Welcome to Our Level 2 Drilling Well Control Course

1

Introduction

- –Your name?
- –Your current position?
- –Any experience with well control/blowout pipe events?

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Methods

- Class Discussion
- Simulator Demonstrations
- Practice Exercises
- Testing

3

Section One:

- Need for Well Control
- Principles of Well Control
  - Hydrostatic, Formation and Bottom Hole Pressure
- Circulating Pressures
- Causes of Kicks
- Influx Characteristics and Behaviour
- Tripping and Tripping Calculations
- Barriers
- Shallow Gas

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Need for Well Control Training

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Why do You Need to Take Well Control Training?

IOGP Report 476 states that the foundations of well control training are prevention, detection, and management of well control incidents with the ultimate objective of avoiding uncontrolled release of hydrocarbons

This means:

- Being able to demonstrate you possess both the relevant well control knowledge and the ability to execute your well control responsibilities

Involves:

- Proof of attending a certified training course with a minimum number of teaching hours
- Passing both the written and practical examinations

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Our Goal is a Competent Workforce

- ➢Makes for a more pleasant workplace
- ➢More trust from the stakeholders
  - ✓Legislators, landowners, and members of the public
- ➢Less *over regulation* from nervous law makers
  - ✓*Seen* to be making improvements

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Our Goal is a Competent Workforce

- ➢Regain our corporate and industry image
  - ✓Easier to attract new employees and investors
- ➢Ensures regulatory compliance
  - ✓Better educated workforce
    - ➢More robust training and examinations
- ➢Reduced severity of the impact of a well control event

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How do We Achieve Our Goal?

- Increase the competency of our industry

✓Through well-trained personnel

➢Providing *ongoing* well control training

➢Including online and on-the-job

- All job requirements to be in job descriptions

✓Periodic reviews of task performances

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What is a Well Control Incident?

A well control incident *is any unsafe conditions that can result in, or have the potential to escalate to, the loss of well control*

What is a Loss of Well Control?

A loss of well control is defined as *an uncontrolled release of formation or other well fluids*.

This can be either:
Uncontrolled flow between two or more exposed formations.
✓Underground blowout or

Flow of formation or other well fluids to surface, including through a diverter
✓Blowout

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How Does an Incident Impact Us?

Any well control incident has a negative impact on us

- Jeopardizes our co-worker's personal wellbeing
  - ✓Overall levels of comfort, health, and happiness
- Risks personal injuries and loss of life
  - ✓To us and our co-workers

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How Does an Incident Impact Us?

- Diminished job opportunities with:
  - ✓*Loss in personal reputation*: harder for you to find work
  - ✓*Loss in corporate reputation:* fewer contracts for your employer
- Capital losses:
  - ✓Smaller operating budgets
  - ✓Harder to raise new capital

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How Does an Incident Impact Us?

- Environment impacts:
  - ✓Societal losses
    - ➢Degradation of the surroundings
    - ➢Diminished recreational enjoyment
    - ➢Destroyed local livelihoods
- Lost public trust:
  - ✓Both real and perceived impacts
  - ✓Over regulation by various jurisdictions
  - ✓ Punitive measures imposed to assuage public outrage

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How do We Avoid an Incident?

Avoiding an incident means *managing the risks*

Managing risks is a way to avoid surprises by:

1. **Foreseeing potential problems** before they arise

   - ✓ With sufficient advance notice to be able to avert them.
     - ➢Anticipate problems.
     - ➢React to problems as they occur
     - ➢Avoid conditions that can lead to problems.

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How do We Avoid an Incident?

2. Developing a sound plan:

✓Developing procedures for problems:

- ➢Normal
- ➢Likely
- ➢ Most severe

✓Keeping the plan updated

✓Keeping the rig crews informed of new developments/procedures

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Unfortunately, this still happens

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Well Control Training and Assessment:

We are here this week to gain knowledge of how to minimize the effect of well control incidents and to gain the trust of operating companies, investors, and the general public by operating safely and efficiently.

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Pre-operation Planning

Prior to any well control related operation a meeting should be conducted with all involved personnel for the purpose of outlining the operation and ensuring that all personnel know their individual responsibilities.

The obvious benefits are:

- The objective of the operation is presented
- All involved personnel know their jobs and what's expected
- All safety aspects are discussed and stop the job procedures are presented and discussed
- Contingencies are presented and discussed so all parties involved know what to do "if" something happens – taking the correct first action can be critical

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Risk management is a systematic process conducted when planning an operation and on site to evaluate the potential risks that may be involved in a projected activity, especially:

- New or non-standard operations.
- Operations involving use of new or modified equipment.
- Hazardous operations.
- Change in actual conditions which may increase the risk.

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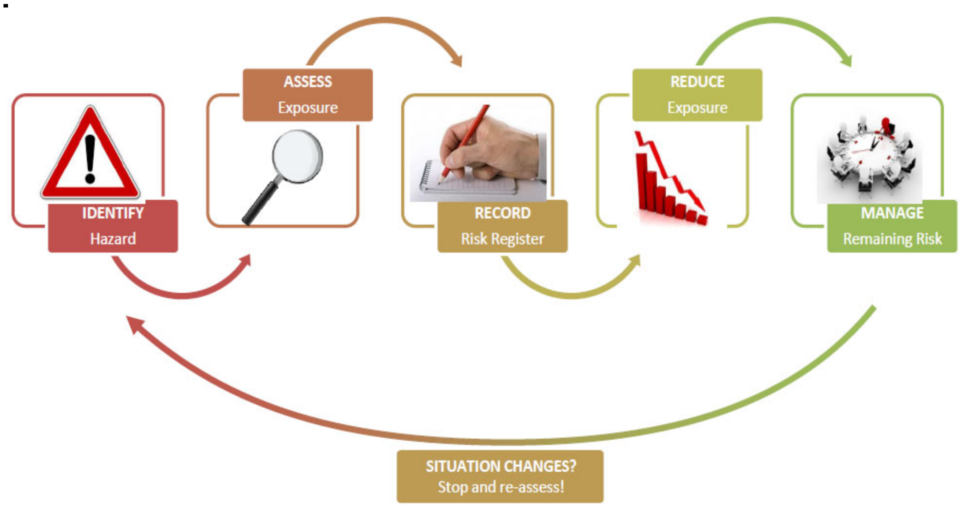
Risk assessment is the forecasting and evaluation of risks together with the identification of procedures to avoid or minimize their impact.



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Risk Management

At the Worksite

- Get a proper Handover of the well.
- Use Tested, inspected Equipment and conduct site checks according to company guidelines.
- Pre job Meeting to insure all understand work & emergency procedure, clear about their roles and get feedback from crew.
- Have crew properly trained on emergency procedure.
- Request Management of Change When plans are changed.
- Assign responsibility on who shuts the well : Well Intervention Equipment Operator or Designated Well Panel Control Operator.

During Emergency

- Shut in and secure the well.
- Analyze the problem and give possible causes invite input from site team, state your action and ask office support team to comment.

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Pre-job Safety meeting

The purpose of this meeting is to familiarise personnel on the rig with:

Define roles and responsibilities before starting certain operation.

- ✓ Discuss hazards/ risks associated with that specific operation.
- ✓ Discuss actions to be taken in case of emergency.
- ✓ Ensure procedures to be undertaken are understood.

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What is Risk?

Risk is a function of *probability* and *consequences*

It is the *likelihood of an event happening within a specified time period*

And the severity of the consequences resulting from such an event

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Risk of Injury Matrix

Likelihood	Severity of Consequences				
	Insignificant No medical aid or first aid attention likely to be required	*Marginal* First aid administered by on-site medics. No outside medical assistance required	*Moderate* Patient(s) requiring medical attention in a hospital as an outpatient	*Critical* Injury(s) requiring admission to a hospital overnight, but not requiring intensive care	*Catastrophic* Fatality or multiple critically-injured patients requiring intensive care
Highly likely > 90% certainty	Moderate	High	Extreme	Extreme	Extreme
Very likely 60% - 90% chance	Moderate	High	High	Extreme	Extreme
Moderate chance 40% - 69% chance	Low	Moderate	High	Extreme	Extreme
Unlikely 10% - 39% chance	Low	Low	Moderate	High	Extreme
Highly unlikely < 10% chance	Low	Low	Moderate	Moderate	High

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How Does Risk Management Help?

Every project comes with risk

Risk management helps to:

- ➢Identify, assess, and rank the risks
- ➢Focus on the major risks
- ➢Make informed decisions on specific risks
- ➢Minimize damage in worst-case event

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How Does Risk Management Help?

- Manage and control the uncertain aspects of well projects
- Clarify and *formalize* individual roles in risk management:
  - ✓Company’s role
  - ✓Contractor’s role
  - ✓Service companies’ roles
- Identify the opportunities to enhance project performance

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Management of Change

Management of change (MOC) is defined as:

A process to evaluate and properly manage any modifications to the design, control, or operations (including staffing) of a covered process

Each company must have a system in place, which describes how a change is identified, analyzed, approved, and implemented

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Management of Change

Management of Change (MOC) is a project management process wherein changes to the scope of a project are formally introduced and approved such as:

- New or non-standard operations.
- Operations involving use of new or modified equipment.
- Hazardous operations.
- Change in actual conditions which may increase the risk.

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Management of Change

MOC process is required to provide assurance that, when changes are introduced, new risks are not unknowingly incurred, or the main risk profile is not poorly changed without appropriate mitigation.

A change is defined as a planned action or intervention that modifies a system or components of a system on a permanent or temporary basis.

- **All team members must be aware of the agreed change before starting the operation.**
- **All changes to a procedure require authorization and documentation by the accountable/authorized manager.**

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Contingency Plans

Any operation with well-control implications should also have an associated checklist and blowout contingency plan.

This *blowout contingency plan* should include:

- A strategy for killing the well
- A checklist of equipment and services likely to be needed:
  - ✓Locations of contingency equipment, services, and personnel
- A checklist of measures required for limiting the consequences of an incident
- A formal method of recording and reporting an incident

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Role of Emergency Drills in Managing Risk

Regular, realistic well control and emergency drills are useful tools in reducing the risk of an event occurring.

- They allow the crews *to regularly practice procedures that are normally non-routine*
- Provide the documentary evidence of crew competency and training

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How Often Should an Emergency Drill be Repeated?

IOGP (Report 628) says that drills should be linked to actual risks which could be encountered and the competency of the team which could need to respond.

- Frequency of drills at a minimum should be one drill weekly for each crew and more should be performed if the crew performance is low
- Alternate the types of drills
  - ➢Example, diverter drills should be practiced before and repeated while drilling with a diverter

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Well Control Drills

Well control drills shall be performed to:

1. Ensure that crew is adequately trained
2. To check team members understand their role.
3. Remain alert to implement early kick detection
4. Closing procedures of BOP to shut in the well correctly
5. To check equipment is ready

Drills should be initiated at unscheduled times when operations and hole condition permits.

Drills should be **clearly announced** so all concerned know that a drill, not an actual event, is taking place. (API RP59) Total time taken to complete the drill should be recorded along with other performance metrics to measure the effectiveness of the drill program. (Times are generally < 2 min)

Drills should be documented, executed, repetitive and followed-up to correct identified problems. (API RP59)

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Principles of Well Control

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Well Control Definitions

Kick: Intrusion of formation fluids into the wellbore

Well Influx: The formation fluids that unintentionally flows into a well

Blowout: An uncontrolled flow of well fluids and/or formation fluids from the wellbore (to atmosphere or to another lower-pressured subsurface formation)

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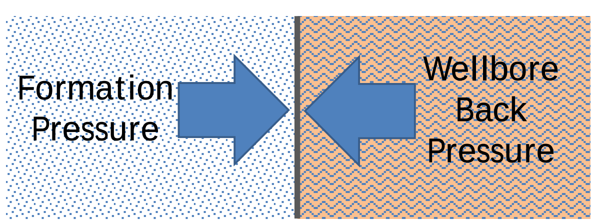
Fluid Movement

To prevent fluid movement into the well, we *need to keep the pressure in the wellbore at least equal to the pore pressure*

This involves the use of some sort of *backpressure* on the formation



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Concept of Pressure

Pressure: Force/Unit Area

- SI: Newton per square metre N/m^2
- Pounds per square inch psi,
- Kilo-grams per square cm Kg/cm^2
- 1 kg/cm^2 = 98.0665 kPa =14.223 psi

- Formation Pressure: Out of our control
- Hydrostatic Pressure: We can manipulate (Proportional to Density & TVD)
- Formation Strength: Property of formation

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Concept of Density

Density : Mass/ Unit Volume

- SI: Kilogram per cubic meter Kg/m^3
- Pounds per Gallon ppg,
- Grams per cubic cm gm/cm^3

- Density of Fresh Water= 1 gm/cm^3 = 8.33 ppg

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Hydrostatic, Formation, and Bottom Hole Pressure (API RP59 Definitions)

Hydrostatic Pressure:

- The pressure that exists at any point in the wellbore due to the weight of the vertical column of fluid above that point

Formation Pressure or pore pressure:

- The pressure exerted by the fluids within the pore space of a formation.

Bottom Hole Pressure:

- Depending upon the context, either a pressure exerted by a column of fluid contained in the wellbore or the formation pressure at the depth of interest.
  - Under static conditions when a well is overbalanced, the $BHP = HP$.
  - When circulating: $BHP = HP + APL$
  - When underbalanced and circulating out a kick: $BHP = HP + APL + SICP$

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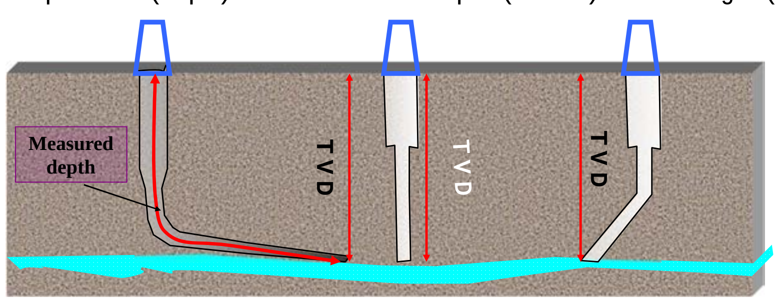
Hydrostatic Pressure

HYDROSTATIC PRESSURE ?

Pressure exerted by mud column on bottom of the hole is

HYDROSTATIC PRESSURE

Hydrostatic pressure (in psi) = 0.052 x TVD Depth (in feet) x Mud weight (in ppg)



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Hydrostatic Pressure

The pressure exerted by a column of fluid depends on its DENSITY and vertical height or DEPTH.

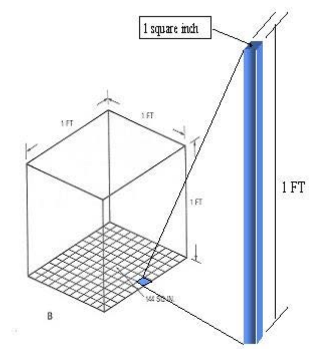
HP = TVD (ft) x 0.052 x Mud Weight (ppg).

0.052 is a conversion factor and is derived as follows:

1 Cubic foot contains 7.48 U.S. gallons.
A fluid weighing 1 ppg would weigh 7.48 pounds per cubic foot.

The pressure exerted by that one foot column of fluid over the area of the base would be:

$$\frac{7.48 \text{ pounds}}{144 \text{ square inch}} = 0.0519 \approx 0.052$$



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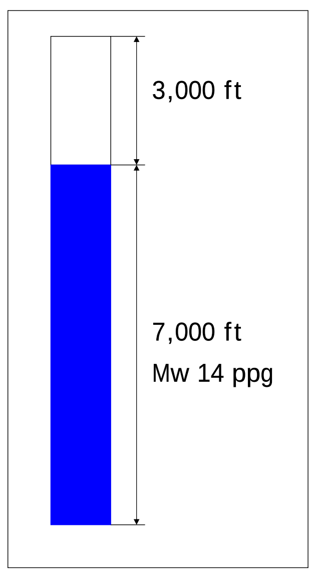
Hydrostatic Pressure

What is the pressure at the bottom if the fluid level drops by 3000 ft?

Hydrostatic pressure at bottom =
7,000 x 14 x 0.052 = 5096 psi

How much did the bottom hole pressure drop?

Drop in Hydrostatic Head =
3,000 x 14 x 0.052 = 2,184 psi



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Hydrostatic Pressure

What is the pressure at the bottom of a well filled with 2 fluids?

Hydrostatic light mud =

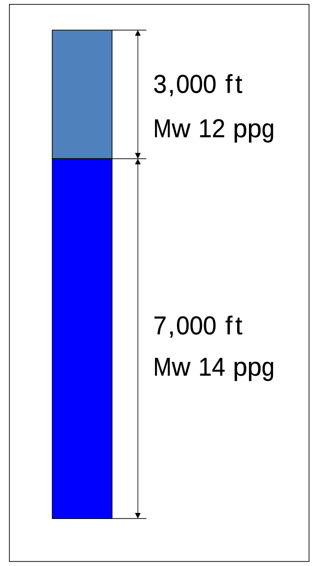
3,000 x 12 x 0.052 = 1872 psi

Hydrostatic heavy mud =

7,000 x 14 x 0.052 = 5096 psi

Total Hydrostatic Head =

1872 + 5096 = 6968 psi



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What is Hydrostatic Pressure Gradient?

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Pressure Gradient

- Hydrostatic Pressure gradient is the rate at which hydrostatic pressure increases in psi/ft

Pressure/Depth or 0.052 x MW

Fresh Water Gradient: 8.33 x 0.052= 0.433 psi/ft

Saline Water Gradient: 8.92 x 0.052= 0.465 psi/ft

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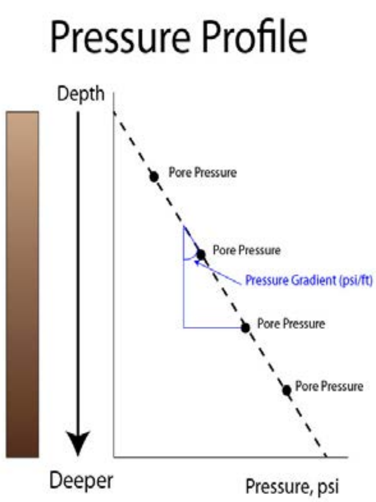
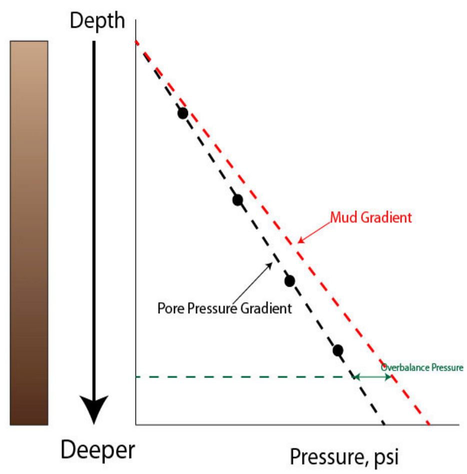
Pressure Gradient





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Example

1. Convert the following mud densities into pressure gradients.

a. 13.5 ppg ______________ psi/ft
b. 16 ppg ______________ psi/ft
c. 12 ppg ______________ psi/ft

2. Convert the following gradients into mud densities.

a. 0.806 psi/ft ______________ ppg
b. 0.598 psi/ft ______________ ppg
c. 0.494 psi/ft ______________ ppg

3. Calculate the hydrostatic pressure for the following.

a. 9.5 ppg mud at 9000ft MD/8000 ft TVD =______________
b. 15.5 ppg mud at 18000ft TVD/21000ft MD =______________
c. 0.889 psi/ft mud at 11000ft MD/9000ft TVD =______________

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Example

4. Convert the following pressures into equivalent mud weights in PPG.

a. 3495 psi at 7000ft =______________
b. at 4000ft with 2787 psi =______________
c. 12000ft MD/10500ft TVD with 9000 psi =______________

5. High bottom hole temperatures could affect the hydrostatic pressure gradients resulting in:

a. An increase in the hydrostatic gradient
b. A decrease in the hydrostatic gradient
c. Would have no effect

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Answers

1. MUD WEIGHT x 0.052
a. 13.5 x 0.052 = 0.702 psi/ft
b. 16.0 x 0.052 = 0.832 psi/ft
c. 12.0 x 0.052 = 0.624 psi/ft

2. GRADIENT ÷ 0.052
a. 0.806 ÷ 0.052 = 15.5 ppg
b. 0.598 ÷ 0.052 = 11.5 ppg
c. 0.494 ÷ 0.052 = 9.5 ppg

3. T.V.D. x MUD WEIGHT x 0.052
a. 8000 x 9.5 x .052 = 3952 psi
b. 18000 x 15.5 x .052 = 14508 psi
c. 9000 x 0.889 = 8001 psi

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Answers

4. PRESSURE /T.V.D x 0.052

a. 3495 / 7000 x 0.052 = 9.6 ppg
b. 2787 /4000 x 0.052 = 13.39 ppg (13.4)
c. 9000 /10500 x 0.052 = 16.48 ppg (16.5)

5. b. A decrease in the hydrostatic gradient

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Formula 2

$$Pressure\ Gradient = Mud\ Density \times .052$$

What is the gradient of 12.0 ppg mud?

Answer:

$Gradient = 12.0 \times .052 = 0.624\ psi/ft$

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Convert psi/ft to ppg

A gradient can be converted to a mud weight by dividing by .052:

$$MW = \frac{0.468\ psi/ft}{.052} = 9.0\ ppg$$

What is the Maximum Mud Weight if a fracture gradient is 0.832 psi/ft?

$$Max\ MW = .832 \div .052 = 16.0\ ppg$$

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Formula 1

HYDROSTATIC PRESSURE (psi)

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

Calculate the hydrostatic pressure of a well 15,000 feet MD and 10,000 TVD drilling with 10.0 ppg mud.

_______ psi

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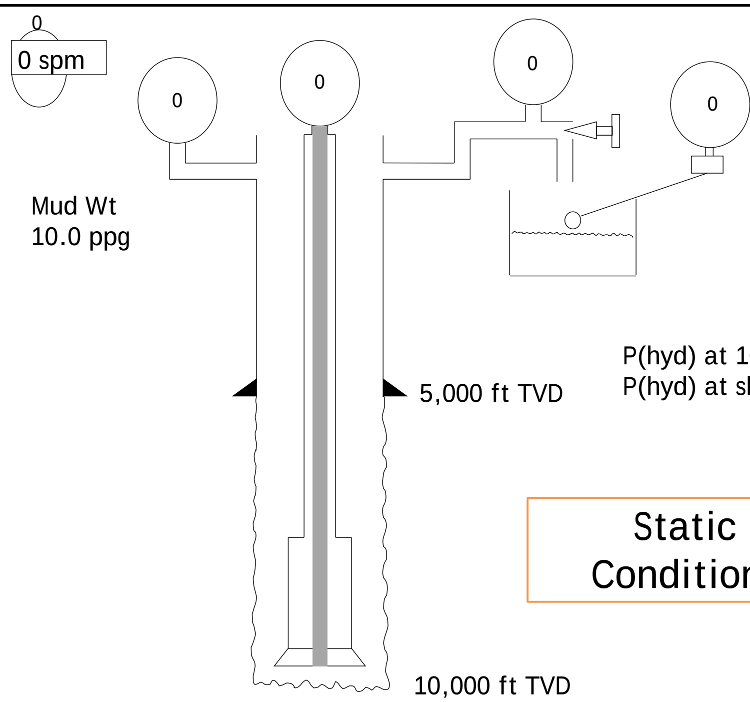

P(hyd) at 10,000’ = **5200 psi**
P(hyd) at shoe = **2600 psi**

Static Conditions

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Formula 1

HYDROSTATIC PRESSURE (psi)

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

Calculate the hydrostatic pressure loss on a 15,000 feet MD and 10,000 TVD well drilling with 10.0 ppg mud if the annulus dropped 150 ft because of losses.

_______ psi

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Formula 3

DRILLING MUD DENSITY (ppg)

Pressure (psi) ÷ TVD (ft) ÷ 0.052

or

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

Calculate the mud weight in a 15,000 foot (TVD) well that has a BHP of 7,644 psi

_______ ppg

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Circulating Pressures

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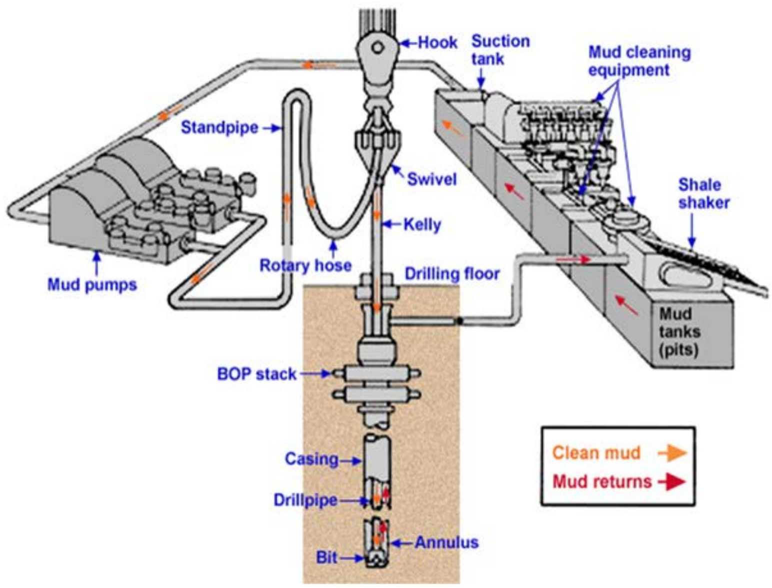
Circulation System



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Circulating Pressure

Circulating pressure is the total of pressure losses in:

- Surface Lines,
- Drill-string,
- Bit Nozzles,
- Annulus

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Factors Affecting Pump Pressure

- **Fluid properties:** mud weight, viscosity, gel strength and yield point
- **Pump rate**
- **Hole size/drill string size :** ID of D/P
- **BHA and Bit :** Length of BHA, Nozzle Size
- **Well Depth**

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Pressure Losses

- Pressure loss is the pressure required to force a fluid through a pipe
- It is the pump pressure used up by the **friction** along the way
- Highest at the pump end and decrease towards the flow line

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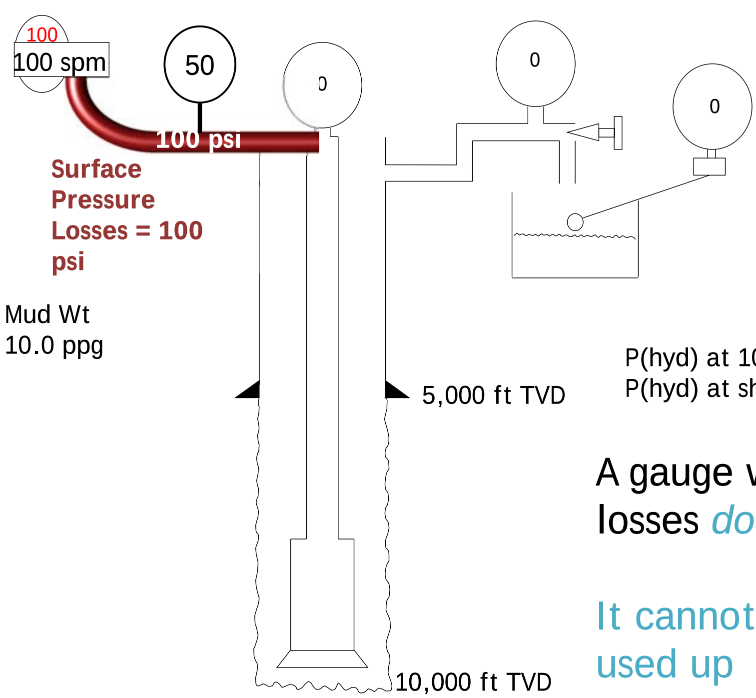

P(hyd) at 10,000' = 5200 psi
P(hyd) at shoe = 2600 psi

A gauge will only read the friction losses *downstream* of that gauge.

It cannot read what has already been used up

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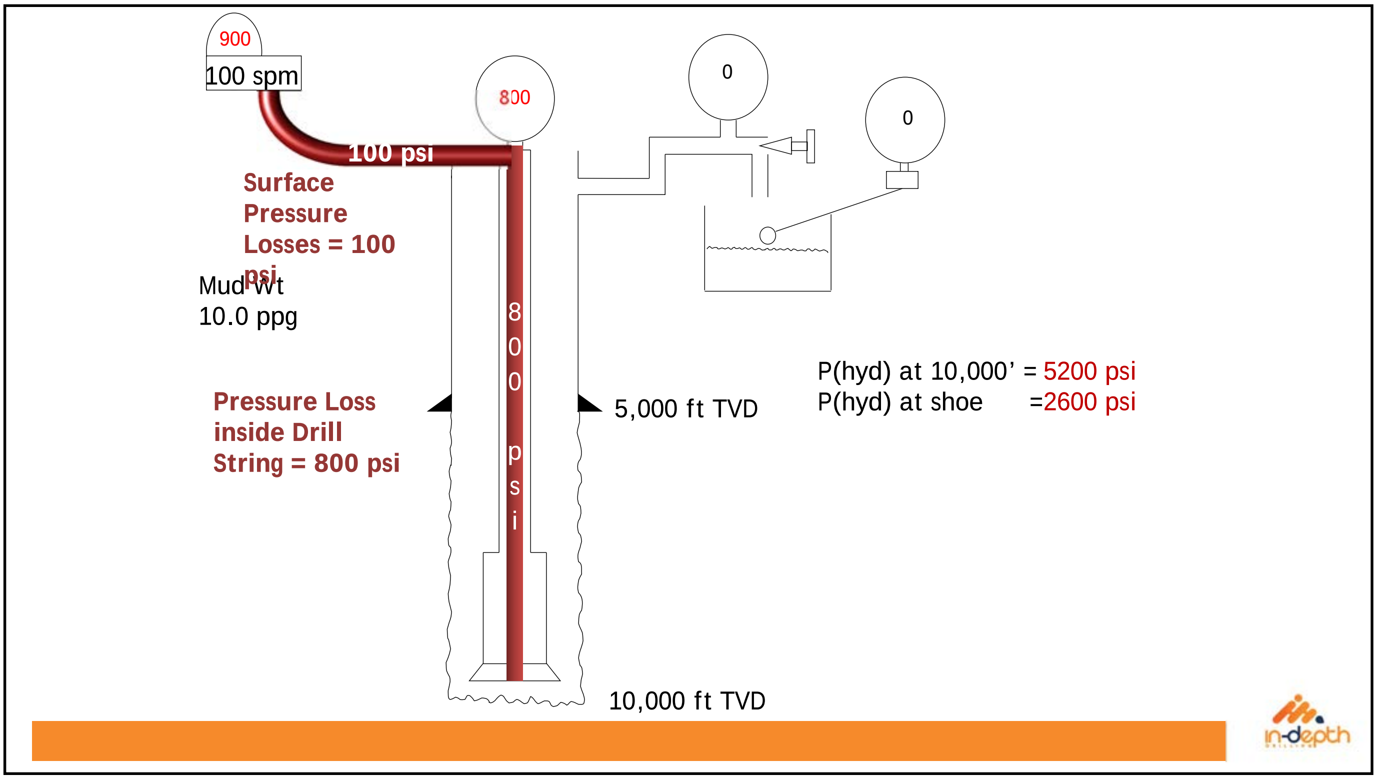
900
100 spm
800
0
0
100 psi
Surface Pressure Losses = 100 psi
Mud Wt 10.0 ppg
800 psi
Pressure Loss inside Drill String = 800 psi
5,000 ft TVD
P(hyd) at 10,000' = 5200 psi
P(hyd) at shoe =2600 psi
10,000 ft TVD

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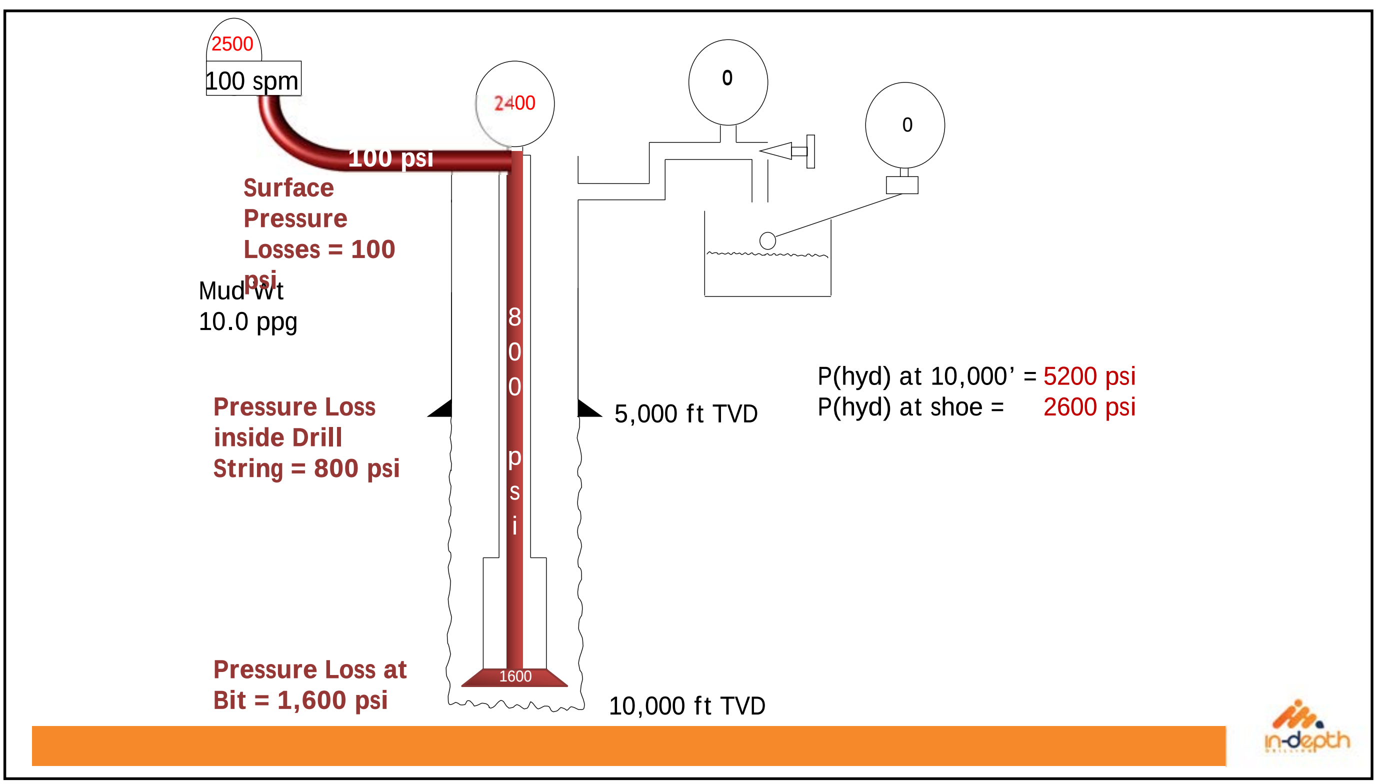
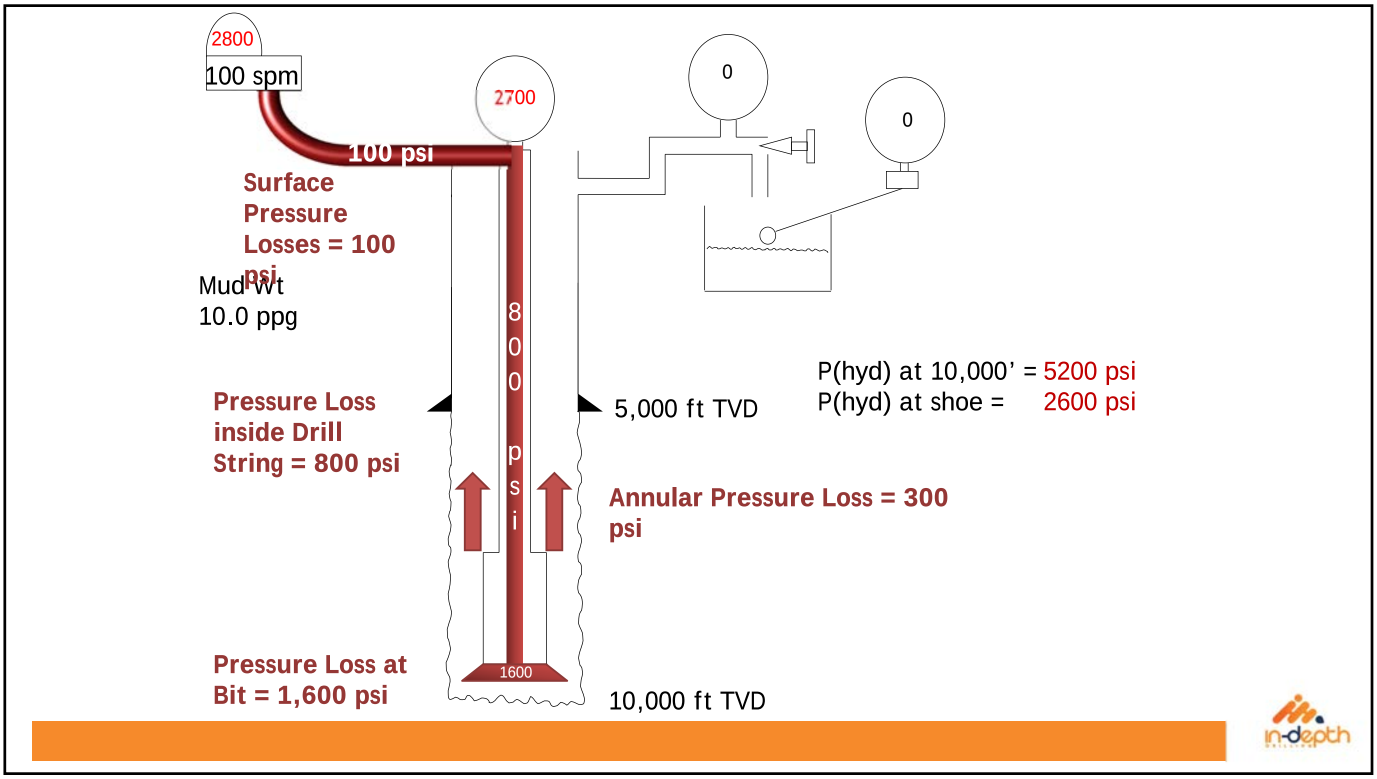

2500
100 spm
2400
0
0
100 psi
Surface Pressure Losses = 100 psi
Mud Wt 10.0 ppg
800 psi
Pressure Loss inside Drill String = 800 psi
5,000 ft TVD
P(hyd) at 10,000' = 5200 psi
P(hyd) at shoe = 2600 psi
1600
Pressure Loss at Bit = 1,600 psi
10,000 ft TVD

64



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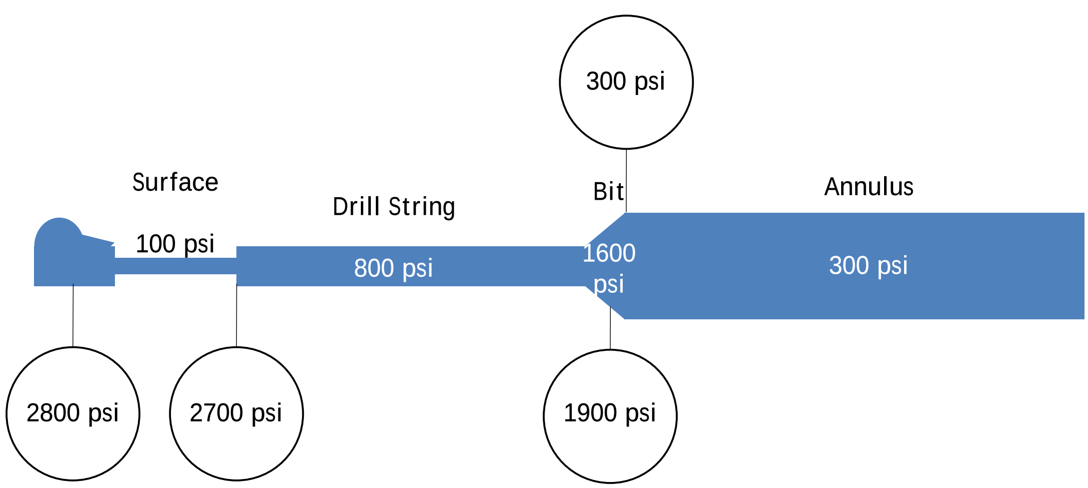
Circulating Pressures Use Measured Depth



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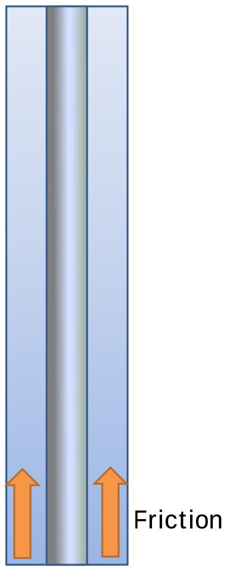
Annular Pressure Losses(APL)



Annular Pressure Losses:

- Friction loss of the mud in the annulus
- *APL are added to the BHP*
- May not be accurately known without PWD

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Given the following well data, calculate the dynamic BHP:

- TVD = 10,000 feet
- Mud weight = 10.0 ppg
- APL = 300 psi

[ ] psi

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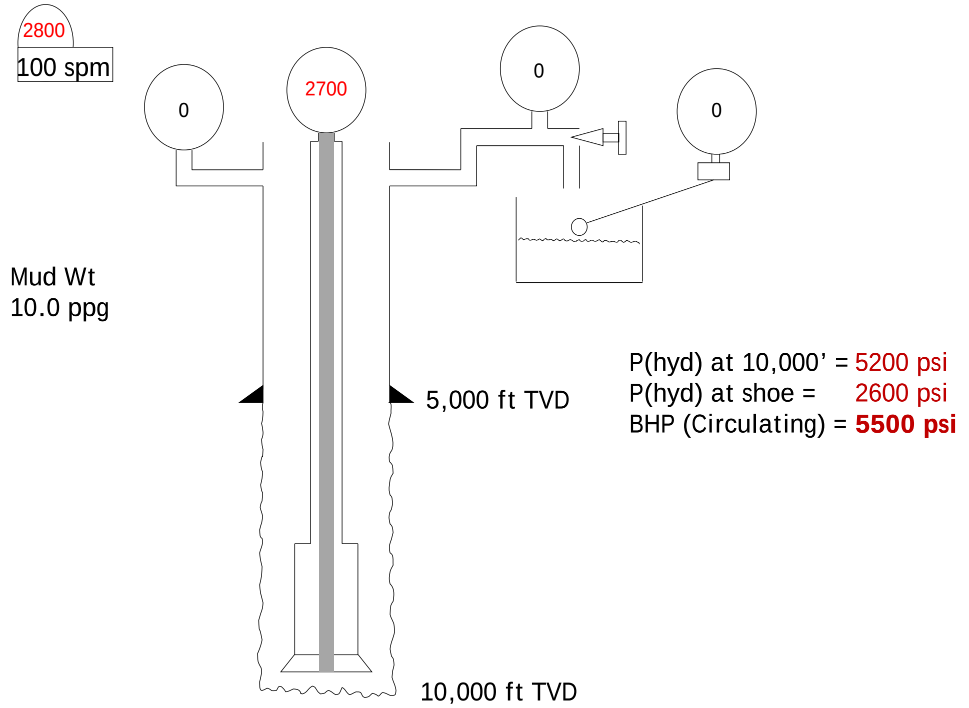

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Equivalent Circulating Density

The mud weight that would have a hydrostatic pressure equivalent to the dynamic BHP

A 10,000' TVD well is being circulated with an APL of 300 psi

The APL can be expressed as an equivalent mud weight:

The APL contributes the equivalent of an additional 0.577 ppg to the BHP

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Dynamic BHP

$$BHP = Hydrostatic\ P + APL + Imposed\ P$$

Well Data:

Mud weight: 10.0 ppg
Well Depth (TVD): 10,000 feet
APL at SCR: 52 psi

Well is being circulated through the choke at SCR, holding 500 psi casing pressure. The influx has just been circulated out of the annulus. Calculate the BHP.

5752 psi

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Equivalent Circulating Density

True or False:

The additional BHP from annular pressure losses have the potential to cause lost circulation where formation fracture pressures are low

True

We need to minimize the annular pressure losses when killing a well

True

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Formula 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 (ppg)

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

or

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

Calculate the ECD of a well with the following data:

- TVD = 10,000 feet
- Mud weight = 10.0 ppg
- APL = 300 psi

[ ] ppg

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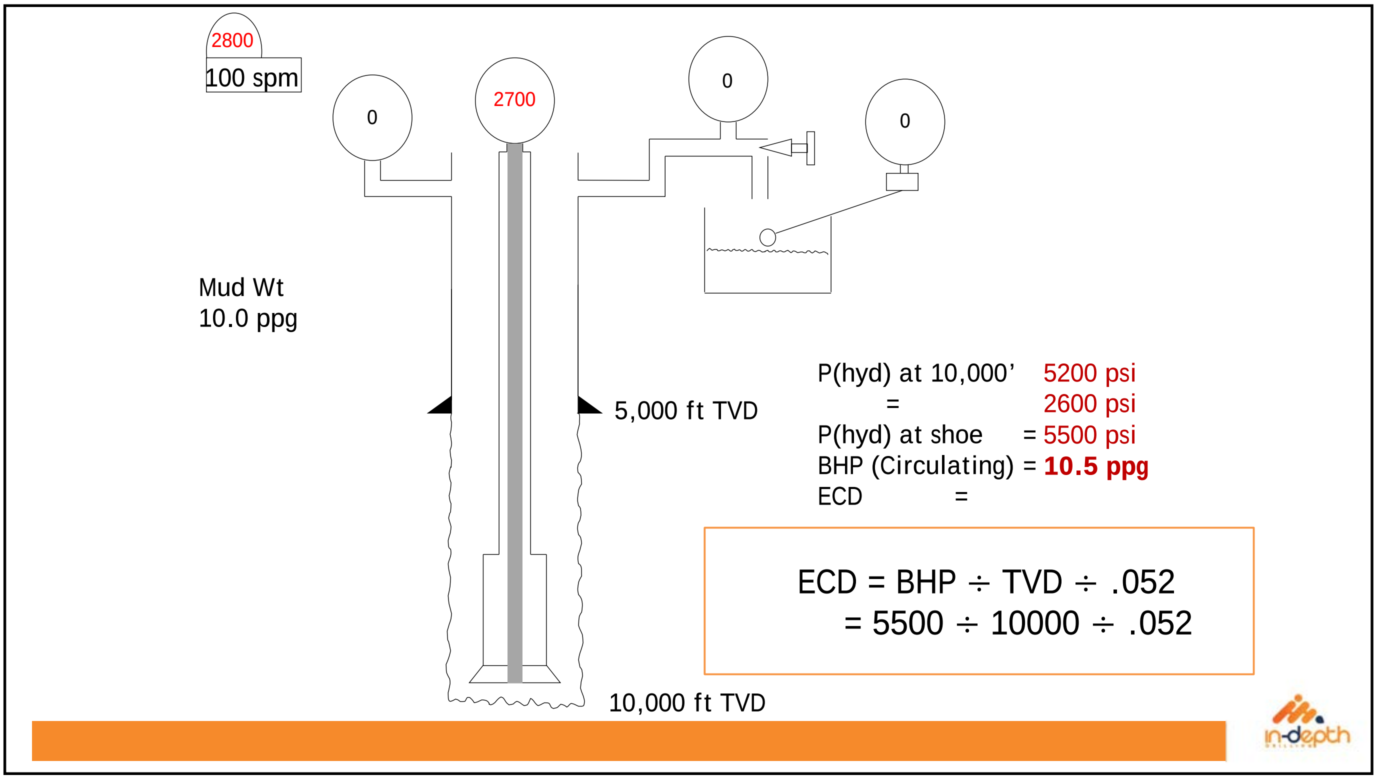
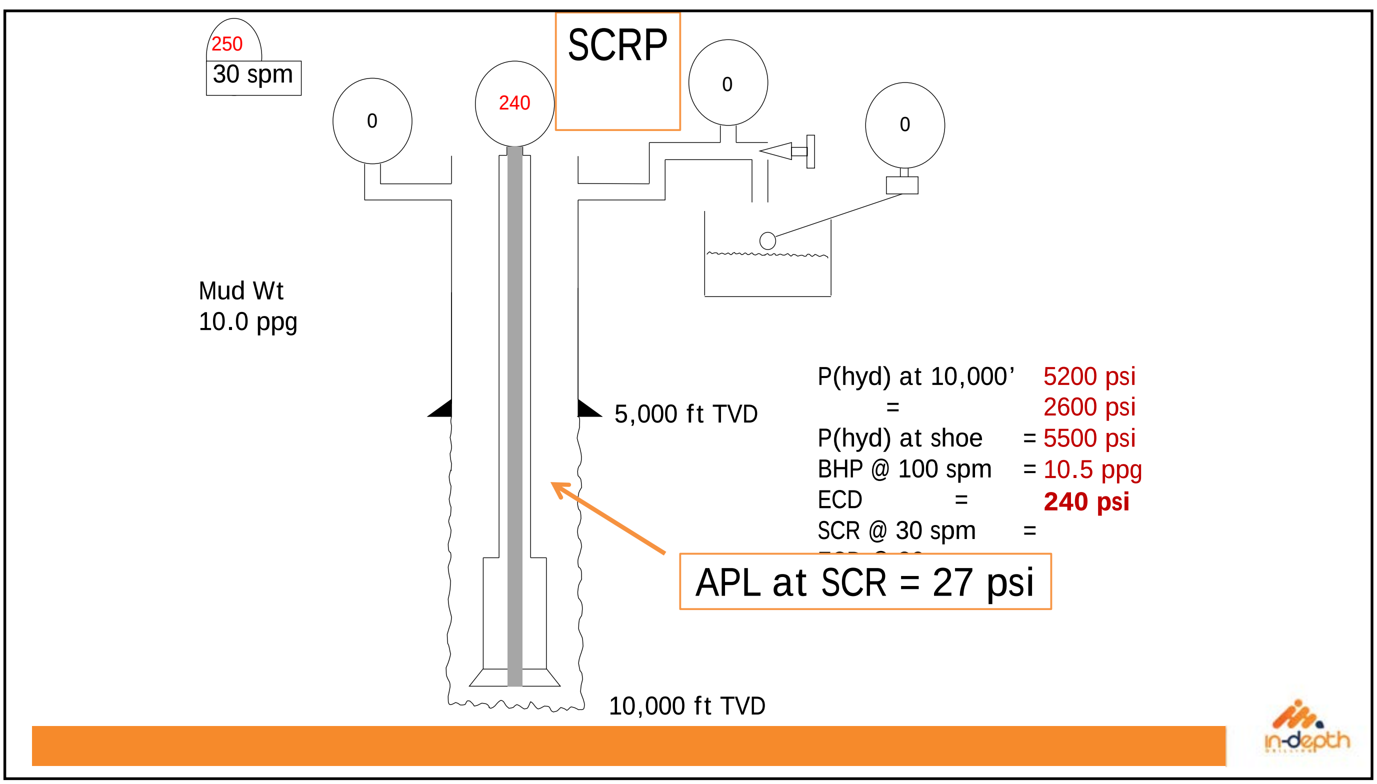

2800
100 spm
0
2700
0
0
Mud Wt
10.0 ppg
5,000 ft TVD
10,000 ft TVD
P(hyd) at 10,000' 5200 psi
= 2600 psi
P(hyd) at shoe = 5500 psi
BHP (Circulating) = 10.5 ppg
ECD =
ECD = BHP ÷ TVD ÷ .052
= 5500 ÷ 10000 ÷ .052
in-depth

75


250
30 spm
SCRP
0
240
0
0
Mud Wt
10.0 ppg
5,000 ft TVD
10,000 ft TVD
P(hyd) at 10,000' 5200 psi
= 2600 psi
P(hyd) at shoe = 5500 psi
BHP @ 100 spm = 10.5 ppg
ECD = 240 psi
SCR @ 30 spm =
APL at SCR = 27 psi
in-depth

76

Calculate the ECD at SCR, given the APL = 27 psi.

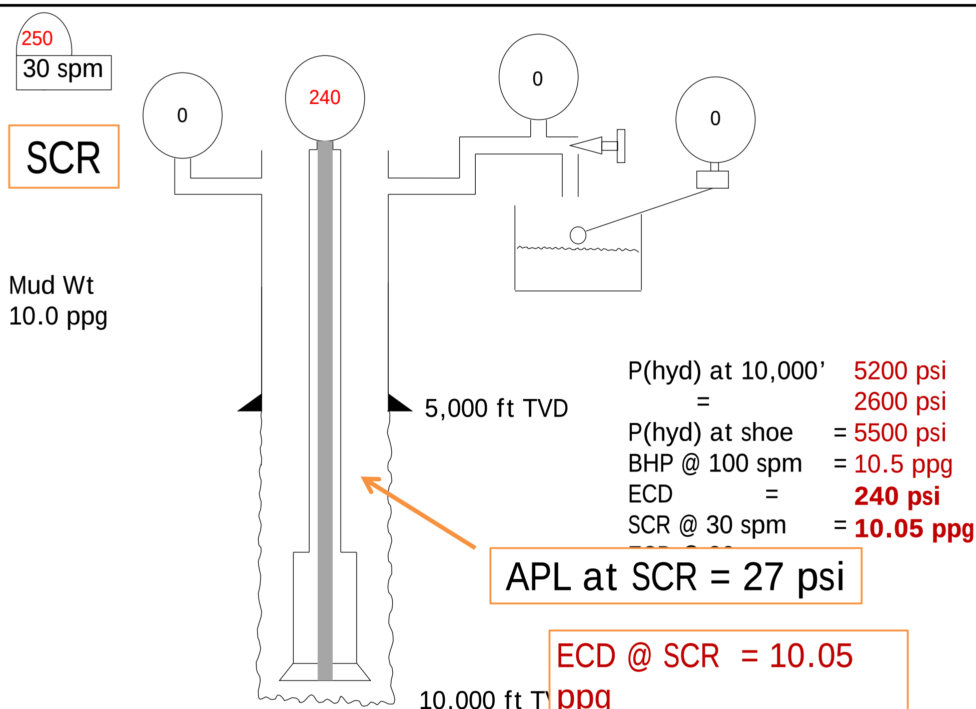
Well Data:

TVD = 10,000 feet

Mud weight = 10.0 ppg

10.05 PPG

77



78

Pump Output
and
Annular Velocity

79

Formula 5

PUMP OUTPUT (bbl/min)

Pump Displacement (bbl/stroke) x Pump Rate (SPM)

A pump has a displacement of 0.119 bbl/stroke. What is the pump output at 40 strokes per minute?

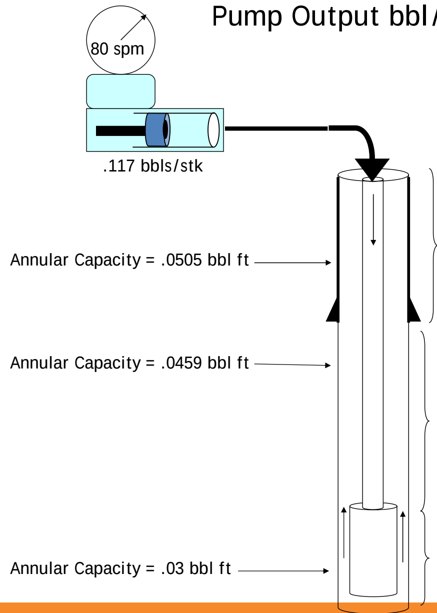
______ bbl/min

80

Annular Velocities

Pump Output bbl/min = Pump Displacement bbl/stk x Pump Speed stk/min

.117 x 80 = **<u>9.36</u>** bbls/min



$$\frac{PO}{An\ Cap} = \frac{9.36}{.0505} = \mathbf{185}\ ft/min$$

$$Annular\ Velocity = \frac{PO}{Annular\ Capacity}$$

$$\frac{PO}{An\ Cap} = \frac{9.36}{.0459} = \mathbf{204}\ ft/min$$

$$\frac{PO}{An\ Cap} = \frac{9.36}{.03} = \mathbf{312}\ ft/min$$

81

Formula 6

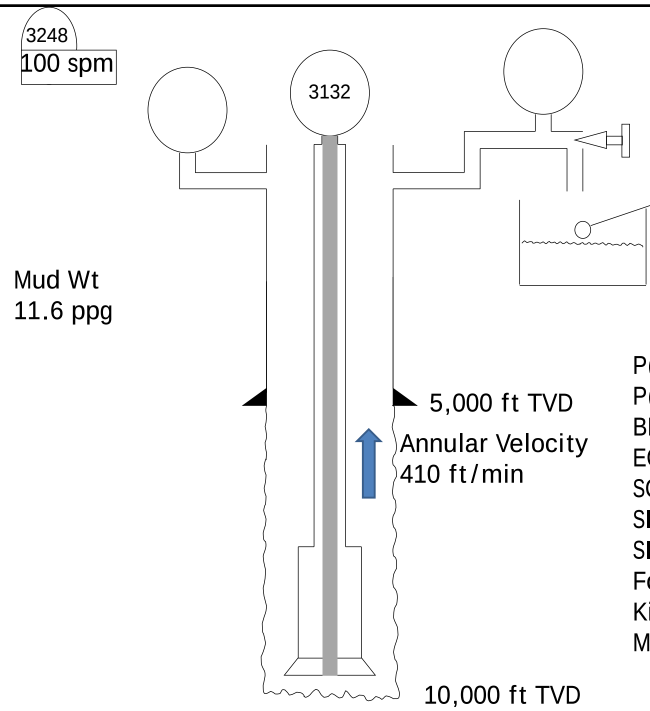
ANNULAR VELOCITY (ft/min)

$$\frac{\text{Pump Output (bbl/min)}}{\text{Annular Capacity (bbl/ft)}}$$

A rig is pumping at 100 spm on a pump with a displacement of .119 bbl/stroke. The annular capacity DP-OH is .029 bbl/ft. What is the annular velocity around the drillpipe?

Feet per minute

82

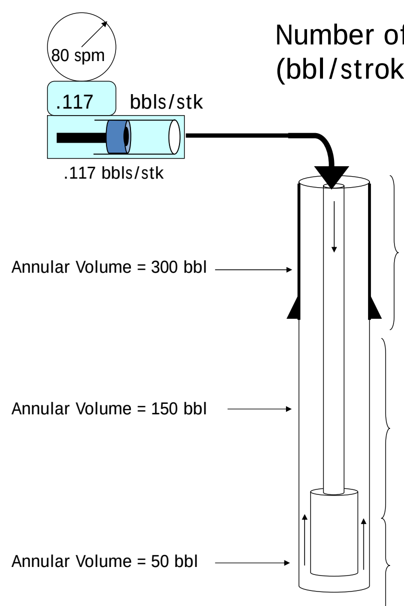


P(hyd) at 10,000’	=	5200 psi
P(hyd) at shoe	=	2600 psi
BHP @ 100 spm	=	5500 psi
ECD	=	10.5 ppg
SCR @ 30 spm	=	240 psi
SIDPP	=	500 psi
SICP	=	650 psi
Formation P	=	5700 psi
Kill Weight Mud	=	11.0 ppg
MW w/ trip margin	=	11.6 ppg

83

Pump Strokes

Number of Pump Strokes = Annular Volume (bbl) ÷ Pump Displacement (bbl/stroke)



$$Pump\ Stks = \frac{300}{.117} = \mathbf{2564}\ stks$$

$$Pump\ Stks = \frac{150}{.117} = \mathbf{1282}\ stks$$

$$Pump\ Stks = \frac{50}{.117} = \mathbf{427}\ stks$$

84

Given:

- DC open hole capacity around 8” DC’s is 0.029 bbl/foot
- Length of drill collars = 656 feet
- Pump output = 0.119 bbl/stk

Strokes
=
Volume
÷
Pump
Displacement

Calculate the number of strokes required to displace DC - OH annulus

160 Strokes

85

Minutes Required to Pump

Minutes required to pump = Strokes ÷ Pump Rate (stks/min)

Calculate the number of minutes required to displace the DC-OH annulus

Well Data:

- Strokes required to displace DC-OH annulus = 160 strokes
- Pump rate = 30 strokes per minute

Calculate the number of strokes required to displace DC - OH annulus

Minutes

Report minutes to nearest minute. Allowed ± 1 minute

86

Formation Pressure
Normal, Abnormal, and Subnormal

87

Formation Pore Pressure

Formation pore pressure = formation pressure

Formation pore pressure (P_f) is the pressure of the fluids inside the pore spaces.

- *Normal P_f is independent of Overburden Pressure*

Overburden Pressure is the pressure from the weight of both overlying *rock and the fluids* it contains

88

API RP 59 definitions

- **Normal formation pressure** *is equal to the pressure exerted by a vertical column of water with salinity normal for that geographic area*
    - Requires communication with surface

- A normal pore pressure gradient is usually between the gradient of fresh water, 0.433 psi/ft, and *0.465 psi/ft*

- NORSOK D 010 uses 0.445 psi/ft as normal pressure gradient
    - Commonly assumed as the gradient seawater

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Differential Pressure

It is the difference between Formation Pressure and the bottomhole pressure.

Over balanced

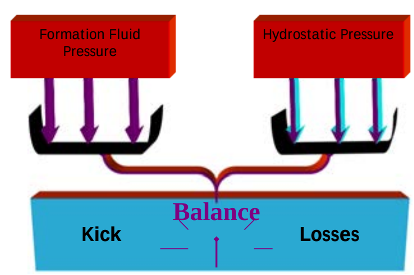
HP > Formation Pressure

Underbalanced

HP < Formation Pressure

Balanced

HP = Formation Pressure



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Formation Pressure

- Normal and Abnormal/Subnormal Pressures

Normal Pressure Gradient: 0.433-0.465 psi/ft

Abnormal Pressure Gradient: 0.465-1.0 psi/ft

Sub-normal Pressure Gradient < 0.433 psi/ft

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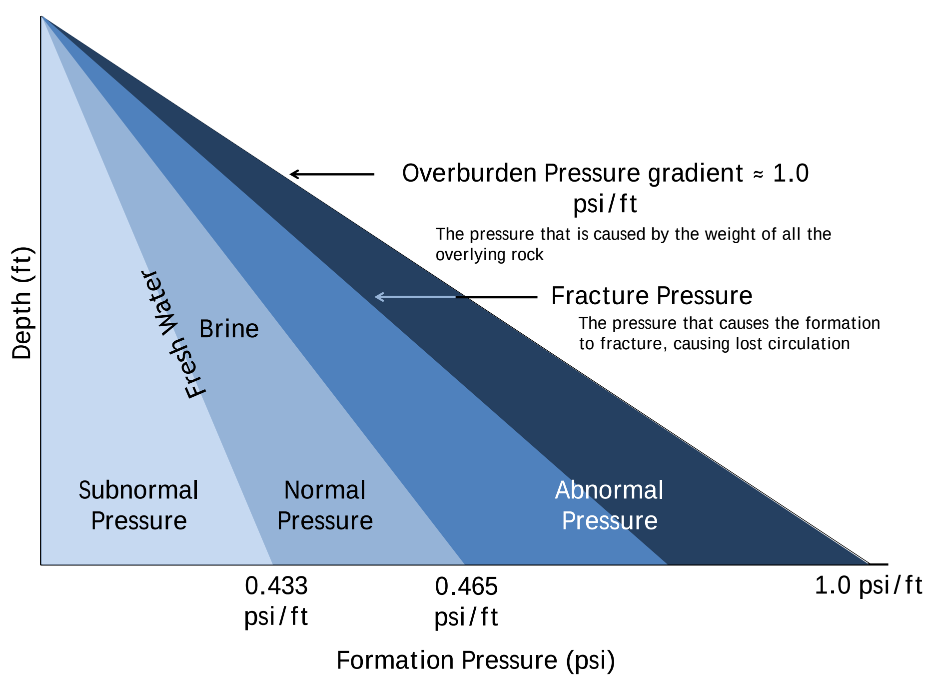

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Sedimentary Rocks

Most of the world's oil and gas reservoirs are contained in sedimentary formations

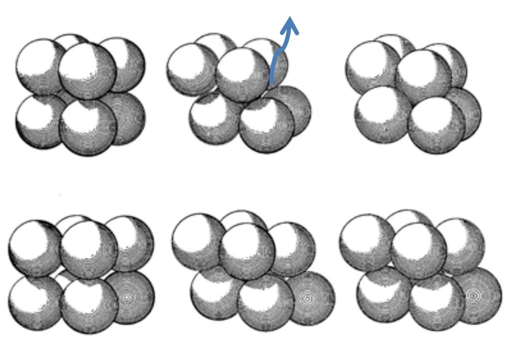
They are existing rocks which are worn down by:

- Ice sheets
- Running water
- Freezing and thawing cycles
- Wind
- Wave action
- Chemical leaching

93

Shale Source Rocks

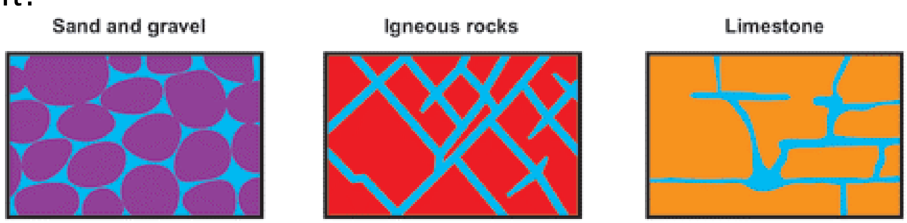
- Laid down in *low-energy marine or lake environments*
- Overburden pressure becomes *compacting* pressure
- Compaction and grading causes *pore fluids to be expelled*



94

Porosity

- Porosity is defined as the relationship between the pore volume and the total volume of the rock (%).
- Porosity provides the storage space for fluids and gases
- Reservoir rocks commonly have porosity ranging from 5% to 30%
- Porosity is expressed as a percentage and has no other specific unit of measurement associated with it.

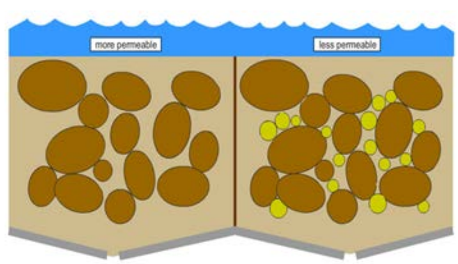


95

Permeability

Permeability is the ability of fluid to flow from one pore space to another.

Permeability value is the Darcy (Millidarcy, mD is 1 Darcy/1000)



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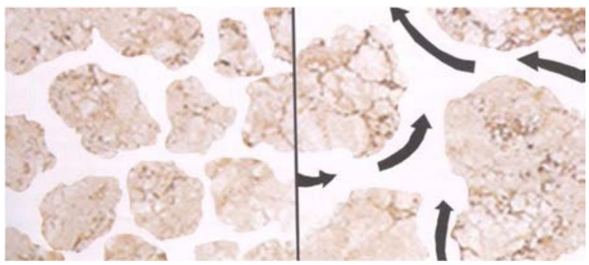
Porosity & Permeability

The essential properties of reservoir rocks are their porosity and permeability.

These properties will determine how much and how quick a kick will enter into the well.

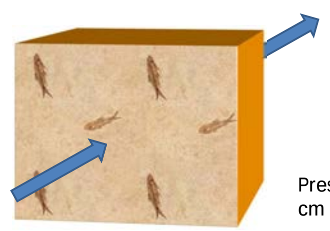
Kicks will enter a wellbore faster from rocks having high permeability.



97

Permeability Units

Permeability -
- ❑ Pore spaces must be connected
- ❑ Measured in darcys
- ❑ Typically, reservoirs are measured in millidarcys



- 1 Darcy = permits a flow of 1 cc per second of a 1 centipoise liquid through a 1 cm cube of rock with a pressure differential of 1 atmosphere.
- Typical permeability range = 100,000 darcys for gravel to .01 microdarcys for granite.
- Sand has a permeability of approximately 1 darcy.

98

How Does Permeability Affect Well-Control?

Permeability affects well control because:

Fluids from highly permeable rocks can enter the wellbore at a faster rate

This can result in:
- A greater kick volume
- Higher wellbore and casing pressures
- Makes the kick more difficult to kill
- Increased danger to personnel, equipment, and environment
- But shut-in pressures will stabilize faster

99

Formation Pressure

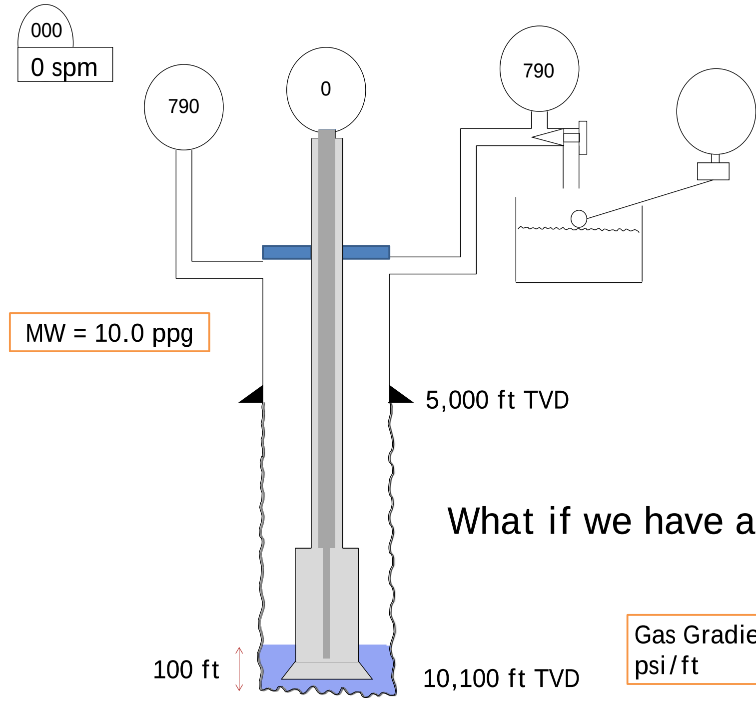
$$\mathcal{Formation\ Pressure} = \mathcal{SIDPP} + \mathcal{Mud\ Hydrostatic\ Pressure}.$$

Calculate the formation pressure, given the following data:

a. TVD = 10100 feet
b. Mud density = 10.0 ppg
c. SIDPP = 748 psi

6000 psi

100



What if we have a float in the string?

Gas Gradient = 0.1 psi/ft

101

Find the SIDPP with a Float

If the drillstring has a non-ported float, the SIDPP will read zero.

- To get a SIDPP reading, slowly start the pump, with the well still shut in, until the casing gauge starts to register movement
- Immediately stop the pump
- Read the DPP. This is your SIDPP
- If the casing pressure rose significantly, deduct the same amount from the DPP

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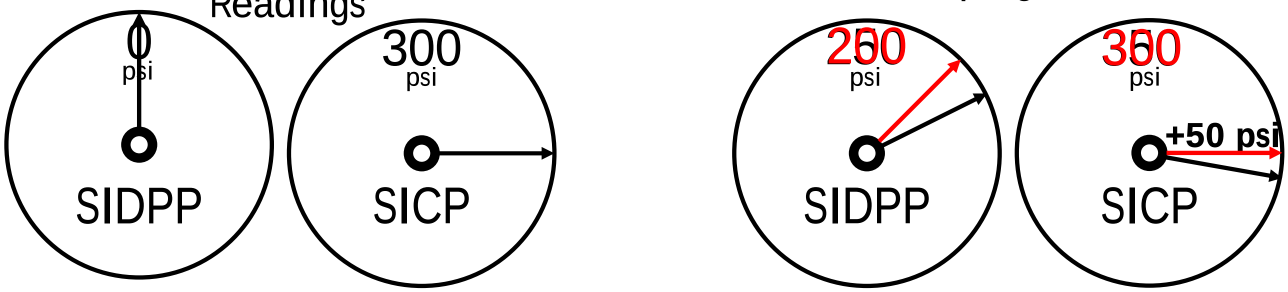
Initial Shut-in Readings

Shut-in Readings After Bumping Float

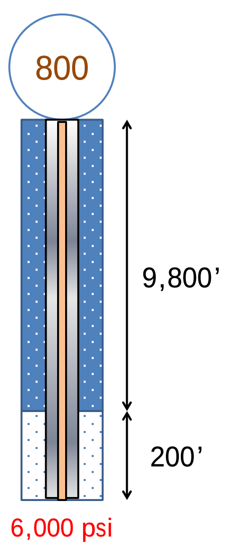


Identify the SIDPP on this rig

a) 0
b) 100 psi
c) 200 psi **250 - 50**
d) 250 psi
e) 300 psi

103

Calculating Formation Pressure(Well Underbalance)



SIDPP

$6000\ psi - 5200\ psi = 800psi$

Hydrostatic Pressure

$10.0\ ppg \times .052 \times 10\,000' = 5200psi$

Formation Pressure $6000\ psi$

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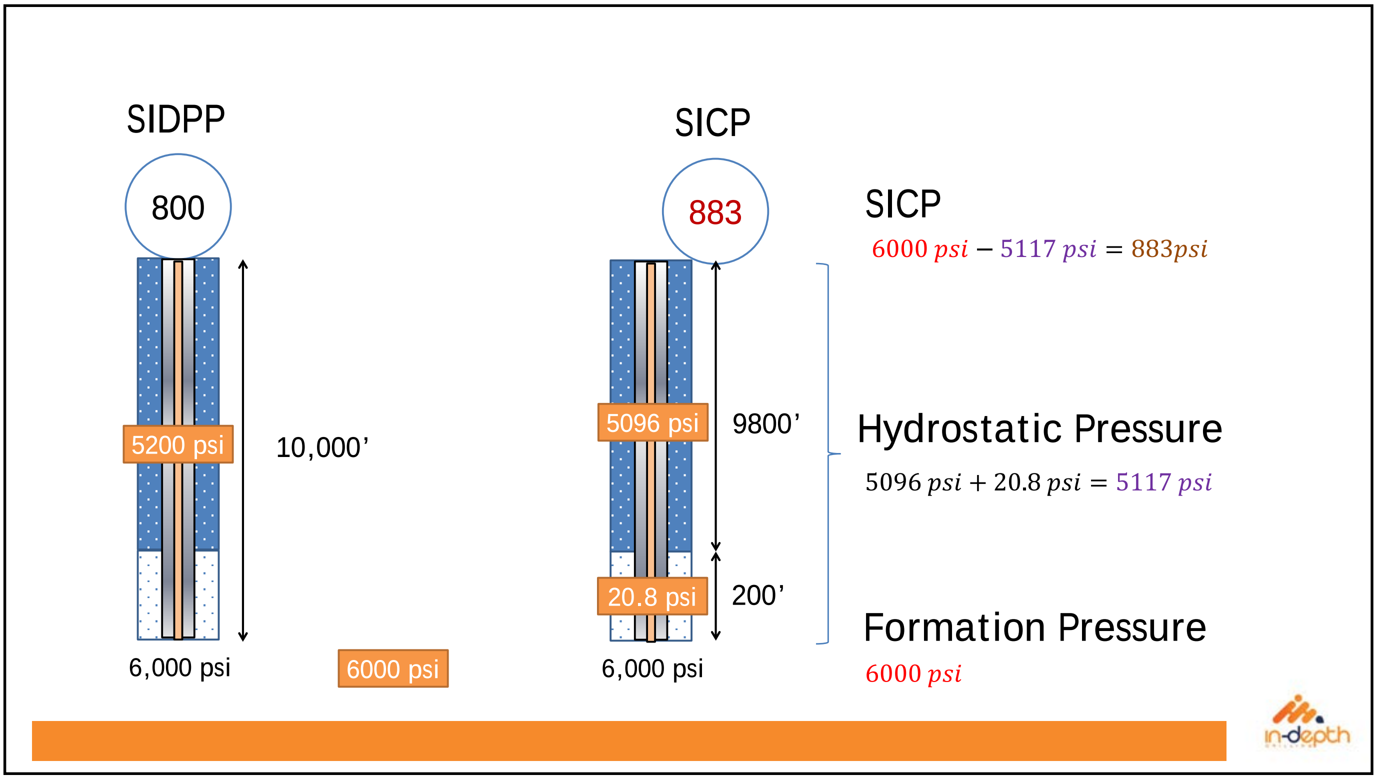

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Formation Pressure

The Lower Limit to
Mud Weight

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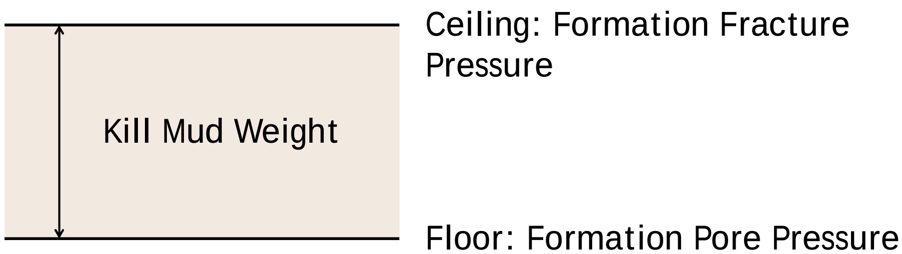
Lower Limit to Mud Weight

Formation pressure determines the lowest KMW



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Formation Pressure

When Shut-in on a kick:

- If we will assume there is no influx in the DP

Then

$$\text{Formation pressure} = \text{Hydrostatic Pressure} + \text{SIDPP}$$

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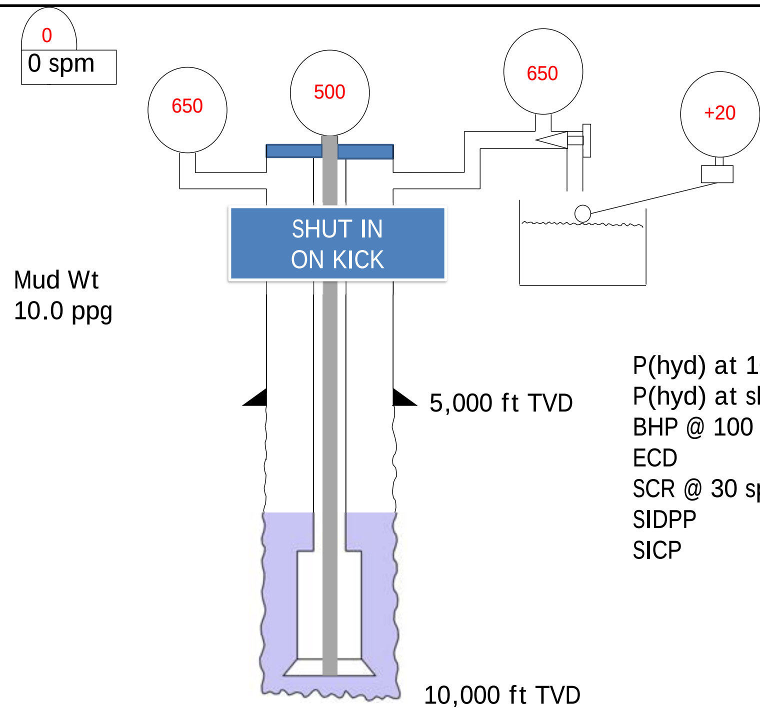

P(hyd) at 10,000’	=	5200 psi
P(hyd) at shoe	=	2600 psi
BHP @ 100 spm	=	5500 psi
ECD	=	10.5 ppg
SCR @ 30 spm	=	240 psi
SIDPP	=	**500 psi**
SICP	=	**650 psi**

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Formula 4

FORMATION PORE PRESSURE (psi)

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

A well has just taken a kick and was shut in. Calculate the formation pressure using the following shut-in data:

- TVD = 10,000 feet
- Mud weight = 10.0 ppg
- SIDPP = 500 psi
- SICP = 650 psi

5700 psi

110

Calculate the mud density equivalent to the formation pressure (Minimum KMW).

- TVD = 10,000 feet
- Mud density = 10.0 ppg
- SIDPP = 500 psi

[ ] ppg Round KMW up to one decimal place

111

A well was drilling at 10,000 feet TVD when it took a kick. The SIDPP was recorded as 500 psi. Calculate the mud weight increase required to kill the well.

[ ] ppg

Read the question!

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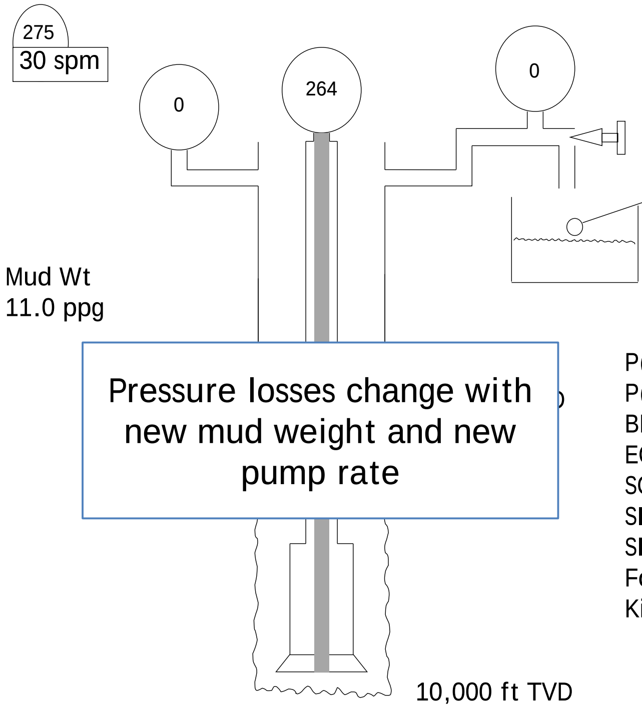

P(hyd) at 10,000’	=	5200 psi
P(hyd) at shoe	=	2600 psi
BHP @ 100 spm	=	5500 psi
ECD	=	10.5 ppg
SCR @ 30 spm	=	240 psi
SIDPP	=	500 psi
SICP	=	650 psi
Formation P	=	**5700 psi**
Kill Weight Mud	=	**11.0 ppg**

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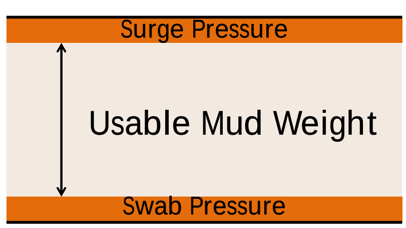
Usable Mud Weight

Usable mud weight will allow well operations without:

- Going underbalanced when hoisting pipe
- Breaking down formation when running pipe

Ceiling: Formation Fracture Pressure



Floor: Formation Pore Pressure

114

Calculate the minimum usable mud weight required to kill the following well. Company policy requires a 400 psi trip margin.

- TVD = 10,000 feet
- Mud density = 10.0 ppg
- SIDPP = 500 psi

[ ] ppg

115

Causes of Kicks

Two conditions are required for a formation to kick:

– Formation pressure greater than the pressure in the wellbore
  - ✓ Underbalanced well
  - ✓ Primary well control is lost

– The kicking formation must have sufficient permeability
  - ✓ Flow path into wellbore

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Causes of Kicks - Insufficient Hydrostatic Pressure

Two primary causes of kicks are insufficient fluid density and insufficient fluid level in the wellbore:

1. Insufficient Density
   - ➢ Fluid contaminated with less dense fluids
   - ➢ Improper fluid conditioning
   - ➢ Penetrating a formation with higher than expected pore pressure
     - o Results from uncertain or erroneous pore pressure data
     - o Poor planning

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Causes of Kicks

2. Lost circulation

✓The loss can result from natural or induced causes

- ➢ Natural causes: Fractured, vugular, cavernous, subnormal-pressured or pressure-depleted formations
- ➢ Induced loss: Uncertain or erroneous formation fracture pressure data
  - Excessive drilling fluid density
  - Excessive annular circulating pressure
  - Pressure surges due to running pipe/tools
  - Breaking circulation
  - Packing-off in the annulus

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Causes of Kicks

- ✓ Swabbing/Surging on trips or running casing
  - Poor tripping practices
  - Not using a self-filling float
  - Tubulars too large for hole size
  - Poor mud conditioning
- ✓ Swabbing/Surging from reciprocating while cementing
  - Poor pipe movement practice
- ✓ Swabbing from wireline tool movement
  - Holes with close tolerance
  - Mud with progressive gel strengths

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Causes of Kicks

3. Failure to keep the hole full during trips
   - ✓Improper hole filling during trips
   - ✓Swabbing

Two of the most common causes of blowouts

If the hole fails to take the proper amount of fluid on trip:

- STOP hoisting & Flow check
- If flowing: Shut In and strip to bottom
- If not flowing:
  - ✓*Return to bottom and circulate out the influx*

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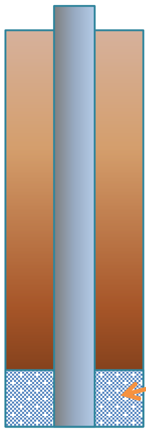
An Influx

An influx can consist of gas, oil, water, or any combination of all three



Most often is less dense than the drilling fluid

Gas may migrate with time up the wellbore through buoyancy

Must be removed in a controlled manner

An influx usually forms a slug in the annulus

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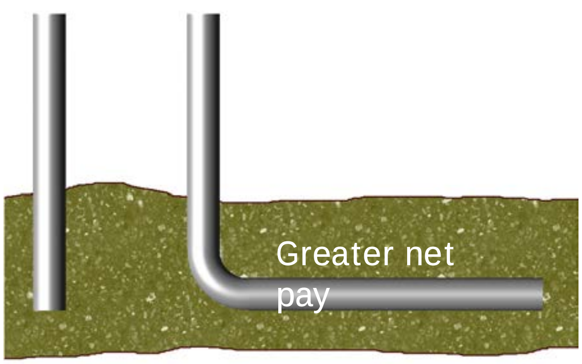
Size of Influx

Size is influenced by the formation productivity, quantity of underbalance, and time

The well with the greater net pay will have a potential for a larger kick



Formation productivity increases with:

- Permeability
- Net pay in units of md.ft

Assuming permeability is the same in each case

- The horizontal well will have the greater potential for a larger kick

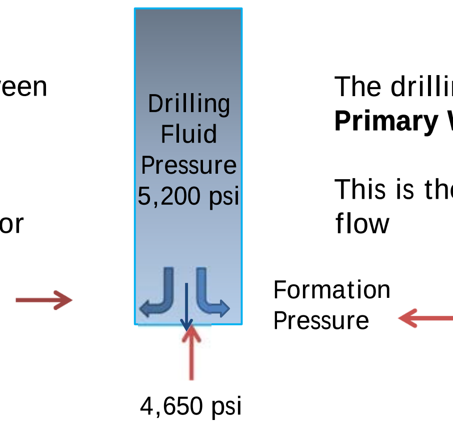
122

Primary Well Control

Primary well control is preventing inflow by *keeping hydrostatic pressure equal to or greater than formation pressure*.

Overbalance / underbalance pressure is the difference between the mud hydrostatic and the formation pressure.

Often expressed in units of psi or ppg or in a gradient of either



The drilling fluid overbalance is the **Primary Well Barrier**.

This is the first object that prevents flow

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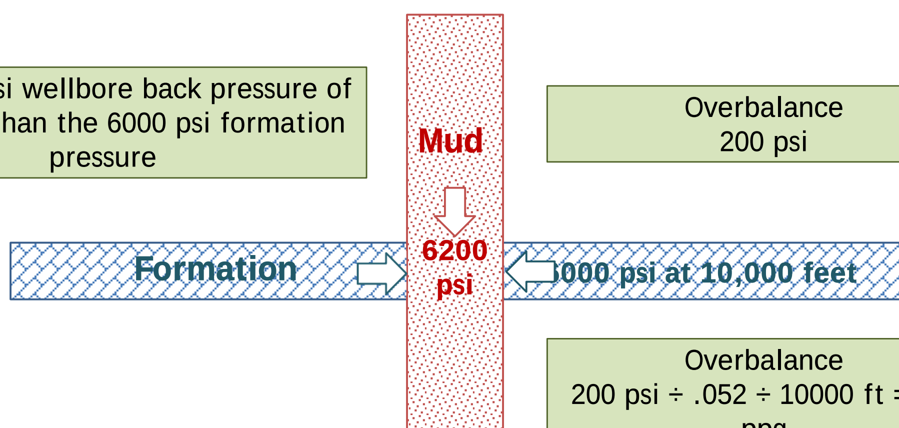
Primary Well Control

Example of overbalance

The 6200 psi wellbore back pressure of is greater than the 6000 psi formation pressure



Overbalance
200 psi

Overbalance
200 psi ÷ .052 ÷ 10000 ft = .38 ppg

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Controlling Well Flow

Through the application of *pressure*:

1. Hydrostatic pressure
   - ✓ Drilling fluid *hydrostatic overbalance*
2. APL
   - ✓ Increasing pump rate increases backpressure
3. Flow restriction at surface
   - ✓ Closing the choke more increases BHP backpressure

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Secondary Well Control

When primary well control is lost, it must be regained by safely managing secondary well control

- Secondary well control uses the **rig BOP equipment** to apply the backpressure
- This backpressure is called *Mechanical backpressure*
  - Mechanical backpressure is applied equally throughout the wellbore
  - It *represents the amount of underbalance* expressed in psi
    - SICP = underbalance (psi) in annulus
    - SIDPP = underbalance (psi) in drill string

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Tertiary Well Control

Used where both primary and secondary well control methods fail or cannot be implemented

Examples:

- Drilling a relief well
- Pumping a cement plug
- Dynamic kill while diverting shallow gas
  - –Cannot shut in or halt flow
  - –Limited backpressure from APL and diverter losses (Max 200 psi – 300 psi)

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Influx Characteristics

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Influx Fluid

An influx fluid can be:

- Water / brine
- Oil
- Gas
  - –Hydrocarbon gases such as CH_4, C_2H_6, ...
  - –H_2S, SO_2, He, or CO_2
- Combination of two or more of the above

129

Boyle's Law

Gas is highly compressible:

- Volume dependents upon pressure and temperature

(If we ignore temperature changes, we can apply Boyle's Law)

$$P_1 \times V_1 = P_2 \times V_2$$

Many gases are soluble in OBM and WBM:

- Some are *highly soluble* in oil and synthetic oil-based muds
  - –Gas in solution does **not** behave like free gas
    - ✓May *mask a kick situation*

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Boyle's Law

Boyle tells us there is relationship between volume and pressure:

- o If pressure goes ↓
- o Volume must ↑

Conversely

- o If the volume goes ↑
- o Pressure must ↓

131

Basic Principles of Bubble Management:

1. A gas influx *must be allowed to expand* as it rises up the hole
   – Results in *decreased hydrostatic pressure* in annulus

2. *Annular pressures must be allowed to increase* as a gas influx is brought up to the surface
   – Casing pressure must increase to *maintain constant BHP*

   $BHP = Hydrostatic\ Pressure + SICP$

3. We must avoid fracturing the formation or bursting the casing

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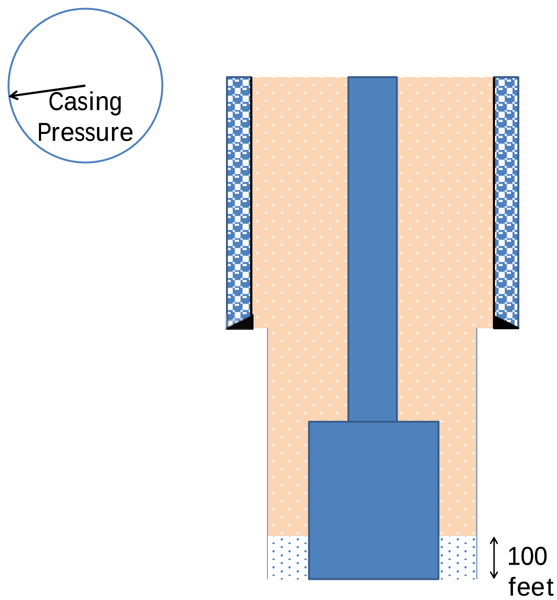
Casing Gauge Pressure With Gas Influx



BHP = Formation Pressure

BHP = Hydrostatic Pressure + SICP

Gas Influx

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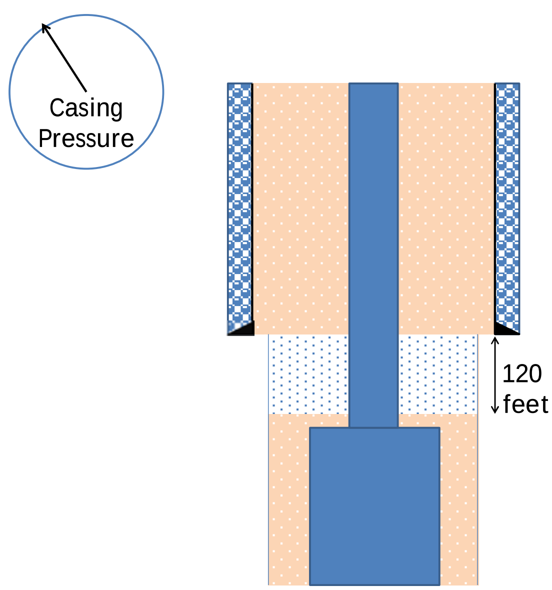
Casing Gauge Pressure as Gas Ascends Annulus



Gas at Csg Shoe

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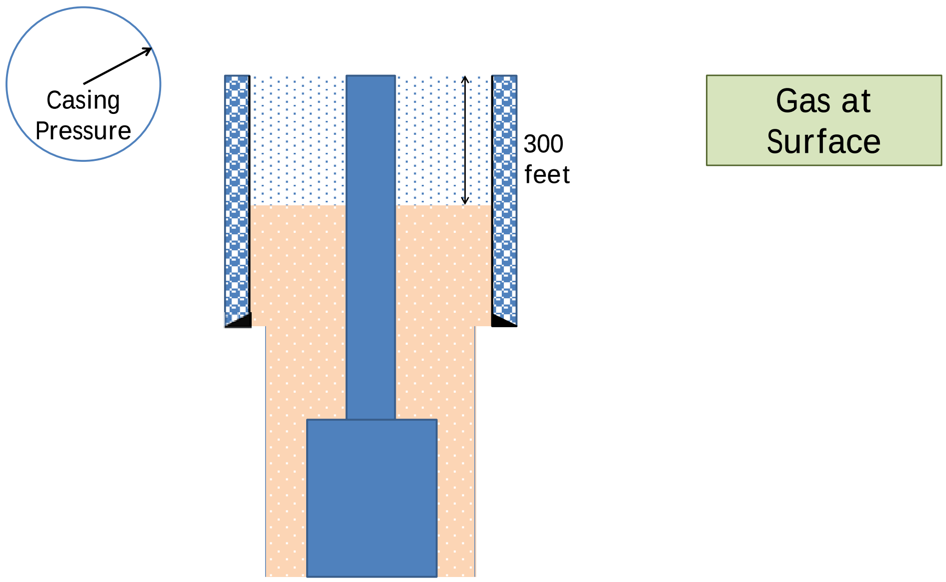
Casing Pressure Maximum with Gas Kick



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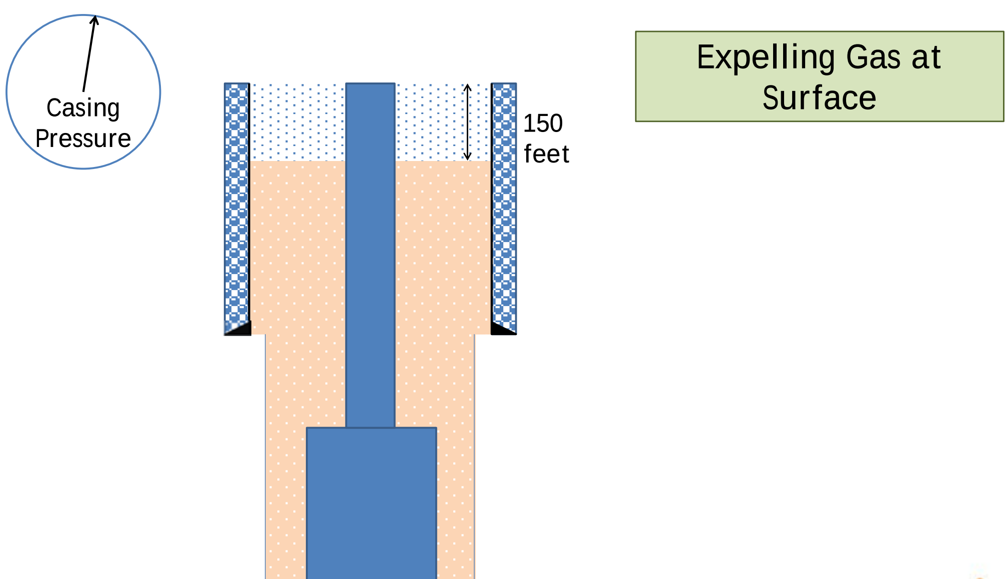
Casing Pressure Rapidly Dropping



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What can we expect the casing pressure to do as a gas influx is circulated up the annulus while we maintain constant BHP?

A. The casing pressure will increase
B. The casing pressure will decrease
C. The casing pressure will remain the same

137

Gas Kick-Risks

Excessive wellbore pressure increases the risk of:

- Lost circulation leading to underground blowouts
  - Can be very expensive to cure
  - Can quickly escalate into a surface blowout and loss of well
- Broaching to surface
  - Can be extremely dangerous for bottom-supported rigs

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Gas Kick-Risks

Returns start out equal to, but soon *exceed pump output*

- –As a bubble expands, it displaces more mud at surface
- –Most of the gas expansion occurs after the gas is half-way up the hole
- –The return rate curve closely follows the casing pressure curve
- –Can be loosely predicted by Boyle's Law
- –Pit gain volume decreases to zero after gas has been expelled

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Water Kick

Water is nearly *incompressible*

- Does not expand when pumped up the wellbore
  - –Volume remains constant throughout the kill
- Pumping and return rates are equal
  - –No expansion of kick (Assuming no gas in solution)
- Kick *volume remains constant* throughout kill
- *Casing pressure may decline* as the influx enters a larger annulus

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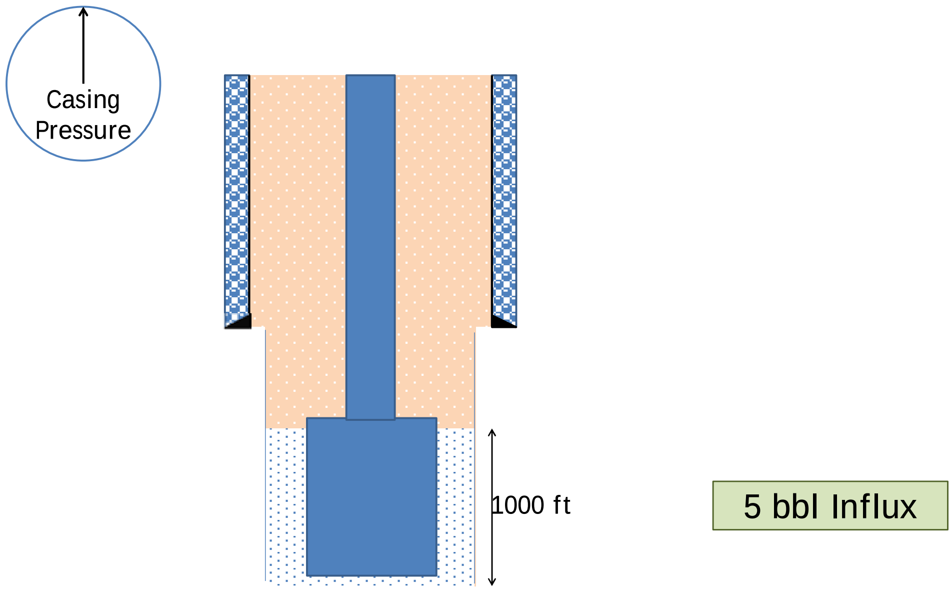
Casing Gauge Pressure Immediately After Shutting in a Water Kick



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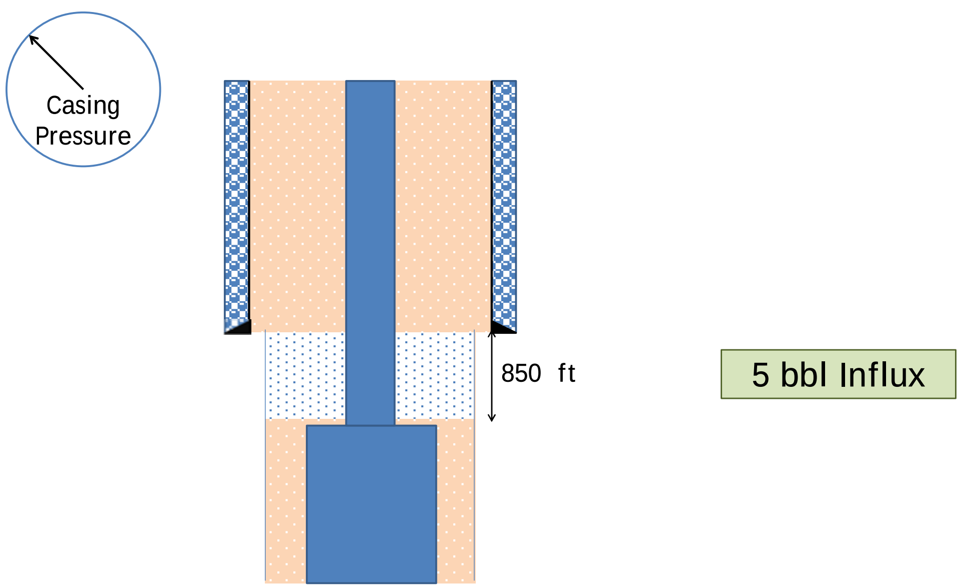
Casing Gauge Decreases



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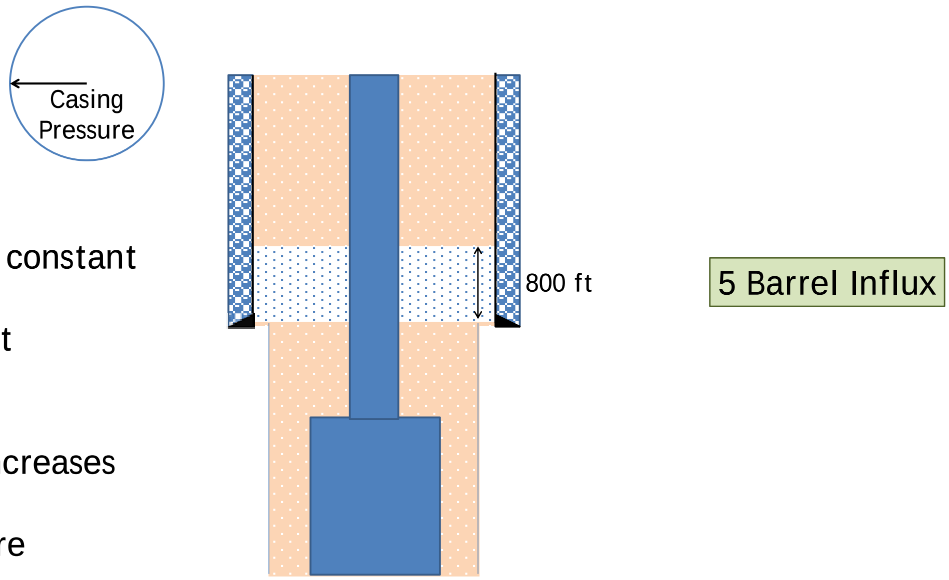
Further Decrease in Casing Pressure



- Influx volume constant
- Vertical height decreases
- Hydrostatic increases
- Casing pressure decreases

143

Water Kicks

Caveat: The preceding assumes the following:

1. The water is lighter than the drilling fluid
2. The water contains no associated gas
   - Water influxes may contain some dissolved gas
     - Dissolved gas will *start* breaking out at "*bubble Point*"
     - Most will break out at surface

Treat all kicks as if they contain solution gas

144

Effect of Water Influx on the Fluid Barrier

- *Density reduction* through dilution with a lighter fluid
- *Density increase* through changes in oil:water ratio in low-density OBM
- *Rheology changes*:
  - Viscosity increase in OBM
  - Possible flocculation in WBM if invading fluid is a brine
  - Possible viscosity reduction in WBM if invading fluid is fresh water
- *Chemical changes:*
  - Possible buffering/pH changes
  - Chloride changes
    - ✓Increase in freshwater mud
    - ✓Decrease in OBM or saturated salt mud

145

Oil Kicks

Almost always contains dissolved gas

- Should be treated like a smaller gas kick
- Dissolved gas has a *phase change* near and at surface
  - Can be extremely dangerous
    - ✓Little or no indication of a kick

Gas in solution

- Increases with pressure
- Decreases with temperature
- Decreases with agitation

Pressure required to force gas back into solution is usually higher than the bubble point pressure

146

Effect of Oil Influx on the Fluid Barrier

- *Density reduction* through dilution with a lighter fluid
- *Rheology changes:*
  - Possible viscosity decrease in OBM
  - Possible flocculation in WBM if invading fluid is a brine
  - Possible changes in the fluid loss in a WBM

147

Actions to Combat Gas Breakout

Actions Required to Mitigate Effects

- *Immediately shut in the well*
- Circulate bottoms up through the choke and MGS
- Increase mud density to KMD

148

Gas-cut Mud
and
Its Effect on BHP

149

Gas-Cut Mud

- Can be an early warning signs of a potential kick
  - –Can cause a reduction in drilling fluid density
- **Not** always a positive kick indication
- Crew needs to *monitor trends*
  - –Determine the downhole cause
  - –*Alert the supervisor to trend changes*
  - –*Start the degasser*

150

Background Gas

Total concentration of gas measured in mud while drilling shales

- Is used to establish a *baseline (Background)*
- Can be used to track the pore pressure changes *(trends)*

  - Assumes interbedded permeable formations are in equilibrium with shale
  - Increases in background gas may indicate increases in pore pressure
  - Monitoring *trend lines*
  - Monitoring offset information

151

Causes of Gas-cut Mud

Downhole causes of Gas-cut mud:

- Drilled gas resulting from drilling gas-bearing rocks
  - Not resulting from insufficient mud density
  - Mud density reduction can be considerable in surface tanks
  - May need to close annular to prevent belching and loss of mud
  - Usually little reduction upon BHP because the majority of the gas expansion is at surface

- Trip gas from swabbing and APL loss while tripping
  - If the well did not flow during trip, likely is result of swabbing
  - Trip gas readings should be compared to previous trips. Look for trends.
  - **Warning sign**

152

Causes of Gas-cut Mud

- Connection gas from swabbing and loss of APL at connections
  - Compare to trend from previous connections
  - **Warning sign**

- Gas from drilled under-compacted shales
  - Increasing background gas accompanied by pressure spalling
  - **Warning sign**

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Gas-cut Mud

Warning:

- Drilled gas in *shallow sands* can rapidly gas-cut the mud to the extent that the hydrostatic pressure loss can cause flow
- Control drill to reduce gas loading
- Run degasser
- Be prepared to shut in or divert

154

Liquid-cut Mud

Signs of liquid-cut mud:

- Pit gain
- Small reduction in mud density
  - Liquid kicks usually result in only a small density reduction
- Slight increase in string weight
- Possible change in chlorides in mud
- Possible change in rotary torque

155

Tripping and Tripping Calculations

156

Tripping Process

- Prepare the hole for tripping
  - Ensure the hole is clean and stable
  - May need to circulate several btms up in horizontal well
- Prepare fluid properties for tripping
- Prepare the floor for tripping
- Flow check
- Pump a heavy slug
  - Calculate returns and confirm

157

Tripping Process

- Trip out of the hole
  - Monitor hole fill using trip tank. Complete trip sheet
  - Prepare for non-shearables in the BOP stack
  - Continue to monitor hole/flow when out of hole
- Run pipe back in
- Monitor displacements
  - Use trip sheet and trip tank

158

Tripping Practices

- Pump a slug
  - Dry pipe on trip
- Trip Margin
  - To maintain BHP above formation pressure
  - Offsets swab pressures
- Pumping out of the hole
  - Keeps the hole full
  - Offsets swabbing effect through tight spots
  - Flow rate must be sufficient to overcome swabbing
  - Pump output must be sufficient to fill the space below the bit
    - Annular velocity greater than tripping speed

159

Risks Associated with Tripping

Most well control incidents occur when tripping.

- Tripping is a high-risk operation

Primary risks are associated with *swabbing* and *surging*

- Tripping out - swabbing in a kick
  - Greater risk:
    - Mud with low trip margin
    - High viscosity or contaminated mud with progressive gel strengths
    - Balled-up bit and tools
    - Fast tripping speed
    - Large diameter BHA, tools, or casing
    - Slim hole with reduced annular clearances

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Risks Associated with Tripping

- Tripping out - *swabbing, not keeping hole full*
  - Greater risk:
    - Pulling BHA through BOP stack
    - Not filling the hole
    - Not using trip sheet
    - Floor not prepared for trip
      - DPSV and IBOP readily available
      - Crossover subs readily available

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Risks Associated with Tripping

Most well control incidents occur when tripping.

- Tripping is a high-risk operation

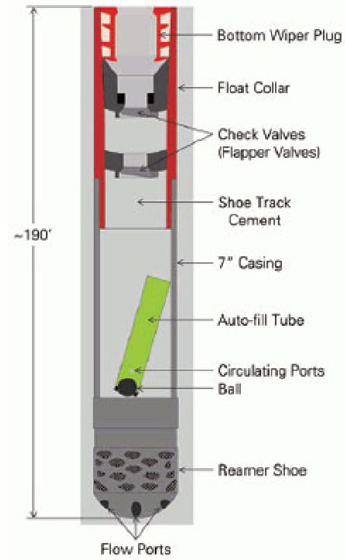
Primary risks are associated with *swabbing, surging, and incorrect hole fill*

- Running in – *induced losses* from surging
  - Greater risk:
    - Weak open formations
    - High mud weight close to maximum mud weight
    - High viscosity or contaminated mud with progressive gel strengths
    - Large diameter or long BHA, tools or casing
    - Slim hole or reduced annular clearances
    - Fast tripping speed
    - Small bit nozzles or a conventional casing float (non-self filling)

162

Self-Filling Casing Float

- Reduces the surge pressures when running casing
  - Essential in deep water wells
- Requirement to convert before cementing
- Failure to convert causes serious well control issues
  - Check that the float is converted by looking for reduction in pressure
  - Also check for leakage after displacing the cement
  - Ensuring there is no flow back after cementing



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Trip Management

Responsibilities of supervisor:

A trip requires direct supervisory oversight

- Check tripping
  - Hole and mud correctly conditioned
  - Floor correctly prepared
  - Correct trip tank lineup
  - Appropriate tripping practices
  - Trip sheets correctly filled in
- Swab and surge monitoring
- Wet/dry trip monitoring

164

Identify Items	Identify all the non-shearables and non-sealables. Post in doghouse
Fill Hole	Ensure hole is full. Use continuous hole fill. Verify volumes with trip sheet
Verify No Flow	Flow check
Prepare Floor	Ensure crossover sub and DPSV are readily accessible. Consider making up stand with DPSV in place
Shut-in Procedure	Identify procedure to shut-in with non-shearables in the stack. Post procedure and perform regular drills

Management of Non-Shearables

165

Trip Sheet

Trip Sheet

While trip out of or in to the hole, it is important to calculate the volume of metal pulled out or ran in.

- In Dry tripping: Volume= Metal displacement,
- In Wet tripping: Volume= Metal Displacement + Pipe Capacity

To prevent kick while tripping, basic requirement is that hole must be kept full of mud

Note:

If hole does not take proper amount of mud. Whenever such situation is noticed the pipe should be run back to bottom and mud be circulated to clear the hole.

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Trip Sheet

Essential Features:

- Calculated volume of the pipe when pulled dry
- Calculated volume of the closed-end displacement
- Calculated cumulative volume
- Actual cumulative volume
- Difference between calculated and actual cumulative volumes

167

Trip Sheet

Stand Number	Calculated Displacement per Stand (Bbl/Std)	Calculated Cummulative Displacement (Bbl)	Trip Tank Volume (bbl)	Actual Cummulative Displacement (Bbl)	Difference between actual and calculated volume (Bbl)	Trip Tank Mudlogger (Bbl)	Cummulative Displacement Mudlogger (Bbl)	Difference between Mudlogger actual and calculated (bbl)	Notes
1	0.729	0.729	9.3	0.700	-0.029	9.28	0.720	-0.009	
2	0.729	1.458	8.6	1.400	-0.058	8.59	1.410	-0.048	
3	0.729	2.187	7.91	2.090	-0.097	7.9	2.100	-0.087	
4	0.729	2.916	7.18	2.820	-0.096	7.2	2.800	-0.116	
5	0.729	3.645	6.45	3.550	-0.095	6.46	3.540	-0.105	
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									

Theoretical Displacement

Theoretical Cumulative Displacement

Actual Cumulative Displacement

Cumulative gain or loss

Negative number indicates the well is taking insufficient mud

Trip Sheet and Monitoring Returns

168

Trip Tank

Essential Features:

- Small auxiliary mud tank
  - Allows measurement of small pit level changes
  - A fraction of a barrel per inch
- Usually equipped with an inside gauge marked off in one barrel intervals or even smaller
  - Mechanical float attached to pulleys
  - Electronic, sonar, or infrared sensors
- Continuously circulating pump
  - Used when tripping
  - Keeps the hole full on trips

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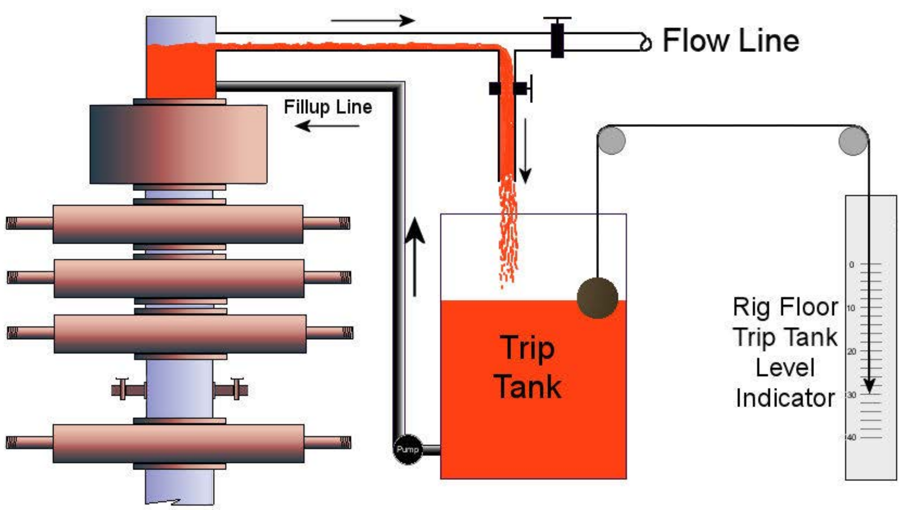
Trip Tank



170

Prior to tripping, a driller pumped 25 bbls of heavy slug, stopped the pumps, and disconnected the top drive. How does this action affect the BHP after the well has stabilized?

A. BHP will increase
B. BHP will decrease
C. BHP will remain the same

171

Had the driller in the last question continued to pump the heavy slug, when would the slug first affect the BHP?

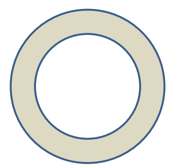
A. Immediately the slug starts entering the drillstring
B. When the leading edge of the slug reaches the bit
C. When the leading edge of the slug starts entering the annulus
D. Once the entire slug is in the annulus

172

Hole Fill

While pulling out of the hole <u>dry</u>:

The driller should fill the hole with sufficient mud to replace the displacement volume of the steel removed



Note: Metal displacement is sometimes simply called *displacement*

173

A string of 5” drillpipe is being tripped out of the well. After the driller pulls five stands dry, how many barrels of mud should be used to fill the hole?

Well Data:

Drillpipe capacity: .0176 bbl/ft
Drillpipe displacement: .0076 bbl/ft
Average stand: 93 feet

3.53 bbl

174

$$Hole\ fill = Pipe\ Disp \times No\ of\ Stands \times Std\ L$$

$$Vol\ Reqd = .0076 \times 5 \times 93\ ft = 3.534\ bbl$$

175

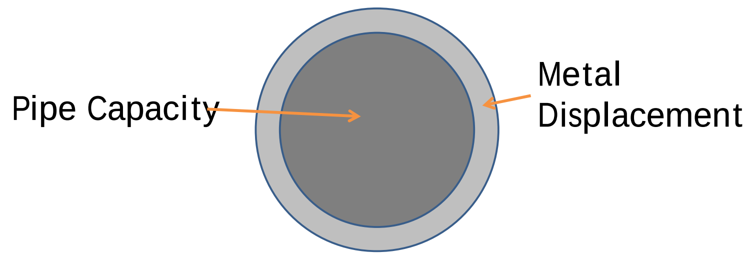
Hole Fill

While pulling out of the hole wet:

The driller should fill the hole with sufficient mud to replace the *closed end displacement* volume being removed

$$Closed\ end\ displacement = Metal\ displacement + pipe\ capacity$$

176



Closed End Displacement

Assume mud inside drillpipe does not return to the well

Pipe Capacity + Metal Displacement

177

A string of 5" drillpipe is being tripped out of the well. After the driller pulls five stands wet, how many barrels of mud should be used to fill the hole?

Well Data:

Drillpipe capacity: .0176 bbl/ft
Drillpipe displacement: .0076 bbl/ft
Average stand: 93 feet

11.72 bbl

178

$$Hole\ Fill = Closed\ end\ displacement \times No\ of\ Stds \times Std\ L$$

$$Hole\ Fill = (.0176 + .0076) \times 5 \times 93$$

$$= .0252 \times 5 \times 93$$

$$= 11.718\ bbls$$

179

Tripping In

When tripping in, the driller must verify that sufficient mud is returning to the trip tank.

If the trip tank shows insufficient fluid return, the well must be taking fluid.

If the trip tank shows excessive fluid return and flow checks prove negative, the well most likely has been swabbed on the trip out.

180

The volume of return while tripping in should be equal to the metal displacement, if no float

A string of 5” drillpipe is being tripped into the well. After the driller runs ten stands, how many barrels of mud should be returned to the trip tank? Assume there is no float in the string.

- Well Data:
- Drillpipe capacity: .0176 bbl/ft
- Drillpipe displacement: .0076 bbl/ft
- Average stand: 93 feet

$\boxed{7.07}$ bbl

181

$$Returns = Metal\ Disp \times No\ of\ Stds \times Std\ L$$

$$Returns = .0076 \times 10 \times 93$$

$$= 7.068\ \text{bbl}$$

182

After pulling 10 stands off bottom, the driller finds the well is not taking the correct amount of fluid. A flow check is negative. What should the driller do?

a. Pull another 5 stands and flow check again
b. Run or strip back to bottom and circulate bottoms up
c. Shut the well in and check for pressure
d. Since there is no flow, it is safe to continue tripping out

183

Incorrect Volume: Actions to Take

Deviation from predicted trip tank volumes:

- Stop tripping
- Communicate with the supervisor
- Flow check

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Incorrect Volume: Actions to Take

Trip sheets indicates a swabbed influx:

- Flow check
- Run or strip back to bottom
- Circulate the influx out through the choke and MGS

185

Swab Pressure and Surge Pressure

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Swab Pressure

When tripping out of the well, the pipe movement creates a temporary negative pressure losses in the annulus

One of the primary causes of kicks

This negative pressure is called swab pressure

The amount of swabbing will depend upon the mud properties, formation characteristics, measured depth, hole geometry, string configurations, and *rate of pipe movement*

187

Surging & Swabbing

What is surge pressure?

When pipe moves downward with mud circulation through drill string, **additional bottom hole** pressure called "Surge Pressure" is created. If surge pressure is too much, many problems will occur such as formation brake down, partial mud loss and lost circulation.

What is swab pressure?

If a drill string , casing string or logging tool is being pulled out of hole too fast, due to bigger diameter almost same hole size, BHA/ bit, casing or logging tool will possibly swab the hole and cause the bottom hole hydrostatic pressure **to be reduced**. Pressure reduction created by this situation is called **"Swab Pressure".**

188

Swabbing

- If the swab pressures exceed the trip margin:
  - The well will go underbalanced
  - Formation fluids *may* enter the wellbore
- This *can* result in taking on a kick while tripping
  - Even if the flow check was negative at the beginning of the trip

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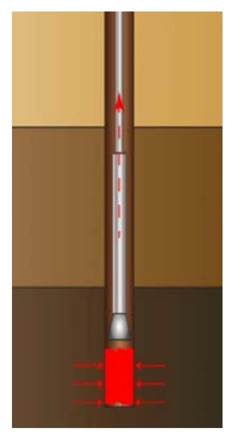
Swabbing



Factors that increase a chance of swabbing in are as below:

- **High Mud viscosity and gel strength**
- **Pipe movement is rapid/fast.**
- **Wall cake is thick**
- **Annular clearance against BHA is small**
- **Formation pressure vs hydrostatic pressure(equal to or slightly above formation pressure)**
- **Swelling/Heaving Formations**

A "negative pressure'' is created when the drill string is lifted through the mud. When this happens a decrease in bottom hole pressure occurs which may lead in a kick.

Anytime during a trip, if the hole begins taking less mud than it should for the displacement of the pipe being removed, swabbing might be the reason.

It is recommended to keep the pump running while trip out.

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What to do in case of Swabbing

If swabbing has been detected and the well is not flowing a non return valve should be installed and run to bottom. Flow check each stand. Once back on bottom the well should be circulated and the bottoms up **with same mud**, sample checked for contamination.

If the well is flowing or the returns from the well are excessive when tripping in then the following should be carried out:
Install a non return valve. If there is a strong flow then a kelly cock may have to be installed first.

Shut the well in.
Prepare for stripping.
Strip in to bottom.
Circulate the well, check bottoms up for contamination.

191

Swabbing

How To Minimize Swabbing

There are several items which can minimize swabbing as listed below;

- Keep the mud in good condition
- Pull out of hole with reasonable speed
- Add lubricant additives and maintain good drilling hydraulic to prevent bit/BHA balled up
- Add chemical to prevent clay swelling in water based mud or use oil based mud drilling into clay formation
- Pump out of hole instead of pulling out

192

Trip Margin

What is Trip Margin?

It is an increase in the hydrostatic pressure of mud that compensates for the reduction of bottom pressure due to stop pumping and/or swabbing effect while pulling pipe out of hole. Trip Margin is calculated by following equation:

How do we calculate trip margin?

The formula used to calculate trip margin is listed below;

Trip Margin (PPG) = (Margin needed (Psi) - Present Margin (Psi))/ (0.052xTVD (ft))

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Example of Swab Pressure

Well Data Given:

Well Depth; 10000 Ft, MW: 10 ppg, Formation Pressure: 5200 psi,
Swab Pressure: 150 psi,

Will the well flow?

- ❑Yes ?
- ❑No ?

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Swabbing

Which of the following would increase the risk of swabbing during a trip?

A. Balled up bit
B. Tripping in too fast
C. Viscous mud
D. Heavy mud weight
E. Tripping through tight spots with the pump off
F. Pulling pipe slowly

195

Swabbing

Which of the following will swabbing always result in?

A. Increase in BHP
B. Decrease in BHP
C. Lost circulation
D. A kick
E. Increase in chlorides in mud

196

Trip Margin

To avoid going underbalanced while tripping, we often add a safety margin called a *trip margin* to compensate for the effects of swabbing

The KMW on a 10,000 ft TVD well is calculated to be 11.0 ppg. The operator is asking for a trip margin equal to the APL of 300 psi. What is the new mud weight?

[ ] ppg

197

Surge Pressures

Additional pressure imposed on the well while running pipe or tools

- Undesirable – increase risk of induced lost circulation, leading to a well control issue
- Caused by running into the hole too fast

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Surge Pressures

Which of the following is likely to increase Surge pressures?

A. Running in with large nozzles
B. Running in with a float in the string
C. Pulling out with high-viscosity mud
D. Tripping into the hole fast
E. Tripping in slim hole

199

Surging

Which of the following will surging always result in?

A. Increase in BHP
B. Decrease in BHP
C. Bridging
D. Lost circulation
E. A kick

200

Actions to Minimise Swabbing and Surging

- Use appropriate running and pulling speeds
- Monitor carefully to identify gains and losses
  - Refer to trip sheet
- Optimise fluid properties
  - Non-progressive gel strengths
  - Minimize bit/stabilizer balling
- Optimise the hole conditions
  - Circulate hole clean of debris before tripping
    - Remove obstructions, bridges, or key seats beforehand
- Properly-designed BHA
- Consider circulating during pipe movement
  - Maintain constant BHP
  - Keep hole full below bit

201

Well Barriers to Flow

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Barriers to Flow

Something that prevents flow from one side to the other

–Police barricade for control crowd movement

–Hydro-electric dam to control a river

–Bucket to transport water

To be ineffective the barrier only needs a small breach

–Example a hole in a water bucket

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Barriers to Flow

API RP 59 11.11.1

If a well is considered to have potential to flow, maintenance of a two barriers to flow should be considered.

NORSOK Standard D-010 4.2.3.2

- *One well barrier is required to be in place where there is potential for cross flow between formations*
- *Two well barriers* available *where there is a potential for flow to surface*
- When drilling a well, two *tested barriers* need to be available *at all times*

204

API on Barriers to Flow

Barrier Element

A component or practice that contributes to the total system reliability by preventing liquid or gas flow if properly installed

The barrier design should incorporate the following:

- Ability to withstand the maximum anticipated wellbore pressure
- Ability to be tested for function or leaks
- Failure of a single barrier will not result in uncontrolled flow from the well
- The operating environment is within the design specifications of the barrier element

- Must be able to *document* that it will *solely prevent* an incident within expected and verified limits, otherwise a *combination of barriers is required*
- The barriers should be independent of each other without any barrier elements in common

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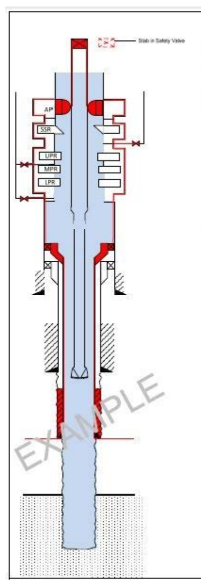
Concept of Well Barrier

Primary well barrier:

This is the first object that prevents flow from a source.

Secondary well barrier:

This is the second object that prevents flow from a source.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Fluid column	1	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
High pressure riser (J/P)	26	
Drilling BOP	4	
Drill string	3	
Stab-in safety valve	40	

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What are Well Barriers

- A "Well Barrier Envelope" is defined as a combination of one or more Well Barrier Elements that together constitute a method of containment of fluids within a well that prevents uncontrolled flow of fluids into another formation, or, to escape at surface.
- A "Well Barrier Element" is defined as a component part of a well designed to prevent fluids or gases from flowing unintentionally from a formation, into another formation or to escape at surface.
- Well barrier(s) shall be defined prior to commencement of an activity or operation by description of the required WBE's to be in place and the specific acceptance criteria.
- Must be defined in the well plan, including:
  - A description of the barriers
  - Specific *acceptance criteria* defined

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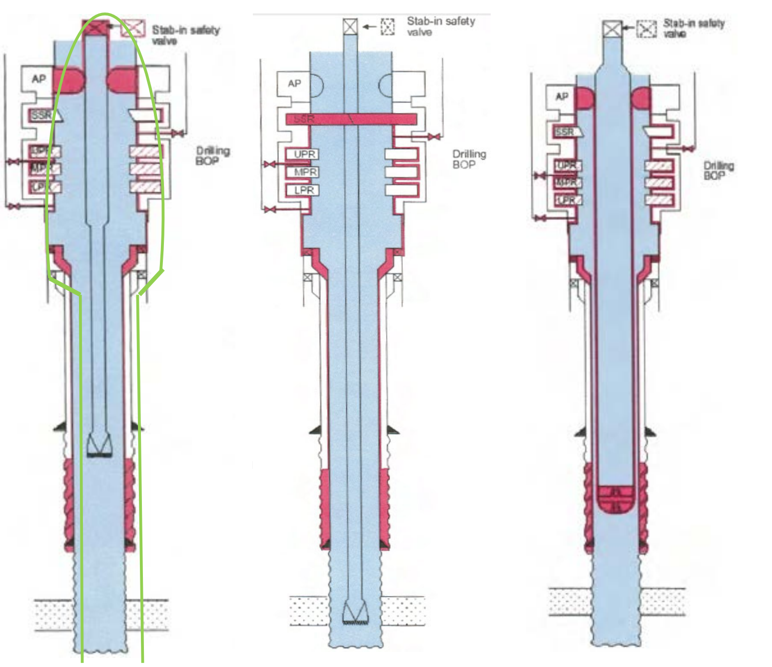

An Envelope

- An envelope is a sheath that completely encloses the well
- Consists of a number of WBEs
- Each element *must be tested* to be sufficient to prevent flow at the highest anticipated pressure
- Elements may be incapable of preventing flow by themselves
- If one element fails, it may cause the entire envelope to fail

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Well Barrier Elements (WBE)

Well Barrier Element:

Part of the envelope, but may not be sufficient *alone* to prevent flow

Examples of WBEs are:

- **Fluid barriers**
- **BOP preventers**
- **The cement sheath**
- **Drill pipe safety valve (DPSV)**

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Barrier Influencing Factor

Something that *influences how a barrier performs*

Example:

BOP equipment is not a barrier unless activated in a **timely** manner. The influencing factors would be:

- Crew *preparedness*
- Remembering to activate the alarms
- Level of crew training/knowledge

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Types of Barriers to Flow

A barrier is *a measure designed to reduce the probability of triggering an incident* and/or *reduce the consequences* of that incident.

Primary well barrier: *preventing barrier*

- *First object that prevents flow* NORSOK Standard D-010 3.1.26
- Proper overbalance
  - Impossible to take a kick when in place
  - Needs *constant monitoring* to qualify as a barrier
    - A mud check is only a snapshot of **current** conditions

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Types of Barriers to Flow

A barrier is *a measure designed to reduce the probability of triggering an incident* and/or *reduce the consequences* of that incident.

- Primary well barrier: *preventing barrier*
  - *First object that prevents flow* NORSOK Standard D-010 3.1.26
  - Lubricator packing in a live well intervention situation

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Types of Barriers to Flow

- Secondary well barrier: *mitigating barrier*
  - *Second object that prevents flow* NORSOK Standard D-010 3.1.32
  - Uses BOP equipment to provide backpressure
  - Minimizes the consequences of a kick
    - Minimizes the size of the kick
    - Minimizes amount of well leakage
    - Prevents a blowout

Minimizes Consequences Of Kick

213

Types of Barriers to Flow

Hydrostatic Barrier:

- Must be capable of being maintained
  - Density within the correct parameters
    - ➢Mixing facilities
    - ➢Available mud additives
    - ➢Capable of being circulated
- Must be capable of being monitored
  - Volume
    - ➢Gains and losses
  - Hydrostatic pressure

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Hydrostatic Barriers Need Monitoring

The hydrostatic barrier needs constant monitoring and evaluation:

- ➢Flow rate in and out (Continuous electronic monitoring)
- ➢Pit volume (Continuous electronic monitoring)
- ➢Mud, spacer, and slurry weight (Continual monitoring)
- ➢Pressure While Drilling (PWD) reports
- ➢Equivalent Circulation Density (ECD) reports

215

Factors that Affect Hydrostatic Barrier

Hydrostatic barrier:

- *Swabbing during trips*
- *Not keeping hole full on trips*

} *Most common causes of blowouts*

  – Often not immediately noticed

- Lost circulation reduces the overbalance
  – Cuttings loading in annulus can **induce** lost circulation
    - ➢Increases the hydrostatic in annulus
    - ➢Increases risk of cuttings packing off and pressuring annulus

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Factors that Affect Hydrostatic Barrier

- Reduction in fluid density
  - During periods of fast drilling
    - Derrickman unable to keep up with mixing demands
  - **Solids settling and barite sag**
    - In mud, spacers, and cement slurries
    - *In the horizontal leg when not pumping*
  - Excessive use of solids equipment or dilution

- Development of *static gel strengths in cement*
  - Reduced hydrostatic pressure on formation and casing

217

Cement Barriers Monitoring

The well program needs to *predict the BHP changes* during the cementing process and plan for these changes during cement placement and the cement curing time

Needs monitoring and evaluation to verify the integrity is sufficient for now but also for the entire *life of the well.*

218

Cement Barriers Monitoring

Measure and verify the following:

- The *location of the cement* is correct with sufficient head above the reservoir
- The *pressure profile* is correct
  - The BHP is maintained between the pore pressure and the fracture pressure during cementing
- *Returns* are as expected
- *Slurry weight* is consistently correct
- The *quantity* of cement is correct
- The *setting time* is as expected
- Plugs are *bumped* as expected
- *No flow back* after bumping plug
- Cement seal is holding

219

Casing and Cement Barriers

Causes of failure:

- Mud contamination of cement during displacement
  - *Poor mud removal*
    - Low pump rates when cementing
    - Poor mud and hole conditioning
    - No or inappropriate pipe movement
- Incorrect cement placement
- Incorrect pressure testing techniques
- Trapped pressure in annulus

220

Casing and Cement Barriers

- Lost circulation when cementing
  - monitor pressures and volumes
- Poor centralization
  - Follow the centralizer program
- *Inappropriate cement mix* or insufficient volume
  - *Cement degradation*
  - Follow the cementing program
- Casing wear
  - Use *ditch magnets* and casing calibre logs
- Poorly made up or damaged casing threads
- Casing hanger seal assembly or self-fill shoe failure

221

Types of Barriers to Flow

Mechanical Barrier:

- Must be capable of being *pressure tested*
  - If possible, *in the direction of flow* (from the well)
  - If not possible in the direction of flow
    - ✓Must be *risk assessed* and verified
- Needs continual monitoring for leaks
- Requires a protocol to confirm it has operated correctly

222

BOPE Barriers

Needs to be *closed in a timely manner* to be a barrier

- Potential problems:
  - Flow not recognized
    - Transferring mud
    - Poor communication with driller
    - Rig motion from weather or crane action (subsea)
    - Pit sensors not working or insufficient number of sensors (subsea)

223

Barrier Acceptance Criteria

Every well program should include details of the acceptance criteria for each barrier element.

Well barrier acceptance criteria are:

The technical and operational requirements that need to be fulfilled in order to qualify a barrier or a WBE for its intended use.

224

Barrier Acceptance Criteria

The acceptance criteria should include:

- The function and number of barriers defined
- Barrier design, selection, and construction details, including:
  - Ability to withstand *the maximum anticipated pressure*
  - Leak tested and function tested
  - Lost barrier capable of being re-established or replaced
  - Capable of operating in the anticipated environment
  - Location and status of well is capable of being continuously monitored
  - Criteria for verifying the barrier

225

The Reference Sources for Barrier Test Criteria

The testing criteria may come form a number of sources:

- The well program which must be in place before spud
- Company operations manuals
- Company operating policies
- Industry standards and practices
- Governmental regulations
- Manufacturer's technical specifications

226

Barrier Test Documentation

A barrier test needs *documentation* that it is fit for purpose:
The key elements of a test document are:

- *Accurate records* retained for the life of the well
- *Testing procedures*, pressures, and fluid type
- Components tested and volumes used
- Results of test and *measures taken to rectify any deficiencies*
- *Signature of authorized person* representing the well owner

227

Failed WBE

If a WBE fails **during a test:**

- Deem the test a failure
- *Do not proceed* with operations until:
  - –Failed element(s) have been *repaired or replaced*
  - –Measures taken to remedy deficiency are *documented*

If a WBE fails in service **during operations**:

- **Stop** current well operations
- **Secure** the well by closing a BOP or by some other means
- **Repair** or replace the failed element
- Document

228

Formation Strength
and
Maximum Pressure at the Shoe

229

Formation Strength

The maximum permissible wellbore pressure is determined by formation strength

- Rock mechanical data to be acquired to ensure integrity of well
- The type of test shall be determined by the objective of the test

Two tests that are performed to determine the formation competence:

a. **Leak-off Test**—to establish the pressure the wellbore is capable of supporting
   – Fracture pressure is the *upper limit of the usable mud weight*
b. **Formation Competency Test** (FCT) or Formation Integrity Test (FIT)-to confirm the formation is capable of supporting a predefined pressure

230

Leak-off Test

✓*Determines the pressure at which the formation will fracture*
(The pressure at which the exposed formation accepts whole fluid from wellbore) API RP 59

✓Performed after drilling a short distance below a new casing shoe
  ✓Usually 5 feet to 15 feet

✓Drilling fluid is pumped into the well at about ¼ to ½ bbl/min against a closed choke

231

Leak-off Test

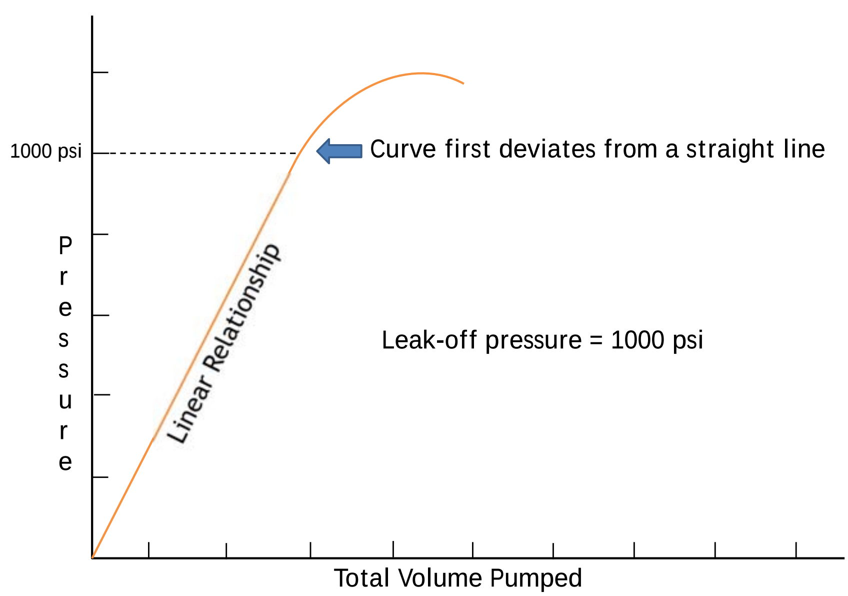
- Construct a pressure verses volume pumped plot
- *The point where the pressure-volume curve first deviates from a straight line is the leak-off pressure*
- The pump is stopped once a deviation from the linear pressure vs volume curve is observed
- The *formation fracture pressure* is the leak-off pressure plus the mud hydrostatic at the shoe (API RP 59 4.7.1)

232

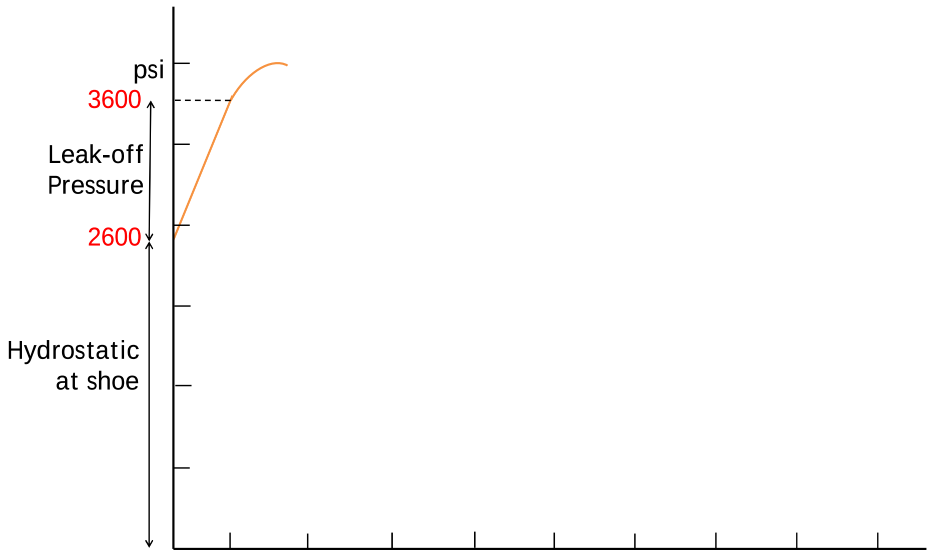
Formation Integrity Test

- PIT/FIT/FCT are performed by applying a pre-determined pressure to the formation
- Sufficient formation integrity shall be defined and documented to qualify formation as a WBE
- Shall *exceed the section design pressures* including the highest hydrostatic pressure

233



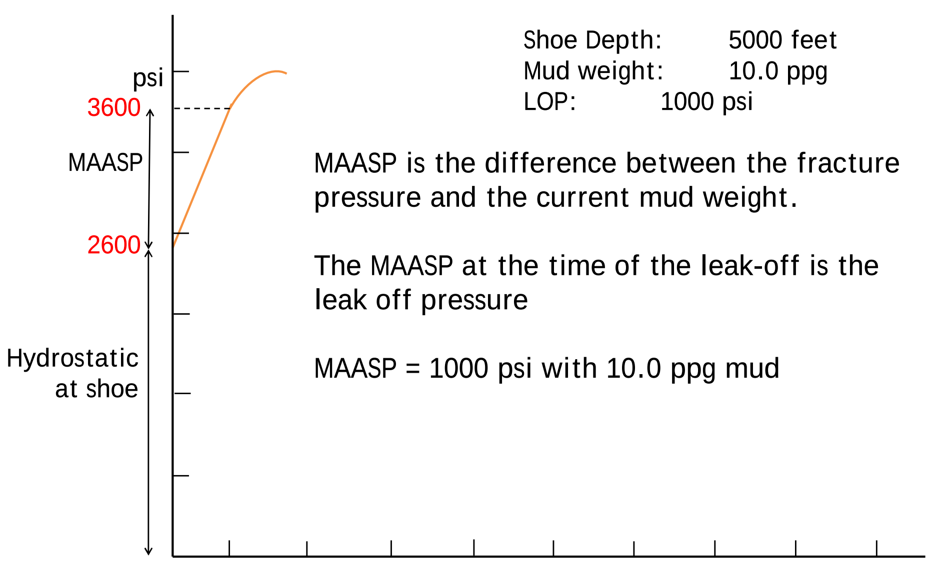
234



235

LOT Data:

Shoe Depth: 5000 feet
Mud weight: 10.0 ppg
LOP: 1000 psi

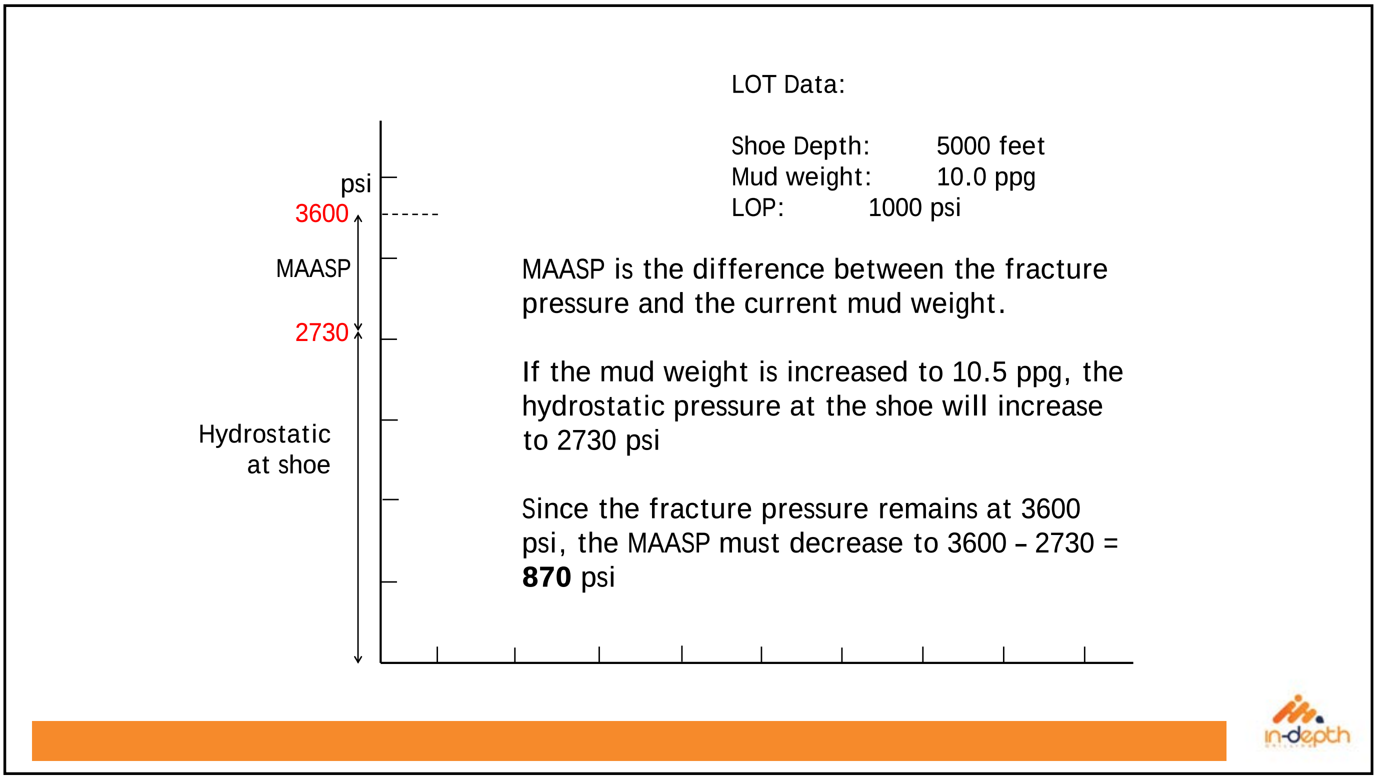


MAASP is the difference between the fracture pressure and the current mud weight.

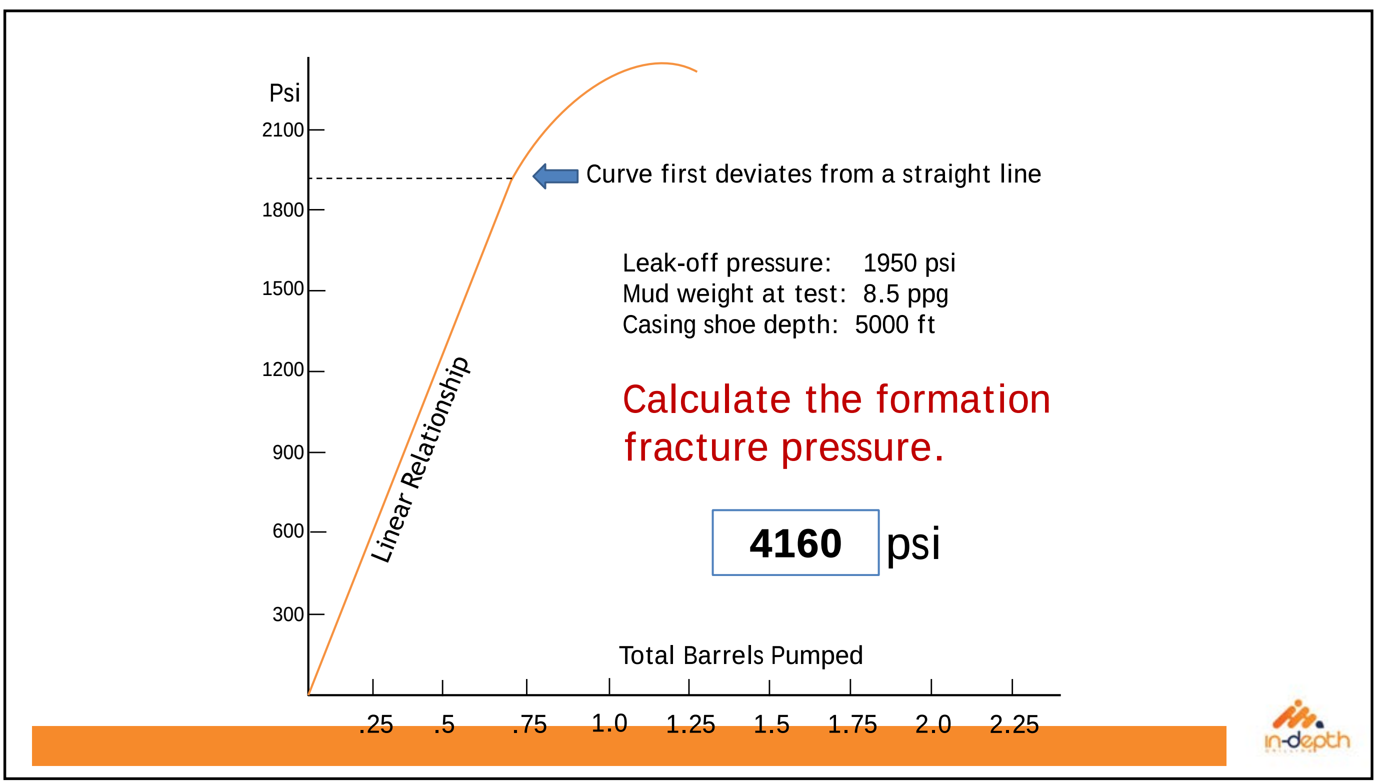
The MAASP at the time of the leak-off is the leak off pressure

MAASP = 1000 psi with 10.0 ppg mud

236


LOT Data:
Shoe Depth: 5000 feet
Mud weight: 10.0 ppg
LOP: 1000 psi
psi
3600
MAASP
2730
Hydrostatic at shoe
MAASP is the difference between the fracture pressure and the current mud weight.
If the mud weight is increased to 10.5 ppg, the hydrostatic pressure at the shoe will increase to 2730 psi
Since the fracture pressure remains at 3600 psi, the MAASP must decrease to 3600 – 2730 = **870** psi

237


Psi
2100
1800
1500
1200
900
600
300
Curve first deviates from a straight line
Linear Relationship
Leak-off pressure: 1950 psi
Mud weight at test: 8.5 ppg
Casing shoe depth: 5000 ft
Calculate the formation fracture pressure.
4160 psi
Total Barrels Pumped
.25
.5
.75
1.0
1.25
1.5
1.75
2.0
2.25

238

Formation Fracture Pressure

- Fracture pressure = the LOP plus the hydrostatic pressure at the shoe
- Must use the weight of the test fluid

$$Formation\ Fracture\ pressure\ (psi) = LOP + (Test\ Fluid\ Weight(ppg) \times .052 \times \text{TVD of Shoe})$$

239

Pressure at the Shoe

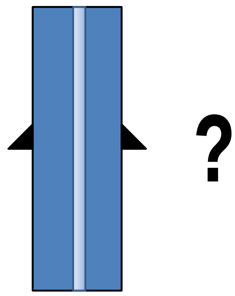
If we know the hydrostatic pressure at the shoe during a LOT, we can get:

- The total pressure at the shoe
- The maximum mud weight that can be used before we fracture the formation
- The Maximum Allowable Annular Surface Pressure (MAASP)

240

Pressure at Shoe

What is the pressure at the shoe?

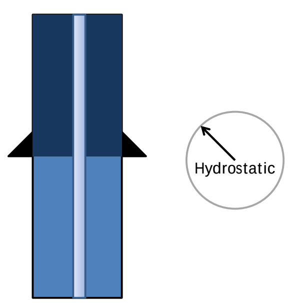


241

Pressure at Shoe

The pressure at the shoe is equal to:

Hydrostatic at shoe

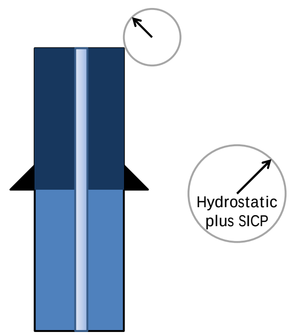


242

Pressure at Shoe

The pressure at the shoe is equal to:

Hydrostatic at shoe + Imposed Pressure (SICP and choke backpressure)



243

Pressure at Shoe

The pressure at the shoe is equal to:

Hydrostatic at shoe + Imposed Pressure (SICP and choke backpressure)

Calculate the pressure at the shoe in the following:

- Shoe depth = 5000 feet
- Mud weight = 10.0 ppg
- SICP = 790 psi

psi

244

Consequences of Uncertain Fracture Data

Using uncertain or erroneous fracture pressure data in well planning:

- Can lead to breaking down the shoe
  - ✓ Lost Circulation
  - ✓ Loss of primary well control
    - ➢ Can be difficult to heal
    - ➢ Can quickly escalate to an uncontrolled blowout

245

Mud Conditioning for LOT

For a LOT data to be valid, it is imperative the mud weight is accurately known and is consistent throughout the system.

If the derrickman tells you there is a light spot in the mud, what should you do?

1. Carry on and compensate for the light spot
2. Circulate until the mud weight is consistent.

246

LOT Data:

Leak-off pressure:	1000 psi
Mud weight at the time of test:	10.0 ppg
Shoe measured depth:	5100 feet
Shoe TVD:	5000 feet

What is the maximum mud weight that will not cause the formation below the shoe to fracture?

13.8 ppg

247

Formula 11

MAXIMUM ALLOWABLE MUD DENSITY (ppg)

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

or

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

Example:

$$Max\ MW = \left(\frac{1000}{5000 \times .052}\right) + 10.0\ ppg$$

$$= 3.846 + 10.0 = 13.846\ ppg$$

$$= 13.8\ \text{ppg}$$

248

MAASP

MAASP is the maximum surface pressure that will not fracture the formation
- Re-calculated every mud weight or hydrostatic change

Formula 12:

$$MAASP\ psi = [Max\ MW - New\ MW] \times .052 \times Shoe\ TVD$$

- MAASP is also affected by:
  - –Drilling into subsequent weak zones
  - –Drilling into low-pressure loss formations

249

MAASP

LOT Data:

Leak-off pressure:	1000 psi
Mud weight at the time of test:	10.0 ppg
Shoe measured depth:	5100 feet
Shoe TVD:	5000 feet

What is the MAASP when 12.2 ppg mud is used?

416 psi

250

Leak-off pressure: 1000 psi
Mud weight at the time of test: 10.0 ppg
Shoe measured depth: 5100 feet
Shoe TVD: 5000 feet

What is the MAASP when 12.2 ppg mud is used?

FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST **(A)** **1000** psi

MUD WEIGHT AT TEST **(B)** **10.0** ppg

MAXIMUM ALLOWABLE MUD WEIGHT =

$$(B) + \frac{(A)}{\text{SHOE T.V. DEPTH} \times 0.052} = (C)\ \mathbf{13.8}\ \text{ppg}$$

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

= **416** psi

251

Formation Fracture Gradient

API RP 59 (Two definitions)

1. The hydrostatic value expressed in psi/ft that is required to *initiate a fracture* in a subsurface formation

2. The pressure gradient (psi/ft) at which *the formation accepts whole fluid from the wellbore*.

252

Formation Fracture Gradient

The formation fracture is often given as a gradient

$$Fracture\ Pressure = Fracture\ Gradient \times TVD\ Shoe$$

What is the fracture pressure if the fracture gradient is 0.72 psi/ft and the shoe TVD is 5000 ft?

$\boxed{3600}$ psi

253

Fracture Gradient

You are often not given any leak-off data and simply told the fracture gradient.

Simply convert the fracture gradient to the maximum allowable mud weight by dividing by .052

DO NOT ATTEMPT TO CALCULATE THE LOT

254

Formation Fracture Gradient

The formation fracture gradient can be expressed as an equivalent mud weight by dividing by .052

$$Fracture\ Pressure\ Equivalent\ Mud\ Weight\ (ppg) = Fracture\ Gradient \div .052$$

A formation fracture gradient is given as .722 psi/ft, what is the maximum mud weight this well can hold under static conditions?

13.8 ppg

13.88
Round Down

Would 13.9 fracture?

255

The well took a kick and was killed with 13.0 ppg kill mud. What will the new MAASP be?

FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST	**(A)**	**1000**	psi
MUD WEIGHT AT TEST	**(B)**	**10.0**	ppg

MAXIMUM ALLOWABLE MUD WEIGHT =

$$\textbf{(B)} + \frac{\textbf{(A)}}{\text{SHOE T.V. DEPTH x 0.052}} = \textbf{(C)}\ \ \textbf{13.8}\ \text{ppg}$$

INITIAL MAASP **=**

(**(C)** - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052)

= **208** psi

256

A well has a formation fracture gradient of .832 psi/ft.
Well data:
Casing shoe: 5000 feet TVD
Present mud weight: 10.0 ppg
What is the MAASP with this mud weight?

FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST	**(A)**	psi
MUD WEIGHT AT TEST	**(B)**	ppg
MAXIMUM ALLOWABLE MUD WEIGHT = **(B) +** $\frac{\textbf{(A)}}{\text{SHOE T.V. DEPTH x 0.052}}$ =	**(C)** **16.0**	ppg
INITIAL MAASP = ((**C**) - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052) =		psi

$$Maximum\ MW$$

$$= \frac{.832}{.052}$$

$$= 16.0\ ppg$$

257

A well has a formation fracture gradient of .832 psi/ft.
Well data:
Casing shoe: 5000 feet TVD
Present mud weight: 10.0 ppg
What is the MAASP with this mud weight?

FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST	**(A)**	psi
MUD WEIGHT AT TEST	**(B)**	ppg
MAXIMUM ALLOWABLE MUD WEIGHT = **(B) +** $\frac{\textbf{(A)}}{\text{SHOE T.V. DEPTH x 0.052}}$ =	**(C)** **16.0**	ppg
INITIAL MAASP = ((**C**) - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052) =	**1560**	psi

$$(16 - 10) \times 5000 \times .052$$
$$= 1560\ psi$$

258

Maximum Pressure at Shoe

$$Fracture\ Pressure = LOP + Mud\ Hydrostatic\ at\ the\ test$$

Calculate the maximum pressure the formation immediately below the shoe can take before the formation breaks down.

- LOT pressure = 1950 psi
- Drilling fluid density at test = 8.5 ppg
- TVD of shoe = 5000 feet

psi

259

A leak-off test has just been performed on a well full of 12.2 ppg mud. The leak-off pressure was recorded as 990 psi and the shoe depth was 6800 feet MD and 6200 feet TVD.

Calculate the maximum allowable mud weight.

ppg

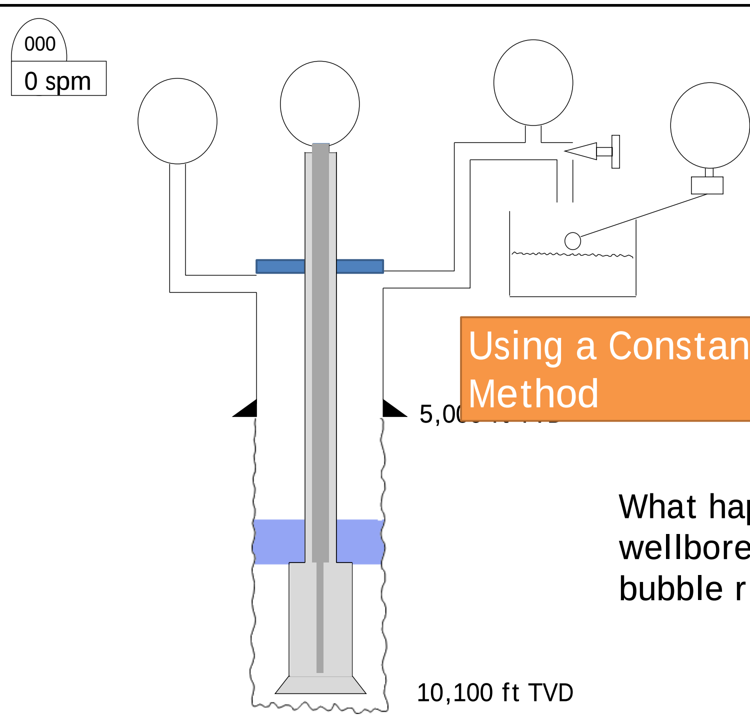
260

Constant BHP

To avoid exceeding the well integrity limitations, the bubble must be allowed to expand as it travels up the hole

If done correctly, *constant BHP* will be maintained throughout the kill

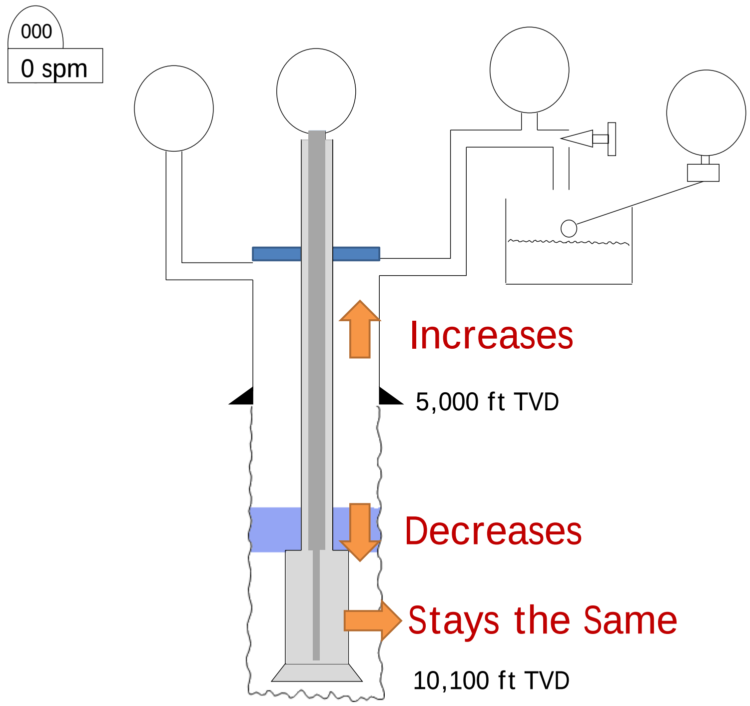
261



Using a Constant Bottom Hole Method

What happens to the wellbore pressures as the bubble rises?

262



263

Shallow Gas

264

What is Shallow Gas?

- *Gas which occurs before setting pressure-containing casing string*
- Or where *the formation strength at the shoe would not permit shutting in without breaking down*
- *Almost always is abnormally pressured*

265

Shallow Gas

- The possibility should be considered in all well programs
- *Shallow seismic surveying* where there is a possibility
- Locate rig outside high risk areas, if possible
- *Cannot be shut in (Cannot use secondary well control)*
  - No casing set
  - Low formation strengths
- Drill with a *diverter* or *riser less*
- *High erosion* of surface equipment

266

Shallow Gas

- Rig should establish step-by-step procedures and incorporate into *regular drills*
- High noise levels making communication difficult
- Small volume influx can significantly decrease hydrostatic in annulus
- *Fast developing event:* short reaction time. No time for flow checks, etc
- Care should be taken not to let influx in during cementing process

267

Consequences of Shallow Gas

- *Rapidly developing event*
  - Need for adequate training and drills
- Equipment failure
  - Overloading undersized equipment
  - *Erosion* from rapid flow of abrasive materials
    - Poor vent line design
  - Plugging vent line
  - Incorrectly sized or unlocked inserts
- Broaching to surface
  - Underpinning bottom-supported rigs

268

Consequences of Shallow Gas

- Gas around the rig
  - Gas *explosion* hazard
  - Poisonous gas or breathing hazard
  - Gas in moonpool of drill ships
- High noise levels
  - *Difficult to communicate*
    - Need for training and diverter drills

269

Shallow Gas Prevention

Critical Drilling Parameters:

- *Keep the hole full*
- *Control drill* to avoid annulus overloading with drilled gas
  - Can reduce hydrostatic pressure from
    - Density reduction
    - Belching
- Drill with *kill mud density* greater than seawater
  - Have contingency kill-weight fluid already mixed on standby
- *Control tripping speeds* in and out
- *Pump out of the hole*

270

Shallow Gas Prevention

Critical Drilling Parameters:

- *Pilot hole* drill to near casing point (size dependent upon depth of gas zone / water depth and formation characteristics, etc)
  - Improves dynamic kill
  - Reduces formation productivity
- Minimize time when pumps are down
  - Maintain the APL
  - Improve gas/mud ratio of drilled gas
    - Decrease annular drilled gas loading

271

Reaction to Shallow Gas

Procedures if well starts to flow:

- Suspend well operations
- *Keep pumping*. Requires a *dynamic kill* (Tertiary well control)
  - Do not flow check
- Activate the diverter
  - Do not shut in: divert downwind

272

Reaction to Shallow Gas

- Maintain the optimum pump rate for *dynamic kill*
  - *Tertiary Well Control*
  - *Do not stop pumping*
- *Switch to kill mud*
  - not always possible without fracturing formation
- If drilling mud becomes exhausted, pump water or whatever is available
- Make preparations for pumping cement, if it becomes necessary
- Consider evacuating non-essential personnel

273

Rig Considerations for Shallow Gas

- Careful rig selection
- Needs *properly-sized/designed diverter* vent system
  - Preferably 12" or larger offshore (8" or larger for surface applications)
  - Minimum flow restriction/backpressure
  - Straight as possible, erosion resistant, and sloping down hill
  - Capable of operating regardless of wind direction
- Venting in Moonpool
  - Drill ships harder to vent gas in moonpool
    - Drill ships have no air gap open to air currents

API RP 64

274

Level 2 Drilling Well Control Course

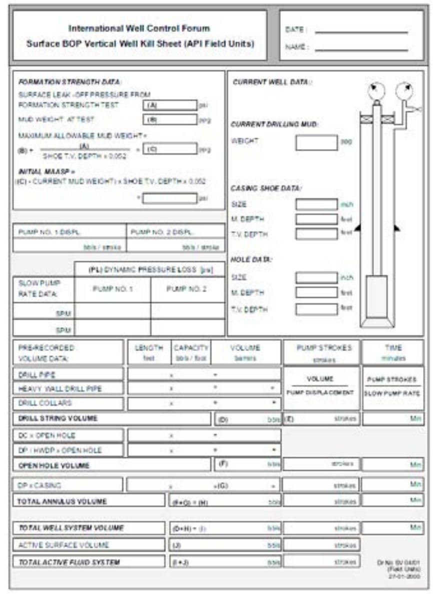
1

Section Two:

– Kill Sheets (Surface and Subsea)
– Kick Warning Signs and Indicators
– Kick Tolerance and Fluid Behaviour
– Shut-in Procedures
– Well Control Methods
– Operations that affect Bottom Hole Pressure (BHP)

2

Surface BOP Kill Sheet



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 =
$(B) + \frac{(A)}{\text{SHOE T.V. DEPTH} \times 0.052} = (C)$ 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

3

Key Elements of a Pre-Tour Kill Sheet

A pre-tour kill sheet is a document used to facilitate killing a well

- Contains prerecorded data deemed by the well operator as essential
  - Requires routine updating

A basic pre-tour kill sheet consists of the following key elements:

- A means of calculating the current BHP
- Formation strength data, including Maximum Allowable Mud Weight and MAASP
- Pump displacement data

4

Key Elements of a Pre-Tour Kill Sheet

- A means of calculating bottoms up strokes/time
- Surface to bit strokes/time
- Bit to shoe strokes/time
- Dynamic pressure loss data at reduced pump rates
- Drill string capacity data
- Annular capacity data

5

To Know How to Complete a Surface BOP Kill Sheet from Well Data and Calculate:

a. Volume of tanks and pits
b. Formation, hydrostatic and BH Pressures
c. Open Hole and annular volumes, capacities, and displacement times
d. Drill string volumes, capacities, and displacement times
e. Fracture, leak-off, and MAASP pressures
f. Convert pressure to ECD
g. Kill mud weight
h. ICP and FCP
i. Pump outputs and relationship between pump speed and pressures and circulation times
j. Pressure drop per step

6

CURRENT WELL DATA::

CURRENT DRILLING MUD:

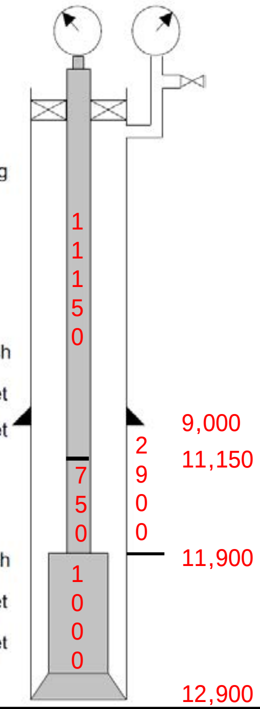
WEIGHT 12.5 ppg

CASING SHOE DATA:

SIZE	9⅝"	inch
M. DEPTH	9,000	feet
T.V. DEPTH	9,000	feet

HOLE DATA:

SIZE	8½"	inch
M. DEPTH	12,900	feet
T.V. DEPTH	12,200	feet



7

FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST	(A) 2350	psi
MUD WEIGHT AT TEST	(B) 11.0	ppg

MAXIMUM ALLOWABLE MUD WEIGHT =

$$(B) + \frac{(A)}{\text{SHOE T.V. DEPTH} \times 0.052} = (C)\ 16.0 \text{ ppg}$$

INITIAL MAASP =

((C) - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052

= 1,638 psi

8

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

	(PL) DYNAMIC PRESSURE LOSS [psi]	
SLOW PUMP RATE DATA:	PUMP NO. 1	PUMP NO. 2
40 SPM	740 psi	
SPM		

9

Slow Circulating Pressure

Slow circulating rate pressures should be performed at the following times:

- After drilling out casing or liner
- After any change in tubular configuration
- After any change in mud properties (viscosity or density)
- At the beginning of each shift,
- After change in bit nozzles or BHA,
- After drilling a long interval of hole (500 ft) in a shift,
- After pump fluid end repair

10

Criteria for SCR/Kill Rate Selection

Criteria used for selecting the slow rates include:

- Mud mixing capacity, weighting up ,(Hopper type/condition, etc.)
- Mud-gas separator capacity ,degassing of the mud and disposal of the influx
- Minimum sustainable pump speeds
- Choke line friction (Subsea)
- Choke manipulation speed (human factor, Level of crew training/skill
- Minimise Annular pressure loss(Wellbore and drillstring geometry)
- Wellbore conditions(Formation strength)
- Reduce risk of over pressuring system if plugging occurs
- Reduce the risk of choke erosion as low annular velocity prevents cuttings entering
- Allows for more controlled choke adjustments

11

Deepwater Effect on SCR Selection

- Higher likelihood of low fracture gradients:
- Requires kick to be circulated out at very slow kill rates

12

Where to Take SCRs

Which gauge do we use to read the SCRs?

Why?

13

Changing Pump Strokes

If we know the pressure loss at a given pump rate, we can estimate the pressure at a different rate

- Assuming the mud properties remain the same
- Pump pressure is proportional to the square of the strokes

14

Changing Pump Strokes

This tells us that if we:

1. Double the strokes, the pressure will increase by four times

2. Half the strokes, the pressure will decrease to one quarter

in-depth

15

Formula 9

NEW PUMP PRESSURE (psi) WITH NEW PUMP RATE approximate

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

Calculate the likely pump pressure at 100 spm if the SCR at 40 spm was recorded at 540 psi

[ ] psi

in-depth

16

Identify the Correct Reasons for using a SCR when Killing a Well

1. To reduce the size of the gas bubble as it is circulated up the wellbore
2. To minimize the excess APL to reduce the risk of losses while killing the well
3. To enable the surface equipment better handle the volume of gas as it arrives at surface
4. To decrease the pressure below the bubble

17

New Pump Pressure

When we change the mud weight, the pressure loss will change

- This pressure change is *directly proportional to the density change*
- We can estimate the new pump pressure using formula 10

18

Formula 10

NEW PUMP PRESSURE (psi) WITH NEW MUD DENSITY approximate

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

A well recorded the SCR at 240 psi with a pump speed of 30 spm and a mud weight of 10.0 ppg. Estimate the FCP when the well has been circulated with 11.0 ppg KWM

[ ] psi

19

PRE-RECORDED VOLUME DATA:	LENGTH feet	CAPACITY bbls / foot	VOLUME barrels	PUMP STROKES strokes	TIME minutes
DRILL PIPE	11,150 x	.0142 =	158.33	VOLUME / PUMP DISPLACEMENT	PUMP STROKES / SLOW PUMP RATE
HEAVY WALL DRILL PIPE	750 x	.0088 =	6.6 +		
DRILL COLLARS	1,000 x	.008 =	8.0 +		
DRILL STRING VOLUME			(D) 172.93 bbls	(E) 1,478.03 strokes	36.95 Min
DC x OPEN HOLE	1,000 x	.03 =	30.00		
DP / HWDP x OPEN HOLE	2,900 x	.0505 =	146.45 +		
OPEN HOLE VOLUME			(F) 176.45 bbls	1,508.11 strokes	37.70 Min
DP x CASING	9,000 x	.0562 =(G)	505.80 +	4,323.07 strokes	108.07 Min
TOTAL ANNULUS VOLUME		(F+G) = (H)	682.25 bbls	5,831.19 strokes	145.77 Min
TOTAL WELL SYSTEM VOLUME		(D+H) = (I)	855.18 bbls	7,309.23 strokes	182.73 Min
ACTIVE SURFACE VOLUME		(J)	250 bbls	2,136.75 strokes	
TOTAL ACTIVE FLUID SYSTEM		(I +J)	1,105.18 bbls	9,445.98 strokes	

Surface Lines = 15 bbl

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International Well Control Forum

Surface BOP Kill Sheet - Vertical Well (API Field Units)

DATE :

NAME :

KICK DATA : SIDPP 300 psi SICP 450 psi PIT GAIN 9.0 barrels

KILL MUD WEIGHT KMW	CURRENT MUD WEIGHT + SIDPP / (TVD x 0.052) 12.5 + 300 / (12,200 X 0.052) = 12.97	13.0 ppg
INITIAL CIRCULATING PRESSURE ICP	DYNAMIC PRESSURE LOSS + SIDPP 740 + 300 =	1,040 psi
FINAL CIRCULATING PRESSURE FCP	KILL MUD WEIGHT / CURRENT MUD WEIGHT x DYNAMIC PRESSURE LOSS 13.0 / 12.5 x 740 = 769.60	770 psi

(K) = ICP - FCP = 1,040 - 770 = 270 psi

(K) x 100 / (E) = 270 X 100 / 1478 = 18 psi / 100 strokes

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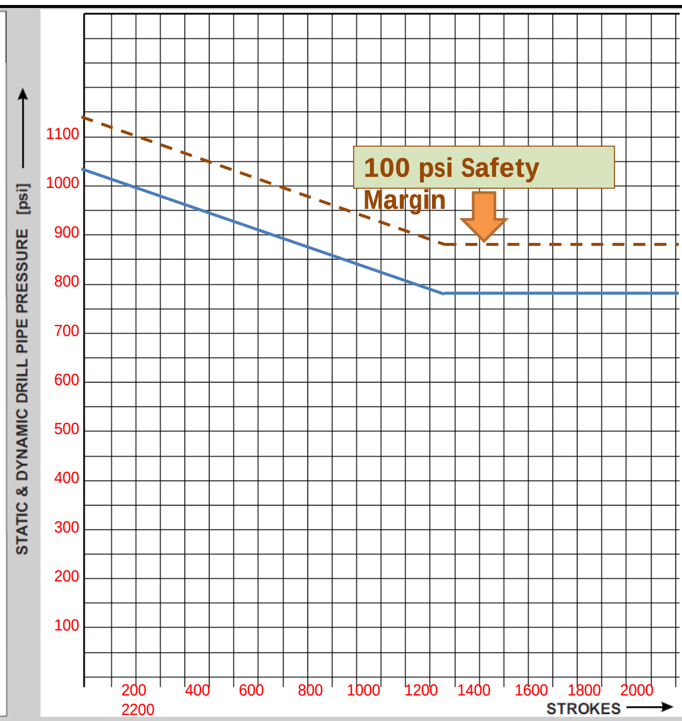
STROKES	PRESSURE [psi]
0	1040
100	1022
200	1004
300	986
400	968
500	950
600	932
700	914
800	896
900	878
1000	860
1100	842
1200	824
1300	806
1400	788
1478	770



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Dynamic Drillpipe Pressure

As you pump KWM down the drillpipe, the drillpipe pressure at any point = Circulating pressure losses (SCR) + SIDPP.

At zero strokes, DPP = $\underset{SCR}{740} + \underset{SIDPP}{300} = 1040$ psi

After 1478 strokes, DPP = $\underset{SCR}{\left\{740 \times \frac{13.0}{12.5}\right\}} + \underset{SIDPP}{0}\ psi$

23

SIDPP

As you pump the KWM down the drillpipe, the well is being killed on the drillpipe side

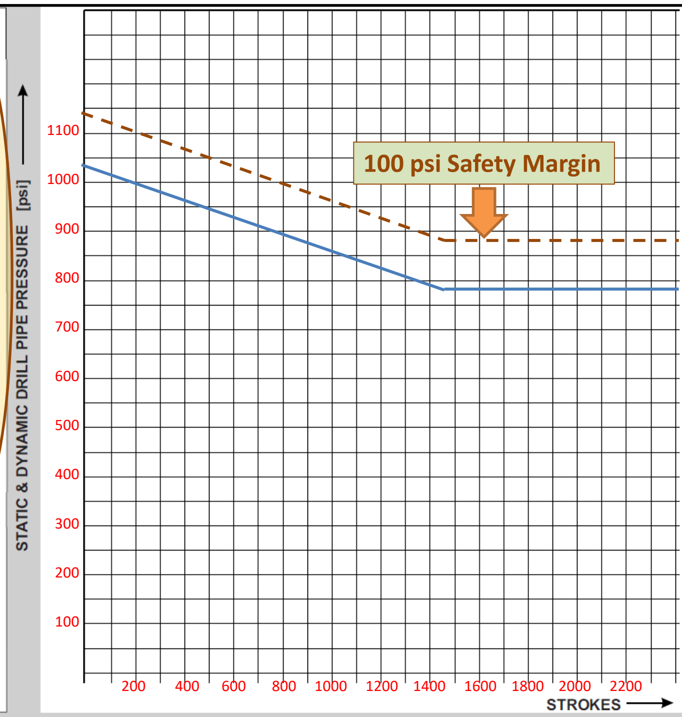
The SIDPP will therefore decrease as the KWM fills the drill pipe

At zero strokes, the SIDPP = 300 psi

After 1478 strokes, the SIDPP = 0 psi

24

STROKES	PRESSURE [psi]	
0	1040	300
100	1022	280
200	1004	260
300	986	240
400	968	220
500	950	200
600	932	180
700	914	160
800	896	140
900	878	120
1000	860	100
1100	842	80
1200	824	60
1300	806	40
1400	788	20
1478	770	0



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What is the maximum allowable mud weight that will not fracture the shoe?

16.0 ppg

Based on the leak off test, what is the MAASP?

1638 psi

26

What is the maximum allowable mud weight that will not fracture the shoe?

16.0 ppg

Based on the leak off test, what is the MAASP?

1638 psi

Calculate the formation pressure.

8230 psi

27

What kill mud is required to balance the formation?

13.0 ppg

What is the ICP at 40 spm?

1040 psi

What is the FCP at 40 spm?

770 psi

28

After reaching the FCP, it was decided to increase the pump to 45 spm. What is the new FCP?

| 975 | psi |

Calculate the static BHP before the kick

| 7930 | psi |

What was the ECD before the kick? APL = 325 psi

| 13.0 | ppg |

What is the bottoms up time for drilling at 80 spm?

| 73 | min |

29

How many strokes from surface to bit?

| 1478 | stk s |

How many strokes from the bit to the casing shoe?

| 1508 | stks |

What is the initial dynamic casing pressure at kill speed?

| 450 | psi |

How many minutes does it take to circulate the total well system volume at SCR?

| 183 | minutes |

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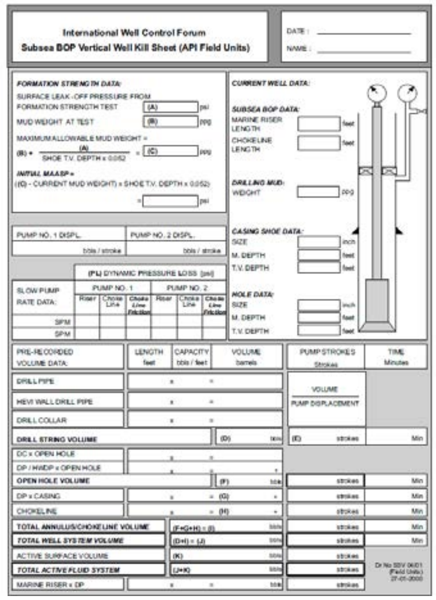
Subsea Kill Sheet


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 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:
SUBSEA BOP DATA: MARINE RISER LENGTH feet; CHOKELINE LENGTH feet
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. bbls / stroke; PUMP NO. 2 DISPL. bbls / stroke
(PL) DYNAMIC PRESSURE LOSS (psi)
SLOW PUMP RATE DATA: PUMP NO. 1 (Riser, Choke Line, Choke Line Friction); PUMP NO. 2 (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
HEVI WALL DRILL PIPE
DRILL COLLAR
DRILL STRING VOLUME (D) bbls; (E) strokes; Min
VOLUME / PUMP DISPLACEMENT
DC x OPEN HOLE
DP / HWDP x OPEN HOLE
OPEN HOLE VOLUME (F) bbls
DP x CASING (G)
CHOKELINE (H)
TOTAL ANNULUS/CHOKELINE VOLUME (F+G+H) = (I) bbls
TOTAL WELL SYSTEM VOLUME (D+I) = (J) bbls
ACTIVE SURFACE VOLUME (K) bbls
TOTAL ACTIVE FLUID SYSTEM (J+K) bbls
MARINE RISER x DP

60
640
8300
2900
<u>1000</u>
12,900
11150
750
<u>1000</u>
12,900

CURRENT WELL DATA:

SUBSEA BOP DATA:

MARINE RISER LENGTH 700 feet

CHOKELINE LENGTH 715 feet

DRILLING MUD:

WEIGHT 12.5 ppg

CASING SHOE DATA:

SIZE 9⅝" inch

M. DEPTH 9,000 feet

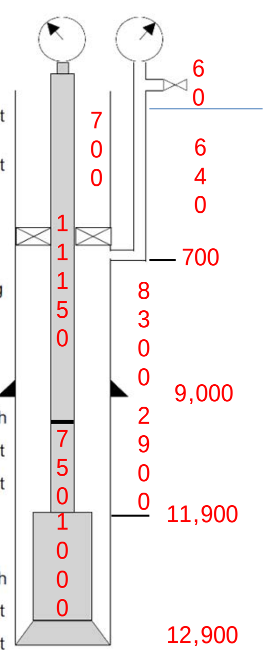
T.V. DEPTH 9,000 feet

HOLE DATA:

SIZE 8½" inch

M. DEPTH 12,900 feet

T.V. DEPTH 12,200 feet



FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST **(A)** 2350 psi

MUD WEIGHT AT TEST **(B)** 11.0 ppg

MAXIMUM ALLOWABLE MUD WEIGHT =

$$(B) + \frac{(A)}{\text{SHOE T.V. DEPTH} \times 0.052} = (C)\ 16.0 \text{ ppg}$$

INITIAL MAASP =

((**C**) - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052

= 1,638 psi

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

	(PL) DYNAMIC PRESSURE LOSS [psi]					
SLOW PUMP RATE DATA:	PUMP NO. 1			PUMP NO. 2		
	Riser	Choke Line	***Choke Line Friction***	Riser	Choke Line	***Choke Line Friction***
40 SPM	740	900	160			
SPM						

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Establishing Choke Line Friction (Subsea)

Four methods for establishing the CLF on a subsea stack:

1. *Drill pipe method*:

- First, circulate down the drill pipe and up riser at SCR and record the pressure
- Second, circulate down the drill pipe and up the choke line through a fully-open choke at SCR and record the pressure
- Third, record the choke line friction as the difference between the two

2. *Choke line method*:

- First, circulate *down the choke* line and *up the riser* at SCR
- Second, record the drill pipe gauge reading on the remote choke panel as the choke line friction

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Establishing Choke Line Friction (Subsea)

3. *Dynamic kill line method*:

- First, circulate *down the kill line* and *up the choke* line at SCR
- Second, record the drill pipe pressure on the remote choke panel ÷ 2 as the choke line friction

4. *Static kill line method*:

- First, circulate *down the drill pipe* and *up the choke* line, monitoring the kill line
- Second, record the *static kill line pressure* as the choke line friction

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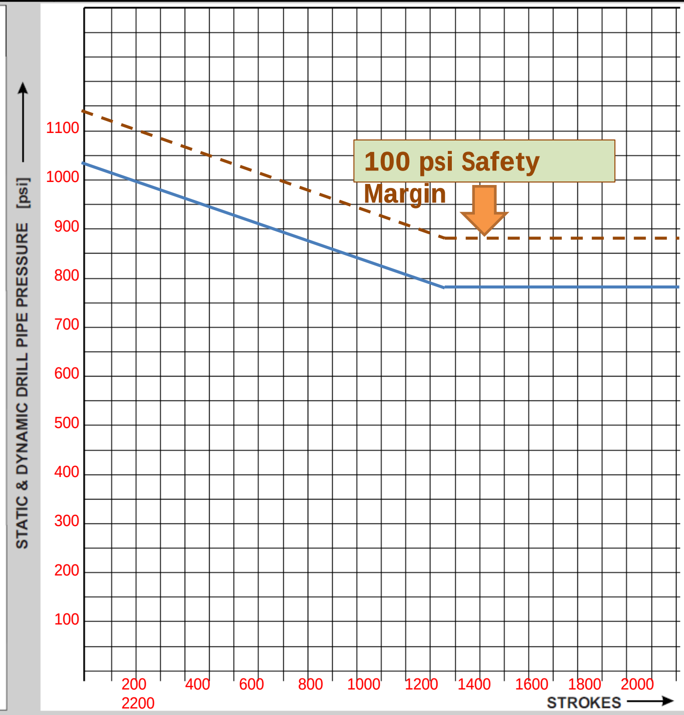
PRE-RECORDED VOLUME DATA:	LENGTH feet	CAPACITY bbls / feet	VOLUME barrels	PUMP STROKES Strokes	TIME Minutes
DRILL PIPE	11,15 (0)	x .0142 =	158.3	VOLUME / PUMP DISPLACEMENT	
HEVI WALL DRILL PIPE	750 (0)	x .0088 =	6.60 (3)	0.117 bbl/stk	
DRILL COLLAR	1,000	x .008 =	8.00		
DRILL STRING VOLUME			(D) 172.9 bbls	(E) 1,478.03 strokes	36.95 Min
DC x OPEN HOLE	1,000	x .03 =	30.00 (3)		
DP / HWDP x OPEN HOLE	2,900	x .0505 =	146.4 +		
OPEN HOLE VOLUME			(F) 176.4 (5) bbls	1,508.11 strokes	37.70 Min
DP x CASING	8,300	x .0562 =	(G) 466.4 (5) +	3,986.83 strokes	99.67 Min
CHOKELINE	715	x .0087 =	(H) 6.22 (6) +	53.16 strokes	1.32 Min
TOTAL ANNULUS/CHOKELINE VOLUME			(F+G+H) = (I) 649.1 bbls	5548.11 strokes	138.70 Min
TOTAL WELL SYSTEM VOLUME			(D+I) = (J) 822.0 (3) bbls	7026.15 strokes	175.65 Min
ACTIVE SURFACE VOLUME			(K) 250.0 (6) bbls	2136.75 strokes	Dr No SSV 04/01 (Field Units) 27-01-2000
TOTAL ACTIVE FLUID SYSTEM			(J+K) 1072.06 (0) bbls	9162.90 strokes	
MARINE RISER x DP	700.00	x .3403 =	238.21 bbls	2035.98 strokes	

Surface Lines = 15 bbl

KICK DATA :	SIDPP 300 psi SICP 450 psi	PIT GAIN 9 barrels
KILL MUD WEIGHT KMW	CURRENT MUD WEIGHT + $\frac{\text{SIDPP}}{\text{TVD x 0.052}}$ 12.5 + $\frac{300}{12,200}$ X 0.052 = 12.97	13.0 ppg
INITIAL CIRCULATING PRESSURE ICP	DYNAMIC PRESSURE LOSS + SIDPP 740 + 300 =	1040 psi
FINAL CIRCULATING PRESSURE FCP	$\frac{\text{KILL MUD WEIGHT}}{\text{CURRENT MUD WEIGHT}}$ x DYNAMIC PRESSURE LOSS $\frac{13.0}{12.5}$ x 740 = 769.6	770 psi
(L) = ICP - FCP = 1040 - 770 = 270 psi	$\frac{\text{(L) x 100}}{\text{(E)}}$ = $\frac{270 \text{ X } 100}{1,478}$ = 18	$\frac{\text{psi}}{\text{100 strokes}}$
INITIAL DYNAMIC CASING PRESSURE AT KILL PUMP RATE	SICP - CHOKE LINE FRICTION 450 - 160 =	290 psi

STROKES	PRESSURE [psi]
0	1040
100	1022
200	1004
300	986
400	968
500	950
600	932
700	914
800	896
900	878
1000	860
1100	842
1200	824
1300	806
1400	788
1478	770



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Dynamic MAASP

What will the initial dynamic MAASP be at the start of the kill operation?

The initial dynamic MAASP = MAASP – CLF

= 1638 psi – 160 psi

= **1478 psi**

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Casing Pressure About to Exceed MAASP

- Evaluate the influx position
- Reduce overkill margin
- Reduce kill speed
- Bleed off value of pressure losses at shoe, if known
- Reduce CLF by circulating both choke and kill lines (subsea)
- Consider converting to Volumetric Method
- Use standpipe choke to reduce transient pressures when starting pump (If available)

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Kick Warning Signs

Indicator a well *MIGHT* be, or may soon be, going underbalanced

Three general classifications of warning signs:

- Offset information
- Physical responses from your well
- Chemical and technical responses from your well

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Offset Information

Gives us intelligence on:

- Depths of zones capable of flowing
- Formation pressure gradients
- Fracture gradients and loss zones
- Formation permeability

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Physical Response from our Well

Physical response indicators are:

- Pit *gain or loss*
- Increase in flow with no change in pump rate
- *Increase in the temperature* at the flowline
- *Drilling breaks*
- Variations in pump pressure

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Physical Response from our Well

- Drilling fluid *density reduction* at flowline
- Drilling fluid *pH change*
- Drilling fluid *viscosity change*
- Increase in *background, trip and connection gas*
- Tight hole, packing off and sloughing
  - Changes in **drag and/or torque**
- Changes in **cuttings size, shape, and quantity**
- Continuing to flow after pumps have stopped
- Incorrect hole fill on trips

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Kick Warning Signs

1. ROP (Drilling Rate)
2. Drilling Break,
3. Torque and Drag,
4. Shale Density,
5. Cutting Shapes and Size,
6. Chloride Content (salinity),
7. Flow line temperature,
8. Trip, connection and Background Gases
9. Well fails to take correct volume of mud when POOH

FLOW CHECK IS NEEDED, NO DELAYS

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Chemical and Technical Indicators

- Chloride changes in mud
  - Can be an increase or decrease
- Oil shows and oil staining
  - On cuttings or shaker screens
- Increased gas shows on gas chromatograph
- Formation water in mud
  - Change in oil : water ratio in oil muds
- *Shale density reduction*
  - Recorded on LWD tools
  - Can be an indication of under compacted shale
- *"d" exponent decrease* and electric logs

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Causes of Loss of Hydrostatic Pressure

1. Improper Hole Fill up on trips,
2. Swabbing,
3. Abnormal Formation Pressure,
4. Insufficient Mud Density,
5. Lost Circulation,
6. Gas Cut Mud

Regular Mud Checks

Alert Crews

Communication

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Operations which can Reduce the Hydrostatic Head

- Cement setting – hydrostatic degradation
- Temperature effects on fluids
- Barite sag
- Swabbing

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Increase in Rate of Penetration

- An increase in the penetration rate
  - Most often it is simply a formation change
  - But may be an indicator of an increase in formation pressure
    - A drilling break is regularly less abrupt than a formation change
    - Since it is more gradual, it is *frequently not recognized*

- May be preceded by a drop in the drilling rate
  - May indicate a reservoir cap (seal)

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Not a definite indicator:

Penetration rate can also be influenced by:

- ✓ WOB
- ✓ RPM
- ✓ Hydraulics (Bit nozzles, annular velocity, etc..)
- ✓ Mud type and properties
  - ✓ Density and viscosity
  - ✓ Fluid loss
  - ✓ Suspended solids

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Changes in Pump Speed/Pressure

- Initial indication is an increase in pump pressure
  - Usually not recognized because of short duration
- Followed by a gradual decrease in pump pressure
  - May be accompanied by an increase in pump speed in mechanical pumps
- Can also indicate a drill string washout
  - *Initially assume it is a kick warning sign*

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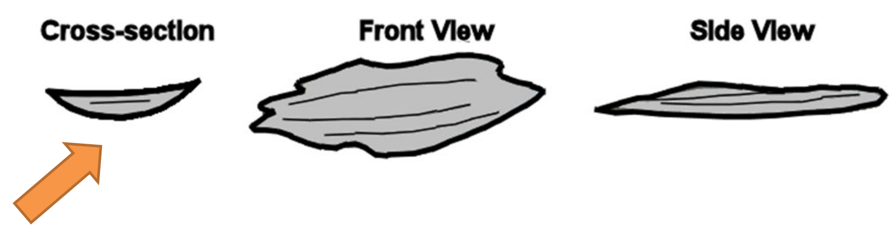
Change in Cuttings Size and Shape



- Long, thin, needle-like cuttings
  - Often confused with cleavages in laminated shale
- Convex-concave, eyeglass lens cross section
  - Not a definite sign of under compacted shale

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Lost Circulation

Lost circulation can quickly degrade the hydrostatic overbalance

Recognized by:

- Pit loss
- Decrease in rate of returns
- Hole fill greater than calculated on a trip

Caused by:

- Surging on trips or running casing
- Faults and fractures
- Vuggy limestone
- Induced losses
  - Poor well cleaning
  - Pressuring up well - Supercharging

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What To Do in the Case of Kick Warning Sign While Drilling

1. Stop drilling
2. Pick up off bottom and position tool joint (space out in BOP)
3. Stop rotary
4. Stop pump
5. Observe well for flow (Flow check in trip tank)
6. Inform supervisor
7. If flowing, close BOP and open HCR
8. Monitor flow from riser-use diverter if necessary
9. Read and record SIDPP, SICP on both lines, and pit gain
10. Set compensator to mid stroke and prepare to hang off

Rule out Ballooning

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Kick Warning Signs While Tripping

- Swabbing (Improper hole fill)
  - Hole not taking calculated hole fill on trip
- Increasing drag during trip
- String weight change

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What To Do in the Case of Kick Warning Sign While Drilling

1. Position tool joint at working level on rig floor and set slips
2. Install and close DPSV
3. Observe well for flow
4. If flowing, pick up, remove slips and position pipe for hang-off
5. Close BOP and open C & K (HCR) lines
6. Monitor flow from riser---close diverter if necessary
7. Record SIDPP, SICP, and pit gain
8. Prepare to strip back to bottom

Close DPSV Before BOP

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Action in Case of Losses

1. Stop rig operations
2. Start the flow check
3. Alert the supervisor
4. Establish the rate and source of losses
5. Prepare to top fill the hole

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Three Positive Kick Indicators

- An unaccounted for *pit volume gain*
- An *increase in flow* with a constant pump speed
- **Flowing** with the *pumps off*

  – *Must rule out the following by careful fingerprinting and trend analysis:*
    - Thermal expansion of mud, especially OBM
    - Rig heave with insufficient, faulty, or poorly-placed sensors
    - Formation ballooning

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When a kick is detected, shut-in as quickly as possible

Why?

To minimize the influx volume

Increased influx volume means:

- *Higher annular pressures* (Decreased hydrostatic in annulus)
- Higher likelihood of *lost circulation*
- Making the kick more difficult to handle

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MAASP

WHAT IS A KICK ?

While drilling, when hydrostatic pressure goes below formation pressure,

HYDROSTATIC PRESSURE < FORMATION PRESSURE

We take a

KICK

Types of Kicks

What Happens When We Take A Kick?

Fluids flow into well bore

Fluids can be

GAS

OR

OIL

OR

WATER

OR

Combination of 2 or 3 above

Types of Kicks

The following equation is used for estimating type of influx:

- Influx weight= Current MW- $\frac{[\text{ SICP} - \text{SIDPP}]}{\text{Influx Height X } 0.052}$

Once you know weight of influx, you can compare with these figures below to determine type of influx.

- 1 – 3 ppg : most likely gas influx.
- 3 – 7 ppg : most likely oil kick or combination between gas and oil kick
- 7 – 9 ppg : most likely water influx

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Behaviour of Fluids

What Is The Behaviour Of Different Fluids?

Pure liquid does not expand no reduction in BHP. Therefore we can handle easily.

Gas expands with reduction in BHP. Therefore, very difficult to handle.

Since water and oil contains gas along with it, with lesser affect it behaves like gas kicks.

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Behaviour of Fluids

Therefore,

What ever is the fluid, we have to consider all kicks as GAS kicks.

So, We need to know how gas kick behaves.

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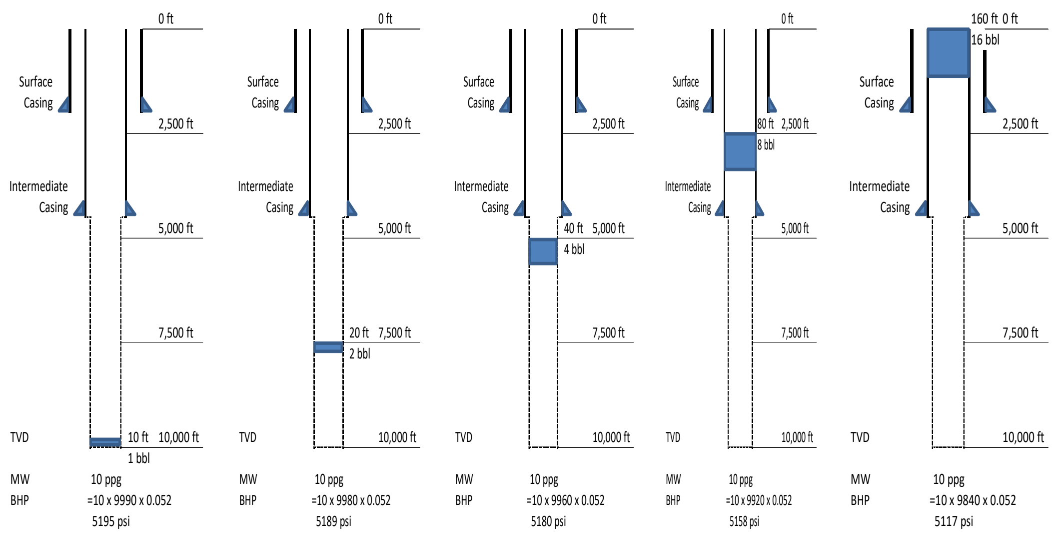
Open Well Gas Migration



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Open Well Gas Migration

- Bottom hole pressure reduces
- Pressure below bubble reduces
- Pressure of gas bubble reduces
- Pressure above bubble remains constant

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in-depth

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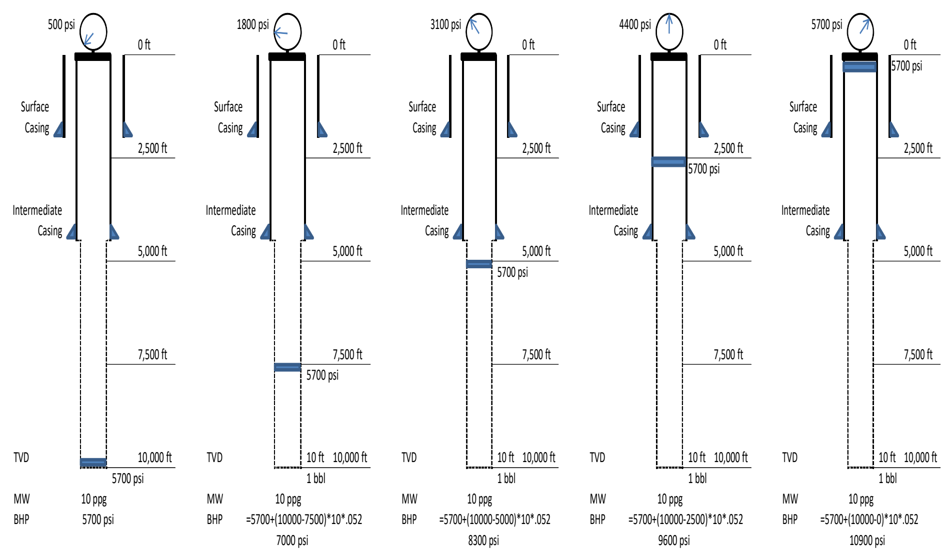
Closed Well Gas Migration



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Closed Well Gas Migration

- Bottom hole pressure increases
- Pressure below bubble increases
- Pressure of gas bubble remains constant
- Pressure above bubble increases

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Kick Behaviour in Oil Base

- Gas / Oil kick dissolves in Oil Base Mud (OBM).
- Therefore, it is very difficult to notice positive sign of influx.
  - We will not see increase in flow rate
  - We will not see increase in pit volume
- When circulating gas up the hole, when the hydrostatic pressure above the kick reaches bubble point, gas separates and expands at very fast rate.
- Reaction time is very less.
- We need to close while kick is at bottom and not while circulating.

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Gas Influx in WBM & OBM

Water Base Mud

Easier to detect

Higher migration rate

Gas stay as a separate phase

On bottom bigger kick size

Higher casing pressure

Expansion:

- Slow first then Fast

Oil Base Mud

More difficult to detect

Lower migration

Gas goes in to solution

On bottom small kick size

Lower casing pressure

Expansion:

- None first then very fast at bubble point

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Gas Influx in WBM & OBM

	Water based mud	Oil based mud
Gas solubility	Less	More
Remain in solution	Less	Longer
Gas expansion rate	More	Less
Reduction BHP	Large	Small
Pit gain	More	Less
Detection	Easier	Harder

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A well has been shut-in on a kick. Which gauge should the driller use to record the SIDPP?

A. Standpipe gauge
B. Mud pump gauge
C. Choke panel drillpipe gauge
D. Drillpipe pressure on driller's panel
E. Drillpipe gauge at manifold

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Which of the following are affected by the permeability of the formation?

A. KMW
B. Volume of influx
C. SIDPP
D. Time taken for shut-in pressures to stabilize
E. SICP
F. Pit gain

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Shut-in Procedure

If the primary barrier fails:
Immediately implement one or more of the secondary barrier elements:

Procedure used must be:
1. An industry-recognised standard procedure
2. Known by the crew
3. Be possible to implement under circumstances
4. Have been regularly practiced by the crew

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Shut-in Options

We have a choice of two shut-in options:

1. Soft shut-in

2. Hard shut-in

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Soft Shut-in Lineup

During normal drilling/tripping operations

- The Remote choke is held OPEN
- The choke line valves are kept OPEN
- HCR is kept CLOSED

API RP 59 4.9.1

Open all the way from the HCR to the MGS

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Soft Shut-in Lineup

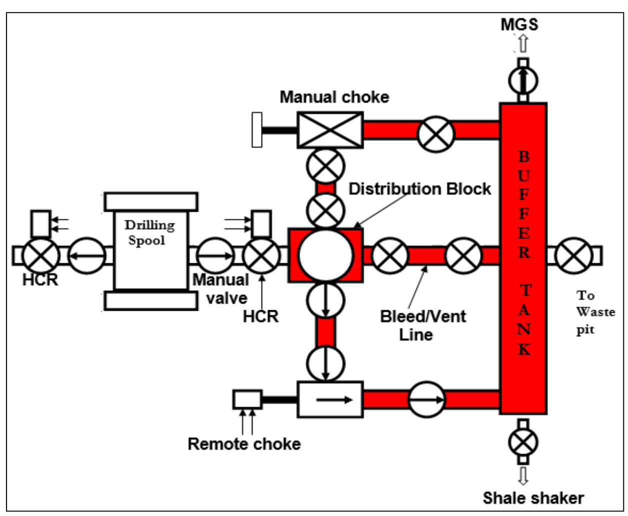
Manual Valve : OPEN

HCR valve: CLOSED

Valves to R.Choke: OPEN

<u>Remote Choke:</u> <u>OPEN</u>

Valves to MGS: OPEN



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Soft Shut-in Procedure

The soft shut-in procedure while drilling is:

Always open HCR first

1. Open the HCR valve on the choke line
2. Close the BOP
3. Close the choke, making sure not to exceed MAASP
4. Notify company personnel
5. Read and record pressures and pit gain

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Soft Shut-in Advantages

Permits the monitoring of casing pressure during choke closure

Permits use of the low-choke procedure before MAASP is exceeded

Soft Shut-in Dis-advantages

- Requires more time, resulting in a larger influx of formation fluids
- Greater reduction of hydrostatic in annulus
- Higher wellbore pressures
- More complicated and requires greater personnel skills
- May require greater strength casing or more casing strings

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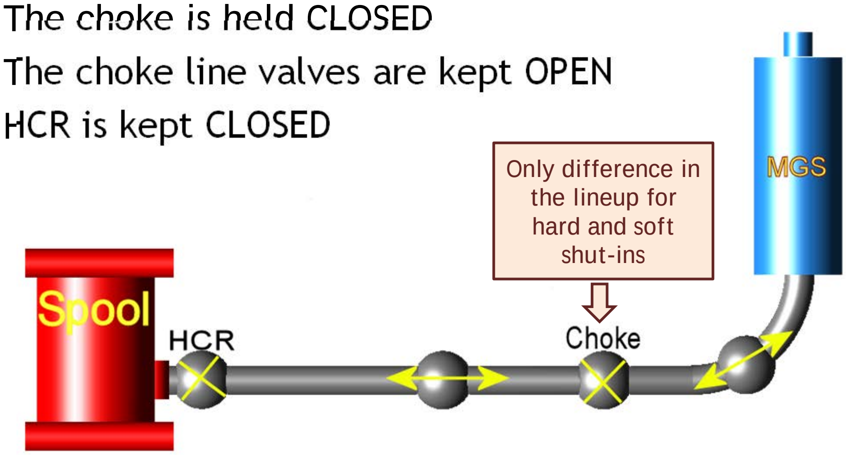
Hard Shut-in Lineup

During normal drilling/tripping operations

- The choke is held CLOSED
- The choke line valves are kept OPEN
- HCR is kept CLOSED



API RP 59 4.9.2

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Hard Shut-in Lineup

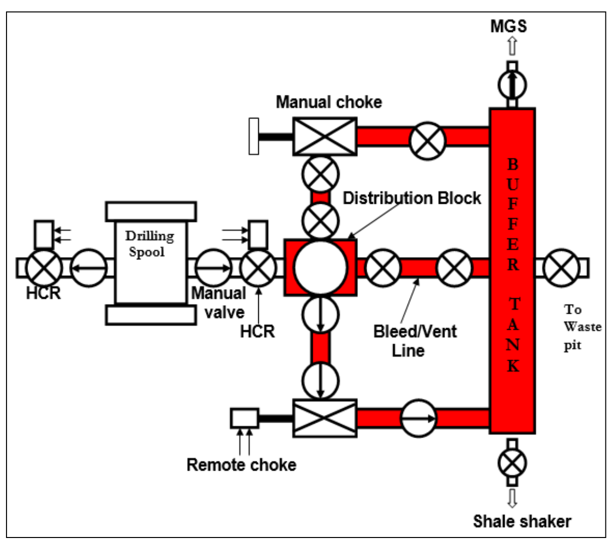
Manual Valve : OPEN

HCR valve: CLOSED

Valves to R.Choke: OPEN

Remote Choke: CLOSED

Valves to MGS: OPEN



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Hard Shut-in Procedure

1. *Close the BOP*
2. *Open the HCR*
3. Notify company personnel
4. Read and record pressures and pit gain

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Hard Shut-in Advantages

The Procedure is simple
Allows well closure in the fastest possible time
  Minimizes influx volume
  Minimizes wellbore pressures
Can be performed by one person working the rig floor

Hard Shut-in Dis-Advantages

Cannot be used where casing pressures would likely exceed MAASP

Should not be used where a formation could broach to the surface
  ✓Especially on offshore bottom-supported rigs

Should not be used where formations are unstable and would be affected by hydraulic shock
  ✓Studies show hydraulic shock may not be a factor if shut in immediately
  ✓ Preventer rubber erosion can be significant when shutting in on a flowing well

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Hard Shut-in when Drilling

1. Pick up off bottom and position tool joint (space out in BOP)
2. Stop rotary
3. Stop pumping
4. Flow check. If flowing:
   a) Close the desired BOP, make sure BOP sealing
   b) Open HCR or fail safes
   c) Notify company representative
   d) Read and record the pressures and pit gain

in-depth

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Hard Shut-in when Tripping

1. Position tool joint at working level on the rig floor
2. Install a FOSV in the OPEN position
3. Close the FOSV
4. Flow check. **If flowing:**

   A. Space out tool joint in BOP stack
   B. Close BOP, make sure BOP sealing
   C. Open HCR
   D. Pick up and install Kelly
   E. Open the FOSV
   F. Read and record pressures and pit gain

in-depth

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Hard Shut-in when Running Casing/Tubing

1. Space out the casing couplings in the BOP stack
2. Secure the string
3. Install circulating swage or casing-drill pipe crossover**(water Bushing)**
4. Install FOSV and close
5. Surface casing will require diverting

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Hard Shut-in when Running Casing/Tubing

6. Subsequent strings - shut in by closing any of:
   a. Casing rams
   b. VBR rams
   c. Annular preventer
7. Open the HCR or K & C valves
8. Or close the annular preventer
   a. Reduce annular hydraulic pressure, if necessary
   b. Take care with Shaffer not to damage the casing with the steel inserts
9. Consider stripping liner to bottom or back into casing

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Hard Shut-in when Cementing

- Space out coupler in the stack
- Shut down cement pump
- Secure string
- Close appropriate BOP
- Open HCR/fail safes
- Notify supervisor
- Consider circulating cement out through the choke

Note: Choke manifold has to inspect after circulating cementing via choke

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Hard Shut-in While Logging with Lubricator

- Stop logging
- Space out the logging tool to ensure it is **not in the BOPs**
- Energize the pack off seals at the lubricator
- Close the wireline BOPs
- Open the HCR/K&C line valves
- Notify the company personnel
- Shear the wireline, if necessary
  - Using shear rams with wireline in tension or
  - With wireline cutting tool
  - **DO NOT SHEAR THE Wireline TOOLS**

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Hard Shut-in While Logging with no Lubricator

- Stop logging
- Space out the logging tool to ensure it is *not in the BOPs*
- Regulate annular hydraulic pressure to CSO pressure
- Close the *annular on the wireline*
- Open the HCR/K&C line valves
- Notify the company personnel
- Shear the wireline, if necessary
  - Using shear rams with *wireline in tension* (Limitations)
  - With wireline cutting tool
  - **DO NOT SHEAR THE TOOL**

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Shut-in Procedures

Sl. No.	Soft Shut-in	Hard Shut-in
1	Open HCR/Manual Valve on choke line	Close BOP (preferably Annular)
2	Close BOP (preferably Annular)	Open HCR/Manual Valve on choke line when choke is in fully closed position
3	Gradually close choke, monitoring casing pressure	Make up kelly and open FOSV
4	Make up kelly and open FOSV	Notify rig site supervisors.
5	Notify rig site supervisors.	Allow pressures to stabilise and record SIDPP, SICP and Pit Gain
6	Allow pressures to stabilise and record SIDPP, SICP and Pit Gain	

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Hard vs. Soft Shut-in

	Advantages	Disadvantages
Hard Shut-in	- Influx stopped in short possible time. - Quick and simple procedure.	- Increase in pressure pulse or 'Water Hammer'
Soft Shut-in	- Pressure pulse is reduced.	– Larger influx is obtained due to delay in fully shutting well in. – More complex due to requirement of ensuring valve alignment before closing BOP

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Factors that might cause an Influx Up the Drill String

Drilling with no bit float valve

- Blown kelly hose during kick
- Blown pump pop valve during kick

Closing the BOP before closing the DPSV (FOSV)

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Confirm a Well is Shut-in

- BOP *panel pressures* are verified correct
- BOP panel *flow meter* reading is verified to be correct
- No flow past BOPs has been verified
  - *Trip tank is being monitored* and alarmed
- Shut-in pressures are observed to be stable
  - *Shut in pressures are being recorded* regularly
- *Correct functions* have been operated and verified

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Shut-in Unsuccessful

If a barrier fails after shut in:

- Activate a second barrier element

  ✓ Shut alternative BOP below leaking preventer

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Monitoring after Shut-in

- Divert flow above BOP to trip tank
  - ✓Monitor flow for leaking BOP
    - Activate alternative BOP if leak
- Monitor SIDPP and SICP
  - ✓Regular intervals
    - -Maintain SIDPP constant or use Volumetric Method
- Monitor pit volume/gain
- Monitor surface equipment for leaks/erosion
- Monitor for subsurface leaks

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Recording Shut-in Data

After shutting in, read and record the shut-in data on a regular basis, which should include as a minimum:

- SIDPP and SICP
- Pit and trip tank volumes
- Pit gain

If the influx migrate in a closed well, both the SIDPP and SICP will increase in same amount.

- **Record these changes**
- **Inform the supervisor**

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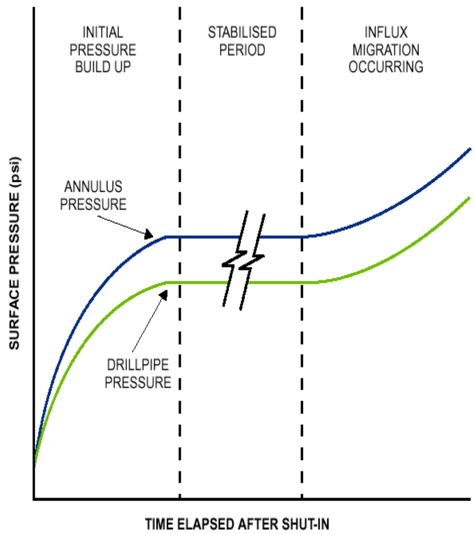
Pressure Build Up after Shut-In



- What determines the initial build-up rate?
- How could we determine SIDPP with a float/IBOP in the string?
- SIDPP and SICP need to be taken at remote choke – why?
- Ensure gauge is read properly, not sticking, no parallax.

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Recognizing Losses after Shut-in

Indications that MAASP has been exceeded during a well control incident:

- A sudden drop in casing pressure
- Followed by a drop in the drill pipe pressure
- A decrease in returns
- Unexpected need to close choke during kill

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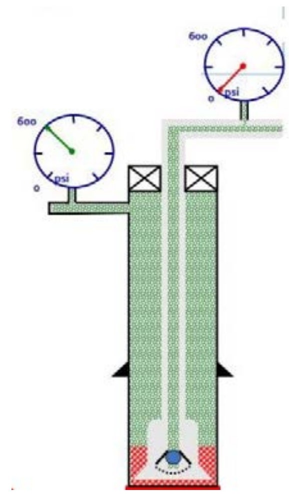
Determining S.I.D.P.P. with Float

1. Pump into the closed drillpipe at a slow rate (3 to 5 SPM) and closely monitor drillpipe and casing pressure.
2. When the CSG pressure just begins to rise.
3. Shut off the pump and record the DP pressure.
4. This value will be the Shut-In Drill Pipe Pressure.



Controlling a Well

Difference Between Controlling and Killing a Well

If primary fluid barrier fails

- Foremost concern is to get the well under control
- In most cases this means shutting well in

If kill operations cannot be immediately instigated

- Continue to *control* the well
  - ✓ Insufficient weighting material
  - ✓ Fluid mixing equipment failure
  - ✓ Unable to circulate
  - ✓ Well intervention rig-up

Well Control Methods

After a kick has been closed in:

- Establish circulation
- Circulate kick to surface, maintaining a constant bottom hole pressure
- Re-establish primary well control by increasing the mud weight to KWM

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Well Control Methods

3 Methods for Circulating Kicks Through Choke

1. *Drillers Method*
   - Kick is circulated out using the original mud weight
   - Kill well with KWM on second circulation
   - When there is insufficient weight material on location
   - When the mud mixing equipment fails
2. *Wait and Weight Method*
   - Well is shut in until KWM has been mixed
   - Kill well in one circulation using drill pipe pressure schedule
   - Generally will result in the lowest casing shoe pressure
3. *Concurrent Method*
   - Start adding weight material as soon as circulation is established
   - May take a number of circulations

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Well Control Methods

2 Methods When Circulation is not Possible

- *Volumetric Method*---let the influx expand by bleeding off a calculated volume of mud through the choke at intervals
  - Used when the well *cannot be circulated* and kick is not at surface
    - Unable to circulate
    - Drillpipe out of the hole
    - Drillstring plugged
    - Washout in drill string with kick below washout
    - Kick below bit
- *Lubricate and Bleed*---pump KWM into annulus and bleed off SICP equivalent to the hydrostatic pressure of the mud injected
  - Used when *gas is at the surface*

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Drillers Method First Circulation

- ➢Zero the strokes
- ➢Bring pumps up to the SCR, holding the casing pressure constant at its closed-in value
- ➢Drill pipe pressure should approximate calculated ICP
- ➢Circulate influx from well using the current mud weight and holding the DPP constant at ICP
- ➢Shut down pumps, holding the casing pressure constant
- ➢The SIDPP should approximate the original SIDPP
- ➢Record the time, pressures, strokes, and volumes

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Drillers Method Second Circulation

- Zero the strokes. Record time.
- Bring pumps up to SCR, holding the CP constant
- Pump KWM from pump to table holding ICP constant
- Zero the strokes
- Pump KWM from surface to bit while holding the CP constant
- DPP will reduce from ICP to FCP as mud is pumped to bit
- Pump KWM from bit to surface while holding the DPP constant
- Casing pressure will fall to zero as the KWM is pumped to surface
- Shut down and check for zero pressures
- Record time, pressures, volumes, and strokes

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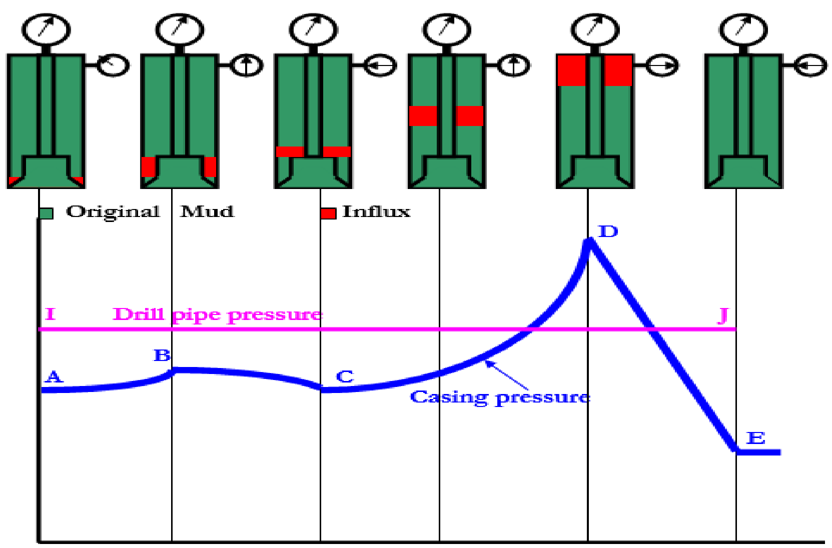
Drillers Method - 1st Cycle



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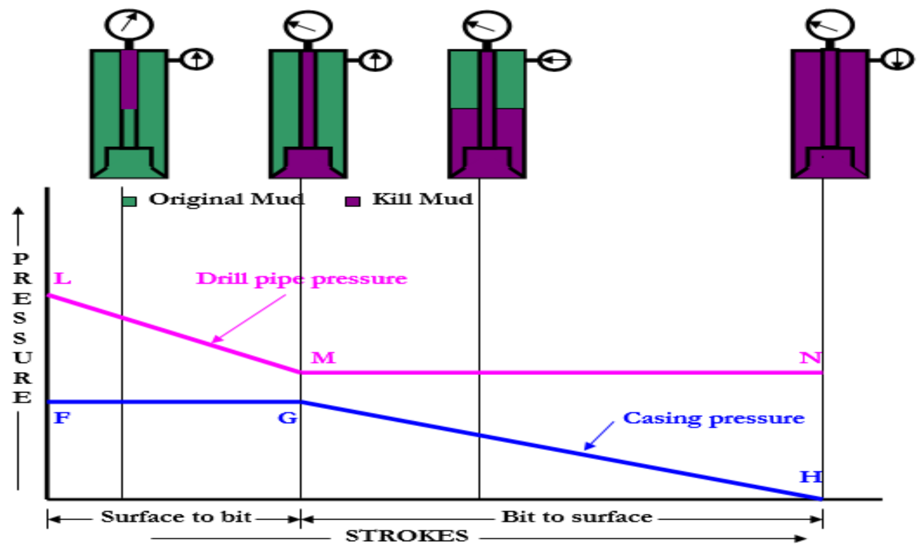
Drillers Method - 2nd Cycle



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Wait & Weight Method

- Zero strokes. Record time
- Bring pumps up to SCR holding the CP constant
- Pump KWM from pump to table holding ICP constant
- Zero strokes
- Pump the KWM from surface to bit while allowing the DPP fall from ICP to FCP, following a calculated pressure reduction schedule
- Pump KWM from the bit to surface, holding the DPP constant
- Shut down and check for zero pressure
- Record time pressures, volumes, and strokes
- Open preventers after displacing riser and associated lines to kill mud and clearing any trapped pressure

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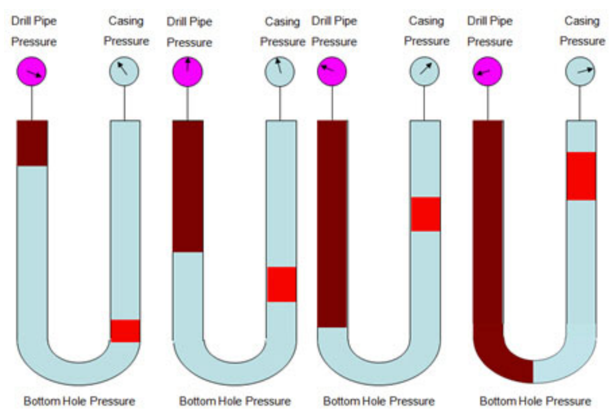
Wait & Weight Method

1) Displace kill weight mud to the bit



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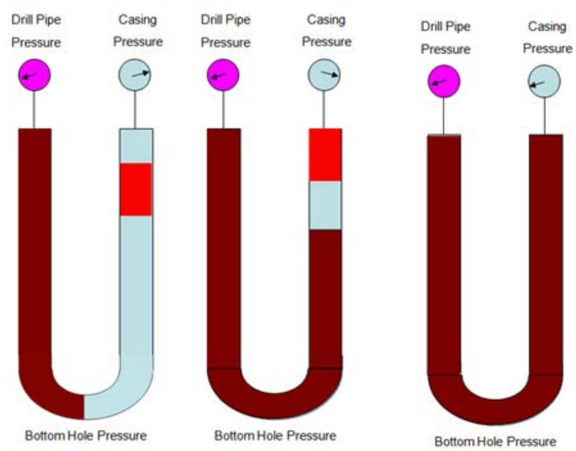
Wait & Weight Method

2) Displace kill weight mud from bit to surface



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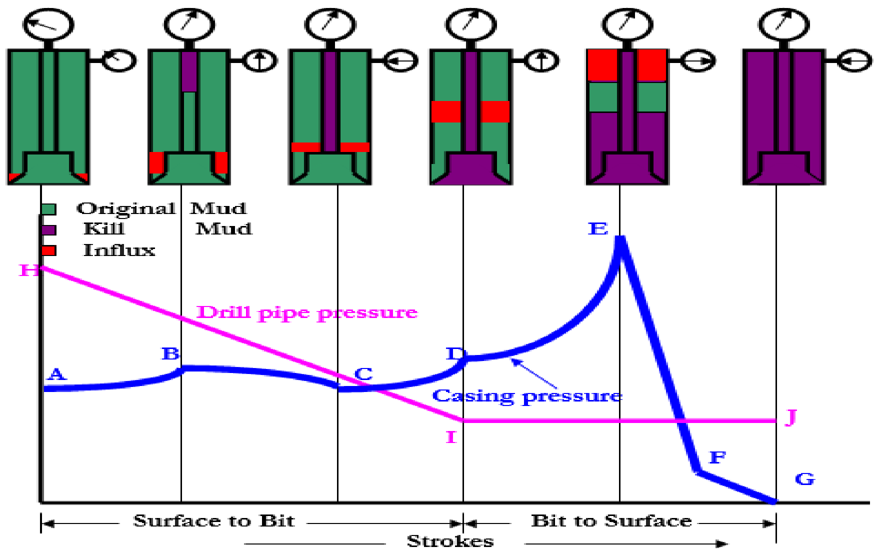
Wait & Weight Method



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Formula Required

- KMW= OMW+(SIDPP/TVD/0.052),
- ICP= SIDP + KRP, at 0 strokes,
- FCP = KMW/OMW x KRP, after pumping to the bit
- STB Strokes= Drill-string Volume/Pump Output,
- Bit to Shoe Stks= OH Volume/Pump Output,
- BTS Strokes= Annular Volume/Pump Output,
- Pressure Drop/100 Stks= (ICP-FCP)/STB Stks x 100

Wait & Weight Method

WELL DATA:

SCR: 300 psi, SIDPP: 600,
Depth: 10000', MW: 10 ppg,
String Volume= 800 Stks

Prepare Step-down table

1. ICP= SCR+ SIDPP= 300+600= 900 psi,
2. KMW= 600/(10000*0.052) + 10.00 = 11.20 ppg
3. FCP= 300 (11.20 / 10) = 336 psi,
4. Pressure Drop = 70 psi/ 100 strokes

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Wait & Weight Method

Strokes	Pressure
0	900 ICP
100	830
200	760
300	690
400	620
500	550
600	480
700	410
800	340

SIDPP	SCR
600	300
525	305
450	310
375	315
300	320
225	325
150	330
75	335
0	340

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Comparison of Methods

W & W Method

Advantages	Disadvantages
Lower annular pressures	Longer waiting and non-circulating time
Lower casing shoe pressure when OH volume is more than string volume	Chances of sand settling around BHA are high
Well is killed in one cycle	Involves more calculations
Less time to be spent on choke	More chances of gas migration

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Comparison of Methods

Driller's Method

Advantages	Disadvantages
Simple to understand	Higher annular pressures
Minimum calculations	Higher casing shoe pressures in case of gas kick
No waiting as influx can be circulated out immediately, hence, minimum chance of sand settling D/C	Takes long to kill the well as minimum two cycles are required

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Methods of Killing a Well

3rd Method

Volumetric Method

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Volumetric Method (Non-Circulation)

A Controlled Migration of The Influx to Surface

- *Simplest* to use and teach
- Requires *communication* with bit
- Often used while waiting on kill mud
- Used when *circulation is not possible*

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Volumetric Method

It is a method of well control in which bottom hole pressure is kept constant when circulation is not possible and gas is migrating up the hole. Bottom hole pressure is maintained slightly higher than formation pressure while the gas is allowed to expand in a controlled manner as it moves to the surface.

Volumetric Method

The volumetric method is a way of allowing controlled expansion of gas during migration.

The Volumetric method is based on the assumption that the influx is gas that migrates upwards in the well. It cannot be used if the influx fluid is either salt water or oil.

Volumetric Method

When We Use This Method

This method is used when :

- There is bit plugging – No circulation possible
- Very less string in hole – cannot circulate from bottom
- No string in the hole – No circulation possible
- Wash out in the string – No circulation possible
- We cannot strip in
- Cannot circulate due to other reasons

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Volumetric Method

- Calculate the volume to bleed
- Wait until SICP reaches a pre-determined amount
- Bleed off small amounts, but do not allow casing pressure to drop below a calculated Min casing pressure

$$\begin{gathered}\mathit{Current\ Minimum\ Casing\ Pressure}\\ = \mathit{Initial\ SICP} + 100\ \mathit{psi} + \mathit{pressure\ increase\ per\ bbl\ vented} \times \mathit{total\ volume\ vented}\end{gathered}$$

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Volumetric Method

- When the gas reaches surface:

  Convert over to the Lubricate and Bleed method

Deep water wells may require mud be pumped across the stack to keep chokeline from gelling up

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Lubricate and Bleed Method

The *Lubricate and Bleed Method* reduces surface pressures *when gas is at the surface and circulation cannot be established* or the pipe is out of the hole

- Establish a safety margin and predetermine the maximum pressure
- Pump a measured volume of kill fluid into the hole until the pressure reaches the *maximum limit*
- Allow kill fluid to settle
- Bleed gas (do not bleed drilling fluid) until the pressure is reduced by an amount *equivalent to the hydrostatic pressure of the injected kill fluid*
- Repeat until gas is out of hole

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Volumetric Method

The Two Steps

Bleeding: Uses Migration and Controlled expansion

- Bleed calculated volume of mud keeping BHP constant
- Allow casing pressure increase as desired to maintain BHP constant
- Bleed until gas is at surface

Lubrication:

- Pump calculated volume of heavy mud and allowed to fall down through the gas into the annulus & wait,
- Bleed gas influx to predetermined pressure keeping BHP constant
- Repeat the process until all gas is out of well and Well is either killed or desired pressure is achieved

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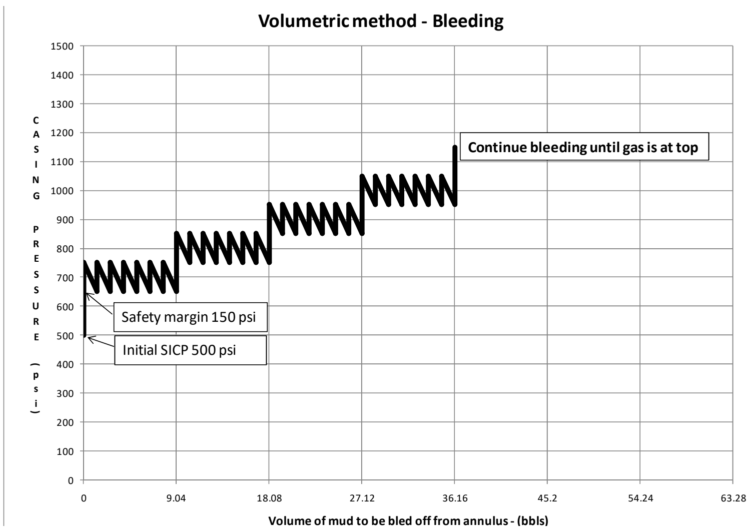
Volumetric Method - Bleeding



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Bullheading

Applications:

- Kick tolerance indicates it is unsafe to circulate out the kick
- An increase in pressures when penetrating the kick would make it unsafe to strip into the well
- High H_2S
- Losses during a kick
- Parted drill pipe

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Bullheading

- Must have *good permeability*
- Must be gas or *low-viscosity influx*
- Difficult if kick has become contaminated with mud
- Difficult if influx has migrated—mud below must also be bullheaded
- Formation breakdown considerations
- Casing and wellhead pressure considerations

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Which kill method pumps KWM at the same time as circulating the influx out of the annulus?

A. Drillers Method

B. Wait and Weight

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A well has taken a gas kick, but the bit has become plugged. Which of the following methods should be considered to continue the kill?

A. Wait and Weight method
B. Concurrent method
C. Volumetric method
D. Drillers method

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Drillers Method

Remove The Influx From The Wellbore with Original Mud

Pump Kill Mud During Second Circulation

Maintaining Bottom Hole Pressure At Least Equal To Formation Pressure.

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Drillers Method First Circulation (Subsea)

- Bring pumps up to the SCR, *holding the kill line pressure constant* at its closed-in value
- Casing gauge will be reduced by the amount of the CLF
- Drill pipe pressure should approximate calculated ICP
- Dynamic MAASP will be MAASP minus CLF
- Hold the kill line constant as the gas enters the choke line
- Circulate influx from well using the current mud weight and holding the DPP constant at ICP
- Hold the kill line constant as the original mud enters the choke line
- Shut down pumps, *holding the kill line pressure constant at its current value*
- The SIDPP should approximate the original SIDPP
- Record the pressures and pit volume

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Drillers Method Second Circulation (Subsea)

- Bring pumps up to SCR, *holding the kill line constant* at its current value
- Pump KWM from pump to table holding ICP constant
- Pump KWM from surface to bit while holding the CP or kill line pressure constant
- DPP will reduce from ICP to FCP as mud is pumped to bit
- Pump KWM from bit to the surface while holding the DPP constant
- Casing pressure will fall to zero as the KWM is pumped to surface
- Shut down and check for zero pressures

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Wait And Weight Method

Remove the influx from the wellbore at the same time as pumping kill mud

Maintaining bottom hole pressure at least equal to formation pressure.

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Wait And Weight Method

- The pump is brought to speed as the CP is held constant
- The drillpipe pressure (ICP) is established
- The KWM is pumped, using a DPP schedule until it reaches the bit (FCP)
- FCP is then held constant until kill mud arrives at surface
- The pump is shut down, holding the CP constant
- The well secured
- With the well closed in, the shut-in pressures should both read zero

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Wait and Weight (Subsea)

- Bring pumps up to SCR holding the kill line pressure constant at its shut-in value
- Pump KWM from pump to table holding ICP constant
- Pump the KWM from surface to bit while allowing the DPP fall from ICP to FCP, following a calculated pressure reduction schedule
- Hold the kill line constant as the gas enters the choke line
- Pump KWM from the bit to the BOP surface, holding the DPP constant
- Shut down and check for zero pressure
- Clear the stack of trapped pressure

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Operations that can Affect the BHP

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Operations that can Affect the Hydrostatic

- Hydrostatic degradation during cement transition period
  - More likely when gel strengths are between 250 lb/100 sq ft and 500 lb/100 sq ft
- Temperature effect upon wellbore fluids
  - OBM is particularly prone to expansion with temperature
- Barite sagging
  - Inconsistent mud weight in wellbore
- Induced losses
  - Supercharging the well, cuttings loading, and surging
- Tripping out
  - Swabbing

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Swabbing- Operations that Decrease BHP

- Tripping out of the well, the pipe movement creates negative (swab) pressures in the annulus
- The amount of swabbing depends upon the mud properties, hole size, string and tool sizes, hole conditions , formation properties, the length of the reservoir open hole section, well measured depth, hole deviation and rate of pipe movement
- Negative pressures are caused by the friction between the moving pipe and the static mud
- This is sometimes referred to as the piston effect

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Surging- Operations that Increase BHP

- Additional pressures caused by the piston effect of the drill string when running pipe and tools into the well
- Surging is caused by running into the hole too fast
  - ✓Will always increase the wellbore pressure below the pipe
- The amount of surging will depend upon the following:
  - ✓Mud properties
  - ✓Hole size and string geometry
  - ✓Rate of pipe movement into the well

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Minimize Surging and Swabbing

- Condition mud to optimum properties
- Condition hole (Clean and obstruction free)
- Monitor mud additions/gains
- Control tripping speed
  - Reduce tripping speed if swab or surge indicated
- Optimize BHA/tool design
- Pump out through tight spots
  - Sufficient annular velocity

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Diverter Uses

- To seal off the annulus …and
- To divert wellbore fluids away from rig
- To *protect rig and rig personnel*
- *Not designed to shut the well in or halt flow*

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Situations for a Diverter

Used to divert flow in these situations:

- Shallow gas or fluid flows
- Drilling with a rotating head
- Gas in a marine riser
- Gas-cut mud

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Operations Where a Diverter is Needed

1. Drilling below drive pipe
2. Fracture gradient is insufficient to circulate kill fluid
3. Where gas may enter the riser before the BOP can be closed
   - Used to evacuate gas from riser
4. Locations where personnel cannot be easily evacuated
   - *Buys the crews added time* for an orderly evacuation

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Low Fracture Gradients

Offshore fracture gradients can be very low. This may mean wells cannot be closed-in on a kick without the likelihood of:

– Lost circulation
– Broaching to the surface

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Principles of Diverting

- **Divert away from the rig**
  - ✓ Will result in loss of drilling fluid
    - ➢ Do not attempt to recover mud through MGS
- **The formation fluid will continue to flow until:**
  - ✓ The hole is dynamically killed
  - ✓ The hole bridges off
  - ✓ The reservoir is depleted
  - ✓ Primary well control can be regained
    - ➢ Using kill mud

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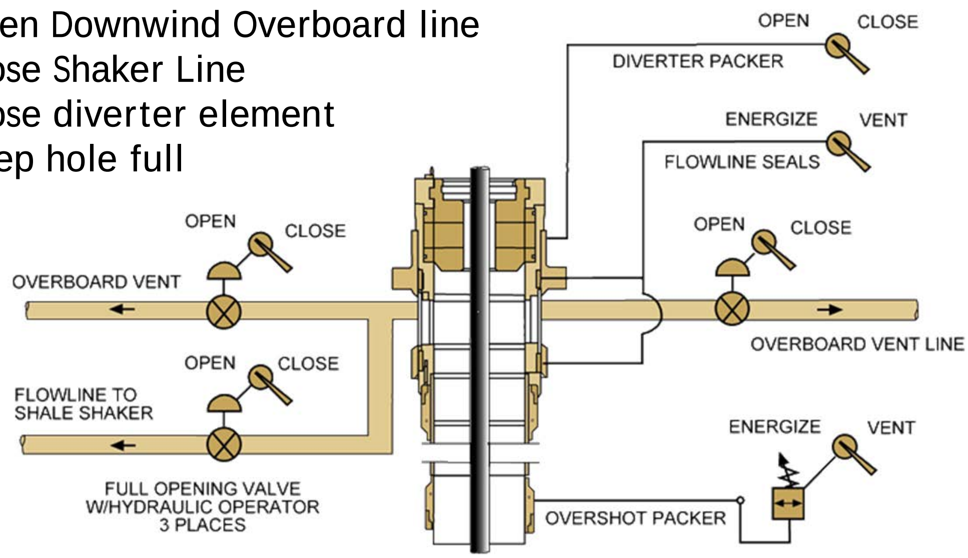
1. Open Downwind Overboard line
2. Close Shaker Line
3. Close diverter element
4. Keep hole full



HYDRAULIC FUNCTION ARRANGEMENT

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Stripping with an Annular

Stripping with an annular is moving pipe through a closed annular into or out of the wellbore against wellbore pressure

- Limit lowering speed to one foot per second, slower past tool joints
- Pass tool joints slowly through the packer
- Use a lubricant such as motor oil or gel-water mixture in the bowl on top of the packer rubber
- When stripping over irregular shaped or sharp tools, use a combination of an annular and ram
- Adjust the closing pressure until a leak rate of 1 gal/min is achieved

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Stripping with an Annular

1. Make up the landing nipple and back pressure valve
2. Lower the pipe and ease each tool joint through the preventer.
3. Land and fill the pipe
4. Install a FOSV on the new stand
5. Remove the FOSV from the joint in the slips
6. Make up a new stand
7. Repeat

- Install a *stripping bottle* on the close line and check the annular regulator valve on the accumulator
- Bleed off pressure according to the volumetric method, using a *stripping sheet schedule*
- Return fluid should be directed to the *strip tank* (or trip tank) and monitored carefully

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Losses:

- Incorrect pit level
  - Decrease in returns
- Incorrect pressures
  - Drop in DPP
  - Followed by drop in CP
  - Need to close the choke more
- Take off over kill safety margin
- Reduce kill speed
- Reduce CLF (subsea stack)
- Consider Volumetric Method

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Hydrates

What are hydrates?

- Hydrates are a solid mixture of water and natural gas (commonly methane).
- Once formed, hydrates are similar to dirty ice .
- Hydrates are a mixture of Hydrocarbon gas and water that form a solid substance, these are crystalline water-based solids physically resembling ice.
- Hydrate formation is a function of Motionless time, Pressure, Temperature, Gas Composition and free water available in the drilling fluid.

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Hydrate Formation

Why are they important?

- Hydrates can cause severe problems by forming a Plug in Well Control equipment, and may completely blocking flow path and store trapped pressure
- The trapped pressure may be released as the hydrate dissolves or melts.
- Light gases form hydrates more quickly than heavy gases

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Hydrate Formation

Conditions Require for Hydrate Formation

- Hydrate will happen at low temperature
- Hydrate will happen High Differential pressure

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Hydrate Formation

How to prevent hydrates?

- Good primary well control= no gas in well bore
- Composition of Drilling Fluid by using OBM or Chloride (Salt) in WBM.
- Well bore temperature as high as possible(Raise the temperature)
- Select proper Mud Weight to minimize wellhead pressure.
- Injecting thermodynamic inhibitors such as methanol or glycol at a rate of 0.5 -1 gal per minutes on the upstream side of a choke

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in-depth DRILLING

Level 2 Drilling Well Control Course

1

Section Three:

- Blow-out Preventer (BOP) Stack Configuration
- Associated Well Control Equipment
- Chokes and Choke Manifold
- Safety Valves
- Subsea Equipment

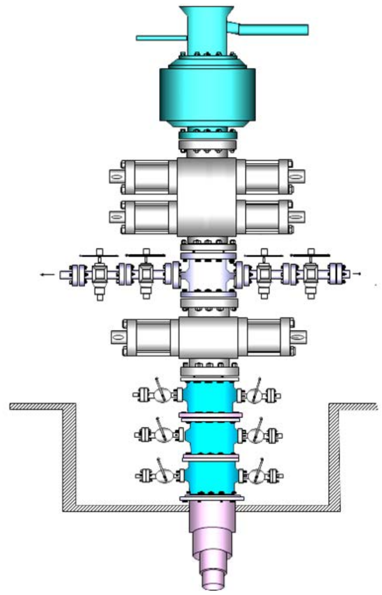
2

in-depth

2

Stack Configurations

BOP STACK	The complete assembly of well control equipment, including preventers spools, valves, and nipples connected to the top of the wellhead or wellhead assemblies



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BOP Stack Configuration

Configuration issues for BOPs are complex. Type and arrangement depend on a variety of factors:

- Maximum anticipated Surface Pressure
- Types of formation fluids
- able to
  - Close on pipe
  - Close on open hole
  - Provide circulating paths
  - Alternate circulating paths
- Operator/Contractor: – Policy and Availability
- Height and Weight, etc.

4

4

Stack Classifications

Subsea stacks must also be able to perform the following functions:

- Hang off on drill pipe and control the well
- Shear pipe and seal wellbore
- Disconnect the riser
- Circulate after drill pipe disconnect
- Circulate across BOP stack to remove trapped gas

5

Well Control Equipment

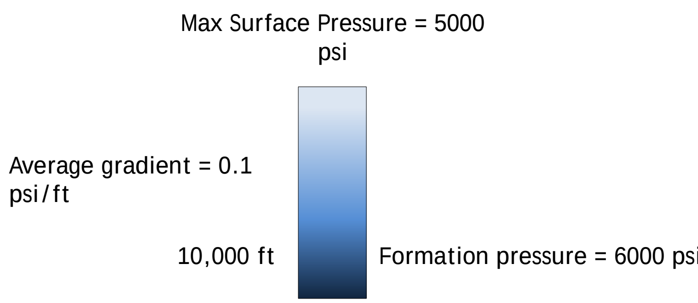
In order to control of well flow, control equipment are used, and these are called secondary well control equipment:

1. **Annular BOP's**
2. **Pipe Ram (Fixed or Variable)**
3. **Blind or Blind/Shear Ram**
4. **Diverter**
5. **Rotating-head,**
6. **Full Opening Safety Valve (FOSV),**
7. **Upper and Lower Kelly Cocks,**
8. **Inside BOP's**

6

Stack Arrangements (API Standard 53)

As a minimum, every **ram** BOP should have a working pressure equal to the *maximum anticipated surface pressure* to be encountered.



P Surface$_{(Max)} = Pf - Hydrostatic\ of\ gas = 6000 - 1000\ psi = 5000\ psi$

7

Minimum Stack Working Pressure- API Standard 53

Surface Stack: Maximum Anticipated Surface Pressure (MASP)

MASP: *a design load that represents the maximum pressure that may occur in the well during the construction of the well*

Subsea Stack: Maximum Anticipated Wellhead Pressure (MAWHP)

MAWHP: *the highest pressure predicted to be encountered at the wellhead in a subsea well.*

8

Minimum Working Annular Pressure- API Standard 53

Annular preventers may have a lower rating than ram BOPS.

- Working pressure of the annular(s) should be posted
- The working pressure of annulars in the LMRP are limited to the rated working pressure of the LMRP hydraulic connector

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API Codes for BOP

API RP codes for Blowout Preventer arrangements are:

A = annular type blowout preventer.
R = single ram type preventer with one set of rams: pipe, blind or shear
Rd = double ram type preventer with two sets of rams,
Rt = triple ram type preventer with three sets of rams,
BSR = Blind shear ram
VBR = Variable –bore ram
S = spool with side outlet connections for choke and kill lines.
G = Rotating head
K = 1,000 psi rated working pressure.
M =1 000 psi rated working pressure

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API Codes for BOP Stacks

RWP(Psi)	Min. requirement
2K and 3 K	CLASS 2
< 5K	CLASS 3
< 10K	CLASS 4
10K AND ABOVE	CLASS 5

Subsea BOP stacks shall be Class 5 or greater

Example: Class 6(two annular and four ram preventers or one annular and five ram preventers)

- BOP " class 6-A2-R4" means that the stack contains six components. 2 annular preventers and 4 ram preventers(Cavities)

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Stack Component Codes

BOP components are described upward from the uppermost piece of permanent wellhead equipment.

Example:

What is meant by the code 15K – 13-5/8 – RSRRAG?

- **Rating:** 15,000 psi
- **Through bore(ID of Flange):** 13-5/8"
- **From bottom to top:** Ram, Spool, Ram, Ram, Annular, Rotating Head

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Additional Subsea Stack Component Codes

- C_W = Hydraulic wellhead connector
- A_L = Lower Annular
- C_R = Hydraulic riser connector
- A_U = Upper Annular

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Selection Criteria of BOP's

API STD53 - Every installed ram BOP should have, as a minimum, a RWP equal to the maximum anticipated surface pressure (MASP), or maximum anticipated wellhead pressure (MAWHP) for subsea BOPs, to be encountered.

Surface Pressure= Formation Pressure – Gas Hydrostatic

Note: Annular preventers having a lower RWP than ram preventers are acceptable.

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BOP Size and Rate

- **Standard sizes of BOP's:**

7.1/16", 9", 11" 13.5/8", 16.3/4", 18.3/4",21.1/4", 26.3/4", 28", 29.1/2", 30"

- **Pressure Rating: 2,3,5,10,15,20 K**

- **Rated Working Pressure**

API Definition of RWP: *The maximum internal pressure that equipment is designed to contain or control*

- **Shell Test as per API (1.5 times)**

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RAMS

Most common types of rams are:

- **Fixed Bore Pipe Ram**
  - Seals on only one size pipe.
- **Variable bore (VBR).**
  - Seals on multiple or range of pipe sizes.
- **Blind rams.**
  - Seals open well bore. Do not close on pipe or wire line.
- **Blind/shear rams.**
  - Seals well bore after cutting action of its blades.
- **Shear Rams**
  - Cuts pipe.
  - Booster unit may be required to increase shear force.

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Subsea Stack Contrasted with Surface Stack

- Subsea choke and kill lines usually connected directly into rams.
  - Usually connected to spool in surface stacks
- Spools added to space for shearing, hanging off and stripping.
- Choke and Kill lines manifolded to be capable of being interchangeable.
- Blind/shears used in all classes of subsea stack.
  - BSR only required in 10,000 psi or higher surface stacks
- Rams equipped with remote locking systems.

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Drilling Spool: Choke and kill lines may be connected to

- Side outlets of the BOP's
- A drilling spool installed below at least one BOP capable of closing on pipe

Drilling Spool

- To limit erosion to the less expensive spool
- Allows additional space between preventers to facilitate stripping, hang off, and shear operations
- 3K and 5K arrangements should have two side outlets no smaller than 2-inches
- 10K and greater arrangements should have one 3-inch and one 2-inch side outlet as a minimum
- Rated Working Pressure must be equal to RWP of ram BOP's

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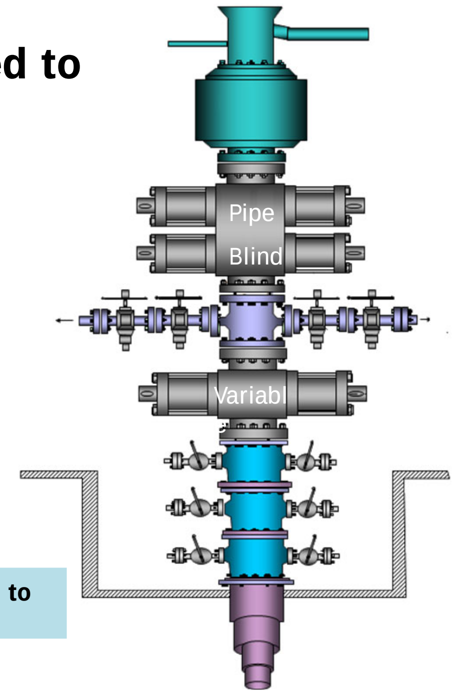
Which ram blocks should be changed to casing rams before running casing?

A. Upper pipe rams
B. Blind rams
C. Lower variable rams

Why?

- We need the blind rams available at all times.
- We need to be able to circulate below rams closed on casing

When running casing, upper pipe rams have to be changed to the casing size, not the lower pipe rams



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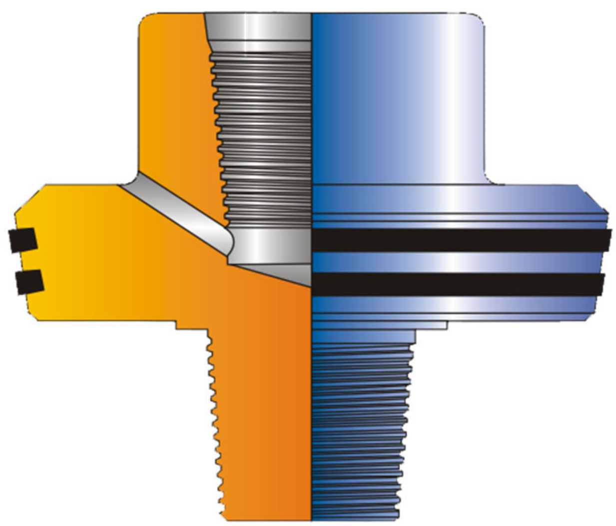
BOP and Equipment Testing



Pressure and function testing is to verify pressure integrity, the compatibility of components, and everything is operationally ready

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Pressure Testing of BOP

Initial Pressure tests:

Surface: This test shall be performed before operations commence. For offshore ops, the ram BOPs shall be tested with the ram locks engaged and the closing and locking pressure vented at commissioning and annually

Subsea: This test shall be performed after the BOP has been latched to the wellhead and before operations commence.

Pressure test evaluation periods shall be a minimum of 5 minutes

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

Ram BOPs: are tested to the RWP of the ram preventer or wellhead system, whichever is lower. If there has been no change out of components, elastomers or ring gaskets it can be tested to ITP (Initial Test Pressure), which is an API pressure designation that is equal to or above the well program MASP.

Annular BOPs: are tested to the RWP of the annular preventer. If there has been no change out of components, elastomers, or ring gaskets they can be tested to MASP or 70% of the annular RWP, whichever is lower.

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Pressure Testing

Subsequent High-Pressure Test:

Subsequent pressure tests shall not exceed 21 days.

The pressure test evaluation period shall be minimum of 5 minutes

Annular(s) & VBR(s) shall be pressure tested on the smallest OD drill pipe expected to be used in the next 21 days

Ram BOPs: Tested to MASP for the hole section

Annular BOPs: Tested to MASP for the hole section or 70% annular RWP, whichever is lower.

The maximum anticipated surface pressure should be determined by the operator based on specific anticipated well conditions.

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Pressure Testing (API Std 53)

- All BOP components that can be exposed to well pressure shall be tested first to a low pressure of **250 psi to 350 psi** and then to a high pressure.
- Any initial pressure above 350psi shall be bled back to a pressure between 250 and 350psi before starting the test. If the initial pressure exceeds 500 psi, pressure shall be bled back to zero and the test shall be reinitiated
- There shall be no visible leaks and the pressure shall remain stable during the evaluation period.
- FUNCTION TESTS – Rams, annulars, choke and kill valves shall be functioned at least every 7 days
- Blind rams, BSRs, and Casing Shear Rams shall be functioned tested at least every 21 days

BOP Test

- Factory Acceptance Test / Body Test / Shell Test – Shall be to 1.5 times the rated working pressure

Pressure Direction

- **The pressure should be applied in the direction of flow. This can either be a positive test or a negative test (i.e. Inflow test).**

- If this is impractical, the pressure can be applied in the opposite direction (i.e.against the flow direction), providing that the well barrier element(WBE) is constructed to seal in both flow directions.

- Valves that are intended to seal against flow from both directions shall be pressure tested from both directions.

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Chart and Test Documentation

The chart and the test documentation usually contains

1-type of test,
2-test fluid,
3-estimated volume of system pressurised,
7- time and date.
4-test duration,
5-system or components tested,
6-volume pumped and bled back,
7- Name & signature of authorized person

❖ **Pressure and function test reports shall be readily available on the rig site for the duration of the well program. For surface offshore installations, reports shall be preserved at an offsite location for a minimum of 2 years**

Pressure chart should signed by **pump operator, contractor's representative, and operating company representative**.

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Postponing of Test Inspection

You may postpone a BOP test if you have well-control problems. You must conduct the required BOP test as soon as possible after the problem has been remedied. You must record the reason for postponing any test in the driller's report.

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Inflow Testing

Differential created by reducing pressure on the downstream side of a well barrier or well barrier element.

Common barriers that are inflow-tested are:

- Liner Laps- prior to well testing,
- Plugs- both mechanical and cement plugs,
- Plugs set prior to removing X-mas tree or test tree

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Subsequent Pressure Tests

- Subsequent pressure tests are conducted sometime *after the shoe has been drilled out*
  - ✓Performed when there is *open hole* not covered by casing
- These tests are performed at *identified periods* during the drilling of a well

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Test Frequency

- ➢Prior to spud or after the initial installation.
- ➢After each casing setting operation.
- ➢Before drilling into any known or suspected high pressure zones
- ➢Routine test period depending upon area of operation
  - ➢ (API STD 53 says *not to exceed 21 days*)
- ➢After a ram change, maintenance, or repair of pressure containing seal. Limited to affected component
- ➢Prior to a production test

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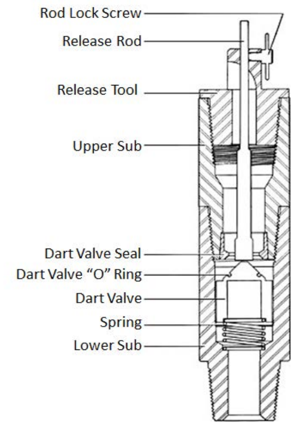
Test Frequency - DPSV and IBOP

– Prior to the initial installation

– Upon installation

– During the well operations when the BOP is tested (Not to exceed 21 days



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Test Procedures

- Ensure that the casing valve(s) are left opened and someone is monitoring the casing valve outlet while testing
- Circulate through choke/kill lines, choke manifold, standpipe manifold, and valves to ensure that all lines are full with water.
- The rams and annulars should be tested in two stages with water.
  - Use water because it has less compressibility than mud

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Acceptable Leak Rates

Monitor non-pressurized side of barrier for leaks

API says *the acceptable leak rate shall be zero*

Acceptance criteria to be established to allow for:

- Temperature effects
- Air entrapment
- Media compressibility
  - Adjust for volume, media type, and pressure

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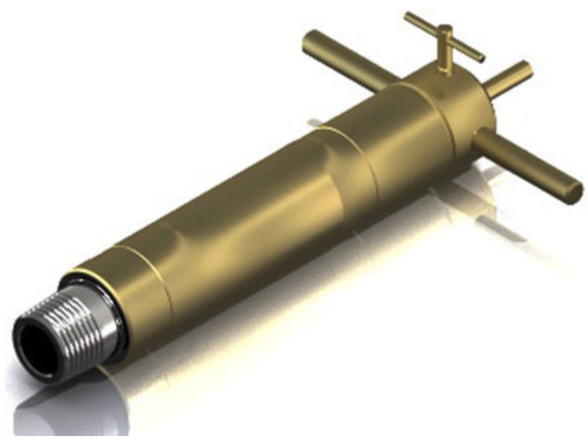
Pressure Test Requirements – DPSV and IBOP

- Initial test to the *MASP for the well program*
- Subsequent tests to the *MASP for the hole section*



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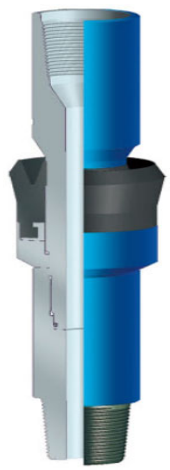
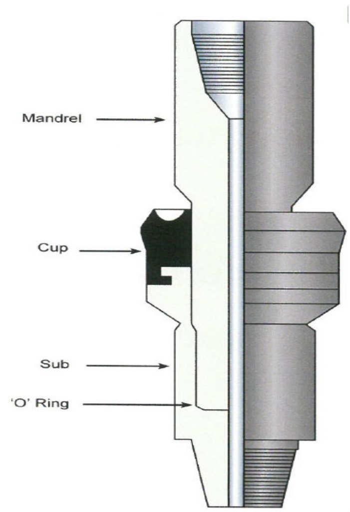
Cup Type Tester



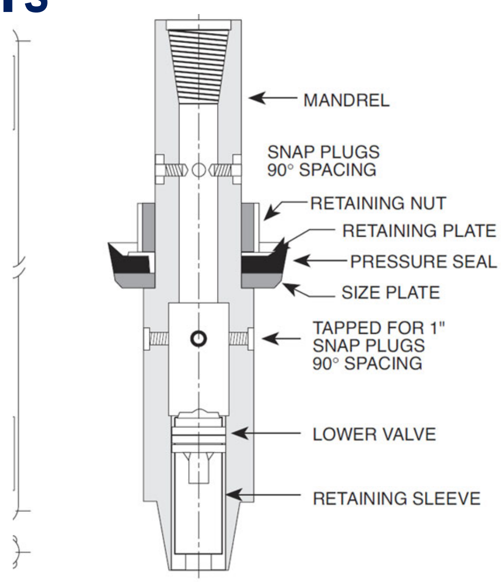


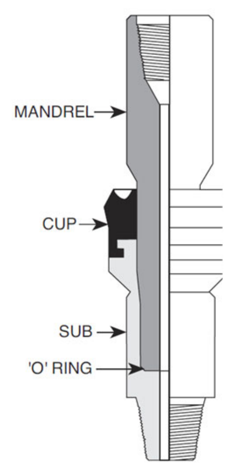
35

Cup Type Testers

Test cups are swabbing devises. Remember to pull slowly!

When pulling, the underside of the cup must always be open through the test string bore





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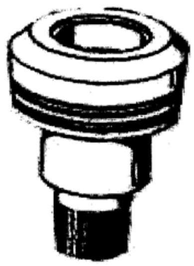
Plug Type Tester



Test Plug

or

Plug Type Tester

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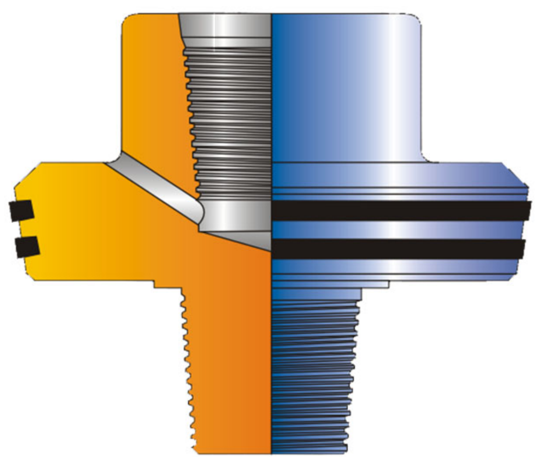
BOP Test Plug

Test plugs are assembled in the drill string and lowered to seat in the casing head body.

Pipe rams are then closed and hydraulic test pressure is applied below the rams.

Blind rams can be tested in the same manner after removing the drill string.



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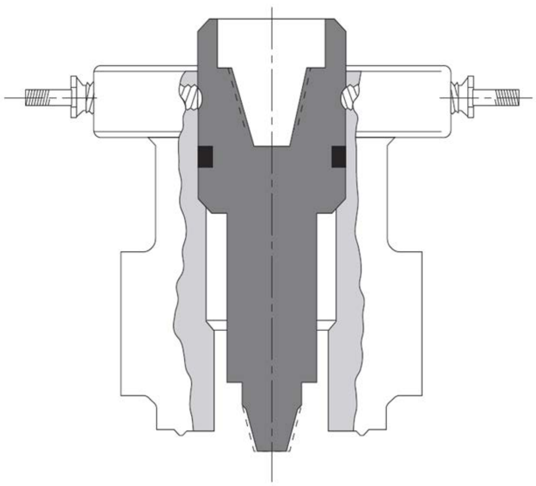
Hanger Test Plugs



Note: When applying pressure against a **casing head plug tester**, always open the casing head outlets below the tester seals *to recognize a leaking seal and prevent formation or casing damage* should the seals leak.

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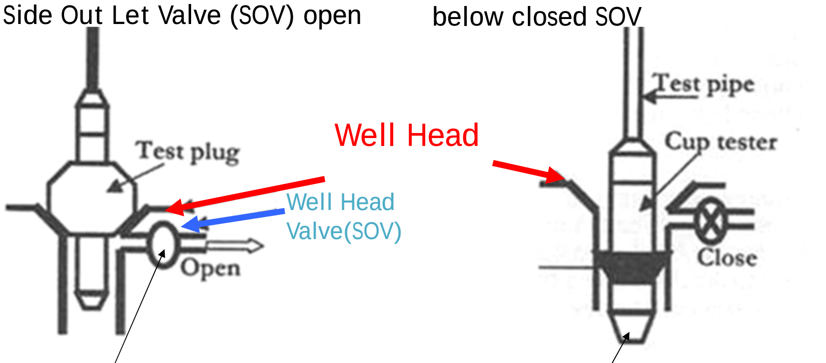
Testing of Well Head

Test Plug sits in top of Well Head with Side Out Let Valve (SOV) open

Cup Type Tester fits inside casing, below closed SOV



Why is the Valve open?

- To Protect the Casing and Casing Shoe in case Plug Tester Leaks
- Test all BOP without any pressure on wellhead

Why is the Test Pipe open?

To Protect the Casing and Casing Shoe in case Leaks

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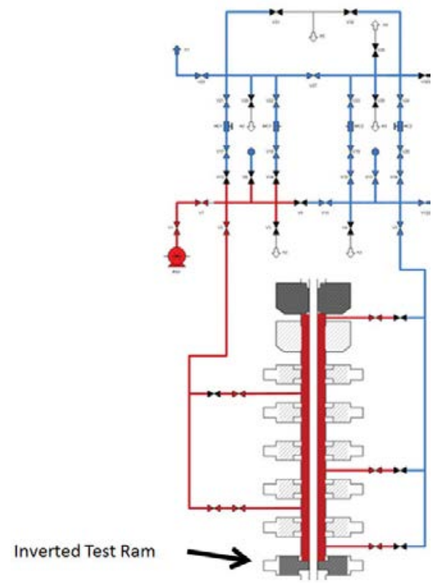
Inverted Rams (Subsea)

- An inverted test ram in the lowest stack cavity eliminates a trip to install a test plug
- Usually an inverted VBR is used
- Allows all the stack components above this rams to be pressure tested without a test plug
- Unless they are "double-acting", these test rams cannot be used for well control



41

Why should the side outlet valves below the test plug be kept in the open position while testing a surface BOP stack? (TWO ANSWERS)

a. Otherwise reverse circulation will be needed to release the plug

b. To prevent potential damage to the casing or formation

c. Because the test will create extreme hook load

d. To monitor the annulus for returns

42

When is a cup type tester used in preference to a plug type tester?

a. To test the BOP stack without applying excess pressure to the well head and casing

b. To test the entire casing head, side outlets and casing to well head seals

c. There is no difference, they are interchangeable

43

From which direction should ram-type BOPs be tested?

From the underside (API says: *direction of wellbore pressure from the formation*)

44

To which pressure should the hydraulic opening and closing chambers in a ram type BOP be initially tested?

RWP recommended by the BOP manufacturer

45

BOP Control Unit

Is used to provide a means to individually actuate components in the BOP stack by providing pressurized hydraulic fluid to the selected stack component.

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Accumulator Bottles

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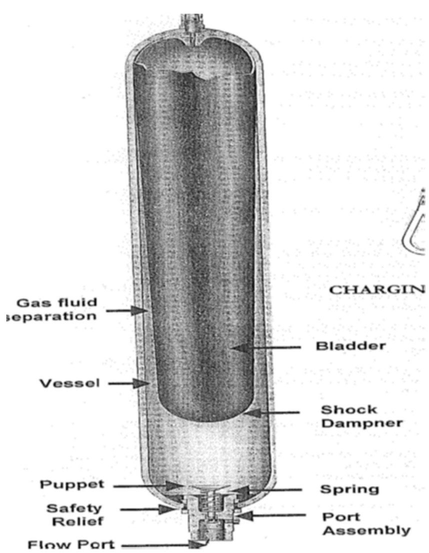
Accumulator Bottles



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Reservoir Tank

- Shall be cleaned, flushed of contaminants, and have vents inspected before fluid is introduced
- Hydraulic fluid reservoir usable capacity shall be at least twice the stored hydraulic fluid capacity of the accumulator system
- Hydraulic fluid shall be filtered to ensure proper operation

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49

API 16D recommends the hydraulic fluid reservoir capacity shall be at least twice the stored hydraulic fluid capacity of the accumulator system.

Reservoir Capacity = **2** X Stored Fluid

50

According to API 16D, the primary pumps shall automatically start before system pressure has decreased to 90 % of the system RWP, and automatically stop between 98 % and 100 % of the system RWP

The primary pumps kick in at minimum of **90 %** of working pressure

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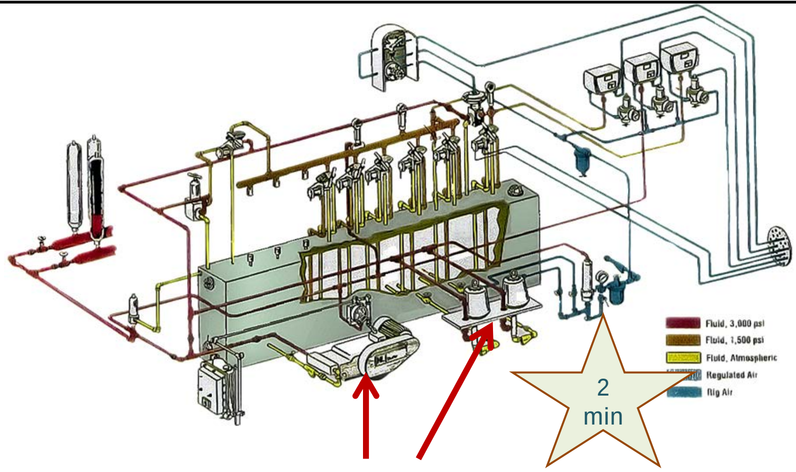

API RP53 (**Surface Stacks**), **each pump system** should be capable of closing one annular and opening the HCR in **two minutes** with the accumulators isolated from service

Two minutes to close annular and open HCR

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BOP Response Times, Surface Stack , API STD 53

The accumulator should be capable of closing each:

BOP	Response time
All Rams	< 30 sec
Choke and Kill valves	Not to exceed minimum observed ram close time
Annular Preventer <18-3/4"	< 30 sec
Annular Preventer >=18-3/4"	< 45 sec

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BOP Response Times, Surface Stack , API STD 53

The accumulator should be capable of closing each:

BOP	Response time
All Rams	< 45 sec
Choke and Kill valves	Not to exceed minimum observed ram close time
Annular Preventer	< 60 sec
Unlatch the riser (LMRP) connector	< 45 sec

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According to API RP 53, what is the maximum closing time for a ram type BOP in a surface stack?

30	Seconds

55

According to API RP 53, what is the maximum closing time for an annular BOP with a through bore of 18¾” on a surface stack?

45	Seconds

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According to API RP 53, what is the maximum closing time for an annular BOP with a through bore of 13⅝" on a surface stack?

30 Seconds

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According to API RP 53, what is the maximum closing time for an annular BOP with a through bore of 13⅝" on a subsea stack?

60 Seconds

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According to API RP 53, what is the maximum closing time for a ram-type BOP with a through bore of 13⅝” on a subsea stack?

45 Seconds

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Manipulator and Selector Valves

3- position 4-way valves are used in the accumulator (Koomey) unit to control the position of BOP.

60

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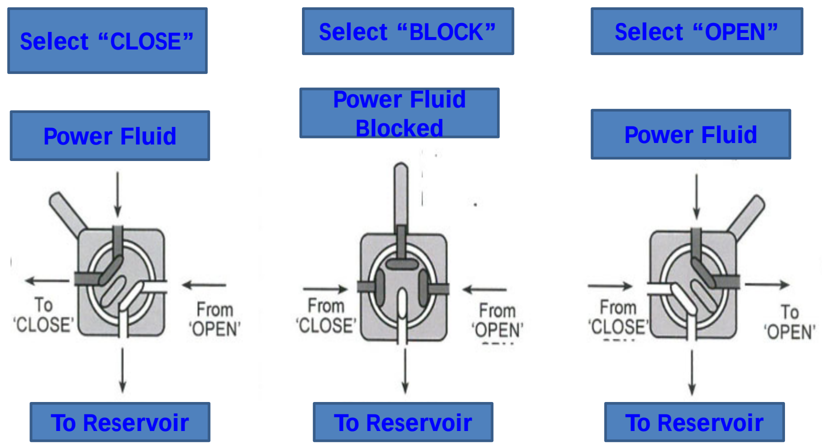
Manipulator and Selector Valves



SURFACE SELECTOR VALVE

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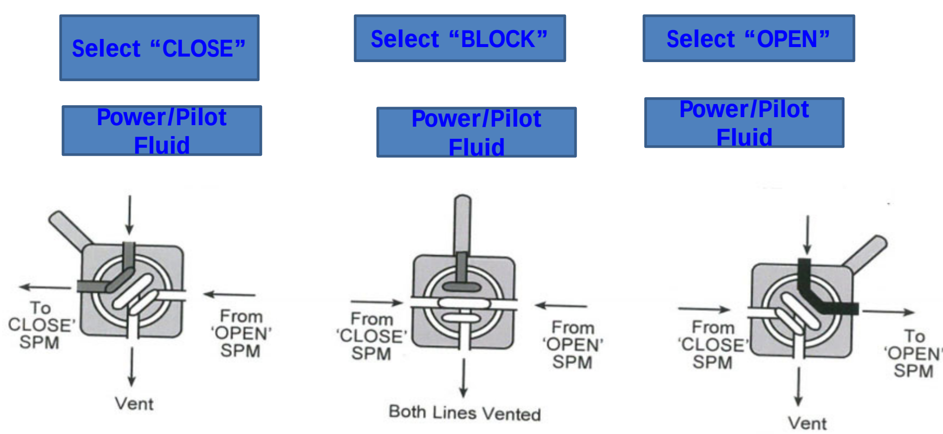
Position 4-Way Valve



SUBSEA MANIPULATOR VALVE

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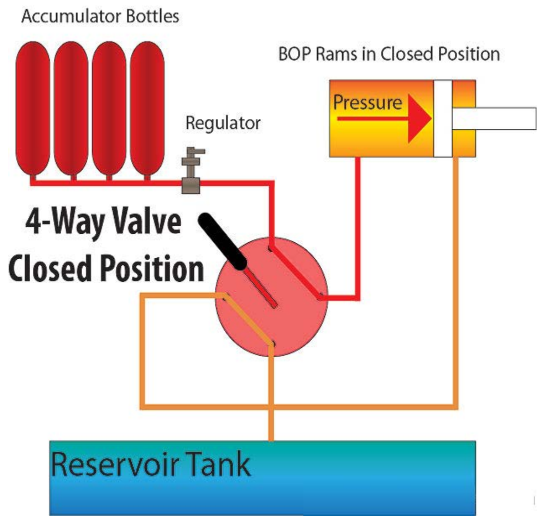
Four-Way Valve in Close Position

The valve is turned into the close position. It means that the hydraulic fluid from the manifold is transferred into the BOP close chamber. The hydraulic fluid from the opening chamber will return back to the reservoir tank..



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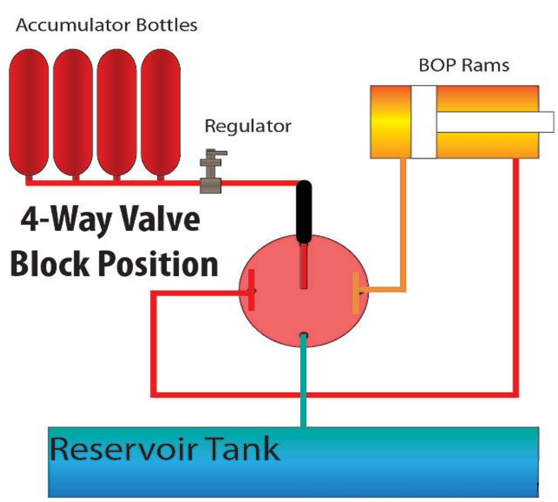
Four-Way Valve in Block Position

- Drilling operation, never leave in block position.
- Valves can be left in the block position during rig move and repairing operation.



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Operating Manifold


65

Operating Manifold


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Accumulator Bottles

- Hydraulic energy for operating BOPs is stored in a number of accumulator bottles
- Bottles come in a variety of sizes and shapes
  - Most common net capacities are 10 gal, 12 gal, 15 gal, 20 gal and 80 gal
- Subsea bottles must be capable of complete discharge prior to recovering BOP to surface

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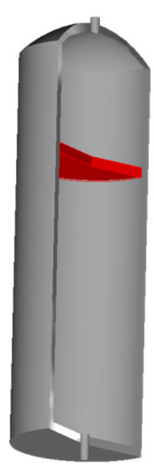
Accumulator Bottles



The separating device can be:

- A diaphragm
- A bladder
- A piston or float

Choice of which type to use can be dependant upon manufacturer recommendation or personal preference

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Purpose of Accumulator Bottles

To provide the quick response necessary for control system functions

And

Serve as a backup source of hydraulic power in case of pump failure

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An empty accumulator bottle is filled with dry nitrogen gas from above

The nitrogen in a 3000 psi system has a *minimum* pre-charge pressure of 1000 psi

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Question?

- Given the volume below, how much hydraulic fluid will be required to carry out the following operation (with 20% Safety Margin)?

Operation : Close , Open and then Close
Equipment : One Annular Preventer
Two pipe Rams
One HCR valve

Volumes :

Annular preventer	18 gallons to close	16 gallons to open
Pipe Ram	6 gallons to close	5 gallons to open
HCR	1 gallon to close	1 gallon to open

A.89 Gallons
B.107 Gallons
C.70 Gallons

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According to API STD 53, which of the following fluids are suitable for use as a control system fluid on a surface BOP stack?

- Hydraulic oil
- Fresh water plus other chemicals
- Salt water plus other chemicals
- Diesel oil
- Kerosene
- 30 Weight Motor Oil
- Chain Oil

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Accumulator Drawdown Test

Purpose

To verify that the main accumulator system, is properly sized to support the fluid volume and pressure requirements of the BOPs on the rig to secure the wellbore.

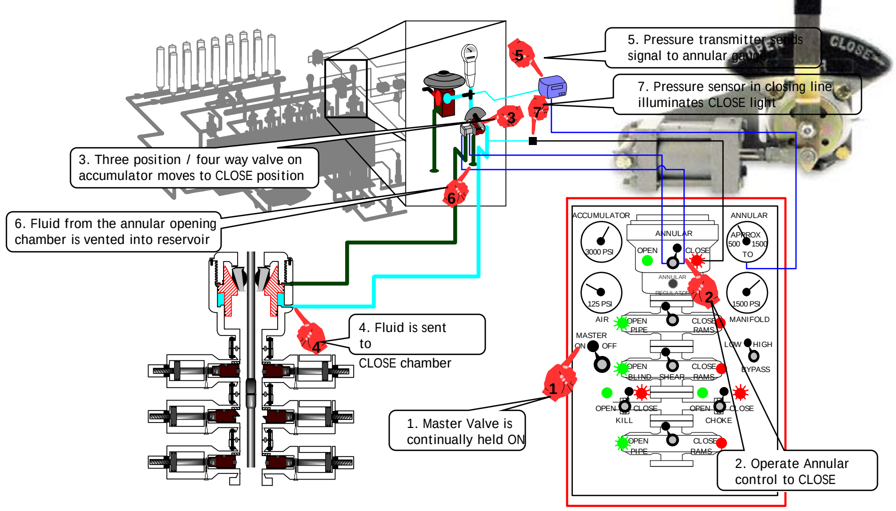
This test shall performed,

1- Prior deployment and upon initial Landing BOPs,(every well, after rig move)

2- After any repairs that required isolation/partial isolation of the system

3- Subsequently not to exceed 180 days from the previous test

To Close the Annular Preventer



What does the red light illuminating and the green light extinguishing tell us?

Proof of Function-Surface Stack

1. Regulated control fluid pressure decreases and subsequently returns to normal
2. Accumulator pressure drops and returns to normal
   – (May not return to normal until the pressure drop is sufficient to start the charge pumps)
3. If the panel is equipped with a flow meter, the volume of fluid used to perform the function will be correct
4. The light on the appropriate function will illuminate while the opposite function light goes out
   – This is not a proof of function, but does *confirm the valve on the closing unit was moved*

75

Ram-Type Preventers

76

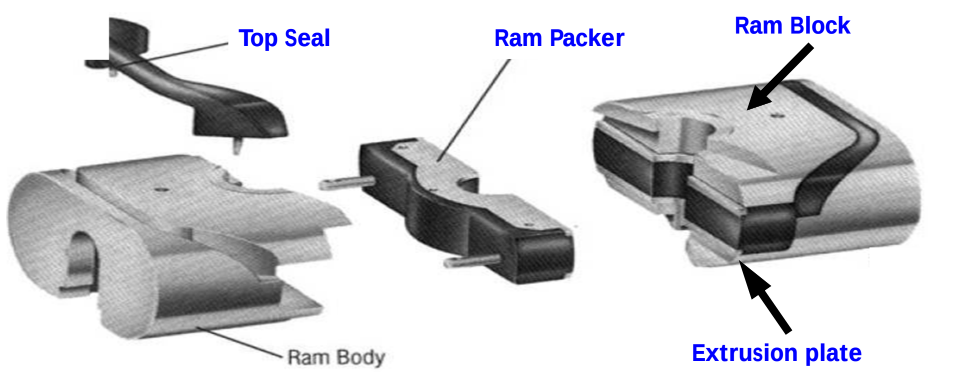
Cameron U and UII Type BOPs

- The Cameron U BOP is the most widely used ram-type BOP for land, platform and subsea.
- Like all other drilling preventers, the rams in the U BOP are pressure-energized.
- Maintain a seal if hydraulic pressure is lost.

77

Fixed Pipe Rams

Fixed Pipe Ram	A closing and sealing components in a ram blowout preventer that seals around a fixed outside diameter of tubular in the wellbore.



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78

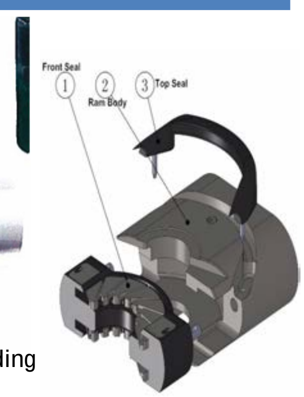
Fixed Rams

- Ram type BOPs should be equipped with a mechanical locking system.
- Fixed bore ram type BOPs can not close and seal on various pipe sizes.
- Fixed bore ram type BOPs can be used to hang off the drill string.
- Ram type BOPs are designed to contain and seal Rated Working Pressure only from below the closed rams.

79

Variable Pipe Rams

Variable Bore Ram	A closing and sealing components in a ram blowout preventer that seals around various sizes of different tubular within a certain range in the wellbore(i.e 3 ½-7"), These rams do not have to be changed when several diameter pipe strings will be used.



- Pressure test against all sizes of pipe in use, excluding drill collars and bottom-hole tools;

80

Blind Rams

- Blind rams do not have pipe 'cutout' on the ram block.
- These have bigger packing elements and are designed to seal without pipe in the bore.
- Blind rams should be pressure tested to rating.
- Should not be closed on tubulars and wire line.

81

81

Blind Shear Rams

- Both shear drill pipe/tubulars and seal the hole
- Capacity to cut through 6 5/8" drill pipe
- Emergency equipment, Can seal on open hole
- Saves space, weight and height as you don't have to have separate blind and shear rams
- Shear rams need higher than normal regulated pressures and/or hydraulic boosters to generate shear force necessary.
- Packer element is small in shear rams.
- Shear Rams have large bore bonnets to accommodate largest OD operating piston (Operating cylinder removed and piston size increased to obtain larger surface area to increase closing/shearing force at same pressure.
- Operating piston needs longer travel than pipe rams, hence, **intermediate flange is thicker**.

82

82

Blind Shear Rams

- Space out string
- Centralize the pipe by closing the pipe ram below the shear ram
- Hang off and reduce tension(subsea)
- Open bypass valve to deliver full accumulator pressure
- Verify that the string is sheared
- Ensure and verify well closure.

83

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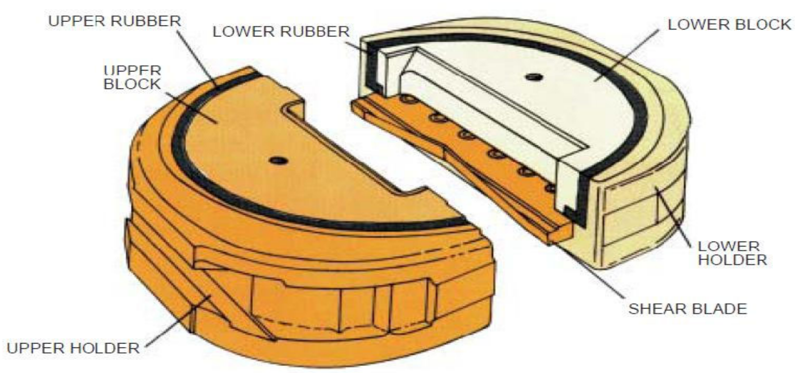
Shear Rams



This is Shaffer Type-72 shear rams where the blade is in the lower block

84

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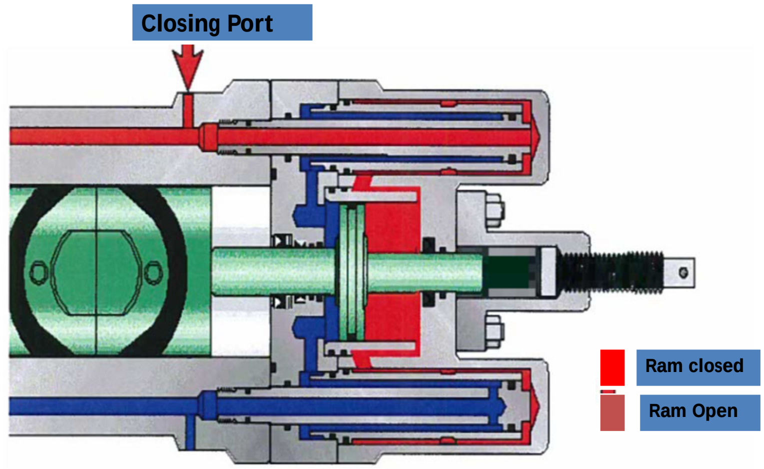
Closing Port



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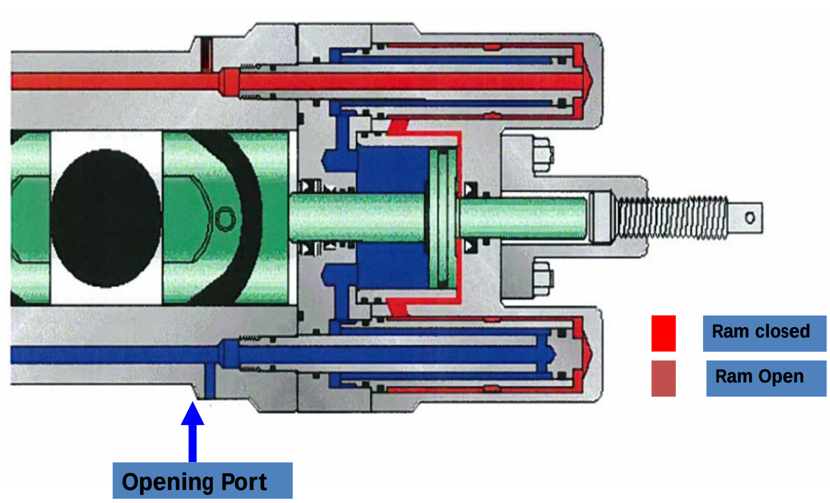
Opening Port



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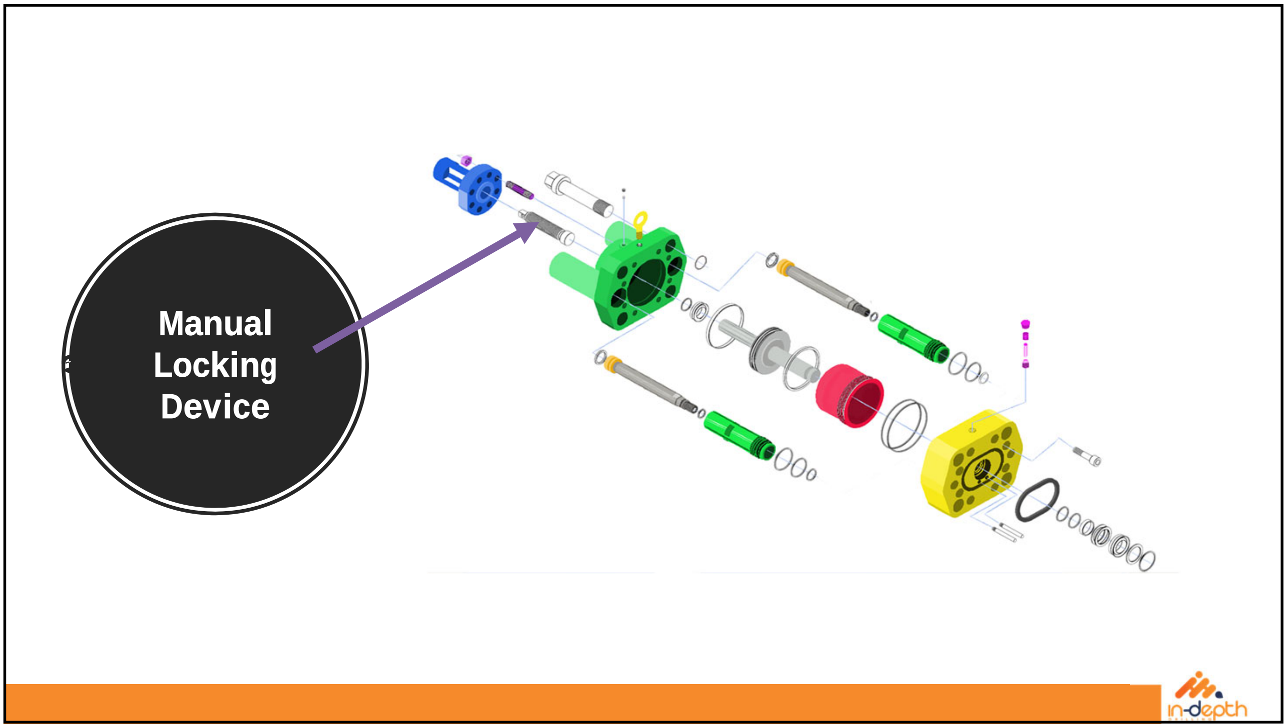
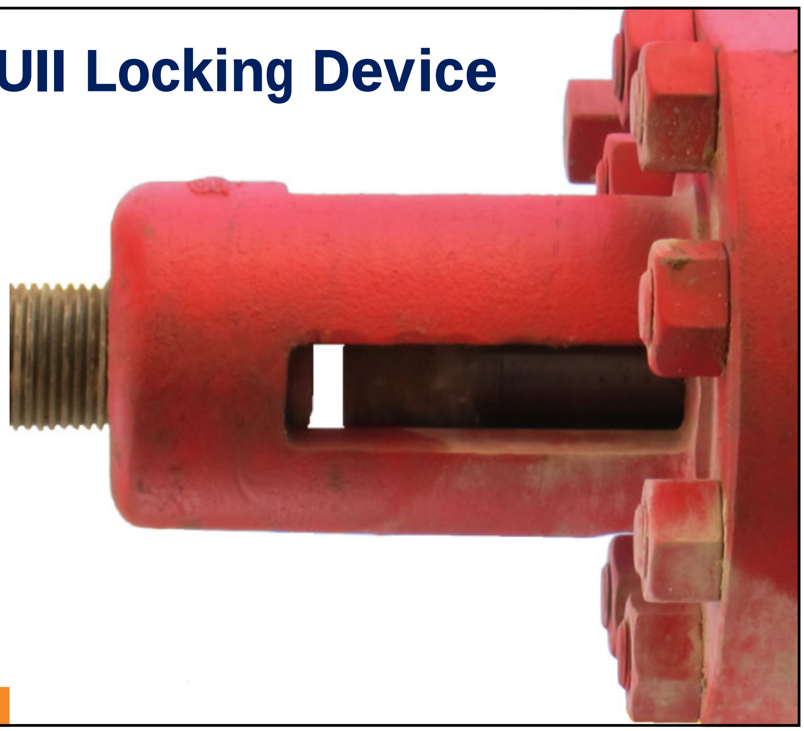


87

Cameron U and UII Locking Device

- The manual locking screw is for locking the BOPs closed

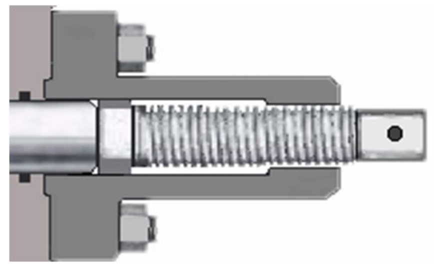
  ✓Preventing the ram from opening if hydraulic closing pressure is lost



88

Cameron U and UII Locking Screw

- Not part of the operating system.
- Must be opened before the rams can be opened.



89

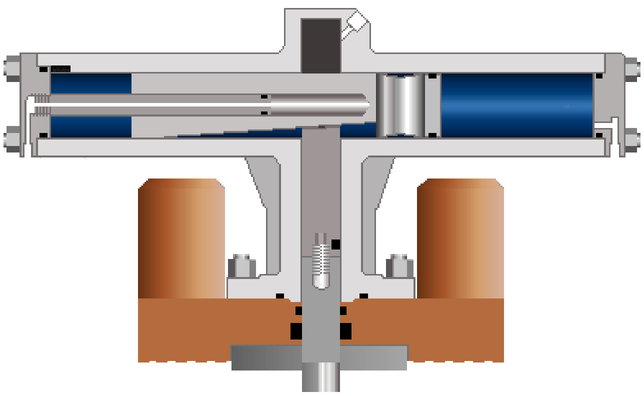
Ram Locking Device

- All sealing rams (fixed , variable , blind , blind shear) have locking devices
- Locking devices not increase the closing pressure on rams

For surface offshore operations: during the initial test, the ram BOPs shall be pressure tested on the ram locks with the closing pressure bled to zero. Hand wheels for manual locks shall be installed, ready and capable for operation.

90

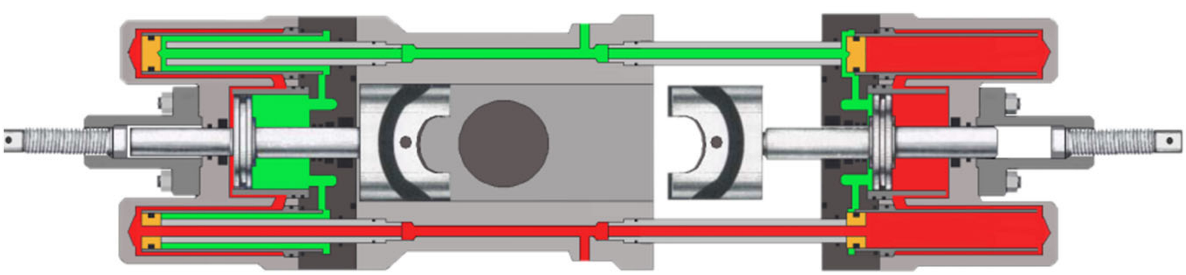
90



Cameron Wedgelocks

- Optional Wedgelock hydraulic lock.
  – Remotely-operated locks are mandatory for subsea
- Hydraulically forces a wedge across the end of the tail rod.

91



Cameron U and UII Type BOP Hydraulic Flow Paths

92

What is the main purpose of a ram locking device?

A. To assist in closing the rams in the event of low hydraulic pressure

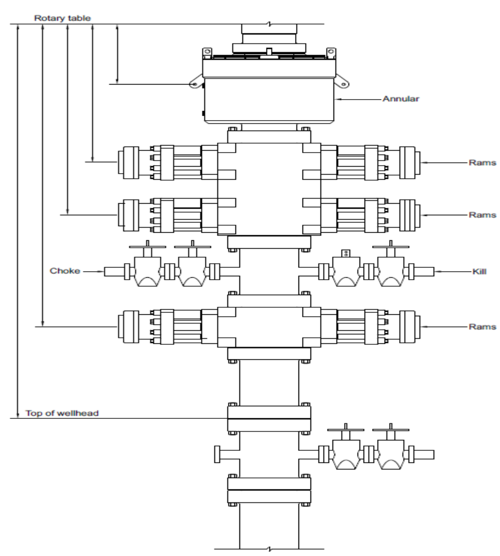
B. To assist in shearing high-tensile pipe

C. To lock the rams closed in the event of hydraulic failure

D. To lock the ram hubs to the rest of a subsea stack

93

Posting of Space Out



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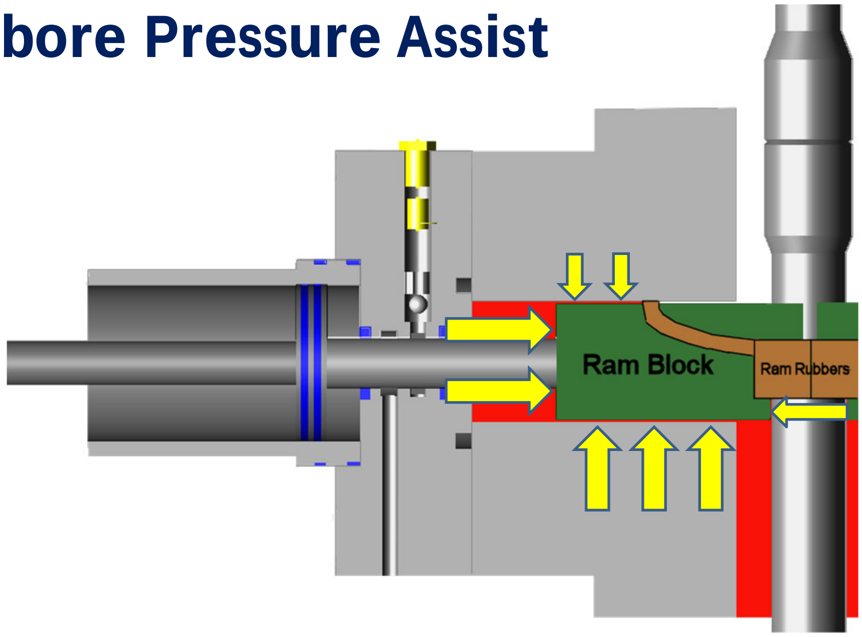
Wellbore Pressure Assist



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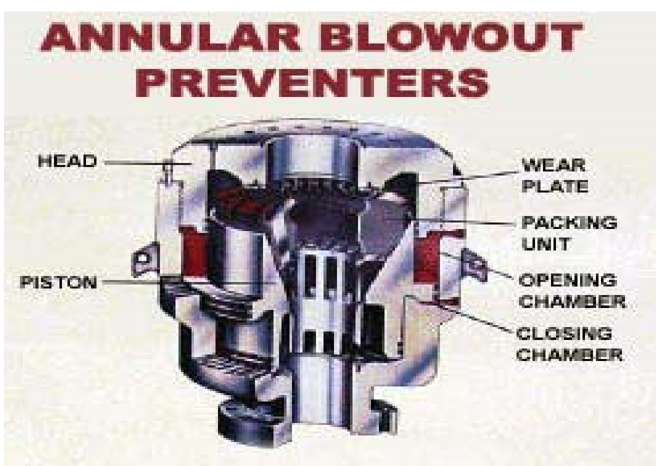
Annular Preventers



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Manufacturers

Hydril:
- Model "GK"
- Model "GL"
- Model "GX"
- Model "MSP"

Shaffer:
- Shaffer Spherical

Cameron Cooper:
- Type "D"
- Type "DL"

97

Annular Preventers

Main Parts of the Annular Preventer are:

➢Circular rubber packer element
➢Piston
➢Body
➢Head

- Hydraulic fluid is pumped into a closing chamber that forces the sealing element inwards.
- The seal is typically obtained by vertical or horizontal packer movement.

98

98

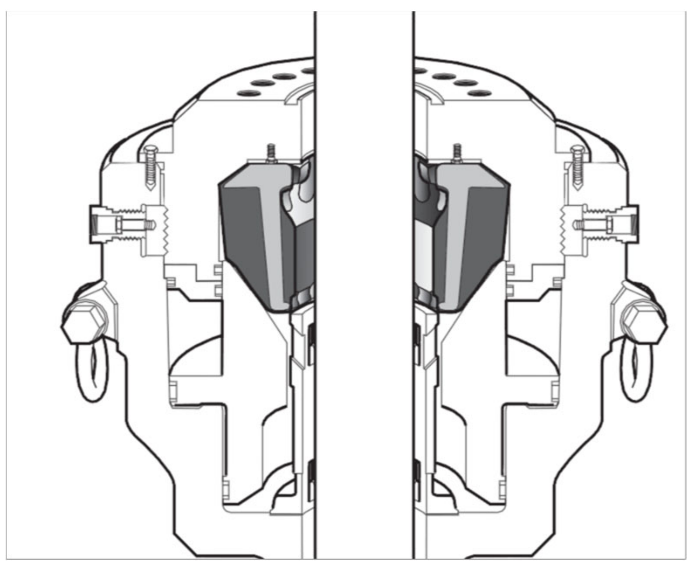
Which of the following statements are correct?

1. Annulars will seal on any tool in the wellbore
2. Annulars cannot seal on a Kelly.
3. Annulars are a WBE for providing secondary well control
4. Annulars cannot provide a seal around wireline

99

Hydril Annular Preventers

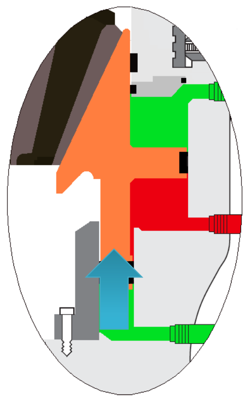
- All Hydril Annular Blowout Preventers use the same basic design.



100

Hydril Annular Preventers

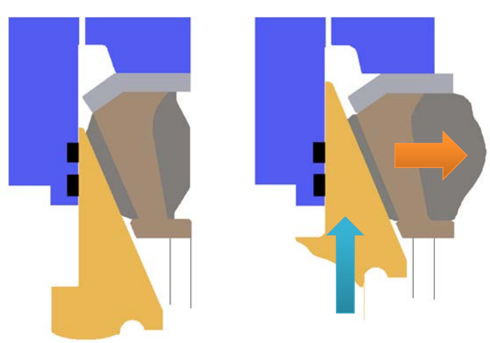
- The piston is raised by applying pressure to the closing chamber.



101

Hydril Annular Preventers

The piston squeezes the packing towards the drill string.



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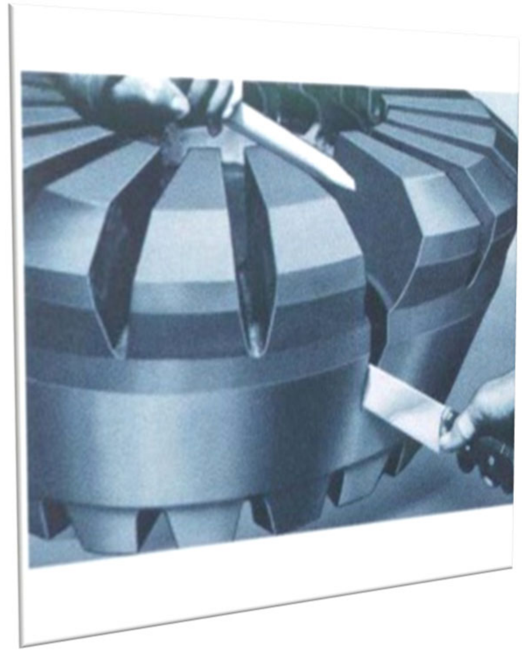
Hydril Annular Preventers

- Closure on the open wellbore is possible with all Hydril Annular BOPs.
- Should only be done in well control situation.
- Packing unit replacement with pipe in the hole in an emergency.



103

Annular Packer Elements (From Hydril)

PACKING UNIT TYPE	IDENTIFICATION		OPERATING TEMPERATURE RANGE	DRILLING FLUID COMPATIBILITY
	Color band	Code / S. N.		
NATURAL Rubber	Black	NR	-30ºF to +225 ºF	Water B. M. /Longest service life
NITRILE Rubber	Red	NBR Band	20ºF to +190 ºF	Oil Base/Oil Additive Fluid
NEOPRENE Rubber	Green	CR	Low temp. -30ºF to +170 ºF	Oil Base Fluid

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Pressure Test Frequency

- Prior to spud or upon installation.
- After the disconnection or repair of any pressure containment seal, but limited to the affected component.
- Before drilling out any string of casing
- Routine periods that shall not exceed 21 days

105

Diverter System

- ❑A diverter system is employed as a means of well control by directing well flows away from the rig and personnel.
- ❑A diverter is not designed to shut or stop flow.
- ❑It is designed to pack-off around the Kelly, drill string, or casing and direct flow to a safe location.
- ❑Vent lines of adequate size (8 inches or larger for Onshore and 12 inches or larger for Offshore) ,
- ❑ Sufficiently distant from the well to permit safe venting and proper disposal of fluid or gas flow from the well.

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Diverter System

- The rated working pressure of the diverter and vent line(s) are designed and sized to permit diverting of well fluids while minimising wellbore back pressure.

- Valves on the vent line these valves should be full opening and full bore (having ID at least equal to line in which they are installed).

- The system should be hydraulically controlled, such that at least one vent line is in the open position, before the diverter packer closes.

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in-depth

107

Diverter Procedures

1. Always open the downwind vent line first
2. Close flowline valve
3. Close the upwind vent, if necessary
4. Close the diverter packer
5. Pump mud at the optimum fast rate

It is a good policy to have sufficient reserve fluid on location where shallow gas is a possibility

in-depth

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Diverters

- Three types of elements:
  - *Annular packer type* can effect a seal on any pipe size, kelly or open hole
  - *Insert type* seal on ranges of pipe sizes. The correct inserts should be in place
  - *Rotating head* can be used as a diverter
- Two sequencing types
  - Automatic sequencing
  - Manual sequencing
    - Requires greater crew training to ensure the functions are operated in the correct order

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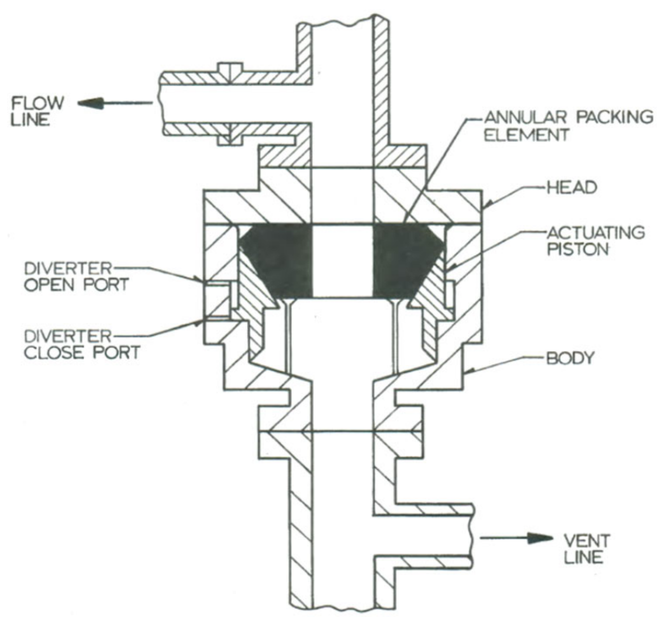
Packer-type Diverter



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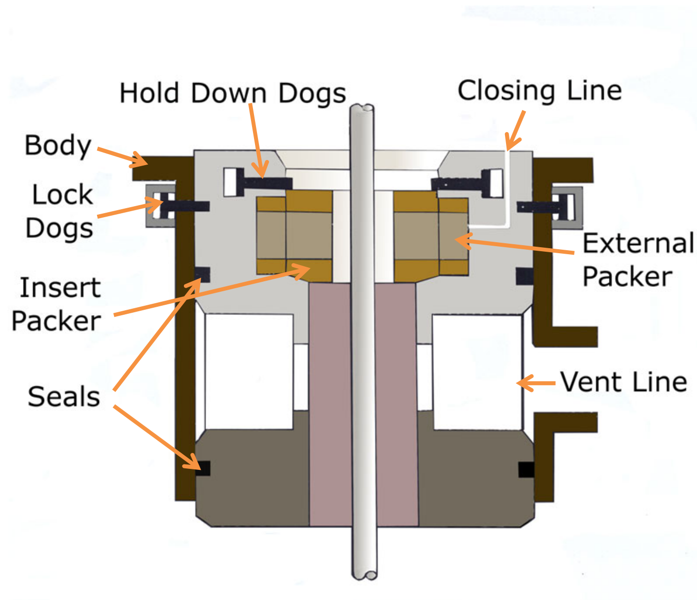
Insert-type Diverter



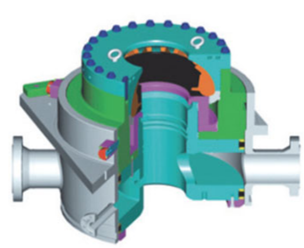
111

Common Type of Diverter

Annular Type (Conventional Annular):

An annular packing element shall seal on the range of tubulars specified by the manufacturer and may seal on an open hole if no pipe is present.

Tests on annular type diverter packing units shall be tested to RWP for the largest and the smallest (CSO if applicable) of applicable pipe sizes.



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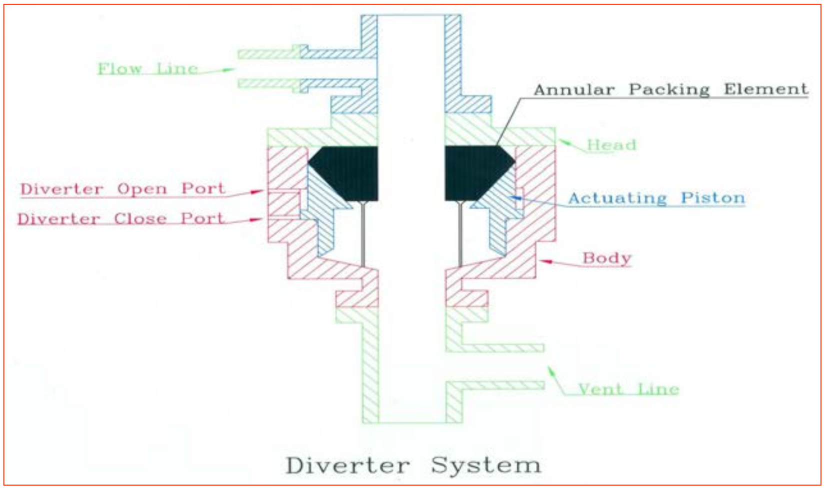
Diverter with Annular Packing



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113

Common Type of Diverter

Insert Packer Type:

A hydraulic or mechanical lock shall latch the insert packer in place.

The manufacturer shall define a procedure to verify that the insert packer is properly locked in place each time the packer is inserted.

Note 1: An insert packing element uses inserts that can close and create a seal on ranges of pipe diameters.

Note 2: The insert packer may be removed to pull or run the bottom-hole assembly

Tests on insert type diverter packing units shall be tested to RWP for the largest and the smallest of applicable pipe sizes for the specified insert packer size.

Note: advantage of this diverter is fast(less than 10 second for closing) and less volume required.
Note: Drift test is not required for insert packer(s).

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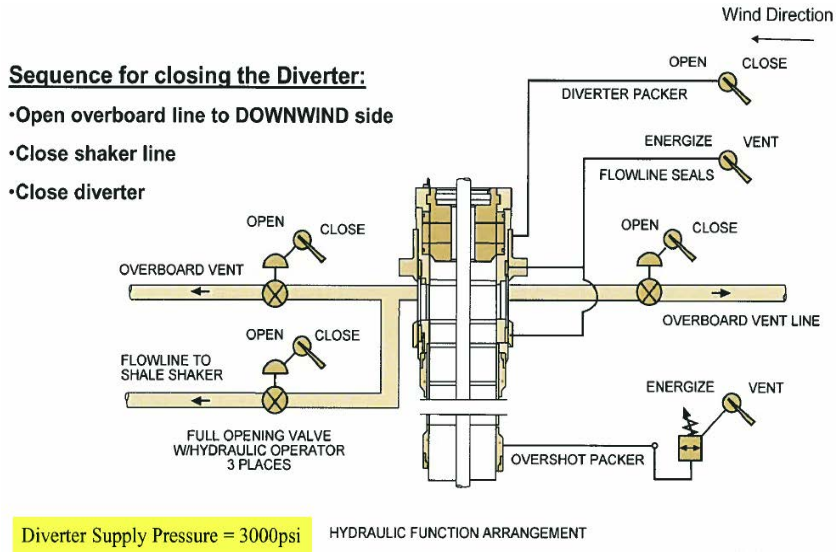
Sequence for Closing Diverter



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Rotating BOP

- Used to pack-off annulus and divert the gas flow,
- Maintains surface back pressure during under-balance drilling,

116

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Closing times for Diverters

Packing Element Nominal bore 20 in.(508 mm) or Less
30 seconds

Packing Element Nominal bore Greater Than 20 in.(508 mm):
45 seconds

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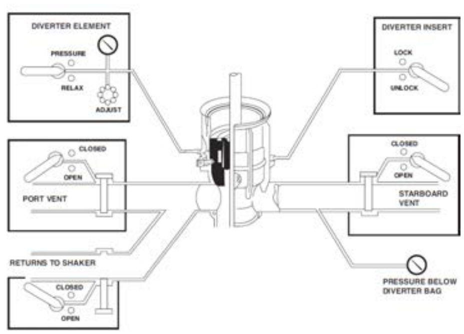


When using a diverter, which action should be taken first when shallow gas is encountered?

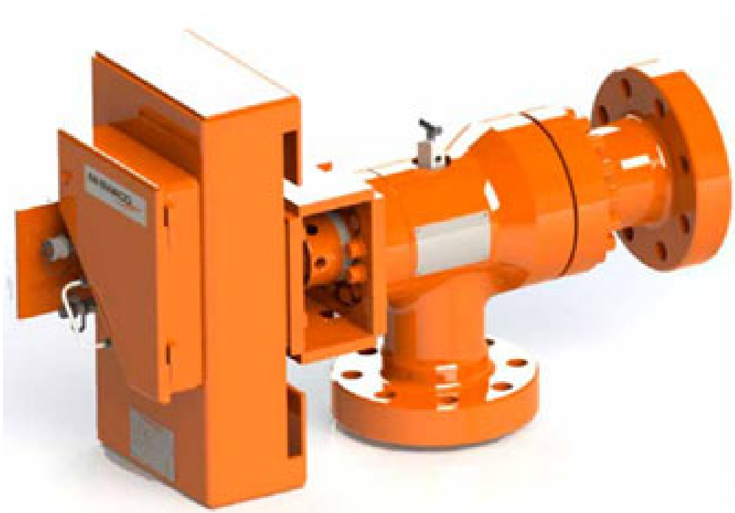
a. Open vent line valve
b. Close flow line valve
c. Close diverter element
d. Flow check

118

What are the main components of a diverter system? (Two Answers)

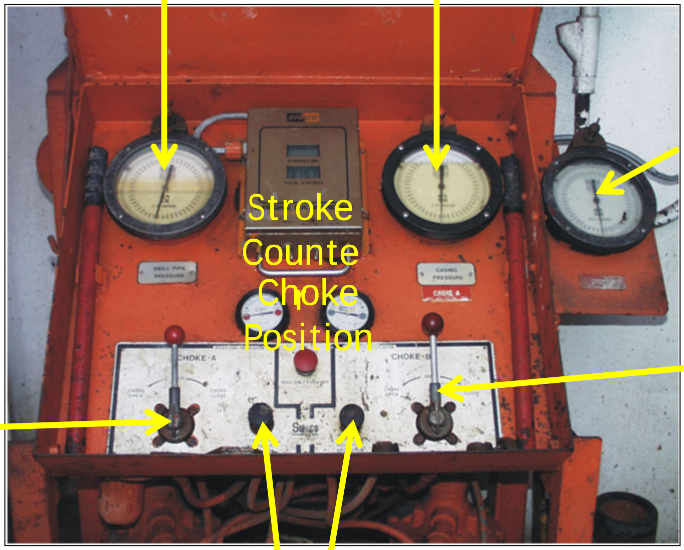
a. A vent line of sufficient diameter to permit safe diverting of wellbore fluids to the mud-gas separator
b. A vent line of sufficient diameter to permit safe diverting of wellbore fluids away from the rig for proper disposal
c. A vent line of sufficient diameter to permit sufficient backpressure to maintain BHP
d. A high-pressure annular preventer of sufficient rating to handle high-pressure, low volume shallow gas pockets
e. A low-pressure annular preventer with a large internal diameter

119



Swaco Super Choke

120



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Side Outlet Valves

- (API STD 53, 5.2.1.2) BOP or drilling spool outlet(s) connected to the choke or kill line shall have two fully opening valves. On the choke line, one of these two valves shall be remotely controlled (surface stack)
- Hydraulically-operated valve can be on the inside or outside.
- Regularly check and flush line between drilling spool and hydraulic valve

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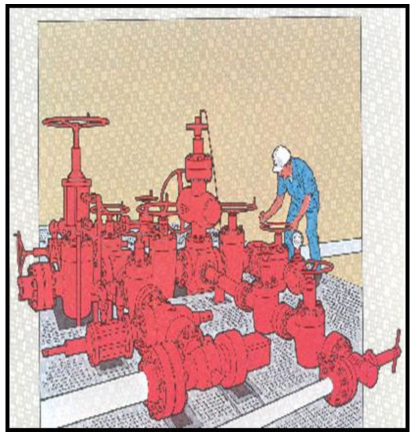
Choke Manifold

- Provide means of applying controlled back pressure to the well whilst circulating a kick
- Resist wear from abrasive well fluid



Choke Manifold

Choke/Kill Line:
A high pressure line that allows fluids to be pumped into or removed from the well with the BOPs closed.

Choke Line:
connects the BOP stack to the choke manifold to apply back pressure on formation when circulating out influx from the wellbore.

Kill Line:
It connects the mud pump to a side outlet of the BOP stack to provide a means o f pumping in to the wellbore when the normal method of circulating down through the drill pipe is not possible.

Choke/Kill Manifold

Choke:

A device with either a fixed or variable aperture used to control the rate of flow of liquids and/or gas and to apply back pressure to the annulus to allow controlled expansion of gas.

There are several types of Chokes.

- **Fixed**

Fixed chokes, such as a production choke are not suitable for well control as the orifice size cannot be adjusted quickly.

- **Adjustable:**

– Manual

– Remote Actuated

Most kill operations use remote adjustable choke.

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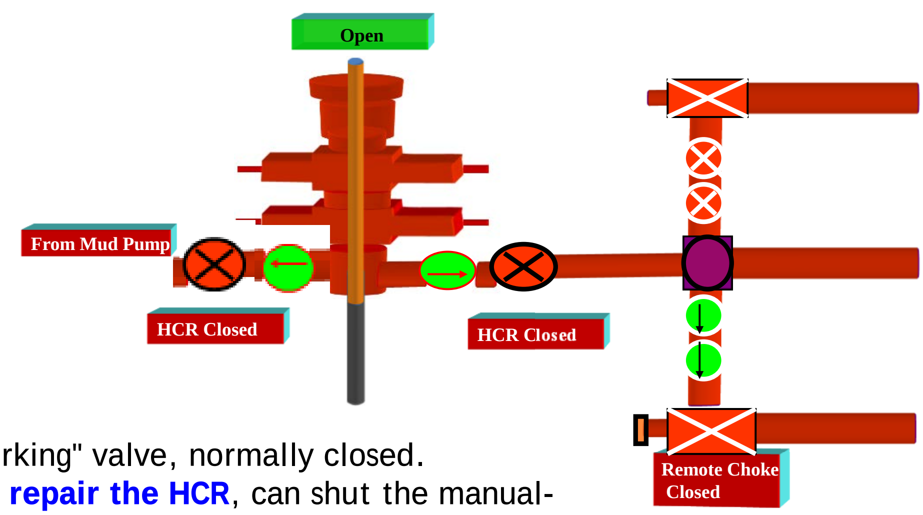
Side Outlet Valves



HCR is the "working" valve, normally closed. **If we want to repair the HCR**, can shut the manual-operated inner valve to isolate the BOPs

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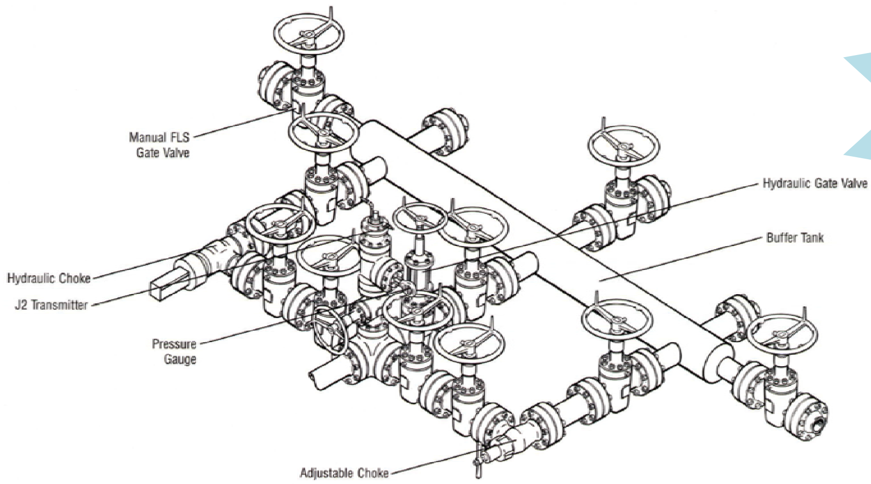
Choke Manifolds



Buffer Tanks Need Targets if no Flow Through

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Safety Valves

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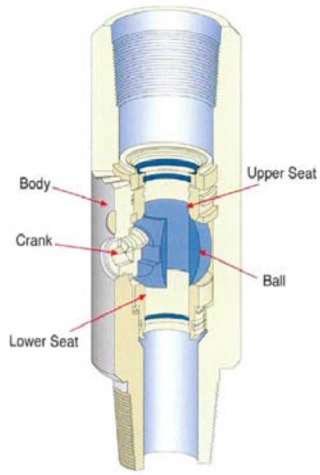
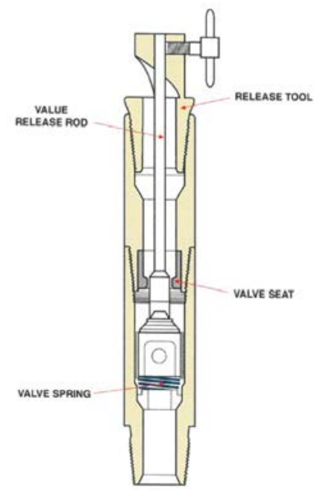
Safety Valve Equipment

Typical safety valves found at a rig are:

- FOSV (DPSV), with appropriate threads
- Inside BOP, with appropriate threads
- Upper and lower kelly valves
- Appropriate darts for size of dart sub
  - ✓If a landing sub has been installed
- Bit float either piston or flapper type
- Upper and lower kelly-mounted valves



Full Opening Safety Valve



Grey Inside BOP

On drilling rigs equipped with a Top Drive System (TDS), one of the kelly valves is to be remotely operable from the driller's position.

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DPSV(FOSV)

At the first sign of a kick while tripping:
- Install a DPSV (FOSV)
- Prevents flow up drillstring when closed
- *Close before closing BOP* (Requires key wrench)
- Allows kelly/topdrive to be safely attached

- The wrench is to be readily available.
- DPSV stored in the open position
  - ✓ In a warm place
  - ✓ Readily accessible

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IBOP

- Release tool allows the valve to be held open to permit stabbing against a backflow of fluid
- Installed above FOSV
- Used to prevent backflow in tubulars when stripping in

131

FOSV and Inside BOP

Function	FOSV	Inside BOP
a. Requires a key to close	√	
b. Pump open to read SIDPP		√
c. Easier to stab when back flow occurs	√	
d. Must not be run into the hole in the closed position	√	
e. Will not allow wire line tools to be run (through)		√
f. Has the potential to leak through the crank	√	

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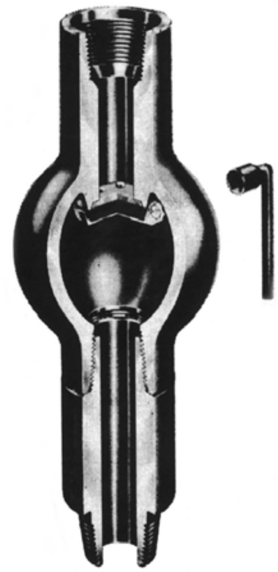
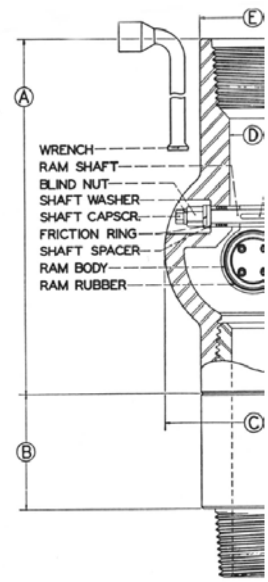
Upper Kelly Cock

- **The upper kelly cock protects the kelly hose, swivel and surface equipment from high well pressure.**
- **Closes with wrench and wrench must be kept on rig floor.**
- **May be remotely actuated in some systems.**
- **The upper kelly cock must be pressure tested to MASP (not RWP as previous API specs) when the stack is tested.**
- **LH threads to prevent unscrewing**





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Top Drive Valves

There are two ball valves on a top drive.

- The upper valve is air or hydraulically operated and controlled from the driller's console.
- The lower valve is usually a standard ball kelly valve (sometimes referred to as a *safety valve)* and manually operated with a hexagonal wrench.
- *May not be rated for the external pressure below the BOP*
  - ✓ *May have an OD greater than the drillpipe*

134

Top Drive Valves

- Remember, once the manual top drive valve is closed and disconnected, a crossover may be needed to install an IBOP
- Once the top drive's manual valve is disconnected from the top drive, another valve or spacer must be installed to take its place.

135

Lower Kelly Cock

- **The lower kelly cock allows removal of kelly with pressure in the string.**
- **It should not be used as a fluid or mud saver valve.**
- **It must seal on pressure and too much use can wear sealing elements.**
- **Galling of the lower kelly cock can occur from continual makeup and breakout.**
- **Closing wrench should be kept on rig floor at all times.**

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Upper Kelly Cock

The upper Kelly valve is installed to isolate the surface installation from well pressure. When should this valve be closed?

A. When connections are made, to save the spilling of drilling fluid.

B. In well control situations when the surface pressure may exceed the rated working pressure of the rotary Kelly hose and the stand pipe manifold.

C. Only when the swivel packing is being replaced.

D. Always when the rotary Kelly hose is being replaced.

B

137

Dart Sub

- Drop or pump down
- Cannot reverse circulate
- Can be retrieved with wireline

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✓

- Note:
  - The dart sub must be installed in the drillstring beforehand
  - The dart must be the correct size for the dart sub
  - The dart must be smaller than the smallest ID between surface and dart sub
  - Wireline cannot be run past dart without first retrieving

139

What is an Inside BOP?

A. A ball valve installed above the drill collars

B. A ball valve installed immediately above the bit sub

C. A device that can be installed in the drill string to act as a non-return valve

D. An element inserted into a ram type preventer to close on multiple pipe sizes

140

Bit Sub (Float Sub)

Drill pipe float valves, or non-return **valves**, are downhole safety **valves** that create barriers to prevent unwanted flow of fluids up the **drill string**. The **valve** locks down the flow of fluids while the crew at the rig floor is making or breaking connections.

141

Float Valves

The two types of float valves:

- **The flapper-type** float valve offers the advantage of having an opening through the valve that is approximately the same ID as that of the tool joint. This valve will permit the passage of balls.
- **The spring-loaded ball**, or dart and seat float valve offers the advantage of an instantaneous and positive shut-off of backflow through the drill string.

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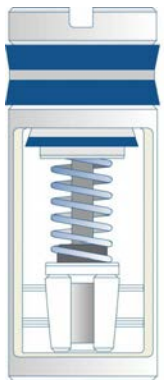
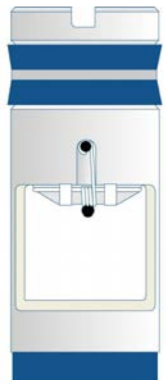
Advantages of Drillstring Float Valve



Spring

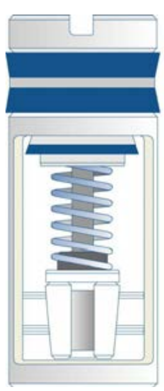


Flapper

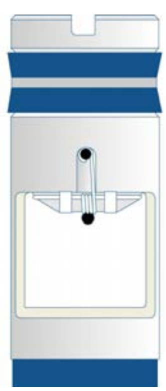
- No flow up the string while
  - *Tripping*
  - *Burst kelly hose*
  - *Blown pump pop valve*
- Less chance of plugging bit and mud motor on trips
- No backflow during a kick
- Allows a FOSV to be safely installed

143

Disadvantages of Drillstring Float Valve



Spring



Flapper

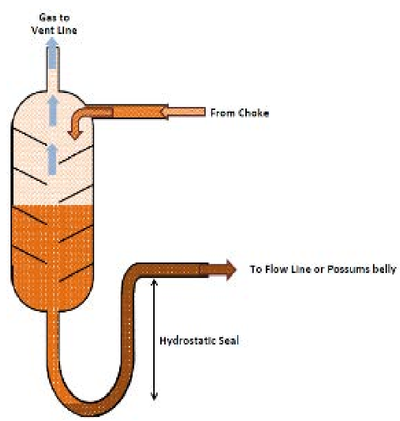
- Cannot directly read SIDPP
- Cannot reverse circulate
- Must stop to fill drill pipe on trips
- Greater surge pressure on trips and connections
- Flapper type can “hang open” on horizontal wells
- Spring loaded and ball types are not full bore
- Cannot bleed off trapped pressure below a bridge unless the float is ported
- Float valves are not tested barrier
- Increase RIH/POOH time, chance of swab and surge

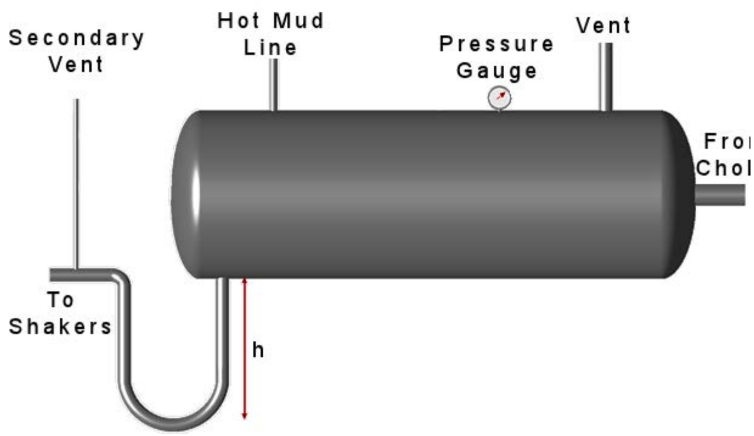
144

Mud Gas Separator

Purpose of Mud Gas Separator

- To remove the gas from the fluid returning from the well before the mud reaches the shale shaker and mud tanks
- Works well in fluid containing large bubbles of free gas





Two basic types:

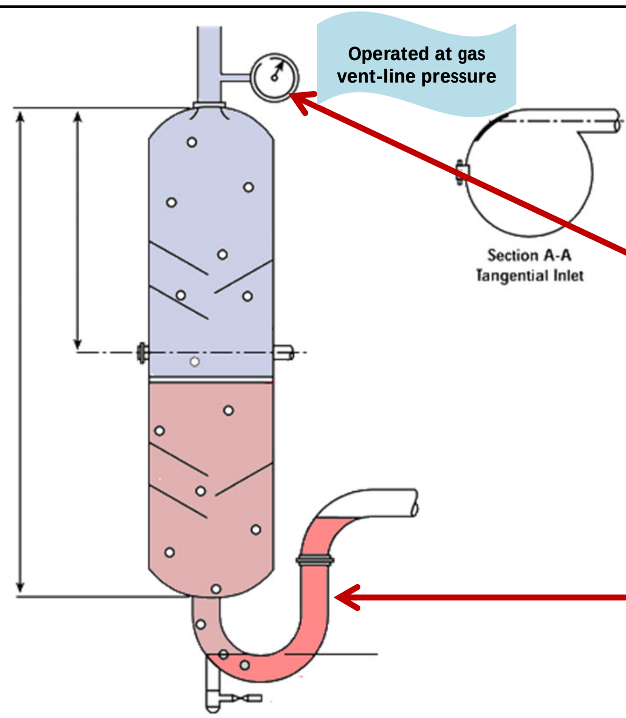
- Atmospheric type (Operating pressures less than 100 psi)
- Pressurized type

May be

- Vertical
- Horizontal

Types of Mud Gas Separators

147



Atmospheric Mud-Gas Separator

Backpressure is a function of:

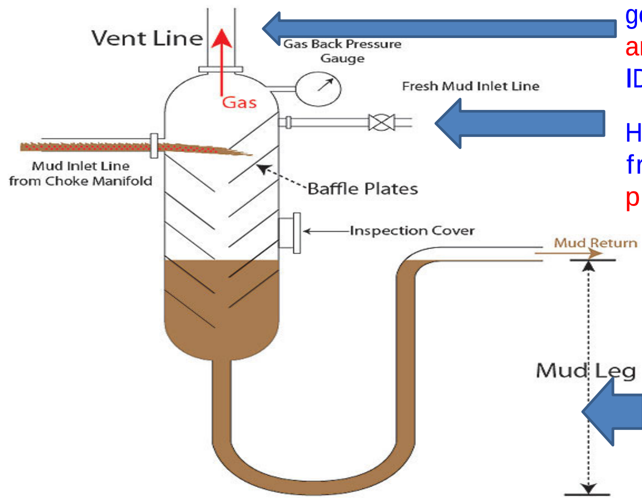
- **Outlet height**
- **Outlet length**
- **Outlet diameter**
- **Number of bends**
- **Rate of flow from choke**

The seal is a function of:

- **Discharge height**
- **Mud weight**

148

Mud-Gas Separator



Back Pressure of vessel is governed by the height and ID of vent line, Min 8" ID

Hot Loop is used to pump in fresh mud from Active mud pits to re-establish liquid seal

Height of Liquid seal x MW x0.052 denoted Max Op pressure of vessel.

Note: If back pressure exceeds Max Op pressure blow through will occur sending gas to shaker. Must shut down and re-establish liquid seal

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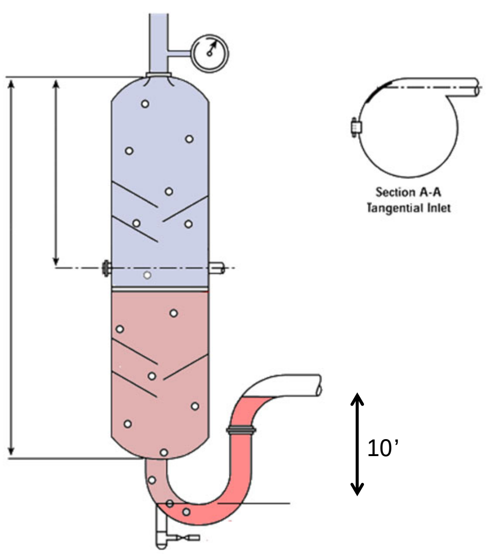
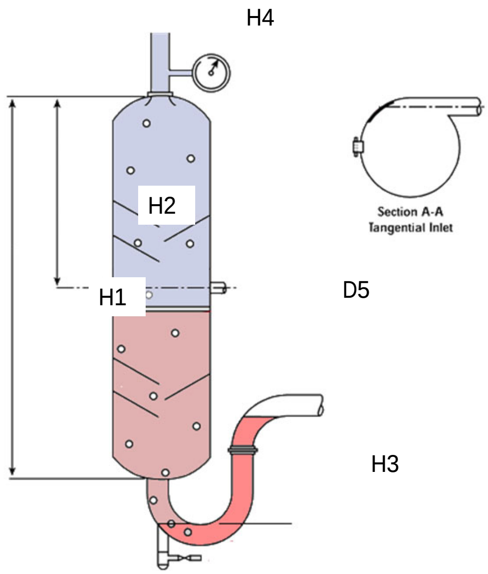


Calculate the amount of backpressure that this mud gas separator can have with 10.0 ppg mud before the seal is lost.

5.2 psi

150



In the illustrated mud-gas separator, identify the dimensions used to determine the maximum internal pressure before blow-through occurs.

A. H1 height of body
B. H2 height above inlet
C. H3 height of trap
D. H4 length of vent line
E. D5 Diameter of inlet

151

Why should the pressure build up in a poor boy degasser be of concern to the drilling personnel?

a. Pressure build up may cause gas to be blown up the derrick vent line
b. Pressure build up may cause an increase in BHP, resulting in lost circulation
c. Pressure build up may cause gas to congregate around the shale shaker and mud tanks
d. Pressure build up may cause back-pressure on the choke

152

Blow Through

Should the working pressure of the MGS be exceeded, it is possible for gas to breach the seal and end up around the mud shakers

- This is a dangerous situation

If a blow-through occurs, the driller must immediately:

1. Immediately start a controlled *shut in*
2. *Bleed down* pressure in the MGS, if required
3. *Re-establish the mud seal* in the MGS
4. Start up the pumps at a *slower rate* to reduce the back pressure

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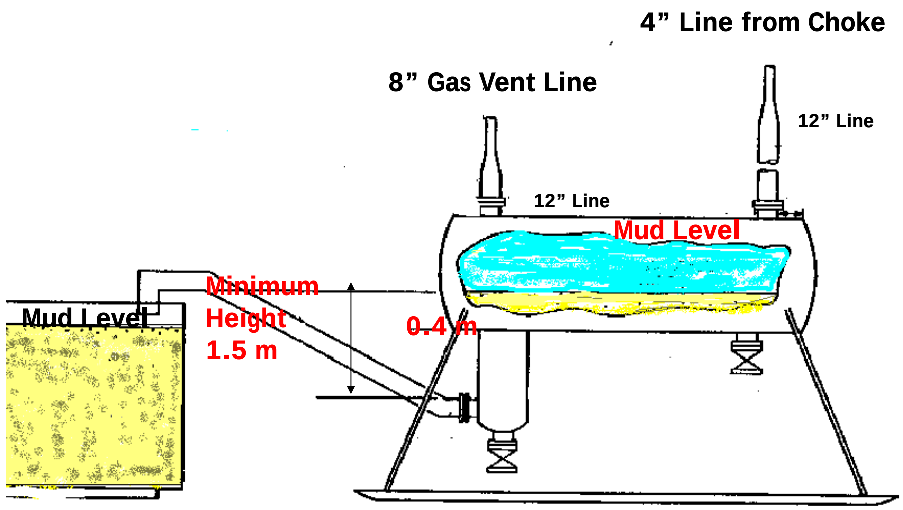
Horizontal Mud-Gas Separator



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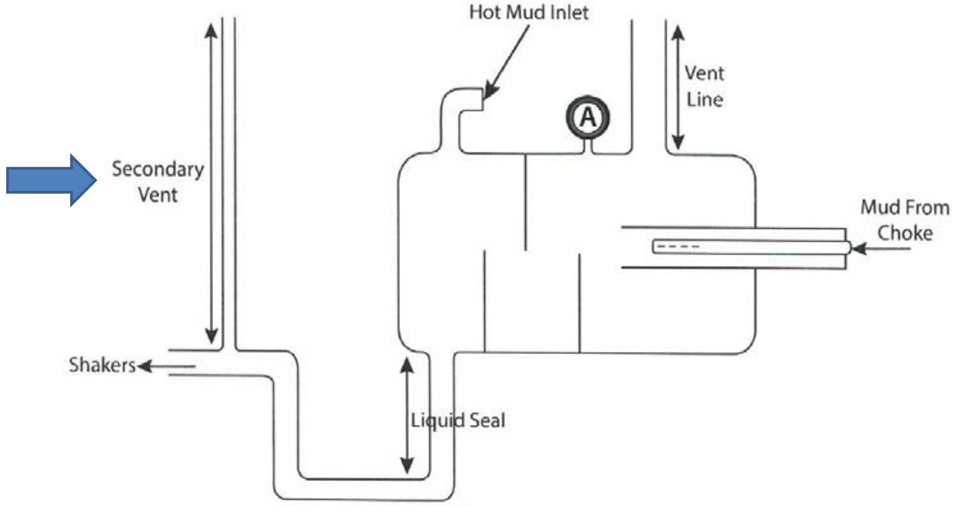
Horizontal Mud-Gas Separator with Secondary Vent



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Degassers

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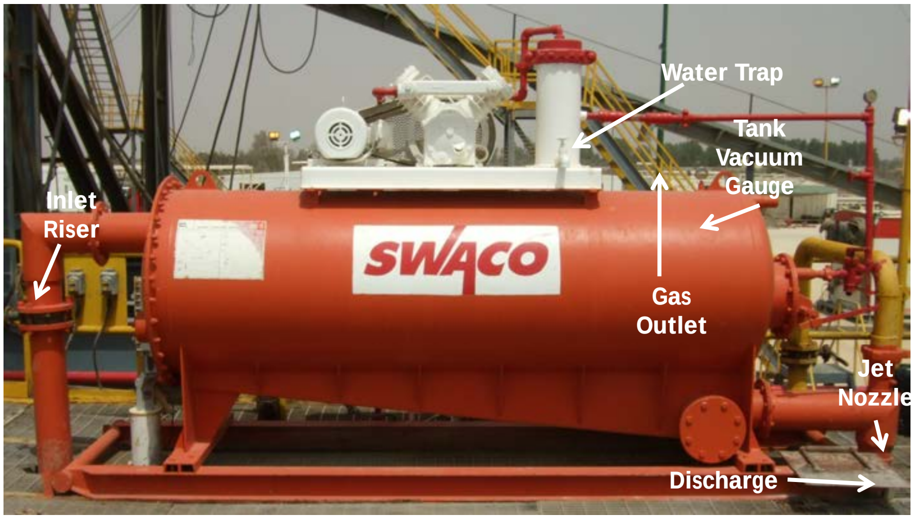
Vacuum Degasser



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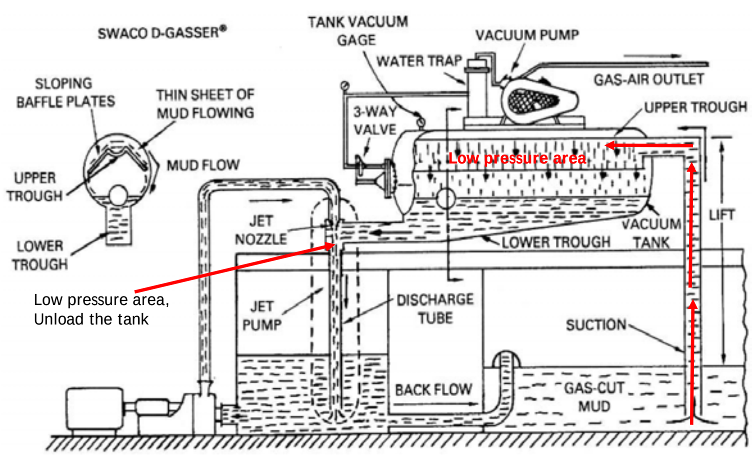
Principle of Vacuum Degasser Operation



A degasser is not designed to handle large volumes of gas. It is located downstream of the Mud Gas Separator

158

Vacuum Degasser

- Degassers are used to remove gases from the circulating fluids. Since thick fluids will NOT allow gas to break free, degassers separate the gas from the fluid using a vacuum chamber, a pressurized chamber, a centrifugal spray or a combination of these.
- Vacuum degassers are generally more effective when operating with heavy viscous muds and when it is difficult to extract the gas.
- As mud viscosity and gel strengths increase, so do degassing time and extraction energy requirements.

in-depth

Which is the primary use of a vacuum degasser?

A. It is only used in emergencies when the poor boy is overloaded

B. It is mostly used as a gas separator while underbalanced drilling

C. It is used mainly for Drill Stem Testing when accurate measurement of gas is required

D. It is used as standby equipment when the gas buster fails

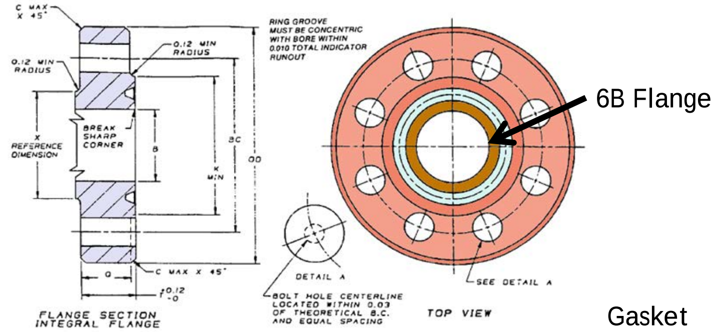
E. It is used mostly to remove gas from the mud while drilling

in-depth

BOP Flanges Ring Gaskets

161

Flange Specs API Spec 6A



Nominal Size

Gasket Number

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Basic Flange Dimensions								Bolting Dimensions						
Nominal Size and Bore of Flange	Maximum Bore *B*	Outside Diameter of Flange *OD*	Tolerance *OD*	Maximum Chamfer *C*	Diameter of Raised Face *K*	Total Thickness of Flange *T*	Basic Thickness of Flange *Q*	Diameter of Hub *X*	Diameter of Bolt Circle *BC*	Number of Bolts	Diameter of Bolts	Diameter of Bolt Holes	Bolt Hole Tolerance (See Note)	Length of Stud Bolts L_{ss}	Ring Number, *R* or *RX*
2 1/16	2.09	6.50	±0.06	0.12	4.25	1.31	1.00	3.31	5.00	8	5/8	0.75	+.06	4.50	23
2 9/16	2.59	7.50	±0.06	0.12	5.00	1.44	1.12	3.94	5.88	8	3/4	0.88	+.06	5.00	26
3 1/8	3.22	8.25	±0.06	0.12	5.75	1.56	1.25	4.62	6.62	8	3/4	0.88	+.06	5.25	31

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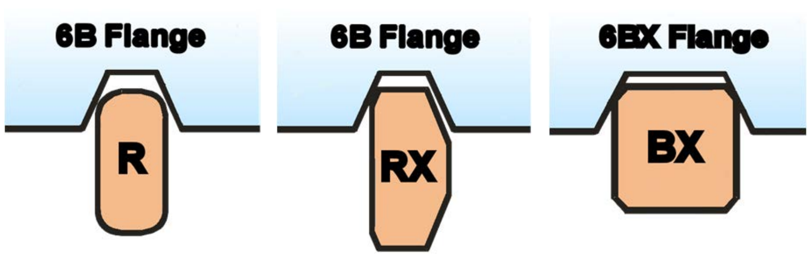
BOP Flanges and Ring Gaskets



API Spec 6A covers three types of ring gaskets for BOP stacks:

1. **R**
2. **RX**
3. **BX**

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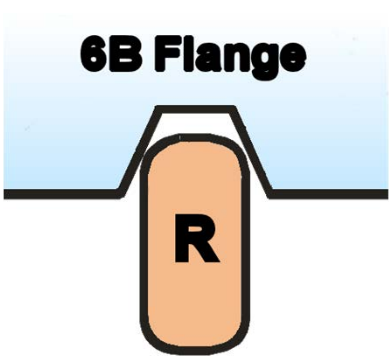
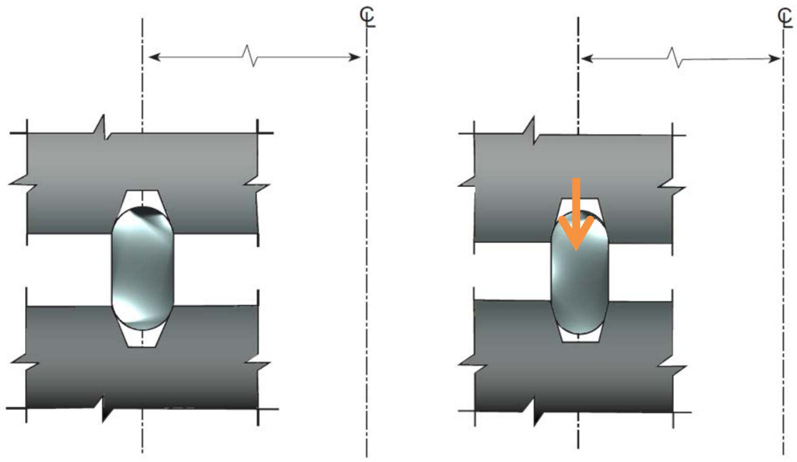
R Type Gaskets



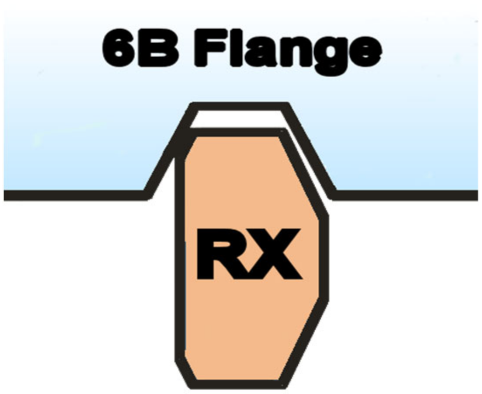
- Both R type gaskets can be used in both 6 and **6B** Flanges
- R gaskets are not pressure energized
- Since R type gaskets may require periodic tightening, they can only be used on flanged and studded connections

164

R Type Gasket Energized



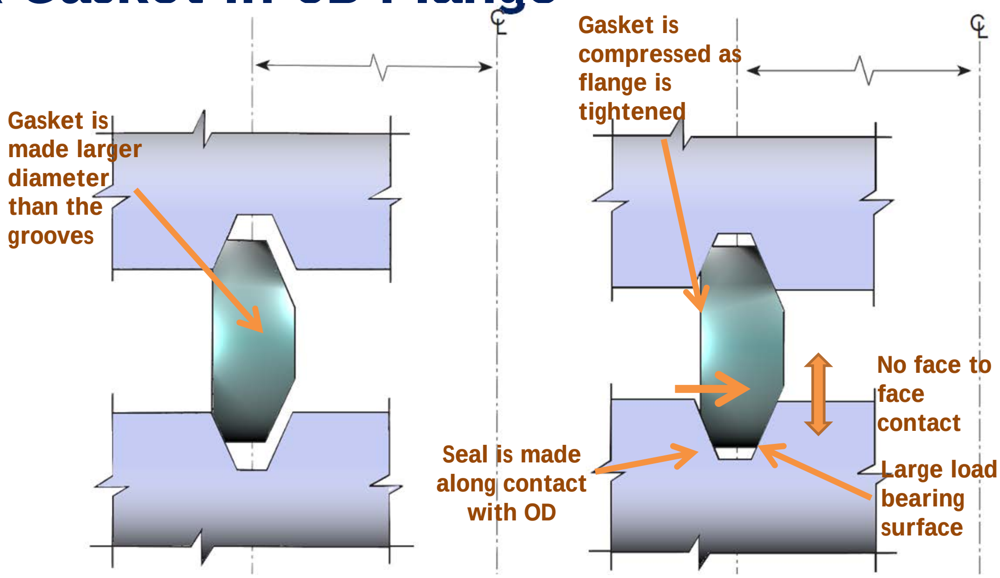
RX Gasket Rings



API RP 53 states:

RX gaskets are used with 6B flanges and 16B hubs

RX Gasket in 6B Flange



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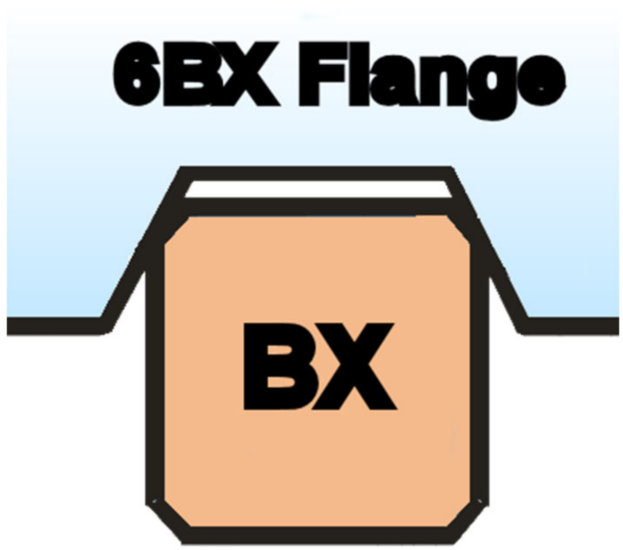
BX Gasket Rings



API RP 53 States:

BX gaskets are used with 6BX flanges and 16BX hubs

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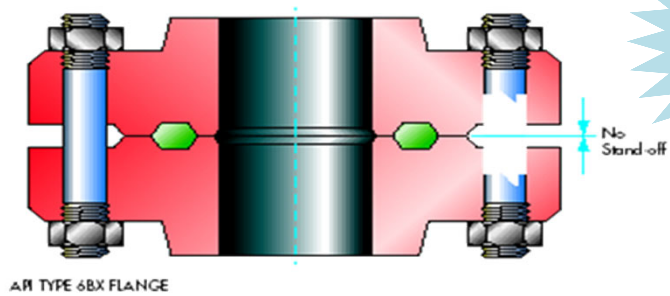
BX Gasket Rings



Face-to-face contact between flanges

Type RX and BX gaskets both provide a pressure-energized seal but are **NOT INTERCHANGABLE**.

169

Gaskets

Only pressure-energized ring gaskets shall be used on well control equipment.

- Metal ring gaskets shall not be reused unless specifically designed for that purpose.
- Ring gaskets should be used clean and dry. No grease should be applied to ring gaskets.
- Metal ring gaskets may be reused for pre-deployment testing
- All gaskets shall be of fire retardant/fire safe material.

170

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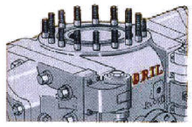
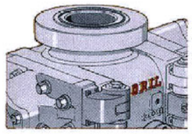
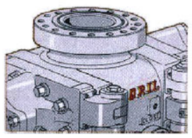
Studded, Clamped or Flanged



Studded Connection



Clamped or hub connection



API Flanged Connection

171

What does 16-3/4" mean when a BOP stack is described as 15K 16-3/4"?

A. The external diameter of the gasket

B. The internal diameter of the gasket

C. The through bore of the BOP

D. The external diameter of the flange

172

What should you do if you were asked to fit a 9” x 3,000 lb 6B flange to a 5,000 lb BOP stack?

A. You would derate the stack to 4,000 lb
B. You would point out a 3,000 lb flange would not fit a 5,000 lb stack
C. You would derate the stack to 3,000 lb
D. The stack rating would remain at 5,000 lb

173

X-Over

There is only one inside BOP with an NC50 (4-1/2 inch IF) pin/box connection on the rig. The drill string consists of:
5-inch drill pipe (NC50).
5-inch Heavy wall drill pipe (NC50).
8-inch drill collars (6-5/8 Reg.).
9-1/2 inch drill collars (7-5/8 Reg.)

Which of the following crossovers must be on the rig floor while tripping? **(TWO ANSWERS)**

- NC50 (4-1/2 inch IF) box x 6-5/8 inch Reg. pin.
- NC50 (4-1/2 inch IF) box x 7-5/8 inch Reg. pin.
- NC50 (4-1/2 inch IF) pin x 6-5/8 inch Reg. box.
- 6-5/8 inch Reg. Pin x 7-5/8 inch Reg. Pin.
- NC50 (4-1/2 inch IF) pin x 7-5/8 inch Reg. box.

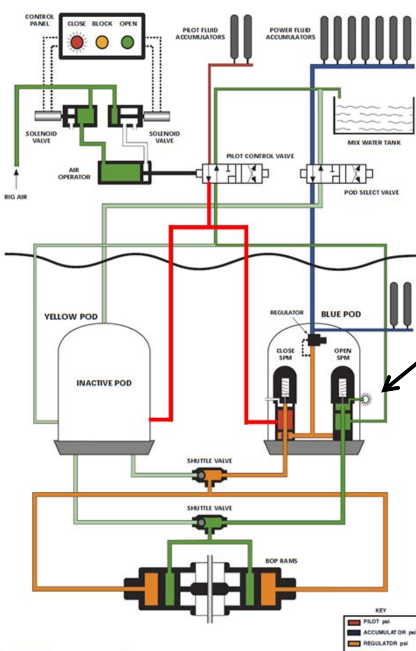
174

174

Subsea Equipment

- Hydraulic and MUX
- Systems

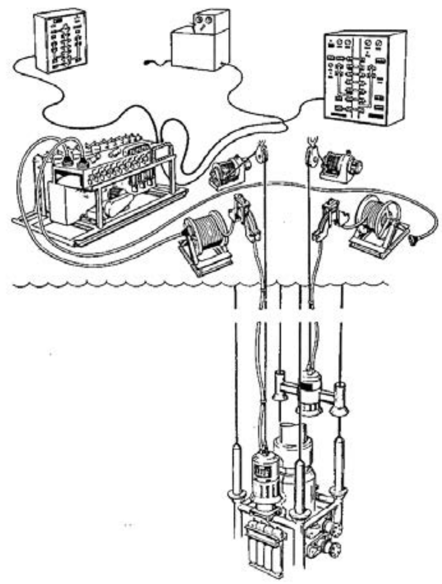
175



Vented fluid returns through whichever pod was last used

The shuttle valve remains in place until the next time opening control fluid is directed through the other pod

176



177

Hydraulic Power Unit (HPU)

Charges and stores the control fluid at surface under pressure

Control fluid is filtered as it flows subsea

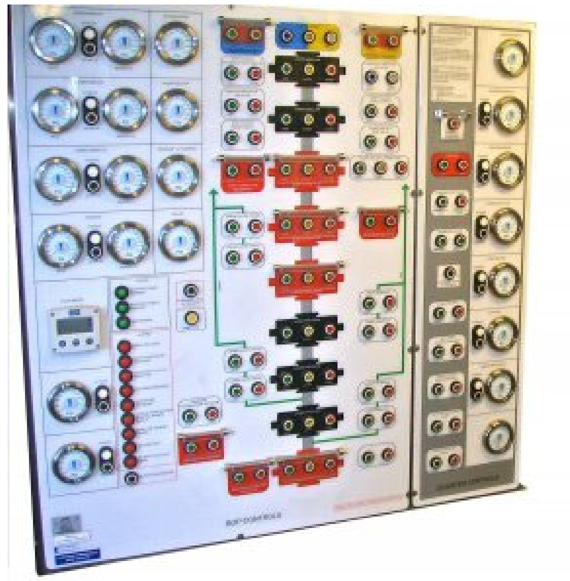
Remote panel sends an electric signal to an electric control box on the HPU

Electric solenoid valve sends rig air to the operating cylinders to shift manipulation valves

178

Subsea Driller's Panel

- Sends signal to HPU to direct rig air to the manipulator valve operating cylinders
- Driller can regulate both annular and manifold pressure in each pod
- Feedback pressure gauges
- Push to activate buttons



179

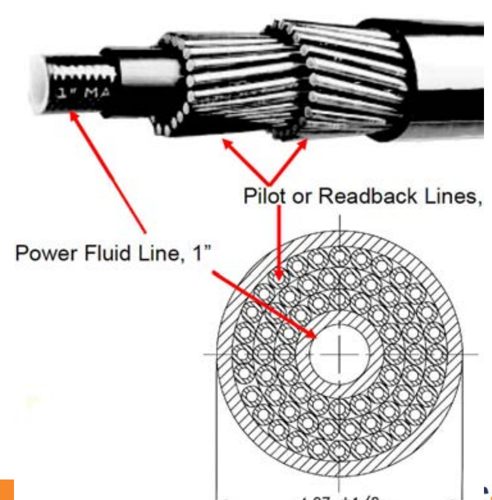
Hydraulic Umbilical Cord

Provide the main supply of power fluid and pilot signals to the subsea control pods

Bundle typically consists of a 1" ID line for control fluid and up to 64 X ¼" to ⅜" ID pilot or read back fluid lines

Low volumetric expansion material to reduce the response times

Subsea bottles compensate for substantial pressure drop in the supply line



180

Hose Reels

- Stores the hose bundle
- Motor driven with brake
- Jumper hose is disconnected when running BOP
- Selected functions can be performed live

181

BOP Pod

An assembly of subsea valves and regulators which when activated from the surface will direct hydraulic fluid through special porting to operate BOP equipment. (API)

Two control pods that each contain pressure regulators and SPM valves

Each pod contains an annular and manifold regulator

SPM valves are downstream of regulators and are connected to the shuttle valves

Pods may be retrievable, either individually or with the LMRP

182

Riser Collapse

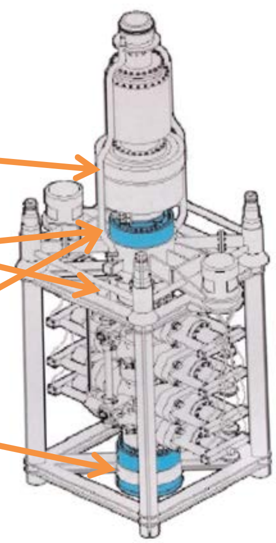
The potential exists in deep water for the riser to collapse from:

- Gas unloading of the riser
- Drive off
- Lost circulation
- Accidental disconnect

183

Contrasting Surface with Subsea Stacks

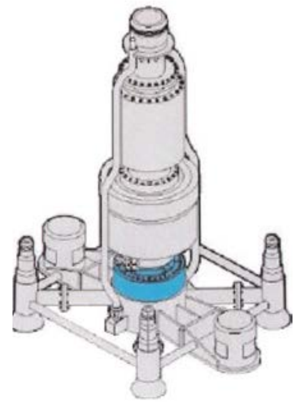
- Two annular preventers
  - ✓ One on LMRP
  - ✓ One on stack
- Two hydraulic connectors
  - ✓ LMRP
  - ✓ Wellhead
- Upper annular rating is limited to rating of the LMRP connector



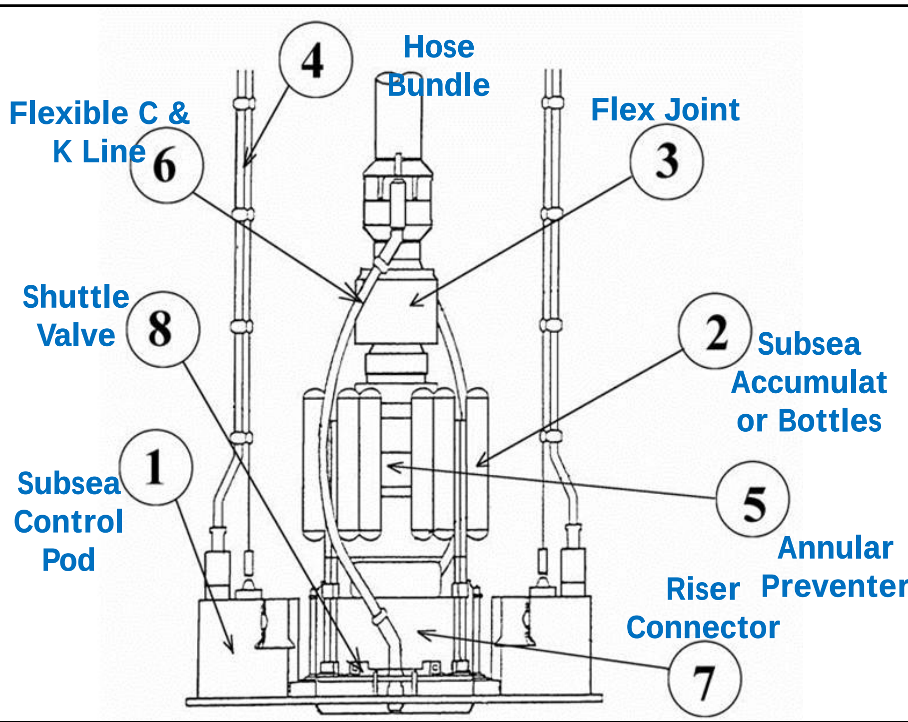
184

LMRP: Lower Marine Riser Package

- Top annular
- LMRP connector
- Flex/ball joint
- Choke and Kill flexible hoses
- Choke and Kill hard piping



185



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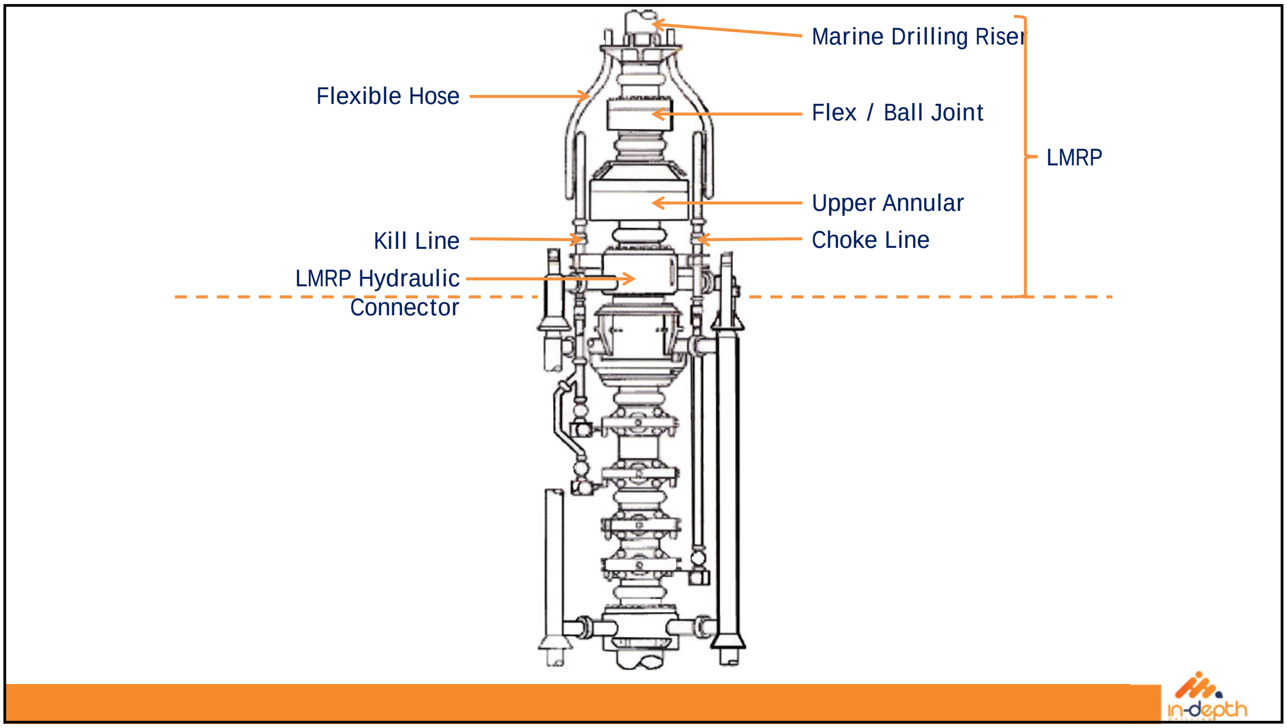
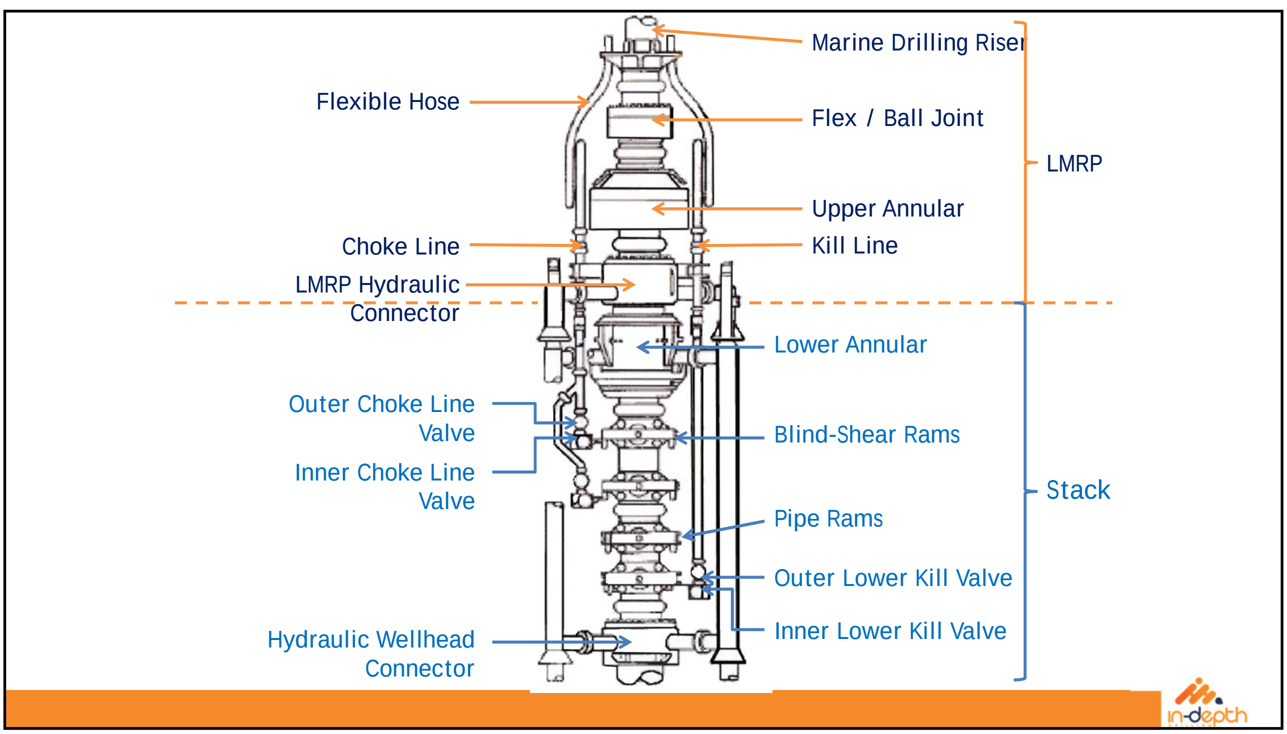


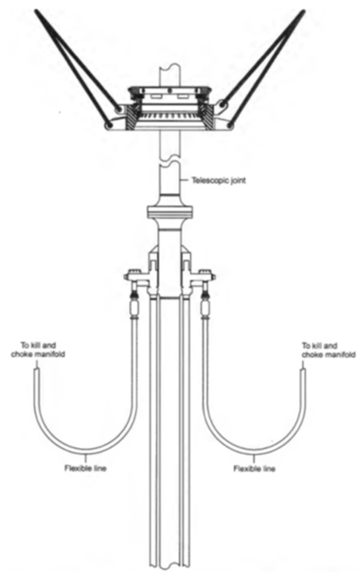
Marine Drilling Riser
Flexible Hose
Flex / Ball Joint
LMRP
Upper Annular
Kill Line
Choke Line
LMRP Hydraulic Connector
in-depth

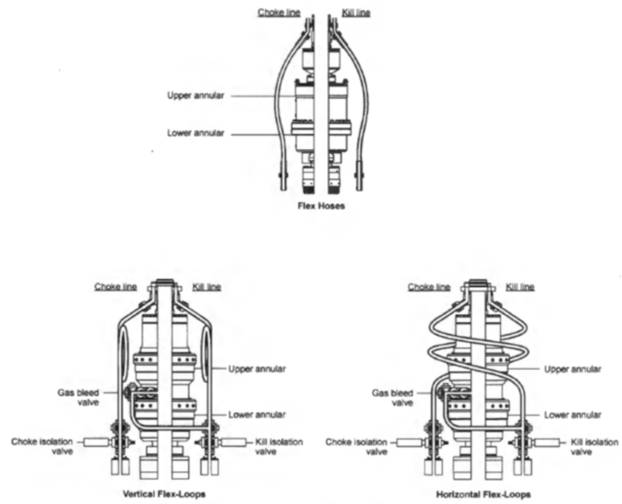
187



Marine Drilling Riser
Flexible Hose
Flex / Ball Joint
LMRP
Upper Annular
Choke Line
Kill Line
LMRP Hydraulic Connector
Lower Annular
Outer Choke Line Valve
Blind-Shear Rams
Inner Choke Line Valve
Stack
Pipe Rams
Outer Lower Kill Valve
Inner Lower Kill Valve
Hydraulic Wellhead Connector
in-depth

188





189

Choke and Kill Line Flexible Hoses

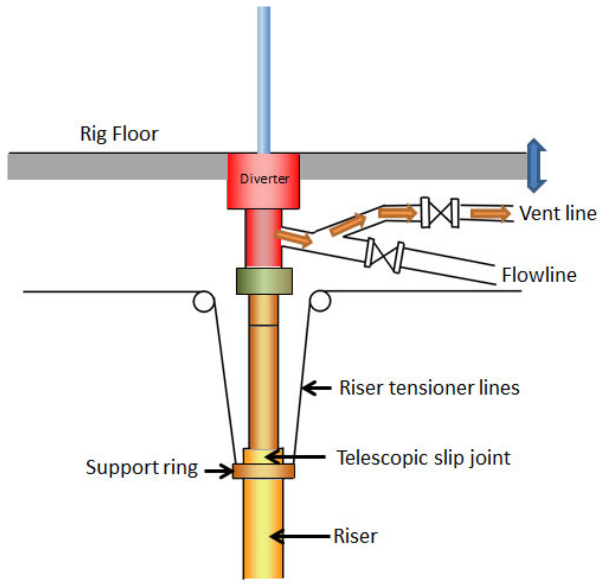
Connect the choke and kill lines to the choke manifold

Typically 60 ft to 90 ft long to allow for the slip joint stroke

High-pressure hoses or steel flex loops on the LMRP are used as jumper hoses to connect the choke and kill lines on the stack to the riser

190

Diverter



191

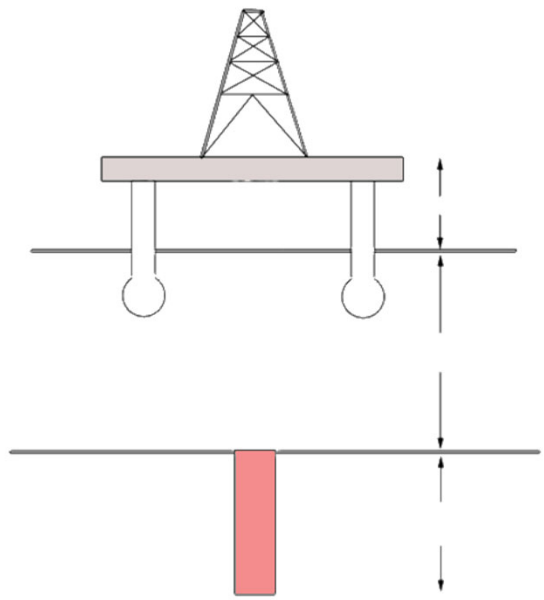
Why are some accumulator bottles placed subsea?

a. To compensate the control fluid pressure for subsea hydrostatic pressure

b. To reduce the response time for BOP functions

192

Risers and Riserless Drilling



193

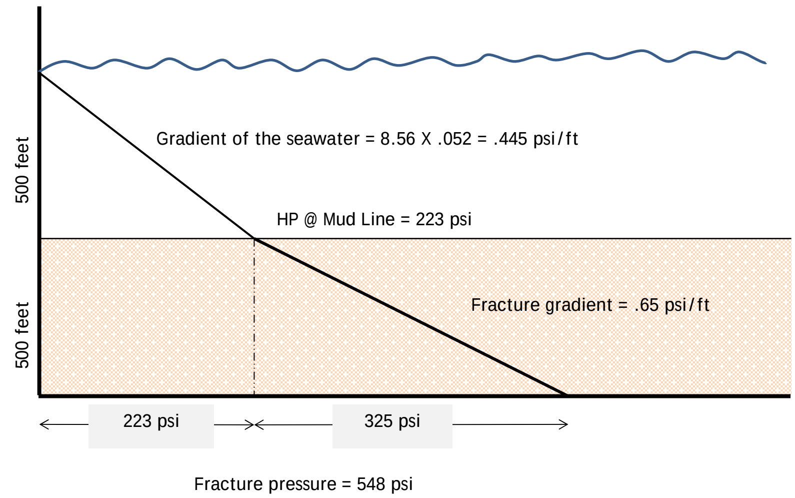
Reduced Fracture Gradients

In deep water, pore pressure and fracture gradients are much closer to each other. This means:

- Increased risk of lost returns
- Increased risk of a well kicking
- Need for lower mud weights and safety margins
- Higher likelihood of ballooning formations
- Increased need for vigilant well monitoring
- Need for more casing strings

194

Subsea Fracture Gradient



195

Drilling Top Hole Without Riser

Advantages:

- Better hole cleaning
- Enables rig to move off quickly
- Reduces risk of lost circulation
- Avoids risk of riser collapse
- Maintains seawater hydrostatic
- No gas directly to the rig

196

Drilling Top Hole Without Riser

Disadvantages:

- Harder to detect a kick/losses
  - ✓Usually by pump pressure, ROV, or gas to surface in shallow water
- No returns to surface
  - ✓Unless mud recovery system is used
- Large contingency mud volumes required
- Limited hydrostatic pressure
  - ✓Limited to hydrostatic of seawater plus mud in the hole

197

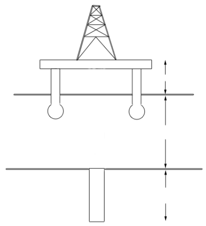
Riser Margin

- The fluid in the wellbore may not be sufficient to prevent flow should the riser become disconnected

  ✓One option is to maintain a drilling fluid density that will provide an overbalance with the marine riser disconnected.

198

A rig is drilling with a riser and needs to disconnect. Calculate the minimum mud weight to balance the well



Well Data:

Air gap:	80 feet
Water Depth:	1465 feet
Well Depth:	2250 feet (TVD)
Mud weight to balance while drilling:	9.5 ppg
Seawater density:	8.5 ppg

$$\frac{[Air\ gap\ (ft) + Water\ Depth\ (ft)] \times MW\ (ppg) - [Water\ Depth\ (ft) \times\ Seawater\ Weight\ (ppg)]}{TVD\ (ft) - Air\ Gap\ (ft) - Water\ Depth\ (ft)}$$

$$\frac{[80\ (ft) + 1465\ (ft)] \times 9.5\ (ppg) - [1465\ (ft) \times 8.5\ (ppg)]}{2250\ (ft) - 80\ (ft) - 1465\ (ft)}$$

$$\frac{14677.5 - 12452.5}{705} = \frac{2225}{705} = 3.15\ ppg$$

Therefore the $\text{MW reqd} = 3.15 + 9.5 = 12.65\ ppg = \underline{12.7}\ ppg$

12.7 X .052 X 705 = 465.58
8.5 X .052 X 1465 = 647.53 +
1113
psi

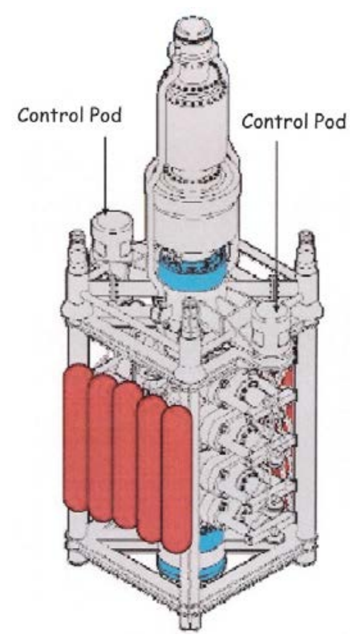
199

Subsea Bottles

Reduce the response time to perform BOP functions

Control fluid is initially supplied from the subsea bottles and supplemented from the surface

Higher pressures than on surface



200