IWCF Well Control Practice Exam

Surface Practice Exam
Principles and Procedures

Name_______________________

Date________________________

Score_______________________
Complete an IWCF Surface Kill Sheet using the following data and answer the questions on the following page (Questions 1a to 1l):

Well Data:

- Hole Size = 12 ¼ inch
- Hole Depth = 6600 ft TVD / 7846 ft MD
- Casing = 13 3/8 in. Casing:
  - 4800 ft TVD / 5180 ft MD

Internal Capacities:

- Drill Pipe 5.0 inch = Capacity = 0.0177 bbl/ft
  - Length = 7316 ft
- Drill Collars 8”od x 3”id = Capacity = 0.0087 bbl/ft
  - Length = 530 ft long,

Annular Capacities:

- Drill collars and open hole = 0.0836 bbl/ft
- Drill pipe plus HWDP and open hole = 0.1215 bbl/ft
- Drill pipe plus HWDP and casing = 0.1353 bbl/ft

Mud Pump Data:

- Displacement at 98% volumetric eff. = 0.119 bbl/stk

Slow Pump Rate Data:

- Slow Circulating Rate Pressure @ 30 spm = 440 psi

Formation Strength Test Data:

A leak-off test was carried out at the 13 3/8 “ casing shoe using a mud density of 10.6 ppg. A surface pressure of 1000 psi was recorded.

Kick Data:

- Shut-in Drill Pipe Pressure = 340 psi
- Shut-in Casing Pressure = 410 psi
- Pit Gain = 12 bbls
- Mud weight at time of kick = 11.4 ppg

The well will be killed using the Wait and Weight Method at 30 spm.
1a. What is the Kill Mud Density required to balance formation pressure? 
(Rounded up to one decimal place and no safety factor.)
____________________ ppg

1b. How many strokes will be required to pump kill mud from the surface to the 
bit?
____________________ strokes

1c. How many strokes are required to pump from the bit to the casing shoe?
____________________ strokes

1d. What is the **Total Annular Volume**?
____________________ bbls

1e. How many strokes are required to pump from the bit to the surface?
____________________ strokes

1f. What is the **MAASP** at the time the well is shut in?
____________________ psi

1g. What is the **Initial Circulating Pressure**?
____________________ psi

1h. What is the **Final Circulating Pressure**?
____________________ psi

1i. What is the gradient of the influx? (Ignore the fact that the well is deviated.)
____________________ psi/ft

1j. What is the drill pipe pressure reduction per 100 strokes as kill mud is being pumped 
to the bit?
____________________ psi/100 strokes

1k. What is **MAASP** after circulation of kill mud?
____________________ psi

1l. What is the time for one complete circulation?
____________________ minutes
2. Prior to pulling pipe out of the hole from 12,562 ft. T.V.D., the pipe is full of 13.2 ppg mud. Pipe capacity is 0.01776 bbl/ft. A 30 bbl slug weighing 15.0 ppg is pumped into the drill pipe. How much pit gain would result from the slug u-tubing into position?

________________________ bbls

3. Using the leak-off plot below, determine the **initial fracture pressure** at the Casing shoe. (Use a straight edge on the plot).

\[\text{Initial Fracture Pressure} \quad \text{psi}\]

4. When should a leak-off test be carried out?

a. Immediately after running and cementing casing.
b. Immediately before running casing
c. After drilling out casing shoe 5 to 15 feet in new formation.
d. Immediately before drilling out casing shoe.
5. When starting a kill operation (Wait and Weight Method) on a surface drilling unit, the choke pressure is kept constant (at its shut-in value) while bringing the pump up to kill speed. The drill pipe gauge now reads 200 psi higher than the pre-calculated Initial Circulating Pressure (ICP). What is the correct action to take?

   a. Open the choke and let the drill pipe pressure drop to the pre-calculated value (ICP).
   b. Continue to circulate with the new ICP and adjust the drill pipe pressure graph accordingly.
   c. There will now be 200 psi overbalance on the bottom which is acceptable. Nothing needs to be done.

6. While tripping out of the hole from 11,000 ft. TVD the hole does not take proper hole fill. With the bit at 9,000 ft. TVD, the well flows and is shut in with 205 psi SICP - float was in place. 13.0 ppg mud in hole. Drill collar length = 1,200 ft. Stand length = 93 ft.

   Drill pipe capacity: = 0.01776 bbl/ft
   Drill pipe displacement: = 0.0076 bbl/ft
   Open hole capacity: = 0.0702 bbl/ft
   Annular capacity: DC/OH = 0.0291 bbl/ft
   Annular capacity: DP/OH = 0.0459 bbl/ft
   Pit gain: = 25 bbl
   Gas gradient: = 0.1 psi/ft

Assume the gas influx is on the bottom and does not migrate.

   a. Calculate the height of the influx in the open hole (HiOH) _______________ ft
   b. Calculate the required stripping volume per stand _____________ bbls
   c. After stripping to bottom and bleeding 50.7 bbls of mud, what was the Height of the influx (HiBHA) _______________ ft
   d. Calculate the SICP once the bit was on bottom _______________ psi

7. We are planning to circulate a kick with the Wait & Weight method. The volume of the surface lines on this rig is 20 bbls. Identify the best procedure for dealing with the volume of the surface lines?

   a. Re-zero the stroke counter once kill mud reaches the bit.
   b. Subtract 20 bbl's (adjusted for pump strokes) from the "strokes to bit" total on the kill sheet.
   c. Ignore the 20 bbl's and use it as a safety factor.
   d. Re-zero the stroke counter when kill mud starts down the drill pipe.
8. Which of the following statements are good operating practice in **TOP HOLE** that has a risk of gas bearing formations? *(Choose two answers)*

   a. Pump out of the hole on trips.
   b. Control drill.
   c. Maintain high rate of penetration to ensure mud viscosity level is as high as possible.
   d. Regularly pump fresh water pill to clean cuttings from hole.
   e. Use a high density mud to create maximum overbalance.

9. What happens to the pressure on the casing shoe while the gas influx is passing from the open hole into the casing? *(Bottom hole pressure is being kept constant).*

   a. Increases
   b. Decreases
   c. Stays the same

10. The pumps are malfunctioning and you can't circulate. A gas kick is migrating up the wellbore and bottom hole pressure must be kept constant. Identify two instances when the volumetric method is appropriate? *(Choose two answers)*

    a. With the bit on bottom, no float in string.
    b. When the bit is a long way off bottom, no float in string.
    c. With the bit on bottom, plugged drill string.

11. Which **three** of the following conditions are essential for the calculation of an accurate formation strength at the shoe? *(Choose three answers)*

    a. Accurate hole volume.
    b. Accurate stroke counter.
    c. Installation of retrievable packer approximately 150 ft. below the wellhead.
    d. Accurate pressure gauge.
    e. Exact mud density.
    f. Exact vertical depth of the casing shoe.

12. A light mud pill is circulated in the well. At what moment will the bottom hole pressure start to decrease?

    a. As soon as the pill starts to be pumped into the drill string.
    b. Once all the pill has been displaced into the annulus.
    c. Once the pill starts to be displaced into the annulus.
    d. Once all the pill is in the annulus.
13. A well was drilled to a TVD of 10,500 ft.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Casing shoe TVD</td>
<td>4500 ft</td>
</tr>
<tr>
<td>Mud density</td>
<td>12.0 ppg</td>
</tr>
<tr>
<td>Open hole capacity</td>
<td>0.0702 bbl/ft</td>
</tr>
<tr>
<td>Pipe metal displacement</td>
<td>0.0080 bbl/ft</td>
</tr>
<tr>
<td>Casing capacity</td>
<td>0.0981 bbl/ft</td>
</tr>
<tr>
<td>Pore pressure</td>
<td>0.598 psi/ft</td>
</tr>
<tr>
<td>Length of one stand</td>
<td>88.5 ft</td>
</tr>
</tbody>
</table>

How many **full stands (complete stands)** of drill pipe can the driller pull **before** the hole level reduces the bottom hole pressure enough to cause the well to go underbalanced?

NOTE: pulling dry pipe.

______________ stands

14. If the Driller pulls all 500 ft of 8" OD x 2 13/16" ID drill collars out of the hole dry, including the bit, without filling the hole, what will be the reduction in the bottom hole pressure?

____________________ psi

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mud weight</td>
<td>13.2 ppg</td>
</tr>
<tr>
<td>Casing capacity</td>
<td>0.1545 bbl/ft</td>
</tr>
<tr>
<td>Metal displacement</td>
<td>0.0545 bbl/ft</td>
</tr>
</tbody>
</table>

15. While circulating out a kick at 40 spm, it is decided to reduce the pump speed to 30 spm. While the driller slows the pump to 30 spm, the choke operator maintains the casing pressure constant until 30 spm has been reached. What is the effect on bottom hole pressure? (Neglect E.C.D. effects):

a. No effects.
b. Bottom hole pressure is reduced.
c. Bottom hole pressure is increased.
16. The well is being killed properly using the Wait and Weight method of well control. 10.6 ppg Kill Weight Mud is being pumped down the drill string. After pumping 600 strokes, the drill pipe pressure is 1300 psi. The crew then reduces the pump rate from 40 spm to 30 spm using proper procedure.

What will be the drill pipe pressure reading at the new rate after pumping a total of 800 strokes?

Data:  
- Original mud weight: 9.6 ppg
- Surface to bit strokes: 1200 stks
- Bit to surface strokes: 2400 stks
- Slow circulating rate pressure: 1000 psi @40spm
- SIDPP: 500 psi
- SICP: 850 psi
- Pit Gain: 22 bbls
- TVD/MD: 10,000 ft
- Kill Weight Mud: 10.6 ppg
- Initial Circulating Pressure: 1500 psi
- Final Circulating Pressure: 1100 psi
- Psi/stk: 0.333

a. 1350 psi  
b. 1234 psi  
c. 769 psi  
d. 694 psi

17. Well Data

Slow circulation rate pressure = 500 psi at 40 strokes/min

The well has been shut-in after a kick:

- Shut-in Drill Pipe Pressure = 800 psi
- Shut-in Casing Pressure = 1100 psi

Before starting to kill the well, there is a complete failure of the pumps. Which pressure has to remain constant in order to maintain the correct bottom hole pressure if the influx migrates?

a. 1600 psi at the casing gauge.  
b. 1100 psi at the casing gauge.  
c. 1300 psi at the drill pipe gauge.  
d. 800 psi at the drill pipe gauge.
18. **Well Data**

Slow circulation rate pressure = 500 psi at 40 strokes/min

The well has been shut-in after a kick:

<table>
<thead>
<tr>
<th>Description</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shut-in Drill Pipe Pressure</td>
<td>800 psi</td>
</tr>
<tr>
<td>Shut-in Casing Pressure</td>
<td>1100 psi</td>
</tr>
</tbody>
</table>

Circulation is started with the original mud. While the pump is being brought up to 40 strokes/min, which pressure has to remain constant to maintain the correct bottom hole pressure?

a. 800 psi at the drill pipe gauge.
b. 1,300 psi at the drill pipe gauge.
c. 1,100 psi at the casing gauge.
d. 1,600 psi at the casing gauge.

19. Slow circulation rate tests are made at different pump rates (SPMs) for use on the Well Kill Sheet. Which **two** of the following can determine the SPM chosen to kill the well? *(Choose two answers)*

a. The capacity of the drill string.
b. Maximum allowable pump pressure.
c. The kill mud mixing capacity on the rig.
d. The capacity of the open hole annulus compared to the drill string capacity.

20. Which **three** of the following practices are likely to increase the chance of swabbing? *(Choose three answers)*

a. Pulling pipe slowly.
b. Maintaining high mud viscosity.
c. Pulling through tight spots with the pump off.
d. Pulling through tight spots with the pump on.
e. Pulling pipe quickly.

21. At 50 spm, with 12.0 ppg mud, the pump pressure is 1500 psi.

What would the pump pressure be if the rate were decreased to 25 spm and the mud weight is increased to 13.5 ppg?

a. 375 psi
b. 422 psi
c. 750 psi
d. 844 psi
22. Calculate the volumes in 22 a and 22 b below:

- Drill Pipe Capacity = 0.01776 bbls/ft
- Drill Pipe Metal Displacement = 0.0076 bbls/ft
- Average Stand Length = 93 ft

Calculate:
- a. Mud required to fill the hole per stand when pulled 'dry'?
  ____________________ bbls
- b. Mud required to fill the hole per stand when pulled 'wet'?
  ____________________ bbls

23. Many factors should be considered when selecting a kill pump rate. However, the objective should be to regain control of the well. Choose the one answer that best meets this objective.

- a. By using the slowest pumping rate.
- b. Before the end of the tour.
- c. As safe as possible considering all aspects of the kill.
- d. As fast as possible by using the maximum rate.

24. While drilling a gas kick is taken and the well is shut-in.

- SICP = 0 psi
- SIDPP = 650 psi

There is no flow from the annulus. What is the probable cause?

- a. The casing pressure gauge is malfunctioning.
- b. The drill string has twisted off.
- c. The well is swabbed in.
- d. The hole has packed off around the bottom hole assembly.
- e. The formation at the casing shoe has fractured.

25. Which of the following drilling practices should be considered when connection gas is noticed? (Choose two answers)

- a. Control drilling rate so that only one slug of connection gas is in the hole at any one time.
- b. Pumping a low viscosity pill around bit to assist in reduction of balled bit or stabilizers.
- c. Minimizing the time during a connection when the pumps are switched off.
- d. Raising the mud yield point.
- e. Pulling out of the hole to change the bit.
26. Well Data

Well depth = 12,000 feet
9 5/8 inch Casing Shoe = 8000 feet
81/2inch Hole Capacity = 0.0702 bbls/ft

Mud density in use = 12.0 ppg

Drill Collars = 6 1/2 inch OD; Length = 1,100 ft
   Capacity = 0.00768 bbls/ft
   Metal Displacement = 0.0330 bbls/ft

Drill pipe 5 inch OD; Capacity = 0.01776 bbls/ft
Metal Displacement = 0.0076 bbls/ft
Volume Drill Collar/Open Hole = 0.0291 bbls/ft
Volume Drill pipe/Open Hole = 0.0459 bbls/ft
Volume Drill pipe/Casing = 0.0515 bbls/ft

After pulling 33 stands the Driller checks the hole fill. The well has not taken the correct amount of mud, a flow check is made - the well is flowing.

   The bit depth at the time is 9,000 ft.
   Shut-in casing pressure is 200 psi.
   Influx volume = 30 bbls
   Gradient of influx = 0.12 psi/ft

Assume that the influx occurred from the bottom of the hole and that no gas migration occurs.

a. Calculate the volume to bleed off per 98 feet of drill pipe stripped back into the hole?
   ______________________ bbls

b. What will be the effect on bottom hole pressure of bleeding off too much mud?
   Increase ☐ Decrease ☐ Stay the Same ☐

c. How would Casing Pressure most likely react as drill string is stripped into influx?
   Increase ☐ Decrease ☐ Stay the Same ☐
27. Select the products commonly used to prevent hydrate formation: 
(Choose two answers)

a. Glycol  
b. Water  
c. Alcohol  
d. Butone  
e. Methanol

28. Pressure build up in the Mud Gas Separator (Poor Boy degasser) while circulating out a kick can be dangerous because:

a. Pressure build up will increase risk of lost circulation.  
b. Pressure build up will affect ability to make choke adjustments.  
c. Pressure build up may allow gas to be blown up the derrick vent line.  
d. Pressure build up may allow gas to enter shale shaker area.

29. If flow rate is kept constant, which two of the following factors will increase the circulation pressure? (Choose two answers):

a. When the mud density in the well is lowered.  
b. When the drilled depth is increased.  
c. When the length of drill collars is increased.  
d. When the bit nozzle size is increased.

30. A gas kick has been taken in a well with a large open hole section. After a short time the drill pipe becomes plugged - presumably by debris blocking the bit. Drill pipe pressure cannot be read, and no pumping is possible down the drill pipe. There is evidence of gas migration taking place.

Which one of the following well control procedures can be applied?

a. Driller’s Method.  
b. Wait and Weight method.  
c. Concurrent method  
d. Volumetric technique.  
e. Back off and pump cement down annulus.

31. A hydraulic delay exists between the time the choke is adjusted to the time the drill pipe pressure reacts. This hydraulic delay is:

a. Equal to the speed of sound.  
b. About 1 second per 300 meters of travel time.  
c. Always equal to 20 seconds.  
d. This is a myth, no hydraulic delay actually exists.
32. In which situation would a pit gain be noticed?
   a. Gas kick in an oil based mud.
      ______True
      ______False
   b. Gas kick in a water based mud.
      ______True
      ______False

33. Under which circumstances would the Wait and Weight Method provide lower equivalent pressures at the casing shoe than the Driller's Method?
   a. When the drill string volume is greater than the annulus open hole volume.
   b. When the drill string volume is less than the annulus open hole volume.
   c. The pressures at the casing are the same regardless of the method used.

34. Casing has been set and cemented. The well program calls for a leak-off test, but the mud weight in the active pits has been increased by 0.5 ppg higher than the mud weight in the hole. Which of the following would provide the most accurate leak-off test results?
   a. Use a cement pump to pump down the drill pipe and record pressures and barrels pumped.
   b. Circulate and condition mud until the density is the same throughout the system.
   c. Use a cement pump to pump down the annulus and record pressures and barrels pumped.
   d. It is impossible to obtain accurate test results, so use pressures from previous tests.

35. When pulling out of the hole from the top of the reservoir at 7,954 ft swab pressures are calculated to be 100 psi.

   Mud weight = 10.3 ppg
   Formation pressure = 4200 psi

   Will the well flow?
   a. Yes
   b. No

36. The following slow rate circulating rate pressures (SCRP) were recorded? Which one does not seem to be correct?
   a. 30 spm = 100 psi
   b. 40 spm = 180 psi
   c. 50 spm = 400 psi
37. The gas/water separation in a well occurs at 3950 ft. A normal formation gradient of 0.464 psi/ft. exists. (Gas gradient is 0.1 psi/ft.) What is the pressure at the top of the reservoir at 3470 ft.?
   a. 1562 psi
   b. 1610 psi
   c. 1785 psi
   d. 1875 psi

38. Throughout the world, what is the most common cause of abnormal formation pressures?
   a. Thick sandstone sections.
   b. Undercompacted shales.
   c. Faults.
   d. Uplifting / erosion.

39. Which 2 of the following would contribute to a higher fracture gradient? (Choose one answer)
   a. Casing setting depth is close to the surface.
   b. Casing setting depth is far from the surface.
   c. A small difference exists between the mud hydrostatic pressure and fracture pressure.
   d. A large difference exists between the mud hydrostatic pressure and fracture pressure.

40. Which one of the following is used to determine the pumping rates for recording reduced circulating pressures?
   a. The depth of the well.
   b. The size of the casing.
   c. Company policy.
   d. Amount of mud weight increase, degasser capacity, surface pressure limitations.
41. The solubility of gas in oil based or water based mud can make a difference in shut-in well data following a kick under identical conditions. Which of the following statements is correct when using oil based mud? **(Choose two answers):**

- a. The initial pit gain will be higher than with water based muds.
- b. The initial pit gain will be lower than with water based muds.
- c. The Shut-in Casing Pressure will be higher than with water based muds.
- d. The Shut-in Casing Pressure will be lower than with water based muds.
- e. There will be no difference in pit gain compared with water based mud.
- f. There will be no difference in Shut-in Casing Pressure compared with water based drilling mud.

42. Current operation is stripping 5.0" 19.5 lb/ft. drill pipe into the hole. Capacity = 0.01776 bbl/ft.; metal displacement = 0.0076 bbl/ft.; 1 stand = 93 ft.

- a. How much volume is required to fill the drill pipe after running one stand in the hole? __________ bbls.
- b. How much volume must be bled off after running one stand in the hole? __________ bbls.

43. A driller observes a warning sign for a kick. Why is it better to continue pumping while raising the pipe to the shut-in position?

- a. To minimize down time.
- b. To minimize the amount of influx by keeping the annular pressure loss as long as possible.
- c. The driller should shut off the pump before picking up to identify the influx as soon as possible.
- d. To prevent sticking the pipe.

44. When out of the hole, partial loss of returns is observed to be 12 bbl/hr. If the well is not filled, what would be the reduction in bottom hole pressure after 3 hours. Casing capacity = 0.0836 bbl/ft.; mud weight = 12.5 ppg.

____________ psi

45. During a well kill operation, using the Driller’s Method, the casing pressure suddenly increases by 150 psi. Shortly thereafter, the operator observes the same pressure increase on the drill pipe pressure gauge. What is the most likely cause of this pressure increase?

- a. A plugged nozzle in the bit.
- b. The choke is partly plugged.
- c. A restriction in the Kelly hose.
- d. A wash out in the drill string.
- e. A second influx has entered the well.
46. What are the advantages / disadvantages of using a float valve in the drill string? Circle the correct letter in each of the following:

A or D a) No reverse circulation is possible.
A or D b) No shut-in drill pipe pressure reading.
A or D c) No cuttings flowback on connections.
A or D d) Increased surge pressures.

47. Why must the pit volume be monitored during a kick killing operation? (Choose two answers)

a. To determine kill weight mud.
b. To determine influx volume.
c. To determine the amount of gas expansion.
d. To determine if lost returns occurs.
e. To determine the gain due to barite additions.

48. During top hole drilling from a jack-up rig. The well starts to flow due to shallow gas. What will be the safest actions to take to secure the safety of rig and personnel? (Choose two answers)

a. Start pumping mud into the well at the highest possible rate.
b. Shut-in the well and prepare for kill operations immediately.
c. Activate the diverter system and remove non-essential personnel from the rig floor and hazardous areas.
d. Line up the mud/gas separator, activate the diverter system and remove personnel from the rig floor.
e. Activate the blind/shear rams to shut in the well.

ATTACHED KILL SHEET

Use the data from the attached kill sheets (following two pages) to answer each of the questions 49a through 49 g about the well killing process.

You are required to indicate the first action that should be taken:

The well will be killed with the Wait and Weight Method at 30 spm.
### Surface BOP Vertical Well Kill Sheet (API Field Units)

#### FORMATION STRENGTH DATA:
- **Surface Leak-Off Pressure FROM**
- **Formation Strength Test**:
  - \((A) \text{ psi}\)
- **Mud Weight AT Test**:
  - \((B) \text{ ppg}\)

**Maximum Allowable Mud Weight**

\[
\text{Maximum Allowable Mud Weight} = (B) + \frac{(A)}{\text{Shoe T.V. Depth} \times 0.052}
\]

**Initial MAASP**

\[
\text{Initial MAASP} = (C) - \text{Current Mud Weight} \times \text{Shoe T.V. Depth} \times 0.052 = 1099 \text{ psi}
\]

#### CURRENT WELL DATA:
- **Current Drilling Mud**:
  - **Weight**:
    - 11.0 \text{ ppg}

#### CASING SHOE DATA:
- **Size**:
  - 13 5/8 \text{ inch}
- **M. Depth**:
  - 6,000 \text{ feet}
- **T.V. Depth**:
  - 5,820 \text{ feet}

#### HOLE DATA:
- **Size**:
  - 12 1/4 \text{ inch}
- **M. Depth**:
  - 7,560 \text{ feet}
- **T.V. Depth**:
  - 6,000 \text{ feet}

#### PUMP DATA:
- **Pump No. 1 Displ.**:
  - 0.119 \text{ bbls / stroke}
- **Pump No. 2 Displ.**:
  - 0.119 \text{ bbls / stroke}

<table>
<thead>
<tr>
<th>SLOW PUMP RATE DATA:</th>
<th>PUMP NO. 1</th>
<th>PUMP NO. 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPM</td>
<td>30</td>
<td>500</td>
</tr>
<tr>
<td>SPM</td>
<td></td>
<td>500</td>
</tr>
</tbody>
</table>

#### PRE-RECORDED VOLUME DATA:
- **Drill Pipe**
- **Heavy Wall Drill Pipe**
- **Drill Collars**

#### DRILL STRING VOLUME
- **DC x Open Hole**
- **DP x HWDP x Open Hole**

#### OPEN HOLE VOLUME
- **DP x Casing**

#### TOTAL ANNULUS VOLUME
- \((F+G) = (H)\)

#### TOTAL WELL SYSTEM VOLUME
- \((D+H) = (I)\)

#### ACTIVE SURFACE VOLUME
- \((J)\)

#### TOTAL ACTIVE FLUID SYSTEM (in-field units)
- \((I+J)\)

---

Dr. No SV 04/91

Field Units

27-01-2000

---

© Intertek Consulting & Training Unpublished work. All rights reserved.
Revised – 1Nov2012

Page 17

Version 4
## International Well Control Forum

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

<table>
<thead>
<tr>
<th>KICK DATA</th>
<th>SIDP</th>
<th>SICP</th>
<th>PIT GAIN</th>
<th>25</th>
<th>barrels</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>550</td>
<td>680</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**KILL MUD WEIGHT**

\[
\text{KMW} = \frac{\text{CURRENT MUD WEIGHT}}{\text{TVD} \times 0.052} + \frac{\text{SIDPP}}{0.052} = 12.8 \text{ ppg}
\]

**INITIAL CIRCULATING PRESSURE**

\[
\text{ICP} = \text{DYNAMIC PRESSURE LOSS} + \text{SIDPP} = 1050 \text{ psi}
\]

**FINAL CIRCULATING PRESSURE**

\[
\text{FCP} = \text{KILL MUD WEIGHT} \times \text{DYNAMIC PRESSURE LOSS} = 582 \text{ psi}
\]

\[
(K) = \text{ICP} - \text{FCP} = \frac{\text{Km}}{\text{Km}} - \frac{\text{Km}}{\text{Km}} = \frac{\text{Km}}{\text{Km}} \times \frac{\text{Km}}{\text{Km}} = 43.1 \text{ psi}
\]

### Strokes vs. Pressure

<table>
<thead>
<tr>
<th>Strokes</th>
<th>Pressure [psi]</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>100</td>
<td>1050</td>
</tr>
<tr>
<td>200</td>
<td>1007</td>
</tr>
<tr>
<td>300</td>
<td>964</td>
</tr>
<tr>
<td>400</td>
<td>921</td>
</tr>
<tr>
<td>500</td>
<td>878</td>
</tr>
<tr>
<td>600</td>
<td>835</td>
</tr>
<tr>
<td>700</td>
<td>792</td>
</tr>
<tr>
<td>800</td>
<td>749</td>
</tr>
<tr>
<td>900</td>
<td>706</td>
</tr>
<tr>
<td>1000</td>
<td>663</td>
</tr>
<tr>
<td>1085</td>
<td>620</td>
</tr>
</tbody>
</table>
49a. After 5 minutes of circulation the following readings are observed on the choke panel:

Drill pipe pressure = 940 psi
Casing pressure = 640 psi
Pump speed = 25 spm
Strokes circulated = 139 strokes

What action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue – Everything is O.K.

49b. After 9 minutes of circulation the following readings are observed on the choke panel:

Drill pipe pressure = 940 psi
Casing pressure = 620 psi
Pump speed = 30 spm
Strokes circulated = 270 strokes

What action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue – Everything is O.K.

49c. After 15 minutes of circulation the following readings are observed on the choke panel:

Drill pipe pressure = 851 psi
Casing pressure = 600 psi
Pump speed = 30 spm
Strokes circulated = 450 strokes

What action should be taken? (One answer).

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue – Everything is O.K.
49d. After 870 strokes have been circulated, the following readings are observed on the choke panel:

- Drill pipe pressure = 750 psi
- Casing pressure = 640 psi
- Pump speed = 30 spm
- Strokes circulated = 870 strokes

What action should be taken? **(One answer)**

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue – Everything is O.K.

49e. After 1400 strokes have been circulated, the well has been shut-in for evaluation. The following readings are observed on the choke panel:

- Drill pipe pressure = 0 psi
- Casing pressure = 620 psi
- Pump speed = 0 spm
- Strokes circulated = 1400 strokes

The kill procedure is continued. What should be done? **(One)**

a. Calculate new kill mud density and pump rate.
b. Start up holding drill pipe pressure constant.
c. Start up holding casing pressure constant while bringing the pump up to kill speed, then hold the observed drill pipe pressure constant.
d. Everything is OK, continue kill procedures with 40 spm and same final circulating pressure.
49f. After 7,000 strokes have been circulated, the following readings are observed on the choke panel:

- Drill pipe pressure = 458 psi
- Casing pressure = 720 psi
- Pump speed = 30 spm
- Strokes circulated = 7,000 strokes

What action should be taken? (One answer)

a. Open the choke slowly.

b. Close the choke slowly.

c. Increase the pump rate.

d. Decrease the pump rate.

e. Continue – Everything is O.K.

49g. After 9,100 strokes have been circulated, the following readings are observed on the choke panel:

- Drill pipe pressure = 570 psi
- Casing pressure = 0 psi
- Pump speed = 30 spm
- Strokes circulated = 9,100 strokes

What action should be taken? (One answer)

a. Open the choke slowly.

b. Close the choke slowly.

c. Stop pumping and resume drilling.

d. Stop pumping, shut-in the well, and observe pressure.

e. Continue – Everything is O.K.

50. What is the correct meaning of the phrase "Secondary Well Control"?

a. Preventing flow of formation fluid into the well bore by maintaining drilling fluid hydrostatic pressure equal to or greater than formation pressure.

b. Preventing flow of formation fluid into the well bore by maintaining the sum of drilling fluid hydrostatic pressure and dynamic pressure loss in the annulus equal to or greater than formation pressure.

c. Preventing flow of formation fluid into the well bore by maintaining the dynamic pressure loss in the annulus equal to or greater than formation pressure.

d. Preventing flow of formation fluid into the well bore by using BOP equipment in combination with hydrostatic pressure in the well bore to balance the formation pressure.
51. While drilling, a severe loss of returns occurred. After the pumps were stopped, it was observed that the fluid in the well dropped far below the flowline. The annulus was then filled to the top with seawater.

| Drilling fluid density | 11.4 ppg |
| Sea water density      | 8.6 ppg |
| Equivalent height of seawater | 350 ft of annulus |

What is the reduction in hydrostatic bottom hole pressure after this action, compared to before the losses?

a. 204 psi  
b. 38 psi  
c. 90 psi  
d. 51 psi

52. There will be little or no difference between SIDPP and SICP as long as the influx stays in the horizontal section of a well. What is the primary reason for this?

a. The influx has little or no effect on the hydrostatic head when in the horizontal section in the annulus.  
b. In horizontal wells, there is usually little or no difference between the density of the drilling fluid and that of the influx.  
c. In horizontal wells, the influx can also enter the drill string, because the BHA is usually very short in comparison with those in vertical wells.  
d. The influx migration rate differs from vertical wells.

53. Gas cut mud is being circulated in a well. The following fluid levels have been measured:

| From surface to 650 ft.  | 11.2 ppg |
| From 650 ft to 1,300 ft  | 11.8 ppg |
| From 1,300 to 5,400 ft   | 12.5 ppg |

The original fluid density was 12.5 ppg. What is the reduction of bottom hole pressure with this gas cut mud in the well?

a. 68 psi  
b. 24 psi  
c. 88 psi
54. While drilling through a fault in the horizontal section of a well, a kick is taken and the well closed in. Calculate the new drilling fluid density required to kill the well, using the well and kick data below.

Well Data: Measured depth at start of horizontal section: 8510 ft
         Measured depth at time of kick : 12,480 ft
         True vertical depth at start of horizontal : 5760 ft
         True vertical depth at time of kick : 5840 ft
         Length horizontal section : 5,990 ft
         Drilling Fluid Density : 13.1 ppg

Kick data:
         Shut-in drill pipe pressure : 260 psi
         Shut-in casing pressure : 270 psi

Answer __________ ppg

ATTACHED KILL SHEET

Use the data from the attached kill sheets (following three pages) to answer each of the questions 55a through 55i about the well killing process.

The well will be killed with the Driller’s Method at 30 spm.
## International Well Control Forum
### Surface BOP Kill Sheet - Deviated Well (API Field Units)

### FORMATION STRENGTH DATA:
- **Surface Leak-off Pressure from Formation Strength Test:**
  
  \[
  \text{(A) } 1545 \text{ psi}
  \]

### WEIGHT AT TEST:

\[
\text{(B) } 10.4 \text{ ppg}
\]

### Maximum Allowable Mud Weight:

\[
\text{(B)} + \frac{\text{(A)}}{\text{Shoe T.V. Depth x 0.052}} = \text{(C) } 16.85 \text{ ppg}
\]

**Initial MAASP**:

\[
\frac{\text{(C) - Current Mud Weight}}{\text{Shoe T.V. Depth x 0.052}} = 1425 \text{ psi}
\]

### CURRENT WELL DATA:
- **Drilling Mud Data**:
  - **Weight**: 10.9 ppg
  - **Gradient**: 0.5668 psf

### Deviation Data:
- **KOP M.D.**: 2,000 ft
- **KOP T.V.D.**: 2,000 ft
- **EOB M.D.**: 5,400 ft
- **EOB T.V.D.**: 4,285 ft

### Casing Data:
- **Size**: 9 5/8 in
- **M. Depth**: 9,000 ft
- **T.V. Depth**: 4,600 ft

### Hole Data:
- **Size**: 8 1/2 in
- **M. Depth**: 13,600 ft
- **T.V. Depth**: 5,000 ft

### Pre-Recorded Volume Data:

<table>
<thead>
<tr>
<th>Pre-Recorded</th>
<th>Length (ft)</th>
<th>Capacity (bbls/ft)</th>
<th>Volume (bbls)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DP - Surface to KOP</td>
<td>2000</td>
<td>0.0178</td>
<td>35.6</td>
</tr>
<tr>
<td>DP - KOP to EOB</td>
<td>3400</td>
<td>0.0178</td>
<td>60.5</td>
</tr>
<tr>
<td>DP - EOB to BHA</td>
<td>7870</td>
<td>0.0178</td>
<td>140.1</td>
</tr>
<tr>
<td>Hevi Wall Drill Pipe</td>
<td>180</td>
<td>0.0087</td>
<td>1.6</td>
</tr>
<tr>
<td>Drill Collar</td>
<td>150</td>
<td>0.0061</td>
<td>0.9</td>
</tr>
<tr>
<td>Drill String Volume</td>
<td>13,600</td>
<td>238.7</td>
<td>3.7</td>
</tr>
<tr>
<td>DC x Open Hole</td>
<td>150</td>
<td>0.0323</td>
<td>4.85</td>
</tr>
<tr>
<td>DP x HWDP x Open Hole</td>
<td>4450</td>
<td>0.0459</td>
<td>204.25</td>
</tr>
</tbody>
</table>

### Open Hole Volume:

\[
\text{DP x Casing} = 9000 \times 0.0515 = (G) 463.5 +
\]

### Total Annulus Volume:

\[
\text{(F+G) = (H)} 672.6 \text{ bbls}
\]

### Total Well System Volume:

\[
\text{(D+H) = (I)} 911.3 \text{ bbls}
\]

### Active Surface Volume:

\[
\text{(J)} \text{ bbls}
\]

### Total Active Fluid System:

\[
\text{(I+J)} \text{ bbls}
\]

---

**Pump Strokes**

<table>
<thead>
<tr>
<th>PUMP</th>
<th>Strokes</th>
<th>TIME</th>
</tr>
</thead>
<tbody>
<tr>
<td>(L)</td>
<td>297</td>
<td>66.3 min</td>
</tr>
<tr>
<td>(M)</td>
<td>504</td>
<td>58 min</td>
</tr>
<tr>
<td>(N1)</td>
<td>1167</td>
<td>129 min</td>
</tr>
<tr>
<td>(N2)</td>
<td>13</td>
<td>187 min</td>
</tr>
<tr>
<td>(N3)</td>
<td>8</td>
<td>253 min</td>
</tr>
</tbody>
</table>

**Dr No SD 0401**

(Fields Units) 27-01-2000

© Intertek Consulting & Training Unpublished work. All rights reserved.
Revised – 1Nov2012

Page 24
Version 4
55a. After 2 minutes of circulation the following readings are observed on the choke panel:

Drill pipe pressure = 950 psi  
Casing pressure = 900 psi  
Pump speed = 26 spm  
Strokes circulated = 45 strokes  
Choke position = 40% open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - everything is O.K.

55b. After 9 minutes of circulation the following readings are observed on the choke panel:

Drill pipe pressure = 1925 psi  
Casing pressure = 1340 psi  
Pump speed = 34 spm  
Strokes circulated = 260 strokes  
Choke position = 45% open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - everything is O.K.

55c. After 15 minutes of circulation the following readings are observed on the choke panel:

Drill pipe pressure = 1155 psi  
Casing pressure = 725 psi  
Pump speed = 30 spm  
Strokes circulated = 440 strokes  
Choke position = 55% open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - everything is O.K.
55d. After 1800 strokes have been circulated the following readings are observed on the choke panel:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drill pipe pressure</td>
<td>1500 psi</td>
</tr>
<tr>
<td>Casing pressure</td>
<td>1520 psi</td>
</tr>
<tr>
<td>Pump speed</td>
<td>30 spm</td>
</tr>
<tr>
<td>Strokes circulated</td>
<td>1800</td>
</tr>
<tr>
<td>Choke position</td>
<td>70%</td>
</tr>
</tbody>
</table>

The casing pressure is increasing very rapidly. What is the probable cause?

a. The well is underbalanced and more influx is entering the wellbore.
b. The choke is plugging.
c. A bit nozzle has plugged.
d. The influx is being circulated from the highly deviated section into the vertical section of the wellbore.

55e. After 2200 strokes have been circulated the following readings are observed on the choke panel:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drill pipe pressure</td>
<td>1500 psi</td>
</tr>
<tr>
<td>Casing pressure</td>
<td>1550 psi</td>
</tr>
<tr>
<td>Pump speed</td>
<td>30 spm</td>
</tr>
<tr>
<td>Choke position</td>
<td>30%</td>
</tr>
</tbody>
</table>

What action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump speed.
d. Decrease the pump speed.
e. Continue - everything is O.K.

55f. At 5700 strokes the influx had been circulated out through the choke valve. What is the stabilized standpipe pressure if the pump is stopped and the well closed-in successfully?

___________________________psi

55g. At 5700 strokes the influx had been circulated out through the choke valve. What is the stabilized casing pressure if the pump is stopped and the well closed-in successfully?

___________________________psi
55h. The mud density has been increased to the kill weight value. The well is brought on line using correct procedures. After the surface system volume has been displaced, the stroke counter was reset to "0" (zero). While pumping kill fluid the following readings are observed on the choke panel:

- Drill pipe pressure = 1340 psi
- Casing pressure = 720 psi
- Pump speed = 30 spm
- Strokes circulated = 50 strokes
- Choke position = 20 % open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - everything is O.K.

55i. After pumping 700 strokes the following readings are observed on the choke panel:

- Drill pipe pressure = 880 psi
- Casing pressure = 720 psi
- Pump speed = 30 spm
- Strokes circulated = 700 strokes
- Choke position = 30 % open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - everything is O.K.

56. A salt water kick is circulated out using the Driller's Method. The drill string consists of drill collars plus drill pipe and a surface BOP stack is used.

When will the surface casing pressure be at its maximum value?

a. When the kill fluid is entering the drill pipe.
b. When the kick has been circulated to the surface.
c. Only when a kick reaches the casing shoe.
d. Just after the kill fluid reaches the bit.
e. Immediately after the well has been shut in.
57. What precautions could be taken to reduce the risk for washouts in the drill string caused by H₂S gas? (Choose three answers).

   a. Use a drilling fluid with a low pH.
   b. Use a drill string with a medium tensile strength (X-95).
   c. Use a scavenger in the drilling mud.
   d. Use a neutralizing agent to coat the tubulars in the drilling fluid system.
   e. Reverse circulate before tripping out.
   f. Use a drill string with a high tensile strength (S-135).

58. Which of the following parameters primarily affect the value of the Shut-in Casing Pressure when a well is shut in during a kick? (Choose three answers)

   a. The pore pressure
   b. The bottom hole temperature.
   c. The hole or annulus capacity.
   d. The drill string capacity.
   e. The kick volume.
   f. The length of the choke line.

59. Why do we need to take into account a large surface line volume (from the mud pumps to the drill floor) when preparing a kill sheet for killing the well with the Wait & Weight Method? (Choose two answers)

   a. If we don't, following the drill pipe pressure graph will result in a BHP too low.
   b. If we don't there will be no effect on the bottom hole pressure
   c. If we don't, following the drill pipe pressure graph will result in a BHP too high.
   d. If we don't, the total time for killing the well will be shorter than calculated.
   e. If we don't, the total time for killing the well will be longer than calculated.

60. Which part of the system pressure losses contributes to the ECD?

   a. The pressure loss in the open hole section only.
   b. The pressure loss in the drill string.
   c. The pressure loss in the surface system.
   d. The pressure loss in the annulus.
   e. The pressure loss over the nozzles.
61. During a kill, while displacing the drill string with kill fluid, a sudden loss in drill pipe pressure was noticed. The driller continued pumping at the same pump rate, while the supervisor adjusted the choke and continued to follow the drill pipe pressure graph as originally planned.

What happened to the bottom hole pressure as a result of this?

a. The bottom hole pressure increased then decreased.
b. The bottom hole pressure remained unchanged.
c. The bottom hole pressure decreased.
d. The bottom hole pressure decreased then increased.
e. The bottom hole pressure increased with the choke adjustment.

62. Prior to starting to POOH, a heavy slug was pumped into the drill pipe.

**DATA:**
- Drill pipe capacity = 0.0174 bbl/ft
- Annulus capacity DP/Casing = 0.0510 bbl/ft
- Density of drilling fluid = 13.2 ppg
- Density of slug = 16.5 ppg
- Volume of slug inside the drill pipe = 20 bbl
- Well depth = 9,600 ft

Using the data to calculate the vertical distance between the drilling fluid level in the drill pipe and in the flowline after the slug has been pumped.

a. 287 ft
b. 270 ft
c. 207 ft
d. 362 ft

63. A vertical well with a surface BOP stack is shut in after a kick. The pressure readings are as follows:

Shut in drill pipe pressure (SIDPP) = 680 psi
Shut in casing pressure (SICP) = 890 psi

What is the reason for the difference in these two pressure readings?

a. The influx is in the drill pipe.
b. The influx has a lower density than the drilling fluid.
c. The influx has a higher density than the drilling fluid.
d. The BOP was closed too fast which caused a trapped pressure in the system.
64. A vertical well with a surface BOP stack is shut in after a gas kick has been taken. The bit is 950 ft off bottom and the influx is calculated to be from bottom to 300 ft above (bottom). Shut-in Drill Pipe Pressure is 450 psi. What will the most likely Shut-in Casing Pressure be?
   a. The same as the shut-in drill pipe pressure.
   b. Higher than the shut-in drill pipe pressure
   c. Lower than the shut-in drill pipe pressure, because of the effect of the ECD.
   d. Impossible to say, if the exact kick location is not known.

Data for Questions 65 & 66

A vertical well is 8020 feet deep and filled with 12.5 ppg drilling fluid. While circulating with 80 SPM the friction losses in the well system are as follows:

<table>
<thead>
<tr>
<th>Loss Type</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure loss through surface equipment</td>
<td>200 psi</td>
</tr>
<tr>
<td>Pressure loss in drill string .</td>
<td>800 psi</td>
</tr>
<tr>
<td>Pressure loss through bit nozzles .</td>
<td>1850 psi</td>
</tr>
<tr>
<td>Pressure loss in annulus .</td>
<td>150 psi</td>
</tr>
</tbody>
</table>

65. What is the bottom hole pressure in the well when the pumps are running at 80 spm?
   a. 5,78 psi
   b. 5363 psi
   c. 8163 psi
   d. 5213 psi

66. What will the pump pressure be when circulating with 80 SPM?
   a. 2850 psi
   b. 4550 psi
   c. 3000 psi
   d. 5213 psi
67. While drilling, a 10 bbl gas kick has been taken and the well is shut in with the bit on bottom. The pressures at surface stabilize after a few minutes. Due to problems with the pumps, the kill operation cannot start. After some time, the pressures at surface have increased due to gas migration.

What will be the simplest and safest action to take to keep the bottom hole pressure constant (assume there is no float in the string)?

a. Bleeding off drilling fluid keeping the drill pipe pressure constant.
b. Bleeding off drilling fluid keeping the casing pressure constant.
c. Start bleeding off drilling fluid and let the casing pressure decrease as per volumetric calculations.
d. Leave it as is. Gas migration will not affect the bottom hole pressure.

68. A well is being killed using the Driller's Method. During the first circulation the drill pipe pressure is kept constant at 690 psi and the pump speed at 30 spm. Halfway through this first circulation the operator on the choke observes a sudden increase in drill pipe pressure. There is no significant change in choke pressure and the pump speed is still 30 SPM.

What could have happened? (select three answers)

a. The bit nozzles have partly plugged.
b. The choke has partly plugged.
c. The kick is about to enter the choke.
d. A partial blockage in the kelly hose.
e. Pressure has built up in the mud-gas separator.
f. A partial blockage in the drill string has occurred.

69. During normal drilling operation a 30 bbl slug of light drilling fluid is pumped into the drill string followed by original drilling weight fluid.

Well Data:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well depth (TVD)</td>
<td>9,600 ft</td>
</tr>
<tr>
<td>Drill pipe capacity</td>
<td>0.0178 bbl/ft</td>
</tr>
<tr>
<td>Original drilling fluid density</td>
<td>12.3 ppg</td>
</tr>
<tr>
<td>Light drilling fluid density</td>
<td>10.5 ppg</td>
</tr>
</tbody>
</table>

Calculate the bottom hole pressure once the light slug is inside the drill pipe.

a. 158 psi    
b. 6,140 psi   
c. 5,982 psi   
d. 4,779 psi
Answer Key

1a. 12.4
1b. 1116-1138
1c. 2528-2578
1d. 1004-1005
1e. 8359-8527
1f. 798-800
1g. 780
1h. 479
1i. .095 - .115

Height of influx
\[
\frac{12_{\text{bbl}}}{.0836_{\text{bbl/ft}}} = 143.5_{\text{feet}}
\]

Gradient of influx
\[
(.052 \times 11.4) - \left( \frac{410_{\text{psi}} - 340_{\text{psi}}}{143.5_{\text{feet}}} \right) = .105_{\text{psi/ft}}
\]

1j. 26 - 27
1k. 549 – 550
1l. 318 - 319
2. 4.09 bbl
\[
\left(30_{\text{bbl}} \times \frac{15_{\text{ppg}}}{13.2_{\text{ppg}}} \right) - 30_{\text{bbl}} = 4.09_{\text{bbl}}
\]

3. 5304 psi
\[
(0.52 \times 11.1_{\text{ppg}} \times 7500_{\text{Feet}}) + 975_{\text{psi}} = 5304_{\text{psi}}
\]

4. c
5. b
6a. 356 feet
\[
\frac{25_{\text{BBL}}}{.0702_{\text{BBL/ft}}} = 356_{\text{Feet}}
\]
6b. 2.36 bbl/ft
\[
(0.01776_{\text{BBL/ft}} + .0076_{\text{BBL/ft}}) \times 93_{\text{ft}} = 2.36_{\text{BBL}}
\]
6c. 859 feet
\[
\frac{25_{\text{BBL}}}{.0291_{\text{BBL/ft}}} = 859_{\text{Feet}}
\]
6d. 495 psi
\[
205_{\text{psi}} + \left( (859_{\text{Feet}} - 356_{\text{Feet}}) \times (676_{\text{psi/ft}} - .1_{\text{psi/ft}}) \right) = 495_{\text{psi}}
\]
7. d
8. a, b
9. b
10. b, c
11. d, e, f
12. c
13. 55 complete stands
   Determine overbalance (subtract formation pressure from hydrostatic pressure)
   \[
   \left(0.052 \times 12 \text{ ppg} \times 10500 \text{ Feet}\right) - \left(0.598 \text{ psi/ft} \times 10500 \text{ Feet}\right) = 273 \text{ psi}
   \]
   Calculate complete stands (formula #24)
   \[
   \frac{\left(273 \text{ psi} \times 0.0981 \text{ bbl/ft} - 0.008 \text{ bbl/ft}\right)}{\left(0.624 \text{ psi/ft} \times 0.008 \text{ bbl/ft}\right)} \approx 4927.34 \text{ Feet} 
   \]
   \[
   \frac{4927.34 \text{ Feet}}{88.5 \text{ Ft/Stnd}} \approx 55.67 \approx 55
   \]
14. 121 psi (formula #22)
   \[
   \left(500 \text{ Feet} \times 0.0545 \text{ bbl/ft}\right) = 176.3 \text{ Feet}
   \]
   \[
   176.3 \text{ Feet} \times 0.52 \times 13.2 \text{ ppg} = 121 \text{ psi}
   \]
15. a
16. c

Pump pressure @ new rate
\[
1000 \text{ psi} \times \left(\frac{30 \text{ spm}}{40 \text{ spm}}\right)^2 = 563 \text{ psi}
\]
New ICP
\[
563 \text{ psi} + 500 \text{ psi} = 1063 \text{ psi}
\]
New FCP
\[
563 \text{ psi} \times \left(\frac{10.6 \text{ ppg}}{9.6 \text{ ppg}}\right) = 622 \text{ psi}
\]
PSI/STK decrease
\[
\frac{\left(1063 \text{ psi} - 622 \text{ psi}\right)}{1200 \text{ Stks To Bit}} = 0.367 \text{ psi/stk}
\]
Pump pressure @ 800 stks
\[
1063 \text{ psi} - \left(800 \text{ stks} \times 0.367 \text{ psi/stk}\right) = 769 \text{ psi}
\]
17. d
18. c
19. b, c
20. b, c, e
21. b
Pump pressure @ new rate

\[
1500_{\text{psi}} \times \left( \frac{25_{\text{spm}}}{50_{\text{spm}}} \right)^2 = 375_{\text{psi}}
\]

Pump pressure @ new mud weight

\[
375_{\text{psi}} \times \left( \frac{13.5_{\text{ppg}}}{12_{\text{ppg}}} \right) = 422_{\text{psi}}
\]

22a. .7068 bbl
\[.0076_{\text{bbl/ft}} \times 93_{\text{feet}} = .7068_{\text{bbl}}\]

22b. 2.36 bbl
\[(.01776_{\text{bbl/ft}} + .0076_{\text{bbl/ft}}) \times 93_{\text{feet}} = 2.358 \approx 2.36_{\text{bbl}}\]

23. c
24. d
25. a, c
26a. 2.48 bbl
\[98_{\text{feet}} \times (.01776_{\text{bbl/ft}} + .0076_{\text{bbl/ft}}) = 2.48_{\text{bbl}}\]

26b. Decrease
26c. Increase
27. a, e
28. d
29. b, c
30. d
31. b
32a. true
32b. true
33. b
34. b
35. a
\[.052 \times 10.3_{\text{ppg}} \times 7954_{\text{feet}} - 100_{\text{psi}} = 4160_{\text{psi}}\]

36. c
37. c
\[3950_{\text{feet}} \times .464_{\text{psi/ft}} - .1_{\text{psi/ft}} \times (3950_{\text{feet}} - 3470_{\text{feet}}) = 1785_{\text{psi}}\]

38. b
39. b
40. d
41. b, d
42a. 1.65 bbl
\[93_{\text{feet}} \times .01776_{\text{bbl/ft}} = 1.65_{\text{bbl}}\]

42b. 2.36 bbl
\[(.01776_{\text{bbl/ft}} + .0076_{\text{bbl/ft}}) \times 93_{\text{feet}} = 2.36_{\text{bbl}}\]
43. b
44. 280 psi
\[
\frac{12 \text{ bbl/hr} \times 3 \text{ hrs}}{36 \text{ bbl}} = 36 \text{ bbl}
\]
\[
\frac{36 \text{ bbl}}{0.0836 \text{ bbl/ft}} = 430.6 \text{ feet}
\]
\[
0.052 \times 12.5 \text{ ppg} \times 430.6 \text{ feet} = 279.8 \approx 280 \text{ psi}
\]
45. b
46. d, d, a, d
47. c, d
48. a, c
49a. c
49b. e
49c. b
49d. a
49e. c
49f. b
49g. d
50. d
51. d
\[
(11.4 \text{ ppg} - 8.6 \text{ ppg}) \times 0.052 \times 350 \text{ feet} = 50.96 \approx 51 \text{ psi}
\]
52. a
53. a
\[
(12.5 \text{ ppg} - 11.2 \text{ ppg}) \times 0.052 \times 650 \text{ feet} = 43.94 \text{ psi}
\]
\[
(12.5 \text{ ppg} - 11.8 \text{ ppg}) \times 0.052 \times 650 \text{ feet} = 23.66 \text{ psi}
\]
\[
\text{Total} = 43.94 \text{ psi} + 23.66 \text{ psi} = 67.6 \text{ psi}
\]
54. 14.0 ppg
\[
\left(\frac{260 \text{ psi}}{0.052 \times 5840 \text{ feet}}\right) + 13.1 \text{ ppg} = 13.95 \approx 14.0 \text{ ppg}
\]
55a. c
55b. d
55c. b
55d. d
55e. e
55f. 875 psi
55g. 875 psi
55h. b
55i. b
56. e
57. b, c, d
58. a, c, e
59. a, e
60. d
61. e
62. a
\[
\left( 20_{bbl} \times \frac{16.5_{ppg}}{13.2_{ppg}} \right) - 20_{bbl} = 5_{bbl}
\]
\[
\frac{5_{bbl}}{.0174_{bbl/ft}} = 287_{feet}
\]
63. b
64. a
65. b
\[
(0.052 \times 12.5_{ppg} \times 8020_{feet}) + 150_{psi} = 5363_{psi}
\]
66. c
\[
200_{psi} + 800_{psi} + 1850_{psi} + 150_{psi} = 3000_{psi}
\]
67. a
68. a, d, f
69. b
IWCF Well Control Course

Surface Equipment Practice Exam

Name______________________

Date_______________________
1. The diagram below represents a diverter assembly typical on a floating rig. Identify the parts shown by placing the proper numbers in the blanks below the drawing.

![Diagram of a diverter assembly]

- a. _____  Housing
- b. _____  Support Dogs
- c. _____  Insert Packer
- d. _____  Flowline
- e. _____  Outer Packer
- f. _____  Closing Port
- g. _____  Lockdown Dogs
- h. _____  Ventline Seals
2. A BOP stack consists of the following components:

- 3 ram BOP's; Shaffer type SL - 13-5/8" 15,000 psi
- 1 annular BOP; Hydril type GK - 13-518" 10,000 psi

After closing in on a kick on 3-1/2" drill pipe using the annular BOP, the stabilized pressures were as follows: SIDPP = 660 psi, SICP = 2000 psi.

Use the diagram below to determine what pressure the annular should be adjusted to. (Choose one answer)

a. 100 to 200 psi  
b. 200 to 300 psi  
c. 300 to 400 psi  
d. 400 to 500 psi
3. The drawing below is a typical mud gas separator. Which set of dimensions determines the back pressure generated within the vessel?

(Choose one answer)

a. The derrick outlet height (H3) and outlet inside diameter (D3).
b. The dip tube height (H2).
c. The body height (H1) and the body inside diameter (D1).
d. The length and inside diameter (D4) of the inlet pipe from the buffer tank to the choke.

4. If the dip tube (H2) in the drawing above is 15 ft long and contains 12.5 ppg mud, calculate the pressure required to unload the separator.

Unloading pressure ______________________ psi
5. The characters "6BX" stamped on the flange represent its?
   a. serial number
   b. pressure rating
   c. type
   d. size

6. What is meant by the closing ratio for a ram-type BOP?
   a. Ratio between closing & opening volume.
   b. Ratio between closing & opening time.
   c. Ratio of the wellhead pressure to the pressure required to close the BOP.

7. API RP 53 states maximum closing times for surface and subsea blowout preventers. Put the proper time in the blank next to each preventer listed below.
   a. 45 seconds
   b. 60 seconds
   c. 30 seconds

   _______ 18-3/4" Annular (surface)
   _______ 18-3/4" Annular (subsea)
   _______ 13-3/8" rams (surface)
   _______ 20" Annular (surface)
   _______ 16" rams (subsea)

8. Which statements are correct with respect to ram-type BOP's?
   (Choose three answers)
   a. Ram-type BOPs are designed to contain and seal Rated Working Pressure only from above the closed rams.
   b. Ram-type BOPs are designed to contain and seal Rated Working Pressure from above the closed rams as well as from below the closed rams.
   c. Ram-type BOPs are designed to contain and seal Rated Working Pressure only from below the closed rams.
   d. Well pressure below closed rams will assist to maintain the rams closed.
   e. Pipe rams can be used to hang off the drill string in an emergency.
9. What does 21¼” specify when the BOP equipment in use is designated as 10M – 21¼” - RSRdA?
   a. The nominal diameter of the BOPs.
   b. The cylinder diameter of the hydraulic actuator for the ram BOPs.
   c. The closing ratio of the ram preventer.
   d. The outside diameter of the flange or hub on the preventer.

10. What has to be checked before installation of any annular packing element? (Two answers)
   a. Maximum hang-off rating in pounds.
   b. Temperature rating of element.
   c. Type of mud to be used.
   d. Desired hydraulic closing pressure.
   e. Maximum pipe outside diameter.

11. Most of the conventional front packer elements fitted on ram BOPs are between steel plates. What are the main reasons for this type of design? (Two answers)
   a. To be able to support the weight of the drill string during hang-off.
   b. To prevent ram rubber from extruding into the ram cavity.
   c. To extrude elastomer into sealing contact with the pipe when sealing face becomes worn.
   d. To prevent any swelling when in use during high temperature operations.

12. What should be done first after connecting the open and close hydraulic lines to the BOP stack?
   a. Function test all items on the BOP stack.
   b. Drain the accumulator cylinders and check the nitrogen precharge pressure.
   c. Place the selector valves on the hydraulic control manifold in neutral or block position and start pressure testing the BOP stack.
   d. Perform closing unit pump capability test.

13. Closing units should be equipped with sufficient number and sizes of pumps to satisfactorily perform the closing unit capacity test as per API RP 53. With the accumulator system isolated, the pumps should be capable of closing the annular preventer on the size of drill pipe being used, open the hydraulically operated choke line valve and obtain a minimum of 200 psi pressure above accumulator precharge pressure on the closing unit manifold, within:
   a. 1 minute or less
   b. 2 minutes or less
   c. 3 minutes or less
   d. 4 minutes or less
14. Match the numbers from the picture below with the appropriate part.

Body       Operating Cylinder
Bonnet     Operating Piston
Lock Screw Ram Assembly
Ram Change Piston Bonnet Bolt

15. Ram type BOPs are designed to open in a situation where Rated Working Pressure is contained below the rams and mud hydrostatic pressure to the flow line is above the rams; for instance in a stripping operation.
   a. True.
   b. False

16. Identify two functions of a "weep-hole" on ram type BOPs from the list below. (Choose two answers)
   a. The weep hole allows visual inspection of the ram shaft and should be plugged between inspections.
   b. The weep hole prevents leakage through the primary ram shaft packing from the well bore to the hydraulic opening chamber and vice versa.
   c. To allow installing a grease nipple. With a grease nipple installed the weep hole is used for greasing the ram shaft.
   d. The weep hole indicates if the primary ram shaft is leaking hydraulic fluid, well bore fluid or both types of fluid.
   e. The weep hole is a grease release port that prevents overgreasing the ram shaft packing.
17. While testing the pipe rams, it is noticed that the weep hole on one of the preventer bonnets is leaking fluid. What action should be taken?

a. The ram packing elements on the ram body are worn out. Secure the well and replace immediately.
b. The primary ram shaft seal is leaking. Secure the well and replace immediately.
c. The weep hole checks the operating chamber. If the amount of leaking fluid is small, no action is required until scheduled maintenance.
d. Energize emergency packing ring. If leak stops, leave it till next scheduled maintenance.

18. Identify the one ram locking device from the list below that does not allow for self feeding ram packers to allow for packer wear.

a. Shaffer "Ultralock"
b. Koomey "Autolock"
c. Hydril "MPL"
d. Cooper (Cameron) "Wedgelock"
e. Shaffer "Poslock"

19. What should be the Rated Working Pressure for the BOP equipment according to API (RP 59)?

a. Maximum anticipated reservoir pressure.
b. Maximum anticipated bottom hole pressure.
c. Maximum anticipated surface pressure.
d. Maximum anticipated hydrostatic drilling fluid pressure.
e. Maximum anticipated dynamic choke pressure.

20. For a surface BOP there is a dedicated annular regulator. What is the requirement for this hydraulic regulator according to API RP 16 E?

a. Controllable from a location close to the BOP hydraulic control unit.
b. Direct manual valve and regulator operability should permit closing the annular BOP and/or maintaining the set regulated pressure in the event of loss of the remote control capability.
c. The regulator should be provided with a regulator bypass valve to override the regulator giving direct accumulator pressure to the annular BOP_function.
21. Which of the following recommendations are stated in API(RP 53) to specify when BOP hydraulic pressure test should occur? (Choose three answers)

a. After circulating out a gas kick.
b. After any change of a component in the BOP
c. No less than once every two months.
d. After setting casing string.
e. Prior to entering a known pressure transition zone

22. There is only one drill pipe safety valve with NC50 (4-1/2 IF) pin/box connection on the rig. The drill string consists of:

| 5 inch drill pipe          | NC50 |
| 5 inch Heavy wall drill pipe | NC50 |
| 8 Inch drill collar        | 6-5/8 Reg. |
| 9-1/2 inch drill collar    | 7-5/8 Reg. |

Select the two crossovers from the list that must be on the rig floor while tripping.

a. NC50 (4-1/2 IF) box x 6-5/8 Reg. pin
b. NC50 (4-1/2 IF) box x 7-5/8 Reg. pin
c. NC50 (4-1/2 IF) box x 6-5/8 Reg. box
d. 6-5/8 Reg. pin x 7-5/8 Reg. pin

23. A well kicks with the bit off bottom and is shut in. The decision is made to strip back into the hole. What equipment should be made up onto the string prior to performing the stripping operation safely, assuming that there is no float sub or dart sub in the string?

a. Only the drill pipe safety valve (closed).
b. Only the Inside Blowout Preventer.
c. Drill pipe full opening safety valve (open) with Inside Blowout Preventer installed on top.
d. Inside Blowout Preventer with drill pipe full opening safety valve (closed) on top.
e. Only the drill pipe safety valve (open).
24. Match the numbers with the following parts in the picture below.

<table>
<thead>
<tr>
<th>Lower ram assembly</th>
<th>Blade packer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top Seal</td>
<td>Upper body</td>
</tr>
<tr>
<td>Side packers</td>
<td>Upper ram assembly</td>
</tr>
</tbody>
</table>

25. New BOPs are subjected to a hydrostatic body test prior to shipment from the manufacturer's facility. Pick the test pressure for an 18-3/4" x 15000 psi BOP according to API Spec 16 A.

a. 15,000 psi  
b. 17,500 psi  
c. 20,000 psi  
d. 22,500 psi

26. What is, according to API RP 53, the usable fluid volume of an accumulator?

a. The total volume recoverable from the cylinders between the accumulator operating pressure and 500 psi above the precharge pressure.
b. The total volume to be stored in the accumulator cylinders.
c. The total volume recoverable from the cylinders between the accumulator operating pressure and 200 psi above the precharge pressure.
d. The total volume recoverable from the cylinders between the accumulator operating pressure and the precharge pressure.
e. The total volume to be stored in the accumulator tank.
27. How often should the precharge on accumulator bottles be tested?

a. As the rig is being moved to a new location.
b. After testing the BOPs after setting surface casing on a new well.
c. The precharge should be checked every time the BOPs are pressure tested.
d. Since the precharge is only tested if a leak develops, if the accumulator pressure is steady then no test has to be conducted.

28. The following statements relate to the driller’s remote control BOP panel located on the rig floor. Decide if the statements are true or false. (Surface BOP)

   True   False  a. If you operate a function without operating the master control valve, that function will not work.
   True   False  b. The master control valve on an air-operated panel allows air pressure to go to each function in preparation for you operating the function.
   True   False  c. The master control valve must be held depressed while BOP functions are operated.
   True   False  d. The master control valve must be depressed for five seconds then released before operating a BOP function.

29. The drawing shows a Shaffer type 72 blind shear ram. Identity the components by placing the proper numbers in the blanks.

Lower ram block _______
Upper ram block _______
Seal _______
Lower blade _______
Ram block holder _______
30. A BOP operating unit has 20 accumulator bottles, each with a capacity of 10 gallons.

   Maximum pressure is 3000 psi.
   Precharge pressure is 1000 psi.

   What is the total usable fluid volume when the minimum BOP operating pressure is 1200 psi? ____________ gallons

31. When testing the BOP stack with a test plug or with a cup tester in place, a means of flow communication from below the tool to atmosphere is established. Choose the one best reason for this practice.

   a. Because of potential damage to casing/open hole.
   b. Because the test will create extreme hook load.
   c. Otherwise reverse circulation will be needed to release the tool.
   d. To avoid swabbing a kick during the test.

32. Match letters with the following parts in the picture.
(Hydril GL Annular Preventer)

   Opening chamber  ________
   Closing chamber  ________
   Opening chamber head ________
   Balancing or Secondary chamber ________

   [Diagram of Hydril GL Annular Preventer]
33. Referring to the previous question concerning a Hydril GL preventer, which statements from the list below are true when this preventer is used in a subsea application. **(Choose two answers)**

   a. The secondary chamber allows balancing the opening force on the piston created by drilling fluid hydrostatic pressure in the marine riser.
   b. Lowest required hydraulic closing pressure when opening chamber and secondary chamber are connected.
   c. Lowest required hydraulic closing pressure when closing chamber and secondary chamber are connected.

34. A surface BOP stack contains the following components:

   1 - Annular BOP
   3 - Ram BOP
   2 - Hydraulically-controlled valves.

   Fluid capacity is to be sufficient to **close - open - then close** again all components. Use the data in the table below to calculate the required fluid capacity.

   **BOP Hydraulic Fluid Volume Requirements**

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Gallons to Close</th>
<th>Gallons to Open</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annular BOP</td>
<td>11.18</td>
<td>9.89</td>
</tr>
<tr>
<td>Ram BOP</td>
<td>5.5</td>
<td>5.1</td>
</tr>
<tr>
<td>Hydraulic Valve</td>
<td>0.9</td>
<td>0.7</td>
</tr>
</tbody>
</table>

   Required fluid capacity = _____________________ gallons.
35. Two types of valves may be used in the drill string:

Type 1: "non-return, stab-in safety valve". (inside BOP)
Type 2: "fully opening stab in kellycock valve". (fully opening safety valve)

Mark the type on the corresponding line with a X.

<table>
<thead>
<tr>
<th>Type 1</th>
<th>Type 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>_____ a. Will not allow for wireline to be run inside the drill string</td>
<td>_____</td>
</tr>
<tr>
<td>_____ b. Must not run in the hole in the closed position</td>
<td>_____</td>
</tr>
<tr>
<td>_____ c. Has to be pumped open to read &quot;shut-in drill pipe pressure&quot;</td>
<td>_____</td>
</tr>
<tr>
<td>_____ d. Requires the use of a key to close</td>
<td>_____</td>
</tr>
<tr>
<td>_____ e. Has potential to leak through the open/close key</td>
<td>_____</td>
</tr>
<tr>
<td>_____ f. Easier to stab if strong flow is encountered up the drill string</td>
<td>_____</td>
</tr>
</tbody>
</table>

36. The drawing below represents a typical inside BOP. Identify the selected parts by placing the proper letters in the blanks. (Not all letters will be used)

- _______ Release Tool
- _______ Upper Body
- _______ Valve Release Rod
- _______ Rod Lock Screw
- _______ Valve
- _______ Lower Body
37. Which option gives the minimum capacity of the hydraulic fluid reservoir on a BOP control unit for a surface BOP installation as recommended in API RP 53?
   
   a. Two times the accumulator capacity.
   b. Two times the hydraulic closing volume of the BOP.
   c. Two times the usable fluid volume of the accumulator system.

The following illustrates the cross-section profiles of four different API ring gaskets commonly used on wellhead equipment.

![Ring Gaskets Diagram]

From the diagrams above, answer questions 38a to 38c below:

38a. Which two are not pressure energised?

   a. Type R Octagonal.
   b. Type R Oval.
   c. Type RX.
   d. Type BX.

38b. Which ring gasket will not match "6B" flange?

   a. Type R Octagonal
   b. Type R Oval
   c. Type RX
   d. Type BX

38c. Which pressure energised ring gasket will match "6B" flange?

   a. Type R Octagonal
   b. Type R Oval
   c. Type RX
   d. Type BX
39. Identify from the sketch below, which valves should be opened to circulate the well using the mud pump, through the remote adjustable choke and the mud gas separator. The well is closed in on the annular.

![Diagram of well circulation system]

- a. 2, 3, 4, 5, 6, 8, 9, 11, 12, 15
- b. 1, 3, 7, 8, 9, 11, 12, 16
- c. 2, 3, 7, 8, 9, 11, 12, 16
- d. 1, 3, 7, 8, 10, 13, 14, 16
- e. 2, 3, 7, 8, 10, 13, 14, 16

40. Identify the BOP components that are controlled by manifold pressure: (Choose three answers)

- a. Pipe rams
- b. Blind rams
- c. Annulars
- d. Hydraulically controlled choke & kill line valves (HCR's)
- e. All of the above.

41. Which two pressure readings would decrease if you operated the pipe rams? (Choose two answers)

- a. Manifold pressure
- b. Annular pressure
- c. Accumulator pressure
- d. Precharge pressure
42. Mark the following with "+" if it is an advantage or "-" if it is a disadvantage of using a float valve in the drill string.

_______ a. For surge pressure.
_______ b. For reverse circulation.
_______ c. For flowback while tripping.
_______ d. For shut-in drill pipe pressure reading.
_______ e. For tripping time.

43. On the electric drillers panel (surface BOP), a ram close function was activated and the following observations made:

- Green light went out.
- Red light came on.
- Annular pressure did not change.
- Manifold pressure did not change.
- Accumulator pressure did not change.

Which choice gives the cause of the problem?

a. Electric pressure switches are malfunctioning.
b. The selector valve (3 position/4 way valve) is stuck in open position.
c. There is a blockage in the hydraulic line connecting the BOP to the BOP Control Unit.
d. There is a leak in the hydraulic line connecting the BOP to the BOP Control Unit.
e. The electric-driven triplex pump is malfunctioning.
44. Match the numbers with the following parts in the picture below:

<table>
<thead>
<tr>
<th>Electric motor driven pump assembly</th>
<th>Accumulator shut-off valve</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accumulator pressure gauge</td>
<td>Manifold pressure gauge</td>
</tr>
<tr>
<td>Manifold bypass valve</td>
<td>Annular pressure gauge</td>
</tr>
<tr>
<td>Pressure transducer for annular BOP</td>
<td>Hydro-electric pressure switch</td>
</tr>
<tr>
<td>Hydro-pneumatic pressure switch</td>
<td>Check valve for triplex pump</td>
</tr>
</tbody>
</table>
ANSWER KEY

1a. 1  
1b. 2  
1c. 3  
1d. 8  
1e. 7  
1f. 6  
1g. 5  
1h. 4  
2. d  
3. a  
4. 9.75 psi  
\[0.052 \times 12.5 \text{ ppg} \times 15 \text{ Feet} = 9.75 \text{ psi}\] 
5. c  
6. c  
7. a  
   b  
   c  
   a  
   a  
8. c, d, e  
9. a  
10. b, c  
11. b, c  
12. a  
13. b  
14. Body 12  
   Operating Cylinder 8  
   Bonnet 5  
   Operating Piston 7  
   Lock Screw 3  
   Ram Assembly 1  
   Ram Change Piston 11  
   Bonnet Bolt 10  
15. b  
16. b, d  
17. b  
18. e  
19. c  
20. b  
21. b, d, e  
22. a, b  
23. c
24. Lower Ram Assembly
   Blade Packer
   Top Seal
   Upper Body
   Side Packers
   Upper Ram Assembly

25. d
26. c
27. a
28. a. TRUE
   b. TRUE
   c. TRUE
   d. FALSE
29. Lower Ram Block
    Upper Ram Block
    Seal
    Lower Blade
    Ram Block Holder
30. 100 gallons
    Deliverable Volume
    \[
    \left( 20 \text{ bottles} \times 10 \text{ gal/bottle} \right) \times \left( \frac{1000 \text{ psi}}{1200 \text{ psi}} - \frac{1000 \text{ psi}}{3000 \text{ psi}} \right) = 100 \text{ gallons}
    \]
31. a
32. Opening Chamber
    Closing Chamber
    Opening Chamber Head
    Balancing/Secondary Chamber
33. a, c
34. 85.5 gallons
    Annular
    \[
    \left( 11.18 \text{ gallons} \times 2 \right) + 9.89 \text{ gallons} = 32.2 \text{ gallons}
    \]
    Rams
    \[
    \left( 5.5 \text{ gallons} \times 2 \right) + 5.1 \text{ gallons} \times 3 = 48.3 \text{ gallons}
    \]
    Valves
    \[
    \left( 9 \text{ gallons} \times 2 \right) + 0.7 \text{ gallons} \times 2 = 5 \text{ gallons}
    \]
    Total Volume
    \[
    32.2 \text{ gallons} + 48.3 \text{ gallons} + 5 \text{ gallons} = 85.5 \text{ gallons}
    \]
35. a. TYPE 1  
b. TYPE 2  
c. TYPE 1  
d. TYPE 2  
e. TYPE 2  
f. TYPE 2  

36. Release Tool  
   Upper Body  
   Valve Release Rod  
   Rod Lock Screw  
   Valve  
   Lower Body  

37. c  

38. a. a, b  
b. d  
c. c  

39. c  

40. a, b, d  

41. a, c  

42. a. -  
b. -  
c. +  
d. -  
e. -  

43. c  

44. Electric Motor Driven Pump Assembly  
   Accumulator Pressure Gauge  
   Manifold By-pass Valve  
   Pressure Transducer for Annular BOP  
   Hydro-pneumatic Switch  
   Accumulator Shut-off Valve  
   Manifold Pressure Gauge  
   Annular Pressure Gauge  
   Hydro-electric Switch  
   Check Valve for Triplex Pump
IWCF Well Control Practice Exam

Subsea Practice Exam
Principles and Procedures

Name__________________________

Date__________________________

Score__________________________
Complete an IWCF Subsea Kill Sheet using the data below and answer the questions on the following page. (01a-01I)

**Well Data:**

- **Hole size** = 8 1/2 inch
- **Hole depth (TVD/MD)** = 10,550 ft.
- **Casing shoe depth (size 9-5/8 in. x 53.5ppf) (TVD/MD)** = 7,580 ft.
- **Water Depth** = 350 ft
- **Air Gap** = 45 ft

**Internal Capacities:**

- **Drill Pipe** 5 inch; = 0.01776 bbls/ft
- **Heavy Weight Drill Pipe** 5 inch; length 810 ft. = 0.0088 bbls/ft
- **Drill Collars** 6-1/2 x 2-13/16 in, length 1,100 ft = 0.0077 bbls/ft
- **Choke line** 3 inch ID, length 395 ft. = 0.0087 bbls/ft
- **Marine Riser** length 380 ft. = 0.3789 bbls/ft

**Annulus capacities between:**

- **Drill collars and open hole** = 0.0291 bbls/ft
- **Drill pipe plus HWDP and open hole** = 0.0447 bbls/ft
- **Drill pipe plus HWDP and casing** = 0.0465 bbls/ft
- **Drill pipe in marine riser** = 0.3535 bbl/ft

**Mud Pump Data:**

- **Displacement at 98% volumetric efficiency** = 0.11 bbl/stk

**Slow pump rate Data:**

- @40 SPM through the riser. = 750 psi
- @40 SPM through the choke line. = 960 psi

**Other information:**

- **Active surface fluid volume** = 525 bbl
- **Drill pipe size 5 inch closed end displacement** = 0.0254 bbl/ft
- **Seawater density** = 8.5 ppg

**Formation strength test data:**

- **Drilling fluid density at formation strength test** = 10.4 ppg
- **Initial MAASP with 10.4 ppg drilling fluid** = 1970 psi

**Kick Data:**

- The well kicked at 10,550 ft. vertical depth.
  - **Shut-in Drill Pipe Pressure** = 600 psi
  - **Shut-in Casing Pressure** = 920 psi
  - **Pit Gain** = 22 bbls
  - **Drilling fluid density at time of kick** = 10.4 ppg

The well will be killed using the Wait and Weight Method at 40 spm.
1a. What is the Kill Mud Density required to balance formation pressure? (Round off to one number past the decimal)
________________ ppg

1b. How many strokes will be required to pump kill mud from the surface to the bit?
________________ strokes

1c. How many minutes are required to circulate the total well system volume at 40 spm?
________________ minutes

1d. Calculate the strokes required to displace the riser to kill fluid before opening the BOP.
________________ strokes

1e. What is the pressure safety margin at the shoe in the static condition. Assume the top of the kick is below the shoe. (MAASP - SICP)
________________ psi

1f. What is the Initial Circulating Pressure?
________________ psi

1g. What is the Final Circulating Pressure, once the kill mud is at the bit?
________________ psi

1h. Calculate the initial dynamic casing pressure at the kill pump rate. (SICP – CLF)
________________ psi

1i. What is the drill pipe pressure reduction per 100 strokes as kill mud is being pumped to the bit?
________________ psi/100 strokes

1j. Calculate MAASP after circulation of kill mud.
________________ psi

1k. Calculate the new mud weight when the riser margin is added.
________________ ppg

1l. Calculate the MAASP when the riser margin is included in the mud weight.
________________ psi
2. Prior to pulling pipe out of the hole from 12,562 ft. TVD., the pipe is full of 13.2 ppg mud. Pipe capacity is 0.01776 bbl/ft. A 30 bbl slug weighing 15.0 ppg is pumped into the drill pipe. How much pit gain would result from pumping the slug into position?

_______________ bbls

3. Using the leak-off plot below, determine the initial fracture pressure at the Casing shoe. (use a straight edge on the plot).

<table>
<thead>
<tr>
<th>PSI</th>
</tr>
</thead>
<tbody>
<tr>
<td>1100</td>
</tr>
<tr>
<td>1000</td>
</tr>
<tr>
<td>900</td>
</tr>
<tr>
<td>800</td>
</tr>
<tr>
<td>700</td>
</tr>
<tr>
<td>600</td>
</tr>
<tr>
<td>500</td>
</tr>
<tr>
<td>400</td>
</tr>
<tr>
<td>300</td>
</tr>
<tr>
<td>200</td>
</tr>
<tr>
<td>100</td>
</tr>
<tr>
<td>0</td>
</tr>
</tbody>
</table>

Casing Depth, TVD = 7500 ft
Mud Density = 11.1 ppg

Initial Fracture Pressure ______________ psi

4. When should a leak-off test be carried out?
   a. Immediately after running and cementing casing.
   b. Immediately before running casing
   c. After drilling out casing shoe 5 to 15 feet in new formation.
   d. Immediately before drilling out casing shoe.
5. When starting a kill operation on a surface drilling unit, the choke pressure is kept constant while bringing the pump up to kill speed. The drill pipe gauge now reads 200 psi higher than the pre-calculated Initial Circulating Pressure (ICP). What is the correct action to take?

a. Open the choke and let the drill pipe pressure drop to the pre-calculated value (ICP).
b. Continue to circulate with the new ICP and adjust the drill pipe pressure graph accordingly.
c. There will now be 200 psi overbalance on the bottom which is acceptable. Nothing needs to be done.

6. While tripping out of the hole from 11,000 ft. TVD, the hole does not take proper hole fill. With the bit at 9,000 ft. TVD, the well flows and is shut in with 350 psi SICP (float was in place). 13.0 ppg Mud in hole. Drill collar length = 1,200 ft. Stand length = 93 ft.

Drill pipe capacity = 0.01776 bbl/ft
Drill pipe displacement = 0.0076 bbl/ft
Open hole capacity = 0.0702 bbl/ft
Annular capacity (drill collars/open hole) = 0.0291 bbl/ft
Annular capacity (drill pipe/open hole) = 0.0459 bbl/ft
Pit gain = 25 bbl
Gas gradient = 0.1 psi/ft

Assume the gas is on the bottom and does not migrate.

a. Calculate the height of the influx in the open hole __________ ft
b. Calculate the volume displaced per stand of pipe stripped into the hole __________ bbls

c. After stripping to bottom and bleeding 50.7 bbls of mud, what was the height of the influx __________ ft
d. Calculate the SICP once the bit was on bottom __________ psi

7. We are planning to circulate a kick with the Wait & Weight method. The volume of the surface lines on this rig is 20 bbls. Identify the best procedure for dealing with the volume of the surface lines?

a. Re-zero the stroke counter once kill mud reaches the bit.
b. Subtract 20 bbls (adjusted for pump strokes) from the "strokes to bit" total on the kill sheet.
c. Ignore the 20 bbls and use it as a safety factor.
d. Re-zero the stroke counter when kill mud starts down the drill pipe.
8. Which of the following statements are good operating practice in TOP HOLE that has a risk of gas bearing formations? (Choose two answers)

a. Pump out of the hole on trips.
b. Control drill.
c. Maintain high rate of penetration to ensure mud viscosity level is as high as possible.
d. Regularly pump fresh water pill to clean cuttings from hole.
e. Use a high density mud to create maximum overbalance.

9. What happens to the pressure on the casing shoe while the gas influx is passing from the open hole into the casing?

a. Increases
b. Decreases
c. Stays the same

10. The pumps are malfunctioning and you can't circulate. A gas kick is migrating up the wellbore and bottom hole pressure must be kept constant. Identify two instances when the Volumetric Method is appropriate? (Choose two answers)

a. With the bit on bottom, no float in string.
b. When the bit is a long way off bottom, no float in string.
c. With the bit on bottom, plugged drill string.

11. Which three of the following conditions are essential for the calculation of an accurate formation strength at the shoe? (Choose three answers)

a. Accurate hole volume.
b. Accurate stroke counter.
c. Installation of retrievable packer approximately 150 ft. below the wellhead.
d. Accurate pressure gauge.
e. Exact mud density.
f. Exact vertical depth of the casing shoe.

12. A light mud pill is circulated in the well. At what moment will the bottom hole pressure start to decrease?

a. As soon as the pill starts to be pumped into the drill string.
b. Once all the pill has been displaced into the annulus.
c. Once the pill starts to be displaced into the annulus.
d. Once all the pill is in the annulus.
13. A well was drilled to a TVD of 10,500 ft.

Casing shoe TVD - 4500 ft  
Mud density - 12.0 ppg  
Open hole capacity - 0.0702 bbl/ft  
Pipe metal displacement - 0.0080 bbl/ft  
Casing capacity - 0.0981 bbl/ft  
Pore pressure - 0.598 psi/ft  
Length of one stand - 88.5 ft

How many **full stands** (complete stands) of drill pipe can the driller pull before the hole level reduces the bottom hole pressure enough to cause the well to go underbalanced?  
NOTE: pulling dry pipe.

________________stands

14. If the Driller pulls all 500 ft of 8” OD x 2 13/16” ID drill collars out of the hole dry, including the bit, without filling the hole, what will be the reduction in the bottom hole pressure?

__________________________ psi

Mud weight = 13.2 ppg  
Casing capacity = 0.1545 bbl/ft  
Metal displacement = 0.0545 bbl/ft

15. While circulating out a kick at 40 spm, it is decided to reduce the pump speed to 30 spm. While the driller slows the pump to 30 spm, the choke operator maintains the casing pressure constant until 30 spm has been reached. What is the effect on bottom hole pressure? (Neglect ECD effects):

a. No effects.  
b. Bottom hole pressure is reduced  
c. Bottom hole pressure is increased.
16. The well is being killed properly using the Wait and Weight Method of well control. 10.6 ppg kill weight mud is being pumped down the drill string. After pumping 600 strokes, the drill pipe pressure is 1300 psi. The crew then reduces the pump rate from 40 spm to 30 spm using proper procedure.

What will be the drill pipe pressure reading at the new rate after pumping a total of 800 strokes?

Data:  
- Original mud weight - 9.6 ppg
- Surface to bit strokes - 1200 stks
- Bit to surface strokes - 2400 stks
- Slow circulating rate pressure - 40 spm - 1000 psi
- SIDPP - 500 psi
- SICP - 850 psi
- Pit Gain - 22 bbls
- TVD/MD - 10,000 ft
- Kill Weight Mud - 10.6 ppg
- Initial Circulating Pressure - 1500 psi
- Final Circulating Pressure - 1100 psi
- Psi/stk - 0.333

a. 1350 psi  
b. 1234 psi  
c. 769 psi  
d. 694 psi

17. Before starting to kill the well, there is a complete failure of the pumps. Which pressure has to remain constant in order to maintain the correct bottom hole pressure if the influx migrates?

Well Data
- Slow rate circulation pressure = 500 psi at 40 strokes/min
- The well has been shut-in after a kick:
  - Shut-in Drill Pipe Pressure = 800 psi
  - Shut-in Casing Pressure = 1100 psi

a. 1600 psi at the casing gauge.  
b. 1100 psi at the casing gauge.  
c. 1300 psi at the drill pipe gauge.  
d. 800 psi at the drill pipe gauge.
18. Circulation is started with the original mud. While the pump is being brought up to 40 strokes/min, which pressure has to remain constant to maintain the correct bottom hole pressure?

**Well Data**  
*(NOTE: Surface BOP STACK)*
- Slow circulation rate pressure = 500 psi at 40 strokes/min
- The well has been shut-in after a kick:
  - Shut-in Drill Pipe Pressure = 800 psi
  - Shut-in Casing Pressure = 1100 psi

a. 800 psi at the drill pipe gauge.  
b. 1300 psi at the drill pipe gauge.  
c. 1100 psi at the casing gauge.  
d. 1600 psi at the casing gauge.

19. Slow circulation rate tests are made at different pump rates (SPM's) for use on the Well Kill Sheet. Which two of the following can determine the SPM chosen to kill the well? *(Choose two answers)*

a. The capacity of the drill string.  
b. Maximum allowable pump pressure.  
c. The kill mud mixing capacity on the rig.  
d. The capacity of the open hole annulus compared to the drill string capacity.

20. Which three of the following practices are likely to increase the chance of swabbing? *(Choose three answers).*

a. Pulling pipe slowly.  
b. Maintaining high mud viscosity.  
c. Pulling through tight spots with the pump off.  
d. Pulling through tight spots with the pump on.  
e. Pulling pipe quickly.

21. At 50 spm, with 12.0 ppg mud, the pump pressure is 1500 psi.

What would the pump pressure be if the rate were decreased to 25 spm and the mud weight is increased to 13.5 ppg?

a. 375 psi  
b. 422 psi  
c. 750 psi  
d. 844 psi
22. Calculate the volumes in 22 a, and 22 b below:

Drill Pipe Capacity = 0.01776 bbls/ft
Drill Pipe Metal Displacement = 0.0076 bbls/ft
Average Stand Length = 93 ft

Calculate:

a. Mud required to fill the hole per stand when pulled 'dry'?
   __________________ bbls

b. Mud required to fill the hole per stand when pulled 'wet'?
   __________________ bbls

23. Many factors should be considered when selecting a kill pump rate. However, the objective should be to regain control of the well. Choose the one answer that best meets this objective.

a. By using the slowest pumping rate.
b. Before the end of the tour.
c. As safe as possible considering all aspects of the kill.
d. As fast as possible by using the maximum rate.

24. While drilling a gas kick is taken and the well is shut-in.

SICP = 0 psi
SIDPP = 650 psi

There is no flow from the annulus. What is the probable cause?

a. The casing pressure gauge is malfunctioning.
b. The drill string has twisted off.
c. The well is swabbed in.
d. The hole has packed off around the bottom hole assembly.
e. The formation at the casing shoe has fractured.

25. Which of the following drilling practices should be considered when connection gas is noticed? (Choose two answers)

a. Control drilling rate so that only one slug of connection gas is in the hole at any one time.
b. Pumping a low viscosity pill around bit to assist in reduction of balled bit or stabilizers.
c. Minimizing the time during a connection when the pumps are switched off.
d. Raising the mud yield point.
e. Pulling out of the hole to change the bit.
26. **Well Data**

Well depth = 12,000 ft
9 5/8 inch casing shoe = 8000 ft
81/2 inch hole capacity = 0.0702 bbls/ft

Mud density in use = 12.0 ppg

Drill Collars = 6 ½ inch OD; Length = 1100 ft
Capacity = 0.00768 bbls/ft
Metal Displacement = 0.0330 bbls/ft.

Drill pipe 5 inch OD; Capacity = 0.01776 bbls/ft.
Metal Displacement = 0.0076 bbls/ft.
Volume Drill Collar/Open Hole = 0.0291 bbls/ft
Volume Drill pipe/Open Hole: = 0.0459 bbls/ft
Volume Drill pipe/Casing: = 0.0515 bbls/ft

After pulling 33 stands the Driller checks the hole fill. The well has not taken the correct amount of mud, a flow check is made – the well is flowing.

  The bit depth at the time is 9,000 ft.
  Shut-in casing pressure is 200 psi.
  Influx volume = 30 bbls
  Gradient of influx = 0.12 psi/ft

Assume that the influx occurred from the bottom of the hole and that no gas migration occurs.

a. Calculate the volume to bleed off per 98 feet of drill pipe stripped back into the hole?
   ___________________ bbls

b. What will be the effect on bottom hole pressure of bleeding off too much mud?
   Increase ☐ Decrease ☐ Stay the Same ☐

c. How would Casing Pressure respond as the drill string is stripped into the influx?
   Increase ☐ Decrease ☐ Stay the Same ☐
27. Select the products commonly used to prevent hydrate formation:
(Choose two answers)

a. Glycol  
b. Water  
c. Alcohol  
d. CMC  
e. Methanol

28. Pressure build up in the Mud Gas Separator (Poor Boy degasser) while circulating out a kick can be dangerous because:

a. Pressure build up will increase risk of lost circulation.  
b. Pressure build up will affect ability to make choke adjustments.  
c. Pressure build up may allow gas to be blown up the derrick vent line.  
d. Pressure build up may allow gas to enter shale shaker area.

29. If flow rate is kept constant, which two of the following factors will increase the circulation pressure? (Choose two answers):

a. When the mud density in the well is lowered.  
b. When the drilled depth is increased.  
c. When the length of drill collars is increased.  
d. When the bit nozzle size is increased.

30. A gas kick has been taken in a well with a large open hole section. After a short time the drill pipe becomes plugged - presumably by debris blocking the bit. Drill pipe pressure cannot be read, and no pumping is possible down the drill pipe. There is evidence of gas migration taking place.

Which one of the following well control procedures can be applied?

a. Driller's Method.  
b. Wait and Weight Method.  
c. Concurrent Method  
d. Volumetric technique.  
e. Back off and pump cement down annulus.

31. A hydraulic delay exists between the time the choke is adjusted to the time the drill pipe pressure reacts. This hydraulic delay is:

a. Equal to the speed of sound.  
b. About 1 second per 300 meters of travel time.  
c. Always equal to 20 seconds.  
d. This is a myth, no hydraulic delay actually exists.
32. In which situation would a pit gain be noticed?
   a. Gas kick in an oil based mud.
      ______ True
      ______ False
   b. Gas kick in a water based mud.
      ______ True
      ______ False

33. Under which circumstances would the Wait and Weight Method provide lower equivalent pressures at the casing shoe than the Driller’s Method?
   a. When the drill string volume is greater than the annulus open hole volume.
   b. When the drill string volume is less than the annulus open hole volume.
   c. The pressures at the casing are the same regardless of the method used.

34. Casing has been set and cemented. The well program calls for a leak-off test, but the mud weight in the active pits has been increased 0.5 ppg higher than the mud weight in the hole. Which of the following would provide the most accurate leak-off test results?
   a. Use a cement pump to pump down the drill pipe and record pressures and barrels pumped.
   b. Circulate and condition mud until the density is the same throughout the system.
   c. Use a cement pump to pump down the annulus and record pressures and barrels pumped.
   d. It is impossible to obtain accurate test results, so use pressures from previous tests.

35. When pulling out of the hole from the top of the reservoir at 7,954 ft swab pressures are calculated to be 100 psi.

\[
\text{Mud weight} = 10.3 \text{ ppg} \\
\text{Formation pressure} = 4,200 \text{ psi}
\]

Will the well flow?
   a. Yes
   b. No

36. The following slow rate circulation pressures (SCRP) were recorded? Which one does not seem to be correct?
   a. 30 spm = 100 psi
   b. 40 spm = 180 psi
   c. 50 spm = 400 psi
37. The gas/water separation in a well occurs at 3,950 ft. A normal formation gradient of 0.464 psi/ft. exists. (Gas gradient is 0.1 psi/ft.) What is the pressure at the top of the reservoir at 3,470 ft.?

   a. 1,562 psi  
   b. 1,610 psi  
   c. 1,785 psi  
   d. 1,875 psi

38. Throughout the world, what is the most common cause of abnormal formation pressures?

   a. Thick sandstone sections.  
   b. Undercompacted shales.  
   c. Faults.  
   d. Uplifting / erosion.

39. Which of the following would contribute to a higher fracture gradient?

   a. Casing setting depth is close to the surface.  
   b. Casing setting depth is far from the surface.  
   c. A small difference exists between the mud hydrostatic pressure and fracture pressure.  
   d. A large difference exists between the mud hydrostatic pressure and fracture pressure.

40. Which one of the following are used to determine the pumping rates for recording reduced circulating pressures?

   a. The depth of the well.  
   b. The size of the casing.  
   c. Company policy.  
   d. Amount of mud weight increase, degasser capacity, surface pressure limitations.

41. The solubility of gas in oil based or water based mud can make a difference in shut-in well data following a kick under identical conditions. Which of the following statements is correct when using oil based mud? (Choose two answers):

   a. The initial pit gain will be higher.  
   b. The initial pit gain will be lower.  
   c. The Shut-in Casing Pressure will be higher.  
   d. The Shut-in Casing Pressure will be lower.  
   e. There will be no difference in pit gain compared with water based mud.  
   f. There will be no difference in Shut-in Casing Pressure compared with water based drilling mud.
42. Current operation is stripping 5.0" 19.5 lb/ft. drill pipe into the hole. Capacity = 0.01776 bbl/ft.; metal displacement = 0.0076 bbl/ft.; 1 stand = 93 ft.
   a. How much volume is required to fill the drill pipe after running one stand in the hole? ________________ bbls.
   b. How much volume must be bled off after running one stand in the hole? ________________ bbls.

43. A driller observes a warning sign for a kick. Why is it better to continue pumping while raising the pipe to the shut-in position?
   a. To minimize down time.
   b. To minimize the amount of influx by keeping the annular pressure loss as long as possible.
   c. The driller should shut off the pump before picking up to identify the influx as soon as possible.
   d. To prevent sticking the pipe.

44. Partial loss of returns is observed to be 12 bbl/hr. If the well is not filled, what would be the reduction in bottom hole pressure after 3 hours. Annular capacity = 0.0836 bbl/ft.; mud weight = 12.5 ppg. ________________ psi

45. During a well kill operation, using the Driller’s Method, the casing pressure suddenly increases by 150 psi. Shortly thereafter, the operator observes the same pressure increase on the drill pipe pressure gauge. What is the most likely cause of this pressure increase?
   a. A plugged nozzle in the bit.
   b. The choke is partly plugged.
   c. A restriction in the Kelly hose.
   d. A wash out in the drill string.
   e. A second influx has entered the well.

46. What are the advantages / disadvantages of using a float valve in the drill string? Circle the correct letter in each of the following:
   A or D a) Reverse circulation.
   A or D b) Reading the shut-in drill pipe pressure.
   A or D c) Cuttings flowback on connections.
   A or D d) Surge pressures.
47. Why must the pit volume be monitored during a kick killing operation?  
(Choose two answers)  

a. To determine kill weight mud.  
b. To determine influx volume.  
c. To determine the amount of gas expansion.  
d. To determine if lost returns occurs.  
e. To determine the gain due to barite additions.

48. During top hole drilling from a jack-up rig, the well starts to flow due to shallow gas.  
What will be the safest actions to take to secure the safety of rig and personnel?  
(Choose two answers)  

a. Start pumping mud into the well at the highest possible rate.  
b. Shut-in the well and prepare for kill operations immediately.  
c. Activate the diverter system and remove non-essential personnel from the rig floor and hazardous areas.  
d. Line up the mud/gas separator, activate the diverter system and remove personnel from the rig floor.  
e. Activate the blind/shear rams to shut in the well.
49. Which list below gives the best description of a Hard Shut-in including hang-off while drilling on a floating rig with a drill string compensator according to API (RP 59)? Circle A, B, or C.

<table>
<thead>
<tr>
<th>List</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Stop drilling and position tool joints free of ram interference. Stop drilling fluid pumps. Close the BOP. Open the choke line on the BOP with the choke valve closed. Adjust hydraulic annular closing pressure to permit stripping of tool joints. Position a tool joint above the hang-off rams allowing lower FOSV above rotary during maximum expected heave and tide. Close hang-off rams. Lower the drill string to rest on hang-off rams. Reduce support pressure on the drill string compensator to support about half the weight of the drill string. Record pressures.</td>
</tr>
<tr>
<td>B</td>
<td>Stop drilling and position tool joints free of ram interference. Stop drilling fluid pumps. Open the choke line. Close the BOP. Close the choke valve. Adjust hydraulic annular closing pressure to permit stripping of tool joints. Position a tool joint above the hang-off rams allowing lower FOSV above rotary during maximum expected heave and tide. Close hang-off rams. Lower the drill string to rest on hang-off rams. Reduce support pressure on the drill string compensator to support about half the weight of the drill string. Record pressures.</td>
</tr>
<tr>
<td>C</td>
<td>Stop drilling and position tool joints free of ram interference. Stop drilling fluid pumps. Close the BOP. Close the choke valve. Adjust hydraulic annular closing pressure to permit stripping of tool joints. Position a tool joint above the hang-off rams allowing lower FOSV above rotary during maximum expected heave and tide. Close hang-off rams. Lower the drill string to rest on hang-off rams. Reduce support pressure on the drill string compensator to support only the weight of the drill string above the BOP. Record pressures.</td>
</tr>
</tbody>
</table>
50. Which list below gives the best description of a Soft Shut-in including hang-off while drilling on a floating rig with a drill string compensator according to API (RP59)?

Circle A, B or C

<table>
<thead>
<tr>
<th>List</th>
<th>Description</th>
</tr>
</thead>
</table>
| A.   | Stop drilling and position tool joints free of ram interference.  
Stop drilling fluid pumps.  
Close the BOP.  
Open the choke line on the BOP with the choke valve closed. Adjust hydraulic annular closing pressure to permit stripping of tool joints  
Position a tool joint above the hang-off rams allowing lower FOSV above rotary during maximum expected heave and tide.  
Close hang-off rams.  
Lower the drill string to rest on hang-off rams.  
Reduce support pressure on the drill string compensator to support about half the weight of the drill string.  
Record pressures. |
| B.   | Stop drilling and position tool joints free of ram interference.  
Stop drilling fluid pumps.  
Open the choke line.  
Close the BOP.  
Close the choke valve.  
Adjust hydraulic annular closing pressure to permit stripping of tool joints.  
Position a tool joint above the hang-off rams allowing lower FOSV above rotary during maximum expected heave and tide.  
Close hang-off rams.  
Lower the drill string to rest on hang-off rams.  
Reduce support pressure on the drill string compensator to support about half the weight of the drill string.  
Record pressures. |
| C.   | Stop drilling and position tool joints free of ram interference.  
Stop drilling fluid pumps.  
Close the BOP.  
Close the choke valve.  
Adjust hydraulic annular closing pressure to permit stripping of tool joints.  
Position a tool joint above the hang-off rams allowing lower FOSV above rotary during maximum expected heave and tide.  
Close hang-off rams.  
Lower the drill string to rest on hang-off rams.  
Reduce support pressure on the drill string compensator to support only the weight of the drill string above the BOP.  
Record pressures. |
51. After a gas kick has been killed on a subsea BOP stack it is known that 10 bbls of gas remain trapped in the BOP stack between the annular preventer and the choke line side outlet.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vertical distance between BOP and rig floor</td>
<td>1500 ft</td>
</tr>
<tr>
<td>Density of kill fluid</td>
<td>16.2 ppg</td>
</tr>
<tr>
<td>Density of drilling fluid in marine riser</td>
<td>15.2 ppg</td>
</tr>
<tr>
<td>Atmospheric pressure</td>
<td>14.6 psi</td>
</tr>
<tr>
<td>Pressure gradient of the gas</td>
<td>0.10 psi/ft</td>
</tr>
</tbody>
</table>

Calculate the expanded volume of gas produced on the rig in case the annular preventer is opened and the gas is allowed to migrate through the marine riser to the rig floor.

a. 812 bbis  
b. 865 bbis  
c. 875 bbis  
d. 1650 bbis

52. Which circumstances on a floating rig in a normal operation may have influence on the accuracy of drilling fluid volume readings and drilling fluid flow readings when monitoring an open well. (Select three answers)

a. Sea water depth.  
b. Rig pitch and roll.  
c. Crane operations.  
d. Number of generators on line.  
e. Riser tension.  
f. Vessel heave.

53. A floating rig is drilling below the 30-inch conductor pipe. Use the data below to answer questions 53a. and 53b:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water depth</td>
<td>1,640 ft</td>
</tr>
<tr>
<td>TVD well from flow line</td>
<td>2,540 ft</td>
</tr>
<tr>
<td>Air gap (sea level to flow line)</td>
<td>80 ft</td>
</tr>
<tr>
<td>Seawater density</td>
<td>8.5 ppg</td>
</tr>
<tr>
<td>Drilling fluid density</td>
<td>9.1 ppg</td>
</tr>
</tbody>
</table>

53a. Calculate reduction in bottom hole pressure if the riser is disconnected at the wellhead housing on the sea floor.

____________________ psi

53b. Calculate the minimum drilling fluid density that will keep the well balanced with the riser disconnected.

____________________ ppg
54. A 17-1/2" hole is being drilled below the 30" conductor. Use the data below to answer questions 54a. and 54b:

Given the following data:
- From the rig floor to sea level: 60’
- Water depth: 550’
- Sea water gradient: 0.445 psi/ft
- 30" conductor set: 1,150’ (from rig floor)

54a. From previous well drilled, the formation fracture gradient beneath the sea bed is estimated to be 0.58 psi/ft. Calculate the theoretical maximum mud weight that can be used in the static condition without exceeding the formation strength.

Maximum Mud Weight: __________ ppg

54b. Calculate the above in the dynamic condition with circulating pressure losses of 10 psi.

Maximum Mud Weight: __________ ppg

55. Which choice below gives the best reason for fitting ram locking devices to subsea BOP stacks?

a. To lock the BOP stack to the wellhead and lock the Lower Marine Riser Package to the BOP stack.
b. To give additional force when closing the shear ram preventers.
c. To give additional force in closing the pipe ram preventers.
d. To lock the ram in the closed position and maintain the shear rams locked during disconnect.

56. A gas kick is being circulated out from a floating rig. At the time when the top of the kick has displaced the drilling fluid in the choke line the choke valve will require adjusting.

Which option describes the required choke valve operation?

a. The valve must close more.
b. The valve must open more.
c. The valve must remain having the same degree of opening.
57. Which option describes the reason for recording choke line friction on a floating drilling rig? **(Choose one answer)**

a. To know the initial circulating drill pipe pressure (ICP) at kill pump rate if SICP is lower than the choke line friction.
b. To know the amount SICP should decrease when establishing kill pump rate while keeping bottom hole pressure constant.
c. To know the amount SICP should increase when establishing kill pump rate while keeping bottom hole pressure constant.
d. To be able to calculate the density of the kill fluid.

Use the data below from a floating rig to answer questions 58, 59 & 60.

<table>
<thead>
<tr>
<th>Vertical depth of casing shoe</th>
<th>7,500 ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>MAASP leak-off value with 9.4 ppg drilling fluid</td>
<td>1,590 psi</td>
</tr>
<tr>
<td>Slow pump rate pressure @ 30 SPM through riser</td>
<td>680 psi</td>
</tr>
<tr>
<td>Slow pump rate pressure @ 30 SPM through choke line</td>
<td>870 psi</td>
</tr>
<tr>
<td>Drilling fluid density</td>
<td>10.1 ppg</td>
</tr>
</tbody>
</table>

After a kick the well was closed in giving the following:

<table>
<thead>
<tr>
<th>SIDPP</th>
<th>650 psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>SICP</td>
<td>1,100 psi</td>
</tr>
<tr>
<td>Vertical depth</td>
<td>9,800 ft</td>
</tr>
</tbody>
</table>

The well will be killed using the Driller’s Method. Choke and kill lines are filled with 10.1 ppg drilling fluid.

58. Calculate the required Initial Circulating Pressure. Select the correct answer from below.

a. 650 psi  
b. 1,100 psi  
c. 1,330 psi  
d. 1,520 psi

59. Calculate the Final Circulating Pressure when the density of the kill fluid is 11.4 ppg. Select the correct answer from below.

a. 310 psi  
b. 662 psi  
c. 982 psi  
d. 768 psi
60. Calculate the maximum allowable value on the annulus pressure gauge when establishing kill pump rate @ 30 spm when initiating the kill operation. Select the correct answer from below.

a. Range: 1,097 to 1,126 psi
b. Range: 910 to 962 psi
c. Range: 1,605 to 1,722 psi
d. Range: 1,390 to 1,590 psi

Questions 61 a - 61 h

ATTACHED KILL SHEET

Use the data below and the data from the already filled out kill sheet (following two pages) to answer each of the questions 61 a through 61 h about the well kill process.

You are required to indicate the first action that should be taken.

The well will be killed using the Driller's method at 30 spm.
### International Well Control Forum

#### Subsea BOP Vertical Well Kill Sheet (API Field Units)

**Formation Strength Data:**

- **Surface Leak-Off Pressure from Formation Strength Test**
  - (A) 1330 psi
- **Mud Weight at Test**
  - (B) 12.5 ppg
- **Maximum Allowable Mud Weight**
  - \(\frac{(A)}{(B) + \text{SHOE T.V. DEPTH} \times 0.052} = (C) 17.48 \text{ ppg}\)

**Initial MAASP**
- \(\frac{(C) - \text{CURRENT MUD WEIGHT}}{\text{SHOE T.V. DEPTH} \times 0.052}\)
  - = 1196 psi

**Pump No. 1 Displ.**
- 0.136 bbls / stroke

**Pump No. 2 Displ.**
- 0.136 bbls / stroke

**Slow Pump Rate Data**

<table>
<thead>
<tr>
<th>(PL) Dynamic Pressure Loss [psi]</th>
<th>PUMP NO. 1</th>
<th>PUMP NO. 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Riser</td>
<td>480</td>
<td>480</td>
</tr>
<tr>
<td>Choke Line</td>
<td>730</td>
<td>730</td>
</tr>
<tr>
<td>Choke Line Friction</td>
<td>250</td>
<td>250</td>
</tr>
<tr>
<td>Riser</td>
<td>480</td>
<td>480</td>
</tr>
<tr>
<td>Choke Line</td>
<td>730</td>
<td>730</td>
</tr>
<tr>
<td>Choke Line Friction</td>
<td>250</td>
<td>250</td>
</tr>
<tr>
<td>SPM</td>
<td>30</td>
<td>SPM</td>
</tr>
</tbody>
</table>

**Pre-Recorded Volume Data:**

- **Length**
  - Drill Pipe: \(x = \) feet
  - Hevi Wall Drill Pipe: \(x = \) feet
  - Drill Collar: \(x = \) feet

**Drill String Volume**
- \((D) \text{ bbls}\)

**DC x Open Hole**
- \(x = \) barrels

**DP / HWDP x Open Hole**
- \(x = +\) barrels

**Open Hole Volume**

<table>
<thead>
<tr>
<th>(F) bbls</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
</tbody>
</table>

**DP x Casings**
- \(x = (G) +\) barrels

**Choke Line**
- \(x = (H) +\) barrels

**Total Annulus/Choke Line Volume**
- \((F+G+H) = (I)\) bbls

**Total Well System Volume**
- \((D+I) = (J)\) bbls

**Active Surface Volume**
- \((K)\) bbls

**Total Active Fluid System**
- \((J+K)\) bbls

**Marine Riser x DP**
- \(x = \) bbls

**Current Well Data:**

- **Subsea BOP Data**
  - Marine Risers: \(925 \text{ feet}\)
  - Choke Line Length: \(930 \text{ feet}\)

- **Drilling Mud:**
  - Weight: 13.0 ppg

- **Casing Shoe Data:**
  - Size: \(\text{inch}\)
  - M. Depth: \(5,130 \text{ feet}\)
  - T.V. Depth: \(5,130 \text{ feet}\)

- **Hole Data:**
  - Size: \(\text{inch}\)
  - M. Depth: \(6,930 \text{ feet}\)
  - T.V. Depth: \(6,930 \text{ feet}\)

**Pump Strokes**
- Strokes

**Time**
- Minutes

---

<table>
<thead>
<tr>
<th>(E)</th>
<th>823 strokes</th>
<th>Min</th>
</tr>
</thead>
<tbody>
<tr>
<td>507</td>
<td>strokes</td>
<td>Min</td>
</tr>
<tr>
<td>1515</td>
<td>strokes</td>
<td>Min</td>
</tr>
<tr>
<td>59</td>
<td>strokes</td>
<td>Min</td>
</tr>
<tr>
<td>2081</td>
<td>strokes</td>
<td>Min</td>
</tr>
<tr>
<td>2904</td>
<td>strokes</td>
<td>Min</td>
</tr>
</tbody>
</table>

---

© Intertek Consulting & Training Unpublished work. All rights reserved.
Revised – 1 Nov 2012

Page 82
Version 4
61a. After 5 minutes of circulation the following readings are observed on the choke panel:

- Drill pipe pressure: 900 psi
- Casing pressure: 820 psi
- Pump speed: 26 SPM
- Strokes circulated: 140 strokes
- Choke position: 40% open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - Everything is OK.

61b. After 9 minutes of circulation the following readings are observed on the choke panel immediately after a choke adjustment:

- Drill pipe pressure: 1,500 psi
- Casing pressure: 40 psi
- Pump speed: 30 SPM
- Strokes circulated: 260 strokes
- Choke position: 80% open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Stop pumping and close the choke.
e. Continue - Everything is OK.
61c. After 15 minutes of circulation the following readings are observed on the choke panel:

- Drill pipe pressure: 855 psi
- Casing pressure: 700 psi
- Pump speed: 30 SPM
- Strokes circulated: 440 strokes
- Choke position: 55% open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - Everything is O.K.

61d. After 1,500 strokes have been circulated, the following readings are observed on the choke panel:

- Drill pipe pressure: 1,200 psi
- Casing pressure: 1,750 psi
- Pump speed: 30 SPM
- Strokes circulated: 1,500 strokes
- Choke position: 70% open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Stop pumping and close the choke.
e. Continue - Everything is O.K.
61 e. After 2,075 strokes have been circulated the following readings are observed on the choke panel:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reading</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drill pipe pressure</td>
<td>1,550 psi</td>
</tr>
<tr>
<td>Casing pressure</td>
<td>1,070 psi</td>
</tr>
<tr>
<td>Pump speed</td>
<td>30 SPM</td>
</tr>
<tr>
<td>Strokes circulated</td>
<td>2,075</td>
</tr>
<tr>
<td>Choke position</td>
<td>10% open</td>
</tr>
</tbody>
</table>

Which should you do? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Stop pumping and close the choke.
e. Continue - Everything is OK

61 f. At 2,100 strokes the influx had been circulated out through the choke valve. What is the stabilized standpipe pressure if the pump was stopped and the well closed-in successfully.

__________ psi

61 g. At 2,100 strokes the influx had been circulated out through the choke valve. What is the stabilized casing pressure if the pump was stopped and the well closed-in successfully.

__________ psi

61 h. The stroke counter was reset to 0 (zero). While pumping the kill fluid the following readings were observed on the choke panel.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reading</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drill pipe pressure</td>
<td>1,340 psi</td>
</tr>
<tr>
<td>Casing pressure</td>
<td>610 psi</td>
</tr>
<tr>
<td>Pump speed</td>
<td>30 spm</td>
</tr>
<tr>
<td>Strokes circulated</td>
<td>50 stks</td>
</tr>
<tr>
<td>Choke position</td>
<td>20% open</td>
</tr>
</tbody>
</table>

Which should you do? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Stop pumping and close the choke.
e. Continue - Everything is O.K.
62. What is the correct meaning of the phrase "Secondary Well Control"?

a. Preventing flow of formation fluid into the well bore by maintaining drilling fluid hydrostatic pressure equal to or greater than formation pressure.

b. Preventing flow of formation fluid into the well bore by maintaining the sum of drilling fluid hydrostatic pressure and dynamic pressure loss in the annulus equal to or greater than formation pressure.

c. Preventing flow of formation fluid into the well bore by maintaining the dynamic pressure loss in the annulus equal to or greater than formation pressure.

d. Preventing flow of formation fluid into the well bore by using BOP equipment in combination with hydrostatic pressure in the well bore to balance the formation pressure.

63. While drilling, a severe loss of returns occurred. After the pumps were stopped, it was observed that the fluid in the well dropped far below the flow line. The well was then filled to the top with seawater.

Drilling fluid density - 11.4 ppg
Sea water density - 8.6 ppg
Equivalent height of seawater - 350 ft of annulus

What is the reduction in hydrostatic bottom hole pressure after this action, compared to before the losses?

a. 204 psi
b. 38 psi
c. 90 psi
d. 51 psi

64. There will be little or no difference between SIDPP and SICP as long as the influx stays in the horizontal section of a well. What is the primary reason for this?

a. The influx has little or no effect on the hydrostatic head in the annulus.

b. In horizontal wells, there is usually little or no difference between the density of the drilling fluid and that of the influx.

c. In horizontal wells, the influx can also enter the drill string, because the BHA is usually very short in comparison with those in vertical wells.

d. The influx migration rate differs from vertical wells.
65. The reason casing pressure is usually higher than the shut-in drill pipe pressure is:

   a. The cuttings in the annulus are lighter, so the pressure is higher.
   b. The influx fluid is usually less dense than the existing mud weight.
   c. The casing pressure is not necessarily higher. It depends on whether it is a land or offshore operation.

66. While drilling through a fault in the horizontal section of a well, a kick is taken and the well closed in. Calculate the new drilling fluid density required to kill the well, using the well and kick data below.

**Well Data:**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measured depth at start of horizontal section</td>
<td>8,510 ft</td>
</tr>
<tr>
<td>Measured depth at time of kick</td>
<td>12,480 ft</td>
</tr>
<tr>
<td>True vertical depth at start of horizontal</td>
<td>5,760 ft</td>
</tr>
<tr>
<td>True vertical depth at time of kick</td>
<td>5,840 ft</td>
</tr>
<tr>
<td>Length horizontal section</td>
<td>5,990 ft</td>
</tr>
<tr>
<td>Drilling Fluid Density</td>
<td>13.1 ppg</td>
</tr>
</tbody>
</table>

**Kick Data:**

- Shut-in Drill Pipe Pressure : 260 psi
- Shut-in Casing Pressure : 270 psi

Answer __________________ ppg

67. Which actions should be considered before opening the subsea BOP, after circulating out a gas kick, to reduce the risk to personnel and equipment? The actions are not necessarily listed in the correct order. (Choose 5 answers)

   a. Displace the marine riser to kill fluid density.
   b. Reduce the pressure of the trapped gas below the BOP as much as possible by circulating seawater.
   c. Close the bottom set of rams
   d. Open the diverter element.
   e. Open the annular BOP slowly by reducing the regulated pressure
   f. Close the diverter element.
   g. Disconnect the riser
   h. Open the riser fill-up line.
PRESSURE GAUGE EXERCISE
ATTACHED KILL SHEET

Use the data from the already completed "highly deviated" kill sheet to answer questions 68a to 68j:

You are only required to indicate the "first" action that should be taken:

This "highly deviated" well will be killed at **30 spm** using the **Driller's Method** of well control.
### International Well Control Forum
#### Surface BOP Kill Sheet - Deviated Well (API Field Units)

**Formation Strength Data:**
- **Surface Leak-Off Pressure from Formation Strength Test**
  - (A) 1545 psi
- **Mud Weight at Test**
  - (B) 10.4 ppg
- **Maximum Allowable Mud Weight**
  \[ (C) = \frac{(B)}{(A)} \times \text{Shoe T.V. Depth} \times 0.052 \]
  - (C) 16.85 ppg
- **Initial MAASP**
  \[ \frac{(C) - \text{Current Mud Weight}}{(C)} \times \text{Shoe T.V. Depth} \times 0.052 \]
  - 1423 psi

**Current Well Data:**
- **Drilling Mud Data:**
  - **Weight**
    - 10.9 ppg
  - **Gradient**
    - 0.5668 psf

**Deviation Data:**
- **KOP M.D.**
  - 2,000 ft
- **KOP T.V.D.**
  - 2,000 ft
- **EOB M.D.**
  - 5,400 ft
- **EOB T.V.D.**
  - 4,285 ft

**Casing Shoe Data:**
- **Size**
  - 9 5/8 in
- **M. Depth**
  - 9,000 ft
- **T.V. Depth**
  - 4,600 ft

**Pump No. 1 Displ.**
- 0.12 bbls / stroke

**Pump No. 2 Displ.**
- 0.12 bbls / stroke

**Slow Pump Rate Data:**
- **(PL) Dynamic Pressure Loss**
  - [Data Table]

**Pump No. 1**
- Spm: 30
- Pressure: 625 psi

**Pump No. 2**
- Spm: 
- Pressure: 

**Pre-Recorded Volume Data:**
- **DP - Surface to KOP**
  - Length: 2000 ft
  - Capacity: 0.0178 bbls / ft
  - Volume: 35.6 bbls
- **DP - KOP to EOB**
  - Length: 3400 ft
  - Capacity: 0.0178 bbls / ft
  - Volume: 60.5 bbls
- **DP - EOB to BHA**
  - Length: 7870 ft
  - Capacity: 0.0178 bbls / ft
  - Volume: 140.1 bbls
- **Hevi Wall Drill Pipe**
  - Length: 180 ft
  - Capacity: 0.0087 bbls / ft
  - Volume: 1.6 bbls
- **Drill Collar**
  - Length: 150 ft
  - Capacity: 0.0061 bbls / ft
  - Volume: 0.9 bbls
- **Drill String Volume**
  - Length: 13,600 ft
  - Diameter: (D)
  - Volume: 238.7 bbls
- **DC x Open Hole**
  - Length: 150 ft
  - Capacity: 0.0323 bbls / ft
  - Volume: 4.85 bbls
- **DP / HWDP x Open Hole**
  - Length: 4450 ft
  - Capacity: 0.0459 bbls / ft
  - Volume: 204.25 bbls
- **Open Hole Volume**
  - Length: (F)
  - Diameter: 209.1email
  - Volume: bbls

**Volume Calculations:**
- **DP x Casing**
  - Length: 9000 ft
  - Capacity: 0.0515 bbls / ft
  - Volume: 463.5 bbls
- **Total Annulus Volume**
  - (F+G) = (H)
  - Volume: 672.6 bbls
- **Total Well System Volume**
  - (D+H) = (I)
  - Volume: 911.3 bbls
- **Active Surface Volume**
  - (J)
  - Volume: bbls
- **Total Active Fluid System**
  - (I+J)
  - Volume: bbls

**Pump Strokes:**
- (L) 297 strokes
- (M) 504 strokes
- (N1) 1167 strokes
- (N2) 13 strokes
- (N3) 8 strokes

**Time:**
- 1989 stks
- 66.3 min

**Additional Calculations:**
- 1743 stks
- 58 min
- 3863 stks
- 129 min
- 5605 stks
- 187 min
- 7594 stks
- 253 min

---

© Intertek Consulting & Training Unpublished work. All rights reserved. Revised – 1 Nov 2012
Page 90 Version 4
**International Well Control Forum**

**Surface BOP Kill Sheet - Deviated Well (API Field Units)**

**KICK DATA:**

| SIDPP  | 875 psi |
| SICP   | 895 psi |
| PIT GAIN | 15 bbl |

**KILL MUD WEIGHT**

\[
\text{KMW} \quad \frac{10.9 \times 5,000}{14.3} \times 0.052 = 14.3 \text{ ppg}
\]

**INITIAL CIRC. PRESSURE**

\[
\text{ICP} \quad \frac{625 + 875}{2} = 1500 \text{ psi}
\]

**FINAL CIRCULATING PRESSURE**

\[
\text{FCP} \quad \frac{14.3 \times 625}{10.9} = 820 \text{ psi}
\]

**DYNAMIC PRESSURE LOSS AT KOP (O)**

\[
\text{PL} \quad \left(\frac{F_{CP-PL} \times KOPMD}{TOMD}\right) \times \frac{820}{2000} = 654 \text{ psi}
\]

**REMAINING SIDPP AT KOP (P)**

\[
\text{SIDPP} \quad \left[\frac{(KMW - CMW) \times 0.052 \times KOPTVD}{2000} \right] = 521 \text{ psi}
\]

**CIRCULATING PRESS. AT KOP (KOP CP)**

\[
\text{(O) + (P) = } \frac{654}{2} = 1175 \text{ psi}
\]

**DYNAMIC PRESSURE LOSS AT EOB (R)**

\[
\text{PL} \quad \left(\frac{F_{CP-PL} \times EOBMD}{TOMD}\right) \times \frac{820}{13,600} = 702 \text{ psi}
\]

**REMAINING SIDPP AT EOB (S)**

\[
\text{SIDPP} \quad \left[\frac{(KMW - CMW) \times 0.052 \times EOBTVD}{4285} \right] = 117 \text{ psi}
\]

**CIRCULATING PRESSURE AT EOB (EOB CP)**

\[
\text{(R) + (S) = } \frac{702}{2} = 819 \text{ psi}
\]

\[
\text{(T) = ICP - KOP CP = } \frac{1500 - 175}{2} = 597.5 \text{ psi}
\]

\[
\text{(U) = KOP CP - EOB CP = } \frac{117 - 819}{2} = 690.5 \text{ psi}
\]

\[
\text{(W) = EOB CP - FCP = } \frac{819 - 820}{2} = 0.5 \text{ psi}
\]

\[
\text{(W) = EOB CP - FCP = } \frac{819 - 820}{2} = 0.5 \text{ psi}
\]

\[
\text{Dr No: BD 04/21 (Field Units) 27-01-2020}
\]
68a. After 1 minute of circulation the following readings are observed on the choke panel:

Drill pipe pressure = 950 psi
Casing pressure = 900 psi
Pump speed = 26 spm
Strokes circulated = 45 strokes
Choke position = 40% open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - everything is O.K.

68b. After 9 minutes of circulation the following readings are observed on the choke panel:

Drill pipe pressure = 1,925 psi
Casing pressure = 910 psi
Pump speed = 34 spm
Strokes circulated = 260 strokes
Choke position = 45% open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - everything is O.K.

68c. After 15 minutes of circulation the following readings are observed on the choke:

Drill pipe pressure = 1,155 psi
Casing pressure = 725 psi
Pump speed = 30 spm
Strokes circulated = 440 strokes

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - everything is O.K.
68d. After pumping 750 strokes, it is noticed that the rotary hose starts to jump violently. The following readings are observed on the remote choke panel:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drill Pipe Pressure</td>
<td>600 psi</td>
</tr>
<tr>
<td>Casing Pressure</td>
<td>310 psi</td>
</tr>
<tr>
<td>Pump Speed</td>
<td>34 spm</td>
</tr>
<tr>
<td>Strokes Circulated</td>
<td>750</td>
</tr>
</tbody>
</table>

What action should be taken? (One Answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue, everything is O.K.
f. Stop the pump and shut the well in.

68e. After 1,500 strokes have been circulated the following readings are observed on the choke panel:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drill pipe pressure</td>
<td>1,500 psi</td>
</tr>
<tr>
<td>Casing pressure</td>
<td>1,225 psi</td>
</tr>
<tr>
<td>Pump speed</td>
<td>30 spm</td>
</tr>
<tr>
<td>Strokes circulated</td>
<td>1,500 strokes</td>
</tr>
<tr>
<td>Choke position</td>
<td>70 % open</td>
</tr>
</tbody>
</table>

The casing pressure is increasing very rapidly. What is the probable cause?

a. The well is under balanced and more influx is entering the well bore.
b. The choke is plugging.
c. A bit nozzle has plugged.
d. The influx is being circulated from the horizontal section into the vertical, section of the wellbore.
68f. After 2,200 strokes have been circulated the following readings are observed on the choke panel:

Drill pipe pressure = 1,500 psi
Casing pressure = 1,540 psi
Pump speed = 30 spm
Choke position = 30 % open

What action should be taken? (One answer)

a. Open the choke slowly, MAASP has been exceeded.
b. Close the choke slowly.
c. Increase the pump speed.
d. Decrease the pump speed.
e. Continue - everything is O.K.

68g. At 5,700 strokes the influx had been circulated out through the choke valve. What is the stabilized standpipe pressure if the pump is stopped and the well closed-in successfully?

___________________________ psi

68h. At 5,700 strokes the influx had been circulated out through the choke valve. What is the stabilized casing pressure if the pump is stopped and the well closed-in successfully?

___________________________ psi

68i. The mud density has been increased to the kill weight value. The well is brought on line using correct procedures. After the surface system volume has been displaced, the stroke counter was reset to "0" (zero). While pumping kill fluid the following readings are observed on the choke panel:

Drill pipe pressure = 1,340 psi
Casing pressure = 720 psi
Pump speed = 30 spm
Strokes circulated = 50 strokes
Choke position = 20 % open

Which action should be taken? (One answer)

a. Open the choke slowly.
b. Close the choke slowly.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - everything is O.K.
68j. After pumping 700 strokes the following readings are observed on the choke panel:

Drill pipe pressure = 880 psi  
Casing pressure = 875 psi  
Pump speed = 30 spm  
Strokes circulated = 700 strokes  
Choke position = 30 % open

Which action should be taken? (One answer)

a. Open the choke slowly.  
b. Close the choke slowly.  
c. Increase the pump rate.  
d. Decrease the pump rate.  
e. Continue - everything is O.K.

69. A salt water kick is circulated out using the Driller's method. The drill string consists of drill collars plus drill pipe and a surface BOP stack is used.

When will the surface casing pressure be at its maximum value?

a. When the kill fluid is entering the drill pipe.  
b. When the kick has been circulated to the surface.  
c. Only when a kick reaches the casing shoe.  
d. Just after the kill fluid reaches the bit.  
e. Immediately after the well has been shut in.

70. What precautions could be taken to reduce the risk for washouts in the drill string caused by H₂S gas?  (Choose three answers).

a. Use a drilling fluid with a low pH.  
b. Use a drill string with a medium tensile strength (X-95).  
c. Use a scavenger in the drilling mud.  
d. Use a neutralizing agent to coat the tubulars in the drilling fluid system.  
e. Reverse circulate before tripping out.  
f. Use a drill string with a high tensile strength (S-135).

71. Which of the following parameters primarily affect the value of the Shut-in Casing Pressure when a well is shut in during a kick? (Choose three answers)

a. The pore pressure.  
b. The bottom hole temperature.  
c. The hole or annulus capacity.  
d. The drill string capacity.  
e. The kick volume.  
f. The length of the choke line.
72. Why do we need to take into account a large surface line volume (from the mud pumps to the drill floor) when preparing a kill sheet for killing the well with the Wait & Weight Method? *(Choose two answers)*

a. If we don't, following the drill pipe pressure graph will result in a BHP too low.
b. If we don't there will be no effect on the bottom hole pressure.
c. If we don't, following the drill pipe pressure graph will result in a BHP too high.
d. If we don't, the total time for killing the well will be shorter than calculated.
e. If we don't, the total time for killing the well will be longer than calculated.

73. Which part of the system pressure losses contributes to the ECD?

a. The pressure loss in the open hole section only.
b. The pressure loss in the drill string.
c. The pressure loss in the surface system.
d. The pressure loss in the annulus.
e. The pressure loss over the nozzles.

74. When starting the kill operation with a Surface BOP, the choke pressure is kept constant while bringing the pump up to speed. The drill pipe gauge now reads 250 psi higher than the precalculated Initial Circulating Pressure (ICP).

To maintain constant BHP, what is the best action to take?

a. Open the choke and let the standpipe pressure drop to the precalculated value (ICP).
b. Continue to circulate with the new ICP and adjust the drill pipe pressure graph accordingly.
c. There will now be 250 psi overbalance on the bottom which is acceptable. Nothing needs to be done.

75. Which statement is correct when comparing the Driller's Method and the Wait & Weight Method?

a. The Driller's Method will give the lowest casing shoe pressure when the open hole annulus volume is larger than the drill string volume.
b. The Wait & Weight Method will give the lowest casing shoe pressure when the open hole annulus volume is smaller than the drill string volume.
c. The Wait & Weight Method will give the lowest casing shoe pressure when the open hole annulus volume minus the gain is larger than the drill string volume.
d. The Wait & Weight Method will always give a lower maximum pressure on the casing shoe than the Driller's Method.
e. The casing shoe pressure will always be the same regardless of method used.
76. During a well kill operation, using the Driller’s Method, the choke pressure suddenly increases by 150 psi. Shortly thereafter the operator observes the same pressure increase on the drill pipe pressure gauge.

Which is the most likely cause for this pressure increase?

a. A second influx has entered the well.
b. A restriction in the kelly hose.
c. A plugged nozzle in the bit.
d. The choke is partly plugged.
e. A wash out in the drill string.

77. What will be the correct action to take when the problem in question 76 occurs?

a. Reduce the pump rate and thus reduce both pressures by 150 psi.
b. Open the choke a little until standpipe pressure returns to the precalculated value.
c. No action required, as this pressure increase does not affect the bottom hole pressure.
d. Stop the kill operation, remove the restriction in the kelly hose or change over to the spare kelly hose.

78. During a kill, while displacing the drill string with kill fluid, a sudden loss in drill pipe pressure was noticed. The driller continued pumping at the same pump rate, while the supervisor adjusted the choke and continued to follow the drill pipe pressure graph as originally planned.

What happened to the bottom hole pressure as a result of this?

a. The bottom hole pressure increased then decreased.
b. The bottom hole pressure remained unchanged.
c. The bottom hole pressure decreased.
d. The bottom hole pressure decreased then increased.
e. The bottom hole pressure increased with the choke adjustment.
79. Prior to starting to POOH, a heavy slug was pumped into the drill pipe.

**DATA:**
- Drill pipe capacity = 0.0174 bbl/ft
- Annulus capacity DP/Casing = 0.0510 bbl/ft
- Density of drilling fluid = 13.2 ppg
- Density of slug = 16.5 ppg
- Volume of slug inside the drill pipe = 20 bbl
- Well depth = 9600 ft

Using the data to calculate the vertical distance between the drilling fluid level in the drill pipe and in the flowline after the slug has been pumped.

a. 287 ft  
b. 270 ft  
c. 207 ft  
d. 362 ft

80. While drilling, a severe loss of returns occurred. After the pumps were stopped, it was observed that the fluid in the well dropped far below the flowline. The well was then filled to the top with seawater.

Drilling fluid density = 10.3 ppg  
Sea water density = 8.5 ppg  
Height of seawater = 240 ft

What is the reduction in hydrostatic bottom hole pressure after this action, compared to before the losses?

a. 407 psi  
b. 189 psi  
c. 22 psi  
d. 17 psi

81. A vertical well with a surface BOP stack is shut in after a kick. The pressure readings are as follows:

Shut in Drill Pipe Pressure (SIDPP) = 680 psi  
Shut in Casing Pressure (SICP) = 890 psi

What is the reason for the difference in these two pressure readings?

a. The influx is in the drill pipe.  
b. The influx has a lower density than the drilling fluid.  
c. The influx has a higher density than the drilling fluid.  
d. The BOP was closed too fast which caused a trapped pressure in the system.
82. A vertical well with a surface BOP stack is shut in after a gas kick has been taken. The bit is 950 ft off bottom and the influx is calculated to be from bottom to 300 ft above (bottom). Shut in drill pipe pressure is 450 psi. What will the probable shut in casing pressure be?

a. The same as the shut in drill pipe pressure.
b. Higher than the shut in drill pipe pressure
c. Lower than the shut in drill pipe pressure, because of the effect of the ECD.
d. Impossible to say, if the exact kick location is not known.

83. During top hole drilling from a jack-up rig the well suddenly starts to flow due to a shallow gas kick. What will be the safest actions to take to rig and personnel? (Select two answers)

a. Activate the blind/shear rams to shut in the well
b. Activate the diverter system and remove non-essential personnel from the rig floor and hazardous areas.
c. Shut in the well and prepare for kill operations immediately.
d. Start pumping kill fluid into the well at the highest possible rate.
e. First line up to the mud-gas separator, activate the diverter system and remove personnel from the rig floor.

84. A vertical well with a surface BOP stack has been shut in after a gas kick. The surface pressures are as follows:

Shut in drill pipe pressure (SIDPP) = 830 psi
Shut in casing pressure (SICP) = 980 psi
Drilling fluid density in the well = 13.3 ppg

The well is left shut in for some time, during which the gas migrates 600 feet up the well. (There is no float in the drill string)
What will be the expected pressures at surface at this moment?

a. Drill pipe pressure - 830 psi, Casing pressure - 2030 psi.
b. Drill pipe pressure - 830 psi, Casing pressure - 1580 psi.
c. Drill pipe pressure - 1245 psi, Casing pressure - 1395 psi.
d. Drill pipe pressure - 1245 psi, Casing pressure - 980 psi.
Data for Questions 85 & 86

A vertical well is 8020 feet deep and filled with 12.5 ppg drilling fluid. While circulating at 80 SPM the friction losses in the well system are as follows:

- Pressure loss through surface equipment = 200 psi
- Pressure loss in drill string = 800 psi
- Pressure loss through bit nozzles = 1,850 psi
- Pressure loss in annulus = 150 psi

85. What is the bottom hole pressure in the well when the pumps are running at 80 SPM?
   a. 5,678 psi  
   b. 5,363 psi  
   c. 8,163 psi  
   d. 5,213 psi

86. What will the pump pressure be when circulating with 80 SPM?
   a. 2,850 psi  
   b. 4,550 psi  
   c. 3,000 psi  
   d. 5,213 psi

87. While drilling, a 10 bbl gas kick has been taken and the well is shut in with the bit on bottom. The pressures at surface stabilize after a few minutes. Due to problems with the pumps, the kill operation cannot start. After some time, the pressures at surface have increased due to gas migration.

What will be the simplest and safest action to take to keep the bottom hole pressure constant (assume there is no float in the string)?

   a. Bleeding off drilling fluid keeping the drill pipe pressure constant.  
   b. Bleeding off drilling fluid keeping the casing pressure constant.  
   c. Start bleeding off drilling fluid and let the casing pressure decrease according to volumetric calculations.  
   d. Leave it as is. Gas migration will not affect the bottom hole pressure
88. A well is being killed using the Driller’s Method. During the first circulation the drill pipe pressure is kept constant at 690 psi and the pump speed at 30 spm. Halfway through this first circulation the operator on the choke observes a sudden increase in drill pipe pressure. There is no significant change in choke pressure and the pump speed is still 30 SPM.

What could have happened? (select three answers)

a. The bit nozzles have partly plugged.
b. The choke has partly plugged.
c. The kick is about to enter the choke.
d. A partial blockage in the kelly hose,
e. Pressure has built up in the mud/gas separator.
f. A partial blockage in the drill string has occurred.

89. During normal drilling operation a 30 bbl slug of light drilling fluid is pumped into the drill string followed by original drilling fluid.

Well Data
Well depth (TVD) = 9,600 ft
Drill pipe capacity = 0.0178 bbl/ft
Original drilling fluid density = 12.3 ppg
Light drilling fluid density = 10.5 ppg

Calculate the bottom hole pressure once the light slug is inside the drill pipe.

a. 158 psi
b. 6,140 psi
c. 5,982 psi
d. 4,779 psi

90. On a floating drilling rig, a gas kick is being circulated out from the well using the Wait and Weight Method. The pressure on the drill pipe gauge as well as on the kill line and choke line gauges are recorded.

Suddenly, the choke operator observes a significant pressure increase on the kill line gauge and shortly after on the drill pipe gauge. The choke line gauge, however, shows no significant changes. What has most likely happened to the circulating system?

a. A malfunctioning kill line gauge.
b. A partial blockage in the choke line.
c. A blockage in the open hole section due to balling stabilizers.
d. This pressure fluctuation is normal on a floater due to rig heave.
e. A partial or complete blockage in the kill line.
91. The well is shut in due to a kick on a floating drilling rig. The drill pipe pressure is 500 psi and the choke line pressure is 700 psi. The kill line pressure, however, reads 800 psi.

What may be the possible reasons for the different readings on the kill line and choke line gauges? [Select two answers]

a. The BOP side outlet valve for the kill line is not functioning correctly.
b. The fluid in the kill line has a higher density than in the choke line.
c. The fluid in the kill line has a lower density than in the choke line.
d. Either one or both gauges are damaged.
e. A partial blockage in the choke line.

92. A surface hole section is being drilled from a floating drilling rig. A 8-1/2 inch pilot hole is being drilled below the 30 inch conductor pipe. Sea water is being used as the drilling fluid. Marine riser is not yet installed.

Well Data: (All depths from RKB)

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Well depth</td>
<td>1800 ft.</td>
</tr>
<tr>
<td>Conductor shoe</td>
<td>1500 ft.</td>
</tr>
<tr>
<td>Sea floor</td>
<td>1050 ft.</td>
</tr>
<tr>
<td>Air gap</td>
<td>50 ft.</td>
</tr>
<tr>
<td>Sea water density</td>
<td>8.56 ppg</td>
</tr>
</tbody>
</table>

While pumping at 10 bbl/min the annulus friction loss in the well is 30 psi. At 1,800 ft the bit drilled into a shallow gas formation with a pore pressure of 750 psi.

Select the correct answer from the list below:

a. It is impossible to control the well without a marine riser installed.
b. The gas will enter the well immediately because the well is already underbalanced.
c. The well is overbalanced even with the pumps off.
d. The well is overbalanced as long as the pumps are running.
93. From a floating drilling rig the top hole section is being drilled with a marine riser in place:

Drilling fluid density = 9.6 ppg  
Sea water density = 8.6 ppg  
Overbalance = 50 psi  

Well Depth from RKB = 1,700 ft  
Water Depth = 1,000 ft  
Riser length = 1,100 ft  

What is the minimum required mud weight when disconnecting the riser?

a. 9.6 ppg  
b. 10.8 ppg  
c. 11.3 ppg  
d. 14.5 ppg

94. The Driller has shut in the well, following a rapid increase in flow. (Floater)

Data:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hole and bit depth</td>
<td>13,000 ft MD and 6,610 ft TVD</td>
</tr>
<tr>
<td>Casing shoe depth</td>
<td>9,160 ft MD and 6,260 ft TVD</td>
</tr>
<tr>
<td>MSL to seabed</td>
<td>1,150 ft</td>
</tr>
<tr>
<td>Drilling fluid density</td>
<td>15.5 ppg</td>
</tr>
<tr>
<td>Shut in Drill Pipe Pressure</td>
<td>955 psi</td>
</tr>
<tr>
<td>Shut in Casing Pressure</td>
<td>990 psi</td>
</tr>
<tr>
<td>Maximum Allowable Annular</td>
<td>1.024 psi</td>
</tr>
</tbody>
</table>

Select the best possible option for the well kill operation. There is only one recorded SCRP at 30 spm.

a. Kill the well with the Driller's Method, using an overbalance of 0.2 ppg over the calculated minimum kill fluid density while pumping at a circulation rate of 30 spm. Circulate through both kill and choke line to minimize friction losses.

b. Kill the well with the Wait & Weight Method, using the calculated minimum kill fluid density while pumping at a circulation rate of 10 spm. Circulate through both kill and choke line to minimize friction losses.

c. Reverse circulate the well. This will be the safest course of action to prevent formation fracture.

d. Kill the well with the Wait & Weight Method, using the calculated minimum kill fluid density while pumping at a circulation rate of 30 spm.

e. Bullhead the influx back into the formation.
95. On a floating drilling rig the Driller’s Method is being used to circulate a kick out of the well. It is halfway through the first circulation.

The constant drill pipe pressure to hold is now 880 psi and the choke pressure at time of recording is 1,310 psi.
The pump is running at 40 SPM.
The choke line friction loss at this pump rate is 160 psi.

The Supervisor wants to reduce the pump rate to 30 SPM.

What will be the correct way to change pump speed while maintaining constant bottom hole pressure? Choose two answers

a. Reduce pump speed, while keeping choke pressure constant at 1,310 psi.
b. Reduce pump speed, while keeping stand pipe pressure constant at 880 psi.
c. Reduce pump speed, while holding kill line pressure constant with the choke; continue with new drill pipe pressure.
d. Reduce pump speed, while reducing the choke pressure by 160 psi.
e. Reduce pump speed, while reducing the stand pipe pressure by 160 psi.
f. Shut down and close the choke. Restart the pumps while holding the kill line pressure constant with the choke. The new standpipe pressure to hold can be seen on the drill pipe gauge when the pump reaches 30 spm.

96. A gas kick has been circulated out of a well and the well is dead.

Data:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water depth</td>
<td>2000 ft</td>
</tr>
<tr>
<td>Choke line length</td>
<td>2070 ft</td>
</tr>
<tr>
<td>Density of kill drilling fluid in the well and choke line</td>
<td>17.2 ppg</td>
</tr>
<tr>
<td>Original drilling fluid density in the riser</td>
<td>14.2 ppg</td>
</tr>
<tr>
<td>Density of sea water</td>
<td>8.6 ppg</td>
</tr>
</tbody>
</table>

Calculate the estimated pressure of the gas trapped in the BOP beneath the closed pipe rams?

a. 1790 psi
b. 1850 psi
c. 1740 psi
d. 930 psi
97. Which of the following should be done before opening the subsea BOP, after circulating out a gas kick, to reduce the risk to personnel and equipment?  
(SELECT FIVE ANSWERS – NOT IN CORRECT ORDER)

a. Disconnect the riser.
b. Close the diverter packer.
c. Isolate the well with the bottom set of rams.
d. Open the diverter packer.
e. Open the annular BOP slowly by reducing the hydraulic regulated pressure.
f. Reduce the pressure of the trapped gas below the BOP as much as possible by circulating sea water through the choke and kill lines.
g. Displace the marine riser to kill fluid density.
h. Line up to take returns to the vacuum degasser in the shaker area.
i. Open the riser fill-up line.

98. During a well kill operation on a semisubmersible, the gas alarm in the shale shaker area sounds indicating a large amount of gas from the mud-gas separator return line. The driller slows his circulation rate from 30 to 20 spm, but the gas level remains very high. Select the most appropriate action to reduce the gas level.

a. Shut the well in, isolate the choke line, open up the kill line to the choke manifold and complete the well kill. Finally, flush the trapped gas below the BOPs using the choke line as a return line.
b. Open up an additional choke to accelerate the mud-gas separation process.
c. Continue killing the well with 30 spm as these high gas levels are usually of a short duration. Meanwhile keep all personnel away from the shaker area as a precautionary measure.
d. Shut the well in, restore the fluid head to the mud-gas separator and continue killing the well with an acceptable low circulation rate.
e. Direct the return from the mud-gas separator to the vacuum degasser using the shortest possible route.
99. A well has been shut in on a kick. The choke line is filled with a glycol/water mix and the rest of the well system is filled with drilling fluid.

Well depth/RKB 12,000 ft  
Casing depth/RKB 9,000 ft  
Riser length 3,000 ft  
Maximum allowable drilling fluid density at shoe 15.8 ppg  
Drilling fluid density 13.4 ppg  
Glycol-mixed water density 9.2 ppg

Calculate the maximum annular surface pressure that can be shut in before the formation fractures.

a. 1,023 psi  
b. 3,213 psi  
c. 7,394 psi  
d. 1,778 psi

100. When drilling from a floating drilling rig, in areas where shallow gas is expected, it is often decided to drill top hole without using a marine riser.

Mark the statements below true or false.

<table>
<thead>
<tr>
<th></th>
<th>True</th>
<th>False</th>
<th>Statement</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td></td>
<td></td>
<td>It is easier to control the bottom hole pressure while drilling without a marine riser.</td>
</tr>
<tr>
<td>B</td>
<td></td>
<td></td>
<td>It is less likely to have large gas volumes at the rig level without a marine riser.</td>
</tr>
<tr>
<td>C</td>
<td></td>
<td></td>
<td>It is easier to move the rig off location in an emergency without a marine riser.</td>
</tr>
<tr>
<td>D</td>
<td></td>
<td></td>
<td>It is a greater hazard for the rig and crew if a blowout occurs without a marine riser.</td>
</tr>
</tbody>
</table>
Answer Key

1a. 11.5
1b. 1521-1551
1c. 141-142
1d. 1209-1233
1e. 1050
1f. 1350
1g. 830
1h. 710
1i. 33-34
1j. 1497-1537
1k. 11.7
1l. 1418 – 1457
2. 4.09 bbl
   \[30_{\text{bbl}} \times \left( \frac{15_{\text{ppg}}}{13.2_{\text{ppg}}} \right) - 30_{\text{bbl}} = 4.09_{\text{bbl}}\]
3. 5304 psi
   \[975_{\text{psi}} + \left( 0.052 \times 11.1_{\text{ppg}} \times 7500_{\text{feet}} \right) = 5304_{\text{psi}}\]
4. c
5. b
6a. 356 feet
   \[\frac{25_{\text{bbl}}}{0.0702_{\text{bbl/ft}}} = 356_{\text{feet}}\]
6b. 2.36 bbl
   \[\left( 0.0176_{\text{bbl/ft}} + 0.0076_{\text{bbl/ft}} \right) \times 93_{\text{feet}} = 2.36_{\text{bbl}}\]
6c. 859 feet
   \[\frac{25_{\text{bbl}}}{0.0291_{\text{bbl/ft}}} = 859_{\text{feet}}\]
6d. 640 psi
   \[350_{\text{psi}} + \left( \left( 859_{\text{feet}} - 356_{\text{feet}} \right) \times \left( 0.676_{\text{psi/ft}} - 1_{\text{psi/ft}} \right) \right) = 640_{\text{psi}}\]
7. d
8. a, b
9. b
10. b, c
11. d, e, f
12. c
13. 55 stands (complete stands)
Use formula #24
Determine Overbalance
\[
(0.052 \times 12 \text{ ppg} \times 10500 \text{ feet}) - (0.598 \text{ psi/ft} \times 10500 \text{ feet}) = 273 \text{ psi}
\]
Number of stands
\[
\frac{(273 \text{ psi} \times (0.0981 \text{ bbl/ft} - 0.008 \text{ bbl/ft}))}{(624 \text{ psi/ft} \times 0.008 \text{ bbl/ft})} = 4927 \text{ feet}
\]
\[
4927 \text{ feet} = 55.67 \approx 55 \text{ complete stnd}
\]
14. 121 psi
Use formula #22
\[
\frac{(500 \text{ feet} \times 0.0545 \text{ bbl/ft})}{0.1545 \text{ bbl/ft}} = 176.37 \text{ feet}
\]
\[
0.052 \times 13.2 \text{ ppg} \times 176.37 \text{ feet} = 121 \text{ psi}
\]
15. a
16. c
Pump pressure @ new rate
\[
1000 \text{ psi} \times \left(\frac{30 \text{ spm}}{40 \text{ spm}}\right)^2 = 563 \text{ psi}
\]
New ICP
\[
563 \text{ psi} + 500 \text{ psi} = 1063 \text{ psi}
\]
New FCP
\[
563 \text{ psi} \times \left(\frac{10.6 \text{ ppg}}{9.6 \text{ ppg}}\right) = 622 \text{ psi}
\]
PSI/STK
\[
\frac{(1063 \text{ psi} - 622 \text{ psi})}{1200 \text{ stk to bit}} = 0.3675 \text{ psi/stk}
\]
Pump pressure @ 800 strokes
\[
1063 \text{ psi} - (800 \text{ stk} \times 0.3675 \text{ psi/stk}) = 769 \text{ psi}
\]
21. b
Pump pressure @ new Rate

\[
1500_{psi} \times \left( \frac{25_{psi}}{50_{spm}} \right)^2 = 375_{psi}
\]

Pump pressure @ new mud weight

\[
375_{psi} \times \left( \frac{13.5_{ppg}}{12_{ppg}} \right) = 422_{psi}
\]

22a. .7068 bbl
\[
.0076_{bbl/ft} \times 93_{feet} = .7068_{bbl}
\]

22b. 2.36 bbl
\[
\left( .01776_{bbl/ft} + .0076_{bbl/ft} \right) \times 93_{feet} = 2.358 \approx 2.36_{bbl}
\]

23. c

24. d

25. a, c

26a. 2.48 bbl
\[
\left( .01776_{bbl/ft} + .0076_{bbl/ft} \right) \times 98_{feet} = 2.48_{bbl}
\]

26b. Decrease

26c. Increase

27. a, e

28. d

29. b, c

30. d

31. b

32a. TRUE

32b. TRUE

33. b

34. b

35. a
\[
\left( 0.052 \times 10.3_{ppg} \times 7954_{feet} \right) - 100_{psi} = 4160_{psi}
\]

36. c

37. c
\[
\left( 3950_{feet} \times .464_{psift} \right) - \left( \left( 3950_{feet} - 3470_{feet} \right) \times .1_{psift} \right) = 1784.8 \approx 1785_{psi}
\]

38. b

39. b

40. d

41. b, d

42a. 1.65 bbl
\[
.01776_{bbl/ft} \times 93_{feet} = 1.65_{bbl}
\]

42b. 2.36 bbl
\[
\left( .01776_{bbl/ft} + .0076_{bbl/ft} \right) \times 93_{feet} = 2.36_{bbl}
\]

43. b
44. 280 psi
\[ \frac{12_{bbl/hr} \times 3_{hrs}}{36_{bbl}} = 36_{bbl} \]
\[ \frac{36_{bbl}}{.0836_{bbl/ft}} = 431_{feet} \]
\[ .052 \times 12.5_{ppg} \times 431_{feet} = 280_{psi} \]

45. b

46. Disadvantage
Disadvantage
Advantage
Disadvantage

c, d

47. c, d

48. a, c

49. a

50. b

51. c

\[ P_1 \left( \frac{.052 \times 16.2_{ppg} \times 1500_{feet}}{14.6_{psi}} \right) + 14.6_{psi} = 1278.2_{psi} \]
\[ P_2 = 14.6 \text{ psi atmospheric pressure} \]

\[ V_2 \left( \frac{1278.2_{psi}}{14.6_{psi}} \right) \times 10_{bbl} = 875_{bbl} \]

52. b, c, f

53a. 89 psi
\[ \left( \frac{.052 \times 9.1_{ppg} \times 1720_{feet}}{14.1_{psi}} \right) - \left( \frac{.052 \times 8.5_{ppg} \times 1640_{psi}}{14.6_{psi}} \right) = 89_{psi} \]

53b. 11.19 ppg
\[ \left( \frac{89_{psi}}{.052 \times 820_{feet}} \right) + 9.1_{ppg} = 1.187 \approx 11.19_{ppg} \]

54a. 9.33 ppg
Fracture psi
\[ \left( \frac{.445_{psi/ft} \times 550_{feet}}{558_{psi}} \right) + \left( \frac{.58_{psi/ft} \times 540_{feet}}{558_{psi}} \right) = 558_{psi} \]
\[ \left( \frac{.052 \times 1150_{feet}}{558_{psi}} \right) = 9.33_{ppg} \]

54b. 9.16 ppg
\[ \left( \frac{558_{psi} - 10_{psi}}{.052 \times 1150_{psi}} \right) = 9.16_{ppg} \]

55. d

56. a

57. b

58. c

\[ 680_{psi} + 650_{psi} = 1330_{psi} \]
59. \( d \)
\[
680_{\text{psi}} \times \left(\frac{11.4_{\text{ppg}}}{10.1_{\text{ppg}}}\right) = 767.5 \approx 768_{\text{psi}}
\]

60. \( a \)
\[
\text{New MAASP} \\
1590_{\text{psi}} - \left(0.052 \times (10.1_{\text{ppg}} - 9.4_{\text{ppg}}) \times 7500_{\text{feet}}\right) = 1317_{\text{psi}}
\]
\[
\text{MAASP - CLFP} \\
1317_{\text{psi}} - 190_{\text{psi}} = 1127_{\text{psi}}
\]

61. \( c \)
61b. \( b \)
61c. \( b \)
61d. \( e \)
61e. \( a \)
61f. 720 psi
61g. 720 psi
61h. \( a \)
62. \( d \)
63. \( d \)
\[
(11.4_{\text{ppg}} - 8.6_{\text{ppg}}) \times 0.052 \times 350_{\text{feet}} = 50.96 \approx 51_{\text{psi}}
\]

64. \( a \)
65. \( b \)
66. \( 14 \text{ ppg} \)
\[
\left(\frac{260_{\text{psi}}}{(0.052 \times 5840_{\text{feet}})}\right) + 13.1_{\text{ppg}} = 13.95 \approx 14_{\text{ppg}}
\]

67. \( a, b, c, e, f \)
68a. \( c \)
68b. \( d \)
68c. \( b \)
68d. \( f \)
68e. \( d \)
68f. \( e \)
68g. 875 psi
68h. 875 psi
68i. \( b \)
68j. \( b \)
69. \( e \)
70. \( b, c, d \)
71. \( a, c, e \)
72. \( a, e \)
73. \( d \)
74. \( b \)
75. \( c \)
76. \( d \)
77. b
78. e
79. a
\[
\left( 20_{bbl} \times \left( \frac{16.5_{ppg}}{13.2_{ppg}} \right) \right) - 20_{bbl} = 5_{bbl}
\]
\[
\frac{5_{bbl}}{.0174_{bbl/ft}} = 287_{feet}
\]
80. c
\[
(10.3_{ppg} - 8.5_{ppg}) \times 240_{feet} = 22.46 \approx 22_{psi}
\]
81. b
82. a
83. b, d
84. c
85. b
\[
\left( .052 \times 12.5_{ppg} \times 8020_{feet} \right) + 150_{psi} = 5363_{psi}
\]
86. c
\[
200_{psi} + 800_{psi} + 1850_{psi} + 150_{psi} = 3000_{psi}
\]
87. a
88. a, d, f
89. b
90. b
91. c, d
92. c
\[
.052 \times 8.6_{ppg} \times 1750_{feet} = 779_{psi}
\]
779 psi > 750 psi
The well is overbalanced even with the pumps off
93. c
\[
\left( .052 \times 9.6_{ppg} \times 1100_{feet} \right) - \left( .052 \times 8.6_{ppg} \times 1000 \right) = 102_{psi}
\]
\[
\left( \frac{102_{psi} - 50_{psi}}{.052 \times 600_{feet}} \right) + 9.6_{ppg} = 11.27_{ppg}
\]
94. b
95. c, f
96. b
\[
.052 \times 17.2_{ppg} \times 2070_{feet} = 1851_{psi}
\]
97. b, c, e, f, g
98. d
99. \(d\)

Fracture pressure
\[
0.052 \times 15.8_{\text{ppg}} \times 9000_{\text{feet}} = 7394.4_{\text{psi}}
\]

Mud hydrostatic pressure
\[
0.052 \times 13.4_{\text{ppg}} \times 6000_{\text{feet}} = 4180.8_{\text{psi}}
\]

Glycol hydrostatic pressure
\[
0.052 \times 9.2_{\text{ppg}} \times 3000_{\text{feet}} = 1435.2_{\text{psi}}
\]

Maximum annular surface pressure
\[
7394.4_{\text{psi}} - (4180.8_{\text{psi}} + 1435.2_{\text{psi}}) = 1778.4 \approx 1778_{\text{psi}}
\]

100a. FALSE
100b. TRUE
100c. TRUE
100d. FALSE
1. Which statements are correct with respect to the subsea BOP control panel Sub Plate Mounted (SPM) valves of the 2 position - 3 way - normally closed - pilot operated - spring return type? (Choose two answers)

a. SPM valves open by spring force.
b. SPM valves open when regulated hydraulic control fluid is supplied to the actuator.
c. SPM valves close by spring force and sea water hydrostatic pressure.
d. SPM valves open when hydraulic pilot fluid is supplied to the actuator.

2. On the hydraulic BOP control unit manifold for a subsea BOP a number of Manipulator valves are installed. Manipulator valves control the SPM valves in the subsea pods.

Which is the correct description of a Manipulator valve?

a. A manipulator valve is a 3 position - 4 way directional control valve that has the pressure inlet port blocked and the operator ports vented in the center position.
b. A manipulator valve is a 3 position - 4 way directional control valve that has the pressure inlet port blocked and the operator ports blocked in the center position.
c. A manipulator valve has two or more supply pressure ports and only one outlet port. When fluid is flowing through one of the supply ports the internal shuttle seals off the other inlet port and allows flow to the outlet port only.
d. A manipulator valve is an electrically operated valve that controls a hydraulic or pneumatic pilot signal or function.

3. When a function on the Subsea BOP is activated from the Driller’s panel a certain process takes place.

Select the correct reaction that occurs.

a. Pilot pressure is sent to the relevant SPM valves in both pods.
b. Pilot pressure activates the relevant SPM valve only in the selected pod.
c. The selected function is activated only from control fluid stored in the subsea accumulator cylinders.
d. Pilot pressure regulated at 1,500 psi operates the selected function.
e. The selected function is activated only from control fluid stored in the surface accumulators.
4. The driller on a floating rig must have available information about tide and rig heave while drilling.

What is the most important reason for this?

a. To adjust the marine riser tension force accordingly.

b. To know the exact distance from the RKB to the bottom of the well.

c. To ensure a sufficient stick-up should drill string hang-off become necessary.

d. To be able to calculate the ton-cycles for the marine riser tensioning lines.

e. To be able to hang off the drill string in the BOP stack to avoid swabbing and surging tendencies over the reservoir during the well kill operation.

5. What are the primary advantages of drilling the top hole section riserless from a floating rig? (Choose 2 answers)

a. The well can be drilled with sea water only.

b. It reduces the risk of having gas at the rig level.

c. The rig can be moved quickly in the event of a shallow gas incident.

d. The well can be drilled with a higher drilling fluid density.

6. What are the advantages of having a dump valve (riser equalizing valve) installed on the marine riser system? (Choose 2 answers)

a. Less tension is required for the marine riser.

b. It keeps the well full of drilling fluid while tripping out of the hole.

c. It reduces the risk of riser collapse.

d. It continuously supplies sea water to the well in case of total loss of circulation.

e. It allows pumping heavy drilling fluid in the riser during kill operations.

7. In case of diverting a shallow gas blowout through a long marine riser a risk occurs that affects the riser.

Which one of the options describes the most potential risk?

a. The marine riser may collapse.

b. The marine riser may burst from the excess pressure exerted by the gas inside the riser.

c. Buoyancy forces acting on the marine riser may require riser tension forces in excess of a situation where the riser is full of drilling fluid.
The main components of a subsea control system are shown in the diagram. Some components have been identified by letter. Note: a letter may be used more than once.

Equipment List

<table>
<thead>
<tr>
<th>Subsea Hose Reels</th>
<th>Answer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Subsea Control Pods</td>
<td>Answer</td>
</tr>
<tr>
<td>Master Electric Panel</td>
<td>Answer</td>
</tr>
<tr>
<td>Electric Power Pack</td>
<td>Answer</td>
</tr>
<tr>
<td>Hydraulic Hose Bundles</td>
<td>Answer</td>
</tr>
<tr>
<td>Retrieving Frame for Pods</td>
<td>Answer</td>
</tr>
<tr>
<td>Accumulator Bottles</td>
<td>Answer</td>
</tr>
<tr>
<td>Jumper Hose Bundles</td>
<td>Answer</td>
</tr>
<tr>
<td>Subsea Bottle Rack</td>
<td>Answer</td>
</tr>
<tr>
<td>Hydraulic Control Manifold</td>
<td>Answer</td>
</tr>
</tbody>
</table>
9. Which choice below best describes the advantage of using the kill line with static fluid to monitor well head pressure during a well kill operation?

a. Response on changes in well head pressure is quicker through the kill line.
b. Effect of choke line friction is reduced to 1/4 when monitoring the kill line gauge during the kill operation.
c. Effect of choke line friction is reduced to 1/2 when monitoring the kill line gauge during the kill operation.
d. Keeping pressure on kill line gauge constant while starting or stopping the pumps eliminates the effect of choke line friction.

10. Master electric panels as well as electric mini panels for operation of functions on a subsea BOP are supplied with an electric "Memory Function".

Which statement is correct?

a. Memory Function indicates a malfunction by giving permanent light on the alarm panel after an alarm has been acknowledged and the audible alarm has stopped.
b. Memory Function reminds the driller to add anti-freeze fluid when the temperature drops below a set level.
c. Memory Function indicates the previous position before "Block position" of three position functions.
d. Memory Function reminds the driller to engage Wedge Locks before hanging off.
11. The diagram illustrates a detail of the hydraulic "principle of redundancy" utilized to control functions on the subsea BOP stack.

![Diagram of hydraulic system]

Which statements are correct with respect to the shuttle valves?  
(Choice two answers)

a. The shuttle valves automatically seal any hydraulic leaks in the selected pod.

b. The shuttle valves isolate pressurized control fluid communication between the selected system and the redundant system.

c. The shuttle valves are pilot operated.

d. The shuttle valves allow retrieving a malfunctioning pod without losing hydraulic BOP control.
12. Place the correct letters in the blanks. (Cameron "Wedge Lock" system)

________ locking wedge

________ locking port

________ preventer operating piston

________ unlocking port

________ tailrod

________ balancing port
13. The figure below illustrates an API type 6BX flange. Match the letter on the figure with the dimension on the list below it. A letter may be used more than once.

Throughbore Diameter

Ring Groove O. D.

Raised Face O.D.

Flange O.D.

Bolt Circle Diameter

Nominal Flange Size
14. The rig is now working for an operator who requires a different stack (13-5/8” x 15,000 psi). This operators policy is to provide sufficient usable hydraulic fluid to function all BOP components with a **minimum pressure remaining to close against full rated BOP working pressure**.

The number of gallons to “function” all BOP components = 118.5 gallons for this stack. The BOP “closing ratio” is 10.0 to 1

Precharge pressure = 1000 psi  System pressure = 3000 psi

How many 10 gallon bottles (cylinders) are required to store this hydraulic fluid?

a. 30 – 10 gallon bottles
b. 36 - 10 gallon bottles
c. 41 - 10 gallon bottles
d. 51 - 10 gallon bottles

15a. From the diagram below, identify the dimensions that determine pressure buildup inside the separator  **(Choose one answer)**

- a. Secondary vent height ($H_3$)
- b. Separator height ($H_2$)
- c. Mud seal height ($H_1$)
- d. Inlet diameter ($D_2$)
- e. Primary vent diameter ($D_1$)
15b. From the diagram, calculate the pressure required to unload the mud gas separator M. W. = 8.5 ppg.
Pressure = ________________ psi

16a. From the diagram below, identify the dimensions that could cause the mud gas separator to overload. (Choose one answer)

- Secondary vent height ($H_3$)
- Separator height ($H_2$)
- Mud seal height ($H_1$)
- Inlet diameter ($D_2$)
- Primary vent diameter ($D_1$)
16b. From the diagram, calculate the pressure required to unload the MGS. Mud weight 12.2 ppg

Pressure ________________________ psi
Answer Key

1. c, d
2. a
3. a
4. c
5. b, c
6. c, d
7. a
8. Subsea Hose Reels 3
   Subsea Control Pods 5
   Master Electric Panel 14
   Electric Power Pack 8 or 9
   Hydraulic Hose Bundles 4
   Retrieving Frame For Pods 7
   Accumulator Bottles 1 or 6
   Jumper Hose Bundles 2
   Subsea Bottle Rack 6
   Hydraulic Control Manifold 11
9. d
10. c
11. b, d
12. Locking Wedge f
    Preventer Operating Piston d
    Tailrod c
    Locking Port a
    Unlocking Port e
    Balancing Port b
13. Throughbore Diameter a
    Ring Groove OD b
    Raised Face OD c
    Flange OD e
    Bolt Circle Diameter d
    Nominal Flange Size a
14. b

Required Minimum Pressure
\[
\frac{15000_{\text{psi}}}{10} = 1500_{\text{psi}}
\]

Useable Volume Per Bottle
\[
10_{\text{gallons/bottle}} \times \left( \frac{1000_{\text{psi}}}{1500_{\text{psi}}} - \frac{1000_{\text{psi}}}{3000_{\text{psi}}} \right) = 3.3_{\text{gallons/bottle}}
\]

Required Number of Bottles
\[
\frac{118.5_{\text{gallons}}}{3.3_{\text{gallons/bottle}}} = 35.55 \approx 36_{\text{bottles}}
\]

15a. e
15b. 4.42 psi
\[
.052 \times 8.5_{\text{ppg}} \times 10_{\text{feet}} = 4.42_{\text{psi}}
\]

16a. e
16b. 11.8 psi
\[
.052 \times 12.2_{\text{ppg}} \times 18.6_{\text{feet}} = 11.8_{\text{psi}}
\]