

Drilling course : **Well planning**

Done by : Abdelaziz Gabr



Biography:

- **Name:** Abdelaziz Gabr , Egyptian.
- **Education:** Bachelor degree in petroleum engineering from Suez university 2010.
- work as **mud engineer** in EMEC company in KSA from 2011 to 2015.
- Work as **drilling & workover supervisor** in Khalda petroleum company in Egypt from 2015 to 2022.
- Work as **drilling & workover supervisor** in Saudi Aramco company from 2022 to 2025.
- **Currently :** Mud specialist in Apache corporation in Egypt.
- Work as **drilling accredited instructor** for drilling engineering topics (mud engineering, stuck pipe and fishing, well control and workover , completion, slickline, drilling problems)
- Have channel on you tube **“ Abdelaziz Gabr”** to deliver drilling engineering courses.



Well planning objective

The objective of well planning is to formulate a program from many variables that has the following characteristics:

- safe
- Minimum cost
- usable
- Unfortunately, constraints such as geology and drilling equipment, i.e., temperature, casing limitations, hole sizing or budget.



Safety

- Safety should be the highest priority in well planning.
- Personnel considerations must be placed above all other aspects of the plan.
- In some cases, the plan must be altered during the course of drilling the well when unforeseen drilling problems endanger the crew.



safety

- The well plan must be designed to minimize the risk of blowouts and other factors that could create problems.
- This design requirement must be adhered to vigorously in all aspects of the plan.



Minimum cost

- Minimize the cost of the well without jeopardizing the safety aspects.
- It is not noble to build "steel monuments" in the name of safety if the additional expense is not required.



Usable holes

- Drilling a hole to the target depth is not completely satisfactory if the final well configuration is not usable.
- The hole diameter should be sufficiently large so an adequate completion can be made.
- The hole or producing formation is not irreparably damaged.



Classifications of well types

The drilling engineer is required to plan a variety of well types, including the following:

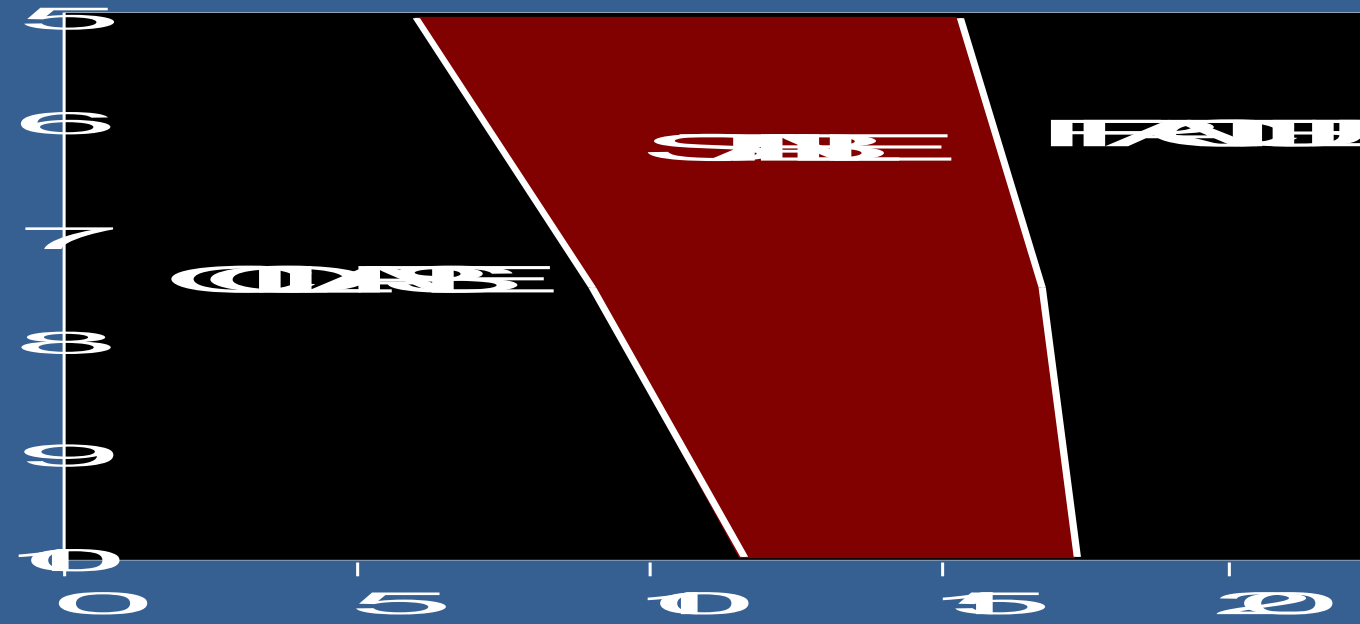
- wildcats
- exploratory holes
- step-outs
- In fills
- reentries



Formation pressure

- The formation pressure encountered by the well significantly affects the well plan.
- The pressures may be normal, abnormal (high), or subnormal (low).
- Normal pressure wells generally do not create planning problems.
- Kicks and blowout prevention problems should be minimized but not eliminated altogether.

Exp(0)

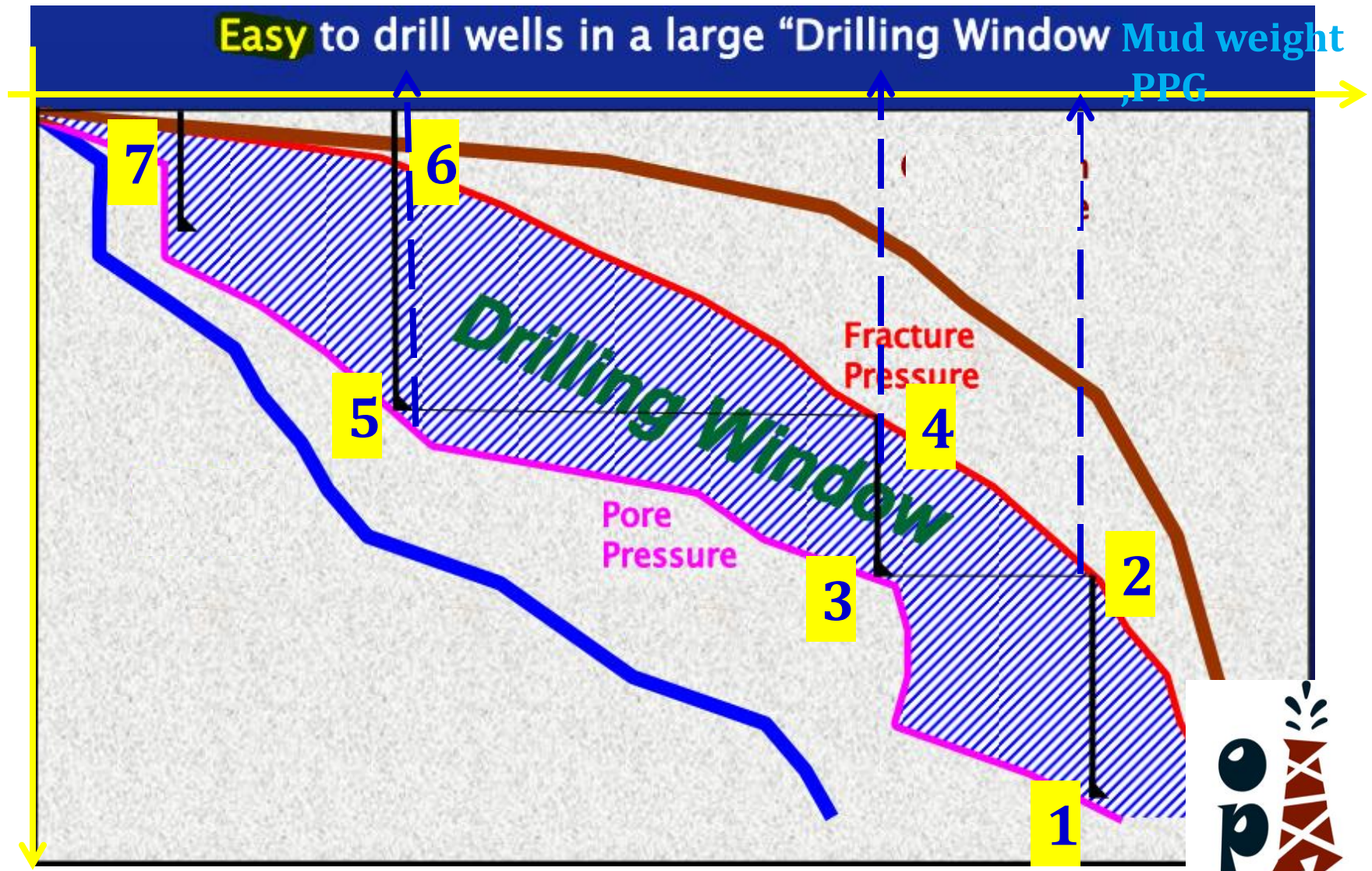


Exp(0)



Drilling window

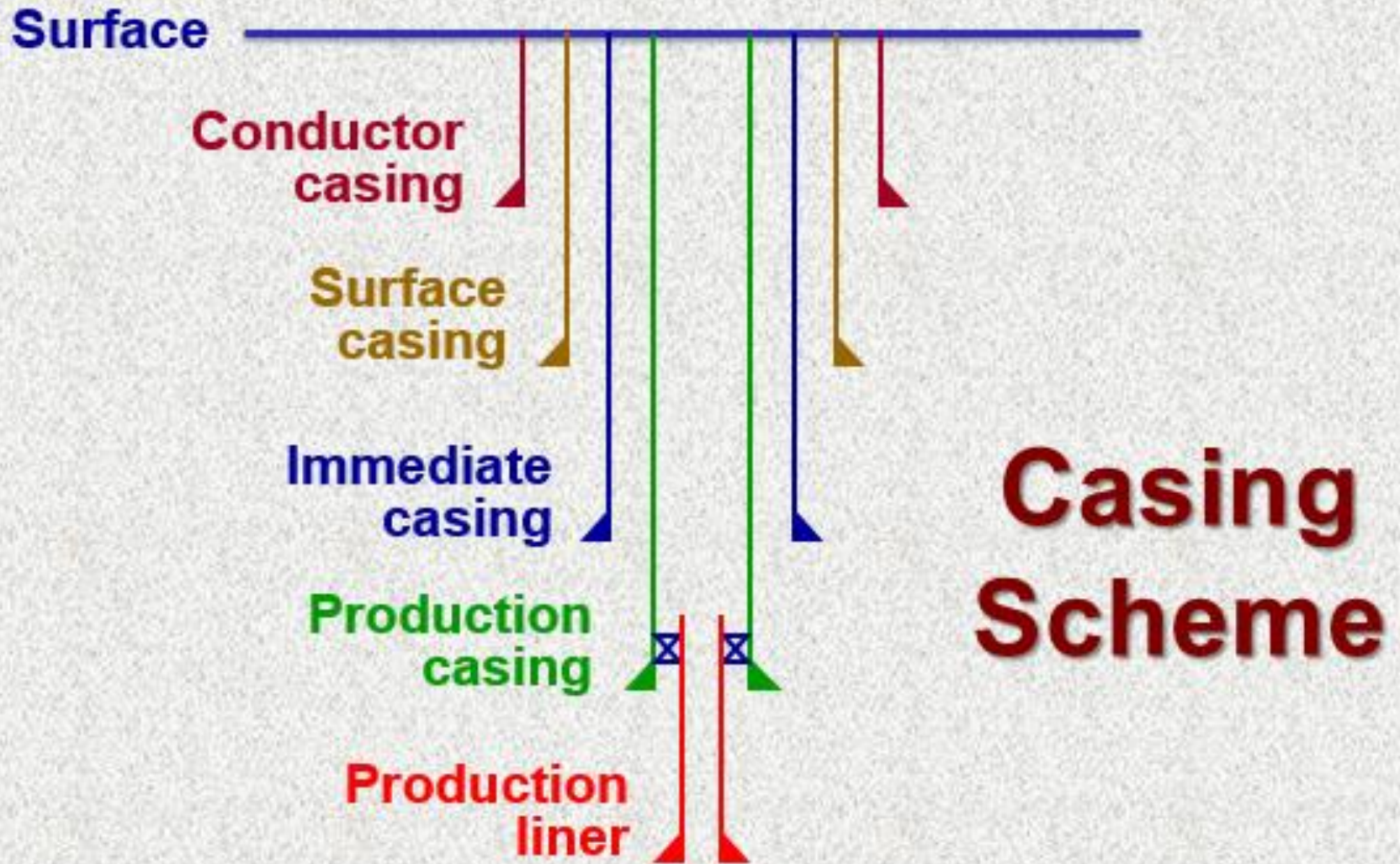
Easy to drill wells in a large "Drilling Window" Mud weight PPG



Depth



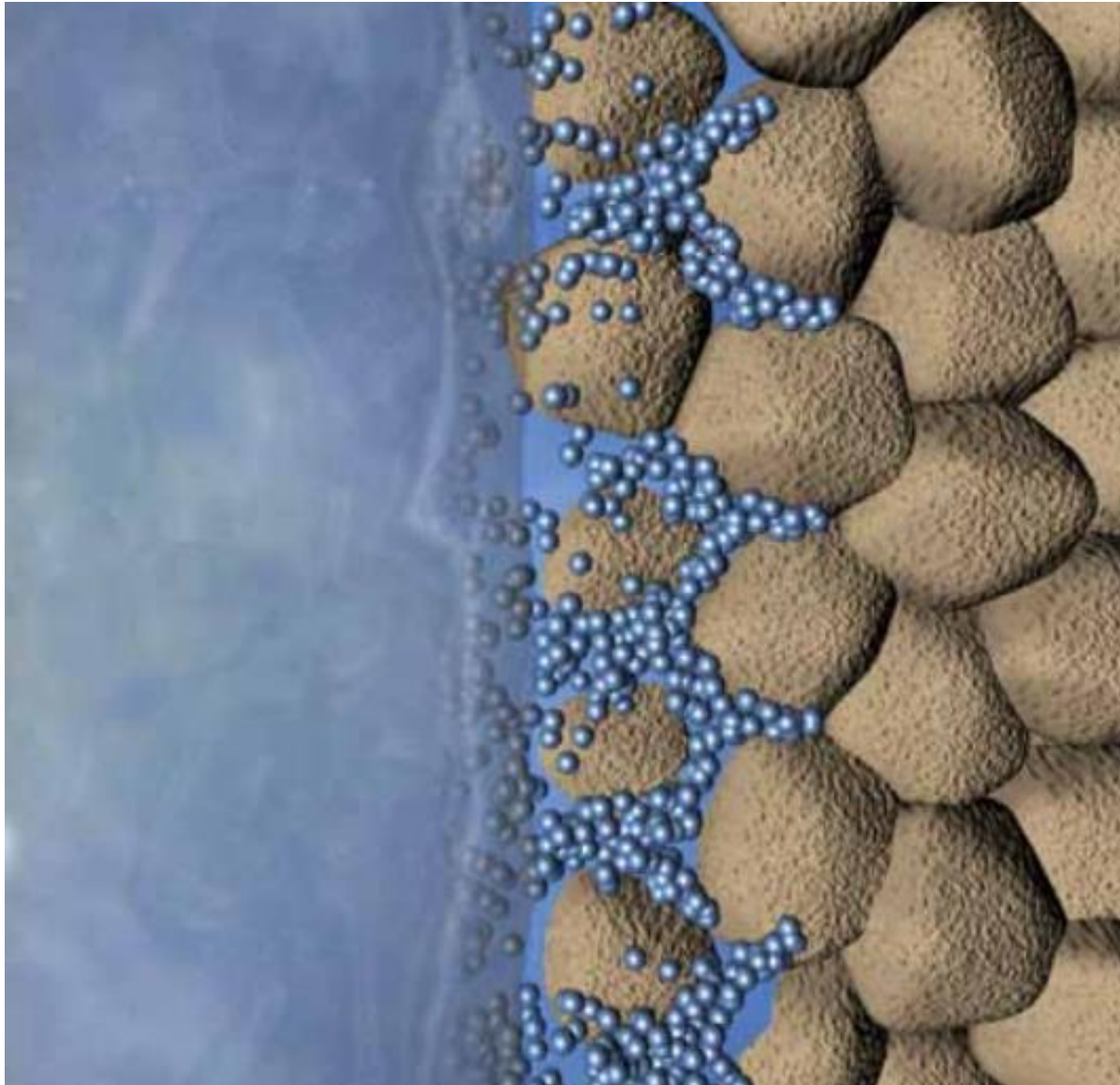
How a Wellbore is Drilled ?



- Casing requirements can be stringent even in normal pressure wells deeper than 20,000 ft due to tension/collapse design constraints.
- **Subnormal pressure wells** may require setting additional casing strings to cover weak or low pressure zones.
- The lower-than-normal pressures may result from geological or tectonic factors or from pressure depletion in producing intervals.

- **Abnormal pressures** affect the well plan in many areas, including the following:
 - A. casing and tubing design
 - B. mud weight and type selection
 - C. casing setting depth selection
 - D. cement planning

Stress cage technique in depleted zones



- **The following problems must be considered as a result of high formation pressures:**
 - A. kicks and blowouts
 - B. differential pressure pipe sticking
 - C. lost circulation resulting from high mud weights
 - D. heaving shale



Well Planning

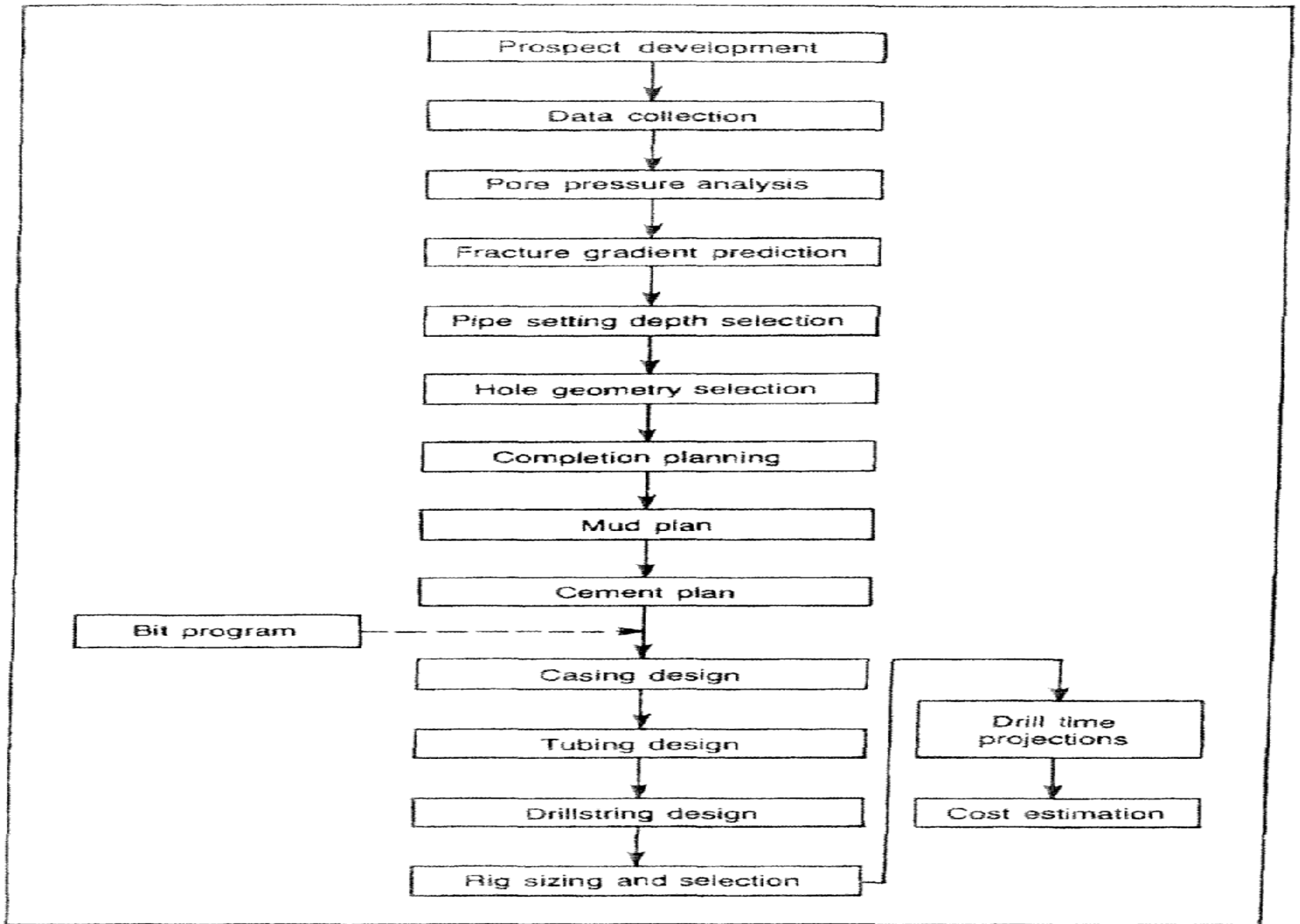
- Prospect development
- Data collection
- Pore pressure analysis
- Fracture gradient prediction
- Pipe setting depth selection
- Hole geometry selection
- Completion planning
- Mud plan
- Cement plan



Cont. Well Planning

- Bit program
- Casing design
- Tubing design
- *Drill string* design
- Rig sizing and selection





Flow path for well Planning

Data collection

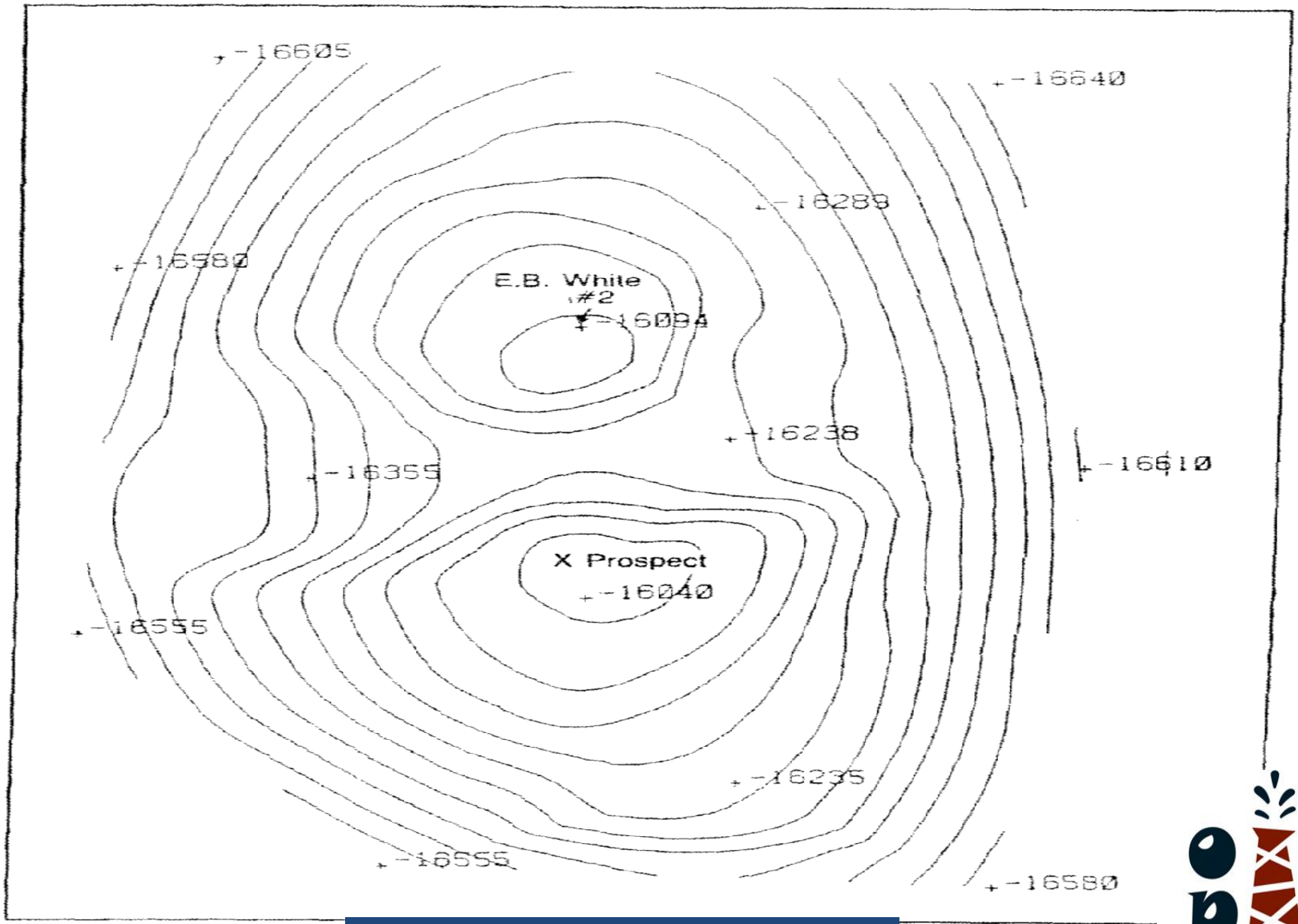
- The most important aspect of preparing the well plan, and subsequent drilling engineering, is determining the **expected characteristics and problems** to be encountered in the well.
- A well cannot be planned properly if these expected environments are not known.
- Therefore, the drilling engineer must initially pursue various types of data to gain insight used to develop the projected drilling conditions.



Offset well selection

- The drilling engineer is usually not responsible for selecting well site.
- However, he must work with the geologist for the **following reasons:**
- Develop an understanding of the **expected drilling geology**
- **Define fault block structures** to help select offset wells that should be similar in nature to the prospect well
- **identify geological anomalies** as they may be encountered in drilling the prospect well





Contour Map



Data sources

Common types of data used by the drilling engineer are as Follows:

- bit records
- mud records
- mud logging records
- IADC drilling reports



- scout tickets
- log headers
- production history
- seismic studies
- well surveys
- geological contours
- databases or service company files



Bit records

- An excellent source of offset drilling information.
- The heading of the bit record provides information such as the following:
 - operator
 - contractor
 - rig number
 - well location
 - drill string characteristics



Mud records

- Describe the physical and chemical characteristics of the mud system
- In addition to the mud data, hole and drilling conditions can be inferred.
- Many drilling personnel believe that the mud record is the most important and useful planning data.
- Mud engineers usually prepare a daily mud check report form.
- Copies are distributed to the operator and drill contractor.



The form contains current drilling data such as:

- well depth
- bit size and number
- pit volume
- pump data
- solids control equipment
- Drill string data



The report also contains mud properties data such as:

- mud weight
- chloride content
- pH
- calcium content
- funnel viscosity
- solids content
- plastic viscosity
- Cation exchange capacity (or MBT)
- yield point
- fluid loss
- gel strength



DRILLING MUD REPORT				REPORT NO	
Date				Depth	
API WELL NO		STATE	WELL		S/T

OPERATOR		CONTRACTOR		RIG NO.	
ADDRESS		ADDRESS		SPUD DATE	
REPROT FOR MR.		REPROT FOR MR.		SECTION -TOWNSHIP RANGE	

WELL NAME AND NO.	FIELD OR BLOCK NO.	country prish or offshore area	STATE OR PROVINCE
-------------------	--------------------	--------------------------------	-------------------

OPERATION		CASING		MUD VOLUME (BBL)		CALCULATION DATE	
PERSENT ACTIVITY		SURFACE		HOLE		ANNULAR VEL MIN	
		IN at FT		PITS		OPPOSITE DP-----	
BIT SIZE (IN)		INTERMEDIATE		TOTAL CIRCULATING		PUMP MAKE	
NO		IN at FT		VOLUME		MODEL	
DRILL PIPE SIZE		PRODUCTION OR LINER		IN STORAGE		BBL/STOKE STROKE/MIN	
TYPE		IN at FT				CIRCULATING -----	
DRILL COLLAR		MUD		BBL /MIN		PRESSURE PSI-----	
SIZE		TYPE				BOTTOMS UP-----	
						SYSTEM	
						TOTAL -----	

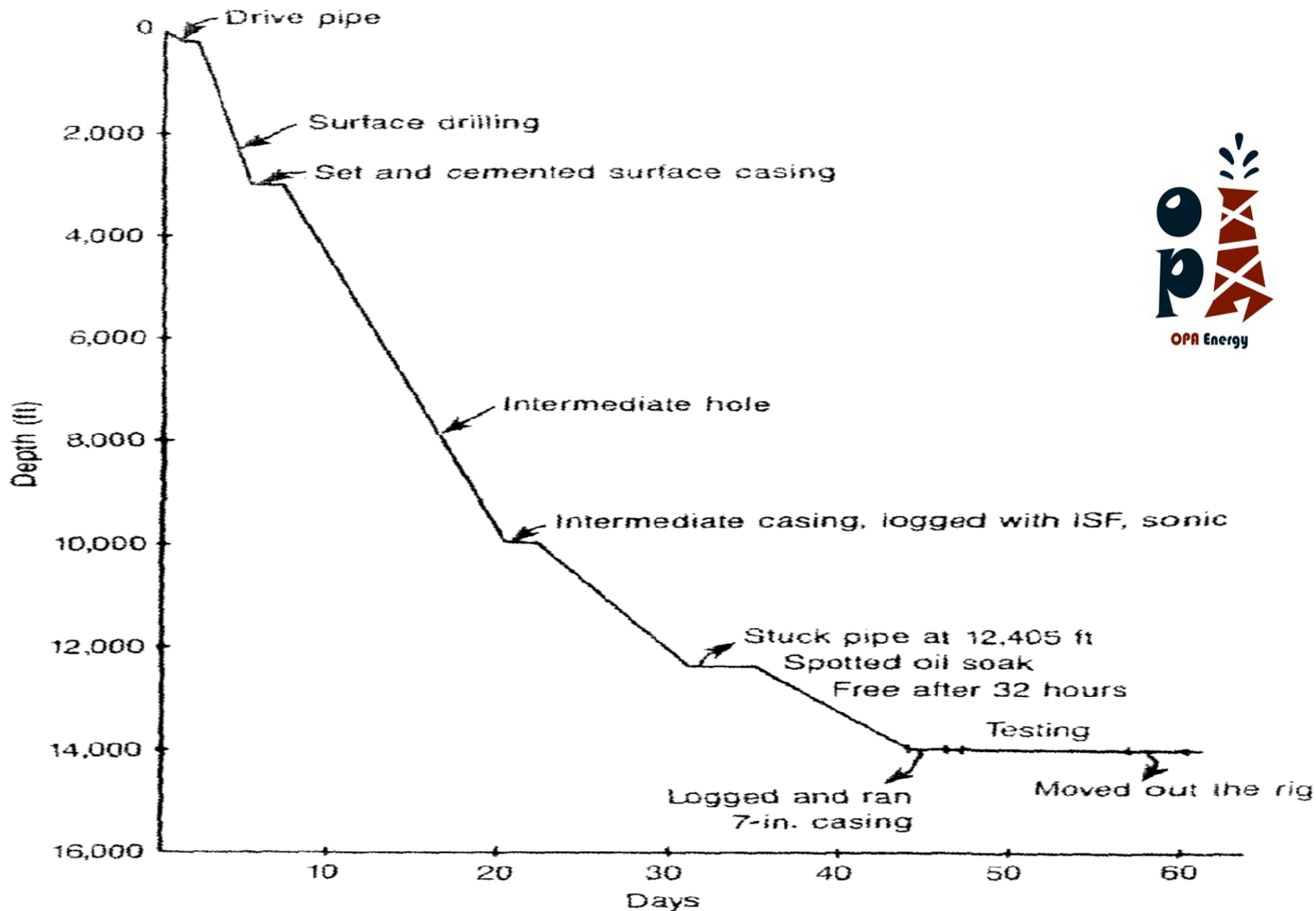
Sample from <input type="checkbox"/> flowline <input type="checkbox"/> pit		MUD PROPERTIES		EQUIPMENT			
Flowline temperature °F				SIZE	HRS/TOUR	SIZE	HRS/ TOUR

Time sample taken				Cent lug				Design			
Depth (ft)				Degasser				shaken			
Weight <input type="checkbox"/> (ppg) <input type="checkbox"/> (ib/cu ft)				Desander				Other			
Mud Gradient (psi/ft)				DAILY COST				CUMULATIVE COST			
Funnel Viscosity (sec / qt) api at ----- °F				MUD PROPERTISE SPECIFICATIONS							
Plastic viscosity cp at ----- °F				WEIGHT		VISCOSITY		FILTRATE			
Yield Point (ib /100 sq ft)				BY AUTHORITY		<input type="checkbox"/> OPERATOR WRITER <input type="checkbox"/> DRILLIGN CONTRACTOR					
Gel strength (ib /100 sq ft) 10 sec/10 min				<input type="checkbox"/> OPERATOR REPRESENTATIVE <input type="checkbox"/> OTHER		MATERIAL RECOMMENDED					
pH strip <input type="checkbox"/> meter											
Filtrate API (mi /30 min)											
API HP - HT Filtrate (mi / 30 min) ----- °F											
Cake Thickness 32 nd in API <input type="checkbox"/> HP-HT <input type="checkbox"/>											
Alkalinity, mud (°m)											
Alkalinity, Filtrate (P _i /M _f)											
chloride <input type="checkbox"/> ppm Salt <input type="checkbox"/> ppm											
<input type="checkbox"/> gpg <input type="checkbox"/> gpg											
Calcium <input type="checkbox"/> ppm <input type="checkbox"/> Gyp (ppb)											
Sand content (% by Vol)											
Solids content (% by Vol)											
Oil content (% by Vol)											
Water content (% by Vol)											
Methylen blue capacity (me /ml mud)											

EXTRA COPY			
THE RECOMMENDATION MADE HEREON SHALL NOT BE CONSTRUED AS AUTHORIZING THE INFRAINGEMENT OF ANY VALIED MADE WITHOUT ASSUMPTION OF ANY LIBILITY BY N L INSUTRIES , INC OR ITS AGENTS AND ARE STATEMENS OF OPINION ONI PRESNTAITIVE			
MOBILE UNITE		HOME ADDRESS	
		WAREHOUSE LOCATION	
		TELEP	
		TELEP	



FIG. 2-10 DAILY MUD CHECK REPORT FORM (COURTESY OF NL BARIOD)



Depth VS days plot developed from a mud record

Production history

- Production records in the offset area can provide clues to problems that may be encountered in the prospect well.
- Oil and gas production can reduce the formation pressure, which can create differential pipe sticking in the prospect well.
- Production records provide pressure data from the flowing zones.



Production records indicate that the original bottom-hole pressure prior to production from the sand was **5,389 psia** at **9,890 ft** TVD.

Currently, the producing BHP is **3,812 psia** and the produced fluid is dry gas.

A mud weight of **10.7 lb/gal** is required to drill the intermediate shale sections contiguous to the sand.

However, a **12.1-lb/gal** mud is required to drill the lower target zone at **12,050 ft**.

If a maximum pressure of **2,000 psi** is established as the upper differential pressure limit,

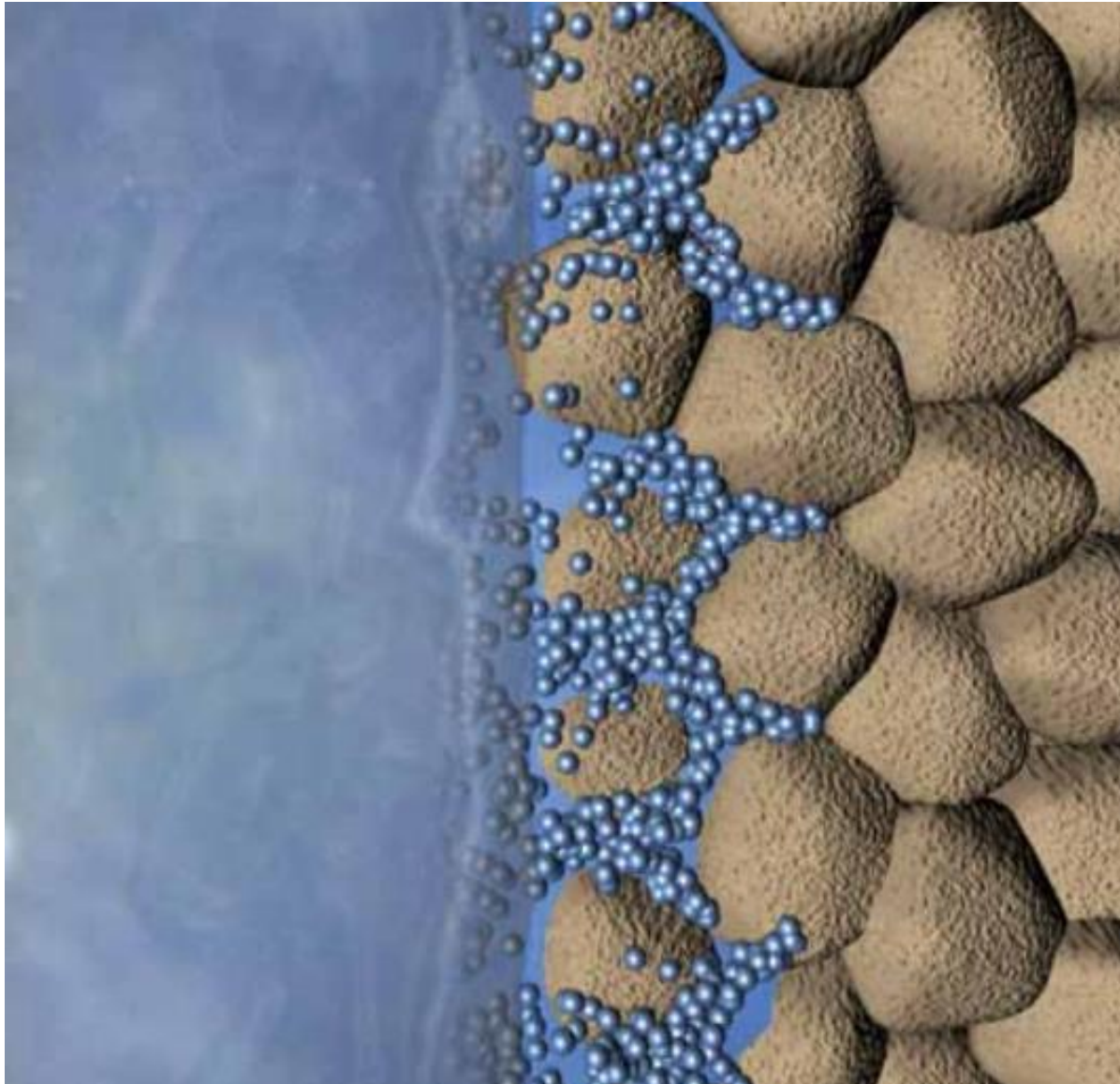
can the well be drilled with the sand exposed or must casing be set below the sand before reaching **12,050 ft**?

Solution

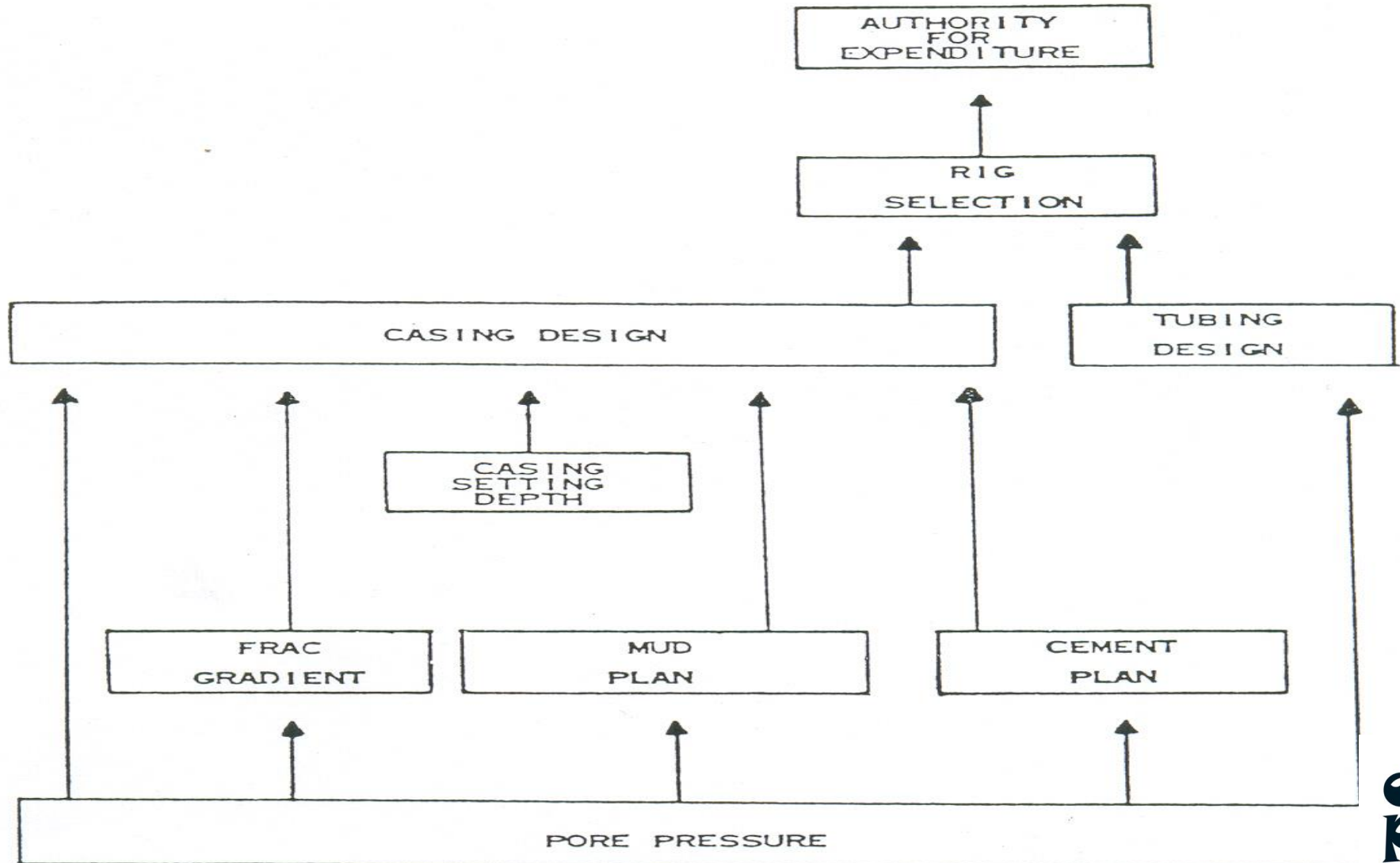
- The mud required to balance the sand is **10.7 lb/gal**, which exerts a hydrostatic pressure of:
 $0.052 \times 9,890 \text{ ft} \times 10.7 \text{ lb/gal} = 5,502 \text{ psig}$
- The differential pressure with **10.7 lb/gal** is:
 $5,517 \text{ psia} - 3,812 \text{ psia} = 1,705 \text{ psia}$
- Therefore, pipe sticking should not be a problem with the **10.7-lb/gal** mud ($5,517 \text{ psia} = 5,502 \text{ psig} + 15 \text{ psia}$).
- A **12.1-lb/gal** mud is required to reach **12,050 ft**. This mud weight will create a hydrostatic pressure at **9,890 ft** of:
 $0.052 \times 12.1 \text{ lb/gal} \times 9,890 \text{ ft} = 6,222 \text{ psig}$

- The differential pressure will be;
 $6,237 \text{ psia} - 3,812 \text{ psia} = 2,425 \text{ psia}$
- A casing string, or liner, must be set below
 $9,890 \text{ ft}$
- 12.1 lb/gal required at the bottom of the well creates a differential pressure in excess of $2,000\text{-psi}$ upper limit.

Max bridge technique

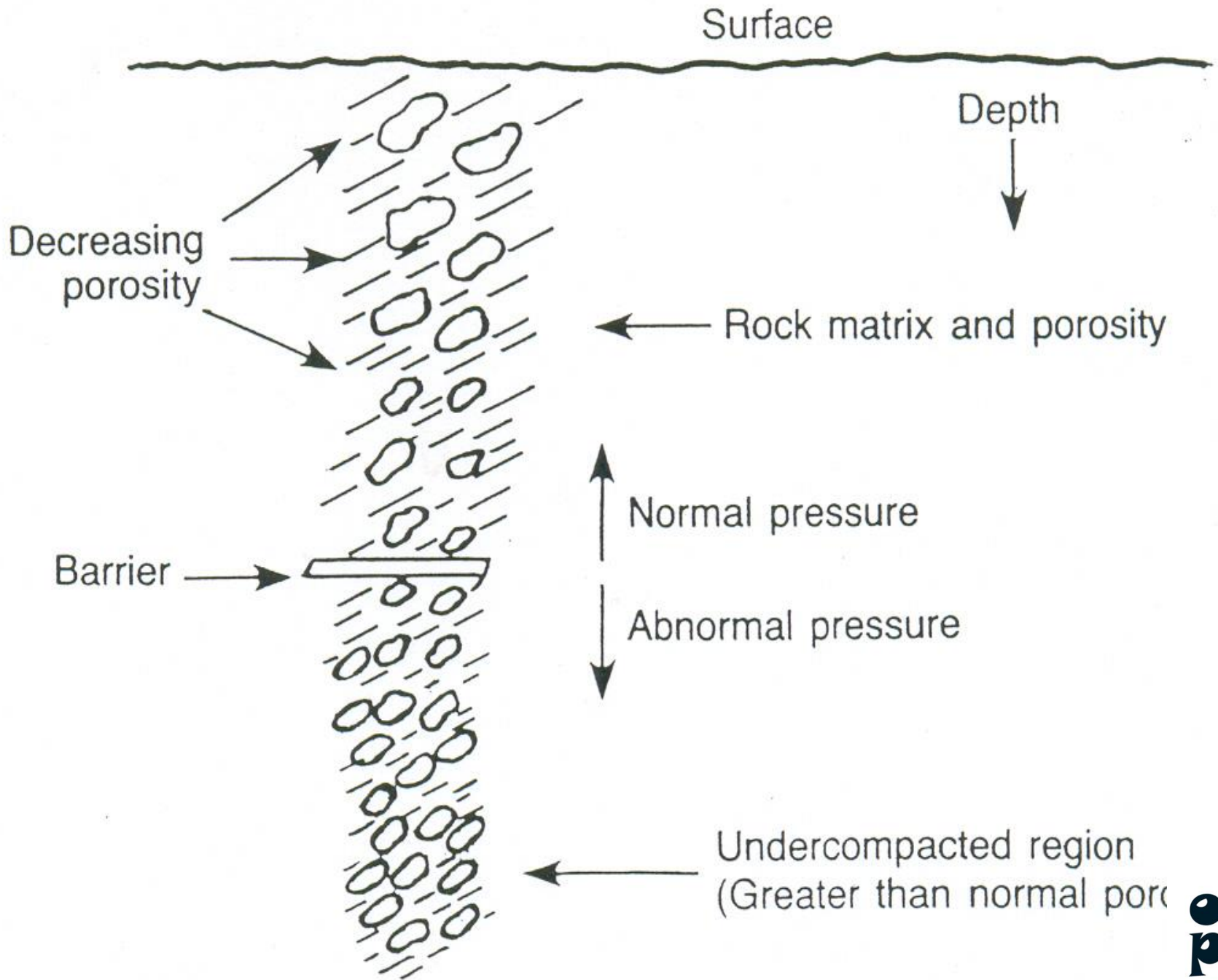


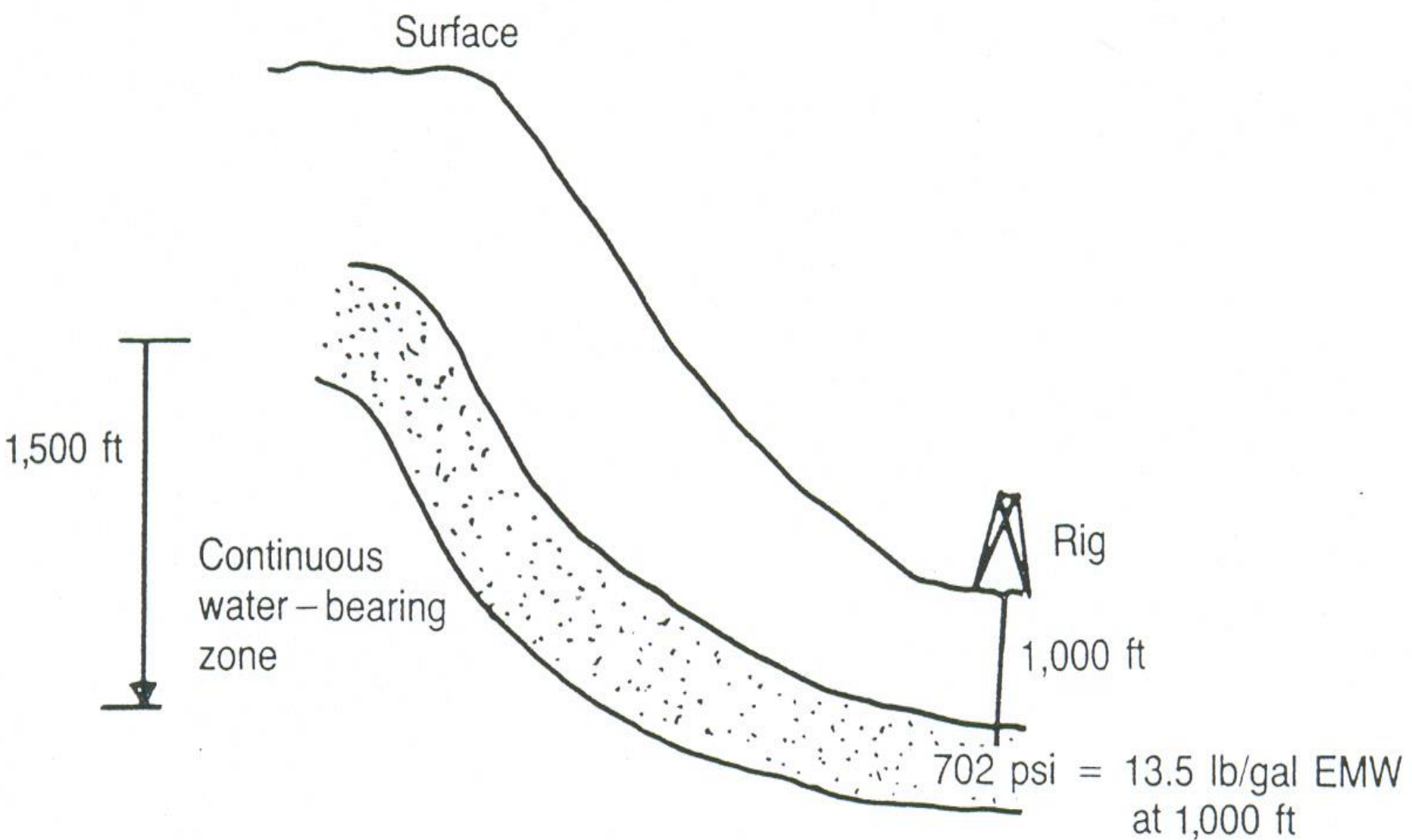
Formation pressure prediction



Causes of abnormal pressure

- Under-compaction
- Artesian System
- Faults
- Salt Beds
- Salt Domes
- Density Differences

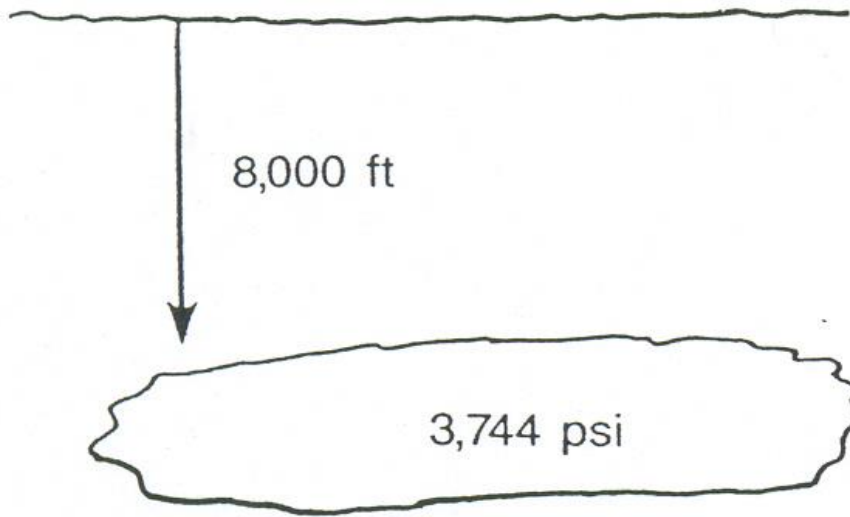




$$0.052 \times 9.0 \text{ lb/gal} \times 1,500 \text{ ft} = 702 \text{ psi}$$

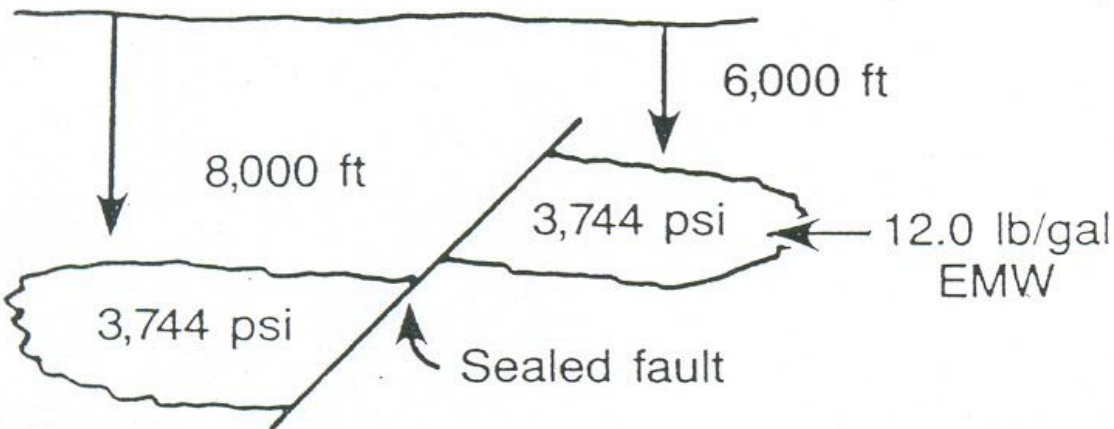


Surface



Sealed zone, normal pressure

- (a) A sealed zone existing at 8,000 ft with normal pressures in the zone and all adjacent formations



- (b) An uplifted section will require 12.0 lb/gal mud. The sealed fault prevented pressure regression or normalization.

Required mud

Surface

9.0 lb/gal

Normal pressure shale sections

$$10,000 \text{ ft} \times 1.0 \frac{\text{psi}}{\text{ft}} = 10,000 \text{ psi (overburden)}$$

Assume a salt overburden gradient of 1.1 psi/ft (21.15 lb/gal)

19.4 lb/gal

Salt beds 1,000 ft \times 1.1 psi/ft = 1,100 psi

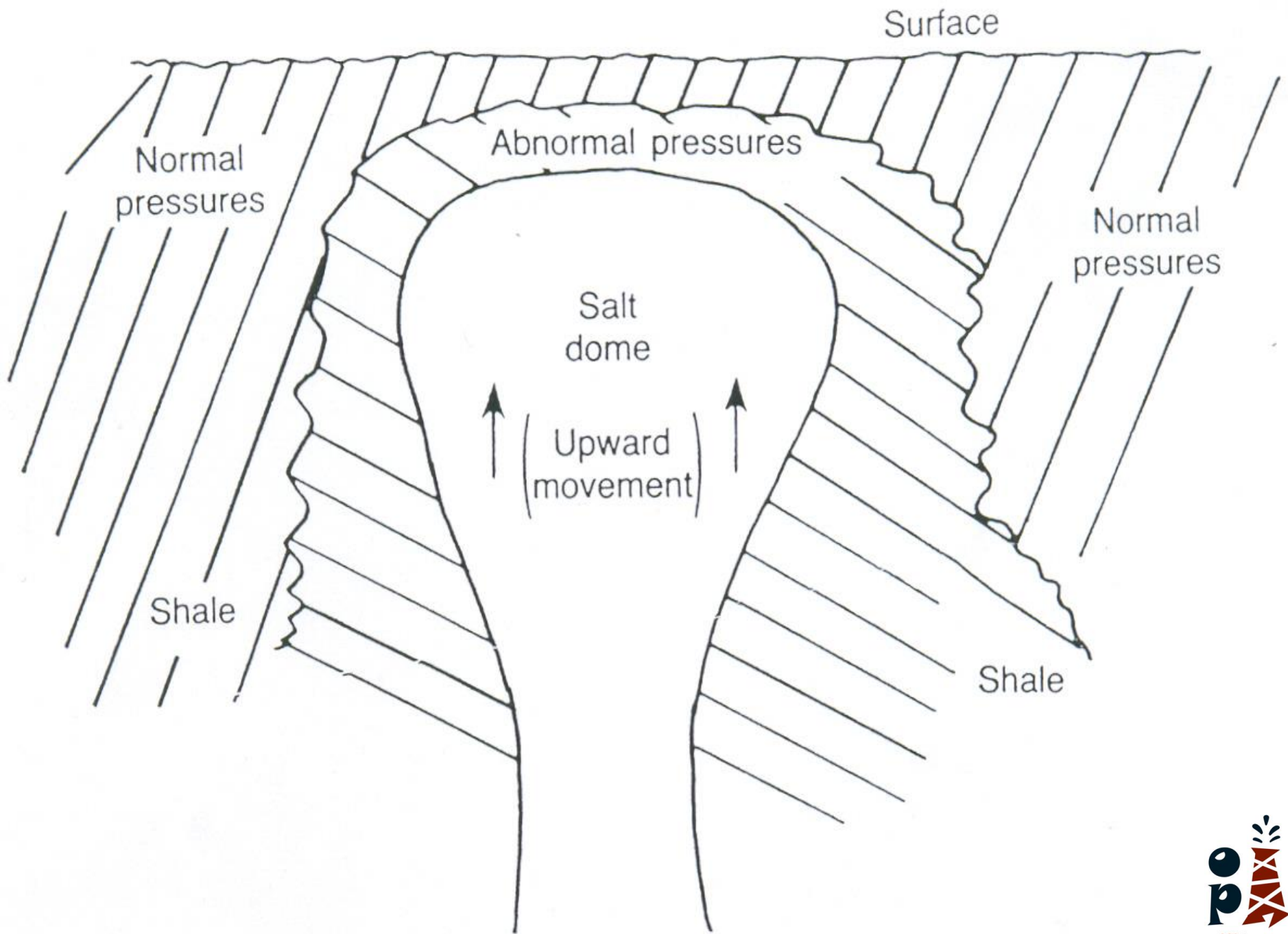
11,000 ft

Pore pressure at 11,000 ft — 10,000 psi

1,100 psi

11,100 psi





Surface

Normal pressure in all adjacent formations

Pressure at 9,000 ft is
 $0.052 \times 9.0 \text{ lb/gal} \times 9,000 \text{ ft} = 4,212 \text{ psi}$

Pressure at 9,001 ft is
 $5,148 \text{ psi} - 0.115 \text{ psi} \times 2,000 \text{ ft} = 4,918 \text{ psi}$
 $= 10.50 \text{ lb/gal EMW}$

11,000 ft
TVD

Fault

9,000 ft

Gas
sand

(0.115 psi/ft assumed)

Gas/water contact

Salt
water

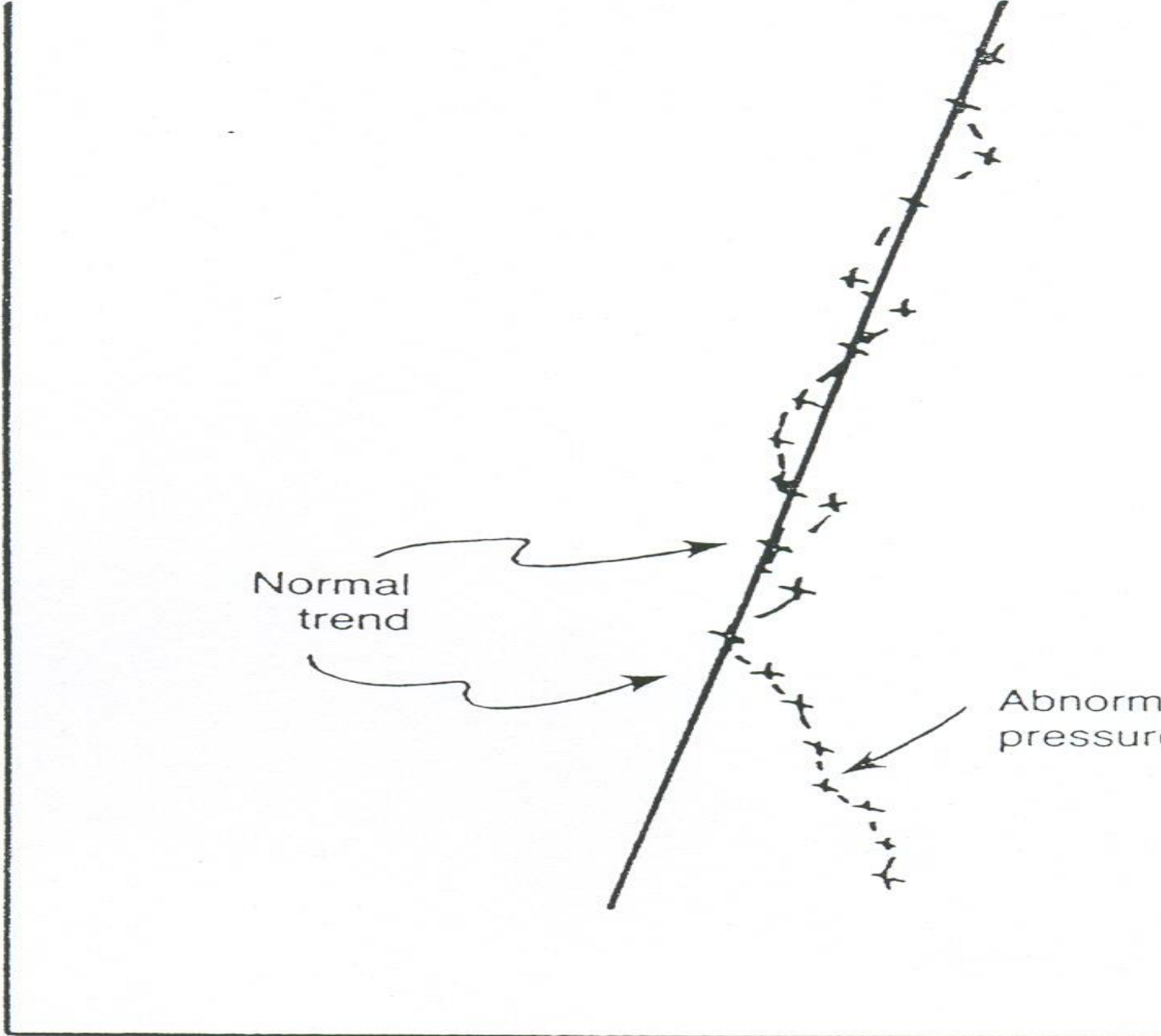
Normal pressure

$0.052 \times 9.0 \text{ lb/gal} \times 11,000 \text{ ft} = 5,148 \text{ psi}$

Methods of formation pressure prediction

- Seismic Analysis
- Well Logging Analysis
- Drilling Data, d-exponent
- Kicks

Depth

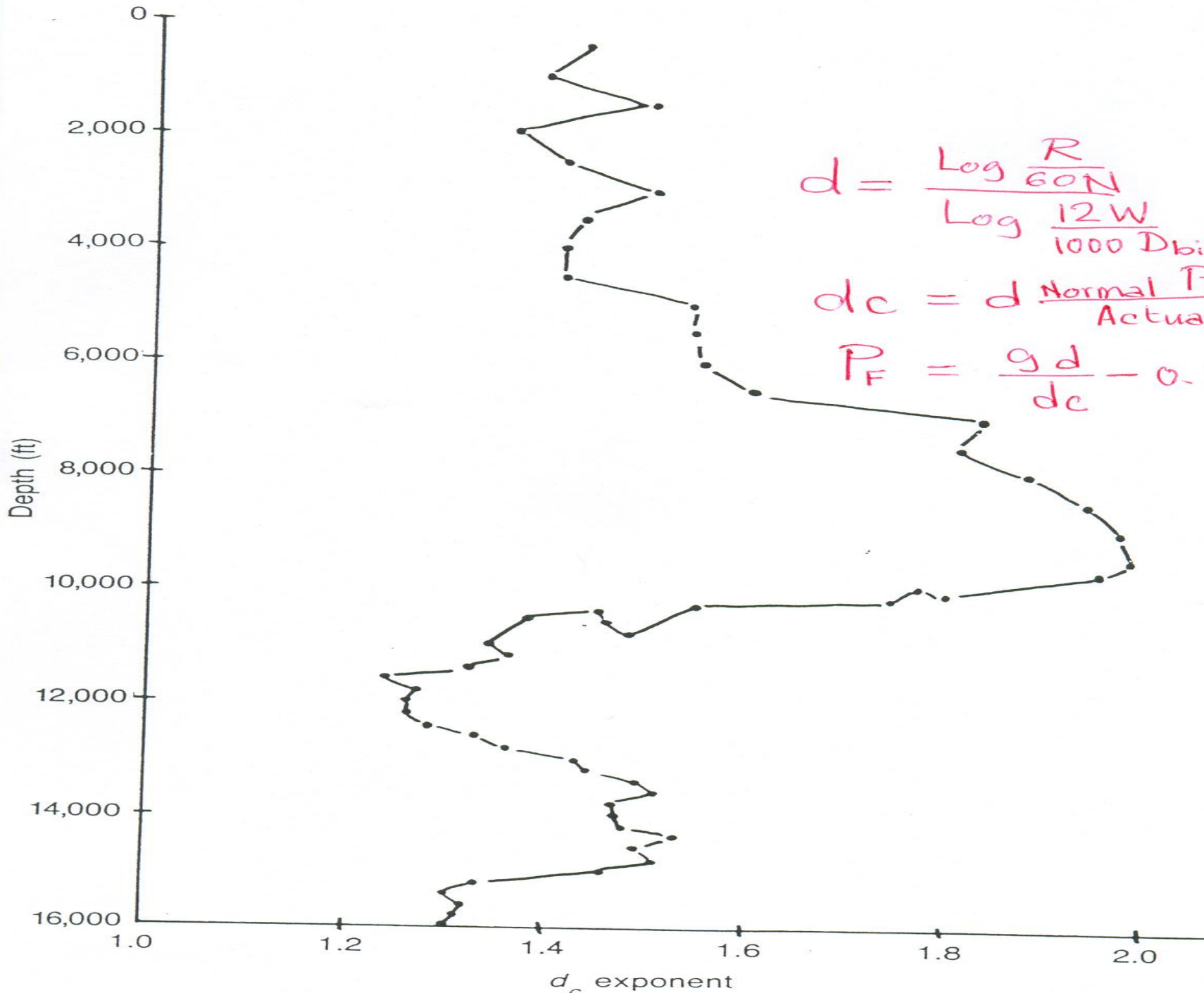


Normal trend

Abnormal pressures

Travel time (μ sec/ft)





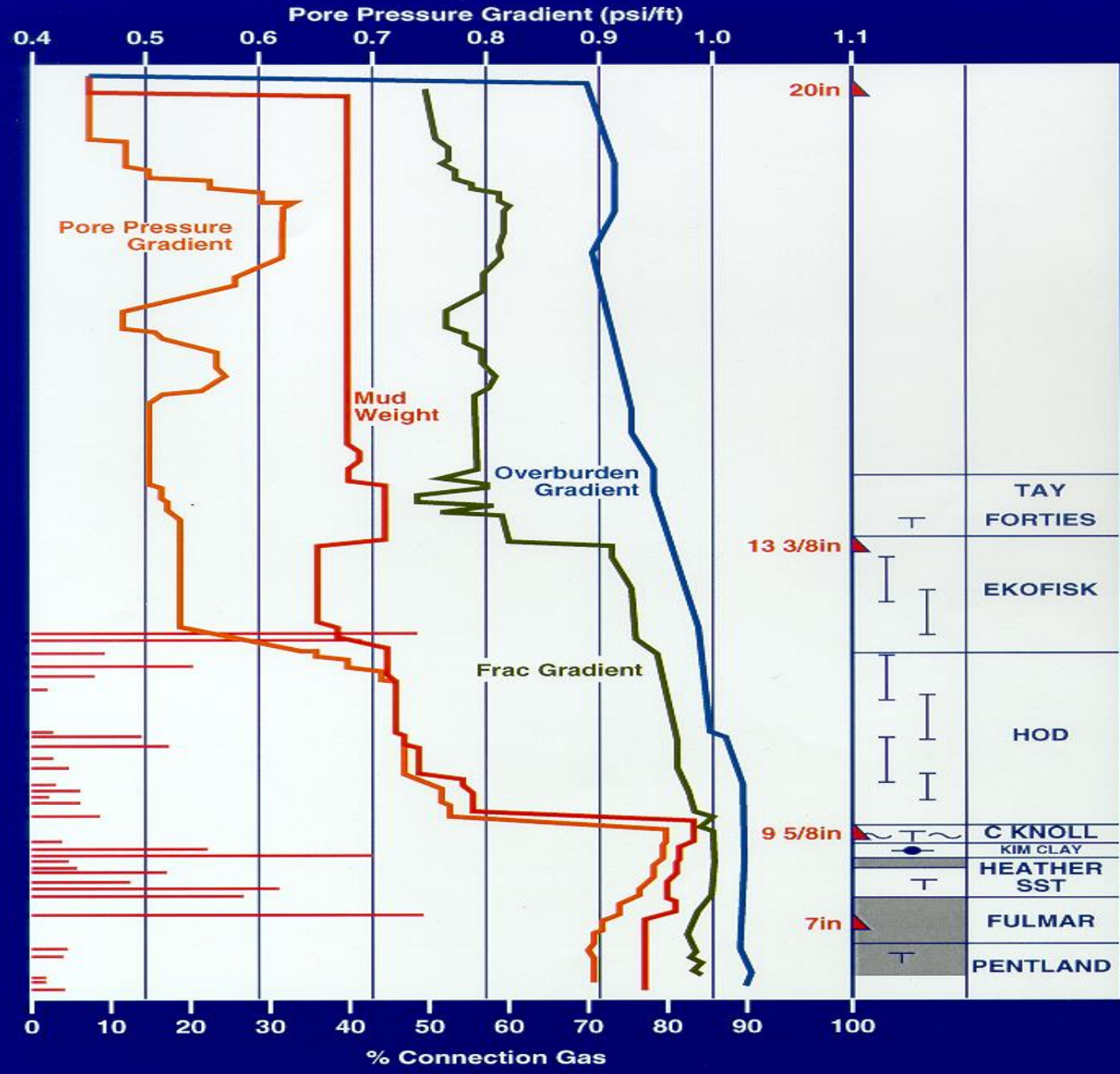
$$d = \frac{\text{Log } \frac{R}{60N}}{\text{Log } \frac{12W}{1000 \text{ Dbit}}}$$

$$d_c = d \frac{\text{Normal } P_F}{\text{Actual MW}}$$

$$P_F = \frac{gd}{d_c} - 0.3$$



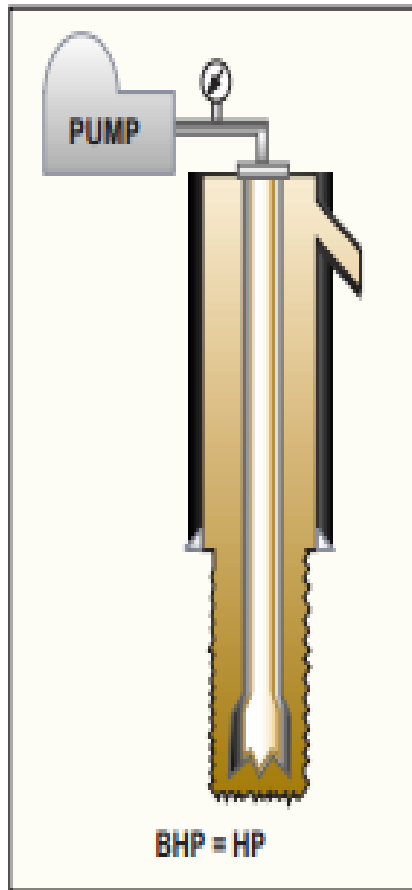
Typical Pressure vs Depth



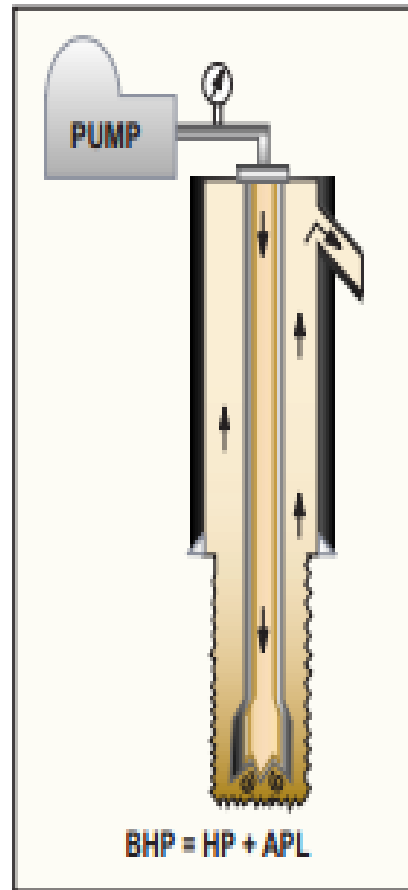
Formation kicks

$$P_f = 0.052 \rho_m H + \text{SIDPP}$$

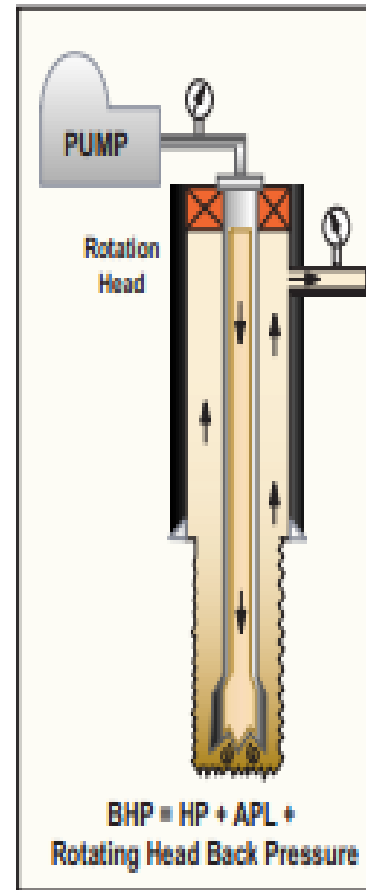
Well static



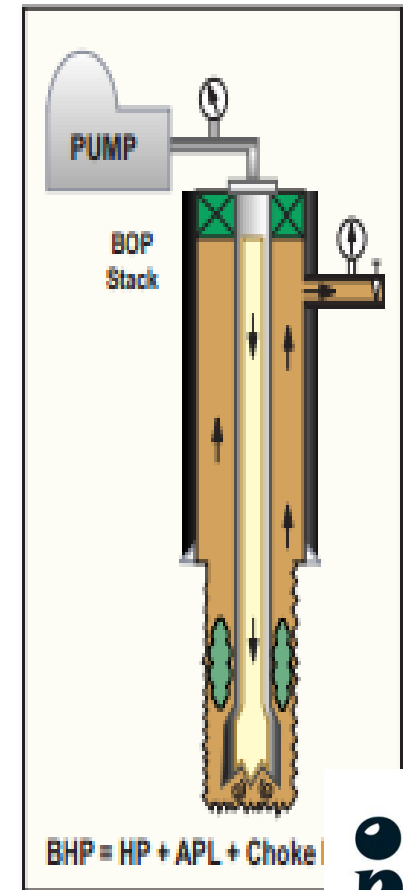
Normal circulation



Circulation with rotating head

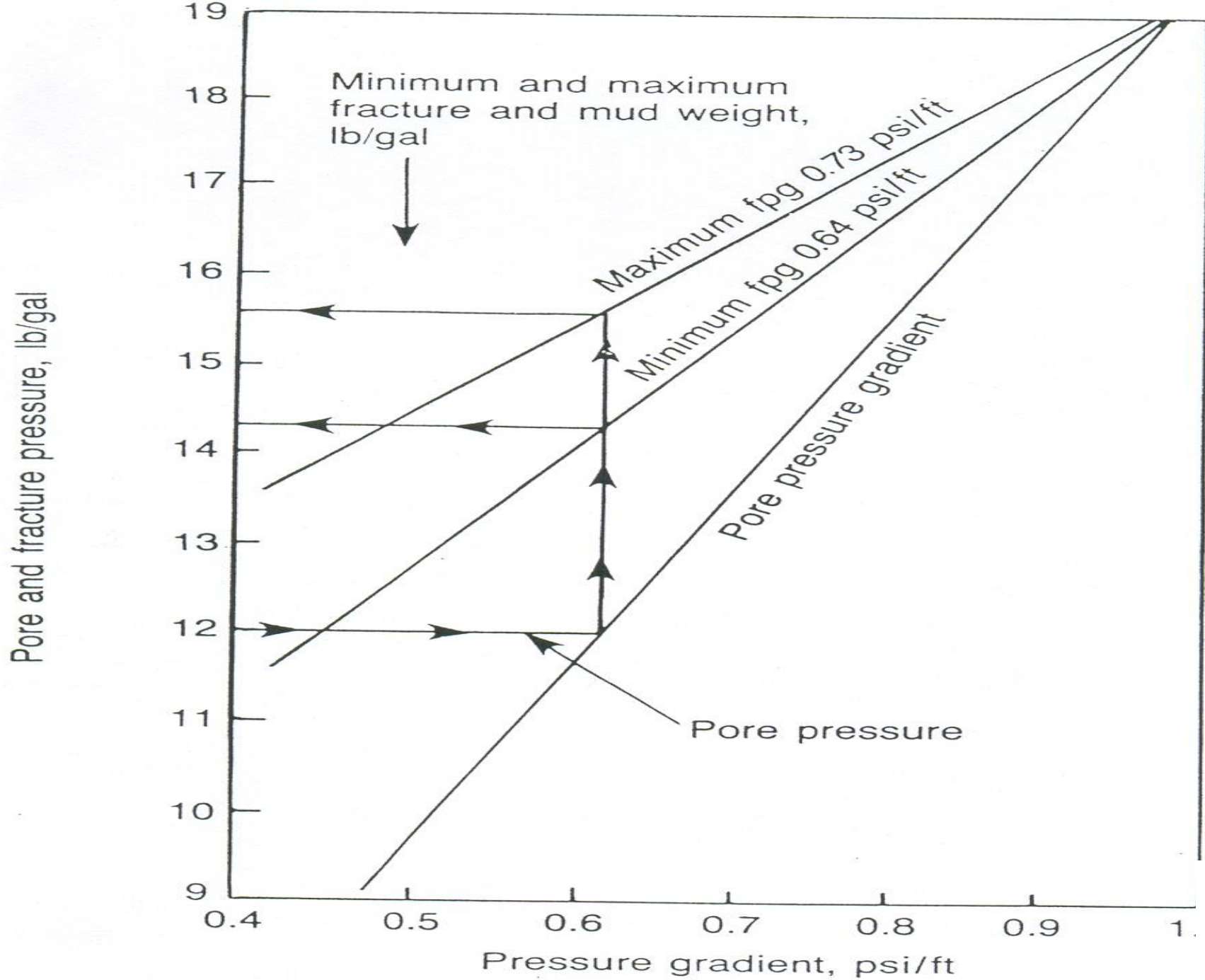


Kick circulation

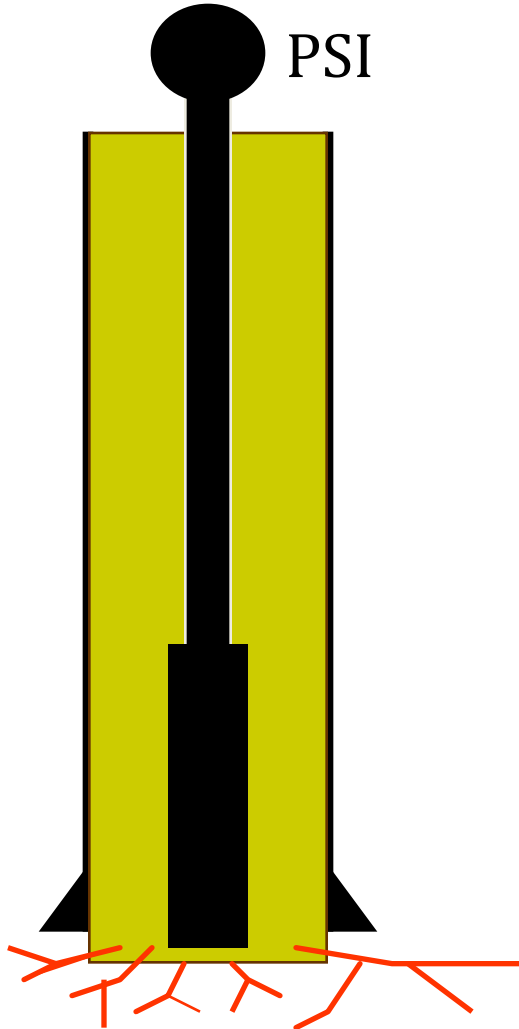


Fracture pressure determination

- Hubbert and Willis
- Matthews and Kelly
- Eaton
- **Field Determination**



Leak Off Test



Purpose

- To measure the fracture pressure of the formation at the shoe
- To test the cement job

Fracture mud weight

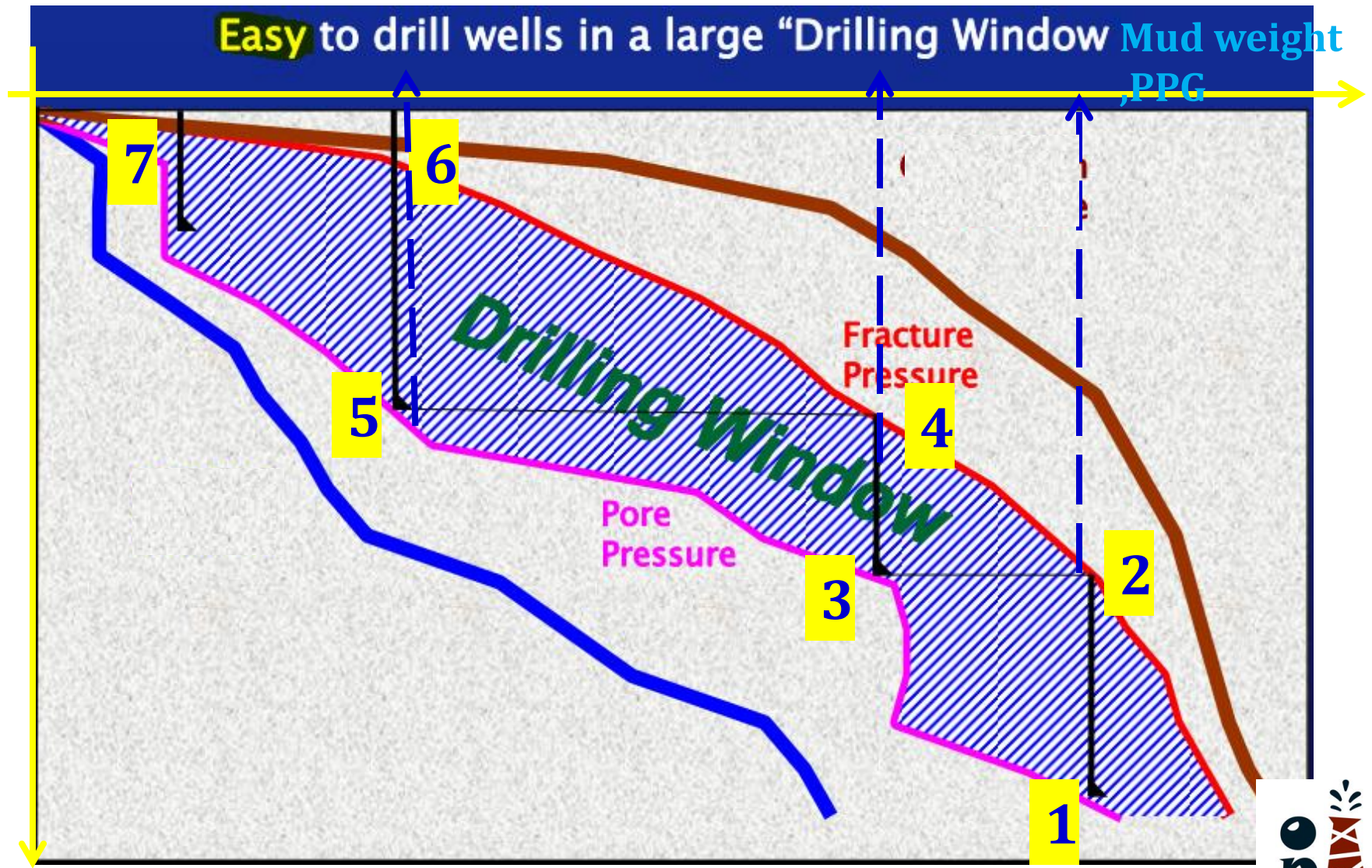
- It can be called “Maximum allowable “ or “Break down” mud weight.
- Fracture mud weight = $(Mwt_{L.O.T}) + ((L.O.T \text{ press.} / 0.052 * TVD_{shoe})$

Casing setting depth selection

- Intermediate Casing Depth Selection
- Liner Depth Selection
- Surface Casing Depth Selection
- Conductor Pipe Depth Selection

Drilling window

Easy to drill wells in a large "Drilling Window" Mud weight PPG



Depth

Operation

Casing inspection:

- Before running 13 3/8" casing it must be inspected
- Passing rabbit in casing to check inner diameter
- Cleaning threads and inspect it
- Check couplings (Box and Pin)

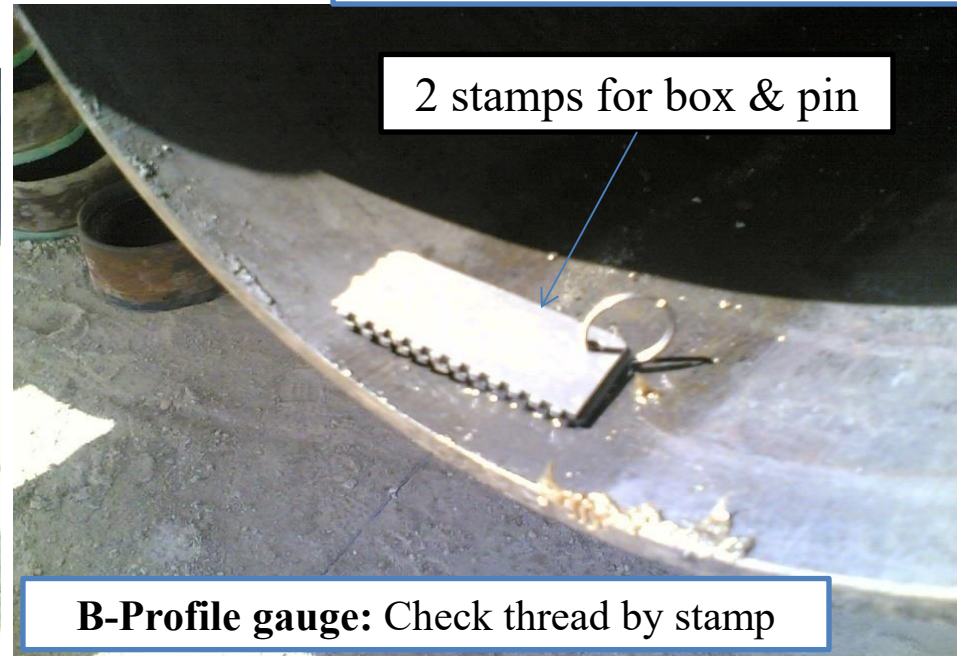
2- Visual thread inspection:

A- First preparation:

Brush to clean, washing by diesel or water with high pressure



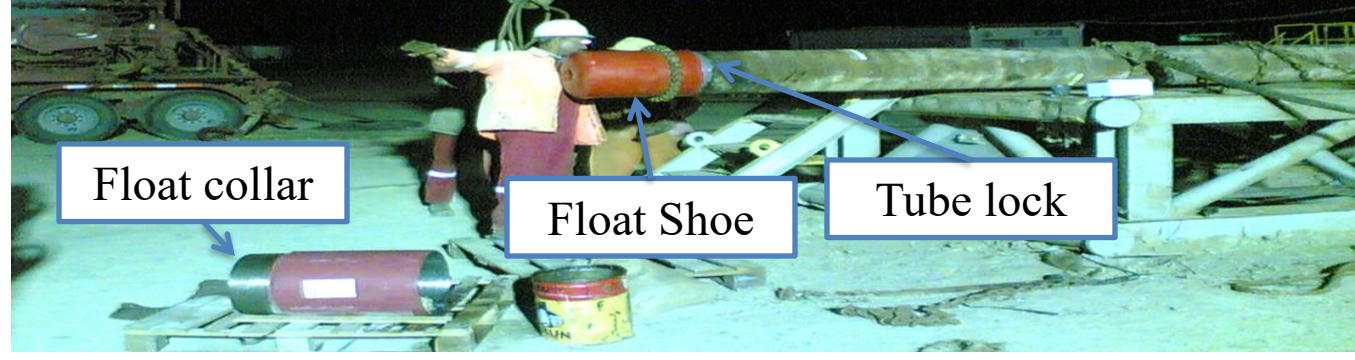
1-Rabbit check "API full length drift"



B-Profile gauge: Check thread by stamp



Float Shoe & Float collar



Float collar

Float Shoe

Tube lock



Tube lock: Prevent unscrewing of float equipments from casing while drilling cement plugs and cement. Unscrewing only by heating

Float shoe: One way valve to prevent cement back inside casing and also act as a guide shoe at the end of casing.
Float collar: One way valve (more confirmation), base for cement plugs.



Spider elevator to elevate casing



Spider Slips: engage casing while running in hole at high depths (engage high weights)

Fill up tool: Filling casing with mud during running in hole (connect with top drive)





Casing slips to engage casing while running in hole



Fill up tool while filling casing with mud



Power unit that feeds the power tong



Fill up tool



Power tong: screw casing till had its torque

Spider slips to engage casing while running in hole at high depths (engage high weights)



Power tong



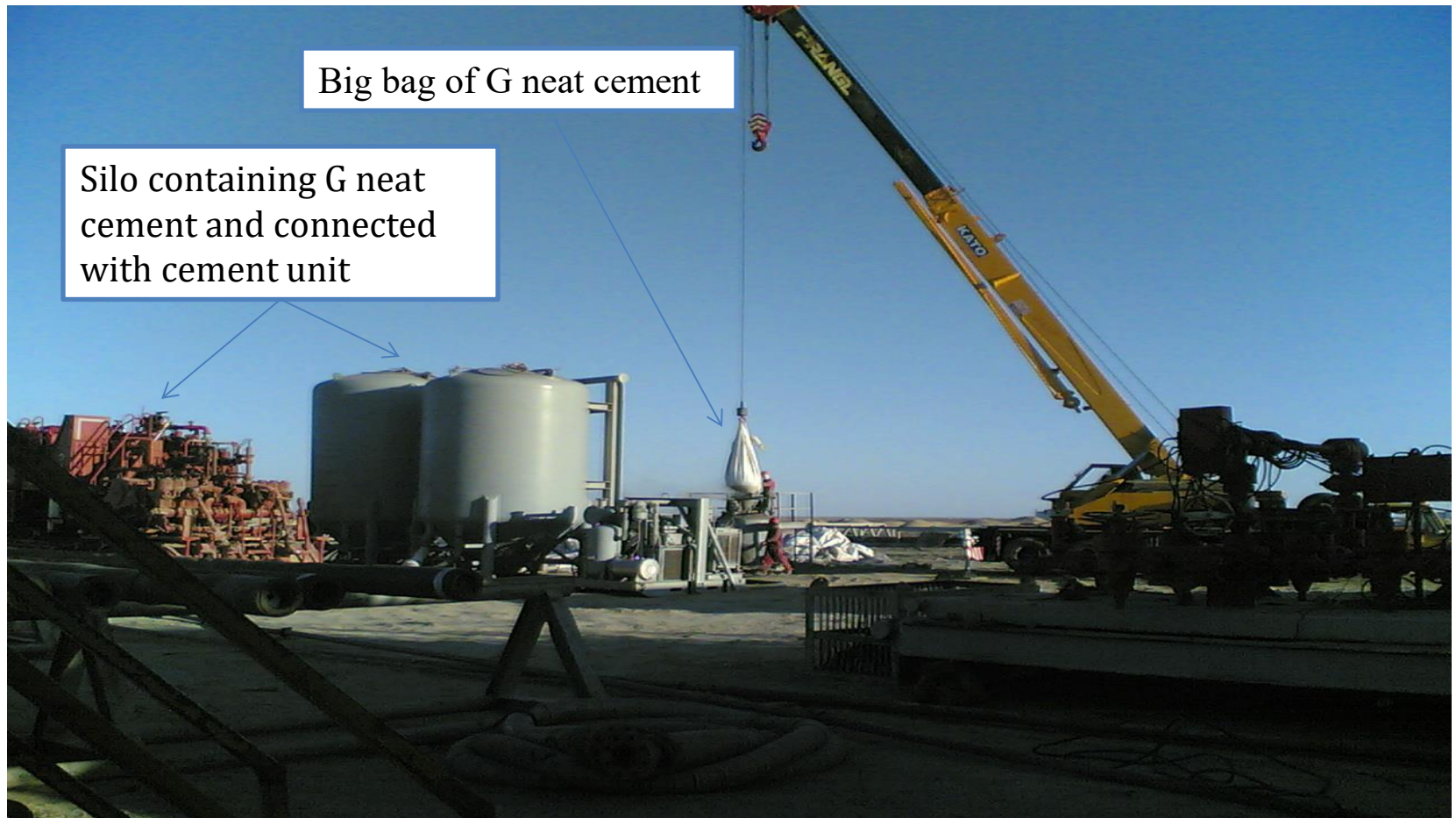
Single elevator to elevate casing from cat walk then through V-door to be above well

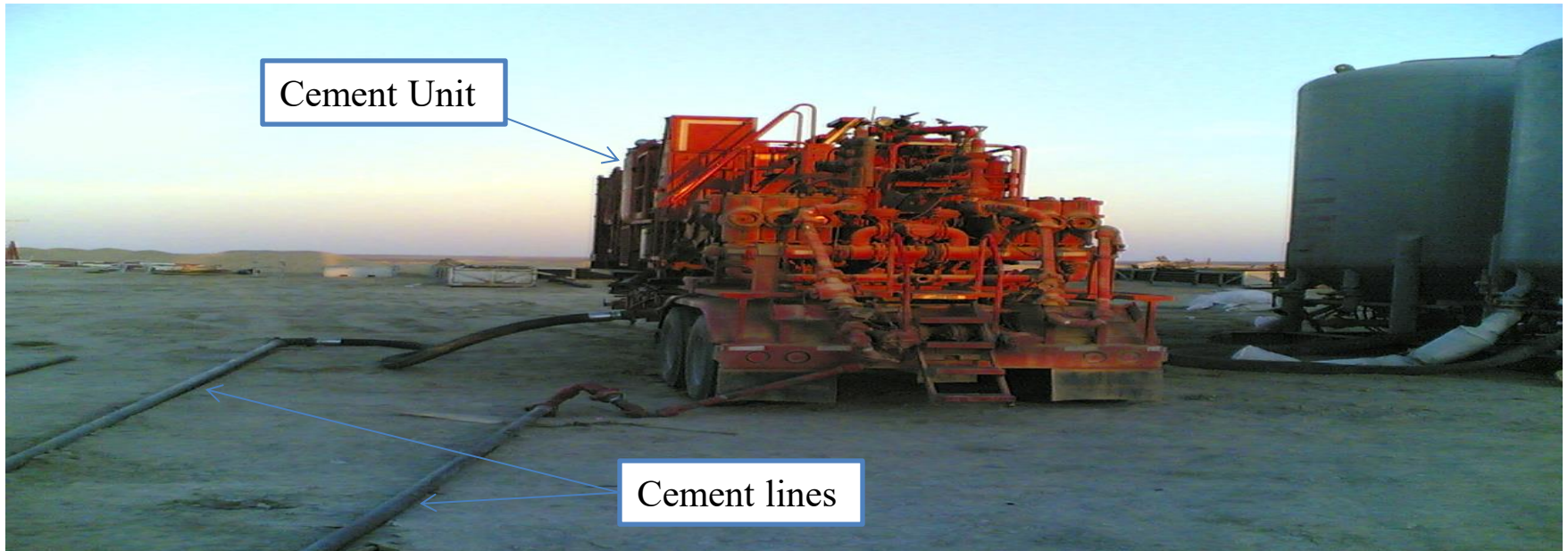
13 3/8 " casing Operations

- Change links to running with 13 3/8" casing.
- Rig up Premier 13 3/8" running equipment
- Held pre job safety meeting
- Check float shoe & float collar
- Running with 13 3/8" casing to depth 2117 ft (Bottom), (68 PPF, K-55, 52 Jts, and BTC)
- **Precautionary wash down last two joints.**
- Set casing off bottom 1 ft @ 2116 ft
- Its found that rig crew made wrong pipe tally measurements (8 ft difference, Bottom was at 2125 ft)

13 3/8 " cement Operations

- Rig up Halliburton cement equipment
- Held pre job safety meeting

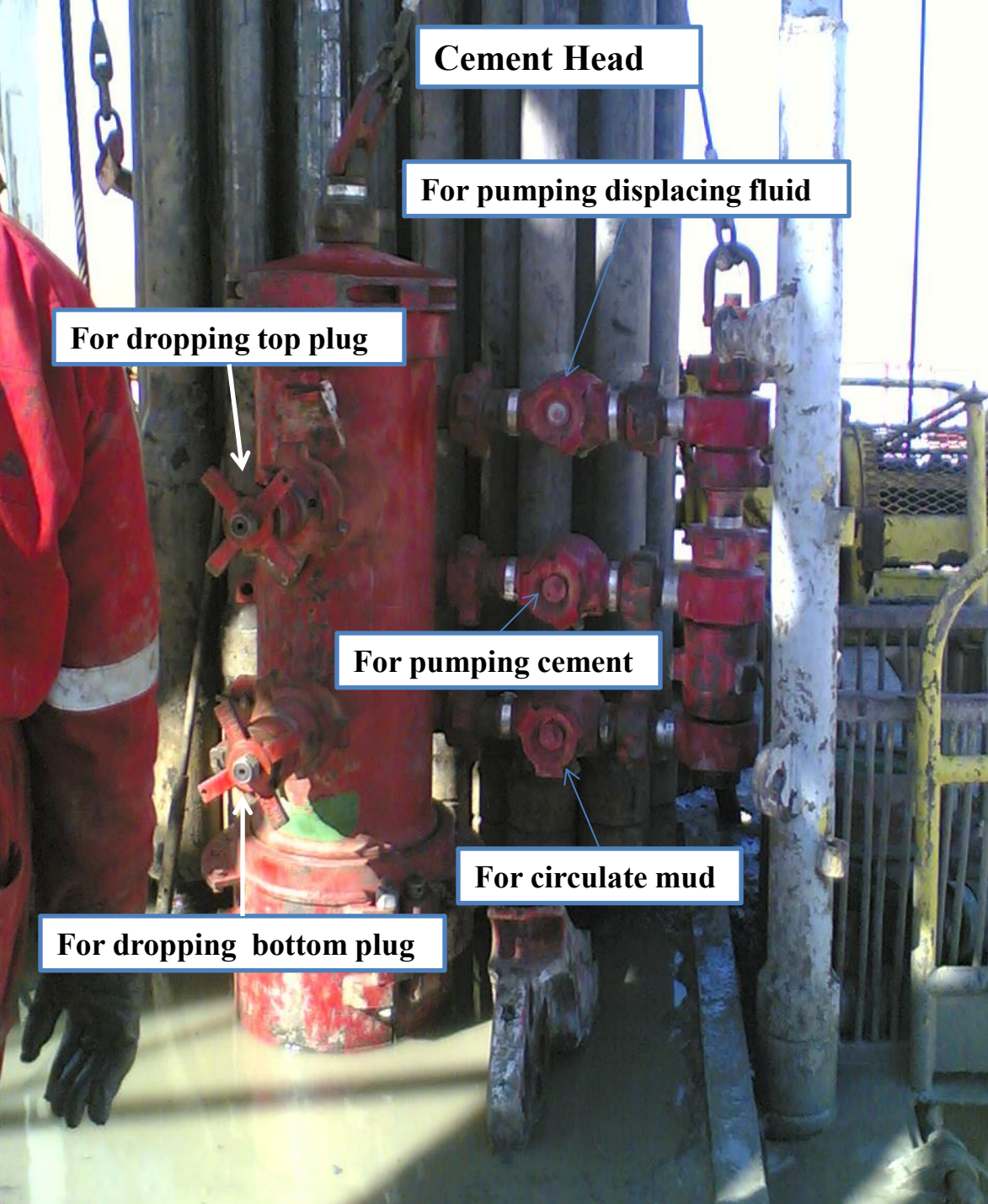






Rig up cement head

Spider Elevator





Three things to distinguish between two plugs:

1- Color: (Bottom plug: Red & Top plug: Yellow or Black)

2- Label: its type printed on it

3- Touching plugs: (the bottom plug contained part of a rubber stopper inside and the top plug formed of aluminum reinforced)

Digital panel on cement unit



Pumping pressure

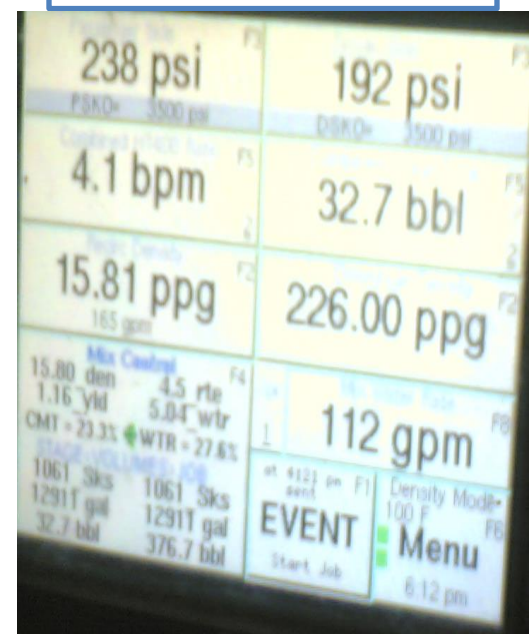
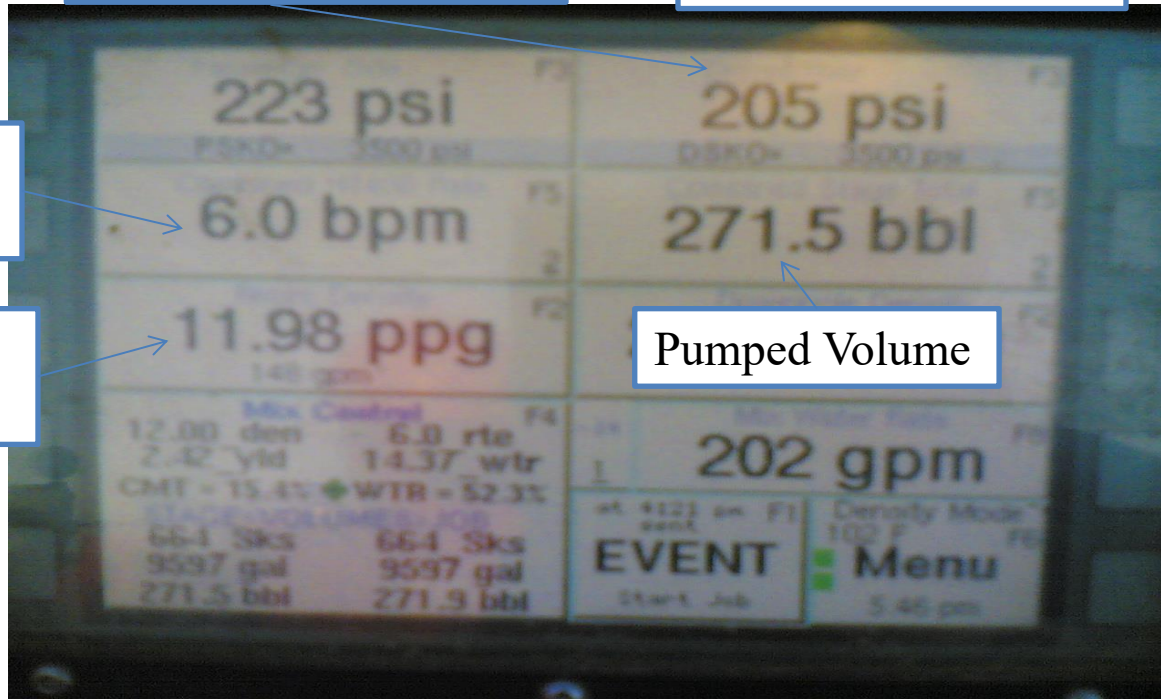
Lead Slurry screen

Tail Slurry screen

Pumping Rate

Slurry Density

Pumped Volume



Cement calculations

Guide shoe = 1.68 ft

Float collar = 1.5 ft

2 Jts "shoe track" = 79.25 ft

Shoe track = 82.43 ft

Volume between casing and conductor (V-1) =

$56 \times 0.167 = 9.352$ BBLs

Volume between casing and hole for lead (V-2) =

$1569 \times 0.1237 \times 1.75$ (excess) = 334.23 BBLs

Total Lead = 343.58 BBLs

Volume between casing and hole for tail (V-3) =

$500 \times 0.1237 \times 1.75$ (excess) = 108.23 BBLs

Shoe track volume (V-4) =

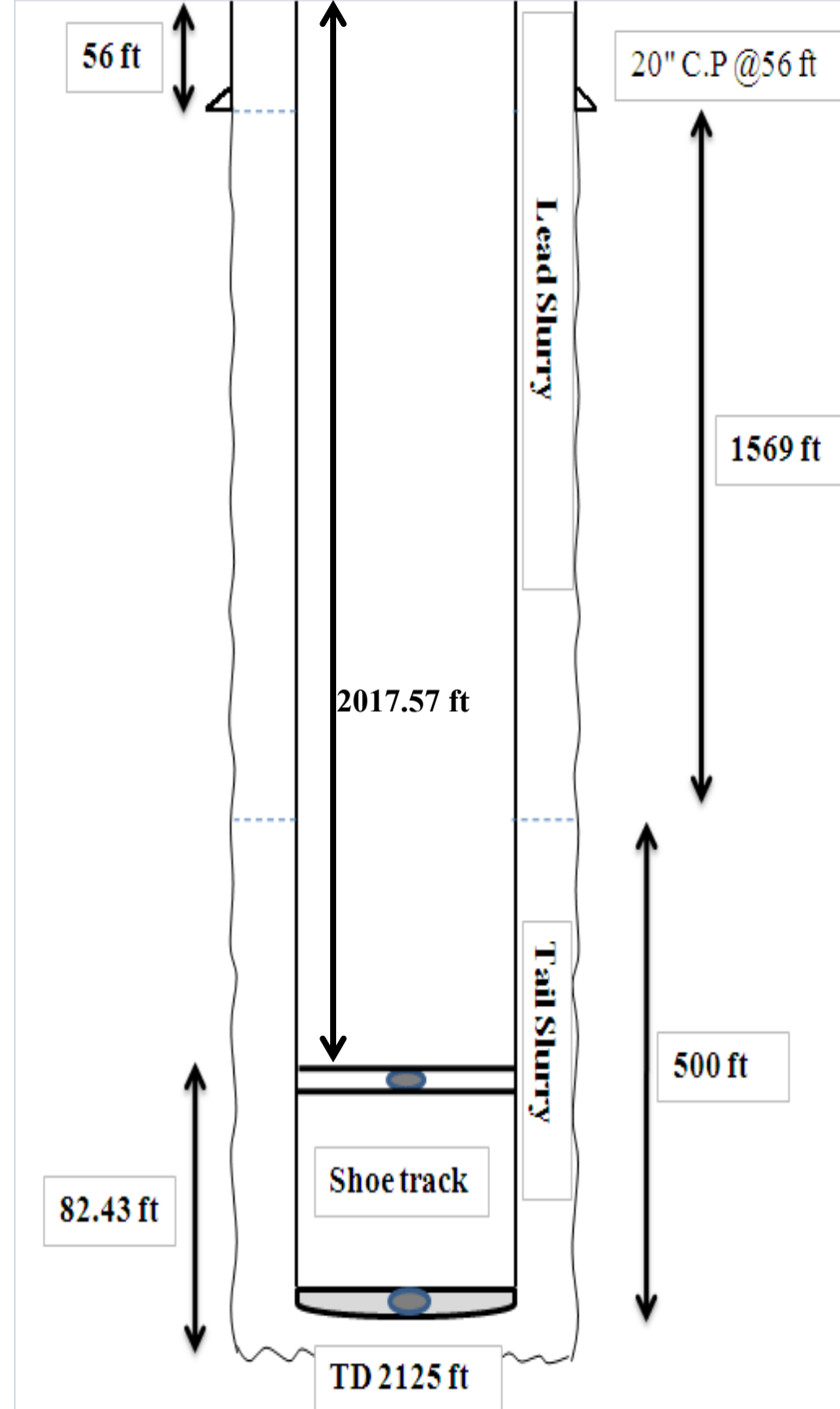
$82.43 \times 0.1497 = 12.339$ BBLs

Total Tail = 120.56 BBLs

Displacement:

$2017.57 \times 0.1497 = 302.03$ BBLs

Displacement Fluid = 302.03 BBLs



Data from lab test

1.9 Lead slurry properties

Company:	NORPETCO	Well : FERDAUS-12	Date:	FEB-28-010
Well Depth (TVD):	2200 FT	RIG:	Mud type:	WBM
Hole size:	17 1/2 in	Job type: 13 3/8 " CSG LEAD	Mud weight:	8.8 ppg
Temp BHST:	112 °F	Temp.Grad:	F/100ft	BHCT: 05 °F

ADITIVES	CONC.	UNIT
BENTONITE	2.5	%bwoc
HALAD-344	0.2	%bwoc
HR-6L	0.03	gal/sk
D-AIR-3000 L	0.1	gal/bbl

CEMENT & MIXING WATER		
Cement type:	DYCK"G" CEMENT	
Slurry Density:	12.0	ppg
Slurry Yield:	2.42	cuft/sk
Mixing Water Required:		
4.78 gps Fresh water + 9.56 gps Drill water		
Total Mix fluid	14.37	gal/sk

FREE FLUID %	API	45°:
	0.4	

API FLUID LOSS:	403	cc/30 min @ 1000	psi	@	95 °F
-----------------	-----	------------------	-----	---	-------

CONSISTENCY	min	0	5	20
	Bc:	5	6	6
	@			95 °F

RHEOLOGY DATA	Fan Readings (RPM)				PV	YP	Temperature	Gel lbs/100ft2	
	600	300	200	100				CP	lbs/100ft ²
		29	21	18	6	3			
					6	4	17	13	95
									6
									9

THICKENING TIME	30	(bc):		hrs:min	@	95 °F	Temp ramp	00:15 hrs:min
	70	(bc):	06:35	hrs:min			Pressure ramp	2,000 psi
	100	(bc):		hrs:min				

COMPRESSIVE STRENGTH	100 psi	12	hrs
current strength	280 psi	24	hrs
	psi		hrs

H ₂ O Analysis:	Chlorides: Fresh Water	300 ppm
	Drill Water	7000 ppm
PH = Prehydrated	DB = Dry Blended	% bwoc = % by weight of cement
		% bwow = % by weight of water

Note:	Calc based on 94 lbs sack of dry cement.
Remarks:	
	Mixing order:F.W,D-AIR 3000L,BENTONITE,D.W,HALAD-344,CFR-3,HR-6L,CEMENT

Data from lab test

1.10 Tail slurry properties

Company:	NORPETCO		Well : FERDAUS-12		Date:	MAR-3-010	
Well Depth (TVD):	2200	FT	RIG: W/F-104		Mud type:		
Hole size:		in	Job type:13 3/8 " CSG TAIL		Mud weight: ppg		
Temp BHST:	112	°F	Temp.Grad:		F/100ft	BHCT: 95 °F	

ADITIVES	CONC.	UNIT	DATE	Source	Batch NO.
HALAD-344	0.2	%bwoc	FEB-20-010	YARD	934564
CFR-3	0.2	%bwoc	FEB-20-010	YARD	835557
HR-6L	0.02	%bwoc	FEB-20-010	YARD	912374
D-AIR-3000 L	0.1	gal/bbl	FEB-20-010	YARD	2009040A

CEMENT & MIXING WATER		
Cement type:	DYCK"G" CEMENT	
Slurry Density:	15.8	ppg
Slurry Yield:	1.16	cuft/sk
Mixing Water Required:	4.99	gal/sk
Total Mix fluid	5.03	gal/sk

FREE FLUID %	API	45°:
	TRACES	

API FLUID LOSS:	320	cc/30 min @ 1000	psi	and	95	°F
-----------------	-----	------------------	-----	-----	----	----

CONSISTENCY	min	0	5	20
	Bc:	8	9	10

RHEOLOGY DATA	Fan Readings (RPM)						PV	YP
	600	300	200	100	6	3	CP	lbs/100ft ²
		90	65	40	8	6	75	15

THICKENING TIME	30	(bc):		hrs:min	@	95	°F
	70	(bc):	04:10	hrs:min			
	100	(bc):		hrs:min			

COMPRESSIVE STRENGTH	500	psi	12	hrs
	2500	psi	24	hrs
	current strength	psi		hrs

H ₂ O Analysis:	Chlorides:	7000 ppm
----------------------------	------------	----------

PH = Prehydrated DB = Dry Blended % bwoc = % by weight of cement % bwow = % by weight of water

Note:	Calc based on 94 lbs sack of dry cement.
Remarks:	

Mixing Order: D, Water, D-AIR 3000 L, HALAD-344, CFR-3, HR-6L, CEMENT

Cement calculations

Number of sacks:

Slurry yield = 2.42 cuft/sk (from lap test)

Lead number of sacks = $343.58 \times 5.615 / 2.42 = 797$ SK

Vol. Fresh water = $797 \times 4.78 / 42 = 90.7$ BBLs

Total volume of F/W = 90.7 + 20 BBLs (Dead volume) = 110.7 BBLs

Vol. Drill water = $797 \times 9.56 / 42 = 181.4$ BBLs

Total volume of D/W = 181.4 + 40 BBLs (Dead volume) = 221.4 BBLs

New number of sacks = $221.4 \times 42 / 9.56 = 973$ SK
= $110.7 \times 42 / 4.78 = 973$ SK

Chemicals:

Bentonite = $973 \times 94 \times 2.5 / 100 = 2286.55$ lb

HALAD 344 = $973 \times 94 \times 0.2 / 100 = 182.92$ lb

HR -6L = $973 \times 0.03 = 29.19$ gal

D-air = $343.58 \times 0.1 = 34.35$ gal

HALAD: Halliburton Anti Losses Additives

HR: Halliburton Retarder

D-air (De-foamer)

1 sack = 50 lb

1 can = 5 gal

CEMENT & MIXING WATER		
Cement type:	DYCK"G" CEMENT	
Slurry Density:	12.0	ppg
Slurry Yield:	2.42	cuft/sk
Mixing Water Required:		
4.78 gps Fresh water + 9.56 gps Drill water		
Total Mix fluid	14.37	gal/sk

or

New number of sacks = 973 SK
Add chemicals based on this number

ADITIVES	CONC.	UNIT
BENTONITE	2.5	%bwoc
HALAD-344	0.2	%bwoc
HR-6L	0.03	gal/sk
D-AIR-3000 L	0.1	gal/bbl

Cement calculations

Number of sacks:

Slurry yield = 1.16 cuft/sk (from lap test)

Tail number of sacks = $120.56 \times 5.615 / 1.16 = 584 \text{ SK}$

Vol. Drill water = $584 \times 5.03 / 42 = 69.66 \text{ BBLs}$

Total volume of D/W = $69.66 + 5 \text{ BBLs (Dead volume)} = 74.66 \text{ BBLs}$

New number of sacks = $74.66 \times 42 / 5.03 = 626 \text{ SK}$

Chemicals:

HALAD 344 = $626 \times 94 \times 0.2 / 100 = 117.688 \text{ lb}$

CFR-3 = $626 \times 94 \times 0.2 / 100 = 117.688 \text{ lb}$

HR -6L = $626 \times 0.02 = 12.52 \text{ gal}$

D-air = $120.56 \times 0.1 = 12.056 \text{ gal}$

HALAD: Halliburton Anti Losses Additives

HR: Halliburton Retarder

CFR: Cement friction Reducer

D-air (DE-FOAMER)

1 Sack = 50 lb

1 Can = 5 Gal

CEMENT & MIXING WATER		
Cement type:	DYCK"G" CEMENT	
Slurry Density:	15.8	ppg
Slurry Yield:	1.16	cuft/sk
Mixing Water Required:	4.99	gal/sk
Total Mix fluid	5.03	gal/sk

New number of sacks = 626 SK
Add chemicals based on this number

ADITIVES	CONC.	UNIT
HALAD-344	0.2	%bwoc
CFR-3	0.2	%bwoc
HR-6L	0.02	%bwoc
D-AIR-3000 L	0.1	gal/bbl

Sequence of operations

- Circulate twice 13 3/8" casing capacity, using Fill up tool (630 BBLs).
- Held pre job safety meeting.
- Rig up cement head and lines and test same to pressure 3000 psi.
- Pump **80 bbl's** Gel Flush (pre-flush ahead)
- Drop bottom cement plug
- Mix & Pump **343.5 bbl's, 12 PPG** lead slurry with 6 bbl/min (Pump Press. 200 - 250 psi)
- Mix & Pump **120 bbl's, 15.8 PPG** tail slurry with 4 bbl/min (Pump Press. 230 - 260 psi)
- Drop top cement plug, displacement with **302 bbl's** 8.8 spud mud, final pump press. 485 psi
- Bump down plug at **1500 psi** hold 10 min, bleed off cement line to zero, had return **3 bbl's**.
- **Had 100 bbl's pure cement to surface**
- Float collar depth @ 2035'.
- Wait on cement.
- Lay down Premiere spider elevator & slips, change top drive links.

**Stop collars: Hold
centralizer in casing**



**Centralizers: centralize
casing in hole**

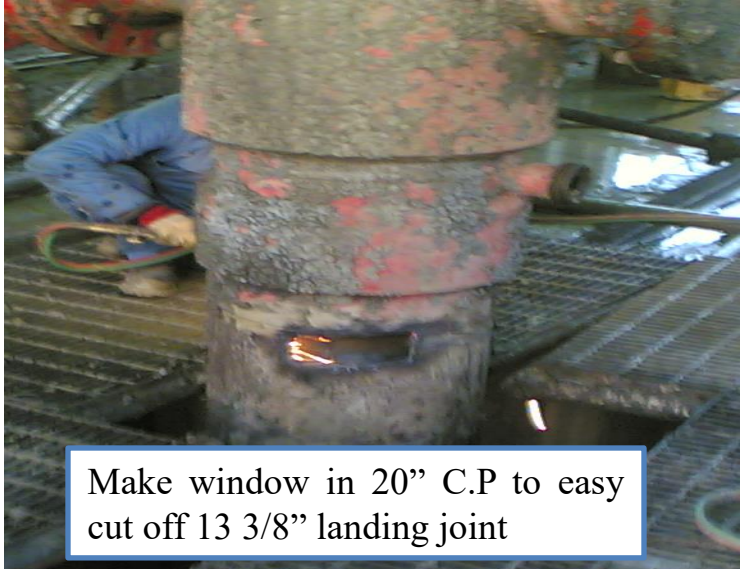


Fluids Pumped:

- Spud Mud
- Gelled Preflush
- Lead Slurry
- Tail Slurry
- Gelled Preflush
- Spud Mud

SEQUENCE OF OPERATIONS

- Rough cut off 13 3/8" landing joint
- Nipple down Diverter system.
- Cut off 20" short joint & remove same
- Final cut 13 3/8" casing with MEDCO cold cutter.



Make window in 20" C.P to easy cut off 13 3/8" landing joint



Midco cold cutter
13 3/8" casing



20" C.P

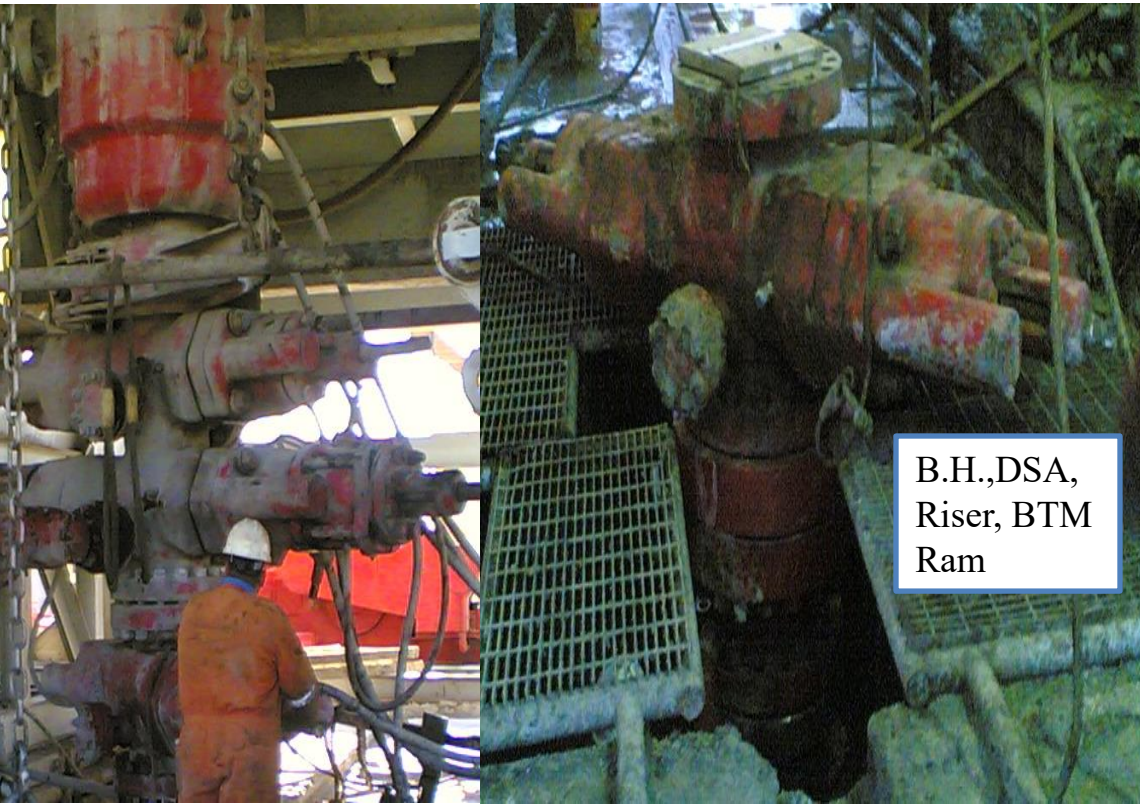
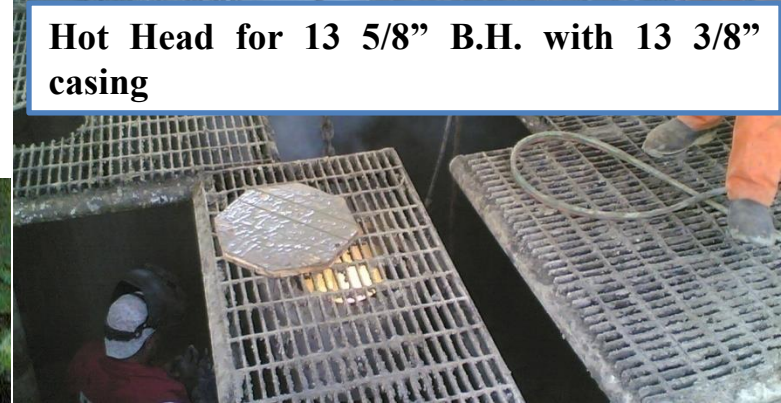
SEQUENCE OF OPERATIONS

- Installed 13 5/8" X 5000 Casing Head Spool. Welded same and pressure test to 1000 PSI for 15 min.
- Nipple up 13 5/8" X 5000 BOP. (Double Stud Adaptor, Riser, Bottom ram, double ram, annular preventer, kill line & chock line)
- Nipple up Flow line, bell Nipple & adjust top drive with rotary, Test BOP



B.H.

Hot Head for 13 5/8" B.H. with 13 3/8" casing



**B.H., DSA,
Riser, BTM
Ram**



SEQUENCE OF OPERATIONS

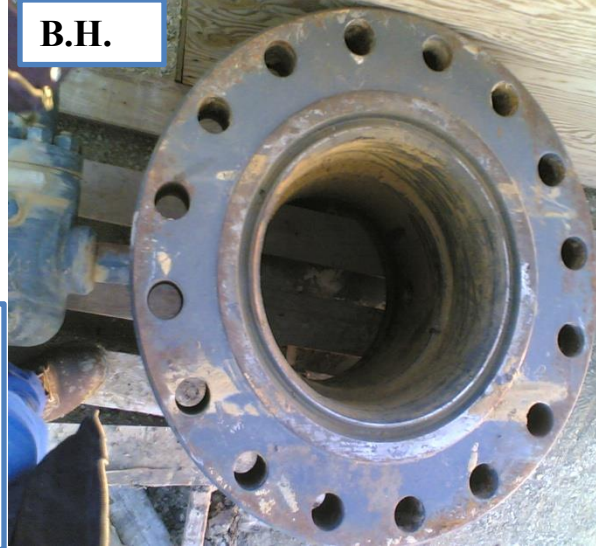
➤ Test BOP, Lay down test Assembly, Installed wear bushing, Pick up, Make up & Running with new 12 ¼" BHA, Wash & Ream down from 1818' to 2005' till tag on cement.



Test plug: Installed in B.H.



Wear bushing: Installed in B.H. by test plug during running with 12.25" drilling assembly



B.H.



BOP Panel on rig floor



12.25" Bit (Reed Hycalog) in Bit breaker

Borehole Problems Appraisal, Prevention and Curing

Bore hole problems

1. Wellbore Instability

A. Shale Problems (Chemical- Physical)

Indicators of problem shales.

- Sloughing shale.
- Hole enlargement.
- Bridges and fill on trips.
- Stuck pipe and fishing difficulty.
- Hole-cleaning problems.
- High fluid-maintenance cost.
- Solids-control problems.

2. Shale hydration (surface adsorption and osmotic adsorption) will result in two distinctly different problems.

- **Swelling** -Expansion of clays due to intake of water. Indicators -Bit balling, mud rings or gumbo attacks, hole washout. elliptical well bores. fine solids buildup.
- **Dispersion** -The disintegration of shale body due to water contact.

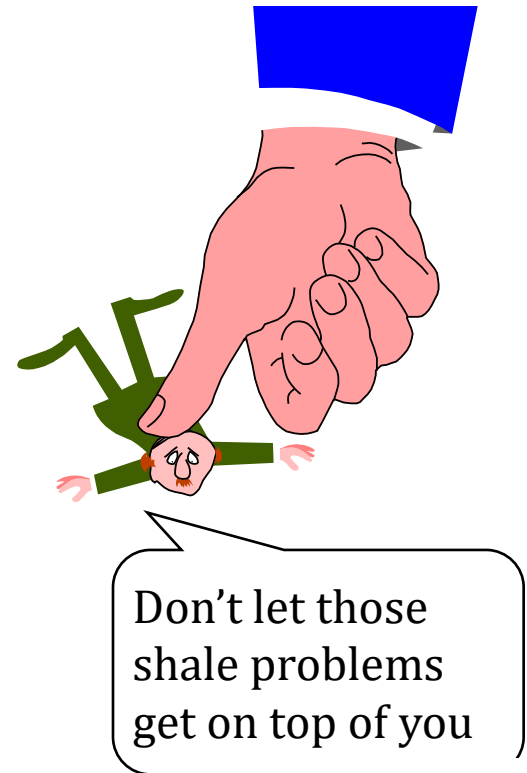
Indicators -Sloughing shale, bridges and fill on trips, hole-cleaning problems.

3. Stabilizing shales through inhibition.

Table 1 lists the chemical and physical process used in stabilizing shale sections and typical fluids which employ these stabilization mechanisms.

Mechanisms of Inhibition

- Oil wetting the surface rocks (**OBM**)
- Cation Exchange (**KCL**)
- Reducing the pH
- Encapsulating polymers (**PHPA**)
- Reducing the fluid loss
- Increasing the Chloride content (**NACL +KCL**)
- Precipitates (**Silicates**)
- Salt Saturated mud for halites
- Changing cloud point (**glycol base mud**)



Drill string design

Drill pipe:

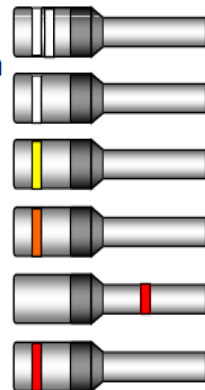
Drill pipe is a tubular steel conduit fitted with special threaded ends called tool joints.

Most common class (G-105) & S-135)

of OD	New Pipe Premium	Original Dimensions. Diameter reduction not higher than 3%
	Class 2	Wall thickness not less than 80% Diameter reduction not higher than 4% of OD Wall thickness not less than 70%
	Class 3	Other imperfection that exceeds Class 2

Color codes of Drill Pipe

- 2 white bands Tool joint premium
- 1 white band New Pipe
- 1 yellow band Tool Joint Class 2
- 1 Orange band Class 3
- 1 Red band on tube Junk
- 1 Red band on tool Joint Junk and can be repaired



Grade

- D55, E75, X95
- G105, S135, S165

Class

- New
- 10% wear
- Premium Class – 20% wear (scrap)
- Class 2 – 30% wear (scrap)

Range

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

Table 6—Used Drill Pipe Torsional and Tensile Data API Class 2

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Size OD in.	New Weight Nominal W/ Threads and Couplings lb/ft	^{1,2} Torsional Yield Strength Based on Uniform Wear, ft-lb				² Tensile Data Based on Uniform Wear Load at Minimum Yield Strength, lb			
		E75	X95	G105	S135	E75	X95	G105	S135
2 ³ / ₈	4.85	3224.	4083.	4513.	5802.	66686.	84469.	93360.	120035.
	6.65	4130.	5232.	5782.	7434.	92871.	117636.	130019.	167167.
2 ⁷ / ₈	6.85	5484.	6946.	7677.	9871.	92801.	117549.	129922.	167043.
	10.40	7591.	9615.	10627.	13663.	143557.	181839.	200980.	258403.
3 ¹ / ₂	9.50	9612.	12176.	13457.	17302.	132793.	168204.	185910.	239027.
	13.30	12365.	15663.	17312.	22258.	183398.	232304.	256757.	330116.
	15.50	13828.	17515.	19359.	24890.	215967.	273558.	302354.	388741.
4	11.85	13281.	16823.	18594.	23907.	158132.	200301.	221385.	284638.
	14.00	15738.	19935.	22034.	28329.	194363.	246193.	272108.	349852.
	15.70	17315.	21932.	24241.	31166.	219738.	278335.	307633.	395528.

Heavy Weight Drill pipe

Similar in appearance to a drill pipe, HWDP has the following different dimensional characteristics;

the **tube wall is heavier about 1" thick** in most sizes

the **tool joints are longer**

the **tube section has a larger diameter at mid length to protect the pipe from wear.**

HWDP were developed for the following reasons;

As a transition member to be run between drill collars and drill pipe,

as a flexible weight member to run on directional drilling,

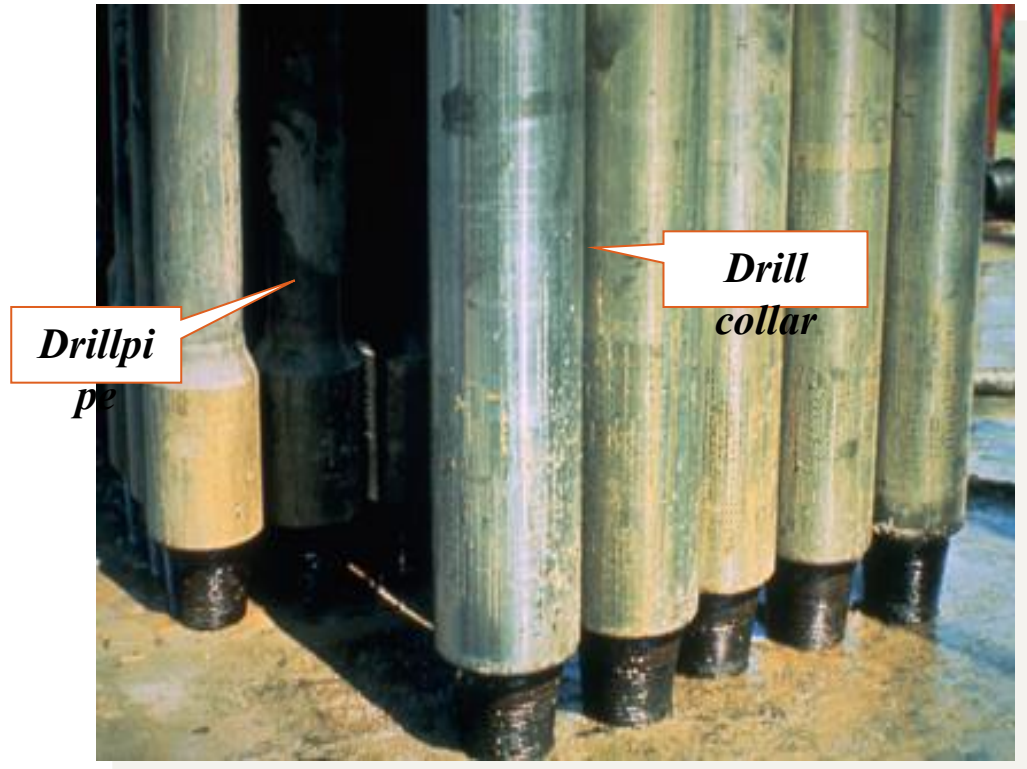
as a weight member on small rigs, drilling small diameter holes.



Drill Collar:

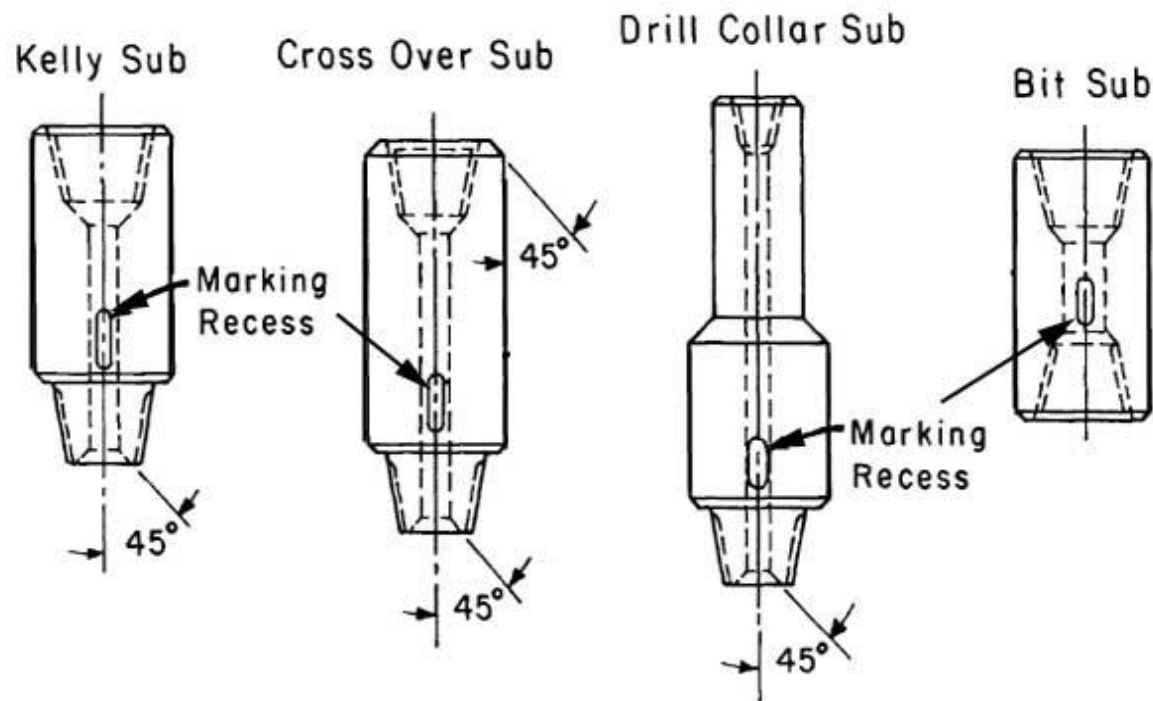
A component of a drillstring that **provides weight on bit for drilling**. Gravity acts on the large mass of the collars to provide the downward force needed for the bits to efficiently break rock.

There are two main types: **round & spiral**



Subs

A short, threaded piece of pipe used to adapt parts of the drilling string that cannot otherwise be screwed together because of difference in thread size or design.



Stabilizers - integral

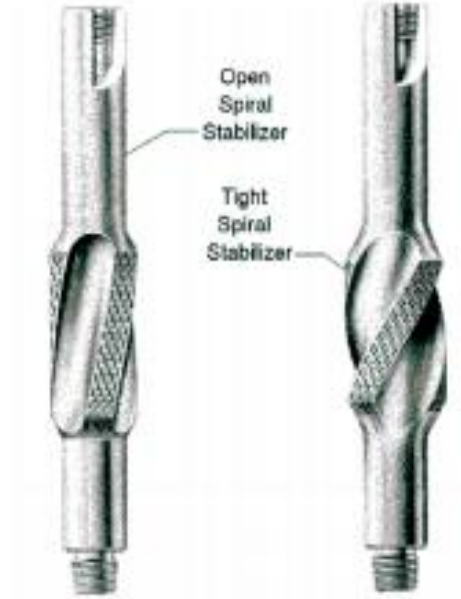
- Single steel forging
- Blades hard faced tungsten inserts
- Straight Blade for Sliding
- or Spiral Blade
 - Open wrap (270° wrap)
 - Full wrap (360° wrap)
- Blade profile
 - Parallel
 - Melon (for Sliding)
 - PDC Cutters or hard facing can be added for reaming



Stabilizers - cont.



Figure 5-5 Welded blade stabilizers



Roller Reamer

- Sealed bearing / unsealed bearing
- Different cutting structures
- Roller pins are retained in body blocks/ pins
- Limited run hours (max. 2.5M revolutions)
- May **help Stick Slip & reduce friction**
- **Important to check roller pins after each run**
- **Rule of thumb** , to keep build or hold tendency, size of RR must be 1/8" under the replaced stabilizer



Concentric PDC Reamers (reaming while drilling)

- Increases borehole diameter behind the drill bit
- Helps **compensate for mobile formations**, poor hole cleaning, ECD management & may allow intermediate or expandable casing string contingency
- Run **above RSS** needing full gauge contact with wellbore to work
- Best if run 30 ft from above MWD
- two can run in tandem for more enlargement



Enlarge While Drilling

- Weight activated with Hydraulic locking mechanism
- Ability to make back reaming



Eccentric PDC Reamers

- Typically run close to bit
- Directional control difficult if run below Motor or RSS
- Potential vibration source due to eccentric forces
- Needs to be stabilised correctly to ensure good borehole enlargement
- Can provide unreliable borehole enlargement.



Subs and X-Overs

- Cross over without OD change
 - Cross over with OD change
 - Saver subs for special connections
 - Near bit Stabilizers
-
- Face area of sub connection should match the face area of adjacent connection – otherwise “lip” can form



Straight OD Subs



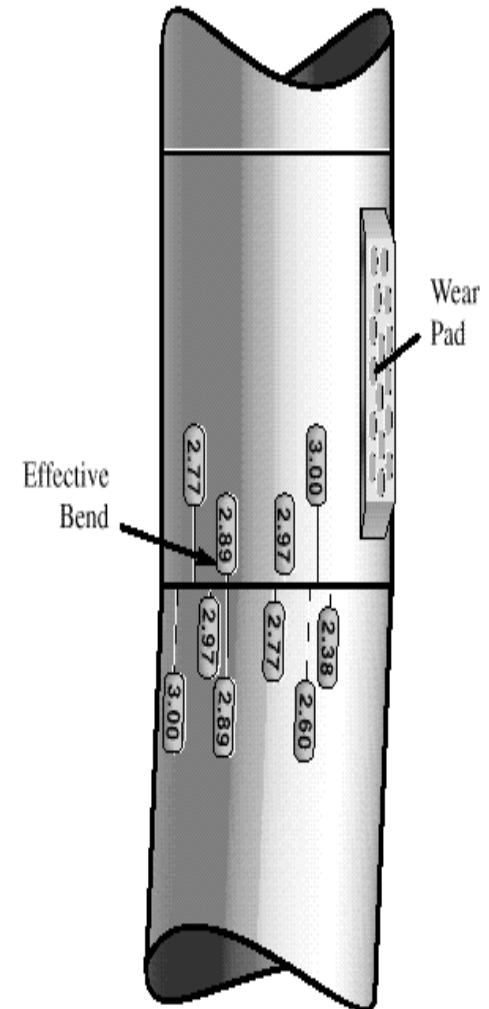
Reduced Section Subs



Saver Subs

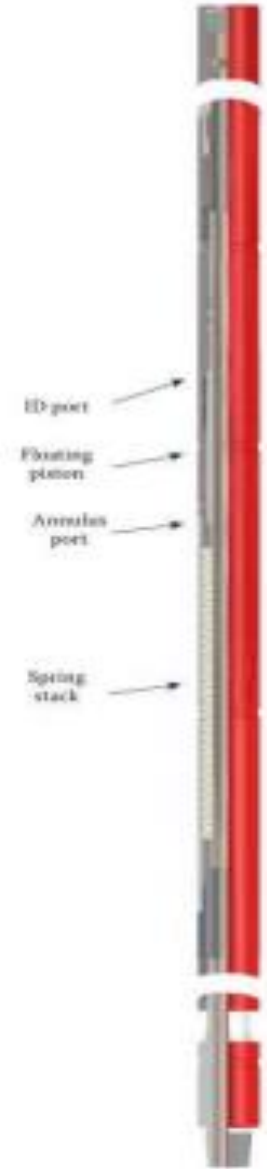
Bent Sub

- Has the pin machined with an angular offset $\frac{1}{2}$ - $2 \frac{1}{2}$ degrees
- May be aligned with shims to motor bend to enhance dogleg capability

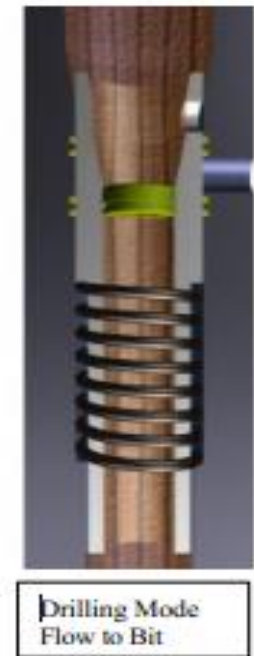


shock SUB

- Absorbs mainly axial shocks
- Shock absorption usually based on a “Belleville stack” spring
- May utilize hydraulic dampening system



- Multiple activating circ sub. Opened by Vinyl Ball, closed by steel ball.
- Activation by 160 psi pressure & deactivation with 2000 psi
- Used to pump LCM pills through it without failure of MWD tools

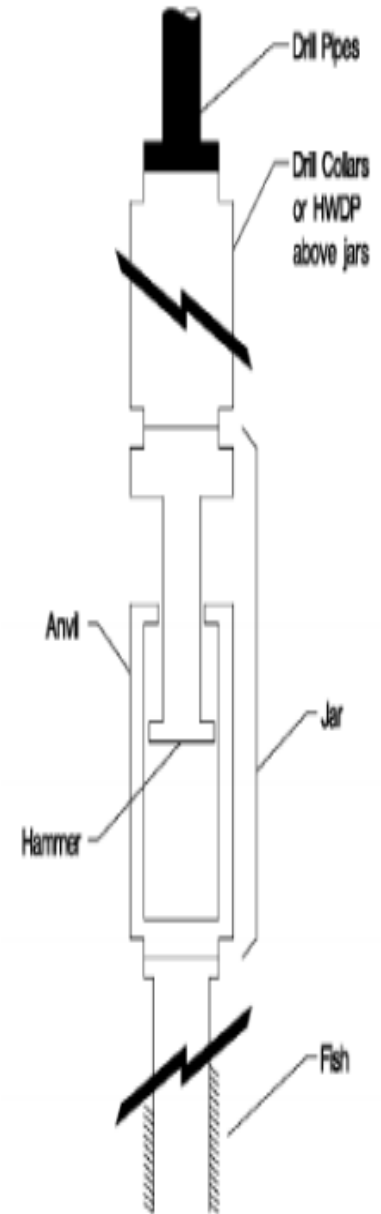


Jar

Jarring is the process of transferring **stored energy** (drill pipe stretch) in the drill string to **kinetic energy** by releasing the detent in the Jar at a given over pull value

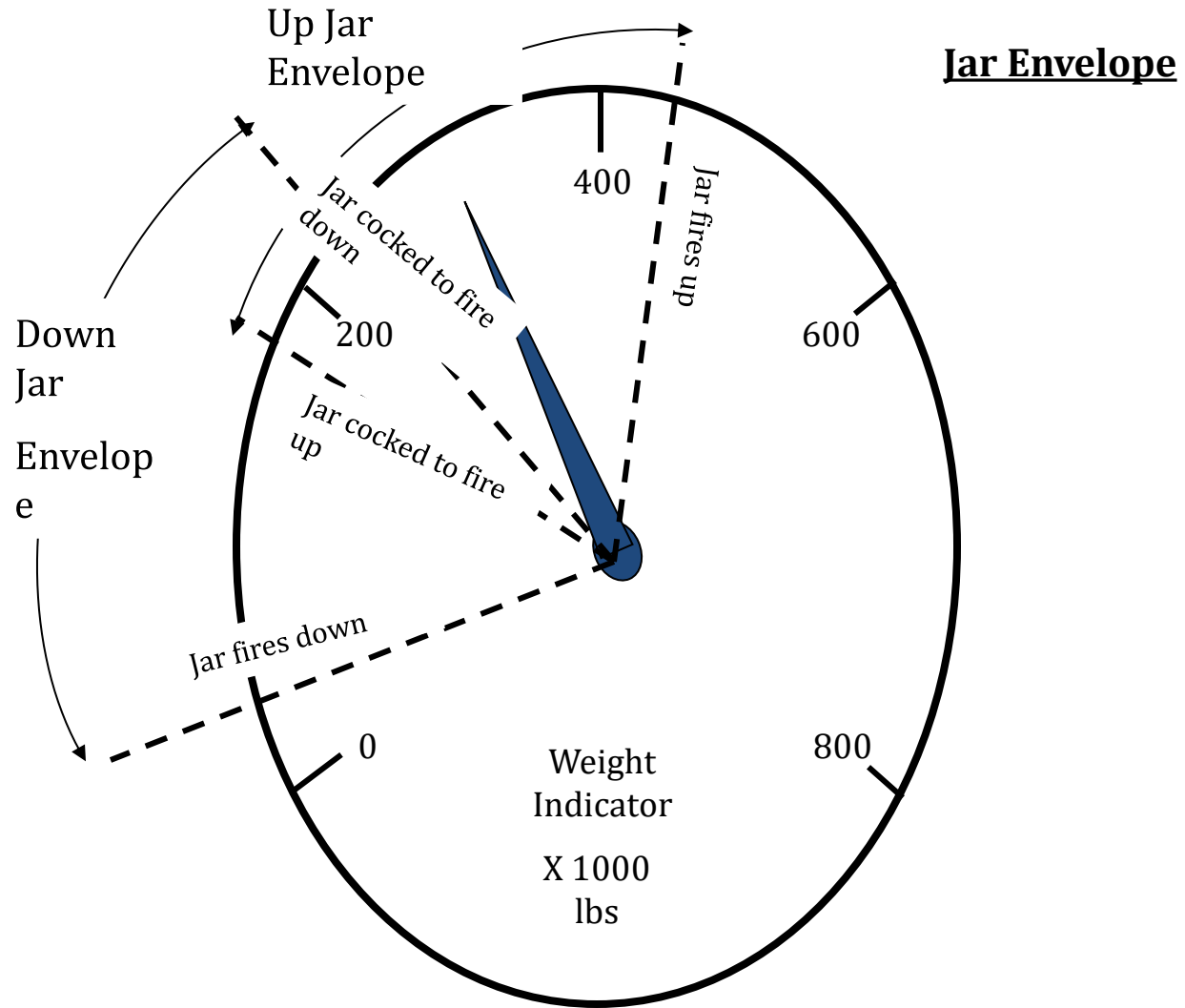
Detent System:

Delay mechanism, Stores potential energy, Sudden release



Types of Jars

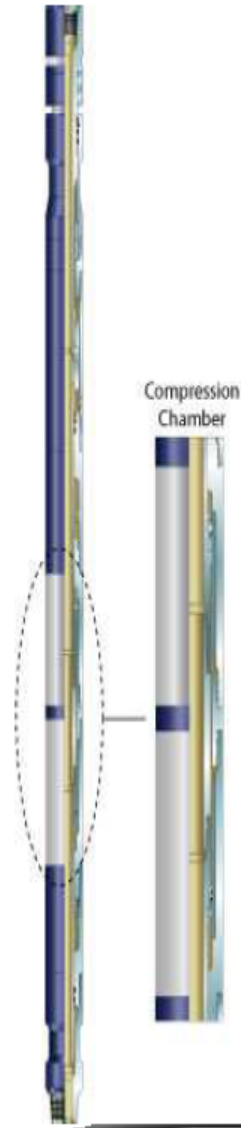
- **Mechanical jars** operate using a series of spring, lock and release mechanism.
- **Hydraulics jars** operate using the controlled passage of hydraulic fluid.
- **Hydro-mechanical jars** are a hybrid of both designs, usually hydraulics up and mechanical down



Accelerators

Accelerator

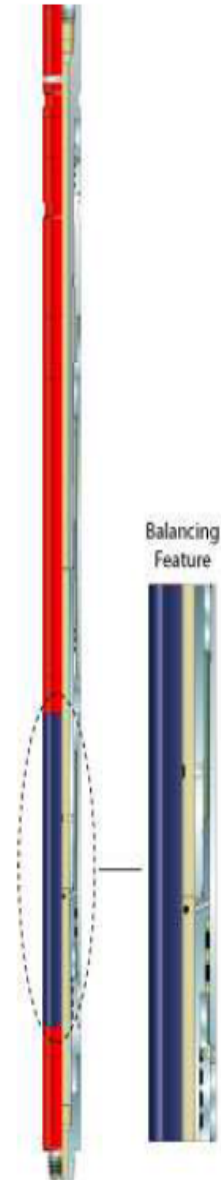
- Typically run several stands above Jars
- Removes the spring dampening of the drillstring
- Allows larger impulse to develop
- Reduced impact stress on upper drillstring

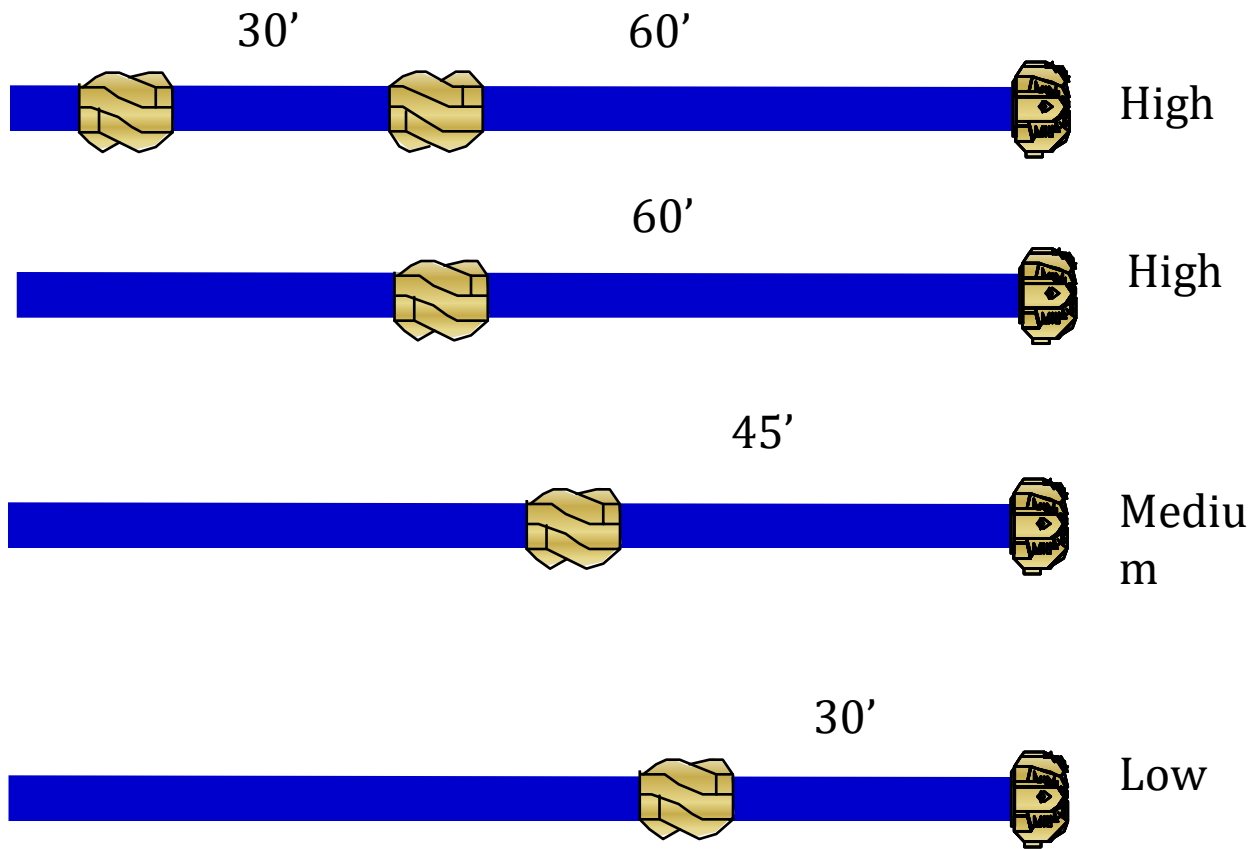


Bumper Sub

Bumper Sub

- Old technology to drill in rough seas without a compensator
- Can be used to give a very even WOB as a DD tool
- Usually placed in BHA at expected neutral point
- Prove to failure and/or washout

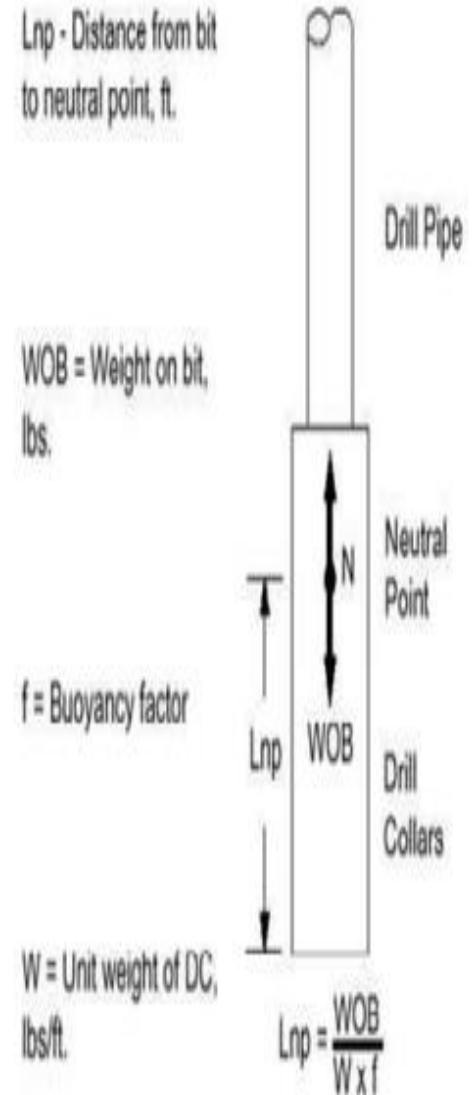




Dropping Assemblies

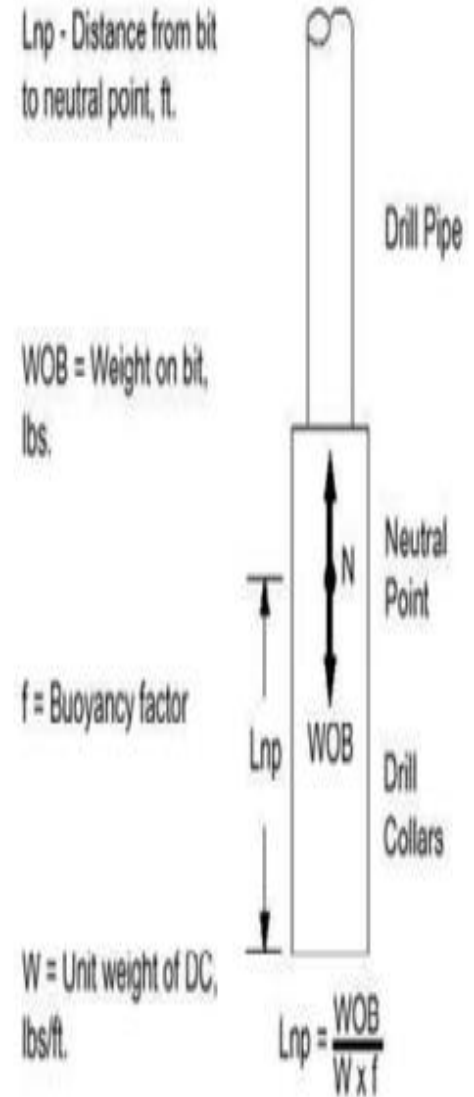
Neutral point

- It is point where drill string transition from **tension to compression**
- Need to be kept in BHA (D/C & HWDP)
- The **lower the WOB**, the **closer to the bit N** is.
- Therefore, the BHA must be designed to account for the worst case i.e. when **maximum WOB is applied**



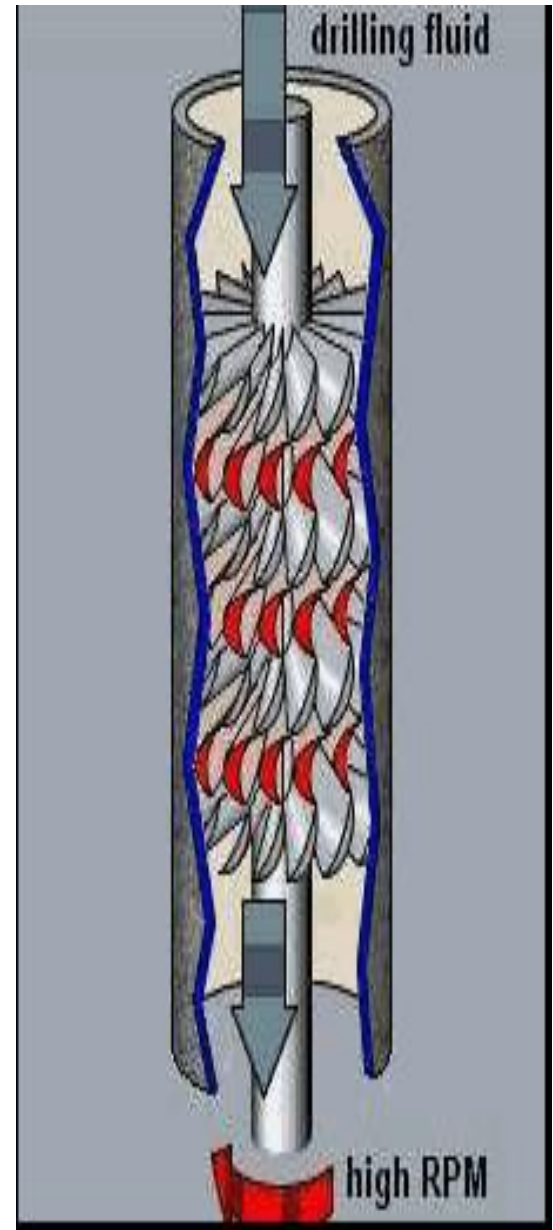
Vertical well

- Before a BHA is designed, an estimate is made of the **maximum weight on bit (WOB)** which will be required.
- This will depend on the **bit specification** and on the **formation**.
- The number of **drill collars** should be kept to the **minimum**.
- HWDP is used to give the remainder of the required WOB.



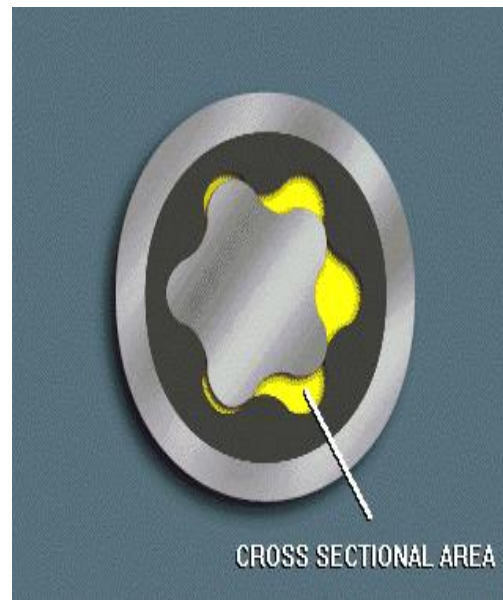
Mud motors

- **1- Turbine type (turbo-drill)**
- Consists of multi-stage blade motor & stator sections & thrust bearing section & drive shaft.
- The stator remains stationary to deflect mud to rotor blades.
- Rotor blades are attached to drive shaft which is attached to bit.
- Mud is pumped under high pressure , so it is deflected by stator blades to rotor blades
- This imparts rotation to the rotor and drive shaft to bit.

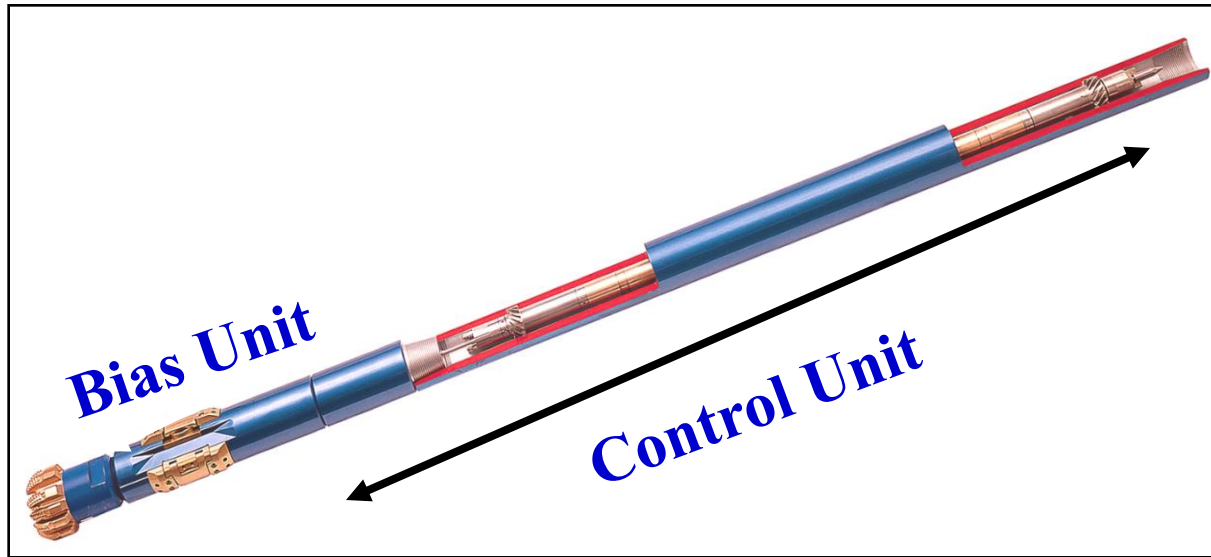


Positive displacement motors (PDM)

- Positive Displacement Motors (PDM) use the flow of mud pumped down the drill string to rotate a drive shaft to which the drill bit is connected.



Rotary steerable system



- **there are two types:**
- Point the bit (power drive XCEED) & “push the bit” (power drive X6) tool
- Pads extend dynamically from a rotating housing
- Not suitable for open hole sidetracks or bicentre bits