IWCF – Drilling

Principles & Procedures

Hey

18+ years of experience, in both Academic and Practical experiences

- Petroleum Engineer
- Practical experience in Drilling Fluids, & Drilling.
- Worked for different companies such as ARAMCO, KOC, EMEC, BHI, GSTC, MTC, EDS in different fields
- Worked in Libya, Egypt, KSA, Qatar, Kuwait, Oman, Sudan & Malaysia.
- SPE e-mentor.
- Certified/Approved trainer for :
  - ✓ Certified IADC Assessor for Well Sharp (Surface – Combined)
  - ✓ Accredited IADC Trainer for Well Cap Workover courses
  - ✓ Certified IADC Assessor for Advanced Drilling Fluids
  - ✓ Certified IADC Assessor for Defensive Driving
  - ✓ Certified IADC Assessor for H_2S
  - ✓ Accredited IWCF Instructor (Surface – Combined)
  - ✓ Accredited IWCF Assessor (Surface – Combined)

PSB/HR/I/1/00
21042022

PANTHELEUM
Oil Services

SAFETY INDUCTION

Covid-19 Control & Prevention

Attend / visit our training centre in a safe manner by following these procedures

The Malaysian Government is making the MySejahtera app mandatory at premises nationwide, for contact tracing, in order to curb the spread of the Covid-19 virus.

- You are required to scan your MySejahtera installed in your cell phone upon arrival at the Pantheleum Training Centre.
- Sanitize your hands before further proceed into the training room / lounge area.
- Please inform the Safety Representative if you're showing / experiencing covid-19 symptoms while you are in the class immediately.

Covid-19 Control & Prevention

Attend / visit our training centre in a safe manner by following these procedures

- Wear cloth face coverings, at a minimum all the times when entering the training centre.
- Frequently wash your hand with soap and water for at least 20 seconds. When soap and running water are not available, use an alcohol-based hand sanitizer with at least 60% ethanol or 70% isopropanol as active ingredients and rub hands together until they are dry.
- Avoid touching your eyes, nose, or mouth with unwashed hands.
- Practice good respiratory etiquette, including covering coughs and neeze or coughing/ sneezing into your elbow/upper sleeve.
- Practice social distancing from the rest of the candidates and training centre's personnel.

Current Safety Procedures

Attend / visit our training centre in a safe manner by following these procedures

- Ergonomic Workstation Set-up
- Observe Warning Signs
- Clean up any spills or messes immediately
- Keep all walkaways and work areas clear of trip hazards
- Use the right tools all the time
- Report any incidents, accidents or near misses
- Follow emergency procedures

Training Facility / Equipment Safety Checks

It is important that we all take an active part ensuring all equipment or training facilities used are safe

- For employee: Each day visually check training equipment / facility to be used
- For training candidate / visitor: visually check the training equipment / facility to be used prior the start of the training.
- Report any identified issues immediately
- Ask if you are unsure about the use and safety of any of the equipment you use.

Procedure For Reporting Minor Risks & Incidents

INFORM SAFETY REPRESENTATIVE IMMEDIATELY

Incase if an accident or sudden illness occurs, attend to any injury and ensure, if possible, that the area is safe. The Safety Representative will take the necessary action.

COMPLETE A HAZARD REPORT

As soon as possible, complete the Hazard Report Form. A copy of this form can be found with the first aid kit at the admin desk. The administrator can help you to complete the form.

SUBMIT FORM TO THE SAFETY REPRESENTATIVE

As soon as possible submit your completed form to the Safety Representative. This form will then be addressed by the safety committee and appropriate action will be taken.

Safety
Representative / Fire Warden 1

Noor Liyana

Level 11-13A, Wisma UOA II.

Contact Number: 017-223 7322

Email – liyana.omar@pantheleum.com

Safety
Representative / Fire Warden 2

Noor Shazlina

Level 11-13A, Wisma UOA II.

Contact Number: 012-444 1252

Email – shazlina.marjuni@pantheleum.com

First Aid Contact

First Aider 1

Noor Liyana Omar

017-2237322

First Aider 2

Noor Shazlina Marjuni

012-4441252

Emergency Service	**General Line**
Fire Rescue	999
Police	999
Ambulance	999

Hospital

Hospital Kuala Lumpur 03 - 2615 5555

Polis DiRaja Malaysia (PDRM)

IPD Kuala Lumpur 03 - 2146 0522

Bukit Aman 03 - 2266 2222

First Aid Procedure

Personnel / Candidate

Illness / Injury happened →

Office Manager / First Aider

To assess, survey and intervene the situation of the ill / injured person and to provide the necessary first aid treatment. →

Once the severity of the illness / injured person identified, call the ambulance at 999. For minor illness / injury, patient can be taken to a general clinic located at lower ground floor in the same building (Klinik Mediviron) →

Inform the candidates' employer immediately about the situation →

Office manager / first aider will record the first aid treatment within the first aid register and replenish the first aid kit box if necessary

Emergency Evacuation Procedure

According to DATS Management Emergency Evacuation Procedure – UOA II, Jalan Pinang.

Thank you.

Emergency Evacuation Procedure

EMERGENCY EVACUATION PROCESS

Fire Alarm Activated

- The fire alarm bell is programmed to ring intermittently for 5 minutes.
- Announcements made through the Public Address (PA) System.

Start to evacuate the building

- Any operating machine should be switched off before evacuating.
- Evacuate the building by way of the nearest emergency exit.
- Walk briskly and move to pre-designated assembly area.
- Do not run or return to the building.

Assemble at assembly area and conduct a headcount

- Line up at the designated assembly area according to the level/company.
- Require cooperation of all occupants in conducting headcount.
- Verify missing persons and report to Evacuation Controller.
- Remain at the assembly area until further advised.

Re-enter to the building respectively.

- Re-enter to the building respectively.
- Wait for further instructions. All committee members and PIC should attend post-mortem meeting.

DATS MANAGEMENT SDN BHD

Emergency Evacuation Procedure

ERT DUTIES & RESPONSIBILITIES – FLOOR WARDEN

Before Evacuation	During Evacuation
➢ Update staff Name list including for special case ➢ Prepare the play card ➢ Get ready the vest for identification. ➢ Keep track of the visitor / contractor movement ➢ Appoint at least 4 Floor Warden	**Floor Warden 1** ➢ Inform all staff to evacuate ➢ Guide the staff evacuate through emergency staircase. ➢ Inform all staff to switched off the electrical supply. ➢ Assist "special case" to evacuate ➢ Start headcount once reach assembly area. ➢ Report headcount to EC.
	Floor Warden 2 ➢ Check all toilet, store, meeting room. Ensure no one left behind. ➢ As a last person leave the unit / floor / building. ➢ Inform EC if someone trapped / injured.

LEVEL 14
DATS MANAGEMENT

DATS MANAGEMENT SDN BHD

Emergency Evacuation Procedure

IMPORTANT OF FIRE SAFETY FEATURES

Emergency Exit Door
- Identify the nearest emergency exit door from your workstation.
- Ensure no obstruction from/to emergency exit door.
- Do not lock your emergency door.

MCP / Emergency break glass (FIRE)
- Identify the nearest MCP (mechanical call point).
- Break the emergency "break glass" in the event of spotting fire/emergency outbreak.

Emergency Door Release
- Identify the location of magnetic door at your floor/level.
- Please check whether the magnetic door linked to Fire Alarm Panel.
- Ensure "Emergency Door Release" installed beside of the magnetic door.

DO NOT MISUSE OF THESE !!!

DATS MANAGEMENT SDN BHD

Emergency Evacuation Procedure

IMPORTANT OF FIRE SAFETY FEATURES

Fireman Intercom

- Identify the nearest Fireman Intercom from your workstation.
- Use the Fireman intercom during emergency to communicate with control room.

Hose Reel

- Identify the nearest hose reel from your workstation.
- Only use it in the event of spotting fire outbreak.

Fire Extinguisher

- Identify the nearest Fire Extinguisher from your workstation.
- Identify the type of Fire Extinguisher installed at your floor/level.
- Use appropriate Fire Extinguisher to extinguish the fire.

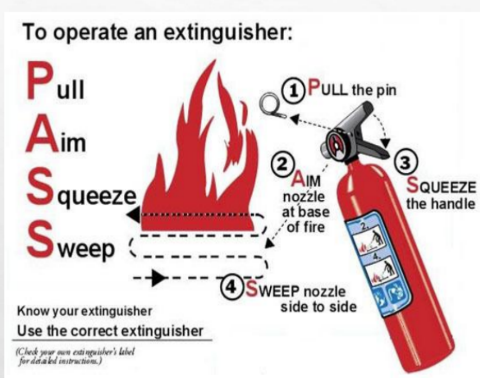
DO NOT MISUSE OF THESE !!!

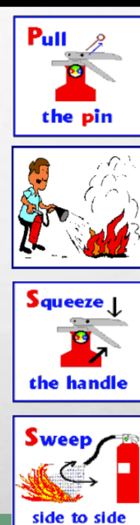
DATS MANAGEMENT SDN BHD

Emergency Evacuation Procedure

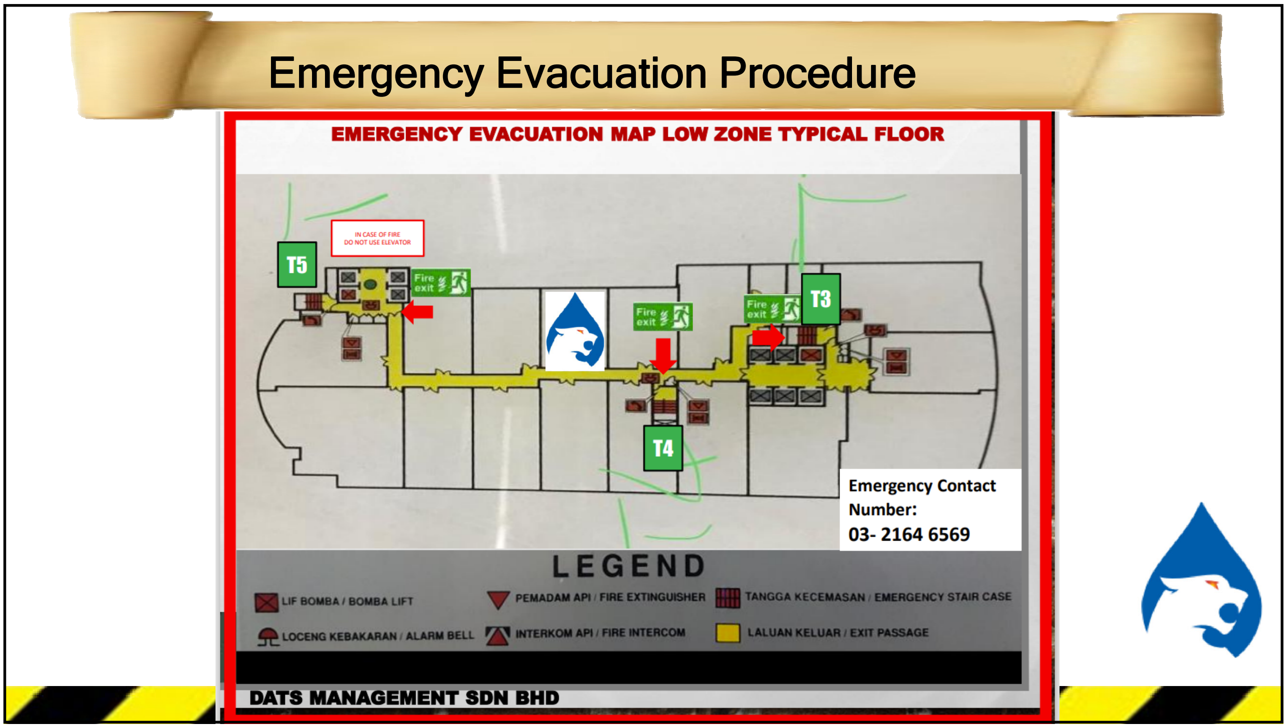
HOW TO USE FIRE EXTINGUISHER?

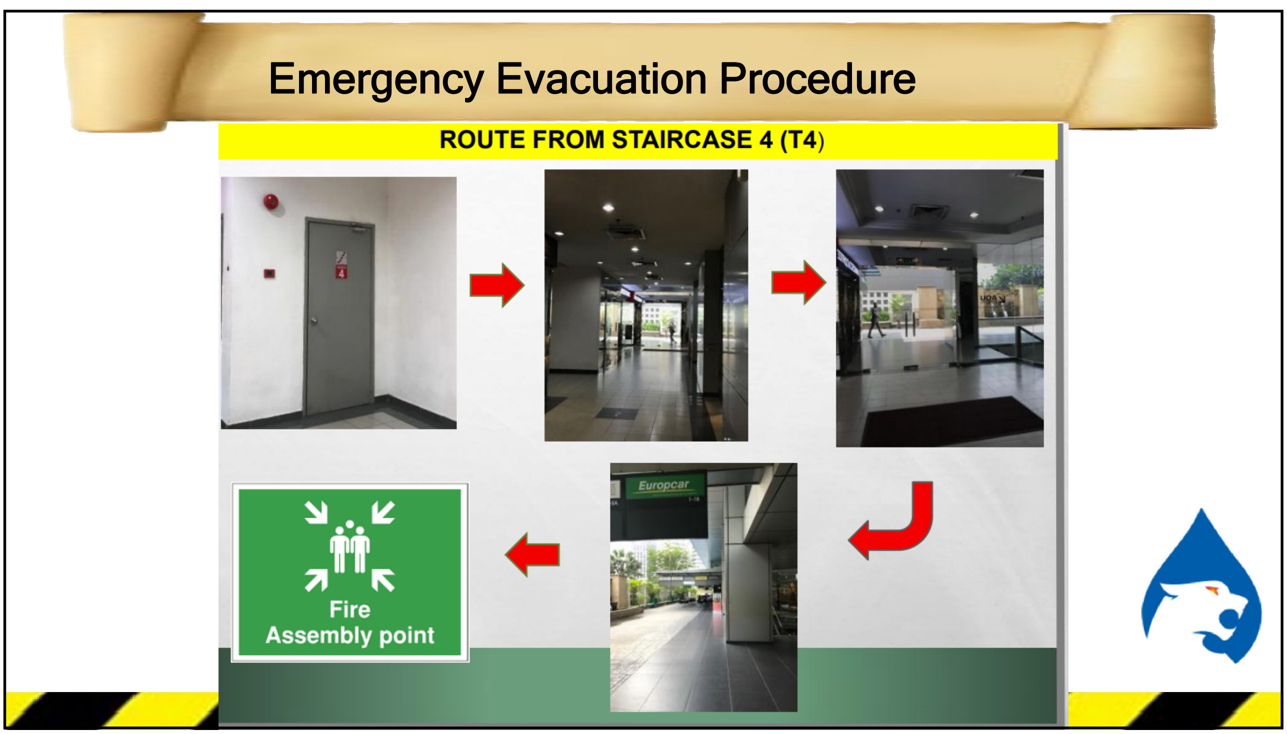
In case of small fire





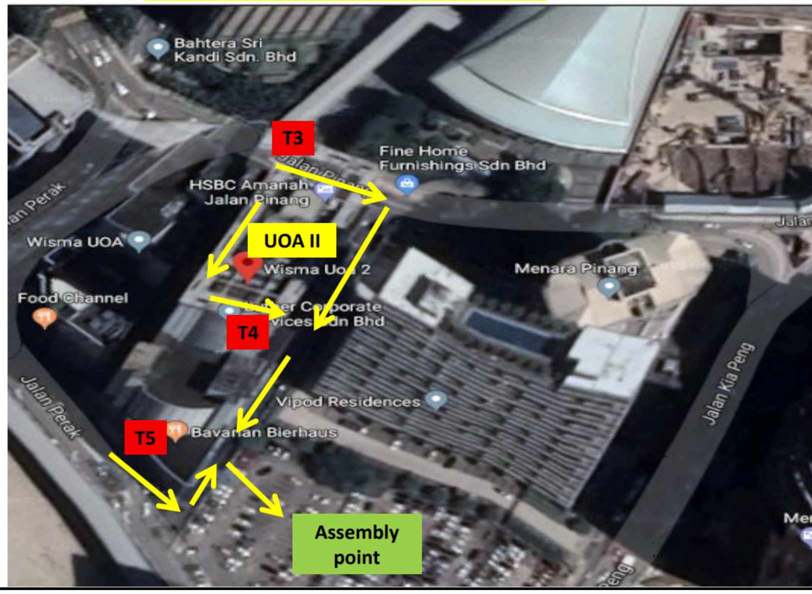
DATS MANAGEMENT SDN BHD


Emergency Evacuation Procedure
EMERGENCY EVACUATION MAP LOW ZONE TYPICAL FLOOR
IN CASE OF FIRE DO NOT USE ELEVATOR
T5
T3
T4
Fire exit
Emergency Contact Number:
03- 2164 6569
LEGEND
LIF BOMBA / BOMBA LIFT
PEMADAM API / FIRE EXTINGUISHER
TANGGA KECEMASAN / EMERGENCY STAIR CASE
LOCENG KEBAKARAN / ALARM BELL
INTERKOM API / FIRE INTERCOM
LALUAN KELUAR / EXIT PASSAGE
DATS MANAGEMENT SDN BHD


Emergency Evacuation Procedure
ROUTE FROM STAIRCASE 4 (T4)
Fire
Assembly point
Europcar

Emergency Evacuation Procedure

EMERGENCY EVACUATION LAYOUT



Procedure For Emergencies

Be Prepared

- Know where your nearest emergency exit is and the escape route
- Know where your assembly point is.
- Know where the fire alarm and fire extinguishers are.
- Know your fire warden and safety representative
- Know your first aid officer and where to find the first aid kit

Do’s & DO NOT

DO' S	DON'TS
Stop Your Work	Do Not Stop To Collect Your Personal Belonging
Follow The Instructions	Do Not Panic
Proceed To Nearest Emergency Exit	Do Not Use Lift
Lead /Assist Visitor Or Vendor	Do Not Run while Descending the Stairs
Assemble at Assembly Area	Do Not Selfie/Update Status
Conduct Head Count by Level	Do Not Smoke at the Escape Route
Assist the Injured Person/pregnant	Do Not Return Until Instructed

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Emergency Evacuation Procedure

Thank you

&

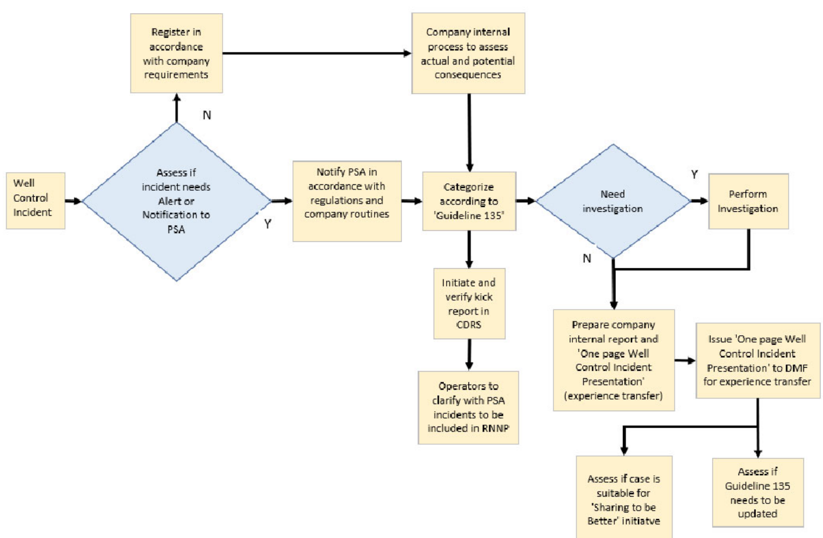
Wish you SAFE stay Together

Let’s have a deal

- Course Schedule (Start, End, Breaks)
- Mobile Phones
- Smoking Area
- Student Package

Overview

Well Control Incident



Well Control Incident Matrix

Level 1 - Red Critical well control incidents	1. **Blowout**	1. Blowout to environment or facility including underground blow out. Failure or malfunction of primary and secondary barriers.
	2. **High HC influx volume/rate**	2. Failure of primary well barrier. Successful activation of the secondary well barrier. Critical kill operations with high risk of blowout.
	3. **High-rate shallow gas flow**	3. Shallow gas incident with unsuccessful kill operation. Gas flowing to seabed or installation (diverter), until all gas is released.
	4. **High-rate shallow water flow**	4. Shallow water flow influencing stability of an installation (jack-up, fixed installation or template)
Level 2 – Yellow Serious well control incidents	1. **Medium HC influx volume/rate**	1. Influx volume above design criteria for kick margin, but possible to regain barrier with standard kill procedure.
	2. **Total Fluid barrier lost**	2. Loss situation without being able to maintain the hydrostatic pressure in the well.
	3. **Medium rate shallow gas flow**	3. Shallow gas incident with kill operations or gas handled on installation by diverter.
Level 3 – Green Regular well control incidents	1. **Low HC or water influx volume/rate**	1. Influx volume below design criteria for kick margin, and successfully regained barrier with standard kill procedure without degrading well integrity.
	2. **Low-rate shallow gas flow**	2. Shallow gas incident with kill operations. No gas handled on installation (riser-less operation)
	3. **Low-rate shallow water flow**	3. Shallow water flow incident.
Level 4 - Non-Classified (NC)	1. **Non-continuous gas/water migration in well - with all barriers in place**	1. Release of a barrier element with contained volume of gas/water trapped below or behind casing.
	2. **Loss of primary or secondary barrier without influx into the well.**	2. Incidents where a barrier is compromised but no influx has occurred.

Well control incident

Norsk olje&gass

Location: <Location> **Rig type:** <Rig type> **Well type:** <Well type> **Date:** <Date>	**Critical Issues:** • Free text evaluation

	Direct Cause:		**Underlying Cause:**
	Prognosis incorrect		Risk accepted
	Shallow gas		Error in program / procedure
	Shallow water flow		Procedure not followed
	Incorrect mud weight		Lack of competence
	Swabbing		Communication error (missing, wrong, incomplete, etc.)
	Ballooning		Incorrect use of equipment
	HC accumulation below barrier element		Equipment failure
	Surface pressure control system failure		BOP failure
	Downhole mechanical barrier failure		Other: …………………………………………
	Downhole cement / casing barrier failure		
	Other: …………………………………………		

Page 2 of 2

Well Control Training & Assessment

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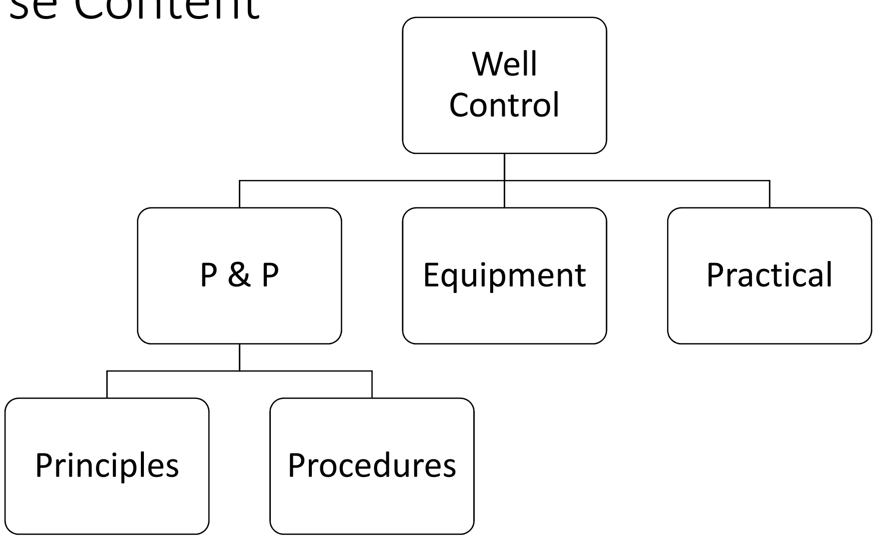
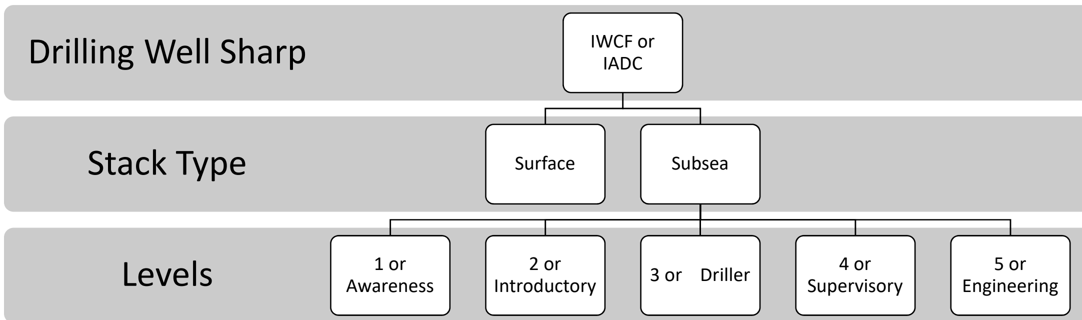
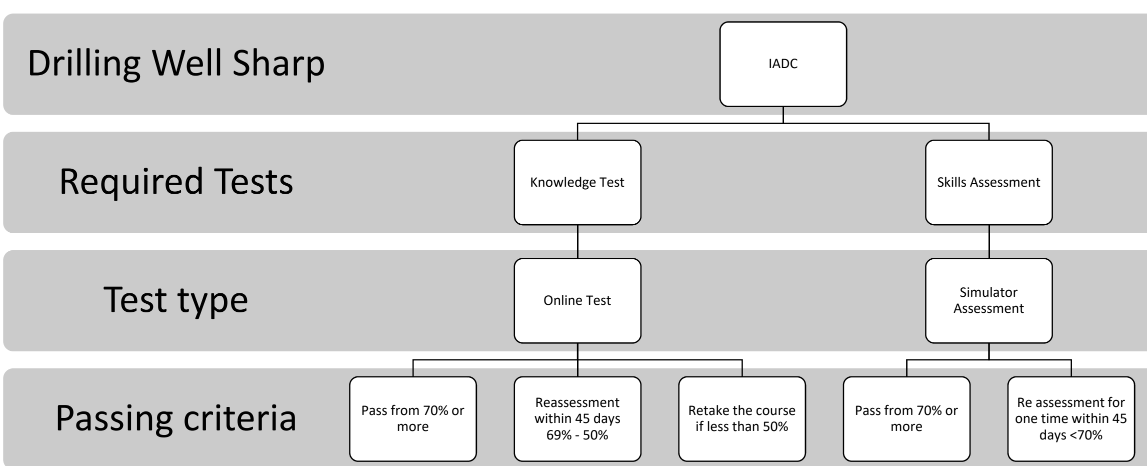
Course Content



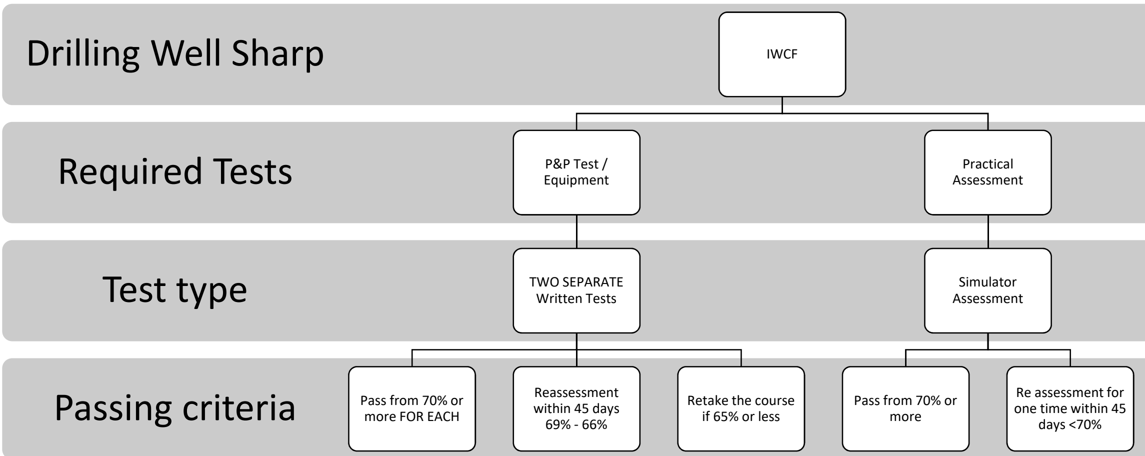
Certification Bodies



Certification Bodies



Certification Bodies



Introduction to Well Control

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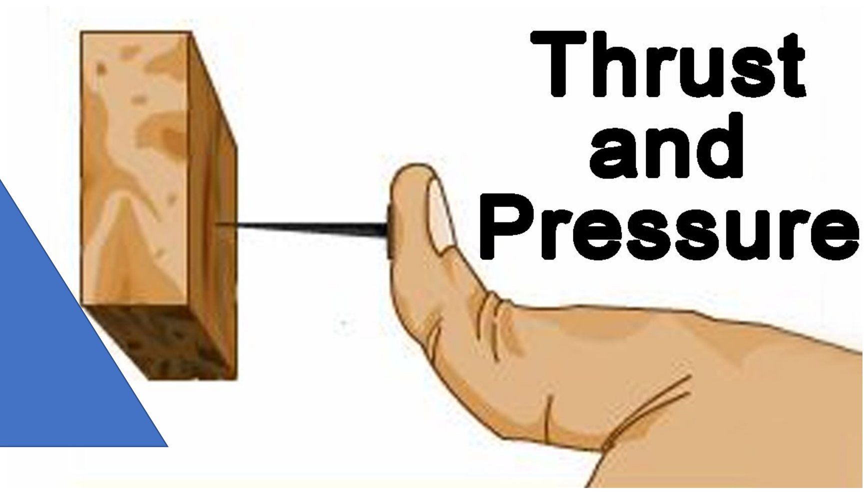
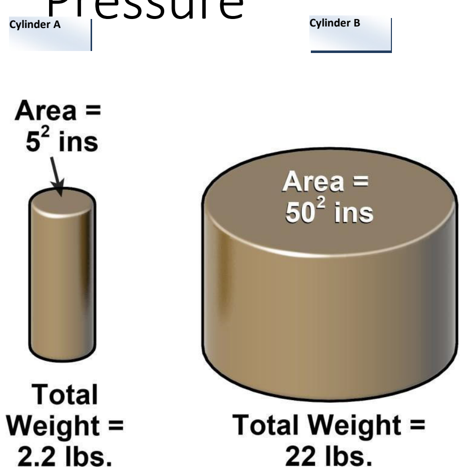
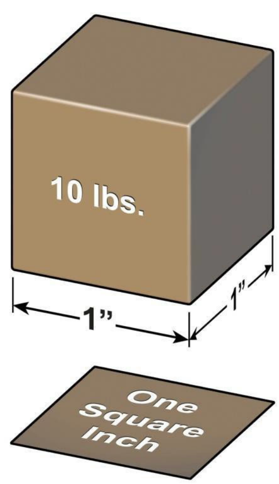
Pressure



Pressure





Here, we see a weight of 10 pounds acting on an area of 1 square inch. The pressure is therefore = 10 pounds ÷ 1 sq inch or = 10 psi

Factors affecting Hydrostatic Pressure

Drilling - English API Formula Sheet

1. HYDROSTATIC PRESSURE (psi)

Mud Density (ppg) x 0.052 x TVD (ft)

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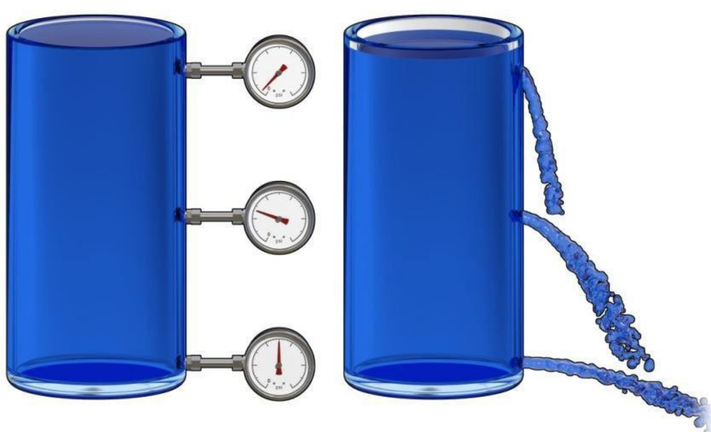
Based on Hydrostatic Pressure formula we can see that there is mainly two factors affecting the pressure value

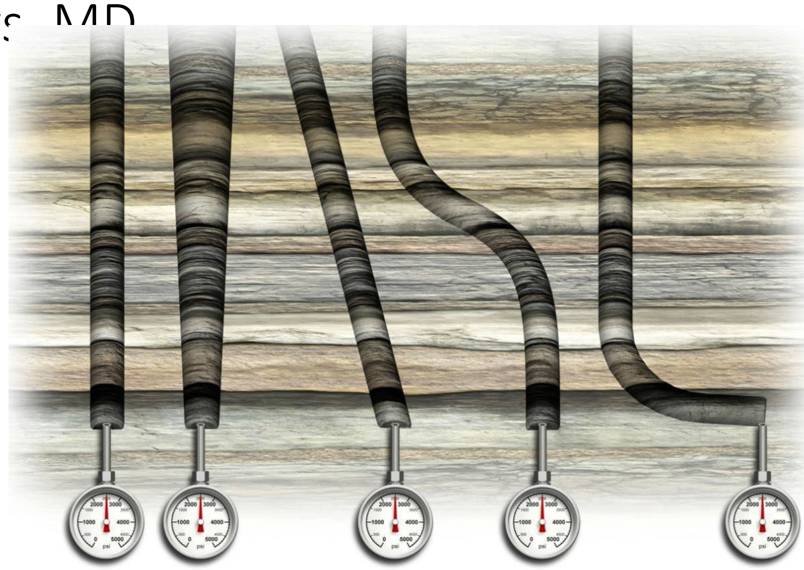
1- Mud Weight

2- Well TVD

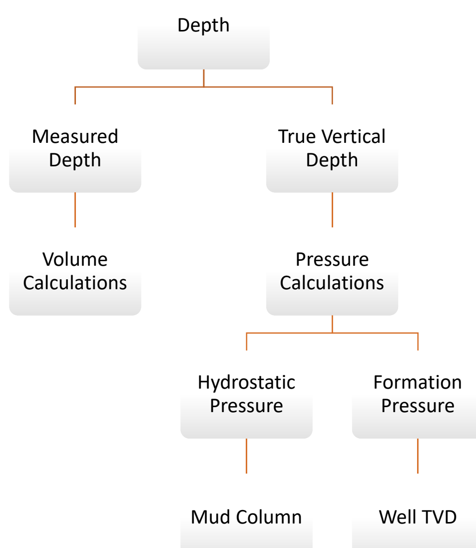
Hydrostatic Pressure



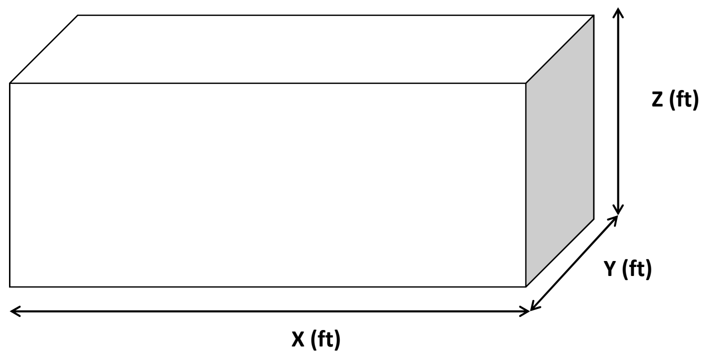
TVD vs. MD



TVD vs. MD

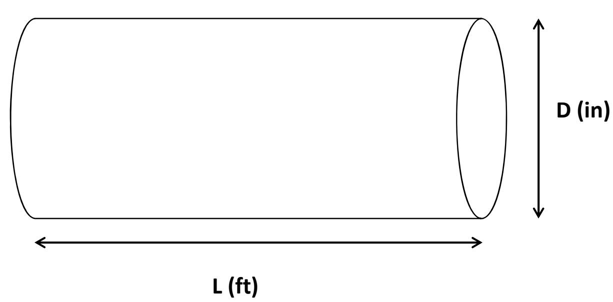


Calculations – Tank Vol.



Volume(bbl) = $X\ (ft) \times Y(ft) \times Z\ (ft) \div 5.165$

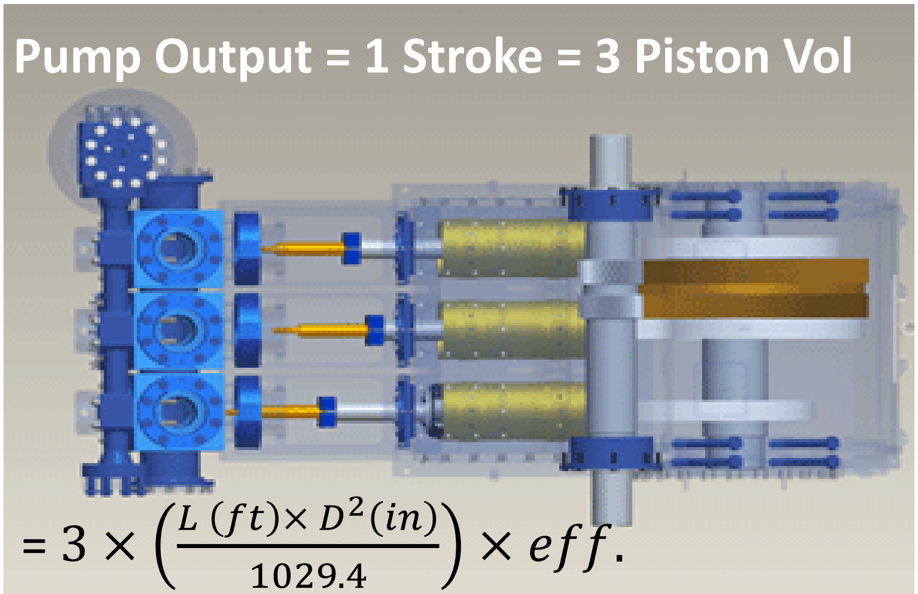
Calculations – Cylinder Vol.



Piston Volume(bbl) = Cylinder Volume

$= \frac{L\ (ft) \times D^2\ (in)}{1029.4}$

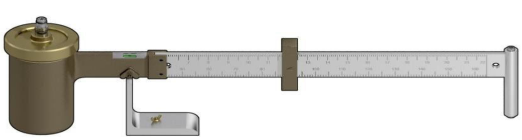
Calculations – Pump Output.



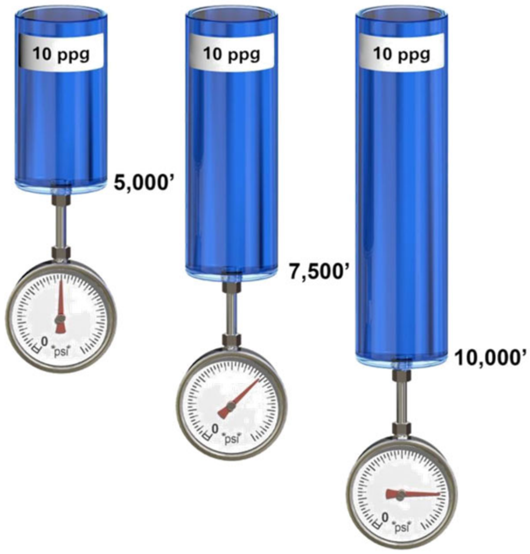
$$= 3 \times \left(\frac{L\,(ft) \times D^2(in)}{1029.4}\right) \times eff.$$

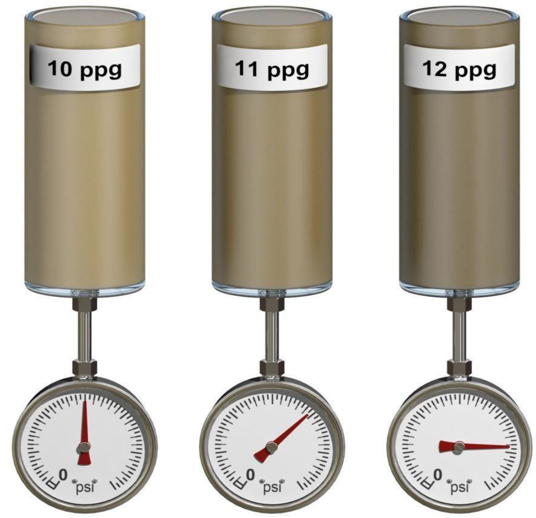
Hydrostatic Pressure

Density
Density is: Weight per Unit of Volume, **or**
(pounds per gallon)
Grams per Cubic Centimeter, **or**
Pounds per Cubic Foot

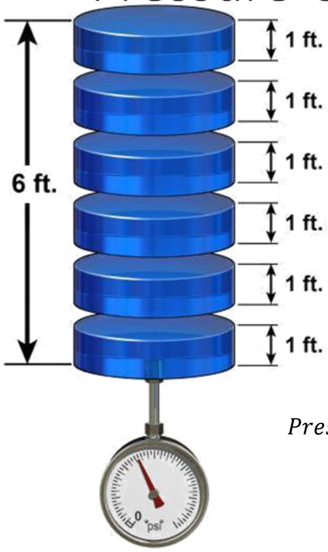


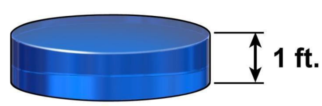
Hydrostatic Pressure





Pressure Gradient – psi/ft





$$Pressure\ Gradient = \frac{P}{TVD} = Mud\ Weight \times 0.052$$

$$Pressure = Mud\ weight\ \times 0.052\ \times TVD = Pressure\ Gradient\ \times TVD$$

Hydrostatic Pressure calculations

Drilling - English API Formula Sheet

2. PRESSURE GRADIENT (psi/ft)

Mud Density (ppg) x 0.052

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Calculate the pressure gradient for Mud weight = 10 ppg
Pressure Gradient = 10 x 0.052
Pressure Gradient = 0.52 psi/ft

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Hydrostatic Pressure calculations

Drilling - English API Formula Sheet

3. DRILLING MUD DENSITY (ppg)

Pressure (psi) ÷ TVD (ft) ÷ 0.052

or

$$\frac{\text{Pressure (psi)}}{\text{TVD (ft)} \times 0.052}$$

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If BHP = 6000 for a 10,000 ft TVD well full with Mud. What will be the mud weight at the bottom
Mud Weight =
Mud Weight = ……… ppg

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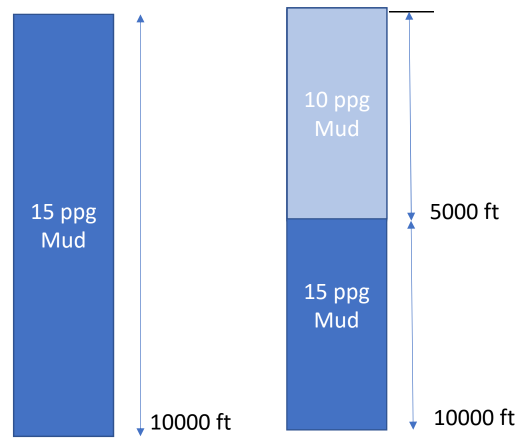
Hydrostatic Pressure calculations - Exercise

10000 ft well been drilled with 15 ppg mud, and then decided to displace the well with 10 ppg mud at 5000 ft Calculate the reduction in BHP due to displacement

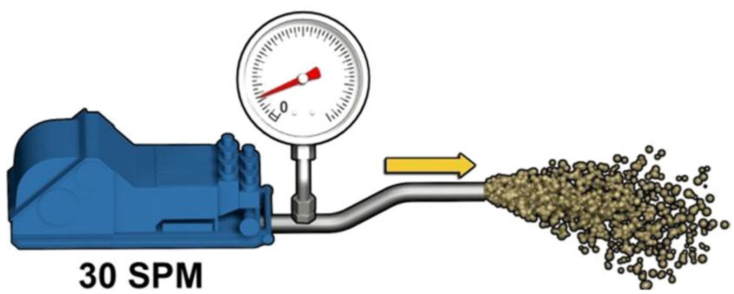
1. **HYDROSTATIC PRESSURE (psi)**

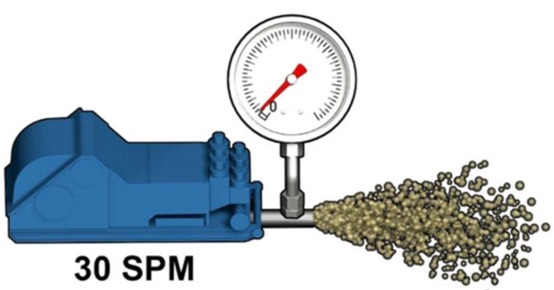
   Mud Density (ppg) x 0.052 x TVD (ft)

BHP 1 = 15 x 10000 x 0.052 = 7800 psi
BHP 2 = (15 x 5000 x 0.052) + (10 x 5000 x x 0.052) = 6500 psi
Reduction BHP = 7800 – 6500 = 1300 psi



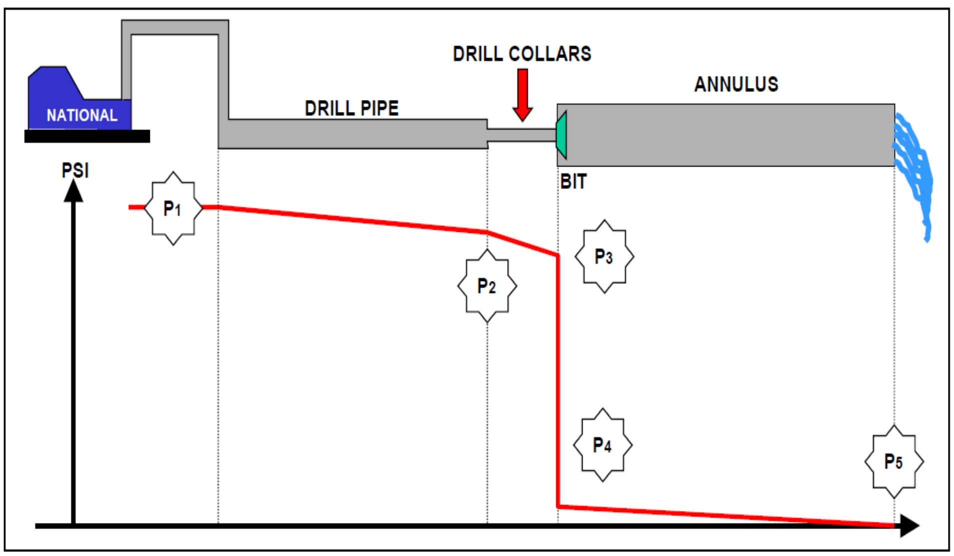
Pump Pressure



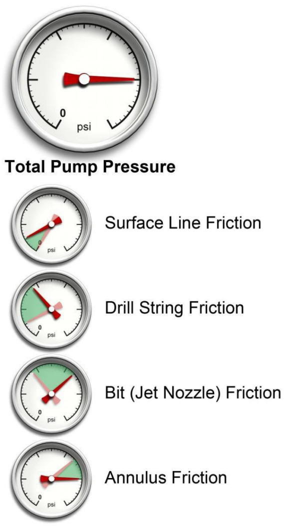


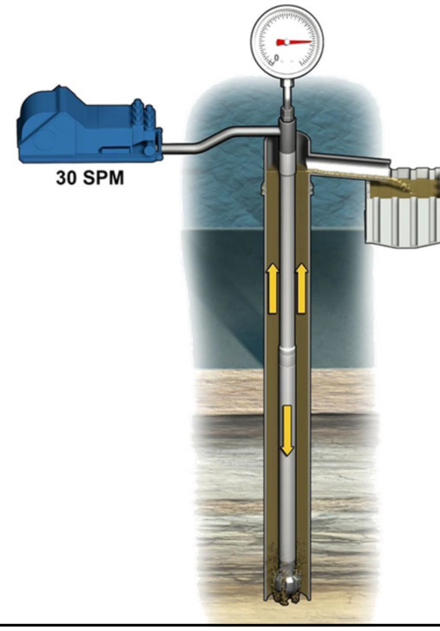
Pump Pressure

Pump Pressure

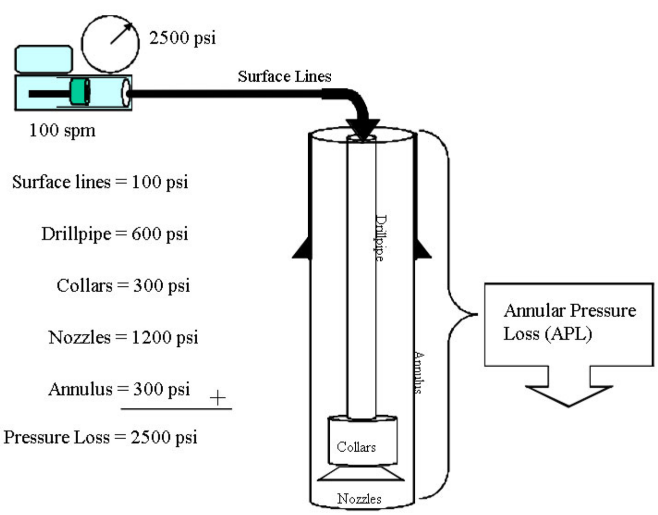


System Pressure Loss





System Pressure Losses



Surface lines = 100 psi

Drillpipe = 600 psi

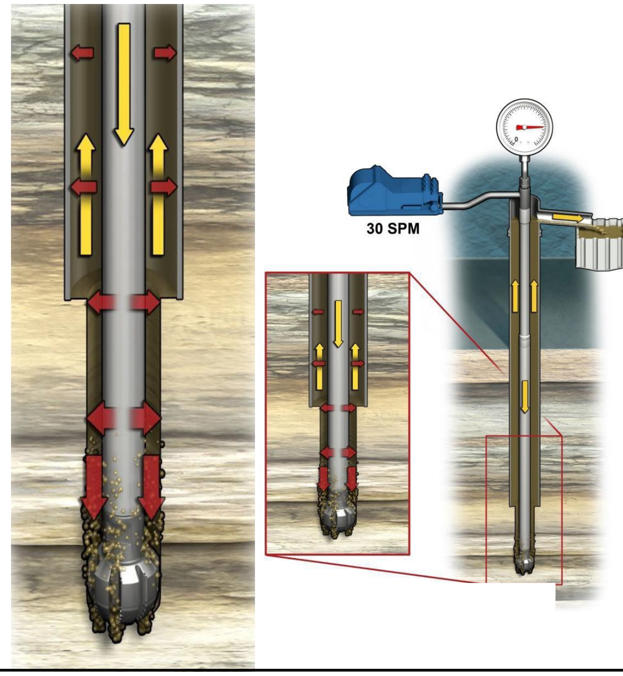
Collars = 300 psi

Nozzles = 1200 psi

Annulus = 300 psi +

Total Pressure Loss = 2500 psi

Annular Pressure Loss



BHP & ECD Calculations

IWCF

Drilling - English API Formula Sheet

7. EQUIVALENT CIRCULATING DENSITY (ppg)

[Annular Pressure Loss (psi) ÷ TVD (ft) ÷ 0.052] + Mud Density (ppg)

Or

$$\frac{\text{Annular Pressure Loss (psi)}}{\text{TVD (ft)} \times 0.052} + \text{Mud Density (ppg)}$$

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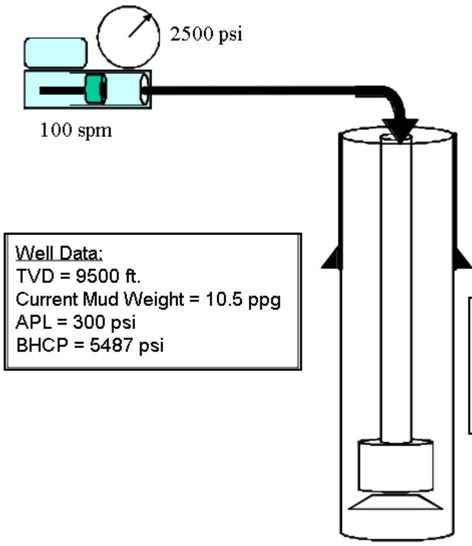
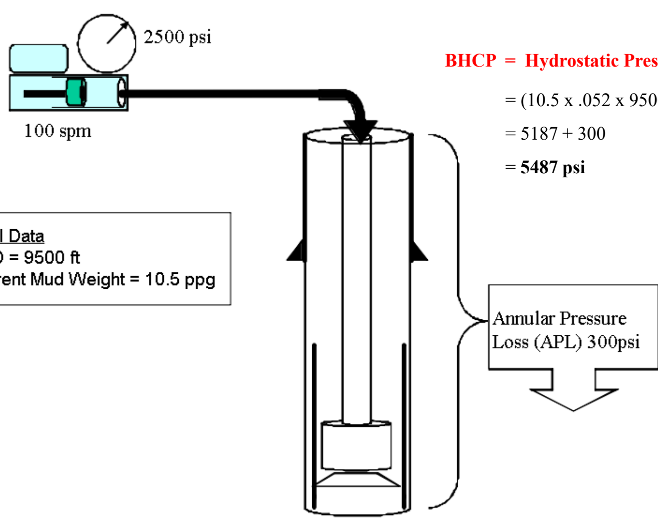
Equivalent Circulating Density



Well Data:
TVD = 9500 ft.
Current Mud Weight = 10.5 ppg
APL = 300 psi
BHCP = 5487 psi

ECD = (APL ÷ .052 ÷ TVD) + OMW
= (300 ÷ .052 ÷ 9500) + 10.5
= **11.1 ppg**

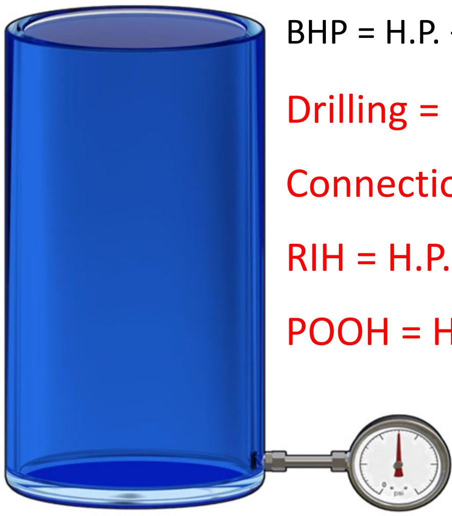
Bottom Hole Circulating Pressure



BHCP = Hydrostatic Pressure + APL
= (10.5 x .052 x 9500) + 300
= 5187 + 300
= **5487 psi**

Well Data
TVD = 9500 ft
Current Mud Weight = 10.5 ppg

Bottom Hole Pressure - BHP



BHP = H.P. + APL + Surface + Surge Pressure – Swab Pressure

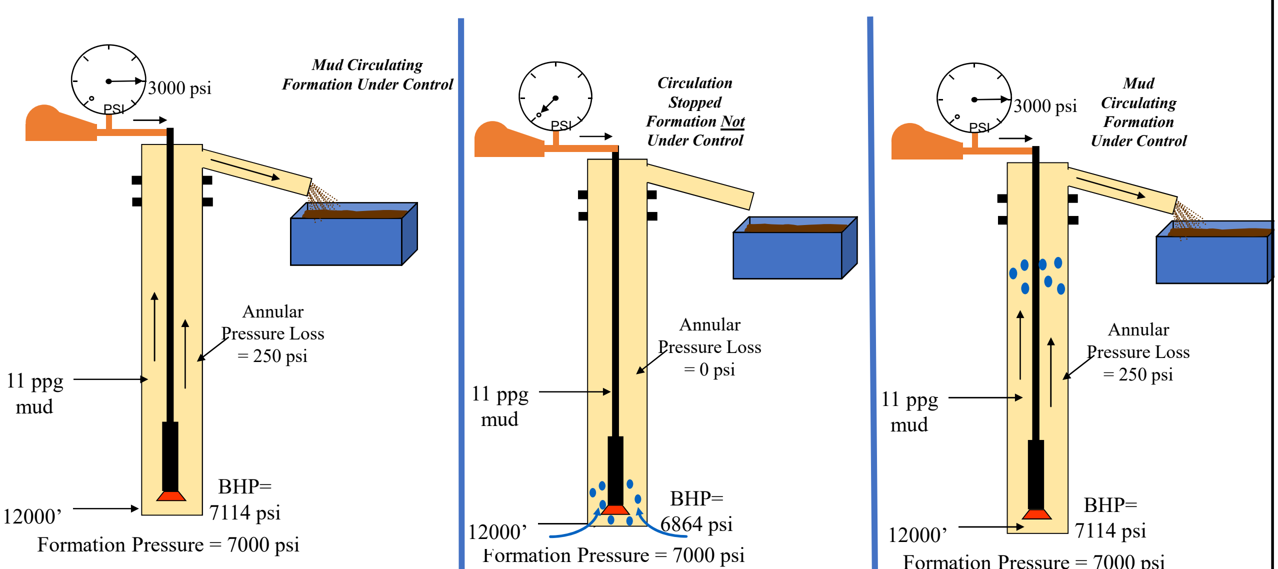
Drilling = H.P. + APL + 0 + 0 – 0

Connection = H.P. + 0 + 0 + 0 – 0

RIH = H.P. + 0 + Surge Pressure – 0

POOH = H.P. + 0 + 0 – Swab Pressure

Connection Gas



Constant BHP

Drilling - English API Formula Sheet

8. MUD DENSITY WITH TRIP MARGIN INCLUDED (ppg)

[Safety Margin (psi) ÷TVD (ft) ÷ 0.052] + Mud Density (ppg)

Or

$$\frac{\text{Safety Margin (psi)}}{\text{TVD (ft)} \times 0.052} + \text{Mud Density (ppg)}$$

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Pump Pressure Vs. Pump Speed

Drilling - English API Formula Sheet

9. NEW PUMP PRESSURE (psi) WITH NEW PUMP RATE approximate

$$\text{Old Pump Pressure (psi)} \times \left(\frac{\text{New Pump Rate (SPM)}}{\text{Old Pump Rate (SPM)}}\right)^2$$

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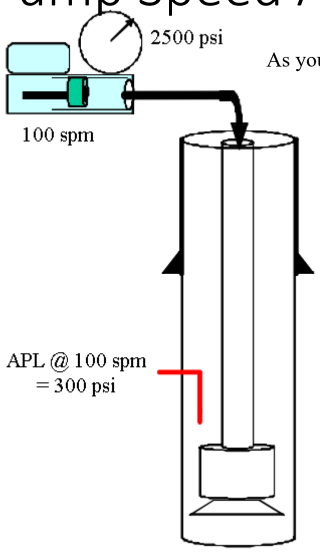
How Pump Speed Affects Pressure



As you change your pump speed, the pressure loss will also change.

The new pressure can be calculated using the formula:

$$\text{New Pressure @ New SPM} = \left[\frac{\text{New SPM}}{\text{Old SPM}}\right]^2 \times \text{Pressure at Old SPM}$$

If the pump speed was reduced to 30 SPM then:

$$\text{New Pressure @ New SPM} = \left[\frac{30}{100}\right]^2 \times 2500 = \mathbf{225\ psi}$$

$$\text{New Pressure @ New SPM} = \left[\frac{30}{100}\right]^2 \times 300 = \mathbf{27\ psi}$$

Pump Pressure Vs. Mud Weight

Drilling - English API Formula Sheet

10. NEW PUMP PRESSURE (psi) WITH NEW MUD DENSITY approximate

$$\text{Old Pump Pressure (psi)} \times \frac{\text{New Mud Density (ppg)}}{\text{Old Mud Density (ppg)}}$$

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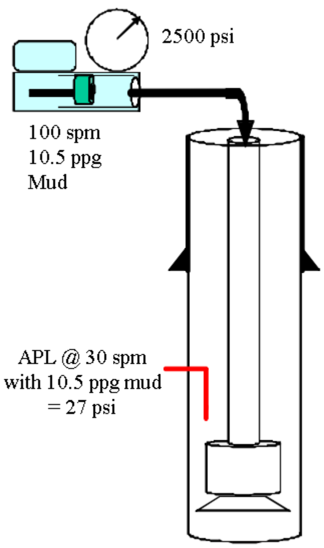
How Mud Weight Affects Dynamic Pressure



As you change your mud weight, the pressure loss will also change.

The new pressure can be calculated using the formula:

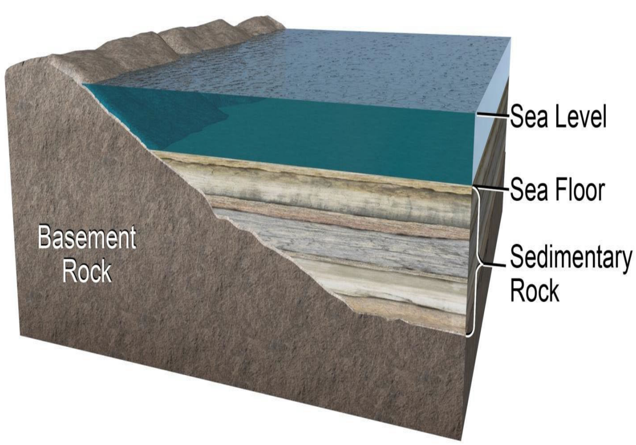
$$\text{New Pressure @ New MW} = \frac{\text{New Mud Wt}}{\text{Old Mud Wt}} \times \text{Pressure at Old Mud}$$

If the mud weight was increased to 11.5 ppg then:

$$\text{New Pressure @ New MW} = \frac{11.5}{10.5} \times 2500 = \mathbf{2738\ psi}$$

$$\text{New Pressure @ New MW} = \frac{11.5}{10.5} \times 27 = \mathbf{30\ psi}$$

Formation pore pressure



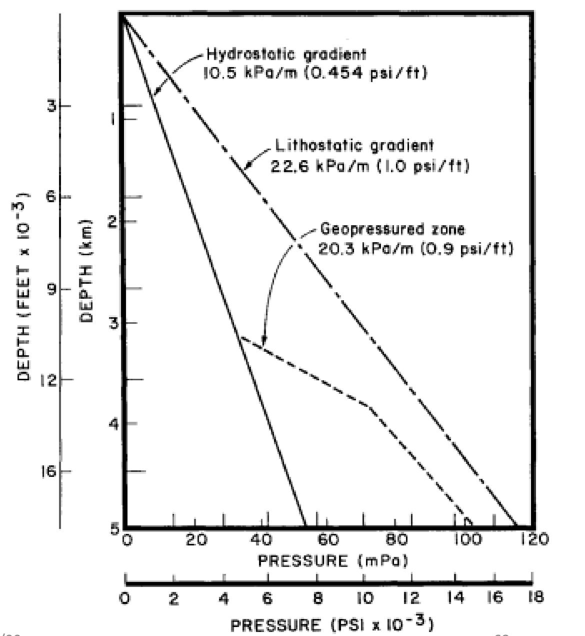


Fig. 1-1. Approximate average subsurface pressure gradient in a geopressured zone.

pore pressure distribution in low-amplitude zone shows the increase with depth

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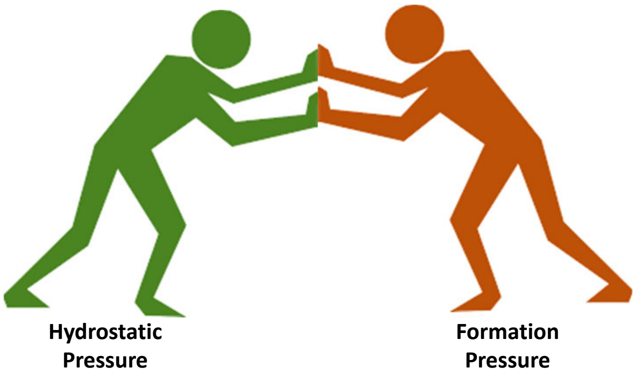
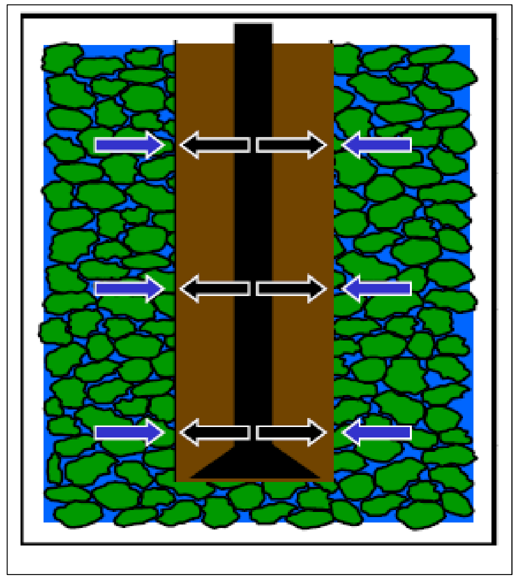
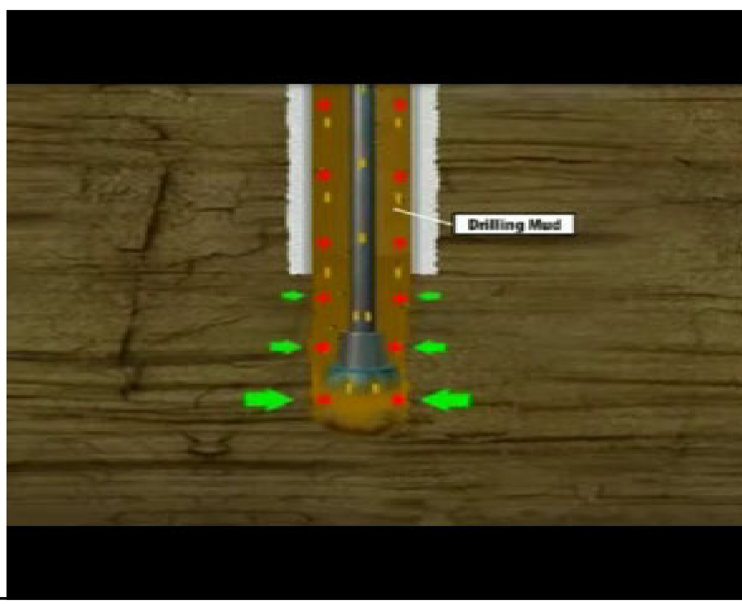
Concept of Balancing





Hydrostatic pressure Vs formation pressure



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Concept of Balancing

Bottom Hole Pressure

Is The Total Pressures Exerted At The Bottom Of The Well.

Formation Pressure

Is The Fluid Pressure In The Pore Spaces Of The Formation.

Over Balance:

Hydrostatic Pressure Greater Than Formation Pressure

Balance:

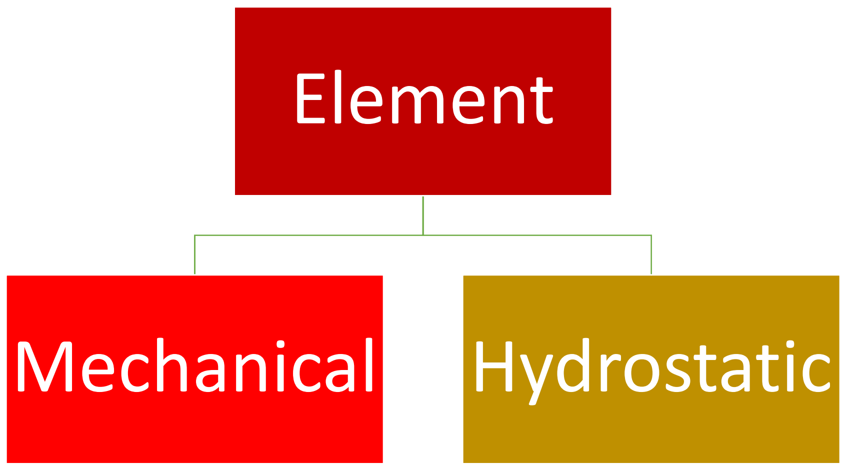
Hydrostatic Pressure = Formation Pressure

Under Balance:

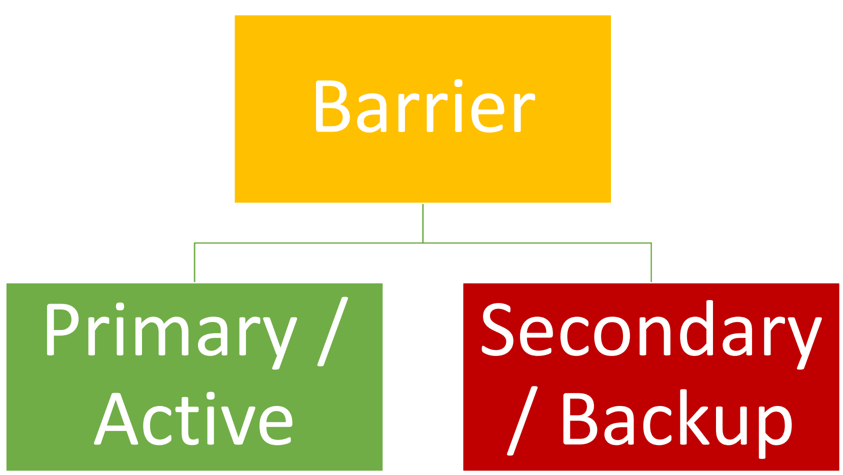
Hydrostatic Pressure Less Than Formation Pressure

Barriers

Well Barrier elements



Barrier terminology



Factors influence primary well control

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Secondary well control

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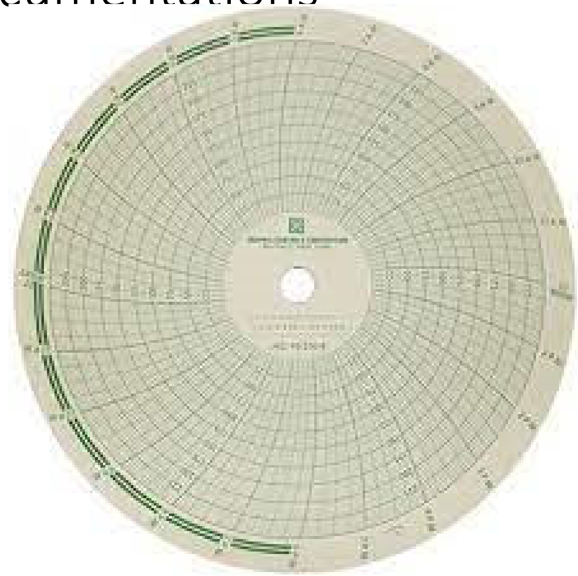
Verification of Well Barrier

Criteria to test barrier elements

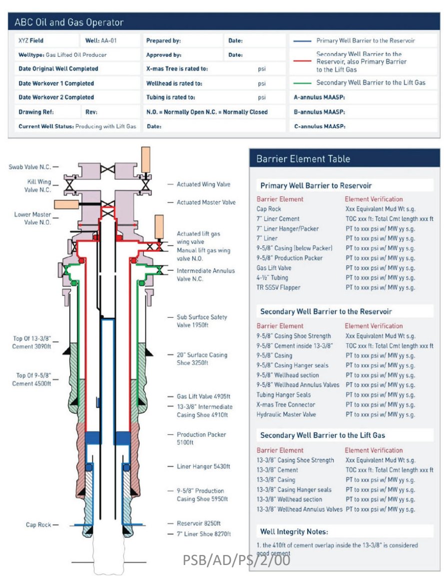
Table C.1 — Example of a barrier element acceptance table (adapted from NORSOK D010r3)

Features	Acceptance criteria	References
A. Description	This describes the WBE in words.	—
B. Function	This describes the main function of the WBE.	—
C. Operating Limits	For WBEs that are constructed in the field (i.e. drilling fluid, cement), this should describe: — design criteria, such as maximal load conditions that the WBE shall withstand and other functional requirements for the period that the WBE will be used; — construction requirements for how to actually construct the WBE or its sub-components, and will in most cases consist only of references to normative standards. For WBEs that are already manufactured, the focus should be on selection parameters for choosing the right equipment and how this is assembled in the field.	Name of specific references
D. Initial test and verification	This describes the methods for verifying that the WBE is ready for use after installation in/on the well and before it can be put into use or is accepted as part of well barrier system.	—
E. Use	This describes proper use of the WBE in order for it to maintain its function and prevent damage to it during execution of activities	—
F. Monitoring	This describes the methods for verifying that the WBE continues to be intact and fulfils it design/selection criteria during use.	—
G. Failure modes	This describes conditions that impair (weaken or damage) the function of the WBE, which can lead to implementing corrective action or stopping the activity/operation.	—

Testing Documentations



Documentation for barrier testing



ABC Oil and Gas Operator

XYZ **Field**	**Well:** AA-01	**Prepared by:**	**Date:**	Primary Well Barrier to the Reservoir
Welltype: Gas Lifted Oil Producer		**Approved by:**	**Date:**	Secondary Well Barrier to the Reservoir, also Primary Barrier to the Lift Gas
Date Original Well Completed		**X-mas Tree is rated to:**	psi	Secondary Well Barrier to the Lift Gas
Date Workover 1 Completed		**Wellhead is rated to:**	psi	**A-annulus MAASP:**
Date Workover 2 Completed		**Tubing is rated to:**	psi	**B-annulus MAASP:**
Drawing Ref:	**Rev:**	**N.O. = Normally Open N.C. = Normally Closed**		**C-annulus MAASP:**
Current Well Status: Producing with Lift Gas		**Date:**		

Barrier Element Table

Primary Well Barrier to Reservoir

Barrier Element	Element Verification
Cap Rock	Xxx Equivalent Mud Wt s.g.
7" Liner Cement	TOC xxx ft: Total Cmt length xxx ft
7" Liner Hanger/Packer	PT to xxx psi w/ MW yy s.g.
7" Liner	PT to xxx psi w/ MW yy s.g.
9-5/8" Casing (below Packer)	PT to xxx psi w/ MW yy s.g.
9-5/8" Production Packer	PT to xxx psi w/ MW yy s.g.
Gas Lift Valve	PT to xxx psi w/ MW yy s.g.
4-½" Tubing	PT to xxx psi w/ MW yy s.g.
TR SSSV Flapper	PT to xxx psi w/ MW yy s.g.

Secondary Well Barrier to the Reservoir

Barrier Element	Element Verification
9-5/8" Casing Shoe Strength	Xxx Equivalent Mud Wt s.g.
9-5/8" Cement inside 13-3/8"	TOC xxx ft: Total Cmt length xxx ft
9-5/8" Casing	PT to xxx psi w/ MW yy s.g.
9-5/8" Casing Hanger seals	PT to xxx psi w/ MW yy s.g.
9-5/8" Wellhead section	PT to xxx psi w/ MW yy s.g.
9-5/8" Wellhead Annulus Valves	PT to xxx psi w/ MW yy s.g.
Tubing Hanger Seals	PT to xxx psi w/ MW yy s.g.
X-mas Tree Connector	PT to xxx psi w/ MW yy s.g.
Hydraulic Master Valve	PT to xxx psi w/ MW yy s.g.

Secondary Well Barrier to the Lift Gas

Barrier Element	Element Verification
13-3/8" Casing Shoe Strength	Xxx Equivalent Mud Wt s.g.
13-3/8" Cement	TOC xxx ft: Total Cmt length xxx ft
13-3/8" Casing	PT to xxx psi w/ MW yy s.g.
13-3/8" Casing Hanger seals	PT to xxx psi w/ MW yy s.g.
13-3/8" Wellhead section	PT to xxx psi w/ MW yy s.g.
13-3/8" Wellhead Annulus Valves	PT to xxx psi w/ MW yy s.g.

Well Integrity Notes:

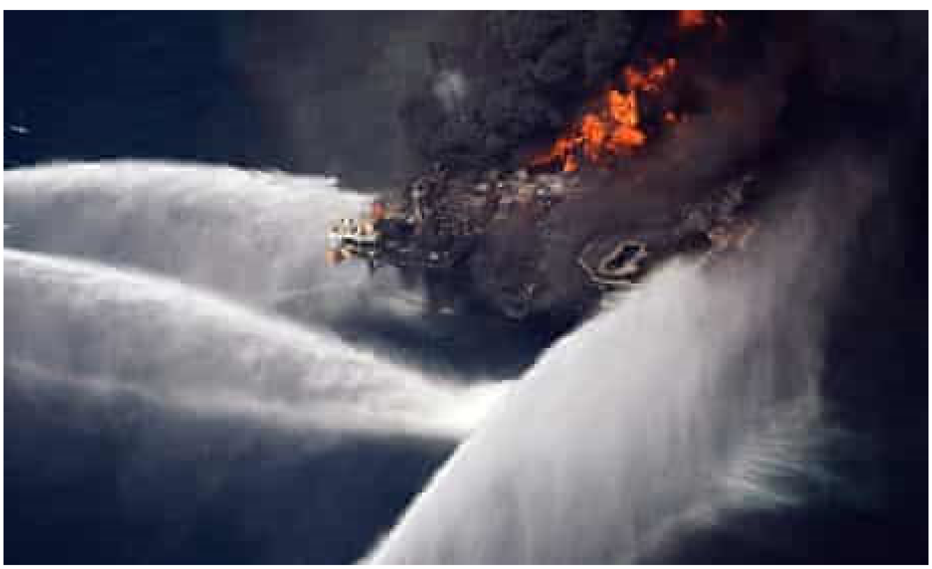
1. the 410ft of cement overlap inside the 13-3/8" is considered good cement

Actions for failure testing

Table E.1 — Example of WBEs, their functions and failure modes

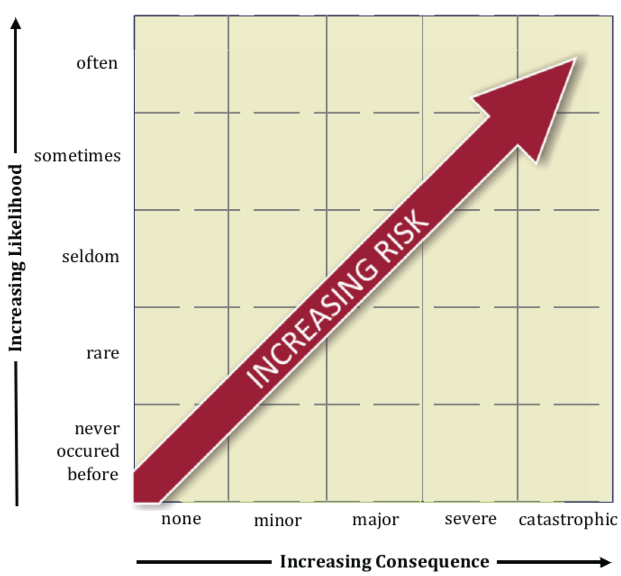
Barrier element type	Function	Failure characteristic (Examples)
Fluid column	Exerts a hydrostatic pressure in the wellbore that prevents well influx/inflow of formation fluid	Leak-off into a formation Flow of formation fluids
Formation	Provides a mechanical seal in an annulus where the formation is not isolated by cement or tubulars Provides a continuous, permanent and impermeable hydraulic seal above the reservoir Impermeable formation located above the reservoir, sealing either to cement/annulus isolation material or directly to casing/liner	Leak through the formation Not sufficient formation strength to withstand annulus pressure Not sufficient formation strength to perform hydraulic seal
Casing	Contains fluids within the wellbore such that they do not leak out into other concentric annuli or into exposed formations	Manufacturing flaw Leak at connections Leak caused by corrosion and/or erosion Wear Parted connections
Wellhead	Provides mechanical support for the suspending casing and tubing strings Provides mechanical interface for connection of a riser, BOP or production tree Prevents flow from the wellbore and annuli to other annuli or the environment	Leaking seals or valves Mechanical overload
Deep-set tubing plug	Provides a mechanical seal in the tubing to prevent flow in the tubing	Leaks across the seals, internal or external
Production packer	Provides a mechanical seal between the completion tubing and the casing/liner, establishing the A-annulus above and thus preventing communication from the formation into the A-annulus	Leak across the external packing elements Leak across the internal seals
Surface-controlled sub-surface safety valve (SCSSV)	Safety valve device installed in the production tubing string that is held open, usually by the application of hydraulic pressure in a control line. If there is loss of control-line hydraulic pressure, the device is designed to close automatically	Lack of control line communication and functional control Leaking above acceptance criteria Failure to close on demand Failure to close within the acceptable closing time

Integrity of well barrier

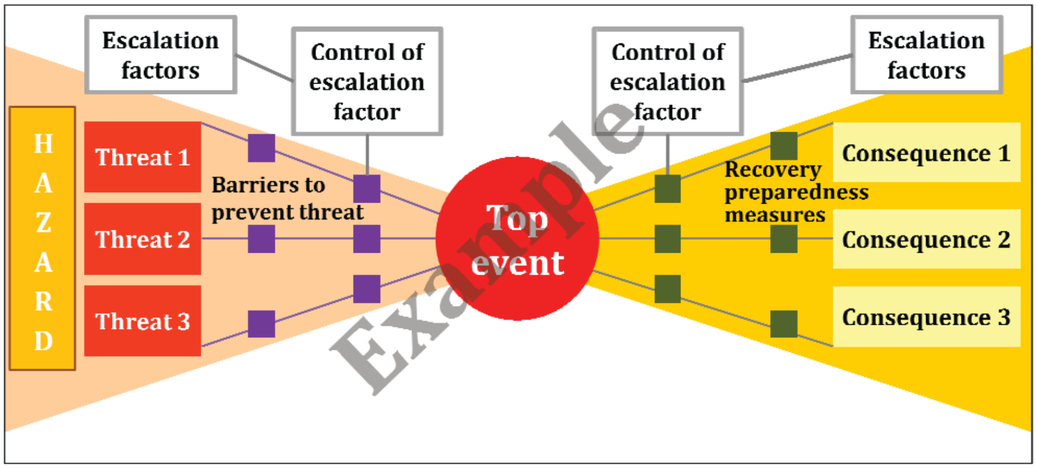


Risk Management

Risk Management



Management Of Change



Checklist

Example of hazard identification checklist

— External corrosion	— Aquifer cross-flow
— Reservoir H_2S	— Reservoir-to-reservoir isolation
— Reservoir CO_2	— Reservoir pressure regime
— Atmospheric corrosion – dew in cellar	— Erosion by sand/aggressive fluids
— Formation compaction – mechanical stress	— Water production – corrosion
— Reservoir temperature effects on casing	— Annulus corrosion through fluids in annuli
— Formation losses affecting cement jobs	— Tubing/completion corrosion
— Wax and scale deposition	— Hydrate formation
— Thermal expansion in annuli exceeding MAASP	— Overburden, strength cratering and subsidence
— Reservoir uncertainties	— Well location near habitation
— Shallow gas potential	— Electrical submersible pump eddy currents
— Cementation failure	— Collision possibility
— Formation fluid corrosiveness	— NORM likelihood
— Casing wear	— Poor formation top isolation

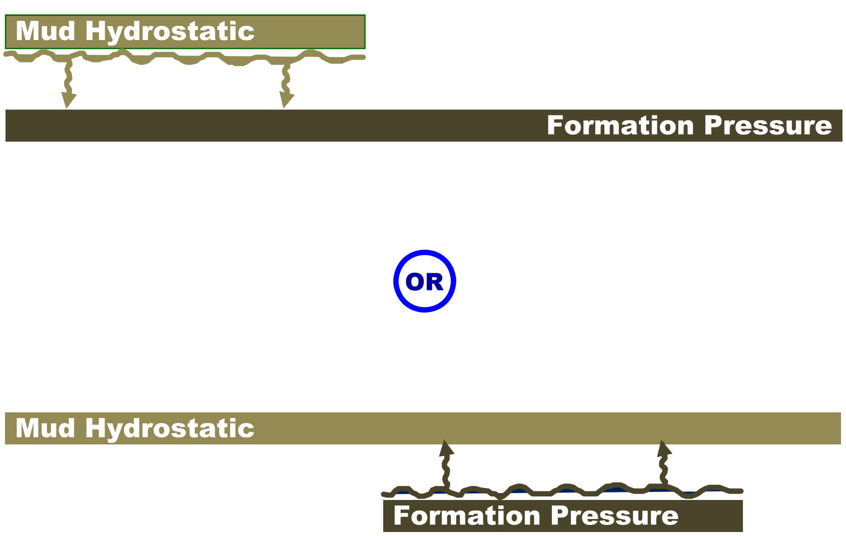
Well Control Drills

Non-Shearable & Non-Sealable

Cameron DSI dual-string interlocking shear rams eliminate all vertical separation between the upper and lower blades. The interlocking feature provides the capability of shearing wireline and braided cable with zero tension in the line. DSI rams do not use a fold-over shoulder and thus have the capacity to shear larger-diameter pipe and casing.

Causes of Kick

Causes of Kick

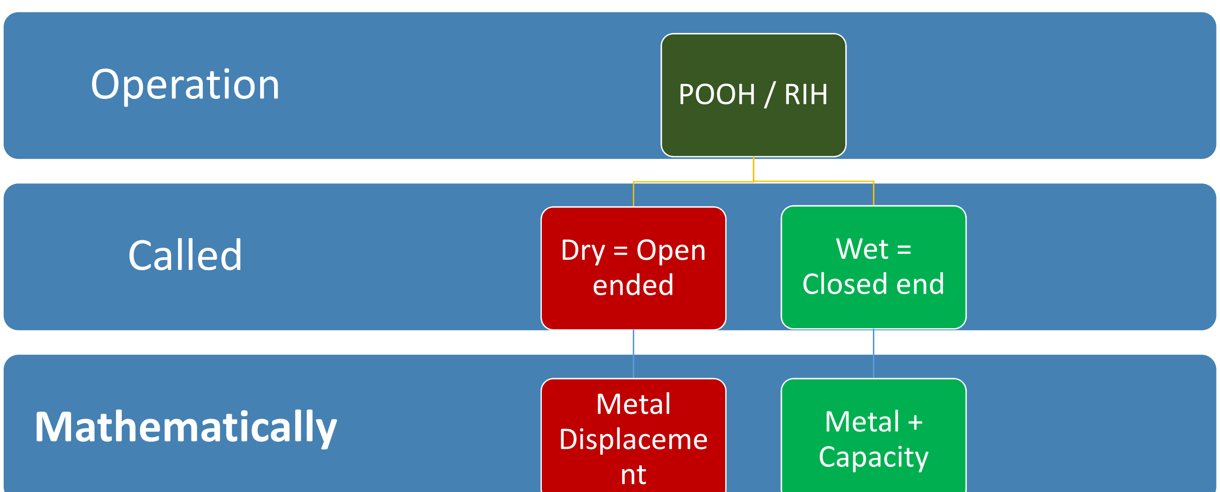


Hydrostatic Reduction

Hydrostatic Pressure =

Mud Wt X Constant X TVD

Failure to keep hole full – Barrels Lost



Failure to keep hole full – Tripping Pipe

Drilling - English API Formula Sheet

19. PRESSURE DROP PER FOOT TRIPPING DRY PIPE (psi/ft)

$$\frac{\text{Drilling Mud Density (ppg)} \times 0.052 \times \text{Metal Displacement (bbl/ft)}}{\text{Riser or Casing Capacity (bbl/ft)} - \text{Metal Displacement (bbl/ft)}}$$

20. PRESSURE DROP PER FOOT TRIPPING WET PIPE (psi/ft)

$$\frac{\text{Drilling Mud Density (ppg)} \times 0.052 \times \text{Closed End Displacement (bbl/ft)}}{\text{Riser or Casing Capacity (bbl/ft)} - \text{Closed End Displacement (bbl/ft)}}$$

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Failure to keep hole full – Tubular pulled dry

Drilling - English API Formula Sheet

21. LEVEL DROP PULLING REMAINING COLLARS OUT OF HOLE DRY (ft)

$$\frac{\text{Length of Collars (ft)} \times \text{Metal Displacement (bbl/ft)}}{\text{Riser or Casing Capacity (bbl/ft)}}$$

22. LEVEL DROP PULLING REMAINING COLLARS OUT OF HOLE WET (ft)

$$\frac{\text{Length of Collars (ft)} \times \text{Closed End Displacement (bbl/ft)}}{\text{Riser or Casing Capacity (bbl/ft)}}$$

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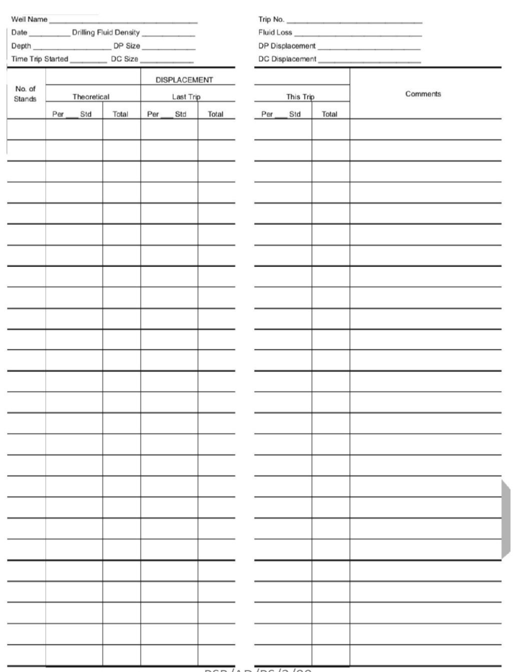
Tripping Process

- Before tripping:
- Prepare the hole
- Optimize fluid properties
- Flow check - Pump a slug (POOH)
- Pull out of hole/run in hole.
- Monitor displacement using trip sheet and trip tank (POOH and RIH).

Trip Sheet



Well Name ____________
Date ________ Drilling Fluid Density ________
Depth ____________ DP Size ________
Time Trip Started ________ DC Size ________

Trip No. ____________
Fluid Loss ____________
DP Displacement ____________
DC Displacement ____________

No. of Stands	DISPLACEMENT						Comments
	Theoretical		Last Trip		This Trip		
	Per ___ Std	Total	Per ___ Std	Total	Per ___ Std	Total	

Action in case of deviation

Stand Group	Trip Tank Vol at start	Actual hole fill	Calculated hole fill	Variation	Cumulative variation
1	51	3.8	3.7	+0.1	+ 0.1
2	47.2	3.9	3.7	+0.2	+ 0.3
3	43.3	3.8	3.7	+0.1	+ 0.4
4	39.5	3	3.7	-0.7	- 0.3
5	36.5	3	3.7	-0.7	- 1.0
6	33.5		3.7		

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Action in case of influx

Stand Group	Trip Tank Vol at start	Actual hole fill	Calculated hole fill	Variation	Cumulative variation
1	51	3.8	3.7	+0.1	+ 0.1
2	47.2	3.9	3.7	+0.2	+ 0.3
3	43.3	3.8	3.7	+0.1	+ 0.4
4	39.5	3	3.7	-0.7	- 0.3
5	36.5	3	3.7	-0.7	- 1.0
6	33.5		3.7		

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Common trip processing

Drilling - English API Formula Sheet

8. MUD DENSITY WITH TRIP MARGIN INCLUDED (ppg)

[Safety Margin (psi) ÷ TVD (ft) ÷ 0.052] + Mud Density (ppg)

Or

$$\frac{\text{Safety Margin (psi)}}{\text{TVD (ft)} \times 0.052} + \text{Mud Density (ppg)}$$

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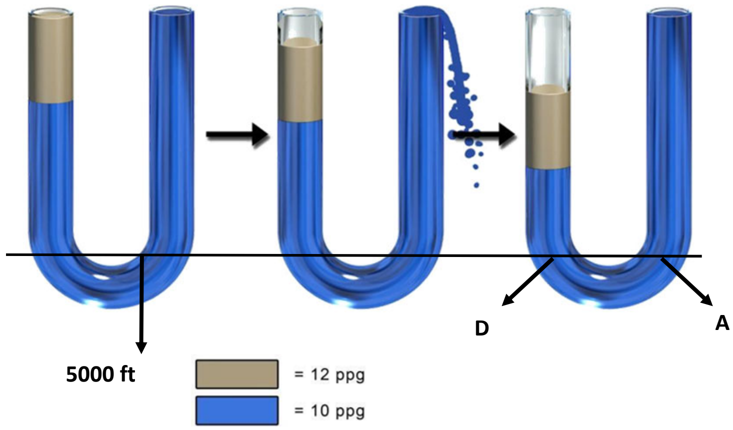
U – Tube concept

Slug concept



Tripping Process – Pumping Slug

Drilling - English API Formula Sheet

26. SLUG VOLUME (bbl) FOR A GIVEN LENGTH OF DRY PIPE

$$\frac{\text{Length of Dry Pipe (ft)} \times \text{Pipe Capacity (bbl/ft)} \times \text{Drilling Mud Density (ppg)}}{\text{Slug Density (ppg)} - \text{Drilling Mud Density (ppg)}}$$

27. PIT GAIN DUE TO SLUG U-TUBING (bbl)

$$\text{Slug Volume (bbl)} \times \left(\frac{\text{Slug Density (ppg)}}{\text{Drilling Mud Density (ppg)}} - 1\right)$$

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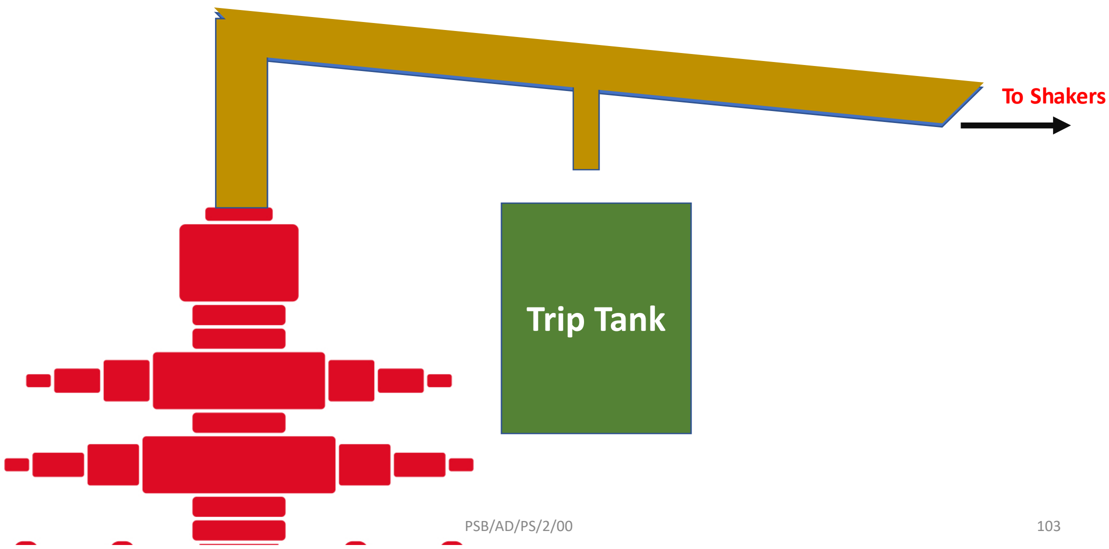
Tripping Process – Trip Monitoring



Risk associated with tripping

Tripping Risk – Losing Over Balance

IWCF Drilling - English API Formula Sheet

23. LENGTH OF TUBULARS TO PULL DRY BEFORE OVERBALANCE IS LOST (ft)

$$\frac{\text{Overbalance (psi)} \times [\text{Riser or Casing Capacity (bbl/ft)} - \text{Metal Displacement (bbl/ft)}]}{\text{Mud Gradient (psi/ft)} \times \text{Metal Displacement (bbl/ft)}}$$

24. LENGTH OF TUBULARS TO PULL WET BEFORE OVERBALANCE IS LOST (ft)

$$\frac{\text{Overbalance (psi)} \times [\text{Riser or Casing Capacity (bbl/ft)} - \text{Closed End Displacement (bbl/ft)}]}{\text{Mud Gradient (psi/ft)} \times \text{Closed End Displacement (bbl/ft)}}$$

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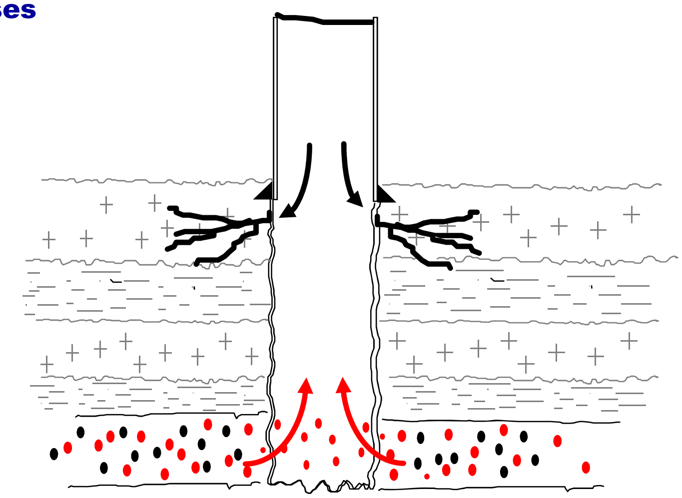
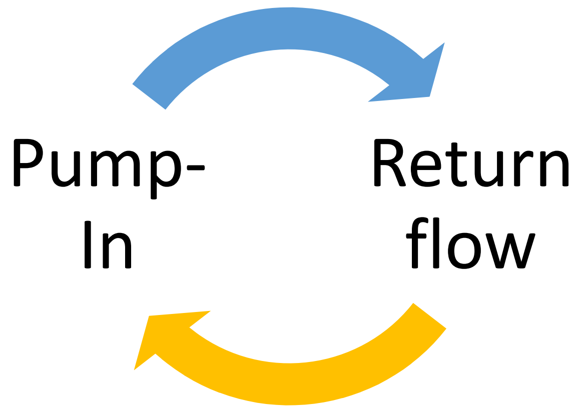
Level Drop – Losses

Losses



Losses recognition

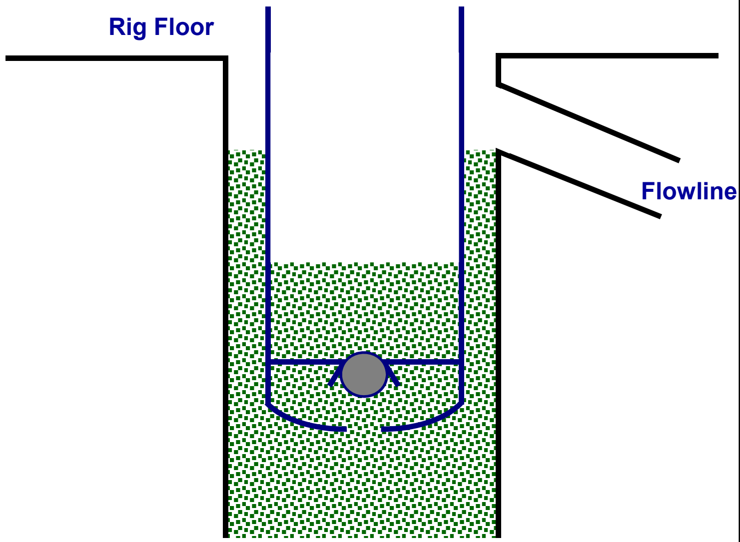


Action required in case of losses

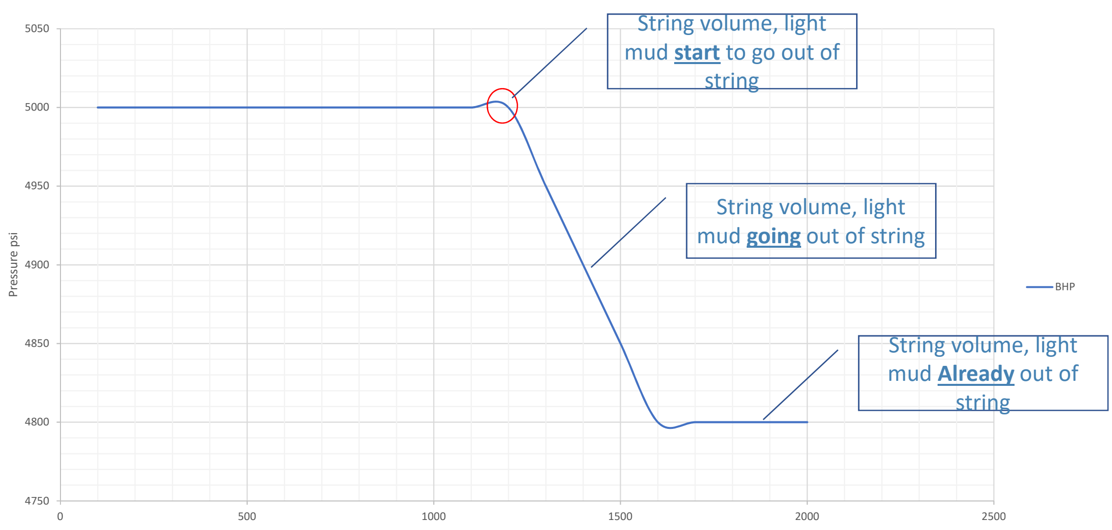
29. HYDROSTATIC PRESSURE LOSS IF CASING FLOAT FAILS (psi)

$$\frac{\text{Mud Density (ppg)} \times 0.052 \times \text{Casing Capacity (bbl/ft)} \times \text{Unfilled Casing Height (ft)}}{\text{Casing Capacity (bbl/ft)} + \text{Annular Capacity (bbl/ft)}}$$

Level Drop – Casing Failure



Change in fluid density – Adding Water



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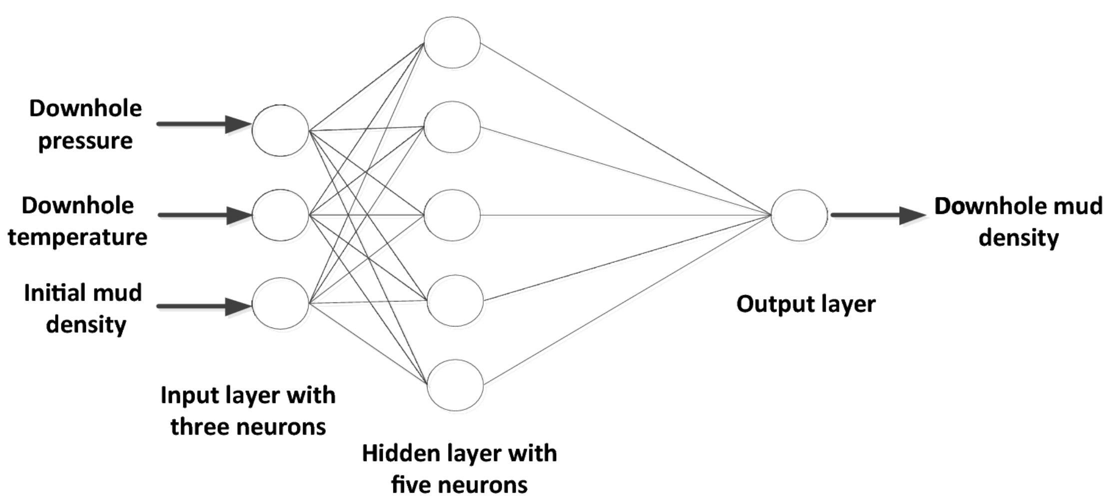
Change in fluid density – Use SCE

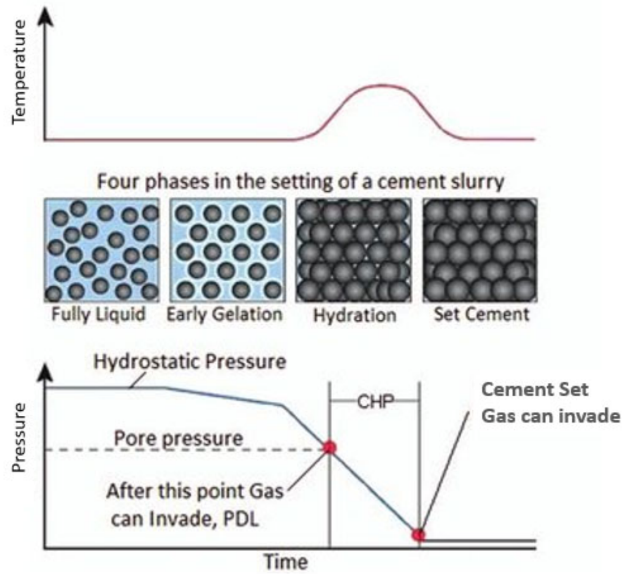
Change in fluid density – Gas cut

Settling in weighting material

Temperature effect



Cement Setting



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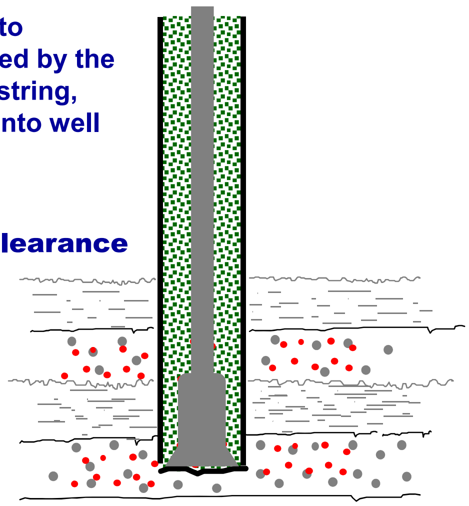
Level Drop – Swabbing

Momentary reduction in BHP due to reduction in hydrostatic force cased by the upward suction action of the drill string, which can allow a small invasion into well bore.

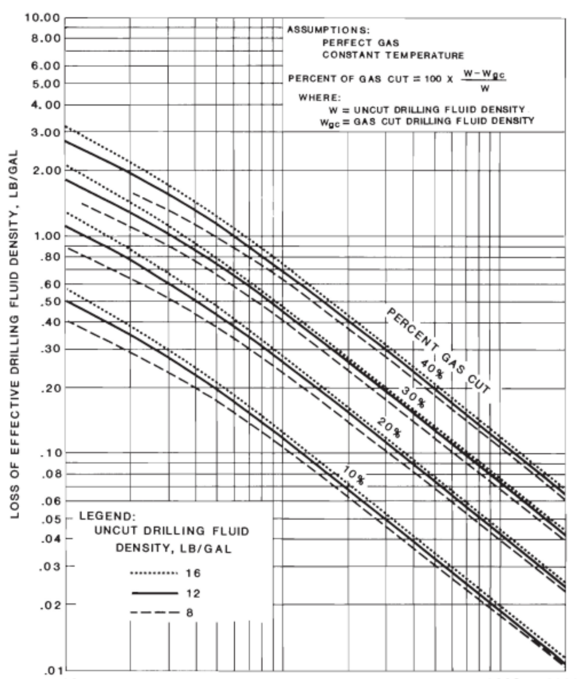
Main Causes:

1. **Small Collar to Hole Wall Clearance**
2. **Pulling Pipe Too Fast**
3. **High Viscosity Mud**
4. **Balled-Up' Bit**



Consequences of Swabbing & Surging

Gas cutting effects

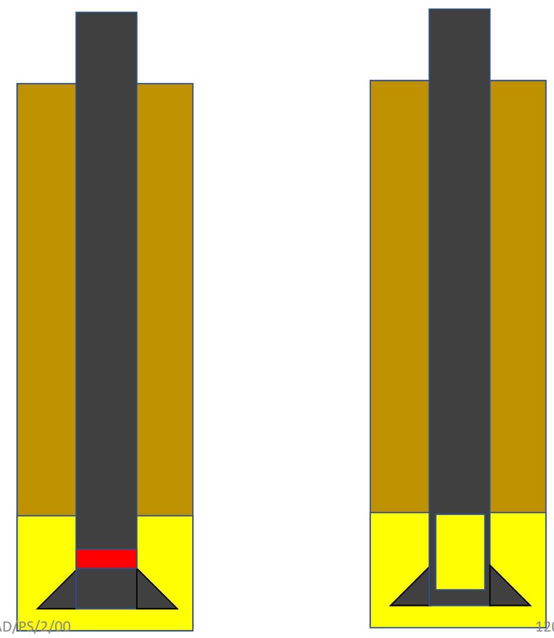


Causes of Gas cutting

- Gas-cut fluid occurs due to one or more of the following downhole conditions:

1. Drilled Gas—drilling a gas-bearing formation with the correct drilling fluid density in the hole;
2. Trip or Connection Gas—swabbing while making connections or making a trip; and
3. Gas Flow—influx of gas from a formation having a pore pressure greater than the pressure exerted by the drilling fluid.

Influx in Tubular



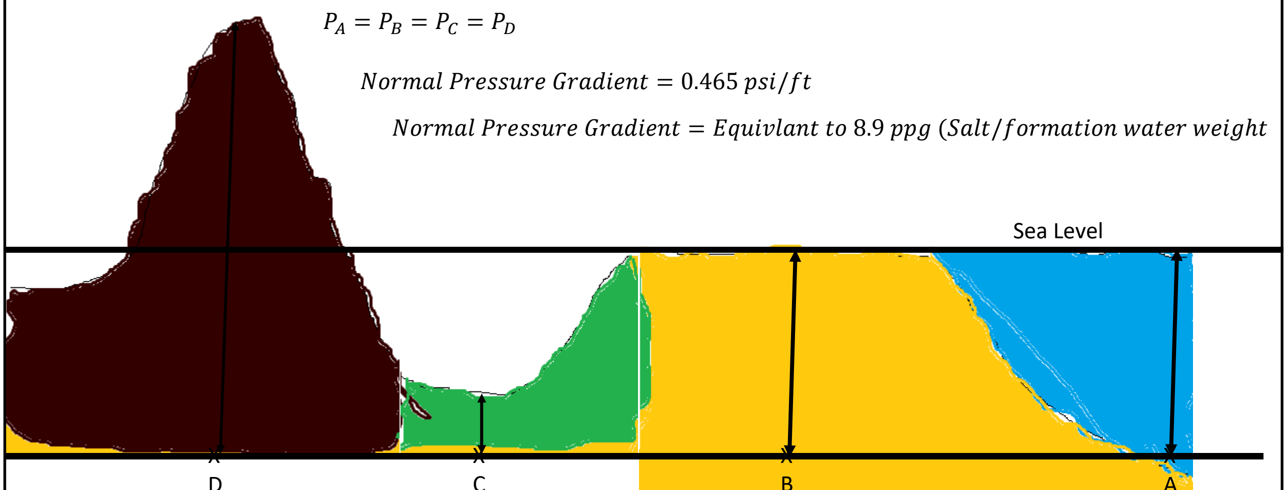
Swabbing in horizontal well

Normal & Abnormal Formation Pressure

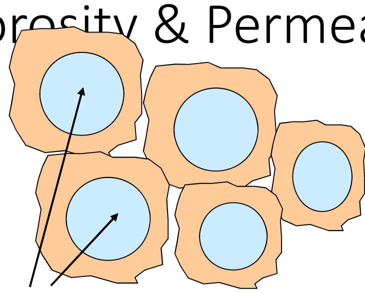
$P_A = P_B = P_C = P_D$

$Normal\ Pressure\ Gradient = 0.465\ psi/ft$

$Normal\ Pressure\ Gradient = Equivlant\ to\ 8.9\ ppg\ (Salt/formation\ water\ weight$



Porosity & Permeability

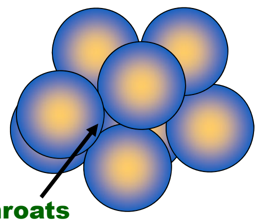


Permeability

The ability of a rock to allow fluid flow through the formation. Permeability is measured in units of darcies or millidarcies.

Porosity

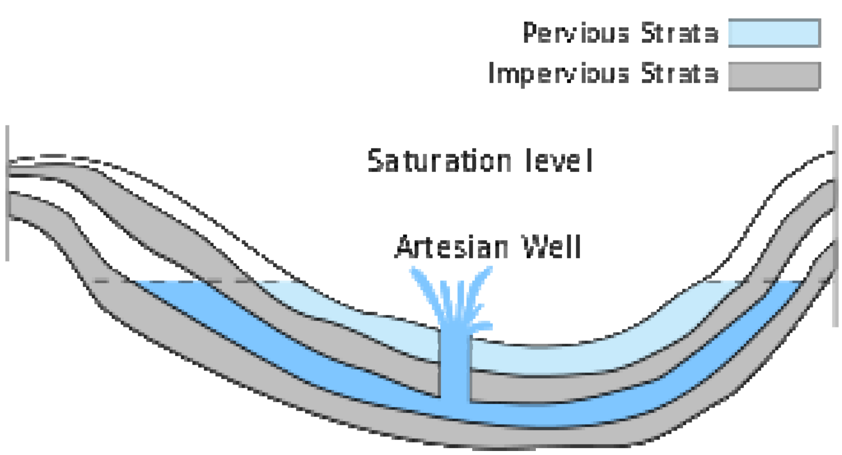
The ratio of the total pore volume of the rock to the total bulk volume of the rock, expressed as a percentage



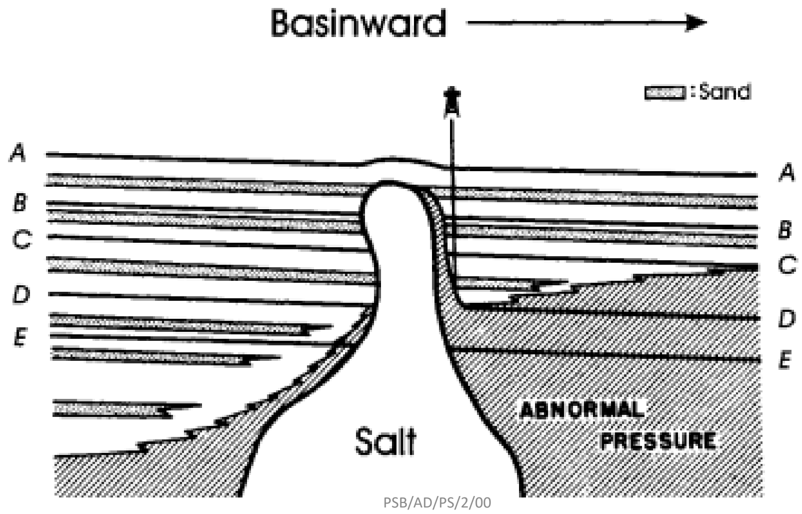
Formation pore pressure - Undercompaction

Formation pore pressure - Faulting

Formation pore pressure – Artesian Effect

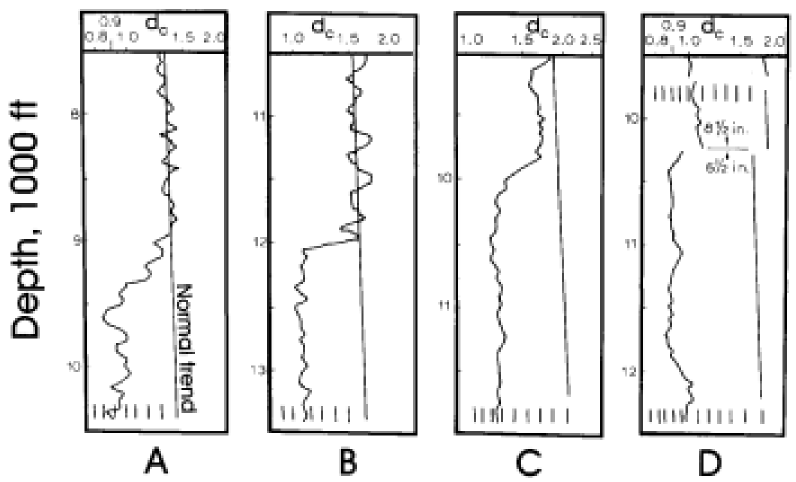


Formation pore pressure – Salt

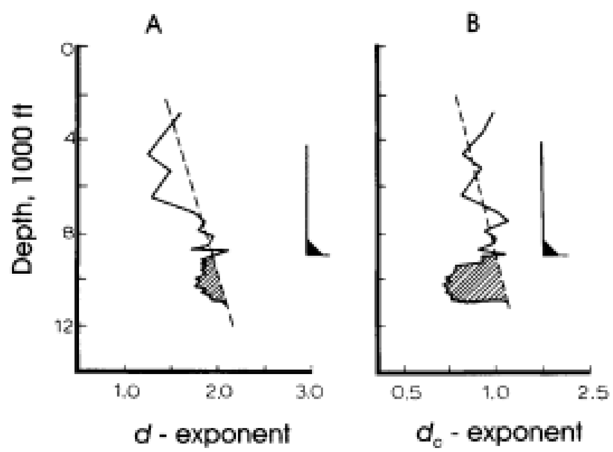


Kick Warning Signs & Indicators

Warning Sign while drilling – ROP



Warning Sign while drilling – d-Exponent



2. Comparison plots of depth versus d-exponent and d_c-exponent in the same well. Protective c

Warning Sign while drilling – Pump Pressure

Warning Sign while drilling – Cutting Size

Warning Sign while drilling – Temperature

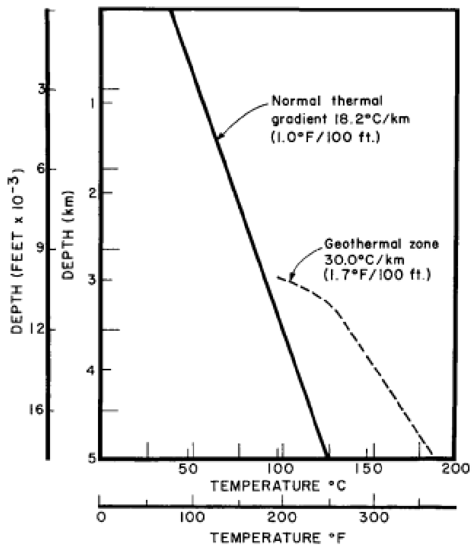


Fig. 1-5. Approximate average subsurface temperature gradients.

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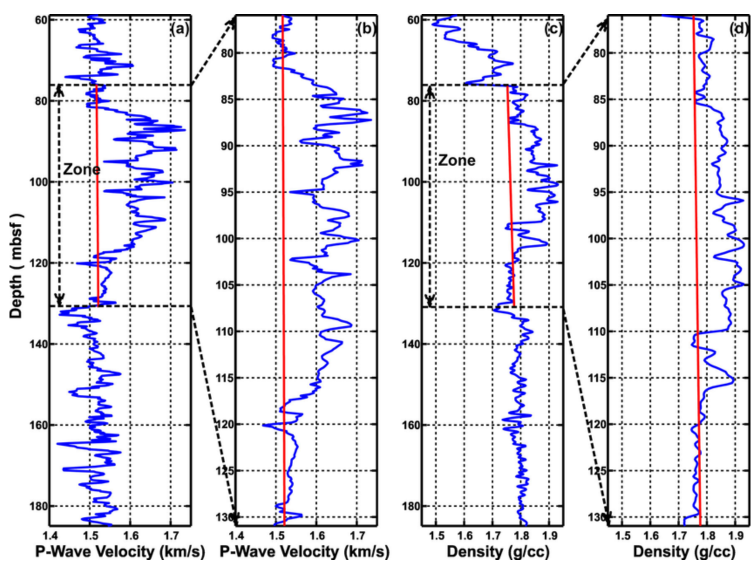
Warning Sign while drilling – Gas Trending



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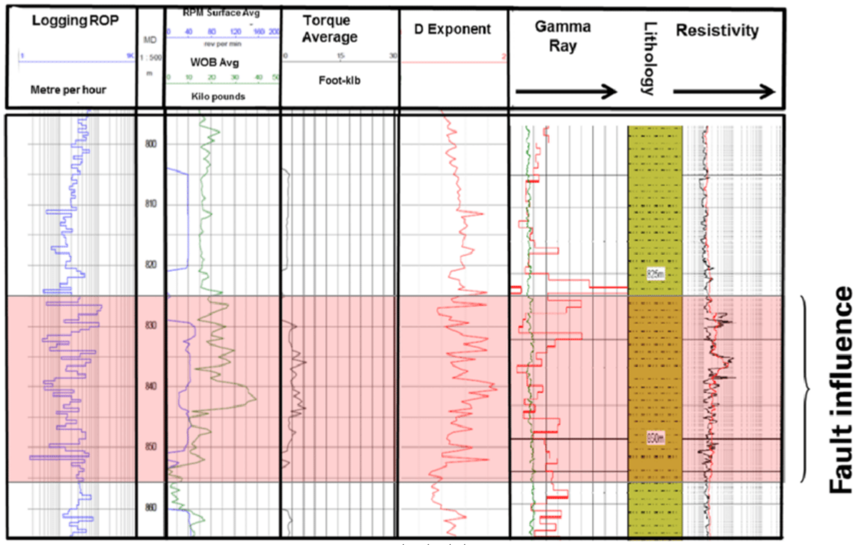
Warning Sign while drilling – Torque



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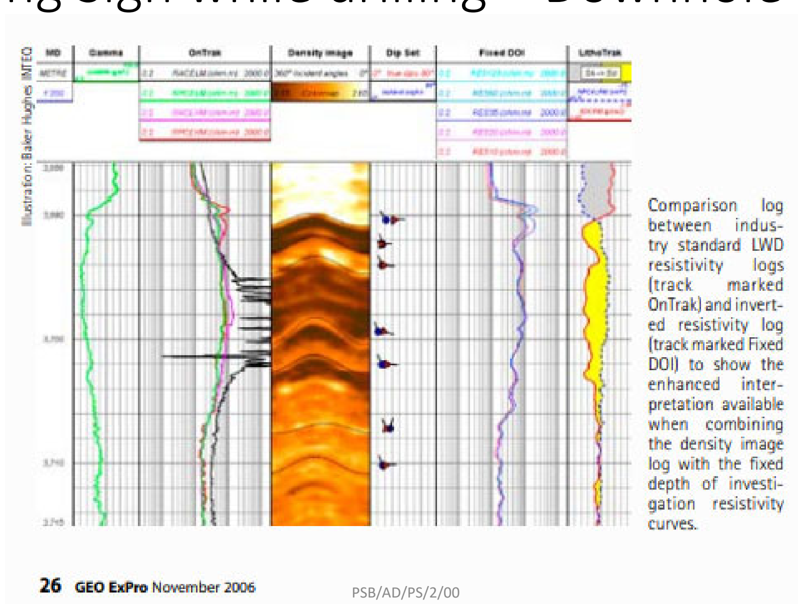
Warning Sign while drilling – Downhole tools



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Warning Sign while drilling – Change mud weight

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Warning Sign while drilling – Data from Mud

- Chloride changes in the drilling fluid.
- Oil show.
- Gas show (chromatograph).
- Formation water.
- Shale density.
- Electric logs.
- Drilling equation exponents

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Warning Sign while Tripping

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Action to take based on Warning Sign

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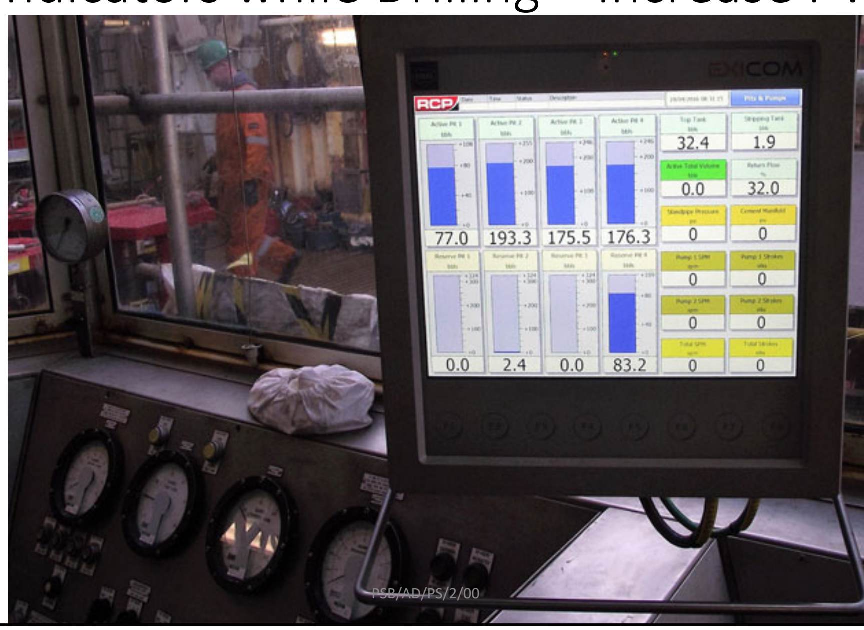
Kick Indicators while Drilling – Increase in flow

Kick Indicators while Drilling – Increase PVT



Kick Indicators while Drilling – Time Factor

Well finger printing

- Depth of zones capable of flowing.
- Formation gradients.
- Fracture gradients.
- Formation content.
- Formation permeability.
- Intervals of lost circulation.

Shallow Gas

Consequences of Shallow Gas

Prevention of Shallow Gas

- when drilling top hole with the risk of shallow gas:

- Keeping the hole full
- Controlled penetration rate
- Drilling fluid density
- Trip speed
- Pump out of hole
- Pump rate
- Hole diameter
- Kill fluid.

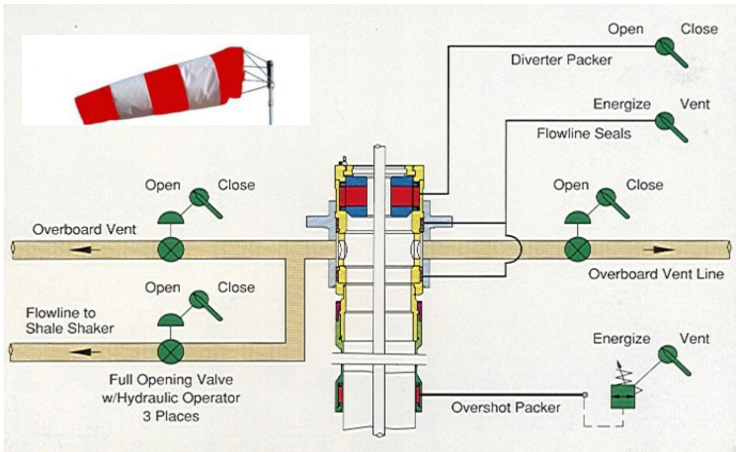
Operation requirements for Shallow Gas

action to prevent gas reaching the rotary table:

- With vent lines open, activate the diverter
- Close the upwind vent line if required
- Keep the hole full.
- Monitor for vent line erosion, and subsurface leaks.

Pumping at a fast rate tends to improve the drilling fluid/ gas ratio and creates a small increase in bottom-hole pressure due to annular friction pressure. Increasing the drilling fluid density at a fast rate increases hydrostatic pressure and can eventually stop flow. Thus, when a shallow gas flow occurs, the following actions should be taken immediately:

1. Pump as fast as possible.
2. Increase drilling fluid density as rapidly as possible while pumping.
3. If drilling fluid supply should be exhausted, continue by pumping water.



Managing Shallow Gas

Killing Steps

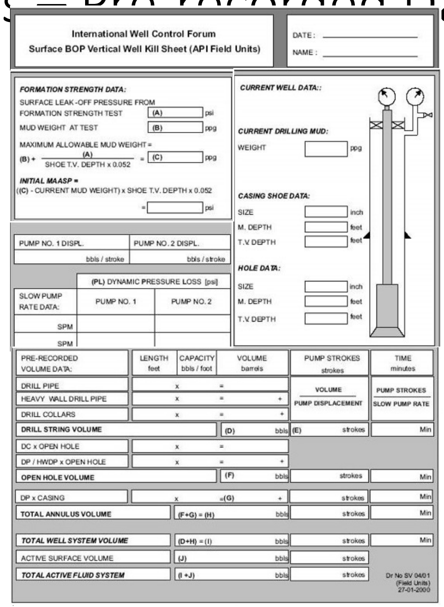
Pre-Recorded Data
- Hole Profile
- Formation Strength
- Pump Data
- Volume Calculations

Shut In the Well
- Shut-In Procedures
- Types of Shut-In
- Shut-In Lineup

Theoretical Killing
- Collect Shut-In data
- Calculate KMW
- Calculate ICP & FCP
- Finish Step down schedule

Practical Killing
- Killing Methods & Procedures
- Unconventional Killing Methods
- Surface gauge problems detection & handling

Killing Steps – Pre-recorded Data



International Well Control Forum
Surface BOP Vertical Well Kill Sheet (API Field Units)

DATE : ____________
NAME : ____________

FORMATION STRENGTH DATA:

SURFACE LEAK-OFF PRESSURE FROM FORMATION STRENGTH TEST (A) psi
MUD WEIGHT AT TEST (B) ppg
MAXIMUM ALLOWABLE MUD WEIGHT =
(B) + (A) / SHOE T.V. DEPTH x 0.052 = (C) ppg

INITIAL MAASP =
((C) - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052
= psi

CURRENT WELL DATA::

CURRENT DRILLING MUD:
WEIGHT ppg

CASING SHOE DATA:
SIZE inch
M. DEPTH feet
T.V DEPTH feet

HOLE DATA:
SIZE inch
M. DEPTH feet
T.V DEPTH feet

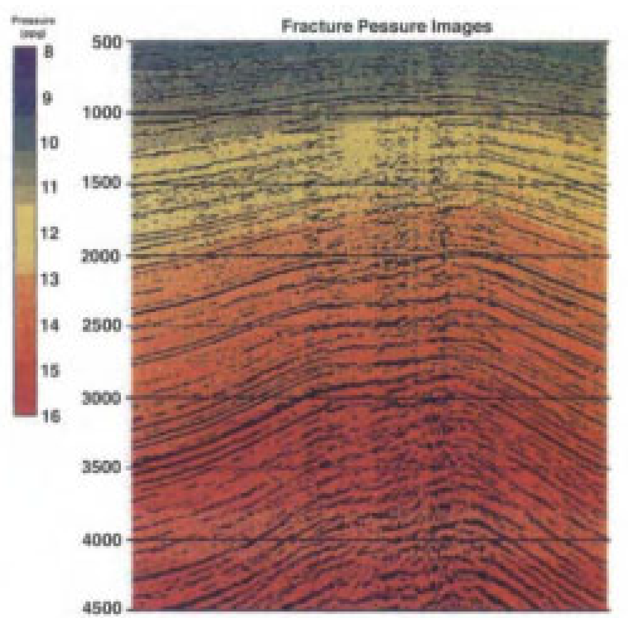
PUMP NO. 1 DISPL.	PUMP NO. 2 DISPL.
bbls / stroke	bbls / stroke

SLOW PUMP RATE DATA:	(PL) DYNAMIC PRESSURE LOSS [psi] PUMP NO. 1	PUMP NO. 2
SPM		
SPM		

PRE-RECORDED VOLUME DATA:	LENGTH feet	CAPACITY bbls / foot	VOLUME barrels	PUMP STROKES strokes	TIME minutes
DRILL PIPE		x	=	VOLUME / PUMP DISPLACEMENT	PUMP STROKES / SLOW PUMP RATE
HEAVY WALL DRILL PIPE		x	= +		
DRILL COLLARS		x	= +		
DRILL STRING VOLUME			(D) bbls	(E) strokes	Min
DC x OPEN HOLE		x	=		
DP / HWDP x OPEN HOLE		x	= +		
OPEN HOLE VOLUME			(F) bbls	strokes	Min
DP x CASING		x	=(G) +	strokes	Min
TOTAL ANNULUS VOLUME			(F+G) = (H) bbls	strokes	Min
TOTAL WELL SYSTEM VOLUME			(D+H) = (I) bbls	strokes	Min
ACTIVE SURFACE VOLUME			(J) bbls	strokes	
TOTAL ACTIVE FLUID SYSTEM			(I +J) bbls	strokes	

Dr No SV 04/01
(Field Units)
27-01-2000

Fracture Pressure



Fracture pressure distribution in low-amplitude zone shows the increase with depth

Parameters affecting LOT

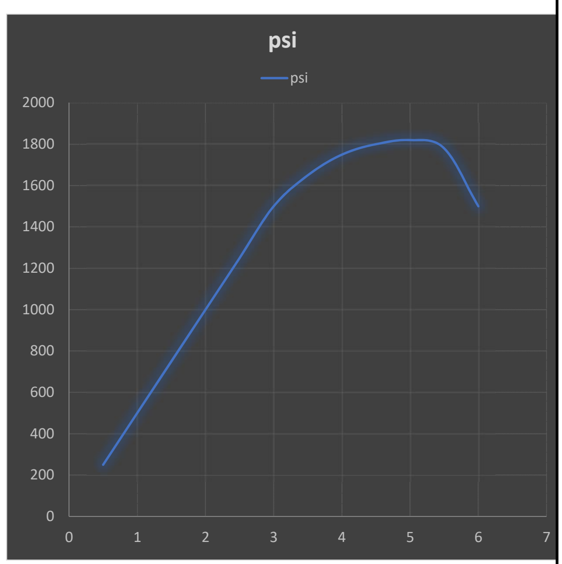
- It is important to have accurate
  - Drilling fluid density and
  - Pressure data:
    - Casing TVD
    - Calibrated gauges

for these tests to yield meaningful results. Use representative samples for measuring the fluid density and use a pressure gauge with the appropriate scale and that has been calibrated.

LOT Procedures

Before starting, gauges should be **checked for accuracy**. The upper pressure limit should be determined.

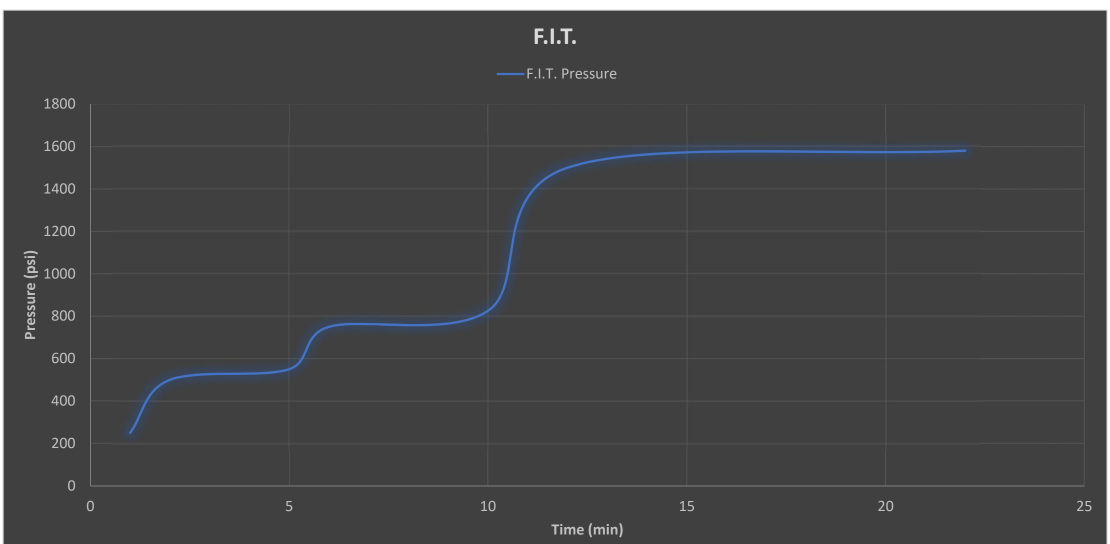
1. The **casing should be tested** prior to drilling out the shoe.
2. **Drill out** the shoe and cement, exposing 5-10 ft new formation.
3. Circulate and **condition** the mud, **check mud density in and out.**
4. Pull the bit inside the casing. **Line up cement pump** and flush all lines to be used for the test.
5. **Close BOPs.**
6. With the well closed in, the cement pump is used to pump **a small volume** at a time into the well typically a **¼ or ½ bbl** per min. Monitor the pressure build up and accurately record the volume of mud pumped. Plot pressure versus volume of mud pumped.
7. Stop the pump when any **deviation from linearity** is noticed between pump pressure and volume pumped.
8. **Bleed off the pressure** and **establish the amounts** of mud, if any, **lost to the formation.**



L.O.T. Vs F.I.T.

L.O.T.	F.I.T.
Exploration well	Development Well
No pressure limits (fracture pressure)	Pre-set limit (offset data)

FIT graph



Fracture pressure & primary well control

Formation Fracture Pressure

Well Data:
Shoe TVD = 5495 ft
Test Mud Weight = 9.8 ppg

Hydrostatic Pressure of Test Mud to the Shoe:

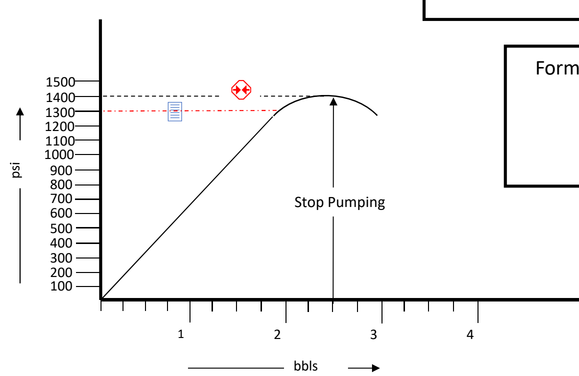
9.8 x .052 x 5495 = 2800 psi

Surface Leak Off Pressure = 1300 psi

Formation Fracture Pressure is equal to

Hydrostatic @ Shoe + SLOP

2800 + 1300 = 4100 psi



MAASP Calculation

Drilling - English API Formula Sheet

11. MAXIMUM ALLOWABLE MUD DENSITY (ppg)

[Surface LOT pressure (psi) ÷ Shoe TVD (ft) ÷ 0.052] + LOT Mud Density (ppg)

or

$$\frac{\text{Surface LOT Pressure (psi)}}{\text{Shoe TVD (ft)} \times 0.052} + \text{LOT Mud Density (ppg)}$$

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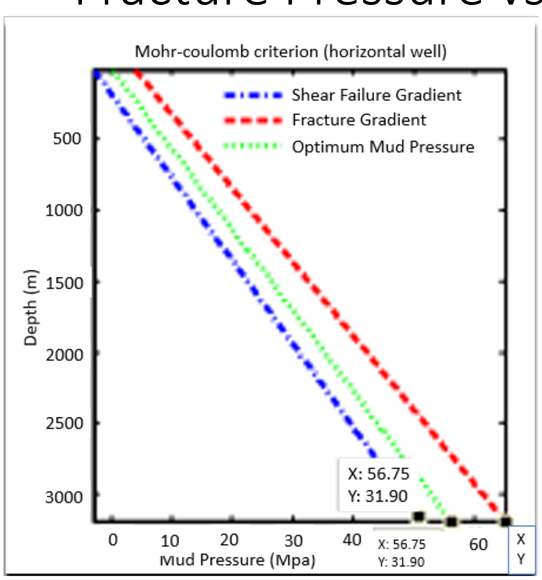
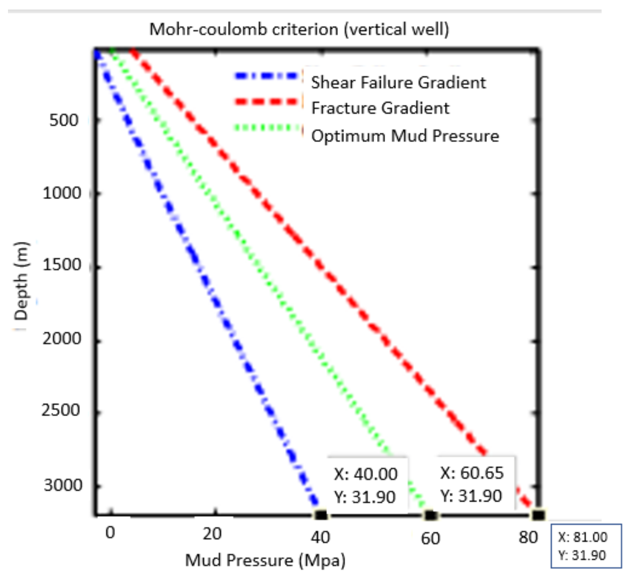
Fracture Pressure vs Mud Window





MAASP Calculation

Drilling - English API Formula Sheet

12. MAASP (psi)

[Maximum Allowable Mud Density (ppg) – Current Mud Density (ppg)] x 0.052 x Shoe TVD (ft)

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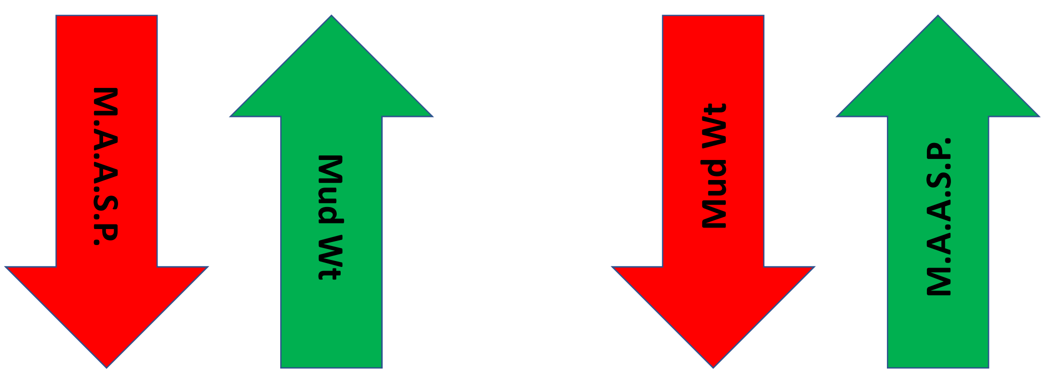
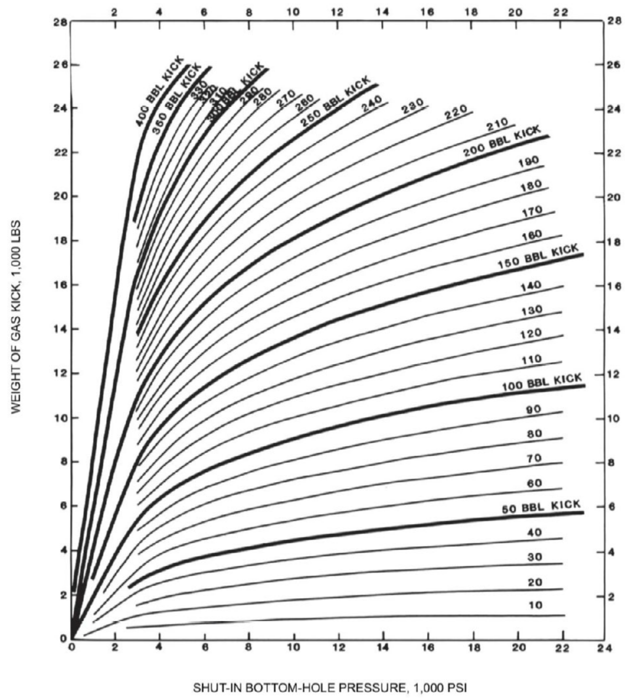
Change in MAASP



Kick Tolerance



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SCR – Choice

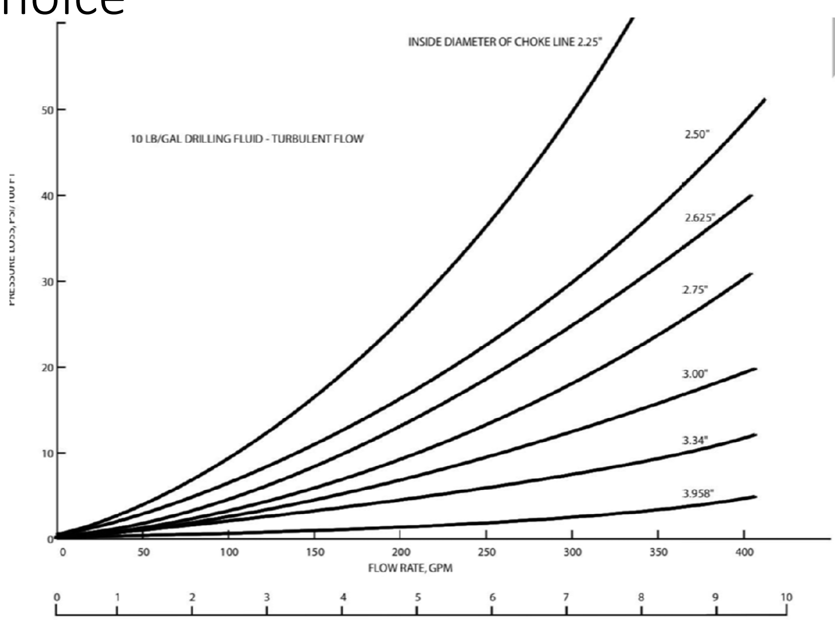

Figure 4.19—Pressure Loss versus Flow Rate

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Slow Circulating Rates (SCR's)

The slow circulating rate pressure is normally taken for each pump at outputs between 1 and 5 bbls per minute. This is usually between 15 and 50 SPM depending on pump liner size.

The Driller pumps down the drill pipe and back up the annulus at the specified reduced Strokes Per Minute (SPM)

The SCR Pressure must be recorded from the gauge that will be used during the well kill operations -<u>Remote Choke Panel Gauges</u>)

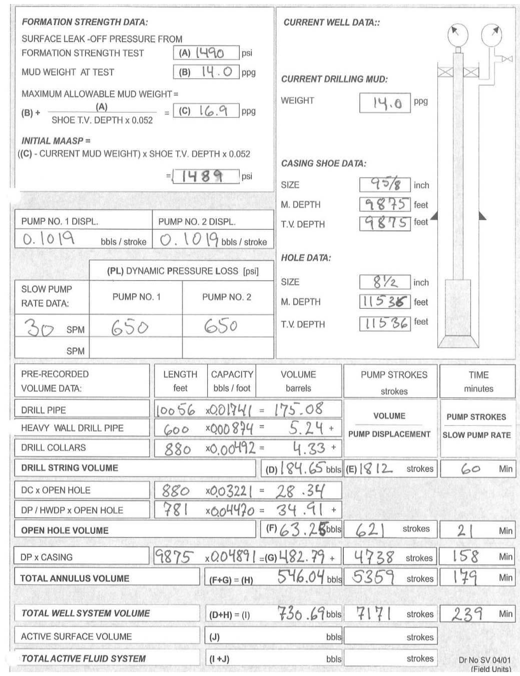
SCR PL – When

Slow circulating rate pressures for each pump must be taken:

- At the beginning of every tour
- Any time the mud properties are changed
- Any time the bit nozzle configuration or bottom hole assembly is changed
- As soon as possible after bottoms-up from any trip
- At least every 1000ft of new hole (500ft in hydrocarbon bearing hole sections)
- After major mud pump or surface equipment changes or repairs

Kill Sheet Calculations

HOLE SIZE	8-1/2	IN
HOLE DEPTH TVD/MD	11536	FT
CASING 9-5/8" TVD/MD	9875	FT
DRILL PIPE CAP.	0.01741	BBL/FT
HEAVY WALL DRILL PIPE	600	FT
CAPACITY	0.00874	BBL/FT
DRILL COLLARS 6-1/4"	880	FT
CAPACITY	0.00492	BBL/FT
DRILLING FLUID DENSITY	14.0	PPG
CAPACITY OPEN HOLE/COLLARS	0.03221	BBL/FT
CAPACITY OPEN HOLE/DP-HWDP	0.04470	BBL/FT
CAPACITY CASING/DRILL PIPE	0.04891	BBL/FT
FRACTURE FLUID DENSITY	16.9	PPG
SIDPP	530	PSI
SICP	700	PSI
PUMP DISPLACEMENT	0.1019	BBL/STRK
SCRP@ 30 SPM	650	PSI
PIT GAIN	10.0	BBL



FORMATION STRENGTH DATA:
SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST (A) 1490 psi
MUD WEIGHT AT TEST (B) 14.0 ppg
MAXIMUM ALLOWABLE MUD WEIGHT = (B) + (A) / SHOE T.V. DEPTH x 0.052 = (C) 16.9 ppg
INITIAL MAASP = ((C) - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052 = 1489 psi

CURRENT WELL DATA::
CURRENT DRILLING MUD: WEIGHT 14.0 ppg
CASING SHOE DATA: SIZE 9 5/8 inch; M. DEPTH 9875 feet; T.V. DEPTH 9875 feet
HOLE DATA: SIZE 8 1/2 inch; M. DEPTH 11536 feet; T.V. DEPTH 11536 feet

PUMP NO. 1 DISPL.	PUMP NO. 2 DISPL.
0.1019 bbls / stroke	0.1019 bbls / stroke

SLOW PUMP RATE DATA:	(PL) DYNAMIC PRESSURE LOSS [psi] PUMP NO. 1	PUMP NO. 2
30 SPM	650	650
SPM		

PRE-RECORDED VOLUME DATA:	LENGTH feet	CAPACITY bbls / foot	VOLUME barrels	PUMP STROKES strokes	TIME minutes
DRILL PIPE	10056	x0.01741	= 175.08	VOLUME / PUMP DISPLACEMENT	PUMP STROKES / SLOW PUMP RATE
HEAVY WALL DRILL PIPE	600	x0.00874	= 5.24 +		
DRILL COLLARS	880	x0.00492	= 4.33 +		
DRILL STRING VOLUME			(D) 184.65 bbls	(E) 1812 strokes	60 Min
DC x OPEN HOLE	880	x0.03221	= 28.34		
DP / HWDP x OPEN HOLE	781	x0.04470	= 34.91 +		
OPEN HOLE VOLUME			(F) 63.25 bbls	621 strokes	21 Min
DP x CASING	9875	x0.04891	=(G) 482.79 +	4738 strokes	158 Min
TOTAL ANNULUS VOLUME			(F+G) = (H) 546.04 bbls	5359 strokes	179 Min
TOTAL WELL SYSTEM VOLUME			(D+H) = (I) 730.69 bbls	7171 strokes	239 Min
ACTIVE SURFACE VOLUME			(J) bbls	strokes	
TOTAL ACTIVE FLUID SYSTEM			(I +J) bbls	strokes	

Dr No SV 04/01
(Field Units)

PSB/AD/PS/2/00

Shut-In Procedures

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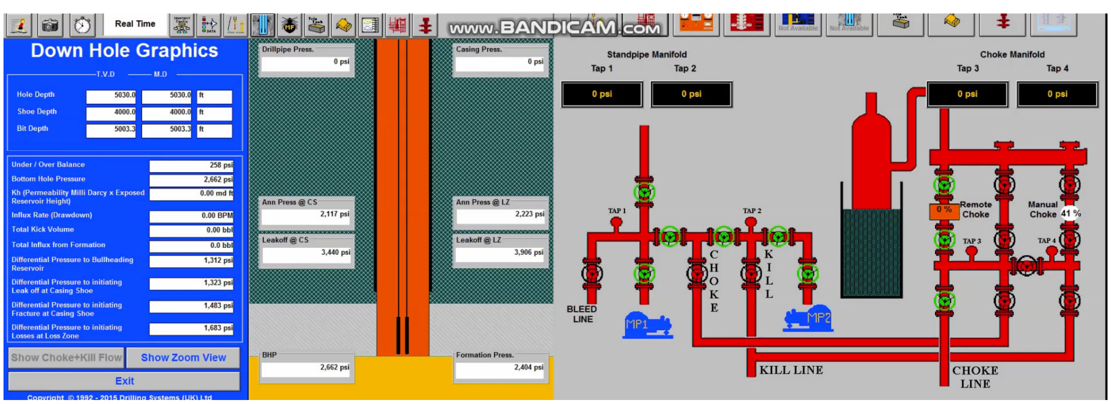
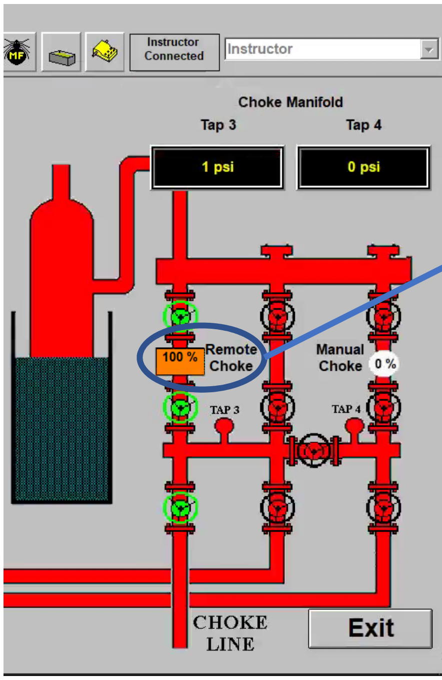
Shut-In – Drilling

Valve	Hard Shut-In		Soft Shut-In	
BOP	Opened 1		Opened 2	
Manual Valve	Closed		Closed	
Remote HCR	Closed 2		1	
Remote Chock Valve	Closed		Opened 3	
MGS Valve	Opened		Opened	

Recognize primary barrier failure

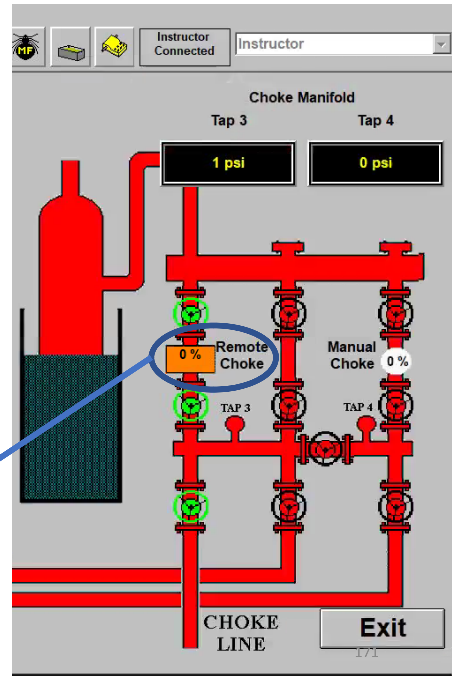


Correct Line-up

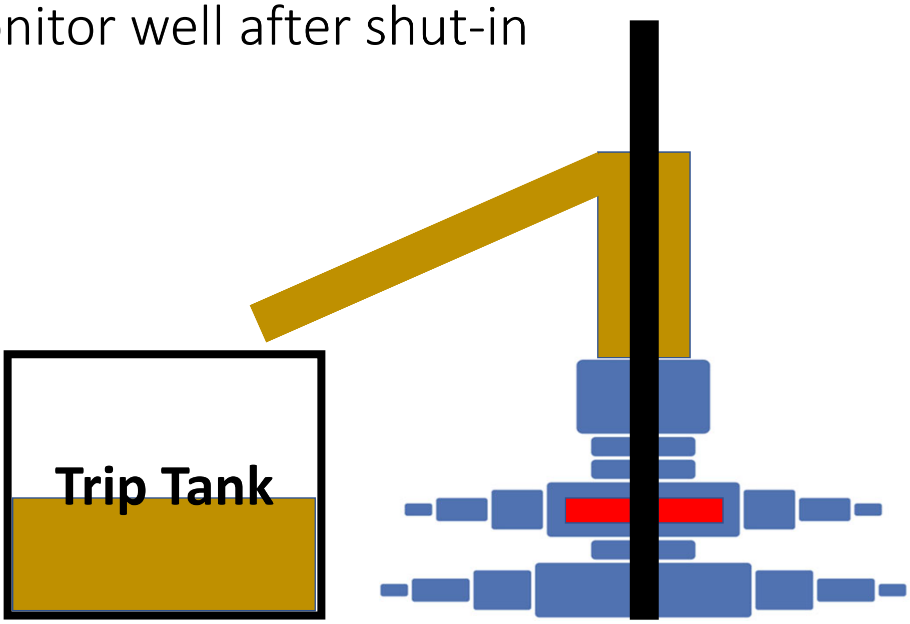


Soft Shut-In

Hard Shut-In



Monitor well after shut-in



Shut-In Confirmation

➢ **Annulus**
- Through BOP
- At the flow line

➢ **Drill-String**
- Pump pressure relief valves
- Standpipe manifold

➢ **Wellhead / BOP**
- Casing valve
- Broaching to surface

➢ **Choke manifold**
- Choke
- Overboard lines

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Shut-In – Tripping

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Shut-In – Running Casing

- Ensure that you have the proper BOP's which match you string OD
- Check your inventory to have any extra equipment based on special operations
- Change RAM to casing ram before running casing operation
- Revise the closing pressure graph in case of using the Annular preventer
- Ensure that the Annular manifold adjusted as per the graph

Shut-In – Cementing

- Gas influx can occur during and after cementing operations. The primary cause of gas influx is loss of hydrostatic head due to:

1. Water separation,
2. Cement dehydration,
3. Poor cement retarder design or performance,
4. Insufficient annulus fill-up,
5. Lost returns during cementing,
6. Cementing with gas-cut drilling fluid, and
7. Swabbing the hole while reciprocating pipe in cementing operations.

Shut-In – Wireline

The following procedure must be used:

1.Inform the loggers and order the winch to be stopped.

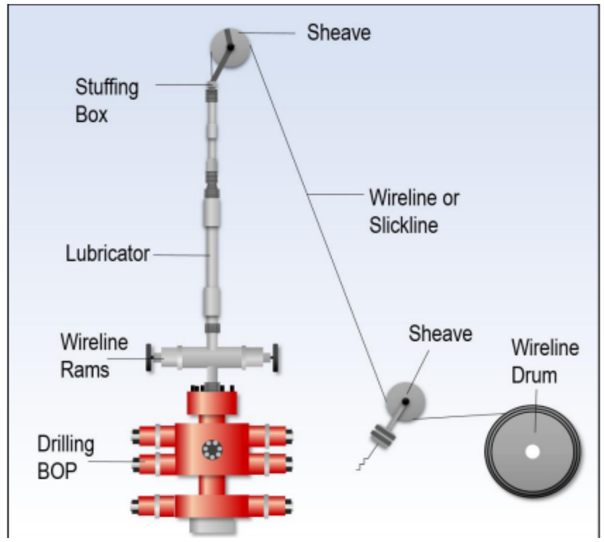
2.If a positive flow is confirmed, or if there is any doubt, close the annular preventer.

3.Open the choke line HCR valve.

4.Commence plotting a graph of SICP against time.

5.Check the pit volume again and record the pit volume increase.

6.Continue to monitor pressures and monitor any change.



BOP Limitation for Wireline Operation

- limitations of conventional well control equipment during wireline operations:

- Annulars
- Shear rams
- Non-shearables across the BOP.

Recording Shut-In Pressure

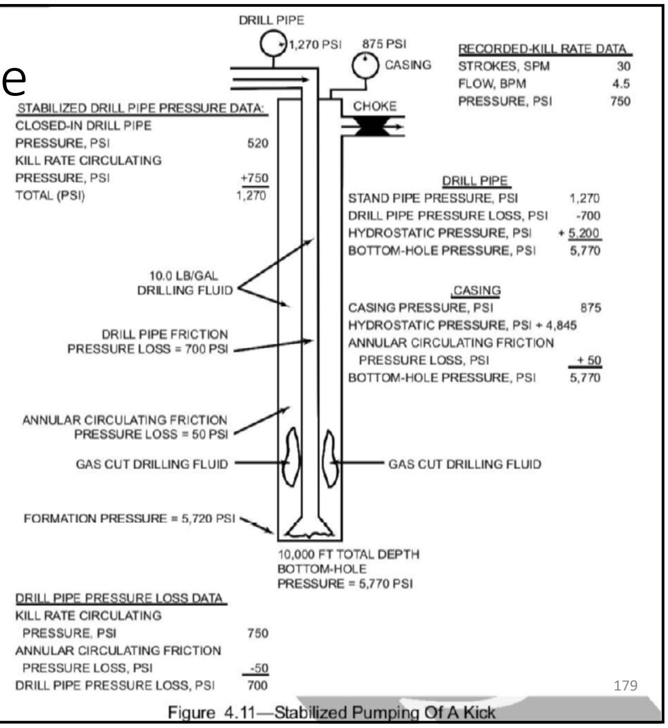


Figure 4.11—Stabilized Pumping Of A Kick

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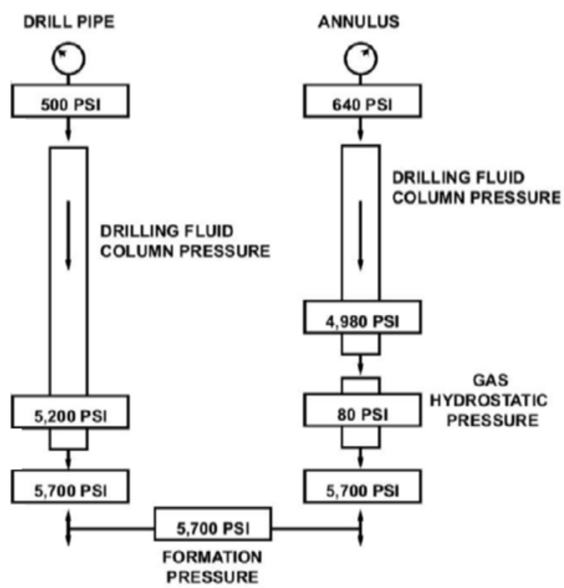
SIDPP Vs. SICP



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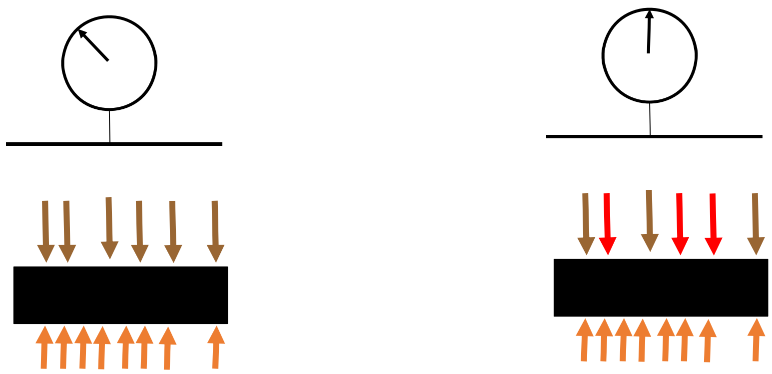
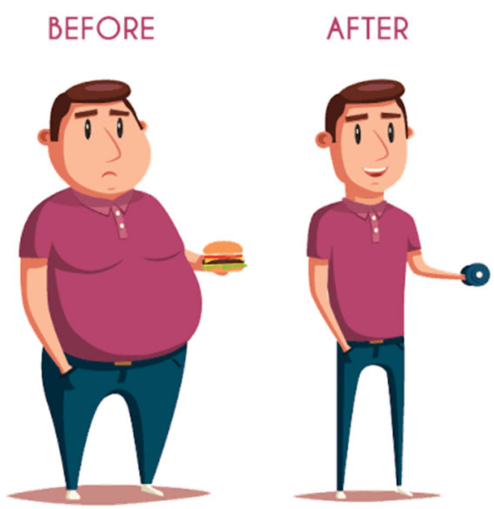
SIDPP vs. SICP

Point # 1

Point # 2



Influx effect on primary fluid barrier



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Gas solubility in Mud

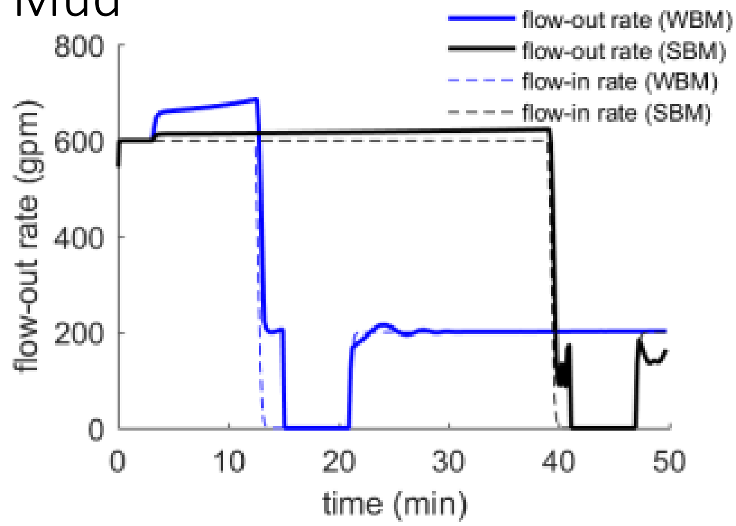

Figure 13—Flow-in/out rate vs. time (zoomed in for 0-50 min) during conventional drilling.

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Gas dissolved in Mud

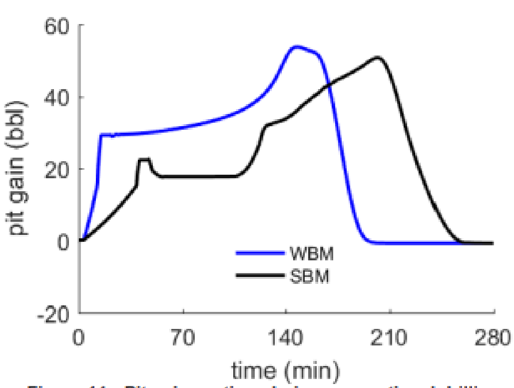

Figure 14—Pit gain vs. time during conventional drilling.

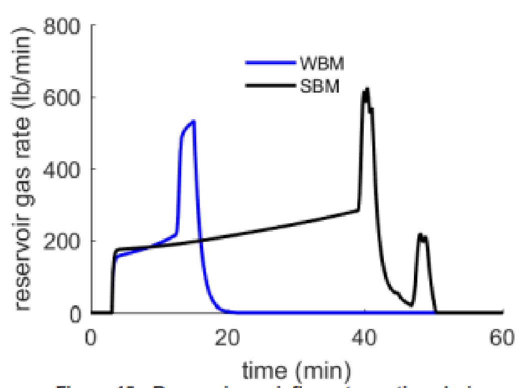

Figure 15—Reservoir gas influx rate vs. time during conventional drilling.

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Gas Breakout from Mud

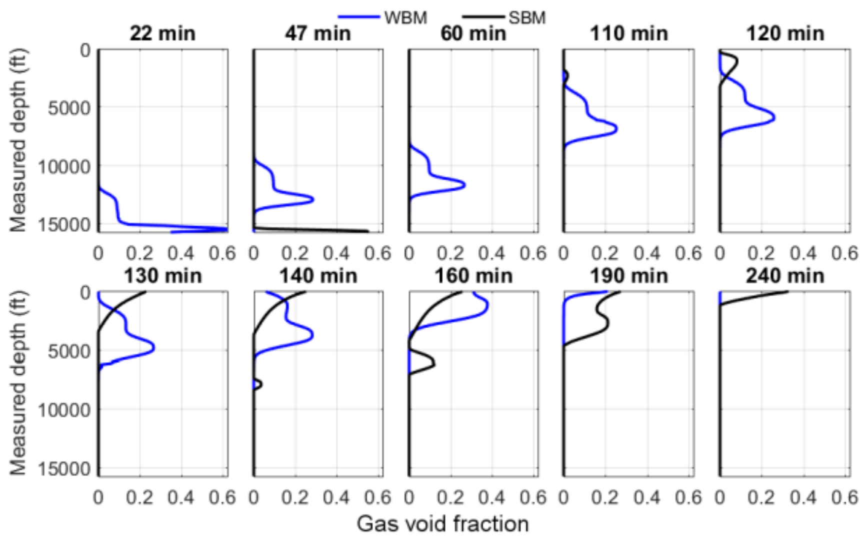
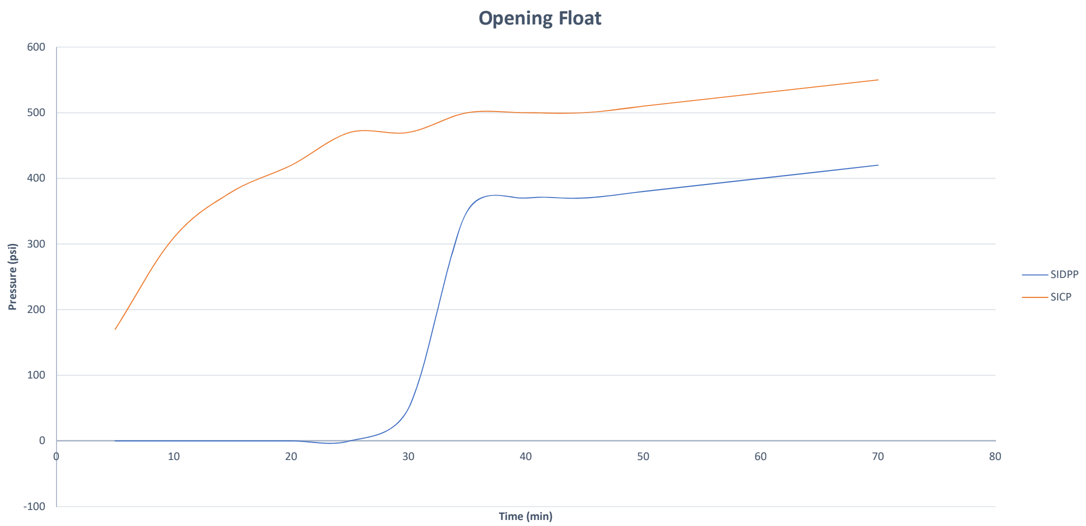


Figure 20 - Gas void fractions vs. measured depth at various times during conventional drilling.

Actions to mitigate gas breakout

SIDPP with Float Valve



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Trapped Pressure

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Pressure gauge limitations

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Influx Characteristic & Behavior

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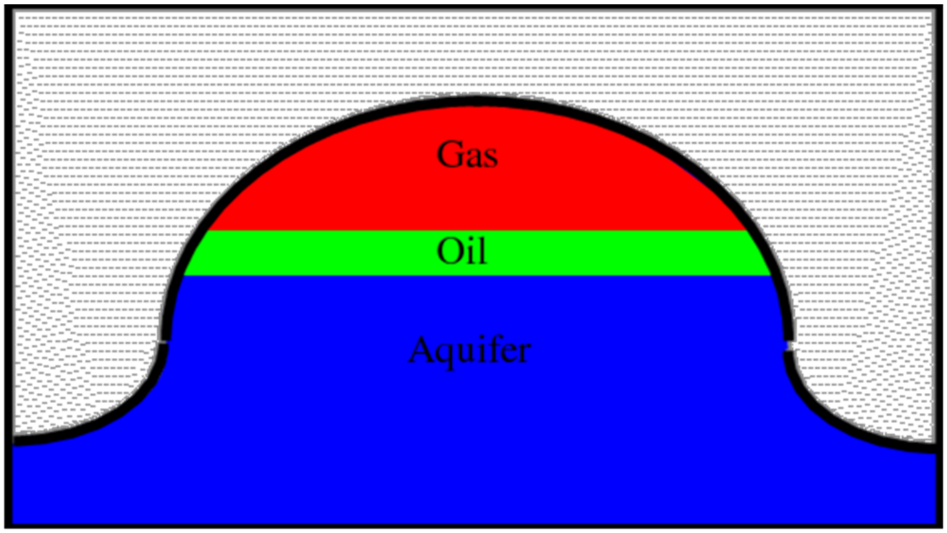
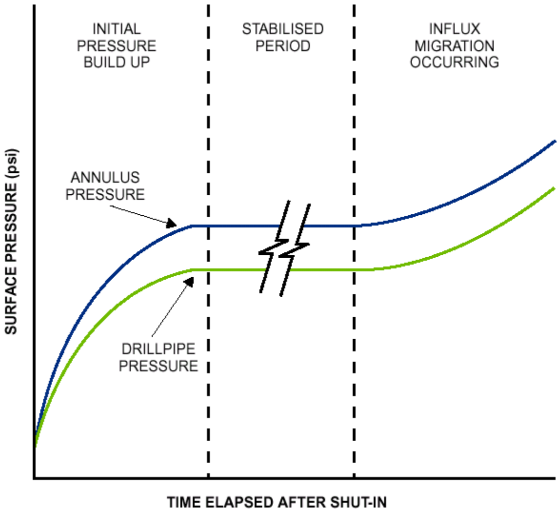
Types of Influx



Action required if influx migrates



Time- Minutes	Drill Pipe	Casing
After 3 minutes	160	210
After 6 minutes	195	265
After 9 minutes	210	290
After 12 minutes	220	300
After 15 minutes	230	310

What is the SIDPP required to calculate the kill mud weight?

Gas Law calculations

Drilling - English API Formula Sheet

18. GAS LAWS

$$P_1 \times V_1 = P_2 \times V_2 \qquad P_2 = \frac{P_1 \times V_1}{V_2} \qquad V_2 = \frac{P_1 \times V_1}{P_2}$$

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Influx Migration

Drilling - English API

17. GAS MIGRATION RATE (ft/hr)

Rate of Increase in Surface Pressure (psi/hr) ÷ Drilling Mud Density (ppg) ÷ 0.052

or

$$\frac{\text{Rate of Increase in Surface Pressure (psi/hr)}}{\text{Drilling Mud Density (ppg)} \times 0.052}$$

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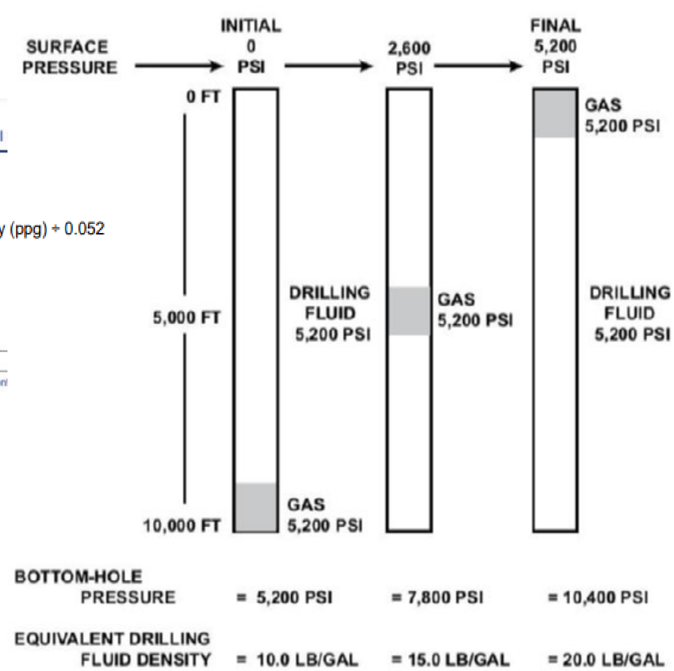

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Constant BHP while influx migrating

Drilling - English API Formula Sheet

25. VOLUME TO BLEED OFF TO RESTORE BHP TO FORMATION PRESSURE (bbl)

$$\frac{\text{Increase in Surface Pressure (psi)} \times \text{Influx Volume (bbl)}}{\text{Formation Pressure (psi)} - \text{Increase in Surface Pressure (psi)}}$$

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Gas behavior in horizontal well

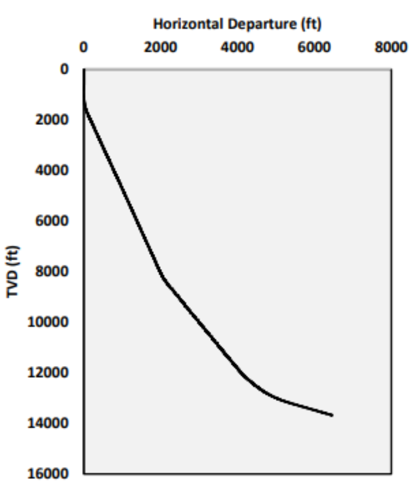

Figure 4 - Wellbore path (TVD vs. horizontal departure).

Table 1—Drillstring, casing and fluid data for the offshore well

Property	Value
Pipe OD, ID, Length	5.875", 5.153", 15188 ft
Heavy Wall Drillpipe OD, ID, Length	5.875", 4", 569 ft
Drill collars OD, ID, Length	6.5625", 3.0625, 90 ft
Annulus Section 1 (casing 1), ID and length	9.56 inch, 6200 ft
Annulus Section 1 (casing 2), ID and length	9.76 inch, 8365 ft
Annulus Section 3 (open hole), ID and length	9.5 inch, 1282 ft
Mud weight	12.6 ppg
Yield stress, τ_y	10.06 Pa
Liquid consistency index, K	0.3285 Pa.sec$^{0.7323}$
Fluid behavior index, m	0.7323
Oil-water ratio of SBM	70-30

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Well Control Method

Well Data:
Well TVD = 9500 ft
Current Mud Weight = 10.5 ppg
SIDPP = 600 psi

Formation Pressure

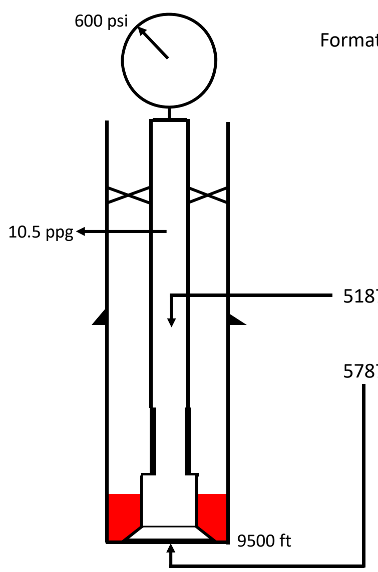
The formula for calculating Formation Pressure is:

Formation Pressure = Hydrostatic Pressure in Drillstring + SIDPP

Hydrostatic pressure in Drillstring

10.5 x .052 x 9500 = 5187 psi

Formation Pressure = 5187 + 600 = 5787 psi

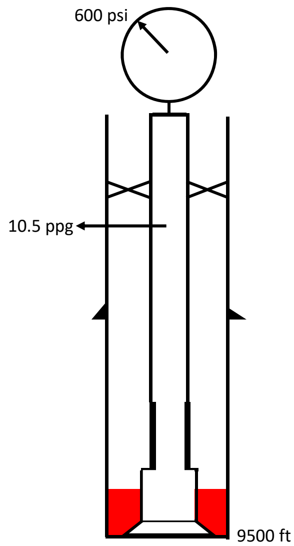


5187 psi Hydrostatic Pressure is pushing down

5787 psi Formation Pressure is pushing up

The difference - 600 psi - can be seen on the drill pipe pressure gauge at surface

Well Data:
Well TVD = 9500 ft
Current Mud Weight = 10.5 ppg
SIDPP = 600 psi



Kill Mud Weight

The formula for Kill Mud Weight (ppg)

= (SIDPP ÷ TVD ÷ .052) + Current Mud Wt

= (600 ÷ 9500 ÷ .052) + 10.5

= 11.71 ppg

KILL MUD WEIGHT MUST
BE <u>ROUNDED UP</u>
TO ONE DECIMAL PLACE

= 11.8 ppg

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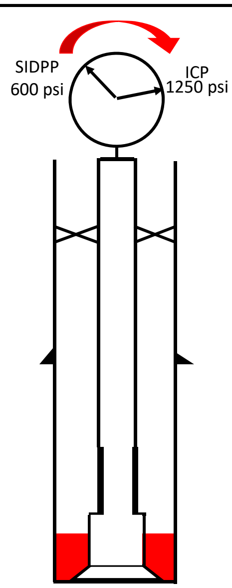
Well Data:
SCRPL @ 40 SPM = 650 psi
SIDPP = 600 psi



Initial Circulating Pressure

Initial Circulating Pressure (ICP) is the reading on the Drill Pipe Pressure Gauge once you start killing the well

ICP (psi) = Slow Circulating Rate Pressure Loss (psi) + SIDPP (psi)

= 650 + 600 = 1250 psi

ICP will be the same regardless of which Kill Method you are using

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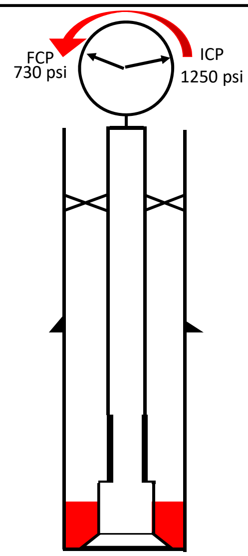
Well Data:
SCRPL @ 40 SPM = 650 psi
Current Mud Weight = 10.5 ppg
Kill Mud Weight = 11.8 ppg
ICP = 1250 psi



Final Circulating Pressure

As Kill Mud is pumped down the string you are killing the string and as a result will be gradually removing the under-balance.

If you were to shut the well in with Kill Mud at the bit then SIDPP would read zero - you have killed the string.

As Kill Mud is pumped down the string friction losses will be increasing due to the heavier mud in the string.

You can calculate what the circulating pressure will be with Kill Mud at the bit using the formula:

$$FCP\ (psi) = \frac{\text{Kill Mud Wt (ppg)}}{\text{Current Mud Wt (ppg)}} \times SCRPL\ (psi)$$

$$= \frac{11.8}{10.5} \times 650 = 730\ psi$$

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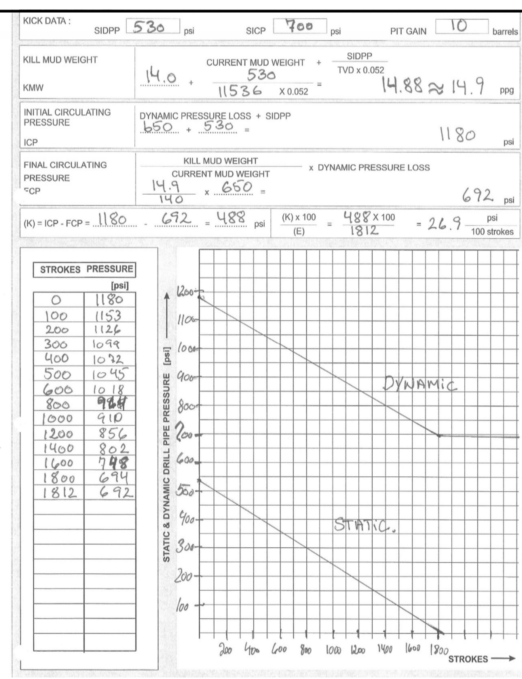
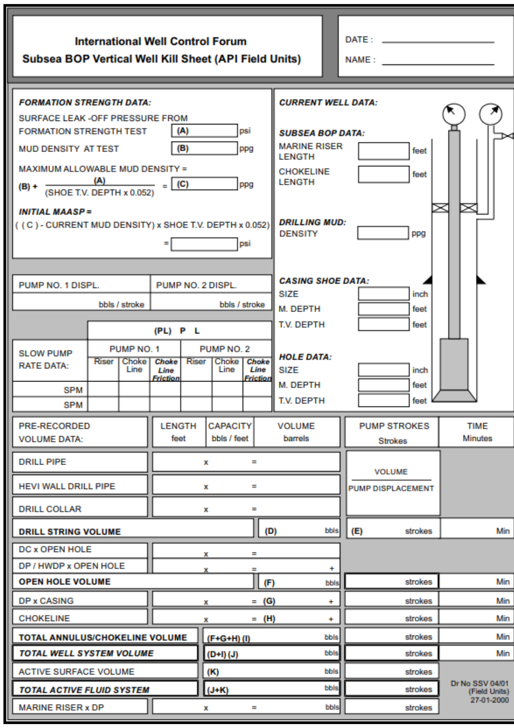
Kill Sheet Calculations

HOLE SIZE	8-1/2	IN
HOLE DEPTH TVD/MD	11536	FT
CASING 9-5/8" TVD/MD	9875	FT
DRILL PIPE CAP.	0.01741	BBL/FT
HEAVY WALL DRILL PIPE	600	FT
CAPACITY	0.00874	BBL/FT
DRILL COLLARS 6-1/4"	880	FT
CAPACITY	0.00492	BBL/FT
DRILLING FLUID DENSITY	14.0	PPG
CAPACITY OPEN HOLE/COLLARS	0.03221	BBL/FT
CAPACITY OPEN HOLE/DP-HWDP	0.04470	BBL/FT
CAPACITY CASING/DRILL PIPE	0.04891	BBL/FT
FRACTURE FLUID DENSITY	16.9	PPG
SIDPP	530	PSI
SICP	700	PSI
PUMP DISPLACEMENT	0.1019	BBL/STRK
SCRP@ 30 SPM	650	PSI
PIT GAIN	10.0	BBL





International Well Control Forum
Subsea BOP Vertical Well Kill Sheet (API Field Units)

DATE : ____________
NAME : ____________

FORMATION STRENGTH DATA:
SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST (A) psi
MUD DENSITY AT TEST (B) ppg
MAXIMUM ALLOWABLE MUD DENSITY =
(B) + (A) / (SHOE T.V. DEPTH x 0.052) = (C) ppg

INITIAL MAASP =
((C) - CURRENT MUD DENSITY) x SHOE T.V. DEPTH x 0.052)
= ____ psi

CURRENT WELL DATA:

SUBSEA BOP DATA:
MARINE RISER LENGTH ____ feet
CHOKELINE LENGTH ____ feet

DRILLING MUD:
DENSITY ____ ppg

CASING SHOE DATA:
SIZE ____ inch
M. DEPTH ____ feet
T.V. DEPTH ____ feet

HOLE DATA:
SIZE ____ inch
M. DEPTH ____ feet
T.V. DEPTH ____ feet

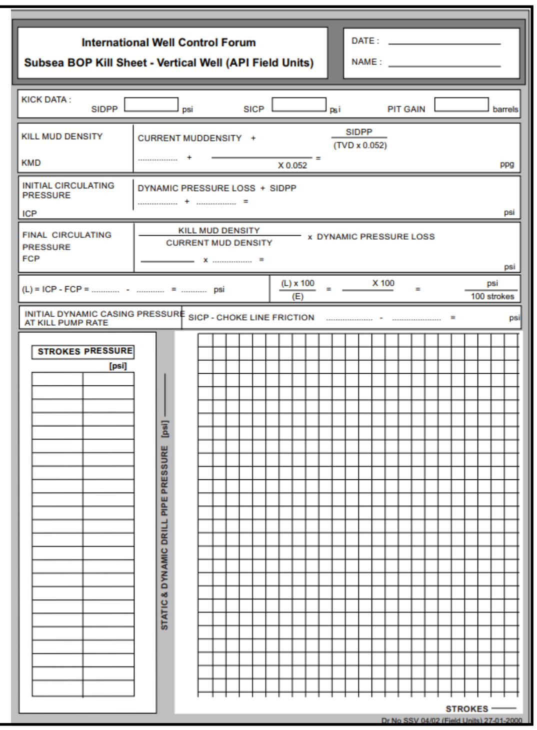
PUMP NO. 1 DISPL.	PUMP NO. 2 DISPL.
bbls / stroke	bbls / stroke

SLOW PUMP RATE DATA:	(PL) P L					
	PUMP NO. 1			PUMP NO. 2		
	Riser	Choke Line	Choke Line Friction	Riser	Choke Line	Choke Line Friction
SPM						
SPM						

PRE-RECORDED VOLUME DATA:	LENGTH feet	CAPACITY bbls / feet	VOLUME barrels	PUMP STROKES Strokes	TIME Minutes
DRILL PIPE		x	=	VOLUME / PUMP DISPLACEMENT	
HEVI WALL DRILL PIPE		x	=		
DRILL COLLAR		x	=		
DRILL STRING VOLUME			(D) bbls	(E) strokes	Min
DC x OPEN HOLE		x	=		
DP / HWDP x OPEN HOLE		x	= +		
OPEN HOLE VOLUME			(F) bbls	strokes	Min
DP x CASING		x	= (G) +	strokes	Min
CHOKELINE		x	= (H) +	strokes	Min
TOTAL ANNULUS/CHOKELINE VOLUME			(F+G+H) (I) bbls	strokes	Min
TOTAL WELL SYSTEM VOLUME			(D+I) (J) bbls	strokes	Min
ACTIVE SURFACE VOLUME			(K) bbls	strokes	
TOTAL ACTIVE FLUID SYSTEM			(J+K) bbls	strokes	
MARINE RISER x DP		x	= bbls	strokes	

Dr No SSV 04/01 (Field Units) 27-01-2000

Subsea Kill Sheet Calculations



International Well Control Forum
Subsea BOP Kill Sheet - Vertical Well (API Field Units)

DATE : ____________
NAME : ____________

KICK DATA : SIDPP ____ psi SICP ____ psi PIT GAIN ____ barrels

KILL MUD DENSITY / KMD: CURRENT MUDDENSITY + SIDPP / (TVD x 0.052)
.... + ________ X 0.052 = ppg

INITIAL CIRCULATING PRESSURE / ICP: DYNAMIC PRESSURE LOSS + SIDPP
.... + ... = psi

FINAL CIRCULATING PRESSURE / FCP: KILL MUD DENSITY / CURRENT MUD DENSITY x DYNAMIC PRESSURE LOSS
________ x .... = psi

(L) = ICP - FCP = ... - .... = ... psi (L) x 100 / (E) = X 100 / ____ = psi / 100 strokes

INITIAL DYNAMIC CASING PRESSURE AT KILL PUMP RATE: SICP - CHOKE LINE FRICTION .... - .... = psi

STROKES	PRESSURE [psi]

Dr No SSV 04/02 (Field Units) 27-01-2000

Formation Pressure

Drilling - English API Formula Sheet

4. FORMATION PORE PRESSURE (psi)

Hydrostatic Pressure in Drill String (psi) + SIDPP (psi)

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Use of Barite

Barite Calculations

Drilling - English API Formula Sheet

16. BARYTE REQUIRED TO INCREASE DRILLING MUD DENSITY (lb/bbl)

$$\frac{[\text{Kill Mud Density (ppg)} - \text{Original Mud Density (ppg)}] \times 1500}{35.8 - \text{Kill Mud Density (ppg)}}$$

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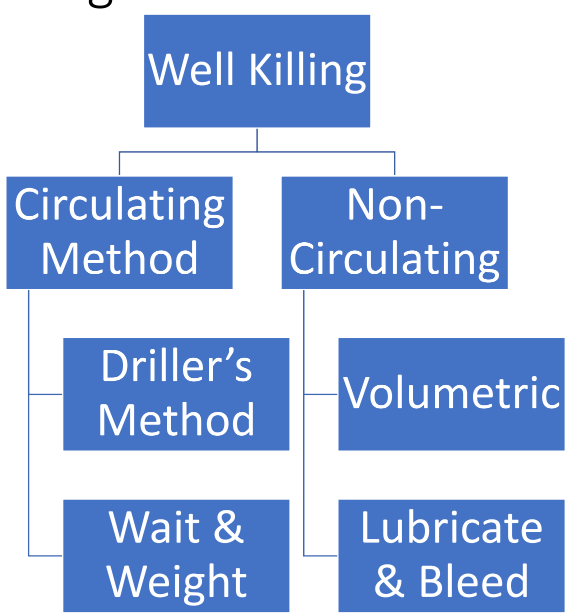
Selection of Killing Method



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Controlling Vs. Killing

- What action you should take when the primary fluid barrier cannot be maintained, for below cases?

1. Insufficient weighting material
2. Fluid mixing equipment failure
3. Unable to circulate
4. Well intervention rig-up.

Selection of SCR

Kill rates refer to;

- ✓ The maximum circulation pressure
- ✓ The capacity of mud gas separator
- ✓ the ability of pumps to pump slow
- ✓ The ability of the mud mixing equipment to weight up mud
- ✓ The reaction time for choke
- ✓ The pressure drop for choke line (subsea well)

The stroke rate and pressure are recorded on the tour sheet for each pump and repeated each time the circulating system pressure is ominously changed. For example: more than 500 ft drilled hole, drilling fluid density, bit nozzles etc.

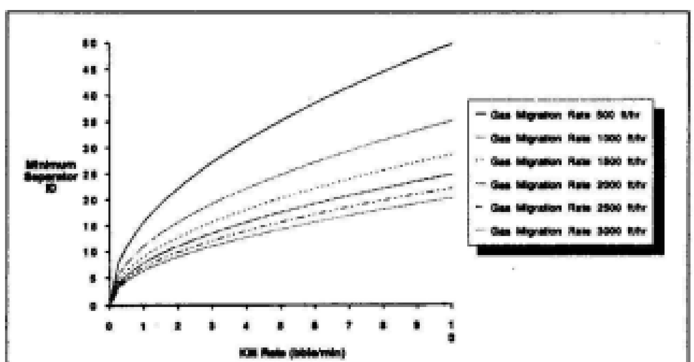

Fig. 7—Effect of circulating kill rate on minimum separator ID.

Selection of Circulating Method

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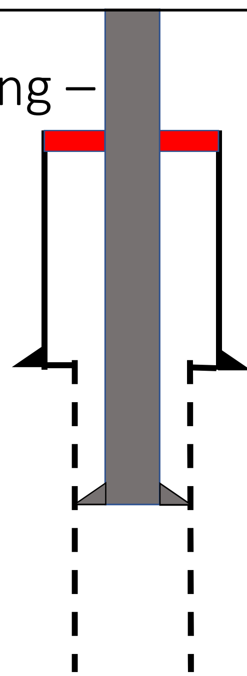
Controlling & Killing – Off bottom



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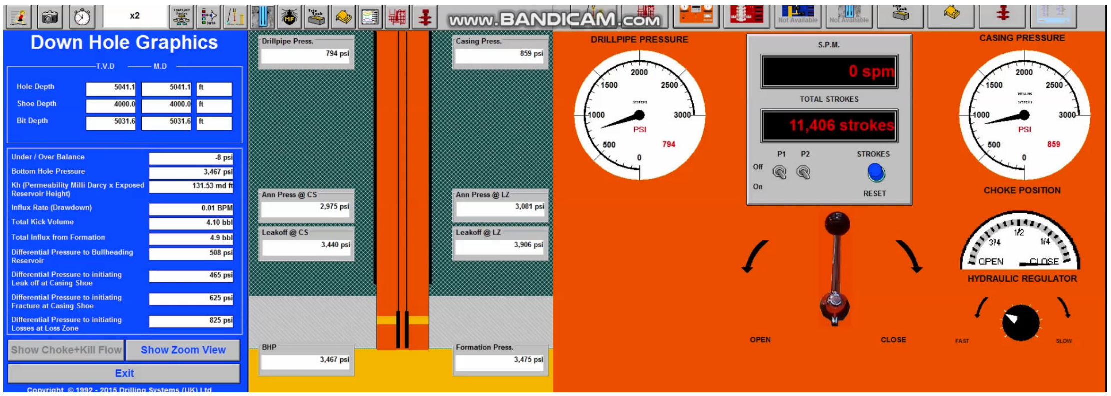
Pump Start-Up Procedures



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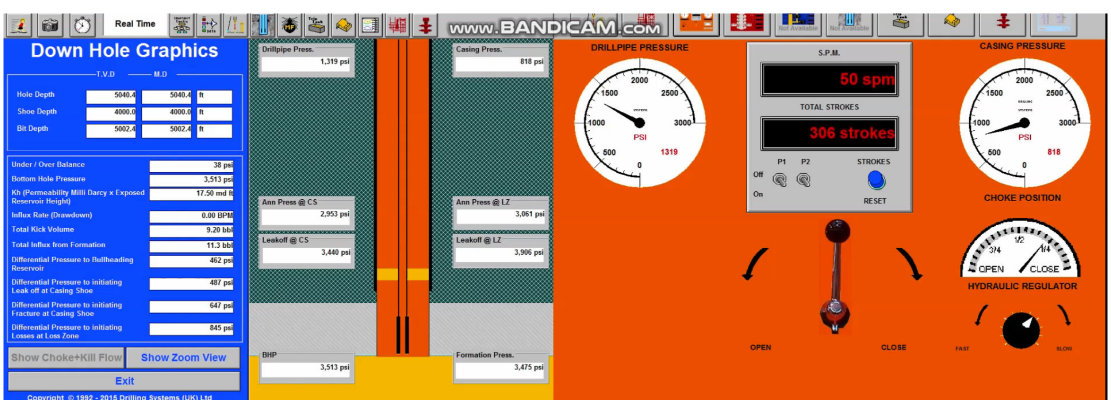
Minimize APL while killing



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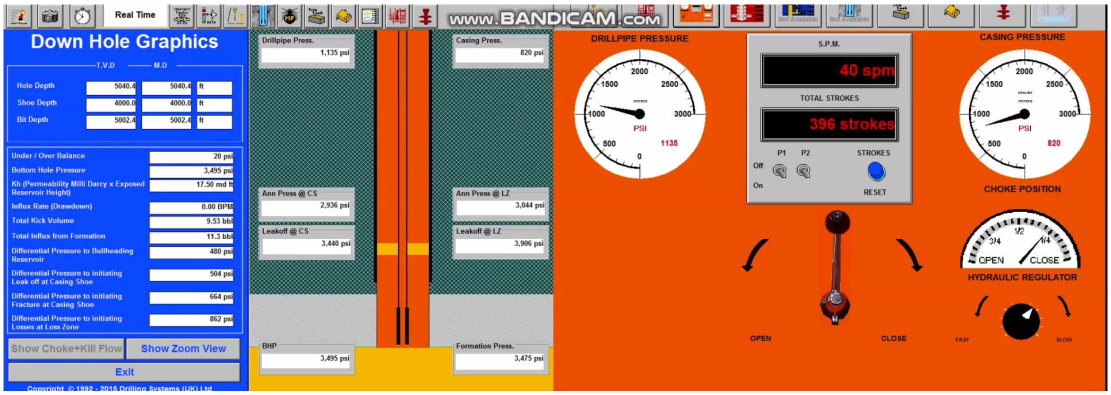
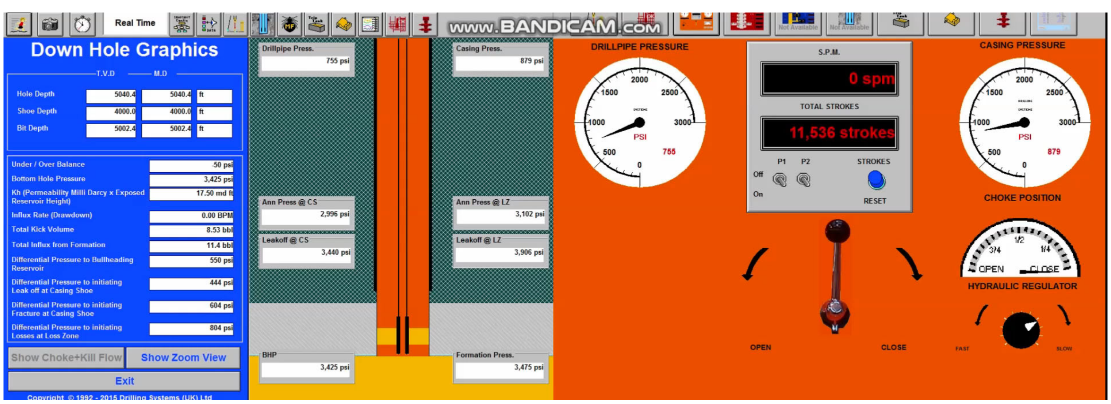
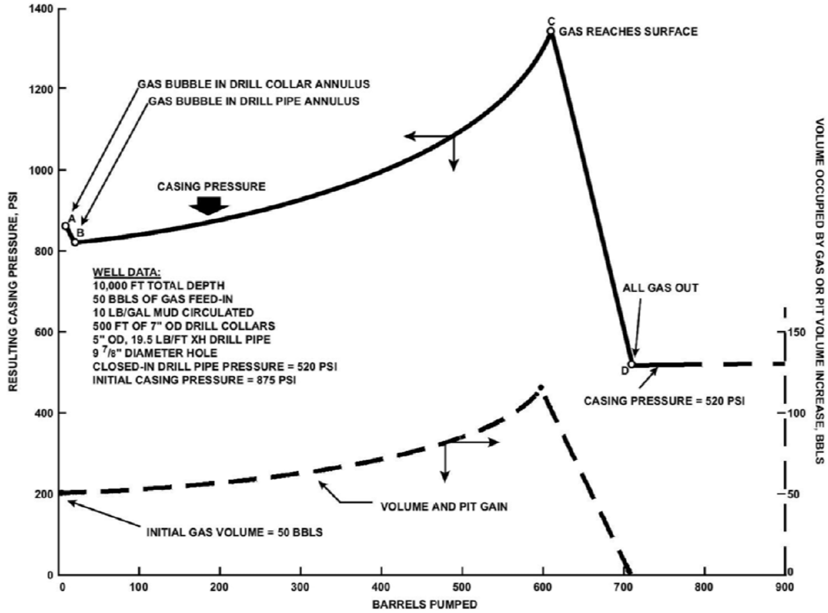
Changing Pump Speed – Speedup Pump



Driller’s Method – 1st Circulation



Driller’s Method – 1st Circulation



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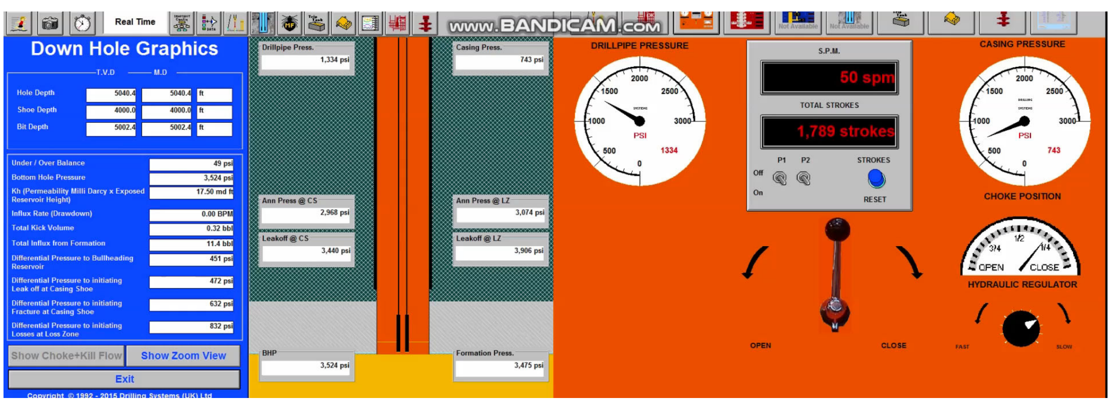
Driller’s Method – 2nd Circulation



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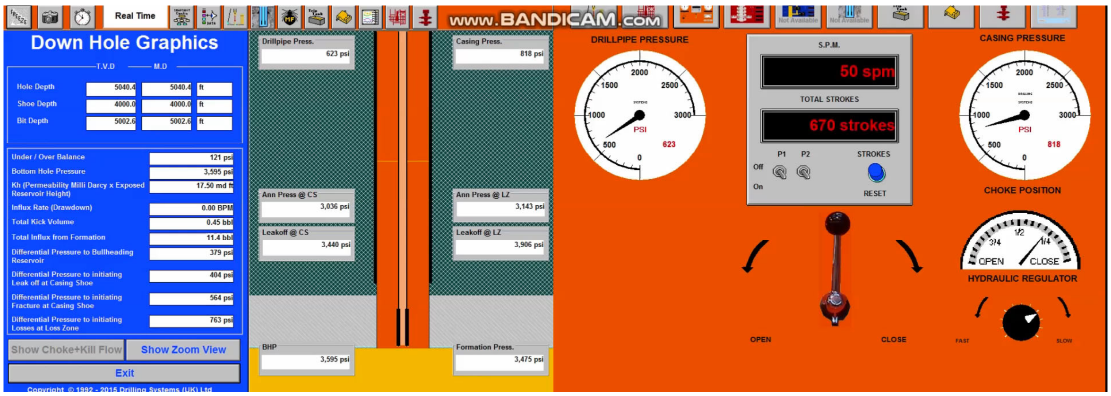
Driller's Method – 2nd Circulation



Wait & Weight Method

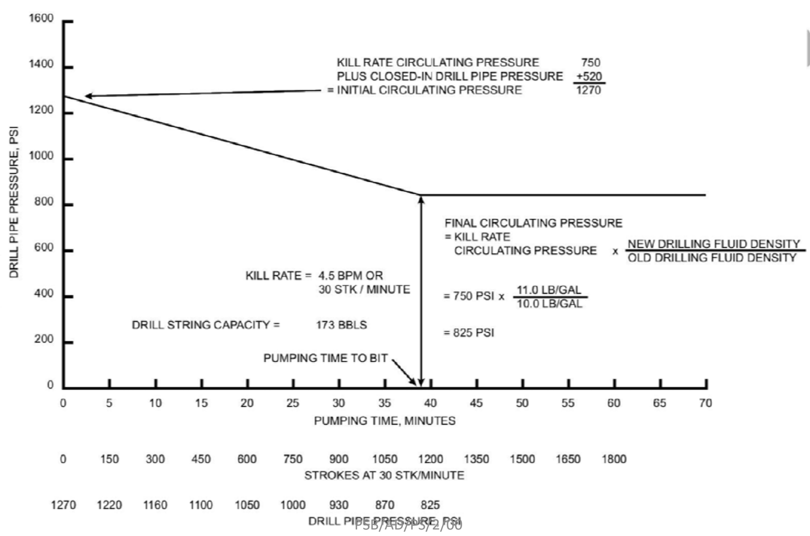
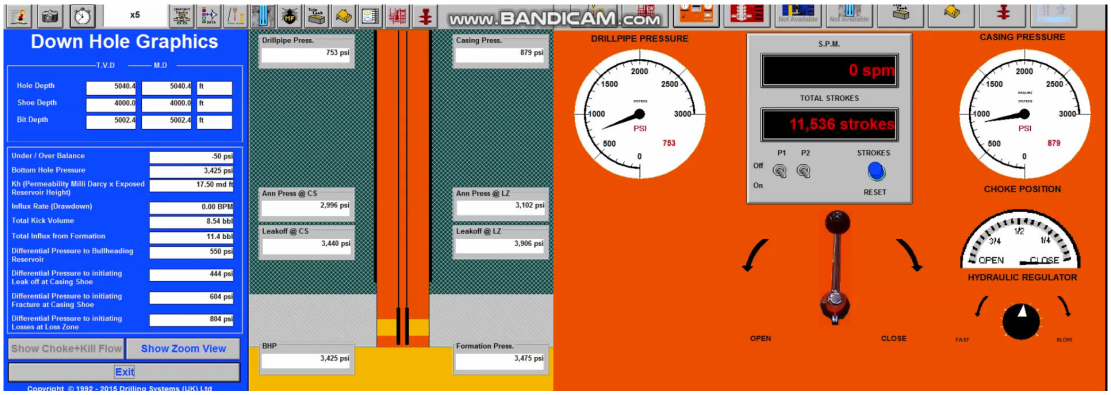
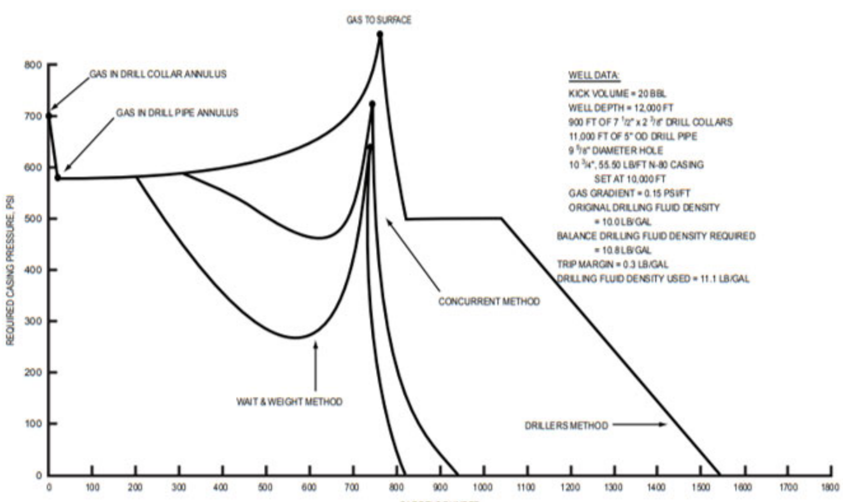


Figure 4.14—Drill Pipe Pressure Schedule for the Wait and Weight Method

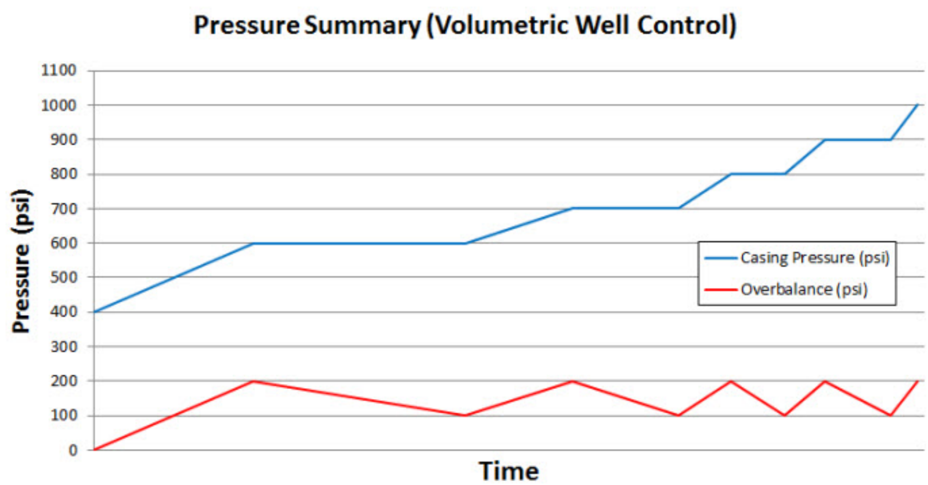
Wait & Weight Method



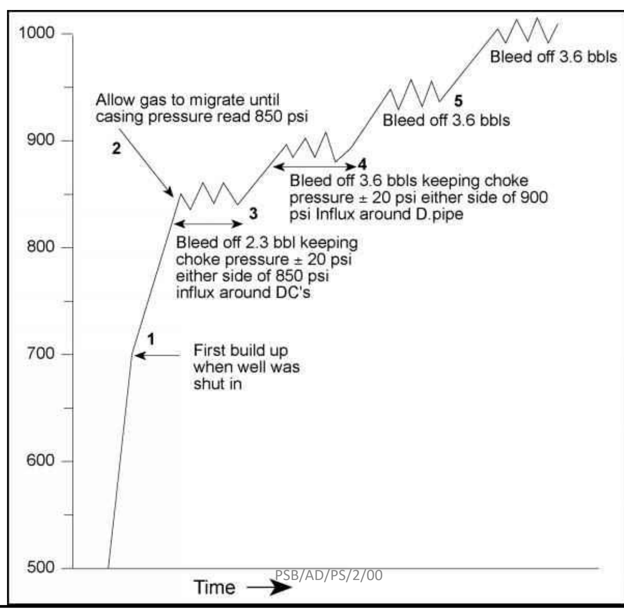
Driller’s Method Vs. W&W



Principles of Volumetric Method



Procedures of Volumetric Method



When to use Volumetric Method

- Normal circulation operations for well drilling are not always possible during well control procedures. A technique known as volumetric control can be used when:

1. Drill stem is a long way off the bottom,
2. There is a washout or parted drill stem near the surface,
3. The bit is plugged, or
4. The pumps are down.

Procedures of Lubricate & Bleed

$$\text{Hydrostatic pressure reduction (psi)} = \frac{53.0 \times \text{kill fluid density (lb/gal)} \times \text{vol. injected (bbls)}}{(\text{casing ID, in.})^2 - (\text{drill pipe OD, in.*})^2}$$

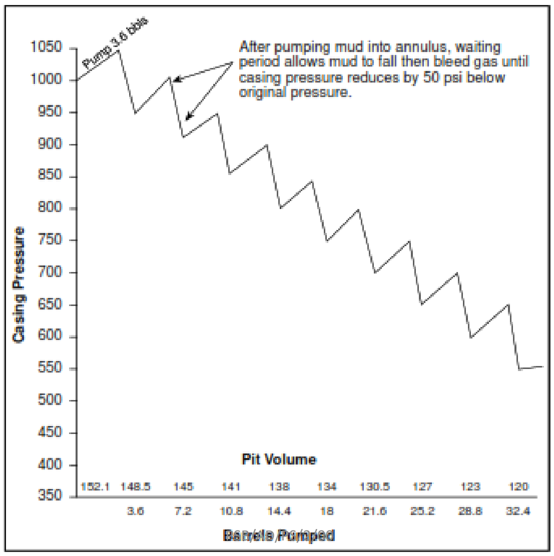
*Note: If pipe is out the hole, use 0.

Example: For 8 bbl of 12 lb/gal drilling fluid pumped into 9 5/8-in. 36-lb/ft casing with 4 1/2-in. drill pipe.

$$\text{Hydrostatic pressure reduction (psi)} = \frac{53.5 \times 12 \times 8}{(8.921)^2 - (4.5)^2} = \frac{53.5 \times 12 \times 8}{59.334} = 87 \text{ psi}$$

When to use Lubricate & Bleed

Figure 5.12 Graphical example of lubricating mud into annulus



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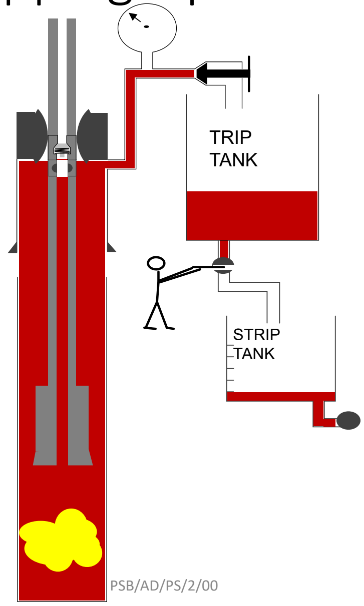
Principles of Stripping Operation



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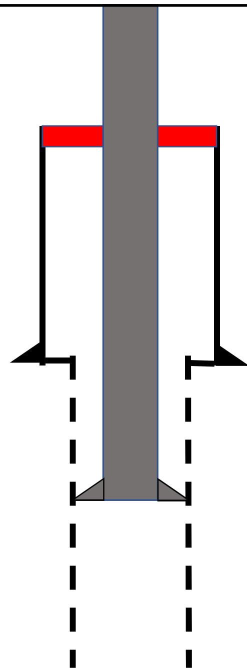
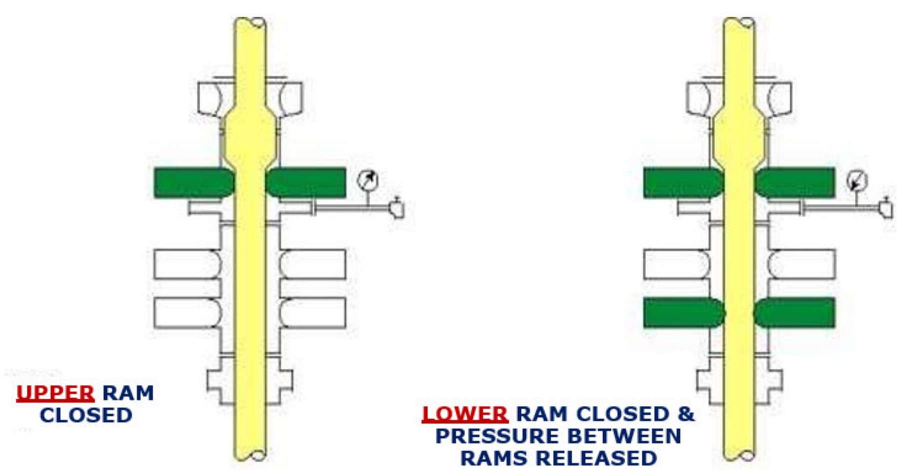
Procedures of Annular stripping

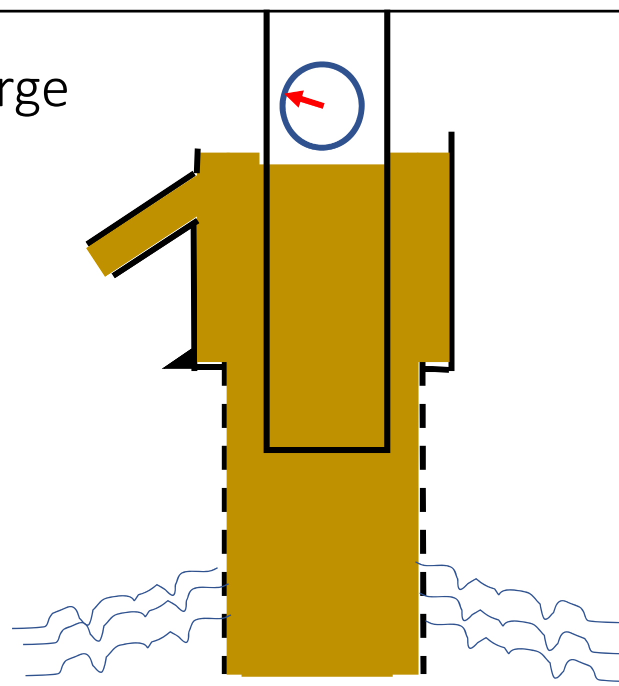


Procedures of RAM to RAM stripping



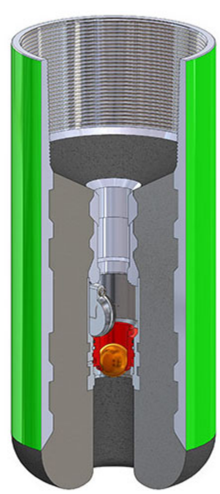
Well Control during Casing & Cementing

Risk of Swab & Surge



Mitigation of Swab & Surge

Float systems



Monitoring return

Drilling - English API Formula Sheet

29. HYDROSTATIC PRESSURE LOSS IF CASING FLOAT FAILS (psi)

$$\frac{\text{Mud Density (ppg)} \times 0.052 \times \text{Casing Capacity (bbl/ft)} \times \text{Unfilled Casing Height (ft)}}{\text{Casing Capacity (bbl/ft)} + \text{Annular Capacity (bbl/ft)}}$$

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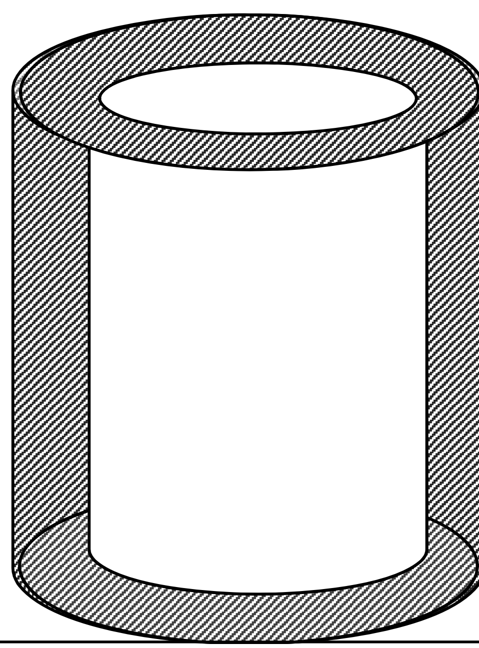
Calculating return



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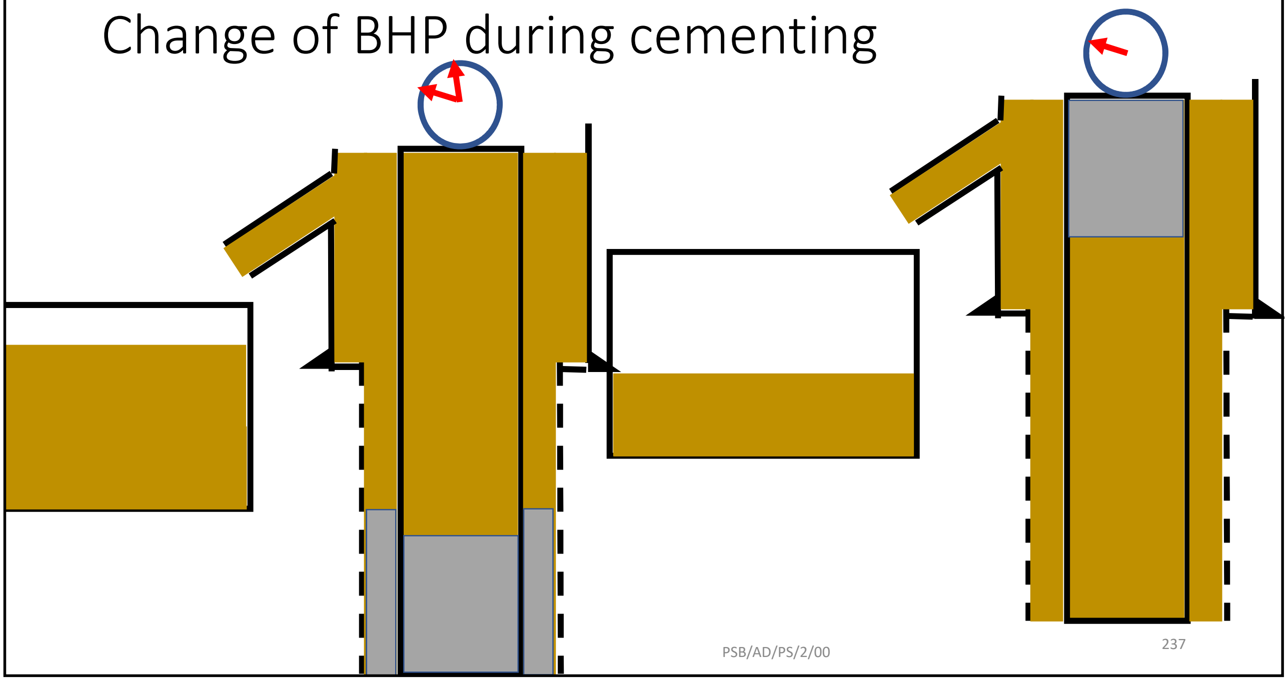
Change of BHP during cementing



Successful cement job

- Quality of successful cement job can be confirmed by:
- Check the pressure profile
- Accurately record returns
- Correct weight and quantity
- Give enough setting time as per lab testing
- Plugs bump at calculated volume
- No back flow.

Poor cement job

- Formation fluid could enter the casing or casing annuli during the life of the well due to different reasons such as;

- Incorrect placement
- Incorrect pressure testing
- Trapped pressure
- Cement degradation.

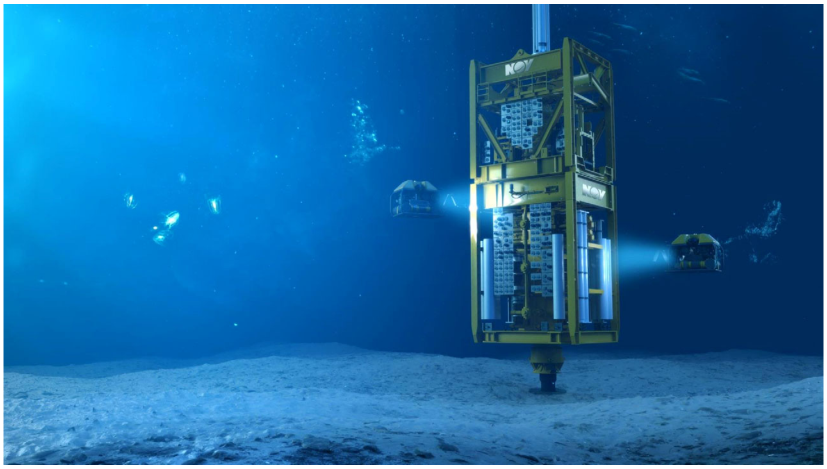
Shut-In the well during casing/cementing

1. Position the casing connection just above the rotary table and check for flow.
2. If a positive flow is confirmed, or if there is any doubt, install a casing swedge and full open safety valve.
3. Close the full-open safety valve.
4. Close the annular preventer (with closing pressure reduced to the appropriate value) or check space out and close casing rams (as per predetermined procedure).
5. Install the top drive, rig Kelly, or circulating head (as per the pre-determined procedure).
6. Open the choke line HCR valve.
7. Commence plotting a graph of SICP and SIDPP against time.
8. Check the pit volume again and record the pit volume increase.
9. Continue to monitor pressures and immediately report any change.

Well Control Management

Pit Drill

BOP Drill



Trip Drill

BHA Drill

Choke Drill

Stripping Drill

Diverter Drill

Exceeding MAASP

- Mechanical failure or formation breakdown can result from excessive casing pressure during initial closure or while circulating out a kick. Mechanical failure of the casing at the surface or of the BOP and related well control equipment could result in loss of well control. Formation breakdown can lead to loss of circulation, an underground blowout, and/or possible broaching to the surface. To prevent these failures a maximum allowable casing pressure must be determined as indicated on the well control worksheets

Contingency Planning

Problem's Indicator

Table 12.1—Indicators of Possible Problems while Circulating Out a Kick

Major Indication Larger Arrow ⬇ — Other Indication Smaller Arrow ↓

	Drill Pipe Pressure	Casing Pressure	Drill String Weight	Pit Level	Pump SPM
Choke Washes Out	⬇	⬇		⬆	↑
Gas Reaches Surface	⬇	⬇	↓	⬇	
Loss of Circulation	⬇	↓	⬆	⬇	↑
Hole in Drill String	⬇				↑
Pipe Parted	⬇		⬇		↑
Bit Nozzle Out	⬇				↑
Pump Volume Drops (Pump Damage Ñ Gas Cut Mud)	↓	↓			↑
Gas Feeding In		↑	↑	⬆	
Choke Plugs	⬆	⬆			↓
Bit Nozzle Plugs	⬆				↓
Hole Caved In	⬆		Stuck	↓	↓

Gauge failure

- Gauge malfunctions can be recognized by:
- Lack of sensitivity
- Comparison with alternative gauges
- Deviation from expected pressure.

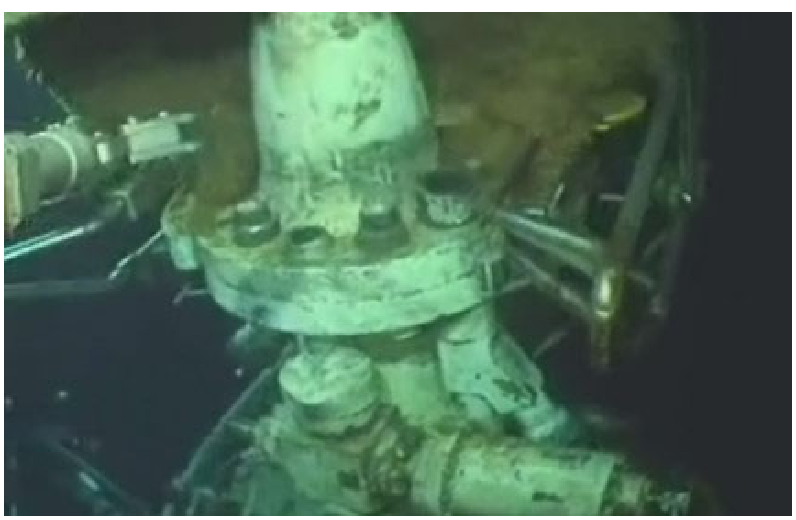
MGS Overloaded

TABLE 1—MUD/GAS SEPARATOR SIZING WORKSHEET

Slow pump rate information, q_{slow}	
Strokes per min	33
psi	790
bbl/stroke	0.091
bbl/min	3.0
Mud/gas separator data	
Separator body ID, in.	36
Gas vent-line ID, d_i, in.	7.0
Gas vent-line effective length, $L_e = L + L_{eq}$, L_{eq} from Table 2, ft	410
Kick data	
Old mud weight, lbm/gal	15.2
Initial shut-in drillpipe pressure, psi	520
Initial shut-in casing pressure, psi	640
Pit gain, bbl	24
True vertical depth, ft	14,400
Peak gas-flow rate calculation	
p_{cmax} for driller's method, psi	1,750
Volume of gas upstream of choke, V_{cmax}, bbl	75.9
Time to pump gas out of well, $t = V_{cmax}/q_{slow}$, minutes	25.3
Volume of gas downstream of choke, $V_c = p_{cmax} V_{cmax}/p_c$, bbl	9,036
Peak gas flow rate, $q_{max} = V_c 8085.6/t$, ft³/D	2,887,806
Vent-line friction-pressure calculation	
$pf = (5.0 \times 10^{-12})(L_e)(q_{max})^2/d_i^5$, psi	1.0
Mud-leg calculation	
Minimum mud leg required, p_f/g_{ml}, ft	3.8
Separator ID calculation	
Minimum separator ID, $15.56 \times \sqrt{q_{slow}}$ (bbl/min), in.	27

If the mud/gas separator does not meet the sizing criteria, refer to the section on trouble-shooting for suggested modifications.

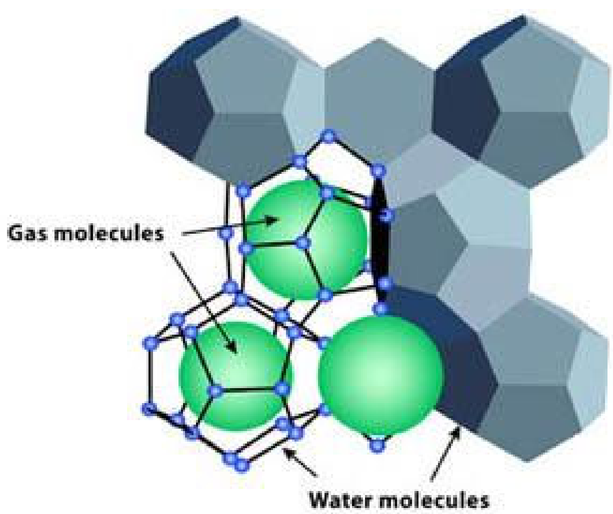
BOP Failure



Loss circulation during killing

- **To identify the lost circulation during a well control event:**
  - Pit level predictions
  - Annulus pressure predictions
  - Relevance of influx above the weak point.
- **Appropriate actions to take such as:**
  - Use a reduced kill speed
  - Reduce the choke line friction
  - Consider using Volumetric Method.

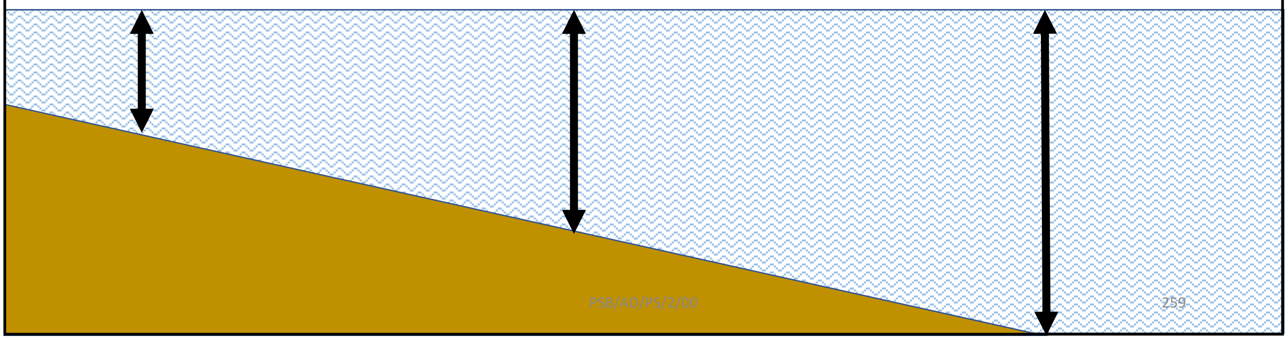
Hydrate Formation



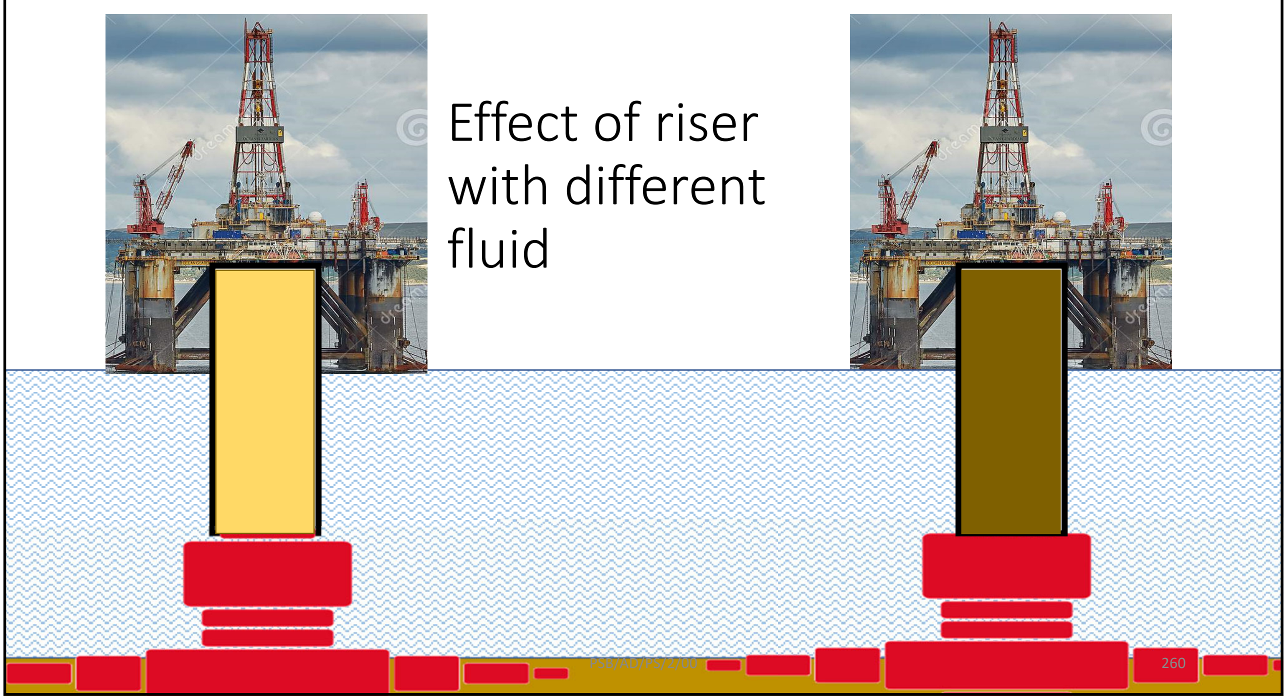
Hydrate Prevention & Removal

Subsea

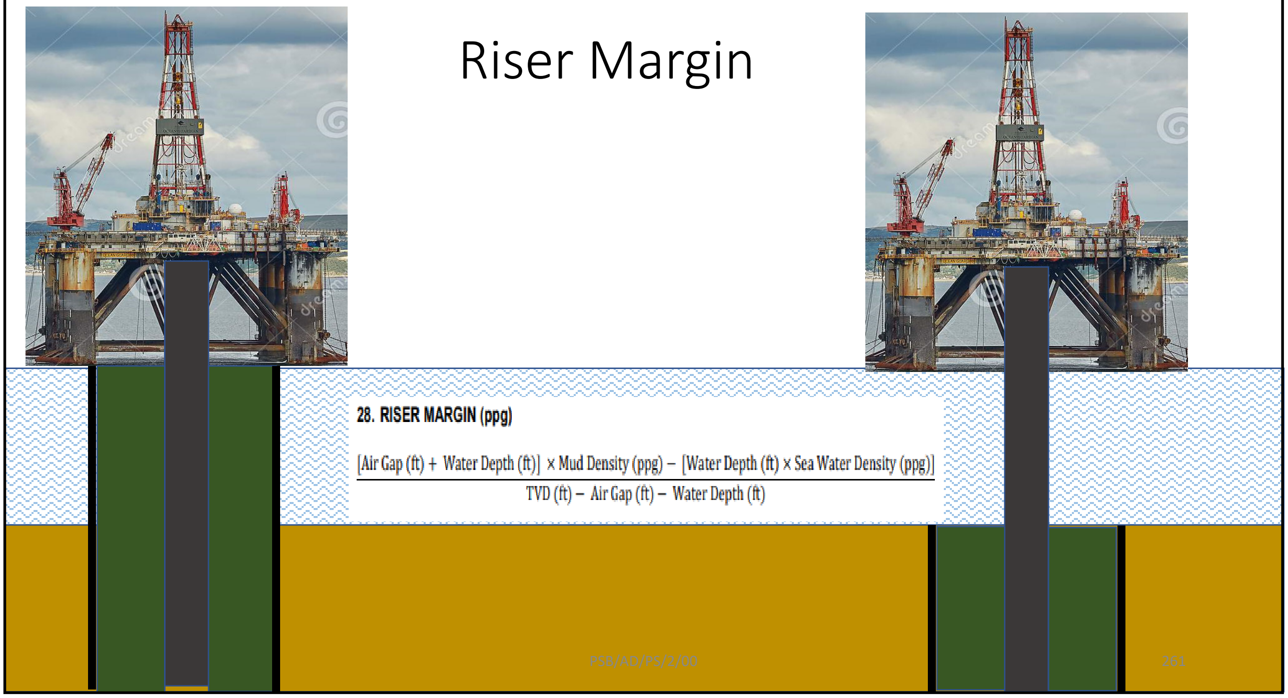
The effect of water depth on Fracture Pressure



Effect of riser with different fluid



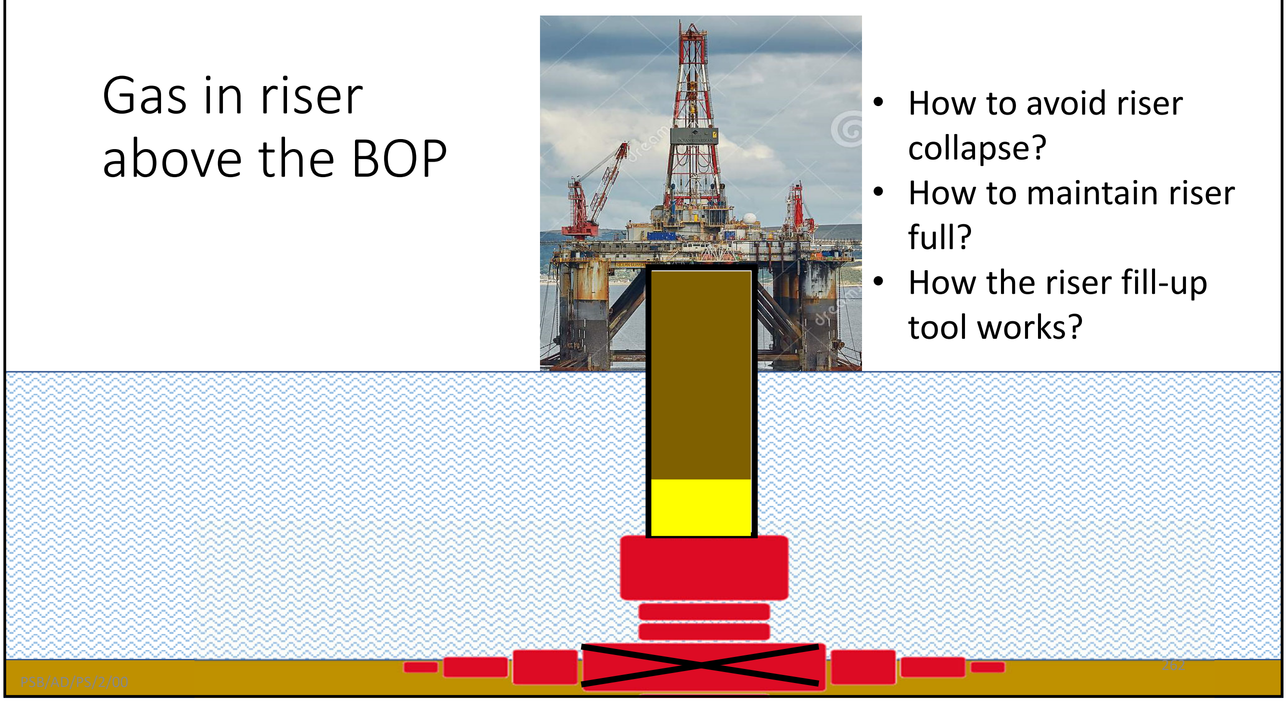
Riser Margin



28. RISER MARGIN (ppg)

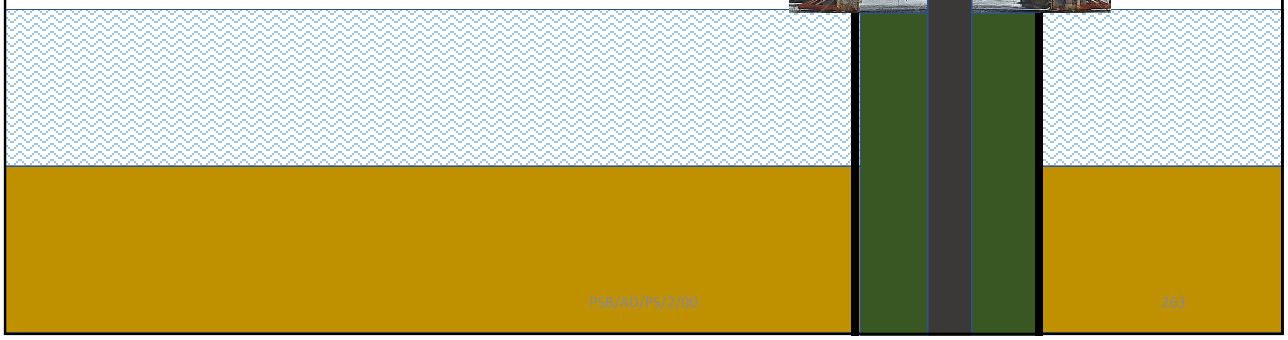
$$\frac{[\text{Air Gap (ft)} + \text{Water Depth (ft)}] \times \text{Mud Density (ppg)} - [\text{Water Depth (ft)} \times \text{Sea Water Density (ppg)}]}{\text{TVD (ft)} - \text{Air Gap (ft)} - \text{Water Depth (ft)}}$$

Gas in riser above the BOP

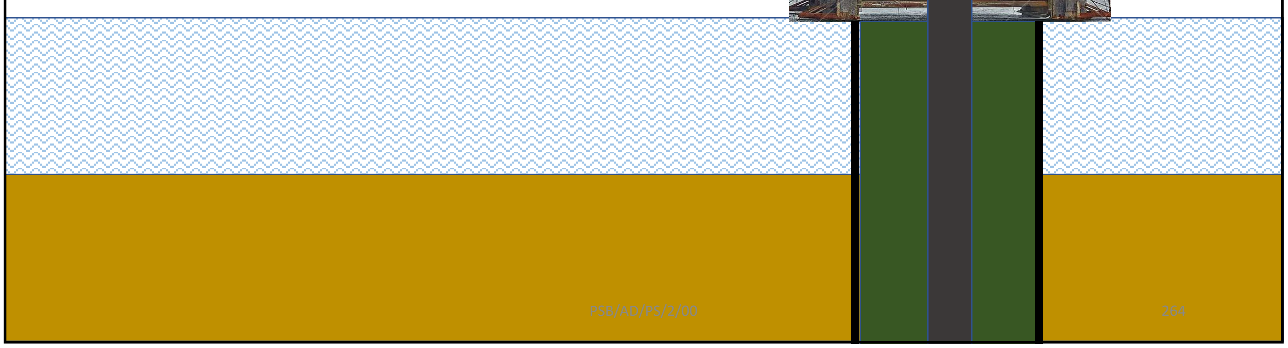


- How to avoid riser collapse?
- How to maintain riser full?
- How the riser fill-up tool works?

Swabbing & Surging for subsea



Kick Indicator While motion



Shallow gas impact

- Identify a shallow gas kick

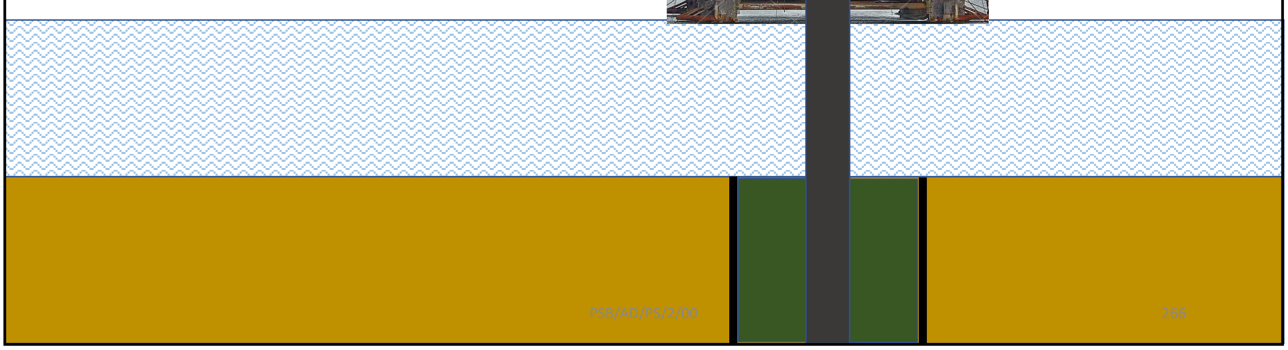
- Monitor the well by Visual (ROV) and sonar
- Surface visual (bubble watch)

- To minimize the impact:

- Anchors
- Rig move.

Top hole without riser

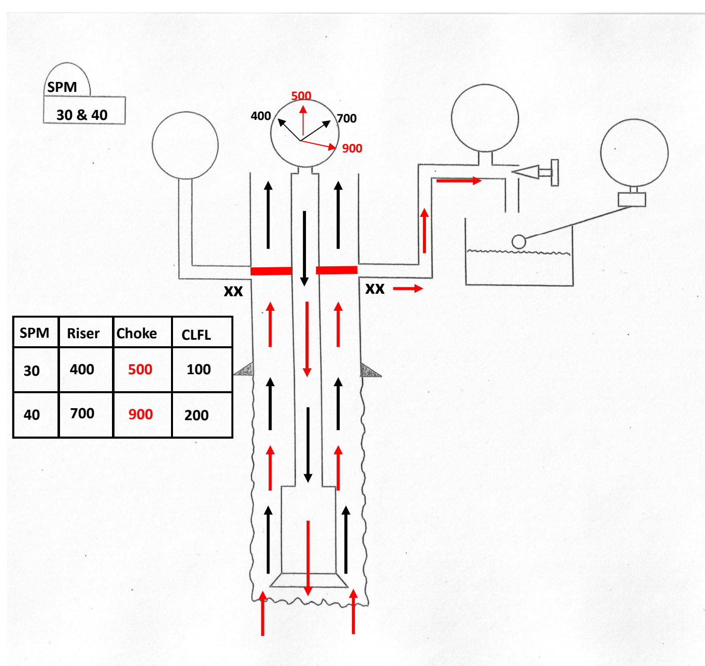
Drill top hole without a riser can help to:
- Avoid gas directly to the rig
- Move off quickly
- Avoid collapse of riser.



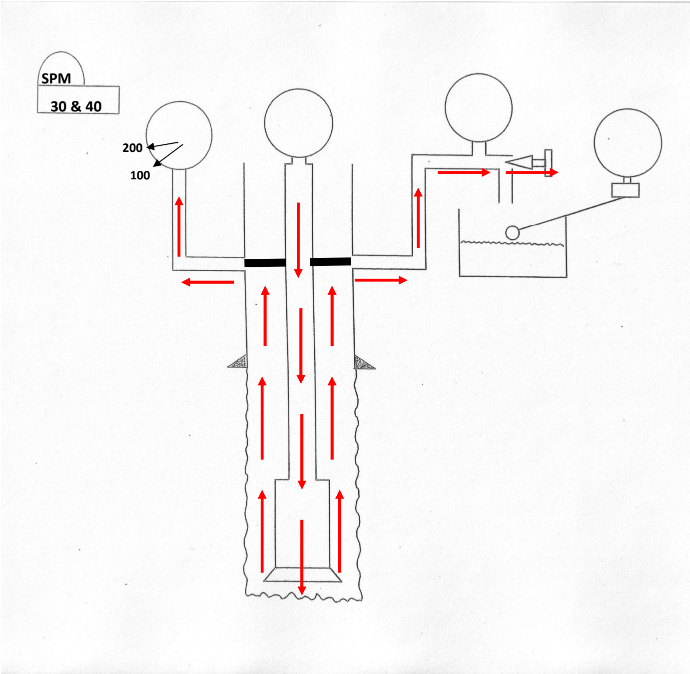
SCR – Subsea

SLOW PUMP RATE DATA:	(PL) P L					
	PUMP NO. 1			PUMP NO. 2		
	Riser	Choke Line	***Choke Line Friction***	Riser	Choke Line	***Choke Line Friction***
SPM						
SPM						

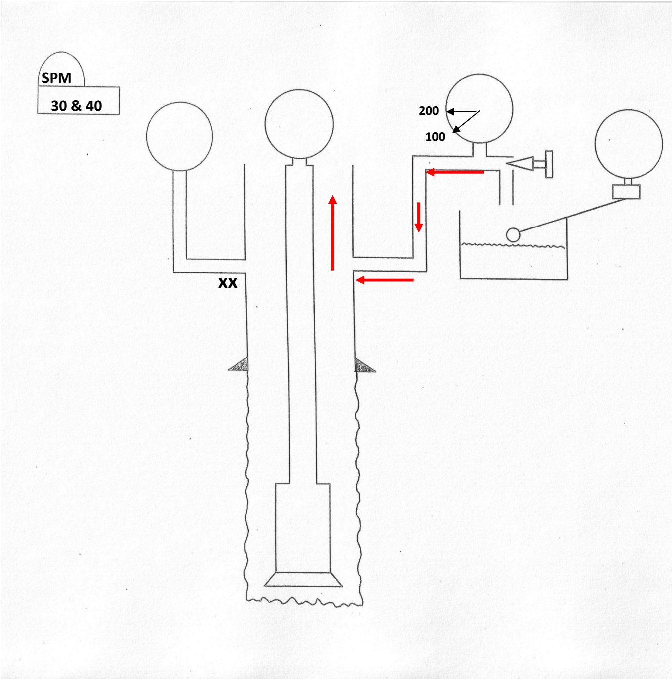
CLFL – 1st Method



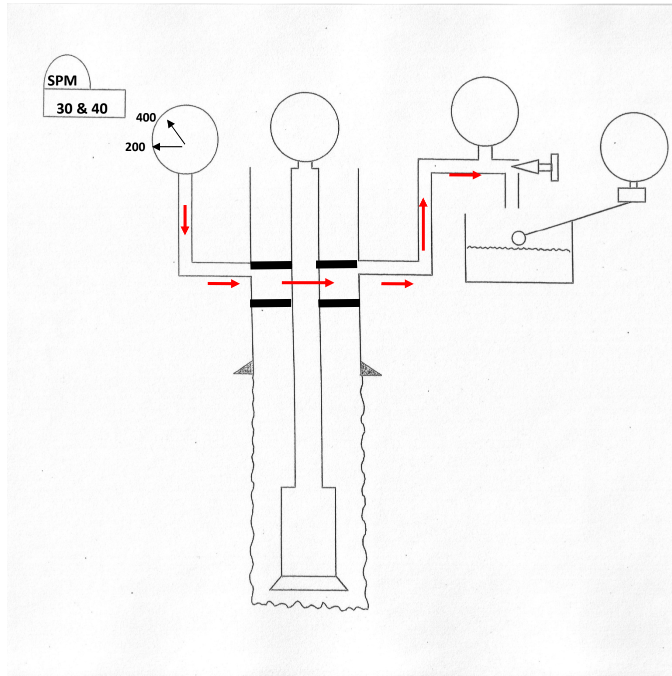
CLFL – 2nd Method



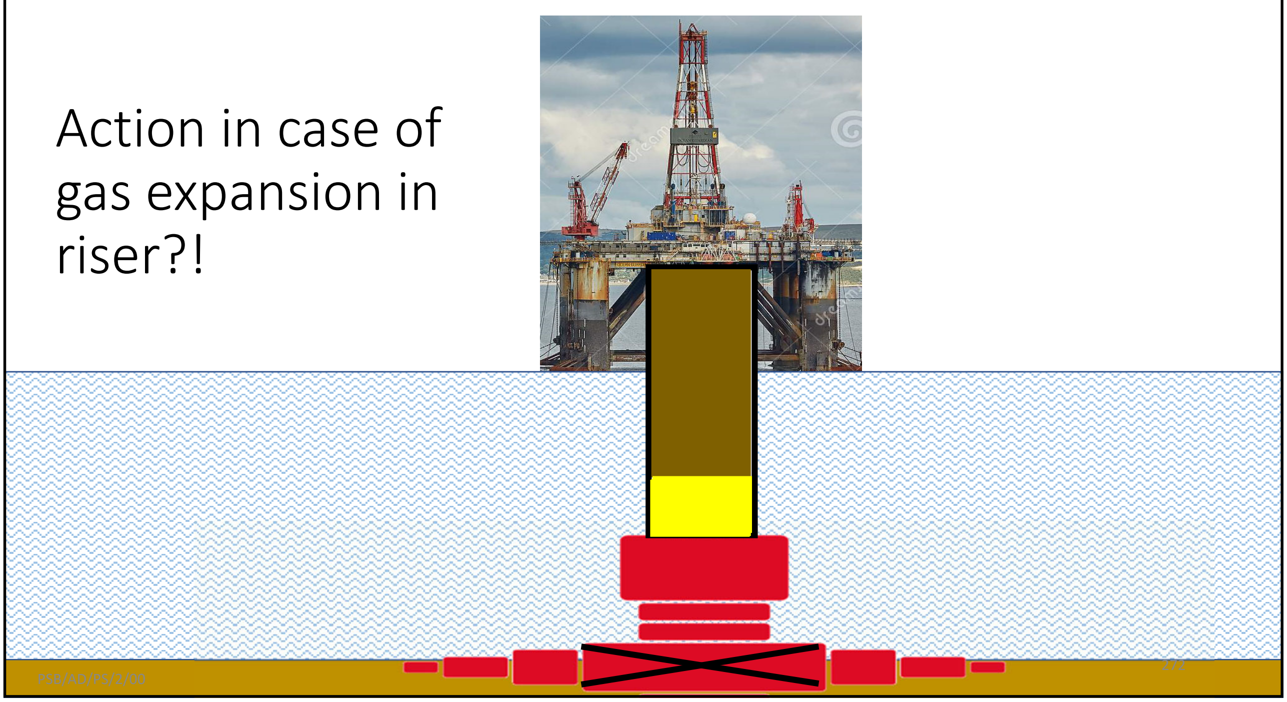
CLFL – 3rd Method



CLFL – 4th Method

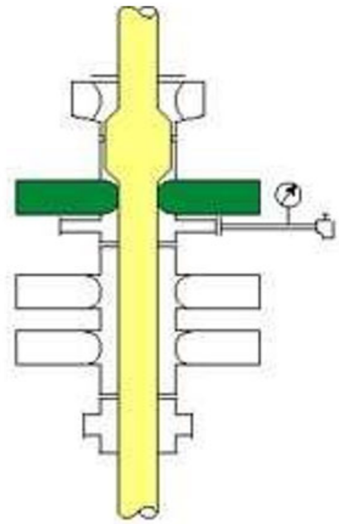


Action in case of gas expansion in riser?!

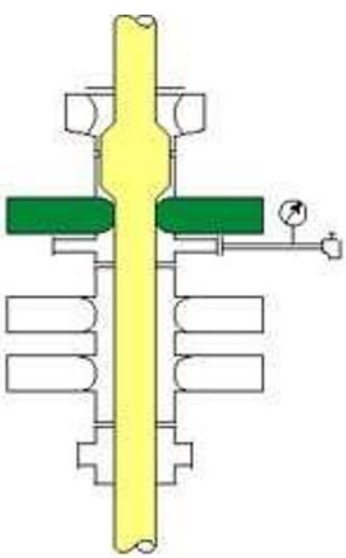


Hang Off Procedures

- Following prescribed procedures, the crew should place the drill string in position for hang-off.
- One hang-off should be made before drilling out of surface pipe to ensure that all necessary equipment is on hand and in working condition.

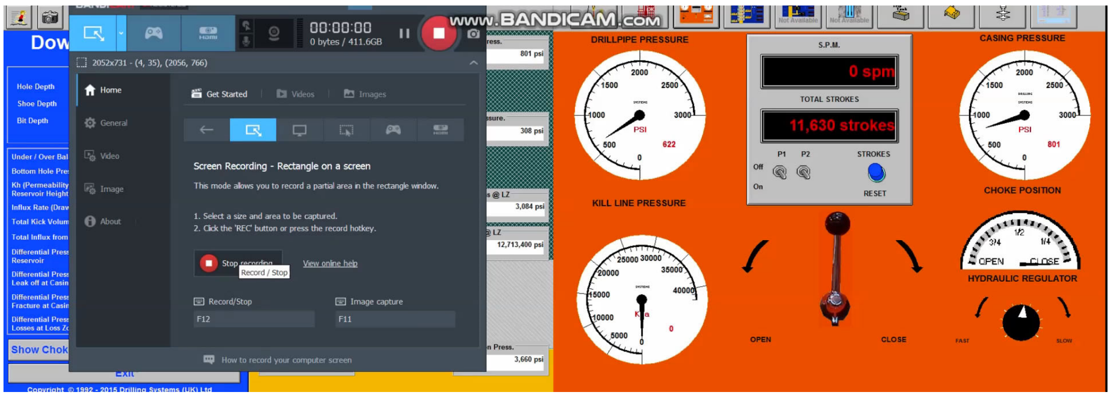


Hang-Off Drill



- Actual hang-off is not normally performed on subsequent drills.
- This drill can be conveniently performed in conjunction with the pit drill.

Start-up pump in subsea



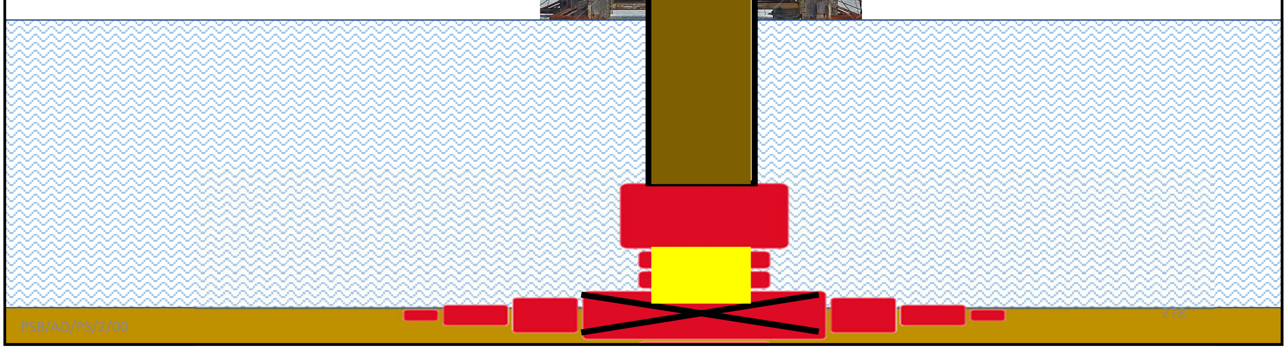
Constant BHP when changing SPM

Always keep **KLL LINE PRESSURE** Constant

Reduce CLFL

- Factors to reduce CLF:
- Pump rate
- Use of kill and choke line.

Displacing Riser

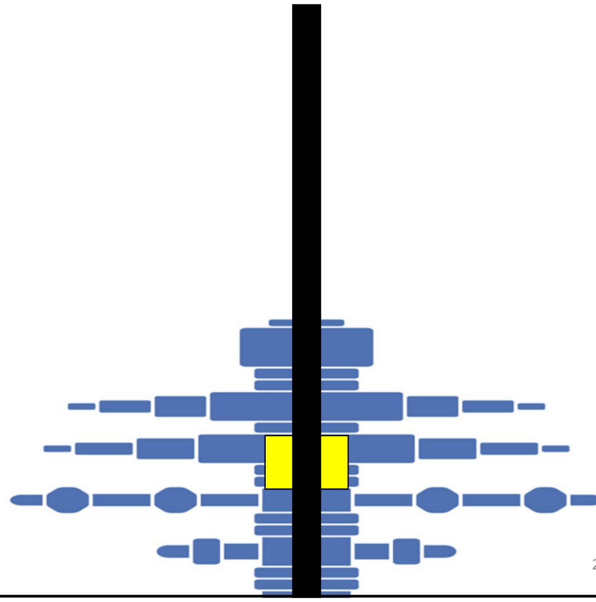
Removing gas trapped in BOP

The following data was available after a well control operation:

Well depth: 14,567 ft MD 8950 ft TVD
Air gap: 50 ft
Water depth: 1250 ft
Choke line length: 1356 ft
Mud density: 11.0 ppg
Kill fluid density: 12.8 ppg
Sea water gradient: 0.445 psi/ft
Atmospheric pressure: 14.7 psi

Kill mud has been circulated back to surface, the well shut in and pressures monitored for 15 minutes, with no build up, the well was opened up through the remote choke and observed on the trip tank for a further 15 minutes with no flow. The riser has yet to be displaced to kill mud and it is estimated that 1.5 bbls of gas are trapped below the upper pipe rams.

Calculate the expanded volume of gas at surface using the data above. ………………………….. bbl



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Drilling Well Control

Equipment

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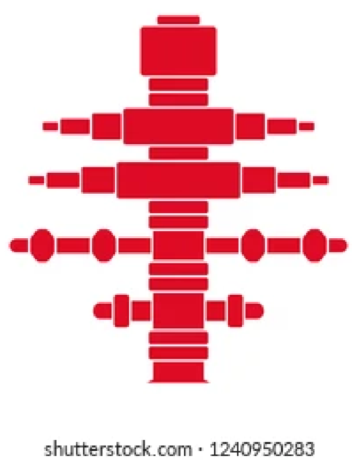
BOP Stack Configurations

BOP Function, configuration



Pressure rating

Rated Working Pressure (RWP) define as: the maximum anticipated annulus surface pressure

Pressure Designation	Rated Working Pressure
2K	2,000 psi (13.8 Mpa)
3K	3,000 psi (20.7 Mpa)
5K	5,000 psi (34.5 Mpa)
10K	10,000 psi (69.0 Mpa)
15K	15,000 psi (103.5 Mpa)
20K	20,000 psi (138.0 Mpa)
25K	25,000 psi (172.4 Mpa)
30K	30,000 psi (207 Mpa)
Note: 1 psi = 0.006894757 Mpa	

Stack Description

The **recommended component codes** for designation of blowout preventer stack arrangements are as follow:
A = annular type blowout preventer.
G = rotating head.
R = single ram type preventer with one set of rams.
Rd = double ram type preventer with two sets of rams.
Rt = triple ram type preventer with three sets of rams.
S = drilling spool with side outlet connections for choke and kill lines.

- A minimum of a **Class 2 BOP** stack arrangement with one blind ram or BSR shall be installed for wells with a MASP of **3000 psi or less.**
- A minimum of a **Class 3 BOP** stack arrangement with one blind ram or BSR and one pipe ram shall be installed for wells with a MASP of greater than **3000 psi to 5000 psi.**
- A minimum of a **Class 4 BOP** stack arrangement with one annular, one blind ram or BSR, and one pipe ram shall be installed for wells with a MASP of greater than **5000 psi to 10,000 psi.**
- A minimum of a **Class 5 BOP** stack arrangement with one annular, one BSR, and two pipe rams shall be installed for wells with a MASP of **greater than 10,000 psi.**

Annular Preventer

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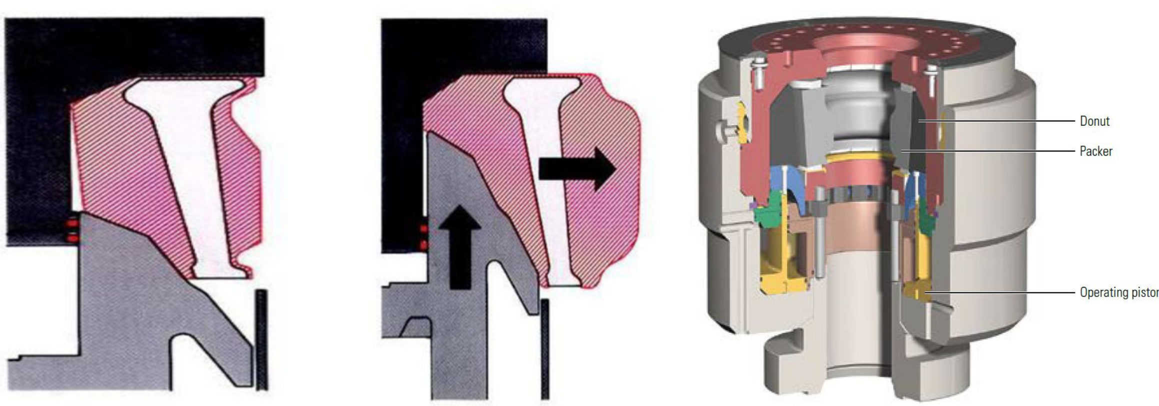
Operating principles of annular preventers



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Operating principles of annular preventers

Annular preventer packing types

Annular element composition will vary depending on the environment that they are to be used in.

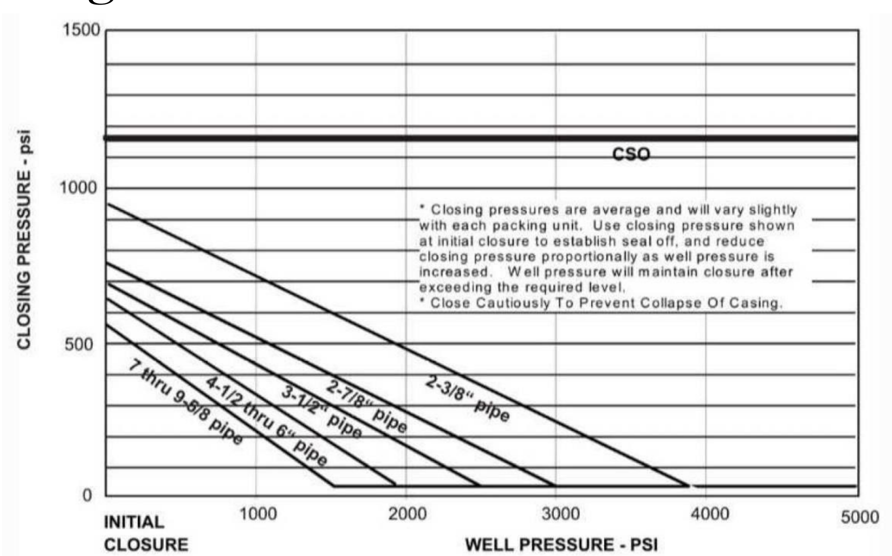
NATURAL	NITRILE Red	NEOPRENE Green

Water Based Muds	Oil based/Synthetic Muds	Oil based/Synthetic Muds
-30F to 225F Used in	20F to 180F	-30F to 170F
Used with wide range Temperatures	High Temperatures	Used in Cold Temps

If not stored correctly (i.e. exposed to UV light) the rubber can harden and prematurely split.

Deterioration and Failure

Closing Pressure



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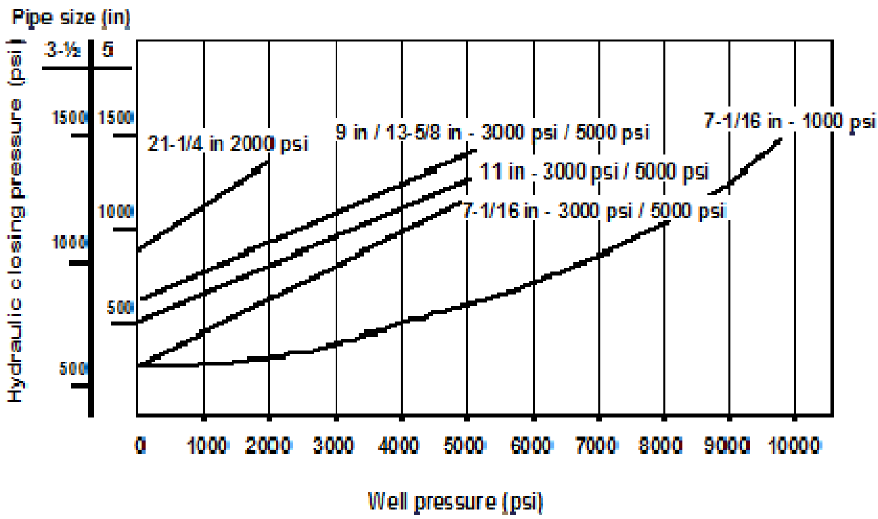
Stripping Pressure



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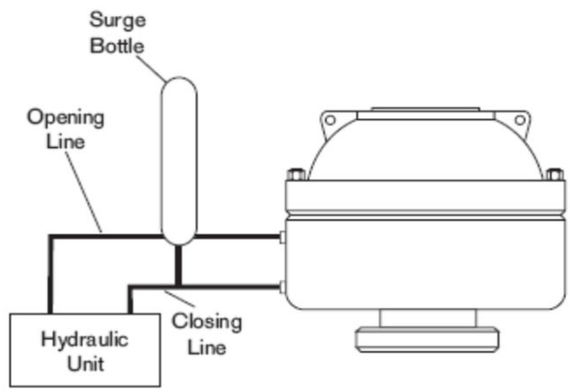
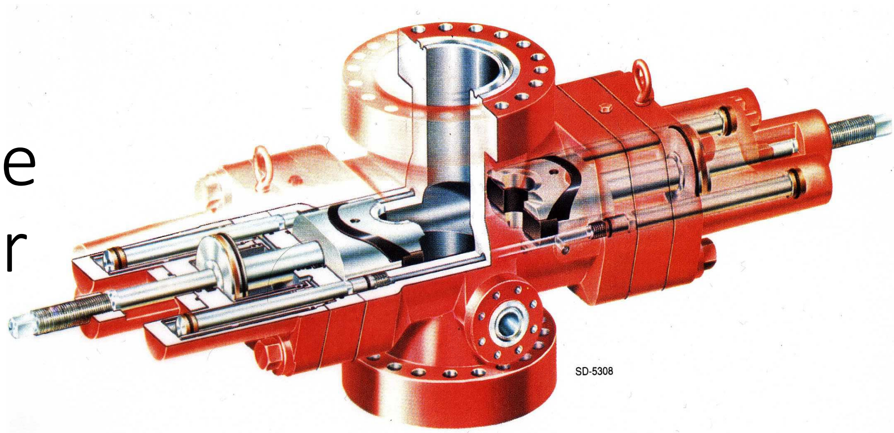
Surge Bottle

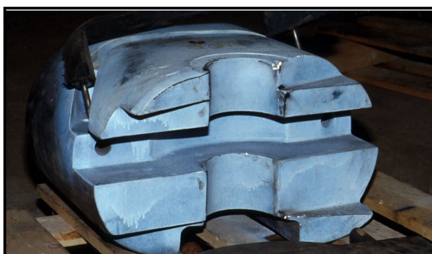
The purpose of the surge bottle is to reduce **the pressure surge,** which occurs in the BOP closing chamber each time a tool joint enters the closed packer. High pressure surges cause excessive and unnecessary **packer wear.**



RAM Type Preventer



Ram BOPs



Ram Body

BOP Body

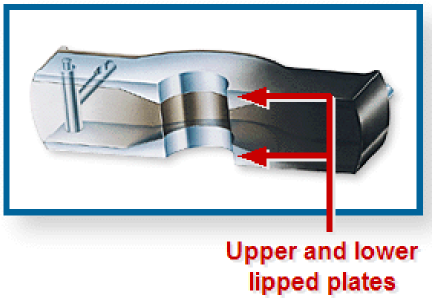
Packer and Top Seal

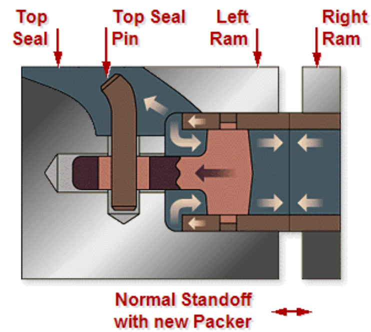
Intermediate Flange

Extrusion Plates

Extrusion plates:

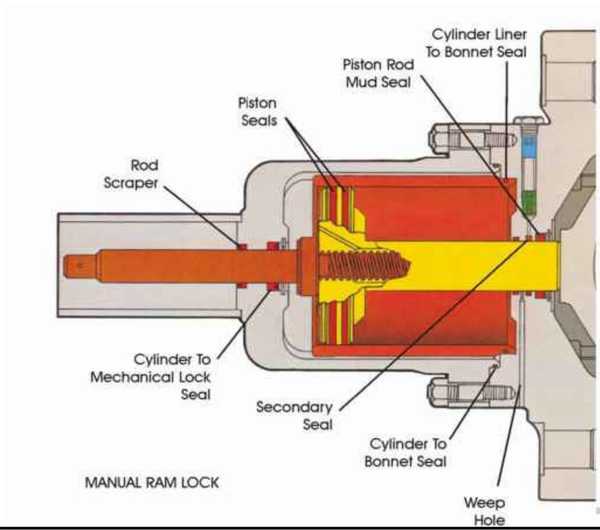
- To support the rubber to prevent **unwanted extrusion** due to well bore forces in the vertical direction.
- Act as pistons to extrude **feedable rubber** to the point of pipe contact.





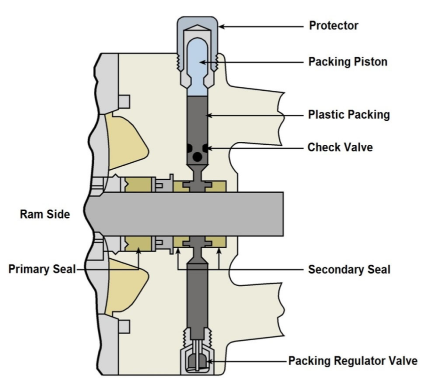
Primary Seal

Weep Hole



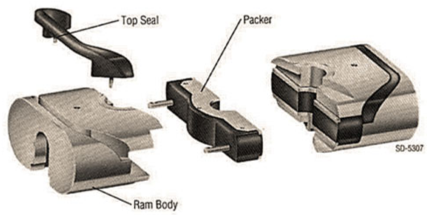
Secondary Seal

The plastic packing **is an emergency seal only**. It is only to be **used** if a ram piston seal leak is discovered **during a well kill operation.** The fluid coming out of the weep hole must be well fluid prior to engaging the plastic packing **(sealing the wellbore side).**



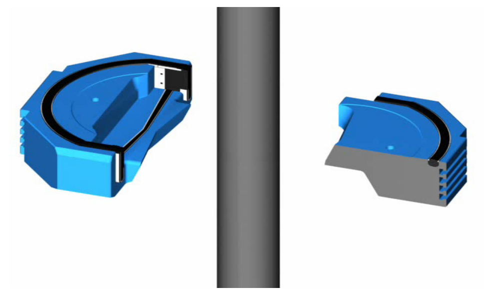
Fixed Rams

A closing and sealing component in a ram blowout preventer that **seals around a fixed outside diameter** of tubular in the wellbore. The ram packer is made of rubber and steel plates.

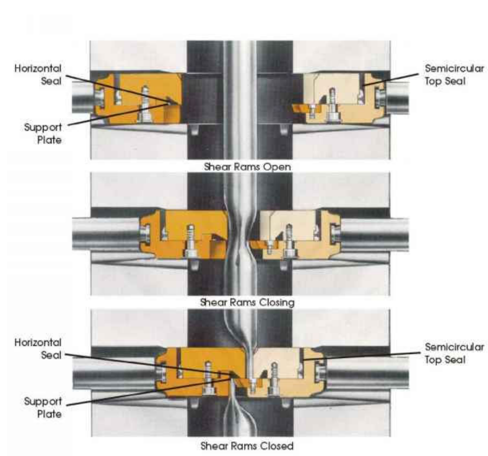


Variable Rams

Shear Blind Rams



Shear ram operational procedures



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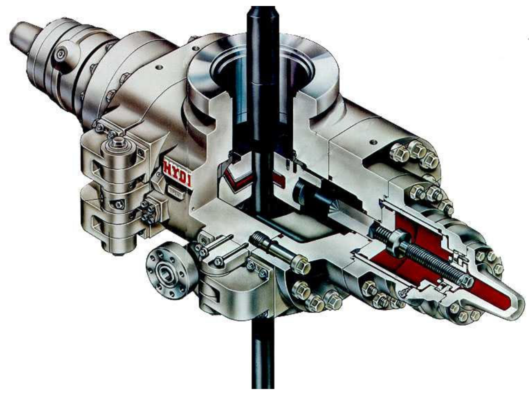
Hang-Off

Fixed Rams:

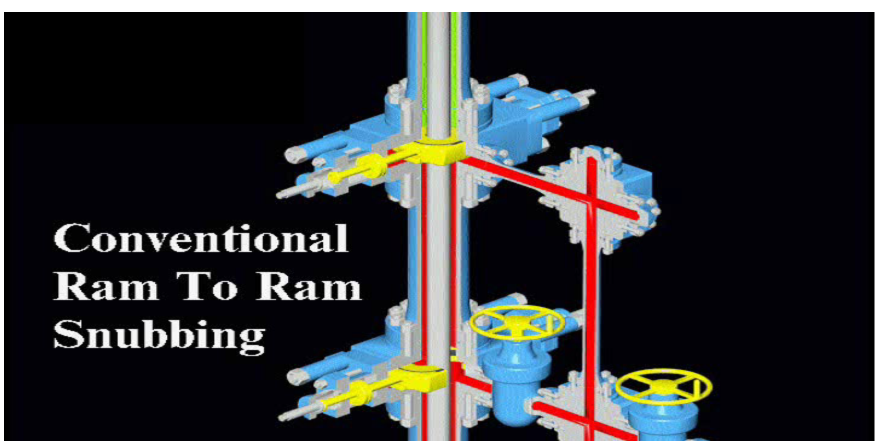
5" pipe	600,000 lbs
3 ½ " pipe	425,000 lbs

Variable Rams:

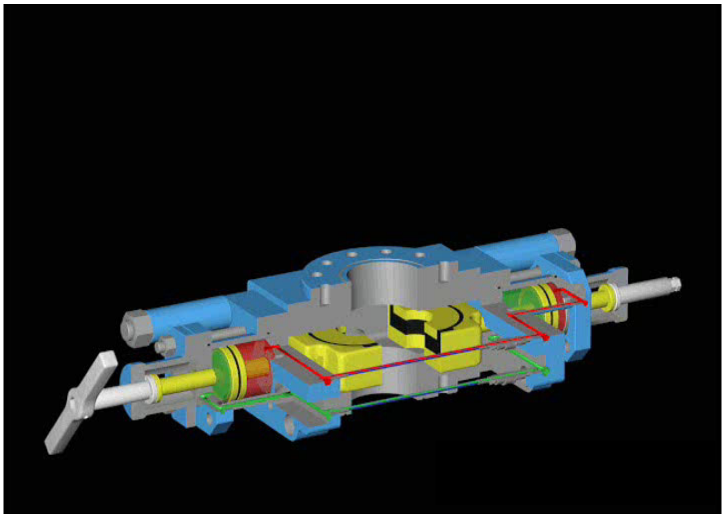
Consult **manufactures recommendations**



Ram Stripping

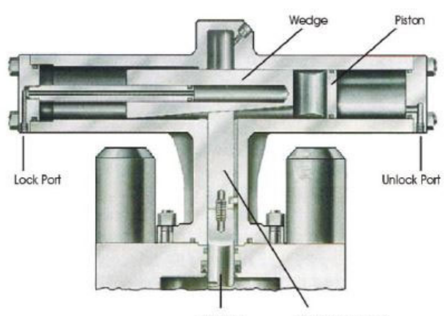


Locking Mechanism



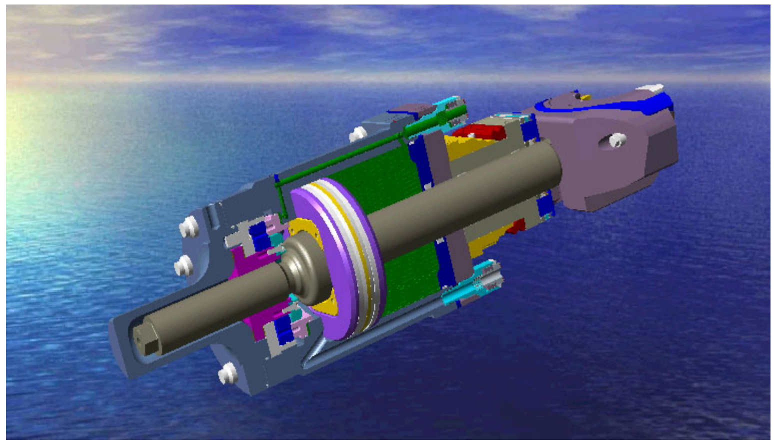
Locking Mechanism

Cameron Wedgelock:
The system **is not locking automatically,** but you can lock and unlock it **remote.** Pressure applied to the closing side will move the wedge to block for the operating piston. It **compensate for Rubber wear** in that it will just move in a little further. As long as the Wedgelock is set the Rams will be in closed position even with the Closing Pressure off **(Multi Position Lock).**



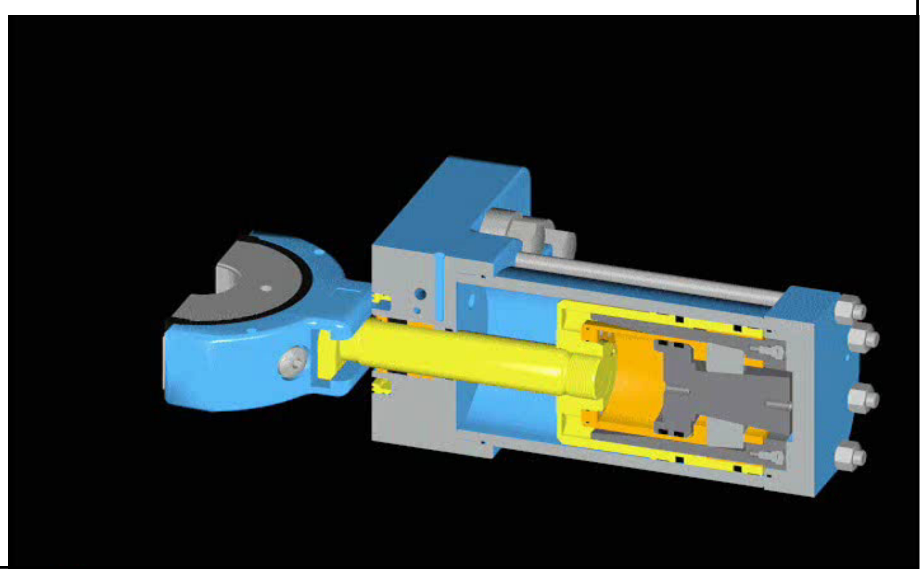
Locking Mechanism

Hydril Multi Position Lock:
Hydril ram blowout preventers are available with automatic Multiple-Position Locking system (MPL). This allows the ram to seal off with optimum seal squeeze at every closure.
MPL automatically locks and maintains the ram closed. Due to the Multiple-Position Locking system it will **compensate for rubber wear,** and the mechanical lock is automatically set each time the ram is closed **(Multi Position Lock).**



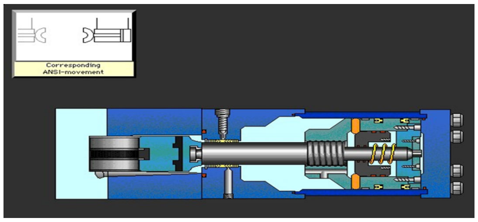
Locking Mechanism

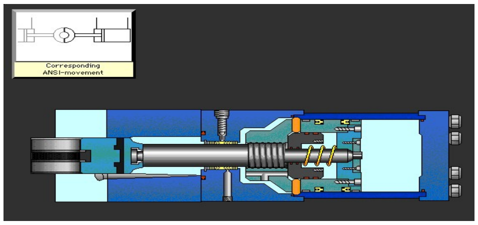
Shaffer Ultra Lock:
The locking system is a mechanical lock which consists of spring loaded segments that are engaged against restrained locking rods. The hydraulics required to operate the UltraLock are provided through the regular opening and closing ports of the preventer. **No additional hydraulic lines** or functions are required for operation of the locks **(Multi Position Lock).**



Locking Mechanism

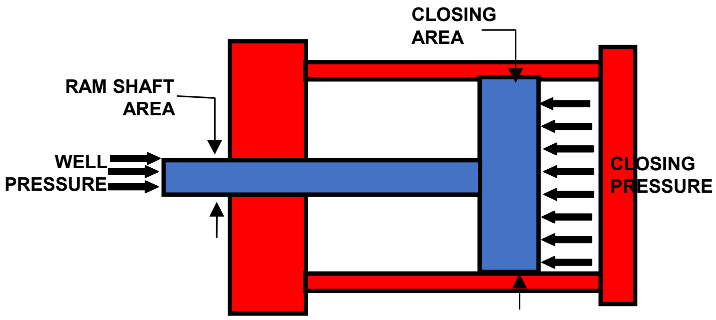
Shaffer Pos-Lock:
When closing hydraulic pressure is applied, the complete piston assembly moves inward and pushes the rams into the well bore. As the piston reaches the fully closed position, the locking segments slides towards the piston O.D. over **the locking shoulder** while the **locking cone** is forced inward by the closing **hydraulic pressure.**
Due to the fact that they lock the rams in at a predetermined position on the cylinder the poslock **does not have the capability to compensate for extra piston travel** due to ram packer wear **(Unique Position Lock).**





Closing Ratios

When a ram is closed against wellbore pressure the wellbore pressure act equally and opposite in all directions on the ram body. The only part of the ram body that is **out of balance** is the **area of the ram shaft.** The wellbore pressure acting upon the ram shaft is opposed by the hydraulic pressure from the control unit. The closing ratio is the ratio between these 2 areas.

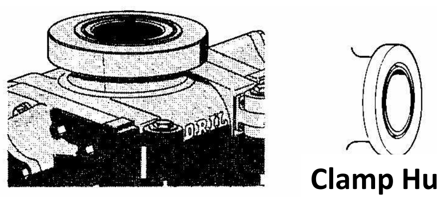


Side outlet valves & Connections

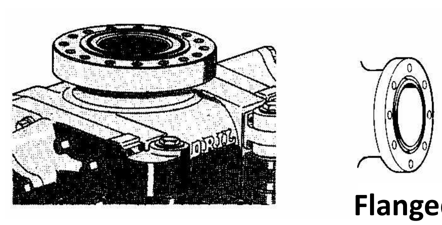
Drilling Spool

While choke and kill lines may be connected to side outlets of the blowout preventers, many operators prefer that these lines be connected to a drilling spool installed below at least one preventer capable of closing on pipe. Utilization of the blowout preventer side outlet reduces the number of stack connections by eliminating the drilling spool and shortens the overall preventer stack height. The reasons for using a drilling spool are to **localize possible erosion in the less expensive tool** and to allow **additional space between rams** to facilitate stripping operations.

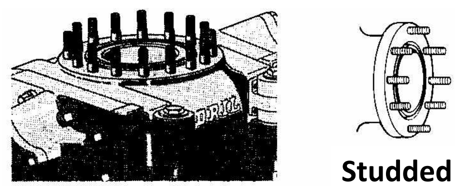
Connection Types



Clamp Hub



Flanged

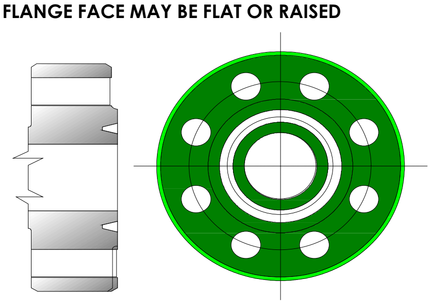


Studded

Flange Types and Ring Gaskets

TYPE 6B FLANGES

TYPE R OR RX TYPE RING GASKETS
DISTANCE BETWEEN MADE-UP FLANGES
FLANGE FACE MAY BE FLAT OR RAISED



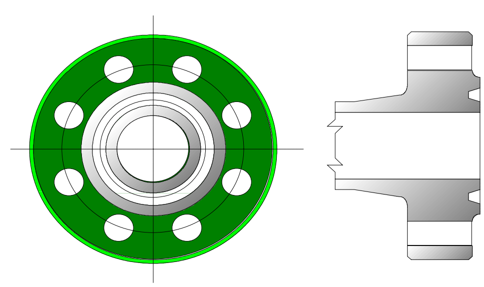
FLANGE SECTION TOP VIEW

PRESSURE RATING

2 – 5 K

TYPE 6BX FLANGES

TYPE BX RING GASKETS
FACE TO FACE MAKE UP
FLANGE FACE SHALL BE RAISED

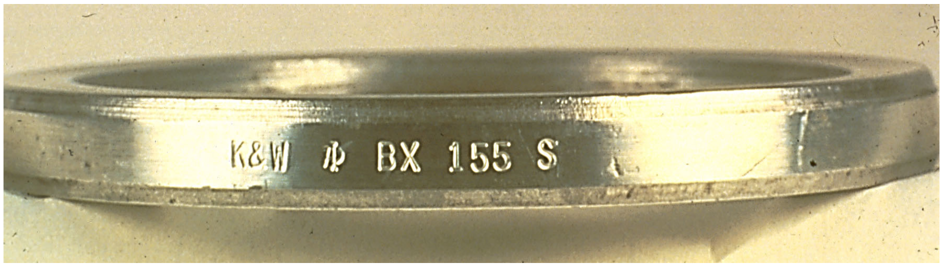


TOP VIEW FLANGE SECTION

PRESSURE RATING

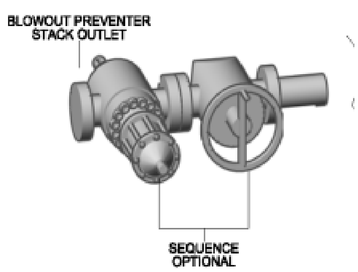
2 – 20 K

Ring Gaskets

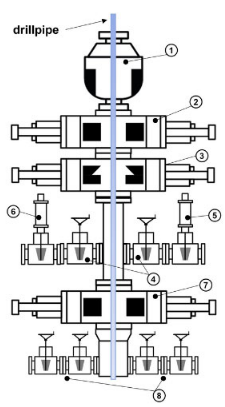


Use One Time Only

Optimal location and size



Drilling



Number	Description
1	annular BOP
2	upper pipe rams
3	blind/shear rams
4	manual valves
5	choke line remotely-controlled side outlet valve
6	kill line remotely-controlled side outlet valve
7	lower pipe rams
8	casing head valves

3.b. Surface BOP stack with remotely-controlled side outlet valves and drillpipe

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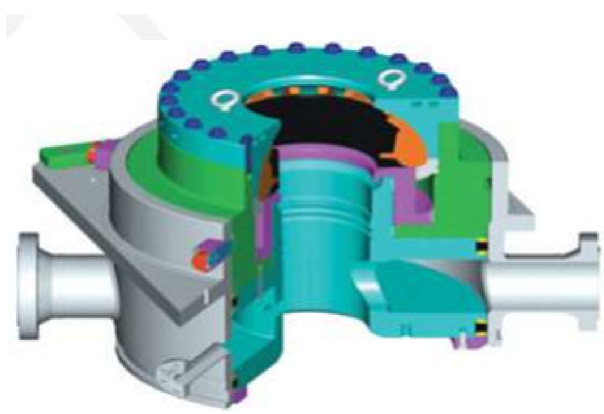
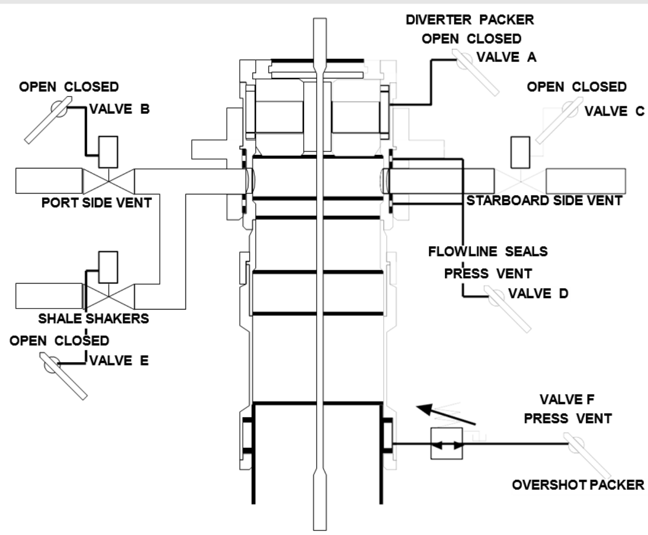
Diverter

Conventional diverter



Insert type diverter

Principles & Mechanism of diverter operations



Inside BOP’s

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Different types of safety valves

Full Opening Safety Valve

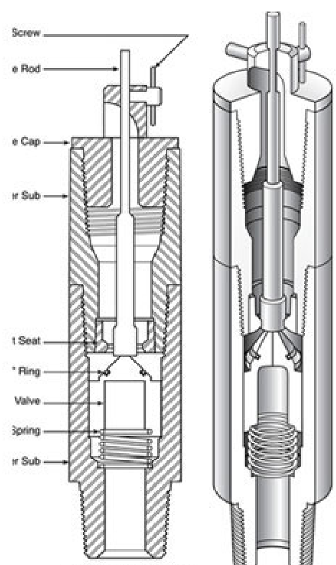

Figure E Inside BOP

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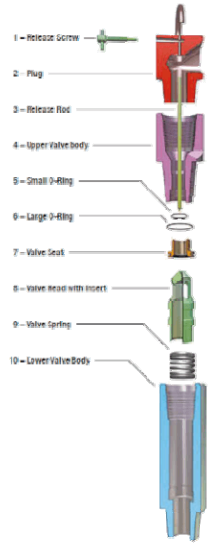
IBOP



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Float Valve

Open

Close

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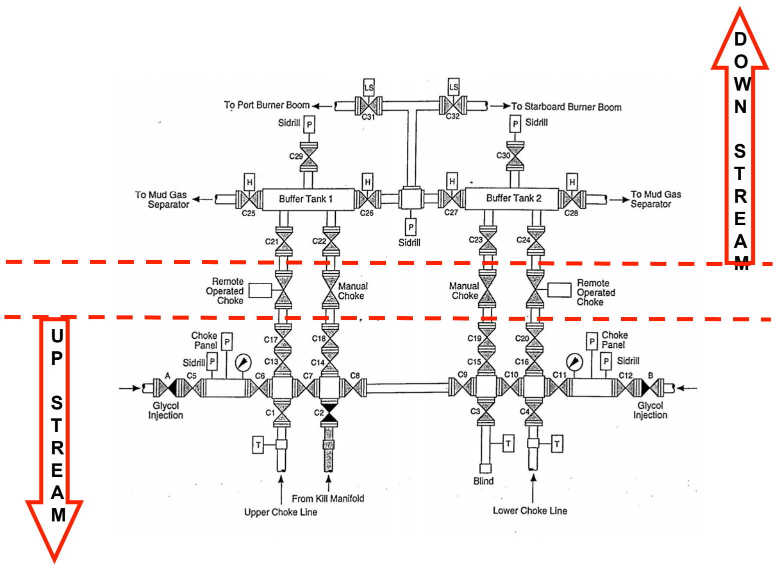
DPSV Installation

Choke manifolds & Chokes

Alternative circulating routes



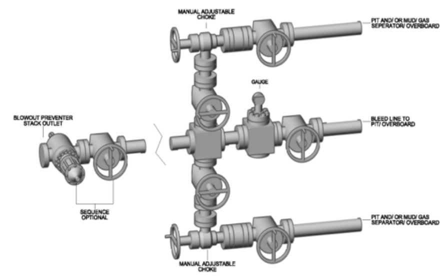
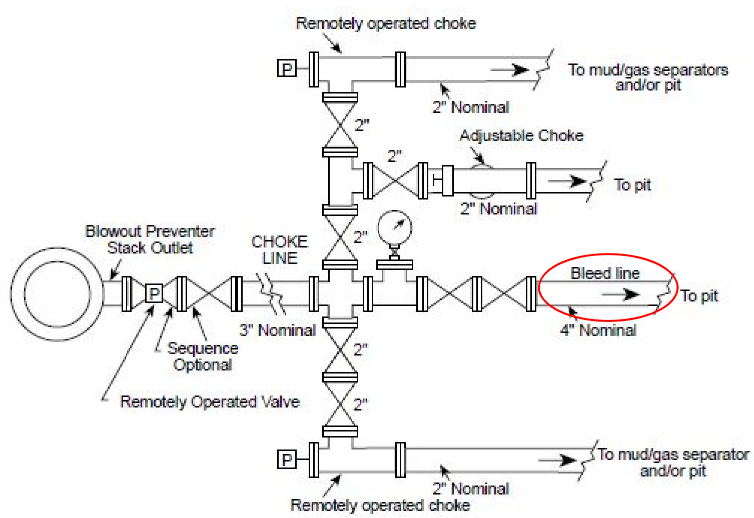
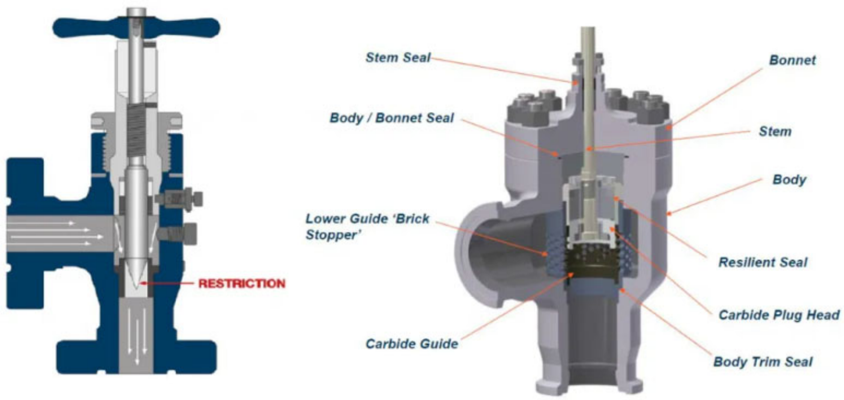


Figure 2—Example 2K and 3K RWP Choke Line and Choke Manifold for Land and Surface Offshore

The Bleed Line



Operating principles and limitations of adjustable chokes



Choke Remote Panel

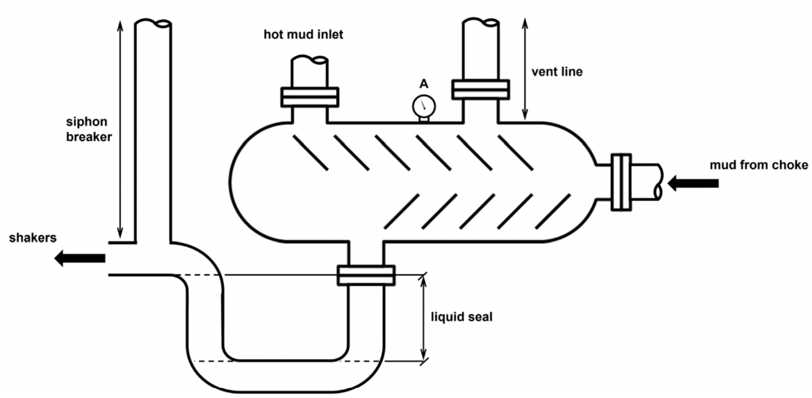
Minimum equipment for surface stack:

- CSG pressure gauge
- DP pressure gauge
- Air pressure
- Choke position
- Pump speed

MGS &Vacuum Degasser

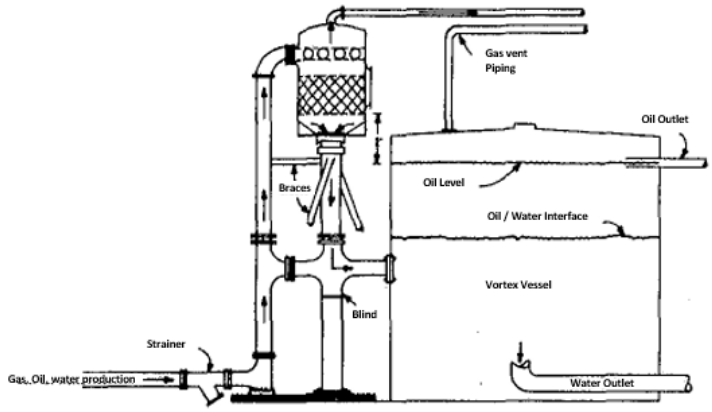
Operating principles and limitations of MGS

Drilling



1.b. Mud gas separator (MGS)

Operating principles and the role of a vacuum degasser



Degasser Installation & Associated Piping

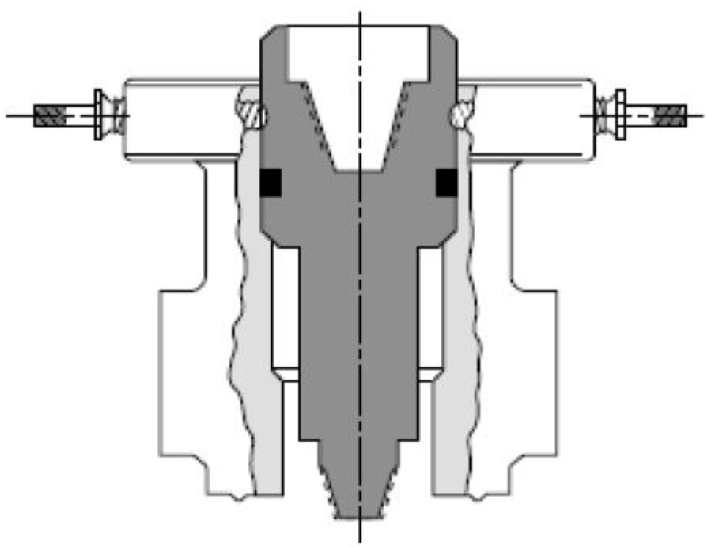
Testing

Importance of the procedures

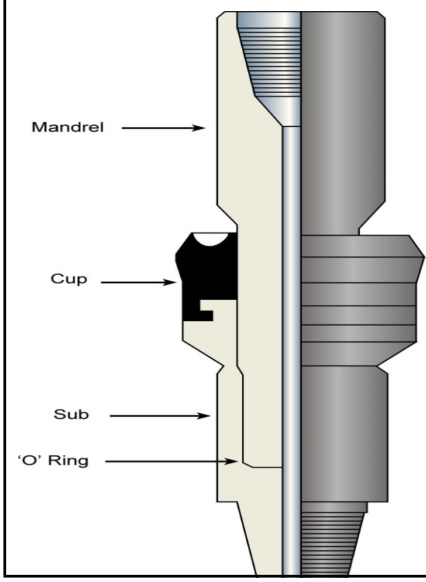
- The criteria for a successful pressure test:
- Direction of pressure applied
- Volume to be pumped
- Instrumentation
- Test fluids
- Test duration
- Safe pressure bleed off and monitored flow returns.

Test Plug





Cup Tester



Initial Function test

Table C.1—Initial Function Testing, Surface BOP Stacks

System/Component	Function Test Description	Test Acceptance Criteria
Dedicated Accumulator Systems Test		
Dedicated shear accumulators[a]	Drawdown tested by operation of high-pressure shear function(s)	Verification of intended operation may be in the form of flowmeter volume counts (when available), pressure testing, or other applicable means Verification that components actuated per design Final accumulator pressure greater than the MOP to secure the well
Primary Control Systems Test		
Control stations[abc]	Function test of all control stations and remote panels	Verification of intended operation
BOP stack operators and valves[a]	BOP functions tested (to include ram operators, annular operators, valves, high-pressure circuits) at maximum pressures expected for well control operations	Visual verification of no leaks Verification of intended operation may be in the form of visual inspection, flowmeter volume counts (when available), pressure testing, or other applicable means Response times to meet 5.3.6.2 Flowmeter volume counts (when available) to be within equipment owner's criteria
Main accumulator system[a] HPU pumps[a]	Drawdown test per 5.3.14 Cumulative output capacity of pump systems to be timed, charging the main accumulator after drawdown test to system RWP	Verification that the final accumulator pressure is greater than the MOP specified in system accumulator sizing Verification that system RWP is achieved within 15 minutes
BOP stack[a]	BOP to be drifted with a minimum diameter tool or drift as determined by the equipment owner and user's requirements	Pass completely through BOP stack after BOP initial pressure and function testing (16A acceptance criteria to drift within 30 minutes not applicable)
Drill Floor Safety Valves		
Valves[a]	Function test	Verification of intended operation
Choke Manifold Test		
Adjustable chokes[a]	Function test	Verification of intended operation

[a] Not required for pad drilling operations when moving to subsequent wells. Additional initial function testing is required for connections where the integrity of a pressure seal is broken.

[b] A function test from a remote panel satisfies the requirement for a local function test of the hydraulic control unit.

[c] Maintenance panels excluded.

Subsequent Function test

Table C.2—Subsequent Operational Function Testing, Surface BOP Stacks

System/Component	Function Test Description	Test Acceptance Criteria	Frequency
Dedicated Accumulator Systems Test			
Dedicated emergency shear accumulators	Drawdown test With charging system isolated, discharge the volume of the greatest consuming emergency system mode	Accumulator pressure greater than the MOP to secure the well	Not to exceed 180 days
Control Systems Test			
BOP rams, annulars, choke and kill valves (excluding shear rams)	Function tested from one designated control station[a] Control stations to be alternated between tests	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response times to meet 5.3.6.2 Flowmeter volume counts (when available) to be within the equipment owner's criteria	Not to exceed 7 days
Casing shear rams, BSRs, and blind rams	Function tested from one designated control station[a] Control stations to be alternated between tests	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response times to meet 5.3.6.2 Flowmeter volume counts (when available) to be within the equipment owner's criteria	Not to exceed 21 days
High-pressure casing shear ram circuit and high-pressure BSRs close circuit	Function tested from one designated control station[a] Control stations to be alternated between tests	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response times to meet 5.3.6.2 Flowmeter volume counts (when available) to be within the equipment owner's criteria	Not to exceed 90 days
Main accumulator system HPU pumps	Drawdown tested per 5.3.14 Cumulative output capacity of pump systems to be timed, charging the main accumulator after drawdown test to system RWP	Verification that the final accumulator pressure is greater than the MOP specified in system accumulator sizing Verification that system RWP is achieved within 15 minutes	Not to exceed 180 days[b]
Drill Floor Safety Valves			
Valves	Function test	Verification of intended operation	Daily
Choke Manifold Test			
Adjustable chokes	Function test	Verification of intended operation	Daily

[a] Maintenance panels excluded.

[b] Temperature variations can affect the usable volume in the accumulator system. An accumulator usable volume calculation or a drawdown test may be used to verify usable fluid when extreme temperature variations occur at the accumulator.

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Scheduled Function test

Table C.3—Scheduled Function Testing, Surface BOP Stacks

System/Component	Function Test Description	Test Acceptance Criteria	Frequency[a]
Primary Control Systems Test			
UPS battery test	Two-hour UPS system function test (the main UPS electrical supply isolated) with the BOP control system powered in routine drilling mode	Verification of the UPS battery system by operation of a single BOP stack function after two hours	Not to exceed 12 months
Control Fluid Reservoir (if applicable)	Control fluid reservoir mixing operation and level alarms	Verification that appropriate visual and/or audible alarm is received from each tank fluid level Verification of automatic mixing system functionality	Not to exceed 12 months
BOP stack hydraulic circuits	The integrity of the BOP stack hydraulic circuits to be verified with regulators set at maximum circuit pressure Test duration to be per equipment owner requirements	Visual verification of no leaks	Not to exceed 12 months
HPU pumps	HPU pump systems start and stop pressures	Verification that primary pump system automatically starts before system pressure has decreased to 90 % of the system RWP and automatically stops at system RWP ±2 % Verification that the secondary pump system automatically starts before system pressure has decreased to 85 % of the system RWP and automatically stops between 95 % and 100 % of the system RWP	Not to exceed 12 months

[a] Testing not to be conducted during operations.

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Function test requirements

EXAMPLE - SURFACE BOP SYSTEMS FUNCTION TEST WORKSHEET

Rig Name: ____________________

Date: ____________________

By: ____________________

BOP Classification: ____________________

Station: ____________________

Function	Close Time/Sec.	Close Vol./Gal.	Open Time/Sec.	Open Vol./Gal.
Annular				
Blind/blind shear				
Lower pipe ram				
Middle pipe ram				
Upper pipe ram				
Choke valve				
Kill valve				

Does the accumulator system function the RAM and annular BOPs with the proper time limits?

Each RAM BOP within in 30 seconds or less. Yes No

Closing time shall not exceed 30 seconds for annular BOPs smaller than 18 3/4 in. nominal bore and 45 seconds for annular preventers of 18 3/4 in. nominal bore and larger. Yes No

NOTE: Closing and opening time should be measured from the moment the function is activated to the initial moment the read back pressure gauge returns to is full operating pressure.

Figure B.1—Example BOP Function Test Worksheet for Land and Surface Offshore

Initial Pressure test

Table C.4—Initial Pressure Testing, Surface BOP Stacks

Component to be Pressure Tested	Pressure Test—Low Pressure[ac] psig (MPa)	Pressure Test—High Pressure[ac] Change Out of Component, Elastomer, or Ring Gasket	Pressure Test—High Pressure[ac] No Change Out of Component, Elastomer, or Ring Gasket
Annular preventer[b]	250 to 350 (1.72 to 2.41)	RWP of annular preventer	MASP or 70% annular RWP, whichever is lower.
Fixed pipe, variable bore, blind, and BSR preventers[bd]	250 to 350 (1.72 to 2.41)	RWP of ram preventer or wellhead system, whichever is lower	ITP
Choke and kill line and BOP side outlet valves below ram preventers (both sides)	250 to 350 (1.72 to 2.41)	RWP of side outlet valve or wellhead system, whichever is lower	ITP
Choke manifold—upstream of chokes[e]	250 to 350 (1.72 to 2.41)	RWP of ram preventers or wellhead system, whichever is lower	ITP
Choke manifold—downstream of chokes[e]	250 to 350 (1.72 to 2.41)	RWP of valve(s), line(s), or MASP for the well program, whichever is lower	
Kelly, kelly valves, drill pipe safety valves, IBOPs	250 to 350 (1.72 to 2.41)	MASP for the well program	

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks.
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the largest and smallest OD drill pipe to be used in well program.

[c] For pad drilling operations, moving from one wellhead to another within the 21 days, pressure testing is required for pressure-containing and pressure-controlling connections when the integrity of a pressure seal is broken.

[d] For surface offshore operations, the ram BOPs shall be pressure tested with the ram locks engaged and the closing and locking pressure vented during the initial test. For land operations, the ram BOPs shall be pressure tested with the ram locks engaged and the closing and locking pressure vented at commissioning and annually.

[e] Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required.

Subsequent Pressure test

Table C.5—Subsequent Operational Pressure Testing, Surface BOP Stacks

Component to be Pressure Tested	Pressure Test—Low Pressure[a] psig (MPa)	Pressure Test—High Pressure[a]	Frequency
Annular preventer[b]	250–350 (1.72–2.41)	MASP for the hole section or 70 % annular RWP, whichever is lower	Not to exceed 21 days
BOP side outlet valves above pipe ram preventers (wellbore side)	250–350 (1.72–2.41)	MASP for the hole section or 70 % annular RWP, whichever is lower	Not to exceed 21 days
BOP side outlet valves above pipe ram preventers (non-wellbore side)	250–350 (1.72–2.41)	MASP for the hole section	Not to exceed 21 days
Fixed and variable bore pipe ram preventers[b]	250–350 (1.72–2.41)	MASP for the hole section	Not to exceed 21 days
Choke and kill line and BOP side outlet valves below pipe ram preventers (both sides)	250–350 (1.72–2.41)	MASP for the hole section	Not to exceed 21 days
Choke manifold—upstream of chokes[c]	250–350 (1.72–2.41)	MASP for the hole section	Not to exceed 21 days
Choke manifold—downstream of chokes[c]	250–350 (1.72–2.41)	RWP of valve(s), line(s), or MASP for the hole section, whichever is lower	Not to exceed 21 days
Kelly, kelly valves, drill pipe safety valves, IBOPs	250–350 (1.72–2.41)	MASP for the hole section	Not to exceed 21 days
Blind and BSR preventers	250–350 (1.72–2.41)	Casing test pressure	At casing points

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks.
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the smallest OD drill pipe expected to be used in the next 21 days.

[c] Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required.

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Subsequent Pressure test

Table C.5—Subsequent Operational Pressure Testing, Surface BOP Stacks

Component to be Pressure Tested	Pressure Test—Low Pressure[a] psig (MPa)	Pressure Test—High Pressure[a]	Frequency
Annular preventer[b]	250–350 (1.72–2.41)	MASP for the hole section or 70 % annular RWP, whichever is lower	Not to exceed 21 days
BOP side outlet valves above pipe ram preventers (wellbore side)	250–350 (1.72–2.41)	MASP for the hole section or 70 % annular RWP, whichever is lower	Not to exceed 21 days
BOP side outlet valves above pipe ram preventers (non-wellbore side)	250–350 (1.72–2.41)	MASP for the hole section	Not to exceed 21 days
Fixed and variable bore pipe ram preventers[b]	250–350 (1.72–2.41)	MASP for the hole section	Not to exceed 21 days
Choke and kill line and BOP side outlet valves below pipe ram preventers (both sides)	250–350 (1.72–2.41)	MASP for the hole section	Not to exceed 21 days
Choke manifold—upstream of chokes[c]	250–350 (1.72–2.41)	MASP for the hole section	Not to exceed 21 days
Choke manifold—downstream of chokes[c]	250–350 (1.72–2.41)	RWP of valve(s), line(s), or MASP for the hole section, whichever is lower	Not to exceed 21 days
Kelly, kelly valves, drill pipe safety valves, IBOPs	250–350 (1.72–2.41)	MASP for the hole section	Not to exceed 21 days
Blind and BSR preventers	250–350 (1.72–2.41)	Casing test pressure	At casing points

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks.
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the smallest OD drill pipe expected to be used in the next 21 days.

[c] Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required.

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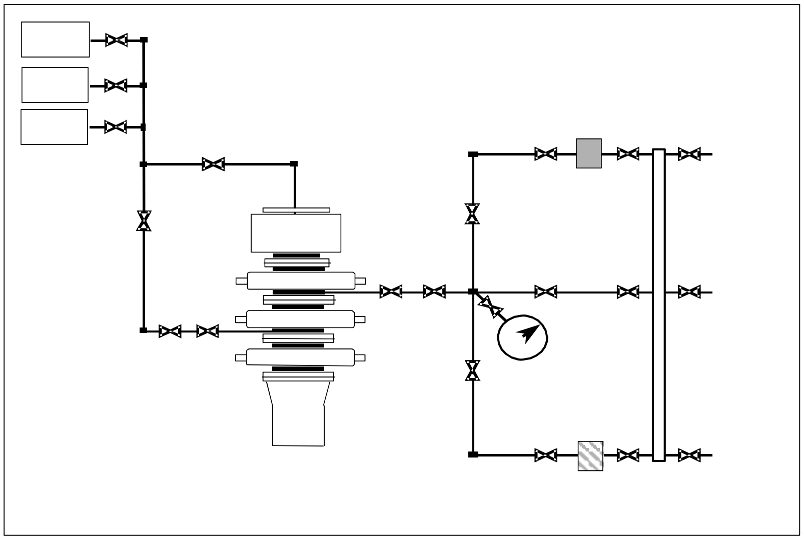
Monitoring the non-pressured side



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Pressure and strength ratings

Table B.1—Example Surface MEWSP Calculations Given Well and Equipment-specific Data

Actual or Calculated Shear Value psig (MPa)	**MASP** psig (MPa)	**Shearing Ratio** (SR)	**Control System Operating Pressure** psig (MPa)
2174 (14.99)	5000 (34.47)	14.64	3000 (20.68)

With Annular Open:

MEWSP = actual or calculated shear value

Example: 2174 psig (to shear pipe with the annular open)

With Annular Closed:

MEWSP = actual or calculated shear + (MASP/SR)

Example: 2174 + (5000/14.64) = 2516 psig (to shear pipe with MASP trapped under a closed annular)

NOTE 1 These equations show relative shear pressures. Accumulator calculations should use absolute pressures.

NOTE 2 These calculations are presented as examples only and are not intended to restrict the use of other methods.

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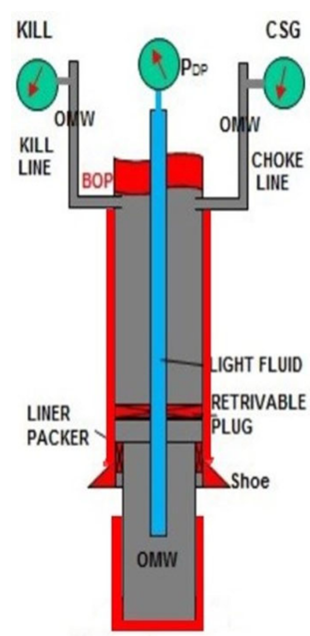
Inflow testing

Principles of inflow testing

When to apply inflow tests:
- Test barriers in direction of flow
- When you cannot apply positive pressure upstream of the barrier.



Mitigations to minimize the kick size

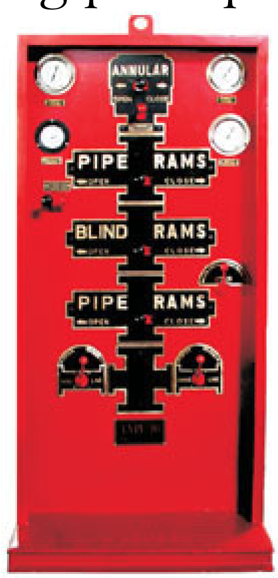
- If an inflow test has failed, immediate actions will be required to take:
- Monitor the return flow
- Identify the path of leak
- Take the correct action to regain primary well control.

Procedures required for an effective inflow test

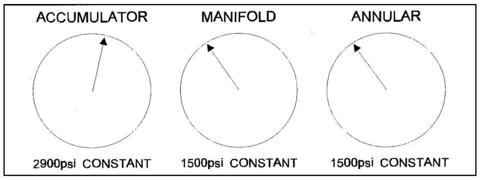
- The appropriate steps for an inflow test and the line-up required: -
- Displace the well
- Monitor for flow
- Record the pressure behavior
- Get test document approved.

BOP Control System

General operating principles of the remote control panel



Normal operating pressures and stored volumes contained in the BOP control system



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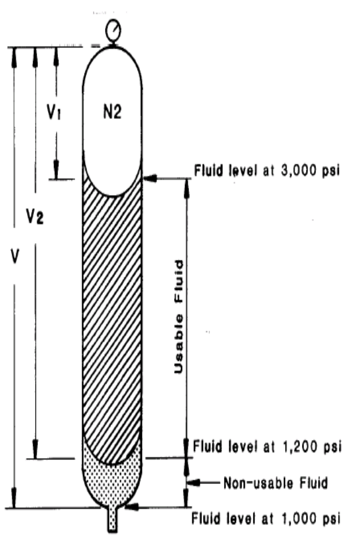
Normal operating pressures and stored volumes contained in the BOP control system



V = Total volume of accumulator (fluid and nitrogen)

P1 = Maximum pressure of the accumulator when completely charged

V1 = Nitrogen gas volume in accumulator at maximum pressure P1

P2 = Minimum pressure left in accumulator after use.
Recommended minimum is 1.200 psi

V2 = Nitrogen volume in accumulator at minimum pressure P2

V2 - V1 = Total usable fluid

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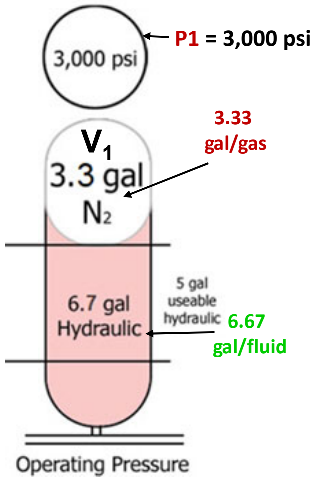
Accumulator bottle (exercise)



$$\frac{P \times V}{P1} = V1$$

P = 1,000 psi

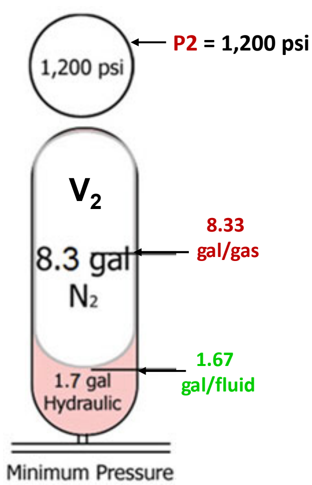
V = 10 gal

$$\frac{1{,}000 \text{ psi} \times 10 \text{ gal}}{3{,}000 \text{ psi}} = 3.33 \text{ gal/gas}$$

10 – 3.33 = 6.67 gal/fluid

Turn on accumulator pumps and charge to maximum operating pressure. 3,000 psi

Accumulator bottle (exercise)



$$\frac{P \times V}{...P2} = V2$$

P = 1,000 psi

V = 10 gal

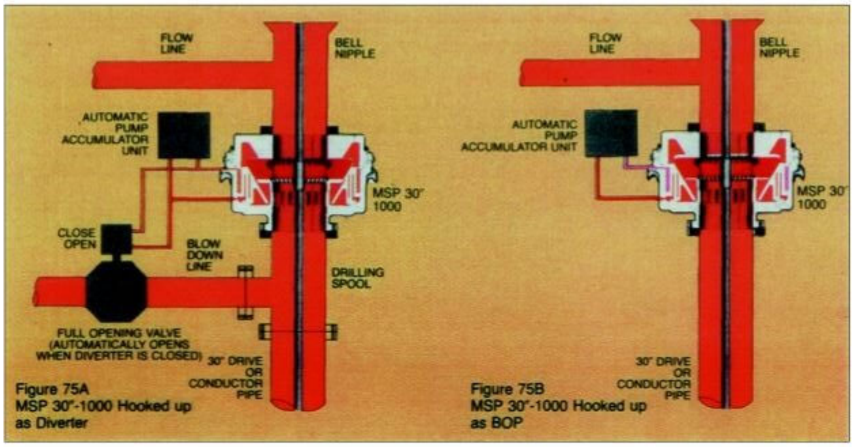
$$\frac{1{,}000 \text{ psi} \times 10 \text{ gal}}{1{,}200 \text{ psi}} = 8.33 \text{ gal/gas}$$

10 – 8.33 = 1.67 gal/fluid

Usable fluid = 6.67 – 1.67 = 5 gal

Minimum operating pressure = 1,200 psi

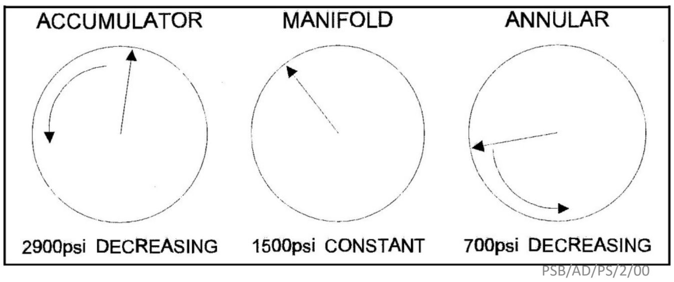
Normal operating pressures and stored volumes contained in the diverter control system

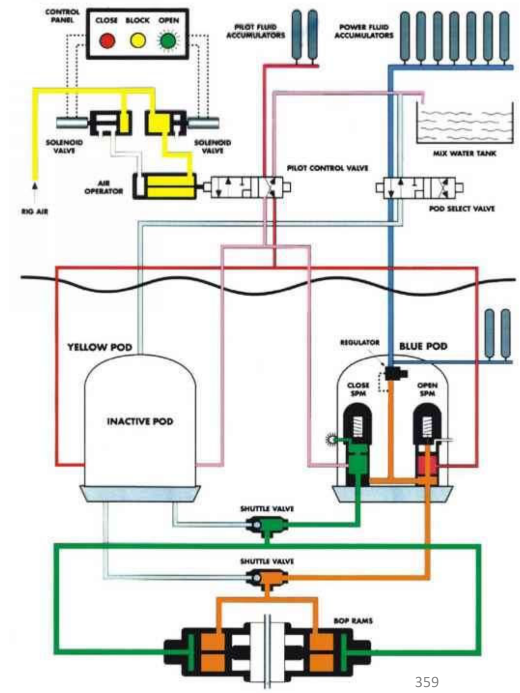


Drawdown Test

System/Component	Function Test Description	Test Acceptance Criteria	Frequency
Dedicated emergency shear accumulators	Drawdown test With charging system isolated, discharge the volume of the greatest consuming emergency system mode	Accumulator pressure greater than the MOP to secure the well	Not to exceed 180 days
Main accumulator system HPU pumps	Cumulative output capacity of pump systems to be timed, charging the main accumulator after drawdown test to system RWP	Verification that the final accumulator pressure is greater than the MOP specified in system accumulator sizing Verification that system RWP is achieved within 15 minutes	Not to exceed 180 days

Confirm if a specific function has successfully operated





Possible function problems

		1	2	3	4	5	6
	Problem	Master valve not held down	3 Position Valve not moved	Closed line blocked.	Leak in line or BOP.	Air lost.	Bulb blown.
A	Close light does not illuminate but pressure drops and later recovers.						
B	Light does not illuminate, and pressure gauge does not drop.						
C	Pressure gauge drops but does not rise back up.						
D	Light illuminates but pressure gauge does not drop.						

Subsea

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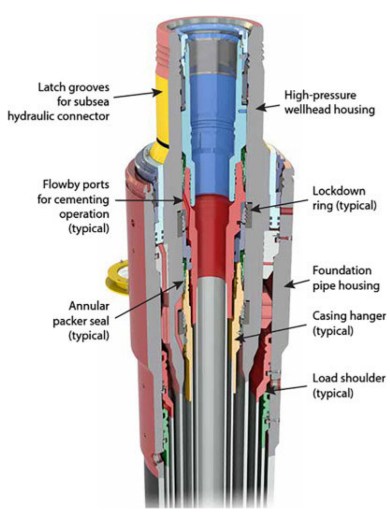
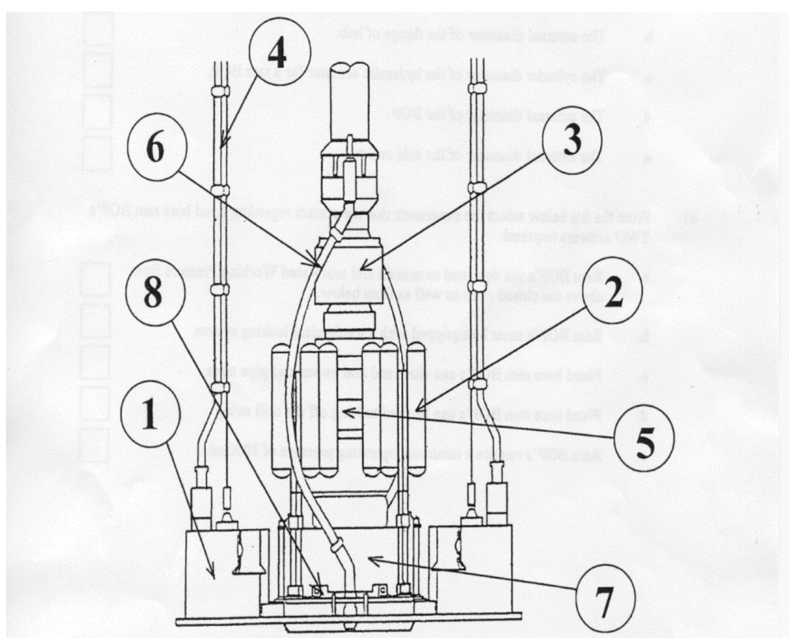
LMRP





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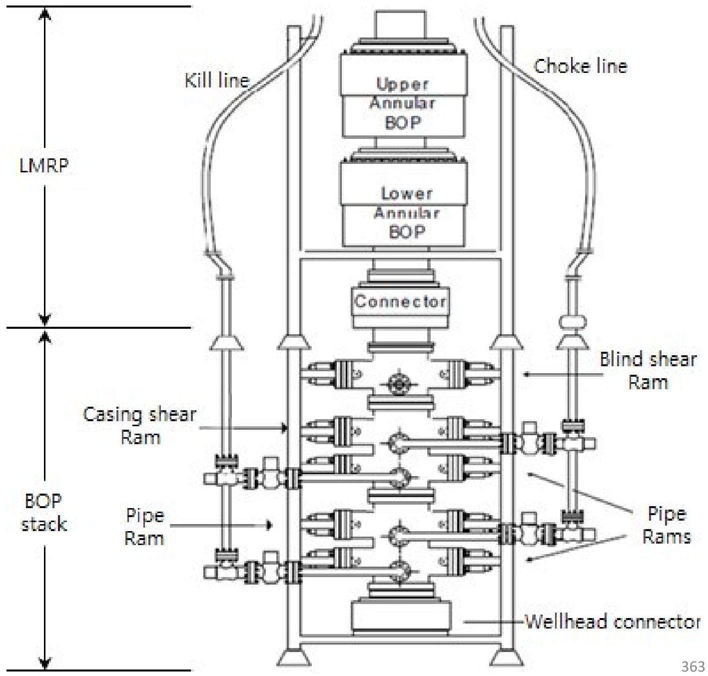
Subsea Annular



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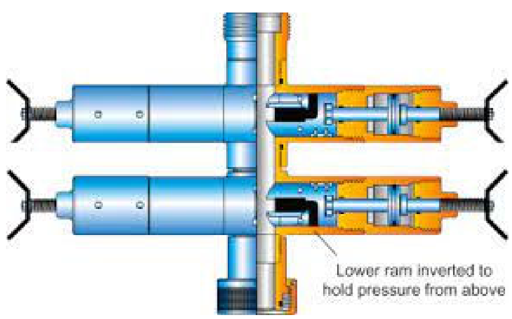
Inverted test ram



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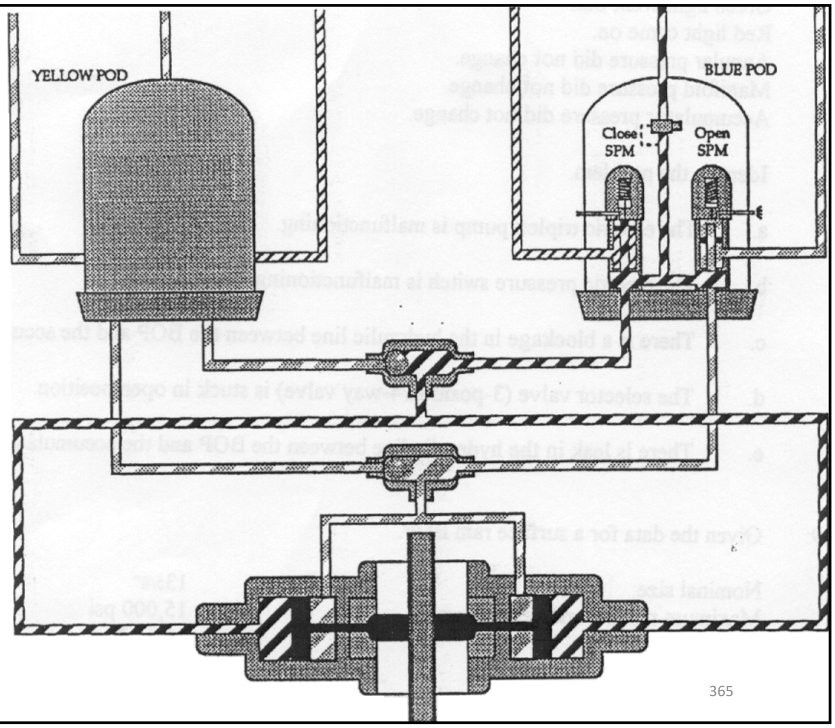
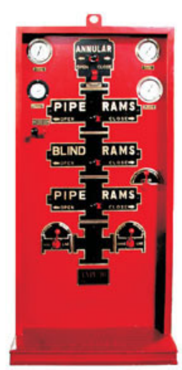
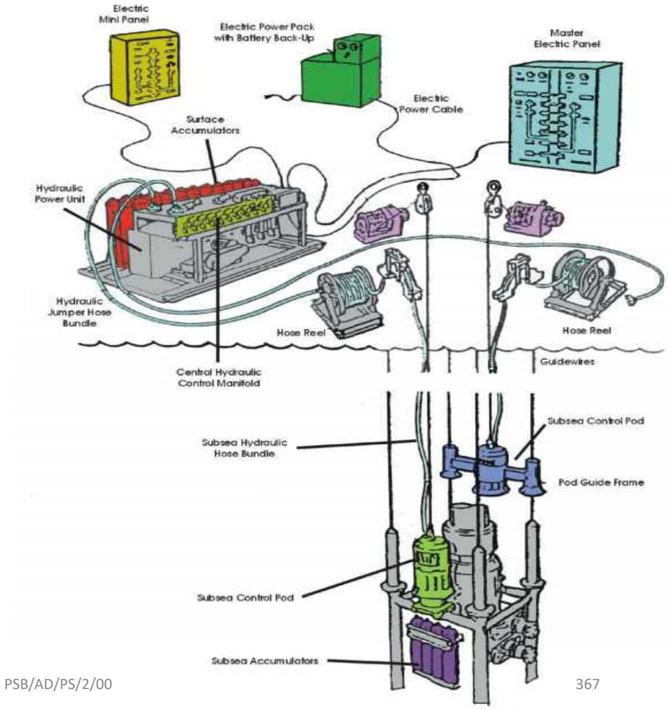
General operating principles of subsea BOP control systems



General operating principles of the remote control panel



Confirm if a specific function has successfully operated



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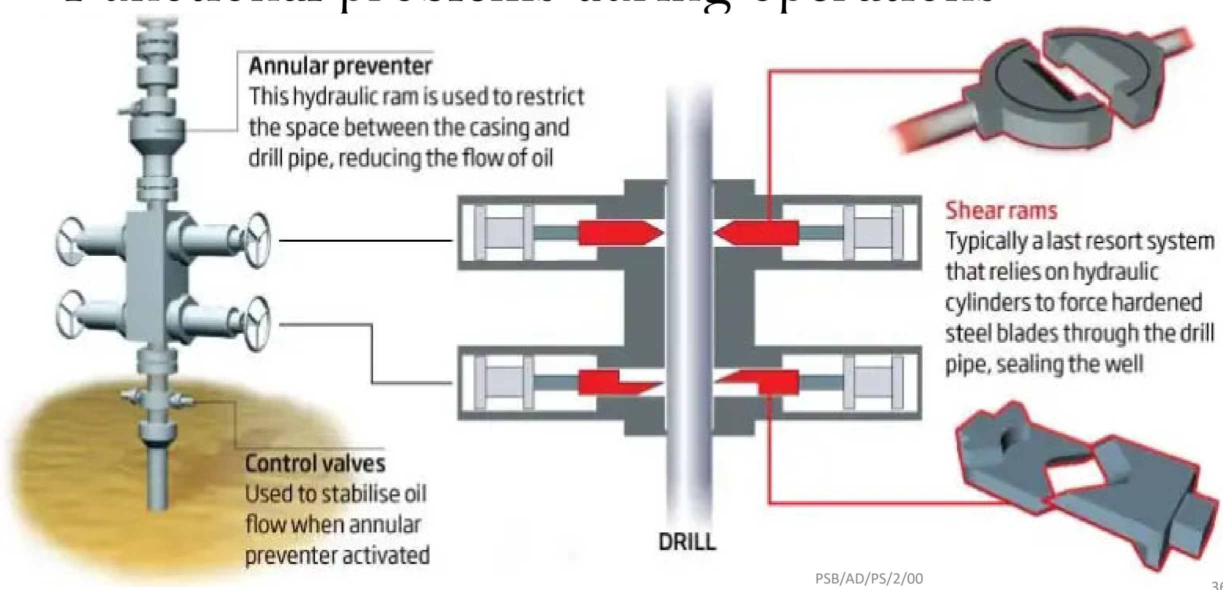
Functional problems during operations



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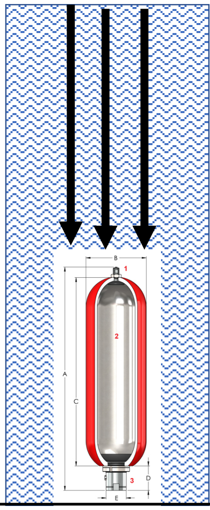
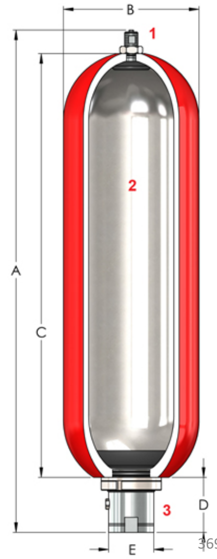
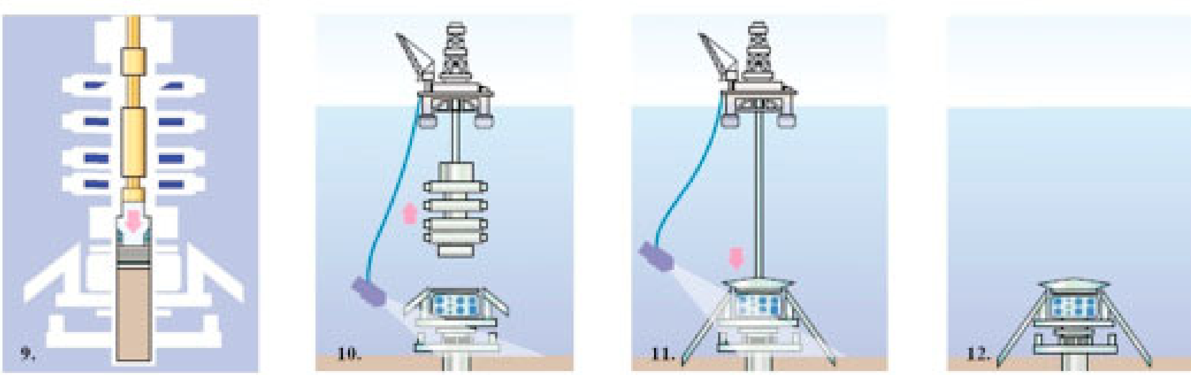
Purpose of having accumulator bottles





Secondary closure systems and emergency device



ESD

KINETIC PRESSURE CONTROL

18-15M K-BOS EMERGENCY SHUT-IN DEVICE (“E-SID”)