IWCF Workbook Day 1

1. Normal formation pressure gradient is generally assumed to be:

A. .496 psi/ft
B. .564 psi/ft
C. .376 psi/ft
D. .465 psi/ft

Normal formation pressure gradient (US Gulf Coast) = .465 psi/ft

2. Referring to the last question, what mud weight would be required to BALANCE normal formation pressure?

A. 9.33 ppg
B. 10.85 ppg
C. 8.94 ppg
D. 7.23 ppg

Mud Density ppg = Normal pressure gradient psi/ft ÷ Constant

.465 ÷ .052 = 8.94 ppg

3. What mud weight is required to BALANCE a formation pressure of 2,930 psi at 5,420 ft. TVD?

A. 9.8 ppg

B. 10.4 ppg

C. 10.2 ppg

D. 9.6 ppg

Formula #3 - Mud Density ppg = Pressure psi ÷ TVD ft ÷ 0.052

*2930 ÷ 5420 ÷ 0.052 = **10.4 ppg***

4. If the fluid level dropped 550 feet in a 9,600 foot hole containing 10.6 ppg mud, what would the hydrostatic pressure be?

A. 5,596 psi

B. 4,988 psi

C. 5,843 psi

D. 5,100 psi

Fluid Level = 9,600 ft – 550 ft = 9050 TVD ft

Formula #1 - Hydrostatic Pressure psi = Mud Density ppg x 0.052 x TVD ft

*10.6 x 0.052 x 9050 = **4,988 psi***

5. What is the <u>primary</u> means of preventing kicks? (what is “primary” well control)

A. The slow circulating rate used in the kill process

B. The use of mud hydrostatics to balance fluid pressure in the formation

C. The use of blowout preventers to close in a well that is flowing

D. The use of pit volume and flow rate measuring devices to recognize a kick

6. The part of the system pressure loss (standpipe pressure) that is exerted on the formation is:

A. Pressure loss of the surface equipment

B. Pressure loss in the annulus

C. Pressure loss through the drill string

D. Pressure loss through the bit

DATA FOR QUESTION 7

Mud weight	10.3 ppg
TVD	11,600 feet
MD	12,500 feet
Surface equipment pressure loss	100 psi
Drill string pressure loss	.08 psi/ft
Bit nozzle pressure loss	1500 psi
Annular pressure loss	.02 psi/ft

7. What is the circulating pressure?

A. 1,600 psi

B. 760 psi

C. 2,850 psi

D. 3,000 psi

Circulating Psi = Surf Equip Press Loss + Drill String Press Loss + Bit Nozzle Press Loss + Ann Press Loss

100 psi + (.08 psi/ft x 12,500md) + 1500 psi + (.02 psi/ft x 12,500md) = ***2,850 psi***

8. What is the bottom hole pressure while circulating?

A. 6,445 psi

B. 6,463 psi

C. 627 psi

D. 6,945 psi

Formula #1- Hydrostatic Pressure psi = Mud Density ppg x 0.052 x TVD ft

10.3 x 0.052 x 11,600 = 6213 psi

Bottom Hole Pressure psi = Hydrostatic Pressure psi + Annular Pressure Loss

6213 psi + (.02 psi/ft x 12,500md) = ***6463 psi***

9. What is meant by Abnormal Pressure (over-pressure) with regard to fluid pressure in the formation?

A. The excess pressure due to circulating mud at high rates

B. The excess pressure that needs to be applied to cause leak-off into a normally pressured formation

C. High density mud used to create a large overbalance

D. Formation fluid pressure that exceeds normal formation water hydrostatic pressure

10. Abnormal formation pressures can be caused by?

A. Thick sandstone sections

B. Insufficient mud weight

C. Formation fluids supporting part of the overburden

D. All of the above

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

A. Thick sandstone sections

B. Under-compacted shale

C. Faults

D. Uplift and erosion

12. A gas bearing formation is over pressured by an artesian effect. Which of the following conditions has created the overpressure?

A. A formation water source located at a higher level than the rig floor.

B. The difference in density between formation gas and formation liquid.

C. Compaction of the formation by shallower, overlying formations.

13. The gas/water contact in this well occurs at 3950 feet where a formation pressure gradient of .464 psi/ft exists. (Gas gradient of .1 psi/ft) What is the pressure at the top of the gas reservoir at 3470 feet?

A. 1056 psi

B. 1610 psi

C. 1785 psi

D. 1833 psi

Formation Pressure psi = Formation Pressure gradient x TVD ft

.464 psi/ft x 3950 ft = 1833 psi

Gas Pressure psi = Gas gradient x TVD ft

.1 psi/ft x (3950 ft – 3470 ft) = 48 psi

Top of Reservoir Pressure = Formation Pressure psi – Gas Pressure psi

1833 – 48 = ***1785 psi***

14. Which of the following statements best describes formation porosity?

A. The ratio of the pore spaces to the total volume of the rock

B. The ability of the fluid and gas to move within the rock

C. The presence of sufficient water volume to provide gas lift

D. All of the above

15. Which of the following statements best describes formation permeability?

A. The ratio of the pore spaces to the total volume of the rock

B. The ability of fluid and gas to move within a rock

C. The presence of sufficient water volume to provide gas lift

D. All of the above

16. Why is a 20 bbl kick in a small annulus more significant than a 20 bbl kick in a large annulus?

A. The kill weight mud cannot be easily calculated

B. It results in higher annular pressures

C. The kicks are usually gas

D. The pipe is more prone to getting stuck

17. While tripping out of the hole the well is swabbed in. The mud weight is 10 ppg and the well depth is 10,500 feet. The formation pressure is 5410 psi. If the swab pressure is 125 psi and the formation has sufficient permeability, will the well flow?

A. YES

B. NO

Formula #1 – Hydrostatic Pressure psi = Mud Density ppg x 0.052 x TVD ft

Initial: Hydrostatic Pressure psi = 10 x 0.052 x 10,500 = 5460 psi

After picking up: Hydrostatic Pressure psi = 5460 – 125 = 5335 psi

Formation Pressure psi = 5410 psi

Formation Pressure psi > Hydrostatic Pressure psi

18. A heavy mud pill is circulated in the well without stopping the pump at any time. At what moment will BHP start to increase?

A. As soon as the pill starts to be pumped into the drill pipe

B. Once the pill is in the annulus

C. Once the pill starts to be displaced into the annulus

19. A light pill is circulated into the well without stopping the pump at any time. At what moment will BHP start to decrease?

A. As soon as the pill enters the drill pipe
B. Once the pill has been displaced into the annulus
C. Once the pill starts to be displaced into the annulus

20. When pumping, the standpipe pressure will be slightly lower than the pressure at the pump. What is the most likely reason for this?

A. The standpipe gauge is situated at a higher elevation than the pump gauge
B. The dynamic pressure loss from the pump to the standpipe
C. The hydrostatic pressure of the mud in the standpipe

21. The principle involved in the *CONSTANT BOTTOM HOLE PRESSURE* method of well control is to maintain a pressure that is:

A. Equal to the slow circulating rate pressure
B. At least equal to formation pressure
C. Equal to the SIDPP
D. At least equal to the SICP

22. If the cuttings load in the annulus was high and the well is shut in on a kick. (Answer YES or NO to each question.)

A. Would the drill pipe pressure be higher than in a “clean” well? ***NO***
B. Would the casing pressure be higher than in a “clean” well? ***NO***
C. Would the casing pressure be lower than in a “clean” well? ***YES***

23. The mud weight is 10.2 ppg. At 10,000 feet the bit has drilled into a salt water zone with a pressure of 6560 psi. With the well closed in what will the stabilized SIDPP be?

___***1256***___ psi

Formula #1 **– HP Drillstring psi = Mud Density ppg x 0.052 x TVD ft**

10.2 x 0.052 x 10,000 = 5304 psi

SIDPP = Formation Pressure – HP Drillstring

6560 psi – 5304 psi = **1256 psi**

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

A. The influx has little or no effect on the hydrostatic head in the annulus while it is in the horizontal section of the hole

B. In horizontal wells, there is usually little or no difference between the density of the drilling fluid and the density 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 used in vertical wells

D. The influx migration rate differs in vertical wells as compared to horizontal wells

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

WELL DATA

Well depth TVD	9600 feet
Drill pipe capacity	.0178 bbl/ft
Original fluid density	12.3 ppg
Light fluid density	10.5 ppg

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

A. 158 psi

B. 6,140 psi

C. 5,982 psi

D. 4,779 psi

Formula #1 – HP in Annulus = Original Mud Density ppg x 0.052 x TVD ft = BHP psi

12.3 x 0.052 x 9600 = **6140 psi**

The annulus consists of the original mud density only. The light fluid slug in the drill pipe will not affect the bottom hole pressure. What happens in the drill pipe stays in the drill pipe.

26. While drilling a severe loss of returns occurs. After the pumps were stopped it was observed that the fluid level in the well dropped far below the flow line. The well was then filled to the top with sea water.

Drilling fluid density	10.3 ppg
Sea water density	8.5 ppg
Equivalent height of sea water	240 feet

What is the reduction in hydrostatic pressure after this action compared to before the losses occurred?

A. 407 psi

B. 189 psi

C. 22 psi

D. 17 psi

Formula #1 Initial: HP psi = Fluid Density ppg x 0.052 x TVD ft

10.3 x 0.052 x 240 = 128 psi

After Displaced w/ SW: HP psi = Fluid Density ppg x 0.052 x TVD ft

8.5 x 0.052 x 240 = 106 psi

Reduction in HP psi = 128 psi – 106 psi = ***22 psi***

27. 13 3/8” 61 lbs/ft casing is being run in the hole with a conventional float valve. The casing capacity is .1521 bbl/ft. Due to a problem with the fill up line, the casing was not filled. Twelve 40 foot joints are run in the hole. If the float valve suddenly were to fail, how would this affect bottom hole pressure? The mud weight is 11.5 ppg and the annular capacity is .124 bbl/ft.

- **A. BHP decreases by 73 psi**
- **B. BHP decreases by 158 psi**
- C. BHP decreases by 264 psi
- D. BHP decreases by 480 psi

Formula # 30 HP Loss if Casing Float Fails = $\frac{MW\ ppg\ x\ 0.052\ x\ Csg\ cap\ x\ Unfilled\ Csg\ Height}{Csg\ cap + Annular\ cap}$

$$\frac{11.5\ x\ 0.052\ x\ .1521\ x\ (12\ joints\ x\ 40\ ft)}{.1521 + .124} = \textbf{158 psi}$$

28. A gas kick is taken with the bit on bottom while drilling a vertical well.

Well depth	13,940 feet TVD
Casing shoe	11,500 feet TVD
Mud Weight	13.4 ppg
Formation Pressure Gradient	.715 psi/ft
Drill Pipe Capacity	.0175 bbl/ft
Height of the influx	425 feet
Influx gradient	.15 psi/ft

What will the expected pressure at the casing shoe be after the well is shut in and pressures have stabilized?

A. 6459 psi

B. 8203 psi

C. 8499 psi

D. 6755 psi

Bottom Up

Formation psi = .715 x 13940 = 9967 psi ↑

HP Gas psi = .15 x 425 = 64 psi ↓

HP mud ↓ csg shoe= 13.4 x 0.052 x 2015= 1404 psi

(9967 - 64 – 1404) = **8499 psi**

Top Down

Formation psi = .715 x 13940 = 9967 psi ↑

HP Drillstring= 13.4 x0.052 x13940 = 9713↓

SIDDP = 9967 – 9713 = 254 psi

SICP = 254 + 425 x (.6968 - .15) = 486 psi

(*HP mud ↑csg shoe) + SICP = Csg shoe psi*

*(13.4 x 0.052 x 11500) + 486 = **8499 psi***

29. A gas kick has been circulated out. At the time the gas reaches the casing shoe at 3126 feet TVD the pressure at the top of the bubble is 2200 psi. If the OWM is 11.6 ppg, what is the casing pressure at the surface?

A. 314 psi
B. 442 psi
C. 542 psi
C. 506 psi

HP of mud above csg shoe = 11.6 x 0.052 x 3126 = 1886 psi ↓
Gas Pressure ↑ – HP of mud above csg shoe ↓ = Casing Pressure
*2200 psi – 1886 psi = **314 psi***

30. The flow sensor shows a total loss of returns. You pick up and check for flow. The mud level in the hole is out of sight. What action would you take?

A. Pump at a reduced rate while mixing LCM
B. Continue drilling blind
C. Close the well in and check for pressures
D. Begin filling the annulus with fluid (water) noting how many barrels are required to fill the hole

31. Which of the following would be affected by the permeability of a formation from which a kick occurred? *(TWO ANSWERS)*

A. The time required for surface pressures to stabilize

B. The calculated kill mud density

C. The Initial Circulating Pressure

D. The size of the influx in the wellbore

E. The shut in drill pipe pressure

32. In which of the following cases would you most likely swab in a kick?

A. When the bit is pulled into the casing

B. When the first few stands are being pulled off bottom

C. About halfway out of the hole

33. Which *THREE* of the following practices are likely to increase the chance of swabbing?

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

F. Pumping out of the hole

34. In which of the following circumstances would a kick be most likely to occur through failure to fill the hole?

A. When the first few stands are pulled off bottom

B. When pulling the drill collars

C. When the drill collars enter the casing

35. While pulling out of the hole it is noticed that mud required to fill the hole is less than calculated. What action must be taken?

A. Flow check. If negative, displace a 100 foot heavy slug into the annulus and continue to pull out of the hole

B. Flow check. If negative, run/ strip back to bottom and monitor returns

C. Pump remaining stand out of the hole

D. Flow check. If negative, continue pulling the pipe out of the hole

E. Shut the well in and circulate the hole clean

36. The driller is tripping pipe out of a 12 ¼” diameter hole. 25 X 92 foot stands of 5” pipe have been removed. There are 85 more stands to pull. The calculated displacement of the 9 ½” collars is .08 bbl/ft. The capacity of the drill pipe is .01776 bbl/ft and the metal displacement is .0075 bbl/ft. The trip tank volume has reduced from 27 bbl to 15 bbl. What action should be taken in this situation?

A. Flow check. If negative continue to pull

B. Shut the well in and circulate the hole clean

C. Flow check. If negative, displace a 100 foot heavy slug into the annulus and continue to pull out of the hole

D. Flow check. If negative, return back to bottom and monitor returns

E. Pump the remaining stands out of the hole

37. A well was drilled to a TVD of 8,200 feet.

Casing Shoe TVD	4,500 feet
Mud Density	13.9 ppg
Open Hole Capacity	.0702 bbl/ft
Pipe Metal Displacement	.0080 bbl/ft
Casing Capacity	.157 bbl/ft
Pore Pressure	.700 psi/ft
Length of 1 stand	93 feet

How many FULL STANDS (complete stands) of drill pipe can the driller pull dry BEFORE the hole level reduces the bottom hole pressure enough to cause the well to go underbalanced?

____***51***____ Stands

Overbalance psi = Hydrostatic Pressure – Formation Pressure

(13.9 x 0.052 x 8200) – (.700 x 8200) = 187 psi

Formula #24 Length of dry pipe pulled out of hole = $\frac{Overbalance\ x\ (Casing\ Cap - Metal\ Disp)}{Mud\ Gradient\ x\ Metal\ Disp}$

$\frac{187\ x\ (.157 - .0080)}{(13.9\ x\ 0.052)x.0080}$ = 4818 ft ÷ 93 ft/std = **51.8 stands**

38. You are pulling out of the hole. Two 93’ stands of 8” drill collars have been stood back in the derrick. The displacement is .0549 bbl/ft. According to your Assistant Driller 5.1 bbl should be pumped into the well. It only takes 5 bbl to fill the hole. (Answer YES or NO to each question)

A. Are the calculations correct? ___***NO***_____

B. Have you taken a 5 bbl influx? ___***YES***______

C. All OK, keep going? ____***NO***_____

Displacement bbls =Length x DC Displacement bbl/ft

(93 ft x 2) x .0549 bbl/ft = 10.2 bbls

39. If the driller pulls 400 feet of 8” X 2 13/16” collars from the hole, including the bit, without filling the hole, what would be the reduction in bottom hole pressure?

Mud weight	11.8 ppg
Casing capacity	.1545 bbl/ft
Metal displacement	.0545 bbl/ft

_____***86.5***_____ psi

Formula #22 Level Drop Pulling Drill Collars = $$\frac{(Length\ of\ Collars\ ft\ x\ Metal\ Disp\ bbl/ft)}{(Casing\ Capacity\frac{bbl}{ft})}$$

$$\frac{(400\ x\ .0545)}{(.1545)} = 141\ ft$$

HP Reduction = 11.8 x .052 x 141 ***= 86.5 psi***

DATA FOR QUESTIONS 40a & 40b BELOW

Drill pipe capacity	.01776 bbl/ft
Drill pipe displacement	.0076 bbl/ft
Average stand length	93 feet

Calculate:

40a. Mud required to fill the hole per stand when pulling dry.

_____***.7***___ bbl

*Displacement = 93 ft x .0076 = **.7 bbl***

40b. Mud required to fill the hole per stand when pulling wet.

___***2.35***__ bbl

*Displacement = 93 ft x (.0076 + .01776) = **2.35 bbls***

41. Gas cut drilling mud normally does not reduce bottom hole pressure enough to cause a well to kick. But BHP is reduced most when:

A. The gas is near the surface
B. The gas is at or near bottom
C. The gas is about halfway up the hole
D. All are about the same

Data for questions 42, 43, 44,

Prior to pulling out of the hole from a depth of 10,485 feet TVD, the pipe is full of 10.4 ppg mud. The pipe capacity is .01776 bbl/ft.
A 25 bbl slug weighing 12.0 ppg is pumped into the drill pipe causing the level to drop inside the drill pipe.

42. What is the drop in bottom hole pressure due to pumping the slug into position?

A. 25 psi
B. 0 psi
C. 117 psi
D. 135 psi

43. How many bbl of mud will be observed in the mud pits due to the U-Tube (backflow) effect?

A. 3.24 bbl

B. 3.85 bbl

C. 4.75 bbl

D. 6.26 bbl

Formula #28 – Pit Gain to Slug U-Tubing bbls = Slug Volume bbls x $\left(\frac{Slug\ Density\ ppg}{Drilling\ Mud\ Density\ ppg} - 1\right)$

25 x $\left(\frac{12.0}{10.4} - 1\right)$ *= 28.85 - (25 bbls slug volume) =* ***3.85 bbls gain in pits***

44. How many feet of dry pipe will there be after the slug is in position?

A. 182 feet

B. 217 feet

C. 267 feet

D. 352 feet

Gain in pit volume bbls ÷ Drill pipe capacity bbls/ft = Dry Pipe ft

3.85 ÷ 0.01776 = ***217 ft***

45. Which *TWO* of the following indications suggest that mud hydrostatic pressure and formation pressure are almost equal?

A. Increase in flow out of the well

B. Increasing background gas, trip gas, and connection gas

C. Temperature anomalies

D. Pit gain

E. All of the above

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

DATA:

Drill pipe capacity	.0174 bbl/ft
Annulus capacity (DP/Csg)	.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 feet

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

A. 287 feet

B. 270 feet

C. 207 feet

D. 362 feet

Formula #28 – Pit Gain to Slug U-Tubing bbls = Slug Volume bbls x $\left(\frac{Slug\ Density\ ppg}{Drilling\ Mud\ Density\ ppg} - 1\right)$

20 x $\left(\frac{16.5}{13.2} - 1\right)$ *= 25 - (20 bbls slug volume) = 5 bbls gain*

Dry Pipe ft = Gain in pit volume bbls ÷ Drill pipe capacity bbls/ft

5 ÷ 0.0174 = ***287 ft***

47. Which of the following can be considered the *SECOND RELIABLE* indication that an influx has entered the well while drilling?

A. Gas cut mud

B. A drilling break

C. A decrease in pump pressure

D. Gain in pit volume

E. Change in the nature of the cuttings

48. Which of the following would not be a warning sign that the bottom hole pressure is approaching formation pressure? *(ONE ANSWER)*

A. Large crescent shaped cuttings

B. Well flowing with pumps off

C. Increase in chloride content of the mud

D. Increase in connection gas

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

A. To minimize down time

B. To minimize the amount of influx by keeping 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 the pipe from getting stuck

50. Which of the following situation would be more difficult to detect?

A. A gas kick in oil-based mud

B. A gas kick in water-based mud

51. While drilling along at a steady rate the derrickman calls to ask if the mud pumps can be slowed down so the shakers can handle the increase in the cuttings coming back in the mud returns. What would be the safest course of action?

A. Check for flow – if none, then continue at the same rate allowing the excess to by-pass the shakers and get caught on the sand trap which can be dumped later

B. Slow down the mud pumps until the shakers can handle the volume of cuttings in the returns as requested by the derrickman

C. Check for flow – if none, then return to the original drilling parameters

D. Check for flow – if none, then circulate bottoms up at a reduced rate so the shakers can handle cuttings volume, flow check periodically during circulation

52. Which of the following is the *FIRST RELIABLE* indication that you have taken a kick while drilling?

A. Increase in torque

B. Gas cut mud

C. Decrease in pump pressure

D. Increase in flow rate

53. Of the following warning signs, which *TWO* would leave little room for doubt that the well is kicking?

A. Flow line temperature increase

B. Increase in rotary torque

C. Flow rate increase

D. Decreased string weight

E. Pit volume gain

F. Increase in rate of penetration

54. It can be said that closing in the well promptly is one of the most important duties of a driller. Any delay may make the well potentially more difficult to kill. From the list of practices below, choose the *SIX MOST LIKELY* to lead to an increase in the size of the influx.

A. Switching off the flow meter alarms

B. Regular briefings for the derrickman on his duties regarding the monitoring of pit levels

C. Drilling a further 20 feet after a drilling break before checking for flow

D. Running regular pit drills for crews

E. Maintaining stab-in valves

F. Testing stab-in valves during regular BOP tests

G. Excluding the drawworks from the SCR assignment

H. Keeping air pressure at the choke panel at 10 psi

I. Calling the tool pusher to the floor prior to shutting in the well (Correct Answer)

J. Not holding down the master air valve on the remote BOP control panel while functioning a preventer

55. Which *TWO* of the following drilling practices should be considered when connection gas is noticed?

A. Pump a low viscosity pill around the bit to assist in reduction of balled bit or stabilizers

B. Control drilling rate so that only one slug of connection gas is in the hole at any one time

C. Pulling out of the hole to change the bit

D. Raising the mud yield point

E. Minimizing the time during connections when the pumps are switched off

56. While tripping in the actual volume of mud displaced is less than the calculated volume. What could cause this?

A. The well is flowing

B. A kick may have been swabbed in

C. A formation is taking fluid

57. If flow through the drill pipe occurs while tripping, what should be the first action to take?

A. Pick up and stab the kelly/ top drive
B. Run back to bottom
C. Close the annular preventer
D. Stab a full opening safety valve

58. What are the advantages/disadvantages of using float in the drill string?

A.	Reverse circulating	Advantage	***Disadvantage***
B.	Reading the SIDPP	Advantage	***Disadvantage***
C.	Cuttings flowback on connections	***Advantage***	Disadvantage
D.	Surge pressure	Advantage	***Disadvantage***

59. After a round trip at 8960 feet with 10.9 ppg mud we kick the pump in and start circulating. An increase in flow is noticed and the well is shut in with 0 psi on the drill pipe and 300 psi on the casing. What is the required mud weight to kill the well? (There is no float in the drill string)

A. No way of knowing

B. 11.5 ppg

C. 10.9 ppg

D. 12.0 ppg

60. What was the most probable cause of the influx in the last question?

A. Abnormal formation pressure

B. The mud weight was not high enough to contain formation pressure

C. The well was swabbed in or the hole was not adequately filled during the trip

D. It’s impossible to tell based on the information given

61. While tripping out of the hole a kick was taken and a full bore kelly cock (full opening safety valve) was stabbed and closed. A safety valve (inside BOP) was made up to the top of the kelly cock prior to stripping in. Answer YES or NO to each question.

A. Should the kelly cock be closed? ___***NO***____

B. If the kelly cock is left in the open position, can a wireline be run inside the drill string? ____***NO***____

62. While running pipe back into the hole, it is noticed that the normal displacement of mud into the trip tank is less than calculated. After reaching bottom and commencing circulation the return flow meter is observed to reduce from 50% to 42%. A pit loss of 2 bbl is noted. What is the most likely cause of these indications?

A. Partial loss of circulation

B. Total loss of circulation

C. A kick has been taken

D. The well has been swabbed in

63. After the well has stabilized, while waiting for kill mud to be mixed, both the drill pipe and the annulus pressures start to increase. What type of influx does this indicate?

A. Fresh water

B. Salt water

C. Oil

D. Gas

64. A gas kick is being circulated up the hole. What is the surface pit volume most likely to do?

A. Increase

B. Stay the same

C. Decrease

65. After shutting in on a kick the SIDPP and SICP pressures have been stable for 15 minutes then they both start slowly rising by the same amount. Which one of the following is the cause?

A. Another influx has entered the well

B. The influx is migrating

C. The gauges are faulty

D. The BOP stack is leaking

66. While preparing to circulate kill weight mud, the gas bubble begins to migrate. If no action is taken, what will the pressure in the gas bubble do as gas rises?

A. Increase

B. Decrease

C. Remain approximately the same

67. What will happen to bottom hole pressure?

A. Increase

B. Decrease

C. Remain approximately the same

68. What will happen to SICP?

A. Increase

B. Decrease

C. Remain approximately the same

69. What will happen to the pressure at the casing seat?

A. Increase

B. Decrease

C. Remain approximately the same

70. A gas kick has been shut in while out of the hole. A stabilized SICP was observed. One hour later the SICP was observed to have risen by 100 psi due to gas migration. The hole capacity is .07323 bbl/ft and the mud weight is 15.4 ppg. How far has the bubble moved up the hole?

_____**125**____ feet

Formula #17 – Gas Migration Rate ft/hr = Rate of Increase in Surface Pressure psi/hr ÷ Mud Density ppg ÷ 0.052

100 ÷ 15.4 ÷ 0.052 = ***125 ft***

71. If the original closed in pressures were 300 psi SIDPP and 500 psi SICP and both started rising close to the maximum allowable would you….

A. Bleed off until the annulus pressure was 500 psi

B. Bleed off until the drill pipe pressure was 300 psi

C. Bleed off until the annulus pressure was 300 psi

72. A vertical well with a surface BOP stack in use has been shut in after a kick. The surface pressures are: SIDPP = 500 psi; SICP = 800 psi; MW = 10 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 the surface at this moment?

	Drill Pipe Pressure	Casing Pressure
A.	500 psi	1112 psi
B.	**812 psi**	**1112 psi**
C.	812 psi	800 psi
D.	500 psi	800 psi

73. While drilling, a gas kick is taken and the surface pressures are:

SIDPP = 300 psi SICP = 475 psi

There is a total pump failure and the influx starts to migrate. The surface pressures start to increase. If the casing pressure is held constant by adjusting the choke, what affect will this have on BHP?

A. It will stay constant
B. It will increase
C. It will decrease

74. A 15 bbl influx of gas was swabbed in at 13200 feet. The formation pressure is 9300 psi and the mud weight in use is 14.2 ppg. What would the expanded volume of the gas be at a depth of 8000 feet? The hole is left open and assumes no change in temperature.

A. 16.3 bbl
B. 23.6 bbl
C. 26.3 bbl
D. 29.6 bbl

P1 = 9300 psi
P2 = 14.2 x 0.052 x 8000 = 5907
V1 = 15 bbls

Formula #18- Gas Law = P1 x V1 = P2 x V2
*(9300 x 15) ÷ 5907 = **23.6 bbls***

75. When tripping out of the hole, with 30 stands remaining it is noticed that the well is flowing. Which one of the following actions should be taken to close the well in using the *SOFT SHUT-IN?*

A. Close the BOP.
Stab in the full opening safety valve
Close the safety valve
Open choke
Record pressures

B. Stab a full opening safety valve
Close the safety valve
Open BOP side outlet valve
Close the BOP
Close the choke
Record pressures

C. Stab full opening safety valve
Open BOP side outlet valve
Close BOP
Close choke
Record pressures

D. Open BOP side outlet valve
Close BOP
Stab full opening safety valve
Close safety valve
Close choke

76. Which list below (a, b, c, or d) describes how the choke manifold will most likely be set up for a SOFT SHUT-IN while drilling.

	BOP Side Outlet Hydraulic Valve	Remote Choke	Degasser Valve
A.	Open	Closed	Closed
B.	Open	Open	Closed
C.	**Closed**	**Open**	**Open**
D.	Closed	Closed	Open

77. Listed below are two procedures shutting in a kicking well:

1. With the choke already open, pick up off bottom, shut down the pumps, open the BOP side outlet hydraulic valve, close the BOP, close the choke, record pressures.

2. With the choke already closed, pick up off bottom, shut down the pumps, close the BOP, and open the BOP side outlet hydraulic valve, record pressures

Match the procedures to the title below, put the number in the spaces provided.

A. Soft Shut-in ______**1**______
B. Hard Shut-in ______**2**______

78. The difference between the hard shut in and the soft shut in is that the hard shut in:

A. The blind rams are used
B. The BOP is closed with the choke open
C. The BOP is closed with the choke closed
D. The kick is diverted

79. The main advantage of the soft shut in procedure over the hard shut in procedure is:

A. To minimize the hydraulic shock on the formation
B. To prevent further influx of formation fluids
C. To allow pressures to be determined
D. All of the above

80. When a kick occurs, why is it important to shut the well in as soon as possible?

A. A larger pit gain will result in higher SIDPP and heavier KWM

TRUE **FALSE**

B. A larger pit gain will result in higher SIDPP and SICP

TRUE **FALSE**

C. A larger pit gain will result in higher SICP but the SIDPP will remain the same

TRUE FALSE

81. We are planning to circulate out a kick with the Wait and Weight Method. The volume of the surface lines on the rig is 20 bbl. Identify the best procedure for dealing with the surface line volume.

A. Re-zero the stroke counter once KWM reaches the bit
B. Subtract 20 bbl (adjusted for pump strokes) from the strokes to bit total on the kill sheet
C. Ignore the surface line volume
D. Re-zero the stroke counter when KWM starts down the drill pipe

82. Why do we need to take into account surface line volume (from the mud pumps to the rig floor) when preparing the kill sheet with the Wait and Weight Method? *(TWO ANSWERS)*

A. If we don't, following the drill pipe pressure graph will result in a BHP that is too low.
B. If we don't, there will be no effect on BHP.
C. If we don't, following the drill pipe pressure graph will result in a BHP that is 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.

83. Why must pit volume be monitored during a well killing operation?

A. To determine KWM
B. To determine the influx volume
C. To determine if lost returns are occurring
D. To determine the gain due to barite additions

84. You have to increase the drill pipe pressure by approximately 100 psi by manipulating the choke during a well kill operation. Of the following options, which one would you choose?

A. Keep closing the choke until you see the drill pipe pressure start to increase

B. Close the choke to increase the casing pressure by 100 psi and wait for the drill pipe pressure to increase.

85. WELL DATA

Slow Circulating Rate Pressure	500 psi @ 40 SPM
SIDPP	800 psi
SICP	1100 psi

The well is shut in

Circulation is started with original weight mud. While the pump is being brought up to 40 spm, which pressure is to remain constant to maintain a constant BHP?

A. 800 on the drill pipe pressure gauge

B. 2300 on the drill pipe pressure gauge

C. 1100 on the casing gauge

D. 1600 on the casing gauge

86. A kick is being circulated out at 30 SPM with a drill pipe pressure reading of 550 psi and a casing pressure of 970 psi. It is decided to slow the pump to 20 spm while maintaining 970 psi on the casing gauge. How will this affect BHP?

A. Increase
B. Decrease
C. Stay the same
D. No way of knowing

87. If a well was closed in after the first circulation of the Driller's Method, what value would you expect on the drill pipe pressure gauge and the casing pressure gauge?

SIDPP = 100 psi SICP = 525 psi

A. Both pressures would be equal to the original SIDPP
B. Both pressures should be reading 0 psi

88. If the pump speed is increased, what happens to the friction losses in the annulus?

A. Decreases
B. Stays the same
C. Increases

89. The main purpose of the Leak-Off Test is to:

A. Determine formation pressure at the shoe
B. Test the surface equipment for pressure integrity
C. Determine the strength of the formation below the casing shoe
D. Test the cement and casing for pressure leaks

90. Which of the following is usually the main limiting factor in determining the *MAXIMUM ALLOWABLE ANNULAR SURFACE PRESSURE?*

A. The maximum pressure that the casing will hold
B. The maximum pressure that the formation below the casing shoe will hold

91. Which of the following defines *MAASP?*

   A. The pressure in excess of mud hydrostatic that, if exceeded, is likely to cause losses at the shoe formation

   B. The total pressure applied at the shoe formation that is likely to causes losses

   C. The maximum BHP allowed during a kill operation

   D. The maximum pressure allowed on the drill pipe gauge during a kill operation

92. Which of the following best describes fracture pressure?

   A. The pressure in excess of mud hydrostatic, that if exceeded, is likely to cause losses at the shoe formation

   B. The total pressure applied to the shoe formation that is likely to cause losses

   C. The maximum BHP during a kill operation

   D. The maximum pressure allowed on the drill pipe gauge during a kill operation

93. Which of the three following conditions are essential for the calculation of an accurate formation strength test? *(CHOOSE THREE ANSWERS)*

   A. Mud volume pumped until leak-off starts

   B. Measured depth of the casing shoe

   C. Mud volume in the casing

   D. Weight of the mud being used

   E. True vertical depth of the casing shoe

94. When should a leak-off test be conducted?

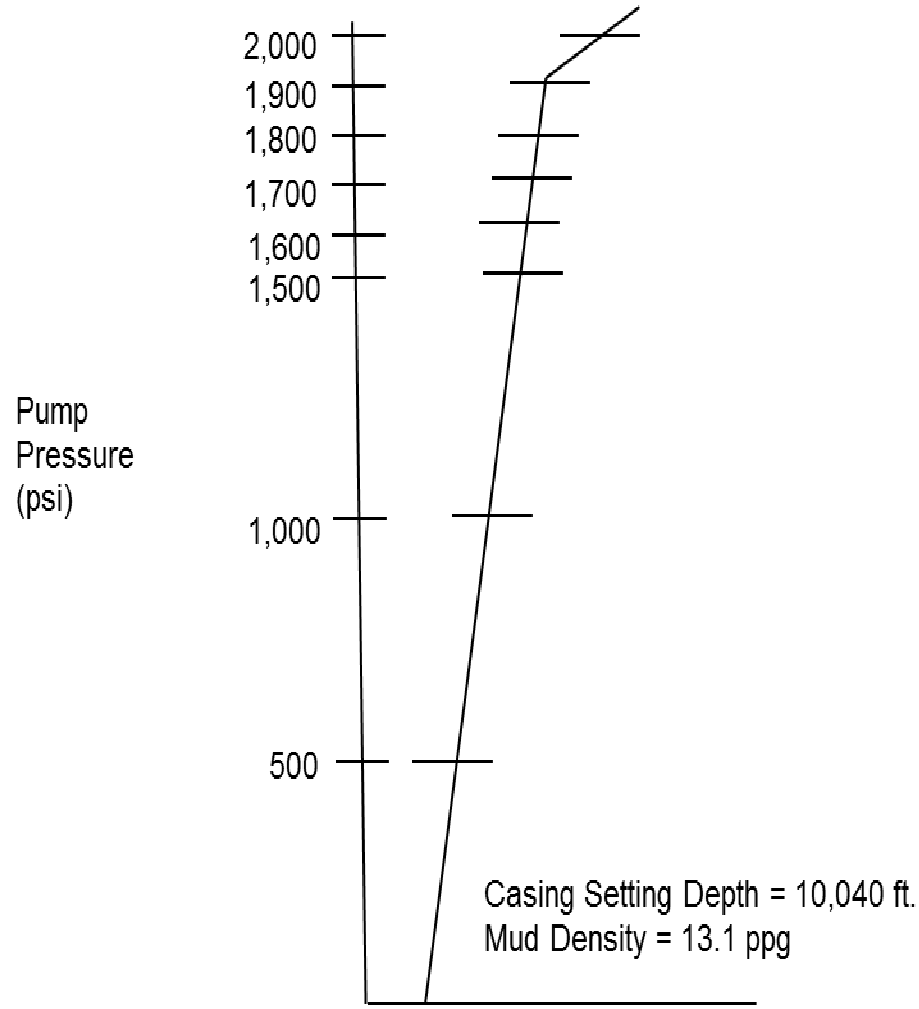
A. Immediately after running and cementing casing
B. Immediately before running casing
C. After drilling out the casing shoe 5 to 15 feet into new formation
D. Immediately before drilling out the casing shoe

95. How often should *MAASP* be calculated?

A. After each bit change
B. After a change in mud weight
C. After every 500 foot interval is drilled

96. Indicate the leak-off pressure from the graph below.

Leak-Off __***<u>1,900</u>***____ psi



97. Use the data from Question 96 to calculate the fracture pressure.

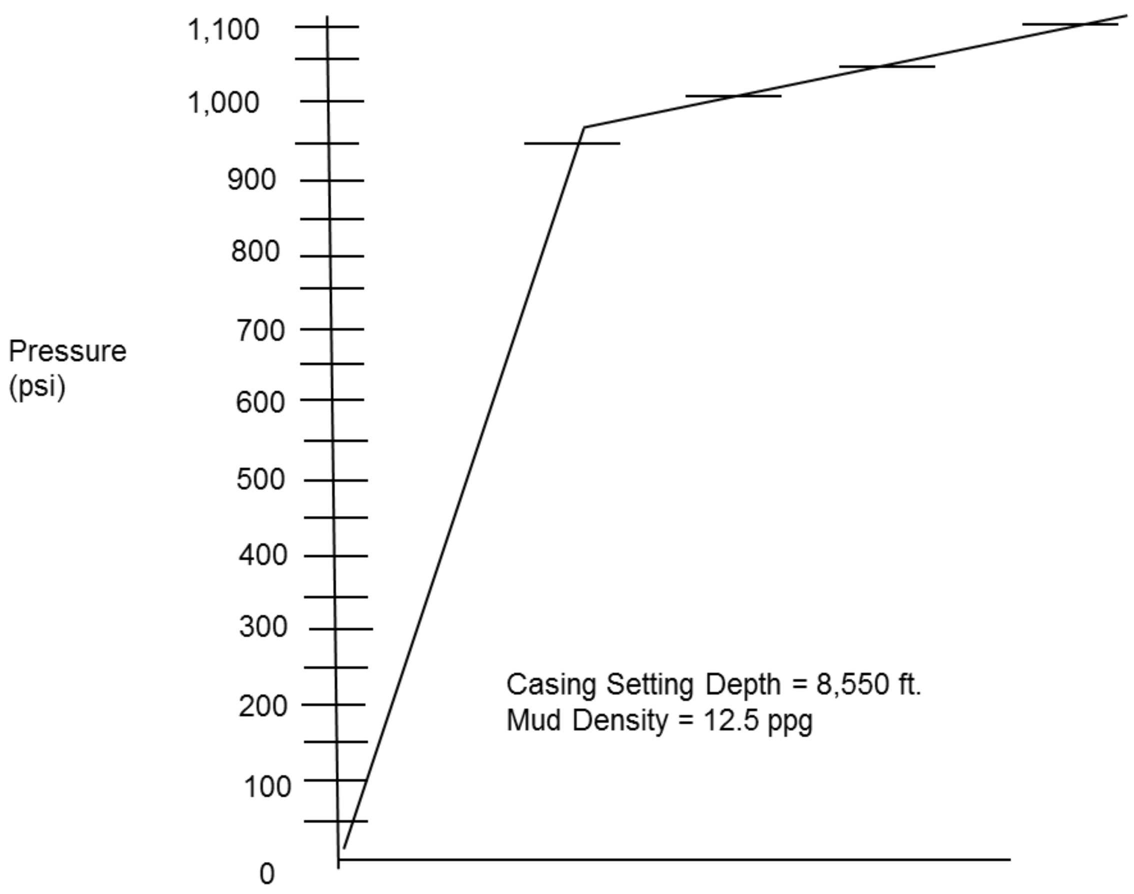
___***8739***__ psi

Formula #11 – MAMW = (1900 psi ÷ 0.052 ÷ 10,040 ft) + 13.1 ppg = 16.73 ppg

*Fracture Pressure =16.73 ppg x 0.052 x 10,040 = **8739 psi***

98. Indicate the leak-off pressure from the graph below.

Leak-Off ___***975***____ psi



99. Use the data from Question 98 to calculate the fracture pressure.

___***6532***___ psi

Formula #11 – MAMW or Frac MW = (975 psi ÷ 0.052 ÷ 8,550 ft) + 12.5 ppg = 14.69 ppg

Fracture Pressure =14.69 ppg x 0.052 x 8,550 = ***6532 psi***

100. 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 to .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 the 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 a previous test

101. Which of the following would contribute to higher fracture gradients?

A. Casing setting depth close to the surface
B. Casing setting depth far from the surface
C. A small difference existing between the mud hydrostatic pressure and fracture pressure
D. A large difference existing between the mud hydrostatic pressure and fracture pressure

102. The mud weight in the well was increased by 1.2 ppg. What will the new *MAASP* be if the casing shoe is set at 5,675 feet MD and 5,125 feet TVD?

A. 354 psi lower than previous MAASP
B. 320 psi higher than previous MAASP
C. 320 psi lower than previous MAASP
D. 354 psi higher than previous MAASP

Formula #12 – MAASP psi = (MAMW ppg – Current MW ppg) x 0.052 x Csg shoe TVD ft

(1.2 ppg increase) x 0.052 x 5,125 ft = ***320 psi ↓***

103. The fracture gradient of an open hole formation at 3680 feet is .618 psi/ft. The drilling mud currently in use is 9.8 ppg. Approximately how much surface casing pressure can be applied to the well before the formation breaks down?

A. 350 to 375 psi
B. 2275 to 1195 psi
C. 630 to 692 psi
D. 382 to 398 psi

MAMW or Frac MW ppg = Fracture Gradient ÷ TVD ft

.618 ÷ 3680 = 11.88ppg

Formula #12 – MAASP psi = (MAMW ppg – Current MW ppg) x 0.052 x TVD ft

(11.88 – 9.8) x 0.052 x 3680 = **398 psi**

DATA FOR QUESTIONS 104 &105

13 3/8” surface casing is set and cemented at 3126’ TVD. The cement is drilled out together with 15 feet of new hole using 10.2 ppg mud. A Leak-Off Pressure of 670 psi is observed.

104. What is the formation fracture gradient?

A. .619 psi/ft
B. .837 psi/ft
C. .7447 psi/ft
D. .530 psi/ft

Formula *#11 - MAMW or Frac MW ppg = (LOT psi ÷ 0.052 ÷ Csg shoe TVD) + Test MW ppg*

(670 ÷ 0.052 ÷ 3126) + 10.2 = 14.32 ppg

14.32 x 0.052 = ***0.7447 psi/ft***

105. What is the *MAXIMUM ALLOWABLE ANNULAR SURFACE PRESURE* for 11.4 ppg mud in use at 6500 feet TVD?

A. 865 to 869 psi

B. 471 to 475 psi

C. 449 to 454 psi

D. 563 to 569 psi

Formula #12 - MAASP psi = (MAMW ppg – Curr MW) x 0.052 x Csg shoe TVD ft

(14.32 – 11.4) x 0.052 x 3126 = ***475 psi***

106. At 40 spm with 10 ppg mud the pump pressure is 1000 psi. What would the pump pressure be if the pump rate were decreased to 25 spm and the mud weight was increased to 11.4 ppg?

A. 713 psi

B. 550 psi

C. 445 psi

D. 390 psi

Formula #9 = New PP psi = Old PP psi x $\left(\frac{New\ SPM}{Old\ SPM}\right)^2$

$1000 \times \left(\frac{25}{40}\right)^2 = 390$ *psi*

Formula #10 = New PP psi = Old PP psi x $\frac{New\ Mud\ Density}{Old\ Mud\ Density}$

$390 \times \frac{11.4\ ppg}{10.0\ ppg} =$ ***445 psi***

107. Pick *Five (5)* situations from the following list under which you would consider taking a new SCRP:

A. Every shift
B. Mud weight changes
C. Significant mud property changes
D. Before and after a leak-off test
E. After each connection when drilling with a top drive
F. When long sections of hole are drilled rapidly
G. After recharging pulsation dampeners
H. When returning to drilling after killing a kick

108. 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 meets this objective.

A. By using the slowest pump 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 pump rate

109. If flow rate is kept constant which TWO of the following factors will INCREASE the circulating pressure?

A. When the mud density in the well is lowered
B. When the well depth is increased
C. When the bit nozzle sizes are increased
D. When the length of the drill collars is increased

110. Shut-in Casing Pressure is used to calculate:

A. KWM
B. Influx gradient and type when the influx volume and well geometry are known
C. Maximum Allowable Annular Surface Pressure
D. Initial Circulating Pressure

111. At what point while correctly circulating out a gas kick is it possible for the pressure at the casing shoe to be at its maximum? *(THREE ANSWERS)*

A. At initial shut in
B. When kill mud reaches the bit
C. When kill mud reaches the casing shoe
D. When the top of the gas reaches the casing shoe

112. Which three of the following conditions in the well increases the risk of exceeding the *MAASP* during a well killing operation?

- **A. Long open hole section**
- B. Large differences between formation breakdown pressure and the mud hydrostatic pressure
- C. Small volume of influx
- D. Short open hole section
- **E. Large volume of influx**
- **F. Small differences between formation breakdown pressure and mud hydrostatic pressure**

113. What is the reason for circulating out a kick at a slow pump rate?

- A. Obtains a smaller expansion of the gas influx thereby reducing casing pressure during the kill process
- B. Create a sufficient pressure loss in the circulating system to give a greater overbalance for a safer kill operation
- **C. Minimize excess pressure exerted on formation during the kill process**

114. A kick was taken and is being circulated out of a deep well with a deep casing shoe. The casing pressure is approaching the maximum allowable and the influx is still in the open hole. Of the actions listed below, which would be the most appropriate?

A. Start pumping mud at least 2 ppg heavier than KWM down the drill pipe
B. Maintain the casing pressure at the maximum allowable by adjusting the choke
C. Minimize any extra pressure in the annulus without allowing BHP to drop below formation pressure

115. Which of the following is *NOT* a warning sign of when a kick may be occurring?

A. Flow rate increase
B. Increased torque
C. Pit gain
D. Well flowing with the mud pumps off