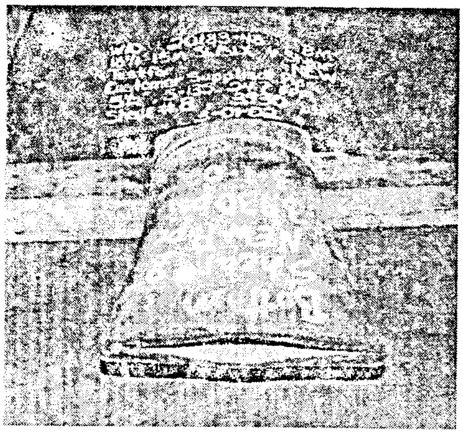
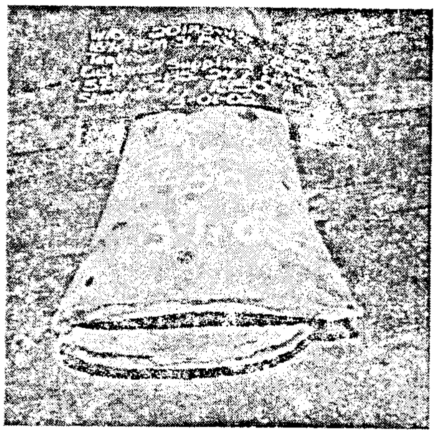
Ram Preventers

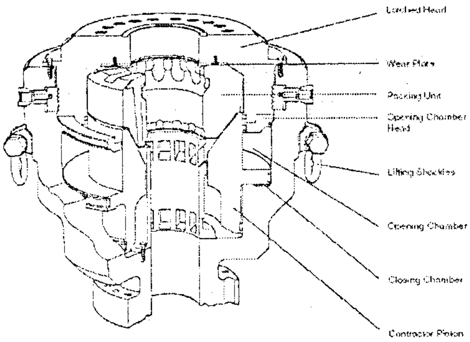


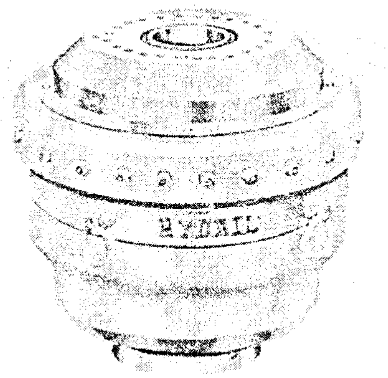


Bag-Type Preventers (Annular Preventers)

This preventer is used the most because the rubber sealing element can conform to any shape or size conduit in the hole. The annular preventer can further collapse completely and seal the annulus with no conduit to the hole. (This is not recommended.) The annular preventers consist of a rubber-covered, metal-ribbed sealing element. This element is caused to collapse and seal by allowing the pressurized hydraulic fluid from the accumulator to move a tapered, form-fitted cylinder against the rubber which causes collapse.

Hydril





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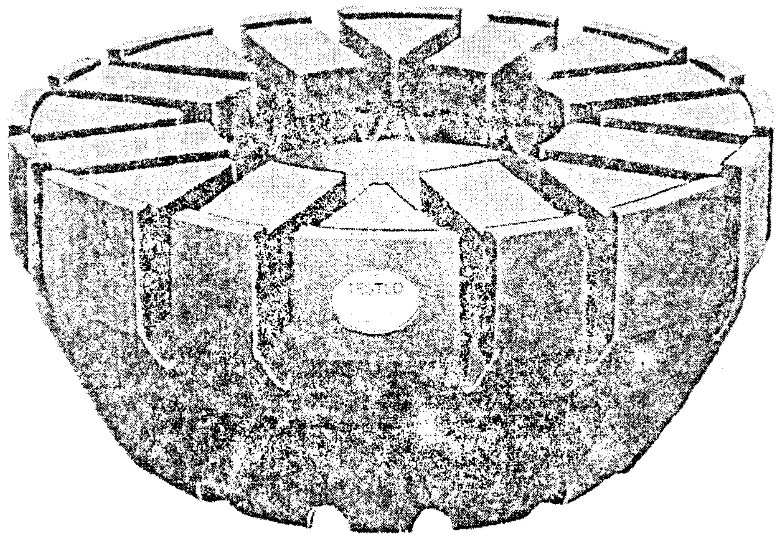
Hydril



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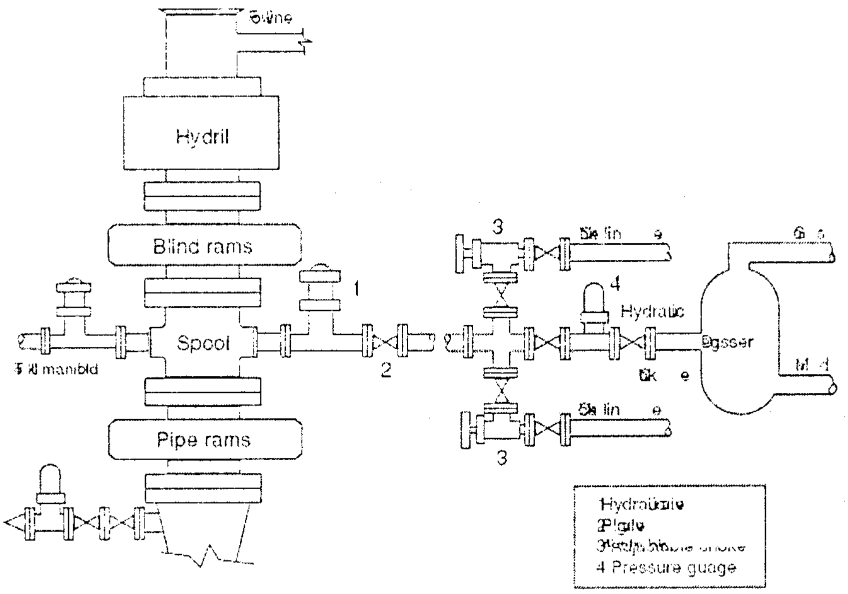
Well Control System



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Well Control System

- Detecting a kick
- Close in the well at surface
- Remove the formation fluid which has flowed into the well
- Make the well safe

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Accumulator

The accumulator is a hydraulic system that maintains and stores enough high-pressured fluid to operate every function of the blow-out preventors (BOP's) at least once and still have a reasonable reserve, as defined by the governing agency rules. The system has a pump which pumps the hydraulic fluid into storage bottlesThe storage bottles have floats which separate the hydraulic fluid from the gas (nitrogen) in the upper part of the chamber. As fluid is pumped into the chamber bottles, the gas is compressed, resulting in the pressure needed to move the hydraulic fluid to operate the BOP's.

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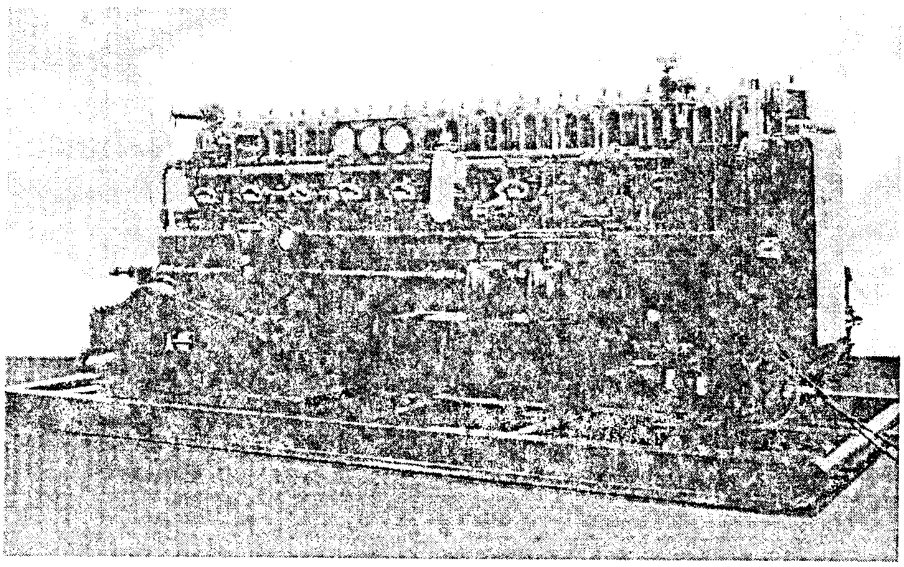
Accumulator



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Ram Preventers

C. The blind rams do have the semicircular opening of the pipe rams. Instead, the front surface of the blind rams is flat, and they can only be used to seal the annulus when there is no pipe in the hole.

D. The shear blind rams are designed to cut through the drill pipe and seal the hole. this type of preventer should only be used as a last resort.

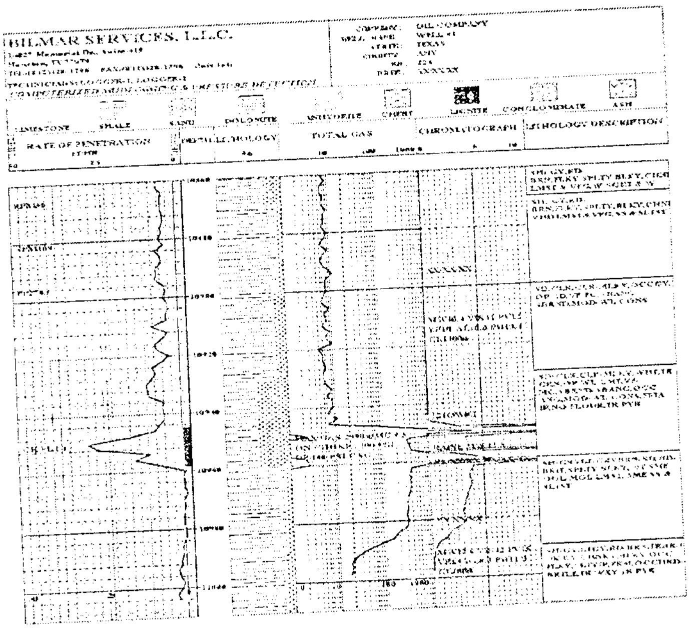
Choke Manifold

This is a system of valves and lines which are attached to the choke line, and in some cases, kill line. The manifold is used to help control a well that has kicked by diverting the flow to various functions such as an adjustable choke. It is designed for versatility in diverting the mud flow after experiencing a kick

2.6 Well Monitoring System

- Drilling Panel (WOB, RPM, Pump Pressure, GPM etc.
- Rig Floor gauges: torque gauges,
- Mud Logging
- Gas detectors

Mud Logging



In the name of God

Drilling Engineering -1

Designed for PUT Undergraduate Program

PART-2

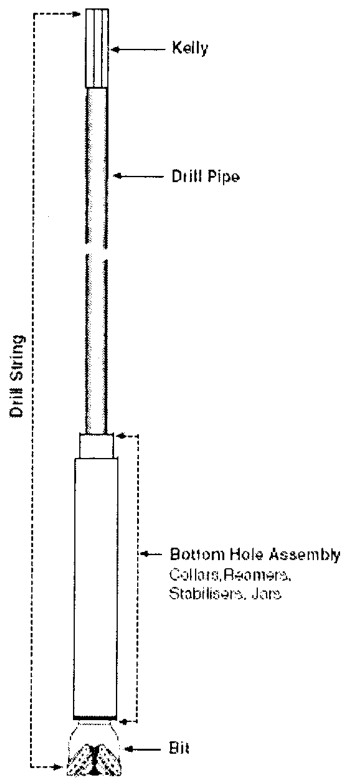
Abdolnabi Hashemi, PhD

February 2008

3. The Drilling String

The functions of drilling string:

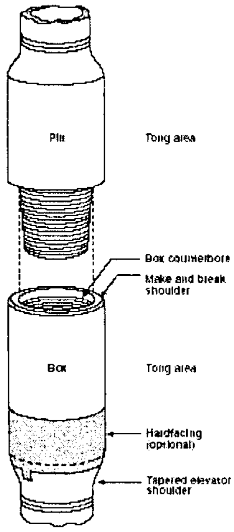
- To suspend the bit
- To transmit rotary torque from the kelly to the bit
- To provide a conduit for circulating drilling fluid to the bit



Drill Pipe

API Range	Length (ft)
1	18-22
2	27-30
3	38-45

Size(OD) (inches)	Weight (lb/ft)	ID (inches)
$2\frac{3}{8}$	6.65	1.815
$2\frac{7}{8}$	10.40	2.151
$3\frac{1}{2}$	9.50	2.992
$3\frac{1}{2}$	13.30	2.764
5	15.50	4.602
5	16.25	4.408
[redacted]		
$5\frac{1}{2}$	25.60	4.000
$5\frac{1}{2}$	21.90	4.776
$5\frac{1}{2}$	24.70	4.670



Drill Pipe/ Selection

If drill pipe is stretched, it will initially go through a region of elastic deformation. In this region, if the stretching force is removed, the drill pipe will return to its original dimensions. The upper limit of this elastic deformation is called the **Yield Strength**, which can be measured in psi.

Beyond this, there exists a region of plastic deformation. In this region, the drill pipe becomes permanently elongated, even when the stretching force is removed. The upper limit of plastic deformation is called the **Tensile Strength**. If the tensile strength is exceeded, the drill pipe will fail.

API Grade	Minimum Yield Stress (psi)	Minimum Tensile Stress (psi)	Yield Stress / Tensile Stress ratio
D	55,000	95,000	0.58
E	75,000	100,000	0.75
X	95,000	105,000	0.70
G	105,000	115,000	0.91
S	135,000	145,000	0.93

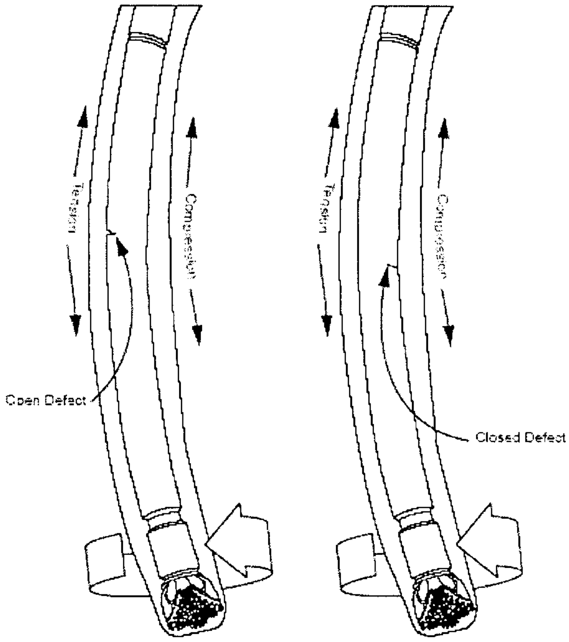
Drill pipe Stress and Failure

High Stresses

- Tension failure
- Torque failure
- Cyclic stress fatigue.

Corrosion

- Oxygen: cause pitting
- CO_2
- Dissolved salts
- Hydrogen sulphide
- Organic acids



Drill Pipe Classification

Drill pipe class defines the physical condition of the drill pipe in terms of dimension, surface damage, and corrosion. Drill pipe class is indicated by paint bands on the drill pipe according to the following code:

API RP 7G

CLASS	# and COLOR of BANDS
I (New)	One White
Premium	Two White
2	One Yellow ▬
3	One Orange ▬
4	One Green ▬
Scrap	One Red ▬

```
YIELD STRENGTH = Yield Strength x π/4 (OD² - ID²)
  (in pounds) (in psi)
```

Example 5" grade G-105, class 1 (new) drill pipe has a nominal weight of 19.5 lb/ft and an ID of 4.276" ...therefore:

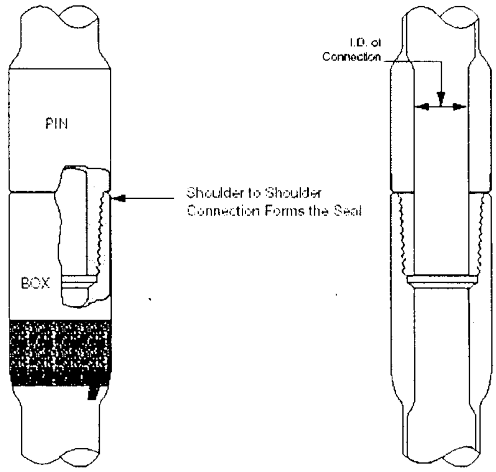
Minimum Yield Strength in pounds= 105,000 x π/4 x (5^2 - 4.276^2) = 553,833 lbs.

Tool Joint

Tool joints are short sections of pipe that are attached to the tubing portion of drill pipe by means of using a flash welding process. The internally threaded tool joint is called a "box", while the externally threaded tool joint if the "pin".

API tool joints

SIZE	TYPE	OD	ID	TPI	TAPE	THREAD FORM
4 1/2"	API REG	5 1/2"	2 1/4"	5	3	V..040
4 1/2"	Full Hole	5 3/4"	3"	5	3	V.040
4 1/2"	NC 46 (4" IF)	6"	3 1/4"	4	2	V.038R
4 1/2"	NC 50 (4 1/2" IF)	6 1/8"	3 3/4"	4	2	V.038R
4 1/2"	H.90	6"	3 1/4"	3 1/2"	2	90° V.050



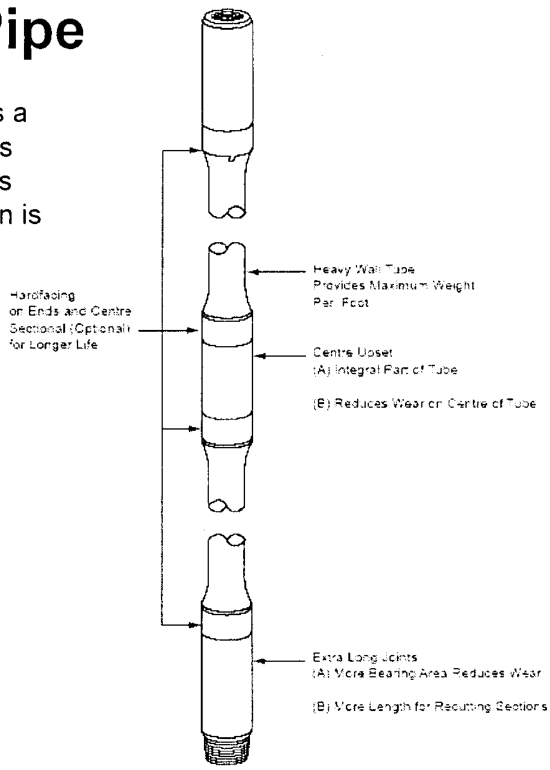
Cross Section

Heavyweight Drill Pipe

Heavy wall drillpipe (or heavy weight drillpipe) has a greater wall thickness than ordinary drillpipe and is often used at the base of the drillpipe where stress concentration is greatest. The stress concentration is due to:

- The difference in cross section and therefore stiffness between the drillpipe and drillcollars.
- The rotation and cutting action of the bit can frequently result in a vertical bouncing effect.

- Increased wall thickness
- Longer tool joints
- Uses more hard facing
- May have a long central upset section (Figure 5)



Drill collar

- To provide enough weight on bit for efficient drilling
- To keep the drillstring in tension, thereby reducing bending stresses and failures due to fatigue.
- To provide stiffness in the BHA for directional control.

The weakest point in the drill collars is the connection and therefore the correct make up torque must be applied to prevent failure.

Anti-wall stick

Square collars: These collars are usually 1/16" less than bit size, and are run to provide maximum stabilisation of the bottom hole assembly.

Monel collars

Drill Collar Weights

(pounds per foot)

Collar O.D.	BORE OF COLLAR 1-1/2	1-3/4	2	2-1/4	2-1/2	2-13/16	3	3-1/4	3-1/2	3-3/4	4
3-3/8	24.4	22.2									
3-1/2	26.7	24.5									
3-3/4	31.5	29.3									
3-7/8	34.0	31.9	29.4	26.5							
4	36.7	34.5	32.0	29.2							
4-1/8	39.4	37.2	34.7	31.9							
4-1/4	42.2	40.0	37.5	34.7							
4-1/2	48.0	45.8	43.3	40.5							
4-3/4	54.2	52.0	49.5	46.7	43.5						
5	60.2	58.5	55.9	53.1	49.9						
5-1/4	67.5	65.3	62.8	59.9	56.8	53.3					
5-1/2	74.7	72.5	69.9	67.2	63.9	60.5	56.7				
5-3/4	82.1	79.9	77.5	74.6	71.5	67.9	64.1				
6	89.9	87.8	85.3	82.5	79.3	75.8	71.9	67.8	63.3		
6-1/4	98.1	95.9	93.5	90.6	87.5	83.9	80.1	75.9	71.5		
6-1/2	106.6	104.5	101.9	99.1	95.9	92.5	88.6	84.5	79.9		
6-3/4	115.5	113.3	110.8	107.9	104.8	101.3	97.5	93.3	88.8		
7	124.6	122.5	119.9	117.1	113.9	110.5	106.6	102.5	97.9	93.1	87.9
7-1/4	134.1	131.9	129.5	126.6	123.5	119.9	116.1	111.9	107.5	102.6	97.5
7-1/2	143.9	141.7	139.3	136.5	133.3	129.8	125.9	121.8	117.3	112.5	107.3
7-3/4	154.1	151.9	149.5	146.6	143.5	139.9	136.1	131.9	127.5	122.6	117.5
8	164.6	162.5	149.9	157.1	153.9	150.5	146.6	142.5	137.9	133.1	127.9
8-1/4	175.4	173.3	170.8	167.9	164.8	161.3	157.5	153.3	148.8	143.9	138.8
8-1/2	186.6	184.4	181.9	179.1	175.9	168.6	172.5	164.5	159.9	155.1	149.9
8-3/4	198.1	195.9	193.9	190.6	187.4	183.9	180.1	175.9	171.4	166.6	161.5
9		207.8	205.3	202.4	199.3	195.8	191.9	187.8	183.3	178.5	173.3
9-1/2		232.4	229.9	227.1	223.9	220.4	216.6	212.4	297.9	203.1	197.9
10			255.9	253.1	249.9	246.4	242.6	238.4	233.9	229.1	223.9
10-1/2			283.3	280.4	277.3	273.8	269.9	265.8	261.3	256.4	251.3
11					305.9	302.4	298.6	294.4	289.9	285.1	279.9

Heavy Weight Drill Pipe

Range II- (pounds per foot)

Nominal Size (in)	ID (in)	Connection Type & OD (in)	Approximate Weight/foot (lb)	Make-Up Torque (ft/lb)	Capacity bbl/100ft	Displacement (bbl/100ft)
3-1/2"	2-1/16"	N.C.38 (3-1/2 I.F.) / 4-3/4	25.3	9,900	0.421	0.921
4"	2-9/16"	N.C.40 (4 F.H.) / 5-1/4"	29.7	13,250	0.645	1.082
4-1/2"	2-3/4"	N.C.46 (4 I.F.) / 6-1/4"	41.0	21,800	0.743	1.493
5"	3"	N.C.50 (4-1/2 I.F.) / 6-1/2"	49.3	29,400	0.883	1.796

Overpull

In tight holes or stuck pipe situations, the operator must know how much additional tension, or pull, can be applied to the string before exceeding the yield strength of the drill pipe. This is known as **Overpull**, since it is the pull force over the weight of the string.

For example, in a vertical hole with 12 ppg mud, a drillstring consists of 600 feet of 7.25-inch x 2.25-inch drill collars and 6,000 ft of 5-inch, New Grade E drill pipe with a nominal weight of 19.5 lbs/ft and an approximate weight of 20.89 lbs/ft.

First, the hookload is determined
Hookload = Air Weight x Buoyancy Factor= [(6,000 x 20.89) + (600 x 127)] 0.817 = 164,658 pounds

Referring to the API RP 7G, the yield strength in pounds for this grade, class, size and nominal weight of drill pipe is 395,595 pounds.

Therefore: Maximum Overpull = Yield Strength In Pounds - Hookload
= 395,595 - 164,658 = 230,937 pounds

The operator can pull 230,937 pounds over the hookload before reaching the limit of elastic deformation (yield strength).

Buoyancy

Drillstrings weigh less in weighted fluids than in air due to a fluid property known as buoyancy. Therefore, what is seen as the hookload is actually the buoyed weight of the drillstring. ***Archimedes's principle states that the buoy force is equal to the weight of the fluid displaced.*** Another way of saying this is that a buoy force is equal to the pressure at the bottom of the string multiplied by the cross sectional area of the tubular.

$$\text{Buoyancy Factor} = 1 - \frac{MW}{65.5}$$

MW=Mud Density (ppg)

$$\text{Buoyancy Factor} = 1 - \frac{MW}{489.5}$$

MW=Mud Density (pcf)

1 ppg=7.48 pcf

Hookload = Air Weight x Buoyancy Factor

BHA Weight & Weight-On-Bit

BHA Design:

1- Burst, collapse and tension

2- Bending strength

3- Provide all of the weight required for drilling

4- Stabilized BHA

One important consideration in designing the BHA is determining the number of drill collars and heavy-weight pipe required to provide the desired weight-on-bit. When drilling vertical wells, standard practice is to avoid putting ordinary drill pipe into compression. This is achieved by making sure that the "buoyed weight" of the drill collars and heavy-weight pipe exceed the maximum weight-on-bit.

$$\text{Required air weight of BHA} = \frac{\text{Maximum WOB x safety factor}}{\textit{buoyancy}\text{ factor x }\cos\theta}$$

$$\text{where the safety factor} = 1 + \frac{\text{percentage safety margin}}{100}$$

Example

Drilling 17.5-inch hole with a roller cone bit, we want to use 45,000 lbs WOB in the tangent section at 30° inclination. What air weight of BHA is required to avoid running any drill pipe in compression? The mud density is 10 ppg. Use a 10% safety margin.

$$\text{Required air weight of BHA} = \frac{45,000 \times 1.1}{0.847 \times \cos 30^\circ} = 67,500\,lbs$$

Drill Pipe Selection

Burst Load: pressure up string when on a plugged bit nozzle or DST, doing a cement squeeze with a packer.

Collapse load:

$$P_c = 0.052 \times MW \times TVD$$

P_c= psi

MW= PPG

Tension load: Can be calculated from known weights of the Dc and Dp below the point of interest

1. The first consideration in tension design is the selection of max. working load which should never be exceeded during normal drilling operation. In the case of DP, this working load should be based on a stress of 85% of the yield strength.
2. The 2nd consideration in tension design is to determine the maximum allowable static load(the hook load when the drill string is hanging free in the hole, and is equal to the string weight in the fluid)

Neutral Point

The neutral point is usually defined as the point in the drillstring where the axial stress changes from compression to tension. The location of this neutral point depends on the weight-on-bit and the buoyancy factor of the drilling fluid. In practice, since the WOB fluctuates, the position of the neutral point changes. It is therefore quite common to refer to a "transition zone" as the section where axial stress changes from compression to tension.

Drillstring components located in this "transition zone" may, therefore, alternately experience compression and tension. These cyclic oscillations can damage downhole tools. A prime example is drilling jars, whose life may be drastically shortened if the jars are located in the transition zone. It is also important, as previously explained, to know if any drill pipe is being run in compression. Therefore it is important to know the location of the neutral point.

Neutral Point

Vertical Well, Neutral Point in the drill collars

$$L_{np} = \frac{WOB}{W_{DC}(BF)}$$

where:

L_{np} is the distance from the bit to the neutral point.

W_{DC} is the weight per foot of the drill collars

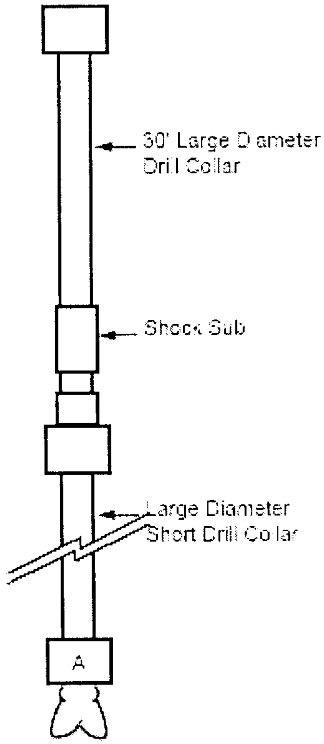
BF is the buoyancy factor of the drilling mud.

Example: Determine the neutral point in 7.25-inch x 2.25-inch collars if the weight-on0bit is 30,000 lbs and mud density is 11 ppg.

$$L_{np} = \frac{30,000}{127 \times 0.832} = 284 ft$$

BHA

Stabilisers are tools placed above the drill bit and along the bottom hole assembly (BHA) to control hole deviation, dogleg severity and prevent differential sticking. They achieve these functions by centralising and providing extra stiffness to the BHA.Improved bit performance is another beneficiary of good stabilisation.



Stabilizers

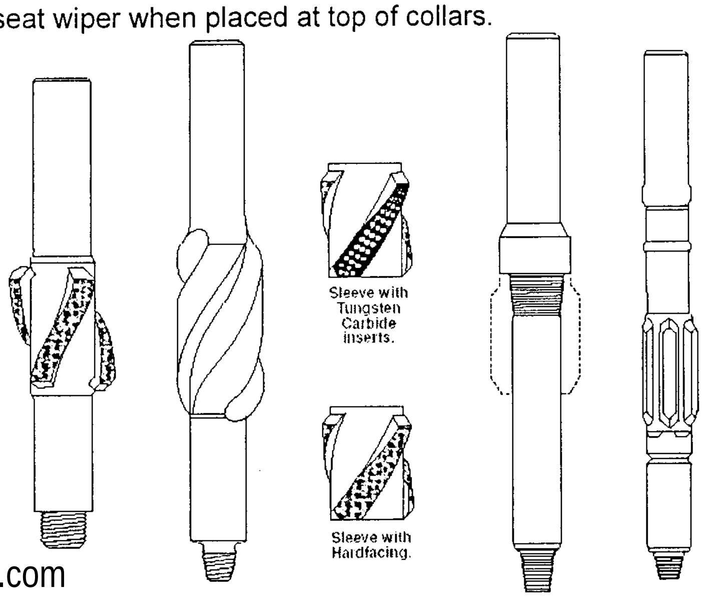
•Reduce buckling and bending stresses on drill collars

• Allow higher WOB since the string remains concentric even in compression.

• Increase bit life by reducing wobble.

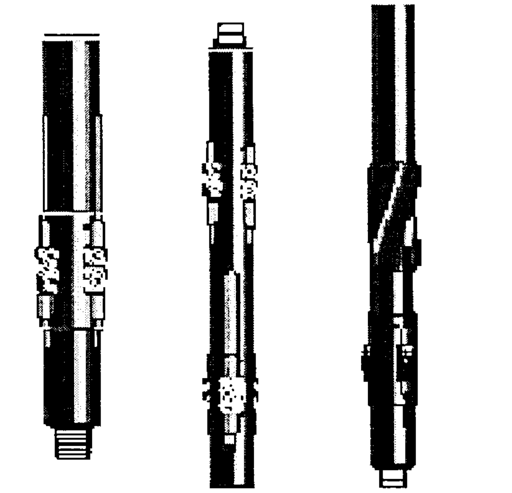
• Help to prevent wall sticking.

• Act as a key seat wiper when placed at top of collars.

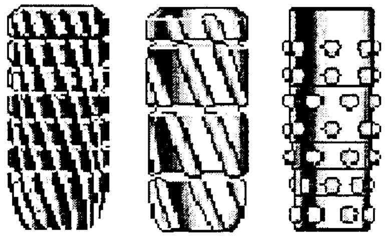


Roller Reamer

Roller reamers are used to replace near bit and string stabilisers in bottom hole assemblies where high torque and swelling or abrasive formations are encountered.



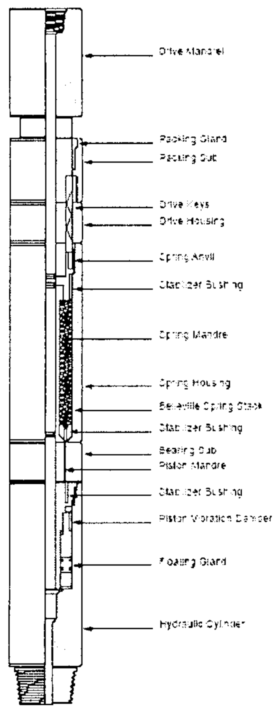
Three point Six point Combination stabilizer/reamer



Button Chert Soft Formation

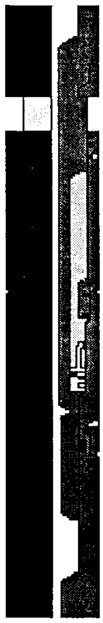
Shock Sub

A shock sub is normally located above the bit to reduce the stress due to bouncing when the bit is drilling through hard rock. The shock sub absorbs the vertical vibration either by using a strong steel spring, or a resilient rubber element (Figure 11).

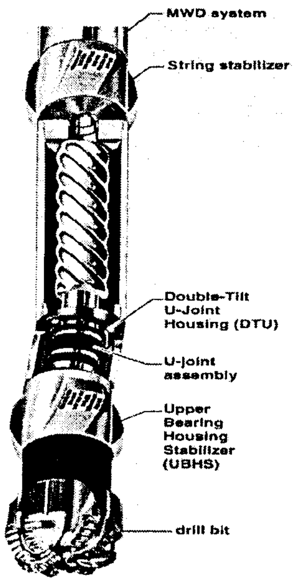


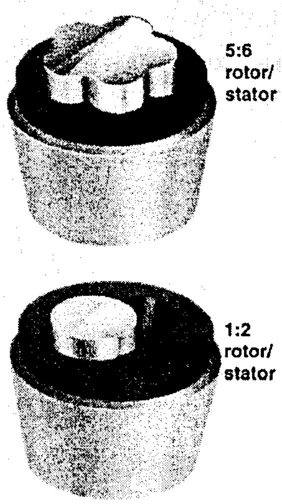
Jar

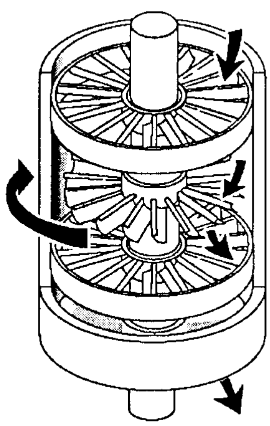
Jars provide a means of supplying powerful upward or downward blows to the stuck drillstring.



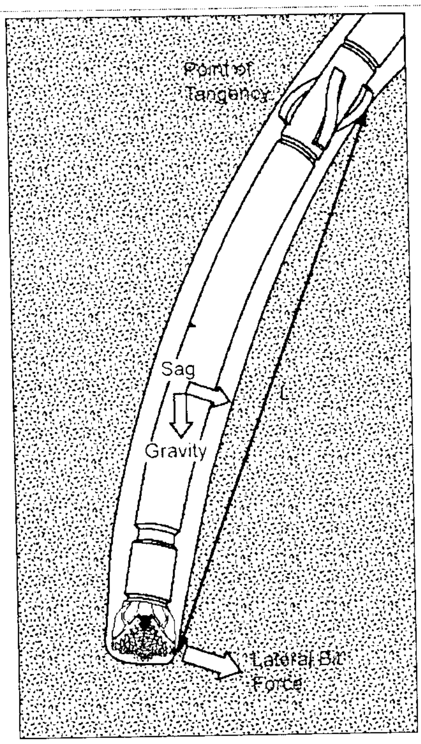
Downhole motors / turbines



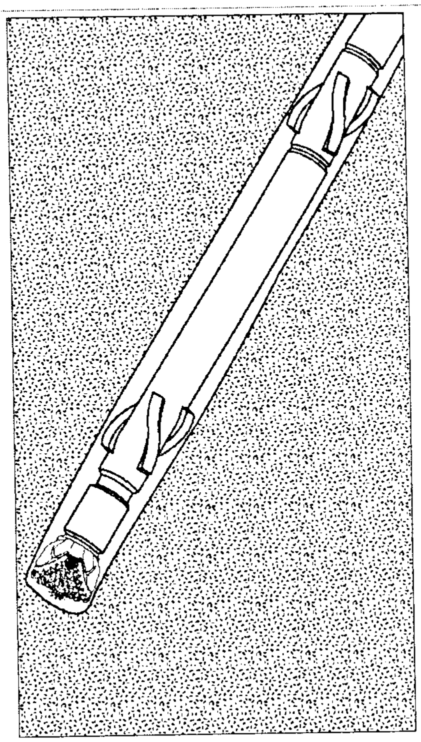




BHA



PENDULUM ASSEMBLY



PACKED HOLE ASSEMBLY

Critical RPM

1. The pipe between each tool joint vibrate transversely or in nodes like a violin string

$$RPM = \frac{4,760,000}{L^2} \times (D^2 + d^2)$$

L= length of drill pipe (in)

D= OD of the dp (in)

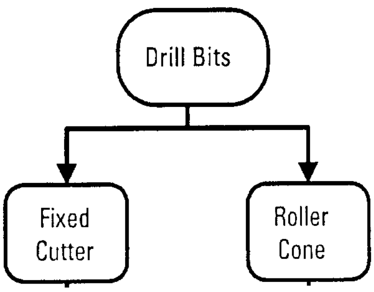
D= ID of the drill pipe (in)

2. The drill pipe string vibrates longitudinally like a spring of pendulum

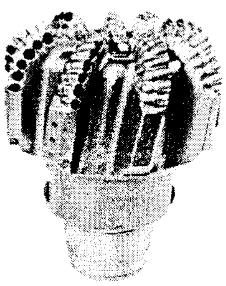
$$RPM = \frac{258000}{L}$$ L= length of drill pipe (ft`)

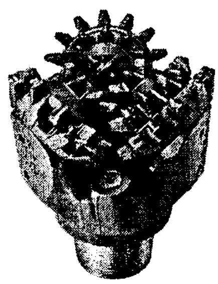
4. Drill Bit Technology

General Overview

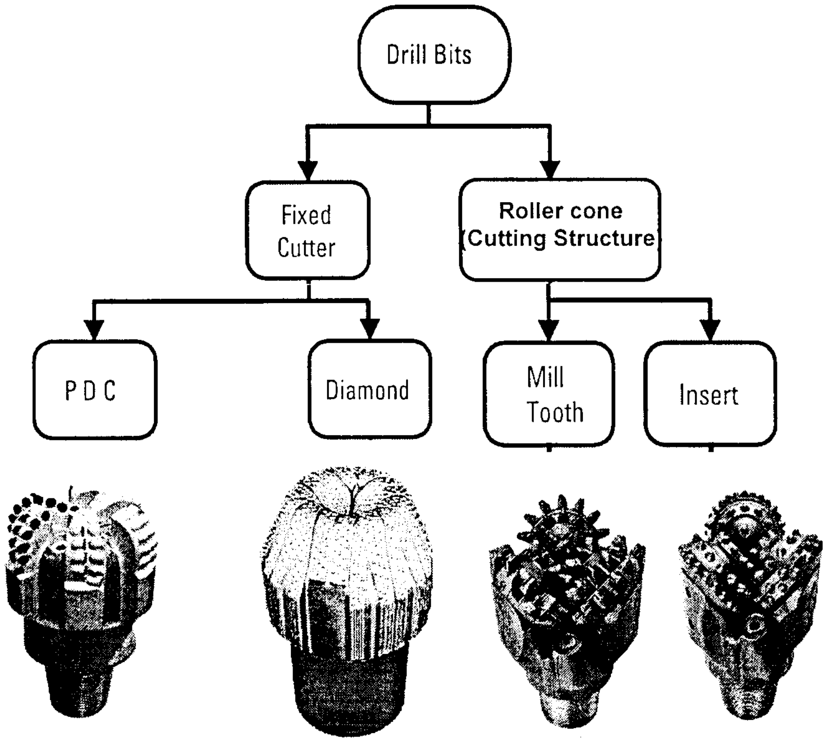


Matrix Body

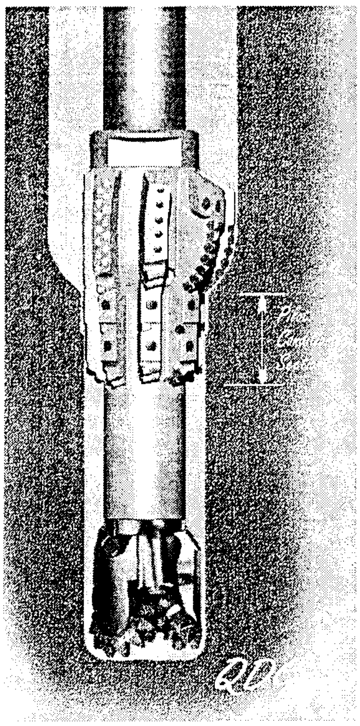


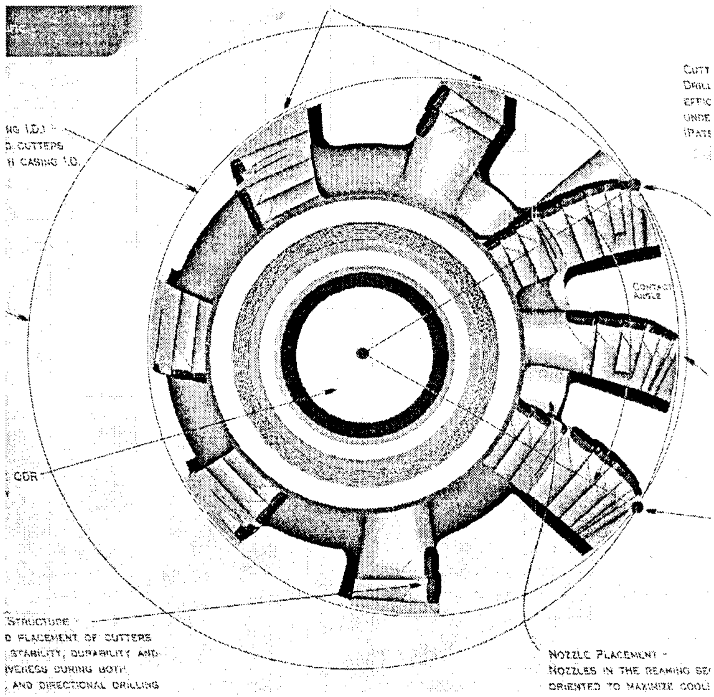


General Overview



Bi-Center Bits





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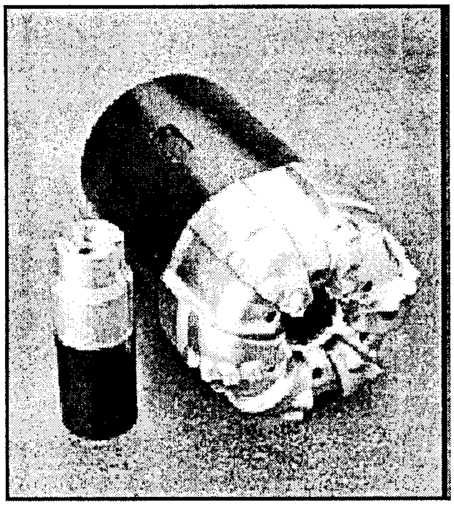
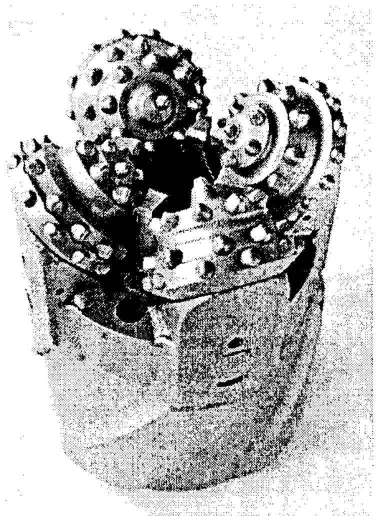
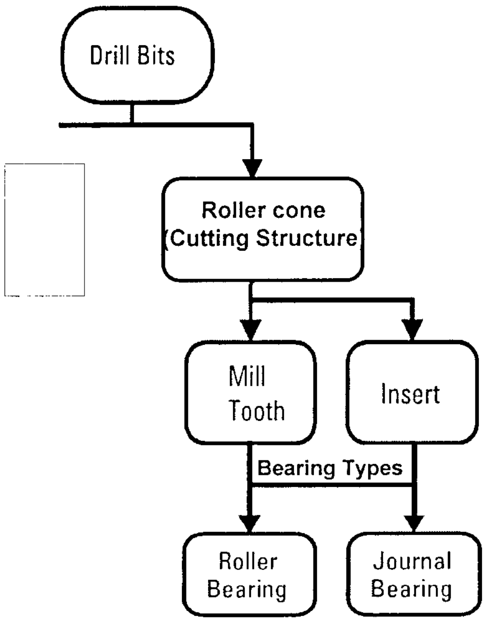
Core Bits





General Overview



The Ideal Bit

"The Ideal Bit" will depend on the type of formation to be drilled

1. High drilling rate
2. Long life
3. Drill full-gauge, straight hole
4. Moderate cost

* **(Low cost per ft drilled)**

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Milestones.....

- 1909 Howard Hughes patented the roller cone rock bit
- 1925 Intermeshing 2-cone cone bits invented
- 1928 Use of tungsten carbide hard facing on bits begins
- 1932 Roller and ball bearings introduced into roller cone bits
- 1933 Three cone bits invented
- 1939 Offset roller cone bits first used
- 1951 Tungsten carbide inserts first used in roller cone bits
- 1963 Sealed bearing roller cone bits first used
- 1996 Fully diamond enhanced inserts first used in roller cone bits.
- 1999 Bits optimized through computer drilling simulations introduced.

PDC bits introduced in 1972

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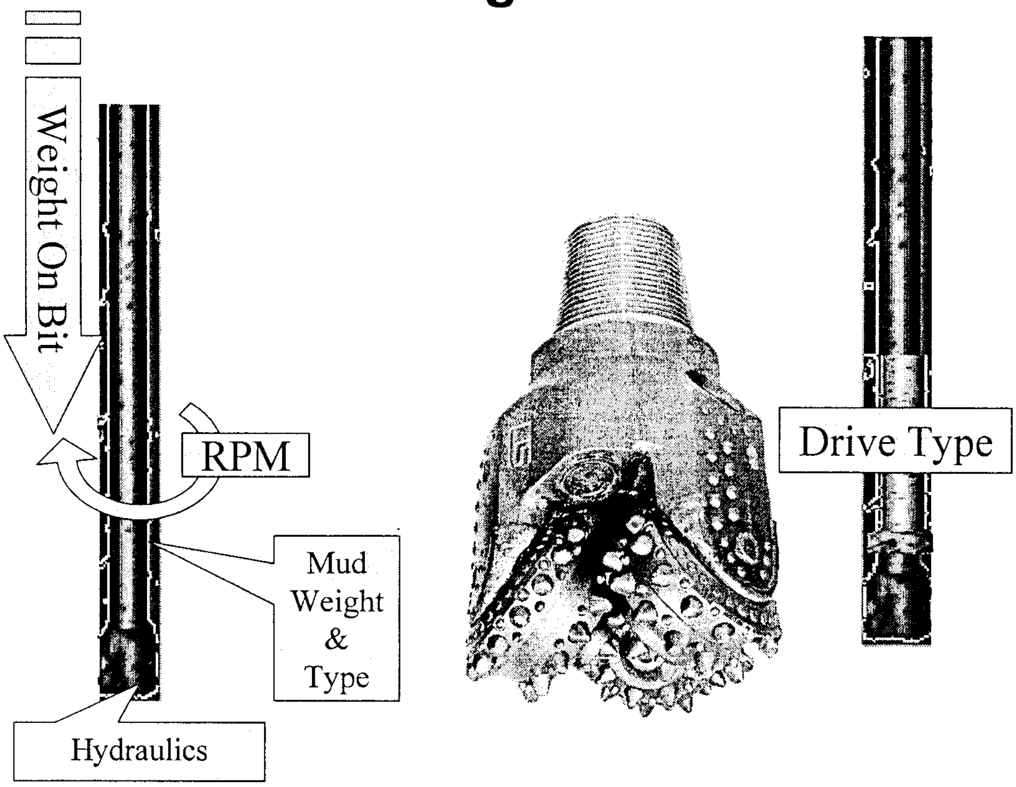
Drilling Fundamentals



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Anatomy of a Roller Cone Bit

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Roller Cone Anatomy #1

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Roller Cone Anatomy #2

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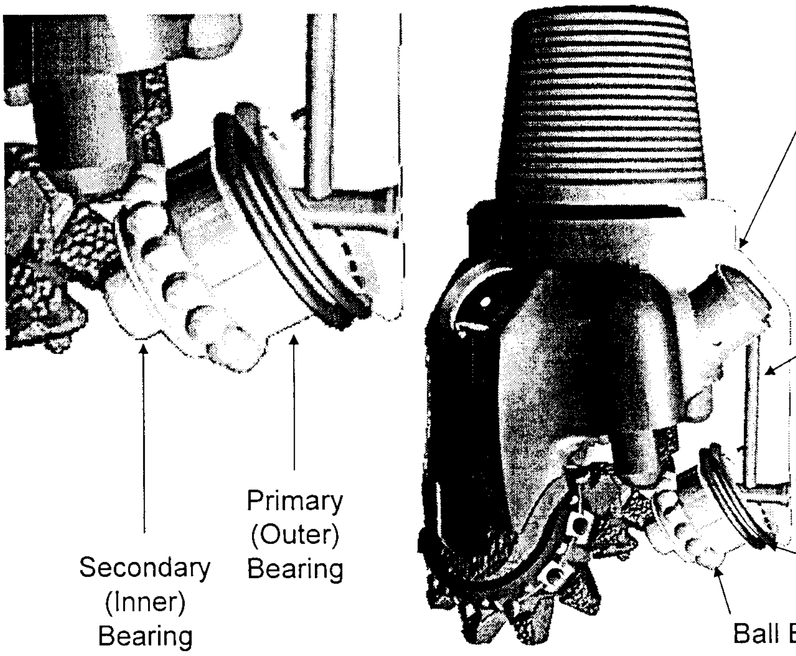
Roller Cone Anatomy #3



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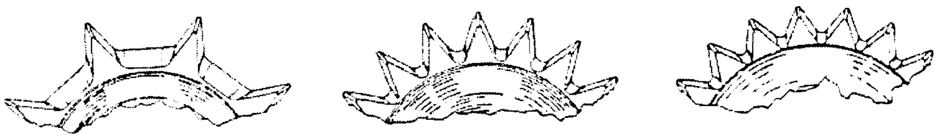
Milled Tooth Bit (Steel Tooth)

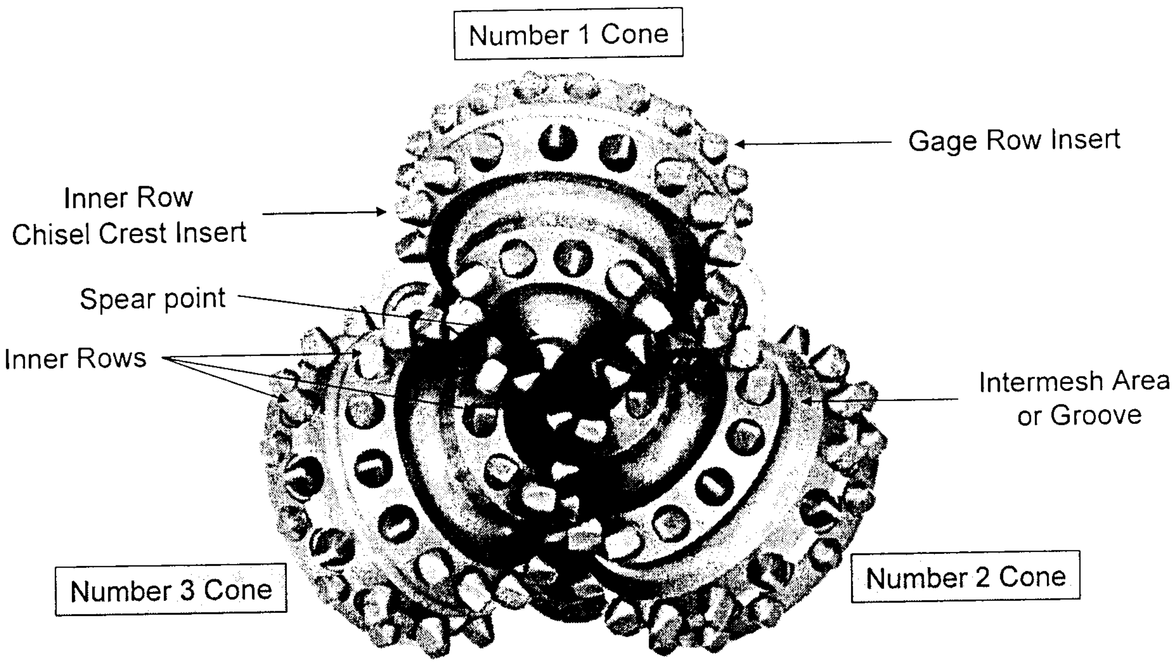


- Long teeth for soft formations
- Shorter teeth for harder formations
- Cone off - set in soft - formation bit results in scraping gouging action
- Self - sharpening teeth by using hardfacing on one side
- High drilling rates - especially in softer rocks

Advantages

- For any type of formation there is a suitable design of rock bit
  - Can handle changes in formation
  - Acceptable life and drilling rate
  - Reasonable cost

Tungsten Carbide Cone Nomenclature



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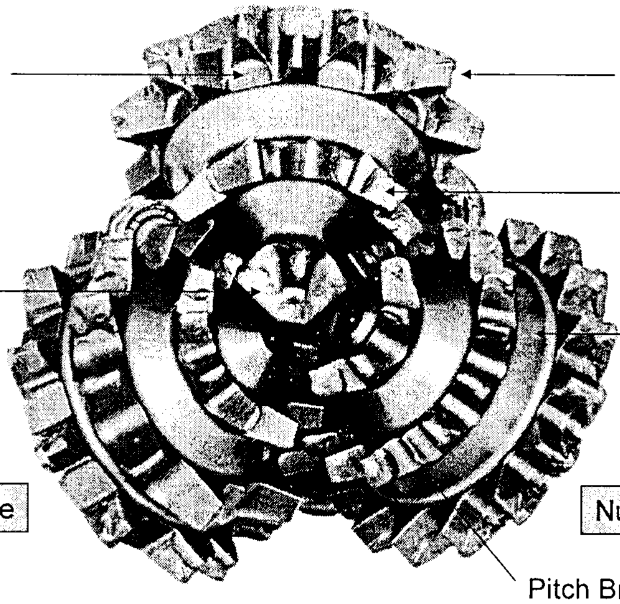
Milled Tooth Cone Nomenclature



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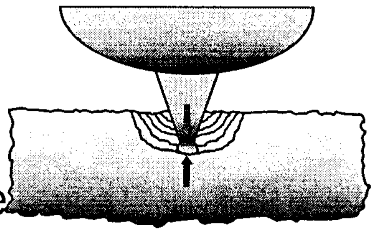
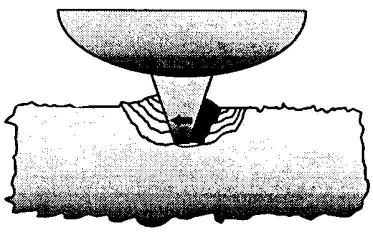
Roller Cone Bit Cutting Action

- Two-step process:
  - Indentation & Fracture
  - Tooth Displacement





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Cutting Action

- Soft Formation : Gouging-Scraping
  - Most Aggressive Cutting Action
  - Typically high ROP applications

- Hard Formation : Chipping-Crushing
  - Most Durable Cutting Action
  - Typically low ROP applications

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Gouging-Scraping

- Like.....using a shovel in the garden

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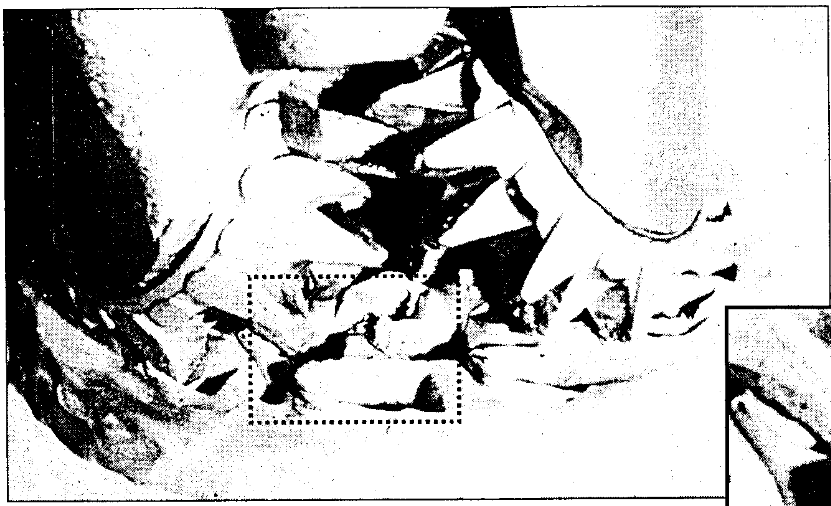
Gouging-Scraping Example



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Chipping-Crushing

- Like.....using a hammer and chisel

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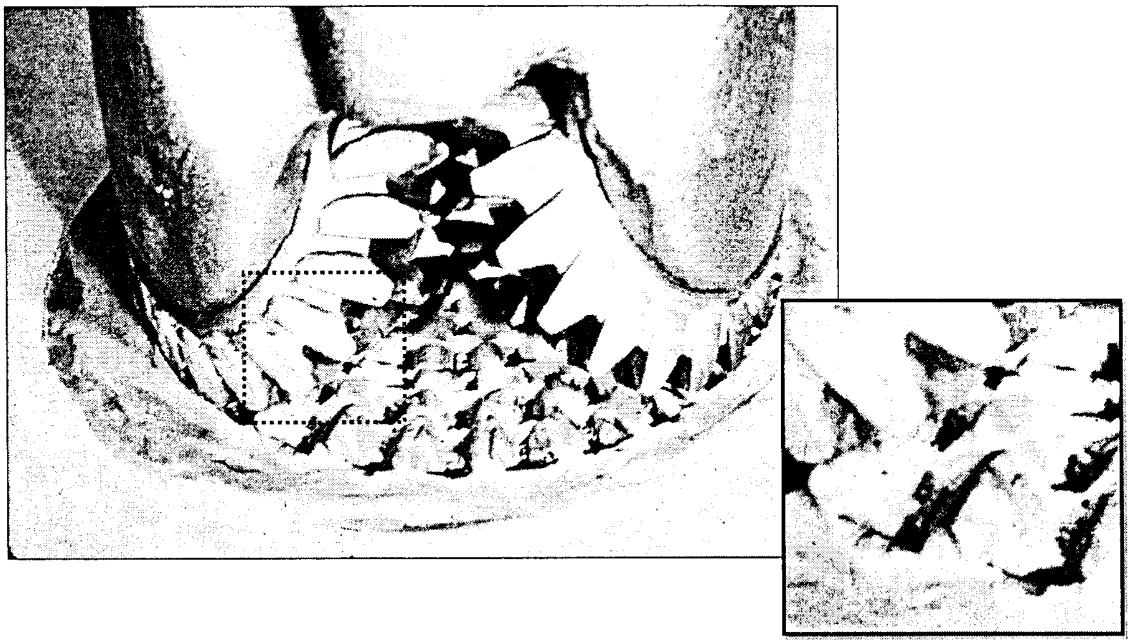
Chipping-Crushing Example



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Geometric Design Elements

- Directly influence the type of Cutting Action
  - Offset
  - Journal Angle
  - Cone Profile Angles
  - Bottom Hole Profile

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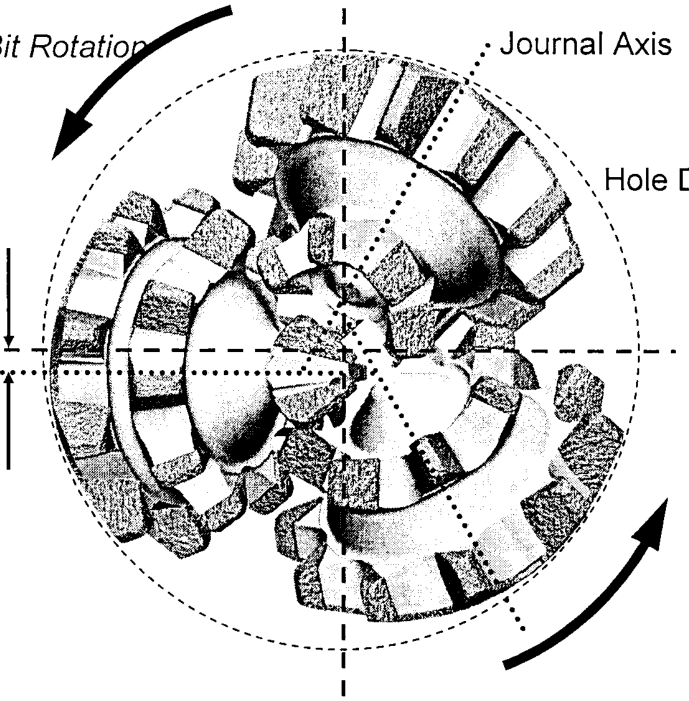
Bit Offset



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Bit Offset

- Definition of Offset:
  - "..the horizontal distance between the axis of the bit and a vertical plane through the axis of the journal."

- Smith Tool Offset measured in inches
  - Very Soft formations (aggressive) *typically 3/8"*
  - Very Hard formations (durable) *typically 1/32"*

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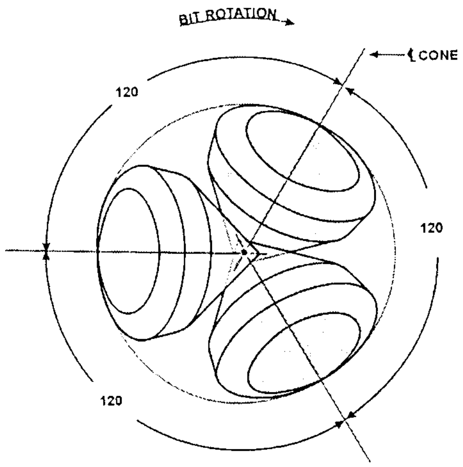
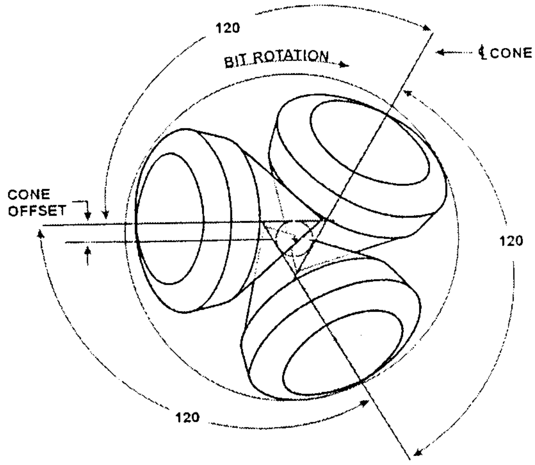
Bit Offset

Hard Formation



Low Offset Bit

Soft Formation



High Offset Bit

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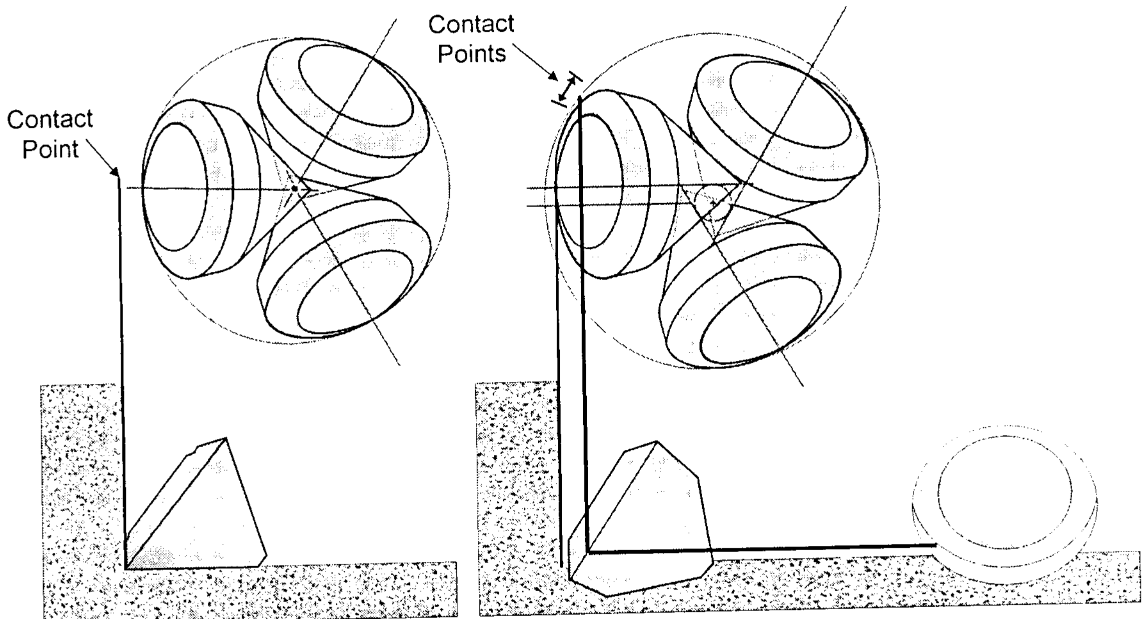
Bit Offset Comparison



Low Offset

High Offset

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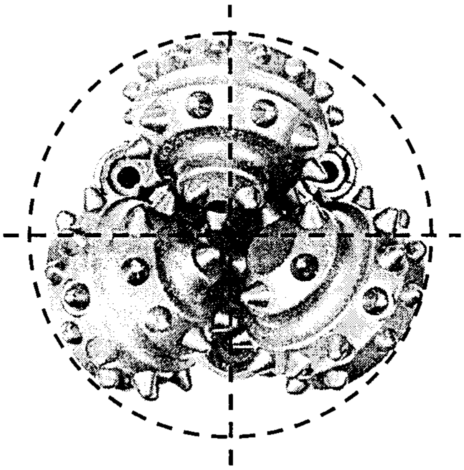
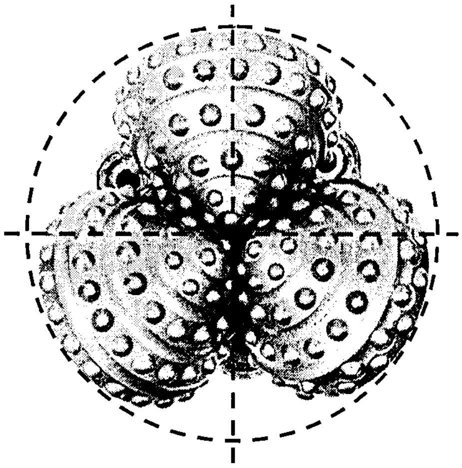
Soft vs. Hard Formation Offset



8¾" F07
IADC: 4-2-7Y
Offset: 10/32" *(0.3125")*



8¾" F90
IADC: 8-3-7Y
Offset: 1/32" *(0.03125")*

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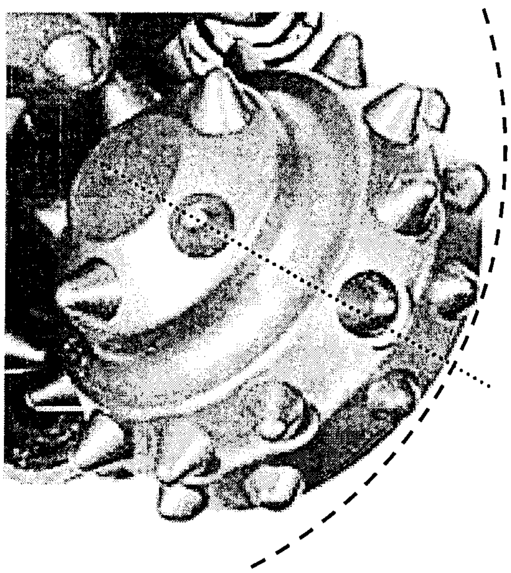
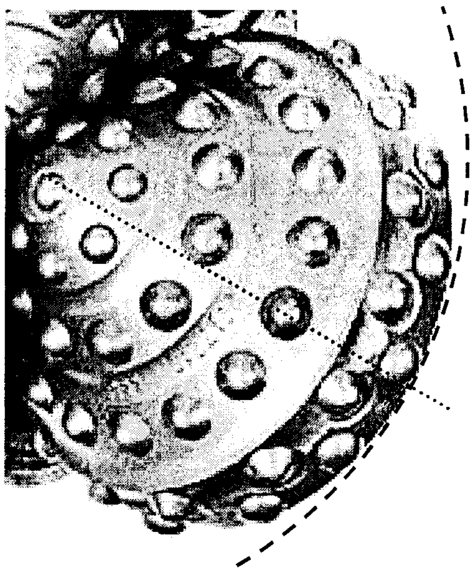
Offset and Gage



8¾" F07
38 Gage Inserts



8¾" F9
58 Gage Inserts

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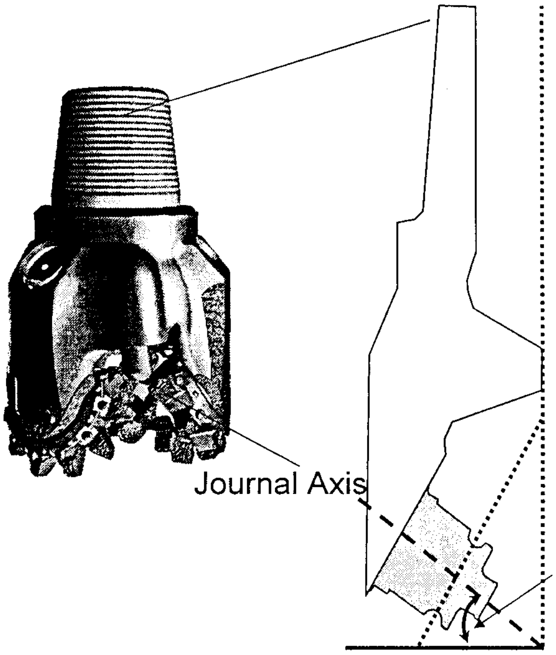
Journal Angle

Definition....

"The journal angle is the angle at which the journal is mounted, relative to a horizontal plane. "

This mounting moves the cutting elements (cones) outside the support members. The journal angle also controls the cutter profile or pattern it drills, and it affects the amount of cutter action on the bottom



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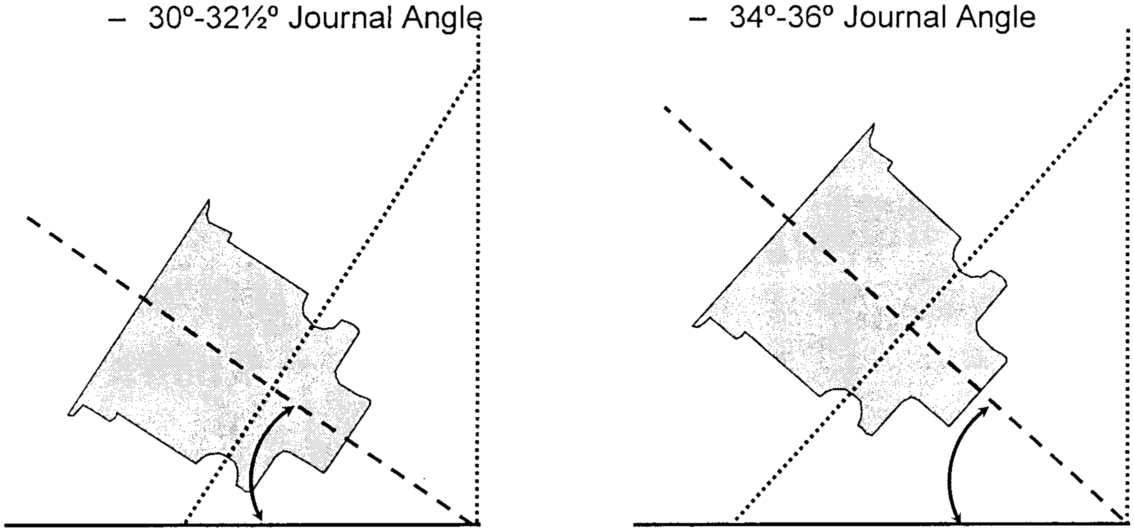
Soft vs. Hard Journal Angle

- Soft to Medium Formations
  - Low Journal Angles
  - 30°-32½° Journal Angle
- Medium to Hard Formations
  - High Journal Angles
  - 34°-36° Journal Angle



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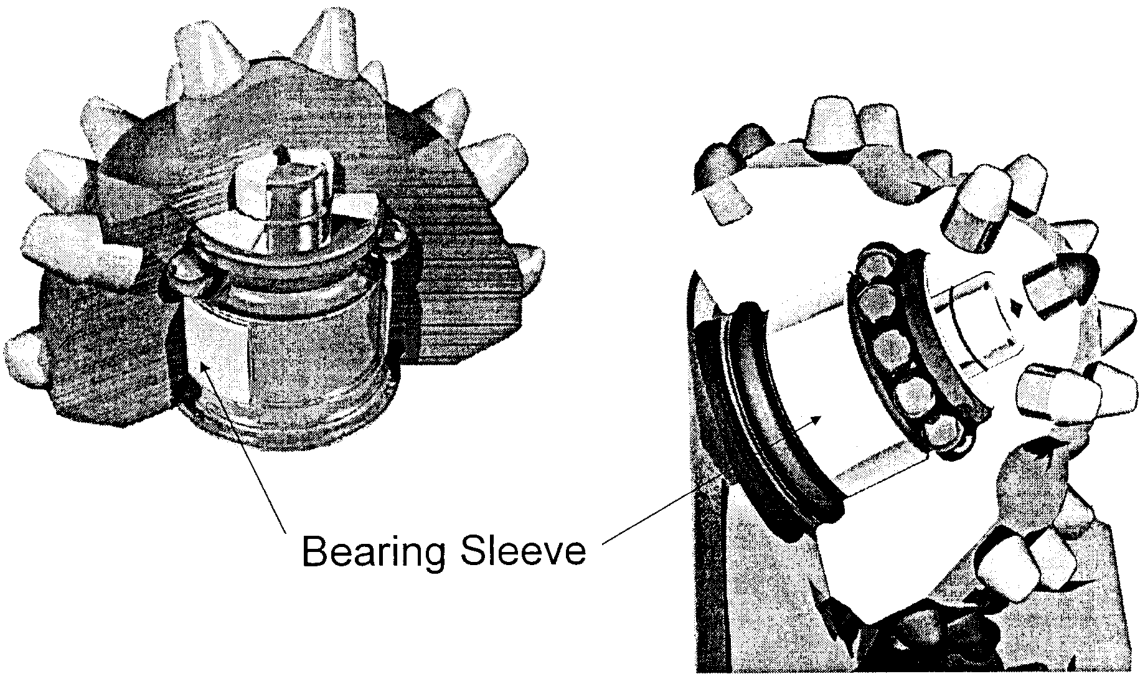
Friction Bearing



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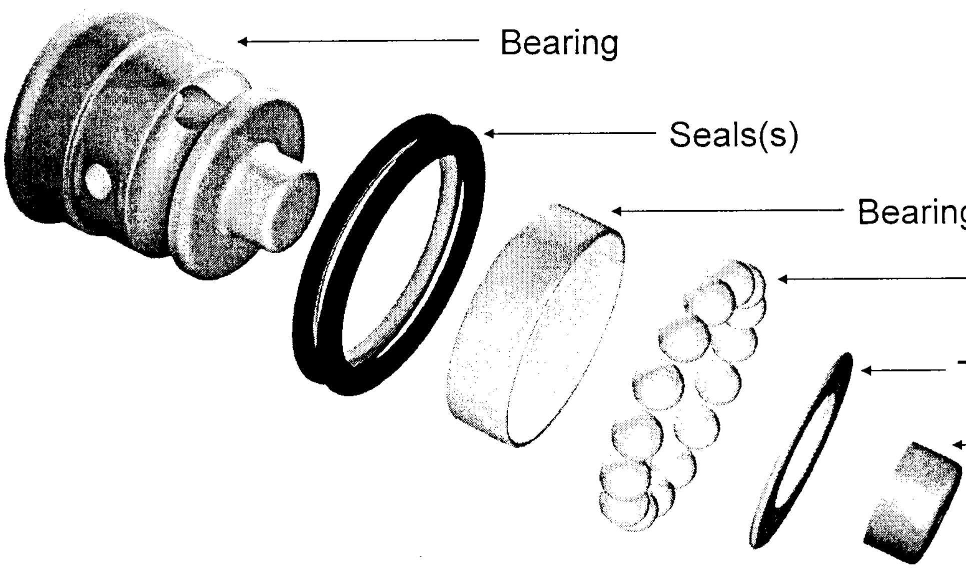
Friction Bearing – Exploded View



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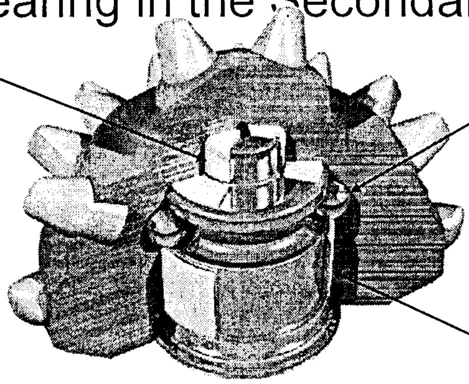
Bearing Structure Types

- F-B-F Bit<6"
  - Friction bearing in the Primary Bearing
  - Ball bearings (cone retention)
  - Friction bearing in the Secondary Bearing



Bit Sizes
$3^{7/8}$" – $12^{1/4}$"

61

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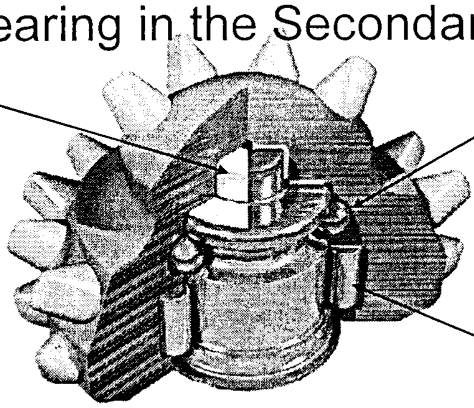
Bearing Structure Types

- R-B-F 6"<Bit<9"
  - Roller bearing in the Primary Bearing
  - Ball bearings (cone retention)
  - Friction bearing in the Secondary Bearing



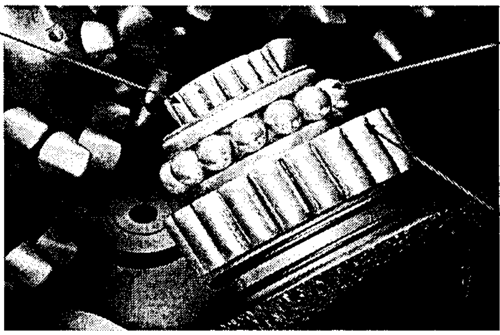
Bit Sizes
$12^{1/4}$" – $15^{1/2}$"

62

Modified after R. Jangani

Bearing Structure Types

- R-B-R Bit>9"
  - **R**oller bearing in the Primary Bearing
  - **B**all bearings (cone retention)
  - **R**oller bearing in the Secondary Bearing



Bit Sizes
16" - 36"

63

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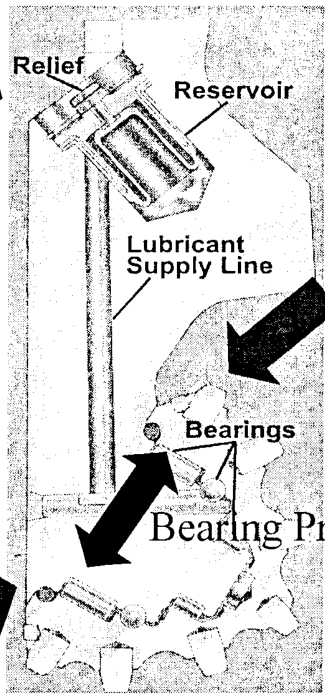
Pressure Equalization System



64

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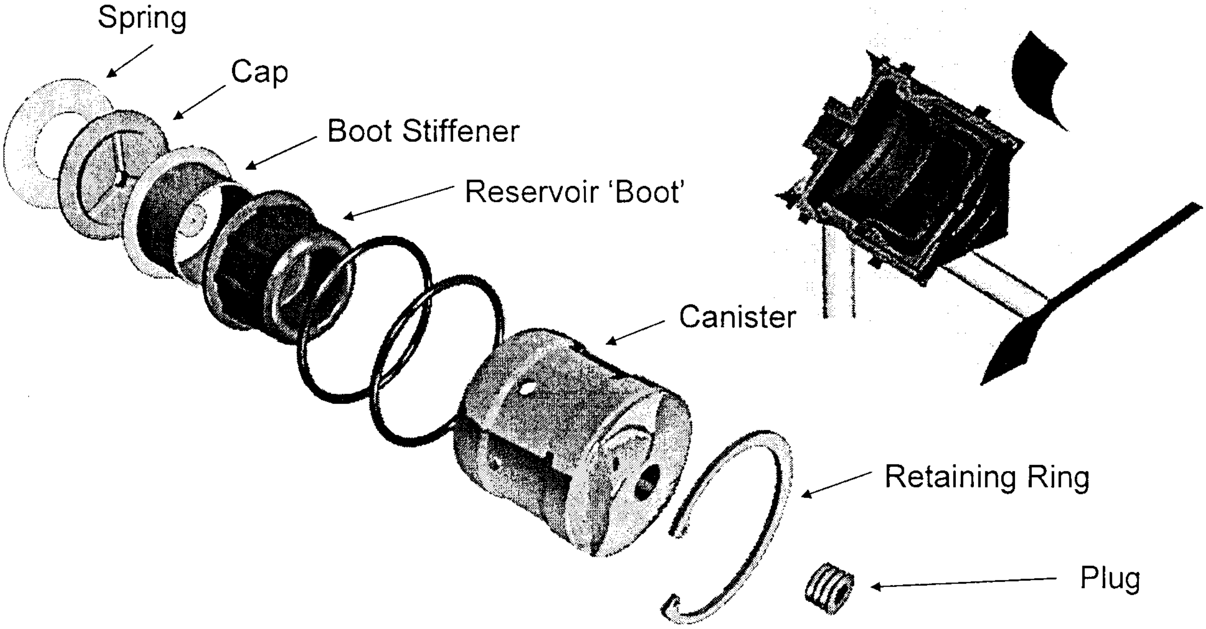
Dome Vent Equalization System



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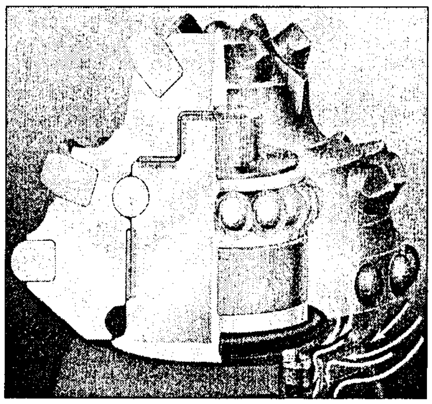
Seals

- Dual Functionality
  - 1) Prevent contaminants from entering the bearing
  - 2) Prevent lubricant from escaping
- Interior vs. Exterior
  - Interior: Grease Side
  - Exterior: Mud Side
- Static vs. Dynamic
  - Cone-Seal Surface: Static
  - Journal-Seal Surface: Dynamic



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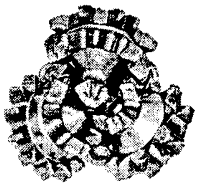
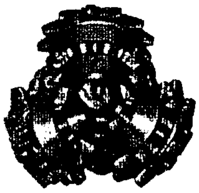
Milled Tooth Cutting Structure

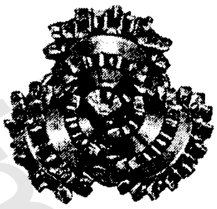
- Very Soft



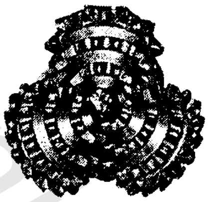
- Soft



- Medium-Soft



- Medium



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What is Tungsten Carbide?

- Tungsten Carbides
  - Hard carbide composites
  - Metal cutting tools, dies and wear parts
  - Metal carbide (WC) and binder (Co)
- History
  - Discovered in 1893
  - Commercial production started in 1926
  - First Roller Cone Bit application in 1951

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Tungsten Carbide Powder: WC

- Tungsten (W)
  - Derived from Metal ores: Scheelite and Wolframite
  - Calcium Tungstate and Iron-Manganese Tungstate
- Carbon (C)
  - Pure Carbon powder
- Carburization at 1400 to 1900°C (2500 to 3800°F)
  - W + C => WC

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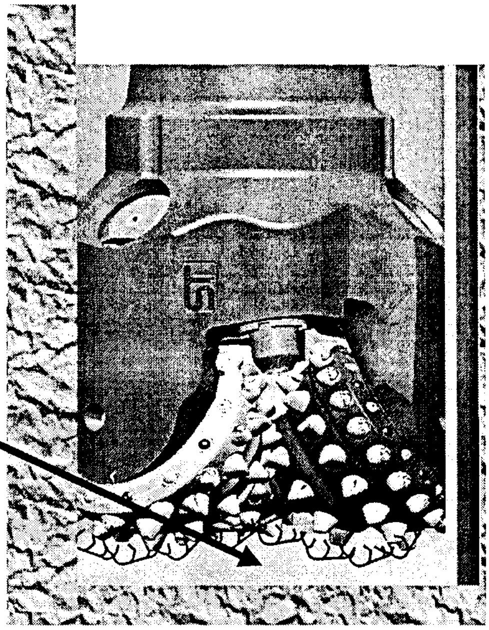
Roller Cone Bit Hydraulics

Bottom-hole Cleaning

- Allocate available hydraulic energy towards the bottom-hole to:
  - Lift all generated cuttings to prevent re-drill
  - Prolong cutting structure life
  - Maximize ROP



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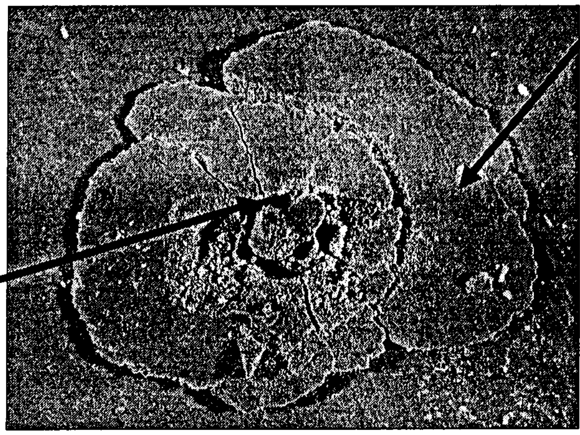
Bottom-hole Cleaning

- Anatomy of a Typical Insert Impact Location



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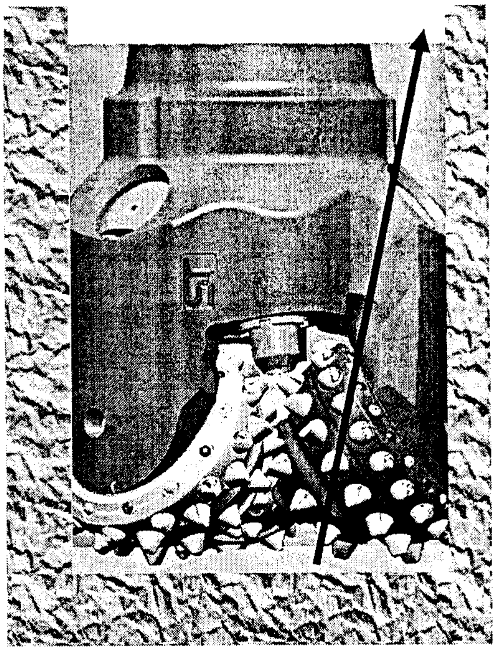
Cuttings Evacuation

- Allocate available hydraulic energy to:
  - Remove all generated cuttings to improve cutting efficiency
  - Prolong cutting structure life
  - Reduce bit balling tendencies
  - Extended seal life
  - Improve ROP
  - Improve dull condition



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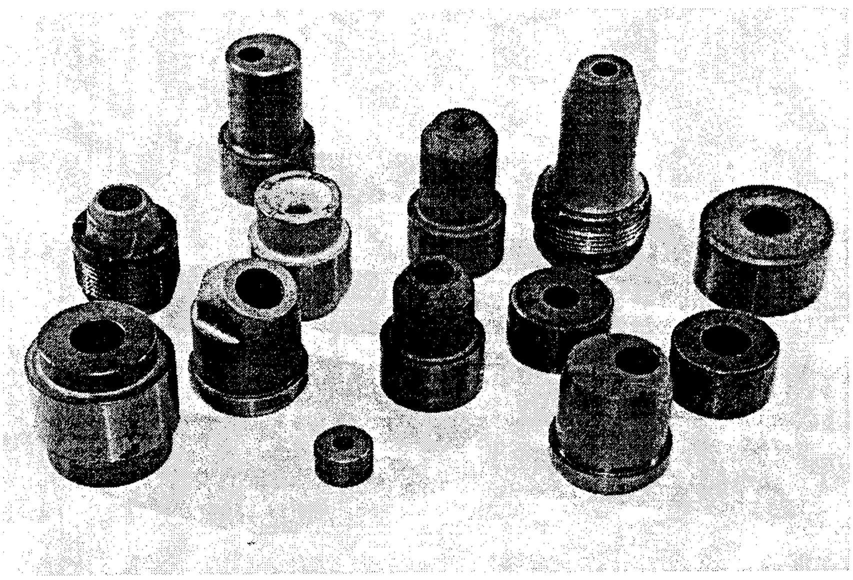
Nozzles



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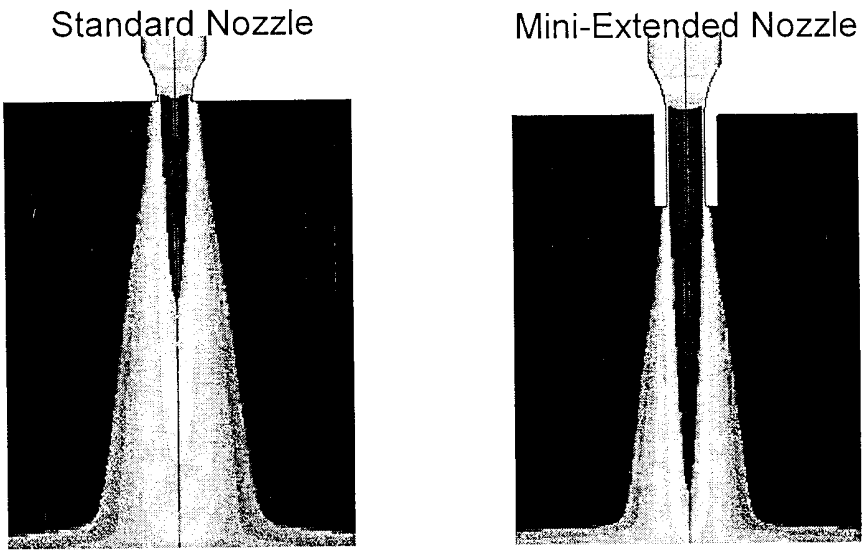
Fluid Velocity Comparison



7⅞" Bit
260 gpm
10 ppg mud
12/32" Nozzle

Fluid Velocity (ft/sec)
0 60 120 180 240

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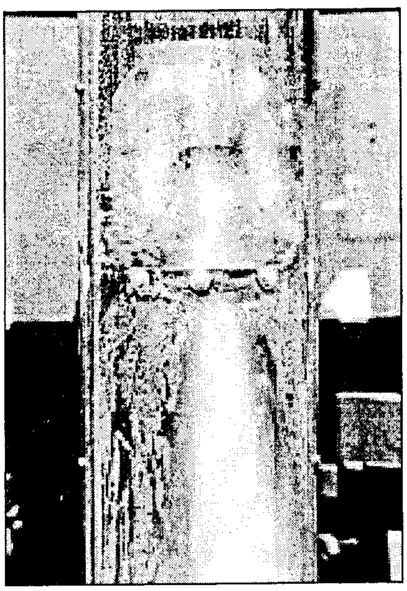
Flow Study Comparison



7⅞" Bit
310 gpm
12/32" Nozzle

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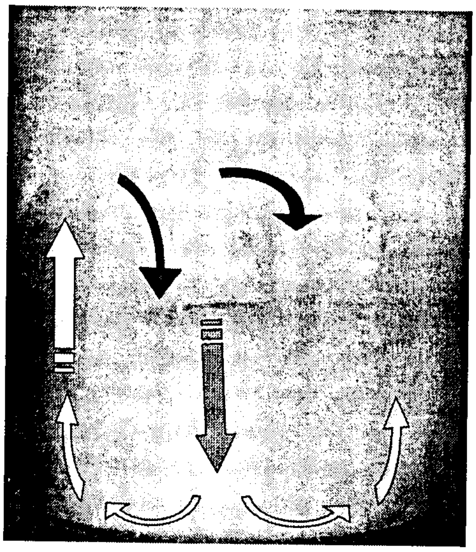
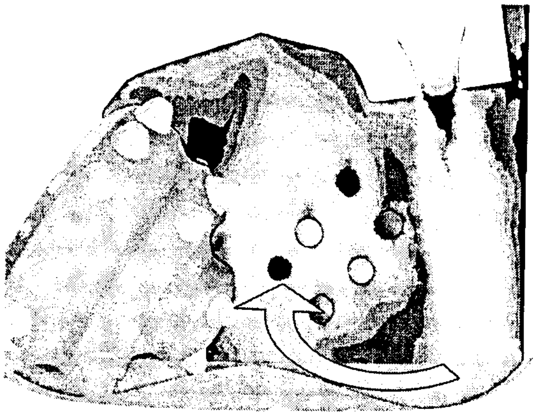
Standard-Flow Characteristics

- Flow Field Regime





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Roller Cone Bits IADC Classification System

IADC System

- Operational since 1972
- Method of Categorizing Roller Cone Rock Bits
- Design and Application related coding
- Most Recent Revision - 1992

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IADC Roller Bit Classification Chart

	FORMATIONS	SERIES	TYPES	BEARING / GAGE: STANDARD ROLLER BEARING (1)	ROLLER BEARING AIR COOLED (2)	ROLLER BEARING GAGE PROTECTED (3)	SEALED ROLLER BEARING (4)	SEALED ROLLER BRG. - GAGE PROTECTED (5)	SEALED FRICTION BEARING (6)	SEALED FRICTION BRG. - GAGE PROTECTED (7)
STEEL TOOTH BITS	SOFT FORMATIONS WITH LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY	1	1							
			2							
			3							
			4							
	MEDIUM TO MEDIUM HARD FORMATIONS WITH HIGH COMPRESSIVE STRENGTH	2	1							
			2							
			3							
			4							
	HARD SEMI-ABRASIVE AND ABRASIVE FORMATIONS	3	1							
			2							
			3							
			4							
INSERT BITS	SOFT FORMATIONS WITH LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY	4	1							
			2							
			3							
			4							
	SOFT TO MEDIUM FORMATIONS WITH LOW COMPRESSIVE STRENGTH	5	1							
			2							
			3							
			4							
	MEDIUM HARD FORMATIONS WITH HIGH COMPRESSIVE STRENGTH	6	1							
			2							
			3							
			4							
	HARD SEMI-ABRASIVE AND ABRASIVE FORMATIONS	7	1							
			2							
			3							
			4							
	[illegible] AND ABRASIVE FORMATIONS	8	1							
			2							
			3							
			4							

FEATURES AVAILABLE

- A - AIR APPLICATION
- B - SPECIAL BEARING SEAL
- C - CENTER JET
- D - DEVIATION CONTROL
- E - EXTENDED JETS (FULL LENGTH)
- G - GAGE / BODY PROTECTION (ADDITIONAL)
- H - HORIZONTAL / STEERING APPLICATION
- J - JET DEFLECTION
- L - LUG PADS
- M - MOTOR APPLICATION
- S - STANDARD STEEL TOOTH MODEL
- T - TWO CONE BIT
- W - ENHANCED CUTTING STRUCTURE
- X - PREDOMINANTLY CHISEL TOOTH INSERT
- Y - CONICAL TOOTH INSERT
- Z - OTHER SHAPE INSERT

Sequence

- Numeric Characters are defined:
  - Series 1st
  - Type 2nd
  - Bearing & Gage 3rd
- Alphabetic Character defined:
  - Features Available 4th

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Classification Chart: Series

	FORMATIONS	SERIES	TYPES	BEARING / GAGE: STANDARD ROLLER BEARING (1)	ROLLER BEARING AIR COOLED (2)	ROLLER BEARING GAGE PROTECTED (3)	SEALED ROLLER BEARING (4)	SEALED ROLLER BRG. - GAGE PROTECTED (5)	SEALED FRICTION BEARING (6)	SEALED FRICTION BRG. - GAGE PROTECTED (7)
STEEL TOOTH BITS	SOFT FORMATIONS WITH LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY	1	1 2 3 4							
	MEDIUM TO MEDIUM HARD FORMATIONS WITH HIGH COMPRESSIVE STRENGTH	2	1 2 3 4							
	HARD SEMI-ABRASIVE AND ABRASIVE FORMATIONS	3	1 2 3 4							
INSERT BITS	SOFT FORMATIONS WITH LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY	4	1 2 3 4							
	SOFT TO MEDIUM FORMATIONS WITH LOW COMPRESSIVE STRENGTH	5	1 2 3 4							
	MEDIUM HARD FORMATIONS WITH HIGH COMPRESSIVE STRENGTH	6	1 2 3 4							
	HARD SEMI-ABRASIVE AND ABRASIVE FORMATIONS	7	1 2 3 4							
	EXTREMELY HARD AND ABRASIVE FORMATIONS	8	1 2 3 4							

FEATURES AVAILABLE

- A - AIR APPLICATION
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- C - CENTER JET
- D - DEVIATION CONTROL
- E - EXTENDED JETS (FULL LENGTH)
- G - GAGE / BODY PROTECTION (ADDITIONAL)
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- M - MOTOR APPLICATION
- S - STANDARD STEEL TOOTH MODEL
- T - TWO CONE BIT
- W - ENHANCED CUTTING STRUCTURE
- X - PREDOMINANTLY CHISEL TOOTH INSERT
- Y - CONICAL TOOTH INSERT
- Z - OTHER SHAPE INSERT

Series

- First Character
- General Formation Characteristics
  - Compressive Strength
  - Abrasivity
- Eight (8) Series
  - Milled Tooth Bits : Series 1, 2 and 3
  - Insert Bits : Series 4, 5, 6, 7 and 8

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Classification Chart: Type

	FORMATIONS	SERIES	TYPES	BEARING / GAGE: STANDARD ROLLER BEARING (1)	ROLLER BEARING AIR COOLED (2)	ROLLER BEARING GAGE PROTECTED (3)	SEALED ROLLER BEARING (4)	SEALED ROLLER BRG. - GAGE PROTECTED (5)	SEALED FRICTION BEARING (6)	SEALED FRICTION BRG. - GAGE PROTECTED (7)
STEEL TOOTH BITS	SOFT FORMATIONS WITH LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY	1	1, 2, 3, 4							
	MEDIUM TO MEDIUM HARD FORMATIONS WITH HIGH COMPRESSIVE STRENGTH	2	1, 2, 3, 4							
	HARD SEMI-ABRASIVE AND ABRASIVE FORMATIONS	3	1, 2, 3, 4							
INSERT BITS	SOFT FORMATIONS WITH LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY	4	1, 2, 3, 4							
	SOFT TO MEDIUM FORMATIONS WITH LOW COMPRESSIVE STRENGTH	5	1, 2, 3, 4							
	MEDIUM HARD FORMATIONS WITH HIGH COMPRESSIVE STRENGTH	6	1, 2, 3, 4							
	HARD SEMI-ABRASIVE AND ABRASIVE FORMATIONS	7	1, 2, 3, 4							
	EXTREMELY HARD AND ABRASIVE FORMATIONS	8	1, 2, 3, 4							

FEATURES AVAILABLE

- A - AIR APPLICATION
- B - SPECIAL BEARING SEAL
- C - CENTER JET
- D - DEVIATION CONTROL
- E - EXTENDED JETS (FULL LENGTH)
- G - GAGE / BODY PROTECTION (ADDITIONAL)
- H - HORIZONTAL · STEERING APPLICATION
- J - JET DEFLECTION
- L - LUG PADS
- M - MOTOR APPLICATION
- S - STANDARD STEEL TOOTH MODEL
- T - TWO CONE BIT
- W - ENHANCED CUTTING STRUCTURE
- X - PREDOMINANTLY CHISEL TOOTH INSERT
- Y - CONICAL TOOTH INSERT
- Z - OTHER SHAPE INSERT

Type

- Second Character

- Degree of Hardness
- Each Series divided into 4 'Types'

- Type 1 Softest Formation in a Series

Increasing Rock Hardness

- Type 4 Hardest Formation in a Series

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Hardness Definition

Hardness	UCS (psi)	Examples
Ultra Soft	< 1,000	gumbo, clay
Very Soft	1,000 - 4,000	unconsolidated sands, chalk, salt, claystone
Soft	4,000 - 8,000	coal, siltstone, schist, sands
Medium	8,000 - 17,000	sandstone, slate, shale, limestone, dolomite
Hard	17,000 - 27,000	quartzite, basalt, gabbro, limestone, dolomite
Very Hard	> 27,000	marble, granite, gneiss

UCS = Uniaxial Unconfined Compressive Strength

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Classification Chart: Bearing & Gage

	FORMATIONS	SERIES	TYPES	BEARING / GAGE: STANDARD ROLLER BEARING (1)	ROLLER BEARING AIR COOLED (2)	ROLLER BEARING GAGE PROTECTED (3)	SEALED ROLLER BEARING (4)	SEALED ROLLER BRG. - GAGE PROTECTED (5)	SEALED FRICTION BEARING (6)	SEALED FRICTION BRG. - GAGE PROTECTED (7)
STEEL TOOTH BITS	SOFT FORMATIONS WITH LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY	1	1 2 3 4							
	MEDIUM TO MEDIUM HARD FORMATIONS WITH HIGH COMPRESSIVE STRENGTH	2	1 2 3 4							
	HARD SEMI-ABRASIVE AND ABRASIVE FORMATIONS	3	1 2 3 4							
INSERT BITS	SOFT FORMATIONS WITH LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY	4	1 2 3 4							
	SOFT TO MEDIUM FORMATIONS WITH LOW COMPRESSIVE STRENGTH	5	1 2 3 4							
	MEDIUM HARD FORMATIONS WITH HIGH COMPRESSIVE STRENGTH	6	1 2 3 4							
	HARD SEMI-ABRASIVE AND ABRASIVE FORMATIONS	7	1 2 3 4							
	EXTREMELY HARD AND ABRASIVE FORMATIONS	8	1 2 3 4							

FEATURES AVAILABLE

- A - AIR APPLICATION
- B - SPECIAL BEARING SEAL
- C CENTER JET
- D DEVIATION CONTROL
- E - EXTENDED JETS (FULL LENGTH)
- G - GAGE / BODY PROTECTION (ADDITIONAL)
- H - HORIZONTAL / STEERING APPLICATION
- J - JET DEFLECTION
- L LUG PADS
- M - MOTOR APPLICATION
- S - STANDARD STEEL TOOTH MODEL
- T - TWO CONE BIT
- W ENHANCED CUTTING STRUCTURE
- X - PREDOMINANTLY CHISEL TOOTH INSERT
- Y - CONICAL TOOTH INSERT
- Z OTHER SHAPE INSERT

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Bearing & Gage

- Third Character
- Bearing Design and Gage Protection
- Seven (7) Categories
  - 1. Non-Sealed (Open) Roller Bearing
  - 2. Roller Bearing Air Cooled
  - 3. Non-Sealed (Open) Roller Bearing Gage Protected
  - 4. Sealed Roller Bearing
  - 5. Sealed Roller Bearing Gage Protected
  - 6. Sealed Friction Bearing
  - 7. Sealed Friction Bearing Gage Protected

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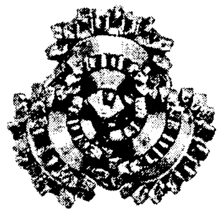
Example - Milled Tooth

SERIES	FORMATIONS	TYPES	1. STANDARD ROLLER BEARING: SMITH	HUGHES	REED	SECURITY	4. SEALED ROLLER BEARING: SMITH	HUGHES	REED	SECURITY	5. SEALED ROLLER BEARING GAGE PROTECTED: SMITH	HUGHES	REED	SECURITY	6. SEALED FRICTION BEARING: SMITH	HUGHES	REED	SECURITY	7. SEALED FRICTION BEARING GAGE PROTECTED: SMITH	HUGHES	REED	SECURITY
1	Soft Formations/ Low-Compressive Strength	1	DS1	R1	Y11	[illegible]	SDS	ATX1 GTX1	S11	[illegible]	MSDSH MSDSSH [illegible] MSDSSHOD	ATXG1 GTXG1 [illegible] MAXG11	S11G MS11G [illegible]	[illegible]	FDS FDS+ FDSS+	ATJ1 GT1 ATJ1S [illegible]	FP11 FP11+ FFP11 FMC11	[illegible]	MFDSH MFDSSH MFDSHOD FDS+2 FDSS+2	[illegible]	[illegible]	[illegible]
		2	DTJ		Y12	[illegible]				[illegible]				[illegible]	FDT		FP12 [illegible]	[illegible]				[illegible]
		3	DG		Y13	[illegible]				S44	SDGH MSDGH MSDGHOD	ATXG3 GTXG3 MAXG3 MAXG11	S13G MS13G [illegible]	S44G SS44G	FDG		FP13	S44F	FDGH MFDGH MFDGHOD	[illegible]	[illegible]	[illegible]
2	Medium to Medium-Hard Formations/High-Compressive Strength	1	[illegible]			[illegible]				[illegible]	[illegible]		[illegible]	[illegible]	FV	[illegible]		[illegible]	FVH	[illegible]	[illegible]	[illegible]
		2		[illegible]		M4																
		3																				
3	Hard, Semi-Abrasive Formations	1		[illegible]		H7				[illegible]			S31G					[illegible]			[illegible]	
		2				[illegible]																
		3												[illegible]								
		4																		[illegible]		

MSDGH   IADC 135



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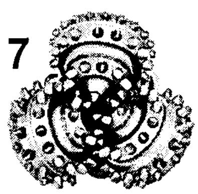
Example - TCI

SERIES	FORMATIONS	TYPES	2. ROLLER BEARING AIR COOLED: SMITH	HUGHES	REED	SECURITY	5. SEALED ROLLER BEARING GAGE PROTECTED: SMITH	HUGHES	REED	SECURITY	7. SEALED FRICTION BEARING GAGE PROTECTED: SMITH	HUGHES	REED	SECURITY
4	Soft Formations/ Low-Compressive Strength	1					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		2					[illegible]		[illegible]	[illegible]	[illegible]	[illegible]		[illegible]
		3					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		4					[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]
5	Soft to Medium-Hard Formations/ Low-Compressive Strength	1					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		2					[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		3					[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		4				[illegible]		[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	Medium-Hard Formations/ High-Compressive Strength	1	[illegible]	[illegible]			[illegible]			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		2			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		3		[illegible]	[illegible]		[illegible]	[illegible]			[illegible]	[illegible]	[illegible]	[illegible]
		4									[illegible]	[illegible]		
7	Hard, Semi-Abrasive and Abrasive Formations	1												[illegible]
		2												
		3	[illegible]	[illegible]	[illegible]						[illegible]	[illegible]	[illegible]	[illegible]
		4				[illegible]						[illegible]		
8	Extremely Hard and Abrasive Formations	1				[illegible]					[illegible]			[illegible]
		2												
		3	[illegible]	[illegible]	[illegible]	[illegible]				[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

F2   IADC 517



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Classification Chart: Features Available

	FORMATIONS	SERIES	TYPES	BEARING / GAGE: STANDARD ROLLER BEARING (1)	ROLLER BEARING AIR COOLED (2)	ROLLER BEARING GAGE PROTECTED (3)	SEALED ROLLER BEARING (4)	SEALED ROLLER BRG. - GAGE PROTECTED (5)	SEALED FRICTION BEARING (6)	SEALED FRICTION BRG. - GAGE PROTECTED (7)
STEEL TOOTH BITS	SOFT FORMATIONS WITH LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY	1	1							
			2							
			3							
			4							
	MEDIUM TO MEDIUM HARD FORMATIONS WITH HIGH COMPRESSIVE STRENGTH	2	1							
			2							
			3							
			4							
	HARD SEMI-ABRASIVE AND ABRASIVE FORMATIONS	3	1							
			2							
			3							
			4							
INSERT BITS	SOFT FORMATIONS WITH LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY	4	1							
			2							
			3							
			4							
	SOFT TO MEDIUM FORMATIONS WITH LOW COMPRESSIVE STRENGTH	5	1							
			2							
			3							
			4							
	MEDIUM HARD FORMATIONS WITH HIGH COMPRESSIVE STRENGTH	6	1							
			2							
			3							
			4							
	HARD SEMI-ABRASIVE AND ABRASIVE FORMATIONS	7	1							
			2							
			3							
			4							
	EXTREMELY HARD AND ABRASIVE FORMATIONS	8	1							
			2							
			3							
			4							

FEATURES AVAILABLE

- A - AIR APPLICATION
- B - SPECIAL BEARING SEAL
- C - CENTER JET
- D - DEVIATION CONTROL
- E - EXTENDED JETS (FULL LENGTH)
- G - GAGE / BODY PROTECTION (ADDITIONAL)
- H - HORIZONTAL / STEERING APPLICATION
- J - JET DEFLECTION
- L - LUG PADS
- M - MOTOR APPLICATION
- S - STANDARD STEEL TOOTH MODEL
- T - TWO CONE BIT
- W - ENHANCED CUTTING STRUCTURE
- X - PREDOMINANTLY CHISEL TOOTH INSERT
- Y - CONICAL TOOTH INSERT
- Z - OTHER SHAPE INSERT

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Features Available

- Fourth Character
  - – Features Available (Optional)
  - – Sixteen (16) Alphabetic Characters
  - – Most Significant Feature Listed

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IADC Features Available

- A - Air Application
- B - Special Bearing/Seal
- C - Center Jet
- D - Deviation Control
- E - Extended Nozzles
- G - Gage/Body Protection
- H - Horizontal Application
- J - Jet Deflection
- L - Lug Pads
- M - Motor Application
- S - Standard Milled Tooth
- T - Two-Cone Bit
- W - Enhanced C/S
- X - Chisel Tooth Insert
- Y - Conical Tooth Insert
- Z - Other Shape Inserts

Summary

- Convenient Categorization System
- Design and Application Code
- Know its Limitations
- Use Carefully in Application Decisions
  - Consider additional sources: offset bit records; dull grading reports; performance analysis and DBOS™

Fixed Cutter Bit Terminology

Review Terminology

- PDC?
  Polycrystalline Diamond Compact
  It is a term used for the entire PDC cutter (diamond table + substrate)
- PCD?
  Polycrystalline Diamond
  The diamond table itself is referred to as the PCD layer
- TSP?
  Thermally Stable Polycrystalline
  Catalyst material is removed using an acid leaching process
- TSD?
  Thermally Stable Diamond
  TSD is thermally stable diamond in which silica carbide (thermal coefficient of expansion similar to diamond) is used in the binder phase instead of cobalt

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PDC Bits

Ref: Oil & Gas Journal, Aug. 14, 1995, p.12

- Increase penetration rates in oil and gas wells
- Reduce drilling time and costs
- Cost 5-15 times more than roller cone bits
- 1.5 times faster than those 2 years earlier
- Work better in oil based muds; however,these areas are strictly regulated

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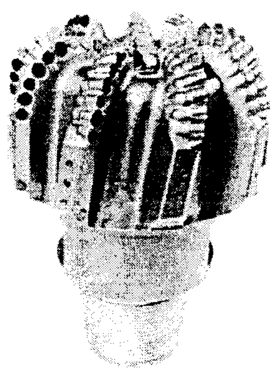
Product Lines: PDC Bits

Steel Body

Matrix Body



Dual Diameter

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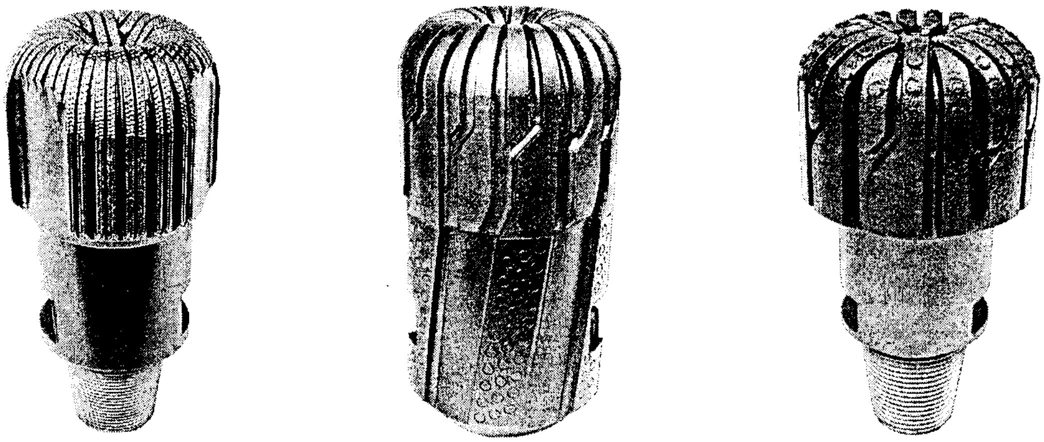
Product Lines: Diamond Bits



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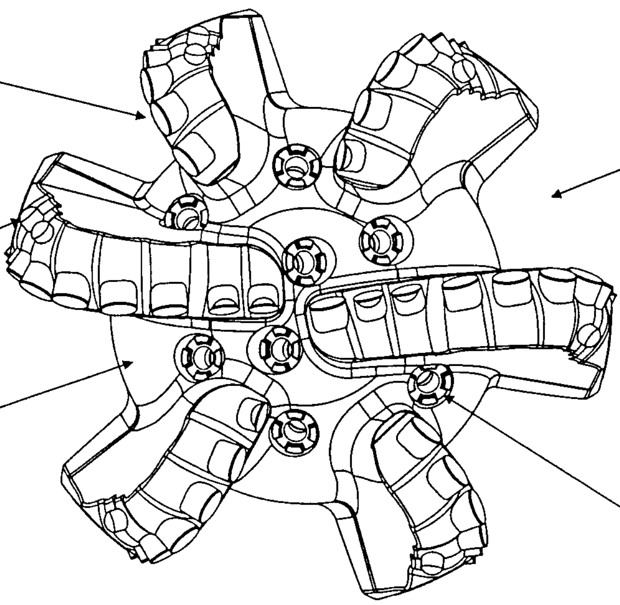
PDC Terminology & Features



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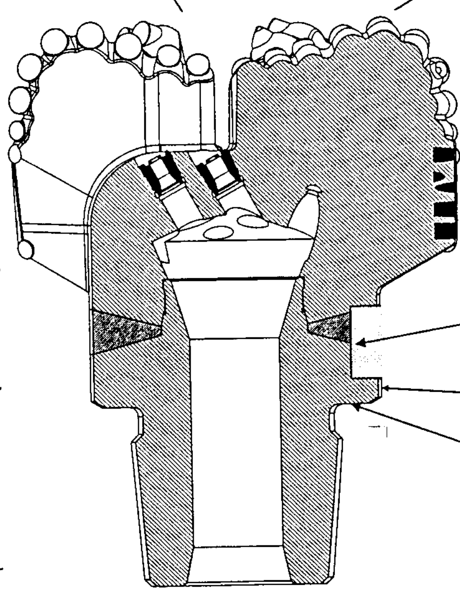
PDC Terminology & Features



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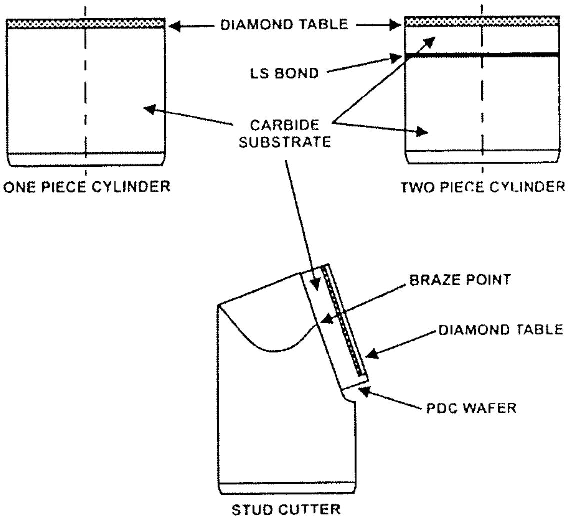
Cutter Terminology

- PCD Layer
  - Also known as the diamond table
- Carbide Substrate
  - Acts as the support for the diamond table, and provides toughness
  - Bonds the cutter into the bit body
- LS Bond
  - Cemented boundary between two carbide substrates that may have different characteristics



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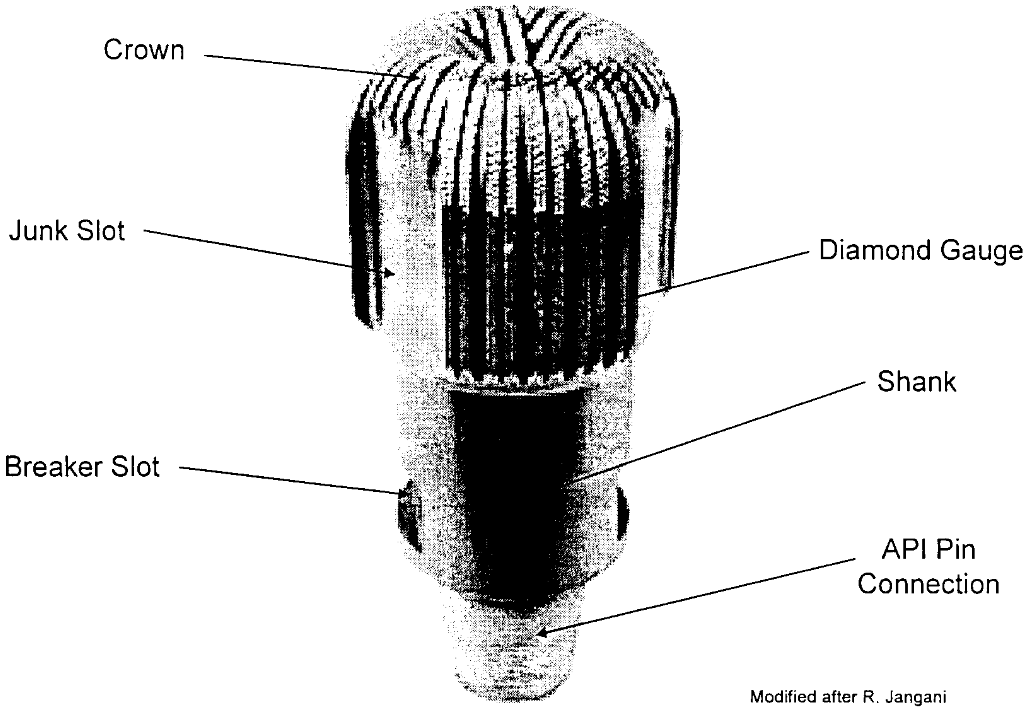
Diamond Bit Terminology & Features



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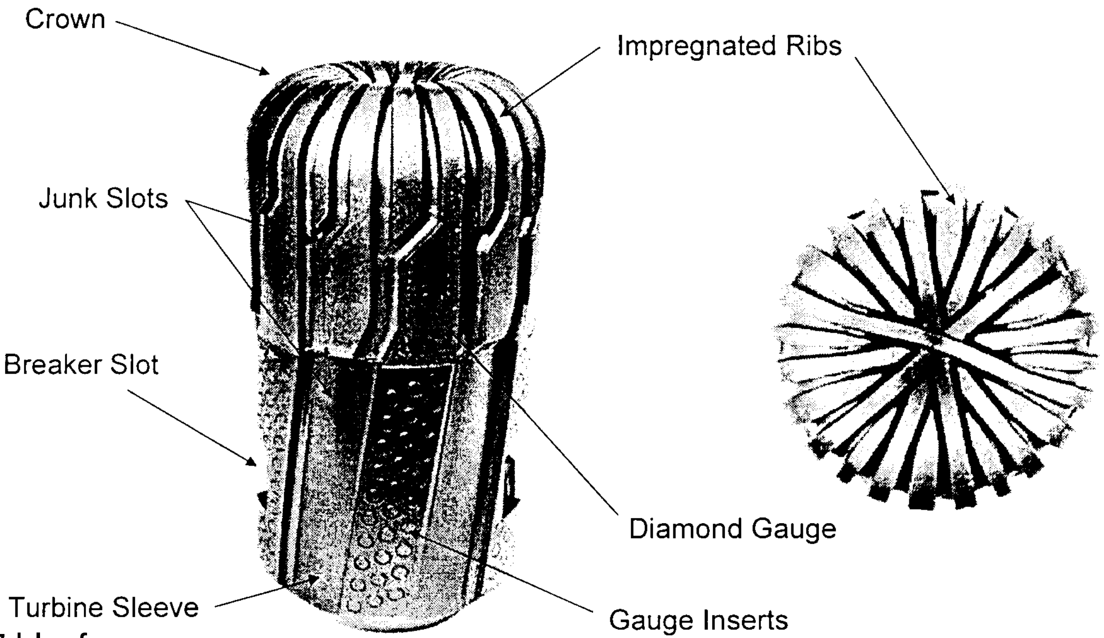
Impregnated Bit Terminology & Features



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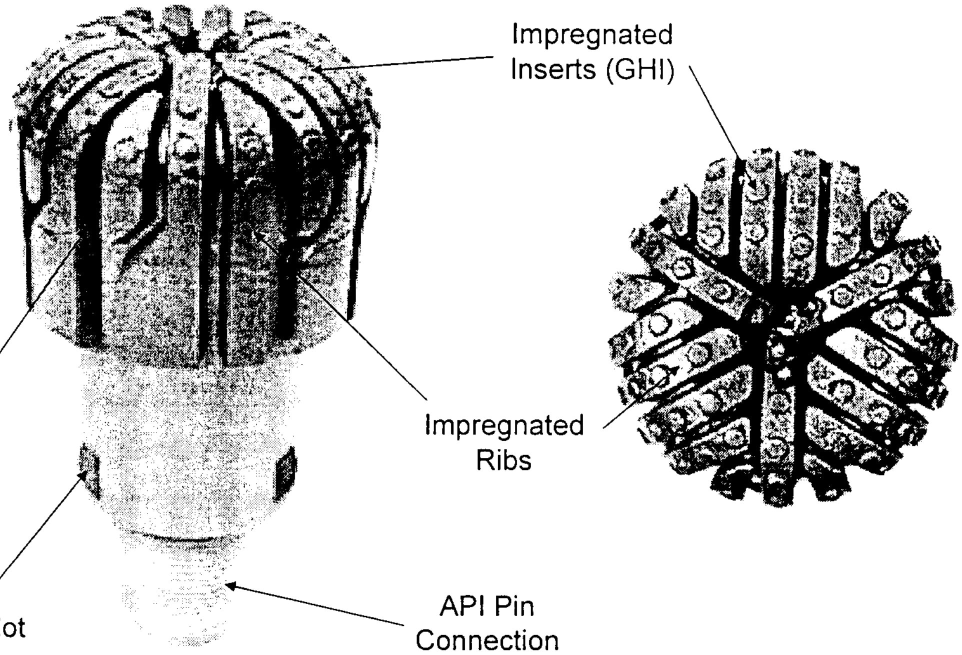
Impregnated Bit Terminology & Features



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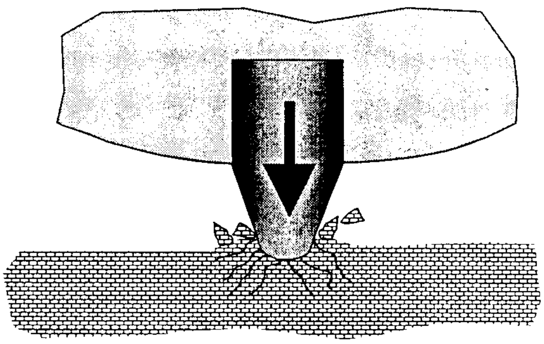
Roller Cone Mechanics

- Roller Cone Bits drill by chipping & crushing and/or gouging & scraping the rock



- Rock requires high energy (WOB) to fracture the rock with compressive loading

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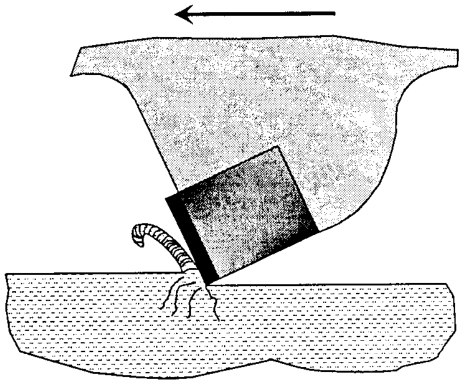
PDC Mechanics

- PDC Bits drill by shearing the rock
- Rocks typically fracture more easily with shear loading (less energy, WOB)
- Most efficient cutting action



Polycrystalline Diamond Compact

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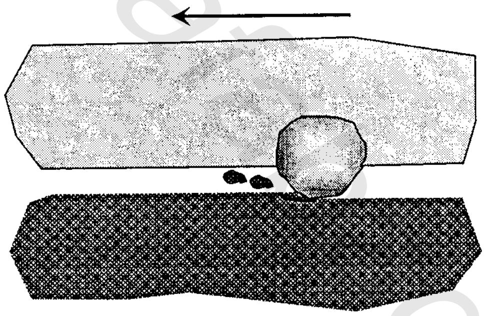
Natural Diamond Mechanics

- Natural Diamond Bits drill by ploughing and grinding the rock
- Normally require higher RPM for better performance (e.g.: high speed motor or turbine)



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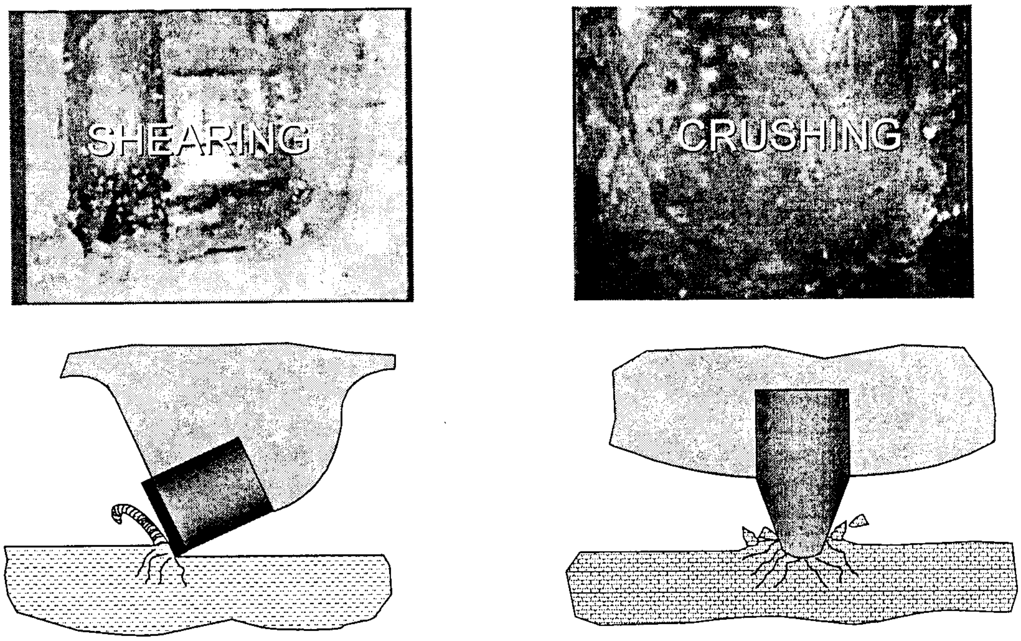
Shearing vs. Crushing



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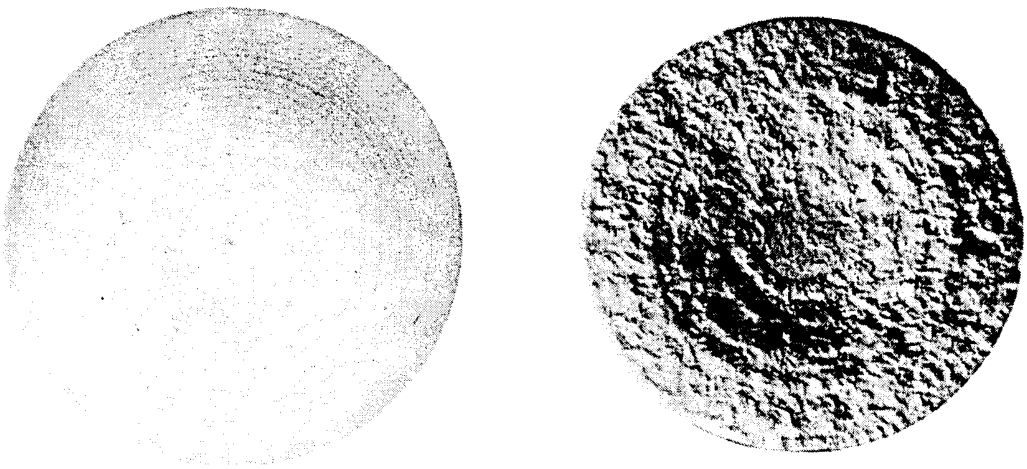
Bottom Hole Profile



PDC

ROLLER CONE

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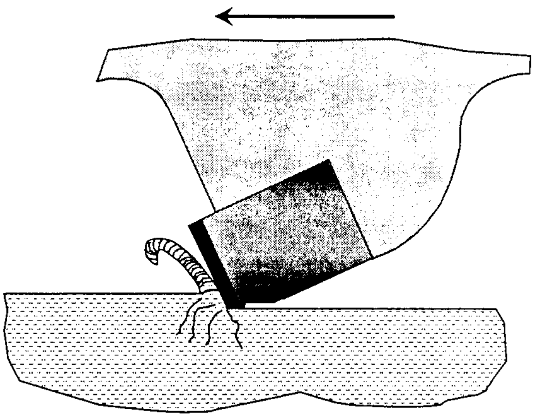
PDC Cutting Mechanism: Advantages

- Unlike Natural Diamonds and Roller cone teeth, PDC cutters exhibit self-sharpening wear.
- The Tungsten Carbide carrier wears faster than Diamond table forming a sharp Diamond lip.



PDC Bit - Self Sharpening

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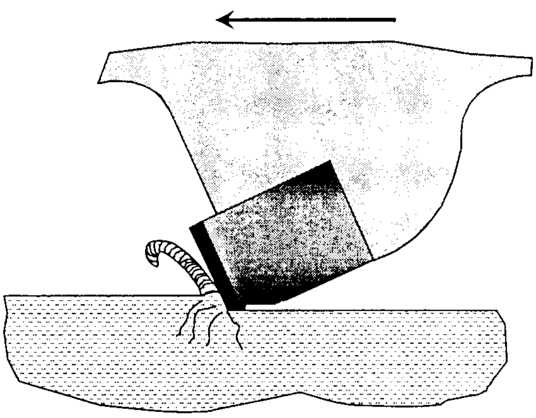
PDC Cutting Mechanism: Advantages

- As cutting elements wear, the specific energy requirement increases reducing the drilling efficiency.
- The self sharpening mechanism of PDC cutters improves drilling efficiency.



PDC Bit - Self Sharpening

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Dull Grading System

Objectives

- Understand the purpose of the system
- Outline the 8-digit system structure
- Provide guidelines for consistency
- Examine the different dull characteristics

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Contents

- Reference Material
- Definitions and Guidelines
- System Structure
  - Detailed Review of the 8-digit system
- Dull Characteristics
  - Information and Photographs

Modified after R. Jangani

Bit Record

KENNEY #15-4
Sec. 15 15N-20W
CUSTER Co.,Ok

RIG COST / HR $200

WELL	BIT #	HOLE SIZE	BIT TYPE	DEPTH IN	DEPTH OUT	BIT HRS.	FTGE BIT	BIT WT	%WN	DEV	DULL	FT/HR BIT	$/FT BIT	ACC. HRS	ACC $/FT
MOSELY #25-4	1	12.25	SDS-C	80	2750	23.00	2670	55	BFR	0.25	4, SB, I	116.10	$2.83	23.00	$2.83
BAKER #31-2	1	12.25	SDS-C	80	2810	24.50	2730	50	BFR	1.00	4, SB, I	111.40	$2.88	24.50	$2.88
HUTCHESON #22	1	12.25	SDSC	100	3030	27.75	2930	50	BFR	0.50	4, 4, I	105.60	$2.92	27.75	$19.39
KENNEY #15-4	1	12.25	CX3A	80	3240	33.00	3160	65	BFR	0.75	5/4/WT/A/SB/I/FC/PR	95.80	$3.05	33.00	$3.05
MOSELY #23-2	1	12.25	SDSC	65	3074	34.00	3009	45	BFR	1.00	6, SB, I	88.50	$3.26	34.00	$3.27
WILSON #16-3	1	12.25	FDSC	80	2805	32.75	2725	40	BFR	1.00	3/3/WT/A/SB/I/SS/PR	83.20	$3.49	32.75	$3.49
MOSELY #25-4	2	12.25	SDS-C	2750	3441	15.75	691	60	BFR	0.50	4, SB, I	43.90	$9.00	38.75	$4.10
HUTCHESON #22	2	12.25	SDSC	3030	3714	16.25	684	70	BFR	0.50	8, SB, I	42.10	$9.31	44.00	$17.50
BAKER #31-2	2	12.25	SDS-C	2810	3812	37.25	1002	65	BFR	0.50	DNS	26.90	$10.57	61.75	$4.94
WILSON #16-3	2	12.25	FDSC	2805	3556	25.00	751	50	BFR	0.25	4/3/WT/A/SB/I/SS/PR	30.00	$10.77	57.75	$5.06
MOSELY #23-2	2	12.25	SDSC	3074	3575	21.25	501	65	BFR	0.75	6, SB, I	23.60	$14.66	55.25	$4.91
KENNEY #15-4	2	12.25	J-33	3240	4100	27.25	860	80	139	0.75	3/2/BT/A/SB/I/NO/TD	31.60	$17.12	60.25	$6.06
MOSELY #25-4	3	12.25	J-33	3441	4038	25.50	597	85	102	0.75	DNS	23.40	$24.06	64.25	$7.11
WILSON #16-3	3	12.25	J-33	3556	4096	28.00	540	50	78	0.50	2/3/BT/A/SB/I/NO/TD	19.30	$27.54	85.75	$8.08
HUTCHESON #22	3	12.25	SDGH	3714	4000	23.75	286	80	BFR	0.25	8, 6, I	12.00	$27.69	67.75	$18.24
MOSELY #23-2	3	12.25	F-3	3575	4050	26.75	475	65	73	1.00	2, SE, I	17.80	$30.77	82.00	$8.00
BAKER #31-2	3	12.25	F-3	3813	4140	17.50	328	55	86	0.00	DNS	18.70	$38.96	79.25	$7.69

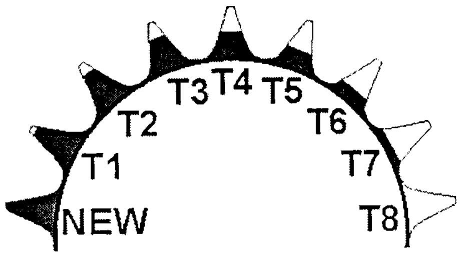
IADC Roller Bit Dull Grading System

T				B	G	REMARKS	
1	2	3	4	5	6	7	8
CUTTING STRUCTURE				B	G	REMARKS	
Inner Rows (I)	Outer Rows (O)	Dull Char. (D)	Loca-tion (L)	Brng. Seal (B)	Gage 1/16 (G)	Other Dull (O)	Reason Pulled (R)

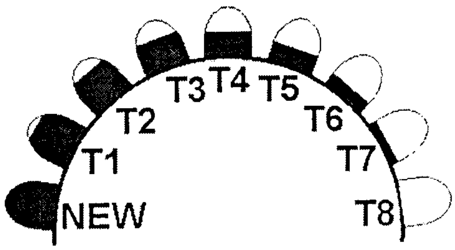
I: Inner Rows

- Used to report the condition of the cutting elements not touching the wall of the hole.
- Linear scale from 0 - 8 measuring the combined cutting structure reduction due to lost, worn and/or broken cutting elements.

- Tooth Height Measurement
  - Steel Tooth Bit



  - Insert Bit



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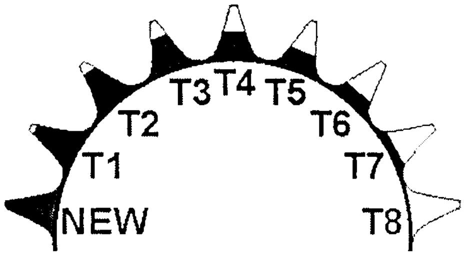
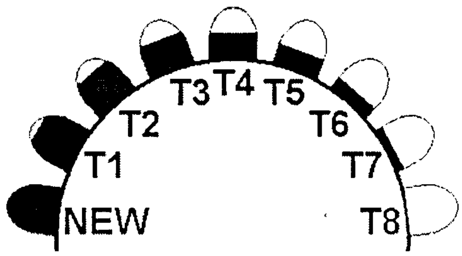
O: Outer Rows

- Used to report the condition of the cutting elements that touch the wall of the hole
- Linear scale from 0 - 8 measuring the combined cutting structure reduction due to lost, worn and/or broken cutting elements.
  - Smith Tool guideline - Do not include heel elements

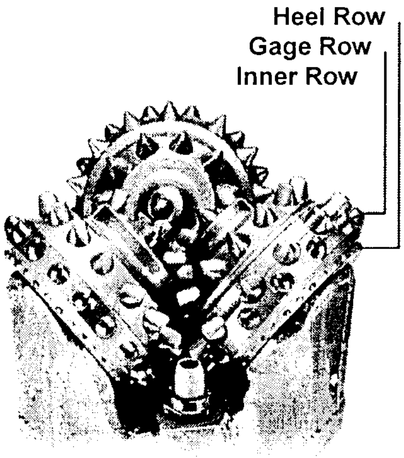
- Tooth Height Measurement
  - Steel Tooth Bit



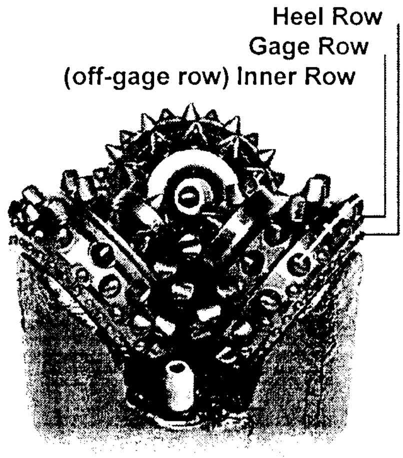
  - Insert Bit



Identifying TCI Rows



Conventional Gage Structure

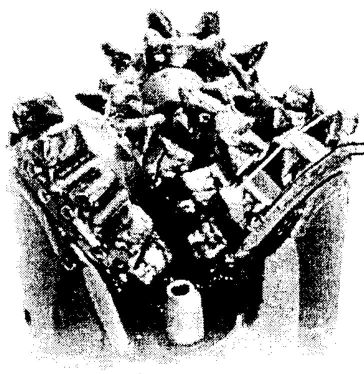


Trucut Gage Structure

Modified after R. Jangani

Identifying Milled Tooth Rows

Conventional Gage Structure



Trucut Gage Structure

Modified after R. Jangani

D: Dull Characteristics

- BC - Broken Cone ✷
- *BF - Bond Failure #*
- BT - Broken Teeth/Cutters
- BU - Balled Up
- CC - Cracked Cone ✷
- CD - Cone Dragged ✷
- CI - Cone Interference
- CR - Cored
- CT - Chipped Teeth/Cutters
- ER - Erosion
- FC - Flat Crested Wear
- HC - Heat Checking
- JD - Junk Damage
- LC - Lost Cone ✷
- LN - Lost Nozzle
- LT - Lost Teeth/Cutters
- NO - No Dull Characteristic
- OC - Off Center Wear
- PB - Pinched Bit
- PN - Plugged Nozzle
- RG - Rounded Gage
- *RO - Ring Out #*
- SD - Shirttail Damage
- SS - Self Sharpening Wear
- TR - Tracking
- WO - Washed Out Bit
- WT - Worn Teeth/Cutters

✷ Show cone number or numbers under location (L)
 # Not used for roller cone bits

D: Dull Characteristics

- Two letter code to indicate the major dull characteristic of the cutting structure.
  - Smith Tool guideline - input only one dull characteristic code
  - This column is only for codes that apply to cutting structures

- Which code do I select?
  - Smith Tool guideline - The cutting structure dull characteristic is the observed characteristic that would most likely limit further usage of the bit in that application

L: Location

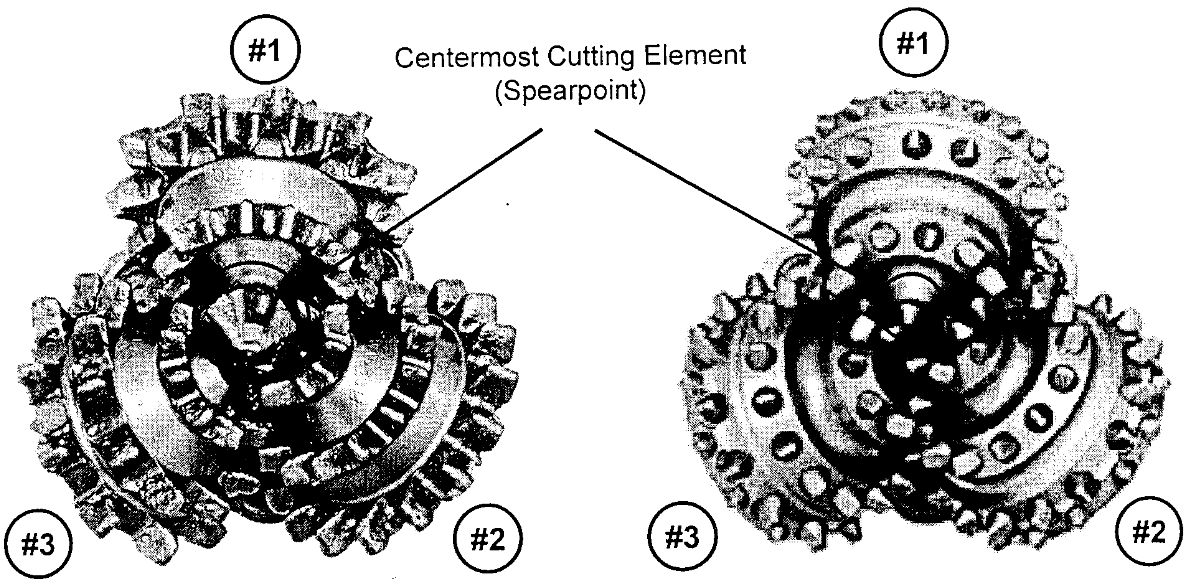
- Uses a letter or number code to indicate the location on the face of the bit where the cutting structure dull characteristic occurs
  - G = Gage: those cutting elements which touch the hole wall.
  - N = Nose: the centermost cutting elements of the bit.
  - M = Middle: the cutting elements between the nose and the gage.
  - A = All rows
  - Cone numbers

  - Smith Tool guideline - a maximum of two characters to be input

L: Location

- Smith Tool Guidelines
  - In general, the #1 cone typically contains the centermost cutting element. The #2 and #3 cones follow in a clockwise rotation.
  - However, accurate determination of #1 cone, on any roller cone bit, by visual examination is not always possible.

General Cone Identification Rule



Modified after R. Jangani

B: Bearings/Seals

- Smith Tool Guidelines
  - This column is used to indicate the condition of the bearing and seal assembly. If either component in the assembly has failed, then the code is F.
  - If any portion of the bearing is exposed or missing, it is considered an ineffective (F) assembly.
  - Use N if unable to determine the condition of both components.
  - Smith Tool grades each assembly separately.
  - If grading all assemblies as one, list the worst case.

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B: Bearings/Seals

- Sealed Bearing Bits
  - E – Seals effective
  - F – Seals failed
  - N – Not able to grade

- Non-Sealed Bearing Bits
  - Linear scale from 0 to 8
  - Estimating bearing life used

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B: Bearings/Seals

- Items to check when determining Bearing/Seal effectiveness
  - Ability to rotate cone
  - Cone springback
  - Seal squeak
  - Internal sounds
  - Weeping grease
  - Shale burn
  - Shale packing
  - Gaps - backface or throat
  - Bearing letdown - inner or outer

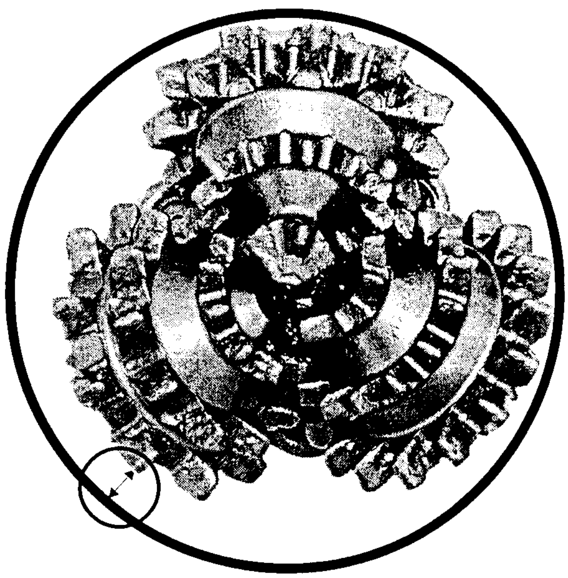
G: Gage

Used to report the undergage condition of the cutting elements that touch the wall of the hole.
- Based upon a nominal ring gage.
- New bits are built to API specifications.

API Tolerances for Roller Cone Bits

– 3⅜" to 13¾"	API Tolerance: + 1/32 : - 0
– 14" to 17½"	API Tolerance: + 1/16 : - 0
– >17⅝"	API Tolerance: + 3/32 : - 0

- 'Specification for Rotary Drilling Equipment'
  - API Specification 7 (Spec 7)



Modified after R. Jangani

R: Reason Pulled

- BHA - Change Bottom Hole Assembly
- CM - Condition Mud
- CP - Core Point
- DMF - Downhole Motor Failure
- DP - Drill Plug
- DSF - Drill String Failure
- DST - Drill Stem Test
- DTF - Downhole Tool Failure
- FM - Formation Change
- HP - Hole Problems
- HR - Hours on Bit
- LIH - Left in Hole
- LOG - Run Logs
- PP - Pump Pressure
- PR - Penetration Rate
- RIG - Rig Repair
- TD - Total Depth / Casing Depth
- TQ - Torque
- TW - Twist Off
- WC - Weather Conditions
- WO - Washout in Drill String

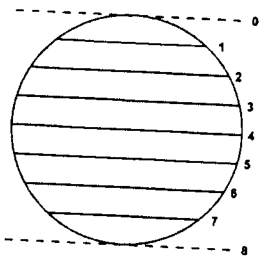
I: Inner Rows

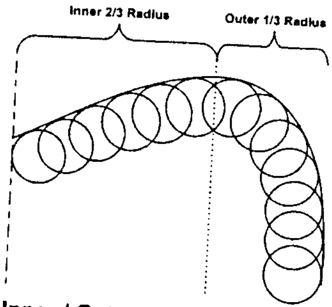
- Used to record the average wear on the inner two-thirds (⅔) of the bit radius
- Cutter wear is recorded using a linear scale from 0 to 8
  - 0 = no diamond wear
  - 8 = no diamond remaining*

  (no usable cutter remaining)

PDC cutter wear should be measured across the diamond table regardless of the cutter shape, size, type or exposure

Degrees of Cutter Wear





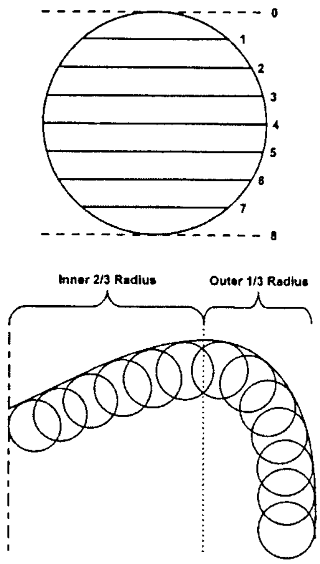
Inner / Outer Body Designation
PDC Bits / Impregnated Bits

Modified after R. Jangani

O: Outer Rows

- Used to record the average wear on the outer one-third (⅓) of the bit radius
- Cutter wear is recorded using a liner scale from 0 to 8
  - 0 = no diamond wear
  - 8 = no diamond remaining*

  (no usable cutter remaining)

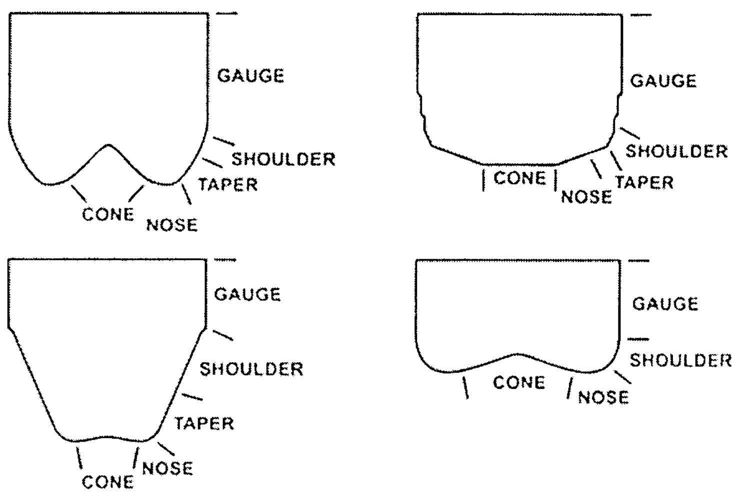


Inner / Outer Body Designation
PDC Bits / Impregnated Bits

Modified after R. Jangani

L: Location

- Uses a letter code to indicate the location on the bit face where the major dull characteristic occurs
  - C = Cone
  - N = Nose
  - S = Shoulder
  - G = Gage
  - A = All Areas



Modified after R. Jangani

B: Bearings/Seals

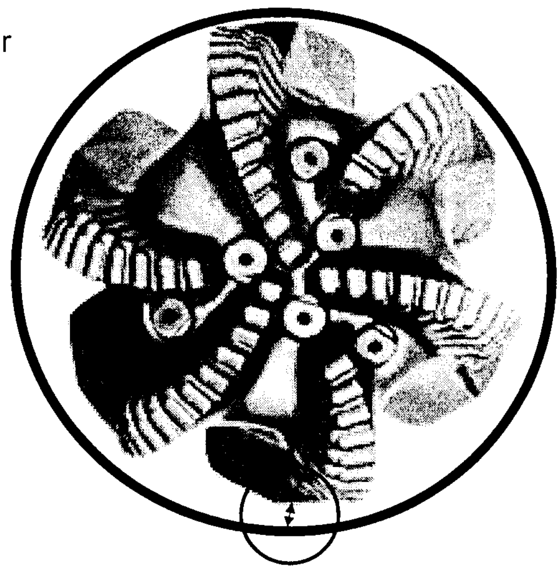
- Not Applicable
  - This space is used only for roller cone bits
  - It will always be marked 'X' for fixed cutter bits

G: Gage

- PDC and Impreg. Bits
  - Measure on the last gauge trimmer and top of the gauge pad

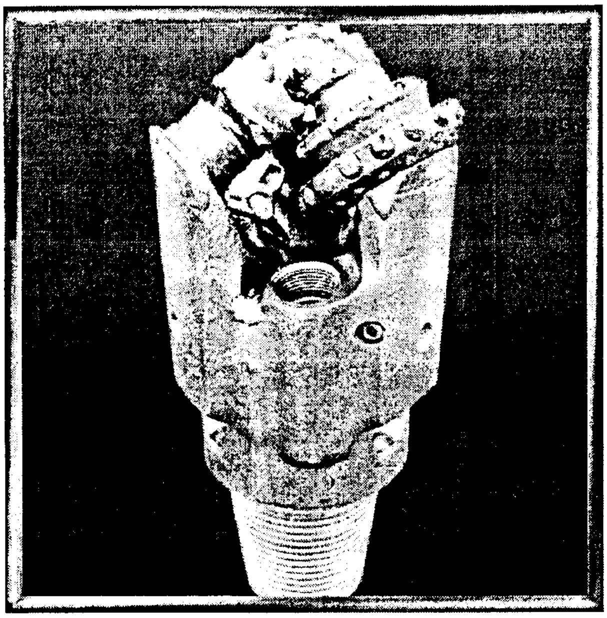
Amount out of gage = Measured distance

Amount Undergage in 16^{ths}
IN = In Gage
1 = $^1/_{16}$"
2 = $^2/_{16}$"
3 = $^3/_{16}$"
etc.

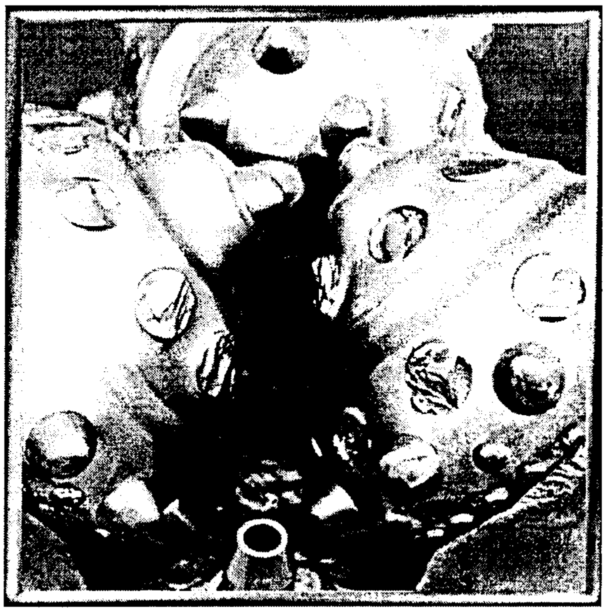


Modified after R. Jangani

BC: Broken Cone

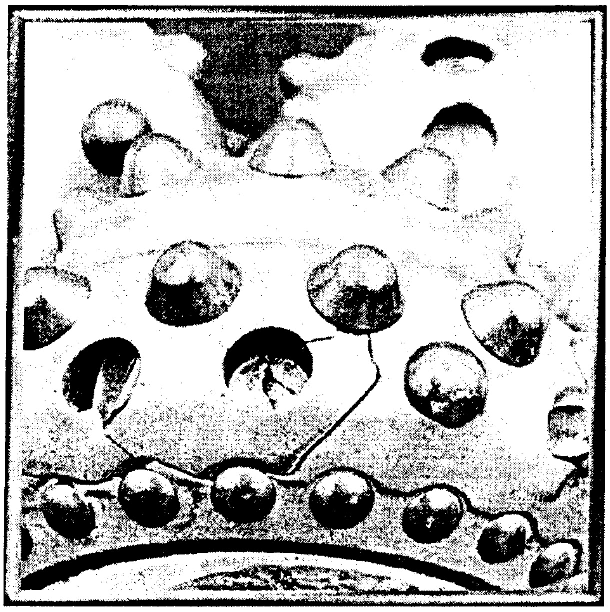



BT - Broken Teeth

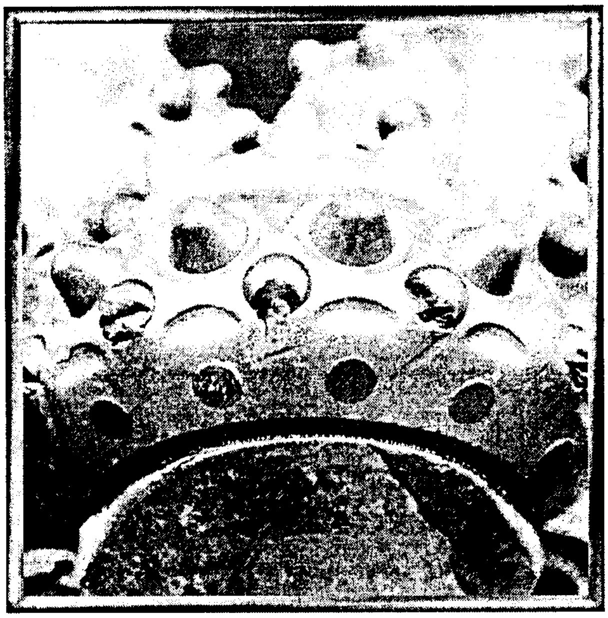



BU - Balled Up

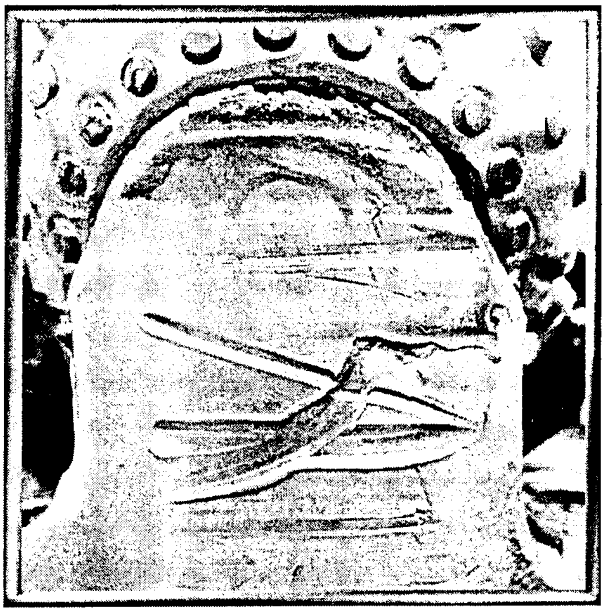
CC - Cracked Cone



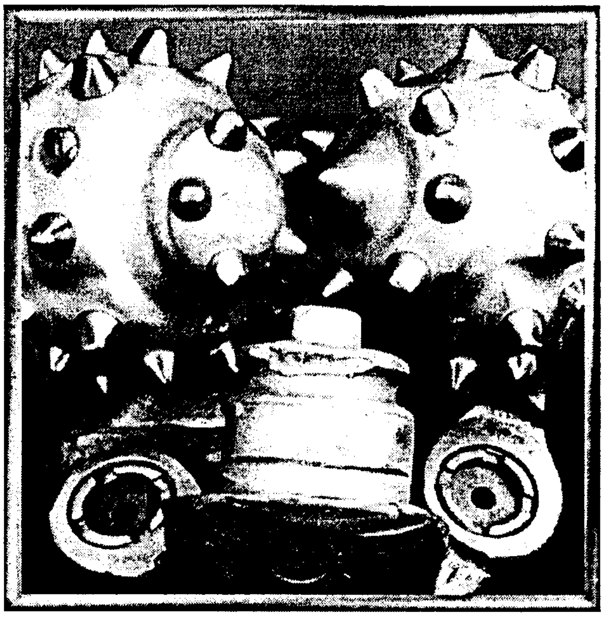
CT - Chipped Teeth



JD - Junk Damage

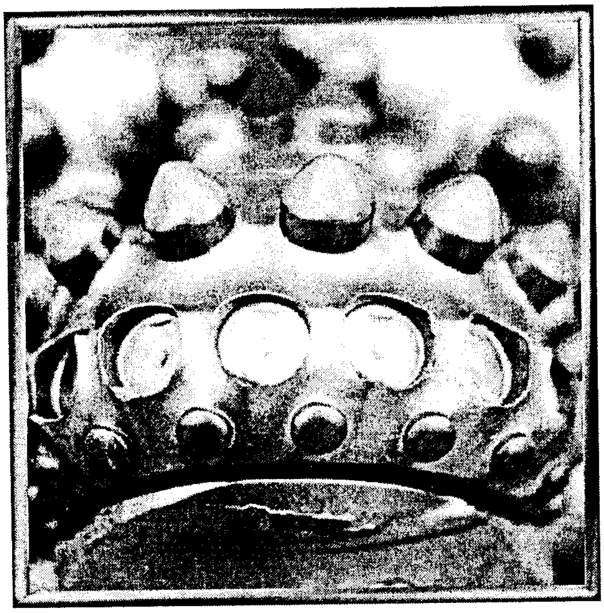


LC - Lost Cone



LN - Lost Nozzle

LT - Lost Teeth



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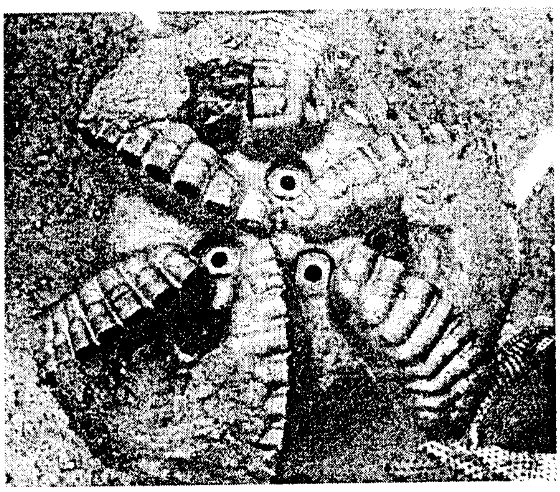
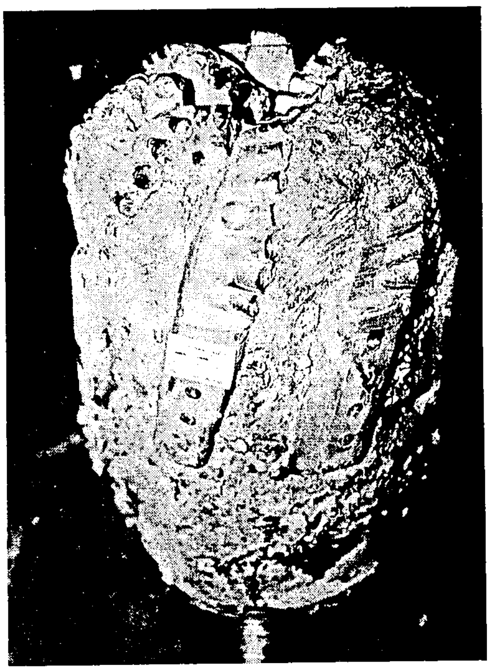
Bit Balling
Code: BU





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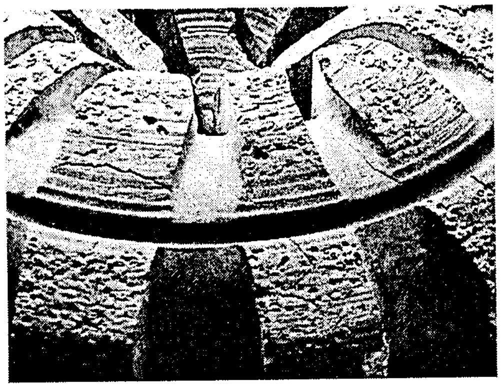
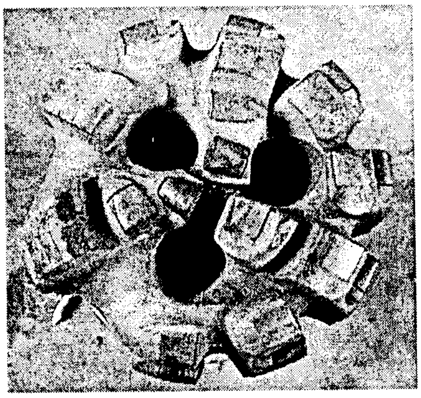
hemi

Ring Out
Code: RO





Broken Blade
Code: BB

PDC Selection Method

Bit Selection Objectives

- Meet the customer's performance objective
- Optimize drilling efficiency
- Lowest $/m
- Avoid catastrophic failure

Modified after R. Jangani

Selection Model

- ☆Gather Well Information
- Analyze Well Information
- Select a Bit
- Recap for TEST runs
- Follow up & Close the case !

Gather Well Information

- Identify:
  - The customer's performance objectives
  - Offset bit records
  - Directional plan
  - Geological information (including well logs)
  - Costs
  - Opportunity Indicators
  - Drilling Constraints (Office v.s Rigs)