ROTARY DRILLING WELL CONTROL
Foreword

Norwegian Petroleum Technology Centre AS (NPS) is a part of the OilComp group. In 2012 the OilComp group was certified to ISO 9001:2008 by Bureau Veritas to ensure that the customer receives predictable training at high quality. NPS was pre accredited as an approved IWCF center in September 2011, with a formal IWCF certification autumn 2012. Certification is valid for 5 years before renewal takes place.

This textbook, which also has been submitted to you as an e-book, will help you prepare for the theory and exercises covered in the IWCF course, which you also will be examined against. The exercises that emphasize the different topics in the text book are organized in a separate workbook. The theory and the exercises will be presented during the course. You will also be given the opportunity to ask questions related to the various topics.

Both the textbook and workbook are based on the IWCF certification requirements for either floating drilling operations (Subsea BOP) or operation at fixed installations (Surface). Surface candidates will find some topics in the text book that are not relevant to the IWCF exams.

The four day course consists of theory, exercises and training on a drilling simulator. All candidates will execute a practical assessment on a drilling simulator (assessed by an IWCF approved assessor) and theoretical exams the fifth day. The exams will be related to your position and duties (Surface or Subsea / Supervisor or Driller).

We would also recommend our e-learning module, where you will find additional exercises (with online responses / multiple choices). It is expected that all IWCF certification candidates have prepared before attending the course. We hope the text- and workbook will be of use before, during and after the course. We realize that it will always be necessary to improve our material, and would welcome your suggestions for improvements, and look forward to your participation in the course.

Important information:
All participants must bring their passport for displaying ID. The passport must be valid for 2 years from the date the course starts. Alternatively you can bring your driver's license.
Include a copy of a valid IWCF Certificate (only those who are certified from before) for registration the first day of class.
It is not possible to use programmable calculator during the exam.

Gunnar Knudsen      Ann Veronica Brekke
Managing Director      Training Manager
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CHAPTER 1 – IWCF SIMULATOR TEST

01. Simulator equipment.

For simulator certification NPS is utilising equipment manufactured by CS Inc. Albuquerque N.M. USA. The company manufacture all the hardware and develops all the software for the following types of simulators:

1. Full Scale Rig Floor Simulator.
2. Super Portable Simulator
3. Ultra-Light Simulator
5. Computer Rig floor Simulator (CRS)

In January 2001 the Ultra-Light Simulator was approved by IWCF for certification testing. As a consequence NPS has not invested in the Full Scale Rig Floor Simulator or the Super Portable Simulator but are conducting all certification tests on the Ultra-Light Simulator.

The Computer Rig floor Simulator (CRS) is a 100% PC-based well control simulator used for training purposes.

02. Simulator test description

The practical test on the simulator is performed by two persons, a driller and a supervisor. In addition to the participants an IWCF approved assessor might be present to evaluate the performance of the assessor during the test.

The test consist of drilling on a fixed or a semi submergible drilling installation, closing in the well due to an influx and circulate out the influx / kick with either the Drillers method or the Wait & Weight method.

The simulator test with the Drillers method and the Wait & Weight method is terminated when the influx has been circulated out and the well is closed in.

During the test one (or two) of the following failure problems will occur;

1. BOP failure when closing the well................................. To be solved by the Driller
2. Recognition of a non-return valve in the drill string and/or Determination of the shut in drill pipe pressure (SIDPP).... To be solved by the Supervisor
3. Total pump failure......................................................To be solved by both
4. A bit nozzle plugs up. ............................................. To be solved by both
5. The choke washes out. .......................................... To be solved by both
6. The choke plugs up. .............................................. To be solved by both
Both the Driller and the Supervisor can fail the test according to the following:

1. The Driller fails the test if he fails to shut in the well or shuts in the well with the pumps running.

2. The Supervisor fails the test if he is unable to prepare a usable kill sheet within 15 min. from collecting the kick data. I.e. Construct a kill graph and calculate accurate ICP, FCP and kill mud density in order to adequately balance the pore pressure, taking into consideration necessary safety margins.
   On request an additional 5 min may be granted to correct possible errors.

3. The Supervisor fails the test if he operates the choke such that the formation breaks down.

4. The Supervisor fails the test if the accumulative additional influx volume taken during the kill operation exceeds 8 bbl.

The assessor will continuously evaluate the performance of the participants as the test progresses and will give marks in accordance with the IWCF - Exercise Grading Sheet.

Further details on the simulator test on a surface well follows below and the details on the simulator test on a subsea well are given in section 04.
03. Simulator surface well data.

Capacities:

- **5" DP**
  - Pump cap. 19,0 l/STR
  - 9 5/8” (47 lbs/ft)
  - 5" DP (19,5 lbs/ft) 1517 m.
  - 1500m MD & TVD
  - LOT: 1,80 sg.
  - 8 1/2" hole
  - 6 1/4" DC 2 1/2" id 183 m.
  - 1700 MD & TVD

- **6 ¼" DC**
- **8 1/2" x 6 1/4"** annulus 6,18 l/m
- **8 1/2" x 5"** annulus 23, 3 l/m
- **9 5/8" x 5"** annulus 24, 9 l/m
- **3" choke line** 4, 56 l/m
04. Test sequence of operation

04.01. The Drillers sequence of operation

1. Prepare drill floor.
   - Line up standpipe manifold, choke manifold and BOP panel including accumulator gauges.
   - Set remote and manually operated chokes as agreed with Supervisor.

2. Start circulating and prepare to drill
   - Record kill rate circulating pressures as requested or agreed with Supervisor.
   - Set flow indicator and Pit Level Totalizer (PVT) alarms.

3. Drill ahead
   - Recognise drilling break and take correct action.

4. Detect kick
   - Follow correct procedure before shutting in well.
   - Shut in well and inform Supervisor immediately.


6. Collect data.
   - Record pressure readings and pit gain.
   - Maintain constant BHP, monitor surface pressures and report to Supervisor

7. Start circulating (Establish circulation correct).
   - Line up circulation system and establish circulation in co-ordinate with Supervisor.


12. Circulate.
   - Maintain kill pump rate, record pressures and pit level in co-operation with Supervisor.

13A. Circulate out kick with Drillers method.
   - Stop pumping and shut in well in co-operation with Supervisor.

13B. Circulate kill mud to bit with Wait & Weigh method.
   - Stop pumping and shut in well in co-operation with Supervisor.
04.02 The Supervisor sequence of operation

1. Supervisor not on the drill floor while Driller lines up equipment on drill floor.
   
   Check drill floor set-up when Driller has finished lining up equipment on drill floor.
   - Standpipe and choke manifolds, BOP valve positions and accumulator gauges.
   - Instruct Driller on action in case of drilling break or influx and shut in procedure.

2. Instruct Driller on how to record slow circulating rates pressures (SCRp)
   - Check alarm settings and agree on drilling parameters.

3. Supervisor not on the drill floor.

4. Supervisor not on the drill floor but informed by Driller.

5. Supervisor not on the drill floor but informed by Driller or called on to assist Driller.

6. Collect essential kick data
   - Recognise presence of a non-return valve in drill string and/or obtain correct SIDPP.
   - Complete the kill sheet and instruct Driller to monitor shut in pressures.
   - Co-ordinate with Driller the kill method, start-up procedure, pump monitoring, pit gain and pump pressure recordings and resetting of pump stroke counters.

7. Start circulating (Establish circulation correct).
   - Agree on and establish circulation according to correct procedure.


12. Circulate and follow kill procedure
    - Maintain bottomhole pressure greater than the pore pressure as dictated by killing method.

13. Circulate out kick with Drillers method.
    - Stop pumping and shut in well in co-operation with Driller. Evaluate shut in pressures.

    - Stop pumping and shut in well in co-operation with Driller. Evaluate shut in pressures.
05. Simulator subsea well data.

Capacities:

- 5" DP: 8,97 l/m
- 6 ¼" DC: 3,167 l/m
- 8 1/2" x 6 1/4" annulus: 6,18 l/m
- 8 1/2" x 5" annulus: 23,3 l/m
- 3" choke line: 4,56 l/m
- Riser: 202 l/m
- 9 5/8" x 5" annulus: 24,9 l/m
- 5" DP closed end capacity: 13,5 l/m
06. Test sequence of operation.

06.01 The Drillers sequence of operation

1. Prepare drill floor.
   - Line up standpipe manifold, choke manifold and BOP panel including accumulator gauges.
   - Set remote and manually operated chokes as agreed with Supervisor.

2. Start circulating and prepare to drill
   - Record kill rate circulating pressures and choke line frictions as agreed with Supervisor.
   - Set flow indicator and Pit Level Totalizer (PVT) alarms.

3. Drill ahead
   - Recognise drilling break and take correct action.

4. Detect kick
   - Follow correct procedure before shutting in well.
   - Shut in well and inform Supervisor immediately.


6. Collect data.
   - Record pressure readings and pit gain.
   - Maintain constant BHP, monitor surface pressures and report to Supervisor.

7. Start circulating (Establish circulation correct).
   - Line up circulation system and establish circulation in co-ordinate with Supervisor.


12. Circulate.
    - Maintain kill pump rate, record pressures and pit level in co-operation with Supervisor.

13. Circulate out kick
    - Stop pumping and shut in well in co-operation with Supervisor.
06.02. The Supervisor sequence of operation

1. Supervisor not on the drill floor while Driller lines up equipment on drill floor.
   Check drill floor set-up when Driller has finished lining up equipment on drill floor.
   - Standpipe and choke manifolds, BOP valve positions and accumulator gauges.
   - Instruct Driller on action in case of drilling break or influx, shut in and hang off procedures.

2. Instruct Driller on how to record slow circulating rates pressures and choke line friction.
   - Check alarm settings and agree on drilling parameters.

3. Supervisor not on the drill floor.

4. Supervisor not on the drill floor but informed by Driller.

5. Supervisor not on the drill floor but informed by Driller or called on to assist Driller.

6. Collect essential kick data
   - Recognise presence of a non-return valve in drill string and/or obtain correct SIDPP.
   - Complete a usable kill sheet within 15 min and instruct Driller to monitor shut in pressures.
   - Co-ordinate with Driller the kill method, start-up procedure, pump monitoring, pit gain and pump pressure recordings and resetting of pump stroke counters.

7. Start circulating (Establish circulation correct).
   - Agree on and establish circulation according to correct procedure.


12. Circulate and follow kill procedure
    - Maintain bottomhole pressure greater than the pore pressure as dictated by killing method.

13. Circulate out kick
    - Stop pumping and shut in well in co-operation with Driller. Evaluate shut in pressures and possible additional influx volume.
07. IWCF grading sheets and kill sheets.

In the simulator assessment room you will find examples of IWCF grading sheets used by the sensor for point-and grading during the role play and simulator test. There is one set of grading sheet for surface, and one for subsea installations.

The work descriptions listed in the grading sheets, under "Driller" and "Supervisor" should roughly be the same as the tasks provided as a concentrated short version in section 04 - Role play.

Kill sheets are available at the official IWCF web page, www.iwcf.org (Useful stuff)

- Surface BOP Kill Sheet - Vertical Well
- Surface BOP Kill Sheet - Deviated Well
- Subsea BOP Kill Sheet - Vertical Well
- Subsea BOP Kill Sheet - Deviated Well
CHAPTER 2 – THEORY AND PROCEDURES

The content of chapter 2 and the next Chapter 3 "Practical Well Control Operations" equals IWCF’s “Principle and Procedures". Combined with the exercises in the Workbook, the given information should cover the necessary knowledge in order to pass the IWCF test paper in Principle & Procedures with success.

01. Explanation to the abbreviations used in this book

- **SIDPP** (Shut in Drill pipe pressure)
- **SICP** (Shut in casing pressure)
- **ICP** (Initial circulating pressure)
- **FCP** (Final circulating pressure)
- **KMW** (Kill mud weight)
- **OMW** (Original mud weight)
- **ICCP** (Initial circulating casing pressure)
- **CCP** (Circulating casing pressure)
- **CL_F** (Choke line friction)
- **SCRp** (Slow circulating rate pressure)
- **SPM** (stroke per minute)
02. Abnormal formation pressure

In order to understand the meaning of abnormal pressure it is necessary to know what a normal pressure is. There are several alternatives to defining normal pressure, but here we have chosen to demonstrate it with the following example;

If we want to calculate the normal pressure in a formation at 1000 m TVD we use the formula:

\[ \text{Hydrostatic pressure (bar)} = \text{True Vertical Depth (m)} \times \text{Drilling Fluid Density (sg)} \times 0.0981 \]

In our example this will give;

Normal pressure at 1000 m TVD = \( 1000 \times 1.03 \times 0.0981 = 101 \text{ bar} \)

when using fluid density or:

Normal pressure at 1000 m TVD = \( 1000 \times 1.01 = 101 \text{ bar} \)

when using pressure gradient.

In order to remember the relationship between the normal fluid density and the normal pressure gradient we can see from above that;

\[ \text{Normal pressure gradient} = \text{normal fluid density} \times 0.0981 \]

Abnormal pressures in an area are mainly regarded as a higher pressure than normal in the area but in certain circumstances it also could be understood as lower pressure than normal.

02.01. Geology and abnormal formation pressure.

Geologically we consider the following five (5) categories of abnormally pressurized formations.

1. Under compaction.
   Fast deposition of sediments traps fluid and causing abnormal pressures by compaction.

   When sediments are deposited fast in the marine environment water and possibly gas may not succeed to escape and be trapped in the sediments during the deposition.
   As layers and layers of new sediments are deposited, the trapped and microscopic size water or gas droplets are compressed and may reach a pressure which is equivalent to the sediment column above the droplets.
   If the average weight of sediments is assumed to be 2.52 sg, the pressure in a water or gas droplet at 1000 m could approach:
   \( 1000 \times 2.52 \times 0.0981 = 226 \text{ bar} \)

2. Faults.
   Movement of formations with normal pressure to a shallower depth.
If a normally pressured formation is moved upwards from 1000 m to 670 m the minimum mud weight required to balance this pressure when drilled at 670 m is:

Minimum mud weight = \[\frac{93 \text{ bar}}{670 \times 0.0981}\] = 1.42 sg.

3. Artesian effect.

The effect of hydrostatic communication with a reservoir at a higher elevation:

If the formation pressure in the figure above is expected to be 5 bars when drilling water well with water of density 1,00 ppg the calculated underbalance would be:

\[5 - 50 \times 1.0 \times 0.0981 = 0.5 \text{ bar}.\]

In case of an artesian situation illustrated on the figure the underbalance would be.

\[(300 \times 1.0 \times 0.0981) - (50 \times 1.0 \times 0.0981) = 24.5 \text{ bar}.\]
4. Gas cap effect

If it is assumed that the top of the oil zone in the figure above is normally pressured and the gas in the gas cap has a density of 0.24 sg the minimum mud weight required to drill into the top of the gas cap will be as follows:

The normal pressure in top of the oil zone: $1000 \text{ m} \times 1.03 \times 0.0981 = 101$ bars

Gas column pressure: $(1000 - 838) \times 0.24 \text{ ppg} \times 0.0981 = 4$ bar

Pressure in top of gas cap: $97$ bar

Minimum required mud weight $= \frac{97 \text{ bar}}{838 \text{ m} \times 0.0981} = 1.18 \text{ sg}$

5. Tectonic effect

Compression in formations as a result of sections of the earth crust is drifting toward each other.

6. Diapiric effect.

Compression in formations as a result of salt movements:
02.02. Reservoirs and abnormal formation pressures.

1. Leaks from neighbouring oil or gas wells.

2. Water and/or gas injection from neighbouring wells.

In produced or drained reservoirs, the pressure can also be abnormally lower than normal

03. Well kick - Condition / Causes / Signals

03.01. Well kick conditions.

1. Underbalance
   The hydrostatic pressure at the formation that can produce an influx must be lower than the formation pore pressure.

2. Permeability.
   The formation that can produce an influx must have sufficient permeability to allow for a flow of formation fluid.

03.02. Well kick causes.

The most common reasons for a well to kick are:

1. Not keeping the well bore full with drilling mud and creating an under balance.
   - Tripping out of the hole.
   - Swabbing

2. Tripping in the hole.
   - Surging
   - Lost circulation. (A high pressured formation above a lost circulation formation.)

3. Insufficient trip margin (Ref. IWCF formula sheets)

4. Insufficient hydrostatic mud pressure.
   - Expansion of gas cut mud in the top of the well.

5. Drilling into adjacent well.

6. Excessive drilling rate through gas sands.
03.03. Swabbing and Surging.

Circumstances that have influence on swabbing and surging action:

1. Hole and borehole geometry.
2. Well depth.
3. Mud properties.
4. Hole condition and formation characteristics.
5. Drill string running and pulling speed (Acceleration and retardation.)

03.04. Well signals.

A well signal can be regarded as a warning sign that a well kick may develop. According to API well signals are classified in three major categories.

1. Previous field history and drilling experience.
2. Physical response from the well.
3. Chemical and other technical responses from the well.

1. Previous field history and drilling experience

   In this category the following well signals are listed.

   o Depth of zones capable of flowing.
   o Formation gradients.
   o Fracture gradients.
   o Formation content.
   o Formation permeability.
   o Intervals of lost circulation.
2. **Physical response from the well**

In this category the following well signals are listed.

- Pit gain or loss.
- Increase in drilling fluid return rate.
- Change in flow line temperature.
- Drilling breaks.
- Variations in pump speed and/or pump pressure.
- Swabbing.
- Drilling fluid density reduction.
- Effect of connection - reduction of equivalent circulating density (ECD)
  - Short trip
  - Trip on shows and gains.
- Hole problems indicating under balance.
  - Tight hole - torque, drag, increasing pump pressure, reduction in pump speed.
  - Packing off - torque, drag, increasing pump pressure, reduction in pump speed.
- Excessive pressure or pressure changes between casing strings.

3. **Chemical and other technical responses from the well**

In this category the following well signals are listed.

- Chloride changes in the drilling fluid.
- Oil shows.
- Gas shows (chromatography).
- Formation water.
- Shale density.
- Electric logs.
- Drilling equation exponent.
For illustration the formula for the Drilling equation exponent is:

\[
\text{Drilling rate (ROP)}\left(\frac{\log}{\text{Bit RPM.}}\right) = \frac{d}{k} \times \frac{\log\left(\frac{\text{Weight on bit (WOB)}}{\text{Bit diameter}}\right)}{\log}\n\]

03.05. Well kick confirmation.

1. Increase in drilling fluid return rate.
2. Volume increase in the mud pits.
3. A positive flow check.
04. Formulas and mathematics.

04.01. Volume- and capacity calculations.

**Volume of a mud pit**

\[
\text{Volume} = B \times L \times H
\]

\[
= .......... \times .......... \times ..........
\]

\[
= ................
\]

\[
= \text{liter}
\]

\[
\text{Volume} = \pi \times R^2 \times H
\]

\[
= \pi \times .......... \times .......... \times .........
\]

\[
= ............
\]

\[
= ............
\]

\[
= \text{litre/ m}
\]
04.02. Displacement of open and closed end pipes.

Volume of a closed pipe:

\[ \text{Volume of a closed pipe:} \]

\[ = \pi \times R^2 \times H \]

\[ = \pi \times \ldots \ldots \times \ldots \ldots \times \ldots \ldots \]

\[ = \ldots \ldots \ldots \text{liter} \]

\[ = \ldots \ldots \ldots \text{liter/m} \]

Displacement of open ended pipe.

Capacity of a closed ended pipe

\[ = \ldots \ldots \ldots \text{litre} \]

Volume of hole in the pipe:

\[ = \pi \times r^2 \times H \]

\[ = \pi \times \ldots \ldots \times \ldots \ldots \times \ldots \ldots \]

\[ = \ldots \ldots \ldots \text{liter} \]

\[ = \ldots \ldots \ldots \text{liter} \]

Capacity of open ended pipe = \ldots \ldots \ldots \text{litre/m}

An alternative method is to use the formula: \[ = \pi \times (R^2 - r^2) \times H \]
04.03. Annular volumes and capacities.

Hole volume.

\[ \text{Hole volume} = \pi \times R^2 \times H \]
\[ = \pi \times ........... \times ........... \times ........... \]
\[ = ................. \times ................. = ................. \text{Litre}. \]

Pipe volume.

\[ \text{Pipe volume} = \pi \times R^2 \times H \]
\[ = \pi \times ........... \times ........... \times ........... \]
\[ = ................. \times ................. \text{litre} \]

Annular volume \( ................. \text{Litre} \)
Annular capacity \( ................. \text{Litre/m} \)

An alternative method is to use the formula:

\[ \text{annular volume} = \pi \times (R^2 - r^2) \times H \]

04.04. Pump capacity.

Calculate the pump capacity of a triplex mud pump with a 6” liner and a 12” pump stroke.
05. Hydrostatic calculations.

05.01. Hydrostatic pressure.

The pressure at the bottom of a hydrostatic column is given by

\[ P = mw \times H \times 0.0981 \]

Where;
- \( P \) = Pressure in bar
- \( mw \) = Drilling fluid density (mud weight) in sg.
- \( H \) = Vertical height of the fluid/gas in m.
- 0.0981 = Gravity constant.

**Example no. 1: One hydrostatic column.**

<table>
<thead>
<tr>
<th>Density</th>
<th>Height</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.24 sg</td>
<td>3962 m</td>
<td>482 bar</td>
</tr>
</tbody>
</table>

**Example no. 2: Two hydrostatic columns.**

<table>
<thead>
<tr>
<th>Density</th>
<th>Height</th>
<th>Pressure 1</th>
<th>Pressure 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.24 sg</td>
<td>3292 m</td>
<td>400 bar</td>
<td></td>
</tr>
<tr>
<td>1.79 sg</td>
<td>671 m</td>
<td>118 bar</td>
<td>518 bar</td>
</tr>
</tbody>
</table>
05.02. Equivalent fluid density.

The general formula for calculating the hydrostatic pressure at the bottom of a well can be rearranged using mathematics as follows.

\[
Mw \ (sg) = \frac{P \ (bar)}{TVD(m) \times 0.0981}
\]

**Example no. 3: To convert pressure to equivalent fluid weight.**

If we use the data in example no. 3 above and shown on the figure at the left, the pressure at the bottom of the mud column is;

\[= \ 521 \ \text{bar}\]

If we want to replace these two fluid columns with one column with uniform weight this new uniform weight is calculated as follows;

\[
mw = \frac{521}{3962 \times 0.0981} = 1.34 \ sg
\]

The fluid weight 1,34 sg is called the **equivalent fluid density** as this new fluid weight exerts the same pressure at the bottom as the two previous hydrostatic columns.
05.03. Equivalent hydrostatic column.

The general formula for calculating the hydrostatic pressure at the bottom of a well can be rearranged using mathematics as follows.

\[
P \text{ (bar)} = \frac{P \text{ (bar)}}{\text{TVD (m)}} = \frac{\text{TVD (m)}}{\text{Mw (sg)} \times 0.0981}
\]

Example no. 4: To convert pressure to an equivalent fluid column.

A well shown on the left hand figure is filled with a fluid weight of 11.2 ppg but the formation at the bottom of the hole can only withstand a pressure of 7250 psi.

The equivalent height of an 11.2 ppg fluid column the well can withstand is calculated as follows;

\[
H = \frac{500}{1.34 \times 0.0981} = 3804 \text{ m}
\]

05.04. Kill mud weight.

The diagrams show the application of kill mud weight calculations.
Looking at the left hand side figure a well filled with a mud weight of 1.53 sg is not enough to control the bottomhole pressure. The well is sealed off at the top and a pressure gauge shows 28 bars. If we want to remove the seal on top of the well we need to increase the mud weight in the well before the seal is remover. The required mud weight is calculated as follows:

\[
\text{Bottom hole pressure due to the mud column: } P = 1.53 \times 3962 \times 0.0981 = 595 \text{ bar}
\]

\[
\text{Bottomhole pressure due to gauge pressure: } = 28 \text{ bar}
\]

\[
\text{Bottom hole pressure} = 623 \text{ bar}
\]

\[
\text{Required mud weight: } mw = \frac{623}{3962 \times 0.0981} = 1.60 \text{ sg}
\]

The calculation of the required mud weight can also be done as follows;

\[
\text{Required mud weight; } mw = \frac{(1.53 \times 3962 \times 0.0981) + 28}{3962 \times 0.0981} = 1.60 \text{ sg}
\]

Looking at the right hand side figure above it shows a well that have been shut in because of a kick with 1.53 sg mud in the drill string and with a shut in drill pipe pressure (SIDPP) of 28 bar.

To calculate the kill mud weight for this situation we use the same reasoning to arrive at the balanced condition as shown on the middle figure above and we can use either of the two calculation methods above to find the kill mud weight. The last method is commonly used.

06. Circulating pressures.

06.01. Pump pressure / fluid weight relationship (At constant pump rate).

The relationship between pump pressure and fluid weight (mud weight) at constant pump rate is given by the general formula;

\[
P_2 = P_1 \times \frac{mw_2}{mw_1}
\]
If we have a circulating pressure $P_1$ with a fluid weight of $mw_1$ in a pipe system then we can find the new pump pressure $P_2$ from the formula when the pipe system is filled with the new fluid weight $mw_2$.

In practical well control operations this formula may have the form:

$$ FCP = \text{Dynamic pressure losses (SCRp)} \times \frac{\text{Kill mud weight}}{\text{Current mud weight}} $$

It is assumed that this formula is based on a practical field experiment on a pipe system lying on the ground with a pump, a pressure gauge and a fluid tank at one end of the pipe, as shown on the figure below.

As the object of the experiment was to find the relationship between the pump pressure and fluid weights at a constant pump rate, the tank and the pipe system was filled with different fluid weights ($mw_1, mw_2, mw_3, \ldots$ etc.) and the corresponding pump pressure ($P_1, P_2, P_3 \ldots$ etc.) recorded at the same pump rate.

The data was then plotted in a diagram, and the relationship between fluid weight and pump pressure appeared to be a straight line as shown below.

It can then be shown mathematically that such a relationship has the general form:

$$ P = k \times mw \quad \text{where} \quad P = \text{Circulating pressure (bar)} $$

$$ mw = \text{Fluid weight (sg)} $$

$$ k = \text{Proportional factor} $$

For one set of data we have:

$$ P_1 = k \times mw_1 \quad k = \frac{P_1}{mw_1} $$

For another set of data we have:

$$ P_2 = k \times mw_2 \quad k = \frac{P_2}{mw_2} $$

As $k = k$ then

$$ \frac{P_2}{mw_2} = \frac{P_1}{mw_1} $$
and we get the general formula: \[ P_2 = P_1 \times \frac{mw_2}{mw_1} \]

06.02. Pump pressure / pump rate relationship (at constant fluid weight).

The relationship between pump pressure and pump rate (circulation rate) with constant fluid rate is given by the general formula:

\[ P_2 = P_1 \times \left( \frac{SPM_2}{SPM_1} \right)^2 \]

If we have a circulating pressure \( P_1 \) at a pump rate of \( SPM_1 \) with a constant fluid weight in a pipe system, then we can find the new pump pressure \( P_2 \) from the formula when the pump rate is changed to \( SPM_2 \).

It is assumed that also this formula is based on a practical field experiment on a pipe system lying on the ground with a pump, a pressure gauge and a fluid tank at one end of the pipe, as shown on the figure below.

As the object of the experiment was to find the relationship between the pump pressure and pump speed (circulation rate) with fluid weight, the tank was filled with a fixed fluid weight, the pump was run at different speeds (\( SPM_1, SPM_2, SPM_3, \ldots \text{etc.} \)) and the corresponding pump pressure (\( P_1, P_2, P_3 \ldots \text{etc.} \)) recorded.

The data was then plotted in a diagram, and the relationship between fluid weight and pump pressure appeared to be a straight line as shown below.

![Diagram showing pump pressure and pump rate relationship](image)

It can then be shown mathematically that such a relationship has the general form:

\[ P = k \times (SPM)^2 \]

- \( P \) = pump pressure (bar)
- \( SPM \) = pump rate (pump strokes or lpm)
- \( k \) = proportional factor

As will be shown later the exponent 2 can vary dependent on fluid properties a/or pump rate.
For one set of data we have:

\[ P_1 = k \times (SPM_1)^2 \]  
\[ k = \frac{P_1}{(SPM_1)^2} \]

For another set of data we have:

\[ P_2 = k \times (SPM_2)^2 \]  
\[ k = \frac{P_2}{(SPM_2)^2} \]

As \( k = k \) then \( \frac{P_1}{(SPM_1)^2} = \frac{P_2}{(SPM_2)^2} \)

and we get the general formula:

\[ P_2 = P_1 \times \frac{SPM_2^2}{SPM_1^2} \quad \text{or} \quad P_2 = P_1 \times \left[ \frac{SPM_2^2}{SPM_1} \right] \]

In the reasoning above we used the general formula \( P = k \times (SPM)^2 \) with the exponent = 2.

However the true general formula is \( P = k \times (SPM)^n \) with the exponent = \( n \).

By applying the logarithmic rules in mathematics we can find the following expression for the exponent \( n \):

\[ n = \frac{\ln P_2 - \ln P_1}{\ln SPM_2 - \ln SPM_1} \]

By inserting actual field values for pump pressures and pump rate in this formula the true value of the exponent \( n \) can be found for different mud systems and pump rates.

Data from an actual field experiment is shown on the next page.
06.02.01. Pump pressure / pump rate - a rig experiment.

**Well no.** A-37

**Well depth** 2340m.

**Hole dimension** 12.6 

**Mud weight** 1.29 KCL mud

**General formula:**

\[ \frac{\text{Ln } SPM_2 - \text{Ln } SPM_1}{\text{Ln } P_2 - \text{Ln } P_1} = n \]

<table>
<thead>
<tr>
<th>Pump rate SPM</th>
<th>Pump pressure bar</th>
<th>Calculated n values</th>
</tr>
</thead>
<tbody>
<tr>
<td>21</td>
<td>23</td>
<td>0.8588</td>
</tr>
<tr>
<td>40</td>
<td>40</td>
<td>0.9164  0.8811</td>
</tr>
<tr>
<td>60</td>
<td>58</td>
<td>1.2036</td>
</tr>
<tr>
<td>80</td>
<td>82</td>
<td>1.4475</td>
</tr>
<tr>
<td>98</td>
<td>110</td>
<td>1.534</td>
</tr>
<tr>
<td>121</td>
<td>152</td>
<td>1.5272</td>
</tr>
<tr>
<td>141</td>
<td>192</td>
<td>1.497</td>
</tr>
<tr>
<td>160</td>
<td>232</td>
<td>1.6967</td>
</tr>
<tr>
<td>178</td>
<td>278</td>
<td></td>
</tr>
</tbody>
</table>

**SCRp at well depth 2173m.**

| 20 | 16 | 0.8580 |
| 40 | 29 | 1.1378 |
| 60 | 48 | 0.9613 |

This experiment shows the exponent **n** has a value closer to 1 than 2 for slow circulating rates.
07. Barite calculations

07.01. Barite requirements.

Barite requirement when weighing up a mud volume is given by the formula:

\[
\text{Barite requirement in Kg/m}^3 = 4200 \times \frac{(mw_2 - mw_1)}{4.2 - mw_2}
\]

- \(mw_1\) = Original mud weight.
- \(mw_2\) = New and higher mud weight.
- 4200 = conversion factor from kg/litre to kg/m^3
- 4.2 = Specific weight of barite

07.02. Volume increase.

Volume increase when weighing up mud is given by the following formula:

\[
V_2 = V_1 + \frac{M}{sg}
\]

- \(V_2\) = Final volume in m^3.
- \(V_1\) = Initial volume = 1000 litre or 1m^3.
- \(M\) = Weight of weighing materials in kg/m^3 or kg/1000 litre
- \(sg\) = Specific weight of the weighting material.
08. Formation integrity testing

08.01. Parameter requirements

1. Accurate pressure gauge.
2. Known weight of a uniform mud column.
3. The vertical depth to the formation to be tested.
4. Constant pump rate.
5. Accurate volume measurements.

08.02. Evaluation of a leak-off test.

The leak off pressure ($P$) is read from the pressure / volume graph at the point where the pressure / volume curve deviates from the straight line.
09. MAASP (Maximum Allowable Annulus Shut-in Pressure)

Maximum Allowable Annulus Shut-in Pressure - MAASP - is the maximum pressure (bar) that can applied on the casing pressure gauge in addition to the hydrostatic mud pressure without breaking down the formations in the open hole.

According to API and IWCF MAASP should be calculated:

1. When a formation integrity test has been performed.
2. When the mud weight is changed.

As formations in an open hole section in general is considered to be weakest below the casing shoe MAASP are almost always related to the formation strength at this point. In other words, the MAASP is dependent on the casing shoe strength obtained from a leak off test (LOT).

On the figure it is illustrated that the casing shoe and a few meters of new formation has been drilled. If we assume that a leak off test has been done and that the leak off pressure is 30 bars, the casing shoe strength can be found as follows;

\[
\begin{align*}
\text{Mud press.} & \quad 800 \times 1.30 \text{ sg} \times 0.0981 \approx 102 \text{ bar} \\
\text{Leak off pressure:} & \quad 30 \text{ bar} \\
\text{Casing shoe strength} & \quad 132 \text{ bar}
\end{align*}
\]

If this pressure is converted to equivalent mud weight we obtain;

\[
\begin{align*}
\frac{132 \text{ bar}}{800 \times 0.0981} \approx 1.68 \text{ sg}
\end{align*}
\]

If it at a later stage during the drilling operation is decided to weight up the mud to for example 1.43 sg, the MAASP can be calculated with the following two methods:

\[
\begin{align*}
\text{Method no. 1:} & \quad \text{Casing shoe strength} \\
& \quad \text{Mud column pressure:} \quad 800 \times 1.43 \text{ sg} \times 0.0981 = 112 \text{ bars} \\
& \quad \text{MAASP} \\
& \quad 20 \text{ bar}
\end{align*}
\]

\[
\begin{align*}
\text{Method no. 2:} & \quad \text{MAASP} = 800 \times (1.68 \text{ sg} - 1.43 \text{ sg}) \times 0.0981 = 20 \text{ bar}
\end{align*}
\]
10. Well hydraulics.

10.01. The circulating system.

The circulating system consists generally of the following components.
- Active pits
- Mud pumps
- Surface piping system
- The drill string with drill pipe and BHA
- Drill bit with nozzle
- The annular space outside the drill string
- The flow line and the mud cleaning systems

When drilling a “standard” well as shown on the figure on left hand side, it is fairly common to have pump pressure in the range 250 bar as shown.

The reason for this pump pressure is the pressure loss in the drill string (roughly 20 % to 40% of the pump pressure), pressure losses through the bit nozzles (roughly 50 % to 70 % of the pump pressure) and the pressure losses in the annulus (roughly 3 % to 8 % of the pump pressure).

The % figures given above are of course only approximate figures and are only stated to give an idea of the magnitude of the pressure losses in a well circulating system.

10.02. Equivalent circulating density. (ECD)

Referring to the figure above and assuming that the pressure loss in the annulus is approximately 3 - 5 % of the total pump pressure - say for example 10 bars, then this pressure loss will be exerted on the bottom of the well in addition to the hydrostatic pressure of the 1,45 sg mud column. Hence the bottomhole pressure while circulating will be,

\[ P = 2000 \text{ m} \times 1,45 \text{ sg} \times 0,0981 + 10 \text{ bar} = 295 \text{ bar} \]

The equivalent circulating density (ECD) will be:

\[ \text{ECD (sg)} = \frac{295 \text{ bar}}{2000 \text{ m} \times 0,0981} = 1,50 \text{ sg}. \]
10.03. Slow circulating rate pressure. (SCRp)

I the previous section it was stated that the pressure loss in the drill string and across the bit nozzles is in the range of 80% to 95% of the pump pressure and the pressure loss in the annulus is in the range of 3 to 8% of the pump pressure. This is also the case when circulating with slow pump rates.

When circulating with slow pump rates the pump pressures are low and a representative situation is shown on the left hand figure.

Assuming that the annulus pressure losses still is 3% to 8% of the pump pressure, the annulus pressure loss in this situation is in the range from 1 to 2 bars.

In well control operations this low pressure losses are considered negligible and for all practical purposes regarded as zero (0 bar)

Consequently, when slow circulating pressures are recorded while circulating down the drill string, through the bit nozzles and up the annulus back through the flow line to the pits, the pressure recorded on the drill pipe pressure gauge is the pressure loss in the drill string and in the bit nozzles as indicated in red colour on the figure.
10.04. Establish circulation.

To establish circulation correctly in a well control situation we start with a shut in well and should end up circulating the well at a steady slow circulating rate. To do this correctly means that the bottomhole pressure in the well should be held constant while going from the static state to the dynamic or circulating state.

To demonstrate this, the well and the data shown on the figure will be used. In addition the slow circulating rate pressure data in the previous section will be used, where pressure loss through the drill string and the bit nozzles was 20bar at 25 SPM with 1,45 sg mud weight.

When considering the shut in situation the pore pressure which caused the well to kick is balanced on the drill string side with the mud column and 36 bar shut in drill pipe pressure.

On the annulus side the pore pressure is balanced with a 1,45 sg mud column, the influx column and 40 bar shut in casing pressure.

Based on the reasoning in the previous section there is no pressure losses in the annulus while circulating at slow rates. Consequently the bottomhole pressure will be constant if the casing pressure is kept constant while bringing the pump speed up to the slow circulating rate - the kill speed of 25 SPM.

In the drill string however it has been established a pressure drop of 24 bars while circulating at slow rate. In order to keep the bottom hole constant through the drill string, this friction loss need to be added to the shut in drill pipe pressure of 36 bars while bringing the pump speed up to the slow circulating rate - the kill speed of 25 SPM.
To establish circulation correct the pump operator brings the pump slowly up to kill speed (25 SPM) while the choke operator keeps the casing pressure constant (40 bar) by adjusting the choke opening. If this is done correctly, the bottom hole pressure will be constant during the operation and the resulting drill pipe pressure will be the sum of the shut in drill pipe pressure (36 bar) and the pressure loss in the drill string and through the bit nozzle (24 bar). 60 bar will then be the initial circulation pressure (ICP = 60 bar).

This is also illustrated on the figure next page where an extra margin of 5 bars is added.
11. Pressure interpretation.

11.01. Pressure readings.

**Static pressure readings**

Is the pressure $P$ higher or lower than 50 bar?
What is the pressure $P$?

**Dynamic pressure readings**

Is the pressure $P_1$ higher or lower than 200 bar?
Is the pressure $P_2$ higher or lower than 200 bar?
Why differs pressure $P_1$ from 200 bar?
11.02. Pressure interpretation when circulating out a kick.

<table>
<thead>
<tr>
<th>Indicators of Possible Problems While Circulating Out a Kick</th>
<th>Drill Pipe Pressure</th>
<th>Casing Pressure</th>
<th>Drill String Weight</th>
<th>Fit Level</th>
<th>Pump SPM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Choke Washes Out</td>
<td>↓</td>
<td>↓</td>
<td></td>
<td></td>
<td>↑</td>
</tr>
<tr>
<td>Gas Reaches Surface</td>
<td>↓</td>
<td></td>
<td></td>
<td></td>
<td>↑</td>
</tr>
<tr>
<td>Loss of Circulation</td>
<td>↓</td>
<td>↓</td>
<td>↑</td>
<td></td>
<td>↑</td>
</tr>
<tr>
<td>Hole in Drill String</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>↑</td>
</tr>
<tr>
<td>Pipe Parted</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>↑</td>
</tr>
<tr>
<td>Bit Nozzle Out</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>↑</td>
</tr>
<tr>
<td>Pump Volume Drops (Pump Damage — Gas Cut Mud)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>↑</td>
</tr>
<tr>
<td>Gas Feeding In</td>
<td>↑</td>
<td>↑</td>
<td>↑</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Choke Plugs</td>
<td>↑</td>
<td>↑</td>
<td></td>
<td></td>
<td>↓</td>
</tr>
<tr>
<td>Bit Nozzle Plugs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>↓</td>
</tr>
<tr>
<td>Hole Caved In</td>
<td></td>
<td></td>
<td>Stack</td>
<td></td>
<td>↓</td>
</tr>
</tbody>
</table>
12. Well shut in methods.

12.01. Hard shut in method.

Arranging the well control equipment:

1. Close the blowout preventer (BOP) valve on the choke line.
2. Open the other choke line valves to the poor boy degasser.
3. Close the choke.

Close in procedure:

1. Close the blowout preventer (BOP)
2. Open the blowout preventer (BOP) valve on the choke line.
3. Record the shut in casing pressure (SICP).

Note! **The well is shut in against closed choke line system**

12.02. Soft shut in method.

Arranging the well control equipment:

1. Close the blowout preventer (BOP) valve on the choke line.
2. Open the other choke line valves to the poor boy degasser.
3. Open the choke.

Close in procedure:

1. Open the blowout preventer (BOP) valve on the choke line.
2. Close the blowout preventer (BOP)
3. Close the choke slowly.
4. Record the shut in casing pressure (SICP).

Note! **The well is shut in against an open choke line system, which is then closed /softly with the choke**
13. Comparison of well kicks in water- and oil based mud.

A well kick in water based mud.

1. Distinct volume increase in the mud pit when influx occurs.
2. Distinct shut in pressures.
3. Distinct volume increase in the mud pits particularly when circulating out a gas influx.

A well kick in oil based mud.

1. Minimal volume increase in the mud pit when influx occurs.
2. Low or no shut in pressures.
3. Minimal or no volume increase in the mud pits when circulating out an influx.
   But in the case of a gas influx a sudden flashing/boiling out of gas at very low hydrostatic pressure.


14.01. Shallow gas drilling parameters.

1. Drilling rate (ROP) controlled
   Drill slowly to reduce the amount of formation gas in the mud.

2. Mud weight.
   Use mud weight to give adequate overbalance in the shallow gas sands.

3. Tripping speed
   Prevent swabbing and surging by optimal tripping speed and acceleration and retardation of the drill string before and after connections.

4. Pump rate.
   Pump at high rates to reduce the amount of formation gas in the mud.

5. Drill pilot holes and use MWD equipment
14.02. Shallow gas killing procedure.

In case a shallow gas kick is developing the following action should be taken.

1. Pump mud as fast as possible.
2. Increase the mud weight as fast as possible.
3. Pump water when mud pits are empty.
4. Divert the well fluids if safety of the rig floor becomes a problem.
5. Carry a reserve of killing fluid (80 to 100 m3) with weight (0.5 to 0.7 sg) above required mud weight.

15. Subsea operations

When comparing subsea operations with operations on land, on jack ups or on offshore platform installations the major difference is that the BOP is installed on the seafloor as illustrated on the figure on this page, where the BOP is approximately 800 ft. below the sea surface. The choke and kill line connected to the BOP is also installed along the Riser and is connected to the well control equipment on the rig floor. As a result the following well control subjects need to be taken into consideration for subsea operations.

1. Choke line friction
2. Establish circulation correct with choke line friction
3. Riser margin
4. Gas in BOP below a ram / bag.
15.01. Choke line friction.

During any well control operation in general a well influx or kick is circulated out through the choke line. Due to the length and the small internal diameter of the choke line there is a fair amount of pressure loss when circulating through the line even at slow circulating rates. These pressure losses need to be recorded for three or four slow circulating rates in good time before a kick situation occurs and should be done during a "kick drill" prior to drilling out of a casing shoe.

This pressure loss is obtained by taking the difference between the pressure recorder when circulating down the drill string - up the annulus/choke line and the pressure recorded when circulating down the drill string - up the annulus/riser.

On the following page the procedure is explained in further detail.

15.02. Slow circulating rate pressure. (SCRp)

In a previous section in this manual it has been stated that the pressure loss in the drill string and across the bit nozzles is in the range of 80 % to 95 % of the pump pressure and the pressure loss in the annulus is in the range of 3 to 8 % of the pump pressure.

The % figures given above are of course only approximate figures and are only stated to give an idea of the magnitude of the pressure losses in a well circulating system.
15.02.01. Circulating down the drill string - up the annulus/riser.

When circulating with slow pump rates the pump pressures are low and a representative situation is shown on the figure on this page.

Assuming that the annulus pressure losses still is 3% to 8% of the pump pressure, the annulus pressure loss in this situation is in the range of 2 bars +/-.

In well control operations this low annulus pressure losses are considered negligible and for all practical purposes regarded as zero (0 bar).

Consequently, when slow circulating pressures are recorded while circulating down the drill string, through the bit nozzles and up the annulus / riser and back through the flow line to the pits, the pressure recorded on the drill pipe pressure gauge is the **pressure loss in the drill string and in the bit nozzles** as indicated in red colour on the figure.
15.02.02. Circulating down the drill string - up the annulus /choke line

To circulate up the choke line it is necessary to close the BOP around the drill string and open the choke as indicated on the figure on this page.

If the same slow circulating rate of 25 SPM is used as was used when circulating down the drill string - up the annulus /riser, the drill pipe pressure will show a higher pressure, for example 45 bar.

This pump pressure of 45 bars is due to all the pressure losses in the circulating system. That is the pressure loss down the drill string of 32 bars that has been recorded earlier, and in addition the pressure loss in the choke line as indicated in red colour on the figure.

As mentioned earlier the pressure loss in the annulus from the bit to the choke line outlet in the BOP is so minimal and is disregarded and considered as zero bars.

The reason for the increase in pump pressure from 32 bar to 45 bar is due to the additional pressure loss of $(45 - 32) = 13$ bar in the choke line as indicated in red colour on the figure.

The circulating pressures at slow pump rates down the drill string - up the annulus/riser and down the drill string - up the annulus/choke line are usual recorded as follows:

- SCRp "R" = 32 bar with 25 SPM and 1.45 sg mud.
- SCRp "Cl" = 45 bar with 25 SPM and 1.45 sg mud.
- Choke line friction = 13 bar with 25 SPM and 1.45 sg mud.

In other words, the only reason to circulate with slow rates down the drill string, up the annulus and the choke line is to find the choke line friction.

Choke line friction is commonly obtained at three to four slow circulating rates for example at 20 SPM, 30 SPM, 40 SPM and 50 SPM. If the mud weight changes during the drilling of a new hole section the new choke line friction can be calculated accurately enough by using the relationship between pump pressure and fluid weights:

$$\text{Clf}_2 = \text{Clf}_1 \times \frac{\text{sg}_2}{\text{sg}_1}$$
15.03. Establish circulation.

To establish circulation correctly in a well control situation we start with a shut in well and should end up circulating the well at a steady slow circulating rate. To do this correctly requires that the bottom hole pressure in the well should be held constant while going from the static state to the dynamic or circulating state.

To demonstrate this, the well and the data shown on the figure on this page will be used. In addition the slow circulating rate pressure data in the previous section will be used, where pressure loss through the drill string and the bit nozzles is 32 bars and the choke line friction is 13 bars at 25 SPM with 1,45 sg mw.

When considering the shut in situation the pore pressure which caused the well to kick is balanced on the drill string side with the mud column and 32 bar shut in drill pipe pressure. On the annulus side the pore pressure is balanced with a 1,45 sg mud column, the influx column and 40 bar shut in casing pressure.

Based on the earlier reasoning there is no pressure losses in the annulus while circulating at slow rates. In order to keep the bottom hole pressure constant while bringing the pump speed up to the slow circulating rate (the kill speed rate) of 25 SPM, the choke must be opened in such a manner that the casing pressure is reduced with the choke line friction from 40 bar to (40 –13) 27 bar.

In other words, as the pump speed is increased to the kill rate (25 SPM) the choke line friction (13 bar) need to be neutralised by the same amount on the casing pressure gauge in order to prevent that this choke line pressure loss is added on the well.

If the bottom hole pressure is kept constant in this manner on the annulus the drill pipe gauge will increase with the drill string friction of 32 from 32 bar shut in pressure to 64 bar, which will be the correct initial circulating pressure (ICP).
When circulation has been established correctly, the casing gauge should read 27 bars and the drill pipe gauge 64 bar when the pump rate is steady at 25 SPM as shown on the figure below. On the next page this is illustrated in more details. Note that an extra 5 bar as safety factor has been added to the circulating pressures in order to create an overbalance on the formation that caused the kick.
CHAPTER 2 – THEORY AND PROCEDURES

Slow circulating press. w/ 25 SPM / 1.45 sg
- up annulus / riser: ......... 32 bar
- up Choke line: ............. 45 bar
giving choke line friction: 13 bar
Safety factor: ................. 6 bar

Initial shut in pressures

2000 m

1.45 sg

Csg. press  DP press  KIli press

SPM  STROKES

25  46

Open  Close

32  69  47

Bar

DP pressure

Kill pressure

Csg. pressure

Strokes
16. Riser margin.

During floating drilling operation a situation may occur that the riser breaks and is lost due to equipment failures or sudden unexpected bad weather conditions. If the mud weight in the well just balances the formation pressures in the open hole section, and the riser breaks before the BOP is closed some hydrostatics pressure is lost and a kick may occur. As a preventive action the mud weight is increased with the "riser margin" to prevent a kick to occur in such a situation.

Considering a situation shown on the figure where 1,60 sg mud has been used to balance the pore pressure at 3200 m. If the riser suddenly breaks at 300 m and drops to the seafloor, a hydrostatic column of 300 m with 1,60 sg is lost. However a sea water column of \((300 - 25) = 275\) m with 1,03 sg is gained and the net hydrostatic pressure loss is as follows:

- Hydro static pressure loss: \(300 \text{ m} \times 1,60 \text{ sg} \times 0,0981 = 47 \text{ bars}\)
- Hydrostatic pressure gain: \(275 \text{ m} \times 1,03 \text{ sg} \times 0,0981 = 28 \text{ bars}\)
- Net hydrostatic pressure loss: \(19 \text{ bar}\)

This net hydrostatic pressure loss needs to be converted to additional mud weight on the original mud column from the depth where the riser breaks at 895 ft. to TD at 8720 ft. as follows:

- Additional mud weight \(= \frac{19}{(3200 - 300) \times 0,0981} = 0,07 \text{ sg}\)

- The additional mud weight of 0,07 sg is defined as the Riser margin

The minimum required mud weight would then be: \(1,60 \text{ sg} + 0,07 \text{ sg} = 1,67 \text{ sg}\).
17. Gas in the BOP after a well kick.

When a gas kick has been circulated out during a subsea operation a certain gas volume is usually accumulated between the choke line outlet on the BOP and a closed ram or annular preventer.

Common questions related to such a situation is how much this volume will be when aerated to the atmosphere and how to get rid of the gas in a safe and controlled manner.

To calculate the gas volume when it is aerated to the atmospheric condition the following gas law relation is used:

\[ P_1 \times V_1 = P_2 \times V_2 \]

If we consider the situation on the figure and denote the conditions in the BOP as (1) and that in the atmosphere as (2) we want to find \( V_2 \) in the formula above as follows. Absolute pressure has to be used, in this case an additional 1 bar (atmospheric pressure) has to be added to \( P_1 \) down hole conditions.

\[
\frac{P_1 \times V_1}{P_2} = V_2
\]

From the figure we have:

\[
P_1 = 295 \text{ m} \times 1.57 \text{ sg} \times 0.0981 = 45.44 \text{ bar}
\]
\[
V_1 = 0.6 \text{ m}^3
\]
\[
P_2 = \text{Atmospheric pressure} = 1 \text{ bar.}
\]

The gas accumulated in the BOP will expand to:

\[
V_2 = \frac{45.44 \text{ bars} \times 0.6 \text{ m}^3}{1 \text{ bar}} = 27.3 \text{ m}^3
\]
To aerate gas which has accumulated below a BOP ram during a kick operation, the following procedure could be used to perform this operation in a safe and controlled manner:

1) Isolate the well by close a BOP ram.
2) Line up the pump and cross circulate through the choke line below the gas bubble with light fluid (sea water.
3) Close the flow line to the shakers.
4) Line up the diverter system downwind.
5) Close the diverter element.
6) Open the BOP ram above the gas and let it divert through the diverter system.
7) Displace the riser to the correct mud weight
8) Open the lower BOP ram and continue drilling.
CHAPTER 3 – PRACTICAL WELL CONTROL OPERATIONS

As mentioned in the introduction to Chapter 2 "Theory and Procedures", chapter 3 and chapter 2 equals IWCF’s “Principle and Procedures”. Combined with the exercises in the Workbook, these three chapters should cover the necessary knowledge in order to pass the IWCF test in Principle & Procedures with success.

However, this chapter is based on the philosophy that it should only contain information which leading drilling personnel must know, in order to perform professionally in an actual well kick and killing operation in the field, as opposed to everything that they ought to know and what is nice to know.

In other words, the chapter is limited to the minimum requirement that professional leading drilling personnel must understand and master from the time a well has been shut in and until it has been stabilized, and normal drilling operation can be resumed.

It is also assumed that personnel during advancement into leading drilling operation positions have demonstrated the ability to lead and organize personnel in demanding and critical situations.

01. Objectives

01.01. General objective in a kick situation

When a kick situation occurs the general goal should be to stabilise the well as safely and efficiently as possible in order to resume normal drilling operation with minimum downtime.

01.02. Objective for practical well control

On the basis of the Wait and Weight method the specific goal for this chapter is:
To repeat or learn a logical, safe, efficient and a practical applicable method to construct a well killing diagram for a well that is drilled along any trajectory with any combination of drill string.
01.03. Well trajectory (one example)
01.04. Drill string (one of many examples)
02. Competency – responsibility - authority

02.01. Competence requirements for a well control operation

Competency consist of the following qualifications

1. Knowledge.
2. Skills
3. Action.

Within well control operations we can list the following below each of these three categories.

1. Knowledge
Mathematics, formulas, the circulating system, pump pressure at low circulating rates, establish circulation, etc. is covered in Chapter 2: “Theory and Procedures”.

2. Skill
To operate the well control equipment: covered in Chapter 1 “IWCF simulator test” including the simulator practise and test.

3. Action
Action can be divided into Planning and Leadership / co-ordination.

Planning consist of dividing a well control operation in safe, practical, logical and efficient working sequences including the tools (calculators, data sheets) necessary to perform the required planning work

This will be covered in this chapter for Drillers method, wait and Weight method on a vertical and a deviated well and the Volumetric method.

Regarding leadership and/or co-ordination it is assumed that drilling personnel, during their theoretical and practical training prior to being promoted to Drillers and supervisory positions, have demonstrated the ability to lead and organise personnel in demanding and critical situations.

02.02. Responsibility and authority.

Responsibilities and authorities in a well control operation to be discussed.
03. Well killing methods

In the following sections three well killing methods will be described and discussed in detail. The three methods are:

1. The Drillers method.
2. The Wait and weight.
3. The Volumetric method.

The Wait and Weight method will be described and discussed for both a vertical and a deviated well.

The common basis for all three well killing methods is to keep the bottom hole pressure constant with a necessary safety margin during the whole killing operation.

04. Drillers method

The Drillers method can be divided into the following five (5) working sequences:

1. **Preparations and data collection.**
   Necessary preparations and data collection to be done prior to drilling out a casing shoe.

2. **Well is shut in due to an influx / kick.**
   Data is collected for necessary calculations, for example kill mud weight.

3. **Establish circulation and circulate out the influx.**
   As soon as the circulation is established correctly (with constant bottom hole pressure) the kick is circulated out with constant drill pipe pressure (ICP). The casing pressure varies dependant on the type of influx that is circulated out.

4. **Circulate kill mud to the bit.**
   As soon as all the influx is circulated out of the annulus and the casing pressure has stabilised on a fixed value the kill mud is pumped down the drill string to the bit with constant casing pressure. The drill pipe pressure will decrease from initial circulating pressure (ICP) to final circulating pressure (FCP).
5. **Circulate kill mud to the choke.**
   As soon as the kill mud is at the bit and final circulating pressure has been reached the circulation continues with constant final circulating pressure until the annulus is full with kill mud and the well is stabilised.

For a detailed discussion of the Drillers method it is assumed that necessary data are collected prior to drilling out of the casing shoe, and only the last three working sequences will be discussed based on the following simplification:

**A. Establish circulation and circulate out the influx with the original mud.**
- With constant drill pipe pressure = initial circulating pressure (ICP)

**B. Circulate kill mud to the bit.**
- With constant casing pressure.

**C. Circulate kill mud to the choke.**
- With constant drill pipe pressure = final circulating pressure (FCP).

For the detailed explanation and discussion of the Drillers method, the well data on the next page will be used.
### WELL DATA

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surface volume</td>
<td>900 litres</td>
</tr>
<tr>
<td>Mud pump capacity</td>
<td>16 litre/ stroke</td>
</tr>
<tr>
<td>Hole dimension</td>
<td>8 1/2&quot;</td>
</tr>
<tr>
<td>Casing size</td>
<td>9 5/8&quot;</td>
</tr>
<tr>
<td>Casing setting depth</td>
<td>3000m MD and TVD</td>
</tr>
<tr>
<td>Drill pipe capacity (5&quot;&quot;)</td>
<td>8,97 litre/ m</td>
</tr>
<tr>
<td>HWDP - capacity and length (5&quot;)</td>
<td>4,59 litre/ m length 150 m</td>
</tr>
<tr>
<td>Drill collars - capacity and length (6 1/4&quot;)</td>
<td>3,13 litre/ m length 285 m</td>
</tr>
<tr>
<td>Capacity - open hole / drill collars</td>
<td>15,18 litre/ m</td>
</tr>
<tr>
<td>Capacity - open hole / HWDP</td>
<td>23,32 litre/ m</td>
</tr>
<tr>
<td>Capacity - 9 5/8” casing / HWDP</td>
<td>24,99 litre/ m</td>
</tr>
<tr>
<td>Capacity - open hole / drill pipe.</td>
<td>23,32 litre/ m</td>
</tr>
<tr>
<td>Capacity - 9 5/8” casing / drill pipe</td>
<td>24,99 litre/ m</td>
</tr>
<tr>
<td>9 5/8” casing shoe strength</td>
<td>1,86 sg equivalent</td>
</tr>
<tr>
<td>Slow Circulating Rate pressure at 30 SPM.</td>
<td>20 bar with 1,68 sg mud.</td>
</tr>
</tbody>
</table>

### KICK DATA

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well depth</td>
<td>3700m TVD</td>
</tr>
<tr>
<td>Shut in drill pipe pressure (SIDPP)</td>
<td>30 bars.</td>
</tr>
<tr>
<td>Shut in casing pressure (SICP)</td>
<td>52 bar.</td>
</tr>
<tr>
<td>Drilling mud weight</td>
<td>1,68 sg</td>
</tr>
<tr>
<td>Kick volume</td>
<td>1, 6 m3.</td>
</tr>
</tbody>
</table>
04.01. The shut in well.

1. The figure shows the shut in well with the data given on
   the previous page.

2. Before it was drilled out of the casing shoe the
   following data was collected according to the data given
   on the previous page.

   SCRp = 20 bar w/ 30 SPM / 1,68 sg mud

3. After the 9 5/8” shoe was drilled out a leak off test was
   carried out and the strength of the formation calculated
   to 1,86 sg equivalent mud weight.

4. As soon as the shut in drill pipe pressure (SIDPP)
   has stabilised the kill mud weight must be
   calculated so that 30 – 40 m3 of kill mud can be
   prepared.

   \[
   \text{Kill mud weight} = 1,68 \text{ sg} + \frac{30 \text{ bar}}{3700 \text{ ft.} \times 0.0981} = 1.77 \text{ sg}
   \]

Based on the well data on the previous page, the following pump strokes can be calculated:

- Pump strokes from the surface (drill floor) to the bit = 1983 STR
- Pump strokes from the bit to the choke = 5658 STR

As stated earlier, the main object is to keep the bottom hole pressure constant when circulating
out a kick and stabilising the well.

In the field additional margins is added to the kill mud weight and the backpressure on the choke, to
prevent any additional influx during the killing operation.
04.02. Establish circulation correct.

1. As soon as the Kill mud weight has been decided on the drill crew can establish circulating correctly and circulate out the kick.

2. To establish circulation correctly implies to keep the bottom hole pressure constant while going from a static shut in to a circulating situation. In order to keep the bottom hole pressure constant while the pump speed increases to 35 SPM, the choke is opened and operated such that the casing pressure is kept constant.

3. A constant casing pressure plus the mud and kick columns in the annulus keeps the bottom hole pressure constant if it is assumed that there is no pressure drop in the annulus at slow pumping rates. Consequently the SCRp = 20 bar is the pressure drop in the drill string which need to be added to the shut in pressure 30 bar, giving the initial circulating pressure (ICP) of 50 bar.
04.03. Circulate out influx.

1. As soon as the circulation is established correctly as described on the previous page, the influx is circulated out by keeping the drill pipe pressure constant.

2. If the influx is gas, the gas expands as it is circulated up the annulus, the light gas column increases and the casing pressure must be increased to keep the bottom hole pressure constant.

3. In this example the initial circulating pressure (ICP = 50 bar) was established as the sum of the shut in drill pipe pressure (SIDPP = 30 bar) and the pressure drop in the drill string (SCRp = 20 bar) at 35 SPM and 1,68 sg mud.

In the field this may not be correct. If a nozzle or to in the bit has plugged or if the 1,68 sg mud properties (viscosity) has changed or if the length of the drill string has increased due to a few 100 m of hole has been drilled since the pressure drop in the drill string (SCRp) was recorded, then pressure drop in the drill string may be more than 20 bar used in this example.
04.04. Circulate killmud to bit.

1. When the influx has been circulated out after 5658 pump strokes and the whole annulus is filled with clean 1,68 sg mud, the casing pressure levels off to a constant pressure, which are 30 bars in this example.

2. By keeping this casing pressure constant, the bottom hole pressure is kept constant and the 1,77sg kill mud can be pumped down the drill string through the bit nozzles.

3. As the kill mud is pumped down the drill string, the drill pipe pressure drops approx. 30 bars, which has been added in equivalent mud weight to the 1,68 sg mud to get the proper kill mud weight.

4. However when the kill mud passes through the bit nozzles the kill mud causes an increase in the friction loss in the drill string. The friction loss in the drill string with 1,68 sg mud was in this example 20 bar. With 1,77 sg kill mud in the drill string the friction loss is:

\[
FCP = 20 \text{ bar} \times \frac{1.77 \text{ sg}}{1.68 \text{ sg}} = 21 \text{ bar}.
\]
04.05. Circulate killmud from bit to choke.

1. When the kill mud has passed the nozzles in the bit after 7,641 pump strokes, the bottom hole pressure is kept constant by keeping the drill pipe pressure constant, which in this example is FCP = 21 bar.

2. When kill mud is pumped into the annulus the casing pressure can be reduced as the kill mud column in the annulus increases.

3. When the kill mud reaches the choke after a total of 13,300 pump strokes, the well is stabilised, the choke is 100% open and the casing pressure 0 bars.
05. Wait and Weight method - vertical well.

With the Drillers method an influx is circulated out and the well stabilised by the use of both the drill pipe and the casing pressure gauges.

With the Wait and Weight method a plan is made - a kill graph - on how the circulating drill pipe pressure should be reduced when kill mud is circulated from the surface to the bit. As opposed to Drillers method only the drill pipe gauge readings are used during the whole well killing operation.

The Wait and Weight method can be divided into the following four (4) working sequences:

1. **PREPARATIONS AND DATA COLLECTION.** (Prior to drilling out a casing shoe)

2. **WELL IS SHUT IN DUE TO AN INFLUX / KICK.**

3. **ESTABLISH CIRCULATION.** (Approx. 40 pump strokes +/-)

4. **CIRCULATE OUT THE INFLUX / KICK.**

Within each of these working sequences only the first priority work will be performed and discussed i.e. only the calculations and preparations that **must** be done during one working sequence prior to continuing on the next working sequence. When all the **musts** are taken care of for all the working sequences, attention can be directed towards the work that **ought** to be done and finally the work that would be **nice** to do.

On the following page this principle and basis is visualised in more detail.
05.01. Wait and Weight method - working sequences.

**Working sequence no.1:**

<table>
<thead>
<tr>
<th>PREPARATIONS AND DATA COLLECTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>What MUST be done or calculated?</td>
</tr>
<tr>
<td>What information MUST we have to carry out what we MUST do or calculate?</td>
</tr>
<tr>
<td>Prior to working sequence no. 2.</td>
</tr>
</tbody>
</table>

**Working sequence no.2:**

<table>
<thead>
<tr>
<th>WELL IS SHUT IN DUE TO AN INFLUX / KICK</th>
</tr>
</thead>
<tbody>
<tr>
<td>What MUST be done or calculated?</td>
</tr>
<tr>
<td>What information MUST we have to carry out what we MUST do or calculate?</td>
</tr>
<tr>
<td>Prior to working sequence no. 3.</td>
</tr>
</tbody>
</table>

**Working sequence no.3:**

<table>
<thead>
<tr>
<th>ESTABLISH CIRCULATION (Ca. 40 pump strokes +/-)</th>
</tr>
</thead>
<tbody>
<tr>
<td>What MUST be done or calculated?</td>
</tr>
<tr>
<td>What information MUST we have to carry out what we MUST do or calculate?</td>
</tr>
<tr>
<td>Prior to working sequence no. 4.</td>
</tr>
</tbody>
</table>

**Working sequence no.4:**

<table>
<thead>
<tr>
<th>CIRCULATE OUT THE INFLUX / KICK.</th>
</tr>
</thead>
<tbody>
<tr>
<td>In order to circulate out the influx / kick and stabilise the well</td>
</tr>
</tbody>
</table>

These working sequences will be illustrated and discussed on the pages that follows and with the well data given on the next page. Data collection and calculations will be shown on the PTTCO simplified Kick Control Sheet.
06. Wait and Weight kick operation - vertical well.

**WELL DATA.**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
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<tbody>
<tr>
<td>Surface volume</td>
<td>900 litres</td>
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</table>

**KICK DATA**

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<td>Shut in casing pressure (SICP)</td>
<td>52 bar.</td>
</tr>
<tr>
<td>Drilling mud weight</td>
<td>1,68 sg</td>
</tr>
<tr>
<td>Kick volume</td>
<td>2,8 m3.</td>
</tr>
</tbody>
</table>
06.01. Working sequence no. 1

PREPARATIONS AND DATA COLLECTION

Assuming that the bit and BHA is run in hole to top of the cementing plug inside the 9 5/8” casing and a practical kick drill has been carried out, the following data can be recorded on the kick control sheet as shown below:

- **Formation Strength Data:***
  - Surface Leak-off Pressure From Formation Strength Test
  - Drilling Fluid Density At Test
  - Max Allowable Drilling Fluid Density = \( A \times (G) \times \text{Shoe T.V. Depth} \times 0.0881 \)
  - Initial MAASP = \( (G) - \text{Current Density} \) \times \text{Shoe T.V. Depth} \times 0.0881

- **Current Well Data:***
  - Current Drilling Fluid:
    - Density

- **Casing Shoe Data:***
  - Size
  - M. Depth
  - TV. Depth

- **Hole Data:***
  - Size
  - M. Depth
  - TV. Depth

- **Pump No. 1 Displ.**
- **Pump No. 2 Displ.**

- **Slow Pump Rate Data**
- **Pump No. 1**
- **Pump No. 2**

- **Pre-recorded Volume Data**

- **Drill Pipe**
- **Heavy Wall Drill Pipe**
- **Drill Collars**

- **Drill String Volume**
  - \( (D) \)
  - \( (E) \)

- **DC x Open Hole**
- **DP x HWDP x Open Hole**

- **Open Hole Volume**
  - \( (F) \)

- **DP x Casing**

- **Total Annulus Volume**

- **Total Well System Volume**

- **Active Surface Volume**

- **Total Active Fluid System**

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(WAR 891)
27-Jan-2000
06.02. Working sequence no. 2

WELL IS SHUT IN DUE TO AN INFLUX / KICK.

The well is shut in and the kick data is recorded on the kick control sheet as shown on the next page.

Calculations and preparations required at this stage is based on the following assumptions

1. The well is close to vertical.
2. Circulation will be established according to API (RP-59), § 3.15 on page 9.
3. The Wait and Weigh method will be used.

The minimum preparations and calculations required at this stage are:

1. To calculate the kill mud weight and prepare the kill mud.
2. Construct the **static kill graph**.
06.03. Working sequence no. 3

ESTABLISH CIRCULATION

Provided proper amount of kill mud is ready and a proper **static kill diagram** has been prepared, establish circulation can start.

In order to establish circulation correct the mud pump stroke counter need to be zeroed. Then the pump should be brought slowly up to kill rate of 30 SPM while the choke is adjusted such that the casing pressure is kept constant at the shut in value.

As soon as uniform mud kill rate is achieved and a stable initial circulation pressure (ICP) is recorded, the following must be done:

1. As soon as the kill mud has reached the drill floor - 50 pump strokes - the mud pump stroke counter must be zeroed.
2. As soon uniform mud kill rate is achieved and a stable initial circulation pressure (ICP) is recorded, the static kill graph must be converted to a dynamic kill graph by
   - establishing the circulation pressure scale along the Y-axis on the kill graph
   
   \[ \text{ICP} = \text{SIDPP} + \text{SCRp} \]
   
   \[ = 30 \text{ bar} + 20 \text{ bar} \quad = 50 \text{ bar} \]
   
   - calculating the final circulating pressure and correct the curve on the graph.
   
   \[ \text{FCP} = 20 \text{ bar} \times \frac{1,77 \text{ sg}}{1,68 \text{ sg}} = 21 \text{ bar} \]

**NOTE**

If the slow circulation rate pressure data (SCRp = pressure loss in the drill pipe and through the bit nozzles) was recorded a long time ago prior to the influx, the SCRp figure should only be used for comparison.

If a few hundred feet of new hole has been drilled since the SCRp reading has been recorded and the mud properties has changed and a bit nozzle has been plugged prior to establishing circulation, the actual SCRp value would be higher than that value recorded earlier. Consequently the ICP would also be higher when establishing circulation. In such cases, as soon as stable initial circulation pressure (ICP) is recorded, the correct pressure loss in the drill pipe and through the bit nozzles - the SCRp - should be calculated as follows.

\[ \text{SCRp} = \text{ICP} - \text{SIDPP} \]

This calculated SCRp value should then be used to calculate the FCP.
06.04. Working sequence no. 4.

**CIRCULATE OUT THE INFLUX / KICK.**

At this stage the “must-work” has be done and the well killing operation according can proceed according to the dynamic kill graph until the well influx is circulated out of the hole and the well stabilised.

If it is agreed that all the **musts** work is accomplished for all the working sequences, attention can be directed towards the work that **ought** to be done and finally the work that would be **nice** to do. Calculations that belong to these categories may be the following.

1. Calculate the MAASP when the well is stabilised with kill mud?

2. Calculate when the bottom of the influx is inside the casing shoe?
   a) Volume in litre or m³?
   b) Number of pump strokes?
   c) How long time in hours and minutes?

3. Calculate when the influx is out of the well?
   a) Volume in litre or m³?
   b) Number of pump strokes?
   c) How long time in hours and minutes?

4. Calculate the density of the influx?

5. etc., etc., etc.,........

For the calculation of the annular volumes in point 2 and 3 above, there is space on the left hand side of the kick control sheet for organising, tabulating the data and calculations in the same manner as for the drill string volume as demonstrated on the kick control sheet on the next page.
06.05. Killing operation summary.
07. Wait and Weight kick operation - deviated well.

IWCF define a well with an angle larger than 45 degrees as a deviated or directional well.

To construct a Wait & Weigh kill graph for a deviated well the approach would be to apply the same practical working sequence as for a vertical well i.e.;

1. **PREPARATIONS AND DATA COLLECTION.** (Prior to drilling out a casing shoe)
2. **WELL IS SHUT IN DUE TO AN INFLUX / KICK.**
3. **ESTABLISH CIRCULATION.** (Approx. 40 pump strokes +/-)
4. **CIRCULATE OUT THE INFLUX / KICK.**

However, in addition to the calculations for a vertical well IWCF requires performing calculations for a Kick off Point (KOP) and an End of Build point (EOB), in order to develop a correct kill graph for a deviated well.

In order to demonstrate this, the working sequences above will be followed with the data on the figure below.

---

**Diagram Description:**

- **Pump capacity:** 16.0 liters/rev.
- **Original mud weight:** 1.22 kg
- **KOP:** 700 m MD & TVD
- **EOB:** 1126 m MD & 1600 m TVD
- **5" DP:** 5.97 liters/rev.
- **5" HVDP:** 4.61 liters/rev.
- **6 1/4" DC:** 4.01 liters/rev.
- **TD:** 2241 m MD & 3400 m TVD

---

**Note:** The figure shows a deviated well with various parameters and data points for calculations.
07.01. Working sequence no. 1

PREPARATIONS AND DATA COLLECTION

Assuming that the bit and BHA is run in hole to top of the cementing plug inside the 9 5/8” casing and a practical kick drill has been carried out, the following data can be recorded on the kick control sheet as shown:

---

**International Well Control Forum**

**Surface BOP Kill Sheet - Deviated Well (Metric/Bar)**

<table>
<thead>
<tr>
<th>FORMATION STRENGTH DATA:</th>
<th>CURRENT WELL DATA:</th>
</tr>
</thead>
<tbody>
<tr>
<td>SURFACE LEAK-OFF PRESSURE FROM FORMATION STRENGTH TEST</td>
<td>DRILLING FLUID DATA:</td>
</tr>
<tr>
<td>(A) bar</td>
<td>DENSITY kg/l</td>
</tr>
<tr>
<td>DRILLING FLUID DENS. AT TEST</td>
<td>GRADIENT bar/ft</td>
</tr>
<tr>
<td>(B) kg/l</td>
<td></td>
</tr>
<tr>
<td>MAX. ALLOWABLE DRILLING FLUID DENSITY =</td>
<td>DEVIATION DATA:</td>
</tr>
<tr>
<td>(A)</td>
<td>KOP M.D. m</td>
</tr>
<tr>
<td>SHOE T.V. DEPTH x 0.0981</td>
<td>KOP T.V.D. m</td>
</tr>
<tr>
<td>(C) kg/l</td>
<td>EOB M.D. m</td>
</tr>
<tr>
<td>INITIAL MAASP =</td>
<td>EOB T.V.D. m</td>
</tr>
<tr>
<td>(C) - Curr. DENS. x SHOE T.V. DEPTH x 0.0981</td>
<td>CASING SHOE DATA:</td>
</tr>
<tr>
<td>= bar</td>
<td>SIZE</td>
</tr>
<tr>
<td></td>
<td>M. DEPTH m</td>
</tr>
<tr>
<td></td>
<td>TV. DEPTH m</td>
</tr>
</tbody>
</table>

| HOLE DATA: |
| SIZE |
| M. DEPTH m |
| TV. DEPTH m |

| SLOW PUMP RATE DATA: |
| PUMP NO. 1 | PUMP NO. 2 |
| SPN | bar |
| SPN | bar |

| (P) DYNAMIC PRESSURE LOSS |
| PUMP NO. 1 | PUMP NO. 2 |
| SPN | bar |
| SPN | bar |

| PRE-RECORDED VOLUME DATA: |
| LENGTH | CAPACITY | VOLUME |
| m | l/m | litre |
| DP - SURFACE TO KOP | x | = |
| DP - KOP TO EOB | x | = |
| DP - EOB TO BHA | x | = |
| HEVI WALL DRILL PIPE | x | = |
| DRILL COLLAR | x | = |
| DRILL STRING VOLUME | (O) | 1 |
| DC x OPEN HOLE | x | = |
| DP / HYD/P x OPEN HOLE | x | = |
| OPEN HOLE VOLUME | (F) | 1 |
| DP x CASING | x | = (G) |
| TOTAL ANNULUS VOLUME | (F+G) = (H) | 1 |
| TOTAL WELL SYSTEM VOLUME | (H) | 1 |
| ACTIVE SURFACE VOLUME | (J) | 1 |
| TOTALACTIVE FLUID SYSTEM | (J+K) | 1 |

**PUMP STROKES**

| TIME |
| minutes |
| (L) | stkks |
| (M) | stkks |
| (N) | stkks |

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---
07.02. Working sequence no. 2

WELL IS SHUT IN DUE TO AN INFLUX / KICK.

The well is shut in and the kick data is recorded on the kick control sheet as shown on the next page.

Calculations and preparations required at this stage is based on the following assumptions

1. The well is close to vertical.
2. Circulation will be established according to API (RP-59), § 3.15 on page 9.
3. The Wait and Weigh method will be used.

The minimum preparations and calculations required at this stage are:

1. To calculate the kill mud weight and prepare the kill mud.
2. Construct the static kill graph.

The static kill graph as if the well was vertical.

For comparison the static kill graph is constructed assuming that the well is a vertical well.

Static calculations for the deviated well:
1. Kill mud weight = \( 1,52 + \frac{24}{1400 \times 0.09812} = 1,70 \text{ sg} \)

2. Kill mud at the drill floor

The Shut In Drill Pipe Pressure (SIDPP) when no kill mud has been pumped down below the drill floor.

Pumped volume: 0 Pump strokes

\( \text{SIDPP} = 25 \text{ bar} \)

3. Kill mud at the KOP

The remaining Shut in Drill Pipe Pressure (SIDPP) and the pumped volume when the kill mud has been pumped down to the KOP at 700 mMD (700 mTVD).

Pumped volume: \( 700 \times 8.97 = 6279 \text{ l} \) Giving 392 strokes

\( \text{SIDPP} = 24 \text{ - } [700 \times (1,70 - 1,52) \times 0.0981] = 12 \text{ bar} \)

Method no. 1:

Pore pressure in the kicking formation at TD 2541 m MD & 1400 m mTVD is.

\( 1400 \times 1.52 \times 0.0981 = 209 \text{ bar} \)

\( \text{SIDPP} = 25 \text{ bar} \)

Pore pressure in the kicking formation = 233 bar

Hydrostatic pressure due to the 1.70 sg kill mud column

\( 700 \times 1.70 \times 0.0981 = 117 \text{ bars} \)

Hydrostatic pressure due to the 1.52 sg original mud column

\( (1400 - 700) \times 1.52 \times 0.0981 = 104 \text{ bar} \)

Total hydrostatic mud pressure = 221 bar

Subtracting the hydrostatic pressures from the formation pore pressure gives the Shut-In Drill Pipe Pressure (SIDPP) with the kill mud at the KOP at 700 m MD & TVD.

**Shut in drill pipe pressure (IDPP):** 233 bar - 221 bar = 12 bar

Method no. 2:

A more efficient method of calculating the remaining shut in drill pipe pressure is;

\( \text{SIDPP} = 24 - [700 \times (1,70 - 1,52) \times 0.0981] = 12 \text{ bar} \)
4. **Kill mud at EOB.**

The remaining Shut In Drill Pipe Pressure (SIDPP) and the volume pumped when the kill mud has been pumped down to the EOB at 1120 m MD & 1030 m TVD.

Pumped volume: \(1120 \times 8.97 = 10046\) l \ giving \(627\) strokes.

\[
SIDPP = 24 - [1030 \times (1.70 - 1.52) \times 0.0981] = 6\ \text{bar}
\]

5. **Kill mud at the bit.**

The remaining Shut In Drill Pipe Pressure (SIDPP) and the volume pumped when the kill mud has been pumped down to the bit at 2541 m MD & 1400 m TVD.

**Pumped volume:**

\[
(174 \times 4.01) + (112 \times 4.6) + (2541 - 174 - 112) \times 8.97 = 21440\ \text{l}
\]

\[
giving\ \boxed{1340\ \text{strokes}}\]

\[
SIDPP = 24 - [1400 \times (1.70 - 1.52) \times 0.0981] = 0.0\ \text{bar}
\]

These shut in drill pipe pressures and the corresponding pump stroke values are then plotted on a graph paper to give the static kill graph as shown on the next page with pump strokes along the x-axis and the static drill pipe pressures along the y-axis.
Dynamic kill curve

Pressure (ICP - FCP) bar

0 200 400 600 800 1000 1200 1400 1600

0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300 320 340 360 380 400 420 440 460

0 200 400 600 800 1000 1200 1400 1600

0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300 320 340 360 380 400 420 440 460

0 200 400 600 800 1000 1200 1400 1600

0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300 320 340 360 380 400 420 440 460

0 200 400 600 800 1000 1200 1400 1600

0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300 320 340 360 380 400 420 440 460

0 200 400 600 800 1000 1200 1400 1600

0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300 320 340 360 380 400 420 440 460

0 200 400 600 800 1000 1200 1400 1600

0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300 320 340 360 380 400 420 440 460

0 200 400 600 800 1000 1200 1400 1600

0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300 320 340 360 380 400 420 440 460
07.03. Working sequence no. 3

**ESTABLISH CIRCULATION.** (Approx. 40 pump strokes +/-)

Provided proper amount of kill mud is ready and a proper **static kill diagram** has been prepared, establish circulation can start.

In order to establish circulation correct the mud pump stroke counter need to be zeroed. Then the pump should be brought slowly up to kill rate of 25 SPM while the choke is adjusted such that the casing pressure is kept constant at the shut in value.

As soon as uniform mud kill rate is achieved and a stable initial circulation pressure (ICP) is recorded, the following must be done:

1. As soon as the kill mud has reached the drill floor the mud pump stroke counter must be zeroed.

2. As soon uniform mud kill rate is achieved and a stable initial circulation pressure (ICP) is recorded, the static kill graph must be converted to a dynamic kill graph by
   - establishing the circulation pressure scale along the Y-axis on the kill graph
     
     $\text{ICP} = \text{SIDPP} + \text{SCRp}$
     
     $= 24 \text{ bar} + 15 \text{ bar} = 39 \text{ bar}$
   
   - calculating the final circulating pressure and correct the curve on the graph.
     
     $\text{FCP} = \frac{1,70 \text{ sg}}{1,52 \text{ bar}} \times 15 \text{ bar} = 17 \text{ bar}$

**NOTE**

If the slow circulation rate pressure data (SCRp = pressure loss in the drill pipe and through the bit nozzles) was recorded a long time ago prior to the influx, the SCRp figure should only be used for comparison.

If a few hundred feet of new hole has been drilled since the SCRp reading has been recorded and the mud properties has changed and a bit nozzle has been plugged prior to establishing circulation, the actual SCRp value would be higher than that value recorded earlier. Consequently the ICP would also be higher when establishing circulation. In such cases, as soon as stable initial circulation pressure (ICP) is recorded, the correct pressure loss in the drill pipe and through the bit nozzles - the SCRp - should be calculated as follows.

$$\text{SCRp} = \text{ICP} - \text{SIDPP}$$

This calculated SCRp value should then be used to calculate the FCP.
07.04. Working sequence no. 4

CIRCULATE OUT THE INFLUX / KICK.

At this stage the work that must be done is to continue the well killing operation according to the dynamic kill graph until the well influx is circulated out of the hole and the well stabilised.

If it is agreed that all the musts work is accomplished for all the working sequences, attention can be directed towards the work that ought to be done and finally the work that would be nice to do. Calculations that belong to these categories may be the following.

1. Calculate the MAASP when the well is stabilised with kill mud?

2. Calculate when the bottom of the influx is inside the casing shoe?
   a) Volume in litre or m³?
   b) Number of pump strokes?
   c) How long time in hours and minutes?

3. Calculate when the influx is out of the well?
   a) Volume in litre or m³?
   b) Number of pump strokes?
   c) How long time in hours and minutes?

4. Calculate the density of the influx?

5. etc, etc, etc,........
08. The IWCF formula approach

By the IWCF approach the following formula is used:

\[ CP'x' = ICP + \left( (FCP - PL) \times \frac{Dx_{MD}}{D_{total_{MD}}} \right) - (Dx_{TVD} \times (Kill\ Fluid\ Grad. - Current\ Fluid\ Grad)) \]

Where:

- \( CP'x' \) = Circulating Pressure at kill pump rate at depth 'x'
- \( ICP \) = Initial circulating pressure
- \( FCP \) = Final circulation pressure
- \( PL \) = Dynamic pressure loss as measured during the slow pump rate test during the drilling phase and with the current (old) drilling fluid gradient.
- \( Dx_{MD} \) = Measured depth at depth 'x'
- \( D_{total_{MD}} \) = Measured depth at total depth
- \( Dx_{TVD} \) = The true vertical depth at point 'x'

08.01. The IWCF kick control sheet - deviated well

The IWCF kick control sheet for a deviated well follows on the next three pages.
CHAPTER 3 – PRACTICAL WELL CONTROL OPERATIONS

International Well Control Forum
Surface BOP Kill Sheet - Deviated Well (Metric/Bar)

KICK DATA:
SIDPP bar
SICP bar
PIT GAIN litre

KILL FLUID DENSITY
CURRENT DRILLING FLUID DENSITY + SIDPP
KMD

\[ \text{KMD} + \frac{\text{SIDPP}}{\text{TVD} \times 0.0981} = \text{kg/l} \]

INITIAL CIRC. PRESS.
ICP bar

\[ \text{ICP} + \text{SIDPP} = \text{bar} \]

FINAL CIRCULATING PRESSURE
FCP bar

\[ \text{KILL FLUID DENSITY} \times \frac{\text{KOPMD}}{\text{TDMD}} \times \left( \frac{\text{SIDPP} \times \text{KOPTVD} - \text{KMD} \times \text{OMD} \times 0.0981 \times \text{EOBTVD}}{\text{EOBMD} \times \text{TDMD}} \right) = \text{bar} \]

DYNAMIC PRESSURE LOSS AT KOP (O)

\[ \text{DPL} \times \left( \frac{\text{FCP}-\text{PL}}{\text{TDMD}} \right) = \left( \frac{\text{KOPMD}}{\text{TVD}} \right) \times \left( \frac{\text{SIDPP} \times \text{KOPTVD} - \text{KMD} \times \text{OMD} \times 0.0981 \times \text{EOBTVD}}{\text{EOBMD} \times \text{TDMD}} \right) = \text{bar} \]

REMAINING SIDPP AT KOP (P)

\[ \text{SIDPP} \left( \frac{\text{KMD} \times \text{OMD} \times 0.0981 \times \text{KOPTVD}}{\text{EOBMD} \times \text{TDMD}} \right) = \text{bar} \]

CIRCULATING PRESS. AT KOP (KOP CP)

\[ (\text{O}) + (\text{P}) = \text{bar} \]

DYNAMIC PRESSURE LOSS AT EOB (R)

\[ \text{DPL} \times \left( \frac{\text{FCP}-\text{PL}}{\text{TDMD}} \right) = \left( \frac{\text{KOPMD}}{\text{TVD}} \right) \times \left( \frac{\text{SIDPP} \times \text{KOPTVD} - \text{KMD} \times \text{OMD} \times 0.0981 \times \text{EOBTVD}}{\text{EOBMD} \times \text{TDMD}} \right) = \text{bar} \]

REMAINING SIDPP AT EOB (S)

\[ \text{SIDPP} \left( \frac{\text{KMD} \times \text{OMD} \times 0.0981 \times \text{EOBTVD}}{\text{EOBMD} \times \text{TDMD}} \right) = \text{bar} \]

CIRCULATING PRESS. AT EOB (EOB CP)

\[ (\text{R}) + (\text{S}) = \text{bar} \]

\[ \frac{(T) \times 100}{(L)} = \frac{(U) \times 100}{(M)} = \frac{(W) \times 100}{(N1+N2+N3)} = \text{bar} \]

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09. The horizontal well.

Drill pipe pressure at 30 SPM up annulus = 19 bar with 1.68 sg mud.

Drill pipe pressure at 30 30 SPM up choke line = 30 bar with 1.68 sg mud.
10. The volumetric method.

The volumetric method can be used in a well control situation when:

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

For the volumetric method with a drill string in the well API refers to the formula,

\[
\text{Pressure increase (psi) per barrel vented} = \frac{MW \times 53.5}{HD^2 - PD^2}
\]

Where:
- \(MW\) = Drilling fluid density (lb./gal)
- \(HD\) = Inside diameter of the wellbore at the top of the gas (inch)
- \(PD\) = The outside diameter of the pipe, tubing, or collars at the top of the gas (use 0 if gas is below the bit)

Further API assumes,

“Normally after the initial 100 psi increase in pressure the gas can be assumed to be inside the casing or in the open hole at nearly the casing diameter, therefore \(HD^2\) is the square of the casing inside diameter and \(PD^2\) is the square of the drill pipe outside diameter.”

In other words, API assumes that the influx migrates in a uniform annulus after approximately 100 psi increase in the shut in casing pressure.

To avoid formulas and confusion when explanation the basic of the volumetric method it is assumed that the drill string has been pulled out of the hole. Further it is assumed that gas has entered the well from a low permeability zone at the bottom of the hole while pulling the drill string out of the hole and that:

1. The well is vertical
2. The gas influx was discovered when the drill string was out of the hole and the well shut in
3. The capacity of the casing is equal to the capacity of the pen hole
4. The shut in casing pressure, the mud weight and the gas influx balances the pore pressure

Based on these assumptions the two phases of the volumetric method is explained on the following two pages.
10.01. Migration of the influx.

1. The well is shut in after the drill string is pulled out of the hole. The well is shut in due to an influx and in this example the shut in casing pressure stabilises at 30 bars.

2. After a certain time the gas influx will start to migrate up the hole and the shut in casing pressure will increase.

3. In this example we let the shut in casing pressure increase with 3 bars to 33 bars. This 3 bar pressure increase result in 3 bar increase in the bottom hole pressure, an overbalance we choose as the safety margin.

4. Due to the continuous migration of the gas influx the shut in casing pressure and the bottom hole pressure continues to increase. If no action is performed, the casing and bottom hole pressures continues to increase which may result in a breakdown of the formation below the casing shoe. In this example an incremental increase of 2 bars is selected resulting in a 35 bar shut in casing pressure.

5. In order to reduce the pressure on the well with 2 bar a hydrostatic mud column equivalent to 2 bar need to be bled off through the choke while the gauge pressure is kept constant at 35 bars. In a vertical well the volume to be bled of is calculated as follows;

\[
H = \frac{2 \text{ bar}}{1.60 \text{ sg} \times 0.0981} = 12.7 \text{ m} \\
\text{Volume: } 12.7 \text{ m} \times 23.6 \text{ l/m} = 300 \text{ l}
\]

When 300 l of 1,60 l mud is bled off while the casing pressure is kept constant at 35 bar the pressure on the well is reduced by 2 bars. The safety margin of 3 bars on bottom is maintained.

6. The migration of the gas influx continues and the casing pressure increases from 35 bar to 37 bar and consequently the bottom hole pressure increases 2 bar.

7. When 300 l of 1,60 l mud is bled off while the casing pressure is kept constant at 37 bar the pressure on the well is reduced by 2 bars.

8. The procedure described in pt. 4, 5 and 6 is then continued until all the gas is accumulated below the BOP and the 3 bar safety margin to prevent an additional influx during the operation.
10.02. Evacuation of the migrated gas.

1. It is assumed that the shut in casing pressure stabilises at 68 bar when all the gas is accumulated below the BOP.

2. As previous calculations shows that 300 l of 1,60 sg mud gives a hydrostatic pressure of 2 bars in this vertical well with a uniform capacity of 23,6 l/m the pump is hooked up and 300 l mud is pumped into the well.

3. When 300 l mud is pumped into the gas volume below the BOP, the gas is compressed and the casing gauge pressure increases. As a result the bottom hole pressure increases equivalent to this increased casing gauge pressure plus 2 bar due to the hydrostatic mud column.

4. To reduce this increase in bottom hole pressure the choke is opened and gas bled off until the casing gauge pressure is reduced to 64 bar.

5. Again 300 l of 1,60 sg mud is pumped into the gas volume below the BOP. As the same fluid volume is pumped into a smaller gas volume the casing gauge should show a higher compression pressure.

As in point 2 above the bottom hole pressure increases again an equivalent to this increase in casing gauge pressure plus 2 bar due to the hydrostatic mud column.

6. To reduce this increase in bottom hole pressure the choke is opened and gas bled off until the casing gauge pressure is reduced to 62 bar.

7. This procedure is then continued until all the gas is replaced with 1,60 sg mud.

If the initial gas influx occurred due to an underbalance in the well with 1,60 sg mud in the hole the casing pressure gauge will show this underbalance pressure, when all the gas has been replaced with 1,60 sg mud. However all the gas is removed and actions can be planned to increase the mud weight and kill the well.
01. Valves installed in the drill string.

01.01. Kelly Cock or Full Opening Safety Valve “FOSV”

The Kelly cock is a ball valve and is a part of the upper part of the drilling equipment and also a part special safety equipment located in a special stand on drill floor close to rotary table. If the rig is using Kelly as drilling device, one manual Kelly cock is placed at each end of the Kelly. Depending of its position decides whether it is called lower or upper Kelly cock. If a TDS (top drive) is used, normally two Kelly cocks, one manual and one remote operated Kelly cock are a part of the drilling assembly. Its function is to seal off the drill string in case of any surface equipment fails, when circulating out a kick or to stop and avoid back flow in the string if the well starts flowing during tripping in or out of the well.

The minimum requirements for a Kelly cock are:

- Inside diameter must be at least as large as the internal diameter of the Kelly.
- Pressure rating should be minimum the expected pressure in the well, but normally it will have the same rating as the BOP.

The Kelly cock valves should be tested during each blowout preventer test.

Important issues:

- Must not be run in the hole in closed position.
- Very often leaks through valve crank sleeve.
- Must have the right key to be operated.
Kelly Safety Valve

As mentioned above the Kelly cock located on drill floor (Kelly safety valve) will always be stored in open position. In some cases a special wheel is screwed in the box end and even with a special dedicated winch hooked to it. On drill floor it should be available Kelly cocks with different size of threads or available x-over during the different operations. These valves should be full opening with a smooth bore. To be able to make up the Kelly cock in the drill string if there is back flow out of the string, the valve has to be in full open position. Then the Kelly valve can be closed using the special key. At this stage there is time to close the BOP.

Kelly safety valves should also be tested during each blowout preventer test.

![Fig. 5.01 Kelly cock.](image)
01.02. Table for pipe dimension and tool joint threads.

<table>
<thead>
<tr>
<th>Pipe Dimension</th>
<th>Tool Joint Threads</th>
</tr>
</thead>
<tbody>
<tr>
<td>3-1/2&quot; DP</td>
<td>NC38 3-1/2&quot;IF</td>
</tr>
<tr>
<td>4-3/4&quot; DC</td>
<td>NC38 3-1/2&quot;IF</td>
</tr>
<tr>
<td>5&quot; DP</td>
<td>NC50 4-1/2&quot;IF</td>
</tr>
<tr>
<td>6-3/4&quot; DC</td>
<td>NC50 4-1/2&quot;IF</td>
</tr>
<tr>
<td>5-1/2&quot; DP</td>
<td>5-1/2&quot;FH</td>
</tr>
<tr>
<td>6-5/8&quot; DP</td>
<td>6-5/8&quot;FH</td>
</tr>
<tr>
<td>8&quot; DC</td>
<td>6-5/8&quot;Reg</td>
</tr>
<tr>
<td>9-1/2&quot; DC</td>
<td>7-5/8&quot;Reg</td>
</tr>
</tbody>
</table>

01.03. Float valve.

Some operators are installing a float valve in the drill string. It will be either a flapper type or spring loaded check valve type. Both types will be installed in the string in a special sub, very often the bit sub is drilled for float. The intention to have a float in the string is to avoid backflow through the string, while tripping in the hole and to minimize the risk of getting formation fluid to enter the drill string when the influx occurs.

If there is a float valve installed in the drill string, it makes it more difficult to read SIDPP. To avoid this problem some flappers are furnished with a ceramic orifice, but it will still minimize the back flow.
Important issues:

Advantage:

- The valve prevents formation fluids from entering the drill string which might create problems with cuttings that causing plugging off nozzles etc.

Disadvantage:

- The drill pipe must be filled when running in.
- More complicated to read shut in drill pipe pressure (SIDPP).
- Reverse circulation is impossible.
- Larger surge effect on the formation when running in with the drill string.
- Increases the overall tripping time.

![Fig. 5.02 Float, Baker SPD.](image)

6. Shock Absorber
01.04. Inside BOP.

An inside BOP is similar to a drill pipe float valve in that fluid can be pumped automatically through the device, pressure from below automatically forced it closed.

There are two general types of inside BOP’s.

The dart type consists of a back pressure valve pinned in the open position so that the valve can be stabbed while mud is flowing. After the valve is installed, the pin is removed to release the dart and this allows the inside BOP to close. Since inside BOP’s are not full opening, stabbing them in may not be as easy as stabbing a safety valve.

The other type of inside BOP is the pump down, or drop, version. It requires that some type of landing sub be present in the drill string. This landing sub is usually located at the bottom color and it does not interfere with normal drilling operations. The inside BOP is pumped down to the landing sub.

The valve should be available on the drilling floor and with a thread corresponding to that of the lower Kelly cock.

When the valve is not in use, it should be kept locked in an open position.

The capacity of holding pressure equals the expected wellbore pressure, but should normally be the same pressure held by the blowout preventer.

The valve must be tested from below, with the same frequency and pressure as the BOP.

Important issues:

- Must be pumped in open position to enable reading of SIDPP.
- Is held in open position by a bolt that is fastened with a T handle.
- It is not possible to run a wire line through the valve.
Fig. 5.03 inside BOP
01.05. Dart and Dart sub

Another kind of safety device to minimize the risk of getting the influx into the drill string is the dart and dart sub. This tool consists of two parts, one dart sub installed at top of the BHA in the drill string and one dart, which fits into the dart sub, stored in the dog house on drill floor.

Operational sequence: The dart sub is permanent part of the drill string and when the situation occurs the dart will be dropped from surface and when it hits the sub it will latch on to it. Then it will act like a back pressure valve. The dart is wire line retrievable.

Important issues:

- Must be pumped in open position to enable reading of SIDPP.
- It is not possible to run a wire line through the valve.

Fig. 5.04 inside BOP, Dart sub
01.06. Installation of string valves when tripping/stripping

1. Install "Kelly cock" in open position
2. Close «Kelly cock” after installing.
3. Install “inside BOP” above “Kelly cock”.
4. Open «Kelly cock” before tripping-/stripping operation

02. Blowout Preventers

02.01. A need for blowout preventers.

The pressure control system must perform four vital functions:

1. A means of closing the top of the hole completely or around the drill pipe or collars.
2. A means of controlling the venting of gas, gas cut fluid, saltwater or other combination of possible kick fluids.
3. A means of pumping into a hole while circulating the well kick.
4. A means of stripping pipe into or out the well.
02.02. Classification of Blowout Preventers.

API classification of example arrangements for blowout preventer equipment is based on working pressure ratings. Example stack arrangements shown in figs. 5.04 and 5.05 should prove adequate in normal environments.

The recommended component codes for designation of blowout preventer stack arrangements are as follows:

A  = Annular type blowout preventer  
G  = Rotating Head  
R  = Single ram type preventer with two sets of rams, positioned in accordance with operators choice.  
Rd = Double ram type preventer with one set of rams, either blank or for pipe, as operator prefers.  
Rt = Triple ram type preventer with three sets of rams, positioned in accordance with operator’s choice.  
S  = Drilling spool with side outlet connections for choke and kill lines  
M  = 1000 psi rated working pressure

Components are listed reading upward from the uppermost piece of permanent wellhead equipment, or from the bottom of the preventer stack. A blowout preventer stack may be fully identified by a very simple designation, such as:

\[ 5M - \text{13}^{3/8} - RSRA \]

This preventer stack would be rated 345 bar (5000 psi) working pressure, would have a through bore of 13\(^{3/8}\) inches, and would be arranged as in Fig 5.05.
Fig. 5.05 Blowout preventer – 3M and 5M rated.

Fig. 5.06 Blowout preventer arrangements for 690 bar (10M) and 1034 bar (15M) working pressure service.
02.03. Subsea BOP

Minimum requirement for Subsea BOP:

- 2 Annulars.
- 2 Pipe rams.
- 1 Shear/blind ram.
- Outlet for choke and kill lines.
- Shear/blind rams and pipe rams must be equipped with integrated or remotely operated locking system, to lock the rams mechanically in locked position

A normal configuration for a subsea bop stack shown in Fig 05.07

There are small differences between surface and subsea Bop’s.

Some differences:

- Kill and choke lines are connected directly to the ram on a subsea stack.
- On a subsea stack kill and choke lines are connected so it gives more circulation possibilities when the Bop is closed ref fig. 5.07.
- Shear/blind rams and pipe rams must be equipped with integrated or remotely operated locking system, to lock the rams mechanically in locked position
- On a subsea Bop there must be two serial connected failsafe close valves. These valves are constructed so they will close off the hydraulic open pressure is lost. Closing force are hydrostatic sea water and spring. The valves must hold pressure from both sides.

Fig. 5.08 shows the lower part of the Bop mounted on a steel frame.

It consists of:

- A steel frame with four guide line posts for steering the Bop using guide lines. The steel frame will also protect the Bop against outer damage.
- A hydraulic connector for connecting the Bop to the wellhead.
- Annular (s), pipe rams and shear/blind ram.
- A hydraulic connector for connecting lower marin riser package (LMRP) to the Bop.
- Kill and choke outlets and lines, with two serial connected fail safe valves on each line.

Lower Marin Riser Package (LMRP), fig. 5.09, is connected to the BOP upper frame. It consists of guide funnels, the hydraulic operating units (Pod’s) an annular preventer, flex joint and connector. There are also couplings for kill and choke line, along the flex joint these lines are constructed to allow flexibility.
Fig. 05.07 Subsea BOP
Fig. 05.08 Lower part of the Subsea BOP mounted on a steel frame.
Fig. 5.09, LMRP Lower Marin Riser Package
Fig. 5.10, LMRP Lower Marin Riser Package without Control Pod and Accumulator bottles
CHAPTER 4 – WELL CONTROL EQUIPMENT

02.04 Inspection and Testing – Surface Installations.

02.04.01 Field Acceptance Inspection and Testing

The field acceptance procedure should be performed each time a new or reworked blowout preventer of unknown condition is placed in service.

Ram Type Preventers and Drilling Spools.
The following are recommended inspections and tested for this equipment:

1. Visually inspect the body and rig grooves (vertical, horizontal, or ram bore) for damage, wear, and pitting.

2. Check bolting, both studs and nuts, for proper type, size, and condition.

3. Check ring-joint gaskets for proper type and condition.

4. Visually inspect ram type preventers for:
   - Wear, pitting, and/or damage to the bonnet or door seal area, bonnet or door seal grooves, ram bores, ram connecting rod, and ram operating rods.
   - Packer wear, cracking, and excessive hardness.
   - Measure ram and ram bore to check for maximum vertical clearance according to manufacturer’s specifications. This clearance is dependent on type, size, and trim of the preventers.
   - If preventer has secondary seals, inspect secondary seals and remove the plugs to expose plastic packing injection ports used for secondary sealing purposes. Remove the plastic injection screw and the check valve in this port. (Some preventers have a release packing regulating valve that will need to be removed.) Probe the plastic packing to ensure it is soft and not energizing the seal. Remove and replace packing if necessary.

5. Hydraulically test with water using the following procedure:
   - Connect closing line(s) to preventer(s).
   - Set the preventer test tool on drill pipe below preventer(s) if testing preventer with pipe rams.
Check for closing chamber seal leaks by applying closing pressure to close the rams and check for fluid leaks by observing opening line port(s). Closing pressure should be equivalent to the manufacturer’s recommended operating pressure for the preventer’s hydraulic system.

Release closing pressure, remove closing line(s) and connect opening line(s).

Check for opening chamber seal leaks by applying opening pressure to open rams and check for fluid leaks by observing closing line port(s). Opening pressure should be equivalent to the manufacturer’s recommended opening pressure for the preventer’s hydraulic system.

Release opening pressure and reconnect closing line(s)

Check for ram packer leaks at low pressure by closing rams with 103 bar (1500-psi) operating pressure and apply pressure under rams to 14 -20 bar (200-300-psi) with blowout preventer test tool installed (when testing preventer containing pipe rams). Hold for three minutes. Check for leaks. If ram packer leaks refer to step 9. If ram packer does not leak, proceed to step 8.

Check for ram packer leaks by increasing pressure slowly to the rated working pressure of the preventer. Hold for three minutes. Check for leaks. If ram packer leaks, proceed to step 9.

If rams leak, check for worn packers and replace if necessary. If the preventer is equipped with an automatic locking device, check same for proper adjustment in accordance with manufacturer’s specifications. Continue testing until a successful test is obtained.

Test the connecting rod for adequate strength by applying opening pressure as recommended by the manufacturer with rams closed and blowout preventer rated working pressure under the rams.

Release opening pressure and release pressure under rams.

Repeat procedure (steps 1 through 9) for each set of pipe rams.

Test blind rams in same manner as pipe rams (step1, steps 3 through 9) with test plug installed but test joint removed.
Annular Blowout Preventers and Diverters

Following are recommended inspections and for this equipment:

1. Visually inspect:

   - Studded face of preventer head for pitting and damage, particularly in ring groove and stud holes.
   - Body for wear and damage.
   - Vertical bore for wear and damage from drill string and drill tools.
   - Inner sleeve for pitting and damage. Look through slots in base of inner liner for cuttings that might be trapped, thereby preventing full movement of the piston.
   - Packer for wear, cracking, excessive hardness, and correct elastomer composition.
   - Bolting (both studs and nuts) for proper type, size, and condition.
   - Ring-joint gaskets for proper type and condition.

2. Hydraulic test using the following procedure:

   - Connect closing line to preventer.
   - Set blowout preventer test tool on drill pipe below preventer.
   - Test the seals between the closing chamber and wellbore and between the closing chamber and opening chamber by closing preventer and applying manufacturer’s recommended closing pressure. If other chambers are located between the wellbore and operating chamber, this seal should also be tested.
02.04.02. Periodic Field Testing.

**Blowout Preventer Operating Test**

A preventer operating test should be performed on each round trip but not more than once per day. The test should be conducted as follows while tripping the drill pipe with the bit just inside casing:

a. Install drill pipe safety valve.

b. Operate the choke line valves.

c. Operate adjustable chokes. Caution: Certain chokes can be damaged if full closure is affected.

d. Position blowout preventer between equipment to check choke manifold. Open adjustable chokes and pump through each choke manifold to ensure that it is not plugged. If choke manifold contains brine, diesel, or other fluid to prevent freeze-up in cold weather, some other method should be devised to ensure manifold, lines, and assembly are not plugged.

e. Close each preventer until all pipe rams in the stack have been operated. Caution: Do not close pipe rams on open hole. If blind rams are in the stack, operate these rams while out of hole.

f. Return all valves and preventers to their original position and continue normal operations. Record test results.

g. Annular preventers need to be operated on each round trip. They should, however, be operated at an interval not to exceed seven (7) days.
02.04.03. Blowout Preventer Hydraulic Test

The following items should be checked each time a preventer is to be hydraulically tested:

a. Verify wellhead type and rated working pressure.
b. Check for wellhead bowl protector.
c. Verify preventer type and rated working pressure.
d. Verify drilling spool, spacer spool, and valve types and rated working pressures.
e. Verify ram placement in preventers and pipe ram size.
f. Verify drill pipe connection size and type in use.
g. Open casing valve during test, unless pressure on the casing or hole is intended.
h. Test pressure should not exceed the manufacturer’s rated working pressure for the body or the seals of the assembly being tested.
i. Test pressure should not exceed the values for tensile yield, collapse.
j. Verify the type and pressure rating of the preventer tester to be used.

<table>
<thead>
<tr>
<th>Table</th>
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<tbody>
<tr>
<td><strong>Test Pressure Recommendations</strong></td>
</tr>
<tr>
<td>Blowout Preventer stack rated working pressure (or as specified in Notes below.)</td>
</tr>
<tr>
<td></td>
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<tr>
<td></td>
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<tr>
<td></td>
</tr>
<tr>
<td>Rated Working Pressure of preventers or 207 bar (3000-psi), whichever is less</td>
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<tr>
<td></td>
</tr>
<tr>
<td>Casing test pressure</td>
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<td></td>
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<tr>
<td>50% of rated working pressure of components</td>
</tr>
<tr>
<td>14 -20 bar (200-300 psi.)</td>
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</table>
Note!

1. Initial test pressure for the blowout preventer stack, manifold, valves, etc., should be the lesser of the rated working pressure of the preventer stack, wellhead, or upper part of the casing string.
2. Optional test – a rated working pressure test on the top flange of the annular preventer. A companion test flange will be required.

An initial pressure test should be conducted on all preventer installations prior to drilling the casing plug. Conduct each component pressure test for at least three minutes. Monitor secondary seal ports and operating lines on each preventer while testing to detect internal seal leaks.

Subsequent pressure tests of blow out preventer equipment should be performed after setting a casing string, prior to entering a known pressure transition zone, and after a preventer ram and/or any preventer stack or choke manifold component change; but less than once every 21 days.

Equipment should be tested to at least 70% of the preventer rated working pressure, but limited to lesser of the rated working pressure of the wellhead or 70% of the minimum internal yield pressure of the upper part of the casing string; however, in no case should these or subsequent test pressure be less than the expected surface pressure. An exception is the annular preventer, which may be tested to 50% of its rated working pressure to minimize pack-off element wear or damage. After a preventer stack or manifold component change, hydraulically test in accordance with an initial pressure test and the table above.

Precautions should be taken not to expose the casing to test pressures in excess of its rated strength. A means should be provided to prevent pressure build up on the casing in the event the test tool leaks.

02.04.04. Auxiliary Equipment Testing.

The lower Kelly valve, Kelly, Kelly cock, and inside blow out preventer should be tested to the same pressure as the blow out preventer stack at the same time the preventer assembly tests are made. This equipment should be tested with pressure applied from below.

02.04.05. Test Plugs and Test Joints.

Several makes of test plugs are available for testing preventer stacks. The testing tool arrangement should provide for testing the bottom blow out preventer flange. Test plugs generally fall into two types, hanger type and cup type.

A cup type pressure element holds pressure from above. Some models contain a back pressure valve to bypass fluid when going in the hole.
03. Annulars and Rams

03.01. Annulars.

An annular preventer is a steel-ribbed rubber packing element which when activated can seal on any diameter of pipe in the well bore or the open hole itself.

The flexibility of the annular preventer makes it often the one chosen when first shutting in a well or if pipe needs to be stripped back into the hole.

The four basic components to the annular preventer are the head, body, piston, and steel-ribbed packing element. When the preventer’s closing mechanism is actuated, hydraulic pressure is applied to the piston, causing it to slide upwards. This forced the packing element to extend into the well bore around the drill string. The preventer element is opened by applying hydraulic pressure to slide the piston downward, this return the packing element to its original position.

Some of the advantages to using an annular preventer are listed below:

1. Even if the preventer is closed, the drill string can still be reciprocated.
2. The drill string can be stripped in and out of the hole.
3. Closure can be obtained on the Kelly.
4. Closure can be obtained on drill collars.
5. Closure can be made on any member of a tapered drilling string.
6. The annular preventer can perform as a master gate by complete closure.

Packer element:

The three basic “rubber-like” materials used in the manufacture of the elements include:

<table>
<thead>
<tr>
<th>Packer Element Type</th>
<th>Recommended Usage</th>
</tr>
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<tbody>
<tr>
<td>Natural Rubber</td>
<td>Water based mud with less than 5% oil. Operating temperatures from -30° to 225°F (-35° to 107°C). Applicable for H2S service.</td>
</tr>
<tr>
<td>Nitrile Rubber (Synthetic)</td>
<td>Oil based mud with operating temperatures from 32° to 190°F (0° to 88°C). Applicable for H2S service.</td>
</tr>
<tr>
<td>Neoprene</td>
<td>Oil based mud with operating temperatures from -30° to 170°F (-35° to 77°C). Applicable for H2S service.</td>
</tr>
</tbody>
</table>

Two important issues that need to be checked before installing a new packing element:

1. Temperature limits to the packing element.
2. Type of mud.
03.01.01. Hydril Type GL.

Hydril GL operating features:

1. Designed and developed for both surface and subsea installations.
2. Closing pressure must be increased as well pressure increases.
3. It has a secondary chamber designed to balance riser hydrostatic pressure in subsea systems.
4. Surface installations: Secondary chamber can be connected in two ways to optimise operations for different effects:
   a. Minimize closing/opening fluid volumes.
   b. Reduce closing pressure.

**Hydril GL**

Fig. 5.07 Hydril GL.
03.01.02. Hydril Type GK.

Hydril GK operating features:

1. Designed for use on surface installations.
2. Sealing assistance is gained from the well pressure after initial seal off.

Closing operation

Open position. Closing action begins Close position. Seal around drill pipe.

Fig. 5.08 Hydril GK.
03.01.03. Shaffer Spherical.

Shaffer manufacture annular preventers that are operating at the same general principle as the Hydril annulars. The annular preventers, called the spherical are widely used.

Shaffer Spherical operating features:

1. Low operating pressure.
2. Will close on open hole.
3. Good stripping service.
4. Slight sealing assistance is gain from the well pressure.

Fig. 5.09: Closing operations for Shaffer Spherical.
Schaffer Spherical

Fig. 5.10 Shaffer Spherical
03.01.04. Cameron/Cooper D type

The “D” annular closing pressure forced the operating piston and pusher plate upward, which displaces the solid elastomer donut and forces the packer inward. As the packer closes, steel reinforcing insert rotate inward to form a continuous steel support ring at the top and bottom of the packer. The insert remain in contact with each other whether the packer is open, closed on pipe, or closed on open hole.

Cooper “D” operating features:

1. Sealing assistance is gained from well pressure.
2. Will close on open hole.
3. Low vertical height.
4. Low element weight.
5. Requires less fluid to open and close the element than comparable models. But at a higher pressure.

**Cameron/Cooper type D**

Fig. 5.11 Cameron/Cooper type D type.
Ratio well pressure versus operation pressure for an annular

The graph shows the ratio, for a closed annular, between well pressure and closing pressure via pipe size.
03.02. Rams.

Pipe rams are sealing elements designed to close off the well bore with blocks of steel having rubber seals affixed to them. Ram preventers derive their name from the hydraulic cylinder and ram shaft which move the sealing ram blocks.

Rams are controlled by a double acting piston that is operated by the hydraulic fluid pressure in the accumulators.

The ratio of well bore pressure to the pressure required for closure is called the "CLOSING RATIO".

The ratio of well bore pressure to opening pressure is called the "OPENING RATIO".

Ram designs allow well bore pressure to reach the back side of the pistons which assist in holding the rams closed.

Ram locking mechanisms are also available which lock the rams closed in the event that hydraulic pressure is lost.

Some of the spare parts, which should be available on the rig at all times for ram type preventers include:

1. A complete set of drill pipe rams and rubbers for each size of drill pipe being used.
2. A complete set of bonnet or doors seals for each size and type of ram preventer being used.
3. Plastic packing for blow out preventer secondary seals.
4. Ring gaskets to fit flange connections.

Ram preventers are available with inter-changeable sealing assemblies called ram blocks. There are four types of ram blocks:

1. Pipe rams.
2. Blind rams.
3. Shear rams.
4. Variable bore rams.
Pipe rams are comparatively rigid and are designed to close around a specific size of pipe, typically drill pipe or tubing. A pipe rams will not effectively close on a tool joint. Each ram is equipped with pipe guides which position the body of the pipe in the centre of the ram and assure that the pipe is not crushed before the seal is obtained.

A drill string can be “hung off”, which means a tool joint shoulder is positioned just above a closed and locked set of rams, so that the rams are supporting the weight of the string below it.

Fig. 5.12 Cameron/Cooper U type Pipe Rams.
03.02.02. Blind Rams.

Blind rams closed in the well when there is no pipe in the wellbore. The element is flat-faced and contains a rubber section. If pipe is accidentally present upon closing, it will be crimped or crushed and seal will not be made.

03.02.03. Shear Rams.

Blind/shear rams are actually a special type of blind ram with shear blades attached. As the name implies, shear rams will cut pipe present in the hole as they close and seal the open hole. Before shearing the pipe, pipe rams with hang off capability must be closed below the shear rams in order to keep the free end of the drill string from falling to the bottom of the well. Since shear rams will not cut a tool joint, space must be provided between the pipe rams and the shear rams to allow room for the tool joint. Without pipe in the wellbore, they perform like blind rams.

03.02.04. Variable – Bore Rams.

Multiple-size or variable-bore rams are an adaptation of the annular preventer’s sealing element design in ram blocks. These rams are designed for closure and sealing on a given range of drill pipe outside diameters. Multiple-size rams use standard ram block holders to house their rubber sealing element. This provides for changeability with regular rams. An additional plus for these rams is that they can be used when there is a tapered pipe string in the well.

03.02.05. Ram Operation.

With the application of hydraulic closing pressure, the ram shafts move the ram blocks into the wellbore. When the rams themselves meet, extrusion plates in the front face of the ram force the sealing rubber section to be in continual tight contact with the drill pipe, even after the rubber itself has become worn. This mechanism of “forced rubber feed” explains why pipe rams become damaged if they are routinely closed on open hole. Rams with a two piece ram block assembly will compress the rear rubber into contact with the ram cavity sealing surface.

Ram preventers are designed to hold pressure from the lower side.

It is wellbore pressure which forces the ram blocks into a tighter seal at the upper sealing surface and across the front face of the blocks.
Cameron/Cooper type U II

Double ram type preventer with two sets of rams, shear rams and variable bore-rams.

Fig. 5.13 Cameron/Cooper U II type double ram.
03.02.06. Cooper ram.

**Cooper type U operating features:**

1. Designed for both surface and subsea operations.
2. Well pressure helps maintain rams closed and increases the sealing force.
3. Rams can be changed and repaired in the field.
4. Has secondary rod seal.
5. A wedge lock mechanism is available to hydro mechanically lock the rams.

**Cooper type U II operating features:**

1. Short stroke bonnet reduces the opening stroke by about 30%, reduces the BOP overall length, and reduces the weight supported by the ram change piston compared to the original type “U” BOP.
2. The BOP has an internally ported hydraulic bonnet tensioning system.

**Fig. 5.12 Show the most important parts to the U II rams.**

- Locking screw.
- Bonnet.
- Bolt bonnet.
- Housing, locking screw.
- Cylinder, ram change.
- Ram change piston, open.
- Ram change piston, close.
- Piston operating.
- Cylinder operating.
- Intermediate flange.
- Seal bonnet.
- Rams assembly.
- Body single.
Fig. 5.14  the most important parts to the U II ram.
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U BOP Pipe Ram Assembly

Shearing/blind Ram Assembly
03.02.07. Shaffer SL Ram.

**Shaffer SL operating features**

1. Available in a wide range of sizes and pressure ratings.
2. Ram can be changed and repaired in the field.
3. PosLock or MultiLock or UltraLock system locks the rams automatically each time the rams are closed. Manual locks are also available.

![Fig. 5.17 Shaffer SL double ram type preventer with one shear ram and one pipe ram.](image-url)
Shaffer SL pipe Ram Assembly

Shaffer SL Shear Ram Assembly
Shaffer SL Multi Ram Assembly

03.02.08. Hydril ram

Hydril ram operating features:

1. Offered in a full range of sizes and pressure ratings.
2. Available with manual locking systems or automatic (Multiple Position Locking – MPL) systems.
3. Secondary rod sealing system.
4. Rams are designed to permit drill pipe “hang off”.
5. Cylinder liner and upper seal seat is field replaceable or field repairable.
Hydril 13 5/8" 10,000 psi/690 bar pipe rams with manual locking systems.

Fig. 5.21 Hydril 13 5/8" 10,000 psi/690 bar pipe rams:
Hydril 18 3/4" 10.000 psi/690 bar pipe rams with automatic (Multiple Position Locking – MPL) systems:

Fig. 5.22 Hydril 18 3/4" 10.000 psi/690 bar pipe rams.
03.02.09. Closing ratios.

Fig. 5.23

Pressure condition when closing = \[
\frac{\text{Operating piston area}}{\text{Piston rod area}}
\]

The closing pressure, which is necessary to close the rams with maximum allowed working pressure in the wellbore = \[
\frac{\text{BOP working pressure}}{\text{Closing ratio}}
\]

Example 1: Shaffer 18 3/4" – 690 bar/10000 psi working pressure.

Closing ratio (pipe rams and shear rams) = 7,11

Closing pressure for to close the rams = \[
\frac{690 \text{ bar/10000 psi}}{7,11} = 97 \text{ bar/1406 psi}
\]

Example 2: Hydril 18 3/4" – 1034 bar/15000 psi
Closing ratio (pipe rams and shear rams) = 7.27

\[
\text{Closing pressure for to close the rams} = \frac{1034 \text{ bar}/15000 \text{ psi}}{7.27} = 142 \text{ bar}/2060 \text{ psi}
\]

Example 2 shows that not all pipe rams close against max. working pressure on the well head at a set normal operating pressure of 100 bar/1450 psi

04. Choke manifolds – Surface installations.

04.01. Purpose.

If the hydrostatic head of the drilling fluid is insufficient to control subsurface pressure, formation fluids will flow into the well. To maintain well control, backpressure is applied by routing the returns through adjustable chokes until the well flow condition is corrected. The chokes are connected to the blowout preventer stack through an arrangement of valves, fittings, and lines, which provide alternative flow routes or permit the flow to be halted entirely. This equipment assemblage is designated the “choke manifold.”

04.02. Design Considerations.

Choke manifold design should consider such factors as anticipated formation and surface pressures, method of well control to be employed, surrounding environment, corrosively, volume, toxicity, and abrasiveness of fluids.
04.03. Installation Guidelines.

Recommended practises for planning and installation of choke manifolds for surface installations include:

a. Manifold equipment subject to well and/or pump pressure (normally upstream of and including the chokes) should have a working pressure equal to the rated working pressure of the blow-out preventers in use. This equipment should be tested when installed in accordance with the BOP initial pressure test.

b. Components should comply with applicable API specifications to accommodate anticipated pressure, temperature, and corrosiveness of the formation fluids and drilling fluids.

c. For working pressures of 200 bar (3M) and above, flanged, welded, or clamped connections should be employed on components subjected to well pressure.

d. The choke manifold should be placed in a readily accessible location, preferably outside the rig substructure.

e. The choke line (which connects the blowout preventer stack to the choke manifold) and lines downstream of the choke should:
   1. Be as straight as practicable; turns, if required, should be targeted.
   2. Be firmly anchored to prevent excessive whip or vibration.
   3. Have a bore of sufficient size to prevent excessive erosion or fluid friction:
      1. Minimum recommended size for choke lines is 3-in. nominal diameter
         (2-in. nominal diameter is acceptable for class 2M installations)
      2. Minimum recommended size for vent lines downstream of the chokes is 2-in. nominal diameter.
      3. For high volumes and air or gas drilling operations, minimum 4-in. nominal diameter lines are recommended.

Alternate flow and flare routes downstream of the choke line should be provided so that eroded, plugged, or malfunctioning parts can be isolated for repair without interrupting flow control.

Consideration should be given to the low temperature properties of the materials used in installations to be exposed to unusually low temperatures.
The bleed off line (the vent line which by-passes the chokes) should be at least in diameter to the choke line. This line allows circulation of the well with the preventers closed while maintaining a minimum of backpressure. It also permits high volume bleed off of well fluids to relieve casing pressure with the preventers closed.

Lines downstream of the choke manifold are not normally required to contain pressure, but should be tested during the initial installation.

Although not shown in the example equipment illustrations, buffer tanks are sometimes installed downstream of the choke assemblies for the purpose of manifolding the bleed lines together. When buffer tanks are employed, provision should be made to isolate a failure or malfunction without interrupting flow control.

Pressure gauges suitable for drilling fluid service should be installed so that drill pipe and annulus pressures may be accurately monitored and readily observed at the station where well control operations are to be conducted.

All choke manifold valves subject to erosion from well flow should be full-opening and designed to operate in high-pressure gas and drilling fluid service. Double, full-opening valves between the blowout preventer stack and the choke line are recommended for installations with rated working pressures of 5M and above.

For installations with rated working pressures of 5M and above the following are recommended:
- One of the valves should be remotely actuated.
- At least one remotely operated choke should be installed.

Spare parts for equipment subject to wear or damage should be readily available.

Testing, inspection and general maintenance of choke manifold components should be performed on the same schedule as employed for the blowout preventer stack in use.

All components of the choke manifold system should be protected from freezing by heating, draining or filling with appropriate fluid.
04.04. Illustrated examples of choke manifolds.

Fig 5.24 and 5.25 illustrate example of choke manifolds with various working pressure. Refinements or modifications such as additional hydraulic valves and choke, redundant pressure gauges, and/or manifolding of vent lines may be dictated by the conditions anticipated for a particular well and the degree of protection desired. The guidelines discussed and illustrated represent examples of industry practice.

![Choke Manifold Diagram](image)

**EXAMPLE CHOKE MANIFOLD ASSEMBLY FOR 2M AND 3M RATED WORKING PRESSURE SERVICE – SURFACE INSTALLATION**

Fig. 5.24 Choke manifold assembly (138-200 bar WP):
CHAPTER 4 – WELL CONTROL EQUIPMENT

Fig. 5.25 Choke manifold assembly (345 bar WP):
05. Closing units – Surface installations.

05.01. Accumulator Requirements.

**General**

Accumulator bottles are containers which store hydraulic fluid under pressure for use in effecting blowout preventer closure. Through use of compressed nitrogen gas, these containers store energy, which can be used to effect rapid preventer closure. There are two types of accumulator bottles in common usage, separator and float types. The separator type uses a flexible diaphragm to effect positive separation of the nitrogen gas from the hydraulic fluid. The float type utilizes a floating piston to effect separation of the nitrogen gas from the hydraulic fluid.
Volumetric Capacity

1. As a minimum requirement, all blowout preventer closing units should be equipped with accumulator bottles with sufficient volumetric capacity to provide the usable fluid volume (with pumps inoperative) to close: One pipe ram and the annular preventer in the stack plus the volume to open the hydraulic choke line valve.

2. Usable fluid volume is defined as the volume of fluid recoverable from an accumulator between the accumulator operating pressure and 14 bar (200 psi) above the precharge pressure. The accumulator operating pressure is the pressure to which accumulators are charged with hydraulic fluid.

The minimum recommended accumulator volume (nitrogen plus fluid) should be determined by multiplying the accumulator size factor (refer to Table below) times the calculated volume to:

- Close the annular preventer and one pipe ram plus the volume to open the hydraulic choke line valve.

Table: Accumulator pressures and volume.

<table>
<thead>
<tr>
<th>Accumulator Operating Pressure, bar (psi)</th>
<th>Minimum Recommended Precharge Pressure, bar (psi)</th>
<th>Usable Volume* (Fraction of bottle size)</th>
<th>Fluid Accumulator Size Factor*</th>
<th>Size</th>
</tr>
</thead>
<tbody>
<tr>
<td>103bar (1500psi)</td>
<td>51 bar (750 psi)</td>
<td>1/8</td>
<td></td>
<td>8</td>
</tr>
<tr>
<td>138bar (2000psi)</td>
<td>69 bar (1000psi)</td>
<td>1/3</td>
<td></td>
<td>3</td>
</tr>
<tr>
<td>207bar (3000psi)</td>
<td>69bar (1000psi)</td>
<td>½</td>
<td></td>
<td>2</td>
</tr>
</tbody>
</table>

Notes:
*(Based on minimum discharge pressure of 83 bar (1200 psi):

Response Time

The closing system should be capable of closing:

- Each ram preventer within 30 seconds.
- Closing time should not exceed 30 seconds for annular preventers smaller than 18 \(\frac{3}{4}\) inches.
- Closing time should not exceed 45 seconds for annular preventers 18 \(\frac{3}{4}\) inches and larger.
Operating Pressure and Precharge Requirements for Accumulators.
No accumulator bottle should be operated at a pressure greater than its rated working pressure. The precharge pressure on each accumulator bottle should be measured during the initial closing unit installation on each well and adjusted if necessary.

Only nitrogen gas should be used for accumulators precharge.
The precharge pressure should be checked frequently during well drilling operations.

Requirements for Accumulator Valves, Fittings, and Pressure Gauges
Multi-bottle accumulator banks should have valves for bank isolation. An isolation valve should have a rated working pressure at least equivalent to the designed working pressure of the system to which it is attached and must be in the open position except when accumulators are isolated for servicing, testing, or transporting. Accumulator bottles may be installed in banks of approximately 605 litres (160 gallons) capacity if desired, but with a minimum of two banks.

The necessary valves and fittings should be provided on each accumulator bank to allow a pressure gauge to be readily attached without having to remove all accumulator banks from service. An accurate pressure gauge for measuring the accumulator precharge pressure should be readily available for installation at any time.

05.02. Closing Unit Pump Requirements

Pump Capacity Requirements
Each closing unit should be equipped with sufficient number and sizes of pumps to satisfactorily perform the operation described in this paragraph:

With the accumulator system removed from service, the pumps should be capable of closing the annular preventer on the size drill pipe being used plus opening the hydraulically operated choke line valve and obtain a minimum of 14 bar (200 psi) pressure above accumulator precharge pressure on the closing unit manifold within two (2) minutes or less.

Pump Pressure Rating Requirements
Each closing unit must be equipped with pumps that will provide a discharge pressure equivalent to the rated working pressure of the closing unit.
Pump Power Requirements

Power for closing unit pumps must be available to the accumulator at all times, such that the pumps will be automatically start when the closing unit manifold pressure has decreased to less than 90% of the accumulator operating pressure.

Two or three independent sources of power should be available on each closing unit. Each independent source should be capable of operating the pumps at a rate that will satisfy the requirement described in - 05.02.01. The dual source power system recommended is an air system plus an electrical system. Minimum recommendations for the dual power source systems are as follows:

a. A dual air/electrical system may consist of the rig air system (provided at least one air compressor is driven independent of the rig compound) plus the rig generator (refer to Fig. 5.27).

b. A dual air system may consist of the rig air system (provided at least one air compressor is driven independently of the rig compound) plus an air storage tank that is separated from both the rig air compressors and the rig air storage tank by check valves. The minimum acceptable requirements for the separate air storage tank are volume and pressure which will permit use of only the air tank to operate the pumps at a rate that will satisfy the operation described in the pump capacity requirements (refer to 05.02.01)

c. A dual electrical system may consist of the normal generating system and a separate generator.

d. A dual air/nitrogen system may consist of the rig air system plus bottled nitrogen gas.

e. A dual electrical/air system may consist of the rig generating system and bottled nitrogen gas.

On shallow wells where the casing being drilled through is set at 152 m or less and where surface pressures less than 200 psi (14 bars) are expected, a backup source of power for the closing unit is not essential.
05.03. Requirements for closing unit valves, fitting lines, and manifold.

All valves and fittings between the closing unit and the blowout preventer stack should be of steel construction with a rated working pressure at least equal to the working pressure rating of the stack up to 207 bar (3000 psi). All lines between the closing unit and blowout preventer should be of steel or an equivalent flexible, fire-resistant hose and end connections with a rated working pressure equal to the stack pressure rating up to 207 bar (3000 psi).
05.04. Valves, Fittings, and other Components Required.

Each installation should be equipped with the following:

A. Each closing unit manifold should be equipped with a full-opening valve into which a separate operating fluid pump can be easily connected.

B. Each closing unit should be equipped with sufficient check valves or shut-off valves to separate both the closing unit manifold and to isolate the annular preventer regulator from the closing unit manifold.

C. Each closing unit should be equipped with accurate pressure gauges to indicate the operating pressure of the closing unit manifold, both upstream and downstream of the annular preventer pressure-regulating valve.

D. Each closing unit should be equipped with a pressure-regulating valve to permit manual control of the annular preventer operating pressure.

E. Each closing unit equipped with a regulating valve to control the operating pressure on the ram type preventers should be equipped with a by-pass line and valves to allow full accumulator pressure to be placed on the closing unit manifold, if desired.

F. Closing unit control valves must be clearly marked to indicate (1) which preventer or choke line valve each control valve operates, and (2) the position of the valves (i.e., open, closed, neutral). Each blowout preventer control valve should be turned to the open position (not the neutral position) during drilling operations.

G. Each annular preventer may be equipped with a full-opening plug valve on both the closing and opening lines. These valves should be installed immediately adjacent to the preventer and should be in the open position at all times except when testing the operating lines. This will permit testing of operating lines in excess of 103 bar (1500 psi) without damage to the annular preventer if desired by the user.

05.05. Requirements for Closing Unit Fluids and Capacity.

A suitable hydraulic fluid (hydraulic oil or fresh eater containing a lubricant) should be used as the closing unit control operating fluid. Sufficient volume of glycol must be added to any closing unit fluid containing water if ambient temperatures below 0° C are anticipated. The use of diesel oil, kerosene, motor oil, chain oil, or any other fluid similar is not recommended due to the possibility of resilient seal damage.

Each closing unit should have a fluid reservoir with a capacity equal to at least twice the usable fluid with a capacity of the accumulator system.
05.06. Closing Unit Location and Remote Control Requirements.

The main pump accumulator unit should be located in a safe place, which is easily accessible to rig personnel in an emergency. It should also be located to prevent excessive drainage or flow back from the operating lines to the reservoir. Should the main pump accumulator be located a substantial distance below the preventer stack, additional accumulator volume should be added to compensate for flow back in the closing lines.

Each installation should be equipped with a sufficient number of control panels such that the operation of each blowout preventer and control valve can be controlled from a position readily accessible to the driller and also from an accessible point at a safe distance from the rig floor.

05.07. Closing Unit Pump Capability Test.

Prior to conducting any tests, the closing unit reservoir should be inspected to be sure it does not contain any drilling fluid, foreign fluid, rocks, or other debris. The closing unit pump capability test should be conducted on each well before pressure testing the blowout preventer stack. This test can be conveniently scheduled either immediately before or after the accumulator closing time test. Test should be conducted according to the following procedure:

a. Position a joint of drill pipe in the blowout preventer stack.

b. Isolate the accumulator from the closing unit manifold by closing the required valves.

c. If the accumulator pumps are powered by air, isolate the rig air system from the pumps. A separate closing unit air storage tank or a bank of nitrogen bottles should be used to power the pumps during this test. When a dual power source system is used, both power supplies should be tested separately.

d. Simultaneously turn the control valve for the annular preventer to the closing position and turn the control valve for the hydraulically operated valve to the opening position.

e. Record the time (in seconds) required for the closing unit pumps to close the annular preventer plus open the hydraulically operated valve and obtain 14 bar (200 psi) above the precharge pressure on the closing unit manifold. It is recommended that the time required for the closing unit pumps to accomplish these operations not exceed two minutes.

f. Close the hydraulically operated valve and open the annular preventer. Open the accumulator system to the closing unit and charge the accumulator system to its designed operating pressure using the pumps.
05.08. Accumulator Tests.

**Accumulator Precharge Pressure Test.**

This test should be conducted on each well prior to connecting the closing unit to the blowout preventer stack. Test should be conducted as follows:

a. Open the bottom valve on each accumulator bottle and drain the hydraulic fluid into the closing unit fluid reservoir.

b. Measure the nitrogen precharge pressure on each accumulator bottle, using an accurate pressure gauge attached to the precharge measuring point, and adjusts if necessary.

**Accumulator Closing Test.**

This test should be conducted on each well prior to pressure testing the blowout preventer stack. Test should be conducted as follows:

a. Position a joint drill pipe in the blowout preventer stack.

b. Close off the power supply to the accumulator pumps.

c. Record the initial accumulator pressure. This pressure should be designed operating pressure of the accumulators. Adjust the regulator to provide 103 bar (1500-psi) operating pressure to the annular preventer.

d. Simultaneously turn the control valves for the annular preventer and one for pipe ram (having the same size ram as the pipe used for testing) to the closing position and turn the control valve for the hydraulically operated valve to the opening position.

e. Record the time required for the accumulators to close the preventers and open the hydraulically operated valve. Record the final accumulator pressure (closing unit pressure). This final pressure should be at least 14 bar (200 psi) above the precharge pressure.

f. After the preventers have been opened, recharge the accumulator system to its designed operating pressure using the accumulator pumps.
05.09. Blowout preventer closing unit arrangements.

Example from API RP 53

Fig. 5.28 Blowout preventer closing unit arrangements
Schematic of typical blowout preventer control system

1. CUSTOMER AIR SUPPLY: Normal air supply is at 8 bar (125 psi). Higher air pressures may require a reducing valve for No. 88660 air pumps.

2. AIR LUBRICATOR: Located on the air inlet line to the air operated pumps. Use SAE 10 lubricating oil.

3. BYPASS VALVE: To automatic hydro-pneumatic pressure switch. When pressures higher than the normal 207 bar (3000 psi) are required, open this valve. Keep closed all other times.

4. AUTOMATIC HYDRO-PNEUMATIC PRESSURE SWITCH: Pressure switch is set to 200 bar (2900 psi) cut-out when air and electric pumps are used. Otherwise set at 207 bar (3000 psi) for air pumps alone. Adjustable.

5. AIR SHUT-OFF VALVES: Manually operated – to open or close the air supply to the air operated hydraulic pumps.

6. AIR OPERATED HYDRAULIC PUMPS: Normal operating air pressure is 8 bar (125 psi.)


8. SUCTION STRAINER: One for each air operated hydraulic pump suction line. Have removable screens.

9. CHECK VALVE: One for each air operated hydraulic pump delivery line.

10. ELECTRIC MOTOR DRIVEN TRIPLEX OR DUPLEX PUMPS ASSEMBLY.

11. AUTOMATIC HYDRO-ELECTRIC PRESSURE SWITCH: Pressure switch is set at 207 bar (3000 psi) cut-out and 16 bar (250 psi) cut-in differential. Adjustable.

12. ELECTRIC MOTOR STARTER (AUTOMATIC): Automatically starts or stops the electric motor driving the triplex or duplex pump. Works in conjunction with the automatic hydro-electric pressure switch.

13. SUCTION SHUT-OFF VALVE: Manually operated, normally open. Located in the suction line of the triplex or duplex pump.
14. SUCTION STRAINER: Located in the suction line of the triplex or duplex pump.

15. CHECK VALVE: Located in the delivery line of the triplex or duplex pump.

16. ACCUMULATOR SHUT-OFF VALVE: Manually operated. Normally in open position when the unit is in operation. Close when testing or skidding rig or when applying pressure over 207 bar (3000 psi) to open side of ram preventers. OPEN WHEN TEST IS COMPLETED.

17. ACCUMULATORS: Check nitrogen precharge in accumulator system every 30 days. Nitrogen precharge should be 69 bar (1000 psi ± 10 %.) CAUTION: Use NITROGEN when adding to precharge. Other gases and air may cause fire and/or explode.

18. ACCUMULATOR RELIEF VALVE: Valve set to relieve at 241 bar (3500 psi).

19. FLUID STRAINER: Located on the inlet side of the pressure reducing and regulating valves.

20. KOOMEY PRESSURE REDUCING AND REGULATING VALVE: Manually operated. Adjust to the required continuous operating pressure of ram type BOP’s.

21. CHECK VALVE: Located on the delivery side of the pressure reducing and regulating valve.

22. 4-WAY VALVES: With air cylinder operators for remote operation from the control panels. Keep in open position when controls are not in use.

23. BYPASS VALVE: With air cylinder operators for remote operation from the control panels. Keep closed unless 207 bar (3000 Psi) (or more) is required on ram type BOP’s.

24. MANIFOLD RELIEF VALVE: Valve set to relieve at 380 bar (5500 psi).

25. HYDRAULIC BLEEDER VALVE: Manually operated – normally closed.  
   NOTE: This valve should be kept OPEN when pre charging the accumulator bottles.

26. PANEL-UNIT SELECTOR: Manual 3-way valve. Used to allow pilot air pressure to the air operated pressure reducing and regulating valve, either from the air regulator on the unit or from the air regulator on the control panel.
27. PRESSURE REDUCING AND REGULATING VALVE – AIR OPERATED: Reduces the accumulator pressure to the required annular operating pressure. Pressure can be varied for stripping operations. Maximum downstream pressure for the annular preventer should not be exceeded.

28. ACCUMULATOR PRESSURE GAUGE.

29. MANIFOLD PRESSURE GAUGE.

30. ANNULAR PREVENTER PRESSURE GAUGE.

31. PNEUMATIC PRESSURE TRANSMITTER FOR ACCUMULATOR PRESSURE.

32. PNEUMATIC PRESSURE TRANSMITTER FOR MANIFOLD PRESSURE.

33. PNEUMATIC PRESSURE TRANSMITTER FOR ANNULAR PREVENTER PRESSURE.

34. AIR FILTER: Located on the supply line to the air regulators.

35. AIR REGULATOR FOR KOOMEY PRESSURE REDUCING AND REGULATING VALVE – AIR OPENED.

36. AIR REGULATOR FOR PNEUMATIC TRANSMITTER FOR BAG PRESSURE, ACCUMULATOR PRESSURE AND MANIFOLD PRESSURE:
   Air Regulator Controls for Items 31, 32, 33, Pneumatic Pressure Transmitter: Normal pressure setting on regulators for pneumatic pressure transmitters is 8 -10 bar (12 to 15 psi). Calibrate the receiver gauges located on the panel to hydraulic pressure gauge on the unit in this manner
   1. Hydraulic pressure gauge should be at the highest operating range of the system; i.e., accumulator and manifold pressure gauges are at 207 bar (3000 psi) and the annular preventer pressure gauge is at 103 bar (1500 psi).
   2. Increase or decrease air pressure, using the air regulators provided, to calibrate panel gauge to hydraulic pressure gauge on the unit.

37. AIR JUNCTION BOX: To connect the air lines on the unit to the air lines coming from the remote control panels through air cable.

38. FLUID LEVEL INDICATOR.

39. HYDRAULIC FLUID FILL HOLE.
40. RIG SKID AND TEST LINE – 4-WAY VALVE: Manually operated, open centre.
   Accumulator Position: Valves handle to the right position. Test Position: Valves handle to
   the centre position. Skid Position: Valve handle to the left position.
   CAUTION: Return valve handle to accumulator position after skidding or testing.

41. CHECK VALVE: Located on the outlet line from the rig skid and test valve and inlet line to
   the accumulators.

42. RIG SKID RELIEF VALVE: Located on the rig skid line.

43. RIG SKID CUSTOMER CONNECTION.

44. TEST LINE CUSTOMER CONNECTION.

45. RIG SKID RETURN CUSTOMER’S CONNECTION.

46. INSPECTION PLUG.
Fig. 5.29 Blowout preventer control system
05.10. BOP remote control panels.

Fig. 5.30 BOP control panel – Surface installation.
Fig. 5.31 BOP control panel – Surface installation.
Fig. 5.32 Annular closing actions.
Fig. 5.33 Pipe ram closing actions.
05.11. Closing sequence with technical symbols

Fig. 5.34 Upper pipe rams in open position.
Fig. 5.35 Upper pipe rams start the closing action.
Fig. 5.36 Upper pipe in close position.
06. Accumulators.

06.01. Definitions.

Usable fluid: Usable fluid volume is defined as the volume of fluid recoverable from an accumulator between the accumulator operating pressure and 14 bar (200 psi) above the precharge pressure.

Absolute pressure: Gauge reading + 1 atm

Precharge pressure: Precharge pressure is defined as the pressure of nitrogen in the accumulator. 69 bar (1000 Psi).

Accumulator operating pressure: The accumulator operating pressure is the pressure to which accumulators are charged with hydraulic fluid. 207 bar (3000 Psi).

Minimum accumulator operating pressure: The minimum accumulator operating pressure is 14 bar (200 Psi) above the precharge pressure. 83 bar (1200 Psi).
ACCUMULATOR CALCULATION

THE GAS LAW.

\[ P_1 \times V_1 = P_2 \times V_2 = P_3 \times V_3 \]

Precharge Pressure:
- \( P_1 = 69 \text{ bar (1000 PSI)} \)
- \( V_1 = \text{Known} \)

Operating Pressure:
- \( P_2 = 207 \text{ bar (3000 PSI)} \)
- \( V_2 = ? \)

Minimum Operating Pressure:
- \( P_3 = 83 \text{ bar (1200 PSI)} \)
- \( V_3 = ? \)

Fluid
06.03. Calculation of usable fluid

**CALCULATION OF USABLE FLUID.**

1. **Start:**
   - $P_1 = 69 \text{ bar (1000Psi)}$
   - $V_1 = 38 \text{ liter}$

2. **The gas law:**
   - \[ P_1 \times V_1 = P_2 \times V_2 \]
   - \[ V_2 = \frac{P_1 \times V_1}{P_2} = \frac{69 \text{ bar}(1000 \text{ Psi}) \times 38 \text{ liter}}{207 \text{ bar}(3000 \text{ Psi})} = 12.7 \text{ liter} \]

3. **The gas law:**
   - \[ P_1 \times V_1 = P_3 \times V_3 \]
   - \[ V_3 = \frac{P_1 \times V_1}{P_3} = \frac{69 \text{ bar}(1000 \text{ Psi}) \times 38 \text{ liter}}{83 \text{ bar}(1200 \text{ Psi})} = 31.6 \text{ liter} \]

**Usable fluid** = $V_3 - V_2$

= 31.6 liter - 12.7 liter = **18.9 liter**
07. Control system for a Subsea BOP.

Goal:
The Participants shall be able to explain the functioning of a subsea BOP control system.

Focus points:

- Understand and apply both API and Ptil’s requirements to the control system on a floating unit.
- Understand the hydraulic control system for a Subsea BOP.

07.01. Requirements to the control system.

The control system for a subsea BOP is to some extent equivalent to the control system on a fixed platform.

Important issues in the API requirements (appendix 1 API RP 53):

Control Panels:

In addition to the Master panel there should at least be one remote panel, which should contain following functions:

- All functions shall be «dual actions”, which means that no functions can be activated with one hand.
- Control functions to override manifold regulator.
- Pressure gauge for accumulator pressure.
- Pressure gauge for Annular Preventer operating (regulator) pressure.
- Pressure gauge for manifold operating (regulator) pressure.
- Pressure gauge for Annular Preventer read back (pilot) pressure, which shows the actual pressure when the Annular Preventer opens or closes.
- Pressure gauge for manifold read back (pilot) pressure, which shows the actual pressure when either the Ram preventers or fail safe valves opens or closes.
- Flow meter which measures the required volume for each activated function.
- Rig Air Pressure gauge.
- Indicator pump start.
Operations from remote panel:

- Able to operate all BOP functions.
- Indicating all positions for functions on the BOP.
- Able to regulate Annular Preventer operating pressure.
- Able to regulate Ram Preventers operating pressure.

Alarms for:

- Low accumulator pressure.
- Low rig air pressure
- Low fluid level in hydraulic tank.

Accumulator capacities

API requirement

- Fluid enough to open and close an annular preventer + open and close all ram preventers
- Min. accumulator pressure is 14 bar (200 psi) above precharge pressure.
- Hydrostatic pressure water depth has to be added to precharge pressure in a subsea mounted accumulators.

NPDs requirements

1. Sufficient fluid to execute following operations: close + open + close +25% of all BOP operations

2. Min. accumulator pressure after the consumption of fluid in point 1 shall not be less than 14 bar (200 psi) the precharge pressure (N2).

3. Sufficient remaining pressure in the accumulators to cut the drill string after fluid consumption during operation like:
   - Close + open one annular preventer.
   - Close + open + close of one ram preventer.

4. Enough pressure to be able to disconnect lower marine riser package (LMRP) after the shearing of the drill string is done. Alternatively a backup system for the shear ram can be implemented.

5. While calculating the capacity of the subsea accumulators both water depth and temperature have to be taken into account.

6. Response time for all the valves are up to 45 sec.
7. An acoustic Back Up control system or another alternative control system to operate the pipe rams, shear ram and riser connector shall be a part of the system. The capacity of accumulators shall be sufficient to close:

- 2 ea. pipe rams.
- 1 ea shear ram.
- Open riser connector.
- + 50% safety factor.

To calculate the capacity of the accumulators, necessary precharge pressure for the actual water depth shall be taken into account. Sufficient pressure left in the acoustic accumulators to shear the drill string, after a pipe ram has been closed. In addition there shall be enough pressure to disconnect riser connector after the string has been sheared. A portable operation unit shall be available to perform the described functions if an emergency situation occurs.

Response time
Response time means the time the control system needs to close the annular preventer and the pipe shear rams.

- Response time for an annular preventer is set up to 60 sec.
- Response time for the rams is set up to 45 sec.

Pump system.
It should be 2 ea. separate pumping system. Normal set up will be one electrical driven triplex pump and 3 ea. pneumatic driven pumps.

The pumps shall be able to pressure up the accumulators from precharge pressure to max pressure, i.e. from 69 bar (1000 psi) to 207 bar (3000 psi) in less than 15 min.

Each of the pump systems shall be able to close the annular preventer and open a choke valve and create a system pressure 14 bar (200 psi) above precharge pressure in less than 2 min without assistance from the accumulators.

The pumps shall start automatically when the accumulator pressure drops below a fixed value (90% of max accumulator pressure).

Automatic mixing system for hydraulic fluid
In the system there shall be an automatic mixing system to mix water, water soluble oil and a.o.b glycol and pump it to the hydraulic tank. The tank must contain minimum twice the useful volume on the accumulator.
Control pods
There are two identical control pods located down on the BOP. i.e. two separate control systems, which perform the same operations. Outlets from the control pods are connected together with a shuttle valve, which leads the flow to the activated function.

Fig. 5.39 shows a complete subsea BOP system.
07.02. Operation mode for the remote control panel.

Note! API 16 E recommends that, when it’s cleared for drilling, all the indicator lights on the remote panels show "GREEN LIGHT". “GREEN LIGHT” indicates closed fail safe valves on choke-kill line.

Fig. 5.40 Drillers control panel for a subsea BOP.
**Electrical memory function (block position)**

The electrical memory will show the last lamp signal on before “block” was activated.

The lamp signal showed open for the ram, before “block” was activated.

![Upper Pipe Rams Diagram](image)

The lamp signal showed closed for the ram, before “block” was activated.
Fig. 5.41 Indicates how the instruments reacts when an annular preventer is closing.
Fig. 5.42 Indicates how the instruments reacts when a Ram is closing.
07.03. Subsea BOP control system

Introduction
All the hydraulic control system for BOP’s have the same purpose, they should control and operate the different functions on the BOP. The different systems are built upon the same basic components.

One of the most common systems is the system manufactured by N.L. Shaffer/Koomey. We have therefore used that system as the base to explain the configuration, operation and control for a subsea BOP.

General description of N.L. Shaffer hydraulic system for subsea BOP’s.
The hydraulic BOP fluid consists of water soluble oil (1-5%) water and in cold climate up to 50% glycol. The fluid is automatically mixed and stored in a tank. In the tank there are mounted 3 ea. floats. 2 ea. to activate stop/start for the mixing pump and alarm for low level.

Two types energy sources powers the hydraulic pumps. One system is driven by air motors and the other is normally electrical driven. The pump systems are controlled by adjustable pressure switches. The pump supplies fluid to the accumulators. The accumulators are precharged with nitrogen and the precharge pressure is supposed to be 69 bar (1000 psi).

Description of the control system
The pressure switches in the remote control panel gives an electrical signal to a pneumatic solenoid 3/2 valve. The 3/2 valves are located on the hydraulic master unit and are normally closed. When one of the 3/2 valves are activated, rig air passes through the valve and led into one side of a dual air cylinder. This pneumatic cylinder is mechanically connected to a hydraulic 4/3 valve. When one of the 4/3 valves is activated, pilot fluid from the accumulators will activate the hydraulic 3/2 valves (SPM) in the control pods on the BOP. Pressure regulated fluid will pass through the SPM valve to the function which is activated e.g. close upper pipe ram. The SPM valve outlet is connected to the open/close side of the different equipment such as Annulars, Rams, Fail safe valves and connectors on the BOP through a shuttle valve.
Operation mode for the hydraulic 4/3 valve (manipulator valve)

Explanation of the hydraulic 4/3 valve (manipulator valve):

The number 4 means 4 Inlets.
- \( P \) = pressure side.
- \( T \) = to tank.
- \( A \) and \( B \) = outlet.

The number 3 means 3 valve positions.

![Diagram of 4/3 valve positions](image)

No 1: Valve in block position

Port \( P \) is closed.
Return fluid flows to tank \( T \) through ports \( A \) and \( B \)

No 2: Valve in open position.

Fluid flows through port \( P \) to \( A \), while the return fluid flows to Tank \( T \) through port \( B \).

No. 3: Valve in closed position.

Fluid flows through port \( P \) to \( B \), while the return fluid flows to Tank \( T \) through port \( A \).

The indicator lights on the control panel shows the different positions of the 4/3 valve. The indicator lights are normally controlled by opened or closed hydraulic pressure switches, located in the outlet lines from the 4/3 valve.
Operation mode for the hydraulic 3/2 valve (pilot valve or SPM valve)

1. “Vent” position
Fluid in the return from the operating cylinders on the Annulars, Rams or fail safe valves flows (vent) through the valve to sea.

**Note**! When the hydraulic controlled 3/2 valve is placed into “vent” position, a powerful spring + the hydrostatic pressure from the water column that complete the operation.

2. Open position:
Pressure regulated fluid is flows through the valve to the open or close chamber on the Annulars, Rams or fail safe valves.

**Note**! When the hydraulic controlled 3/2 valve is activated into “open” position, there is unregulated accumulator pressure. (207 bar/3000 psi).

To adjust the operating pressure for the Annulars, Rams, connectors and fail safe valves on the BOP, electrical switches are used to activate pneumatic 3/2 solenoid valves. Rig air flows through the 3/2 valve to a diaphragm motor on the air controlled convenors (ACG), another 3/2 valve vents the diaphragm motor. The air controlled governor sends a hydraulic signal to the subsea mounted hydraulic governors (HCR) in the control pods.

Pressure transmitters convert read back pressure, (the real open/ close pressure for the valves), to electronic signals. Electrical signals from the pressure transmitters are distributed to the different control panels. On the hydraulic master panel gauges displays the different pressures.

DC (direct current) is used in all remote operations, remote indications and for instrumentation.

The pilot signal will be distributed in the hydraulic control unit before they are sent down to both the control pods. This means that both pods receive through a 1/4” tube the same pilot signals. A 1” hydraulic supply hose (HSH) is connected to both control pods. A selector valve defines which of the control pods will execute the operation. Two flexible pod hoses contains one 1” supply tube and a specific number of ¼” tubes one for each function in the control pod and they are the link between
the control unit and the control pods on the subsea BOP. Each hose drum contains 500 m or more of pod hoses, depending on water depth. The pod hoses distribute both pilot signals and the hydraulic power supply to the BOP functions.

The most common control functions are:
- LMRP. Connector primary/secondary
- Well head connector primary/secondary
- Upper and lower Annular preventer
- Upper, Middle and Lower Pipe Ram
- Upper/Lower – inner/outer Choke and Kill valve

The pod hoses are connected to a junction box on the top of the control pod. From the junction box the control lines are connected to the 3/2 valves (SPM valves) and to the hydraulic governors. The hydraulic supply hoses (HSH) are connected to the inlets on the governors. HSH are also connected to the subsea mounted hydraulic accumulators. The supply to the accumulators comes through a hydraulic controlled valve.

To get faster reaction on the different functions on the BOP there are installed hydraulic accumulators on the subsea BOP.

Redundancy

There is a requirement for redundancy in the control system. A redundant system means there are two separate control systems with equal status. Therefore there are two control pods Yellow and blue.

To separate the active and the redundant system, a shuttle valve is placed in the line at the open/close ports for the different equipment on the BOP.

The Shuttle valve has two main functions:

1. Avoid communication between the active and the redundant system.
2. The design of the valve and system makes it able to pull one of the control pods to surface and at the same time have full communication with the BOP through the remaining pod.
The principle of redundancy
07.04. Technical symbols in the control system.

Subsea control system in “block” position

Fig. 5.48 Subsea control system shown in “block” position.
Subsea control system in “open” position.

Fig. 5.49 Subsea control system shown in “open” position.
Subsea control system in “close” position.

Fig. 5.50 Subsea control system in ”close” position.
07.05. Schematic hydraulic diagrams

Pipe ram in “block” position.

Fig. 5.52 “BLOCK” position.
Pipe ram in “open” position.

1. OPEN POSITION. READY FOR DRILLING.

Fig. 5.53 “OPEN” position.
Pipe ram in closing operation

2. CLOSING
   Electrical push button
   "UPPER PIPE RAM" "CLOSE"
   IS ACTIVATED, CLOSING
   OPERATION STARTS

Fig. 5.54 Pipe ram closing
Pipe ram in “closed” position

3. CLOSED POSITION.
THE CLOSING OPERATION IS COMPLETED.

Fig. 5.55 Pipe ram closed
07.06. Accumulator bottle calculations for a subsea BOP.

**NPD’s: requirements:**
Boyle Marriot’s law for an Isothermal process (GAS Law (constant temp) \( P_1 \times V_1 = P_2 \times V_2 = P_3 \times V_3 \))

Accumulator bottle volume = 38 litre.
Required volume = 2230 litre.
Max working pressure = 207 bar.
Precharge pressure = 69 bar.
Minimum pressure = 83 bar.
Water depth = 390 meter.
Hydrostatic pressure at sea bed. = 390 m \( \times 1,03 \text{ sg} \times 0,0981 = 40 \text{ bar} \).

Calculating the subsea accumulator bottles first:

| Volume required closing one Annular: | 183,0 l |
| + 50 % safety factor                  | 91,5 l |
| Required fluid volume                 | 274,5 l |

The accumulators are precharged to:

| Precharge pressure                  | 69 bar |
| Hydrostatic pressure (water depth)  | 40 bar |
| \( P_1 \)                          | 109 bar |

Before the BOP is lowered down to the seabed.

Working pressure in submerged condition:

| Normal working pressure             | 207 bar |
| Hydrostatic pressure                | 40 bar  |
| \( P_2 \)                          | 247 bar |

\[ V_2 = \frac{P_1 \times V_1}{P_2} = \frac{109 \text{ bar} \times 38 \text{ l}}{248 \text{ bar}} = 16,7 \text{ l} \]
Minimum pressure according to requirement:

Minimum pressure : 83 bar.
Hydrostatic pressure : 40 bar

\[ P_3 = \quad 123 \text{ bar} \]

\[ V_3 = \text{unknown} \]

\[ V_3 = \frac{P_1 \times V_1}{P_3} \]

\[ V_3 = \frac{109 \text{ bar} \times 38 \text{ l}}{123 \text{ bar}} = 33.7 \text{ l} \]

Usable volume = \( V_3 - V_2 = 33.7 \text{ l} - 16.7 \text{ l} = 17 \text{ l} \)

Required volume 274.5 l.

Required number of accumulator bottles : \( \frac{274.5 \text{ l}}{17 \text{ l}} = 16.15 \text{ bottles.} \)

Eq. 17 bottles

Number of surface accumulator bottles.

Required volume : 2230 l
- Subsea volume (17 l x 17 bottles) : 289 l
Required usable surface volume : 1941 l

\[ P_4 = 69 \text{ bar} \]
\[ V_4 = 38 \text{ l} \]
\[ P_5 = 207 \text{ bar} \]
\[ V_5 = \text{unknown} \]
\[ P_6 = 83 \text{ bar} \]
\[ V_6 = \text{unknown} \]
Calculation:

\[ V_5 = \frac{P_4 \times V_4}{P_5} \]
\[ V_5 = \frac{69 \text{ bar} \times 38 \text{ l}}{207 \text{ bar}} = 12.67 \text{ l} \]

\[ V_6 = \frac{P_4 \times V_4}{P_6} \]
\[ V_6 = \frac{69 \text{ bar} \times 38 \text{ l}}{83 \text{ bar}} = 31.59 \text{ l} \]

Useable fluid volume = \( V_6 - V_5 = 31.59 \text{ l} - 12.67 \text{ l} = 18.92 \text{ l} \)

Total fluid volume is 1941 litre.

Number of required accumulator bottles : \( \frac{1941 \text{ l}}{18.92 \text{ l}} = 102.6 \text{ bottles} \)

Eq. 103 bottles

Number of bottles:

On surface = 103 bottles
Subsea = 17 bottles
Total = 120 bottles
08. Diverter systems.

Goal:
The participants shall be able to explain the operation mode for the diverter.

Highlights:
- Be able to name the different components in the diverter system
- Be able to explain the operational sequence for the diverting system.

Low fracture gradient can prevent the normal procedure of controlling a kick by shutting in a well under pressure. A diverter system is a means of controlling well flows found at relatively shallow depths by directing the flow away from the rig and personnel. The system gives some degree of protection prior to setting the casing string on which a blowout preventer stack and choke manifold will be installed.

Basically, a diverter system consists of a low pressure, bag-type annular preventer with a diverter line. The system is designed to pack-off around the Kelly, drill string, casing or open hole and direct the flow of well fluids through the diverter lines and away from the rig. Valves in the system direct the flow. A diverter is not designed to shut in or halt the flow, but instead permits the flow to be routed to a safe distance from the rig. If a kick should occur, the valves are opened and the preventer is closed. The well is then allowed to blow to the atmosphere through the diverter lines.

Conventional annular blowout preventers or rotating heads are commonly used as diverters. The rated working pressure of the diverter and vent line(s) is not of prime importance. They are sized to permit diversion of well fluids while minimizing wellbore back pressure. Vent lines vary from 4 to 12 inches in diameter for land operations. Vent line valves should be full-opening and designed to open automatically whenever the diverter is closed.

Important issue:
- The diverter packer element has a large inner diameter.
- The diverter lines have large inner diameter.
08.01. General description of the diverter system.

If drilling a 26 “hole to set 20” conductor casing with returns taken to the rig, the formation would not stand the pressure generated from a shallow gas shut in at sea bed. The principle of the diverter system is to divert the gas away from the rig without pressurizing the well. The pressure integrity of the diverting system is limited.

08.02. Diverter system on a fixed platform.

On a fixed platform the diverter system consists of a flexible element installed on top of the low pressure riser. The element seals off the well, to prevent the gas reaching drill floor.

When a diverter valve is activated to close, the system is designed in such way that an automatic operation sequence is performed as follows:

- Overboard valve will switch to open.
- Flow line valve will switch to close.
- Trip tank return valve will switch to close.
- Riser fill up line will switch to close.

When the system is reset, the pressure will be bled back to the hydraulic tank without any flow meter or pressure gauges indications.

08.03. Diverter system on a Floating unit.

Diverter system on a floating unit is designed in the same way as on a fixed platform. As there are either one or two diverter lines on a fixed platform there is always two on a semi sub, one line to each side, port/starboard side. On a drill ship, with dynamic position system “DP”, there will be only one line at the rear end.
Manual hydraulic control system for an ABB Vetco Gray KFDJ Diverter system.

Diverter with low pressure annular preventer
The set up for drilling mode:

A = Pressurized
B = Open
C = Open or Closed. Position depending of wind direction
D = Open or Closed. Position depending of wind direction
E = Pressurized
F = Open

If the wind is blowing from starboard towards port (from right to left in the figure below), and a kick situation occurs, following operational sequence for the diverter system will be followed:


![Fig. 5.57 The hydraulic control system for an ABB Vetco Gray KFDJ diverter system.](image-url)
09. Mud gas Separator (Poor Boy)

Goal:
The participants shall be able to understand the principle of the Mud Gas Separator.

Mud gas Separator After drilling mud with entrapped gas leaves the choke; it is routed into a mud – gas separator. This is a large tank like structure containing many layers of baffles. As the mud cascades down through the tank, the entrapped gas is liberated. The mud flows out the bottom of the separator and goes to the shale shaker. The gas flows out of the top of the separator and into a vent line.

The Poor Boy degasser is located after the choke manifold. Its principle use is to separate gas from the mud during a kick situation. The gas is directed to a safe area (most commonly to the top of the derrick) while the mud/ fluid returns to the active mud system.

To keep minimum fluid level in the separator there is a liquid seal in the discharge line. The purpose of the liquid seal is to prevent gas from leaving the poor boy with the mud. Because a liquid seal is maintained inside the separator, large quantities of gas can be liberated from the mud before it is returned to the active system.

There is mounted a siphon breaker the liquid seal to avoid a siphoning action forming if the outlet from the separator is mounted lower than the separator.

The separators pressure rating and the height of the liquid seal is given from the expected friction loss in vent line. We assume that pressure $P_1$ inside the separator is equivalent to the friction loss in vent line.

\[
P_1 = \text{Friction loss in vent line.}
\]

\[
P_2 = \text{Maximum expected pressure equivalent to } P_1 \text{ is a hydrostatic pressure in bar.}
\]

\[
P_2 = Mw \times 0,0981 \times h_2 \text{ (metric) or } Mw \times 0,052 \times h_2 \text{ (oil field units)}
\]

\[
Mw = \text{specific weight of the mud in the liquid seal.}
\]
10. Mechanical Couplings

**Goal:**
The participants shall be able to explain to make use of mechanical couplings.

**Highlights:**
- Be able to name the different flanges for mounting valves to the BOP
- Be able to explain the concept behind nominal diameter.
- Be able to explain the difference between different types API flanges.
10.01. Different types of mechanical couplings.

There are 3 different types of high pressure couplings which can be used to mate together the different kinds of valves on the BOP.

The couplings are:
- Flange.
- Studded.
- Hub & clamp.

A "flange" coupling is a normal flange with API specifications utilizing separate bolts. In the flange there is ring groove into which fit metal ring gaskets such as RX or BX. The bolts must be tightened up according to API specifications.

A "studded" coupling is based on the same principle as a flange coupling, but the bolts are fixed on one side of the flange.

A "hub & clamp" coupling, consists of two flanges (hubs) which will be squeezed together with a clamp and bolts. This kind of coupling has fewer bolts than the other two couplings, and because these bolts are mounted horizontally, less space is required to tighten them up. This kind is therefore often used on subsea mounted BOP to reduce height and weight. RX and BX ring gaskets are also used in this coupling; special AX ring gaskets can also be used.

Fig. 5.59 Clamp- hub-, studded- and flanged couplings.
10.02. Flanges and ring-joint gaskets.

Type R, RX and BX ring-joint gaskets should be used for flanged blowout preventer connections.

- Type R and RX rings are used in conjunctions with API Type 6B flanges.
- Type BX is used with API 6BX flanges.
- Type RX and BX are self-energizing gaskets.
- API 6B flanges has a certain distance between the flanges after connection and will therefore need periodic retightening of bolts and nuts.

Fig. 5.60 shows the nominal dimension for an API flange.
Fig. 5.42 Type 6B flange

Fig. 5.43 Type 6BX flange
11. Marine riser system.

Aim: participants shall be able to understand the design of the Marine riser system.

Issue:
- The composition of the marine riser.
- Description of the different components in the Marine riser system.

11.01. General.

The principle of the marine riser is to connect the floating unit to the well head. The specifications for the riser system are based on API RP 53. The primary function for marine riser is to allow return of mud (fluid) from the well head to the platform and also guide the drill string into the well head.

The composition of the marine riser:

- Riser tubular.
- Choke – kill lines.
- Hydraulic connector.
- Telescope joint. (Slip joint)
- Flex joint.

The marine riser is designed in such a way that it will withstand variable impact from the environment such as:

- Dynamic forces, when the BOP is run, prior to landing the BOP.
- Side forces from the ocean current.
- Cyclic forces created by combinations of waves and platform movements.
- Tension from the riser tensioning system.

The pressure integrity in the riser system should be like the integrity of the diverter + the difference in hydrostatic pressure from mud in the riser and sea water at the BOP. In addition the collapse pressure can be an important factor when drilling in deep water, where the risk of emptying the riser either caused by great losses or shallow gas blow outs, must be considered.
11.02. Hydraulic connector.

The hydraulic connector is mounted at the bottom of the lower marine riser package (LMRP), and connects the marine riser to the BOP (ref. # 05). The connector acts like an emergency disconnecting device, when the situation requires it, to unlash riser from BOP. The design of connector allows it to be connected or disconnected when the riser is at an angle from vertical. There is a maximum angle from the vertical that the connection or disconnection can be executed. The inside diameter in the connector has to be the same as the inside diameter of the BOP.

11.03. Flex joint.

To avoid any bending moments or problems during latch or unlash operation of the LMRP there is a flex joint located both at top and bottom of the marine riser assembly. The operating design criteria are up to 10 deg from vertical.


The marine riser is designed to resist the impact force mentioned above. The inside diameter of the riser has to be big enough to be able to run all different types of running tools, casing hangers, pack offs and wear bushings through the riser and well head.

There are three different marine riser designs.

Integrated type: Choke- and Kill line are an integrated part of the riser joint assembly. The different manufacturers have their own design of riser - and C/K –line connectors. C/K-line connectors are normally stab in connectors or a kind of mini connectors.

Track type: In this type there are two permanent tracks for C/K- lines installed on the riser joint which are guiding a kind of skate attached to c/K-line. The running or installation of the marine riser will be a 2- stage operation where C/K-lines are pulled after the riser is run.

Funnel type: This type has funnels as guides for the installation of C/K-lines after the riser is run.

C/K-lines are normally 3” or larger. The communication between C/K-line on the marine riser and platform goes through flexible hoses. Some operators have installed booster lines on the marine riser to increase the flow rate in the riser or displace the fluid in the riser.
11.05. Telescopic joint or ”Slip joint”.

Telescopic joint or Slip joint is the connection between the rig and the marine riser (wellhead). The slip joint is designed to handle vertical movement created by the sea (waves, current) and has a certain stroke (travel length). The stroke (travel length) is the limitation for the operation due to heave, roll and pitch. The slip joint consists of two parts, inner and outer barrel. The outer barrel is connected to the marine riser and it will be fixed compared to the wellhead. The riser tension wires are attached to the outer barrel with a tension ring or with pad eyes. The outlets for C/K-line are also attached to the outer barrel. The inner barrel is slick and attached to the rig and moves freely in and out of the outer barrel, through a pneumatic or hydro mechanical seal, or like a piston in a cylinder. The inner barrel is attached to the rig at the upper flex joint located close to rig floor (diverter housing).

Note! The seal between inner and outer barrel is assumed to be the first item that fails during a shallow gas blow out.

11.06. Riser tensioning system.

The riser tensioning system shall compensate for the rig movement and be able to keep the marine riser in tension.

- Tension wires and guide wheels.
- Telescopic compensator with guide wheels.
- Hydro pneumatic accumulators.
- Operating panel and piping.
- Air compressors and air vessels.

The risers offset angle has to be as vertical as possible to reduce the bending moment on the riser and the riser has to be kept in tension. Too high tension gives excessive axial stresses. To reduce the tension force on the equipment the marine riser is fitted with buoyant material, this is normal in deep water drilling.

A hydro pneumatic compensator system is used to keep the tension force constant. The tension force is controlled by air pressure and transferred to the riser from telescopic compensators by wires across guide wheels to pad eyes or a tension ring. The system acts in the way that when the rig moves down wards the compensator retracts to reduce the required length of wire and opposite when it moves up wards the compensator extends.

11.07. Automatic riser fill-up valve.

Some marine risers are equipped with an automatic valve to fill up the riser. It operates on differential pressure. When the fluid level in the riser drops and to avoid that the riser collapse the automatic valve opens and fill up the riser with sea water.