**Kill Sheet and Related Calculations**

**Normal Kill Sheet**

Pre-recorded Data

Original mud weight (0MW)..................................... ppg

Measured depth (MD) .......................................... ft

Kill rate pressure (KRP).............. psi @ ................. spm

Kill rate pressure (KRP).............. psi @ ................. spm

**Drill String Volume**

Drill pipe capacity

........... bbl/ft x ........... length (ft) = .............. bbl

Drill pipe capacity

........... bbl/ft x ........... length (ft) = .............. bbl

Drill collar capacity

........... bbl/ft x ........... length (ft) = .............. bbl

Total drill string volume .................................... bbl

**Annular Volume**

Drill collar/open hole

Capacity .......... bbl/ft x .......... length (ft) = .......... bbl

Drill pipe/open hole

Capacity .......... bbl/ft x .......... length (ft) = .......... bbl

Drill pipe/casing

Capacity .......... bbl/ft x .......... length (ft) = .......... bbl

Total barrels in open hole ..................................... bbl

Total annular volume ........................................... bbl

**Pump Data**

Pump output ................... bbl/stk @ ..................... % cflìdency

**Surface to bit strokes :**

Drill string pump output  
vo1ume ............ bbl ÷ ....... bbl/stk = ............... stk

**Bit to casing shoe strokes :**

Open hole pump output  
volume ............ bbl ÷ ........ bbl/stk = .............. stk

Bit to casing shoe strokes :

Annulus pump output  
volume ............ bbl ÷ ........ bbllstk = .............. stk

**Maximum allowable shut-in casing pressure :**

Leak-off test ........... psi, using ............... ppg mud weight

@ cising setting of ............................... TVD

**Kick data**

SIDPP .............................................. psi

SICP ............................................... psi

Pit gain ........................................... bbl

True vertical depth ................................ ft

**Calculations**

Kill Weight Mud (KWM)

= SIDPP .......... psi ÷ 0.052 + TVD .......... ft + 0MW .......... ppg

**Initial Circulating Pressure (ICP)**

= SIDPP .......... psi + KRP .............. psi = ............. psi

Final Circulating Pressure (FCP)

= KWM ............ ppg x KRP .............. psi ÷ OMW ......... ppg

= ................ psi

**Psi/stroke**

ICP ............ psi — FCP ............. psi : strokes to bit ..........

= ................. psi/stk

Case ; Use the following data and fill out a kill sheet :

Data : Original mud weight = 9.6 ppg  
 Measured depth = 10,525 ft

Kill rate pressure @ 50 spm = 1000 psi  
 Kill rate pressure @ 30 spm = 600psi  
 Drill string :  
 drill pipe 5.0 inch — 19.5 lb/ft  
 capacity = 0.01776 bbl/ft  
 HWDP 5.0 inch - 49.3 lb/ft  
 capacity = 0.00883 bbl/ft  
 length = 240 ft  
 drill collars 8.0 inch OD — 3.0 inch ID   
 capacity = 0.0087 bbl/ft  
 length = 360 ft  
 Annulus :  
 hole size = 12-1/4 inch  
 drill collar/open hole capacity = 0.0836 bbl/ft  
 drill pipe/open hole capacity = 0.1215 bbl/ft  
 drill pipe/casing capacity = 0.1303 bbl/ft  
 Mud pump (7 inch x 12 inch triplex @ 95% eff) = 0.136 bbl/stk  
 Leak-off test with 9.0 ppg mud = 1130 psi  
 Casing setting depth = 4000 ft  
 Shut-in drill pipe pressure = 480psi  
 Shut-in casing pressure = 600 psi  
 Pit volume gain = 35 bbl  
 True vertical depth = 10,000 ft

**Calculate**

**Drill string volume :**

Drill pipe capacity

0.01176 bbl/ft x 9925 ft = 176.27 bbl

HWDP capacity

0.00883 bbl/ft x 240 ft = 2.12 bbl

Drill collar capacity

0.0087 bbl/ft x 360 ft = 3.13 bbl

**Total drill string volume = 181.5 bbl**

**Annular volume**

Drill collar/open hole

0.0836 bbl/ft x 360 ft = 30.1 bbl

Drill pipe/open hole

0.1215 bbl/ft x 6165 ft = 749.05 bbl

Drill pipe/casing

0.1303 bbl/ft x 4000 ft = 521.2 bbl

**Total annular volume = 1300.35 bbl**

Strokes to bit

Drill string volume 181.5 bbl + 0.136 bbl/stk

Strokes to bit = 1335 stk

**Bit to casing strokes :**

Open hole volume = 779.15 bbl : 0.136 bbl/stk

**Bit to casing strokes = 5729 stk**

Bit to surface strokes :

Annular volume = 1300.35 bbl : 0.136 bbl/stk

Bit to surface strokes = 9561 stk

Kill weight mud (KWM)

480 psi : 0.052 : 10,000 ft + 9.6 ppg = 10.5 ppg

**Initial circulating pressure (*I*CP)**

480 psi + 1000 psi = 1480 psi

**Final circulating pressure (FCP)**

10.5 ppg x 1000 psi : 9.6 ppg = 1094 psi

**Pressure Chart**

Strokes to bit = 1335 : 10 = 133.5

Therefore, strokes will increase by 133.5 per line

**Pressure**

ICP (1480) psi — FCP (1094) : 10 = 38.6 psi

Therefore, the pressure will decrease by 38.6 psi per line

**Trip Margin (TM)**

TM = Yield point : 11.7 (Dh inch — Dp inch)

Case : Yield point = 10 lb/lOO sq ft ; Dh = 8.5 inch ; Dp = 4.5 inch

TM = 10 : 11.7 (8.5 — 4.5)

= 0.2 ppg

Determine psi/stk

Case : Using the kill sheet just completed, adjust the pressure

chart to read in increments that are easy to read on pressure

gauges.

Example : 50 psi

Data ; Initial circulating pressure = 1480 psi  
 Final circulating pressure = 1094 psi  
 Strokes to bit = 1335 stk

The pressure side of the chart will be as follows :

**Pressure Chart**

|  |  |
| --- | --- |
| Stroke | Pressure |
| 0 | 1480 |
|  | 1450 |
|  | 1400 |
|  | 1350 |
|  | 1300 |
|  | 1250 |
|  | 1200 |
|  | 1150 |
|  | 1100 |
|  | 1094 |

Adjust the strokes as necessary.

For line 2 : How many strokes will be required to decrease the pressure

from 1480 psi to 1450 psi?

1480 psi — 1450 psi = 30 psi

30 psi ÷ 0.2891 psi/stk = 104 strokes

For lines 3 to 7 : How many strokes will be required to decrease the

pressure by 50 psi increments?

50 psi ÷ 0.2891 psi/stk = 173 strokes

Therefore, the new pressure chart will be as follows :

**Pressure Chart**

|  |  |  |
| --- | --- | --- |
|  | Strokes | Pressure |
|  | 0 | 1480 |
| 104 | 104 | 1450 |
| 104 + 173 = | 277 | 1400 |
| + 173 = | 450 | 1350 |
| + 173 = | 623 | 1300 |
| + 173 = | 796 | 1250 |
| + 173 = | 969 | 1200 |
| + 173 = | 1142 | 1150 |
| + 173 = | 1315 | 1100 |
|  | 1335 | 1094 |

**Kill Sheet With a Tapered String**

Note : Whenever a kick is taken with a tapered drill string in the hole,

interim pressures should be calculated for

a. the length of large drill pipe (DPL) and

b. the length of large drill pipe plus the length of small drill

pipe

Case : Drill pipe 1 : 5.0 inch — 19.5 lb/ft  
 capacity = 0.01776 bbl/ft  
 length = 7000 ft  
 Drill pipe 2 : 3-1/2 inch — 13.3 lb/ft  
 capacity = 0.0074 bbl/ft  
 length = 6000 ft   
 Drill collars : 4-1/2 inch — OD x 1-1/2 inch ID  
 capacity = 0.0022 bbl/ft  
 length = 2000 ft  
 Pump output = 0.117 bbl/stk

**Step 1**

Determine strokes :

7000 ft x O.01776 bbl/ft ÷ 0.117 bbl/stk = 1063  
6000 ft x 0.00742 bbl/ft ÷ 0.117 bbl/stk = 381  
2000 ft x 0.0022 bbl/ft ÷ 0.117 bbl/stk = 38

**Total strokes = 1482**

**Data from kill sheet**

Initial drill pipe circulating pressure (ICP) = 1780 psi  
Final drill pipe circulating pressure (FCP) = 1067 psi

**Step 2**

Determine interim pressure for the 5.0 inch drill pipe at 1063 strokes :

**Step 3**

Determine interim pressure for 5.0 inch plus : 3-1/2 inch drill pipe

(1063 + 381) = 1444 strokes :

**Step 4**

Plot data on graph paper :

1000

1500

1268 psi

178 psi

1447 psi

Strokes pumped

Drill pipe pressure (psi)

Note : After pumping 1062 strokes, if a straight line would have been

plotted, the well would have been underbalanced by 178 psi

**Kill Sheet for a Highly Deviated Well**

Whenever a kick is taken in a highly deviated well, the circulating pressure can be excessive when the kill weight mud gets to the kick-off point (KOP).  
If the pressure is excessive, the pressure schedule should be divided into two section :  
1. from surface to KOP

2. from KOP to TD

The following calculations arc used :

Determine strokes from surface to KOP :

Determine strokes from KOP to TD :

Kill weight mud :

*KWM = SIDPP ÷ 0.052 ÷ TVD + 0MW*

Initial circulating pressure :

*ICP = SIDPP + KRP*

Final circulating pressure :

*FCP = KWM x KRP ÷ 0MW*

Hydrostatic pressure increase from surface to KOP :

*Psi = (KWM – OMW) x 0.052 x TVD @ KOP*

Friction pressure increase to KOP :

*FP = (FCP – KRP) x MD @ KOP ÷ MD @ TD*

Circulating pressure when KWM gets to KOP :

*CP @ KOP = ICP — HP increase to KOP + friction pressure increase (psi)*

Note : At this point compare this circulating pressure to the value

obtained when using a regular kill sheet

Case : Original mud weight (0MW) = 9.6 ppg  
 Measured depth (MD) = 15,000 ft  
 Measured depth @ KOP = 5000 ft  
 True vertical depth @ KOP = 5000 ft  
 Kill rate pressure (KRP) @ 30 spm = 600 psi  
 Pump output = 0.136 bbl/stk  
 Drill pipe capacity = 0.01776 bbl/ft  
 Shut-in drill pipe pressure (SIDPP) = 800 psi  
 True vertical depth = 10,000 ft

Solution :

**Strokes from surface to KOP :**

Strokes = 0.01776 bbl/ft x 5000 ft ÷ 0.136 bbl/stk

= 653

**Strokes from KOP to TD :**

Strokes = 0.01776 bbl/ft x 10,000 ft ÷ 0.136 bbl/stk

= 1306

**Total strokes from surface to bit :**

Surface to bit strokes = 653 + 1306

= 1959

**Kill weight mud (KWM):**

*KWM = 800 psi ÷ 0.052 ÷ 10,000 ft + 9.6 ppg*

**Initial circulating pressure (ICP) :**

ICP = 8OO psi + 600 psi

= 1400 psi

**Final circulating pressure (FCP) :**

FCP = 11.1 ppg x 600 psi ÷ 9.6 ppg

= 694 psi

**Hydrostatic pressure increase from surface to KOP :**

HPi = (11.1 — 9.6) x 0.052 x 5000

= 39O psi

**Friction pressure increase to TD :**

FP = (694 - 600) x 5000 ÷ 15,000

= 31 psi

**Circulating pressure when KWM gets to KOP :**

CP = 1400 — 390 + 31

= 1041 psi

Compare this circulating pressure to the value obtained when using a regular kill sheet :

psi/stk = 1400 — 694 ÷ 1959

= 0.36

0.36 psi/stk x 653 strokes = 235 psi

1400 — 235 = 1165 psi

Using a regular kill sheet, the circulating drill pipe pressure would be 1165 psi. The adjusted pressure chart would have 1041 psi on the drill pipe gauge.  
This represents 124 psi difference in pressure, which would also be observed on the annulus (casing) side. It is recommended that if the difference in pressure at the KOP is lOO psi or greater, then the adjusted pressure chart should be used to minimize the chances of losing circulation.

**Prerecorded Information**

**Maximum Anticipated Surface Pressure**

Two methods are commonly used to determine maximum anticipated surface pressure :

Method 1 : Use when assuming the maximum formation pressure is from TD :

**Step 1**

Determine maximum formation pressure (FPmax):

**Step 2**

Assuming 100% of the mud is blown out of the hole, determine the hydrostatic pressure in the wellbore :

Note : 70% to 80% of mud being blown out is sometimes used instead

HPgas = gas gradient (psi/ft) x total depth (ft)

**Step 3**

Determine maximum anticipated surface pressure (MASP):

*MASP = FPmax - HPgas*

Case : Proposed total depth = 12,000 ft  
 Maximum mud weight to be used in drilling well = 12.0 ppg  
 Safety factor = 4.0 ppg  
 Gas gradient = 0.12 psi/ft

Assume that 100% of mud is blown out of well

**Step 1**

FPmax = (12.0 + 4.0) x 0.052 x 12,000 ft

= 9984 psi

**Step 2**

Hpgas = 0.12 x 12,000 ft

= 1440 psi

**Step 3**

MASP = 9984 — 1440

= 8544 psi

Method 2 : Use when assuming the maximum pressure in the wellbore is

attained when the formation at the shoe fractures :

**Step 1**

Determine fracture pressure (psi):

Note : A safety factor is added to ensure the formation fractures before

BOP pressure rating is exceeded

**Step 2**

Determine the hydrostatic pressure of gas in the wellbore (Hpgas):

*HPgas = gas gradient (psi/ft) x casing shoe TVD (ft)*

**Step 3**

Determine the maximum anticipated surface pressure (MASP), psi ;

Case : Proposed casing setting depth = 4000 ft  
 Estimated fracture gradient = 14.2 ppg  
 Safety factor = 1.0 ppg  
 Gas gradient = 0.12 psi/ft

Assume 100% of mud is blown out of the hole

**Step 1**

Fracture pressure (psi) = (14.2 + 1.0) x 0.052 x 4000 ft

= 3162 psi

**Step 2**

HPgas = 0.12 x 4000 ft

= 480 psi

**Step 3**

MASP = 3l62 - 480

= 2682 psi

**Sizing Diverter Lines**

Determine diverter line inside diameter (inch), equal to the area between inside diameter of the casing and the outside diameter of drill pipe in use

*Diverter line ID inch =*

Case :

Casing — 13-3/8 inch — J-55 — 61 lb/ft OD = 12.515 inch  
Drill pipe — 19.5 lb/ft OD = 5.0 inch

Determine the diverter line inside diameter that will equal the area between the casing and drill pipe :

Diverter line ID, inch =

= 11.47 inch

**Formation Pressure Tests**

Two methods of testing :

- Equivalent mud weight test  
- Leak-off test

Precautions to undertaken before testing :

1. Circulate and condition the mud to ensure the mud weight is consistent

throughout the system.  
2. Change the pressure gauge (if possible) to a smaller increment gauge so

a more accurate measure can be determined.  
3. Shut-in the well.  
4. Begin pumping at a very slow rate — 1/4 to 1/2 bbl/min.  
5. Monitor pressure, time, and barrels pumped.  
6. Some operators may have different procedures in running this test,

others may include :  
 a. Increasing the pressure by 100 psi increments, waiting for a few

minute, then increasing by another 100 psi, and so on, until either

the equivalent mud weight is achieved or until Leak-off is achieved.  
 b. Some operators prefer not pumping against a closed system. They

prefer to circulate through the choke and increase back pressure by

slowly closing the choke. In this method, the annular pressure loss

should be calculated and added to the test pressure results.

Testing to an equivalent mud weight :

1. This test is used primarily on development wells where the maximum mud

weight that will be used to drill the next interval is known.  
2. Determine the equivalent test mud weight (ppg), two methods are normally

used.

Method 1 : Add a value to the maximum mud weight that is needed to drill

the interval.

Case : Maximum mud weight necessary to drill the next interval =

11.5 ppg plus safety factor = 1.0 ppg

Method 2 : Subtract a value from the estimated fracture gradient for the

depth of the casing shoe.

Case : Estimated formation fracture gradient = 14.2 ppg

Safety factor = 1.0 ppg

Equivalent test mud weight = 14.2 ppg — 1.0 ppg

Determine surface pressure to be used :

Case :

Mud weight = 9.2 ppg  
Casing shoe TVD = 4000 ft  
Equivalent test mud weight = 13.2 ppg

Solution : Surface pressure = (13.2 — 9.2) x 0.052 x 4000 ft

= 832 psi

**Testing to leak-off test**

1. This test is used primarily on wildcat or exploratory wells or where the

actual fracture is not known.  
2. Determine the estimated fracture gradient from a “Fracture Gradient

Chart”.  
3. Determine the estimated leak-off pressure.

Case : Mud weight = 9.6 ppg  
 Casing shoe TVD = 4000 ft  
 Estimated fracture gradient = 14.4 ppg

Solution :

Estimated leak-off pressure = (l4.4 — 9.6) x 0.052 x 4000 ft

= 4.8 x 0.052 x 4000

= 998 psi

Maximum Allowable Mud Weight From Leak-off Test Data

Case : Determine the maximum allowable mud weight (ppg), using the

following data :

Leak-off pressure = 1044 psi  
Casing shoe TVD = 4000 ft  
Mud weight in use = 10.0 ppg

Max allowable mud weight (ppg) = 1040 ÷ 0.052 ÷ 4000 + 10.0  
  
 = 15.0 ppg

Maximum Allowable Shut-in Casing Pressure (MASICP) also called maximum allowable, shut-in annular pressure (MASP)

Case : Determine the maximum allowable shut-in casing pressure using

the following data :

Maximum allowable mud weight = 15.0 ppg  
Mud weight in use = 12.2 ppg  
Casing shoe TVD = 4000 ft

MASICP = (15.0 — 12.2) x 0.052 x 4000 ft

= 582 psi

**KICK TOLERANCE FACTOR (KTF)**

Case : Determine the kick tolerance factor (KTF) using the following

data :

Maximum allowable mud weight = 14.2 ppg

(from leak-off test data)

Mud weight in use = 10.0 ppg

Casing shoe TVD = 4000 ft  
Well depth TVD = 10,000 ft

KTF = (4000 ft : 10,000 ft) x (14.2 ppg — 10.0 ppg)

= 1.68 ppg

**Maximum Surface Pressure From Kick Tolerance Data**

*Maximum surface pressure = kick tolerance factor (ppg) x 0.052 x TVD (ft)*

Case : Determine the maximum surface pressure (psi) using the

Following data :

Maximum surface pressure = 16.8 ppg x 0.052 x 10,000 ft

= 874 psi

**Maximum Formation Pressure (FP) That Can be Controlled When Shutting-in a Well**

Case : Determine the maximum formation pressure (FP) that can be

controlled when shutting-in a well using the following data :

Data : Kick tolerance factor = 1.68 ppg  
 Mud weight = 10.0 ppg  
 True vertical depth = 10,000 ft

Maximum FP (psi) = (1.68 ppg + 10.0 ppg)x 0.052 x 10,000 ft

= 6074 psi

**Maximum Influx Height Possible to Equal Maximum Allowable Shut-in Casing Pressure (MASICP)**

Case : Determine the influx height (ft) necessary to equal the

Maximum allowable shut-in casing pressure (MASICP) using the

Following data :

Data : Maximum allowable shut-in casing pressure = 874 psi  
 Mud gradient (10.0 ppg x 0.052) = 0.52 psi/ft  
 Gradient of influx = 0.12 psi/ft

Influx height = 874 psi : (0.52 psi/ft —0.12 psi/ft)

= 2185 ft

**Maximum Influx, Barrels to Equal Maximum Allowable Shut-in Casing Pressure (MASICP)**

Case :

Maximum influx height co equal MASICP = 2185 ft   
(from above example)  
Annular capacity — drill collars/open hole = 0.0836 bbl/ft  
(12-4/4 in. x 8.0 in.)  
Drill collar length = 500 ft  
Annular capacity — drill pipe/open hole = 0.1215 bbl/ft  
(12-1/4 in. x 5.0 in.)

**Step 1**

Determine the number of barrels opposite drill collars :

Barrels = 0.0836 bbl/ft x 500 ft

= 41.8

**Step 2**

Determine the number of barrels opposite drill pipe :

Influx height (ft) opposite drill pipe :

ft = 2185 ft — 500 ft

= 1685

Barrels opposite drill pipe :

Barrels = 1685 ft x 0.1215 bbl/ft

= 204.7

**Step 3**

Determine maximum influx (bbl) to equal maximum allowable shut-in casing pressure :

Maximum influx = 41.8 bbl + 204.7 bbl  
 = 246.5 bbl

**Adjusting Maximum Allowable Shut-In Casing Pressure For an Increase in Mud Weight**

*MASICP = PL — [D x(mud wt2 — mud wt1)] O.052*

Where ;

MASICP = maximum allowable shut-in casing (annulus) pressure (psi)  
PL = leak-off pressure (psi)  
D = true vertical depth to casing shoe (ft)  
Mud wt2 = new mud weight (ppg)  
Mud wt1 = original mud weight (ppg)

Case : Leak-off pressure at casing setting depth (TVD) of 4000 ft

Was 1040 psi with 10.0 ppg in use. Determine the maximum

Allowable shut-in casing pressure with a mud weight of 12.5

ppg :

MASICP = 1040 psi — [4000 x (12.5 — 10.0) 0.052

= 1040 psi — 520

= 520 psi