Formulas
and
Calculations
for
Drilling, Production
and
Work-over

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CONTENTS

CHAPTER ONE

BASIC FORMULAS

1. Pressure Gradient

Pressure gradient, psi/ft, using mud weight, ppg

psi/ft = mud weight, ppg x 0.052 *Example:* 12.0 ppg fluid

psi/ft = 12.0 ppg x *0.052*
psi/ft = 0.624

Pressure gradient, psi/ft, using mud weight, lb/ft^3

psi/ft = mud weight, lb/ft^3 x 0.006944 *Example:* 100 lb/ft^3 fluid

psi/ft = 100 lb/ft^3 x 0.006944
psi/ft = 0.6944

OR

psi/ft = mud weight, lb/ft^3 ÷ 144 *Example:* 100 lb/ft^3 fluid

psi/ft = 100 lb/ft^3 ÷ 144
psi/ft = 0.6944

Pressure gradient, psi/ft, using mud weight, specific gravity (SG)

psi/ft = mud weight, SG x 0.433 *Example:* 1.0 SG fluid

psi/ft = 1.0 SG x 0.433
psi/ft = 0.433

Convert pressure gradient, psi/ft, to mud weight, ppg

ppg = pressure gradient, psi/ft ÷ 0.052 *Example:* 0.4992 psi/ft

ppg = 0.4992 psi/ft ÷ 0.052
ppg = 9.6

Convert pressure gradient, psi/ft, to mud weight, lb/ft^3

lb/ft^3 = pressure gradient, psi/ft ÷ 0.006944 *Example:* 0.6944 psi/ft

lb/ft^3 = 0.6944 psi/ft ÷ 0.006944
lb/ft^3 = 100

Convert pressure gradient, psi/ft, to mud weight, SG

SG = pressure gradient, psi/ft 0.433 *Example:* 0.433 psi/ft

SG 0.433 psi/ft ÷ 0.433
SG = 1.0

2. Hydrostatic Pressure (HP)

Hydrostatic pressure using ppg and feet as the units of measure

HP = mud weight, ppg x 0.052 x true vertical depth (TVD), ft

Example: mud weight = 13.5 ppg true vertical depth = 12,000 ft

HP = 13.5 ppg x *0.052 x* 12,000 ft
HP = 8424 psi

Hydrostatic pressure, psi, using pressure gradient, psi/ft

HP = psi/ft x true vertical depth, ft

Example: Pressure gradient = 0.624 psi/ft true vertical depth = 8500 ft

HP = 0.624 psi/ft x 8500 ft
HP = 5304 psi

Hydrostatic pressure, psi, using mud weight, lb/ft^3

HP = mud weight, lb/ft^3 x 0.006944 x TVD, ft

Example: mud weight = 90 lb/ft^3 true vertical depth = 7500 ft

HP = 90 lb/ft^3 x 0.006944 x 7500 ft
HP = 4687 psi

Hydrostatic pressure, psi, using meters as unit of depth

HP = mud weight, ppg x 0.052 x TVD, m x 3.281

Example: Mud weight = 12.2 ppg true vertical depth = 3700 meters

HP = 12.2 ppg x 0.052 x 3700 x 3.281
HP = 7,701 psi

3. Converting Pressure into Mud Weight

Convert pressure, psi, into mud weight, ppg using feet as the unit of measure

mud weight, ppg = pressure, psi ÷ 0.052 + TVD, ft

Example: pressure = 2600 psi true vertical depth = 5000 ft

mud, ppg = 2600 psi ÷ 0.052 ÷ 5000 ft
mud = 10.0 ppg

Convert pressure, psi, into mud weight, ppg using meters as the unit of measure

mud weight, ppg = pressure, psi ÷ 0.052 ÷ TVD, m + 3.281

Example: pressure = 3583 psi true vertical depth = 2000 meters

mud wt, ppg = 3583 psi ÷ 0.052 ÷ 2000 m ÷ 3.281
mud wt = 10.5 ppg

4. Specific Gravity (SG)

Specific gravity using mud weight, ppg

SG = mud weight, ppg + 8.33 *Example:* *15*..0 ppg fluid

SG = 15.0 ppg ÷ 8.33
SG = 1.8

Specific gravity using pressure gradient, psi/ft

SG = pressure gradient, psi/ft 0.433 *Example:* pressure gradient = 0.624 psi/ft

SG = 0.624 psi/ft ÷ 0.433
SG = 1.44

Specific gravity using mud weight, lb/ft^3

SG = mud weight, lb/ft^3 ÷ 62.4 *Example:* Mud weight = 120 lb/ft^3

SG = 120 lb/ft^3 + 62.4
SG = 1.92

Convert specific gravity to mud weight, ppg

mud weight, ppg = specific gravity x 8.33 *Example:* specific gravity = 1.80

mud wt, ppg = 1.80 x 8.33
mud wt = 15.0 ppg

Convert specific gravity to pressure gradient, psi/ft

psi/ft = specific gravity x 0.433 *Example:* specific gravity = 1.44

psi/ft = 1.44 x 0.433
psi/ft = 0.624

Convert specific gravity to mud weight, lb/ft^3

lb/ft^3 = specific gravity x 62.4 *Example:* specific gravity = 1.92

lb/ft^3 = 1.92 x 62.4
lb/ft^3 = 120

5. Equivalent Circulating Density (ECD), ppg

ECD, ppg = (annular pressure, loss, psi) ÷ 0.052 ÷ TVD, ft + (mud weight, in use, ppg)

Example: annular pressure loss = 200 psi true vertical depth = 10,000 ft

ECD, ppg = 200 psi ÷ 0.052 ÷ 10,000 ft + 9.6 ppg
ECD = 10.0 ppg

6. Maximum Allowable Mud Weight from Leak-off Test Data

ppg = (Leak-off Pressure, psi) ÷ 0.052 ÷ (Casing Shoe TVD, ft) + (mud weight, ppg)

Example: leak-off test pressure = 1140 psi casing shoe TVD = 4000 ft
Mud weight = 10.0 ppg

ppg = 1140 psi ÷ 0.052 ÷ 4000 ft + 10.0 ppg ppg = 15.48

7. Pump Output (P0)

Triplex Pump Formula 1

PO, bbl/stk = 0.000243 x (liner diameter, in.)^2 X (stroke length, in.)

Example: Determine the pump output, bbl/stk, at 100% efficiency for a 7-in, by 12-in, triplex pump:

PO @ 100% = 0.000243 x 72 x 12
PO @ 100% = 0.142884 bbl/stk

Adjust the pump output for *95%* efficiency: Decimal equivalent = *95* ÷ 100 = 0.95

PO @ 95% = 0.142884 bbl/stk x 0.95
PO @ *95%* = 0.13574 bbl/stk

Formula 2

PO, gpm = [3 (7^2 x *0.7854)* S] 0.00411 x SPM

where D = liner diameter, in. S = stroke length, in. SPM = strokes per minute

Example: Determine the pump output, gpm, for a 7-in, by 12-in, triplex pump at 80 strokes per minute:

PO, gpm = [3 (72 x 0.7854) 12] 0.00411 x 80
PO, gpm = 1385.4456 x 0.00411 x 80
PO = 455.5 gpm

Duplex Pump Formula 1

0.000324 x (Liner Diameter, in.)^2 x (stroke length, in.) = ________ bbl/stk
-0.000162 x (Liner Diameter, in.)^2 x (stroke length, in.) = ________ bbl/stk
Pump output @ 100% eff = ________ bbl/stk

Example: Determine the output, bbl/stk, of a 5-1/2 in, by 14-in, duplex pump at 100% efficiency. Rod diameter = 2.0 in.:

0.000324 x 5.5^2 x 14 = 0.137214 bbl/stk
-0.000162 x 2.0^2 x 14 = <u>0.009072</u> bbl/stk
pump output 100% eff = 0.128142 bbl/stk

Adjust pump output for 85% efficiency:
Decimal equivalent = 85 ÷ 100 = 0.85

PO @ 85% = 0.128142 bbl/stk x 0.85
PO @ 85% = 0.10892 bbl/stk

Formula 2

PO, bbl/stk = 0.000162 x S [2(D)^2 — d^2]

where D = liner diameter, in. S = stroke length, in. SPM = strokes per minute

Example: Determine the output, bbl/stk, of a 5-1/2-in, by 14-in, duplex pump 100% efficiency. Rod diameter — 2.0 in.:

PO @ 100% = 0.000162 x 14 x [2 (5.5)^2 -2^2]
PO @ 100% = 0.000162 x 14 x 56.5
PO @ 100% = 0.128142 bbl/stk

Adjust pump output for 85% efficiency:

PO @ 85% = 0.128142 bbl/stk x 0.85
PO @ 85% = 0.10892 bbl/stk

8. Annular Velocity (AV)

Annular velocity (AV), ft/min

Formula 1

AV = pump output, bbl/min ÷ annular capacity, bbl/ft

Example: pump output = 12.6 bbl/min annular capacity = 0.126 1 bbl/ft

AV = 12.6 bbl/min ÷ 0.1261 bbl/ft
AV = 99.92 ft/mm

Formula 2

$$\text{AV, ft/mm} = \frac{24.5 \times Q.}{Dh^2 - Dp^2}$$

where Q = circulation rate, gpm, Dh = inside diameter of casing or hole size, in.
Dp = outside diameter of pipe, tubing or collars, in.

Example: pump output = 530 gpm hole size = 12-1/4th. pipe OD = 4-1/2 in.

$$\text{AV} = \frac{24.5 \times 530}{12.25^2 - 45^2}$$

$$\text{AV} = \frac{12{,}985}{129.8125}$$

AV = 100 ft/mm

Formula 3

$$\text{AV, ft/min} = \frac{\text{PO, bbl/min} \times 1029.4}{Dh^2 - Dp^2}$$

Example: pump output = 12.6 bbl/min hole size = 12-1/4 in. pipe OD = 4-1/2 in.

$$\text{AV} = \frac{12.6 \text{ bbl/min} \times 1029.4}{12.25^2 - 45^2}$$

$$\text{AV} = \frac{12970.44}{129.8125}$$

AV = 99.92 ft/mm

Annular velocity (AV), ft/sec

$$\text{AV, ft/sec} = \frac{17.16 \times \text{PO, bbl/min}}{Dh^2 - Dp^2}$$

Example: pump output = 12.6 bbl/min   hole size = 12-1/4 in.   pipe OD = 4-1/2 in.

$$AV = \frac{17.16 \times 12.6 \text{ bbl/min}}{12.25^2 — 45^2}$$

$$AV = \frac{216.216}{129.8125}$$

AV = 1.6656 ft/sec

Pump output, gpm, required for a desired annular velocity, ft/mm

$$\text{Pump output, gpm} = \frac{\text{AV, ft/mm } (Dh^2 — DP^2)}{24\ 5}$$

where AV = desired annular velocity, ft/min
Dh = inside diameter of casing or hole size, in.
Dp = outside diameter of pipe, tubing or collars, in.

Example: desired annular velocity = 120 ft/mm   hole size = 12-1/4 in
pipe OD = 4-1/2 in.

$$PO = \frac{120\ (12.25^2 — 45^2)}{24.5}$$

$$PO = \frac{120 \times 129.8125}{24.5}$$

$$PO = \frac{15577.5}{24.5}$$

PO = 635.8 gpm

Strokes per minute (SPM) required for a given annular velocity

$$SPM = \frac{\text{annular velocity, ft/mm} \times \text{annular capacity, bbl/ft}}{\text{pump output, bbl/stk}}$$

Example. annular velocity = 120 ft/min   annular capacity = 0.1261 bbl/ft
Dh = 12-1/4 in.   Dp = 4-1/2 in. pump output = 0.136 bbl/stk

$$SPM = \frac{120 \text{ ft/mm} \times 0.1261 \text{ bbl/ft}}{0.136 \text{ bbl/stk}}$$

$$SPM = \frac{15.132}{0.136}$$

SPM = 111.3

9. Capacity Formulas

Annular capacity between casing or hole and drill pipe, tubing, or casing

a) Annular capacity, bbl/ft = $\dfrac{Dh^2 — Dp^2}{1029.4}$

Example: Hole size (Dh) = 12-1/4 in. Drill pipe OD (Dp) = 5.0 in.

Annular capacity, bbl/ft = $\dfrac{12.25^2 — 5.0^2}{1029.4}$

Annular capacity = 0.12149 bbl/ft

b) Annular capacity, ft/bbl = $\dfrac{1029.4}{(Dh^2 — Dp^2)}$

Example: Hole size (Dh) = 12-1/4 in. Drill pipe OD (Dp) = 5.0 in.

Annular capacity, ft/bbl = $\dfrac{1029.4}{(12.25^2 — 5.0^2)}$

Annular capacity = 8.23 ft/bbl

c) Annular capacity, gal/ft = $\dfrac{Dh^2 — Dp^2}{24.51}$

Example: *H*ole size (Dh) = 12-1/4 in. Drill pipe OD (Dp) = 5.0 in.

Annular capacity, gal/ft = $\dfrac{12.25^2 — 5.0^2}{24.51}$

Annular capacity = 5.1 gal/ft

d) Annular capacity, ft/gal = $\dfrac{24.51}{(Dh^2 — Dp^2)}$

Example: Hole size (Dh) = 12-1/4 in. Drill pipe OD (Dp) = 5.0 in.

Annular capacity, ft/gal = $\dfrac{24.51}{(12.25^2 — 5.0^2)}$

Annular capacity, ft/gal = 0.19598 ft/gal

e) Annular capacity, ft^3/Iinft — $\frac{Dh^2 — Dp^2}{183.35}$

Example: Hole size (Dh) = 12-1/4 in. Drill pipe OD (Dp) = *5.0* in.

Annular capacity, ft^3/linft = $\frac{12.25^2 — 5.0^2}{183.35}$

Annular capacity = 0.682097 ft^3/linft

f) Annular capacity, linft/ft^3 = $\frac{183.35}{(Dh^2 — Dp^2)}$

Example: Hole size (Dh) = 12-1/4 in. Drill pipe OD (Dp) = *5.0* in.

Annular capacity, linft/ft^3 = $\frac{183.35}{(12.25^2 — 5.0^2)}$

Annular capacity = 1.466 linft/ft^3

Annular capacity between casing and multiple strings of tubing

a) Annular capacity between casing and multiple strings of tubing, bbl/ft:

Annular capacity, bbl/ft = $\frac{Dh^2 — [(T_1)^2 + (T_2)^2]}{1029.4}$

Example: Using two strings of tubing of same size:

Dh = casing — 7.0 in. — 29 lb/ft ID = 6.184 in.
T_1 = tubing No. 1 — 2-3/8 in. OD = 2.375 in.
T_2 = tubing No. 2 — 2-3/8 in. OD = 2.375 in.

Annular capacity, bbl/ft = $\frac{6.1842 — (2.375^2+2.375^2)}{1029.4}$

Annular capacity, bbl/ft = $\frac{38.24 — 11.28}{1029.4}$

Annular capacity = 0.02619 bbl/ft

b) Annular capacity between casing and multiple strings of tubing, ft/bbl:

Annular capacity, ft/bbl = $\frac{1029.4}{Dh^2 — [(T_1)^2 + (T_2)^2]}$

Example: Using two strings of tubing of same size:

Dh = casing — 7.0 in. — 29 lb/ft ID = 6.184 in.
T_1 = tubing No. 1 — 2-3/8 in. OD = 2.375 in.
T_2 = tubing No. 2 — 2-3/8 in. OD = 2.375 in.

$$\text{Annular capacity ft/bbl} = \frac{1029.4}{6.184^2 - (2.375^2 + 2.375^2)}$$

$$\text{Annular capacity, ft/bbl} = \frac{1029.4}{38.24 — 11.28}$$

Annular capacity = 38.1816 ft/bbl

c) Annular capacity between casing and multiple strings of tubing, gal/ft:

$$\text{Annular capacity, gal/ft} = \frac{Dh^2 — [(T\sim)^2+(T_2)^2]}{24.51}$$

Example: Using two tubing strings of different size:
Dh = casing — 7.0 in. — 29 lb/ft ID = 6.184 in.
T_1 = tubing No. 1 — 2-3/8 in. OD = 2.375 in.
T_2 = tubing No. 2 — 3-1/2 in. OD = 3.5 in.

$$\text{Annular capacity, gal/ft} = \frac{6.1842 — (2.375^2+3.5^2)}{24.51}$$

$$\text{Annular capacity, gal/ft} = \frac{38.24 — 17.89}{24.51}$$

Annular capacity = 0.8302733 gal/ft

d) Annular capacity between casing and multiple strings of tubing, ft/gal:

$$\text{Annular capacity, ft/gal} = \frac{24.51}{Dh^2 — [(T_1)^2 + (T_2)^2]}$$

Example: Using two tubing strings of different sizes:
Dh = casing — 7.0 in. — 29 lb/ft ID = 6.184 in.
T_1 = tubing No. I — 2-3/8 in. OD = 2.375 in.
T_2 = tubing No. 2 — 3-1/2 in. OD = 3.5 in.

$$\text{Annular capacity, ft/gal} = \frac{24.51}{6.184^2 — (2.375^2 + 3.5^2)}$$

$$\text{Annular capacity, ft/gal} = \frac{24.51}{38.24 — 17.89}$$

Annular capacity = 1.2044226 ft/gal

e) Annular capacity between casing and multiple strings of tubing, ft^3/linft:

$$\text{Annular capacity, ft}^3\text{/linft} = \frac{Dh^2 — [(T_1)^2 + (T_2)^2 + (T_3)^2]}{183.35}$$

Example: Using three strings of tubing:
Dh = casing — 9-5/8 in. — 47 lb/ft ID = 8.681 in.
T_1 = tubing No. 1 — 3-1/2 in. — OD = 3.5 in.
T_2 = tubing No. 2 — 3-1/2 in. — OD = 3.5 in.
T_3 = tubing No. 3 — 3-1/2 in. — OD = 3.5 in.

$$\text{Annular capacity} = \frac{8.6812 — (35^2 + 35^2 + 35^2)}{183.35}$$

$$\text{Annular capacity, ft}^3\text{/linft} = \frac{75.359 — 36.75}{183.35}$$

Annular capacity = 0.2105795 ft^3/linft

f) Annular capacity between casing and multiple strings of tubing, linft/ft^3:

$$\text{Annular capacity, linft/ft}^3 = \frac{183.35}{Dh_2 — [(T_1)^2 + (T_2)^2 + (T_3)^2]}$$

Example: Using three strings tubing of same size:
Dh = casing 9-5/8 in. 47 lb/ft ID = 8.681 in.
T_1 = tubing No. 1 3-1/2 in. OD = 3.5 in.
T_2 = tubing No. 2 3-1/2 in. OD = 3.5 in.
T_3 = tubing No. 3 3-1/2 in. OD = 3.5 in.

$$\text{Annular capacity} = \frac{183.35}{8.681^2 — (35^2 + 35^2 + 35^2)}$$

$$\text{Annular capacity, linft/ft}^3 = \frac{183.35}{75.359 — 36.75}$$

Annular capacity = 4.7487993 linft/ft^3

Capacity of tubulars and open hole: drill pipe, drill collars, tubing, casing, hole, and any cylindrical object

a) $\text{Capacity, bbl/ft} = \frac{\text{ID in.}^2}{1029.4}$ *Example:* Determine the capacity, bbl/ft, of a 12-1/4 in. hole:

$$\text{Capacity, bbl/ft} = \frac{12\ 25^2}{1029.4}$$

Capacity = 0. 1457766 bbl/ft

b) $\text{Capacity, ft/bbl} = \frac{1029.4}{Dh^2}$ *Example:* Determine the capacity, ft/bbl, of 12-1/4 in. hole:

$$\text{Capacity, ft/bbl} = \frac{1029.4}{12.25^2}$$

Capacity = 6.8598 ft/bbl

c) $\text{Capacity, gal/ft} = \frac{\text{ID in.}^2}{24.51}$ *Example:* Determine the capacity, gal/ft, of 8-1/2 in. hole:

$$\text{Capacity, gal/ft} = \frac{8.5^2}{24.51}$$

$$\text{Capacity} = 2.9477764 \text{ gal/ft}$$

d) Capacity, ft/gal ID in 2 *Example:* Determine the capacity, ft/gal, of 8-1/2 in. hole:

$$\text{Capacity, ft/gal} = \frac{2451}{8.5^2}$$

$$\text{Capacity} = 0.3392 \text{ ft/gal}$$

e) $\text{Capacity, ft}^3\text{/linft} = \frac{\text{ID}^2}{18135}$ *Example:* Determine the capacity, ft³/linft, for a 6.0 in. hole:

$$\text{Capacity, ft}^3\text{/Iinft} = \frac{6.0^2}{183.35}$$

$$\text{Capacity} = 0.1963 \text{ ft}^3\text{/linft}$$

f) $\text{Capacity, linftlft}^3 = \frac{183.35}{\text{ID, in.}^2}$ *Example:* Determine the capacity, linft/ft³, for a 6.0 in. hole:

$$\text{Capacity, unit/ft}^3 = \frac{183.35}{6.0^2}$$

$$\text{Capacity} = 5.09305 \text{ linft/ft}^3$$

Amount of cuttings drilled per foot of hole drilled

a) BARRELS of cuttings drilled per foot of hole drilled:

$$\text{Barrels} = \frac{\text{Dh}^2}{1029.4} \; (1 — \% \text{ porosity})$$

Example: Determine the number of barrels of cuttings drilled for one foot of 12-1/4 in. -hole drilled with 20% (0.20) porosity:

$$\text{Barrels} = \frac{12.25^2}{1029.4} \; (1 — 0.20)$$

Barrels = 0.1457766 x 0.80
Barrels = 0.1166213

b) CUBIC FEET of cuttings drilled per foot of hole drilled:

$$\text{Cubic feet} = \frac{\text{Dh}^2}{144} \times 0.7854 \; (1 — \% \text{ porosity})$$

Example: Determine the cubic feet of cuttings drilled for one foot of 12-1/4 in. hole with 20% (0.20) porosity:

$$\text{Cubic feet} = \frac{12.25^2}{144} \times 0.7854\,(1 - 0.20)$$

$$\text{Cubic feet} = \frac{150.0626}{144} \times 0.7854 \times 0.80$$

c) Total solids generated:

$$Wcg = 35O\ Ch \times L\,(l - P)\ SG$$

where Wcg = solids generated, pounds   Ch = capacity of hole, bbl/ft
L = footage drilled, ft   SG = specific gravity of cuttings
P = porosity, %

Example: Determine the total pounds of solids generated in drilling 100 ft of a 12-1/4 in. hole (0.1458 bbl/ft). Specific gravity of cuttings = 2.40 gm/cc. Porosity = 20%:

$$Wcg = 350 \times 0.1458 \times 100\,(1 - 0.20) \times 2.4$$

$$Wcg = 9797.26 \text{ pounds}$$

10. Control Drilling

Maximum drilling rate (MDR), ft/hr, when drifting large diameter holes (14-3/4 in. and larger)

$$\text{MDR, ft/hr} = \frac{67 \times (\text{mud wt out, ppg} - \text{mud wt in, ppg}) \times (\text{circulation rate, gpm})}{Dh^2}$$

Example: Determine the MDR, ft/hr, necessary to keep the mud weight coming out at 9.7 ppg at the flow line:

Data: Mud weight in = 9.0 ppg   Circulation rate = 530 gpm   Hole size = 17-1/2 in.

$$\text{MDR, ft/hr} = \frac{67\,(9.7 - 9.0)\,530}{17.5^2}$$

$$\text{MDR, ft/hr} = \frac{67 \times 0.7 \times 530}{306.25}$$

$$\text{MDR, ft/hr} = \frac{24{,}857}{306.25}$$

$$\text{MDR} = 81.16 \text{ ft/hr}$$

11. Buoyancy Factor (BF)

Buoyancy factor using mud weight, ppg

$$BF = \frac{65.5 - \text{mud weight, ppg}}{65.5}$$

Example: Determine the buoyancy factor for a 15.0 ppg fluid:

$$BF = \frac{65.5 - 15.0}{65.5}$$

BF = 0.77099

Buoyancy factor using mud weight, lb/ft^3

$$BF = \frac{489 - \text{mud weight, lb/ft}^3}{489}$$

Example: Determine the buoyancy factor for a 120 lb/ft^3 fluid:

$$BF = \frac{489 - 120}{489}$$

BF = 0.7546

12. Hydrostatic Pressure (HP) Decrease When POOH

When pulling DRY pipe

Step 1 Barrels = number of stands pulled X average length per stand, ft X pipe displacement displaced bbl/ft

Step 2

$$\text{HP psi decrease} = \frac{\text{barrels displaced}}{(\text{casing capacity, bbl/ft} - \text{pipe displacement, bbl/ft})} \times 0.052 \times \text{mud weight, ppg}$$

Example: Determine the hydrostatic pressure decrease when pulling DRY pipe out of the hole:

Number of stands pulled = 5
Average length per stand = 92 ft
Mud weight = 11.5 ppg

Pipe displacement = 0.0075 bbl/ft
Casing capacity = 0.0773 bbl/ft

Step 1

Barrels displaced = 5 stands x 92 ft/std x 0.0075 bbl/ft displaced
Barrels displaced = 3.45

Step 2

$$\text{HP, psi decrease} = \frac{3.45 \text{ barrels}}{(0.0773 \text{ bbl/ft} — 0.0075 \text{ bbl/ft})} \times 0.052 \times 11.5 \text{ ppg}$$

$$\text{HP, psi decrease} = \frac{3.45 \text{ barrels}}{0.0698} \times 0.052 \times 11.5 \text{ ppg}$$

HP decrease = 29.56 psi

When pulling WET pipe

Step 1

$$\text{Barrels displaced} = \underset{\text{stands pulled}}{\text{number of}} \times \underset{\text{per stand, ft}}{\text{average length}} \times (\text{pipe disp., bbl/ft} + \text{pipe cap., bbl/ft})$$

Step 2

$$\text{HP, psi} = \frac{\text{barrels displaced}}{\underset{\text{bbl/ft}}{(\text{casing capacity})} — (\underset{\text{bbl/ft}}{\text{Pipe disp.,}} + \underset{\text{bbl/ft}}{\text{pipe cap.,}})} \times 0.052 \times \text{mud weight, ppg}$$

Example: Determine the hydrostatic pressure decrease when pulling WET pipe out of the hole:

Number of stands pulled	= 5	Pipe displacement	= 0.0075 bbl/ft
Average length per stand	= 92 ft	Pipe capacity	= 0.01776 bbl/ft
Mud weight	= 11.5 ppg	Casing capacity	= 0.0773 bbl/ft

Step 1

Barrels displaced = 5 stands x 92 ft/std x (.0075 bbl/ft + 0.01776 bbl/ft)
Barrels displaced = 11 6196

Step 2

$$\text{HP, psi decrease} = \frac{11.6196 \text{ barrels}}{(0.0773 \text{ bbl/ft}) — (0.0075 \text{ bbl/ft} + 0.01776 \text{ bbl/ft})} \times 0.052 \times 11.5 \text{ ppg}$$

$$\text{HP, psi decrease} = \frac{11.6196}{0.05204} \times 0.052 \times 11.5 \text{ ppg}$$

HP decrease = 133.52 psi

13. Loss of Overbalance Due to Falling Mud Level

Feet of pipe pulled DRY to lose overbalance

$$\text{Feet} = \frac{\text{overbalance, psi (casing cap. — pipe disp., bbl/ft)}}{\text{mud wt., ppg} \times 0.052 \times \text{pipe disp., bbl/ft}}$$

Example: Determine the FEET of DRY pipe that must be pulled to lose the overbalance using the following data:

Amount of overbalance	= 150 psi	Casing capacity	= 0.0773 bbl/ft
Pipe displacement	= 0.0075 bbl/ft	Mud weight	= 11.5 ppg

$$\text{Ft} = \frac{150 \text{ psi } (0.0773 — 0.0075)}{11.5 \text{ ppg} \times 0.052 \times 0.0075}$$

$$\text{Ft} = \frac{10.47}{0.004485}$$

Ft = 2334

Feet of pipe pulled WET to lose overbalance

$$\text{Feet} = \frac{\text{overbalance, psi} \times \text{(casing cap. — pipe cap. — pipe disp.)}}{\text{mud wt., ppg} \times 0.052 \times \text{(pipe cap.} \div \text{pipe disp., bbl/ft)}}$$

Example: Determine the feet of WET pipe that must be pulled to lose the overbalance using the following data:

Amount of overbalance	= 150 psi	Casing capacity	= 0.0773 bbl/ft
Pipe capacity	= 0.01776 bbl/ft	Pipe displacement	= 0.0075 bbl/ft
Mud weight	= 11.5 ppg		

$$\text{Feet} = \frac{150 \text{ psi} \times (0.0773 — 0.01776 — 0.0075 \text{ bbl/ft})}{11.5 \text{ ppg} \times 0.052 \ (0.01776 + 0.0075 \text{ bbl/ft})}$$

$$\text{Feet} = \frac{150 \text{ psi} \times 0.05204}{11.5 \text{ ppg} \times 0.052 \times 0.02526}$$

$$\text{Feet} = \frac{7.806}{0.0151054}$$

Feet = 516.8

14. Formation Temperature (FT)

FT, °F = (ambient surface temperature, °F) + (temp. increase °F per ft of depth x TVD, ft)

Example: If the temperature increase in a specific area is 0.0 12 °F/ft of depth and the ambient surface temperature is 70 °F, determine the estimated formation temperature at a TVD of 15,000 ft:

FT, °F = 70 °F + (0.012 °F/ft x 15,000 ft)
FT, °F = 70 °F + 180 °F
FT = 250 °F (estimated formation temperature)

15. Hydraulic Horsepower (HHP)

$$\text{HHP} = \frac{\text{P x Q}}{714}$$

where HHP = hydraulic horsepower P = circulating pressure, psi
Q = circulating rate, gpm

Example: circulating pressure = 2950 psi circulating rate = 520 gpm

$$\text{HHP} = \frac{2950 \text{ x } 520}{1714}$$

$$\text{HHP} = \frac{1{,}534{,}000}{1714}$$

HHP = 894.98

16. Drill Pipe/Drill Collar Calculations

Capacities, bbl/ft, displacement, bbl/ft, and weight, lb/ft, can be calculated from the following formulas:

$$\text{Capacity, bbl/ft} = \frac{\text{ID, in.}^2}{1029.4}$$

$$\text{Displacement, bbl/ft} = \frac{\text{OD, in.}^2 - \text{ID, in.}^2}{1029.4}$$

Weight, lb/ft = displacement, bbl/ft x 2747 lb/bbl

Example: Determine the capacity, bbl/ft, displacement, bbl/ft, and weight, lb/ft, for the following:

Drill collar OD = 8.0 in. Drill collar ID = 2-13/16 in.

Convert 13/16 to decimal equivalent: $13 \div 16 = 0.8125$

a) Capacity, bbl/ft = $\dfrac{2.8125^2}{1029.4}$

Capacity = 0.007684 bbl/ft

b) Displacement, bbl/ft = $\dfrac{8.0^2 - 2.8125^2}{1029.4}$

Displacement, bbl/ft = $\dfrac{56.089844}{1029.4}$

Displacement = 0.0544879 bbl/ft

c) Weight, lb/ft = 0.0544879 bbl/ft x 2747 lb/bbl
Weight = 149.678 lb/ft

Rule of thumb formulas

Weight, lb/ft, for REGULAR DRILL COLLARS can be approximated by the following formula:

Weight, lb/ft = $(\text{OD, in.}^2 - \text{ID, in.}^2) \times 2.66$

Example: Regular drill collars Drill collar OD = 8.0 in.
Drill collar ID = 2-13/16 in.
Decimal equivalent = 2.8125 in.

Weight, lb/ft = $(8.0^2 - 2.8125^2) \times 2.66$
Weight, lb/ft = 56.089844 x 2.66
Weight = 149.19898 lb/ft

Weight, lb/ft, for SPIRAL DRILL COLLARS can be approximated by the following formula:

Weight, lb/ft = $(\text{OD, in.}^2 - \text{ID, in.}^2) \times 2.56$

Example: Spiral drill collars Drill collar OD = 8.0 in.
Drill collar ID = 2-13/16 in.
Decimal equivalent = 2.8 125 in.

Weight, lb/ft = $(8.0^2 - 2.8125^2) \times 2.56$
Weight, lb/ft = 56.089844 x 2.56
Weight = 143.59 lb/ft

17. Pump Pressure/Pump Stroke Relationship (Also Called the Roughneck's Formula)

Basic formula

New circulating pressure, psi = present circulating pressure, psi X (new pump rate, spm ÷ old pump rate, spm)^2

Example: Determine the new circulating pressure, psi using the following data:

Present circulating pressure = 1800 psi
Old pump rate = 60 spm
New pump rate = 30 spm

New circulating pressure, psi = 1800 psi x (30 spm ÷ 60 spm)^2
New circulating pressure, psi = 1800 psi x 0.25
New circulating pressure = 450 psi

Determination of exact factor in above equation

The above formula is an approximation because the factor "^{2}" is a rounded-off number. To determine the exact factor, obtain two pressure readings at different pump rates and use the following formula:

$$\text{Factor} = \frac{\log(\text{pressure 1} \div \text{pressure 2})}{\log(\text{pump rate 1} \div \text{pump rate 2})}$$

Example: Pressure 1 = 2500 psi @ 315 gpm Pressure 2 = 450 psi ~ 120 gpm

$$\text{Factor} = \frac{\log(2500\text{ psi} \div 450\text{ psi})}{\log(315\text{ gpm} \div 120\text{ gpm})}$$

$$\text{Factor} = \frac{\log(5.5555556)}{\log(2.625)}$$

Factor = 1.7768

Example: Same example as above but with correct factor:

New circulating pressure, psi = 1800 psi x (30 spm ÷ 60 spm)$^{1.7768}$
New circulating pressure, psi = 1800 psi x 0.2918299
New circulating pressure = 525 psi

18. Cost Per Foot

$$C_T = \frac{B + C_R\,(t + T)}{F}$$

Example: Determine the drilling cost (CT), dollars per foot using the following data:

Bit cost (B) = \$2500 Rotating time (I) = 65 hours
Rig cost (CR) = \$900/hour Round trip time (T) = 6 hours (for depth - 10,000 ft)
Footage per bit (F) = 1300 ft

$$C_T = \frac{2500 + 900\,(65 + 6)}{1300}$$

$$C_T = \frac{66{,}400}{1300}$$

C_T = \$51.08 per foot

19. Temperature Conversion Formulas

Convert temperature, °Fahrenheit (F) to °Centigrade or Celsius (C)

$°C = \frac{(°F - 32)\,5}{9}$ OR $°C = °F - 32 \times 0.5556$

Example: Convert 95 °F to °C:

$°C = \frac{(95 - 32)\,5}{9}$ OR $°C = 95 - 32 \times 0.5556$

°C =35 °C = 35

Convert temperature, °Centigrade or Celsius (C) to °Fahrenheit

$°F = (°C \times 9) \div 5 + 32$ OR $°F = 24 \times 1.8 + 32$

Example: Convert 24 °C to °F:

$°F = (24 \times 9) \div 5 + 32$ OR $°F = 24 \times 1.8 + 32$
°F = 75.2 °F = 75.2

Convert temperature, °Centigrade, Celsius (C) to °Kelvin (K)

$°K = °C + 273.16$

Example: Convert 35 °C to °K:

$°K = 35 + 273.16$
$°K = 308.16$

Convert temperature, °Fahrenheit (F) to °Rankine (R)

°R = °F + 459.69

Example: Convert 260 °F to °R:

°R = 260 + 459.69
°R = 719.69

Rule of thumb formulas for temperature conversion

a) Convert °F to °C: °C = °F — 30 ÷ 2

Example: Convert 95 °F to °C

°C = 95 — 30 ÷ 2
°C = 32.5

b) Convert °C to °F: °F = °C + °C + 30

Example: Convert 24 °C to °F

°F = 24 +24 +30
°F = 78

CHAPTER TWO

BASIC CALCULATIONS

1. Volumes and Strokes

Drill string volume, barrels

$$\text{Barrels} = \frac{\text{ID, in.}^2}{1029.4,} \times \text{pipe length}$$

Annular volume, barrels

$$\text{Barrels} = \frac{\text{Dh, in.}^2 - \text{Dp, in.}^2}{1029.4}$$

Strokes to displace: drill string, Kelly to shale shaker and Strokes annulus, and total circulation from Kelly to shale shaker.

Strokes = barrels ÷ pump output, bbl/stk

Example: Determine volumes and strokes for the following:

Drill pipe — 5.0 in. — 19.5 lb/f	Inside diameter = 4.276 in.	Length = 9400 ft
Drill collars — 8.0 in. OD	Inside diameter = 3.0 in.	Length = 600 ft
Casing — 13-3/8 in. — 54.5 lb/f	Inside diameter = 12.615 in.	Setting depth = 4500 ft
Pump data — 7 in. by 12 in. triplex	Efficiency = 95%	Pump output = 0.136 @ 95%
Hole size = 12-1/4 in.		

Drill string volume

a) Drill pipe volume, bbl:

$$\text{Barrels} = \frac{4.2762}{1029.4} \times 9400 \text{ ft}$$

Barrels = 0.01776 x 9400 ft
Barrels = 166.94

b) Drill collar volume, bbl:

$$\text{Barrels} = \frac{3.0^2}{1029.4} \times 600 \text{ ft}$$

Barrels = 0.0087 x 600 ft
Barrels = 5.24

c) Total drill string volume: Total drill string vol., bbl = 166.94 bbl + 5.24 bbl
Total drill string vol. = 172.18 bbl

Annular volume

a) Drill collar / open hole:

$$\text{Barrels} = \frac{12.25^2 - 8.0^2}{1029.4} \times 600 \text{ ft}$$

Barrels = 0.0836 x 600 ft
Barrels = 50.16

b) Drill pipe / open hole: $\text{Barrels} = \dfrac{12.25^2 - 5.0^2}{1029.4} \times 4900 \text{ ft}$

Barrels = 0.12149 x 4900 ft
Barrels = 595.3

c) Drill pipe / cased hole: $\text{Barrels} = \dfrac{12.615^2 - 5.0^2}{1029.4} \times 4500 \text{ ft}$

Barrels = 0.130307 x 4500 ft
Barrels = 586.38

d) Total annular volume: Total annular vol. = 50.16 + *595.3* + 586.38
Total annular vol. = 1231.84 barrels

Strokes

a) Surface to bit strokes: Strokes = drill string volume, bbl ÷ pump output, bbl/stk

Surface to bit strokes = 172.16 bbl ÷ 0.136 bbl/stk
Surface to bit strokes = 1266

b) Bit to surface (or bottoms-up strokes):

Strokes = annular volume, bbl ÷ pump output, bbl/stk

Bit to surface strokes = 1231.84 bbl ÷ 0.136 bbl/stk
Bit to surface strokes = 9058

c) Total strokes required to pump from the Kelly to the shale shaker:

Strokes = drill string vol., bbl + annular vol., bbl ÷ pump output, bbl/stk

Total strokes = (172.16 + 1231.84) ÷ 0.136
Total strokes = 1404 ÷ 0.136
Total strokes = 10,324

2. Slug Calculations

Barrels of slug required for a desired length of dry pipe

Step 1 Hydrostatic pressure required to give desired drop inside drill pipe:

HP, psi = mud wt, ppg x 0.052 x ft of dry pipe

Step 2 Difference in pressure gradient between slug weight and mud weight:

psi/ft = (slug wt, ppg — mud wt, ppg) x 0.052

Step 3 Length of slug in drill pipe:

Slug length, ft = pressure, psi ÷ difference in pressure gradient, psi/ft

Step 4 Volume of slug, barrels:

Slug vol., bbl = slug length, ft x drill pipe capacity, bbl/ft

Example: Determine the barrels of slug required for the following:

Desired length of dry pipe (2 stands) = 184 ft Mud weight = 12.2 ppg
Drill pipe capacity 4-1/2 in. — 16.6 lb/ft = 0.01422 bbl/ft Slug weight = 13.2 ppg

Step 1 Hydrostatic pressure required:

HP, psi = 12.2 ppg x 0.052 x 184 ft
HP = 117 psi

Step 2 Difference in pressure gradient, psi/ft:

psi/ft = (13.2 ppg — 12.2 ppg) x 0.052
psi/ft = 0.052

Step 3 Length of slug in drill pipe, ft:

Slug length, ft = 117 psi ÷ 0.052
Slug length = 2250 ft

Step 4 Volume of slug, bbl:

Slug vol., bbl = 2250 ft x 0.01422 bbl/ft
Slug vol. = 32.0 bbl

Weight of slug required for a desired length of dry pipe with a set volume of slug

Step 1 Length of slug in drill pipe, ft:

Slug length, ft = slug vol., bbl ÷ drill pipe capacity, bbl/ft

Step 2 Hydrostatic pressure required to give desired drop inside drill pipe:

HP, psi = mud wt, ppg x 0.052 x ft of dry pipe

Step 3 Weight of slug, ppg:

Slug wt, ppg = HP, psi ÷ 0.052 ÷ slug length, ft + mud wt, ppg

Example: Determine the weight of slug required for the following:

Desired length of dry pipe (2 stands) = 184 ft Mud weight = 12.2 ppg
Drill pipe capacity 4-1/2 in. — 16.6 lb/ft = 0.0 1422 bbl/ft Volume of slug = 25 bbl

Step 1 Length of slug in drill pipe, ft: Slug length, ft = 25 bbl ± 0.01422 bbl/ft
Slug length = 1758 ft

Step 2 Hydrostatic pressure required: HP, Psi = 12.2 ppg x 0.052 x 184 ft
HP, Psi = ll7psi

Step 3 Weight of slug, ppg: Slug wt, ppg = 117 psi ÷ 0.052 ÷ 1758 ft + 12.2 ppg
Slug wt, ppg = 1.3 ppg + 12.2 ppg
Slug wt = 13.5 ppg

Volume, height, and pressure gained because of slug:

a) Volume gained in mud pits after slug is pumped, due to U-tubing:

Vol., bbl = ft of dry pipe x drill pipe capacity, bbl/ft

b) Height, ft, that the slug would occupy in annulus:

Height, ft = annulus vol., ft/bbl x slug vol., bbl

c) Hydrostatic pressure gained in annulus because of slug:

HP, psi = height of slug in annulus, ft X difference in gradient, psi/ft between slug wt and mud wt

Example: Feet of dry pipe (2 stands) = 184 ft Slug volume = 32.4 bbl
Slug weight = 13.2 ppg Mud weight = 12.2 ppg
Drill pipe capacity 4-1/2 in. 16.6 lb/ft = 0.01422 bbl/ft
Annulus volume (8-1/2 in. by 4-1/2 in.) = 19.8 ft/bbl

a) Volume gained in mud pits after slug is pumped due to U-tubing:

Vol., bbl = 184 ft x 0.01422 bbl/ft
Vol. = 2.62 bbl

b) Height, ft, that the slug would occupy in the annulus:

Height, ft = 19.8 ft/bbl x 32.4 bbl
Height = 641.5 ft

c) Hydrostatic pressure gained in annulus because of slug:

HP, psi = 641.5 ft (13.2 — 12.2) x 0.052
HP, psi = 641.5 ft x 0.052
HP = 33.4 psi

3. Accumulator Capacity — Usable Volume Per Bottle

Usable Volume Per Bottle

NOTE: The following will be used as guidelines: Volume per bottle = 10 gal
Pre-charge pressure = 1000 psi Maximum pressure = 3000 psi
Minimum pressure remaining after activation = 1200 psi
Pressure gradient of hydraulic fluid = 0.445 psi/ft

Boyle's Law for ideal gases will be adjusted and used as follows:

$P_1 V_1 = P_2 V_2$

Surface Application

Step 1 Determine hydraulic fluid necessary to increase pressure from pre-charge to minimum:

$P_1 V_1 = P_2 V_2$

1000 psi x 10 gal = 1200 psi x V_2

$\frac{10{,}000}{1200} = V2$

$V_2 = 8.33$ **T**he nitrogen has been compressed from 10.0 gal to 8.33 gal.

10.0 — 8.33 = 1.67 gal of hydraulic fluid per bottle.

NOTE: This is dead hydraulic fluid. The pressure must not drop below this minimum value.

Step 2 Determine hydraulic fluid necessary to increase pressure from pre-charge to maximum:

$P_1 V_1 = P_2 V_2$

1000 psi x 10 gals = 3000 psi x V_2

$\frac{10{,}000}{3000} = V_2$

$V_2 = 3.33$ The nitrogen has been compressed from 10 gal to 3.33 gal.

10.0 — 3.33 = 6.67 gal of hydraulic fluid per bottle.

Step 3 Determine usable volume per bottle:

Useable vol./bottle = Total hydraulic fluid/bottle — Dead hydraulic fluid/bottle

Useable vol./bottle = 6.67 — 1.67
Useable vol./bottle = 5.0 gallons

Subsea Applications

In subsea applications the hydrostatic pressure exerted by the hydraulic fluid must be compensated for in the calculations:

Example: Same guidelines as in surface applications:

Water depth = 1000 ft   Hydrostatic pressure of hydraulic fluid = 445 psi

Step 1 Adjust all pressures for the hydrostatic pressure of the hydraulic fluid:

Pre-charge pressure = 1000 psi + 445 psi = 1445 psi
Minimum pressure = 1200 psi + 445 psi = 1645 psi
Maximum pressure = 3000 psi + 445 psi = 3445 psi

Step 2 Determine hydraulic fluid necessary to increase pressure from pre-charge to minimum:

$P_1 V_1 = P_2 V_2 \quad = \quad 1445 \text{ psi} \times 10 = 1645 \times V_2$

$\frac{14{,}450}{1645} = V_2$

$V_2 = 8.78$ gal

10.0 — 8.78 = 1.22 gal of dead hydraulic fluid

Step 3 Determine hydraulic fluid necessary to increase pressure from pre-charge to maximum:

$1445 \text{ psi} \times 10 = 3445 \text{ psi} \times V_2$

$\frac{14450}{3445} = V_2$

$V_2 = 4.19$ gal

10.0 — 4.19 = 5.81 gal of hydraulic fluid per bottle.

Step 4 Determine useable fluid volume per bottle:

Useable vol./bottle = Total hydraulic fluid/bottle — Dead hydraulic fluid/bottle

Useable vol./bottle = 5.81 — 1.22
Useable vol./bottle = 4.59 gallons

Accumulator Pre-charge Pressure

The following is a method of measuring the average accumulator pre-charge pressure by operating the unit with the charge pumps switched off:

P,psi = vol. removed, bbl ÷ total acc. vol., bbl x ((Pf x Ps) ÷ (Ps — Pf))

where P = average pre-charge pressure, psi   Pf = final accumulator pressure, psi
Ps = starting accumulator pressure, psi

Example: Determine the average accumulator pre-charge pressure using the following data:

Starting accumulator pressure (Ps) = 3000 psi   Final accumulator pressure (Pf) = 2200 psi
Volume of fluid removed = 20 gal   Total accumulator volume = 180 gal

P, psi = 20 ÷ 180 x ((2200 x 3000) ÷ (3000 — 2200))
P, psi = 0.1111 x (6,600,000 ÷ 800)
P, psi = 0.1111 x 8250
P = 9l7psi

4. Bulk Density of Cuttings (Using Mud Balance)

Procedure:

1. Cuttings must be washed free of mud. In an oil mud, diesel oil can be used instead of water.
2. Set mud balance at 8.33 ppg.
3. Fill the mud balance with cuttings until a balance is obtained with the lid in place.
4. Remove lid, fill cup with water (cuttings included), replace lid, and dry outside of mud balance.
5. Move counterweight to obtain new balance.

The specific gravity of the cuttings is calculated as follows:

$$SG = \frac{1}{2\ (O.l2 \times Rw)}$$

where SG = specific gravity of' cuttings — bulk density
Rw = resulting weight with cuttings plus water, ppg

Example: Rw = 13.8 ppg. Determine the bulk density of cuttings:

$$SG = \frac{1}{2 - (0.12 \times 13.8)}$$

$$SG = \frac{1}{0.344}$$

SG = 2.91

5. Drill String Design (Limitations)

The following will be determined:

Length of bottom hole assembly (BHA) necessary for a desired weight on bit (WOB).

Feet of drill pipe that can be used with a specific bottom hole assembly (BHA).

1. Length of bottom hole assembly necessary for a desired weight on bit:

$$\text{Length, ft} = \frac{\text{WOB x f}}{\text{Wdc x BF}}$$

where WOB = desired weight to be used while drilling
f = safety factor to place neutral point in drill collars
Wdc = drill collar weight, lb/ft
BF = buoyancy factor

Example: Desired WOB while drilling = 50,000 lb — Safety factor = 15%
Drill collar weight 8 in. OD—3 in. ID = 147 lb/ft — Mud weight = 12.0 ppg

Solution: a) Buoyancy factor (BF):

$$\text{BF} = \frac{65.5 - 12.0 \text{ ppg}}{65.5}$$

BF = 0.8168

b) Length of bottom hole assembly (BHA) necessary:

$$\text{Length, ft} = \frac{50000 \times 1.15}{147 \times 0.8168}$$

$$\text{Length, ft} = \frac{57{,}500}{120.0696}$$

Length = 479 ft

2. Feet of drill pipe that can be used with a specific BHA

NOTE: Obtain tensile strength for new pipe from cementing handbook or other source.

a) Determine buoyancy factor:

$$\text{BF} = \frac{65.5 - \text{mud weight, ppg}}{65.5}$$

b) Determine maximum length of drill pipe that can be run into the hole with a specific BHA.:

$$\text{Length}_{max} = \frac{[(\text{T x f}) - \text{MOP} - \text{Wbha}] \times \text{BF}}{\text{Wdp}}$$

where T = tensile strength, lb for new pipe
f = safety factor to correct new pipe to no. 2 pipe
MOP = margin of overpull
Wbha = BHA weight in air, lb/ft
Wdp = drill pipe weight in air, lb/ft. including tool joint
BF = buoyancy factor

c) Determine total depth that can be reached with a specific bottom-hole assembly:

Total depth, ft = length_{max} + BHA length

Example: Drill pipe (5.0 in.) = 21.87 lb/ft - Grade G Tensile strength = 554,000 lb
BHA weight in air = 50,000 lb BHA length = 500 ft
Desired overpull = 100,000 lb Mud weight = 13.5 ppg
Safety factor = 10%

a) Buoyancy factor:

$$BF = \frac{65.5 - 13.5}{65.5}$$

BF = 0.7939

b) Maximum length of drill pipe that can be run into the hole:

$$\text{Length}_{max} = \frac{[(554{,}000 \times 0.90) - 100{,}000 - 50{,}000] \times 0.7939}{21.87}$$

$$\text{Length}_{max} = \frac{276.754}{21\ 87}$$

Length_{max} = 12,655 ft

c) Total depth that can be reached with this BHA and this drill pipe:

Total depth, ft = 12,655 ft + 500 ft
Total depth = 13,155 ft

6. Ton-Mile (TM) Calculations

All types of ton-mile service should be calculated and recorded in order to obtain a true picture of the total service received from the rotary drilling line. These include:

1. Round trip ton-miles
2. Drilling or “connection” ton-miles
3. Coring ton-miles
4. Ton-miles setting casing
5. Short-trip ton-miles

Round trip ton-miles (RT_{TM})

$$RT_{TM} = \frac{Wp \times D \times (Lp + D) \div (2 \times D)(2 \times Wb + Wc)}{5280 \times 2000}$$

where RT_{TM} = round trip ton-miles
Wp = buoyed weight of drill pipe, lb/ft
D = depth of hole, ft
Lp = length of one stand of drill pipe, (aye), ft
Wb = weight of travelling block assembly, lb
Wc = buoyed weight of drill collars in mud minus the buoyed weight of the same length of drill pipe, lb
2000 = number of pounds in one ton
5280 = number of feet in one mile

Example: Round trip ton-miles

Mud weight	= 9.6 ppg	Average length of one stand	= 60 ft (double)
Drill pipe weight	= 13.3 lb/ft	Measured depth	= 4000 ft
Drill collar length	= 300 ft	Travelling block assembly	= 15,000 lb
Drill collar weight	= 83 lb/ft		

Solution: a) Buoyancy factor:

BF = 65.5 - 9.6 ppg. ÷ 65.5
BF = 0.8534

b) Buoyed weight of drill pipe in mud, lb/ft (Wp):

Wp = 13.3 lb/ft x 0.8534
Wp = 11.35 lb/ft

c) Buoyed weight of drill collars in mud minus the buoyed weight of the same length of drill pipe, lb (Wc):

Wc = (300 x 83 x 0.8534) — (300 x 13.3 x 0.8534)
Wc = 21,250 — 3,405
Wc = 17,845 lb

$$\text{Round trip ton-miles} = \frac{11.35 \times 4000 \times (60 + 4000) + (2 \times 4000) \times (2 \times 15000 + 17845)}{5280 \times 2000}$$

$$RT_{TM} = \frac{11.35 \times 4000 \times 4060 + 8000 \times (30{,}000 + 17{,}845)}{5280 \times 2000}$$

$$RT_{TM} = \frac{11.35 \times 4000 \times 4060 + 8000 \times 47{,}845}{10{,}560{,}000}$$

$$RT_{TM} = \frac{1.8432\ \ 08 + 3.8276\ \ 08}{10{,}560{,}000}$$

RT_{TM} = 53.7

Drilling or "connection" ton-miles

The ton-miles of work performed in drilling operations is expressed in terms of work performed in making round trips. These are the actual ton-miles of work in drilling down the length of a section of drill pipe (usually approximately 30 ft) plus picking up, connecting, and starting to drill with the next section.

To determine connection or drilling ton-miles, take 3 times (ton-miles for current round trip minus ton-miles for previous round trip):

$$Td = 3(T_2 — T_1)$$

where Td = drilling or "connection" ton-miles
T_2 = ton-miles for one round trip — depth where drilling stopped before coming out of hole.
T_1 = ton-miles for one round trip — depth where drilling started.

Example: Ton-miles for trip @ 4600 ft = 64.6 Ton-miles for trip @ 4000 ft = 53.7

Td = 3 x (64.6 — 53.7)
Td = 3 x 10.9
Td = 32.7 ton-miles

Ton-miles during coring operations

The ton-miles of work performed in coring operations, as for drilling operations, is expressed in terms of work performed in making round trips.

To determine ton-miles while coring, take 2 times ton-miles for one round trip at the depth where coring stopped minus ton-miles for one round trip at the depth where coring began:

$$Tc = 2\,(T_4 — T_3)$$

where Tc = ton-miles while coring
T_4 = ton-miles for one round trip — depth where coring stopped before coming out of hole
T_3 = ton-miles for one round trip — depth where coring started after going in hole

Ton-miles setting casing

The calculations of the ton-miles for the operation of setting casing should be determined as for drill pipe, but with the buoyed weight of the casing being used, and with the result being multiplied by one-half, because setting casing is a one-way (1/2 round trip) operation. Ton-miles for setting casing can be determined from the following formula:

$$Tc = \frac{Wp \times D \times (Lcs + D) + D \times Wb}{5280 \times 2000} \times 0.5$$

where Tc = ton-miles setting casing
Lcs = length of one joint of casing, ft
Wp = buoyed weight of casing, lb/ft
Wb = weight of travelling block assembly, lb

Ton-miles while making short trip

The ton-miles of work performed in short trip operations, as for drilling and coring operations, is also expressed in terms of round trips. Analysis shows that the ton-miles of work done in making a short trip is equal to the difference in round trip ton-miles for the two depths in question.

$Tst = T_6 - T_5$

where Tst = ton-miles for short trip
T_6 = ton-miles for one round trip at the deeper depth, the depth of the bit before starting the short trip.
T_5 = ton-miles for one round trip at the shallower depth, the depth that the bit is pulled up to.

7. Cementing Calculations

Cement additive calculations

a) Weight of additive per sack of cement:

Weight, lb = percent of additive x 94 lb/sk

b) Total water requirement, gal/sk, of cement:

Water, gal/sk = Cement water requirement, gal/sk + Additive water requirement, gal/sk

c) Volume of slurry, gal/sk:

$$\text{Vol gal/sk} = \frac{94 \text{ lb}}{\text{SG of cement x } 8.33 \text{ lb/gal}} + \frac{\text{weight of additive, lb}}{\text{SG of additive x } 8.33 \text{ lb/gal}} + \text{water volume, gal}$$

d) Slurry yield, ft^3/sk:

$$\text{Yield, ft}^3\text{/sk} = \frac{\text{vol. of slurry, gal/sk}}{7.48 \text{ gal/ft}^3}$$

e) Slurry density, lb/gal:

$$\text{Density, lb/gal} = \frac{94 + \text{wt of additive} + (8.33 \text{ x vol. of water/sk})}{\text{vol. of slurry, gal/sk}}$$

Example: Class A cement plus 4% bentonite using normal mixing water:

Determine the following: Amount of bentonite to add, Total water requirements, Slurry yield, Slurry weight

1) Weight of additive:

Weight, lb/sk = 0.04 x 94 lb/sk
Weight = 3.76 lb/sk

2) Total water requirement:

Water = 5.1 (cement) + 2.6 (bentonite)
Water = 7.7 gal/sk of cement

3) Volume of slurry:

$$\text{Vol, gal/sk} = \frac{94}{3.14 \times 8.33} + \frac{3.76}{2.65 \times 8.33} + 7.7$$

Vol. gallsk = 3.5938 + 0.1703 + 7.7
Vol. = 11.46 gal/sk

4) Slurry yield, ft^3/sk:

Yield, ft^3/sk = 11.46 gal/sk ÷ 7.48 gal/ft^3
Yield = 1.53 ft^3/sk

5) Slurry density, lb/gal:

$$\text{Density, lb/gal} = \frac{94 + 3.76 + (8.33 \times 7.7)}{11.46}$$

$$\text{Density, lb/gal} = \frac{61.90}{11.46}$$

Density = 14.13 lb/gal

Water requirements

a) Weight of materials, lb/sk:

Weight, lb/sk = 94 + (8.33 x vol of water, gal) + (% of additive x 94)

b) Volume of slurry, gal/sk:

$$\text{Vol, gal/sk} = \frac{94 \text{ lb/sk}}{\text{SG} \times 8.33} + \frac{\text{wt of additive, lb/sk}}{\text{SG} \times 8.33} + \text{water vol, gal}$$

c) Water requirement using material balance equation:

$D_1 V_1 = D_2 V_2$

Example: Class H cement plus 6% bentonite to be mixed at 14.0 lb/gal. Specific gravity of bentonite = 2.65.

Determine the following: Bentonite requirement, lb/sk; Water requirement, gallsk; Slurry yield, ft^3/sk; Check slurry weight, lb/gal

1) Weight of materials, lb/sk:

Weight, lb/sk = 94 + (0.06 x 94) + (8.33 x “y”)
Weight, lb/sk = 94 + 5.64 + 8.33 “y”
Weight = 99.64 + 8.33”y”

2) Volume of slurry, gal/sk:

$$\text{Vol, gal/sk} = \frac{94}{3.14 \times 8.33} + \frac{5.64}{3.14 \times 8.33} + \text{“y”}$$

Vol, gal/sk = 3.6 + 0.26 + “y”
Vol, gal/sk = 3.86

3) Water requirements using material balance equation

99.64 + 8.33”y” = (3.86 + ”y”) x 14.0
99.64 + 8.33”y” = 54.04 + 14.0 “y”
99.64 - 54.04 = 14.0”y” - 8.33”y”
45.6 = 5.67”y”
45.6 ÷ 5.67 = “y”
8.0 = ”y” Thus , water required = 8.0 gal/sk of cement

4) Slurry yield, ft^3/sk:

$$\text{Yield, ft3/sk} = \frac{3.6 + 0.26 + 8.0}{7.48}$$

$$\text{Yield, ft}^3\text{/sk} = \frac{11.86}{7.48}$$

Yield = 1.59 ft^3/sk

5) Check slurry density, lb/gal:

$$\text{Density, lb/gal} = \frac{94 + 5.64 + (8.33 \times 8.0)}{11.86}$$

$$\text{Density, lb/gal} = \frac{166.28}{11.86}$$

Density = 14.0 lb/gal

Field cement additive calculations

When bentonite is to be pre-hydrated, the amount of bentonite added is calculated based on the total amount of mixing water used.

Cement program: 240 sk cement; slurry density = 13.8 ppg; 8.6 gal/sk mixing water; 1.5% bentonite to be pre-hydrated:

a) Volume of mixing water, gal:

Volume = 240 sk x 8.6 gal/sk
Volume = 2064 gal

b) Total weight, lb, of mixing water:

Weight = 2064 gal x 8.33 lb/gal
Weight = 17,193 lb

c) Bentonite requirement, Lb:

Bentonite = 17,193 lb x 0.015%
Bentonite = 257.89 lb

Other additives are calculated based on the weight of the cement:

Cement program: 240 sk cement; 0.5% Halad; 0.40% CFR-2:

a) Weight of cement:

Weight = 240 sk x 94 lb/sk
Weight = 22,560 lb

b) Halad = 0.5%

Halad = 22,560 lb x 0.005
Halad = 112.8 lb

c) CFR-2 = 0.40%

CFR-2 = 22,560 lb x 0.004
CFR-2 = 90.24 lb

Table 2-1
Water Requirements and Specific Gravity of Common Cement Additives

	Water Requirement ga1/94 lb/sk	Specific Gravity
API Class Cement		
Class A & B	5.2	3.14
Class C	6.3	3.14
Class D & E	4.3	3.14
Class G	5.0	3.14
Class H	4.3 — 5.2	3.14
Chem Comp Cement	6.3	3.14
Attapulgite	1.3/2% in cement	2.89
Cement Fondu	4.5	3.23

Table 2-1 (continued)
Water Requirements and Specific Gravity of Common Cement Additives

	Water Requirement ga1/94 lb/sk	Specific Gravity
Lumnite Cement	4.5	3.20
Trinity Lite-weight Cement	9.7	2.80
Bentonite	1.3/2% in cement	2.65
Calcium Carbonate Powder	0	1.96
Calcium Chloride	0	1.96
Cal-Seal (Gypsum Cement)	4.5	2.70
CFR-l	0	1.63
CFR-2	0	1.30
D-Air-1	0	1.35
D-Air-2	0	1.005
Diacel A	0	2.62
Diacel D	3.3-7.4/10% in cement	2.10
Diacel LWL	0 (up to 0.7%) 0.8:1/1% in cement	1.36
Gilsonite	2/50-lb/ft^3	1.07
Halad-9	0(up to *5%)* 0.4-0.5 over *5%*	1.22
Halad 14	0	1.31
HR-4	0	1.56
HR-5	0	1.41
HR-7	0	1.30
HR-12	0	1.22
HR-15	0	1.57
Hydrated Lime	14.4	2.20
Hydromite	2.82	2.15
Iron Carbonate	0	3.70
LA-2 Latex	0.8	1.10
NF-D	0	1.30
Perlite regular	4/8 lb/ft^3	2.20
Perlite 6	6/38 lb/ft^3	—
Pozmix A	4.6 — *5*	2.46
Salt (NaCI)	0	2.17
Sand Ottawa	0	2.63
Silica flour	1.6/35% in cement	2.63
Coarse silica	0	2.63
Spacer sperse	0	1.32
Spacer mix (liquid)	0	0.932
Tuf Additive No. 1	0	1.23
Tuf Additive No. 2	0	0.88
Tuf Plug	0	1.28

8. Weighted Cement Calculations

Amount of high density additive required per sack of cement to achieve a required cement slurry density

$$x = \frac{(Wt \times 11.207983 \div SGc) + (wt \times CW) - 94 - (8.33 \times CW)}{(1 + (AW \div 100)) - (wt \div (SGa \times 8.33)) - (wt + (AW \div 100))}$$

where x = additive required, pounds per sack of cement
Wt = required slurry density, lb/gal
SGc = specific gravity of cement
CW = water requirement of cement
AW = water requirement of additive
SGa = specific gravity of additive

Additive	Water Requirement ga1/94 lb/sk	Specific Gravity
Hematite	0.34	5.02
Ilmenite	0	4.67
Barite	2.5	4.23
Sand	0	2.63
API Cements		
Class A & B	5.2	3.14
Class C	6.3	3.14
Class D,E,F,H	4.3	3.14
Class G	5.2	3.14

Example: Determine how much hematite, lb/sk of cement, would be required to increase the density of Class H cement to 17.5 lb/gal:
Water requirement of cement = 4.3 gal/sk
Water requirement of additive (hematite) = 0.34 gal/sk
Specific gravity of cement = 3.14
Specific gravity of additive (hematite) = 5.02

Solution:

$$x = \frac{(17.5 \times 11.207983 \div 3.14) + (17.5 \times 4.3) - 94 - (8.33 \times 4.3)}{(1 + (0.34 \div 100)) - (17.5 \div (5.02 \times 8.33)) \times (17.5 \times (0.34 \div 100))}$$

$$x = \frac{62.4649 + 75.25 - 94 - 35.819}{1.0034 - 0.418494 - 0.0595}$$

$$x = \frac{7.8959}{0.525406}$$

x = 15.1 lb of hematite per sk of cement used

9. Calculations for the Number of Sacks of Cement Required

If the number of feet to be cemented is known, use the following:

Step 1 : Determine the following capacities:

a) Annular capacity, ft^3/ft:

$$\text{Annular capacity, } ft^3/ft = \frac{Dh, in.^2 - Dp, in.^2}{183.35}$$

b) Casing capacity, ft^3/ft:

$$\text{Casing capacity, } ft^3/ft = \frac{ID, in.^2}{183.35}$$

c) Casing capacity, bbl/ft:

$$\text{Casing capacity, bbl/ft} = \frac{ID, in.^2}{1029.4}$$

Step 2 : Determine the number of sacks of LEAD or FILLER cement required:

Sacks required = feet to be cemented x Annular capacity, ft^3/ft x excess ÷ yield, ft^3/sk LEAD cement

Step 3 : Determine the number of sacks of TAIL or NEAT cement required

Sacks required annulus = feet to be cemented x annular capacity, ft^3/ft x excess ÷ yield, ft^3/sk TAIL cement

Sacks required casing = no. of feet between float collar & shoe x annular capacity, ft^3/ft x excess ÷ yield, ft^3/sk TAIL cement

Total Sacks of TAIL cement required:

Sacks = sacks required in annulus + sacks required in casing

Step 4 Determine the casing capacity down to the float collar:

Casing capacity, bbl = casing capacity, bbl/ft x feet of casing to the float collar

Step 5 Determine the number of strokes required to bump the plug:

Strokes = casing capacity, bbl ÷ pump output, bbl/stk

Example: From the data listed below determine the following:

1. How many sacks of LEAD cement will be required?
2. How many sacks of TAIL cement will be required?
3. How many barrels of mud will be required to bump the plug?
4. How many strokes will be required to bump the top plug?

Data: Casing setting depth = 3000 ft Hole size = 17-1/2 in.
Casing 54.5 lb/ft = 13-3/8 in. Casing ID = 12.615 in.
Float collar (feet above shoe) = 44 ft
Pump (5-1/2 in. by 14 in. duplex @ 90% eff) 0.112 bbl/stk

Cement program: LEAD cement (13.8 lb/gal) = 2000 ft slurry yield = 1.59 ft^3/sk
TAIL cement (15.8 lb/gal) = 1000 ft slurry yield = 1.15 ft^3/sk
Excess volume = 50%

Step 1 Determine the following capacities:

a) Annular capacity, ft^3/ft:

$$\text{Annular capacity, } ft^3/ft = \frac{17.5^2 - 13.375^2}{183.35}$$

$$\text{Annular capacity, } ft^3/ft = \frac{127.35938}{183.35}$$

$$\text{Annular capacity} = 0.6946\ ft^3/ft$$

b) Casing capacity, ft^3/ft:

$$\text{Casing capacity, } ft^3/ft = \frac{12.615^2}{183.35}$$

$$\text{Casing capacity, } ft^3/ft = \frac{159.13823}{183.35}$$

$$\text{Casing capacity} = 0.8679\ ft^3/ft$$

c) Casing capacity, bbl/ft:

$$\text{Casing capacity, bbl/ft} = \frac{12.615^2}{1029.4}$$

$$\text{Casing capacity, bbl/ft} = \frac{159.13823}{1029.4}$$

$$\text{Casing capacity} = 0.1545\ \text{bbl/ft}$$

Step 2 Determine the number of sacks of LEAD or FILLER cement required:

Sacks required = 2000 ft x 0.6946 ft^3/ft x 1.50 ÷ 1.59 ft^3/sk
Sacks required = 1311

Step 3 Determine the number of sacks of TAIL or NEAT cement required:

Sacks required annulus = 1000 ft x 0.6946 ft^3/ft x 1.50 ÷ 1.15 ft^3/sk
Sacks required annulus = 906
Sacks required casing = 44 ft x 0.8679 ft^3/ft ÷ 1.15 ft^3/sk
Sacks required casing = 33

Total sacks of TAIL cement required:

Sacks = 906 + 33
Sacks = 939

Step 4 Determine the barrels of mud required to bump the top plug:

Casing capacity, bbl = (3000 ft — 44 ft) x 0.1545 bbl/ft
Casing capacity = 456.7 bbl

Step 5 Determine the number of strokes required to bump the top plug:

Strokes = 456.7 bbl ÷ 0.112 bbl/stk
Strokes = 4078

10. Calculations for the Number of Feet to Be Cemented

If the number of sacks of cement is known, use the following:

Step 1 Determine the following capacities:

a) Annular capacity, ft^3/ft:

$$\text{Annular capacity, ft}^3\text{/ft} = \frac{\text{Dh, in.}^2 - \text{Dp, in.}^2}{183, 35}$$

b) Casing capacity, ft^3/ft:

$$\text{Casing capacity, ft}^3\text{/ft} = \frac{\text{ID, in.}^2}{183 .3.5}$$

Step 2 Determine the slurry volume, ft^3

Slurry vol, ft^3 = number of sacks of cement to be used x slurry yield, ft^3/sk

Step 3 Determine the amount of cement, ft^3, to be left in casing:

Cement in casing, ft^3 = (feet of casing — setting depth of cementing tool, ft) x (casing capacity, ft^3/ft) ÷ excess

Step 4 Determine the height of cement in the annulus — feet of cement:

Feet = (slurry vol, ft^3 — cement remaining in casing, ft^3) + (annular capacity, ft^3/ft) ÷ excess

Step 5 Determine the depth of the top of the cement in the annulus:

Depth ft = casing setting depth, ft — ft of cement in annulus

Step 6 Determine the number of barrels of mud required to displace the cement:

Barrels = feet drill pipe x drill pipe capacity, bbl/ft

Step 7 Determine the number of strokes required to displace the cement:

Strokes = bbl required to displace cement ÷ pump output, bbl/stk

Example: From the data listed below, determine the following:

1. Height, ft, of the cement in the annulus
2. Amount, ft^3, of the cement in the casing
3. Depth, ft, of the top of the cement in the annulus
4. Number of barrels of mud required to displace the cement
5. Number of strokes required to displace the cement

Data: Casing setting depth = 3000 ft Hole size = 17-1/2 in.
Casing — 54.5 lb/ft = 13-3/8 in. Casing ID = 12.615 in.
Drill pipe (5.0 in. — 19.5 lb/ft) = 0.01776 bbl/ft
Pump (7 in. by 12 in. triplex @ 95% eff.) = 0.136 bbl/stk
Cementing tool (number of feet above shoe) = 100 ft

Cementing program: NEAT cement = 500 sk Slurry yield = 1.15 ft^3/sk
Excess volume = 50%

Step 1 Determine the following capacities:

a) Annular capacity between casing and hole, ft^3/ft:

$$\text{Annular capacity, ft}^3/\text{ft} = \frac{17.5^2 - 13.375^2}{183.35}$$

$$\text{Annular capacity, ft}^3/\text{ft} = \frac{127.35938}{183.35}$$

$$\text{Annular capacity} = 0.6946\ \text{ft}^3/\text{ft}$$

b) Casing capacity, ft^3/ft:

$$\text{Casing capacity, } ft^3/ft = \frac{12.615^2}{183.35}$$

$$\text{Casing capacity, } ft^3/ft = \frac{159.13823}{183.35}$$

Casing capacity = 0.8679 ft^3/ft

Step 2 Determine the slurry volume, ft^3:

Slurry vol, ft^3 = 500 sk x 1.15 ft^3/sk
Slurry vol = 575 ft^3

Step 3 Determine the amount of cement, ft^3, to be left in the casing:

Cement in casing, ft^3 = (3000 ft — 2900 ft) x 0.8679 ft^3/ft
Cement in casing, ft^3 = 86.79 ft^3

Step 4 Determine the height of the cement in the annulus — feet of cement:

Feet = (575 ft^3 — 86.79 ft^3) ÷ 0.6946 ft^3/ft ÷ 1.50
Feet = 468.58

Step 5 Determine the depth of the top of the cement in the annulus:

Depth = 3000 ft — 468.58 **ft**
Depth = 2531.42 ft

Step 6 Determine the number of barrels of mud required to displace the cement:

Barrels = 2900 ft x 0.01776 bbl/ft
Barrels = 51.5

Step 7 Determine the number of strokes required to displace the cement:

Strokes = 51.5 bbl 0.136 bbl/stk
Strokes = 379

11. Setting a Balanced Cement Plug

Step 1 Determine the following capacities:

a) Annular capacity, ft^3/ft, between pipe or tubing and hole or casing:

$$\text{Annular capacity, } ft^3/ft = \frac{\text{Dh in.}^2 - \text{Dp in.}^2}{183.35}$$

b) Annular capacity, ft/bbl between pipe or tubing and hole or casing:

$$\text{Annular capacity, ft/bbl} = \frac{1029.4}{\text{Dh, in.}^2 - \text{Dp, in.}^2}$$

c) Hole or casing capacity, ft^3/ft:

$$\text{Hole or capacity, ft}^3\text{/ft} = \frac{\text{ID in.}^2}{183.\ 35}$$

d) Drill pipe or tubing capacity, ft^3/ft:

$$\text{Drill pipe or tubing capacity, ft}^3\text{/ft} = \frac{\text{ID in.}^2}{183.35}$$

e) Drill pipe or tubing capacity, bbl/ft:

$$\text{Drill pipe or tubing capacity, bbl/ft} = \frac{\text{ID in.}^2}{1029.4}$$

Step 2 Determine the number of SACKS of cement required for a given length of plug, OR determine the FEET of plug for a given number of sacks of cement:

a) Determine the number of SACKS of cement required for a given length of plug:

Sacks of cement = plug length, ft x hole or casing capacity ft^3/ft , x excess ÷ slurry yield, ft^3/sk

NOTE: If no excess is to be used, simply omit the excess step.

OR

b) Determine the number of FEET of plug for a given number of sacks of cement:

Feet = sacks of cement x slurry yield, ft^3/sk ÷ hole or casing capacity, ft^3/ft ÷ excess

NOTE: If no excess is to be used, simply omit the excess step.

Step 3 Determine the spacer volume (usually water), bbl, to be pumped behind the slurry to balance the plug:

Spacer vol, bbl = annular capacity, ft/bbl ÷ excess x spacer vol ahead, bbl x pipe or tubing capacity, bbl/ft

NOTE: If no excess is to be used, simply omit the excess step.

Step 4 Determine the plug length, ft, before the pipe is withdrawn:

Plug length, ft = sacks of cement x slurry yield, ft^3/sk ÷ annular capacity, ft^3/ft x excess **+** pipe or tubing capacity, ft^3/ft

NOTE: If no excess is to be used, simply omit the excess step.

Step 5 Determine the fluid volume, bbl, required to spot the plug:

$$\text{Vol, bbl} = \left[\left(\begin{array}{c}\text{length of pipe}\\ \text{or tubing, ft}\end{array} - \text{plug length, ft}\right) \times \begin{array}{c}\text{pipe or tubing}\\ \text{capacity, bbl/ft}\end{array}\right] - \begin{array}{c}\text{spacer vol behind}\\ \text{slurry, bbl}\end{array}$$

Example 1: A 300 ft plug is to be placed at a depth of 5000 *ft.* The open hole size is 8-1/2 in. and the drill pipe is 3-1/2 in. — 13.3 lb/ft; ID — 2.764 in. Ten barrels of water are to be pumped ahead of the slurry. Use a slurry yield of 1.15 ft^3/sk. Use 25% as excess slurry volume:

Determine the following:

1. Number of sacks of cement required
2. Volume of water to be pumped behind the slurry to balance the plug
3. Plug length before the pipe is withdrawn
4. Amount of mud required to spot the plug plus the spacer behind the plug

Step 1 Determined the following capacities:

a) Annular capacity between drill pipe and hole, ft^3/ft:

$$\text{Annular capacity, ft}^3\text{/ft} = \frac{8.5^2 - 3.5^2}{183.35}$$

$$\text{Annular capacity} = 0.3272 \text{ ft}^3\text{/ft}$$

b) Annular capacity between drill pipe and hole, ft/bbl:

$$\text{Annular capacity, ft/bbl} = \frac{1029.4}{8.5^2 - 3.5^2}$$

$$\text{Annular capacity} = 17.1569 \text{ ft/bbl}$$

c) Hole capacity, ft^3/ft:

$$\text{Hole capacity, ft}^3\text{/ft} = \frac{8.5^2}{183.35}$$

$$\text{Hole capacity} = 0.3941 \text{ ft}^3\text{/ft}$$

d) Drill pipe capacity, bbl/ft:

$$\text{Drill pipe capacity, bbl/ft} = \frac{2.764^2}{1029.4}$$

$$\text{Drill pipe capacity} = 0.00742 \text{ bbl/ft}$$

e) Drill pipe capacity, ft^3/ft:

$$\text{Drill pipe capacity, ft}^3\text{/ft} = \frac{2.764^2}{183.35}$$

$$\text{Drill pipe capacity} = 0.0417 \text{ ft}^3\text{/ft}$$

Step 2 Determine the number of sacks of cement required:

Sacks of cement = 300 ft x 0.3941 ft^3/ft x 1.25 ÷ 1.15 ft^3/sk
Sacks of cement = 129

Step 3 Determine the spacer volume (water), bbl, to be pumped behind the slurry to balance the plug:

Spacer vol, bbl = 17.1569 ft/bbl ÷ 1.25 x 10 bbl x 0.00742 bbl/ft
Spacer vol = 1.018 bbl

Step 4 Determine the plug length, ft, before the pipe is withdrawn:

Plug length, ft = (129 sk x 1.15 ft3/sk) ÷ (0.3272 ft^3/ft x 1.25 + 0.0417 ft^3/ft)
Plug length, ft = 148.35 ft^3 ÷ 0.4507 ft^3/ft
Plug length = 329 ft

Step 5 Determine the fluid volume, bbl, required to spot the plug:

Vol, bbl = [(5000 ft — 329 ft) x 0.00742 bbl/ft] — 1.0 bbl
Vol, bbl = 34.66 bbl — 1.0 bbl
Volume = 33.6 bbl

Example 2: Determine the number of FEET of plug for a given number of SACKS of cement:

A cement plug with 100 sk of cement is to be used in an 8-1/2 in, hole. Use 1.15 ft^3/sk for the cement slurry yield. The capacity of 8-1/2 in. hole = 0.3941 ft^3/ft. Use 50% as excess slurry volume:

Feet = 100 sk x 1.15 ft^3/sk ÷ 0.3941 ft^3/ft ÷ 1.50
Feet = 194.5

12. Differential Hydrostatic Pressure Between Cement in the Annulus and Mud Inside the Casing

1. Determine the hydrostatic pressure exerted by the cement and any mud remaining in the annulus.
2. Determine the hydrostatic pressure exerted by the mud and cement remaining in the casing.
3. Determine the differential pressure.

Example: 9-5/8 in. casing — 43.5 lb/ft in 12-1/4 in. hole: Well depth = 8000 ft
Cementing program: LEAD slurry 2000 ft = 13.8 lb/gal
TAIL slurry 1000 ft = 15.8 lb/gal
Mud weight = 10.0 lb/gal
Float collar (No. of feet above shoe) = 44 ft

Determine the total hydrostatic pressure of cement and mud in the annulus

a) Hydrostatic pressure of mud in annulus:

HP, psi = 10.0 lb/gal x 0.052 x 5000 ft
HP = 2600 psi

b) Hydrostatic pressure of LEAD cement:

HP, psi = 13.8 lb/gal x 0.052 x 2000 ft
HP = 1435 psi

c) Hydrostatic pressure of TAIL cement:

HP, psi = 15.8 lb/gal x 0.052 x 1000 ft
HP = 822 psi

d) Total hydrostatic pressure in annulus:

psi = 2600 psi + 1435 psi + 822 psi
psi = 4857

Determine the total pressure inside the casing

a) Pressure exerted by the mud:

HP, psi = 10.0 lb/gal x 0.052 x (8000 ft — 44 ft)
HP = 4137 psi

b) Pressure exerted by the cement:

HP, psi = 15.8 lb/gal x 0.052 x 44 ft
HP = 36psi

c) Total pressure inside the casing:

psi = 4137 psi + 36 psi
psi = 4173

Differential pressure

P_D = 4857 psi — 4173 psi
P_D = 684 psi

13. Hydraulicing Casing

These calculations will determine if the casing will hydraulic out (move upward) when cementing

Determine the difference in pressure gradient, psi/ft, between the cement and the mud

psi/ft = (cement wt, ppg — mud wt, ppg) x 0.052

Determine the differential pressure (DP) between the cement and the mud

DP, psi = difference in pressure gradients, psi/ft x casing length, ft

Determine the area, sq in., below the shoe

Area, sq in. = casing diameter, in.^{2} x 0.7854

Determine the Upward Force (F), lb. This is the weight, total force, acting at the bottom of the shoe

Force, lb = area, sq in. x differential pressure between cement and mud, psi

Determine the Downward Force (W), lb. This is the weight of the casing

Weight, lb = casing wt, lb/ft x length, ft x buoyancy factor

Determine the difference in force, lb

Differential force, lb = upward force, lb — downward force, lb

Pressure required to balance the forces so that the casing will not hydraulic out (move upward)

psi = force, lb — area, sq in.

Mud weight increase to balance pressure

Mud wt, ppg = pressure required . ÷ 0.052 ÷ casing length, ft to balance forces, psi

New mud weight, ppg

Mud wt, ppg = mud wt increase, ppg ÷ mud wt, ppg

Check the forces with the new mud weight

a) psi/ft = (cement wt, ppg — mud wt, ppg) x 0.052
b) psi = difference in pressure gradients, psi/ft x casing length, ft
c) Upward force, lb = pressure, psi x area, sq in.
d) Difference in = upward force, lb — downward force, lb force, lb

Example: Casing size = 13 3/8 in. 54 lb/ft Cement weight = 15.8 ppg
Mud weight = 8.8 ppg Buoyancy factor = 0.8656
Well depth = 164 ft (50 m)

Determine the difference in pressure gradient, psi/ft, between the cement and the mud

psi/ft = (15.8 — 8.8) x 0.052
psi/ft = 0.364

Determine the differential pressure between the cement and the mud

psi = 0.364 psi/ft x 164 ft
psi = 60

Determine the area, sq in., below the shoe

area, sq in. = 13.3752 x 0.7854
area, = 140.5 sq in.

Determine the upward force. This is the total force acting at the bottom of the shoe

Force, lb = 140.5 sq in. x 60 psi
Force = 8430 lb

Determine the downward force. This is the weight of the casing

Weight, lb = 54.5 lb/ft x 164 ft x 0.8656
Weight = 7737 lb

Determine the difference in force, lb

Differential force, lb = downward force, lb — upward force, lb
Differential force, lb = 7737 lb — 8430 lb
Differential force = — 693 lb

Therefore: Unless the casing is tied down or stuck, it could possibly hydraulic out (move upward).

Pressure required to balance the forces so that the casing will not hydraulic out (move upward)

psi = 693 lb ÷ 140.5 sq in.
psi = 4.9

Mud weight increase to balance pressure

Mud wt, ppg = 4.9 psi ÷ 0.052 ÷ 164 ft
Mud wt = 0.57 ppg

New mud weight, ppg

New mud wt, ppg = 8.8 ppg + 0.6 ppg
New mud wt = 9.4 ppg

Check the forces with the new mud weight

a) psi/ft = (15.8 — 9.4) x 0.052
psi/ft = 0.3328

b) psi = 0.3328 psi/ft x 164 ft
psi = 54.58

c) Upward force, lb = 54.58 psi x 140.5 sq in.
Upward force = 7668 lb

d) Differential force, lb = downward force — upward force
Differential force, lb = 7737 lb — 7668 lb
Differential force = + 69 lb

14. Depth of a Washout

Method 1

Pump soft line or other plugging material down the drill pipe and notice how many strokes are required before the pump pressure increases.

Depth of washout, ft = strokes required x pump output, bbl/stk ÷ drill pipe capacity, bbl/ft

Example: Drill pipe = 3-1/2 in. 13.3 lb/ft
Capacity = 0.00742 bbl/ft
Pump output = 0.112 bbl/stk (5-1/2 in. by 14 in. duplex @ 90% efficiency)

NOTE: A pressure increase was noticed after 360 strokes.

Depth of washout, ft = 360 stk x 0.112 bbl/stk ÷ 0.00742 bbl/ft
Depth of washout = 5434 ft

Method 2

Pump some material that will go through the washout, up the annulus and over the shale shaker. This material must be of the type that can be easily observed as it comes across the shaker. Examples: carbide, corn starch, glass beads, bright coloured paint, etc.

Depth of washout, ft = strokes required x pump output, bbl/stk ÷ (drill pipe capacity, bbl/ft + annular capacity, bbl/ft)

Example: Drill pipe = 3-1/2 in. 13.3 lb/ft capacity = 0.00742 bbl/ft
Pump output = 0.112 bbl/stk (5-1/2 in. x 14 in. duplex @ 90% efficiency)
Annulus hole size = 8-1/2 in.
Annulus capacity = 0.0583 bbl/ft (8-1/2 in. x 3-1/2 in.)

NOTE: The material pumped down the drill pipe was noticed coming over the shaker after 2680 strokes.

Drill pipe capacity plus annular capacity:

0.00742 bbl/ft + 0.0583 bbl/ft = 0.0657 bbl/ft

Depth of washout, ft = 2680 stk x 0.112 bbl/stk ÷ 0.0657 bbl/ft
Depth of washout = 4569 ft

15. Lost Returns — Loss of Overbalance

Number of feet of water in annulus

Feet = water added, bbl ÷ annular capacity, bbl/ft

Bottomhole (BHP) pressure reduction

BHP decrease, psi = (mud wt, ppg — wt of water, ppg) x 0.052 x (ft of water added)

Equivalent mud weight at TD

EMW, ppg = mud wt, ppg — (BHP decrease, psi ÷ 0.052 ÷ TVD, ft)

Example: Mud weight = 12.5 ppg Water added = 150 bbl required to fill annulus
Weight of water = 8.33 ppg Annular capacity = 0.1279 bbl/ft (12-1/4 x 5.0 in.)
TVD = 10,000 ft

Number of feet of water in annulus

Feet = 150 bbl ÷ 0.1279 bbl/ft
Feet = 1173

Bottomhole pressure decrease

BHP decrease, psi = (12.5 ppg — 8.33 ppg) x 0.052 x 1173 ft
BHP decrease = 254 psi

Equivalent mud weight at TD

EMW, ppg = 12.5 — (254 psi ÷ 0.052 — 10,000 ft)
EMW = 12.0 ppg

16. Stuck Pipe Calculations

Determine the feet of free pipe and the free point constant

Method 1

The depth at which the pipe is stuck and the number of feet of free pipe can be estimated by the drill pipe stretch table below and the following formula.

Table 2-2
Drill Pipe Stretch Table

ID, in.	Nominal Weight, lb/ft	ID, in.	Wall Area, sq in.	Stretch Constant in/1000 lb /1000 ft	Free Point constant
2-3/8	4.85	1.995	1.304	0.30675	3260.0
	6.65	1.815	1.843	0.21704	4607.7
2-7/8	6.85	2.241	1.812	0.22075	4530.0
	10.40	2.151	2.858	0.13996	7145.0
3-1/2	9.50	2.992	2.590	0.15444	6475.0
	13.30	2.764	3.621	0.11047	9052.5
	15.50	2.602	4.304	0.09294	10760.0
4.0	11.85	3.476	3.077	0.13000	7692.5
	14.00	3.340	3.805	0.10512	9512.5
4-1/2	13.75	3.958	3.600	0.11111	9000.0
	16.60	3.826	4.407	0.09076	11017.5
	18.10	3.754	4.836	0.08271	12090.0
	20.00	3.640	5.498	0.07275	13745.0
5.0	16.25	4.408	4.374	0.09145	10935.0
	19.50	4.276	5.275	0.07583	13187.5
5-1/2	21.90	4.778	5.828	0.06863	14570.0
	24.70	4.670	6.630	0.06033	16575.0
6-5/8	25.20	5.965	6.526	0.06129	16315.0

Feet of — stretch, in. x free point constant free pipe — pull force in thousands of pounds

Example: 3-1/2 in. 13.30 lb/ft drill pipe 20 in. of stretch with 35,000 lb of pull force

From drill pipe stretch table: Free point constant = 9052.5 for 3-1/2 in. drill pipe 13.30 lb/ft

$$\text{Feet of free pipe} = \frac{20 \text{ in.} \times 9052.5}{35}$$

Feet of free pipe = 5173 ft

Determine free point constant (FPC)

The free point constant can be determined for any type of steel drill pipe if the outside diameter, in., and inside diameter, in., are known:

FPC = As x 2500

where: As = pipe wall cross sectional area, sq in.

Example 1: From the drill pipe stretch table: 4-1/2 in. drill pipe 16.6 lb/ft — ID = 3.826 in.

FPC = (452 — 3.8262 x 0.7854) x 2500
FPC = 4.407 x 2500
FPC = 11,017.5

Example 2: Determine the free point constant and the depth the pipe is stuck using the following data:

2-3/8 in. tubing — 6.5 lb/ft — ID = 2.441 in. 25 in. of stretch with 20,000 lb of pull force

a) Determine free point constant (FPC):

FPC = (2.875^2 — 2.441^2 x 0.7854) x 2500
FPC = 1.820 x 2500
FPC = 4530

b) Determine the depth of stuck pipe:

$$\text{Feet of free pipe} = \frac{25 \text{ in. x } 4530}{20 \text{ Feet}}$$

Feet of free pipe = 5663 ft

Method 2

$$\text{Free pipe, ft} = \frac{735{,}294 \text{ x } e \text{ x } Wdp}{\text{differential pull, lb}}$$

where e = pipe stretch, in.
Wdp = drill pipe weight, lb/ft (plain end)

Plain end weight, lb/ft, is the weight of drill pipe excluding tool joints:

Weight, lb/ft = 2.67 x pipe OD, in.^{2} — pipe; ID, in.^{2}

Example: Determine the feet of free pipe using the following data:

5.0 in. drill pipe; ID — 4.276 in.; 19.5 lb/ft
Differential stretch of pipe = 24 in.
Differential pull to obtain stretch = 30,000 lb

Weight, lb/ft = 2.67 x (5.0^2 — 4.276^2)
Weight = 17.93 lb/ft

Free pipe, ft = $\dfrac{735{,}294 \times 24 \times 17.93}{30{,}000}$

Free pipe = 10,547 ft

Determine the height, ft of unweighted spotting fluid that will balance formation pressure in the annulus:

a) Determine the difference in pressure gradient, psi/ft, between the mud weight and the spotting fluid:

psi/ft = (mud wt, ppg — spotting fluid wt, ppg) x 0.052

b) Determine the height, ft, of unweighted spotting fluid that will balance formation pressure in the annulus:

Height ft = amount of overbalance, psi ÷ difference in pressure gradient, psi/ft

Example. Use the following data to determine the height, ft, of spotting fluid that will balance formation pressure in the annulus:

Data: Mud weight = 11.2 ppg Weight of spotting fluid = 7.0 ppg
Amount of overbalance = 225.0 psi

a) Difference in pressure gradient, psi/ft:

psi/ft = (11.2 ppg — 7.0 ppg) x 0.052
psi/ft = 0.2184

a) Determine the height, ft. of unweighted spotting fluid that will balance formation pressure in the annulus:

Height, ft = 225 psi ÷ 0.2184 psi/ft
Height = 1030 ft

Therefore: Less than 1030 ft of spotting fluid should be used to maintain a safety factor to prevent a kick or blow-out.

17. Calculations Required for Spotting Pills

The following will be determined:

a) Barrels of spotting fluid (pill) required
b) Pump strokes required to spot the pill

Step 1 Determine the annular capacity, bbl/ft, for drill pipe and drill collars in the annulus:

$$\text{Annular capacity, bbl/ft} = \frac{\text{Dh in.}^2 - \text{Dp in.}^2}{1029.4}$$

Step 2 Determine the volume of pill required in the annulus:

Vopl bbl = annular capacity, bbl/ft x section length, ft x washout factor

Step 3 Determine total volume, bbl, of spotting fluid (pill) required:

Barrels = Barrels required in annulus plus barrels to be left in drill string

Step 4 Determine drill string capacity, bbl:

Barrels = drill pipe/drill collar capacity, bbl/ft x length, ft

Step 5 Determine strokes required to pump pill:

Strokes = vol of pill, bbl pump output, bbl/stk

Step 6 Determine number of barrels required to chase pill:

Barrels = drill string vol, bbl — vol left in drill string, bbl

Step 7 Determine strokes required to chase pill:

Strokes = bbl required to chase pill ÷ pump output, bbl/stk + strokes required to displace surface system

Step 8 Total strokes required to spot the pill:

Total strokes = strokes required to pump pill + strokes required to chase pill

Example: Drill collars are differentially stuck. Use the following data to spot an oil based pill around the drill collars plus 200 ft (optional) above the collars. Leave 24 bbl in the drill string:

Data:	Well depth	= 10,000 ft	Pump output	= 0.117 bbl/stk
	Hole diameter	= 8-1/2 in.	Washout factor	= 20%
	Drill pipe	= 5.0 in. 19.5 lb/ft	Drill collars	= 6-1/2 in. OD x 2-1/2 in. ID
	capacity	= 0.01776 bbl/ft	capacity	= 0.006 1 bbl/ft
	length	= 9400 ft	length	= 600 ft

Strokes required to displace surface system from suction tank to the drill pipe = 80 stk.

Step 1 Annular capacity around drill pipe and drill collars:

a) Annular capacity around drill collars:

$$\text{Annular capacity, bbl/ft} = \frac{8.5^2 - 6.5^2}{1029.4}$$

Annular capacity = 0.02914 bbl/ft

b) Annular capacity around drill pipe:

$$\text{Annular capacity, bbl/ft} = \frac{8.5^2 - 5.0^2}{1029.4}$$

Annular capacity = 0.0459 bbl/ft

Step 2 Determine total volume of pill required in annulus:

a) Volume opposite drill collars:

Vol, bbl = 0.02914 bbl/ft x 600 ft x 1.20
Vol = 21.0 bbl

b) Volume opposite drill pipe:

Vol, bbl = 0.0459 bbl/ft x 200 ft x 1.20
Vol = 11.0 bbl

c) Total volume bbl, required in annulus:

Vol, bbl = 21.0 bbl + 11.0 bbl
Vol = 32.0 bbl

Step 3 Total bbl of spotting fluid (pill) required:

Barrels = 32.0 bbl (annulus) + 24.0 bbl (drill pipe)
Barrels = 56.0 bbl

Step 4 Determine drill string capacity:

a) Drill collar capacity, bbl:

Capacity, bbl = 0.0062 bbl/ft x 600 ft
Capacity = 3.72 bbl

b) Drill pipe capacity, bbl:

Capacity, bbl = 0.01776 bbl/ft x 9400 ft
Capacity = 166.94 bbl

c) Total drill string capacity, bbl:

Capacity, bbl = 3.72 bbl + 166.94 bbl
Capacity = 170.6 bbl

Step 5 Determine strokes required to pump pill:

Strokes = 56 bbl ÷ 0.117 bbl/stk
Strokes = 479

Step 6 Determine bbl required to chase pill:

Barrels = 170.6 bbl — 24 bbl
Barrels = 146.6

Step 7 Determine strokes required to chase pill:

Strokes = 146.6 bbl ÷ 0.117 bbl/stk + 80 stk
Strokes = 1333

Step 8 Determine strokes required to spot the pill:

Total strokes = 479 + 1333
Total strokes = 1812

18. Pressure Required to Break Circulation

Pressure required to overcome the mud's gel strength inside the drill string

Pgs = (y ÷ 300 ÷ d) L

where Pgs = pressure required to break gel strength, psi
y = 10 mm gel strength of drilling fluid, lb/100 sq ft
d = inside diameter of drill pipe, in.
L = length of drill string, ft

Example: y = 10 lb/100 sq ft d = 4.276 in. L= 12,000 ft

Pgs = (10 ÷ 300 — 4.276) 12,000 ft
Pgs = 0.007795 x 12,000 ft
Pgs = 93.5 psi

Therefore, approximately 94 psi would be required to break circulation.

Pressure required to overcome the mud's gel strength in the annulus

Pgs = y ÷ [300 (Dh, in. — Dp, in.)] x L

where Pgs = pressure required to break gel strength, psi
L = length of drill string, ft
y = 10 mm. gel strength of drilling fluid, lb/100 sq ft
Dh = hole diameter, in.
Dp = pipe diameter, in.

Example: L = 12,000 ft y = 10 lb/100 sq ft
Dh = 12-1/4 in. Dp = 5.0 in.

Pgs = 10 ÷ [300 x (12.25 — 5.0)] x 12,000 ft
Pgs = 10 ÷ 2175 x 12,000 ft
Pgs = 55.2 psi

Therefore, approximately 55 psi would be required to break circulation.

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CHAPTER THREE

DRILLING FLUIDS

1. Increase Mud Density

Mud weight, ppg, increase with barite (average specific gravity of barite - 4.2)

$$\text{Barite, sk/100 bbl} = \frac{1470\,(W_2 — W_1)}{35 — W_2}$$

Example: Determine the number of sacks of barite required to increase the density of 100 bbl of 12.0 ppg (W_1) mud to 14.0 ppg (W_2):

$$\text{Barite sk/100 bbl} = \frac{1470\,(14.0 — 12.0)}{35 — 14.0}$$

$$\text{Barite, sk/100 bbl} = \frac{2940}{21.0}$$

Barite = 140 sk/ 100 bbl

Volume increase, bbl, due to mud weight increase with barite

$$\text{Volume increase, per 100 bbl} = \frac{100\,(W_2 — W_1)}{35 — W_2}$$

Example: Determine the volume increase when increasing the density from 12.0 ppg (W_1) to 14.0 ppg (W_2):

$$\text{Volume increase, per 100 bbl} = \frac{100\,(14.0 — 12.0)}{35 — 14.0}$$

$$\text{Volume increase, per 100 bbl} = \frac{200}{21}$$

Volume increase = 9.52 bbl per 100 bbl

Starting volume, bbl, of original mud weight required to give a predetermined final volume of desired mud weight with barite

$$\text{Starting volume, bbl} = \frac{V_F\,(35 — W_2)}{35 — W_1}$$

Example: Determine the starting volume, bbl, of 12.0 ppg (W_1) mud required to achieve 100 bbl (V_F) of 14.0 ppg (W_2) mud with barite:

$$\text{Starting volume, bbl} = \frac{100\,(35 — 14.0)}{35 — 12.0}$$

$$\text{Starting volume, bbl} = \frac{2100}{23}$$

Starting volume = 91.3 bbl

Mud weight increase with calcium carbonate (SG — 2.7)

NOTE: The maximum practical mud weight attainable with calcium carbonate is 14.0 ppg.

$$\text{Sacks/ 100 bbl} = \frac{945(W_2 - W_1)}{22.5 - W_2}$$

Example: Determine the number of sacks of calcium carbonate/l00 bbl required to increase the density from 12.0 ppg (W_1) to 13.0 ppg (W_2):

$$\text{Sacks/ 100 bbl} = \frac{945\,(13.0 - 12.0)}{22.5 - 13.0}$$

$$\text{Sacks/ 100 bbl} = \frac{945}{9.5}$$

Sacks/ 100 bbl = 99.5

Volume increase, bbl, due to mud weight increase with calcium carbonate

$$\text{Volume increase, per 100 bbl} = \frac{100\,(W_2 - W_1)}{22.5 - W_2}$$

Example. Determine the volume increase, bbl/100 bbl, when increasing the density from 12.0 ppg (W_3) to 13.0 ppg (W_2):

$$\text{Volume increase, per 100 bbl} = \frac{100\,(13.0 - 12.0)}{22.5 - 13.0}$$

$$\text{Volume increase, per 100 bbl} = \frac{100}{9.5}$$

Volume increase = 10.53 bbl per 100 bbl

Starting volume, bbl, of original mud weight required to give a predetermined final volume of desired mud weight with calcium carbonate

$$\text{Starting volume, bbl} = \frac{V_F\,(22.5 - W2)}{22.5 - W_1}$$

Example: Determine the starting volume, bbl, of 12.0 ppg (W_1) mud required to achieve 100 bbl (V_F) of 13.0 ppg (W_2) mud with calcium carbonate:

$$\text{Starting volume, bbl} = \frac{100\,(22.5 - 13.0)}{22.5 - 12.0}$$

$$\text{Starting volume, bbl} = \frac{950}{10.5}$$

Starting volume = 90.5 bbl

Mud weight increase with hematite (SG — 4.8)

Hematite, sk/100 bbl $= \frac{1680\ (W_2 — W\text{~})}{40 — W_2}$

Example: Determine the hematite, sk/100 bbl, required to increase the density of 100 bbl of 12.0 ppg (W_1) to 14.0 ppg (W_2):

Hematite, sk/100 bbl $= \frac{1680\ (14.0 — 12.0)}{40 — 14.0}$

Hematite, sk/100 bbl $= \frac{3360}{26}$

Hematite = 129.2 sk/100 bbl

Volume increase, bbl, due to mud weight increase with hematite

Volume increase, per 100 bbl $= \frac{l00\ (W_2 — W_1)}{40 — W_2}$

Example: Determine the volume increase, bbl/100 bbl, when increasing the density from 12.0 ppg (W,) to 14.0 ppg (W_2):

Volume increase, per 100 bbl $= \frac{100\ (14.0 — 12.0)}{40 — 14.0}$

Volume increase, per 100 bbl $= \frac{200}{26}$

Volume increase = 7.7 bbl per 100 bbl

Starting volume, bbl, of original mud weight required to give a predetermined final volume of desired mud weight with hematite

Starting volume, bbl $= \frac{V_F\ (40.0 — W2)}{40 — W_1}$

Example: Determine the starting volume, bbl, of 12.0 ppg (W_1) mud required to achieve 100 bbl (V_F) of 14.0 ppg (W_2) mud with hematite:

Starting volume, bbl $= \frac{100\ (40 — 14.0)}{40 — 12.0}$

Starting volume, bbl $= \frac{2600}{28}$

Starting volume = 92.9 bbl

2. Dilution

Mud weight reduction with water

$$\text{Water, bbl} = \frac{V_1(W_1 - W_2)}{W_2 - Dw}$$

Example: Determine the number of barrels of water weighing 8.33 ppg (Dw) required to reduce 100 bbl (V_1) of 14.0 ppg (W_1) to 12.0 ppg (W_2):

$$\text{Water, bbl} = \frac{100\ (14.0 - 12.0)}{12.0 - 8.33}$$

$$\text{Water, bbl} = \frac{2000}{3.67}$$

Water = 54.5 bbl

Mud weight reduction with diesel oil

$$\text{Diesel, bbl} = \frac{V_1(W_1 - W_2)}{W_2 - Dw}$$

Example: Determine the number of barrels of diesel weighing 7.0 ppg (Dw) required to reduce 100 bbl (V_1) of 14.0 ppg (W_1) to 12.0 ppg (W_2):

$$\text{Diesel, bbl} = \frac{100\ (14.0 - 12.0)}{12.0 - 7.0}$$

$$\text{Diesel, bbl} = \frac{200}{5.0}$$

Diesel = 40 bbl

3. Mixing Fluids of Different Densities

Formula: $(V_1\,D_1) + (V_2\,D_2) = V_F\,D_F$

where V_1 = volume of fluid 1 (bbl, gal, etc.) D_1 = density of fluid 1 (ppg,lb/ft^3, etc.)
V_2 = volume of fluid 2 (bbl, gal, etc.) D_2 = density of fluid 2 (ppg,lb/ft^3, etc.)
V_F = volume of final fluid mix D_F = density of final fluid mix

Example 1: A limit is placed on the desired volume:

Determine the volume of 11.0 ppg mud and 14.0 ppg mud required to build 300 bbl of 11.5 ppg mud:

Given: 400 bbl of 11.0 ppg mud on hand, and
400 bbl of 14.0 ppg mud on hand

Solution: let V_1 = bbl of 11.0 ppg mud
V_2 = bbl of 14.0 ppg mud

then a) $V_1 + V_2 = 300$ bbl
b) $(11.0)\ V_1 + (14.0)\ V_2 = (11.5)(300)$

Multiply Equation A by the density of the lowest mud weight (D_1 = 11.0 ppg) and subtract the result from Equation B:

$$
\begin{array}{lll}
 & \text{b)} & (11.0)(V_1) + (14.0)(V_2) = 3450 \\
- & \text{a)} & \underline{(11.0)(V_1) + (11.0)(V_2) = 3300} \\
 & & 0 \qquad\qquad (3.0)(V_2) = 150 \\
 & & \qquad\qquad\quad 3 \quad V_2 = 150
\end{array}
$$

$$V_2 = \frac{150}{3}$$

$$V_2 = 50$$

Therefore: V_2 = 50 bbl of 14.0 ppg mud
$V_1 + V_2 = 300$ bbl
$V_1 = 300 - 50$
V_1 = 250 bbl of 11.0 ppg mud

Check: V_1 = 50 bbl D_1 = 14.0 ppg
V_2 = 150 bbl D_2 = 11.0 ppg
V_F = 300 bbl D_F = final density, ppg

$$
\begin{aligned}
(50)(14.0) + (250)(11.0) &= 300\ D_F \\
700 + 2750 &= 300\ D_F \\
3450 &= 300\ D_F \\
3450 \div 300 &= D_F \\
11.5 \text{ ppg} &= D_F
\end{aligned}
$$

Example 2: No limit is placed on volume:

Determine the density and volume when the two following muds are mixed together:

Given: 400 bbl of 11.0 ppg mud, and
400 bbl of 14.0 ppg mud

Solution: let V_1 = bbl of 11.0 ppg mud D_1 = density of 11.0 ppg mud
V_2 = bbl of 14.0 ppg mud D_2 = density of 14.0 ppg mud
V_F = final volume, bbl D_F = final density, ppg

Formula: $(V_1 D_1) + (V_2 D_2) = V_F D_F$

$$
\begin{aligned}
(400)(11.0) + (400)(14.0) &= 800\ D_F \\
4400 + 5600 &= 800\ D_F \\
10{,}000 &= 800\ D_F \\
10{,}000 \div 800 &= D_F \\
12.5 \text{ ppg} &= D_F
\end{aligned}
$$

Therefore: final volume = 800 bbl
final density = 12.5 ppg

4. Oil Based Mud Calculations

Density of oil/water mixture being used

$(V_1)(D_,) + (V_2)(D_2) = (V\sim + V_2)D_F$

Example: If the oil/water (o/w) ratio is 75/25 (75% oil, V_1, and 25% water V_2), the following material balance is set up:

NOTE: The weight of diesel oil, $D_1 = 7.0$ ppg
The weight of water, $D_2 = 8.33$ ppg

$(0.75)\ (7.0) + (0.25)\ (8.33) = (0.75 + 0.25)\ D_F$
$5.25 + 2.0825 = 1.0\ D_F$
$7.33 = D_F$

Therefore: The density of the oil/water mixture = 7.33 ppg

Starting volume of liquid (oil plus water) required to prepare a desired volume of mud

$$SV = \frac{35 - W_2}{35 - W_1} \times DV$$

where SV = starting volume, bbl W$_1$ = initial density of oil/water mixture, ppg
W$_2$ = desired density, ppg Dv = desired volume, bbl

Example: $W_1 = 7.33$ ppg (o/w ratio — 75/25) $W_2 = 16.0$ ppg Dv = 100 bbl

Solution:

$$SV = \frac{35 - 16}{35 - 7.33} \times 100$$

$$SV = \frac{19}{27.67} \times 100$$

SV = 0.68666 x 100
SV = 68.7 bbl

Oil/water ratio from retort data

Obtain the percent-by-volume oil and percent-by-volume water from retort analysis or mud still analysis. From the data obtained, the oil/water ratio is calculated as follows:

a) $\% \text{ oil in liquid phase} = \dfrac{\% \text{ by vol oil}}{\% \text{ by vol oil} + \% \text{ by vol water}} \times 100$

b) $\% \text{ water in liquid phase} = \dfrac{\% \text{ by vol water}}{\% \text{ by vol oil} + \% \text{ by vol water}} \times 100$

c) Result: The oil/water ratio is reported as the percent oil and the percent water.

Example: Retort analysis: % by volume oil = 51
% by volume water = 17
% by volume solids = 32

Solution:

a) $\% \text{ oil in liquid phase} = \dfrac{51}{51 \times 17} \times 100$

$\% \text{ oil in liquid phase} = 75$

b) $\% \text{ water in liquid phase} = \dfrac{17}{51 + 17} \times 100$

$\% \text{ water in liquid phase} = 25$

c) Result: Therefore, the oil/water ratio is reported as 75/25: 75% oil and 25% water.

Changing oil/water ratio

NOTE: If the oil/water ratio is to be increased, add oil; if it is to be decreased, add water.

Retort analysis: % by volume oil = 51
% by volume water = 17
% by volume solids = 32

The oil/water ratio is 75/25.

Example 1: Increase the oil/water ratio to 80/20:

In 100 bbl of this mud, there are 68 bbl of liquid (oil plus water). To increase the oil/water ratio, add oil. The total liquid volume will be increased by the volume of the oil added, but the water volume will not change. The 17 bbl of water now in the mud represents 25% of the liquid volume, but it will represent only 20% of the new liquid volume.

Therefore: let x = final liquid volume

then, $0.20x = 17$
$x = 17 \div 0.20$
$x = 85$ bbl

The new liquid volume = 85 bbl

Barrels of oil to be added:

Oil, bbl = new liquid vol — original liquid vol
Oil, bbl = 85 — 68
Oil = 17 bbl oil per 100 bbl of mud

Check the calculations. If the calculated amount of liquid is added, what will be the resulting oil/water ratio?

$$\%\text{ oil in liquid phase} = \frac{\text{original vol oil + new vol oil}}{\text{original liquid oil + new oil added}} \times 100$$

$$\%\text{ oil in liquid phase} = \frac{51+17}{68+17} \times 100$$

% oil in liquid phase = 80
% water would then be: 100 — 80 = 20

Therefore: The new oil/water ratio would be 80/20.

Example 2: Change the oil/water ratio to 70/30:

As in Example I, there are 68 bbl of liquid in 100 bbl of this mud. In this case, however, water will be added and the volume of oil will remain constant. The 51 bbl of oil represents 75% of the original liquid volume and 70% of the final volume:

Therefore: let x = final liquid volume

then, $0.70x = 51$
$x = 51 \div 0.70$
$x = 73$ bbl

Barrels of water to be added:

Water, bbl = new liquid vol — original liquid vol
Water, bbl = 73 — 68
Water = 5 bbl of water per 100 bbl of mud

Check the calculations. If the calculated amount of water is added, what will be the resulting oil/water ratio?

$$\%\text{ water in liquid phase} = \frac{17+5}{68+5} \times 100$$

% water in liquid = 30
% oil in liquid phase = 100 — 30 = 70

Therefore, the new oil/water ratio would be 70/30.

5. Solids Analysis

Basic solids analysis calculations

NOTE: Steps 1 — 4 are performed on high salt content muds. For low chloride muds begin with Step *5*.

Step 1 Percent by volume saltwater (SW)

$SW = (5.88 \times 10^{-8}) \times [(\text{ppm Cl})^{1.2} + 1] \times \text{ \% by vol water}$

Step 2 Percent by volume suspended solids (SS)

$SS = 100 — \text{\%by vol oil} — \text{\% by vol SW}$

Step 3 Average specific gravity of saltwater (ASGsw)

$ASGsw = (\text{ppm Cl})^{0.95} \times (1.94 \times 10\text{-}6) + 1$

Step 4 Average specific gravity of solids (ASG)

$$ASG = \frac{(12 \times MW) — (\text{\% by vol SW} \times ASGsw) — (0.84 \times \text{\% by vol oil})}{SS}$$

Step 5 Average specific gravity of solids (ASG)

$$ASG = \frac{(12 \times MW) — \text{\% by vol water} — \text{\% by vol oil}}{\text{\% by vol solids}}$$

Step 6 Percent by volume low gravity solids (LGS)

$$LGS = \frac{\text{\% by volume solids} \times (4.2 — ASG)}{1.6}$$

Step 7 Percent by volume barite

Barite, % by vol = % by vol solids — % by vol LGS

Step 8 Pounds per barrel barite

Barite, lb/bbl = % by vol barite x 14.71

Step 9 Bentonite determination

If cation exchange capacity (CEC)/methytene blue test (MBT) of shale and mud are KNOWN:

a) Bentonite, lb/bbl:

$\text{Bentonite, lb/bbl} = 1 \div (1 — (S \div 65) \times (M — 9 \times (S \div 65)) \times \text{\% by vol LGS}$

Where S = CEC of shale M = CEC of mud

b) Bentonite, % by volume:

Bent, % by vol = bentonite, lb/bbl ÷ 9.1

If the cation exchange capacity (CEC)/methylene blue (MBT) of SHALE is UNKNOWN:

a) Bentonite, % by volume = $\dfrac{M - \%\text{ by volume LGS}}{8}$

where M = CEC of mud

b) Bentonite, lb/bbl = bentonite, % by vol x 9.1

Step 10 Drilled solids, % by volume

Drilled solids, % by vol = LGS, % by vol — bentonite, % by vol

Step 11 Drilled solids, lb/bbl

Drilled solids, lb/bbl = drilled solids, % by vol x 9.1

Example: Mud weight = 16.0 ppg
CEC of mud = 30 lb/bbl
Retort Analysis:
Chlorides = 73,000 ppm
CEC of shale = 7 lb/bbl
water = 57.0% by volume
oil = 7.5% by volume
solids = 35.5% by volume

1. Percent by volume saltwater (SW)

SW = $[(5.88 \times 10^{-8})(73{,}000)^{1.2} + 1] \times 57$
SW = $[(5.88^{-8} \times 685468.39) + 1] \times 57$
SW = $(0.0403055 + 1) \times 57$
SW = 59.2974 percent by volume

2. Percent by volume suspended solids (SS)

SS = 100 — 7.5 — 59.2974
SS = 33.2026 percent by volume

3. Average specific gravity of saltwater (ASGsw)

ASGsw = $[(73{,}000)^{0.95} - (1.94 \times 10^{-6})] + 1$
ASGsw = $(41{,}701.984 \times l.94^{-6}) + 1$
ASGsw = 0.0809018 + I
ASGsw = 1.0809

4. Average specific gravity of solids (ASG)

ASO = $\dfrac{(12 \times 16) - (59.2974 \times 1.0809) - (0.84 \times 7.5)}{33.2026}$

$$ASG = \frac{121.60544}{33.2026}$$

ASG = 3.6625

5. Because a high chloride example is being used, Step 5 is omitted.

6. Percent by volume low gravity solids (LGS)

$$LGS = \frac{33.2026 \times (4.2 - 3.6625)}{1.6}$$

LGS = 11.154 percent by volume

7. Percent by volume barite

Barite, % by volume = 33.2026 — 11.154
Barite = 22.0486 % by volume

8. Barite, lb/bbl

Barite, lb/bbl = 22.0486 x 14.71
Barite = 324.3349 lb/bbl

9. Bentonite determination

a) lb/bbl = 1 ÷ (1— (7 ÷ 65) x (30 — 9 x (7 ÷ 65)) x 11.154
lb/bbl = 1.1206897 x 2.2615385 x 11.154
Bent = 28.26965 lb/bbl

b) Bentonite, % by volume

Bent, % by vol = 28.2696 ÷ 9.1
Bent = 3.10655% by vol

10. Drilled solids, percent by volume

Drilled solids, % by vol = 11.154 — 3.10655
Drilled solids = 8.047% by vol

11. Drilled solids, pounds per barrel

Drilled solids, lb/bbl = 8.047 x 9.1
Drilled solids = 73.2277 lb/bbl

6. Solids Fractions

Maximum recommended solids fractions (SF)

SF = (2.917 x MW) — 14.17

Maximum recommended low gravity solids (LGS)

LGS = ((SF ÷ 100) — [0.3125 x ((MW ÷ 8.33) — 1)]) x 200

where SF = maximum recommended solids fractions, % by vol
LGS = maximum recommended low gravity solids, % by vol
MW = mud weight, ppg

Example: Mud weight = 14.0 ppg

Determine: Maximum recommended solids, % by volume
Low gravity solids fraction, % by volume
Maximum recommended solids fractions (SF), % by volume:

SF = (2.917 x 14.0) — 14.17
SF = 40.838 — 14.17
SF = 26.67 % by volume

Low gravity solids (LOS), % by volume:

LGS = ((26.67 ÷ 100) — [0.3125 x ((14.0 ÷ 8.33) — 1)]) x 200
LGS = 0.2667 — (0.3125 x 0.6807) x 200
LGS = (0.2667 — 0.2127) x 200
LGS = 0.054 x 200
LGS = 10.8 % by volume

7. Dilution of Mud System

$$Vwm = \frac{Vm\,(Fct - Fcop)}{Fcop - Fca}$$

where Vwm = barrels of dilution water or mud required
Vm = barrels of mud in circulating system
Fct = percent low gravity solids in system
Fcop = percent total optimum low gravity solids desired
Fca = percent low gravity solids (bentonite and/or chemicals added)

Example: 1000 bbl of mud in system. Total LOS = 6%. Reduce solids to 4%. Dilute with water:

$$Vwm = \frac{1000\,(6 - 4)}{4}$$

$$Vwm = \frac{2000}{4}$$

Vwm = 500 bbl

If dilution is done with a 2% bentonite slurry, the total would be:

$$Vwm = \frac{1000\,(6 - 4)}{4 - 2}$$

$$Vwm = \frac{2000}{2}$$

Vwm **=** 1000 bbl

8. Displacement — Barrels of Water/Slurry Required

$$Vwm = \frac{Vm\,(Fct - Fcop)}{Fct - Fca}$$

where Vwm = barrels of mud to be jetted and water or slurry to be added to maintain constant circulating volume:

Example: 1000 bbl in mud system. Total LGS = 6%. Reduce solids to 4%:

$$Vwm = \frac{1000\,(6 - 4)}{6}$$

$$Vwm = \frac{2000}{6}$$

Vwm = 333 bbl

If displacement is done by adding 2% bentonite slurry, the total volume would be:

$$Vwm = \frac{1000(6 - 4)}{6 - 2}$$

$$Vwm = \frac{2000}{4}$$

Vwm = 500 bbl

9. Evaluation of Hydrocyclone

Determine the mass of solids (for an unweighted mud) and the volume of water discarded by one cone of a hydrocyclone (desander or desilter):

Volume fraction of solids (SF): $SF = \frac{MW — 8.22}{13.37}$

Mass rate of solids (MS): $MS = 19{,}530 \times SF \times \frac{V}{T}$

Volume rate of water (WR) $WR = 900\ (1 — SF)\ \frac{V}{T}$

where SF = fraction percentage of solids
MW = average density of discarded mud, ppg
MS = mass rate of solids removed by one cone of a hydrocyclone, lb/hr
V = volume of slurry sample collected, quarts
T = time to collect slurry sample, seconds
WR = volume of water ejected by one cone of a hydrocyclone, gal/hr

Example: Average weight of slurry sample collected = 16.0 ppg Sample collected in 45 seconds
Volume of slurry sample collected 2 quarts

a) Volume fraction of solids: $SF = \frac{16.0 — 8.33}{13.37}$

$SF = 0.5737$

b) Mass rate of solids: $MS = 19{,}530 \times 0.5737 \times \frac{2}{45}$

$MS = 11{,}204.36 \times 0.0444$
$MS = 497.97$ lb/hr

c) Volume rate of water: $WR = 900\ (1 — 0.5737) — \frac{2}{45}$

$WR = 900 \times 0.4263 \times 0.0444$
$WR = 17.0$ gal/hr

10. Evaluation of Centrifuge

a) Underflow mud volume:

$QU = [\ \frac{QM \times (MW — PO)] — [QW \times (PO — PW)]}{PU — PO}$

b) Fraction of old mud in Underflow:

$$FU = \frac{35 - PU}{35 - MW + (QW \div QM) \times (35 - PW)}$$

c) Mass rate of clay:

$$QC = \frac{CC \times [QM - (QU \times FU)]}{42}$$

d) Mass rate of additives:

$$QC = \frac{CD \times [QM - (QU \times FU)]}{42}$$

e) Water flow rate into mixing pit:

$$QP = \frac{[QM \times (35 - MW)] - [QU \times (35 - PU)] - (0.6129 \times QC) - (0.6129 \times QD)}{35 - PW}$$

f) Mass rate for API barite:

$$QB = QM - QU - QP - \frac{QC}{21.7} - \frac{QD}{21.7} \times 35$$

where :

MW = mud density into centrifuge, ppg
QM = mud volume into centrifuge, gal/m
QW = dilution water volume, gal/mm
CD = additive content in mud, lb/bbl
QU = Underflow mud volume, gal/mm
FU = fraction of old mud in Underflow
QB = mass rate of API barite, lb/mm
QP = water flow rate into mixing pit, gal/mm
PU = Underflow mud density, ppg
PW = dilution water density, ppg
PO = overflow mud density, ppg
CC = clay content in mud, lb/bbl
QC = mass rate of clay, lb/mm
QD = mass rate of additives, lb/mm

Example: Mud density into centrifuge (MW) = 16.2 ppg
Mud volume into centrifuge (QM) = 16.5 gal/mm
Dilution water density (PW) = 8.34 ppg
Dilution water volume (QW) = 10.5 gal/mm
Underfiow mud density (PU) = 23.4 ppg
Overflow mud density (P0) = 9.3 ppg
Clay content of mud (CC) = 22.5 lb/bbl
Additive content of mud (CD) = 6 lb/bbl

Determine: Flow rate of Underflow
Volume fraction of old mud in the Underflow
Mass rate of clay into mixing pit
Mass rate of additives into mixing pit
Water flow rate into mixing pit
Mass rate of API barite into mixing pit

a) Underfiow mud volume, gal/mm:

$$QU = \frac{[16.5 \times (16.2 - 9.3)] - [10.5 \times (9.3 - 8.34)]}{23.4 - 9.3}$$

$$QU = \frac{113.85 - 10.08}{14.1}$$

QU = 7.4 gal/mm

b) Volume fraction of old mud in the Underflow:

$$FU = \frac{35 - 23.4}{35 - 16.2 + [(10.5 \div 16.5) \times (35 - 8.34)]}$$

$$FU = \frac{11.6}{18.8 + (0.63636 \times 26.66)}$$

FU = 0.324%

c) Mass rate of clay into mixing pit, lb/mm:

$$QC = \frac{22.5 \times [16.5 - (7.4 \times 0.324)]}{42}$$

$$QC = \frac{22.5 \times 14.1}{42}$$

QC = 7.55 lb/min

d) Mass rate of additives into mixing pit, lb/mm:

$$QD = \frac{6 \times [16.5 - (7.4 \times 0.324)]}{42}$$

$$QD = \frac{6 \times 14.1}{42}$$

QD = 2.01 lb/mm

e) Water flow into mixing pit, gal/mm:

$$QP = \frac{[16.5 \times (35 - 16.2)] - [7.4 \times (35 - 23.4)] - (0.6129 \times 7.55) - (0.6129 \times 2)}{(35 - 8.34)}$$

$$QP = \frac{310.2 - 85.84 - 4.627 - 1.226}{26.66}$$

$$QP = \frac{218.507}{26.66}$$

QP = 8.20 gal/mm

f) Mass rate of API barite into mixing pit, lb/mm:

QB = l6.5 — 7.4 — 8.20 — (7.55 ÷ 21.7) — (2.01 ÷ 21.7) x 35
QB = 16.5 — 7.4 — 8.20 — 0.348 — 0.0926 x 35
QB = 0.4594 x 35
QB = 16.079 lb/mm

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CHAPTER FOUR

PRESSURE CONTROL

1. Kill Sheets and Related Calculations

Normal Kill Sheet

Pre-recorded Data

Original mud weight (OMW)_________________________ 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 @ ________________ % efficiency

Surface to bit strokes:

Drill string volume ________ bbl ÷ ________ pump output, bbl/stk = ________ stk

Bit to casing shoe strokes:

Open hole volume ________ bbl ÷ ________ pump output, bbl/stk = ________ stk

Bit to surface strokes:

Annulus volume ________ bbl ÷ _____ __ pump output, bbl/stk = ________ stk

Maximum allowable shut-in casing pressure:

Leak-off test ______ psi, using ppg mud weight @ casing setting depth 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 + OMW _____ ppg = ________ 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

Pressure Chart

	Strokes	Pressure	
	0		< Initial Circulating Pressure
Strokes to Bit >			<Final Circulating Pressure

Example: 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	= 600 psi
Drill string:	
drill pipe 5.0 in. — 19.5 lb/ft capacity	= 0.01776 bbl/ft
HWDP 5.0 in. 49.3 lb/ft	
capacity	= 0.00883 bbl/ft
length	= 240 ft
drill collars 8.0 in. OD — 3.0 in. ID	
capacity	= 0.0087 bbl/ft
length	= 360 ft
Annulus:	
hole size	= 12 1/4 in.
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 in. x 12 in. 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	= 480 psi
Shut-in casing pressure	= 600 psi
Pit volume gain	= 35 bbl
True vertical depth	= 10,000 ft

Calculations

Drill string volume:

Drill pipe capacity 0.01776 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 = 30.10 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 = 521.20 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 (ICP) 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 Chart

	Strokes	Pressure
133.5 rounded up	0	
133.5 + 133.5 =	134	
+ **133.5** =	267	
+ **133.5** =	401	
+ **133.5** =	534	
+ **133.5** =	668	
+ **133.5** =	801	
+ **133.5** =	935	
+ **133.5** =	1068	
+ **133.5** =	1202	
+ **133.5 =**	1335	

Pressure

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

Therefore, the pressure will decrease by 38.6 psi per line.

Pressure Chart

	Strokes	Pressure	
1480 — 38.6 =	0	1480	**< ICP**
— 38.6 =		1441	
— 38.6 =		1403	
— 38.6 =		1364	
— 38.6 =		1326	
— 38.6 =		1287	
— 38.6 =		1248	
— 38.6 =		1210	
— 38.6 =		1171	
— 38.6 =		1133	
— 38.6 =		1094	**< FCP**

Trip Margin (TM)

TM = Yield point ÷ 11.7(Dh, in. — Dp, in.)

Example: Yield point = 10 lb/l00 sq ft; Dh = 8.5 in.; Dp = 4.5 in.

TM = 10 ÷ 11.7 (8.5 — 4.5)
TM = 0.2 ppg

Determine Psi/stk

$$\text{psi/stk} = \frac{\text{ICP - FCP}}{\text{strokes to bit}}$$

Example: 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 psi

$$\text{psi/stk} = \frac{1480 - 1094}{1335}$$

psi/stk = 0.289 1

The pressure side of the chart will be as follows:

Pressure Chart

Strokes	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?

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

psi @ _____ strokes = ICP — [(DPL ÷ DSL) x (ICP — FCP)]

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.

Example: Drill pipe 1: 5.0 in. 19.5 lb/ft Capacity = 0.01776 bbl/ft Length = 7000 ft
Drill pipe 2: 3-1/2 in. 13.3 lb/ft Capacity = 0.0074 bbl/ft Length = 6000 ft
Drill collars: 4 1/2 in. OD x 1-1/2 in. ID Capacity = 0.0022 bbl/ft Length = 2000 ft

Step 1 Determine strokes:

7000 ft x 0.01776 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 in. drill pipe at 1063 strokes:

psi @ 1063 strokes = 1780 — [(7000 ÷ 15,000) x (1780 — 1067)]
= 1780 — (0.4666 x 713)
= 1780 — 333
= 1447 psi

Step 3 Determine interim pressure for 5.0 in. plus 3-1/2 in. drill pipe (1063 + 381) = 1444 strokes:

psi @ 1444 strokes = 1780 — [(11,300 ÷ 15,000) x (1780 — 1067)]
= 1780 — (0.86666 x 713)
= 1780 — 618
= 1162 psi

Step 4 Plot data on graph paper

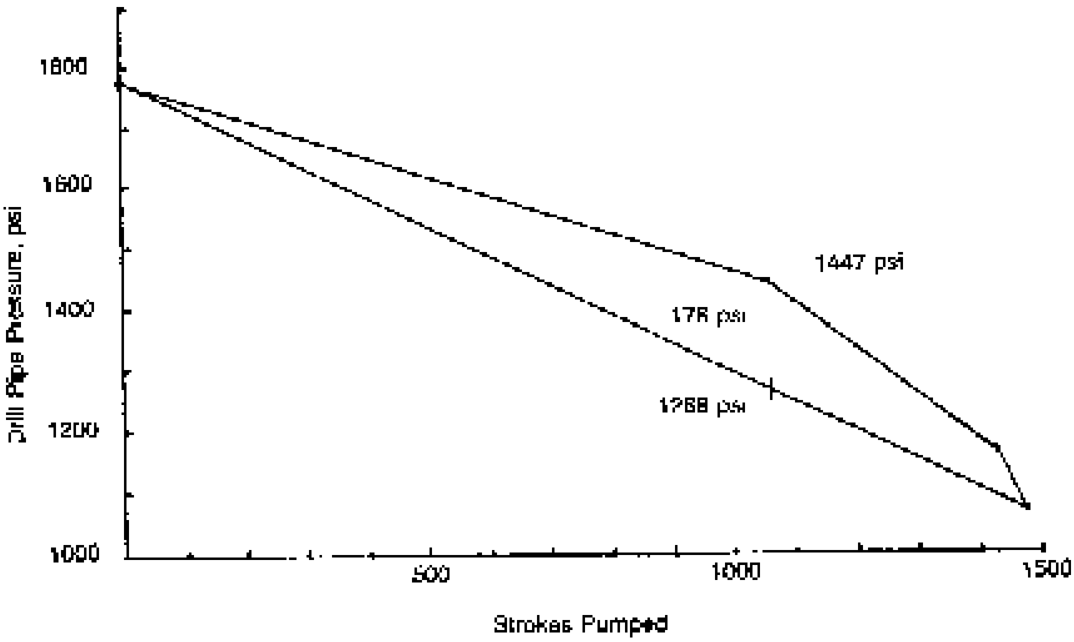

Figure 4-1. Data from kill sheet.

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 sections: 1) from surface to KOP, and 2) from KOP to TD. The following calculations are used:

Determine strokes from surface to KOP:

Strokes = drill pipe capacity, bbl!ft x measured depth to KOP, ft x pump output, bbl/stk

Determine strokes from KOP to TD:

Strokes = drill string capacity, bbl/ft x measured depth to TD, ft x pump output, bbl/stk

Kill weight mud: KWM = SIDPP ÷ 0.052 ÷ TVD + OMW

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.

Example:	Original mud weight (OMW)	= 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 (TVD)	= 10,000 ft

Solution:

Strokes from surface to KOP:

Strokes = 0.01776 bbl/ft x 5000 ft ÷ 0.136 bbl/stk
Strokes = 653

Strokes from KOP to TD:

Strokes = 0.01776 bbl/ft x 10,000 ft + 0.136 bbl/stk
Strokes = 1306

Total strokes from surface to bit:

Surface to bit strokes = 653 + 1306
Surface to bit strokes = 1959
Kill weight mud (KWM):

KWM = 800 psi 0.052 + 10,000 ft + 9.6 ppg
KWM = 11.1 ppg

Initial circulating pressure (ICP):

ICP = 800 psi + 600 psi
ICP = 1400 psi

Final circulating pressure (FCP):

FCP = 11.1 ppg x 600 psi ± *9.6* ppg
FCP = 694 psi

Hydrostatic pressure increase from surface to KOP:

HPi = (11.1 — 9.6) x 0.052 x 5000
HPi = 390 psi

Friction pressure increase to TD:

FP = (694 — 600) x 5000 ÷ 15,000
FP = 31 psi

Circulating pressure when KWM gets to KOP:

CP = 1400 — 390 + 31
CP = 1041 psi

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

psi/stk = 1400 — 694 + 1959
psi/stk = 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 100 psi or greater, then the adjusted pressure chart should be used to minimise the chances of losing circulation.

The chart below graphically illustrates the difference:

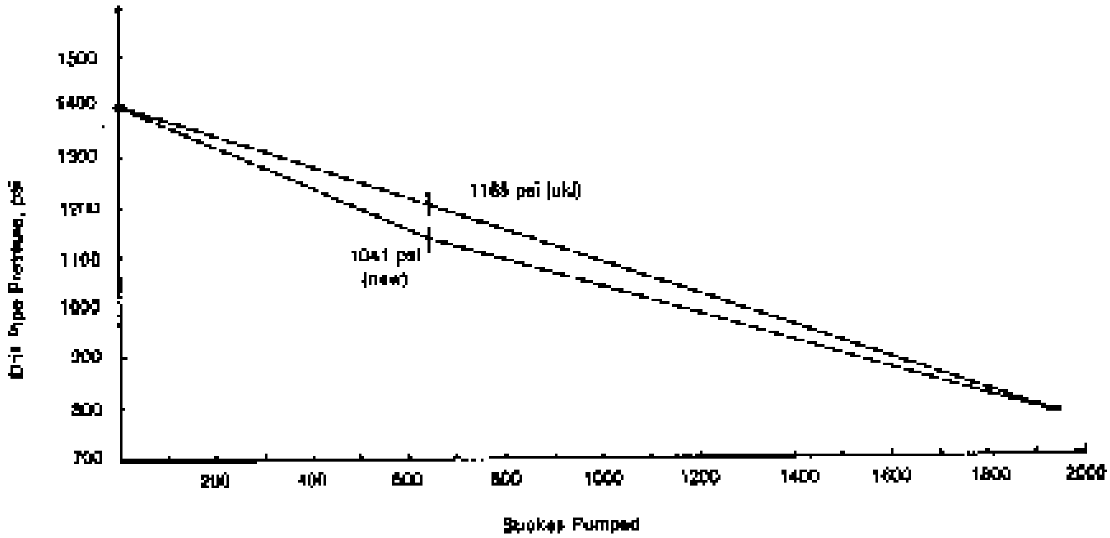

Figure 4—2. Adjusted pressure chart.

2. Pre-recorded 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):

FP max = (maximum mud wt to be used, ppg + safety factor, ppg) x 0.052 x (total depth, ft)

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 of l00%.

HPgas = gas gradient, psi/ft x total depth, ft

Step 3 Determine maximum anticipated surface pressure (MASP):

MASP = FPmax — HPgas

Example: 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 Determine fracture pressure, psi:

FPmax = (12.0 + 4.0) **x** 0.052 x 12,000 ft
FPmax = 9984 psi

Step 2

HPgas = 0.12 x 12,000 ft
HPgas = 1440 psi

Step 3

MASP = 9984 — 1440
MASP = 8544 psi

Method 2: Use when assuming the maximum pressure in the wellbore is attained when the formation at the shoe fractures:

Step 1

Fracture pressure, psi = (estimated fracture gradient, ppg + safety factor, ppg) x 0.052 x (casing shoe TVD, ft)

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:

Example: 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
Fracture pressure, psi = 3162 psi

Step 2 HPgas = 0.12 x 4000 ft
HPgas = 480 psi

Step 3 MASP = 3162 — 480
MASP = 2682 psi

Sizing Diverter Lines

Determine diverter line inside diameter, in., equal to the area between the inside diameter of the casing and the outside diameter of drill pipe in use:

Diverter line ID, in. = ~Ib~bp2

Example: Casing— 13-3/8 in. — J-55 — 61 IbIft ID = 12.515 in.
Drill pipe — 19.5 lb/ft OD = 5.0 in.

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

Diverter line ID, in. = sq. root (12.515^2 — 5.0^2)
Diverter line ID = 11.47 in.

Formation Pressure Tests

Two methods of testing:
- Equivalent mud weight test
- Leak-off test

Precautions to be 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 minutes, 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.

Example: Maximum mud weight necessary to drill the next interval = 11.5 ppg plus safety factor = 1.0 ppg

Equivalent test mud weight, ppg = (maximum mud weight, ppg) + (safety factor, ppg)

Equivalent test mud weight = 11.5 ppg + 1.0 ppg
Equivalent test mud weight = 12.5 ppg

Method 2: Subtract a value from the estimated fracture gradient for the depth of the casing shoe.

Equivalent test mud weight = (estimated fracture gradient, ppg) — (safety factor)

Example: 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:

Surface pressure, psi = (equiv. Test (mud wt, ppg — mud wt, in use, ppg) x 0.052 x (casing seat, TVD ft)

Example: 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
Surface pressure = 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.

Estimated leak-off pressure = (estimated fracture (gradient — mud wt in use, ppg) x 0.052 x (casing shoe) (TVD, ft)

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

Solution: Estimated leak-off pressure = (14.4 — 9.6) x 0.052 x 4000 ft
Estimated leak-off pressure = 4.8 x 0.052 x 4000
Estimated leak-off pressure = 998 psi

Maximum Allowable Mud Weight From Leak-off Test Data

Max allowable mud weight, ppg = (leak off pressure, psi) ÷ 0.052 ÷ (casing shoe TVD, ft) + (mud wt in use, ppg)

Example: Determine the maximum allowable mud weight, ppg, using the following data:

Leak-off pressure = 1040 psi
Casing shoe TVD = 4000 ft
Mud weight in use = 10.0 ppg

Max allowable mud weight, ppg = 1040 + 0.052 -~- 4000 + 10.0
Max allowable mud weight, ppg = 15.0 ppg

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

MASICP = (maximum allowable mud wt, ppg — mud wt in use, ppg) x 0.052 x (casing shoe TVD, ft)

Example: 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
MASICP = 582 psi

Kick Tolerance Factor (KTF)

$$\text{KTF} = \frac{\text{Casing shoe TVD, ft)}}{\text{well depth}} \times (\text{maximum allowable mud wt, ppg} - \text{mud wt in use, ppg})$$

Example: Determine the kick tolerance factor (KTF) using the following data:

Mud weight in use = 10.0 ppg
Casing shoe TVD = 4000 ft
Well depth TVD = 10,000 ft
Maximum allowable mud weight (from leak-off test data) = 14.2 ppg

KTF = (4000 ft ÷ 10,000 ft) x (14.2 ppg — 10.0 ppg)
KTF = 1.68 ppg

Maximum Surface Pressure From Kick Tolerance Data

Maximum surface pressure = kick tolerance factor, ppg x 0.052 x TYD, ft

Example: Determine the maximum surface pressure, psi, using the following data:

Maximum surface pressure = 1.68 ppg x 0.052 x 10,000 ft
Maximum surface pressure = 874 psi

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

Maximum FP, psi = (kick tolerance factor, ppg + mud wt in use, ppg) x 0.052 x TYD, ft

Example: 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
Maximum FP = 6074 psi

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

Influx height = MASICP, psi ÷ (gradient of mud wt in use, psi/ft — influx gradient, psi/ft)

Example: 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/fl)
Influx height = 2185 ft

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

Example: Maximum influx height to equal MASICP (from above example) = 2185 ft
Annular capacity — drill collars/open hole (12-1/4 in. x 8.0 in.) = 0.0826 bbl/ft
Annular capacity — drill pipe/open hole (12-1/4 in. x 5.0 in.) = 0.1215 bbl/ft
Drill collar length = 500 ft

Step 1 Determine the number of barrels opposite drill collars:

Barrels = 0.0836 bbl/ft x 500 ft
Barrels = 41.8

Step 2 Determine the number of barrels opposite drill pipe:

Influx height, ft, opposite drill pipe: ft = 2185 ft — 500 ft
ft = 1685

Barrels opposite drill pipe: Barrels = 1685 ft x 0.1215 bbl/ft
Barrels = 204.7

Step 3 Determine maximum influx, bbl, to equal maximum allowable shut-in casing pressure:

Maximum influx = 41.8 bbl + 204.7 bbl
Maximum influx = 246.5 bbl

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

MASICP = P_L — [D x (mud wt_2 — mud wt_1)] 0.052

where MASICP = maximum allowable shut-in casing (annulus) pressure, psi
P_L = leak-off pressure, psi
D = true vertical depth to casing shoe, ft
Mud wt_2 = new mud wt, ppg
Mud wt_1 = original mud wt, ppg

Example: 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]
MASICP = 1040 psi — 520
MASICP = 520 psi

3. Kick Analysis

Formation Pressure (FP) With the Well Shut-in on a Kick

FP, psi = SIDPP, psi + (mud wt, ppg x 0.052 x TVD, ft)

Example: Determine the formation pressure using the following data:

Shut-in drill pipe pressure = 500 psi Mud weight in drill pipe = 9.6 ppg
True vertical depth = 10,000 ft

FP, psi = 500 psi + (9.6 ppg x 0.052 x 10,000 ft)
FP, psi = 500 psi + 4992 psi
FP = 5492 psi

Bottom hole Pressure (BHP) With the Well Shut-in on a Kick

BHP, psi = SIDPP, psi + (mud wt, ppg x 0.052 x TVD, ft)

Example: Determine the bottom hole pressure (BHP) with the well shut-in on a kick:

Shut-in drill pipe pressure = 500 psi Mud weight in drill pipe = 9.6 ppg
True vertical depth = 10,000 ft

BHP, psi = 500 psi + (9.6 ppg x 0.052 x 10,000 ft)
BHP, psi = 500 psi + 4992 psi
BHP = 5492 psi

Shut-in Drill Pipe Pressure (SIDPP)

SIDPP, psi = formation pressure, psi — (mud wt, ppg x 0.052 x TVD, ft)

Example: Determine the shut-in drill pipe pressure using the following data:

Formation pressure = 12,480 psi Mud weight in drill pipe =. 15.0 ppg
True vertical depth = 15,000 ft

SIDPP, psi = 12,480 psi — (15.0 ppg x 0.052 x 15,000 ft)
SIDPP, psi = 12,480 psi — 11,700 psi
SIDPP = 780 psi

Shut-in Casing Pressure (SICP)

SICP =(formation pressure, psi) — (HP of mud in annulus, psi + HP of influx in annulus, psi)

Example: Determine the shut-in casing pressure using the following data:

Formation pressure = 12,480 psi Mud weight in annulus = 15.0 ppg
Feet of mud in annulus = 14,600 ft Influx gradient = 0.12 psi/ft
Feet of influx in annulus = 400 ft

SICP, psi = 12,480 —[(15.0 x 0.052 x 14,600) + (0.12 x 400)]
SICP, psi = 12,480 — 11,388 + 48
SICP = 1044 psi

Height, Fl, of Influx

Height of influx, ft = pit gain, bbl ÷ annular capacity, bbl/ft

Example 1: Determine the height, ft, of the influx using the following data:

Pit gain = 20 bbl Annular capacity — DC/OH = 0.02914 bbl/ft
(Dh = 8.5 in. — Dp = 6.5)

Height of influx, ft = 20 bbl ÷ 0.029 14 bbl/ft
Height of influx = 686 ft

Example 2: Determine the height, ft, of the influx using the following data:

Pit gain = 20 bbl Hole size = 8.5 in.
Drill collar OD = 6.5 in. Drill collar length = 450 ft
Drill pipe OD = 5.0 in.

Determine annular capacity, bbl/ft, for DC/OH:

$$\text{Annular capacity, bbl/ft} = \frac{8.5^2 - 6.5^2}{1029.4}$$

Annular capacity = 0.02914 bbl/ft

Determine the number of barrels opposite the drill collars:

Barrels = length of collars x annular capacity
Barrels = 450 ft x 0.029 14 bbl/ft
Barrels = 13.1

Determine annular capacity, bbl/ft, opposite drill pipe:

$$\text{Annular capacity, bbl/ft} = \frac{8.5^2 - 5.0^2}{1029.4}$$

Annular capacity = 0.0459 bbl/ft

Determine barrels of influx opposite drill pipe:

Barrels = pit gain, bbl — barrels opposite drill collars
Barrels = 20 bbl — 13.1 bbl
Barrels = 6.9

Determine height of influx opposite drill pipe:

Height, ft = 6.9 bbl -:- 0.0459 bbl/ft
Height = 150 ft

Determine the total height of the influx:

Height, ft = 450 ft + 150 ft
Height = 600 ft

Estimated Type of Influx

Influx weight, ppg = mud wt, ppg — ((SICP — SIDPP) ÷ height of influx, ft x 0.052)

then: 1 — 3 ppg = gas kick
4 — 6 ppg = oil kick or combination
7 — 9 ppg = saltwater kick

Example: Determine the type of the influx using the following data:
Shut-in casing pressure = 1044 psi Height of influx = 400 ft
Shut-in drill pipe pressure = 780 psi Mud weight = 15.0 ppg

Influx weight, ppg = 15.0 ppg — ((1044 — 780) ÷ 400 x 0.052)
Influx weight, ppg = 15.0 ppg — $\frac{264}{20.8}$

Influx weight = 2.31 ppg

Therefore, the influx is probably “gas.”

Gas Migration in a Shut-in Well

Estimating the rate of gas migration, ft/hr:

Vg = I $2e^{(—\ 0.37)(\text{mud wt. ppg})}$
Vg = rate of gas migration, ft/hr

Example: Determine the *estimated* rate of gas migration using a mud weight of 11.0 ppg:

Vg = $12e^{(—\ 0.37)(11.0\ \text{ppg})}$
Vg = $12e^{(—4.07)}$
Vg = 0.205 ft/sec
Vg = 0.205 ft/sec x 60 sec/min
Vg = 12.3 ft/min x 60 min/hr
Vg = 738 ft/hr

Determining the *actual* rate of gas migration after a well has been shut-in on a kick:

$$\text{Rate of gas migration, ft/hr} = \frac{\text{increase in casing pressure, psi/hr}}{\text{pressure gradient of mud weight in use, psi/ft}}$$

Example: Determine the rate of gas migration with the following data:

Stabilised shut-in casing pressure = 500 psi
SICP after one hour = 700 psi
Pressure gradient for 12.0 ppg mud = 0.624 psi/ft
Mud weight = 12.0 ppg

Rate of gas migration, ft/hr = 200 psi/hr ÷ 0.624 psi/ft
Rate of gas migration = 320.5 ft/hr

Hydrostatic Pressure Decrease at TD Caused by Gas Cut Mud

Method 1:

$$\text{HP decrease, psi} = \frac{100\,(\text{weight of uncut mud, ppg} - \text{weight of gas cut mud, ppg})}{\text{weight of gas cut mud, ppg}}$$

Example: Determine the hydrostatic pressure decrease mud using the following data:

Weight of uncut mud = 18.0 ppg
Weight of gas cut mud = 9.0 ppg

$$\text{HP decrease, psi} = \frac{100 \times (18.0 \text{ ppg} - 9.0 \text{ ppg})}{9.0 \text{ ppg}}$$

HP Decrease = 100 psi

Method 2: $P = (MG \div C)\,V$

where P = reduction in bottomhole pressure, psi
C = annular volume, bbl/ft
MG = mud gradient, psi/ft
V = pit gain, bbl

Example: MG = 0.624 psi/ft
C = 0.0459 bbl/ft (Dh = 8.5 in.; Dp = 5.0 in.)
V = 20 bbl

Solution: P = (0.624 psi/ft ÷ 0.0459 bbl/ft) 20
P = 13.59 x 20
P = 271.9 psi

Maximum Surface Pressure From a Gas Kick in a Water Base Mud

$$MSPgk = 0.2\sqrt{P \times V \times KWM \div C}$$

where MSPgk = maximum surface pressure resulting from a gas kick in a water base mud
P = formation pressure, psi
V = pit gain, bbl
KWM = kill weight mud, ppg
C = annular capacity, bbl/ft

Example: P = 12,480 psi V = 20 bbl
KWM = 16.0 ppg C = 0.0505 bbl/ft (Dh = 8.5 in. x Dp = 4.5 in.)

Solution: $MSPgk = 0.2 \sqrt{\dfrac{12{,}480 \times 20 \times 16.0}{0.0505}}$

$MSPgk = 0.2 \sqrt{79081188}$
MSPgk = 0.2 x 8892.76
MSPgk = 1779 psi

Maximum Pit Gain From Gas Kick in a Water Base Mud

$MPGgk = 4 \sqrt{\dfrac{P \times V \times C}{KWM}}$

where MPGgk = maximum pit gain resulting from a gas kick in a water base mud
P = formation pressure, psi
V = original pit gain, bbl
C = annular capacity, bbl/ft
KWM = kill weight mud, ppg

Example: P = 12,480 psi V = 20 bbl C = 0.0505 bbl/ft (8.5 in. x 4.5 in.)

Solution: $MPGgk = 4 \sqrt{\dfrac{12{,}480 \times 20 \times 0.0505}{16.0}}$

$MPGgk = 4 \sqrt{787.8}$
MPGgk = 4 x 28.06
MPGgk = 112.3 bbl

Maximum Pressures When Circulating Out a Kick (Moore Equations)

The following equations will be used:

1. Determine formation pressure, psi: **Pb = SIDP + (mud wt, ppg x 0.052 x TVD, ft)**

2. Determine the height of the influx, ft: **hi = pit gain, bbl ÷ annular capacity, bbl/ft**

3. Determine pressure exerted by the influx, psi: **Pi = Pb — [Pm (D — X) + SICP]**

4. Determine gradient of influx, psi/ft: **Ci = Pi ÷ hi**

5. Determine Temperature, °R, at depth of interest: **Tdi = 70°F + (0.012°F/ft. x Di) + 460**

6. Determine A for unweighted mud: **A = Pb — [Pm (D — X) — Pi]**

7. Determine pressure at depth of interest: $\mathbf{Pdi = \dfrac{A}{2} + \left(\dfrac{A^2}{4} + \dfrac{pm\ Pb\ Zdi\ T°Rdi\ hi}{Zb\ Tb}\right)^{1/2}}$

8. Determine kill weight mud, ppg: **KWM, ppg = SIDPP ÷ 0.052 ÷ TVD, ft + 0MW, ppg**

9. Determine gradient of kill weight mud, psi/ft: **pKWM = KWM, ppg x 0.052**

10. Determine FEET that drill string volume will occupy in the annulus:

Di = drill string vol, bbl ÷ annular capacity, bbl/ft

11. Determine A for weighted mud: **A = Pb — [pm (D — X) — Pi] + [Di (pKWM — pm)}**

Example: Assumed conditions:

Well depth	= 10,000 ft	Hole size	= 8.5 in.
Surface casing	= 9-5/8 in. @ 2500 ft	Casing ID	= 8.921 in.
Fracture gradient @ 2500 ft	= 0.73 psi/ft (14.04 ppg)	Casing ID capacity	= 0.077 bbl/ft
Drill pipe	= 4.5 in. — 16.6 lb/ft	Drill collar OD	= 6-1/4 in.
Drill collar OD length	= 625 ft	Mud weight	= 9.6 ppg

Mud volumes:

8-1/2 in. hole	= 0.07 bbl/ft	8.921 in. casing x 4-1/2 in. drill pipe	= 0.057 bbl/ft
Drill pipe capacity	= 0.014 bbl/ft	8-1/2 in. hole x 6-1/4 in. drill collars	= 0.032 bbl/ft
Drill collar capacity	= 0.007 bbl/ft	8-1/2 in. hole x 4-1/2 in. drill pipe	= 0.05 bbl/ft

Super compressibility factor (Z) = 1.0

The well kicks and the following information is recorded

SIDP = 260 psi
SICP = 500 psi
pit gain = 20 bbl

Determine the following:

Maximum pressure at shoe with drillers method
Maximum pressure at surface with drillers method
Maximum pressure at shoe with wait and weight method
Maximum pressure at surface with wait and weight method

Determine maximum pressure at shoe with drillers method:

1. Determine formation pressure: Pb = 260 psi + (9.6 ppg x 0.052 x 10,000 ft)
Pb = 5252 psi

2. Determine height of influx at TD: hi = 20 bbl ÷ 0.032 bbl/ft
hi = 625 ft

3. Determine pressure exerted by influx at TD:

Pi = 5252 psi — [0.4992 psi/ft (10,000 — 625) + 500]
Pi = 5252 psi — [4680 psi + 500]
Pi = 5252 psi — 5180 psi
Pi = 72 psi

4. Determine gradient of influx at TD:

Ci = 72 psi ÷ 625 ft
Ci = 0.1152 psi/ft

5. Determine height and pressure of influx around drill pipe:

h = 20 bbl ÷ 0.05 bbl/ft
h = 400 ft

Pi = 0.1152 psi/ft x 400 ft
Pi = 46 psi

6. Determine T °R at TD and at shoe:

T°R @ 10,000 ft = 70 + (0.012 x 10,000) + 460
= 70 + 120 + 460
T°R @ 10,000ft = 650
T°R @ 2500 ft = 70 + (0.012 x 2500) + 460
= 70 + 30 + 460
T°R@ 2500ft = 560

7. Determine A:

A = 5252 psi — [0.4992 (10,000 — 2500) + 46]
A = 5252 psi — (3744 — 46)
A = 1462 psi

8. Determine maximum pressure at shoe with drillers method:

$$P_{2500} = \frac{1462}{2} + \left[\frac{1462^2}{4} \frac{(0.4992)(5252)(1)(560)(400)}{(1)(650)}\right]^{1/2}$$

= 731 + (534361 + 903512)12
= 731 + 1199
P_{2500} = 1930 psi

Determine maximum pressure at surface with drillers method:

1. Determine A:

A = 5252 — [0.4992 (10,000) + 46]
A = 5252 — (4992 + 46)
A = 214 psi

2. Determine maximum pressure at surface with drillers method:

$$Ps = \frac{214}{2} + \left[\frac{214^2}{4} \frac{(0.4992)(5252)(1)(530)(400)}{650}\right]^{1/2}$$

= 107 + (11449 + 855109) $^{1/2}$
= 107 + 931
Ps = 1038 psi

Determine maximum pressure at shoe with wait and weight method:

1. Determine kill weight mud:

KWM, ppg = 260 psi ÷ 0.052 ÷ 10,000 ft + 9.6 ppg
KWM, ppg = 10.1 ppg

2. Determine gradient (pm), psi/ft for KWM:

pm = 10.1 ppg x 0.052
pm = 0. 5252 psi/ft

3. Determine internal volume of drill string:

Drill pipe vol = 0.014 bbl/ft x 9375 ft = 131.25 bbl
Drill collar vol = 0.007 bbl/ft x 625 ft = 4.375 bbl
Total drill string volume = 135.625 bbl

4. Determine FEET drill string volume occupies in annulus:

Di = 135.625 bbl ÷ 0.05 bbl/ft
Di = 2712.5

5. Determine A:

A = 5252 — [0.5252 (10,000 — 2500) — 46) + (2715.2 (0.5252 — 0.4992)]
A = 5252 — (3939 — 46) + 70.6
A = 1337.5

6. Determine maximum pressure at shoe with wait and weight method:

$$P_{2500} = \frac{1337.5}{2} + \left[\frac{1337.5^2}{4} + \frac{(0.5252)(5252)(1)(560)(400)}{(1)\ (650)}\right]^{1/2}$$

$$= 668.75 + (447226 + 950569.98)^{1/2}$$
$$= 668.75 + 1182.28$$
$$= 1851 \text{ psi}$$

Determine maximum pressure at surface with wait and weight method:

1. Determine A:

A = 5252 — [0.5252(10,000) — 46] + [2712.5(0.5252 — 0.4992)]
A = 5252 — (5252 — 46) + 70.525
A = 24.5

2. Determine maximum pressure at surface with wait and weight method:

$$Ps = \frac{12.25}{2} + \left[\frac{24.5^2}{4} + \frac{(0.5252)(5252)(l)(560)(400)}{(fl(650)}\right]^{1/2}$$

$Ps = 12.25 + (150.0625 + 95069.98)^{1/2}$
$Ps = 12.25 + 975.049$
$Ps = 987$ psi

Nomenclature:

A	= pressure at top of gas bubble, psi
Ci	= gradient of influx, psi/ft
D	= total depth, ft
Di	= feet in annulus occupied by drill string volume
MW	= mud weight, ppg
Pdi	= pressure at depth of interest, psi
Pi	= pressure exerted by influx, psi
pm	= pressure gradient of mud weight in use, ppg
psihi	= height of influx, ft
Pb	= formation pressure, psi
pKWM	= pressure gradient of kill weight mud, ppg
Ps	= pressure at surface, psi
SIDP	= shut-in drill pipe pressure, psi
SICP,	= shut-in casing pressure,
T°F	= temperature, degrees Fahrenheit, at depth of interest
T°R	= temperature, degrees Rankine, at depth of interest
X	= depth of interest, ft
Zb	= gas supercompressibility factor TD
Zdi	= gas supercompressibility factor at depth of interest

Gas Flow Into the Wellbore

Flow rate into the wellbore increases as wellbore depth through a gas sand increases:

Q = 0.007 x md x Dp x L ÷ U x ln(Re Rw) 1,440

where Q = flow rate, bbl/min
Dp = pressure differential, psi
U = viscosity of intruding gas, centipoise
Rw = radius of wellbore, ft
md = permeability, millidarcys
L = length of section open to wellbore, ft
Re = radius of drainage, ft

Example: md = 200 md Dp = 624 psi L =2Oft U = 0.3cp ln(Re ÷ Rw) = 2,0

Q = 0.007 x 200 x 624 x 20 ÷ 0.3 x 2.0 x 1440
Q = 20 bbl/min

Therefore: If one minute is required to shut-in the well, a pit gain of ‘ 20 bbl occurs in addition to the gain incurred while drilling the 20-ft section.

4. Pressure Analysis

Gas Expansion Equations

Basic gas laws: $P_1 V_1 \div T_1 = P_2 V, \div T_2$

where P_1 = formation pressure, psi
P_2 = hydrostatic pressure at the surface or any depth in the wellbore, psi
. V_1 = original pit gain, bbl
V_2 = gas volume at surface or at any depth of interest, bbl
T_1 = temperature of formation fluid, degrees Rankine (°R = °F + 460)
T_2 = temperature at surface or at any depth of interest, degrees Rankine

Basic gas law plus compressibility factor: $P_1 V_1 + T_1 Z_1 = P_2 V_2 + T_2 Z_2$

where Z_1 = compressibility factor under pressure in formation, dimensionless
Z_2 = compressibility factor at the surface or at any depth of interest, dimensionless

Shortened gas expansion equation: $P_5 V_1 = P, V_2$

where P_1 = formation pressure, psi
P_2 = hydrostatic pressure plus atmospheric pressure (14.7 psi), psi
V_1 = original pit gain, bbl
V_2 = gas volume at surface or at any depth of interest, bbl

Hydrostatic Pressure Exerts by Each Barrel of Mud in the Casing

With pipe in the wellbore:

$$\text{psi/bbl} = \frac{1029.4}{Dh^2 — Dp^2} \times 0.052 \times \text{mud wt, ppg}$$

Example: Dh — 9-5/8 in, casing — 43.5 lb/ft = 8.755 in. ID Dp = 5.0 in. OD
Mud weight = 10.5 ppg

$$\text{psi/bbl} = \frac{1029.4}{8.755^2 — 5.0^2} \times 0.052 \times 10.5 \text{ ppg}$$

psi/bbl = 19.93029 x 0.052 x 10.5 ppg
psi/bbl = 10.88

With no pipe in the wellbore:

$$\text{psi/bbl} = \frac{1029.4}{ID^2} \times 0.052 \times \text{mud wt ppg}$$

Example: Dh — 9-5/8 in. casing — 43.5 lb/ft = 8.755 in. ID Mud weight = 10.5 ppg

$$\text{psi/bbl} = \frac{1029.4}{8.755^2} \times 0.052 \times 10.5 \text{ ppg}$$

psi/bbl = 13.429872 x 0.052 x 10.5 ppg
psi/bbl = 7.33

Surface Pressure During Drill Stem Tests

Determine formation pressure:

psi = formation pressure equivalent mud wt, ppg x 0.052 x TVD, ft

Determine oil hydrostatic pressure:

psi = oil specific gravity x 0.052 x TVD, ft

Determine surface pressure:

Surface pressure, psi = formation pressure, psi — oil hydrostatic pressure, psi

Example: Oil bearing sand at 12,500 ft with a formation pressure equivalent to 13.5 ppg. If the specific gravity of the oil is 0.5, what will be the static surface pressure during a drill stem test?

Determine formation pressure, psi:

FP, psi = 13.5 ppg x 0.052 x 12,500 ft
FP = 8775 psi

Determine oil hydrostatic pressure:

psi = (0.5 x 8.33) x 0.052 x 12,500 ft
psi = 2707

Determine surface pressure:

Surface pressure, psi = 8775 psi — 2707 psi
Surface pressure = 6068 psi

5. Stripping/Snubbing Calculations

Breakover Point Between Stripping and Snubbing

Example: Use the following data to determine the breakover point:

DATA: Mud weight = 12.5 ppg
Drill collars (6-1/4 in.— 2-13/16 in.) = 83 lb/ft
Length of drill collars = 276 ft
Drill pipe = 5.0 in.
Drill pipe weight = 19.5 lb/ft
Shut-in casing pressure = 2400 psi
Buoyancy factor = 0.8092

Determine the force, lb, created by wellbore pressure on 6-1/4 in. drill collars:

Force, lb = (pipe or collar OD, In)^2 x 0.7854 x (wellbore pressure, psi)

Force, lb = 6.252 x 0.7854 x 2400 psi
Force = 73,631 lb

Determine the weight, lb, of the drill collars:

Wt, lb = drill collar weight, lb/ft x drill collar length, ft x buoyancy factor

Wt, lb = 83 lb/ft x 276 ft x 0.8092
Wt, lb = 18,537 lb

Additional weight required from drill pipe:

Drill pipe weight, lb = force created by wellbore pressure, lb — drill collar weight, lb

Drill pipe weight, lb = 73,631 lb — 18,537 lb
Drill pipe weight, lb = 55,094 lb

Length of drill pipe required to reach breakover point:

Drill pipe = (required drill pipe weight, lb) ÷ (drill pipe weight, lb/ft x factor buoyancy)
length, ft

Drill pipe length, ft = 55,094 lb ÷ (19.5 lb/ft x 0.8092)
Drill pipe length, ft = 3492 ft

Length of drill string to reach breakover point:

Drill string length, ft = drill collar length, ft + drill pipe length, ft

Drill string length, ft = 276 ft + 3492 ft
Drill string length = 3768 ft

Minimum Surface Pressure Before Stripping is Possible

Minimum surface pressure, psi = (weight of one stand of collars, lb) ÷ (area of drill collars, sq in.)

Example: Drill collars — 8.0 in. OD x 3.0 in. ID = 147 lb/ft Length of one stand 92 ft

Minimum surface pressure, psi = (147 lb/ft x 92 ft) ÷ (8^2 x 0.7854)
Minimum surface pressure, psi = 13,524 ÷ 50.2656 sq in.
Minimum surface pressure = 269 psi

Height Gain From Stripping into Influx

$$\text{Height, ft} = \frac{L\,(Cdp + Ddp)}{Ca}$$

where L = length of pipe stripped, ft
Cdp = capacity of drill pipe, drill collars, or tubing, bbl/ft
Ddp = displacement of drill pipe, drill collars or tubing, bbl/ft
Ca = annular capacity, bbl/ft

Example: If 300 ft of *5.0* in. drill pipe — 19.5 lb/ft is stripped into an influx in a 12-1/4 in. hole, determine the height, ft, gained:

DATA: Drill pipe capacity = 0.01776 bbl/ft Length drill pipe stripped = 300 ft
Drill pipe displacement = 0.00755 bbl/ft Annular capacity = 0.1215 bbl/ft

Solution:

$$\text{Height, ft} = \frac{300\,(0.01776 + 0.00755)}{0.1215}$$

Height = 62.5 ft

Casing Pressure Increase From Stripping Into Influx

psi = (gain in height, ft) x (gradient of mud, psi/ft — gradient of influx, psi/ft)

Example: Gain in height = 62.5 ft
Gradient of mud (12.5 ppg x 0.052) = 0.65 psi/ft
Gradient of influx = 0.12 psi/ft

psi = 62.5 ft x (0.65 — 0.12)
psi = 33 psi

Volume of Mud to Bleed to Maintain Constant Bottomhole Pressure with a Gas Bubble Rising

With pipe in the hole:

$$\text{Vmud} = \frac{Dp \times Ca}{\text{gradient of mud, psi/ft}}$$

where Vmud = volume of mud, bbl, that must be bled to maintain constant bottomhole pressure with a gas bubble rising.
Dp = incremental pressure steps that the casing pressure will be allowed to increase.
Ca = annular capacity, bbllft

Example: Casing pressure increase per step = 100 psi
Gradient of mud (13.5 ppg x 0.052) = 0.70 psi/ft
Annular capacity (Dh = 12-1/4 in.; Dp = 5.0 in.) = 0.1215 bbl/ft

$$\text{Vmud} = \frac{100 \text{ psi} \times 0.1215 \text{ bbl/ft}}{0.702 \text{ psi/ft}}$$

Vmud = 17.3 bbl

With no pipe in hole: $\text{Vmud} = \frac{\text{Dp} \times \text{Ch}}{\text{gradient of mud, psi/ft}}$

Example: Casing pressure increase per step = 100 psi
Gradient of mud (*13.5* ppg x 0.052) = 0.702 psi/ft
Hole capacity (12-1/4 in.) = 0.1458 bbl/ft

$$\text{Vmud} = \frac{100 \text{ psi} \times 0.1458 \text{ bbl/ft}}{0.702 \text{ psi/ft}}$$

Vmud = 20.77 bbl

Maximum Allowable Surface Pressure (MASP) Governed by the Formation

MASP, psi = (maximum allowable mud wt, ppg — mud wt, in use, ppg) 0.052 x casing shoe TVD, ft

Example: Maximum allowable mud weight = 15.0 ppg (from leak-off test data)
Mud weight = 12.0 ppg
Casing seat TVD = 8000 ft

MASP, psi = (15.0 — 12.0) x 0.052 x 8000
MASP = 1248 psi

Maximum Allowable Surface Pressure (MASP) Governed by Casing Burst Pressure

MASP = (casing burst pressure, psi x safety factor) — (mud wt in use, ppg — mud wt outside casing, ppg) x 0.052 x casing, shoe TVD ft

Example: Casing — 10-3/4 in. — 51 lb/ft N-80 Casing burst pressure = 6070 psi
Casing setting depth = 8000 ft Mud weight in use = 12.0 ppg
Mud weight behind casing = 9.4 ppg Casing safety factor = 80%

MASP = (6070 x 80%) — [(12.0 — 9.4) x 0.052 x 8000]
MASP = 4856 — (2.6 x 0.052 x 8000)
MASP = 3774 psi

6. Subsea Considerations

Casing Pressure Decrease when Bringing Well on Choke

When bringing the well on choke with a subsea stack, the casing pressure (annulus pressure) must be allowed to decrease by the amount of choke line pressure loss (friction pressure):

Reduced casing pressure, psi = (shut-in casing pressure, psi) — (choke line pressure loss, psi)

Example: Shut-in casing (annulus) pressure (SICP) = 800 psi
Choke line pressure loss (CLPL) = 300 psi

Reduced casing pressure, psi = 800 psi — 300 psi
Reduced casing pressure = 500 psi

Pressure Chart for Bringing Well on Choke

Pressure/stroke relationship is not a straight line effect. While bringing the well on choke, to maintain a constant bottomhole pressure, the following chart should be used:

Pressure Chart

	Strokes	Pressure
Line 1: Reset stroke counter to “0” =	0	
Line 2: 1/2 stroke rate = 50 x 0.5 =	25	
Line 3: 3/4 stroke rate = 50 x 0.75 =	38	
Line 4: 7/8 stroke rate = 50 x 0.875 =	44	
Line 5: Kill rate speed =	50	

Strokes side: Example: kill rate speed = 50 spm

Pressure side: Example. Shut-in casing pressure (SICP) = 800 psi
Choke line pressure loss (CLPL) = 300 psi

Divide choke line pressure loss (CLPL) by 4, because there are 4 steps on the chart:

$$\text{psi/line} = \frac{\text{(CLPL) 300 psi}}{4} = 75 \text{ psi}$$

Pressure Chart

	Strokes	Pressure
Line 1: Shut-in casing pressure, psi =		800
Line 2: Subtract *75* psi from Line 1 =		725
Line 3: Subtract *75* psi from Line 2 =		650
Line 4: Subtract *75* psi from Line 3 =		575
Line *5:* Reduced casing pressure =		500

Maximum Allowable Mud Weight, ppg, Subsea Stack as Derived from Leak-off Test Data

Maximum allowable = (leak-off test) ÷ 0.052 ÷ (TVD, ft RKB) + (mud wt in use, ppg)
mud weight ppg (pressure, psi) (to casing shoe)

Example: Leak-off test pressure = 800 psi
TVD from rotary bushing to casing shoe = 4000 ft
Mud in use = 9.2 ppg

Maximum allowable mud weight, ppg = 800 0.052 ÷ 4000 + 9.2
Maximum allowable mud weight = 13.0 ppg

Maximum Allowable Shut-in Casing (Annulus) Pressure

MASICP = (maximum allowable — mud wt in) x 0.052 x (RKB to casing shoe TVD, ft)
(mud wt, ppg use, ppg)

Example: Maximum allowable mud weight = 13.3 ppg
Mud weight in use = 11.5 ppg
TVD from rotary Kelly bushing to casing shoe = 4000 ft

MASICP = (13.3 ppg — 11.5 ppg) x 0.052 x 4000 ft
MASICP = 374

Casing Burst Pressure — Subsea Stack

Step 1 Determine the internal yield pressure of the casing from the “Dimensions and Strengths” section of cement company’s service handbook.

Step 2 Correct internal yield pressure for safety factor. Some operators use 80%; some use 75%, and others use70%:

Correct internal yield pressure, psi = (internal yield pressure, psi) x SF

Step 3 Determine the hydrostatic pressure of the mud in use:

NOTE: The depth is from the rotary Kelly bushing (RKB) to the mud line and includes the air gap plus the depth of seawater.

HP, psi = (mud weight in use, ppg) x 0 052 x (TVD, ft from RKB to mud line)

Step 4 Determine the hydrostatic pressure exerted by the seawater:

HPsw = seawater weight, ppg x 0.052 x depth of seawater, ft

Step 5 Determine casing burst pressure (CBP):

CBP x (corrected internal) — (HP of mud in use, psi + HP of seawater, psi)
(yield pressure, psi)

Example: Determine the casing burst pressure, subsea stack, using the following data:

DATA: Mud weight = 10.0 ppg Weight of seawater = 8.7 ppg
Air gap = 50 ft Water depth = 1500 ft
Correction (safety) factor = 80%

Step 1 Determine the internal yield pressure of the casing from the "Dimension and Strengths" section of a cement company handbook:

9-5/8" casing — C-75, 53.5 lb/ft

Internal yield pressure = 7430 psi

Step 2 Correct internal yield pressure for safety factor:

Corrected internal yield pressure = 7430 psi x 0.80
Corrected internal yield pressure = 5944 psi

Step 3 Determine the hydrostatic pressure exerted by the mud in use:

HP of mud, psi = 10.0 ppg x 0.052 x (50 ft + 1500 ft)
HP of mud = 806 psi

Step 4 Determine the hydrostatic pressure exerted by the seawater:

HPsw = 8.7 ppg x 0.052 x 1500 ft
HPsw = 679 psi

Step 5 Determine the casing burst pressure:

Casing burst pressure, psi = 5944 psi — 806 psi + 679 psi
Casing burst pressure = 5817 psi

Calculate Choke Line Pressure Loss (CLPL), Psi

$$\text{CLPL} = \frac{0.000061 \times \text{MW, ppg} \times \text{length, ft} \times \text{GPM}^{1.86}}{\text{choke line ID, in.}^{4.86}}$$

Example: Determine the choke line pressure loss (CLPL), psi, using the following data:

DATA: Mud weight = 14.0 ppg Choke line length = 2000 ft
Circulation rate = 225 gpm Choke line ID = 2.5 in.

$$\text{CLPL} = \frac{0.000061 \times 14.0\ \text{ppg} \times 2000\ \text{ft} \times 225^{1.86}}{2.5^{4.86}}$$

$$\text{CLPL} = \frac{40508.611}{85.899066}$$

CLPL = 471.58 psi

Velocity, Ft/Mm, Through the Choke Line

$$\text{V, ft/mm} = \frac{24.5 \times \text{gpm}}{\text{ID, in.}^2}$$

Example: Determine the velocity, ft/mm, through the choke line using the following data:

Data: Circulation rate = 225 gpm Choke line ID = 2.5 in.

$$\text{V, ft/min} = \frac{24.5 \times 225}{2.5^2}$$

V = 882 ft/min

Adjusting Choke Line Pressure Loss for a Higher Mud Weight

$$\text{New CLPL} = \frac{\text{higher mud wt, ppg} \times \text{CLPL}}{\text{old mud weight, ppg}}$$

Example: Use the following data to determine the new estimated choke line pressure loss:
Data: Old mud weight = 13.5 ppg
New mud weight = 15.0 ppg
Old choke line pressure loss = 300 psi

$$\text{New CLPL} = \frac{15.0 \text{ ppg} \times 300 \text{ psi}}{13.5 \text{ ppg}}$$

New CLPL = 333.33 psi

Minimum Conductor Casing Setting Depth

Example: Using the following data, determine the minimum setting depth of the conductor casing below the seabed:

Data: Maximum mud weight (to be used while drilling this interval) = 9.0 ppg
Water depth = 450 ft Gradient of seawater = 0.445 psi/ft
Air gap = 60 ft Formation fracture gradient = 0.68 psi/ft

Step 1 Determine formation fracture pressure:

psi = (450 x 0.445) + (0.68 x “y”) psi = 200.25 + O.68”y”

Step 2 Determine hydrostatic pressure of mud column:

psi = 9.0 ppg x 0.052 x (60 + 450 + “y”)
psi = [9.0 x 0.052 x (60 + 450)] + (9.0 x 0.052 x “y”)
psi = 238.68 + 0.468 ”y”

Step 3 Minimum conductor casing setting depth:

200.25 + 0.68”y” = 238.68 + 0.468”y”
0.68”y” — 0.468”y” = 238.68 — 200.25
0.212”y” = 38.43

$$“y” = \frac{38.43}{0.212}$$

“y” = 181.3 ft

Therefore, the minimum conductor casing setting depth is 181.3 ft below the seabed.

Maximum Mud Weight with Returns Back to Rig Floor

Example: Using the following data, determine the maximum mud weight that can be used with returns back to the rig floor:

Data: Depths - Air gap = 75 ft
Depths - Water depth = 600ft
Seawater gradient = 0.445 psi/ft
Conductor casing psi/ft set at = 1225 ft RKB
Formation fracture gradient = 0.58 psi/ft

Step 1 Determine total pressure at casing seat:

psi = [0.58 (1225 — 600 — 75)] + (0.445 x 600)
psi = 319 + 267
psi = 586

Step 2 Determine maximum mud weight:

Max mud wt = 586 psi 0.052 ÷ 1225 ft
Max mud wt = 9.2 ppg

Reduction in Bottomhole Pressure if Riser is Disconnected

Example: Use the following data and determine the reduction in bottom-hole pressure if the riser is disconnected:

Data: Air gap = 75 ft
Seawater gradient = 0.445 psi/ft
Mud weight = 9.0 ppg
Water depth = 700 ft
Well depth = 2020 ft RKB

Step 1 Determine bottomhole pressure:

BHP = 9.0 ppg x 0.052 x 2020 ft
BHP = 945.4 psi

Step 2 Determine bottomhole pressure with riser disconnected:

BHP = (0.445 x 700) + [9.0 x 0.052 x (2020 — 700 — 75)]
BHP = 311.5 + 582.7
BHP = 894.2 psi

Step 3 Determine bottomhole pressure reduction:

BHP reduction = 945.4 psi — 894.2 psi
BHP reduction = 51.2 psi

Bottomhole Pressure When Circulating Out a Kick

Example: Use the following data and determine the bottomhole pressure when circulating out a kick:

Data:

Total depth — RKB	= 13,500 ft	Gas gradient	= 0.12 psi/ft
Height of gas kick in casing	= 1200 ft	Kill weight mud	= 12.7 ppg
Original mud weight	= 12.0 ppg	Pressure loss in annulus	= 75 psi
Choke line pressure loss	= 220 psi	Air gap	= 75 ft
Annulus (casing) pressure	= 631 psi	Water depth	= 1500 ft
Original mud in casing below gas	= 5500 ft		

Step 1 Hydrostatic pressure in choke line:

psi = 12.0 ppg x 0.052 x (1500 + *75)*
psi = 982.8

Step 2 Hydrostatic pressure exerted by gas influx:

psi = 0.12 psi/ft x 1200 ft
psi = 144

Step 3 Hydrostatic pressure of original mud below gas influx:

psi = 12.0 ppg x 0.052 x 5500 ft
psi = 3432

Step 4 Hydrostatic pressure of kill weight mud:

psi = 12.7 ppg x 0.052 x (13,500 — 5500 — 1200 — 1500 — 75)
psi = 12.7 ppg x 0.052 x 5225
psi = 3450.59

Step 5 Bottomhole pressure while circulating out a kick:

Pressure in choke line	= 982.8	psi
Pressure of gas influx	= 144	psi
Original mud below gas in casing	= 3432	psi
Kill weight mud	= 3450.59	psi
Annulus (casing) pressure	= 630	psi
Choke line pressure loss	= 200	psi
Annular pressure loss	= 75	psi
	8914.4	psi

7. Workover Operations

NOTE: The following procedures and calculations are more commonly used in workover operations, but at times they are used in drilling operations.

Bullheading

Bullheading is a term used to describe killing the well by forcing formation fluids back into the formation by pumping kill weight fluid down the tubing and in some cases down the casing.

The Bullheading method of killing a well is primarily used in the following situations:

a) Tubing in the well with a packer set. No communication exists between tubing and annulus.
b) Tubing in the well, influx in the annulus, and for some reason, cannot circulate through the tubing.
c) No tubing in the well. Influx in the casing. Bullheading is simplest, fastest, and safest method to use to kill the well.

NOTE: Tubing could be well off bottom also.

d) In drilling operations, bullheading has been used successfully in areas where hydrogen sulphide is a possibility.

Example calculations involved in bullheading operations:

Using the information given below, the necessary calculations will be performed to kill the well by bullheading. The example calculations will pertain to “a” above:

DATA:		
	Depth of perforations	= 6480 ft
	Fracture gradient	= 0.862 psi/ft
	Formation pressure gradient	= 0.40 1 psi/ft
	Tubing hydrostatic pressure (THP)	= 326 psi
	Shut-in tubing pressure	= 2000 psi
	Tubing	= 2-7/8 in. — 6.5 lb/ft
	Tubing capacity	= 0.00579 bbl/ft
	Tubing internal yield pressure	= 7260 psi
	Kill fluid density	= 8.4 ppg

NOTE: Determine the best pump rate to use. The pump rate must exceed the rate of gas bubble migration up the tubing. The rate of gas bubble migration, ft/hr, in a shut-in well can be determined by the following formula:

$$\text{Rate of gas migration, ft/hr} = \frac{\text{increase in pressure per/hr, psi}}{\text{completion fluid gradient, psi/ft}}$$

Solution: Calculate the maximum allowable tubing (surface) pressure (MATP) for formation fracture:

a) MATP, initial, with influx in the tubing:

MATP, initial = (fracture gradient, psi/ft x depth of perforations, ft) — (tubing hydrostatic pressure, psi)

MATP, initial = (0.862 psi/ft x 6480 ft) — 326 psi
MATP, initial = 5586 psi — 326 psi
MATP, initial = 5260 psi

b) MATP, final, with kill fluid in tubing:

MATP, final = (fracture gradient, psi/ft x depth of perforations, ft) — (tubing hydrostatic pressure, psi)

MATP, final = (0.862 x 6480) — (8.4 x 0.052 x 6480)
MATP, final = 5586 psi — 2830 psi
MATP, final = 2756 psi

Determine tubing capacity:

Tubing capacity, bbl = tubing length, ft x tubing capacity, bbl/ft

Tubing capacity bbl, = 6480 ft x 0.00579 bbl/ft
Tubing capacity = 37.5 bbl

Plot these values as shown below:

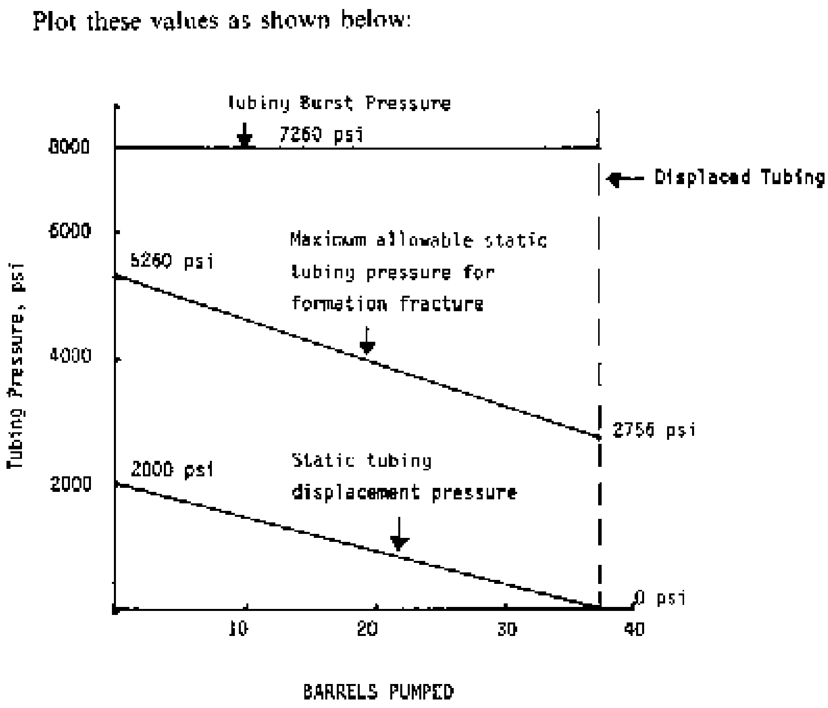

Figure 4-3. Tubing pressure profile.

Lubricate and Bleed

The lubricate and bleed method involves alternately pumping a kill fluid into the tubing or into the casing if there is no tubing in the well, allowing the kill fluid to fall, then bleeding off a volume of gas until kill fluid reaches the choke. As each volume of kill fluid is pumped into the tubing, the SITP should decrease by a calculated value until the well is eventually killed.

This method is often used for two reasons: 1) shut-in pressures approach the rated working pressure of the wellhead or tubing and dynamic pumping pressure may exceed the limits, as in the case of bullheading, and 2) either to completely kill the well or lower the SITP to a value where other kill methods can be safely employed without exceeding rated limits.

This method can also be applied when the wellbore or perforations are lugged, rendering bullheading useless. In this case, the well can be killed without necessitating the use of tubing or snubbing small diameter tubing.

Users should be aware that the lubricate and bleed method is often a very time consuming process, whereas another method may kill the well more quickly. The following is an example of a typical lubricate and bleed kill procedure.

Example: A workover is planned for a well where the SITP approaches the working pressure of the wellhead equipment. To minimise the possibility of equipment failure, the lubricate and bleed method will be used to reduce the SITP to a level at which bullheading can be safely conducted. The data below will be used to describe this procedure:

TVD	= 6500 ft	Depth of perforations	= 6450 ft
SITP	= 2830 psi	Tubing 6.5 lb/ft-N-80	= 2-7/8 in.
Kill fluid density	= 9.0 ppg	Wellhead working pressure	= 3000 psi
Tubing internal yield	= 10,570 psi	Tubing capacity	= 0.00579 bbl/ft (172.76 ft/bbl)

Calculations: Calculate the expected pressure reduction for each barrel of kill fluid pumped:

psi/bbl = tubing capacity, ft/bbl x 0.052 x kill weight fluid, ppg
psi/bbl = 172.76 ft/bbl x 0.052 x 9.0 ppg
psi/bbl = 80.85

For each one barrel pumped, the SITP will be reduced by 80.85 psi.

Calculate tubing capacity, bbl, to the perforations:

bbl = tubing capacity, bbl/ft x depth to perforations, ft
bbl = 0.00579 bbl/ft x 6450 ft
bbl = 37.3 bbl

Procedure:

1. Rig up all surface equipment including pumps and gas flare lines.
2. Record SITP and SICP.
3. Open the choke to allow gas to escape from the well and momentarily reduce the SITP.
4. Close the choke and pump in 9.0 ppg brine until the tubing pressure reaches 2830 psi.
5. Wait for a period of time to allow the brine to fall in the tubing. This period will range from 1/4 to 1 hour depending on gas density, pressure, and tubing size.
6. Open the choke and bleed gas until 9.0 brine begins to escape.
7. Close the choke and pump in 9.0 ppg brine water.
8. Continue the process until a low level, safe working pressure is attained.

A certain amount of time is required for the kill fluid to fall down the tubing after the pumping stops. The actual waiting time is not to allow fluid to fall, but rather, for gas to migrate up through the kill fluid. Gas migrates at rates of 1000 to 2000 ft/hr. Therefore considerable time is required for fluid to fall or migrate to 6500 ft. Therefore, after pumping, it is important to wait several minutes before bleeding gas to prevent bleeding off kill fluid through the choke.

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CHAPTER FIVE

ENGINEERING CALCULATIONS

1. Bit Nozzle Selection — Optimised Hydraulics

These series of formulas will determine the correct jet sizes when optimising for jet impact or hydraulic horsepower and optimum flow rate for two or three nozzles.

1. Nozzle area, sq in.:

$$\text{Nozzle area, sq in.} = \frac{N1^2 + N2^2 + N3^2}{1303.8}$$

2. Bit nozzle pressure loss, psi (Pb):

$$Pb = \frac{gpm^2 \times MW, ppg}{10858 \times \text{nozzle area, sq in.}^2}$$

3. Total pressure losses except bit nozzle pressure loss, psi (Pc):

Pc_1 & Pc_2 = circulating pressure, psi — bit nozzle pressure Loss.

4. Determine slope of line M:

$$M = \frac{\log (Pc_1 \div Pc_2)}{\log (Q_1 \div Q_2)}$$

5. Optimum pressure losses (Popt)

a) For impact force:

$$Popt = \frac{2}{M+2} \times Pmax$$

b) For hydraulic horsepower:

$$Popt = \frac{1}{M+1} \times Pmax$$

6. For optimum flow rate (Qopt):

a) For impact force:

$$Qopt, gpm = \left(\frac{Popt}{Pmax}\right)^{1 \div M} \times Q1$$

b) For hydraulic horsepower:

$$Qopt, gpm = \left(\frac{Popt}{Pmax}\right)^{1 \div M} \times Q1$$

7. To determine pressure at the bit (Pb): $Pb = Pmax - Popt$

8. To determine nozzle area, sq in.:

$$\text{Nozzle area, sq in.} = \sqrt{\frac{Qopt^2 \times MW, ppg}{10858 \times Pmax}}$$

9. To determine nozzles, 32nd in. for three nozzles:

$$\text{Nozzles} = \sqrt{\frac{\text{Nozzle area, sq in.}}{3 \times 0.7854}} \times 32$$

10. To determine nozzles, 32nd in. for two nozzles:

$$\text{Nozzles} = \sqrt{\frac{\text{Nozzle area, sq in.}}{2 \times 0.7854}} \times 32$$

Example: Optimise bit hydraulics on a well with the following:

Select the proper jet sizes for impact force and hydraulic horsepower for two jets and three jets:

DATA: Mud weight	= 13.0 ppg	Maximum surface pressure	= 3000 psi
Pump rate 1	= 420 gpm	Pump pressure 1	= 3000 psi
Pump rate 2	= 275 gpm	Pump pressure 2	= 1300 psi
Jet sizes	= 17-17-17		

1. Nozzle area, sq in.:

$$\text{Nozzle area, sq in.} = \frac{17^2 + 17^2 + 17^2}{1303.8}$$

Nozzle area, sq in. = 0.664979

2. Bit nozzle pressure loss, psi (Pb):

$$Pb, = \frac{4202 \times 13.0}{10858 \times 0.6649792}$$

Pb, = 478 psi

$$Pb_2 = \frac{275^2 \times 13.0}{10858 \times 0.6649792}$$

Pb_2 = 205 psi

3. Total pressure losses except bit nozzle pressure loss (Pc), psi:

Pc, = 3000 psi — 478 psi
Pc, = 2522 psi

Pc_2 = 1300 psi — 205 psi
Pc_2 = 1095 psi

4. Determine slope of line (M):

$$M = \frac{\log (2522 \div 1095)}{\log (420\ 275)}$$

$$M = \frac{0.3623309}{0.1839166}$$

M = 1.97

5. Determine optimum pressure losses, psi (Popt):

a) For impact force:

$$Popt = \frac{2}{1.97 + 2} \times 3000$$

Popt = 1511 psi

b) For hydraulic horsepower:

$$Popt = \frac{1}{1.97 + 1} \times 3000$$

Popt = 1010 psi

6. Determine optimum flow rate (Qopt):

a) For impact force:

$$Qopt, gpm = \left(\frac{1511}{3000}\right)^{1 \div 1.97} \times 420$$

Qopt = 297 gpm

b) For hydraulic horsepower:

$$Qopt, gpm = \left(\frac{1010}{3000}\right)^{1 \div 1.97} \times 420$$

Qopt = 242 gpm

7. Determine pressure losses at the bit (Pb):

a) For impact force:

Pb = 3000 psi — 1511 psi
Pb = 1489 psi

b) For hydraulic horsepower:

Pb = 3000 psi — 1010 psi
Pb = 1990 psi

8. Determine nozzle area, sq in.:

a) For impact force:

$$\text{Nozzles area, sq. in.} = \sqrt{\frac{297^2 \times 13.0}{10858 \times 1489}}$$

$$\text{Nozzles area, sq. in.} = \sqrt{0.070927}$$

Nozzle area, = 0.26632 sq. in.

b) For hydraulic horsepower:

$$\text{Nozzles area, sq. in.} = \sqrt{\frac{242^2 \times 13.0}{10858 \times 1990}}$$

$$\text{Nozzles area, sq. in.} = \sqrt{0.03523}$$

Nozzle area, = 0.1877sq. in.

9. Determine nozzle size, 32nd in.:

a) For impact force:

$$\text{Nozzles} = \sqrt{\frac{0.26632}{3 \times 0.7854}} \times 32$$

Nozzles = 10.76

b) For hydraulic horsepower:

$$\text{Nozzles} = \sqrt{\frac{0.1877}{3 \times 0.7854}} \times 32$$

Nozzles = 9.03

NOTE: Usually the nozzle size will have a decimal fraction. The fraction times 3 will determine how many nozzles should be larger than that calculated.

a) For impact force: 0.76 x 3 = 2.28 rounded to 2
so: 1 jet = 10/32nds
2 jets = 11/32nds

b) For hydraulic horsepower: 0.03 x 3 = 0.09 rounded to 0
so: 3 jets = 9/32 nd in.

10. Determine nozzles, 32nd in. for two nozzles:

a) For impact force:

$$\text{Nozzles} = \sqrt{\frac{0.26632}{2 \times 0.7854}} \times 32$$

Nozzles = 13.18 sq in.

b) For hydraulic horsepower:

$$\text{Nozzles} = \sqrt{\frac{0.1877}{2 \times 0.7854}} \times 32$$

Nozzles = 11.06 sq in.

2. Hydraulics Analysis

This sequence of calculations is designed to quickly and accurately analyse various parameters of existing bit hydraulics.

1. Annular velocity, ft/mm (AV): $$AV = \frac{24.5 \times Q}{Dh^2 - Dp^2}$$

2. Jet nozzle pressure loss, psi (Pb): $$Pb = \frac{156.5 \times Q^2 \times MW}{[(N)^2 + (N_2)^2 + (N_3)^2]^2}$$

3. System hydraulic horsepower available (Sys HHP): $$SysHHP = \frac{\text{surface, psi} \times Q}{1714}$$

4. Hydraulic horsepower at bit (HHPb): $$HHPb = \frac{Q \times Pb}{1714}$$

5. Hydraulic horsepower per square inch of bit diameter: $$HHPb/\text{sq in.} = \frac{HHPb \times 1.27}{\text{bit size}^2}$$

6. Percent pressure loss at bit (% psib): $$\%psib = \frac{Pb}{\text{surface, psi}} \times 100$$

7. Jet velocity, ft/sec (Vn): $$Vn = \frac{417.2 \times Q}{(N_1)^2 + (N_2)^2 + (N_3)^2}$$

8. Impact force, lb, at bit (IF): $$IF = \frac{(MW)\ (Vn)\ (Q)}{1930}$$

9. Impact force per square inch of bit area (IF/sq in.): $\text{IF/sq in.} = \dfrac{\text{IF} \times 1.27}{\text{bit size}^2}$

Nomenclature:

AV = annular velocity, ft/mm
Dh = hole diameter, in.
MW = mud weight, ppg
Pb = bit nozzle pressure loss, psi
Vn = jet velocity, ft/sec
IF/sq in. = impact force lb/sq in of bit diameter

Q = circulation rate, gpm
Dp = pipe or collar OD, in.
$N_1\ N_2\ N_3$ = jet nozzle sizes, 32nd in.
HHP = hydraulic horsepower at bit
IF = impact force, lb

Example: Mud weight = 12.0 ppg
Nozzle size 1 = 12-32nd/in.
Nozzle size 2 = 12-32nd/in.
Nozzle size 3 = 12-32nd/in.

Circulation rate = 520 gpm
Surface pressure = 3000 psi
Hole size = 12-1/4 in.
Drill pipe OD = 5.0 in.

1. Annular velocity, ft/mm:

$$\text{AV} = \frac{24.5 \times 520}{12.25^2 - 5.0^2}$$

$$\text{AV} = \frac{12740}{125.0625}$$

AV = 102 ft/mm

2. Jet nozzle pressure loss:

$$\text{Pb} = \frac{156.5 \times 5202 \times 12.0}{(12^2 + 12^2 + 12^2)^2}$$

Pb = 2721 psi

3. System hydraulic horsepower available:

$$\text{Sys HHP} = \frac{3000 \times 520}{1714}$$

Sys HHP = 910

4. Hydraulic horsepower at bit:

$$\text{HHPb} = \frac{2721 \times 520}{1714}$$

HHPb = 826

5. Hydraulic horsepower per square inch of bit area:

$$\text{HHP/sq in.} = \frac{826 \times 1.27}{12.252}$$

HHP/sq in. = 6.99

6. Percent pressure loss at bit:

$$\text{\% psib} = \frac{2721}{3000} \times 100$$

% psib = 90.7

7. Jet velocity, ft/see:

$$Vn = \frac{417.2 \times 520}{12^2 + 12^2 + 12^2}$$

$$Vn = \frac{216944}{432}$$

$$Vn = 502 \text{ ft/sec}$$

8. Impact force, lb:

$$IF = \frac{12.0 \times 502 \times 520}{1930}$$

$$IF = 1623 \text{ lb}$$

9. Impact force per square inch of bit area:

$$IF/\text{sq in.} = \frac{1623 \times 1.27}{12.\ 25^2}$$

$$IF/\text{sq in.} = 13.7$$

3. Critical Annular Velocity and Critical Flow Rate

1. Determine n:

$$n = 3.32 \log \frac{\phi 600}{\phi 300}$$

2. Determine K:

$$K = \frac{\phi 600}{1022^n}$$

3. Determine X:

$$X = \frac{81600\ (Kp)\ (n)^{0.387}}{(Dh — Dp)^n\ MW}$$

4. Determine critical annular velocity:

$$AVc = (X)^{1 \div 2 — n}$$

5. Determine critical flow rate:

$$GPMc = \frac{AVc\ (Dh^2 - Dp^2)}{24.5}$$

Nomenclature:

n = dimensionless
K = dimensionless
X = dimensionless
ϕ600 = 600 viscometer dial reading
ϕ300 = 300 viscometer dial reading
Dh = hole diameter, in.
Dp = pipe or collar OD, in.
MW = mud weight, ppg
Avc = critical annular velocity, ft/mm
GPMc = critical flow rate, gpm

Example: Mud weight = 14.0 ppg
ϕ600 = 64
ϕ300 = 37
Hole diameter = 8.5 in.
Pipe OD = 7.0 in.

1. Determine n: $n = 3.32 \log \frac{64}{37}$

   $n = 0.79$

2. Determine K: $K = \frac{64}{1022^{0.79}}$

   $K = 0.2684$

3. Determine X: $X = \frac{81600\ (0.2684)\ (079)0.387}{8.5 — 70.79 \times 14.0}$

   $X = \frac{19967.413}{19.2859}$

   $X = 1035$

4. Determine critical annular velocity: $AVc = (1035)^{1 \div (2\ —\ 0.79)}$

   $AVc = (1035)^{08264}$

   $AVc = 310$ ft/mm

5. Determine critical flow rate: $GPMc = \frac{310\ (8.52 — 7.02)}{24.5}$

   $GPMc = 294$ gpm

4. "d" Exponent

The "d" exponent is derived from the general drilling equation: $\mathbf{R \div N = a\ (W^d \div D)}$

where R = penetration rate
N = rotary speed, rpm
W = weight on bit, lb
d = exponent in general drilling equation, dimensionless
a = a constant, dimensionless

"d" exponent equation: "d" = log (R ÷ 60N) ÷ log (12W ÷ 1000D)

where d = d exponent, dimensionless
N = rotary speed, rpm
D = bit size, in.
R = penetration rate, ft/hr
W = weight on bit, 1,000 lb

Example: R = 30 ft/hr N = 120 rpm W = 35,000 lb D = 8.5 in.

Solution: d = log [30 ÷ (60 x 120)] ÷ log [(12 x 35) (1000 x 8.5)]
d = log (30 ÷ 7200) ÷ log (420 ÷ 8500)
d = log 0.0042 ÷ log 0.0494
d = — 2.377 ÷ — 1.306
d = 1.82

Corrected "d" exponent:

The "d" exponent is influenced by mud weight variations, so modifications have to be made to correct for changes in mud weight:

$d_c = d\ (MW_1 \div MW_2)$

where dc = corrected "d" exponent MW_1 = normal mud weight — 9.0 ppg
MW_2 = actual mud weight, ppg

Example: d = 1.64 MW_1 = 9.0 ppg MW_2 = 12.7 ppg

Solution: $d_c = 1.64\ (9.0 \div 12.7)$
$d_c = 1.64 \times 0.71$
$d_c = 1.16$

5. Cuttings Slip Velocity

These calculations give the slip velocity of a cutting of a specific size and weight in a given fluid. The annular velocity and the cutting net rise velocity are also calculated.

Method 1

Annular velocity, ft/mm: $AV = \dfrac{24.5 \times Q}{Dh^2 - Dp^2}$

Cuttings slip velocity, ft/mm:

$$Vs = 0.45\left(\frac{PV}{(MW)(Dp)}\right)\left[\sqrt{36{,}800 \div (PV \div (MW)(Dp))^2 \times (Dp)((DenP \div MW) - l) + 1} - 1\right]$$

where Vs = slip velocity, ft/min PV = plastic viscosity, cps
MW = mud weight, ppg Dp = diameter of particle, in.
DenP = density of particle, ppg

DATA: Mud weight = 11.0 ppg Plastic viscosity = 13 cps
Diameter of particle = 0.25 in. Density of particle = 22 ppg
Flow rate = 520 gpm Diameter of hole = 12-1/4 in.
Drill pipe OD = 5.0 in.

Annular velocity, ft/mm: $AV = \dfrac{24.5 \times 520}{12.25^2 - 5.0^2}$

$AV = 102$ ft/min

Cuttings slip velocity, ft/mm:

$$Vs = 0.45\left(\frac{13}{(11 \times 0.25)}\right) \left[\sqrt{36{,}800 \div (13 \div (11 \times 0.25))^2 \times 0.25((22 \div 11) - l) + 1^{-1}}\right]$$

$$Vs = 0.45[4.7271 \left[\sqrt{36{,}800 \div [4.727]^2 \times 0.25 \times 1 + 1} - 1\right]$$

$$Vs = 2.12715 \left(\sqrt{4l2.68639} - 1\right)$$

$$Vs = 2.12715 \times 19.3146$$

$$Vs = 41\ .085 \text{ ft/mm}$$

Cuttings net rise velocity:	Annular velocity	= 102 ft/min
	Cuttings slip velocity	= — 41 ft/min
	Cuttings net rise velocity	= 61 ft/min

Method 2

1. Determine n: $n = 3.32 \log \frac{\phi 600}{\phi 300}$

2. Determine K: $K = \frac{\phi 600}{511^n}$

3. Determine annular velocity, ft/mm: $v = \frac{24.5 \times Q}{Dh^2 - Dp^2}$

4. Determine viscosity (u): $\mu = \left(\frac{2.4v}{Dh - Dp} \times \frac{2n + 1}{3n}\right)^n \times \left(\frac{200K\,(Dh - Dp)}{v}\right)$

5. Slip velocity (Vs), ft/mm: $Vs = \frac{(DensP - MW)^{0.667} \times 175 \times DiaP}{MW^{0.333} \times \mu^{0.333}}$

Nomenclature:

n = dimensionless
K = dimensionless
ϕ600 = 600 viscometer dial reading
ϕ300 = 300 viscometer dial reading
Dp = pipe or collar OD, in.
μ = mud viscosity, cps
Q = circulation rate, gpm
Dh = hole diameter, in.
DensP = cutting density, ppg
DiaP = cutting diameter, in.
v = annular velocity, ft/min

Example: Using the data listed below, determine the annular velocity, cuttings slip velocity, and the cutting net rise velocity:

DATA:

Mud weight = 11.0 ppg	Plastic viscosity = 13 cps
Yield point = 10 lb/100 sq. ft	Diameter of particle = 0.25 in.
Hole diameter = 12.25 in.	Density of particle = 22.0 ppg
Drill pipe OD = 5.0 in.	Circulation rate = 520 gpm

1. Determine n:

$$n = 3.32 \log \frac{36}{23}$$

$$n = 0.64599$$

2. Determine K:

$$K = \frac{23}{511^{0.64599}}$$

$$K = 0.4094$$

3. Determine annular velocity, ft/mm:

$$v = \frac{24.5 \times 520}{12.25^2 — 5.0^2}$$

$$v = \frac{12{,}740}{125.06}$$

$$v = 102 \text{ ft/min}$$

4. Determine mud viscosity, cps:

$$\mu = \left(\frac{2.4 \times 102}{12.25 — 5.0} \times \frac{2(0.64599) + 1}{3 \times 0.64599}\right)^{0.64599} \times \frac{(200 \times 0.4094 \times (12.25 — 5)}{102}$$

$$\mu = \left(\frac{2448}{7.25} \times \frac{2.292}{1.938}\right)^{0.64599} \times \frac{593.63}{102}$$

$$\mu = (33.76 \times 1.1827)^{0.64599} \times 5.82$$

$$\mu = 10.82 \times 5.82$$

$$\mu = 63 \text{ cps}$$

5. Determine slip velocity (Vs), ft/mm:

$$Vs = \frac{(22 — 11)^{0.667} \times 175 \times 0.25}{11^{0.333} \times 63^{0.333}}$$

$$Vs = \frac{4.95 \times 175 \times 0.25}{2.222 \times 3.97}$$

$$Vs = \frac{216.56}{8.82}$$

$$Vs = 24.55 \text{ ft/min}$$

6. Determine cuttings net rise velocity, ft/mm:

Annular velocity	=	102 ft/mm
Cuttings slip velocity	=	— 24.55 ft/mm
Cuttings net rise velocity	=	77.45 ft/mm

6. Surge and Swab Pressures

Method 1

1. Determine n: $n = 3.32 \log \frac{\phi600}{\phi300}$

2. Determine K: $K = \frac{\phi600}{511^n}$

3. Determine velocity, ft/mm:

For plugged flow: $v = \left[0.45 + \frac{Dp^2}{Dh^2 - Dp^2} \right] Vp$

For open pipe: $v = \left[0.45 + \frac{Dp^2 - Di^2}{Dh^2 - Dp^2 + Di^2} \right] Vp$

4. Maximum pipe velocity: $Vm = 1.5 \times v$

5. Determine pressure losses: $Ps = \left(\frac{2.4\ Vm}{Dh - Dp} \times \frac{2n + 1}{3n}\right)^n \times \frac{KL}{300\ (Dh - Dp)}$

Nomenclature:

n = dimensionless
K = dimensionless
$\phi600$ = 600 viscometer dial reading
$\phi300$ = 300 viscometer dial reading
v = fluid velocity, ft/min
Vm = maximum pipe velocity, ft/mm
Di = drill pipe or drill collar ID, in.
Dh = hole diameter, in.
Dp = drill pipe or drill collar OD, in
Ps = pressure loss, psi
Vp = pipe velocity, ft/min
L = pipe length, ft

Example 1: Determine surge pressure for plugged pipe:

Data:
Well depth = 15,000 ft
Hole size = 7-7/8 in.
Drill collar length = 700 ft
Drill pipe OD = 4-1/2 in.
Drill pipe ID = 3.82 in.
Mud weight = 15.0 ppg
Average pipe running speed = 270 ft/mm
Drill collar = 6-1/4” OD x 2-3/4” ID
Viscometer readings: $\phi600 = 140$
$\phi300 = 80$

1. Determine n: $n = 3.32 \log \frac{140}{80}$

$n = 0.8069$

2. Determine K: $K = \frac{80}{511^{0.8069}}$

$K = 0.522$

3. Determine velocity, ft/mm: $v = \left[0.45 + \frac{4.5^2}{7.875^2 - 4.5^2} \right] 270$

$v = (0.45 + 0.484)270$
$v = 252$ ft/min

4. Determine maximum pipe velocity, ft/min: $Vm = 1.5 \times 252$
$Vm = 378$ ft/min

5. Determine pressure losses, psi:

$$Ps = \left[\frac{2.4 \times 378}{7.875 - 4.5} \times \frac{2(0.8069) + 1}{3(0.8069)} \right]^{0.8069} \times \frac{(0.522)(14300)}{300\,(7.875 - 4.5)}$$

$$Ps = (268.8 \times 1.1798)^{0.8069} \times \frac{7464..6}{1012.5}$$

$Ps = 97.098 \times 7.37$
$Ps = 716$ psi surge pressure

Therefore, this pressure is added to the hydrostatic pressure of the mud in the wellbore.

If, however, the swab pressure is desired, this pressure would be subtracted from the hydrostatic pressure.

Example 2: Determine surge pressure for open pipe:

1. Determine velocity, ft/mm: : $v = \left[0.45 + \frac{4.5^2 - 3.82^2}{7.875^2 - 4.5^2 + 3.82^2} \right] 270$

$v = \left(0.45 + \frac{5.66}{56.4}\right) 270$

$v = (0.45 + 0.100)270$
$v = 149$ ft/mm

2 . Maximum pipe velocity, ft/mm: $Vm = 149 \times 1.5$
$Vm = 224$ ft/mm

3 . Pressure loss, psi: $$Ps = \left[\frac{2.4 \times 224}{7.875 - 4.5} \times \frac{2(0.8069) + 1}{3(0.8069)} \right]^{0.8069} \times \frac{(0.522)(14300)}{300(7.875 - 4.5)}$$

$$Ps = (159.29 \times 1.0798)^{0.8069} \times \frac{7464.5}{1012.5}$$

$Ps = 63.66 \times 7.37$
$Ps = 469$ psi surge pressure

Therefore, this pressure would be added to the hydrostatic pressure of the mud in the wellbore.

If, however, the swab pressure is desired, this pressure would be subtracted from the hydrostatic pressure of the mud in the wellbore.

Method 2

Surge and swab pressures

Assume: 1) Plugged pipe
2) Laminar flow around drill pipe
3) Turbulent flow around drill collars

These calculations outline the procedure and calculations necessary to determine the increase or decrease in equivalent mud weight (bottomhole pressure) due to pressure surges caused by pulling or running pipe. These calculations assume that the end of the pipe is plugged (as in running casing with a float shoe or drill pipe with bit and jet nozzles in place), not open ended.

A. Surge pressure around drill pipe:

1. Estimated annular fluid velocity (v) around drill pipe: $v = \left[0.45 + \frac{Dp^2}{Dh^2 - Dp^2} \right] Vp$

2. Maximum pipe velocity (Vm): $Vm = v \times 1.5$

3. Determine n: $n = 3.32 \log \frac{\phi 600}{\phi 300}$

4. Determine K: $K = \frac{\phi 600}{511^n}$

5. Calculate the shear rate (Ym) of the mud moving around the pipe: $Ym = \frac{2.4 \times Vm}{Dh - DP}$

6. Calculate the shear stress (T) of the mud moving around the pipe: $T = K\,(Ym)^n$

7. Calculate the pressure (Ps) decrease for the interval: $Ps = \frac{3.33\,T}{Dh - Dp} \times \frac{L}{1000}$

B. Surge pressure around drill collars:

1. Calculate the estimated annular fluid velocity (v) around the drill collars:

$$v = \left[0.45 + \frac{Dp^2}{Dh^2 - Dp^2} \right] Vp$$

2. Calculate maximum pipe velocity (Vm): $Vm = v \times 1.5$

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flow rate (Q):

$$Q = \frac{Vm\,[(Dh)^2 — (Dp)^2]}{24.5}$$

4. Calculate the pressure loss for each interval (Ps): $Ps = \frac{0.000077 \times MW^{0.8} \times Q^{1\sim8} \times PV^{0.2} \times L}{(Dh — Dp)^3 \times (Dh + Dp)^{1.8}}$

C. Total surge pressures converted to mud weight:

Total surge (or swab) pressures: psi = Ps (drill pipe) + Ps (drill collars)

D. If surge pressure is desired: SP, ppg = Ps ÷ 0.052 ÷ TVD, ft "+" MW, ppg

E. If swab pressure is desired: SP, ppg = Ps ÷ 0.052 ÷ TVD, ft "—" MW, ppg

Example: Determine both the surge and swab pressure for the data listed below:

Data: Mud weight	= 15.0 ppg	Plastic viscosity	= 60 cps
Yield point	= 20 lb/l00 sq ft	Hole diameter	= 7-7/8 in.
Drill pipe OD	= 4-1/2 in.	Drill pipe length	= 14,300 ft
Drill collar OD	= 6-1/4 in.	Drill collar length	= 700 ft
Pipe running speed	= 270 ft/min		

A. Around drill pipe:

1.Calculate annular fluid velocity (v) around drill pipe: $v = \left[\, 0.45 + \frac{(45)^2}{7.875^2 — 4.5^2}\right] 270$

$v = [0.45 + 0.4848]\; 270$
$v = 253$ ft/mm

2. Calculate maximum pipe velocity (Vm): Vm = 253 x 1.5
Vm = 379 ft/min

NOTE: Determine n and K from the plastic viscosity and yield point as follows:

PV + YP = ϕ300 reading ϕ300 reading + PV = ϕ600 reading

Example: PV = 60 YP = 20

60 + 20 = 80 (ϕ300 reading) 80 + 60 = 140 (ϕ600 reading)

3. Calculate n: $n = 3.32 \log 80\,\frac{140}{80}$

$n = 0.8069$

4. Calculate K: $K = \frac{80}{511^{0.8069}}$

$K = 0.522$

5. Calculate the shear rate (Ym) of the mud moving around the pipe:

$$Ym = \frac{2.4 \times 379}{(7.875 — 4.5)}$$

$$Ym = 269.5$$

6. Calculate the shear stress (T) of the mud moving around the pipe:

$$T = 0.522\ (269.5)^{0.8069}$$
$$T = 0.522 \times 91.457$$
$$T = 47.74$$

7. Calculate the pressure decrease (Ps) for the interval:

$$Ps = \frac{3.33\ (47.7)}{(7.875 — 4.5)} \times \frac{14{,}300}{1000}$$

$$Ps = 47.064 \times 14.3$$
$$Ps = 673 \text{ psi}$$

B. Around drill collars:

1. Calculate the estimated annular fluid velocity (v) around the drill collars:

$$v = [\ 0.45 + (6.25^2\ \div (7.875^2\ — 6.25^2))]\ 270$$
$$v = (0.45 + 1.70)270$$
$$v = 581 \text{ ft/mm}$$

2. Calculate maximum pipe velocity (Vm):

$$Vm = 581 \times 1.5$$
$$Vm = 871.54 \text{ ft/mm}$$

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flow-rate (Q):

$$Q = \frac{871.54\ (7.875^2 — 6.25^2)}{24.5}$$

$$Q = \frac{20004.567}{24.5}$$
$$Q = 816.5$$

4. Calculate the pressure loss (Ps) for the interval:

$$Ps = \frac{0.000077 \times 15^{0.8} \times 816^{1.8} \times 60^{0.2} \times 700}{(7.875 — 6.25)^3 \times (7.875 + 6.25)^{1.8}}$$

$$Ps = \frac{185837.9}{504.126}$$

$$Ps = 368.6 \text{ psi}$$

C. Total pressures:

$$psi = 672.9 \text{ psi} + 368.6 \text{ psi}$$
$$psi = 1041.5 \text{ psi}$$

D. Pressure converted to mud weight, ppg:

$$ppg = 1041.5 \text{ psi} \div 0.052 \div 15{,}000 \text{ ft}$$
$$ppg = 1.34$$

E. If surge pressure is desired: Surge pressure, ppg = 15.0 ppg + 1.34 ppg
Surge pressure = 16.34 ppg

F. If swab pressure is desired: Swab pressure, ppg = 15.0 ppg — 1.34 ppg
Swab pressure = 13.66 ppg

7. Equivalent Circulation Density (ECD)

1. Determine n: $n = 3.32 \log \dfrac{\phi600}{\phi300}$

2. Determine K: $K = \dfrac{\phi600}{511^n}$

3. Determine annular velocity (v), ft/mm: $v = \dfrac{24.5 \times Q}{Dh^2 - D^2}$

4. Determine critical velocity (Vc), ft/mm:

$$Vc = \left(\frac{3.878 \times 10^4 \times K}{MW}\right)^{(1 \div (2 - n))} \times \left(\frac{2.4}{Dh - Dp} \times \frac{2n+1}{3n}\right)^{(n \div (2 - n))}$$

5. Pressure loss for laminar flow (Ps), psi: $Ps = \left(\dfrac{2.4v}{Dh - Dp} \times \dfrac{2n+1}{3n}\right)^n \times \dfrac{KL}{300\,(Dh - Dp)}$

6. Pressure loss for turbulent flow (Ps), psi: $Ps = \dfrac{7.7 \times 10^{-5} \times MW^{0.8} \times Q^{1.8} \times PV^{0.2} \times L}{(Dh - Dp)^3 \times (Dh + Dp)^{1.8}}$

7. Determine equivalent circulating density (ECD), ppg:

ECD, ppg = Ps — 0.052 TVD, ft + 0MW, ppg

Example: Equivalent circulating density (ECD), ppg:

Data:

Mud weight	= 12.5 ppg	Plastic viscosity	= 24 cps
Yield point	= 12 lb/100 sq ft	Circulation rate	= 400 gpm
Drill collar OD	= 6.5 in.	Drill pipe OD	= 5.0 in
Drill collar length	= 700 ft	Drill pipe length	= 11,300 ft
True vertical depth	= 12,000 ft	Hole diameter	= 8.5 in.

NOTE: If $\phi600$ and $\phi300$ viscometer dial readings are unknown, they may be obtained from the plastic viscosity and yield point as follows:

24 + 12 = 36 Thus, 36 is the $\phi300$ reading.
36 + 24 = 60 Thus, 60 is the $\phi600$ reading.

1. Determine n: $n = 3.321og \frac{60}{36}$

$n = 0.7365$

2. Determine K: $K = \frac{36}{511^{0.7365}}$

$K = 0.3644$

3a. Determine annular velocity (v), ft/mm, around drill pipe: $v = \frac{24.5 \times 400}{8.5^2 — 5.0^2}$

$v = 207$ ft/mm

3b. Determine annular velocity (v), ft/mm, around drill collars: $v = \frac{24.5 \times 400}{8.5^2 — 6.5^2}$

$v = 327$ ft/mm

4a. Determine critical velocity (Vc), ft/mm, around drill pipe:

$$Vc = \left(\frac{3.878 \times 10^4 \times 0.3644}{12.5}\right)^{(1 \div (2 — 0.7365))} \times \left(\frac{2.4}{8.5 — 5.0} \times \frac{2(0.7365) + l}{3(0.7365)}\right)^{(0.7365 \div (2 — 0.7365))}$$

$Vc = (1130.5)^{0.791} \times (0.76749)^{0.5829}$
$Vc = 260 \times 0.857$
$Yc = 223$ ft/mm

4b. Determine critical velocity (Yc), ft/mm, around drill collars:

$$Vc = \left(\frac{3.878 \times 10^4 \times 0.3644}{12.5}\right)^{(1 \div (2 — 0.7365))} \times \left(\frac{2.4}{8.5 — 6.5} \times \frac{2(0.7365) + l}{3(0.7365)}\right)^{(0.7365 \div (2 — 0.7365))}$$

$Vc = (1\ 130.5)^{0.791} \times (1.343)^{0.5829}$
$Vc = 260 \times 1.18756$
$Vc = 309$ ft/mm

Therefore: Drill pipe: 207 ft/mm (v) is less than 223 ft/mm (Vc), Laminar flow, so use Equation 5 for pressure loss.
Drill collars: 327 ft/mm (v) is greater than 309 ft/mm (Vc) turbulent flow, so use Equation 6 for pressure loss.

5. Pressure loss opposite drill pipe:

$$Ps = \left[\frac{2.4 \times 207}{8.5 — 5.0} \times \frac{2 (0.7365)+ 1}{3(0.7365)}\right]^{0.7365} \times \frac{0.3644 \times 11,300}{300(8.5 — 5.0)}$$

$$Ps = \left[\frac{2.4 \times 207}{8.5 — 5.0} \times \frac{2(0.7365) + 1}{3(0.7365}\right]^{0.7365} \times \frac{3.644 \times 11,300}{300(8.5 — 5.0)}$$

$Ps = (141.9 \times 1.11926)^{0.7365} \times 3.9216$
$Ps = 41.78 \times 3.9216$
$Ps = 163.8$ psi

6. Pressure loss opposite drill collars:

$$Ps = \frac{7.7 \times 10^{-5} \times 12.5^{0.8} \times 400^{1.8} \times 24^{0.2} \times 700}{(8.5 - 6.5)^3 \times (8.5 + 6.5)^{1.8}}$$

$$Ps = \frac{37056.7}{8 \times 130.9}$$

Ps = 35.4 psi

Total pressure losses: psi = 163.8 psi + 35.4 psi
psi = 199.2 psi

7. Determine equivalent circulating density (ECD), ppg:

ECD, ppg = 199.2 psi ÷ 0.052 ÷ 12,000 ft + 12.5 ppg
ECD = 12.82 ppg

9. Fracture Gradient Determination - Surface Application

Method 1: Matthews and Kelly Method

$F = P/D + Ki\ \sigma/D$

where F = fracture gradient, psi/ft
σ = matrix stress at point of interest, psi
Ki = matrix stress coefficient, dimensionless
P = formation pore pressure, psi
D = depth at point of interest, TVD, ft

Procedure:

1. Obtain formation pore pressure, P, from electric logs, density measurements, or from mud logging personnel.

2. Assume 1.0 psi/ft as overburden pressure (S) and calculate σ as follows: $\sigma = S - P$

3. Determine the depth for determining Ki by: $D = \dfrac{\sigma}{0.535}$

4. From Matrix Stress Coefficient chart, determine Ki:

4. From Matrix Stress Coefficient chart, determine Ki:

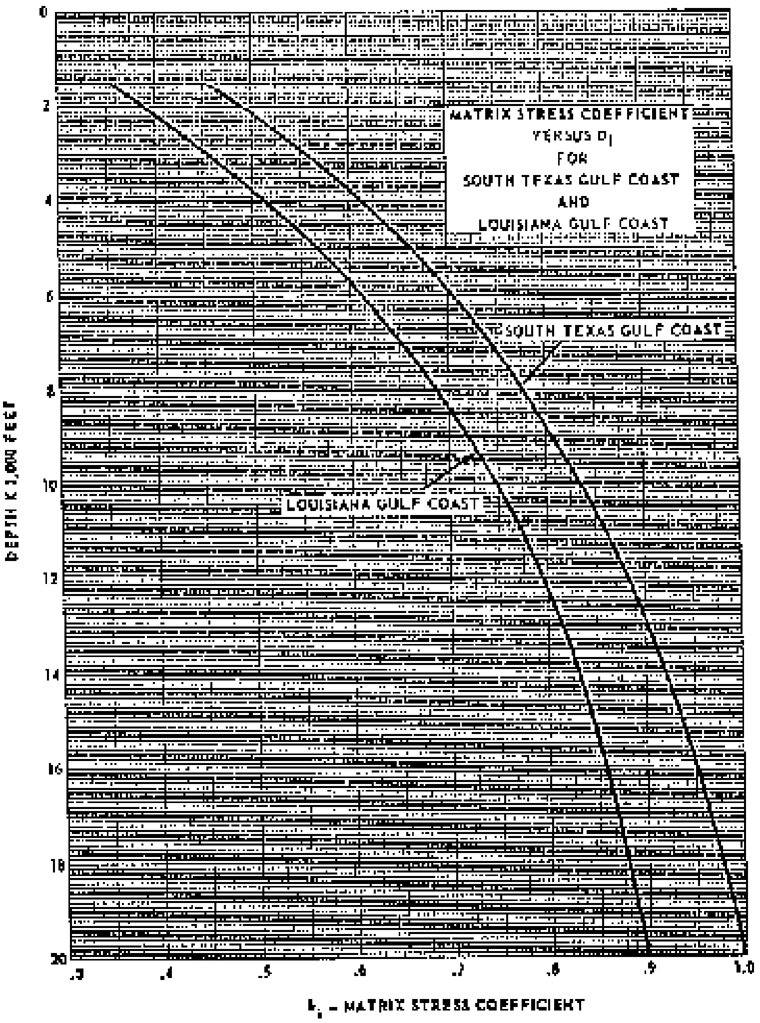


Figure 5-1. Matrix stress coefficient chart

5. Determine fracture gradient, psi/ft: $F = \frac{P}{D} + Ki \times \frac{\sigma}{D}$

6. Determine fracture pressure, psi: F, psi = F x D

7. Determine maximum mud density, ppg: MW, ppg = F ÷ 0.052

Example: Casing setting depth = 12,000 ft
Formation pore pressure (Louisiana Gulf Coast) = 12.0 ppg

1. P = 12.0 ppg x 0.052 x 12,000 ft
P = 7488 psi

2. σ = 12,000 psi — 7488 psi
σ = 4512 psi

3. $D = \dfrac{4512 \text{ psi}}{0.535}$

   D = 8434 ft

4. From chart = Ki = 0.79 psi/ft

5. $F = \dfrac{7488}{12{,}000} + 0.79 \times \dfrac{4512}{12{,}000}$

   F = 0.624 psi/ft + 0.297 psi/ft
   F = 0.92 psi/ft

6. Fracture pressure, psi = 0.92 psi/ft x 12,000 ft
   Fracture pressure = 11,040 psi

7. Maximum mud density, ppg = $\dfrac{0.92 \text{ psi/ft}}{0.052}$

   Maximum mud density = 17.69 ppg

Method 2: Ben Eaton Method

F = ((S ÷ D) — (Pf ÷ D)) x (y ÷ (1 — y)) + (Pf ÷ D)

where S/D = overburden gradient, psi/ft
Pf/D = formation pressure gradient at depth of interest, psi/ft
y = Poisson's ratio

Procedure:

1. Obtain overburden gradient from "Overburden Stress Gradient Chart."
2. Obtain formation pressure gradient from electric logs, density measurements, or from logging operations.
3. Obtain Poisson's ratio from "Poisson's Ratio Chart."
4. Determine fracture gradient using above equation.
5. Determine fracture pressure, psi: psi = F x D
6. Determine maximum mud density, ppg: ppg = F ÷ 0.052

Example: Casing setting depth = 12,000 ft Formation pore pressure = 12.0 ppg

1. Determine S/D from chart = depth = 12,000 ft S/D = 0.96 psi/ft

2. Pf/D = 12.0 ppg x 0.052 = 0.624 psi/ft

3. Poisson's Ratio from chart = 0.47 psi/ft

4. Determine fracture gradient: $F = (0.96 — 0.6243) (0.47 \div 1 — 0.47) + 0.624$
$F = 0.336 \times 0.88679 + 0.624$
$F = 0.29796 + 0.624$
$F = 0.92$ psi/ft

5. Determine fracture pressure: psi = 0.92 psi/ft x 12,000 ft
psi = 11,040

6. Determine maximum mud density: $ppg = \frac{0.92 \text{ psi/ft}}{0.052}$
ppg = 17.69

9. Fracture Gradient Determination - Subsea Applications

In offshore drilling operations, it is necessary to correct the calculated fracture gradient for the effect of water depth and flow-line height (air gap) above mean sea level. The following procedure can be used:

Example: Air gap = 100 ft Density of seawater = 8.9 ppg
Water depth = 2000 ft Feet of casing below mud-line = 4000 ft

Procedure:

1. Convert water to equivalent land area, ft:

a) Determine the hydrostatic pressure of the seawater: HPsw = 8.9 ppg x 0.052 x 2000 ft
HPsw = 926 psi

b) From Eaton's Overburden Stress Chart, determine the overburden stress gradient from mean sea level to casing setting depth:

From chart: Enter chart at 6000 ft on left; intersect curved line and read overburden gradient at bottom of chart:

Overburden stress gradient = 0.92 psi/ft

c) Determine equivalent land area, ft: $\text{Equivalent feet} = \frac{926 \text{ psi}}{0.92 \text{ psi/ft}}$

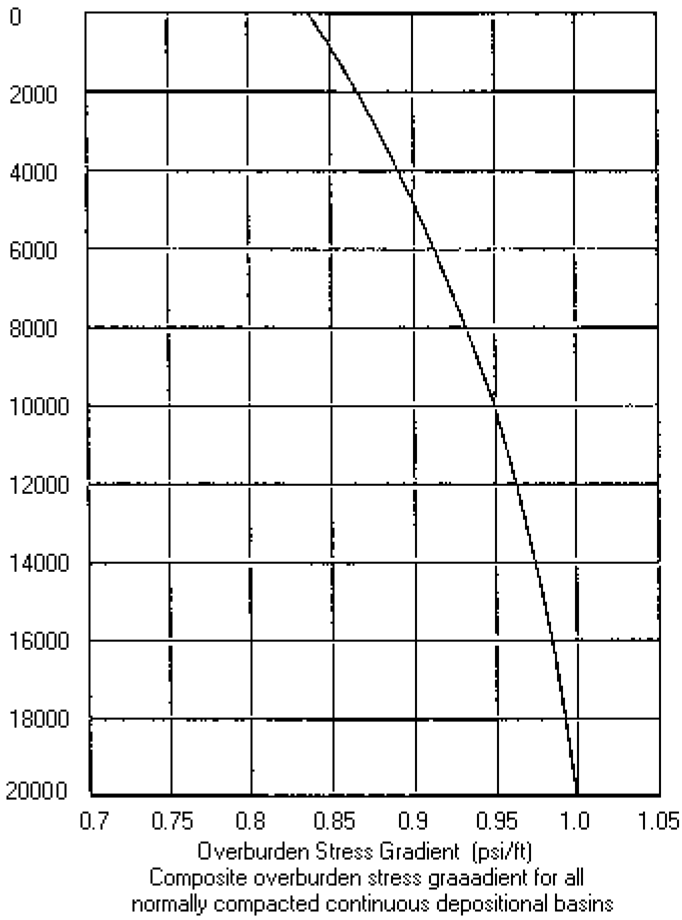


Figure 5-2. Eaton's overburden stress chart.

2. Determine depth for fracture gradient determination: Depth, ft = 4000 ft + 1006 ft
Depth = 5006 ft

3. Using Eaton's Fracture Gradient Chart, determine the fracture gradient at a depth of 5006 ft:

   From chart: Enter chart at a depth of 5006 ft; intersect the 9.0 ppg line; then proceed up and read the fracture gradient at the top of the chart:

   Fracture gradient = 14.7 ppg

4. Determine the fracture pressure: psi = 14.7 ppg x 0.052 x 5006 ft
psi = 3827

5. Convert the fracture gradient relative to the flow-line: Fc = 3827 psi 0.052 ÷ 6100 ft
Fc = 12.06 ppg

where Fc is the fracture gradient, corrected for water depth, and air gap.

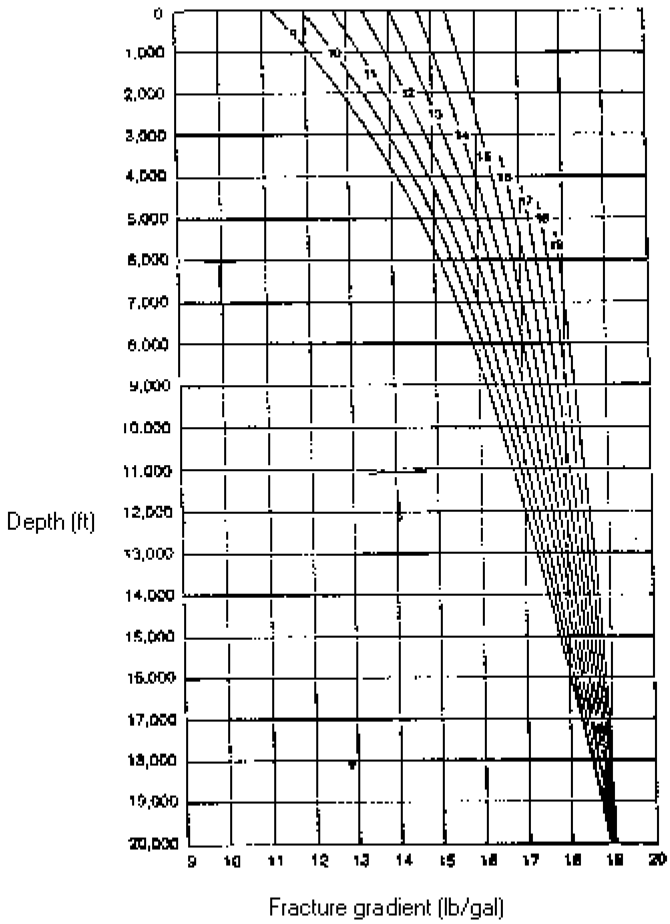


Figure 5-3 Eaton's Fracture gradient chart

10. Directional Drilling Calculations

Directional Survey Calculations

The following are the two most commonly used methods to calculate directional surveys:

1. Angle Averaging Method

$$\text{North} = \text{MD x sin.}\left(\frac{I1 + I2}{2}\right) \text{ x cos.}\left(\frac{Al + A2}{2}\right)$$

$$\text{East} = \text{MD x sin.}\left(\frac{I1 + I2}{2}\right) \text{ x sin.}\left(\frac{Al + A2}{2}\right)$$

$$\text{Vert.} = \text{MD x cos.}\left(\frac{I1 + I2}{2}\right)$$

2. Radius of Curvature Method

$$\text{North} = \frac{\text{MD}(\cos. I1 - \cos. I2)(\sin. A2 - \sin. A1)}{(I2 - I1)(A2 - A1)}$$

$$\text{East} = \frac{\text{MD}(\cos. I1 - \cos. I2)(\cos. A2 - \cos. A1)}{(I2 - I1)(A2 - A1)}$$

$$\text{Vert.} = \frac{\text{MD}(\sin. I2 - \sin. I1)}{(I2 - I1)}$$

where MD = course length between surveys in measured depth, ft
I1, I2 = inclination (angle) at upper and lower surveys, degrees
A1, A2 = direction at upper and lower surveys

Example: Use the Angle Averaging Method and the Radius of Curvature Method to calculate the following surveys:

	Survey 1	**Survey 2**
Depth, ft	7482	7782
Inclination, degrees	4	8
Azimuth, degrees	10	35

Angle Averaging Method:

$$\text{North} = 300 \times \sin. \left(\frac{4+8}{2}\right) \times \cos. \left(\frac{10+35}{2}\right)$$

North = 300 x sin (6) x cos. (22.5)
North = 300 x .104528 x .923879
North = 28.97 ft

$$\text{East} = 300 \times \sin. \left(\frac{4+8}{2}\right) \times \sin. \left(\frac{10+35}{2}\right)$$

East = 300 x sin. (6) x sin. (22.5)
East = 300 x .104528 x .38268
East = 12.0 ft

$$\text{Vert.} = 300 \times \cos. \left(\frac{4+8}{2}\right)$$

Vert. = 300 x cos. (6)
Vert. = 300 x .99452
Vert. = 298.35 ft

Radius of Curvature Method:

$$\text{North} = \frac{300(\cos. 4 — \cos. 8)(\sin. 35 — \sin. 10)}{(8 — 4)(35 — 10)}$$

$$\text{North} = \frac{300\ (.99756 — .990268)(.57357 — .173648)}{4 \times 25}$$

North = 0.874629 ÷ 100
North = 0.008746 x 57.3^2
North = 28.56 ft

$$\text{East} = \frac{300(\cos. 4 — \cos. 8)(\cos. 10 — \cos. 35)}{(8 — 4)(35 — 10)}$$

$$\text{East} = \frac{300\ (99756 — .99026)(.9848 — .81915)}{4 \times 25}$$

$$\text{East} = \frac{300\ (0073)\ (.16565)}{100}$$

$$\text{East} = \frac{0.36277}{100}$$

East = 0.0036277 x 57.3^2
East = 11.91 ft

$$\text{Vert.} = \frac{300\ (\sin. 8 — \sin. 4)}{(8 — 4)}$$

$$\text{Vert.} = \frac{300\ (0.13917 — 0.069756)}{(8 — 4)}$$

$$\text{Vert.} = \frac{300 \times .069414}{4}$$

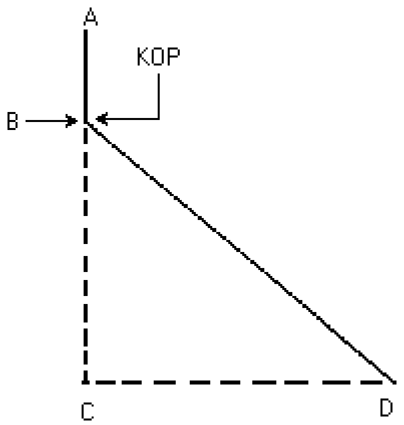
$$\text{Vert.} = \frac{300 \times 0.069414}{4}$$

Vert. = 5.20605 x 57.3
Vert. = 298.3 ft

Deviation/Departure Calculation

Deviation is defined as departure of the wellbore from the vertical, measured by the horizontal distance from the rotary table to the target. The amount of deviation is a function of the drift angle (inclination) and hole depth.

The following diagram illustrates how to determine the deviation/departure:



DATA:

AB = distance from the surface location to the KOP
BC = distance from KOP to the true vertical depth (TVD)
BD = distance from KOP to the bottom of the hole (MD)
CD = Deviation/departure—departure of the wellbore from the vertical
AC = true vertical depth
AD = Measured depth

Figure 5-4. Deviation/Departure

To calculate the deviation/departure (CD), ft: CD, ft = sin I x BD

Example: Kick off point (KOP) is a distance 2000 ft from the surface.
MD is 8000 ft. Hole angle (inclination) is 20 degrees.
Therefore the distance from KOP to MD = 6000 ft (BD):

CD, ft = sin 20 x 6000 ft
CD, ft = 0.342 *x* 6000 ft
CD = 2052 ft

From this calculation, the measured depth (MD) is 2052 ft away from vertical.

Dogleg Severity Calculation

Method 1

Dogleg severity (DLS) is usually given in degrees/100 ft. The following formula provides dogleg severity in degrees/100 ft and is based on the Radius of Curvature Method:

DLS = {cos.$^{-1}$ [(cos. I1 x cos. I2) + (sin. I1 x sin. 12) x cos. (A2 — Al)]} x (100 ÷ CL)

For metric calculation, substitute x (30 ÷ CL) i.e.

DLS = {cos.$^{-1}$ [(cos. I1 x cos. I2) + (sin. I1 x sin. 12) x cos. (A2 — Al)]} x (30 ÷ CL)

where DLS = dogleg severity, degrees/l00 ft
CL = course length, distance between survey points, ft
I1, I2 = inclination (angle) at upper and lower surveys, ft
Al, A2 = direction at upper and lower surveys, degrees
^Azimuth = azimuth change between surveys, degrees

Example:	**Survey 1**	**Survey 2**
Depth, ft	4231	4262
Inclination, degrees	13.5	14.7
Azimuth, degrees	N 10 E	N 19 E

DLS = {cos.$^{-1}$ [(cos. 13.5 x cos. l4.7) + (sin. 13.5 x sin. 14.7 x cos. (19 — 10)]} x (100 ÷ 31)
DLS = {cos.$^{-1}$ [(.9723699 x .9672677) + (.2334453 x .2537579 x .9876883)]} x (100 ÷ 31)
DLS = {cos.$^{-1}$ [(.940542) + (.0585092)]} x (100 ÷ 31)
DLS = 2.4960847 x (100 ÷ 31)
DLS = 8.051886 degrees/100 ft

Method 2

This method of calculating dogleg severity is based on the tangential method:

$$\text{DLS} = \frac{100}{\text{L [(sin. I1 x sin. I2)(sin. A1 x sin. A2 + cos. A1 x cos. A2) + cos. I1 x cos. I2]}}$$

where DLS = dogleg severity, degrees/ 100 ft
L = course length, ft
Il, 12 = inclination (angle) at upper and lower surveys, degrees
Al, A2 = direction at upper and lower surveys, degrees

Example:	**Survey 1**	**Survey 2**
Depth	4231	4262
Inclination, degrees	13.5	14.7
Azimuth, degrees	N 10 E	N 19 E

$$\text{DLS} = \frac{100}{\text{31[(sin.13.5 x sin.14.7)(sin.10 x sin.19) + (cos.10 x cos.1l9)+(cos.13.5 x cos.14.7)]}}$$

$$\text{DLS} = \frac{100}{30.\ 969}$$

DLS = 3.229 degrees/100 ft

Available Weight on Bit in Directional Wells

A directionally drilled well requires that a correction be made in total drill collar weight because only a portion of the total weight will be available to the bit:

P = W x Cos I

where P = partial weight available for bit
I = degrees inclination (angle)
Cos = cosine
W = total weight of collars

Example: W = 45,000 lb I = 25 degrees

P = 45,000 x cos 25
P = 45,000 x 0.9063
P = 40,784 lb

Thus, the available weight on bit is 40,784 lb.

Determining True Vertical Depth

The following is a simple method of correcting for the TVD on directional wells. This calculation will give the approximate TVD interval corresponding to the measured interval and is generally accurate enough for any pressure calculations. At the next survey, the TVD should be corrected to correspond to the directional Driller's calculated true vertical depth:

$TVD_2 = \cos I \times CL + TVD_1$

where TVD_2 = new true vertical depth, ft
TVD_1 = last true vertical depth, ft
CL = course length — number of feet since last survey
cos = cosine

Example: TVD (last survey) = 8500 ft Deviation angle = 40 degrees
Course length = 30 ft

Solution: $TVD_2 = \cos 40 \times 30 \text{ ft} + 8500 \text{ ft}$
$TVD_2 = 0.766 \times 30 \text{ ft} + 8500 \text{ ft}$
$TVD_2 = 22.98 \text{ ft} + 8500 \text{ ft}$
$TVD_2 = 8522.98 \text{ ft}$

11. Miscellaneous Equations and Calculations

Surface Equipment Pressure Losses

$$SEpl = C \times MW \times \left(\frac{Q}{100}\right)^{1.86}$$

where SEpl = surface equipment pressure loss, psi Q = circulation rate, gpm
C = friction factor for type of surface equipment W = mud weight, ppg

Type of Surface Equipment	C
1	1.0
2	0.36
3	0.22
4	0.15

Example: Surface equipment type = 3 C = 0.22
Mud weight = 11.8 ppg Circulation rate = 350 gpm

$$SEpl = 0.22 \times 11.8 \times \left(\frac{350}{100}\right)^{1.86}$$

$$SEpl = 2.596 \times (35)^{1.86}$$
$$SEpl = 2.596 \times 10.279372$$
$$SEpl = 26.69 \text{ psi}$$

Drill Stem Bore Pressure Losses

$$P = \frac{0.000061 \times MW \times L \times Q^{1.86}}{d^{4.86}}$$

where P = drill stem bore pressure losses, psi MW = mud weight, ppg
L = length of pipe, ft Q = circulation rate, gpm
d = inside diameter, in.

Example: Mud weight = 10.9 ppg Length of pipe = 6500 ft
Circulation rate = 350 gpm Drill pipe ID = 4.276 in.

$$P = \frac{0.000061 \times 10.9 \times 6500 \times (350)^{1.86}}{4.276^{4.86}}$$

$$P = \frac{4.32185 \times 53946.909}{1166.3884}$$

$$P = 199.89 \text{ psi}$$

Annular Pressure Losses

$$P = \frac{(1.4327 \times 10^{-7}) \times MW \times L \times V^2}{Dh - Dp}$$

where P = annular pressure losses, psi MW = mud weight, ppg
L = length, ft V = annular velocity, ft/mm
Dh = hole or casing ID, in. Dp = drill pipe or drill collar OD, in.

Example: Mud weight = 12.5 ppg Length = 6500 ft
Circulation rate = 350 gpm Hole size = 8.5 in.
Drill pipe OD = 5.0 in.

Determine annular velocity, ft/mm:

$$v = \frac{24.5 \times 350}{8.5^2 - 5.0^2}$$

$$v = \frac{8575}{47.25}$$

$$v = 181 \text{ ft/min}$$

Determine annular pressure losses, psi: $P = \frac{(1.4327 \times 10^{-7} \times 12.5 \times 6500 \times 181^2}{8.5 - 5.0}$

$P = \frac{381.36}{3.5}$

P = 108.96 psi

Pressure Loss Through Common Pipe Fittings

$$P = \frac{K \times MW \times Q^2}{12{,}031 \times A^2}$$

where P = pressure loss through common pipe fittings
K = loss coefficient (See chart below)
Q = circulation rate, gpm
A = area of pipe, sq in.
MW = weight of fluid, ppg

List of Loss Coefficients (K)

K = 0.42 for 45 degree ELL
K = 0.90 for 90 degree ELL
K = 1.80 for tee
K = 2.20 for return bend
K = 0.19 for open gate valve
K = 0.85 for open butterfly valve

Example: K = 0.90 for 90 degree ELL
MW = 8.33 ppg (water)
Q = 100 gpm
A = 12.5664 sq. in. (4.0 in. ID pipe)

$P = \frac{0.90 \times 8.33 \times 1002}{12{,}031 \times 12.56642}$

$P = \frac{74970}{1899868.3}$

P = 0.03946 psi

Minimum Flow-rate for PDC Bits

Minimum flow-rate, gpm = 12.72 x bit diameter, in. $^{1.47}$

Example: Determine the minimum flow-rate for a 12-1/4 in. PDC bit:

Minimum flow-rate, gpm = $12.72 \times 12.25^{1.47}$
Minimum flow-rate, gpm = 12.72 x 39.77
Minimum flow-rate = 505.87 gpm

Critical RPM: RPM to Avoid Due to Excessive Vibration (Accurate to Approximately 15%)

$$\text{Critical RPM} = \frac{33055}{\text{L, ft}^2} \times \sqrt{\text{OD, in.}^2 + \text{ID, in.}^2}$$

Example: L = length of one joint of drill pipe = 31 ft
OD = drill pipe outside diameter = 5.0 in.
ID = drill pipe inside diameter = 4.276 in.

$$\text{Critical RPM} = \frac{33055}{31^2} \times \sqrt{5.0^2 + 4.276^2}$$

$$\text{Critical RPM} = \frac{33055}{961} \times \sqrt{43.284}$$

Critical RPM = 34.3965 x 6.579
Critical RPM = 226.296

NOTE: As a rule of thumb, for 5.0 in. drill pipe, do not exceed 200 RPM at any depth.

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APPENDIX A

Table A-1
CAPACITY AND DISPLACEMENT
(English System)
DRILL PIPE

Size OD in.	Size ID in.	WEIGHT lb/ft	CAPACITY bbl/ft	DISPLACEMENT bbl/ft
2-3/8	1.815	6.65	0.01730	0.00320
2-7/8	2.150	10.40	0.00449	0.00354
3-1/2	2.764	13.30	0.00742	0.00448
3-1/2	2.602	15.50	0.00658	0.00532
4	3.340	14.00	0.01084	0.00471
4-1/2	3.826	16.60	0.01422	0.00545
4-1/2	3.640	20.00	0.01287	0.00680
5	4.276	19.50	0.01766	0.00652
5	4.214	20.50	0.01730	0.00704
5-1/2	4.778	21.90	0.02218	0.00721
5-1/2	4.670	24.70	0.02119	0.00820
5-9/16	4.859	22.20	0.02294	0.00712
6-5/8	5.9625	25.20	0.03456	0.00807

Table A-2
HEAVY WEIGHT DRILL PIPE AND DISPLACEMENT

Size OD in.	Size ID in.	WEIGHT lb/ft	CAPACITY bbl/ft	DISPLACEMENT bbl/ft
3-1/2	2.0625	25.3	0.00421	0.00921
4	2.25625	29.7	0.00645	0.01082
4-1/2	2.75	41.0	0.00743	0.01493
5	3.0	49.3	0.00883	0.01796

Additional capacities, bbl/ft, displacements, bbl/ft and weight, lb/ft can be determined from the following:

$$\text{Capacity, bbl/ft} = \frac{\text{ID, in.}^2}{1029.4}$$

$$\text{Displacement, bbl/ft} = \frac{\text{Dh, in.} - \text{Dp, in.}^2}{1029.4}$$

Weight, lb/ft = Displacement, bbl/ft x 2747 lb/bbl

Table A-3
CAPACITY AND DISPLACEMENT
(Metric System)
DRILL PIPE

Size OD in.	Size ID in.	WEIGHT lb/ft	CAPACITY ltrs/ft	DISPLACEMENT ltrs/ft
2-3/8	1.815	6.65	1.67	1.19
2-7/8	2.150	10.40	2.34	1.85
3-1/2	2.764	13.30	3.87	2.34
3-1/2	2.602	15.50	3.43	2.78
4	3.340	14.00	5.65	2.45
4-1/2	3.826	16.60	7.42	2.84
4-1/2	3.640	20.00	6.71	3.55
5	4.276	19.50	9.27	3.40
5	4.214	20.50	9.00	3.67
5-1/2	4.778	21.90	11.57	3.76
5-1/2	4.670	24.70	11.05	4.28
5-9/16	4.859	22.20	11.96	3.72
6-5/8	5.965	25.20	18.03	4,21

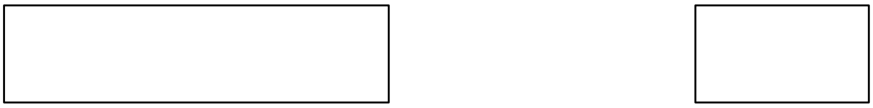
Table A-4
DRILL COLLAR CAPACITY AND DISPLACEMENT

	I.D.	1½”	1¾”	2”	2¼”	2½”	2¾”	3”	3¼”	3½”	3¾”	4”	4¼”
	Capacity	**.0022**	**.0030**	**.0039**	**.0049**	**.0061**	**.0073**	**.0087**	**.0103**	**.0119**	**.0137**	**.0155**	**.0175**
OD	#/ft	36.7	34.5	32.0	29.2								
4”	Disp.	.0 133	.0125	.0116	.0106								
4¼”	#/ft	34.7	42.2	40.0	37.5								
	Disp.	.0126	.0153	.0145	.0136								
4½”	#/ft	48.1	45.9	43.4	40.6								
	Disp.	.0175	.0167	.0158	.0148								
4¾”	#/ft	54.3	52.1	49.5	46.8	43.6							
	Disp.	.0197	.0189	.0180	.0170	.0159							
5”	#/ft	60.8	58.6	56.3	53.3	50.1							
	Disp.	.0221	.0213	.0214	.0194	.0182							
5¼”	#/ft	67.6	65.4	62.9	60.1	56.9	53.4						
	Disp.	.0246	.0238	.0229	.0219	.0207	.0194						
5½”	#/ft	74.8	72.6	70.5	67.3	64.1	60.6	56.8					
	Disp.	.0272	.0264	.0255	.0245	.0233	.0221	.0207					
5¾”	#/ft	82.3	80.1	77.6	74.8	71.6	68.1	64.3					
	Disp.	.0299	.0291	.0282	.0272	.0261	.0248	.0234					
6”	#/ft	90.1	87.9	85.4	82.6	79.4	75.9	72.1	67.9	63.4			
	Disp.	.0328	.0320	.0311	.0301	.0289	.0276	.0262	.0247	.0231			
6¼”	#/ft	98.0	95.8	93.3	90.5	87.3	83.8	80.0	75.8	71.3			
	Disp.	.0356	.0349	.0339	.0329	.0318	.0305	.0291	.0276	.0259			
6½”	#/ft	107.0	104.8	102.3	99.5	96.3	92.8	89.0	84.8	80.3			
	Disp.	.0389	.0381	.0372	.0362	.0350	.0338	.0324	.0308	.0292			
6¾”	#/ft	116.0	113.8	111.3	108.5	105.3	101.8	98.0	93.8	89.3			
	Disp.	.0422	.0414	.0405	.0395	.0383	.0370	.0356	.0341	.0325			
7”	#/ft	125.0	122.8	120.3	117.5	114.3	110.8	107.0	102.8	98.3	93.4	88.3	
	Disp.	.0455	.0447	.0438	.0427	.0416	.0403	.0389	.0374	.0358	.0340	.0321	
7¼”	#/ft	134.0	131.8	129.3	126.5	123.3	119.8	116.0	111.8	107.3	102.4	97.3	
	Disp.	.0487	.0479	.0470	.0460	.0449	.0436	.0422	.0407	.0390	.0372	.0354	
7½”	#/ft	144.0	141.8	139.3	136.5	133.3	129.8	126.0	121.8	117.3	112.4	107.3	
	Disp.	.0524	.0516	.0507	.0497	.0485	.0472	.0458	.0443	.0427	.0409	.0390	
7¾”	#/ft	154.0	151.8	149.3	146.5	143.3	139.8	136.0	131.8	127.3	122.4	117.3	
	Disp.	.0560	.0552	.0543	.0533	.0521	.0509	.0495	.0479	.0463	.0445	.0427	
8”	#/ft	165.0	162.8	160.3	157.5	154.3	150.8	147.0	142.8	138.3	133.4	123.3	122.8
	Disp.	.0600	.0592	.0583	.0573	.0561	.0549	.0535	.0520	.0503	.0485	.0467	.0447
8¼”	#/ft	176.0	173.8	171.3	168.5	165.3	161.8	158.0	153.8	149.3	144.4	139.3	133.8
	Disp.	.0640	.0632	.0623	.0613	.0601	.0589	.0575	.0560	.0543	.0525	.0507	.0487
8½”	#/ft	187.0	184.8	182.3	179.5	176.3	172.8	169.0	164.8	160.3	155.4	150.3	144.8
	Disp.	.0680	.0672	.0663	.0653	.0641	.0629	.0615	.0600	.0583	.0565	.0547	.0527
8¾”	#/ft	199.0	106.8	194.3	191.5	188.3	194.8	181.0	176.8	172.3	167.4	162.3	156.8
	Disp.	.0724	.0716	.0707	.0697	.0685	.0672	.0658	.0613	.0697	.0609	.0590	.0570
9”	#/ft	210.2	268.0	205.6	202.7	199.6	196.0	192.2	188.0	183.5	178.7	173.5	168.0
	Disp.	.0765	.0757	.0748	.0738	.0726	.0714	.0700	.0685	.0668	.0651	.0632	.0612
10”	#/ft	260.9	258.8	256.3	253.4	250.3	246.8	242.9	238.8	234.3	229.4	224.2	118.7
	Disp.	.0950	.0942	.0933	.0923	.0911	.0898	.0884	.0869	.0853	.0835	.0816	.0796

1. Tank Capacity Determinations

Rectangular Tanks with Flat Bottoms

SIDE END



$$\text{Volume, bbl} = \frac{\text{length, ft} \times \text{width, ft} \times \text{depth, ft}}{5.61}$$

Example 1: Determine the total capacity of a rectangular tank with flat bottom using the following data:

Length = 30 ft Width = 10 ft Depth = 8 ft

$$\text{Volume, bbl} = \frac{30\text{ ft} \times 10\text{ ft} \times 8\text{ ft}}{5.61}$$

$$\text{Volume, bbl} = \frac{2400}{5.61}$$

Volume = 427.84 bbl

Example 2: Determine the capacity of this same tank with only 5-1/2 ft of fluid in it:

$$\text{Volume, bbl} = \frac{30\text{ ft} \times 10\text{ ft} \times 5.5\text{ ft}}{5.61}$$

$$\text{Volume, bbl} = \frac{1650}{5.61}$$

Volume = 294.12 bbl

Rectangular Tanks with Sloping Sides:

SIDE END

$$\text{Volume bbl} — \frac{\text{length, ft} \times [\text{depth, ft (width, + width}_2)]}{5.62}$$

Example: Determine the total tank capacity using the following data:

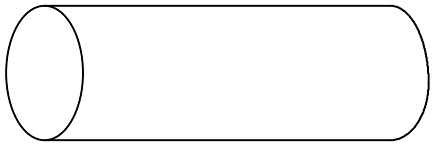
Length = 30 ft Width, (top) = 10 ft Depth = 8 ft Width_2 (bottom) = 6 ft

$$\text{Volume, bbl} = \frac{30 \text{ ft} \times [\, 8\text{ft} \times (\, 10 \text{ ft} + \ 6 \text{ ft})]}{5.62}$$

$$\text{Volume, bbl} = \frac{30 \text{ ft} \times 128}{5.62}$$

Volume = 683.3 bbl

Circular Cylindrical Tanks:



side

$$\text{Volume, bbl} = \frac{3.14 \times r^2 \times \text{height, ft}}{5.61}$$

Example: Determine the total capacity of a cylindrical tank with the following dimensions:
Height = 15 ft Diameter = 10 ft

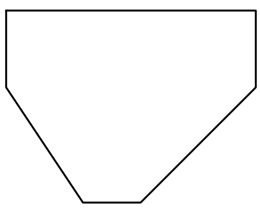
NOTE: The radius (r) is one half of the diameter: $r = \frac{10}{2} = 5$

$$\text{Volume, bbl} = \frac{3.14 \times 5 \text{ ft}^2 \times 15 \text{ ft}}{5.61}$$

$$\text{Volume bbl} = \frac{1177.5}{5.61}$$

Volume = 209.89 bbl

Tapered Cylindrical Tanks:



a) Volume of cylindrical section: $Vc = 0.1781 \times 3.14 \times Rc^2 \times Hc$

b) Volume of tapered section: $Vt = 0.059 \times 3.14 \times Ht \times (Rc^2 + Rb^2 + Rb\ Rc)$

where Vc = volume of cylindrical section, bbl Rc = radius of cylindrical section, ft
Hc = height of cylindrical section, ft Vt = volume of tapered section, bbl
Ht = height of tapered section, ft Rb = radius at bottom, ft

Example: Determine the total volume of a cylindrical tank with the following dimensions:

Height of cylindrical section = 5.0 ft Radius of cylindrical section = 6.0 ft
Height of tapered section = 10.0 ft Radius at bottom = 1.0 ft

Solution:

a)Volume of the cylindrical section: $Vc = 0.1781 \times 3.14 \times 6.02 \times 5.0$
$Vc = 100.66$ bbl

b) Volume of tapered section: $Vt = 0.059 \times 3.14 \times 10 \text{ ft} \times (6^2 + 1^2 + 1 \times 6)$
$Vt = 1.8526 (36 + 1 + 6)$
$Vt = 1.8526 \times 43$
$Vt = 79.66$ bbl

c) Total volume: bbl = 100.66 bbl + 79.66 bbl
bbl = 180.32

Horizontal Cylindrical Tank:

a) Total tank capacity: $\text{Volume, bbl} = \dfrac{3.14 \times r^2 \times L\ (7.48)}{42}$

b) Partial volume;

$\text{Vol. ft}^3 = L[0.017453 \times r^2 \times \cos^{-1} (r - h \div r) - \text{sq. root } (2hr - h^2 (r - h))]$

Example I: Determine the total volume of the following tank;

Length = 30 ft Radius = 4 ft

a) Total tank capacity;

$\text{Volume, bbl} = \dfrac{3.14 \times 42^2 \times 30 \times 7.48}{48}$

$\text{Volume, bbl} = \dfrac{11273.856}{48}$

Volume = 234.87 bbl

Example 2: Determine the volume if there are only 2 feet of fluid in this tank; (h = 2 ft)

Volume, ft^3 = 30 **[**0.0l7453 x4^2 x $\cos^{-1}$ (4 — (2÷ 4)) — sq. root (2 x 2 x 4 —2^2) x (4 —2)**]**
Volume, ft^3 = 30 **[**0.279248 x $\cos^{-1}$ (0.5) — sq. root 12 *x* (2)**]**
Volume, ft^3 = 30 (0.279248 x 60 — 3.464 x 2)
Volume, ft^3 = 30 x 9.827
Volume = 294 ft^3

To convert volume, ft^3. to barrels, multiply by 0.1781.
To convert volume, ft^3, to gallons, multiply by 7.4805.

Therefore, 2 feet of fluid in this tank would result in;

Volume, bbl = 294 ft^3 x 0.1781
Volume = 52.36 bbl

NOTE: This is only applicable until the tank is half full (r — h). After that, calculate total volume of the tank and subtract the empty space. The empty space can be calculated by h = height of empty space.

APPENDIX B

Conversion Factors

TO CONVERT FROM	TO	MULTIPLY BY
Area		
Square inches	Square centimetres	6.45
Square inches	Square millimetres	645+2
Square centimetres	Square inches	0.155
Square millimetres	Square inches	1.55×10^{-3}
Circulation Rate		
Barrels/min	Gallons/min	42.0
Cubic feet/min	Cubic meters/sec	4.72×10^{-4}
Cubic feet/min	Gallons/min	7.48
Cubic feel/mm	Litres/min	28.32
Cubic meters/sec	Gallons/min	15850
Cubic meters/sec	Cubic feet/min	2118
Cubic meters/sec	Litres/min	60000
Gallons/min	Barrels/ruin	0.0238
Gallons/min	Cubic feet/min	0.134
Gallons/min	Litres/min	3.79
Gallons/min	Cubic meters/sec	6.309×10^{-5}
Litres/min	Cubic meters/sec	1.667×10^{-5}
Litres/min	Cubic feet/min	0.0353
Litres/min	Gallons/min	0.264
Impact Force		
Pounds	Dynes	4.45×10^{-5}
Pounds	Kilograms	0.454
Pounds	Newtons	4.448
Dynes	Pounds	2.25×10^{-6}

TO CONVERT FROM	TO	MULTIPLY BY
Kilograms	Pounds	2.20
Newtons	Pounds	0.2248

Length

Feet	Meters	0.305
Inches	Millimetres	25.40
Inches	Centimetres	2.54
Centimetres	Inches	0.394
Millimetres	Inches	0.03937
Meters	Feet	3.281

Mud Weight

Pounds/gallon	Pounds/cu ft	7.48
Pounds/gallon	Specific gravity	0.120
Pounds/gallon	Grams/cu cm	0.1198
Grams/cu cm	Pounds/gallon	8.347
Pounds/cu ft	Pounds/gallon	0.134
Specific gravity	Pounds/gallon	8.34

Power

Horsepower	Horsepower (metric)	1.014
Horsepower	Kilowatts	0.746
Horsepower	Foot pounds/sec	550
Horsepower (metric)	Horsepower	0.986
Horsepower (metric)	Foot pounds/sec	542.5
Kilowatts	Horsepower	1.341
Foot pounds/sec	Horsepower	0.00181

Pressure

Atmospheres	Pounds/sq. in.	14.696
Atmospheres	Kgs/sq. cm	1.033
Atmospheres	Pascals	1.013×10^{5}
Kilograms/sq. cm	Atmospheres	0.9678
Kilograms/sq. cm	Pounds/sq. in.	14.223
Kilograms/sq. cm	Atmospheres	0.9678
Pounds/sq. in.	Atmospheres	0.680
Pounds/sq. in.	Kgs/sq. cm	0.0703
Pounds/sq. in.	Pascals	6.894×10^{-3}

TO CONVERT FROM	TO	MULTIPLY BY
	Velocity	
Feet/sec	Meters/sec	0.305
Feet/mm	Meters/sec	5.08×10^{-3}
Meters/sec	Feet/mm	196.8
Meters/sec	Feet/sec	3.28
	Volume	
Barrels	Gallons	42
Cubic centimetres	Cubic feet	3.531×10^{-3}
Cubic centimetres	Cubic inches	0.06102
Cubic centimetres	Cubic meters	10^{-6}
Cubic centimetres	Gallons	2.642×10^{-4}
Cubic centimetres	Litters	0.001
Cubic feet	Cubic centimetres	28320
Cubic feet	Cubic inches	1728
Cubic feet	Cubic meters	0.02832
Cubic feet	Gallons	7.48
Cubic feet	Litters	28.32
Cubic inches	Cubic centimetres	16.39
Cubic inches	Cubic feet	5.787×10^{-4}
Cubic inches	Cubic meters	1.639×10^{-5}
Cubic inches	Gallons	4.329×10^{-3}
Cubic inches	Litres	0.01639
Cubic meters	Cubic centimetres	10^{6}
Cubic meters	Cubic feet	35.31
Cubic meters	Gallons	264.2
Gallons	Barrels	0.0238
Gallons	Cubic centimetres	3785
Gallons	Cubic feet	0.1337
Gallons	Cubic inches	231
Gallons	Cubic meters	3.785×10^{-4}
Gallons	Litres	3.785
	Weight	
Pounds	Tons (metric)	4.535×10^{-4}
Tons (metric)	Pounds	2205
Tons (metric)	Kilograms	1000

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