FOURTH EDITION

Formulas and Calculations for Drilling, Production, and Workover

All the Formulas You Need to Solve Drilling and Production Problems

William C. Lyons | Thomas Carter | Norton J. Lapeyrouse

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PREFACE

This is the fourth edition of a collection of equations and formulas used in the drilling, completion, workover, and production operations of the oil field. We have expanded the subjects to include items such as drill string design and slip crushing calculations, leak-off test with procedures to set up the analysis graph, rig loads, kick tolerance determinations, an expanded section on hydraulics and pressure loss, and temperature and pressure effects on downhole mud density. We have also reorganized the sections to make it easier to use the contents. Our goal is to provide a quick reference for those people working either in the field or in the office on problems that require calculations for a safe completion of the assigned task.

Many years of experience has taught me that working equations just from memory can often lead to the wrong answer. It is better to have the correct equation available in print to make sure all of the necessary inputs are included in the solution. Many people would prepare their own personal material with guidelines and formulas in a flip pad they would keep in their pocket or at their desk. Then the service companies began to publish handbooks for distribution to customers, but they would be focused on one subject or just cover the technical items related to the products they were marketing. When Norton Lapeyrouse published the first edition of his formulas book, it provided a handy quick reference that could be used by everyone associated with rig operations. When he was no longer available to continue this effort, we were very pleased to contribute to his original idea.

After nearly 30 years of college level teaching, Bill Lyons retired from the New Mexico Institute of Mining and Technology in 2006. In the early 2007 he and I joined the BP Chevron Drilling Training Alliance (DTA) in Houston, Texas. Bill wanted to continue his teaching career in the professional development instruction arena. I had over 48 years of experience in engineering and operations and also wanted to give back the benefit of that experience to the industry as so many others had done for me. At the end of 2012, BP and Chevron dissolved the DTA and went their separate ways to carry out internal professional development of their staffs. The DTA was managed through most of its very successful 18 years of operation by Gary Massie with the competent managerial assistance of Saad Hashmi. At the end of 2012, the DTA was honored with ASME's Excellence in Professional Instruction.

We have received comments and suggestions from many people about items to include in this collection of equations and would like to express our appreciation for their valuable input. We would also like to include a special thanks to John Lofton for his suggestions and review of the material presented in this publication.

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September, 2015

CHAPTER ONE

Basic Equations

1.1 Terminology

Density: The term "density" is the mass per unit volume. In the System International (SI), this is *kg/m³*, or *kg/liter*, *g/cm³*. In the British Imperial System (BIS) and United States Customary System (USCS), the mechanical properties of a fluid are not published in mass per unit volume units (the BIS and USCS are basically the same). In the USCS, the mass per unit volume must be calculated from the published weight per unit volume (this latter term is denoted as specific weight). For decades, the oil and gas industry in the West has used the "density" name as a form of an oil field slang term for the USCS weight per unit volume published fluid mechanical properties usually published as lb/ft.^{3} or lb/gal (the latter also written as *ppg*). The weight per unit volume of fresh water is 62.4 lb/ft.^{3} or 8.34 lb/gal. To obtain the USCS density terms (equivalent to the SI density terms) from the published specific weight values, both terms must be divided by the USCS acceleration of gravity constant, namely, 32.2 ft./s^2. This would give density values of

$$\rho_{\text{fw}} = \frac{\gamma_{\text{fw}}}{g} = \frac{62.4}{32.2} = 1.94\frac{\text{lb}-\text{s}^2}{\text{ft.}^4} = 1.94\frac{\text{slug}}{\text{ft.}^3}$$
$$\rho_{\text{fw}} = \frac{\gamma_{\text{fw}}}{g} = \frac{8.34}{32.2} = 0.258\,\frac{\text{lb}-\text{s}^2}{\text{ft.}-\text{gal}} = 0.258\,\frac{\text{slug}}{\text{gal}}$$

Where: ρ_{fw} = Density of fresh water
g = Gravity constant

The slug term is not used often in engineering practice. Basically, it is the USCS equivalent to the SI kilogram. The USCS slug is

$$1\ \text{slug} = 1\frac{\text{lb}-\text{s}^2}{\text{ft.}}$$

http://dx.doi.org/10.1016/B978-0-12-803417-0.00001-9

Likewise, the SI kilogram is

$$1\,\text{kg} = 1\frac{\text{N} - \text{s}^2}{\text{m}}$$

where the N is the Newton which is the force unit equivalent to the lb force unit in the USCS (the conversion is 4.445 N = 1 lb). As the slug is not often written in the technical literature and the kilogram is very rarely written in the terms its basic terms of

$$\frac{\text{N} - \text{s}^2}{\text{m}}$$

Specific Weight: Since the SI mechanical properties of a fluid are listed in density units, then these density terms must be used to calculate the specific weight so that practical engineering calculations can be made. Therefore, the density of fresh water can be written in SI units as 1000 kg/m^3 or 1 kg/liter. To carry these calculations out, we must **multiply** these density terms by the SI acceleration of gravity constant, namely, 9.81 m/s^2. This would give the specific weight values of

$$\gamma_{\text{fw}} = \rho_{\text{fw}} g = 1000(9.81) = 9810\frac{\text{N}}{\text{m}^3}$$

or

$$\gamma_{\text{fw}} = \rho_{\text{fw}} g = 1(9.81) = 9.810\frac{\text{N}}{\text{liter}}$$

Where: γ_{fw} = Specific weight

Specific Gravity: The above is a complicated units situation especially for engineers who may have worked in one part of the world where either the SI or the USCS was being used and later is assigned to work in another part of the world where the other unit system was dominates. Fortunately, instead of dealing with such complicated units situations, the specific gravity of a fluid can be determined from either the published SI density data or from the published USCS specific weight data. The specific gravity term can be defined as

$$\text{Specific gravity} = \frac{\text{Density of a fluid}}{\text{Density of fresh water}}$$
$$= \frac{\text{Specific weight of a fluid}}{\text{Specific weight of fresh water}}$$

For example, if an engineer from Germany is working temporarily for his operating company at a drilling location in the Gulf Coast region of the United States and wants to convert his SI density calculation result for a new cement slurry to a USCS specific weight value for service company staff working at the location. His calculation result for the new cement slurry is 1.88 kg/liter. Therefore, the specific gravity of this new cement slurry is

$$\text{Specific gravity} = \frac{1.88}{1.00} = 1.88$$

Therefore, the new cement slurry specific weight is

$$\text{Specific weight} = 1.88(8.34) = 15.7\frac{\text{lb}}{\text{gal}}$$

or

$$\text{Specific gravity} = 1.88(62.4) = 117.3\,\frac{\text{lb}}{\text{ft.}^3}$$

1.2 Mud Weight MW (lb/ft.^{3}), Mud Weight MW (ppg), and Specific Gravity (SG) [USCS/British]

Definition: Mud weight of fresh water in lb/ft.^{3}

$$\text{MW}_{\text{fw}} = 62.4\,\text{lb/ft.}^3 \tag{1.1}$$

Where: MW_{fw} = Fresh water mud weight in lb/ft.^{3}

Example: Mud weight of fresh water in ppg

$$MW_{fw} = \left(\frac{62.4}{(12^3)}\right)(231) \tag{1.2}$$

$$MW_{fw} = 8.34\,\text{ppg}$$

Where: 1 gal = 231 in.^{3}
1 ft. = 12 in.

Example: Specific gravity of fresh water SG

$$SG_{fw} = \left(\frac{62.4}{62.4}\right) = 1.0 \tag{1.3}$$

or

$$SG_{fw} = \left(\frac{8.34}{8.34}\right) = 1.0 \tag{1.4}$$

Example: SG of a mud weight of 12.0 ppg

$$SG_m = \left(\frac{12.0}{8.34}\right) = 1.44 \tag{1.5}$$

1.3 Density ρ (kg/m^3 or kg/liter), Mud Weight MW (N/m^3 or N/liter), and Specific Gravity (SG) [SI-Metric]

Definition: Mud density of fresh water ρ (kg/m^3)

$$\rho_{fw} = 1000.0\,\text{kg/m}^3 \tag{1.6}$$

Example: Mud density of fresh water ρ (kg/liter)

$$\rho_{fw} = 1000.0(10^{-3})$$
$$\rho_{fw} = 1.0 \text{ kg/liter}$$

Where: $1 \text{ liter} = 10^{-3} \text{ m}^3$

Example: Mud weight of fresh water MW (N/m^3)

$$MW_{fw} = 1000.0 \text{ g} = 1000.0(9.81)$$
$$MW_{fw} = 9810.0 \text{ N/m}^3$$

Where: $g = 9.81 \text{ m/s}^2$

Example: Mud weight of fresh water MW (N/liter)

$$MW_{fw} = 1.0 \text{ g} = 1.0(9.81)$$
$$MW_{fw} = 9.81 \text{ N/liter}$$

Example: Specific gravity of fresh water SG (using density)

$$SG_{fw} = \left(\frac{1000.0}{1000.0}\right) = 1.0$$

or

$$SG_{fw} = \left(\frac{1.0}{1.0}\right) = 1.0$$

Example: Specific gravity of fresh water SG (using mud weight)

$$SG_{fw} = \left(\frac{9810.0}{9810.0}\right) = 1.0$$

or

$$SG_{fw} = \left(\frac{9.81}{9.81}\right) = 1.0$$

Conversion: Mud weight of 12.0 ppg to mud weight MW (N/liter)

$$MW = 12.0(1.175) = 14.1\ N/liter \tag{1.7}$$

Where: 1 ppg = 1.175 N/liter

Example: Mud weight of 14.1 N/liter to density ρ (kg/liter)

$$\rho_m = 14.1\left(\frac{1}{g}\right) = 1.44\ kg/liter$$

Example: SG of mud using density of 1.44 kg/liter

$$SG_m = \left(\frac{1.44}{1.0}\right) = 1.44$$

Example: SG of a mud with a specific weight of 14.1 N/liter (Table 1.1)

$$SG_m = \left(\frac{14.1}{9.81}\right) = 1.44$$

Table 1.1
Mud Weight and Density Conversion Factors Summary

From		To		
Density	**Mud Wt**	**Mud Wt**	**SG**	**Multiply by**
	lb/ft.^{3}	lb/gal		0.134
	lb/ft.^{3}		SG	(1/62.4)
	lb/gal		SG	(1/8.34)
kg/m^3		N/m^3		9.81
kg/liter		N/liter		9.81
kg/m^3		N/liter		(9.81/1000)
	N/liter		SG	(1/9.81)
	N/m^3		SG	(1/9810)

1.4 Hydrostatic Pressure (P) and (p) [USCS/British]

Definition: The Conversion Factor used to convert the mud weight to a pressure gradient in psi/ft. is

$$F_c = \left(\rho_w \frac{\text{lb}}{\text{ft.}^3}\right)\left(\frac{1\,\text{ft.}^2}{A\,\text{in.}^2}\right)\left(\frac{1\,\text{gal}}{\rho_w\,\text{lb}}\right) \tag{1.8}$$

Where: F_c = Conversion Factor in gal/ft. in.^{2}
ρ_w = Weight of water in lb/ft.^{3}
A = Area in in.^{2}

Example: Determine the conversion factor using

$\rho_w = 62.4$ lb/ft.^{3}

$A = 144$ in.^{2}

$$F_c = \left(\frac{62.4\ \text{lb}}{\text{ft.}^3}\right)\left(\frac{1\,\text{ft.}^2}{144\,\text{in.}^2}\right)\left(\frac{1\,\text{gal}}{8.34\,\text{lb}}\right)$$

$$F_c = (62.4)(0.00694)(0.1199)$$

$$F_c = 0.0519\frac{\text{gal}}{\text{ft.in.}^2}$$

Or

$$F_c = 0.052\frac{\text{gal}}{\text{ft.in.}^2}$$

Definition: Hydrostatic pressure P (lb/ft.^{2}) at a depth H (ft.) below surface is

$$P = (\text{MW})(H) \tag{1.9}$$

Where: P = Hydrostatic pressure in lb/ft.^{2} (psi)
MW = Mud weight in lb/ft.^{3}
H = True vertical depth (TVD) in ft.

Note: The TVD is always used and *not* the measured depth even for an inclined wellbore.

Example: Pressure (lb/ft.^{2}) in fresh water at a depth of 1000 ft.

$$P = (62.4)(1000) = 62{,}400 \text{ lb/ft.}^2$$

Example: Pressure (lb/ft.^{2}) in 12.0 ppg at a depth of 1000 ft.

$$P = (89.9)(1000) = 89{,}900 \text{ lb/ft.}^2$$

Definition: Hydrostatic pressure P (psi) at a depth H (ft.) below surface is (using Equation (1.9))

$$P(\text{psi})(12)^2 = \text{MW}\left(\text{lb/ft.}^3\right) H(\text{ft.}) \tag{1.10}$$

which reduces to

$$P(\text{psi}) = \text{MW}\left(\text{lb/ft.}^3\right)\left(\frac{1}{(12)^2}\right) H(\text{ft.})$$

or

$$p = (0.00694)(\text{MW})(H)$$

Where: p = Hydrostatic pressure in psi

Example: Pressure (psi) in fresh water (lb/ft.^{3}) at a depth of 1000 ft.

$$p = (0.00694)(62.4)(1000) = 434 \text{psi}$$

Example: Pressure (psi) in 12.0 ppg at a depth of 1000 ft.

$$p = (0.00694)(12.0)(1000) = 624 \text{psi}$$

Definition: Hydrostatic pressure p (psi) at a depth H (ft.) below surface is (using Equation (1.9))

$$p(\text{psi})(12)^2 = \text{MW}(\text{ppg})\left(\frac{(12)^3}{231}\right)H(\text{ft.})$$

which reduces to

$$p(\text{psi}) = \text{MW}(\text{ppg})\left(\frac{12}{231}\right)H(\text{ft.})$$

or

$$p(\text{psi}) = 0.052\,\text{MW}(\text{ppg})\,H(\text{ft.}) \tag{1.11}$$

Example: Pressure (psi) in fresh water at a depth of 1000 ft.

$$p = 0.052(8.34)(1000) = 434\,\text{psi}$$

Example: Pressure (psi) in 12.0 ppg mud at a depth of 1000 ft.

$$p = 0.052(12.0)(1000) = 624\ \text{psi}$$

1.5 Hydrostatic Pressure (*P*) and (*p*) [SI-Metric]

Definition: Hydrostatic pressure *P* (N/m^2) at a depth *H* (m) below surface is (using N/m^3)

$$P\left(N/m^2\right) = \text{MW}\left(N/m^3\right)H(\text{m}) \tag{1.12}$$

Example: Pressure (N/m^2) in fresh water at a depth of 305 m (~1000 ft.)

$$P = (9810)(305) = 2{,}992{,}050\,N/m^2$$

Definition: Hydrostatic pressure *P* (N/m^2) at a depth *H* (m) below surface is (using N/liter)

$$P\left(\mathrm{N/m^2}\right) = 1000\ \mathrm{MW(N/liter)}\, H(\mathrm{m}) \tag{1.13}$$

Example: Pressure ($\mathrm{N/m^2}$) in fresh water at a depth of 305 m (~1000 ft.)

$$P = 1000(9.81)(305) = 2{,}992{,}050\ \mathrm{N/m^2}$$

Definition: Hydrostatic pressure P ($\mathrm{N/m^2}$) at a depth H (m) below surface is (using SG)

$$P\left(\mathrm{N/m^2}\right) = \mathrm{SG}\ \mathrm{MW_{fw}}\left(\mathrm{N/m^3}\right) H(\mathrm{m}) \tag{1.14}$$

or

$$P\left(\mathrm{N/m^2}\right) = 1000\ \mathrm{SG}\ \mathrm{MW_{fw}(N/liter)}\, H(\mathrm{m}) \tag{1.15}$$

Example: Pressure ($\mathrm{N/m^2}$) in fresh water at a depth of 305 m (~1000 ft.)

$$P = 1000(1.0)(9.81)(305) = 2{,}992{,}050\ \mathrm{N/m^2}$$

Example: Pressure ($\mathrm{N/m^2}$) in mud with an $\mathrm{SG_m}$ of 1.44 at a depth of 305 m (~1000 ft.)

$$P = 1000(1.44)(9.81)(305) = 4{,}308{,}552\ \mathrm{N/m^2}$$

Definition: Hydrostatic pressure p ($\mathrm{N/cm^2}$) at a depth H (m) below surface is (using SG)

$$p\left(\mathrm{N/cm^2}\right) = 10^{-4}\mathrm{SG}\ \mathrm{MW_{fw}}\left(\mathrm{N/m^3}\right) H(\mathrm{m}) \tag{1.16}$$

Example: Pressure ($\mathrm{N/cm^2}$) in fresh water at a depth of 305 m (~1000 ft.)

$$p = 10^{-4}(1.0)(9810)(305) = 299\ \mathrm{N/cm^2}$$

Example: Pressure (N/cm^2) in mud with an SG of 1.44 at a depth of 305 m (~1000 ft.)

$$p = 10^{-4}(1.44)(9810)(305) = 431\ \mathrm{N/cm^2}$$

Note: The values of p (N/cm^2) are 0.69 of the values of p (psi).

1.6 Pressure Gradient ∇ (psi/ft.), *G* (ppg) [USCS/British]

Definition: Pressure gradient ∇ (psi/ft.) is obtained from Equation (1.10)

$$\nabla(\mathrm{psi/ft.}) = \left(\frac{p(\mathrm{psi})}{H(\mathrm{ft.})}\right) = 0.052\ \mathrm{MW(ppg)} \qquad (1.17)$$

$$\nabla(\mathrm{psi/ft.}) = 0.052\ \mathrm{MW(ppg)}$$

Where:

∇ = Pressure gradient in psi/ft.

Example: Pressure gradient ∇_{fw} (psi/ft.) for fresh water

$$\nabla_{fw} = 0.052(8.34)$$
$$\nabla_{fw} = 0.434\ \mathrm{psi/ft.}$$

Example: Pressure gradient ∇_m (psi/ft.) for 12.0 ppg mud

$$\nabla_m = 0.052(12.0)$$
$$\nabla_m = 0.624\ \mathrm{psi/ft.}$$

Definition: Pressure gradient G (ppg) is also obtained from Equation (1.10)

$$G(\mathrm{ppg}) = \left(\frac{P(\mathrm{psi})}{0.052\ H(\mathrm{ft.})}\right) = \mathrm{MW(ppg)} \qquad (1.18)$$

$$G(\mathrm{ppg}) = \mathrm{MW(ppg)}$$

Example: Pressure gradient G_{fw} (ppg) for fresh water

$$G_{fw} = 8.34 \text{ ppg}$$

Example: Pressure gradient G_m (ppg) for 12.0 ppg mud

$$G_m = 12.0 \text{ ppg}$$

1.7 Pressure Gradient *G* (SG) [SI-Metric]

Definition: Pressure gradient *G* (SG) is obtained from Equation (1.12)

$$G(\text{N/liter}) = \left(\frac{P(\text{N/m}^2)}{1000\ H(\text{m})}\right) = \text{MW}(\text{N/liter}) \tag{1.19}$$
$$G(\text{N/liter}) = \text{MW}(\text{N/liter})$$

Example: Pressure gradient G_{fw} (SG) for fresh water

$$G_{fw} = 1.0$$

Example: Pressure gradient G_m (SG) for 12.0 ppg mud

$$G_m = 1.44$$

Definition: Pressure gradient *G* (SG) is obtained from Equation (1.14)

$$G(\text{SG}) = \left(\frac{P(\text{N/m}^2)}{1000\ \text{MW}_{fw}(\text{N/liter})\, H(\text{m})}\right) = \text{SG} \tag{1.20}$$
$$G(\text{SG}) = \text{SG}$$

Example: Pressure gradient G_{fw} (SG) for fresh water

$$G_{fw} = 1.0$$

Example: Pressure gradient G_m (SG) for 12.0 ppg mud (Table 1.2)

$$G_m = 1.44$$

Table 1.2
Pressure Gradient Conversion Factors Summary

Pressure Unit	Depth Unit	Mud Weight Unit	Factor
Psi	Feet	lb/ft.^{3}	0.00694
Psi	Feet	ppg	0.052
N/m^2	Meters	N/liter	1000
N/m^2	Meters	SG	9810

1.8 Mud Pump Output *q* (bbl/stk) and *Q* (gpm) [USCS/British]

1.8.1 Triplex Pump

Formula 1:

$$q_s = (0.0102)\left(D_l^2\right)(S)(e_v) \quad (1.21)$$

Where: q_s = Pump output in gallons per stroke (gal/stk)
D_l = Liner diameter in inches
S = Stroke length in inches
e_v = Volumetric efficiency in percent (%)

Example: q (gal/stk) at 100% volumetric efficiency for a 7 in. by 12 in. triplex pump

$$q_s = (0.0102)\left(7^2\right)(12)(1.0) = 6.0 \text{gal/stk}$$

The above assumes 100% volumetric efficiency of the pump.

Note: Most published information on pump output per stroke assumes 100% volumetric efficiency. The pump manufacturers can be contacted to get actual pump volumetric efficiencies. These efficiencies can vary from 0.85 to 0.98. Published data can be checked by assuming $e_v = 1.0$.

Example: Adjust the above result for a pump with a volumetric efficiency of 0.90.

$$q_a = 6.0 \times 0.90 = 5.4 \text{gal/stk}$$

Where: q_a = Actual pump output with a reduced volumetric efficiency in gal/stk

Formula 2:

$$Q = (0.0102)\left(D_l^2\right)(S)(N)(e_v) \tag{1.22}$$

Where: Q = Pump output in gpm
D_l = Liner diameter in inches
S = Stroke length in inches
N = Strokes per minute (also rpm of pump flywheel)
e_v = Volumetric efficiency in percent (%)

Example: Determine the pump output Q (gpm) at 100% volumetric efficiency, for a 7 in. by 12 in. triplex pump at 80 SPM.

$$Q = (0.0102)\left(7^2\right)(12)(80)(1.0) = 480 \text{ gpm}$$

1.8.2 Duplex Pump

Formula 1:

$$q_s = (0.0068)\left(2\left(D_l^2 - D_r^2\right)\right)(S)(e_v) \tag{1.23}$$

Where: q_s = Pump output in gal/stk
D_l = Liner diameter in inches
D_r = Rod diameter in inches
S = Stroke length in inches
e_v = Volumetric efficiency in percent (%)

Example: Determine the output q_s (bbl/stk) of a 5½ in. by 14 in. duplex pump at 100% efficiency. Pump has a rod diameter = 2.0 in.

$$q_s = (0.0068)\left(2\left(5.5^2 - 2.0^2\right)\right)(14)(1.0) = 5.38 \text{ gal/stk}$$

Example: Adjust the above result for a pump with a volumetric efficiency of 0.88.

$$q_a = (5.38)(0.88) = 4.74 \text{gal/stk}$$

Formula 2:

$$Q = (0.0068)\left(2\left(D_l^{\,2} - D_r^{\,2}\right)\right)(S)(N)(e_v) \tag{1.24}$$

Where: Q = Pump output in gpm
D_l = Liner diameter in inches
D_r = Rod diameter in inches
S = Stroke length in inches
N = Strokes per minute (also rpm of pump flywheel)
e_v = Volumetric efficiency in percent (%)

Example: Determine the output Q (gpm) of a 5½ in. by 14 in. duplex pump at 100% efficiency. Pump has a rod diameter = 2.0 in. N is 50 spm.

$$Q = (0.0068)\left(2\left(5.5^2 - 2.0^2\right)\right)(14)(50)(1.0) = 269 \text{ gpm}$$

1.9 Hydraulic Horsepower

Formula 1 (Circulating):

$$\text{HHP} = \frac{(P)(Q)}{1714} \tag{1.25}$$

Where: HHP = Hydraulic horsepower
P = Circulating pressure in psi
Q = Circulating rate in gpm

Example:

$P = 2950$ psi

$Q = 520$ gpm

$$\text{HHP} = \frac{(2950)(520)}{1714} = 894.98$$

Formula 2 (Input):

$$\text{HHP}_i = \frac{(P)(Q)}{(1714)(e_v)(e_m)} \tag{1.26}$$

Where: HHP_i = Input hydraulic horsepower
e_v = Volumetric efficiency (~0.85 to 0.98)
e_m = Mechanical efficiency (~0.80 for continuous operations and ~0.9 for intermittent operations)

Example: Determine the hydraulic horsepower of a pump that has a volumetric output of 480 gpm at a pressure of 1800 psi.

$$HHP = \frac{(1800)(480)}{1714} = 504$$

This represents the horsepower that the pump must apply to move the drilling mud within the pump.

Example: Determine the input horsepower that must be applied to the pumping unit by a prime mover to pump the drilling mud in the above example with continuous operations ($e_m \sim 0.80$) and the pump has a volumetric efficiency of 0.96.

$$HHP_i = \frac{(1800)(480)}{(1714)(0.96)(0.80)} = 656$$

1.10 Estimated Weight of Drill Collars in Air

Formula 1 (REGULAR drill collar weight in lb/ft.):

$$W_{Rdc} = 2.66\left(OD^2 - ID^2\right) \tag{1.27}$$

Where: W_{Rdc} = Weight of REGULAR drill collar in lb/ft.
OD = Outside diameter of drill collar in inches
ID = Inside diameter of drill collar in inches

Example: Determine the weight of an $8 \times 2^{13}/_{16}$ in. regular drill collar in lb/ft.:

$$\text{OD} = 8.0 \text{ in.}$$
$$\text{ID} = 2\ ^{13}/_{16} \text{ in.} \left(\frac{13}{16} = 0.8125\right)$$

$$W_{\text{Rdc}} = (2.66)\left(8^2 - 2.8125^2\right)$$
$$W_{\text{Rdc}} = (2.66)(56.089844) = 149.19898 \text{ lb/ft.}$$

Formula 2 (SPIRAL drill collar weight in lb/ft.):

$$W_{\text{Sdc}} = (2.56)\left(\text{OD}^2 - \text{ID}^2\right) \tag{1.28}$$

Where: W_{Sdc} = Weight of SPIRAL drill collar in lb/ft.

Example: Determine the weight of an $8 \times 2^{13}/_{16}$ in. regular drill collar in lb/ft.

$$\text{OD} = 8.0 \text{in.}$$
$$\text{ID} = 2^{13}/_{16} \text{in.} \left(\frac{13}{16} = 0.81125\right)$$

$$W_{\text{Rdc}} = (2.56)\left(8^2 - 2.8125^2\right)$$
$$W_{\text{Rdc}} = (2.56)(56.089844) = 143.59 \text{ lb/ft.}$$

1.11 Open Hole and Tubular Capacity and Displacement Formulas

1.11.1 Capacity of Open Hole or Tubulars

Formula 1 (Open hole or tubular capacity in bbl/ft.):

$$C = \frac{\text{ID}^2}{1029.4} \tag{1.29}$$

Where: C = Capacity of open hole, casing, drill pipe, or drill collars in bbl/ft.
ID = Internal diameter of open hole, casing, drill pipe, or drill collars in inches

Note: For hole "washout," increase the DIAMETER of the hole size (not volume) with the estimated percent increase.

Example: Determine the capacity in bbl/ft., of a 12¼ in. hole.

$$C = \frac{12.25^2}{1029.4}$$

$$C = 0.145766 \text{ bbl/ft.}$$

Determine the capacity in bbl/ft., of a 12¼ in. hole with a 10% washout in hole DIAMETER. (That is about equal to a ⅝ in. increase in hole size on either side of the bit).

$$C = \frac{(12.25 \times 1.10)^2}{1029.4}$$

$$C = \frac{(13.475)^2}{1029.4}$$

$$C = 0.176389 \text{ bbl/ft.}$$

For $8 \times 2^{13}/_{16}$ in. drill collars, the capacity in bbl/ft. would be:

Convert $^{13}/_{16}$ to decimal equivalent: $13 \div 16 = 0.8125$

$$C = \frac{2.8125^2}{1029.4}$$

$$C = 0.007684 \text{ bbl/ft.}$$

Formula 2 (Open hole or tubular capacity in ft./bbl):

$$C = \frac{1029.4}{\text{ID}^2} \tag{1.30}$$

Example: Determine the capacity of a 12¼-in. hole in ft./bbl.

$$C_a = \frac{1029.4}{12.25^2}$$

$$C_a = 6.8598 \text{ ft./bbl}$$

Formula 3 (Open hole or tubular capacity in gal/ft.):

$$C_a = \frac{\text{ID}^2}{24.51} \tag{1.31}$$

Example: Determine the capacity, gal/ft., of an 8½-in. hole.

$$C_a = \frac{8.5^2}{24.51}$$

$$C_a = 2.947764 \text{ gal/ft.}$$

Formula 4 (Open hole or tubular capacity in ft./gal):

$$C_a = \frac{24.51}{\text{ID}^2} \tag{1.32}$$

Example: Determine the capacity, ft./gal, of an 8½-in. hole.

$$C_a = \frac{24.51}{8.5^2}$$

$$C_a = 0.3392 \text{ft./gal}$$

Formula 5 (Open hole or tubular capacity in ft.^{3}/linear ft.):

$$C_a = \frac{\text{ID}^2}{183.35} \tag{1.33}$$

Example: Determine the capacity, ft.^{3}/linear ft., for a 6.0-in. hole.

$$C_a = \frac{6.0^2}{183.35}$$

$$C_a = 0.1963 \text{ ft.}^3\text{/linear ft.}$$

Formula 6 (Open hole or tubular capacity in linear ft./ft.^{3}):

$$C_a = \frac{183.35}{\text{ID}^2} \tag{1.34}$$

Example: Determine the capacity, linear ft./ft.^{3}, for a 6.0-in. hole.

$$C_a = \frac{183.35}{6.0^2}$$

$$C_a = 5.093051 \text{ linear ft./ft.}^3$$

1.11.2 Displacement of Tubulars

Formula 1 (Tubular displacement in bbl/ft.):

$$D = \frac{\left(\mathrm{OD}^2 - \mathrm{ID}^2\right)}{1029.4} \tag{1.35}$$

Where: D = Displacement of tubular in bbl/ft.
OD = Outside diameter of tubular in inches
ID = Internal diameter of tubular in inches

Example: Determine the displacement for 5×4.276 in. drill pipe in bbl/ft.

$$D = \frac{\left(5.0^2 - 4.276^2\right)}{1029.4}$$

$$D = 0.006524 \text{ bbl/ft.}$$

Formula 2 (Tubular displacement in ft./bbl):

$$D = \frac{1029.4}{\left(\mathrm{OD}^2 - \mathrm{ID}^2\right)} \tag{1.36}$$

Where: D = Displacement of tubular in ft./bbl

Example: Determine the displacement for 5×4.276 in. drill pipe in ft./bbl.

$$D = \frac{1029.4}{\left(5^2 - 4.276^2\right)}$$

$$D = \frac{1029.4}{6.7158}$$

$$D = 153.2798\,\text{ft./bbl}$$

Formula 3 (Tubular displacement in gal/ft.):

$$D = \frac{\left(\text{OD}^2 - \text{ID}^2\right)}{24.51} \tag{1.37}$$

Where: D = Displacement of tubular in gal/ft.

Example: Determine the displacement for 5×4.276 in. drill pipe in gal/ft.

$$D = \frac{\left(5^2 - 4.276^2\right)}{24.51}$$

$$D = \frac{6.7158}{24.51}$$

$$D = 0.2740\,\text{gal/ft.}$$

Formula 4 (Tubular Displacement in ft./gal)

$$D = \frac{24.51}{\left(\text{OD}^2 - \text{ID}^2\right)} \tag{1.38}$$

Where: D = Displacement of tubular in ft./gal

Example: Determine the displacement for 5×4.276 in. drill pipe in ft./gal.

$$D = \frac{24.51}{\left(5^2 - 4.276^2\right)}$$

$$D = \frac{24.51}{6.7158}$$

$$D = 3.6496\,\text{ft./gal}$$

Formula 5 (Tubular displacement in ft.^{3}/linear ft.):

$$D = \frac{\left(\text{OD}^2 - \text{ID}^2\right)}{183.35} \tag{1.39}$$

Where: D = Displacement of tubular in ft.^{3}/linear ft.

Example: Determine the displacement for 5×4.276 in. drill pipe in ft.^{3}/linear ft.

$$D = \frac{\left(5^2 - 4.276^2\right)}{183.35}$$

$$D = \frac{6.7158}{183.35}$$

$$D = 0.03663\,\text{ft.}^3/\text{linear ft.}$$

Formula 6 (Tubular displacement in linear ft./ft.^{3}):

$$D = \frac{183.35}{\left(\text{OD}^2 - \text{ID}^2\right)} \tag{1.40}$$

Example: Determine the displacement for 5×4.276 in. drill pipe in linear ft./ft^3.

$$D = \frac{183.35}{\left(\text{OD}^2 - \text{ID}^2\right)}$$

$$D = \frac{183.35}{6.7158}$$

$$D = 27.3013\,\text{linear ft./ft.}^3$$

1.11.3 Annular Capacity Between Casing or Hole and Drill Pipe, Tubing, or Casing

Formula 1 (Capacity of annulus in bbl/ft.):

$$C_a = \frac{{D_h}^2 - {D_p}^2}{1029.4} \tag{1.41}$$

Where: C_a = Capacity of annulus in bbl/ft.
D_h = Diameter of hole in inches

Note: The bit size may be used if the actual hole size is not known. Larger sizes may be used based on estimated hole "washout."

D_p = Diameter of drill pipe in inches

Example:

Bit or hole size (D_h) = 12¼ in.

Drill pipe OD (D_p) = 5.0 in.

$$C_a = \frac{12.25^2 - 5^2}{1029.4}$$

$$C_a = 0.12149 \text{ bbl/ft.}$$

Formula 2 (Capacity of annulus in ft./bbl):

$$C_a = \frac{1029.4}{{D_h}^2 - {D_p}^2} \tag{1.42}$$

Where: C_a = Capacity of annulus in ft./bbl

Example:

Bit or hole size (D_h) = 12¼ in.

Drill pipe OD (D_p) = 5.0 in.

$$C_a = \frac{1029.4}{(12.25^2 - 5^2)}$$
$$C_a = 8.23\,\text{ft./bbl}$$

Formula 3 (Capacity of annulus in gal/ft.):

$$C_a = \frac{(D_h{}^2 - D_p{}^2)}{24.51} \tag{1.43}$$

Where: C_a = Capacity of annulus in gal/ft.

Example:

Bit or hole size (D_h) = 12¼ in.

Drill pipe OD (D_p) = 5.0 in.

$$C_a = \frac{12.25^2 - 5^2}{24.51}$$
$$C_a = 5.1\,\text{gal/ft.}$$

Formula 4 (Capacity of annulus in ft./gal):

$$C_a = \frac{24.51}{(D_h{}^2 - D_p{}^2)} \tag{1.44}$$

Where: C_a = Capacity of annulus in ft./gal

Example:

Bit or hole size (D_h) = 12¼ in.

Drill pipe OD (D_p) = 5.0 in.

$$C_a = \frac{24.51}{(12.25^2 - 5^2)}$$
$$C_a = 0.19598\,\text{ft./gal}$$

Formula 5 (Capacity of annulus in ft.³/linear ft.):

$$C_a = \frac{\left(D_h{}^2 - D_p{}^2\right)}{183.35} \tag{1.45}$$

Where: C_a = Capacity of annulus in ft.³/linear ft.

Example:

Bit or hole size (D_h) = 12¼ in.

Drill pipe OD (D_p) = 5.0 in.

$$C_a = \frac{12.25^2 - 5^2}{183.35}$$
$$C_a = 0.682097\,\text{ft.}^3/\text{linear ft.}$$

Formula 6 (Capacity of annulus in linear ft./ft.³):

$$C_a = \frac{183.35}{\left(D_h{}^2 - D_p{}^2\right)} \tag{1.46}$$

Where: C_a = Capacity of annulus in linear ft./ft.³

Example:

Bit or hole size (D_h) = 12¼ in.

Drill pipe OD (D_p) = 5.0 in.

$$C_a = \frac{183.35}{\left(12.25^2 - 5^2\right)}$$
$$C_a = 1.466\,\text{linear ft./ft.}^3$$

1.11.4 Annular Capacity Between Casing and Multiple Strings of Tubing

Formula 1 (Annular capacity between casing and multiple strings of tubing in bbl/ft.):

$$C_a = \frac{D_i^2 - \left[(T_1)^2 + (T_2)^2\right]}{1029.4} \tag{1.47}$$

Where: C_a = Capacity of annulus in bbl/ft. or appropriate units
D_i = ID of casing in inches
T_1 = Tubing No. 1 OD size in inches
T_2 = Tubing No. 2 OD size in inches

Example: Using two strings of tubing of same size:

D_i = Casing—7.0 in., 29 lb/ft. ID = 6.184 in.

T_1 = Tubing No. 1—OD = 2.375 in.

T_2 = Tubing No. 2—OD = 2.375 in.

$$C_a = \frac{6.184^2 - \left[(2.375)^2 + (2.375)^2\right]}{1029.4}$$

$$C_a = \frac{38.24 - 11.28}{1029.4}$$

$$C_a = 0.026\,\text{bbl/ft.}$$

Formula 2 (Annular capacity between casing and multiple strings of tubing in ft./bbl):

$$C_a = \frac{1029.4}{D_i^2 - \left[(T_1)^2 + (T_2)^2\right]} \tag{1.48}$$

Example: Using two strings of tubing of same size:

D_i = Casing—7.0 in., 29 lb/ft. ID = 6.184 in.

T_1 = Tubing No. 1—OD = 2.375 in.

T_2 = Tubing No. 2—OD = 2.375 in.

$$C_a = \frac{1029.4}{6.184^2 - \left[(2.375)^2 + (2.375)^2\right]}$$

$$C_a = \frac{1029.4}{38.24 - 11.28}$$

$$C_a = 38.1816 \text{ ft./bbl}$$

Formula 3 (Annular capacity between casing and multiple strings of tubing in gal/ft.):

$$C_a = \frac{D_i^2 - \left[(T_1)^2 + (T_2)^2\right]}{24.51} \tag{1.49}$$

Example: Using two strings of tubing with different sizes

D_i = Casing—7.0 in., 29 lb/ft. ID = 6.184 in.

T_1 = Tubing No. 1—OD = 2.375 in.

T_2 = Tubing No. 2—OD = 3.5 in.

$$C_a = \frac{6.184^2 - \left[(2.375)^2 + (3.5)^2\right]}{24.51}$$

$$C_a = \frac{38.24 - 17.89}{24.51}$$

$$C_a = 0.8302733 \text{ gal/ft.}$$

Formula 4 (Annular capacity between casing and multiple strings of tubing in ft./gal):

$$C_a = \frac{24.51}{D_i^2 - \left[(T_1)^2 + (T_2)^2\right]} \tag{1.50}$$

Example: Using two strings of tubing with different sizes

D_i = Casing—7.0 in., 29 lb/ft. ID = 6.184 in.

T_1 = Tubing No. 1—OD = 2.375 in.

T_2 = Tubing No. 2—OD = 3.5 in.

$$C_a = \frac{24.51}{6.184^2 - \left[(2.375)^2 + (3.5)^2\right]}$$

$$C_a = \frac{24.51}{38.24 - 17.89}$$

$$C_a = 1.2044226\,\text{ft./gal}$$

Formula 5 (Annular capacity between casing and multiple strings of tubing in ft.^{3}/linear ft.):

$$C_a = \frac{D_i^2 - \left[(T_1)^2 + (T_2)^2 + (T_3)^2\right]}{183.35} \quad (1.51)$$

Example: Using three strings of tubing

D_i = Casing—9 in., 47 1b/ft. ID = 8.681 in.

T_1 = Tubing No. 1—OD = 3.5 in.

T_2 = Tubing No. 2—OD = 3.5 in.

T_3 = Tubing No. 3—OD = 3.5 in.

$$C_a = \frac{8.681^2 - \left[(3.5)^2 + (3.5)^2 + (3.5)^2\right]}{183.35}$$

$$C_a = \frac{75.359 - 36.75}{183.35}$$

$$C_a = 0.2105795\,\text{ft.}^3/\text{linear ft.}$$

Formula 6 (Annular capacity between casing and multiple strings of tubing in linear ft./ft.^{3}):

$$C_a = \frac{183.35}{D_i^2 - \left[(T_1)^2 + (T_2)^2 + (T_3)^2\right]} \tag{1.52}$$

Example: Using three strings of tubing

D_i = Casing—9 in., 47 1b/ft. ID = 8.681 in.

T_1 = Tubing No. 1—OD = 3.5 in.

T_2 = Tubing No. 2—OD = 3.5 in.

T_3 = Tubing No. 3—OD = 3.5 in.

$$C_a = \frac{183.35}{8.681^2 - \left[(3.5)^2 + (3.5)^2 + (3.5)^2\right]}$$

$$C_a = \frac{183.35}{75.359 - 36.75}$$

$$C_a = 4.7487993 \text{linear ft./ft.}^3$$

1.12 Amount of Cuttings Drilled per Foot of Hole Drilled

Formula 1 (Cuttings generated per foot of hole drilled in BARRELS):

$$V_c = \frac{D_h{}^2}{1029.4}(1 - \phi) \tag{1.53}$$

Where: V_c = Volume of cuttings in bbls
D_h = Diameter of bit or hole size (plus washout) in inches
ϕ = Porosity in formaton in percent (%)

Example: Determine the number of barrels of cuttings drilled for 1 ft. of 12¼ in. a hole drilled with 20% (0.20) porosity.

$$V_c = \frac{12.25^2}{1029.4}(1 - 0.20)$$

$$V_c = (0.1457766)(0.80)$$

$$V_c = 0.1166213 \text{ bbls}$$

Formula 2 (Cuttings generated per foot of hole drilled in CUBIC FEET):

$$V_c = \left(\frac{D_h{}^2}{144}\right)(0.7854)(1 - \phi) \tag{1.54}$$

Example: Determine the cubic feet of cuttings drilled for 1 ft. of 12¼ in. hole with 20% (0.20) porosity.

$$V_c = \left(\frac{12.25^2}{144}\right)(0.7854)(1 - 0.20)$$

$$V_c = (0.818465)(0.8)$$

$$V_c = 0.6547727 \text{ft.}^3$$

Formula 3 (Cuttings generated per foot of hole drilled in POUNDS):

$$W_{cg} = 350((C_a)(L_d))(1 - \phi)(\text{SG}) \tag{1.55}$$

Where: W_{cg} = Solids generated in lbs
C_a = Capacity of hole in bbl/ft.
L_d = Footage drilled in ft.
ϕ = Porosity of cuttings in percent (%)
SG = Specific gravity of cuttings

Example: Determine the total pounds of solids generated in drilling 100 ft. of a 12¼-in. hole (0.1458 bbl/ft.). Specific gravity (average bulk density) of cuttings = 2.40 g/cc. Porosity = 20%.

$$W_{cg} = 350((0.1458)(100))(1 - 0.20)(2.40)$$

$$W_{cg} = (5103)(0.80)(2.40)$$

$$W_{cg} = 9797.26 \text{lb}$$

1.13 Annular Velocity (AV)

Formula 1 (Annular velocity in ft./min):

$$AV = \frac{O_p}{C_a} \tag{1.56}$$

Where: AV = Annular velocity in ft./min
O_p = Pump output in bbl/min
C_a = Capacity of annulus in bbl/ft.

Example:

Pump output = 12.6 bbl/min

Capacity of annulus = 0.1261 bbl/ft.

$$AV = \frac{12.6}{0.1261}$$

$$AV = 99.92 \text{ft./min}$$

Formula 2 (Annular velocity in ft./min):

$$AV = \frac{24.5(Q)}{\left(D_h^2 - D_p^2\right)} \tag{1.57}$$

Where: Q = Circulation rate in gpm
D_h = Inside diameter of casing or hole size in inches
D_p = Outside diameter of pipe, tubing, or collars in inches

Example:

Q = 530 gpm

D_h = 12¼ in.

D_p = 4½ in.

$$\mathrm{AV} = \frac{24.5(530)}{\left(12.25^2 - 4.5^2\right)}$$

$$\mathrm{AV} = \frac{12{,}985}{129.81}$$

$$\mathrm{AV} = 100\,\mathrm{ft./min}$$

Formula 3 (Annular velocity in ft./min):

$$\mathrm{AV} = \frac{O_\mathrm{p}(1029.4)}{\left(D_\mathrm{h}^2 - D_\mathrm{p}^2\right)} \tag{1.58}$$

Example:

Pump output = 12.6 bbl/min

Hole size = 12¼ in.

Pipe OD = 4½ in.

$$\mathrm{AV} = \frac{12.6(1029.4)}{\left(12.25^2 - 4.5^2\right)}$$

$$\mathrm{AV} = \frac{12{,}970.44}{129.81}$$

$$\mathrm{AV} = 99.92\,\mathrm{ft./min}$$

Formula 4 (Annular velocity in ft./s):

$$\mathrm{AV} = \frac{(17.16)\left(O_\mathrm{p}\right)}{\left(D_\mathrm{h}^2 - D_\mathrm{p}^2\right)} \tag{1.59}$$

Example:

Pump output = 12.6 bbl/min

Hole size = 12¼ in.

Pipe OD = 4½ in.

$$AV = \frac{(17.16)(12.6)}{\left(12.25^2 - 4.5^2\right)}$$

$$AV = \frac{216.216}{129.81}$$

$$AV = 1.6656\,\text{ft./s}$$

1.13.1 Metric Calculations (m/min) and (m/s)

Formula 1 (Annular velocity in m/min):

$$AV = \frac{O_p}{C_a} \tag{1.60}$$

Where: AV = Annular velocity in m/min
O_p = Pump output in liter/min
C_a = Capacity of annulus in liter/m

Formula 2 (Annular velocity in m/s):

$$AV = \frac{O_p + 60}{C_a} \tag{1.59}$$

Where: AV = Annular velocity in m/s
O_p = Pump output in liter/min

1.13.2 SI Unit Calculations

$$AV = \frac{O_p}{C_a} \tag{1.61}$$

Where: AV = Annular velocity in m/min
O_p = Pump output in m^3/min
C_a = Capacity of annulus in m^3/m

1.14 Pump Output Required in GPM for a Desired Annular Velocity, ft./min

Formula 1:

$$O_p = \frac{AV\left(D_h^2 - D_p^2\right)}{24.5} \tag{1.62}$$

Where: O_p = Pump output in gpm
AV = Annular velocity in ft./min
D_h = Inside diameter of casing or hole size, in.
D_p = outside diameter of pipe, tubing, or collars, in.

Example:

AV = Annular velocity 120 ft./min

Hole size = 12¼ in.

Pipe OD = 4½ in.

$$O_p = \frac{120\left(12.25^2 - 5^2\right)}{24.5}$$

$$O_p = \frac{120\,(129.8125)}{24.5}$$

$$O_p = \frac{15{,}577.5}{24.5}$$

$$O_p = 635.8\,\text{gpm}$$

Formula 2 (Strokes per minute (SPM) required for a given annular velocity):

$$\text{SPM} = \frac{(AV)(C_a)}{O_p} \tag{1.63}$$

Where: SPM = Pump strokes per minute

Example:

$AV = 120$ ft./min

$C_a = 0.1261$ bbl/ft.

$O_p = 0.136$ bbl/stk

$$SPM = \frac{(120)(0.126)}{0.136}$$

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

$$SPM = 111.3$$

1.15 Pump Pressure/Pump Stroke Relationship (the Roughneck's Formula)

Step 1: Basic Formula

$$P_N = (P_O)\left(\frac{SPM_N}{SPM_O}\right)^2 \tag{1.64}$$

Where: P_N = New circulating pressure in psi
P_O = Old circulating pressure in psi
SPM_N = New pump rate in strokes per minute
SPM_O = Old pump rate in strokes per minute

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

$$P_N = (1800)\left(\frac{30}{60}\right)^2$$

$$P_N = (1800)(0.25)$$

$$P_N = 450\,\text{psi}$$

Step 2: 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.

$$F = \frac{\log\left(\frac{P_N}{P_O}\right)}{\log\left(\frac{Q_N}{Q_O}\right)} \tag{1.65}$$

Where: F = Factor used to calculate a new pump pressure with a new pump rate
Q_N = New pump output in gpm
Q_O = Old pump output in gpm

Example:

$P_N = 2500$ psi

$P_O = 450$ psi

$Q_N = 315$ gpm

$Q_O = 120$ gpm

$$F = \frac{\log\left(\frac{2500}{450}\right)}{\log\left(\frac{315}{120}\right)}$$

$$F = \frac{\log(5.555556)}{\log(2.625)}$$

$$F = \frac{0.74498}{0.41913}$$

$$F = 1.7768$$

Example: Same example as above but with the correct Factor.

$$P_N = (1800)\left(\frac{30}{60}\right)^{1.7768}$$
$$P_N = (1800)(0.2918299)$$
$$P_N = 525\,\text{psi}$$

1.15.1 Metric Calculation

$$P_N = (P_O)\left(\frac{SPM_N}{SPM_O}\right)^2 \quad (1.66)$$

Where: P_N = New Circulating pressure in bar
P_O = Old Circulating pressure in bar
SPM_N = New pump rate in strokes per minute
SPM_O = Old pump rate in strokes per minute

1.15.2 SI Unit Calculation

$$P_N = (P_O)\left(\frac{SPM_N}{SPM_O}\right)^2 \quad (1.67)$$

Where: P_N = New circulating pressure in bar
P_O = Old circulating pressure in bar

1.16 Buoyancy Factor (BF)

Formula 1 (Buoyancy Factor using mud weight in ppg):

$$BF = \frac{65.5 - MW}{65.5} \quad (1.68)$$

Where: BF = Buoyancy Factor
65.5 = Weight of steel in ppg (plain carbon steel AISI SAE 1020 = 7.86 gm/cm^3)
MW = Mud weight in ppg

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

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

$$BF = 0.77099$$

Formula 2 (Buoyancy Factor using mud weight in lb/ft.^{3}):

$$BF = \frac{489 - MW}{489} \tag{1.69}$$

Where: 489 = Weight of steel in lb/ft.^{3}

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

$$BF = \frac{489 - 120.0}{489}$$

$$BF = 0.7546$$

1.17 Formation Temperature (T_f)

$$T_f = T_s + \left(T_G\left(\frac{TVD}{100}\right)\right) \tag{1.70}$$

Where: T_f = Estimated temperature of formation at a specific depth in °F
T_s = Ambient temperature at the surface in °F
T_G = Geothermal gradient in °F per 100 ft. of depth
TVD = Total vertical depth in feet

Example: Determine the formation temperature with the following:

T_s = 70 °F

T_G = 1.2 °F/100 ft.

TVD = 15,000 ft.

$$T_f = 70 + \left(1.2\left(\frac{15,000}{100}\right)\right)$$

$$T_f = 70 + 180$$

$$T_f = 205°F$$

1.18 Temperature Conversion Formulas

Formula 1a (convert temperature, Fahrenheit (°f) to Centigrade or Celsius (°c)):

$$C = \frac{5(F - 32)}{9} \tag{1.71}$$

Where: C = Centigrade or Celsius temperature in degrees (°)
F = Fahrenheit temperature in degrees (°)

Example: Convert 95 °F to °C.

$$C = \frac{5(95 - 32)}{9} = 35°C$$

Formula 1b (Convert temperature, Fahrenheit (°F) to Centigrade or Celsius (°C)):

$$C = (F - 32)(0.5556) \tag{1.72}$$

Example: Convert 95 °F to °C.

$$C = (95 - 32)(0.5556) = 35°C$$

Formula 2a (Convert temperature, Centigrade or Celsius (°C) to Fahrenheit (°F)):

$$F = \frac{(9(C))}{5} + 32 \tag{1.73}$$

Example: Convert 24 °C to °F.

$$F = \frac{(9(24))}{5} + 32 = 75.2°F$$

Formula 2b (Convert temperature, Centigrade or Celsius (C) to Fahrenheit (°F)):

$$F = (1.18(C)) + 32 \qquad (1.74)$$

Example: Convert 24 °C to °F.

$$F = (1.18(24)) + 32 = 75.2°F$$

Formula 3a (Convert temperature, Centigrade or Celsius (C) to Kelvin (°K)):

$$K = C + 273.16 \qquad (1.75)$$

Example: Convert 35 °C to °K.

$$K = 35 + 273.16 = 308.16°K$$

Formula 4a (Convert temperature, Fahrenheit (°F) to Rankin (°R)):

$$R = F + 459.69 \qquad (1.76)$$

Example: Convert 260 °F to °R.

$$R = 260 + 459.69 = 719.69°R$$

Rules of Thumb Formulas for Temperature Conversion

Convert °F to °C.

$$C = \frac{(F - 30)}{2} \qquad (1.77)$$

Example: Convert 95 °F to °C.

$$C = \frac{(95 - 30)}{2} = 32.5\,°C$$

Convert °C to °F.

$$F = C + C + 30 \tag{1.78}$$

Example: Convert 24 °C to °F.

$$F = 24 + 24 + 30 = 78\,°F$$

CHAPTER TWO

Rig Calculations

2.1 Accumulator Capacity

2.1.1 Useable Volume per Bottle

Note: The following will be used as guidelines:

Volume per bottle	= 10 gal
Precharge pressure	= 1000 psi
Minimum pressure (remaining after activation)	= 1200 psi
Pressure gradient of hydraulic fluid	= 0.445 psi/ft.
Maximum pressure	= 3000 psi

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

$$(P_1)(V_1) = (P_2)(V_2) \tag{2.1}$$

Where: P = Pressure in psi
V = Volume in gal

2.1.2 Surface Application

Step 1: Calculate the hydraulic fluid necessary to increase pressure from the precharge to the minimum:

$$(1000)(10) = (1200)(V_2)$$

$$V_2 = \frac{(1000)(10)}{1200} = 8.33 \text{ gal}$$

The nitrogen has been compressed from 10.0 to 8.33 gal.

Next, calculate the volume of the hydraulic fluid in the bottle.

$$10.0 - 8.33 = 1.67 \text{ gal of hydraulic fluid per bottle}$$

Note: This is dead hydraulic fluid. The pressure must not drop below the minimum 1200 psi value.

http://dx.doi.org/10.1016/B978-0-12-803417-0.00002-0

Step 2: Calculate the amount of hydraulic fluid necessary to increase pressure from precharge to the maximum:

$$(1000)(10) = (3000)(V_2)$$

$$V_2 = \frac{(1000)(10)}{3000} = 3.33 \text{ gal}$$

The nitrogen has been compressed from 10 to 3.33 gal.

$$10.0 - 3.33 = 6.67 \text{ gal of hydraulic fluid per bottle}$$

Step 3: Calculate the useable volume per bottle in gal:

$$V_u = (V_{tb} - V_d) \tag{2.2}$$

Where: V_u = Useable volume per bottle in gal
V_{tb} = Total hydraulic volume per bottle in gal
V_d = Dead hydraulic volume per bottle in gal

$$V_u = (6.67 - 1.67) = 5.0 \text{ gal}$$

2.1.3 English Units

$$V_u = (V_b)\left(\left(\frac{P_p}{P_f}\right) - \left(\frac{P_p}{P_m}\right)\right) \tag{2.3}$$

Where: V_b = Volume capacity of bottle in gal
P_p = Precharge pressure in psi
P_f = Minimum pressure after activation in psi
P_m = Maximum system pressure in psi

Example: Calculate the amount of usable hydraulic fluid delivered from a 20-gal bottle:

Precharge pressure = 1000 psi (P_P)
Maximum system pressure = 3000 psi (P_m)
Final pressure = 1200 psi (P_f)

$$V_u = (20)\left(\left(\frac{1000}{1200}\right) - \left(\frac{1000}{3000}\right)\right) = 10 \text{ gal}$$

2.1.4 Deepwater Applications

In deepwater applications, the hydrostatic pressure exerted by the hydraulic fluid must be compensated for in the calculations due to the hydrostatic head of the seawater.

Example: Same guidelines as in surface applications:

Water depth = 1500 ft.
Hydrostatic pressure on the hydraulic fluid = 889 psi or [(8.55)(0.052)(2000)]

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

$$P_p = (1000 + 889) = 1889 \text{psi}$$
$$P_m = (3000 + 889) = 3889 \text{psi}$$
$$P_f = (1200 + 889) = 2089 \text{psi}$$

Step 2: Calculate the volume of hydraulic fluid necessary to increase the pressure from the precharge to the minimum:

$$(1889)(10) = (2089)(V_2)$$
$$V_2 = \frac{(1889)(10)}{(2089)} = 9.04 \text{gal}$$
$$V_u = (10 - 9.04) = 0.96 \text{ gal}$$

Note: This is dead hydraulic fluid. The pressure must not drop below the minimum value of 2089 psi.

Step 3: Calculate the amount of hydraulic fluid necessary to increase the pressure from the precharge to the maximum:

$$(1889)(10) = (3889)(V_2)$$
$$V_2 = \frac{(1889)(10)}{(3889)} = 4.86 \text{ gal}$$

The nitrogen has been compressed from 10 to 4.86 gal.

$$10 - 4.86 = 5.14 \text{ gal of hydraulic fluid per bottle}$$

Step 4: Calculate the useable hydraulic fluids per bottle:

$$V_u = (4.86 - 0.96) = 3.9 \text{ gal}$$

2.1.5 Accumulator Precharge Pressure

The following is a method of calculating the average accumulator precharge pressure by operating the unit with the charge pumps switched off:

$$P_p = \left(\frac{V_r}{V_t}\right)\left(\frac{((P_e)(P_s))}{(P_s - P_t)}\right) \qquad (2.4)$$

Where: P_p = Precharge pressure in psi
V_r = Volume of hydraulic fluid removed in gal
V_t = Total accumulator volume in gal
P_f = Final accumulator pressure in psi
P_s = Starting accumulator pressure in psi

Example: Calculate the average accumulator precharge pressure using the following data:

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

$$P_p = \left(\frac{20}{180}\right)\left(\frac{((2200)(3000))}{(3000 - 2200)}\right) = (0.1111)\left(\frac{(6,600,000)}{800}\right)$$
$$= 917 \text{ psi}$$

2.2 Slug Calculations

2.2.1 Barrels of Slug Required for a Desired Length of Dry Pipe

Step l: Calculate the hydrostatic pressure required to give desired mud drop inside the drill pipe:

$$S_{HP} = (W_m)(0.052)(L_{pd}) \tag{2.5}$$

Where: S_{HP} = Slug hydrostatic pressure in psi
W_m = Mud weight in ppg
L_{pd} = Length of dry pipe in ft.

Step 2: Calculate the difference in pressure gradient between the slug weight and mud weight:

$$S_{PG} = (S_w - W_m)(0.052) \tag{2.6}$$

Where: S_{PG} = Slug pressure gradient in psi/ft.
S_w = Slug weight in ppg
W_m = Mud weight in use in ppg

Step 3: Calculate the length of the slug in the drill pipe:

$$S_l = \left(\frac{S_{HP}}{S_{PG}}\right) \tag{2.7}$$

Where: S_l = Slug length in ft.

Step 4: Calculate the volume of the slug in bbl:

$$S_v = (S_l)(V_{dp}) \tag{2.8}$$

Where: S_v = Volume of slug in bbl
V_{dp} = Capacity of drill pipe in bbl/ft.

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

Desired length of dry pipe (2 stands)	= 184 ft.
Mud weight	= 12.2 ppg
Slug weight	= 13.2 ppg
Drill pipe capacity (6⅝ in.)	= 0.03457 bbl/ft.

Step 1: Hydrostatic pressure required:

$$S_{HP} = (12.2)(0.052)(184) = 117\,\text{psi}$$

Step 2: Difference in pressure gradient:

$$S_{PG} = (13.2 - 12.2)(0.052) = 0.052\,\text{psi/ft.}$$

Step 3: Length of slug in drill pipe:

$$S_l = \left(\frac{117}{0.052}\right) = 2250\,\text{ft.}$$

Step 4: Volume of slug:

$$S_v = (2250)(0.03457) = 77.8 \approx 80.0\ \text{bbl}$$

2.2.2 Weight of Slug Required for a Desired Length of Dry Pipe with a Set Volume of Slug

Step 1: Calculate the length of the slug in the drill pipe in ft.:

$$S_l = \left(\frac{S_v}{V_{dp}}\right) \tag{2.9}$$

Where: S_l = Slug length in ft.

Step 2: Calculate the hydrostatic pressure required to give the desired drop of mud inside the drill pipe in psi (from Equation (2.5)):

$$S_{HP} = (W_m)(0.052)\left(L_{pd}\right)$$

Where: S_{HP} = Slug hydrostatic pressure in psi
W_m = Mud weight in ppg
L_{pd} = Length of dry pipe in ft.

Step 3: Calculate the weight of the desired slug:

$$S_w = \left(\frac{\left(\frac{S_{HP}}{0.052}\right)}{S_l}\right) + W_m \tag{2.10}$$

Where: S_w = Slug weight in ppg

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

Desired length of dry pipe (2 stands)	= 184 ft.
Mud weight	= 12.2 ppg
Volume of slug	= 75 bbl
Drill pipe capacity (6⅝ in.)	= 0.03457 bbl/ft.

Step 1: Length of slug in drill pipe:

$$S_l = \left(\frac{75}{0.03457}\right) = 2170\,\text{ft.}$$

Step 2: Hydrostatic pressure required:

$$S_{HP} = (12.2)(0.052)(184) = 117\,\text{psi}$$

Step 3: Weight of slug:

$$S_w = \left(\frac{\left(\frac{117}{0.052}\right)}{2170}\right) + 12.2 = 13.3\,\text{ppg}$$

2.2.3 Volume, Height, and Pressure Gained Because of Placement of Slug in Drill Pipe

Step 1: Calculate the volume gained in mud pits after slug is pumped, due to U-tubing:

$$S_{pit} = (S_l)\left(V_{dp}\right) \tag{2.11}$$

Where: S_{pit} = Volume increase in mud pit in bbl
V_{dp} = Capacity of drill pipe in bbl/ft.

Step 2: Calculate the height of slug in the annulus in ft.:

$$S_h = (V_{ac})(S_v) \tag{2.12}$$

Where: S_h = Height of the slug in the annulus in ft.
V_{ac} = Volume of the open hole and drill pipe in ft./bbl

Step 3: Calculate the hydrostatic pressure gained in the annulus because of the slug in psi:

$$S_{HP} = (S_h)(S_w - W_m)(0.052) \tag{2.13}$$

Where: S_{HP} = Increase in hydrostatic pressure in the annulus due to the slug in psi

Example: Calculate the increase in hydrostatic pressure gained with the following:

Feet of dry pipe (2 stands)	= 184 ft.
Slug volume	= 75 bbl
Slug weight	= 13.2 ppg
Mud weight	= 12.2 ppg
Drill pipe capacity (6⅝ in.)	= 0.03457 bbl/ft.
Annulus volume (9⅞ × 8½ in.)	= 40.74 ft./bbl
Annulus volume (9⅞ × 6⅝ in.)	= 19.20 ft./bbl

Step 1: Volume gained in mud pits after slug is pumped, due to U-tubing:

$$S_{pit} = (184)(0.03457) = 6.4\,\text{bbl}$$

Step 2: Calculate the height of slug in the annulus in ft.:

Note that the slug volume will cover the drill collars and part of the drill pipe section.

$$S_h = \left[(19.2)\left(75 - \left(\frac{600}{40.74}\right)\right)\right] + (600) = 1757.2\,\text{ft.}$$

Step 3: Calculate the hydrostatic pressure gained in the annulus because of the slug:

$$S_{HP} = (1757.2)(13.2 - 12.2)(0.052) = 91.4\,\text{psi}$$

2.2.4 English Units Calculation

Step 1: Volume gained pumping slug in bbl:

$$S_{vg} = \left((S_v)\left(\frac{S_w}{W_m}\right)\right) - (S_v) \tag{2.14}$$

Where: S_{vg} = Volume gained due to pumping slug in bbl

Step 2: Calculate the length of dry pipe after pumping the slug in ft.:

$$S_{ldp} = \left(\frac{S_{vg}}{V_{dp}}\right) \tag{2.15}$$

Where: S_{ldp} = Length of dry pipe after pumping the slug in ft.

Example: Calculate the number of barrels of mud gained due to pumping the slug and calculate the feet of dry pipe:

Mud weight	= 12.6 ppg
Slug weight	= 14.2 ppg
Barrels of slug pumped	= 50 barrels
Drill pipe capacity (6⅝ in.)	= 0.03457 bbl/ft.

Step 1: Volume gained due to pumping slug:

$$S_{vg} = \left((50)\left(\frac{14.2}{12.6}\right)\right) - (50) = 6.35\ \text{bbl}$$

Step 2: Calculate the number of feet of dry pipe after pumping the slug:

$$S_{ldp} = \left(\frac{6.35}{0.03457}\right) = 184 \text{ ft.}$$

2.2.5 SI Calculation

Convert English Units to SI Units with:

Barrels (bbl)	$\times 0.159$	$=$ cubic meters (m^3)
Mud weight (ppg)	$\times 120$	$=$ kilograms/cubic meter (kg/m^3)

2.3 Bulk Density of Cutting Using the Mud Balance

Procedure:

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

$$SG_c = \left(\frac{1}{2 - ((0.12)(W_r))}\right) \tag{2.16}$$

Where: SG_c = Specific gravity (average bulk density) of cuttings in gm/cm^3
W_r = Resulting mud weight with cuttings plus water in ppg

Example: Calculate the average bulk density of cuttings with a final weight of 13.0 ppg:

$$SG_c = \left(\frac{1}{2-((0.12)(13.0))}\right) = 2.27\ \text{gm/cm}^3$$

A graph may also be prepared to provide a quick direct reading of the average bulk density.

2.4 Drill String Design

2.4.1 Estimated Weight of Drill Collars in Air

Formula 1: REGULAR drill collar weight in lb/ft.:

$$W_{Rdc} = 2.674\left(OD^2 - ID^2\right) \tag{2.17}$$

Where: W_{Rdc} = Weight of REGULAR drill collar in lb/ft.
OD = Outside diameter of drill collar in inches
ID = Inside diameter of drill collar in inches

Example: Determine the weight of an $8 \times 2^{13}/_{16}$ in. regular drill collar in lb/ft.:

Drill collar OD = 8.0 in.
Drill collar ID = $2^{13}/_{16}$ in. $\left(\frac{13}{16} = 0.8125\right)$

$$W_{Rdc} = 2.674\left(8^2 - 2.8125^2\right)$$
$$W_{Rdc} = 2.674(56.089844) = 149.98 \cong 150\,\text{lb/ft.}$$

Formula 2 (SPIRAL drill collar weight in lb/ft.):

$$W_{Sdc} = 2.56\left(OD^2 - ID^2\right) \tag{2.18}$$

Where: W_{Sdc} = Weight of SPIRAL drill collar in lb/ft.

Example: Determine the weight of an $8 \times 2^{13}/_{16}$ in. regular drill collar in lb/ft.:

Drill collar OD = 8.0 in.
Drill collar ID = $2^{13}/_{16}$ in. $\left(\frac{13}{16} = 0.8125\right)$

$$W_{\text{Rdc}} = 2.56\left(8^2 - 2.8125^2\right)$$

$$W_{\text{Rdc}} = 2.56(56.089844)$$

$$W_{\text{Rdc}} = 143.59\,\text{lb/ft.}$$

2.4.2 Tensile Strength of Tubulars in lb (Ref.: API Spec 5D & 7)

Tensile strength for Class 1 (New) drill pipe is listed in Table 2.1. These values should be reduced based on the class of the pipe as follows:

Class	minimum weight %
1 (new)	87.5
Premium (used)	80.0
Class 2 (used)	70.0

Other dimensions may be found in Table C.1 of the API publication Spec 5D.

Non-API Z-140 and V-150 grades are covered by proprietary specifications and can be found in T. H. Hill's Standard DS-1™.

Table 2.1
Pipe Tensile Requirements

	Yield Strength (psi)	
Drill Pipe Body Grade	**Minimum**	**Maximum**
E	75,000	105,000
X	95,000	125,000
G	105,000	135,000
S	135,000	165,000
Tool joint	120,000	165,000

Ref: API Spec 5D, Table C.5

2.4.3 Calculate the Reduced Tensile Yield Strength in lb

Step 1: Calculate the minimum weight wall thickness in inches:

$$P_t = W_{min}(W_t) \tag{2.19}$$

Where: P_t = Reduced pipe wall thickness in inches
W_{min} = Wall thickness reduction according to pipe Class in %
W_t = Wall thickness of new pipe in inches

Example: Calculate the reduced wall thickness of 6⅝ in., ID—5.965 in., 25.5 lb/ft., S-135 drill pipe with 0.330 in. wall.

$$P_t = 0.80(0.330) = 0.264\,\text{in.}$$

Step 2: Calculate the reduction in the OD of the Premium pipe in inches:

$$OD_r = ID + [2(P_t)] \tag{2.20}$$

Where: OD_r = Reduced pipe OD in inches

$$OD_r = 5.965 + [2(0.264)] = 6.493\,\text{in.}$$

Step 3: Calculate the cross-sectional area of the reduced tube in in.^{2}:

$$A_r = \frac{\pi\left(OD_r^2 - ID^2\right)}{4} \tag{2.21}$$

Where: A_r = Reduced cross-sectional area in in.^{2}

$$A_r = \frac{3.14\left(6.493^2 - 5.965^2\right)}{4} = 5.166\,\text{in.}^2$$

Step 4: Calculate the reduced tensile yield strength in lb:

$$T_{Sr} = A_r(\gamma_m) \tag{2.22}$$

Where: T_{sr} = Reduced tensile yield strength in lb
γ_m = Minimum yield strength in lbs from Table 2.1.

$$T_{Sr} = 5.166(135,000) = 697,410\,\text{lb}$$

2.4.4 Calculate the Adjusted Weight of the Drill Pipe and Tool Joints in lb/ft

Step 1: Calculate the approximate adjusted weight of the tube in lb/ft.:

$$W_{ta} = W_{pe} + \left(\frac{e_w}{29.4}\right) \tag{2.23}$$

Where: W_{ta} = Approximate adjusted weight of the tube in lb/ft.
e_w = Weight of the upset in API Spec 5D, Table C.13.
W_{pe} = Plain-end pipe-body unit mass (without upsets) in lb/ft. (Ref: API Spec 5-DP, Table C.14, p. 97).

Example: 6⅝ in., 25.5 lb/ft., S-135 drill pipe.

$$W_{ta} = 22.19 + \left(\frac{24.87}{29.4}\right) = 23.04 \text{ lb/ft.}$$

Step 2: Calculate the approximate weight of the tool joint in lb:

$$W_{tja} = 0.222(L_{tj})\left(OD_{tj}^2 - ID_{tj}^2\right) + 0.167\left(OD_{tj}^3 - D_{te}^3\right) - 0.510\left(ID_{tj}^2\right)(OD_{tj} - D_{te}) \tag{2.24}$$

Where: W_{tja} = Approximate weight of tool joint in lb

OD_{tj} = Outside diameter of tool joint in inches
ID_{tj} = Inside diameter of tool joint in inches
D_{te} = Inside diameter of pipe weld neck in inches
L_{tj} = Length of tool joint in inches

$$W_{tja} = 0.222(19)\left(8.0^2 - 4.25^2\right) + 0.167\left(8.0^3 - 6.938^3\right) - 0.510\left(4.25^2\right)(8.0 - 6.938) = 213.7 \text{ lb}$$

Step 3: Calculate the adjusted length of the tool joint in ft.:

$$L_{tja} = \frac{L_{tj} + 2.253\left(OD_{tj} - D_{te}\right)}{12} \tag{2.25}$$

Where: L_{tja} = Adjusted length of tool joint in ft.

Example: Calculate the adjusted length of the 6⅝ in. tool joint with an 8.5 in. OD, length—19 in., and a 6.938 weld neck.

$$L_{tja} = \frac{19 + 2.253(8.5 - 6.938)}{12} = 1.877\,\text{ft.}$$

Step 4: Calculate the adjusted weight of the drill pipe and tool joint in lb/ft.:

$$W_{adj} = \frac{[W_{ta}\,(29.4)] + W_{tja}}{\left(W_{tja} + 29.4\right)} \tag{2.26}$$

Where: W_{adj} = Adjusted weight of the drill pipe and tool joint in lb/ft.

$$W_{adj} = \frac{[23.0359(29.4)] + 260.96}{(1.877 + 29.4)} = 30.0\,\text{lb/ft.}$$

2.4.5 Calculate the Length of BHA Necessary for a Desired Weight on the Bit

The following will be determined: Length of bottom hole assembly (BHA) necessary for a desired weight on bit (WOB). Feet of Premium drill pipe that can be used with a specific bottom hole assembly.

Step 1: Calculate the Buoyancy Factor (from Section 1.16):

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

Step 2: Calculate the length of BHA necessary for a desired weight on the bit:

$$L_{BHA} = \left(\frac{(W_{bit})(1 + f_{dc})}{(W_{dc})(BF)}\right) \tag{2.27}$$

Where: LBM_{HA} = Length of BHA necessary for a desired WOB in ft.
W_{bit} = Desired weight on bit (WOB) in lb
f_{dc} = Safety factor to place neutral point in drill collars
W_{dc} = Weight of drill collar in lb/ft.

Example: Calculate the BHA length necessary for a desired WOB:

Desired WOB while drilling = 50,000 lb
Safety factor = 15%
Mud weight = 12.0 ppg
Drill collar weight (8 × 3 in.) = 147 lb/ft.

Step 1: Calculate the Buoyancy Factor (from Section 1.16):

$$BF = \left(\frac{65.5 - 12.0}{65.5}\right) = 0.8168$$

Step 2: Calculate the length of the BHA necessary for this weight on bit:

$$L_{BHA} = \left(\frac{(50,000)(1 + 0.15)}{(147)(0.8168)}\right) = 479\,\text{ft.}$$

2.4.6 Calculate the Maximum Length of Premium Drill Pipe That Can Be Run into the Hole with a Specific BHA Assemble Based on Margin of Overpull

Note: Obtain tensile strength for new pipe from Table 2.2 and adjust for Premium service.

Step 1: Calculate the Buoyancy Factor (from Section 1.16):

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

Step 2: Calculate the maximum length of Premium drill pipe that can be run into the hole with a specific BHA assemble based on margin of overpull:

$$L_{max} = \frac{(((T_{Sr})(f_{dp})) - MOP - ((W_{BHA})(BF)))}{(W_{dpa})(BF)} \tag{2.28}$$

Table 2.2
Drill Pipe Data

Size OD (in.)	Size ID (in.)	Nominal Weight (lb/ft.)	Grade	Connection	Tensile Yield Strength (lb)	Pipe Body Section Area (in.^{2})
3½	2.764	13.30	X 95	NC 38	344,000	3.621
			G 105	NC 38	380,000	
			S 135	NC 38	488,800	
			Z 140	HT 31	506,900	
			V 150	HT 31	543,100	
4	3.240	15.70	X 95	NC 40	410,000	4.322
			G 105	NC 40	453,000	
			S 135	NC 40	583,400	
			Z 140	HT 40	605,000	
			V 150	HT 40	648,200	
4½	3.826	16.60	X 95	NC 50	418,700	4.407
			G 105	NC 50	462,800	
			S 135	NC 50	595,000	
			Z 140	HT 50	617,000	
			V 150	HT 50	661,100	
5	4.276	19.5	X 95	NC 50	501,100	5.275
			G 105	NC 50	553,800	
			S 135	NC 50	712,100	
			Z 140	HT 50	738,400	
			V 150	HT 50	791,200	
6⅝	5.965	25.50	X 95	FH	620,000	6.526
			G 105	FH	685,200	
			S 135	FH	881,000	
			Z 140	FH	913,700	
			V 150	FH	978,900	

Ref: Grant Prideco, Drill Pipe Data Catalog, 2003.

Where: L_{max} = Maximum length of Premium drill pipe that can be run into the hole with a specific BHA in ft.

T_{Sr} = Reduced tensile strength for Premium (used) drill pipe in lb

f_{dp} = Safety factor

MOP = Margin of overpull in lb

W_{BHA} = Air weight of the BHA in lb

W_{dp} = Adjusted weight of the Premium drill pipe with tool joints in lb/ft.

Step 3: Calculate the total depth that can be reached with a specific BHA in ft.:

$$D_T = L_{max} + L_{BHA} \tag{2.29}$$

Where: D_T = Total depth that can be reached with a specific BHA in ft.
L_{BHA} = Length of BHA to be run in ft.

Example:

Drill pipe (6⅝ in.)	= 25.20 lb/ft. (S-135) (adjusted weight = 30.0 lb/ft.)
Tensile strength	= 881,000 lb (Class 1—New)
Reduced tensile strength	= 697,410 lb (Premium—used, calculated from Equation (2.22))
BHA weight in air	= 50,000 lb
BHA length	= 500 ft.
Desired overpull	= 100,000 lb
Mud weight	= 13.5 ppg
Safety factor	= 10%

Step 1: Buoyancy Factor:

$$BF = \left(\frac{65.5 - 13.5}{65.5}\right) = 0.7939$$

Step 2: Calculate the maximum length of Premium drill pipe that can be run into the hole based on a margin of overpull in ft.:

$$L_{max} = \frac{(((697,410)(0.9)) - 100,000 - ((50,000)(0.7939)))}{(30.0)(0.7939)}$$

$$L_{max} = \frac{487,974}{23.817} = 20,488.5 \cong 20,489 \text{ ft.}$$

Step 3: Calculate the total depth that can be reached with this BHA and this Premium drill pipe in ft.:

$$D_T = 20,489 + 500 = 20,989 \text{ ft.}$$

2.4.7 Calculate the Length of Premium Drill Pipe Based on Overpull and Slip Crushing

Step 1: Calculate the tensile strength of the drill pipe in psi:

$$W_S = \gamma_m (A_r) \tag{2.30}$$

Where: W_S = Working strength in psi
γ_m = Minimum yield strength in psi

Example: Calculate the tensile strength of 6⅝ in. S-135 drill pipe with a cross-sectional area of 6.526 in.^{2}

$$W_S = 135{,}000(6.526) = 881{,}010\,\text{psi}$$

2.4.7.1 Slip Crushing

Definition: The slip crushing relationship describes the possibility that the drill pipe can be crushed by the axial load due to high hoop stresses that exist in the cylindrical pipe body while hung in the rotary slips with a large string load.

Step 1: Calculate the minimum stress ratio $\left(\frac{\sigma_h}{\sigma_t}\right)$. (Also available in Table 2.3):

$$R_{ms} = \sqrt{1 + \left(\frac{D(k)}{2(L_s)}\right) + \left(\frac{D(k)}{2(L_s)}\right)^2} \tag{2.31}$$

Where: R_{ms} = Minimum stress ratio $\left(\frac{\sigma_h}{\sigma_t}\right)$. [$\sigma_h$ = Pipe body hoop stress;
σ_t = Pipe body tensile axial stress]
D = OD of pipe in inches
k = Lateral load factor of the slips (refer to Table 2.3)
L_s = Length of the slips in inches

Step 2: Calculate the axial tensile stress of the pipe body at the slips:

$$\sigma_t = \frac{W_s}{A_p} \tag{2.32}$$

Table 2.3

Minimum Ratios $\left(\frac{\sigma_h}{\sigma_t}\right)$ to Prevent Slip Crushing

Slip Length (in.)	Coefficient of Friction	Lateral Load Factor	Minimum Ratio $\left(\frac{\sigma_h}{\sigma_t}\right)$ Pipe Size (in.)						
			2⅜	2⅞	3½	4	4½	5	5½
12	0.06	4.36	1.27	1.34	1.43	1.50	1.58	1.65	1.73
	0.08	4.00	1.25	1.31	1.39	1.45	1.52	1.59	1.66
	0.10	3.68	1.22	1.28	1.35	1.41	1.47	1.54	1.60
	0.12	3.42	1.21	1.26	1.32	1.38	1.43	1.49	1.55
	0.14	3.18	1.19	1.24	1.30	1.34	1.40	1.45	1.50
16	0.06	4.36	1.20	1.24	1.30	1.36	1.41	1.47	1.52
	0.08	4.00	1.18	1.22	1.28	1.32	1.37	1.42	1.47
	0.10	3.68	1.16	1.20	1.25	1.29	1.34	1.38	1.43
	0.12	3.42	1.15	1.18	1.23	1.27	1.31	1.35	1.39
	0.14	3.18	1.14	1.17	1.21	1.25	1.28	1.32	1.36

Where: σ_t = Axial tensile stress of the tube in psi
W_s = Weight of the string in lb
A_p = Cross-sectional area of the pipe in in.^{2}

Step 3: Calculate the hoop stress of the pipe body in psi:

$$\sigma_h = R_{ms}(\sigma_t) \tag{2.33}$$

Where: σ_h = Pipe body hoop stress in psi
R_{ms} = Minimum stress ratio from Step 1 or Table 2.3.

Step 4: Calculate the approximate safety factor for pipe body slip crushing:

$$SF_{sc} = \frac{\gamma_m}{\sigma_h} \tag{2.34}$$

Where: SF_{SC} = Safety factor for slip crushing
γ_m = Minimum Yield Strength in psi (from Table 2.1).

Example: Calculate the safety factor for the following conditions:

DP = 5.0 in. (G-105, 19.5 lb/ft., NC50, Class1—New)
String weight = 220,000 lb

Cross-sectional area	$= 5.275$ in.^{2}
Coefficient of friction	$= 0.08$
Lateral load factor	$= 4.0$
Slip length	$= 16$ in.

Step 1: Calculate the minimum stress ratio $\left(\frac{\sigma_h}{\sigma_t}\right)$:

$$R_{ms} = \sqrt{1 + \left(\frac{5.0(4.0)}{2(16)}\right) + \left(\frac{5.0(4.0)}{2(16)}\right)^2}$$

$$R_{ms} = \sqrt{1 + 0.625 + 0.3906} = \sqrt{2.0156} = 1.4197$$

Step 2: Calculate the axial tensile stress of the pipe body at the slips:

$$\sigma_t = \frac{220,000}{5.275} = 41,706\,\text{psi}$$

Step 3: Calculate the hoop stress of the pipe body in psi:

$$\sigma_h = 1.4197(41,906) = 59,210\,\text{psi}$$

Step 4: Calculate the approximate safety factor for pipe body slip crushing:

$$\text{SF}_{sc} = \frac{105,000}{59,210} = 1.77$$

2.4.8 Design of a Drill String for a Specific Set of Well Conditions

This design method will use two conditions to calculate the length of the various grades of drill pipe: margin of overpull and slip crushing. The objective of this technique is to select the smallest length of pipe calculated with the two methods.

$$L_{psc} = \left[\frac{\left(\frac{(\gamma_m\,(f_{dp}))}{K_s}\right) - [W_{DS}(\text{BF})]}{\left(W_{dpa}\right)(\text{BF})}\right] \tag{2.35}$$

Where: L_{psc} = Length of drill pipe based on slip crushing.
K_s = Constant for the minimum ratio $\left(\frac{\sigma_h}{\sigma_t}\right)$ of hoop stress to tensile stress that can be found in Table 2.3.
W_{DS} = Air weight of the drill string, including the BHA, in lb
W_{dpa} = Adjusted weight of the drill pipe with tool joints in lb/ft.

Step 1: Calculate length of drill collars in ft.:

$$L_{DCbj} = \frac{\left(W_b + T_j\right)}{(BF(W_{DC}))} \tag{2.36}$$

Where: L_{DCbj} = Length of drill collars below jars in ft.
W_b = Weight on bit in lb
T_j = Jarring tension in lb
W_{DC} = Weight of drill collar in lb/ft.

Step 2: Calculate the total length of drill collars required in ft.:

$$L_{DCT} = L_{DCbj} + L_{DCaj} \tag{2.37}$$

Where: L_{DCT} = Total length of drill collars required in ft.
L_{DCaj} = Length of drill collars above jars in ft.

Step 3: Calculate the length of heavy weight drill pipe in ft.:

$$L_{HW} = \frac{W_j - \left[\left(L_{HWj}\right)(W_{DC})(BF)\right]}{(W_{HW})(BF)} \tag{2.38}$$

Where: L_{HW} = Length of heavy weight drill pipe in ft. (round off heavy weight to full joints)
L_{HWj} = Length of heavy weight to provide jarring weight in lb
W_{HW} = Weight of heavy weight drill pipe in lb

Step 4: Calculate the buoyed weight of the BHA:

$$L_{BHA} = L_{DCT} + L_{HW} \tag{2.39}$$

Step 5: Calculate the air weight of the BHA in lb:

$$W_{BHAa} = [W_{DC}(L_{DCT})] + [W_{HW}(L_{HW})] \tag{2.40}$$

Where: W_{BHAa} = Air weight of BHA in lb

Step 6: Calculate the buoyed weight of the BHA in lb:

$$W_{BHA} = W_{BHAa}(\text{BF}) \tag{2.41}$$

Where: W_{BHA} = Buoyed weight of the BHA in lb

Step 7: Design Section 1 of drill string above the BHA:

Use Equation (2.28) to calculate the L_{max} based on the margin of overpull in ft.
Use Equation (2.35) to calculate the L_{psc} based on slip crushing in ft.
Select the shortest length to use in Section 1.

Step 8: Add the BHA and the drill pipe selected for Section 1 to find the buoyed weight needed to design the next section (see example).

Step 9: Repeat Steps 7 and 8 until the top section of the drill string has been selected.

Step 10: Prepare a summary of the BHA and Sections 1, 2 and 3 of the drill pipe.

Step 11: Prepare a check of the margin of overpull for each grade of drill pipe selected.

Step 12: Prepare a summary of the String Design.

Example: Design a drill string to drill to 18,000 ft. using:

Weight on bit	= 30,000 lb
Jarring tension	= 7000 lb
DC for jarring wt.	= 62 ft.
Average length of DC	= 31 ft.
HW to complete jarring wt.	= 12,000 lb (less 2 DCs)
Mud weight	= 16.0 ppg (BF = 0.7557)
Slip length	= 16 in.
Coefficient of friction	= 0.08

Available String

#	Item	Pipe Size OD (in.)	Pipe Size ID (in.)	Wt (lb/ft.)	Grade	W_{min} (in.)	OD_r (in.)	A_r (in.)	TS_r (lb)	W_{ta} (lb/ft.)	W_{tja} (lb)	L_{tja} (in.)	W_{adj} (lb/ft.)
1	DC	7	2.8125	110	NC50								
2	HW	5	3.0	42.72	NC50								49.77
3	DP	5	4.276	19.5	X-95	0.2896	4.855	4.152	394,440	18.22	137.8	1.748	21.62
4	DP	5	4.276	19.5	G-105	0.2896	4.855	4.152	435,960	18.22	145.7	1.748	21.88
5	DP	5	4.276	19.5	S-135	0.2896	4.855	4.152	560,520	18.22	159.7	1.748	22.32

Step 1: Calculate the length of the drill collars for bit weight and jarring tension:

$$L_{DCbj} = \frac{(30{,}000 + 7000)}{(0.7557)(110)} = 445\,\text{ft.}$$

Step 2: Calculate the total length of the drill collars:

$$L_{DCT} = 445 + 62 = 507\,\text{ft.}$$

Step 3: Calculate the length of the heavy weight drill pipe:

$$L_{HW} = \frac{12{,}000 - [(62)(110)(0.7557)]}{(49.77)(0.7557)} = 182.4 \cong 186\,\text{ft. (2 stands)}$$

Step 4: Summary: BHA.

Length = 507 + 186 = 693 ft.
Air wt. = [507 (110)] + [186 (49.77)] = 65,027 lb
Buoyed wt. = 65,027 (0.7557) = 49,141 lb

Step 5: Calculate the length of the first section (#3) of drill pipe:

$$L_{max} = \frac{(((394,440)(0.9)) - 100{,}000 - (49,141))}{(21.62)(0.7557)} = 12{,}600\,\text{ft.}$$

$$L_{psc} = \left[\frac{\left(\frac{(394{,}440\,(0.9))}{1.42}\right) - (65{,}027(0.7557))}{(21.62)(0.7557)}\right] = 12{,}294\,\text{ft.}$$

Select the smallest length, therefore the design is limited by slip crushing.

Step 6: Summary: BHA and Section 1 (#3) of drill pipe:

BHA wt. = 49,141 lb
Grade X air wt. = 12,294 (21.62) = 265,796 lb
Grade X buoyed wt. = 265,796 (0.7557) = 200,862 lb
Total buoyed wt. = 49,141 + 200,862 lb = 250,003 lb

Step 7: Calculate the length of the second section (#4) of drill pipe:

$$L_{\max} = \frac{(((435,960)(0.9)) - 100,000 - (250,003))}{(21.88)(0.7557)} = 2562\,\text{ft.}$$

$$L_{\text{psc}} = \left[\frac{\left(\frac{(435,960\,(0.9))}{1.42}\right) - (250,003)}{(21.88)(0.7557)}\right] = 1591\,\text{ft.}$$

Select the smallest length, therefore the design is limited by slip crushing.

Step 8: Summary: BHA and Sections 1 (#3) & 2 (#4) of drill pipe:

BHA wt.	= 49,141 lb
Grade X	= 200,862 lb
Grade G air wt.	= 1591 (21.88) = 34,811 lb
Grade G buoyed wt.	= 34,811 (0.7557) = 26,307 lb
Total buoyed wt.	= 49,141 + 200,862 + 26,307 = 276,310 lb

Step 9: Calculate the length of the third section (#5) of drill pipe:

$$L_{\max} = \frac{(((560,520)(0.9)) - 100,000 - (276,310))}{(22.32)(0.7557)} = 7598\,\text{ft.}$$

$$L_{\text{psc}} = \left[\frac{\left(\frac{(560,520(0.9))}{1.42}\right) - (276,310)}{(22.32)(0.7557)}\right] = 4681\,\text{ft.}$$

Select the smallest length, therefore the design is limited by slip crushing.

Step 10: Summary: BHA and Sections 1 (#3), 2 (#4) and 3 (#5) of drill pipe.

Drill collars	= 507 ft.
Heavy weight DP	= 186 ft.
Grade X DP	= 12,294 ft.
Grade G DP	= 1591 ft.
Sub total	= 14,578 ft.
Grade S DP length	= 18,000 − 14,578 = 3422 ft.
Total drill string	= 18,000 ft.

Total buoyed wt. = 276,310 + [(3422)(22.32)(0.7557)]
= 334,030 lb

Total depth possible = 14,578 + 4681 = 19,259 ft.

Step 11: Margin of overpull check:

Grade X = [(394,440)(0.90)] − 250,003 = 104,993 lb
Grade G = [(435,960)(0.90)] − 276,310 = 116,054 lb
Grade S = [(560,520)(0.90)] − 334,030 = 170,438 lb

Step 12: Summary of design.

Item Description	Length (ft.)	Air Wt. (lb)	Buoyed Wt. (lb)	Accumulated Wt. (lb)	MOP (lb)
DC: $7 \times 2^{13}/_{16} \times 110$, NC50	507	55,770	42,145	42,145	
HW: $5 \times 3 \times 49.77$, NC50	186	9257	6996	49,141	
BHA summary	693	65,027	49,141	49,141	
DP:					
5,19.5, Grade X, NC50	12,294	265,796	200,862	250,003	104,993
5,19.5, Grade G, NC50	1591	34,811	26,307	276,310	116,054
5,19.5, Grade S, NC50	3422	76,379	57,720	334,030	170,438
Total	18,000	442,013	334,030	334,030	104,993 limited

Ref: Murchison Drilling School.

2.5 Depth of a Washout

Method 1:

Pump soft line or other plugging material down the drill pipe and note how many strokes are required before the pump pressure increases. Use a moderate pump rate to prevent forcing the plugging material through the washed out pipe.

$$D_{\mathrm{pwol}} = \left(\frac{(C_{\mathrm{r}})(O_{\mathrm{p}})}{V_{\mathrm{pc}}}\right) \tag{2.42}$$

Where: D_{pwo1} = Depth of pipe washout in ft.
C_{r} = Strokes required for the pump pressure to increase
O_{p} = Pump output in bbl
V_{pc} = Capacity of drill pipe in bbl/ft.

Example:

Drill pipe = 3½ in.—13.3 lb/ft.
DP capacity = 0.00742 bbl/ft.
Pump output = 0.112 bbl/stk (5½ × 14 in. duplex @ 90% efficiency)

Note: A pressure increase was noted after 360 stk.

$$D_{\text{pwol}} = \left(\frac{(360)(0.112)}{0.00742}\right) = 54.34 \text{ ft.}$$

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, uncooked rice, corn starch, glass or plastic beads, brightly colored paint, and so on. In nonaqueous fluids, use a red dye designed for use to identify cement spacers.

$$D_{\text{pwo2}} = \left(\frac{(C_r)(O_p)}{(V_{\text{pc}} + V_{\text{acb}})}\right) \tag{2.43}$$

Where: D_{pwo2} = Depth of pipe washout in ft.
V_{acb} = Capacity of the annulus between the open hole or casing in bbl/ft.

Example:

Drill pipe = 3½ in.—13.3 lb/ft.
Drill pipe capacity = 0.00742 bbl/ft.
Pump output = 0.112 bbl/stk (5½ × 14 in. duplex @ 90% efficiency)
Annulus hole size = 8½ in.
Annulus capacity = 0.0583 bbl/ft. (8½ × 3½ in.)

Note: The material pumped down the drill pipe came over the shaker after 2680 stk.

$$D_{\text{pwo2}} = \left(\frac{(2680)(0.112)}{(0.00742 + 0.0583)}\right) = 4569 \text{ ft.}$$

2.6 Stuck Pipe Calculations

2.6.1 Determine the Length of Free Pipe in Feet 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 using the data in the drill pipe stretch Table 2.4 is shown below with the following formula.

Table 2.4
Drill Pipe Stretch Table

ID (in.)	Nominal Weight (lb/ft.)	ID (in.)	Wall Area (in.^{2})	Stretch Constant in 1000 lb/1000 ft.	Free Point Constant
2⅜	4.85	1.995	1.304	0.30675	3260.0
	6.65	1.815	1.843	0.21704	4607.7
2⅞	6.85	2.241	1.812	0.22075	4530.0
	10.40	2.151	2.858	0.13996	7145.0
3½	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	11.85	3.476	3.077	0.13000	7692.5
	14.00	3.340	3.805	0.10512	9512.5
4½	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	16.25	4.408	4.374	0.09145	10935.0
	19.50	4.276	5.275	0.07583	13187.5
5½	21.90	4.778	5.828	0.06863	14570.0
	24.70	4.670	6.630	0.06033	16575.0
6⅝	25.20	5.965	6.526	0.06129	16315.0

$$P_{f1} = \frac{(P_{dps})(K_{fpt})}{F_p} \tag{2.44}$$

Where: P_{f1} = Length of free pipe in ft.
P_{dps} = Drill pipe stretch in inches
K_{fpt} = Free point constant from Table 2.4
F_p = Pull force in 1000 lb

Example: Calculate the length of free drill pipe with the following data:

Drill pipe = 6.625 in. – 25.2 lb/ft. (S-135)
Stretch = 20 in.
Pull force = 35,000 lb

Step 1: Determine the drill pipe stretch from Table 2.4:

$K_{fpt} = 16315.0$

Step 2: Calculate the length of free pipe:

$$P_{f1} = \frac{(34)(16315.0)}{35} = 15,849 \text{ ft.}$$

Method 2: Calculate the free point constant (K_{fpc}). The free point constant can be calculated for any type of steel drill pipe if the outside diameter (OD, in.) and inside diameter (ID, in.) are known:

Step 1: Calculate the cross-sectional area of the drill pipe wall in square inches:

$$A_s = \left(D_p^2 - D_i^2\right)(0.7854) \tag{2.45}$$

Where: A_s = Cross-sectional area of the pipe wall in square inches
D_p = Outside diameter of drill pipe in inches
D_i = Inside diameter of drill pipe in inches

Step 2: Calculate the free point constant for the drill pipe:

$$K_{fpc} = (A_s)(2500) \tag{2.46}$$

Where: K_{fpc} = Calculated free point constant

Example: Calculate the free point constant with the following data:

Drill pipe size and weight = 6.625 × 5.965 in., 25.2 lb/ft.

Step 1: Calculate the cross-sectional area:

$$A_s = \left(6.625^2 - 5.965^2\right)(0.7854) = 6.53 \text{ in.}^2$$

Step 2: Calculate the free point constant:

$$K_{fpc} = (6.53)(2500) = 16,325$$

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

Tubing size and weight = 2.375 × 2.441 in., 6.5 lb/ft.
Stretch = 25 in.
Pull force = 20,000 lb

Step 1: Calculate the cross-sectional area:

$$A_s = \left(2.375^2 - 1.815^2\right)(0.7854) = 1.843 \text{ in.}^2$$

Step 2: Calculate the free point constant:

$$K_{fpc} = (1.843)(2500) = 4607.5$$

Step 3: Calculate the depth of stuck pipe:

$$P_{f1} = \frac{(25)(4607.5)}{20} = 5759 \text{ ft.}$$

Method 3: This method of calculating the length of free pipe does not use the free point constant listed in Table 2.4.

Step 1: Calculate the weight of the drill pipe tube without the tool joints in lb/ft.:

$$W_{dpt} = 2.674\left(D_p^2 - D_i^2\right) \quad (2.47)$$

Where: W_{dpt} = Weight of drill pipe tube in lb/ft.

Step 2: Calculate the length of free pipe in ft.:

$$P_{f2} = \frac{(735,294)(P_{dps})(W_{dpt})}{F_{pd}} \tag{2.48}$$

Where: P_{f2} = Length of free pipe in ft.
P_{dps} = Pipe stretch from Table 2.2 in inches
W_{dpt} = Weight of drill pipe tube in lb/ft. (excluding tool joints)
F_{pd} = Differential pull force in lb

Note: The weight of the drill pipe tube without the tool joints may be used if known instead of the calculated value.

Example: Calculate the length of free pipe using the following data:

Drill pipe size	= 5.0 × 4.276 in. (19.5 lb/ft.)
Stretch of pipe	= 24 in.
Differential pull force to obtain stretch	= 30,000 lb

Step 1: Calculate the weight of the drill pipe tube:

$$W_{dpt} = (2.674)(5.0^2 - 4.276^2) = 17.958\,\text{lb/ft.}$$

Step 2: Calculate the length of free pipe:

$$P_{f2} = \frac{(735,294)(24)(17.958)}{30,000} = 10,564\,\text{ft.}$$

2.6.2 Stuck Pipe Overbalance Guidelines

$$P_{OBG} = \left(\frac{1500}{K}\right) - ((\sin \sphericalangle)(1000)) \tag{2.49}$$

Table 2.5
Angle Sin Values

Angle	Sin	Angle	Sin	Angle	Sin
5	0.087156	35	0.573576	65	0.906308
10	0.173648	40	0.642788	70	0.939693
15	0.258819	45	0.707107	75	0.965926
20	0.342020	50	0.766044	80	0.984808
25	0.422618	55	0.819152	85	0.996195
30	0.500000	60	0.866025	90	1.000000

Where: P_{OBG} = Overbalance pressure guideline in psi (stuck pipe risk may be over 90% above this value)
K = Mud type factor (0.75 for OBM or SBM; 1.0 for WBM)
$\sphericalangle$ = Angle of hole in degrees (decimal value) (Table 2.5)

Example 1: Determine the overbalance guideline for reducing the risk of stuck pipe with SBM in psi:

Data: Hole angle = 30°
Mud type = Synthetic base mud (SBM)

$$P_{OBG} = \left(\frac{1500}{0.75}\right) - ((0.50)(1000)) = 1500\,\text{psi}$$

Example 2: Determine the overbalance guideline for reducing the risk of stuck pipe with WBM in psi:

Data: Hole angle = 30°
Mud type = Water base mud (WBM)

$$P_{OBG} = \left(\frac{1500}{1.0}\right) - ((0.50)(1000)) = 1000\,\text{psi}$$

2.7 Calculations Required for Placing Spotting Pills in an Open Hole Annulus

2.7.1 Calculate the Amount of Spotting Fluid Pill in Barrels Required to Cover the Stuck Point of the Drill String or Casing, Then Calculate the Number of Pump Strokes Required to Spot the Pill

Step 1: Calculate the hole "washout" size in inches:

$$D_{hwo} = ((D_{bit})(H_{wo})) + D_{bit} \tag{2.50}$$

Where: D_{hwo} = Diameter of hole "washout" in inches
D_{bit} = Diameter of bit in inches
H_{wo} = Hole "washout" factor in percent

Step 2: Calculate the annular volume for the drill pipe (or HWDP) and drill collars in bbl/ft.

$$C_a = \frac{\left(D_{hwo}^2 - D_p^2\right)}{1029.4} \tag{2.51}$$

Where: C_a = Annular capacity in bbl/ft.
D_p = Outside diameter of drill pipe, HWDP or drill collars in inches

Step 3: Calculate the volume of the spotting fluid pill required for the annulus in bbl:

$$V_{sfpa} = (V_a)\left(L_{sfpa}\right) \tag{2.52}$$

Where: V_{sfpa} = Volume of spotting fluid pill the annulus in bbl
L_{sfpa} = Length of spotting fluid pill in annulus in ft.

Step 4: Calculate the total volume of the spotting fluid pill required to cover the fish in bbl:

$$V_{sfpt} = V_{sfpa} + V_{sfpds} \tag{2.53}$$

Where: V_{sfpt} = Total volume of spotting fluid pill required in bbl

V_{sfpds} = Predetermined volume of spotting fluid pill to be left inside drill string in bbl

Step 5: Calculate the drill string capacity for each pipe section in bbl:

$$C_p = \left(\frac{D_i^2}{1029.4}\right)(L_s) \tag{2.54}$$

Where: C_p = Volume of drill pipe, HWDP, or drill collar section in bbl
D_i = Inside diameter (ID) of drill pipe, HWDP, or drill collars in inches
L_s = Length of drill pipe, HWDP, or drill collar section in ft.

Step 6: Calculate the strokes required to pump the spotting fluid pill:

$$S_{sfp} = \frac{V_{sfpt}}{O_p} \tag{2.55}$$

Where: C_{sfp} = Strokes to pump spotting fluid pill
O_p = Pump output in bbl/stk

Step 7: Calculate the volume required to chase the spotting fluid pill in bbl:

$$V_{csfp} = \left(V_{ds} - V_{sfpds}\right) \tag{2.56}$$

Where: V_{csfp} = Volume required to chase the spotting fluid in bbl
V_{ds} = Volume of drill string in bbl
V_{sfpds} = Volume of spotting fluid pill left in drill string in bbl

Step 8: Calculate the pump strokes required to chase the spotting fluid pill:

$$S_{csfp} = \left(\frac{V_{csfp}}{O_p}\right) + S_{ss} \tag{2.57}$$

Where: S_{csfp} = Strokes required to chase the spotting fluid
S_{ss} = Strokes required to pump spotting fluid through surface system

Step 9: Calculate the total strokes to spot the pill:

$$S_{sfpt} = S_{sfp} + S_{csfp} \tag{2.58}$$

Where: S_{sfpt} = Total strokes to spot the pill

Example: The drill collars are differentially stuck. Use the following data to spot a base oil pill around the drill collars plus 200 ft. (optional) above the collars and leave 30 barrels in the drill string:

Well depth (MD)	= 10,000 ft.
Hole diameter	= 8½ in.
Washout factor	= 20%
Drill pipe	= 5.0 in. (19.5 1b/ft.)
DP capacity	= 0.0178 bbl/ft.
DP length	= 9400 ft.
Drill collars	= 6½ × 2½ in.
DC capacity	= 0.0061 bbl/ft.
DC length	= 600 ft.
Pump output	= 0.117 bbl/stk
Surface system	= 80 stk (strokes required to pump the pill to the drill string).

Step 1: Calculate the hole "washout" size in inches:

$$D_{hwo} = ((8.5)(0.20)) + 8.5 = 10.2 \text{ in.}$$

Step 2: Calculate the annular volume for the drill pipe and drill collars:

(a) Annular capacity around the drill collars:

$$V_{adc} = \frac{(10.2^2 - 6.5^2)}{1029.4} = 0.0600 \text{ bbl/ft.}$$

(b) Annular capacity around the drill pipe:

$$V_{\text{adp}} = \frac{(10.2^2 - 5.0^2)}{1029.4} = 0.0768 \text{ bbl/ft.}$$

Step 3: Calculate the total volume of pill required in the annulus:

(a) Volume opposite the drill collars:

$$V = (0.0600)(600) = 36 \text{ bbl}$$

(b) Volume opposite the drill pipe:

$$V = (0.0768)(200) = 15.4 \text{ bbl}$$

(c) Total volume, bbl, required in the annulus:

$$V = 36 + 15.4 = 51.4 \text{ bbl}$$

Step 4: Calculate the total volume required for the spotting fluid pill:

$$V_{\text{t}} = 51.4 + 30 = 81.4 \text{ bbl} \approx 81 \text{ bbl}$$

Step 5: Calculate the drill string capacity:

(a) Drill collar capacity in bbl:

$$V_{\text{dc}} = (0.0061)(600) = 3.7 \text{ bbl}$$

(b) Drill pipe capacity in bbl:

$$V_{\text{dp}} = (0.0178)(9400) = 167.3 \text{ bbl}$$

(c) Total drill string capacity in bbl:

$$V_{\text{tds}} = 3.7 + 167.3 = 171 \text{ bbl}$$

Step 6: Calculate the strokes required to pump the pill:

$$S_{sfp} = \frac{81}{0.117} + 80 = 692\,\text{stk}$$

Step 7: Calculate the volume required to chase the spotting fluid pill:

$$V_{csfp} = (171 - 30) = 141\ \text{bbl}$$

Step 8: Calculate the strokes required to chase the pill:

$$S_{csfp} = \left(\frac{141}{0.117}\right) + 80 = 1285\,\text{stk}$$

Step 9: Calculate the strokes required to spot the pill:

$$S_{sfpt} = 692 + 1285 = 1977\,\text{stk}$$

2.7.2 Determine the Length of an Unweighted Spotting Fluid Pill That Will Balance Formation Pressure in the Annulus in ft

Step 1: Calculate the difference in pressure gradient between the mud weight and the spotting fluid pill in psi/ft.:

$$G_{sfp} = \left(W_m - W_{sfp}\right)(0.052) \tag{2.59}$$

Where: G_{sfp} = Difference in pressure gradient in psi/ft.
W_m = Weight of mud in lb/gal
W_{sfp} = Weight of spotting fluid pill in lb/gal

Step 2: Calculate the length of an unweighted spotting fluid pill that will balance formation pressure in the annulus:

$$L_{sfp} = \frac{\text{OB}}{G_{sfp}} \tag{2.60}$$

Where: L_{sfp} = Length of unweighted spotting fluid pill in ft.
OB = Overbalance pressure needed to control pore pressure in psi

Example: Use the following data to determine the length of an unweighted spotting fluid pill that will balance formation pressure in the annulus:

Mud weight	= 11.2 ppg
Weight of spotting fluid pill	= 6.7 ppg (diesel = 7.0 ppg/synthetic = 6.7 ppg)
Amount of overbalance	= 250.0 psi

Step 1: Calculate the difference in pressure gradient in psi/ft.:

$$G_{\text{sfp}} = (11.2 - 6.7)(0.052) = 0.234 \text{ psi/ft.}$$

Step 2: Calculate the length of an unweighted spotting fluid pill that will balance formation pressure in the annulus:

$$L_{\text{sfp}} = \frac{250}{0.234} = 1068 \text{ ft.}$$

Therefore: Less than 1068 ft. of an unweighted spotting fluid pill should be used to maintain a safe balance of the formation pore pressure and prevent an influx that would cause a kick or blowout.

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CHAPTER THREE

Pressure Control: Kill Sheets and Related Calculations

3.1 Normal Kill Sheet

3.1.1 Prerecorded Data

Original mud weight (OMW) ______________________________ ppg
Measured depth (MD) ____________________________________ ft.
Kill rate pressure (KRP) ________________ psi @______________ spm
Kill rate pressure (KRP) ________________ psi @______________ spm

3.1.2 Drill String Volume

Drill pipe capacity: _____ bbl/ft. × ______ length, ft. = ________ bbl
Drill pipe capacity: _____ bbl/ft. × ______ length, ft. = ________ bbl
Drill collar capacity: ____ bbl/ft. × ______ length, ft. = ________ bbl
Total drill string volume: _________bbl

3.1.3 Annular Volume

Drill collar/open hole:
Capacity _______ bbl/ft. × ______ length, ft. = ______________ bbl
Drill pipe/open hole:
Capacity _______ bbl/ft. × ______ length, ft. = ______________ bbl
Drill pipe/casing:
Capacity _______ bbl/ft. × ______ length, ft. = ______________ bbl
Total barrels in open hole: ______________ bbl
Total annular volume: ___________________ bbl

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3.1.4 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 MW ____ ppg
@ Casing setting depth of ________ TVD

3.1.5 Kick Data

SIDPP _______________ psi
SICP ________________ psi
Pit Gain ______________ bbl
TVD ________________ ft.

3.2 Calculations for the Pressure Chart

Kill weight mud (KWM): SIDPP _____ psi ÷ 0.052 ÷ TVD ___ ft. + OMW ___ ppg = KWM ___ ppg

Initial circulating pressure (ICP): SIDPP _______ psi + KRP ____ psi = _____ psi

Final circulating pressure (FCP): KWM _____ ppg × KRP _____ psi − OMW ____ ppg = _____ psi

Psi/stroke: ICP _____ psi − FCP _____ psi/strokes to bit _____ = ________ psi/stk

	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.
HWDP length = 240 ft.
Drill collars (8.0 in. OD × 3.0 in. ID) Capacity = 0.0087 bbl/ft.
Drill collars length = 360 ft.

Annulus:

Hole size	= 12¼ 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. × 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.

3.2.1 Drill String Volume

Drill pipe capacity: (0.01776 bbl/ft.) (9925 ft.)	= 176.27 bbl
HWDP capacity: (0.00883 bbl/ft.) (240 ft.)	= 2.12 bbl
Drill collar capacity: (0.0087 bbl/ft.) (360 ft.)	= 3.13 bbl
Total drill string volume	**= 181.5 bbl**

3.2.2 Annular Volume

Drill collar/open hole: (0.0836 bbl/ft.) (360 ft.)	= 30.1 bbl
Drill pipe/open hole: (0.1215 bbl/ft.) (6165 ft.)	= 749.05 bbl
Drill pipe/casing: (0.1303 bbl/ft.) (4000 ft.)	= 521.2 bbl
Total annular volume	**= 1300.35 bbl**

3.2.3 Strokes/Pressures

Strokes to bit: Drill string volume (181.5 bbl) ÷ (0.136 bbl/stk) = **1335 stk**

Bit-to-casing strokes: Open hole volume (779.15 bbl) ÷ (0.136 bbl/stk) = **5729 stk**

Bit-to-surface strokes: Annular volume (1300.35 bbl) ÷ (0.136 bbl/stk) = **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) (1000 psi) ÷ (9.6 ppg) = **1094 psi**

3.2.4 Pressure Chart: Prepare a Chart with Pressure and Strokes Used During the Kill

$$S_b = \frac{V_{ds}}{10} \tag{3.1}$$

Where: S_b = Stokes to the bit per line in the pressure chart
V_{ds} = Volume of drill string in bbl

Pressure Chart

	Strokes	Pressure
	0	
133.5 rounded up	134	
133.5 + 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	

3.2.5 Pressure Decrease per Line

$$P_D = \left(\frac{(\text{ICP} - \text{FCP})}{10}\right) \tag{3.2}$$

Where: P_D = Pressure decrease per line in psi

$$P_D = \left(\frac{(1480 - 1094)}{10}\right) = 38.6\,\text{psi}$$

Pressure Chart

	Strokes	Pressure
	0	1480
1480 - 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

3.2.6 Trip Margin (TM)

$$\text{TM} = \frac{\overline{\text{YP}}}{11.7(D_h - D_p)} \tag{3.3}$$

Where: TM = Trip margin in ppg
D_h = Hole diameter in in.
D_p = Drill pipe OD in in.

Example: Yield Point = 10 lb/100 ft.^{2}
D_h = 8.5 in.
D_p = 4.5 in.

$$TM = \frac{10}{11.7(8.5 - 4.5)} = 0.2\,\text{ppg}$$

3.2.7 Determine psi/stk for Pressure Chart

$$P_{stk} = \frac{(ICP - FCP)}{S_b} \tag{3.4}$$

Where: P_{stk} = Pressure per pump stroke in psi
ICP = Initial circulating pressure in psi
FCP = Final circulating pressure in psi
S_b = Strokes to the bit

Example: Using the kill sheet just completed, adjust the pressure chart to read in increments that are easy to read on pressure gauges. (Generally, 50 psi).

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

$$P_{stk} = \frac{(1480 - 1094)}{1335} = 0.2891\,\text{psi/stk}$$

The pressure side of the chart will appear 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 to 1450 psi?

$$1480 - 1450 \text{ psi} = 30 \text{ psi}$$

$$\frac{30}{0.2891} = 104 \text{ stk}$$

For lines 3–7: How many strokes will be required to decrease the pressure by 50 psi increments?

$$\frac{50}{0.2891} = 173 \text{ stk}$$

Therefore, the new pressure chart will appear 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

3.2.8 Kill Sheet with a Tapered String

$$P_{ts} = \text{ICP} - \left[\frac{(L_{DP})}{S_b}\right] \tag{3.5}$$

Where: P_{ts} = Pressure with a tapered string in psi
L_{DP} = Length of drill pipe in ft.
S_b = Strokes to the bit

$$P_{stk} = \text{ICP} - \left[\left(\frac{L_{DP}}{L_{DS}}\right)(\text{ICP} - \text{FCP})\right] \tag{3.6}$$

Where: P_{stk} = Pressure at strokes for pipe section in psi
L_{DS} = Length of drill string in ft.

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.)
DP capacity = 0.01776 bbl/ft.
DP length = 7000 ft.
Drill pipe 2: 3½ in. (13.3 lb/ft.)
DP capacity = 0.0074 bbl/ft.
DP length = 6000 ft.
Drill collars: 4½ in. OD × 1½ in. ID
DC capacity = 0.0022 bbl/ft.
DC length = 2000 ft.
Pump output = 0.117 bbl/stk

Step 1: Determine strokes to pump down the drill string:

$$S_{DS} = \frac{(L_{DS})(C_{DS})}{P_O} \tag{3.7}$$

Where: S_{DS} = Strokes to pump down the drill string
L_{DS} = Length of the drill string in ft.
C_{DS} = Capacity of the drill string in bbl/ft.
P_O = Pump output in bbl/stk

Example: Drill pipe length—Section 1 = 7000 ft.
Capacity of the drill string—Section 1 = 0.01776 bbl/ft.
Drill pipe length—Section 2 = 6000 ft.
Capacity of the drill string—Section 2 = 0.00742 bbl/ft.
Drill collars length—Section 3 = 2000 ft.
Capacity of the drill string—Section 3 = 0.0022 bbl/ft.
Pump output = 0.117 bbl/stk

Pipe 1: 5.0 in. (19.5 lb/ft.)

$$S_{DS} = \frac{(7000)(0.01776)}{0.117} = 1063 \text{ stk}$$

Pipe 2: 3½ in. (13.3 lb/ft.)

$$S_{DS} = \frac{(6000)(0.00742)}{0.117} = 381 \text{ stk}$$

Pipe 3: 4½ in. OD × 1½ in. ID

$$S_{DS} = \frac{(2000)(0.0022)}{0.117} = 38 \text{ stk}$$

Total strokes = 1063 + 381 + 38 = 1482 stk

3.2.9 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 stk:

$$P_{stk} = 1780 - \left[\left(\frac{7000}{15,000}\right)(1780 - 1067)\right]$$

$$P_{stk} = 1780 - [(0.46666)(713)]$$

$$P_{stk} = 1780 - 333 = 1447 \text{ psi@ } 1063 \text{ stk}$$

Step 3: Determine interim pressure for 5.0 in. plus 3½ in. drill pipe (1063 + 381) = 1444 stk:

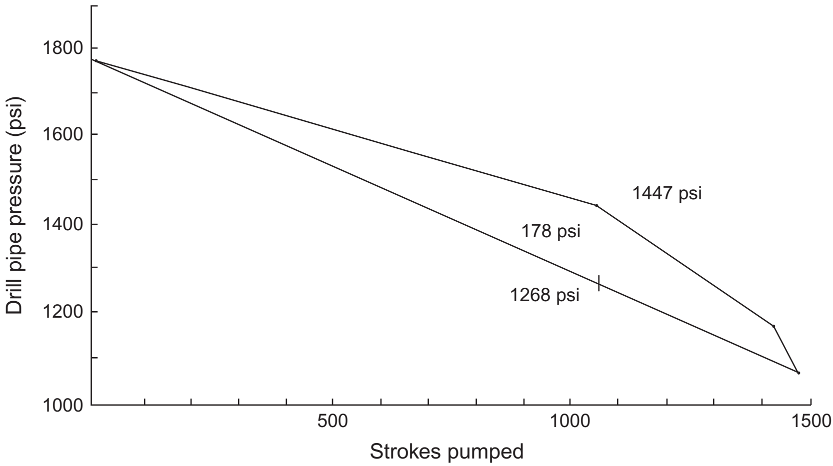

Figure 3.1 Data from kill sheet.

$$P_{\text{stk}} = 1780 - \left[\left(\frac{13{,}000}{15{,}000}\right)(1780 - 1067)\right]$$

$$P_{\text{stk}} = 1780 - [(0.86666)(713)]$$

$$P_{\text{stk}} = 1780 - 618 = 1162 \text{ psi@1444 stk}$$

Step 4: Plot data on graph paper (Figure 3.1):

Note: After pumping 1062 stk, if a straight line would have been plotted, the well would have been underbalanced by 178 psi.

3.2.10 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.

Step 1: Determine strokes from surface to KOP:

$$S_{\text{KOP}} = \frac{(C_{\text{dp}})(\text{MD}_{\text{KOP}})}{O_{\text{p}}} \tag{3.8}$$

Where: S_{KOP} = Strokes to pump to KOP
C_{dp} = Capacity of drill pipe in bbl/ft.
MD_{KOP} = Length of drill pipe to KOP in ft.
O_{p} = Pump output in bbl/stk

Step 2: Determine strokes from KOP to TD:

$$S_{\text{TD}} = \frac{(C_{\text{dp}})(L_{\text{MD}})}{O_{\text{p}}} \tag{3.9}$$

Where: S_{TD} = Strokes from KOP to measured depth
L_{MD} = Length of drill pipe to measured depth in ft.

Step 3: Determine the total strokes from surface to the bit:

$$S_{\text{B}} = S_{\text{KOP}} + S_{\text{TD}} \tag{3.10}$$

Where: SB = Strokes from the surface to the bit

Step 4: Determine the kill weight mud:

$$\text{KWM} = \left(\frac{\text{SIDPP}}{(0.052)(\text{TVD}_{\text{TD}})}\right) + \text{MW} \tag{3.11}$$

Where: KWM = Kill weight mud in ppg
SIDPP = Shut-in drill pipe pressure in psi
TVD_{TD} = Total vertical depth in ft.
MW = Current mud weight in ppg

Step 5: Determine the initial circulating pressure:

$$\text{ICP} = \text{SIDPP} + \text{KRP} \tag{3.12}$$

Where: ICP = Initial circulating pressure in psi
KRP = Kill rate pressure in psi

Step 6: Determine the final circulating pressure:

$$FCP = \frac{(KWM)(KRP)}{OMW} \tag{3.13}$$

Where: FCP = Final circulating pressure in psi
OMW = Old mud weight in ppg

Step 7: Determine the Hydrostatic Pressure increase from surface to the KOP:

$$HP_{KOP} = (KWM - OMW)(0.052)(MD_{KOP}) \tag{3.14}$$

Where: HP_{KOP} = Hydrostatic pressure increase from surface to the KOP in psi
MD_{KOP} = Total vertical depth at the KOP in ft.

Step 8: Determine the friction pressure increase to KOP:

$$FP_{KOP} = (FCP - KRP)\left(\frac{MD_{KOP}}{MD_{TD}}\right) \tag{3.15}$$

Where: FP_{KOP} = Friction pressure increase to KOP in psi
MD_{TD} = Measured depth at TD in ft.

Step 9: Circulating pressure when KWM gets to KOP:

$$CP = (ICP - HP_{KOP}) + FP_{KOP} \tag{3.16}$$

Where: CP = Circulating pressure when KWM gets to KOP in 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.

Step 1: Strokes from surface to KOP:

$$S_{\mathrm{KOP}} = \frac{(0.01776)(5000)}{0.136} = 653 \text{ stk}$$

Step 2: Determine strokes from KOP to TD:

$$S_{\mathrm{TD}} = \frac{(0.01776)(10,000)}{0.136} = 1306 \text{ stk}$$

Step 3: Determine the total strokes from the surface to the bit:

$$S_{\mathrm{B}} = 653 + 1309 = 1959 \text{ stk}$$

Step 4: Determine the kill weight mud:

$$\mathrm{KWM} = \left(\frac{800}{(0.052)(10,000)}\right) + 9.6 = 11.1 \text{ ppg}$$

Step 5: Determine the initial circulating pressure (ICP):

$$\mathrm{ICP} = 800 + 600 = 1400 \text{ psi}$$

Step 6: Determine the final circulating pressure:

$$\mathrm{FCP} = \frac{(11.1)(600)}{9.6} = 694 \text{ psi}$$

Step 7: Determine the hydrostatic pressure increase from surface to the KOP:

$$HP_{KOP} = (11.1 - 9.6)(0.052)(5000) = 390\,\text{psi}$$

Step 8: Determine the friction pressure increase to KOP:

$$FP_{KOP} = (694 - 600)\left(\frac{5000}{15{,}000}\right) = 31\,\text{psi}$$

Step 9: Circulating pressure when KWM gets to KOP:

$$CP = (1400 - 390) + 31 = 1041\,\text{psi}$$

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

a. Calculate the psi/stk:

$$P_{\text{stk}} = \frac{(1400 - 694)}{1959} = 0.36\,\text{psi/stk}$$

b. Calculate the pressure drop to the bit in psi:

$$(0.36)(653) = 235\text{ psi}$$

c. Calculate circulating pressure when KWM gets to KOP:

$$1400 - 235 = 1165\,\text{psi}$$

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. If the difference in pressure at the KOP is 100 psi or greater, then the adjusted pressure chart should be used to minimize the chances of losing circulation.

Figure 3.2 graphically illustrates the difference.

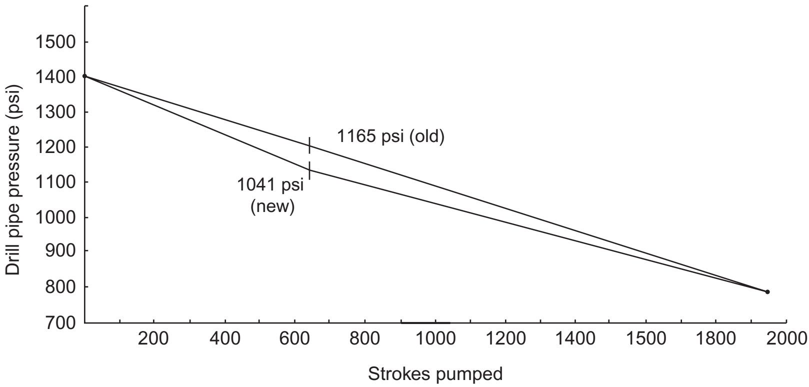

Figure 3.2 Adjusted pressure chart.

3.2.11 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:

$$P_{FM} = (MW_M + MW_{SF})(0.052)(TVD) \tag{3.17}$$

Where: P_{FM} = Maximum formation pressure in psi
MW_M = Maximum mud weight in ppg
MW_{SF} = Mud weight safety factor in ppg
TVD = Total vertical depth in ft.

Step 2: Assuming 100% of the mud is blown out of the hole, determine the hydrostatic pressure in the wellbore:

Note: 70%–80% of mud being blown out is sometimes used instead of 100%.

$$HP_{gas} = (G_{gas})(TVD) \tag{3.18}$$

Where: HP_{gas} = Hydrostatic pressure of a gas column in psi
G_{gas} = Gas gradient in psi/ft.

Step 3: Determine maximum anticipated surface pressure (MASP):

$$MASP = P_{FM} - HP_{gas} \tag{3.19}$$

Where: MASP = maximum anticipated surface pressure in psi

Example:

Proposed total vertical depth	= 12,000 ft.
Maximum mud weight to be used in drilling the well	= 12.0 ppg
Mud weight safety factor	= 4.0 ppg
Gas gradient	= 0.12 psi/ft.

Assume that 100% of the mud is blown out of well.

Step l: Determine maximum formation pressure:

$$P_{FM} = (12.0 + 4.0)(0.052)(12,000) = 9984 \text{ psi}$$

Step 2: Determine the hydrostatic pressure of the gas in the evacuated wellbore:

$$HP_{gas} = (0.12)(12,000) = 1440 \text{ psi}$$

Step 3: Determine maximum anticipated surface pressure (MASP):

$$MASP = 9984 - 1440 = 8544 \text{ psi}$$

Method 2: Use when assuming the maximum pressure in the wellbore is attained when the formation at the shoe fractures:

Step 1: Determine fracture pressure in psi:

$$FP = (FG + MW_{SF})(0.052)\left(TVD_{csg}\right) \tag{3.20}$$

Where: FP = Fracture pressure of the formation at the casing shoe in psi
FG = Fracture gradient at the casing shoe in ppg
TVD_{csg} = Total vertical depth at the casing shoe in 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 in psi (From Equation 3.18):

$$HP_{gas} = \left(G_{gas}\right)(TVD)$$

Step 3: Determine the maximum anticipated surface pressure (MASP) in psi (From Equation 3.19):

$$MASP = P_{FM} - HP_{gas}$$

Example: Proposed casing setting total vertical depth = 4000 ft.
Estimated fracture gradient = 14.2 ppg
Mud weight safety factor = 1.0 ppg
Gas gradient = 0.12 psi/ft.

Assume 100% of mud is blown out of the hole.

Step l: Determine fracture pressure in psi:

$$FP = (14.2 + 1.0)(0.052)(4000) = 3162\,psi$$

Step 2: Determine the hydrostatic pressure of gas in the wellbore in psi:

$$HP_{gas} = (0.12)(4000) = 480\,psi$$

Step 3: Determine the maximum anticipated surface pressure (MASP) in psi:

$$MASP = 3162 - 480 = 2682\,psi$$

3.2.12 Sizing Diverter Lines

Determine diverter line inside diameter in inches, equal to the area between the inside diameter of the casing and the outside diameter of drill pipe in use:

$$D_{DL} = \sqrt{\left(D_h^2 - D_p^2\right)} \tag{3.21}$$

Example: Casing = 13⅜ in., J-55, 61 lb/ft. (ID = 12.515 in.)
Drill pipe = 5.0 in., 19.5 lb/ft.

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

$$D_{DL} = \sqrt{\left(12.515^2 - 5.0^2\right)} = 11.47 \text{ in.}$$

3.3 Formation Pressure Tests

Two methods of testing:

- Equivalent mud weight test (often referred to as the FIT)
- Leak-off test

3.3.1 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—¼-½ bbl/min.
5. Monitor pressure, time, and barrels pumped.
6. Some operators may use 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 or 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.

3.3.2 Testing to an Equivalent Mud Weight (FIT)

(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 in ppg. Three methods can be used to calculate the surface pressure for the test in psi.

Step 1: Determine the mud weight needed to calculate the surface pressure for the test in ppg.

Method 1: Use the maximum mud weight that is programmed for the next hole interval with NO safety factor in ppg:

$$MW_{TE1} = MW_M \tag{3.22}$$

Where: MW_{TE1} = Equivalent test mud weight for Method 1 in ppg
MW_M = Maximum mud weight programmed for next interval in ppg

Method 2: Add a safety factor to the maximum mud weight programmed for the next internal to prevent taking a kick and exceeding the estimated fracture gradient at the casing shoe in ppg:

$$MW_{TE2} = MW_M + MW_{SF} \tag{3.23}$$

Where: MW_{TE2} = Equivalent test mud weight for Method 2 in ppg
MW_{SF} = Safety factor mud weight in ppg

Method 3: Subtract a safety factor from the estimated fracture gradient at the casing shoe to prevent formation breakdown in ppg:

$$MW_{TE3} = FG - MW_{SF} \tag{3.24}$$

Where: MW_{TE3} = Equivalent test mud weight for Method 3 in ppg
FG = Estimated fracture gradient from the drilling program in ppg

Step 2: Determine surface pressure to be used for the test in psi:

$$P_S = (MW_{TEn} - MW)(0.052)\left(TVD_{csg}\right) \tag{3.25}$$

Where: P_S = Surface pressure used for test in psi
MW_{TEn} = Mud weight determined in one of the three methods detailed above in ppg
MW = Mud weight in use at the time of the test in ppg

Example: Mud weight = 10.0 ppg
Casing shoe TVD = 4000 ft.
Maximum mud weight for next interval = 12.0 ppg
Fracture gradient at shoe = 14.0 ppg
Safety factor = 0.5 ppg

Method 1: Use the maximum mud weight that is programmed for the next hole interval with NO safety factor in ppg:

$$P_S = (12.0 - 10.0)(0.052)(4000) = 416 \text{ psi}$$

Method 2: Add a safety factor to the maximum mud weight programmed for the next internal to prevent taking a kick and exceeding the estimated fracture gradient at the casing shoe in ppg:

$$MW_{TE2} = 12.0 + 0.5 = 12.5 \text{ ppg}$$
$$P_S = (12.5 - 10.0)(0.052)(4000) = 520 \text{ psi}$$

Method 3: Subtract a safety factor from the estimated fracture gradient at the casing shoe to prevent formation breakdown in ppg:

$$MW_{TE3} = 14.0 - 0.5 = 13.5 \text{ ppg}$$
$$P_S = (13.5 - 10.0)(0.052)(4000) = 728 \text{ psi}$$

Note: The pressure that would cause formation breakdown would be to use the estimated fracture gradient in psi:

$$P_{FG} = (FG - MW)(0.052)(TVD_{csg}) \quad (3.26)$$

Where: P_{FG} = Formation breakdown pressure at casing shoe in psi

Example: Using the data from above:

$$P_{FG} = (14.0 - 10.0)(0.052)(4000) = 832 \text{ psi}$$

3.3.3 Testing to Leak-Off Test Pressure

(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." (Refer to Figure 3.4)
(3) Determine the estimated leak-off pressure.

3.3.4 Procedure to Prepare the Graph to Record Leak-Off Pressure Data

On the linear chart drawn for the casing pressure test, draw three horizontal lines corresponding to:

(1) Maximum allowable pressure in psi (80% or 90% of the overburden)
(2) Estimated LOT pressure in psi

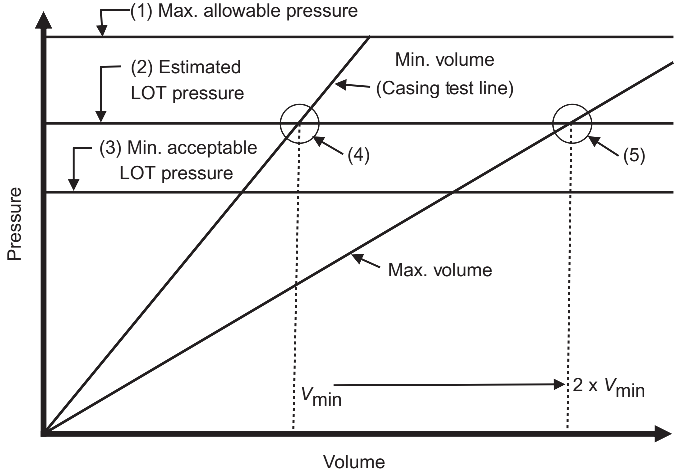

Figure 3.3 Leak-off test graph.

(3) Minimum acceptable leak-off test pressure in psi
(4) V_{min} determined from intersection of minimum volume line from casing test with estimated LOT line
(5) Draw maximum volume line from zero through the intersection of $2 \times V_{min}$ with the estimated LOT line (Figure 3.3).

3.3.5 Prepare the Graph

Step 1: Determine the maximum allowable pressure line (1) in psi:

$$P_{MXL} = [(\sigma_{OB})(SF_{OB})(TVD_{csg})] - [(MW)(0.052)(TVD_{csg})] \quad (3.27)$$

Where: P_{MXL} = Maximum allowable pressure line in psi (Option—use the casing pressure test line).
σ_{OB} = Variable overburden in psi/ft.
SF_{OB} = Safety factor to prevent exceeding the overburden value

TVD_{csg} = Total vertical depth of casing shoe in ft.
MW = Mud weight in ppg

Note: If the variable overburden is not known, 1.0 psi/ft. can be used instead. In this case, the safety factor should be decreased to 85.0% or 80.0%.

Step 2: Determine the estimated leak-off test line (2) in psi:

$$P_{LOTL} = \left((FG - MW)(0.052)\left(TVD_{csg}\right)\right) \tag{3.28}$$

Where: P_{LOTL} = Estimated leak-off test pressure line in psi
FG = Estimated fracture gradient in ppg
MW = Mud weight in use in ppg

Step 3: Determine the minimum acceptable leak-off test pressure line (3) in psi:

(a) Determine the frictional pressure loss in the system in psi:

(1) If only using the **drill pipe** to conduct the test, determine the frictional pressure loss in psi:

$$P_{fdp} = \frac{(\gamma_G)\left(L_p\right)}{300\left(ID_p\right)} \tag{3.29}$$

Where: P_{fdp} = Frictional pressure loss down the drill pipe in psi
γ_G = Gel strength of the mud in lb/100 ft.^{2}
L_p = Length of the drill pipe in ft.
ID_p = Internal diameter of the drill pipe in in.

(2) When testing down the **casing annulus** only, determine the frictional pressure loss in psi:

$$P_{fa} = \frac{(\gamma_G)\left(L_{csg}\right)}{300\left(ID_{csg} - OD_p\right)} \tag{3.30}$$

Where: P_{fa} = Frictional pressure loss down the casing annulus in psi

γ_G = Gel strength of the mud in lb/100 ft.^{2}
L_{csg} = Length of the casing in ft.
ID_{csg} = Internal diameter of the casing in in.
OD_p = Outside diameter of the drill pipe in in.

(3) When testing down b**oth** the drill pipe and the casing annulus, determine the frictional pressure for each section and add those values together for the psi:

$$P_s = \left(P_{fdp}\right) + \left(P_{fa}\right) \tag{3.31}$$

Where: P_s = Frictional pressure loss for the system in psi

Step 4: Determine the slope for the minimum volume line (4), if the casing test line is **NOT** used:

(a) Determine the Compressibility of the mud:

$$C_m = \left(\left[3.0 \times 10^{-6}\right](W_{\%})\right) + \left(\left[5.0 \times 10^{-6}\right](O_{\%})\right) + \left(\left[0.2 \times 10^{-6}\right](S_{\%})\right) \tag{3.32}$$

Where: C_m = Compressibility of the mud
$W_{\%}$ = Water content of the mud in %
$O_{\%}$ = Oil content of the mud in %
$S_{\%}$ = Solids content of the mud in %

(b) Determine the volume of the mud system in bbl:

$$V_s = \left(\left(C_p\right)\left(L_p\right)\right) + \left((C_a)(L_a)\right) + \left((C_h)(L_h)\right) \tag{3.33}$$

Where: V_s = Volume of system in bbl
C_p = Capacity of drill pipe in bbl/ft.
L_p = Length of drill pipe in ft.
C_a = Capacity of annulus in bbl/ft.
L_a = Length of annulus (casing) in ft.
C_h = Capacity of open hole in bbl/ft.
L_h = Length of open hole in ft.

(c) Determine the slope of the minimum volume line (4) in psi/bbl:

$$S_{PVL} = \frac{1}{((C_m)(V_s))} \tag{3.34}$$

Where: S_{PVL} = Slope of the minimum volume line in psi/bbl

(d) Record the volume as V_{ML} where the minimum volume line (4) crosses the estimated LOT pressure line in bbl.

Where: V_{ML} = Minimum volume line intersection at LOT pressure line in bbl

Step 5: Determine the maximum volume line (5) in bbl:

$$V_{MXL} = 2(V_{ML}) \tag{3.35}$$

Where: V_{MXL} = Maximum volume line at LOT pressure in bbl

3.3.6 Prepare Data for Plotting on the Graph

Example:

Overburden	= 1.0 psi/ft.
Overburden safety factor	= 80%
Casing TVD (also length of annulus)	= 4000 ft.
Casing size	= 13⅜ in. (61 lb/ft., ID = 12.515 in.)
Annulus capacity	= 0.12787 bbl/ft.
Drill pipe	= 5.0 in. × 4.276 in. (19.5 lb/ft.)
Drill pipe length	= 4000 ft.
Drill pipe capacity	= 0.01776 bbl/ft.
Open hole size	= 12¼ in.
Open hole length	= 30 ft.
Open hole capacity	= 0.14578 bbl/ft.
Mud weight	= 10.0 ppg
Oil content	= 72%
Water content	= 18%
Solids content	= 10%
Oil/water ratio	= 80/20
Gel strength	= 15 lb/100 ft.^{2}
Maximum mud weight for next interval	= 12.0 ppg
Fracture gradient	= 14.0 ppg

Test performed down the drill pipe.

Step 1: Determine the maximum allowable pressure line (1) in psi:

$$P_{ML} = [(1.0)(0.80)(4000)] - [(MW)(0.052)(4000)] = 1120\,\text{psi}$$

Step 2: Determine the estimated leak-off test line (2) in psi:

$$P_{LOTL} = ((14.0 - 10.0)(0.052)(4000)) = 832\,\text{psi}$$

Step 3: Determine the minimum acceptable leak-off test pressure line (3) in psi:

(a) Determine the frictional pressure loss in the system in psi:

(1) If only using the **drill pipe** to conduct the test, determine the frictional pressure loss in psi:

$$P_{fdp} = \frac{(15)(4000)}{300(4.276)} = 46.8 \approx 47\,\text{psi}$$

Step 4: Determine the slope for the minimum volume line (4), if the casing test line is **NOT** used:

(a) Determine the compressibility of the mud:

$$C_m = \left(\left[3.0 \times 10^{-6}\right](0.18)\right) + \left(\left[5.0 \times 10^{-6}\right](0.72)\right) + \left(\left[0.2 \times 10^{-6}\right](0.10)\right) = 4.16 \times 10^{-6}$$

(b) Determine the volume of the mud system in bbl:

$$V_s = ((0.01776)(4000)) + ((0.12787)(4000)) + ((0.14578)(30)) = 586.9 \approx 587\,\text{bbl}$$

(c) Determine the slope of the minimum volume line (4) in psi/bbl:

$$S_{PVL} = \frac{1}{\left(\left(4.16 \times 10^{-6}\right)(587)\right)} = 409.5\,\text{psi/bbl}$$

This means that a 1000 psi casing test will require the following:

$$\text{Casing test} = \frac{1000}{409.5} = 2.44\,\text{bbl}$$

(d) Record the volume as V_{ML} where the minimum volume line (4) crosses the estimated LOT pressure line in bbl.

$$V_{ML} = 2.44\,\text{bbl@}1000\,\text{psi}$$

Step 5: Determine the maximum volume line (5) in bbl:

$$V_{MXL} = 2(2.44) = 4.88\,\text{bbl@}1000\,\text{psi}$$

3.3.7 Maximum Allowable Mud Weight from Leak-Off Test Data

$$MW_{MA} = \left(\frac{P_{LOT}}{(0.052)(TVD_{csg})}\right) + MW \tag{3.36}$$

Where: MW_{MA} = Maximum allowable mud weight in 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

$$MW_{MA} = \left(\frac{1040}{(0.052)(4000)}\right) + 10.0 = 15.0\,\text{ppg}$$

3.3.8 Maximum Allowable Shut-In Casing Pressure (MASICP) Also Called Maximum Allowable Shut-In Annular Pressure (MASP)

$$MASICP = (MW_{MA} - MW)(0.052)(TVD_{csg}) \tag{3.37}$$

Where: MASICP = Maximum allowable shut-in casing pressure in psi

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.

$$MASICP = (15.0 - 12.2)(0.052)(4000) = 582\,psi$$

3.4 Fracture Gradient

3.4.1 Fracture Gradient Determination: Surface Application

Method 1: Matthews and Kelly method

$$F = P/D + K_i \sigma/D \tag{3.38}$$

Where: F = Fracture gradient, psi/ft.
P = Formation pore pressure, psi
σ = Matrix stress at point of interest, psi
D = Depth at point of interest, TVD, ft.
K_i = matrix stress coefficient, dimensionless

Procedure:

1. Obtain formation pore pressure, P, from electric logs, density measurements, or mud logging personnel.
2. Assume 1.0 psi/ft. as overburden pressure (S) and calculate σ as follows:

$$\sigma = S - P \tag{3.39}$$

3. Determine the depth for determining K_i by:

$$D = \frac{\sigma}{0.535} \tag{3.40}$$

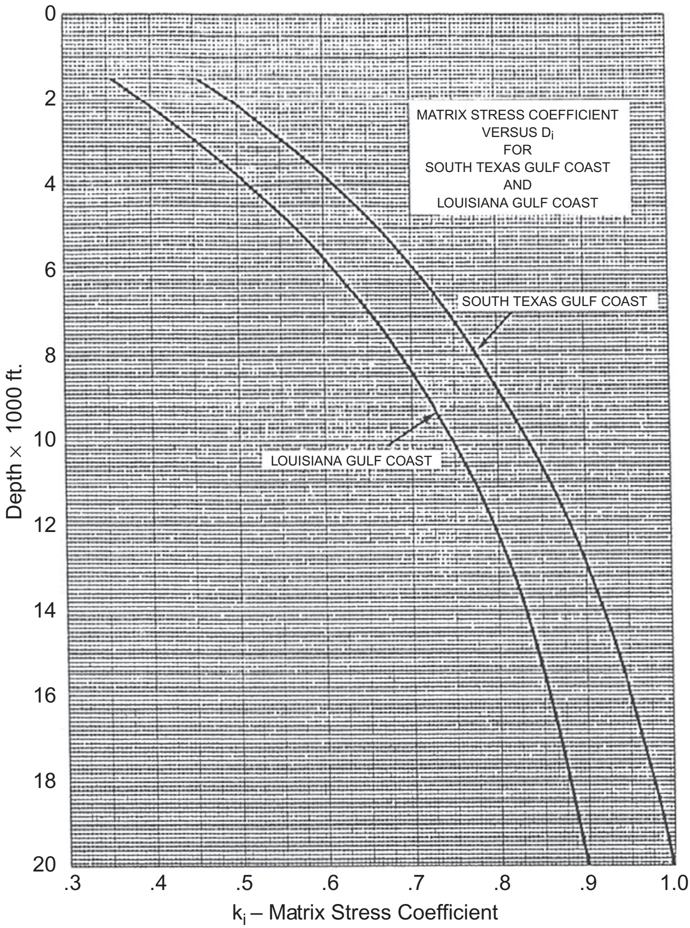

Figure 3.4 Matrix stress coefficient chart.

4. From matrix stress coefficient chart (Figure 3.4), determine K:
5. Determine fracture gradient, psi/ft.:

$$F = \frac{P}{D} + K_i \frac{\sigma}{D} \tag{3.41}$$

6. Determine fracture pressure, psi:

$$F(\text{psi}) = F \times D \tag{3.42}$$

7. Determine maximum mud density, ppg:

$$\text{MW(ppg)} = \frac{F}{0.052} \tag{3.43}$$

Example: Casing setting depth = 12,000 ft.
Formation pore pressure = 12.0 ppg
(Louisiana Gulf Coast)

1. $P = 12.0 \text{ ppg} \times 0.052 \times 12{,}000 \text{ ft.}$

   $P = 7488 \text{ psi}$
2. $\sigma = 12{,}000 - 7488 \text{ psi}$

   $\sigma = 4512 \text{ psi}$
3. $D = \dfrac{4512 \text{psi}}{0.535}$

   $D = 8434 \text{ ft.}$
4. From chart = $K_i = 0.79$
5. $F = \dfrac{7488}{12{,}000} \times 0.79 \times \dfrac{4512}{12{,}000}$

   $F = 0.624 \text{ psi/ft.} + 0.297 \text{ psi/ft.}$
   $F = 0.92 \text{ psi/ft.}$
6. Fracture pressure, psi = 0.92 psi/ft. × 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

$$F = \left(\frac{S}{D} - \frac{P_\text{f}}{D}\right) \times \left(\frac{\mu}{1-\mu}\right) + \left(\frac{P_\text{f}}{D}\right) \tag{3.44}$$

Where: S/D = Overburden gradient, psi/ft.
P_f/D = Formation pressure gradient at depth of interest, psi/ft.
μ = Poisson's ratio

Procedure:

1. Obtain overburden gradient from "overburden stress gradient chart (From Figure 3.5)."
2. Obtain formation pressure gradient from electric logs, density measurements, or logging operations.
3. Obtain Poisson's ratio from "Poisson's ratio chart."
4. Determine fracture gradient using above equation.
5. Determine fracture pressure, psi:

$$\text{psi} = F \times D \tag{3.45}$$

6. Determine maximum mud density, ppg:

$$\text{ppg} = \frac{F}{0.052} \tag{3.46}$$

Example: Casing setting depth = 12,000 ft.
Formation pore pressure = 12.0 ppg

1. Determine S/D from chart = depth = 12,000 ft.

$$S/D = 0.96\,\text{psi/ft.}$$

2. $P_f/D = 12.0\text{ ppg} \times 0.052 = 0.624$ psi/ft.
3. Poisson's ratio from chart = 0.47
4. Determine fracture gradient:

$$F = (0.96 - 0.6243)\left(\frac{0.47}{1-0.47}\right) + 0.624$$
$$F = 0.336 \times 0.88679 + 0.624$$
$$F = 0.29796 + 0.624$$
$$F = 0.92\,\text{psi/ft.}$$

5. Determine fracture pressure:

$$\text{psi} = 0.92\,\text{psi/ft.} \times 12{,}000\,\text{ft.}$$
$$\text{psi} = 11{,}040$$

6. Determine maximum mud density, ppg:

$$\text{ppg} = \frac{0.92\,\text{psi/ft.}}{0.052}$$
$$\text{ppg} = 17.69$$

3.4.2 Fracture Gradient Determination – Subsea Applications

During offshore deepwater drilling operations, it is necessary to correct the calculated fracture gradient for the effect of water depth and flowline 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 mudline = 4000 ft.

Procedure:

1. Convert water to equivalent land area, ft.:

   (a) Determine the bydrostatic pressure of the seawater:

   $$HP_{sw} = 8.9\,\text{ppg} \times 0.052 \times 2000\,\text{ft.}$$
   $$HP_{sw} = 926\,\text{psi}$$

   (b) From Eaton's overburden stress chart, determine the overburden stress gradient from mean seal level to casing setting depth:
   From Figure 3.5: 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.

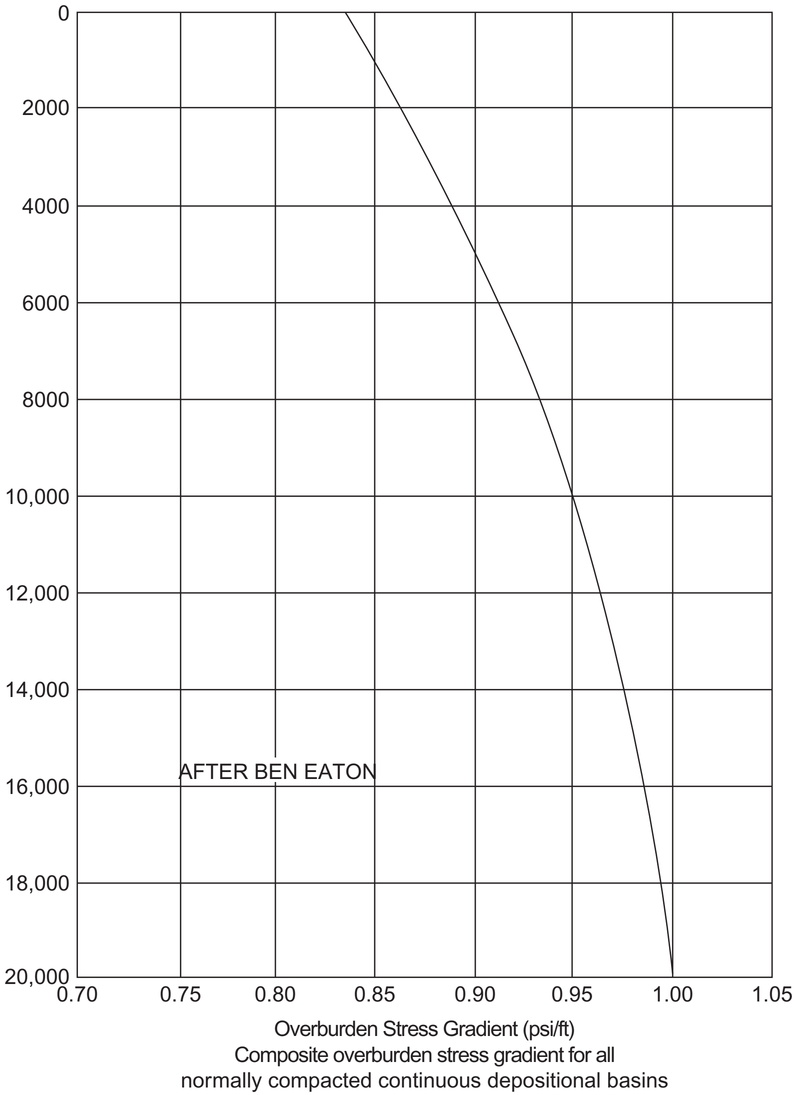

Figure 3.5 Eaton's overburden stress chart.

(c) Determine equivalent depth for an onshore land well, ft.:

$$\text{Equivalent feet} = \frac{926\,\text{psi}}{0.92\,\text{psi/ft.}}$$
$$\text{Equivalent feet} = 1006$$

2. Determine depth for fracture gradient determination:

Depth, ft. = 4000 + 1006 ft.
Depth = 5006 ft.

3. Using Eaton's fracture gradient chart (Figure 3.6), determine the fracture gradient at a depth of 5006 ft.:

From Figure 3.6: 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:

$$\text{psi} = 14.7\,\text{ppg} \times 0.052 \times 5006\,\text{ft.}$$
$$\text{psi} = 3827$$

5. Convert the fracture gradient relative to the flowline:

$$F_c = 3827\,\text{psi} \div 0.052 + 6100\,\text{ft.}$$
$$F_c = 12.06\,\text{ppg}$$

where F_c is the fracture gradient, corrected for water depth, and air gap.

3.5 Kick Tolerance

Definitions: The kick tolerance intensity (KT_I) is the amount of kick in equivalent mud weight that can be taken with the current mud weight in use at the time of the kick. The kick tolerance volume (KT_V) is the maximum kick volume for a specific kick intensity that can be taken when circulating out and not exceed the formation breakdown pressure (fracture gradient) at the casing shoe.

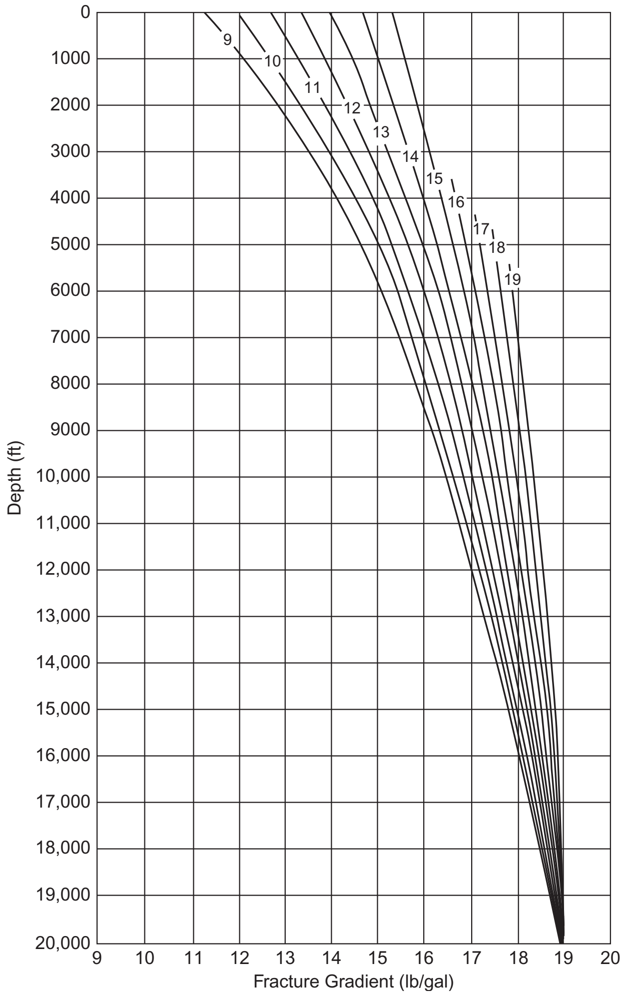

Figure 3.6 Eaton's fracture gradient chart.

3.5.1 Kick Tolerance Intensity

Formula 1: Determine the kick tolerance intensity at any vertical depth in ppg:

$$KT_I = (FG - MW)\left(\frac{TVD_{csg}}{TVD_{TD}}\right) \tag{3.47}$$

Where: KT_I = Kick tolerance intensity in ppg
FG = Fracture gradient at the casing shoe in ppg
MW = Mud weight in use at total vertical depth in ppg

Example: Determine the kick tolerance intensity using the following data:

Data:

Maximum allowable mud weight	= 13.0 ppg (from leak-off test data)
Mud weight at TVD	= 12.0 ppg
Casing shoe TVD	= 5000 ft.
Well depth TVD	= 10,000 ft.

$$KT_I = (13.0 - 12.0)\left(\frac{5000}{10,000}\right) = 0.50\,\text{ppg}$$

Formula 2: Determine the maximum surface pressure in psi:

$$P_{MS} = (KT)(0.052)(TVD_{TD}) \tag{3.48}$$

Where: P_{MS} = Surface pressure in psi

Example: Determine the maximum surface pressure in psi:

$$P_{MS} = (0.5)(0.052)(10,000) = 260\,\text{psi}$$

Formula 3: Determine the maximum formation pressure that can be controlled when shutting-in a well in psi:

$$P_{MF} = (KT_I + MW)(0.052)(TVD_{TD}) \tag{3.49}$$

Where: P_{MF} = Maximum formation pressure in psi

Example: Determine the maximum formation pressure that can be controlled when shutting-in a well, using the following data:

Kick tolerance intensity	= 0.5 ppg
Mud weight	= 12.0 ppg
True vertical depth	= 10,000 ft.

$$P_{MF} = (0.5 + 12.0)(0.052)(10,000) = 6500\,\text{psi}$$

Formula 4: Determine the maximum influx length that can be taken with the gas at the casing shoe without breakdown in ft.:

$$L_I = \frac{\text{MASICP}}{(G_M - G_I)} \tag{3.50}$$

Where: L_I = Length of influx in ft.
G_M = Gradient of mud in psi/ft.
G_I = Gradient of influx in psi/ft.

Example: Determine the influx length necessary to equal the maximum allowable shut-in surface pressure in ft.:

Data: MASICP at 10,000 ft. = 260 psi
Mud gradient ((12.0 ppg)(0.052)) = 0.624 psi/ft.
Gradient of influx = 0.12 psi/ft.
Capacity of annulus = 0.1215 (12¼ in. × 5.0 in.)

$$L_I = \frac{260}{(0.624 - 0.12)} = 515.9 \approx 516\,\text{ft.}$$

3.5.2 Kick Tolerance Volume

Formula 1: Determine the maximum influx volume to equal maximum allowable shut-in surface pressure at the casing shoe in bbl:

$$\text{KT}_V = \frac{[((\text{FG})(0.052)(\text{TVD}_{csg}))(L_I)(C_a)]}{[(\text{MW})(0.052)(\text{TVD}_{TD})]} \tag{3.51}$$

Where: KT_V = Volume of kick at the casing shoe in bbl
C_a = Capacity of the annulus with the drill pipe in bbl

$$\text{KT}_V = \frac{[((13.0)(0.052)(5000))(516)(0.1215)]}{[(12.0)(0.052)(10,000)]} = 33.95 \approx 34.0\,\text{bbl}$$

3.5.3 Summary

TVD_{TD} (ft.)	MW (ppg)	MASICP (psi)	KT (ppg)	Influx Length @ Casing Shoe (ft.)	Kick Volume (bbl)
5000	11.0	520	2.0	1150.0	165.1
7500	11.5	390	1.0	815.8	74.7
10,000	12.0	260	0.5	515.9	34.0

3.6 Kick Analysis

3.6.1 Formation Pressure (FP) with the Well Shut-In on a Kick

$$P_F = \text{SIDPP} + ((\text{MW})(0.052)(\text{TVD}_{\text{TD}})) \tag{3.52}$$

Where: P_F = Formation pressure in psi

Example: Determine the formation pressure using the following data:

Shut-in drill pipe pressure = 500 psi
Mud weight = 9.6 ppg
True vertical depth = 10,000 ft.

$$P_F = 500 + ((9.6)(0.052)(10,000))$$
$$P_F = 500 + 4992 = 5492\,\text{psi}$$

3.6.2 Bottomhole Pressure (BHP) with the Well Shut-In on a Kick

$$\text{BHP} = \text{SIDPP} + ((\text{MW})(0.052)(\text{TVD}_{\text{TD}})) \tag{3.53}$$

Where: BHP = Bottomhole pressure in psi

Example: Determine the bottomhole pressure (BHP) with the well shut-in on a kick:

Shut-in drill pipe pressure = 500 psi
Mud weight = 10.0 ppg
True vertical depth = 10,000 ft.

$$\text{BHP} = 500 + ((10.0)(0.052)(10,000))$$
$$\text{BHP} = 500 + 5200 = 5700\ \text{psi}$$

3.6.3 Shut-In Drill Pipe Pressure (SIDPP)

$$\text{SIDPP} = P_F - ((\text{MW})(0.052)(\text{TVD}_{\text{TD}})) \quad (3.54)$$

Where: SIDPP = Shut-in drill pipe pressure in psi

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.

$$\text{SIDPP} = 12,480 - ((15.0)(0.052)(15,000))$$
$$\text{SIDPP} = 12,480 - 11,700 = 780\,\text{psi}$$

3.6.4 Shut-In Casing Pressure (SICP)

$$\text{SCIP} = P_F - [((\text{MW})(0.052)(\text{TVD}_{\text{TD}})) + ((G_I)(L_I))] \quad (3.55)$$

Where: SCIP = Shut-in casing pressure in psi
G_I = Gradient of influx in psi/ft.
L_I = Length of influx in ft.

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.

$$\text{SCIP} = 12,480 - [((15.0)(0.052)(14,600)) + ((0.12)(400))]$$
$$\text{SCIP} = 12,480 - [(11,388) + (48)] = 1044\,\text{psi}$$

3.6.5 Length of Influx in ft.

$$L_I = \frac{V_{pg}}{C_a} \quad (3.56)$$

Where: L_I = Length of influx in ft.

V_{pg} = Volume of pit gain in bbl

Example 1: Determine the length of the influx in feet using the following data:

Pit gain = 20 bbl

Annular capacity – DC/OH = 0.02914 bbl/ft. ($D_h = 8½$ in.; $D_p = 6½$ in.)

$$L_I = \frac{20}{0.02914} = 686 \text{ ft.}$$

Example 2: Determine the length of the influx in feet using the following data:

Pit gain	= 20 bbl
Hole size	= 8½ in.
Drill collar OD	= 6½ in.
Drill collar length	= 450 ft.
Drill pipe OD	= 5.0 in.

Step 1: Determine annular capacity for DC/OH in bbl/ft.:

$$C_{DC/OH} = \frac{(8.5^2) - (6.5^2)}{1029.4} = 0.02914 \text{ bbl/ft.}$$

Step 2: Determine the number of barrels opposite the drill collars:

$$V_{DC/OH} = (450)(0.02914) = 13.1 \text{ bbl}$$

Step 3: Determine annular capacity opposite the drill pipe/OH in bbl/ft.:

$$C_{DP/OH} = \frac{(8.5^2) - (5.0^2)}{1029.4} = 0.0459 \text{ bbl/ft.}$$

Step 4: Determine barrels of influx opposite drill pipe:

$$V_I = V_{pg} - V_{DC/OH} \tag{3.57}$$

Where: V_I = Volume of pit gain in bbl

$$V_I = 20 - 13.1 = 6.9\,\text{bbl}$$

Step 5: Determine length of influx opposite drill pipe in ft.:

$$L_I = \frac{6.9}{0.0459} = 150\,\text{ft.}$$

Step 6: Determine the total height of the influx in ft.:

$$L_I = 450 + 150 = 600\,\text{ft.}$$

3.6.6 Estimated Type of Influx

$$W_K = \text{MW} - \left(\frac{\text{SCIP} - \text{SIDPP}}{(L_I)(0.052)}\right) \qquad (3.58)$$

Where: W_K = Weight of influx in ppg

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 in ppg:

Shut-in casing pressure = 1044 psi
Shut-in drill pipe pressure = 780 psi
Length of influx = 400 ft.
Mud weight = 15.0 ppg

$$W_K = 15.0 - \left(\frac{1044 - 780}{(400)(0.052)}\right)$$

$$W_K = 15.0 - \left(\frac{264}{20.8}\right) = 2.31\,\text{ppg}$$

Therefore, the influx is probably "**gas**."

3.7 Gas Cut Mud Weight Measurement Calculations

3.7.1 Determine the Original Mud Weight of a Gas Cut Mud at the Flowline

Procedure:

(1) Dilute a 250 ml sample of the gas cut mud with an equal amount of water or base oil.
(2) Be sure to keep the mud solids in suspension by stirring the slurry as the sample is poured into the mud balance cup.
(3) Measure the density of the slurry and use the following equation to determine the original mud weight in ppg:

$$MW_O = \frac{(MW_{GC})(MW_D)}{((MW_{GC} + MW_{BL}) - MW_D)} \tag{3.59}$$

Where: MW_O = Original uncut mud weight in ppg
MW_{GC} = Mud weight of gas cut mud in ppg
MW_D = Mud weight of diluted slurry in ppg
MW_{BL} = Mud weight of base liquid used to dilute the gas cut mud in ppg

(4) Determine the gas content of the mud in percent:

$$C_{gas} = 100\left(\frac{(MW_O - MW_C)}{MW_O}\right) \tag{3.60}$$

Where: C_{gas} = Gas content in cut mud in %

Example: Determine the original mud weight in ppg and the percent of gas in the mud.

Data: Mud type = Water base mud
MW_C = 9.2 ppg
MW_D = 10.0 ppg
MW_{BL} = 8.34 ppg

$$\mathrm{MW_O} = \frac{(9.2)(10.0)}{((9.0 + 8.34) - 10.0)} = 12.5\,\mathrm{ppg}$$

$$C_{\mathrm{gas}} = 100\left(\frac{(12.5 - 9.2)}{12.5}\right) = 26.4\%$$

3.7.2 Determine the Reduction in the Mud Weight at the Flowline When a Gas Formation Is Drilled with No Kick

Step 1: Determine the volume of cuttings generated by the ROP in ft.^{3}/h:

$$V_{\mathrm{C}} = \left[\left(5.45 \times 10^{-3}\right)\left(D_{\mathrm{h}}^{2}\right)\right](\mathrm{ROP}) \tag{3.61}$$

Where: V_{C} = Volume of cuttings from the ROP in ft.^{3}/h
D_{h} = Diameter of the hole in in. (bit size if amount of washout is not known)
ROP = Rate of penetration in ft./h

Step 2: Determine the volume of the gas in the formation pores ft.^{3}/ft.^{3}:

$$V_{\mathrm{Gf}} = (\varnothing_{\mathrm{f}})(1 - W_{\mathrm{S}}) \tag{3.62}$$

Where: V_{Gf} = Volume of gas in the formation pores in ft.^{3}/ft.^{3}
$\varnothing_{\mathrm{f}}$ = Formation porosity in %
W_{S} = Water saturation in %

Step 3: Determine the volume of gas in the cuttings at the bottom of the hole in ft.^{3}/h:

$$V_{\mathrm{GC}} = (V_{\mathrm{C}})(V_{\mathrm{Gf}}) \tag{3.63}$$

Where: V_{Gf} = Volume of gas in the cuttings in ft.^{3}/h

Step 4: Determine the bottomhole pressure in psi:

$$P_{BH} = (MW)(0.052)(TVD_{TD}) \tag{3.64}$$

Where: P_{BH} = Bottomhole pressure of gas in psi
MW = Mud weight in ppg
TVD_{TD} = Total vertical depth in ft.

Step 5: Determine the volume of the gas at the flowline in ft.^{3}/h:

$$V_{GFL} = (0.0292)(P_{BH}) \tag{3.65}$$

Where: V_{GFL} = Volume of gas at the flowline in gpm

Step 6: Determine the mud weight of the gas cut mud at the flowline in ppg:

$$MW_C = (MW)\left(\frac{Q}{(Q) + (V_{GFL})}\right) \tag{3.66}$$

Where: MW_C = Mud weight of gas cut mud at the flowline in ppg
Q = Pump output in gpm

Example: Determine the mud weight of gas cut mud at the flowline with the following:

Data: Depth of hole = 10,000 ft.
Bit size = 12¼ in.
ROP = 50 ft./h
Pump output = 650 gpm
Formation porosity = 18%
Water saturation = 25%
Formation pressure = 12.0 ppg
Mud weight = 12.5 ppg

Step 1: Determine the volume of cuttings generated by the ROP in ft.^{3}/h:

$$V_{C} = \left[\left(5.45 \times 10^{-3}\right)\left(12.25^{2}\right)\right](50) = 40.9\,\text{ft.}^{3}/\text{h}$$

Step 2: Determine the volume of the gas in the formation pores ft.^{3}/ft.^{3}:

$$V_{Gf} = (0.18)(1 - 0.25) = 0.135\,\text{ft.}^{3}/\text{ft.}^{3}$$

Step 3: Determine the volume of gas in the cuttings at the bottom of the hole in ft.^{3}/h:

$$V_{GC} = (40.9)(0.135) = 5.52\,\text{ft.}^{3}/\text{h}$$

Step 4: Determine the bottomhole pressure in psi:

$$P_{BH} = (12.0)(0.052)(10,000) = 6240\,\text{psi}$$

Step 5: Determine the volume of the gas at the flowline in gpm:

$$V_{GFL} = (0.0292)(6240) = 182.2\,\text{gpm}$$

Step 6: Determine the mud weight of the gas cut mud at the flowline in ppg:

$$\text{MW}_{C} = (12.5)\left(\frac{650}{(650) + (182.2)}\right) = 9.76 \approx 9.8\,\text{ppg}$$

3.8 Gas Migration in a Shut-In Well

3.8.1 Gas Migration

Formula 1: Estimate the rate of gas migration in ft./h:

$$R_{GM} = (12)\left(e^{(-0.37)(\text{MW})}\right)(3600) \tag{3.67}$$

Where: RGM = Rate of gas migration in ft./h
12 = Constant
e = Natural logarithm equal to 2.718 281 828
3600 = Conversion from seconds to hours

Example: Determine the estimated rate of gas migration using a mud weight of 11.0 ppg:

$$R_{GM} = (12)\left(2.718^{(-0.37)(11.0)}\right)(3600)$$
$$R_{GM} = (12)\left(2.718^{(-4.07)}\right)(3600)$$
$$R_{GM} = (12)(0.01708)(3600) = 737.8 \approx 738\,\text{ft./h}$$

Formula 2: Determining the ***actual*** rate of gas migration after a well has been shut-in on a kick in ft./h:

$$R_{GM} = \frac{P_{Icsg}}{MW_G} \tag{3.68}$$

Where: R_{GM} = Rate of gas migration in ft./h
P_{Icsg} = Increase of casing pressure in psi/h
MW_G = Pressure gradient of mud weight in psi/ft.

Example: Determine the rate of gas migration with the following data:

Stabilized shut-in casing pressure	= 500 psi
SICP (after 1 h)	= 700 psi
Mud weight	= 12.0 ppg
Pressure gradient for 12.0 ppg mud	= 0.624 psi/ft.

$$R_{GM} = \frac{200}{0.624} = 320.5\,\text{ft./h}$$

3.8.2 Metric Calculation

$$R_{GM} = \frac{P_{Icsg}}{(MW)(0.0981)} \tag{3.69}$$

Where: R_{GM} = Rate of gas migration in m/h
P_{Icsg} = Increase of casing pressure in bar/h
MW = Mud weight in kg/l

3.8.3 S.I. Units Calculation

$$R_{GM} = \frac{P_{Icsg}(102)}{(MW)} \tag{3.70}$$

Where: R_{GM} = Rate of gas migration in m/h
P_{Icsg} = Increase of casing pressure in kPa/h
MW = Mud weight in kg/m^3

3.9 Hydrostatic Pressure Decrease at TD Caused by Gas-Cut Mud

3.9.1 Hydrostatic Pressure

Method 1: Determine the hydrostatic pressure decrease caused by gas-cut mud in psi.

$$P_{HD} = \frac{100\left(MW - MW_{gc}\right)}{MW_{gc}} \tag{3.71}$$

Where: P_{HD} = Hydrostatic pressure decrease in psi
MW = Uncut mud weight in ppg
MW_{gc} = Gas-cut mud weight in ppg

Example: Determine the hydrostatic pressure decrease caused by gas-cut mud using the following data:

Weight of uncut mud = 18.0 ppg
Weight of gas-cut mud = 9.0 ppg

$$HP_D = \frac{100(18.0 - 9.0)}{9.0} = 100\,\text{psi}$$

Method 2: Determine the hydrostatic pressure decrease caused by gas-cut mud in psi.

$$\text{HP}_\text{D} = \left(\frac{\text{MW}_\text{G}}{C_\text{a}}\right) V_\text{pg} \tag{3.72}$$

Where: H_{PD} = Hydrostatic pressure decrease in psi
MW_G = Mud weight gradient in psi/ft.
C_a = Capacity of the annular in bbl/ft.
V_{gc} = Pit gain in bbl

Example: MW_G = 0.624 psi/ft.
C_a = 0.0459 bbl/ft. (D_h = 8½ in.; D_p = 5.0 in.)
V_{gc} = 20 bbl

$$\text{HP}_\text{D} = \left(\frac{0.624}{0.0459}\right) 20 = 271.9\,\text{psi}$$

3.9.2 Maximum Surface Pressure from a Gas Kick in a Water-Base Mud

$$P_\text{MS} = (0.2)\sqrt{\frac{(P_\text{F})(V_\text{PG})(\text{KWM})}{C_\text{a}}} \tag{3.73}$$

Where: P_{MS} = Maximum surface pressure resulting from a gas kick in a water-base mud in psi
P_F = Formation pressure in psi
V_{PG} = Pit gain in bbl
KWM = Kill weight mud in ppg
C_a = annular capacity in bbl/ft

Example: Formation pressure = 12,480 psi
Pit gain = 20 bbl
KWM = 16.0 ppg
Annular capacity = 0.0505 bbl/ft. (D_h = 8½ in. × D_p = 4½ in.)

$$P_{MS} = (0.2)\sqrt{\frac{(12,480)(20)(16.0)}{0.0505}}$$
$$P_{MS} = (0.2)\sqrt{79,081,188}$$
$$P_{MS} = (0.2)8892.8 = 1779\,\text{psi}$$

3.9.3 Maximum Pit Gain from Gas Kick in a Water-Base Mud

$$V_{MPG} = (4)\sqrt{\frac{(P_F)(V_{OPG})(C_a)}{\text{KWM}}} \tag{3.74}$$

Where: V_{MPG} = Maximum pit gain volume in bbl
V_{OPG} = Original pit gain volume in bbl

Example: Formation pressure = 12,480 psi
Pit gain = 20 bbl
KWM = 16.0 ppg
Annular capacity = 0.0505 bbl/ft. (D_h = 8½ in. × D_p = 4½ in.)

$$V_{MPG} = (4)\sqrt{\frac{(12,480)(20)(0.0505)}{16.0}}$$
$$V_{MPG} = (4)\sqrt{787.8}$$
$$V_{MPG} = (4)(28.068) = 112.3\,\text{bbl}$$

3.10 Maximum Pressures When Circulating Out a Kick (Moore Equations)

3.10.1 Maximum Pressure Calculations

Step 1: Determine formation pressure in psi:

$$P_F = \text{SIDP} + [(\text{MW})(0.052)(\text{TVD})] \tag{3.75}$$

Where: P_F = Formation pressure in psi

Step 2: Determine the length of the influx in ft.:

$$L_I = \frac{V_{pg}}{C_a} \tag{3.76}$$

Where: L_I = Length of influx in ft.
V_{pg} = Volume of pit gain in bbl
C_a = Capacity of annulus in bbl/ft.

Step 3: Determine pressure exerted by the influx in psi:

$$P_I = P_F - [\mathrm{MW_G}(\mathrm{TVD} - L_{DC}) + \mathrm{SICP}] \tag{3.77}$$

Where: P_I = Pressure exerted by the influx in psi
$\mathrm{MW_G}$ = Mud weight gradient in psi/ft.
TVD = Total vertical depth in ft.
L_{DC} = Length of drill collars in ft.
SICP = Shut-in casing pressure in psi

Step 4: Determine pressure gradient of influx in psi/ft.:

$$P_{GI} = \frac{P_I}{L_I} \tag{3.78}$$

Where: P_{GI} = Pressure gradient of influx in psi/ft.

Step 5: Determine temperature in Rankin (°R) at depth of interest:

$$T_{Di} = 70 + [(0.012)(\mathrm{TVD})] + 460 \tag{3.79}$$

Where: T_{Di} = Temperature at depth of interest in °R
70 = Ambient temperature in °F
0.012 = Temperature in °F/ft.
TVD = Total vertical depth in ft.
460 = Constant

Step 6: Determine the pressure at the top of the influx bubble (A) for an unweighted mud in psi:

$$A = P_F - [MW_G(TVD - L_{DC}) + P_I] \tag{3.80}$$

Where: A = Pressure at the top of the gas bubble for an un-weighted mud in psi

Step 7: Determine pressure at depth of interest in psi:

$$P_{Di} = \frac{A}{2} + \left(\frac{A^2}{4} + \frac{(MW_G)(P_F)(Z)(T_{csg})(L_I)}{(Z)(T_{TVD})}\right)^{1/2} \tag{3.81}$$

Where: P_{Di} = Pressure at depth of interest in psi
Z = Super compressibility factor (1)
T_{csg} = Rankin temperature at casing shoe in °R
T_{TVD} = Rankin temperature at total vertical depth in °R

Step 8: Determine kill weight mud in ppg:

$$KWM = \frac{SIDPP}{(0.052)(TVD)} + MW \tag{3.82}$$

Where: KWM = Kill mud weight in ppg

Step 9: Determine gradient of kill weight mud in psi/ft.:

$$KWM_G = KWM(0.052) \tag{3.83}$$

Where: KWM_G = Kill mud weight gradient in psi/ft.

Step 10: Determine the internal volume of the components of the drill string in bbl:

$$V_P = (L_P)(C_P) \tag{3.84}$$

Where: V_P = Volume of pipe in bbl
L_P = Length of pipe in ft.
C_P = Capacity of pipe in bbl/ft.

Step 11: Determine length that the drill string volume will occupy in the annulus in ft.:

$$L_{DSV} = \frac{V_P}{C_a} \tag{3.85}$$

Where: L_{DSV} = Length of drill string volume occupies in the annulus in ft.
V_P = Pipe volume in bbl
C_a = Capacity of the annulus in bbl/ft.

Step 12: Determine the length of the influx around the drill pipe in ft.:

$$L_{IDP} = \frac{V_{pg}}{C_{aDP}} \tag{3.86}$$

Where: L_{IDP} = Length of influx around drill pipe in ft.
C_{aDP} = Capacity of annulus around drill pipe in bbl/ft.

Step 13: Determine the pressure of the influx around the drill pipe in psi:

$$P_{IDP} = (P_{GI})(L_{IDP}) \tag{3.87}$$

Where: P_{IDP} = Pressure of influx around drill pipe in psi

Step 14: Determine the pressure at the top of the influx bubble (A_W) for a weighted mud in psi:

$$A_W = P_F - \left[\left((\text{KWM}_G)\left(\text{TVD} - L_{csg}\right)\right) + P_{IDP}\right] + \left[(L_{DSV})(\text{KWM}_G - \text{MW}_G)\right] \tag{3.88}$$

Where: A_W = Pressure at the top of the gas bubble for a weighted mud in psi
L_{csg} = Depth of casing shoe in ft.

Example: Assumed conditions:

Well depth	= 10,000 ft.
Surface casing	= 9⅝ in. @ 2500 ft.
Casing ID	= 8.921 in.
Casing capacity	= 0.077 bbl/ft.
Hole size	= 8½ in.
Drill pipe	= 4½ in., 16.6 1b/ft.
Drill collar OD	= 6¼ in.
Drill collar length	= 625 ft.
Mud weight	= 9.6 ppg
Fracture gradient @ 2500 ft.	= 0.73 psi/ft. (14.04 ppg)

Mud Volumes:

8½ in. hole	= 0.07 bbl/ft.
8½ in. hole × 4½ in. drill pipe	= 0.05 bbl/ft.
8½ in. hole × 6¼ in. drill collars	= 0.032 bbl/ft.
8.921 in. casing × 4½ in. drill pipe	= 0.057 bbl/ft.
Drill pipe capacity	= 0.014 bbl/ft.
Drill collar capacity	= 0.007 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:

A. Maximum pressure at the casing shoe with the drillers method.
B. Maximum pressure at the surface with the drillers method.

C. Maximum pressure at the casing shoe with the wait and weight method.
D. Maximum pressure at the surface with the wait and weight method.

A. Determine the maximum pressure at the shoe with the drillers method.

Step 1: Determine the formation pressure in psi:

$$P_F = 260 + [(9.6)(0.052)(10,000)]$$
$$P_F = 260 + 4992 = 5252 \text{ psi}$$

Step 2: Determine the length of influx at TD in ft.:

$$L_I = \frac{20}{0.032} = 625 \text{ ft.}$$

Step 3: Determine pressure exerted by the influx at TVD in psi:

$$P_I = 5252 - [0.4992(10,000 - 625) + 500]$$
$$P_I = 5252 - 5180 = 72 \text{ psi}$$

Step 4: Determine pressure gradient of influx at TVD in psi/ft.:

$$P_{GI} = \frac{72}{625} = 0.1152 \text{ psi/ft.}$$

Step 5: Determine the length of the influx around the drill pipe in ft.:

$$L_{IDP} = \frac{20}{0.05} = 400 \text{ ft.}$$

Step 6: Determine the pressure of the influx around the drill pipe in psi:

$$P_{IDP} = (0.1152)(400) = 46\,\text{psi}$$

Step 7: Determine temperature in Rankin (°R) at the TVD:

$$T_{10,000} = 70 + [(0.012)(10,000)] + 460$$
$$T_{10,000} = 70 + 120 + 460 = 650\ °\text{R}$$

Step 8: Determine temperature in Rankin (°R) at the casing shoe:

$$T_{2500} = 70 + [(0.012)(2500)] + 460$$
$$T_{2500} = 70 + 30 + 460 = 560\ °\text{R}$$

Step 9: Determine the pressure at the top of the influx bubble

$$A = 5252 - [0.4992(10,000 - 2500) + 46]$$
$$A = 5252 - 3790 = 1462\,\text{psi}$$

Step 10: Determine maximum pressure at shoe with drillers method:

$$P_{2500} = \frac{1462}{2} + \left(\frac{1462^2}{4} + \frac{(0.4992)(5252)(1.0)(560)(400)}{(1.0)(650)}\right)^{1/2}$$
$$P_{2500} = 731 + (531,361 + 903,512)^{1/2}$$
$$P_{2500} = 731 + 1199 = 1930\,\text{psi}$$

B. Determine the maximum pressure at the surface with the drillers method.

Step 1: Determine A:

$$A = 5252 - [0.4992(10,000) + 46]$$
$$A = 5252 - [4992 + 46] = 214\,\text{psi}$$

Step 2: Determine maximum pressure at surface with drillers method:

$$P_{\text{Surface}} = \frac{214}{2} + \left(\frac{214^2}{4} + \frac{(0.4992)(5252)(1.0)(530)(400)}{(1.0)(650)}\right)^{1/2}$$

$$P_{\text{Surface}} = 107 + (11{,}449 + 855{,}109)^{1/2}$$

$$P_{\text{Surface}} = 107 + 931 = 1038\,\text{psi}$$

Note: The temperature in the numerator is calculated with the depth at 0 as follows:

$$T_{\text{Surface}} = 70 + 460 = 530\ {}^{\circ}\text{R}.$$

C. Determine the maximum pressure at the casing shoe with the wait and weight method.

Step 1: Determine the kill weight mud in ppg:

$$\text{KWM} = \frac{260}{(0.052)(10{,}000)} + 9.6 = 10.1\,\text{ppg}$$

Step 2: Determine gradient of kill weight mud in psi/ft.:

$$\text{KWM}_{\text{G}} = 10.1(0.052) = 0.5252\,\text{psi/ft.}$$

Step 3: Determine internal volume of the drill string:

$$V_{\text{DP}} = (0.014)(10{,}000 - 625) = 131.25\,\text{bbl}$$
$$V_{\text{DC}} = (0.007)(625) = 4.375\,\text{bbl}$$
$$V_{\text{DS}} = (131.25) + (4.375) = 135.625\,\text{bbl}$$

Step 4: Determine length that the drill string volume will occupy in the annulus in ft.:

$$L_{\text{DSV}} = \frac{135.625}{0.05} = 2712.5\,\text{ft.}$$

Step 5: Determine the pressure at the top of the influx bubble (A_W) for a weighted mud in psi:

$$A_W = 5252 - [((0.5252)(10{,}000 - 2500)) + 46] + [(2715.2)(0.5252 - 0.4992)]$$

$$A_W = 5252 - [3939 + 46] + 70.6$$

$$A_W = 1267 + 70.6 = 1337.5\,\text{psi}$$

Step 6: Determine the maximum pressure at shoe with wait and weight method in psi:

$$P_{2500} = \frac{1337.5}{2} + \left(\frac{1337.5^2}{4} + \frac{(0.5252)(5252)(1.0)(560)(400)}{(1.0)(650)}\right)^{1/2}$$

$$P_{2500} = 668.75 + (447{,}226 + 950{,}570)^{1/2}$$

$$P_{2500} = 668.75 + 1182 = 1850.75 \approx 1851\,\text{psi}$$

D. Determine the maximum pressure at the surface with the wait and weight method.

Step 1: Determine A:

$$A = 5252 - [((0.5252)(10{,}000)) + 46] + [(2715.2)(0.5252 - 0.4992)]$$

$$A = 5252 - [5252 + 46] + 70.6$$

$$A = -46 + 70.6 = 24.5\,\text{psi}$$

Step 2: Determine the maximum pressure at surface with the wait and weight method in psi:

$$P_{\text{Surface}} = \frac{24.5}{2} + \left(\frac{24.5^2}{4} + \frac{(0.5252)(5252)(1.0)(530)(400)}{(1.0)(650)}\right)^{1/2}$$

$$P_{\text{Surface}} = 12.3 + (150 + 899{,}647)^{1/2}$$

$$P_{\text{Surface}} = 12.3 + 948.6 = 960.9 \approx 961\,\text{psi}$$

3.10.2 Summary of Maximum Pressures When Circulating Out a Kick (Moore Equations)

Case	Method	Location	Pressure (psi)
A	Drillers	Casing shoe	1930
B	Drillers	Surface	1038
C	Wait and weight	Casing shoe	1851
D	Wait and weight	Surface	961

3.11 Gas Flow into the Wellbore

Flow rate into the wellbore increases as wellbore depth through a gas sand increases:

$$Q = \frac{(0.007)(k)(P_d)(L)}{(\mu)\left(\ln\left(\frac{R_e}{R_w}\right)\right)(1440)} \tag{3.89}$$

Where: Q = Flow rate in bbl/min
k = Permeability in millidarcys (md)
P_d = Pressure differential in psi
L = Length of section open to wellbore in ft.
μ = Viscosity of intruding gas in centipoise (cP)
R_e = Radius of drainage in ft.
R_w = Radius of wellbore in ft.

Example: k = 200 md
P_d = 624 psi
L = 20 ft.
μ = 0.3 cP
$\ln\left(\frac{R_e}{R_w}\right) = 2.0$

$$Q = \frac{(0.007)(200)(624)(20)}{(0.3)(2.0)(1440)}$$

$$Q = \frac{17472}{864} = 20.2\,\text{bbl/min}$$

Therefore: If 1 min is required to shut-in the well, a pit gain of 20.2 bbl occurs in addition to the gain incurred while drilling the 20-ft. section.

3.12 Pressure Analysis

3.12.1 Gas Expansion Equations

Formula 1: Basic gas laws:

$$\frac{(P_1)(V_1)}{(T_1)} = \frac{(P_2)(V_2)}{(T_2)} \tag{3.90}$$

Where: P_1 = Formation pressure in psi
P_2 = Hydrostatic pressure at the surface or any depth in the wellbore in psi
V_1 = Original pit gain in bbl
V_2 = Gas volume at surface or at any depth of interest in bbl
T_1 = Temperature of formation fluid in degrees Rankine (°R = °F + 460)
T_2 = Temperature at surface or at any depth of interest in degrees Rankine

Formula 2: Basis gas law plus compressibility factor:

$$\frac{(P_1)(V_1)}{(T_1)(Z_1)} = \frac{(P_2)(V_2)}{(T_2)(Z_2)} \tag{3.91}$$

Where: Z_1 = Compressibility factor under pressure in formation, dimensionless
Z_2 = Compressibility factor at the surface or at any depth of interest, dimensionless

Formula 3: Shortened gas expansion equation:

$$(P_1)(V_1) = (P_2)(V_2) \tag{3.92}$$

Where: P_1 = Formation pressure in psi
P_2 = Hydrostatic pressure plus atmospheric pressure (14.7 psi) in psi
V_1 = Original pit gain in bbl
V_2 = Gas volume at surface or at any depth of interest in bbl

3.12.2 Hydrostatic Pressure Exerted by Each Barrel of Mud in the Casing

Formula 1: With pipe in the wellbore:

$$P = \frac{1029.4}{\left(D_h^2 - D_p^2\right)}(0.052)(\mathrm{MW}) \tag{3.93}$$

Where: P = Pressure of mud with pipe in the wellbore in psi/bbl

Example: D_h = 9⅝ in. casing (43.51 lb/ft., 8.755 in. ID)
D_p = 5.0 in.
Mud weight = 10.5 ppg

$$P = \frac{1029.4}{\left(8.755^2 - 5.0^2\right)}(0.052)(10.5) = 10.88\,\mathrm{psi/bbl}$$

Formula 2: With **NO** pipe in the wellbore:

$$P = \frac{1029.4}{\mathrm{ID}}(0.052)(\mathrm{MW}) \tag{3.94}$$

Example: D_h = 9⅝ in. casing (43.51 lb/ft., 8.755 in. ID)
Mud weight = 10.5 ppg

$$P = \frac{1029.4}{8.755}(0.052)(10.5) = 7.33\,\mathrm{psi/bbl}$$

3.12.3 Surface Pressure During Drill Stem Tests

Step 1: Determine formation pressure in psi:

$$P_F = (P_{Fe})(0.052)(TVD) \tag{3.95}$$

Where: P_F = Formation pressure in psi
P_{Fe} = Formation pressure equivalent mud weight in ppg

Step 2: Determine oil hydrostatic pressure in psi:

$$P_O = (F_F)(0.052)(TVD) \tag{3.96}$$

Where: P_O = Hydrostatic pressure of oil in psi
F_F = Oil specific gravity (SG)

Step 3: Determine surface pressure in psi:

$$P_S = P_F - P_O \tag{3.97}$$

Where: P_S = Surface pressure in 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?

Step 1: Determine formation pressure in psi:

$$P_F = (13.5)(0.052)(12,500) = 8775 \text{ psi}$$

Step 2: Determine oil hydrostatic pressure in psi:

$$P_O = (0.5(8.34))(0.052)(12,500) = 2711 \text{ psi}$$

Step 3: Determine the surface pressure in psi:

$$P_S = 8775 - 2711 = 6064 \text{ psi}$$

3.13 Stripping/Snubbing Calculations

3.13.1 Breakover Point Between Stripping and Snubbing

Example: Use the following data to determine the breakover point:

Data: Mud weight = 12.5 ppg
Drill collars = 6¼ 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

Step 1: Determine the force created by wellbore pressure on 6¼ in. drill collars in lb:

$$F_{WP} = \left(P^2\right)(0.7854)(\text{SICP}) \tag{3.98}$$

Where: F_{WP} = Force created by wellbore pressure in lb
P = Drill pipe or drill collars in in.
SICP = Shut-in casing pressure in psi

$$F = \left(6.25^2\right)(0.7854)(2400) = 73{,}631\,\text{lb}$$

Step 2: Determine the weight of the drill collars in lb:

$$W_{DC} = (W_c)(L_{DC})(\text{BF}) \tag{3.99}$$

Where: W_{DC} = Weight of the drill collars in lb
W_c = Drill collar weight in lb/ft.
L_{DC} = Length of the drill collars in ft.

$$W_{DC} = (83)(276)(0.8092) = 18{,}537\,\text{lb}$$

Step 3: Additional weight required from drill pipe in lb:

$$W_{DP} = F_{WP} - W_{DC} \tag{3.100}$$

Where: W_{DP} = Weight of drill pipe in lb
F_{WP} = Force created by wellbore pressure in lb

$$W_{DP} = 73,631 - 18,537 = 55,094 \text{lb}$$

Step 4: Length of drill pipe required to reach breakover point in ft.:

$$L_{DP} = \frac{W_{DP}}{(W_{dp})(\text{BF})} \tag{3.101}$$

Where: L_{DP} = Length of drill pipe required to reach breakover point in ft.
W_{dp} = Drill pipe weight in lb/ft.

$$L_{DP} = \frac{55,094}{(19.5)(0.8092)} = 3492 \text{ ft.}$$

Step 5: Length of drill string required to reach breakover point in ft.:

$$L_{DS} = L_{DC} + L_{DP} \tag{3.102}$$

Where: L_{DS} = Length of drill string in ft.

$$L_{DS} = 276 + 3492 = 3768 \text{ ft.}$$

3.13.2 Minimum Surface Pressure Before Stripping Is Possible

$$P_{MS} = \frac{W_{DCS}}{A_{DC}} \tag{3.103}$$

Where: P_{MS} = Minimum surface pressure in psi
W_{DCS} = Weight of one stand of drill collars in lb
A_{DC} = Area of drill collar in in.^{2}

Example: Drill collars = 8.0 in. OD × 3.0 in. ID (147 1b/ft.)
Length of one stand = 92 ft.

$$P_{MS} = \frac{(147)(92)}{(8^2)(0.7854)}$$

$$P_{MS} = \frac{13,325}{50.2656} = 269\ \text{psi}$$

3.13.3 Height Gain from Stripping into Influx

$$H_G = \frac{(L_{SP})\left(C_{dp} + D_P\right)}{C_a} \tag{3.104}$$

Where: H_G = Height gain from stripping into the influx in ft.
L_{SP} = Length of pipe stripped in ft.
C_{dp} = Capacity of drill pipe, drill collars, or tubing in bbl/ft.
D_p = Displacement of drill pipe, drill collars, or tubing in bbl/ft.
C_a = Annular capacity in bbl/ft.

Example: If 300 ft. of 5.0 in. drill pipe (19.5 lb/ft.) is stripped into an influx in a 12¼ in. hole, determine the height gained in ft.:

Data: Drill pipe capacity = 0.01776 bbl/ft.
Drill pipe displacement = 0.00755 bbl/ft.
Length drill pipe stripped = 300 ft.
Annular capacity = 0.1215 bbl/ft.

$$H_G = \frac{(300)(0.01776 + 0.00755)}{0.1215} = 62.5\ \text{ft.}$$

3.13.4 Casing Pressure Increase from Stripping into Influx

$$P_{Ci} = (H_G)(MW_G - I_G) \tag{3.105}$$

Where: P_{Ci} = Casing pressure increase from stripping into influx in psi
I_G = Influx gradient in psi/ft.

Example: Gain in height = 62.5 ft.
Mud weight gradient ((12.5 ppg)(0.052)) = 0.65 psi/ft.
Influx gradient = 0.12 psi/ft.

$$P_{Ci} = (62.5)(0.65 - 0.12) = 33 \text{ psi}$$

3.13.5 Volume of Mud That Must Be Bled to Maintain Constant Bottomhole Pressure with a Gas Bubble Rising

Formula 1: With pipe in the hole:

$$V_{Mp} = \frac{(P_d)(C_a)}{MW_G} \tag{3.106}$$

Where: V_{Mp} = Volume of mud that must be bled to maintain CBHP with a gas bubble rising with pipe in the hole in bbl
P_d = Incremental pressure steps that the casing pressure will be allowed to increase in psi

Example: Casing pressure increase per step = 100 psi
Mud weight gradient ((13.5 ppg)(0.052)) = 0.702 psi/ft.
Annular capacity = 0.1215 bbl/ft. (D_h = 12¼ in.; D_p = 5.0 in.)

$$V_M = \frac{(100)(0.1215)}{0.702} = 17.3 \text{ bbl}$$

Formula 2: With no pipe in hole:

$$V_M = \frac{(P_d)(C_{h/p})}{MW_G} \tag{3.107}$$

Where: V_M = Volume of mud that must be bled to maintain CBHP with a gas bubble rising with **NO** pipe in the hole in bbl
$C_{h/p}$ = Capacity of the hole or casing ID in bbl/ft.

Example: Casing pressure increase per step = 100 psi
Mud weight gradient (13.5 ppg) = 0.702 psi/ft.
Hole capacity (12¼ in.) = 0.1458 bbl/ft.

$$V_M = \frac{(100)(0.1458)}{0.702} = 20.77\,\text{bbl}$$

3.13.6 Maximum Allowable Surface Pressure (MASP) Governed by the Formation

$$\text{MASP} = (\text{MW}_M - \text{MW})(0.052)\left(\text{TVD}_{csg}\right) \tag{3.108}$$

Where: MASP = Maximum allowable surface pressure in psi
MW_M = Maximum allowable mud weight in ppg
MW = Mud weight in use in ppg

Example: Maximum allowable mud weight = 15.0 ppg (from leak-off test data)
Mud weight = 12.0 ppg
Casing seat TVD = 8000 ft.

$$\text{MASP} = (15.0 - 12.0)(0.052)(8000) = 1248\,\text{psi}$$

3.13.7 Maximum Allowable Surface Pressure (MASP) Governed by Casing Burst Pressure

$$\text{MASP}_{CB} = ((P_{CB})(\text{SF})) - ((\text{MW}) - (\text{MW}_{OC}))(0.052)\left(\text{TVD}_{csg}\right) \tag{3.109}$$

Where: MASP_{CB} = Maximum allowable surface pressure governed by casing burst pressure in psi

P_{CB} = Casing burst pressure in psi
SF = Safety factor
MW_{OC} = Mud weight outside of casing in ppg

Example: Casing = 10¾ in. (51 lb/ft., N-80)
Casing burst pressure = 6070 psi
Casing setting depth = 8000 ft.
Mud weight outside casing = 9.4 ppg
Mud weight = 12.0 ppg
Casing safety factor = 80%

$$MASP_{CB} = ((6070)(0.80)) - ((12.0) - (9.4))(0.052)(8000)$$

$$MASP_{CB} = (4856) - (2.6)(0.052)(8000)$$

$$MASP_{CB} = (4856) - (1081.6) = 3774.4 \approx 3774\,\text{psi}$$

3.14 Subsea Considerations

3.14.1 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):

$$P_{csgR} = SICP - P_{CL} \quad (3.110)$$

Where: P_{csgR} = Reduced casing pressure in psi
SICP = Shut-in casing pressure in psi
P_{CL} = Choke line pressure loss in psi

Example: Shut-in casing pressure (SICP) = 800 psi
Choke line pressure loss = 300 psi

$$P_{csgR} = 800 - 300 = 500\,\text{psi}$$

3.14.2 Pressure Chart for Bringing Well on Choke

The pressure/stroke relationship is not linear. When 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 .5	=	25	
Line 3: 3/4 stroke rate = 50 x .75	=	38	
Line 4: 7/8 stroke rate = 50 x .875	=	44	
Line 5: Kill rate speed	=	50	

Strokes side: Kill rate speed = 50 spm

Pressure side: Shut-in casing pressure (SICP) = 800 psi
Choke line pressure loss = 300 psi

Divide choke line pressure loss (P_{CL}) by 4, because there are four steps on the chart:

$$P_{Line} = \frac{P_{CL}}{4} \tag{3.111}$$

Where: P_{Line} = Choke line pressure loss for pressure chart in psi

$$P_{Line} = \frac{300}{4} = 75\,\text{psi/Line}$$

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 1 =		650
Line 4: Subtract 75 psi from Line 1 =		575
Line 5: Reduced casing pressure =		500

3.14.3 Maximum Allowable Mud Weight for Subsea Stack as Derived from Leak-Off Test Data

$$\text{MAMW} = \frac{(P_{\text{LOT}})}{(0.052)(\text{TVD}_{\text{csg}})} + \text{MW} \tag{3.112}$$

Where: MAMW = Maximum allowable mud weight in ppg
P_{LOT} = Leak-off test pressure in psi
TVD_{csg} = Casing shoe depth from RKB in ft.

Example: Leak-off test pressure = 800 psi
TVD from rotary bushing to casing shoe = 4000 ft.
Mud weight = 9.2 ppg

$$\text{MAMW} = \frac{(800)}{(0.052)(4000)} + 9.2 = 13.0\,\text{ppg}$$

3.14.4 Maximum Allowable Shut-In Casing (Annulus) Pressure

$$\text{MASICP} = (\text{MAMW} - \text{MW})(0.052)(\text{TVD}_{\text{csg}}) \tag{3.113}$$

Where: MASICP = Maximum allowable shut-in casing pressure in psi

Example: Maximum allowable mud weight = 13.3 ppg
Mud weight = 11.5 ppg
TVD from rotary Kelly bushing to casing shoe = 4000 ft.

$$MASICP = (13.3 - 11.5)(0.052)(4000) = 374\,psi$$

3.14.5 Casing Burst Pressure: Subsea Stack

Step 1: Determine the internal yield pressure of the casing from the "Dimensions and Strengths" section in a cement company's service handbook.

Step 2: Correct internal yield pressure for safety factor in psi. Some operators use 80%; some use 75%, and others use 70%:

$$\gamma_{IC} = (\gamma_I)(SF) \tag{3.114}$$

Where: γ_{IC} = Correct internal yield pressure of casing in psi
γ_I = Internal yield pressure of casing from reference book in psi
SF = Safety factor

Step 3: Determine the hydrostatic pressure of the mud in use in psi:

Note: The depth is from the rotary Kelly bushing (RKB) to the mud line and includes the air gap plus the depth of seawater.

$$HP_M = (MW)(0.052)(TVD_{WD} + L_{AG}) \tag{3.115}$$

Where: HP_M = Hydrostatic pressure of the mud in psi
TVD_{ML} = Total vertical depth from RKB to mud line in ft.
L_{AG} = Length of the air gap in ft.

Step 4: Determine the hydrostatic pressure exerted by the seawater in psi:

$$HP_{SW} = (MW_{SW})(0.052)(TVD_{WD}) \tag{3.116}$$

Where: HP_{SW} = Hydrostatic pressure of seawater in psi
MW_{SW} = Mud weight of seawater in ppg
TVD_{WD} = Total vertical depth of seawater in ft.

Step 5: Determine casing burst pressure in psi:

$$P_{CB} = (\gamma_{IC} - HP_M) + (HP_{SW}) \quad (3.117)$$

Where: P_{CB} = Casing burst pressure at the stack in psi

Example: Determine the casing burst pressure in psi with a 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.
Safety factor = 80%

Step 1: Determine the internal yield pressure of the casing from the "Dimension and Strengths" section of a cement company handbook:

$9^5/_8$ in. casing (C-75, 53.5 1b/ft.)
Internal yield pressure = 7430 psi

Step 2: Correct internal yield pressure for the safety factor:

$$\gamma_{IC} = (7430)(0.80) = 5944\,\text{psi}$$

Step 3: Determine the hydrostatic pressure exerted by the mud in use in psi:

$$HP_M = (10.0)(0.052)(1500 + 50) = 806\,\text{psi}$$

Step 4: Determine the hydrostatic pressure exerted by the seawater in psi:

$$HP_{SW} = (8.7)(0.052)(1500) = 679\,\text{psi}$$

Step 5: Determine the casing burst pressure in psi:

$$P_{CB} = (5944 - 806) + (679) = 5817\,\text{psi}$$

3.14.6 Calculate Choke Line Pressure Loss in psi

$$P_{CL} = \frac{(0.00061)(\text{MW})(L_{CL})\left(Q^{1.86}\right)}{\text{ID}_{CL}^{4.86}} \tag{3.118}$$

Where: P_{CL} = Choke line pressure loss in psi
L_{CL} = Length of the choke line in ft.
Q = Flow rate in the choke line in gpm
ID_{CL} = Internal diameter of the choke line in in.

Example: Determine the choke line pressure loss in 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.

$$P_{CL} = \frac{(0.00061)(14.0)(2000)\left(225^{1.86}\right)}{2.5^{4.86}}$$

$$P_{CL} = \frac{40,508.6}{85.9} = 471.6 \approx 472\,\text{psi}$$

3.14.7 Velocity Through the Choke Line in ft./min

$$V_{CL} = \frac{24.5(Q)}{\left(\text{ID}_{CL}^{2}\right)} \tag{3.119}$$

Where: V_{CL} = Velocity through the choke line in ft./min

Example: Determine the velocity through the choke line in ft./min using the following data:

Data: Circulation rate = 225 gpm
Choke line ID = 2.5 in.

$$V_{CL} = \frac{24.5(225)}{(2.5^2)} = 882\,\text{ft./min}$$

3.14.8 Adjusting Choke Line Pressure Loss for a Higher Mud Weight in ppg

$$P_{CLN} = \frac{(MW_N)(P_{CL})}{MW_O} \tag{3.120}$$

Where: P_{CLN} = Adjusted new choke line pressure loss in psi
MW_N = New mud weight in ppg
MW_O = Old mud weight in ppg

Example: Use the following data to determine the new estimated choke line pressure loss in psi:

Data: Old mud weight = 13.5 ppg
New mud weight = 15.0 ppg
Old choke line pressure loss = 300 psi

$$P_{CLN} = \frac{(15.0)(300)}{13.5} = 333.33\,\text{psi}$$

3.14.9 Minimum Conductor Casing Setting Depth in ft.

To solve this problem, solve for the unknown "*y*" by using the formation fracture pressure and the hydrostatic pressure of the mud column placed inside the conductor using the example.

Example: Using the following data, determine the minimum setting depth of the conductor casing below the seabed:

Data: Water depth = 450 ft.
Seawater gradient = 0.445 psi/ft.

Air gap	= 60 ft.
Formation fracture gradient	= 0.68 psi/ft.
Maximum mud weight	= 9.0 ppg (to be used while drilling this interval)

Step 1: Determine formation fracture pressure in psi:

$$P_{FF} = ((TVD_{WD})(G_{SW})) + ((G_{FF})(y)) \tag{3.121}$$

Where: P_{FF} = Formation fracture pressure in psi
TVD_{WD} = Total vertical depth of seawater in ft.
G_{SW} = Gradient of seawater in psi/ft.
G_{FF} = Gradient of formation fracture in psi/ft.
y = Unknown

$$P_{FF} = ((450)(0.445)) + ((0.68)(y))$$

$P_{FF} = (200.25) + (0.68\,y)$ (this will be used in Step 3).

Step 2: Determine hydrostatic pressure of mud column in psi:

$$HP_M = ((MW)(0.052)(TVD_{WD} + L_{AG})) + ((MW)(0.052)(y)) \tag{3.122}$$

Where: HP_M = Hydrostatic pressure of mud column in psi

$$HP_M = ((9.0)(0.052)(450 + 60)) + ((9.0)(0.052)(y))$$

$HP_M = (238.7) + (0.468\,y)$ (this will be used in Step 3).

Step 3: Minimum conductor casing setting depth in ft.:

$$P_{FF} = HP_M \tag{3.123}$$

$$(200.3) + (0.68\,y) = (238.7) + (0.468\,y)$$

$$(0.68\,y) - (0.468\,y) = (238.7) - (200.3)$$

$$(0.212\,y) = (38.4)$$

$$y = \left(\frac{38.4}{0.212}\right) = 181.1\text{ ft.}$$

Therefore, the minimum conductor casing setting depth is 181.1 ft. below the mud line of the seabed.

3.14.10 Maximum Mud Weight with Returns Back to Rig Floor in ppg

Step l: Determine total pressure at casing seat in psi:

$$P_{csg} = (FG)(L_C - TVD_{WD} - L_{AG}) + ((G_{SW})(TVD_{WD})) \tag{3.124}$$

Where: P_{csg} = Pressure at the casing shoe in psi

Step 2: Determine maximum mud weight in ppg:

$$MW_M = \frac{P_{csg}}{(0.052)(TVD_C)} \tag{3.125}$$

Where: MW_M = Maximum mud weight in ppg

Example: Using the following data, determine the maximum mud weight that can be used with returns back to the rig floor:

Data: Air gap = 75 ft.
Water depth = 600 ft.
Conductor casing = 1225 ft. RKB
Seawater gradient = 0.445 psi/ft.
Fracture gradient = 0.58 psi/ft.

Step l: Determine total pressure at casing seat in psi:

$$P_{csg} = (0.58)(1225 - 600 - 75) + ((0.445)(600))$$

$$P_{csg} = (319) + (267) = 586\,\text{psi}$$

Step 2: Determine maximum mud weight in ppg:

$$MW_M = \frac{586}{(0.052)(1225)} = 9.2\,\text{ppg}$$

3.14.11 Reduction in Bottomhole Pressure If Riser is Disconnected in psi

Step 1: Determine bottomhole pressure in psi:

$$P_{BH} = (MW)(0.052)(TVD_{TD}) \tag{3.126}$$

Where: P_{BH} = Bottomhole pressure in psi

Step 2: Determine bottomhole pressure with riser disconnected in psi:

$$P_{BHRD} = ((G_{SW})(L_{WD})) + (MW)(0.052)((TVD_{TD}) - (L_{WD}) - (L_{AG})) \tag{3.127}$$

Where: P_{BHRD} = Bottomhole pressure with riser disconnected in psi

Step 3: Determine bottomhole pressure reduction in 4psi:

$$P_{BHR} = (P_{BH}) - (P_{BHRD}) \tag{3.128}$$

Where: P_{BHR} = Bottomhole pressure reduction in psi

Example: Use the following data and determine the reduction in bottomhole pressure if the riser is disconnected:

Data:

Air gap	= 75 ft.
Water depth	= 700 ft.
Seawater gradient	= 0.445 psi/ft.
Well depth	= 2020 ft. RKB
Mud weight	= 9.0 ppg

Step 1: Determine bottomhole pressure in psi:

$$P_{BH} = (9.0)(0.052)(2020) = 945.4\text{ psi}$$

Step 2: Determine bottomhole pressure with riser disconnected in psi:

$P_{BHRD} = ((0.445)(700)) + (9.0)(0.052)((2020) - (700) - (75))$
$P_{BHRD} = (311.1) + (582.7) = 894.2\,\text{psi}$

Step 3: Determine bottomhole pressure reduction in psi:

$P_{BHR} = (945.4) - (894.2) = 51.2\,\text{psi}$

3.14.12 Bottomhole Pressure When Circulating Out a Kick in psi

Example: Use the following data and determine the bottomhole pressure when circulating out a kick in psi:

Data:

Total depth—RKB	= 13,500 ft.
Length of gas kick in casing	= 1200 ft.
Gas gradient	= 0.12 psi/ft.
Original mud weight	= 12.0 ppg
Kill weight mud	= 12.7 ppg
Pressure loss in annulus	= 75 psi
Choke line pressure loss	= 220 psi
Air gap	= 75 ft.
Water depth	= 1500 ft.
Annulus (casing) pressure	= 631 psi
Original mud in casing below gas	= 5500 ft.

Step 1: Determine the hydrostatic pressure in choke line in psi:

$$P_{HCL} = (MW_O)(0.052)((TVD_{WD}) + (L_{AG})) \tag{3.129}$$

Where: P_{HCL} = Hydrostatic pressure in the choke line in psi
MW_O = Original mud weight in ppg
TVD_{WD} = Water depth in ft.
L_{AG} = Length of the air gap in ft.

$P_{HCL} = (12.0)(0.052)((1500) + (75)) = 982.8\,\text{psi}$

Step 2: Determine the hydrostatic pressure exerted by gas influx in psi:

$$P_{HI} = (G_I)(L_I) \tag{3.130}$$

Where: P_{HI} = Hydrostatic pressure of influx in psi
G_I = Gas gradient in psi/ft.
L_I = Length of influx in ft.

$$P_{HI} = (0.12)(1200) = 144\,\text{psi}$$

Step 3: Determine the hydrostatic pressure of original mud below gas influx in psi:

$$P_{HOM} = (MW_O)(0.052)(L_{BI}) \tag{3.131}$$

Where: P_{HOM} = Hydrostatic pressure of original mud below gas influx in psi
L_{BI} = Length of mud below influx in ft.

$$P_{HOM} = (12.0)(0.052)(5500) = 3432\,\text{ft.}$$

Step 4: Determine the hydrostatic pressure of the kill weight mud in psi:

$$P_{HKWM} = (KWM)(0.052)((TVD_{TD}) - (L_{BI}) - (L_I) - (TVD_{WD}) - (L_{AG})) \tag{3.132}$$

Where: P_{HKWM} = Hydrostatic pressure of the kill weight mud in psi

$$P_{HKWM} = (12.7)(0.052)((13,500) - (5500) - (1200) - (1500) - (75)) = 3450.6\,\text{psi}$$

Step 5: Summary

Bottomhole pressure while circulating out a kick:

Pressure in choke line	= 982.8 psi
Pressure of gas influx	= 144.0 psi
Original mud below gas in casing	= 3432.0 psi

Kill weight mud	= 3450.6 psi
Annulus (casing) pressure	= 630.0 psi
Choke line pressure loss	= 200.0 psi
Annular pressure loss	= + 75.0 psi
Bottomhole pressure while circulating out a kick	= 8914.4 psi

3.15 Workover Operations

Note: The following procedures and calculations are more commonly used in workover operations, but at times they are used in drilling operations.

3.15.1 Bullheading

Bullheading is a term used to describe killing the well by forcing formation fluids back into the formation. This involves 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 sulfide is a possibility.

Example calculations involved in bullheading operations:

Using the information given below, 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	= 0.401 psi/ft.
Tubing hydrostatic pressure	= 326 psi
Shut-in tubing pressure	= 2000 psi
Tubing size	= 2⅞ in. (6.5 1b/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./h, in a shut-in well can be determined by the following formula:

$$M_{gas} = \left(\frac{P_{HI}}{CBF_G}\right) \tag{3.133}$$

Where: M_{gas} = Rate of gas migration up hole in ft./h
P_{HI} = Increase in surface pressure per hour in psi
CBF_G = Completion brine fluid gradient in psi/ft.

Step 1: Calculate the maximum allowable tubing (surface) pressure (MATP) for formation fracture in psi:

(a) Determine the initial maximum allowable tubing pressure initial with influx in the tubing in psi:

$$MATP_I = ((FG_G)(TVD_P)) - (HP_T) \tag{3.134}$$

Where: $MATP_I$ = Maximum allowable tubing (surface) pressure in psi
FG_G = Fracture gradient in psi/ft.
HP_T = Hydrostatic pressure of tubing in psi

Example: Use the data listed above:

$$MATP_I = ((0.862)(6480)) - (326)$$
$$MATP_I = (5586) - (326) = 5260\,psi$$

(b) Determine the final maximum allowable tubing pressure with kill fluid in tubing in psi:

$$MATP_F = ((FG_G)(TVD_P)) - (HP_T) \tag{3.135}$$

Where: $MATP_F$ = Final maximum allowable tubing pressure in psi

Example: Use the data listed above:

$$MATP_F = ((0.862)(6480)) - ((8.4)(0.052)(6480))$$
$$MATP_F = (5586) - (2830) = 2756\,\text{psi}$$

Step 2: Determine tubing capacity in bbl:

$$C_T = (L_T)(C_T) \tag{3.136}$$

Where: C_T = Tubing capacity in bbl
L_T = Length of tubing in ft.
C_T = Capacity of tubing in bbl/ft.

Example: Use the data listed above:

$$C_T = (6480)(0.00579) = 37.5\,\text{bbl}$$

Plot these values as shown in Figure 3.7.

3.15.2 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

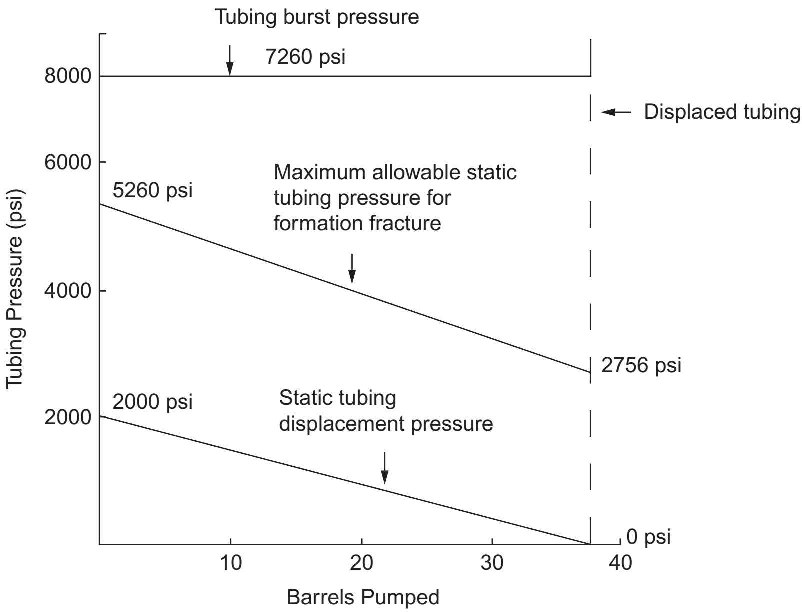

Figure 3.7 Tubing pressure profile.

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 plugged, rendering bullheading useless. In this case, the well can be killed without 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 minimize 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:

Data:

TVD	= 6500 ft.
Depth of perforations	= 6450 ft.
SITP	= 2830 psi
Tubing size	= $2^7/_8$ in. (6.5 lb/ft., N-80)
Tubing capacity	= 0.00579 bbl/ft. (172.76 ft./bbl)
Tubing internal yield	= 10,570 psi
Wellhead working pressure	= 3000 psi
Kill weight fluid	= 9.0 ppg

Step 1: Calculate the expected pressure reduction for each barrel of kill fluid pumped in psi:

$$P_{\mathrm{RT}} = (C_{\mathrm{T}})(0.052)(\mathrm{KWF}) \tag{3.137}$$

Where: P_{RT} = Pressure reduction in the tubing for each barrel of kill fluid pumped in psi/bbl
C_{T} = Capacity of the tubing in ft./bbl
KWF = Kill weight fluid in ppg

Example: Use the data listed above:

$$P_{\mathrm{RT}} = (172.76)(0.052)(9.0) = 80.85\,\mathrm{psi/bbl}$$

For each barrel pumped, the SITP will be reduced by 80.85 psi.

Step 2: Calculate the tubing capacity to the perforations in bbl:

$$C_{\mathrm{TP}} = (C_{\mathrm{T}})\left(D_{\mathrm{perf}}\right) \tag{3.138}$$

Where: C_{TP} = Capacity of the tubing to the perforations in bbl
C_{T} = Capacity of the tubing in bbl/ft.
D_{perf} = Depth of the perforations in ft.

Example: Use the data listed above:

$$C_{\mathrm{TP}} = (0.00579)(6450) = 37.3\,\mathrm{bbl}$$

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 ¼ to 1 h depending on gas density, pressure, and tubing size.
6. Open the choke and bleed gas until 9.0 ppg 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 needed not to allow fluid to fall, but rather, for gas to migrate up through the kill fluid. Gas migrates at rates of 1000-2000 ft./h. 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.

3.16 Controlling Gas Migration

Gas migration can occur when a well is shut in on a gas kick. It is indicated by a uniform increase in both the SIDPP and SICP. If the influx is allowed to migrate without expanding, pressures will increase everywhere in the wellbore. If it is ignored, it can cause formation damage and mud losses. The worst-case scenario would be an underground blowout.

Gas migration can be controlled using two methods:

- Drill pipe pressure method
- Volumetric method

3.16.1 Drill Pipe Pressure Method

3.16.1.1 English Units

This is a constant bottomhole pressure method of well control, and it is the simplest method. In order to use this method, the bit must be on bottom with no float in the string.

Procedure:

1. Allow the SIDPP to increase by a safety margin: 50-100 psi. This is the lower limit. The SIDPP must not be allowed to decrease below this level.
2. Next, allow the drill pipe pressure to further increase by another 50-100 psi. This is the upper limit.
3. Open the choke and bleed fluid out of the well until the drill pipe pressure drops to the lower limit.
4. Repeat steps 2 and 3 until circulation is possible or the gas migrates to the top of the well.

3.16.1.2 Metric Units

Procedure:

1. Allow the SIDPP to increase by a safety margin: 350-1400 kPa. This is the lower limit.
2. Next, allow the drill pipe pressure to further increase by another 350-1400 kPa. This is the upper limit.
3. Open the choke and bleed mud out of the well until the drill pipe pressure drops to the lower limit value.
4. Repeat steps 2 and 3 until circulation is possible or the gas migrates to the top of the well.

3.16.2 Volumetric Method of Gas Migration

3.16.2.1 English Units

Procedure:

1. Select a safety margin, P_s, and a working pressure, P_w. (Recommended: $P_s = 100$ psi; $P_w = 100$ psi.)

2. Calculate the hydrostatic pressure per barrel of mud, HP/bbl:

$$P_H = \frac{(G_M)}{C_a} \tag{3.139}$$

Where: P_H = Hydrostatic pressure per barrel of mud in psi/bbl
G_M = Mud gradient in psi/ft.
C_a = Capacity of the annulus in bbl/ft.

3. Calculate the volume to bleed each cycle: Volume, bbl to bleed each cycle = P_w/HP/bbl
4. Allow the shut-in casing pressure to increase by P_s without bleeding from the well.
5. Allow the shut-in casing pressure to further increase by P_w without bleeding from the well.
6. Maintain casing pressure constant by bleeding small volumes of mud from the well until total mud bled equals the correct volume to bleed per cycle.
7. Repeat steps 5 and 6 until another procedure is implemented or all gas is at the surface.

3.16.2.2 Metric Units

Procedure:

1. Select a safety margin, P_s, and a working pressure, P_w in kPa. (Recommended: P_s = 700 kPa; P_w = 700 kPa.)
2. Calculate the hydrostatic pressure increase per m^3 of mud.

$$P_H = \frac{G_M}{C_a} \tag{3.140}$$

Where: P_H = Hydrostatic pressure in kPa/m^3
G_M = Pressure gradient in kPa/m
C_a = Upper annular capacity in m^3/m

3. Calculate the volume to bleed per cycle:

$$V_M = P_W + HP \tag{3.141}$$

Where: V_M = Volume of mud to bleed to maintain P_w in the annulus in m^3

4. Allow shut-in casing pressure to increase by P_s without bleeding mud from the well.
5. Allow the shut-in casing pressure to further increase by P_w without bleeding mud from the well.
6. Maintain constant casing pressure by bleeding small volumes of mud from the well until total mud bled from the well equals correct volume to bleed per cycle.
7. Repeat steps 5 and 6 until another procedure is implemented or all gas is at the surface.

3.17 Gas Lubrication

Gas lubrication is the process of removing gas from beneath the BOP stack while maintaining constant bottomhole pressure. Lubrication is best suited for surface stacks, but the dynamic gas lubrication procedure can be used to vent gas from beneath a subsea stack.

Lubrication can be used to reduce pressures or to remove gas from beneath a surface stack prior to stripping or after implementing the volumetric procedure for controlling gas migration. The volume of mud lubricated into the well must be accurately measured.

3.17.1 Gas Lubrication: Volume Method

3.17.1.1 English Units

Procedure:

1. Select a range of working pressure, P_w in psi. (Recommended $P_w = 100\text{-}200$ psi.)
2. Calculate the hydrostatic pressure increase in the upper annulus per bbl of lube mud:

$$P_H = \frac{G_M}{C_a} \tag{3.142}$$

Where: P_H = Hydrostatic pressure per barrel of mud in psi/bbl
G_M = Mud gradient in psi/ft.
C_a = Capacity of the annulus in bbl/ft.

3. Pump lube mud through the kill line to increase the casing pressure by the working pressure range, P_w.
4. Measure the trip tank and calculate the hydrostatic pressure increase of the mud lubricated for this cycle.
5. Wait 10-30 min for the mud to lubricate through the gas.
6. Bleed "dry" gas from the choke to reduce the casing pressure by the hydrostatic pressure increase plus the working pressure range.
7. Repeat steps 3 through 6 until lubrication is complete.

3.17.1.2 Metric Units

Procedure:

1. Select a working pressure range, P_w in kPa. (Recommended $P_w = 700\text{-}1400$ kPa.)
2. Calculate the hydrostatic pressure increase in the upper annulus per m^3 of lube mud:

$$P_H = \frac{G_M}{C_a} \tag{3.143}$$

Where: P_H = Hydrostatic pressure per barrel of mud in kPa/m^3
G_M = Mud gradient in kPa/m
C_a = Capacity of the annulus in m^3/m

3. Pump lube mud through kill line to increase casing pressure by working pressure range, P_w.
4. Measure the trip tank and calculate the hydrostatic pressure increase of the mud lubricated for this cycle.
5. Wait 10-30 min for the mud to "lubricate" through the gas.
6. Bleed "dry" gas from the choke to reduce the casing pressure by the hydrostatic pressure increase plus the working pressure range.
7. Repeat steps 3 through 6 until lubrication is complete.

3.17.2 Gas Lubrication: Pressure Method

Because of its simplicity, the pressure method is the preferred method of gas lubrication. However, it is only applicable when the mud weight being lubricated is sufficient to kill the well, as in the case of a swabbed influx. The pressure method is also the only accurate method whenever the formation is "taking" fluid, as is the case for most completed wellbores and whenever seepage loss is occurring.

The pressure method of gas lubrication utilizes the following formula:

$$P_3 = \frac{P_1^2}{P_2} \tag{3.144}$$

Where: P_1 = Original shut-in pressure in psi
P_2 = Pressure increase due to pumping lubricating fluid into the wellbore (increase is due to compression) in psi
P_3 = Pressure to bleed down after adding the hydrostatic of the lubricating fluid in psi

Procedure:

1. Select a working pressure range, P_w in psi. (Recommended P_w = 50-100 psi.)
2. Pump lubricating fluid through the kill line to increase the casing pressure by the working pressure, P_w.
3. Allow the pressure to stabilize. The pressure may drop by a substantial amount.
4. Calculate the pressure to bleed down to by using the formula above.
5. Repeat steps 2 through 4 until all the gas is lubricated out of the well.

3.18 Annular Stripping Procedures

3.18.1 Strip and Bleed Procedure

Application: Appropriate when stripping 30 stands or less or when gas migration is not a problem.

Procedure:

1. Strip the first stand with the choke closed to allow the casing pressure to increase. **Note**: Do not allow the casing pressure to rise above the maximum allowable surface pressure derived from the most recent leak-off test.

2. Bleed enough volume to allow the casing pressure to decrease to a safety margin of 100-200 psi above the original shut-in casing pressure.
3. Continue to strip pipe with the choke closed unless the casing pressure approaches the maximum allowable surface pressure. If the casing pressure approaches the maximum allowable surface pressure, then bleed volume as the pipe is being stripped to minimize the casing pressure.
4. Once the bit is back on bottom, utilize the driller's method to circulate the influx out of the well.

3.18.2 Combined Stripping/Volumetric Procedure

Application: Procedure to use when gas migration is a factor. Gas is allowed to expand while stripping. Mud is bled into a trip tank and then closed end displacement into a smaller tank.

Trip tank measures gas expansion similar to volumetric method. Pressure is stepped up as in the volumetric method.

3.18.3 Worksheet

1. Select a working pressure, P_w in psi. (Recommended $P_w = 50$-100 psi.)
2. Calculate the hydrostatic pressure in psi/bbl:

$$P_H = \frac{G_M}{C_a} \tag{3.145}$$

Where: P_H = Hydrostatic pressure per barrel of mud in psi/bbl
G_M = Mud gradient in psi/ft.
C_a = Capacity of the annulus in bbl/ft.

3. Calculate influx length in the open hole:

$$L_{Ioh} = \frac{V_I}{C_{oh}} \tag{3.146}$$

Where: L_{Ioh} = Length of influx in the open hole in ft.
V_I = Volume of influx in bbl
C_{oh} = Open hole capacity in bbl/ft.

4. Calculate influx length after the BHA has penetrated the influx:

$$L_{\mathrm{IBHA}} = \frac{V_{\mathrm{I}}}{C_{\mathrm{oh/DC}}} \tag{3.147}$$

Where: L_{IBHA} = Length of influx after the BHA has penetrated the influx in ft.
$C_{\mathrm{oh/DC}}$ = Annular capacity between the drill collars and the open hole in bbl/ft.

5. Calculate the pressure increase due to bubble penetration in psi:

$$P_{\mathrm{b}} = (L_{\mathrm{Ioh}} - L_{\mathrm{IBHA}})(G_{\mathrm{M}} - G_{\mathrm{G}}) \tag{3.148}$$

Where: P_{b} = Pressure increase due to bubble in psi
G_{M} = Mud gradient in psi/ft.
G_{G} = Gas gradient in psi/ft. (Use 0.1 psi/ft. if gas SG is not known.)

6. Calculate the *P*choke values in psi:

$$P_{\mathrm{C1}} = \mathrm{SCIP} + P_{\mathrm{W}} = P_{\mathrm{b}} \tag{3.149}$$

$$P_{\mathrm{C2}} = P_{\mathrm{C1}} + P_{\mathrm{W}} \tag{3.150}$$

$$P_{\mathrm{C3}} = P_{\mathrm{C2}} + P_{\mathrm{W}} \tag{3.151}$$

7. Calculate the Incremental Volume (V_{M}) of Hydrostatic Equal to P_{w} in the Upper Annulus

$$V_{\mathrm{M}} = \frac{P_{\mathrm{W}}}{\mathrm{HP}} \tag{3.152}$$

Where: V_{M} = Volume of mud to bleed to maintain P_{W} in the annulus in bbl

Procedure:

1. Strip in the first stand with the choke closed until the casing pressure reaches $P\mathrm{choke}_1$.
2. As the driller strips the pipe, the choke operator should open the choke and bleed mud, being careful to hold the casing pressure at $P\mathrm{choke}_1$.

3. With the stand down, close the choke. Bleed the closed end displacement volume from the trip tank to the stripping tank.
4. Repeat steps 2 and 3 above, stripping stands until V_M accumulates in the trip tank.
5. Allow casing pressure to climb to the next *P*choke level.
6. Continue stripping, repeating steps 2 through 4 at the new *P*choke value.
7. When the bit is on the bottom, kill the well with the driller's method.

3.19 Barite Plug

A barite plug is often used to control underground flows that have broken down the formation at the casing shoe. The technique involves placing a volume of barite and water or base oil that the solids settle out of suspension forming a solids plug of high density that can be drilled out easier than a cement plug. This also prevents the risk of sidetracking while drilling the plug.

Step 1: Determine the capacity of the open hole without drill pipe in bbl:

$$C_h = \frac{((D_B)(1 + (WO)))^2}{1029.4} \tag{3.153}$$

Where: C_h = Capacity of open hole without drill pipe in bbl/ft.
D_B = Diameter of the bit in in.
WO = Washout of hole in % (optional)

Step 2: Determine the volume of barite to set a 100-ft. plug of settle barite in bbl:

$$V_b = 100(C_h) \tag{3.154}$$

Where: V_b = Volume of barite for a 100-ft. plug in bbl

Step 3: Determine the amount of base liquid needed to mix with the barite in bbl:

$$((V_b) + (V_L))(MW_p) = ((V_b)(MW_b)) + ((V_L)(MW_L)) \tag{3.155}$$

Where: V_L = Volume of base liquid to mix with barite in bbl
MW_p = Mud weight of plug slurry in ppg
MW_b = Mud weight of barite in ppg (((8.34)(4.2)) =35.028 ppg)
MW_L = Mud weight of base liquid in ppg

Step 4: Determine the final volume of the plug slurry in bbl:

$$V_{ps} = V_L + V_b \tag{3.156}$$

Where: V_{ps} = Volume of plug slurry in bbl

Step 5: Determine the capacity of the annulus with drill pipe in bbl/ft.:

$$C_{ap} = \frac{((D_B)(1 + (WO)))^2 - (D_P)^2}{1029.4} \tag{3.157}$$

Where: C_{ap} = Capacity of the annulus with drill pipe in bbl/ft.
D_P = Size of the drill pipe in in.

Step 6: Determine the length of the plug slurry in the annulus with the pipe in the hole in ft.:

$$L_{pSP} = \frac{V_{pS}}{C_{ap}} \tag{3.158}$$

Where: L_{pSP} = Length of plug slurry in the annulus with the pipe in the hole in ft.

Step 7: Determine the length of the plug slurry with **NO** pipe in the annulus in ft.:

$$L_{pS} = \frac{V_{pS}}{C_a} \tag{3.159}$$

Where: L_{pS} = Length of the plug slurry in the annulus with **NO** pipe in ft.

Step 8: Determine the length of the settled barite in the annulus in ft.:

$$L_{bs} = \frac{V_b}{C_a} \tag{3.160}$$

Where: L_{bs} = Length of the settled barite in ft.

Step 9: Determine the amount of barite required for the plug in sacks:

$$B_{ar} = (V_b)(14.7) \tag{3.161}$$

Where: B_{ar} = Number of 100 lb sacks of barite needed for the plug

Example: Calculate the materials required for an open hole, water-based, barite plug with the following:

Bit size	= 12¼ in.
Washout	= 15% (increase in diameter)
Drill pipe	= 5.0 in.
Length of settled barite	= 100 ft.
Plug mud weight	= 18.0 ppg

Step 1: Determine the capacity of the open hole without drill pipe in bbl:

$$C_h = \frac{((12.25)(1 + (0.15)))^2}{1029.4} = 0.1928 \text{ bbl/ft.}$$

Step 2: Determine the volume of barite to set a 100-ft. plug of settle barite in bbl:

$$V_b = 100(0.1928) = 19.3 \text{ bbl}$$

Step 3: Determine the amount of base liquid needed to mix with the barite in bbl:

$$((19.3) + (V_L))(18.0) = ((19.3)(35.0)) + ((V_L)(8.34))$$

$$(347.4) + (18.0\, V_L) = (675.5) + (8.34\, V_L)$$

$$(18.0\, V_L) - (8.34\, V_L) = (675.5) - (347.4)$$

$$(9.66\, V_L) = (328.1)$$

$$V_L = 33.96 \text{ bbl}$$

Step 4: Determine the final volume of the plug slurry in bbl:

$$V_{ps} = 33.96 + 19.3 = 53.26 \approx 53.3\,\text{bbl}$$

Step 5: Determine the capacity of the annulus with drill pipe in bbl/ft.:

$$C_{ap} = \frac{((12.25)(1 + (0.15)))^2 - (5.0)^2}{1029.4} = 0.1685\,\text{bbl/ft.}$$

Step 6: Determine the length of the plug slurry in the annulus with the pipe in the hole in ft.:

$$L_{pSP} = \frac{53.3}{0.1685} = 316.3\,\text{ft.}$$

Step 7: Determine the length of the plug slurry with **NO** pipe in the annulus in ft.:

$$L_{pS} = \frac{53.3}{0.1928} = 276.5\,\text{ft.}$$

Step 8: Determine the length of the settled barite in the annulus in ft.:

$$L_{bs} = \frac{19.3}{0.1928} = 100.1\,\text{ft.}$$

Step 9: Determine the amount of barite required for the plug in sacks:

$$B_{ar} = (19.3)(14.7) = 283.7 \approx 284\,\text{sks}$$

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CHAPTER FOUR

Drilling Fluids

4.1 Mud Density Increase and Volume Change

4.1.1 Increase Mud Density—*No* Base Liquid Added and *No* Volume Limit

Various dry materials may be used to increase the density of drilling, completion, and workover fluids. Those materials may include barite, hematite, calcium carbonate, magnesium carbonate, various dry salts (e.g., sodium, calcium, zinc chloride, and/or sodium formate), and blends. It is important to know the average specific gravity (ASG) of the material being used. For example, the current API ASG specification for barite is 4.2. The ASG of the dry material you are using should be obtained from the company supplying the product.

(a) Short formula for mud weight increase:

$$W_M = 5(\rho_n)(\rho_n - \rho_o) \tag{4.1}$$

Where: W_M = Number of 100 lb sacks of weight material required for 100 bbl of mud
ρ_o = Original mud weight in ppg
ρ_n = New mud weight in ppg

(b) Volume increase based on the amount of weight material:

$$V_i = \frac{W_M}{3.5(SG_{wm})} \tag{4.2}$$

Where: V_i = Volume increase in bbl
SG_{wm} = Specific gravity of weight material

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Example: Calculate the number of sacks of 4.2 ASG of barite required to increase the density of 100 bbl of 12.0 ppg (ρ_o) mud to 14.0 ppg (ρ_n) and the resultant volume increase.

$$W_M = 5(14.0)(14.0 - 12.0)$$

$W_M = 140$ sacks of barite required for 100 bbl of 12.0 ppg mud.

$$V_i = \frac{140}{3.5(4.2)}$$

$V_i = 9.5$ bbl volume increase.

(c) Increase mud weight:

$$W_M = \frac{(350\,SG_{wm})(\rho_n - \rho_o)}{(8.34\,SG_{wm}) - \rho_n} \tag{4.3}$$

Where: 350 = Weight of 1 barrel of fresh water in lb
8.34 = Mud weight of fresh water in lb/gal (ppg)
SG_{wm} = Specific gravity of weight material, g/cc

(d) Volume increase with 100 lb sacks of weight material based on the change in mud weight:

$$V_i = \frac{100(\rho_n - \rho_o)}{(8.34\,SG_{wm}) - \rho_n} \tag{4.4}$$

Where: V_i = Volume increase in bbl

Example: Calculate the number of sacks of 4.2 ASG barite required to increase the density of 100 barrels of 12.0 ppg (ρ_o) mud to 14.0 ppg (ρ_n):

$$W_M = \frac{(350(4.2))(14.0 - 12.0)}{(8.34(4.2)) - 14.0}$$

$$W_M = \frac{(1470)(2.0)}{(35.0 - 14.0)} = \frac{2940}{21.0}$$

W_M required = 140 sk of barite per 100 bbl of 12.0 ppg mud.

$$V_i = \frac{100(14.0 - 12.0)}{(8.34(4.2)) - 14.0}$$

$$V_i = \frac{200}{21.0}$$

$V_i = 9.5$ bbl of volume increase

4.1.2 Increase Mud Weight—*No* Base Liquid Added *but* Limit Final Volume

Step 1: Calculate the starting volume required:

$$V_s = \frac{(8.34\,\mathrm{SG_{wm}}) - \rho_n}{(8.34\,\mathrm{SG_{wm}}) - \rho_o}(V_f) \tag{4.5}$$

Where: V_s = Starting volume of mud in bbl
V_f = Final volume of mud in bbl

Step 2: Calculate the amount of weight material to be added:

$$W_{Ma} = (V_f - V_s)(\mathrm{SG_{wm}})(350) \tag{4.6}$$

Where: W_{Ma} = Weight material in 100 lb sacks adjusted for the desired final volume

Example: Calculate the number of sacks of 4.2 ASG barite required to increase the density of 12.0 ppg (ρ_o) mud to end up with 100 bbl of 14.0 ppg (ρ_n) mud:

$$V_s = \frac{(8.34(4.2)) - 14.0}{(8.34(4.2)) - 12.0}(100)$$

$$V_s = 0.91(100)$$

V_s = Starting volume is 91 bbl.

$$W_{Ma} = (100 - 91)(4.2)(3.5)$$

W_{Ma} = 132 sacks of barite added to 91 bbl of 12.0 ppg mud to result in 100 bbl of 14.0 ppg mud.

4.1.3 Increase the Mud Density—*With* Base Liquid Added and *No* Volume Limit

Adding dry powder to a mud will cause an increase in the viscosity of that mud. It is a general rule that the volume of base liquid must be added to wet the surface of any dry weight material added to an existing mud. From experience, at least 1½ gal of base liquid must be added per 100 lb of weight material added. This base liquid volume has to be "weighed up" to the final mud weight required for the total mud system. Therefore the amount of weight material calculated with the previous equations is the minimum amount that would be required before adding the additional base liquid. The following equations can be used to calculate the amount of base liquid to be added to the amount of weighting material to reach the desired mud weight.

Step 1: Calculate the mud weight of the weight material-base liquid mixture:

$$MW_X = \frac{(8.34\,SG_{wm}) + (0.1251\,SG_{wm}(L_b)(L_{SG}))}{1 + (0.1251\,SG_{wm})} \tag{4.7}$$

Where: MW_X = Mud weight of weight material-base liquid mixture in ppg
L_b = Base liquid mud weight in ppg
L_{SG} = Specific gravity of base liquid

Step 2: Calculate the amount of weight material required:

$$W_{MX} = \frac{(0.42\,MW_X)(\rho_n - \rho_o)}{(MW_X - \rho_n)(1 + (0.015 L_b))}(V_s) \tag{4.8}$$

Where: W_{MX} = Number of 100 lb sacks of weight material required for the mixture

Step 3: Calculate the final volume with the weight material-base liquid mixture added:

$$V_f = V_s\left[1 + \left(\frac{MW_M}{350\,SG_{wm}}\right) + \left(\frac{1.5\,MW_M}{4200}\right)\right] \tag{4.9}$$

Where: V_f = Final volume of mud in bbl
V_s = Starting volume of mud in bbl

Example: Calculate the number of sacks of 4.2 ASG barite required to increase the density of 100 bbl of 12.0 ppg (ρ_o) mud to 14.0 ppg (ρ_n) using fresh water as the wetting agent:

$$MW_X = \frac{(8.34(4.2)) + (0.1251(4.2)(8.34)(1.0))}{1 + (0.1251(4.2))}$$

$$MW_X = \frac{(35) + (4.38)}{1 + (0.525)}$$

MW_X = 25.8 ppg, the mud weight of the weight material-fresh water mixture.

$$W_{MX} = \frac{(0.42(25.8))(14.0 - 12.0)}{(25.8 - 14.0)(1 + (0.015(8.34)))}(100)$$

$$W_{MX} = \frac{21.67}{13.27}(100)$$

W_{MX} = 163 sacks of weight material required for 100 bbl of 12.0 ppg mud.

$$V_f = 100\left[1 + \left(\frac{25.8}{350(4.2)}\right) + \left(\frac{1.5(25.8)}{4200}\right)\right]$$

$$V_f = 100[1 + (0.11088) + (0.0582)]$$

V_f =116.9 bbl final volume of 14.0 ppg mud.

4.1.4 Increase Mud Weight—*With* Base Liquid Added *but* Limit Final Volume

Step 1: Calculate the starting volume of mud required to obtain the desired final mud volume:

$$V_s = \frac{V_f}{\left(1 + \left(\frac{W_{MX}}{350\,SG_{wm}} + \frac{1.5\,W_{MX}}{4200}\right)\right)} \tag{4.10}$$

Step 2: Calculate the amount of mud that must be dumped to have available pit space for the final volume in the system:

$$V_d = V_f - V_s \tag{4.11}$$

Where: V_d = Volume of mud in bbl to be dumped out of the system to make room for the mud weight increase

Step 3: Calculate the amount of base liquid added to wet the weight material:

$$V_{wL} = V_f - (V_s + V_i) \tag{4.12}$$

Where: V_{wL} = Volume of base liquid in bbl required to wet weight material added to increase the mud weight

Example: Calculate the amount of mud to be dumped when increasing the mud weight from 12.0 to 14.0 ppg with a final volume of 1000 bbl.

$$V_s = \frac{1000}{\left(1 + \left(\frac{25.8}{350(4.2)} + \frac{1.5(25.8)}{4200}\right)\right)}$$

$$V_s = \frac{1000}{(1 + (0.11088) + (0.0582))}$$

$V_s = 855$ bbl starting volume for increasing the mud weight with a limited final volume.

$$V_d = 1000 - 855$$

$V_d = 145$ bbl of 12.0 ppg mud must be dumped before increasing the mud weight to 14.0 ppg with a system volume limited to 1000 bbl.

$$W_{MX} = \frac{(0.42(25.8))(14.0 - 12.0)}{(25.8 - 14.0)(1 + (0.015(8.34)))}(855)$$

$$W_{MX} = \frac{21.67}{13.28}(855)$$

$W_{MX} = 1395$ sacks of barite required for mud weight increase.

$$V_i = \frac{1395}{3.5(4.2)}$$

$V_i = 95$ bbl volume of barite required for mud weight increase.

$$V_{wL} = 1000 - (855 + 95)$$

$V_{wL} = 50$ bbl of base liquid required for wetting the barite weight material.

4.1.5 Increase Mud Weight—*with* Base Liquid Added *but* Limit Final Volume and *Limited* Weight Material Inventory

Step 1: Calculate the amount of weight material-base liquid (W_{MX}) required to increase the mud weight of the total mud system volume:

$$W_{MX} = \frac{(0.42\,MW_X)(\rho_n - \rho_o)}{(MW_X - \rho_n)(1 + (0.015\,L_b))}(V_C) \tag{4.13}$$

Where: V_C = Current total volume of mud system in bbl

If this amount of weight material required is more than the current inventory, then a new starting volume must be calculated.

Step 2: Calculate the new starting volume for the weight material inventory on the rig:

$$V_{ns} = \left(\frac{W_{MI}}{W_{MX}}\right) V_C \tag{4.14}$$

Where: V_{ns} = New starting volume for limited weight material inventory in bbl
W_{MI} = Weight material inventory on rig in 100 lb sacks

Step 3: Recalculate the amount of weight material-base liquid (W_{MX}) required to increase the mud weight of the new starting mud system volume:

$$W_{MX} = \frac{(0.42\,MW_X)(\rho_n - \rho_o)}{(MW_X - \rho_n)(1 + (0.015\,L_b))}(V_{ns}) \tag{4.15}$$

Example: Calculate the amount of weight material required to increase the mud weight from 12.0 to 14.0 ppg with a limited mud volume and the following data:

Current mud volume:	1000 bbl
Maximum mud volume:	1000 bbl
Weight material inventory:	1400 sacks

$$W_{MX} = \frac{(0.42(25.8))(14.0 - 12.0)}{(25.8 - 14.0)(1 + (0.015(8.34)))}(1000)$$

$$W_{MX} = \frac{21.67}{13.28}(1000)$$

$W_{MX} = 1631.8$ or 1632 sacks required to increase the density of 1000 bbl of mud.

$$V_{ns} = \left(\frac{1400}{1632}\right)1000$$

$V_{ns} = 857.8$ or 858 bbl of new starting mud volume in bbl.

$$W_{MX} = \frac{(0.42(25.8))(14.0 - 12.0)}{(25.8 - 14.0)(1 + (0.015(8.34)))}(858)$$

$$W_{MX} = \frac{21.67}{13.28}(858)$$

$W_{MX} = 1400$ sacks required to increase the mud weight of the new starting volume with limited weight material inventory.

4.1.6 Increase Mud Weight to a Maximum Mud Weight *with* Base Liquid Added *but* with *Limited* Weight Material Inventory

$$MW_{MX} = \frac{((100\,W_{MI})(MW_X)(1+(0.015\,L_b))) + (42(MW_X)(V_s)(\rho_o))}{((100\,W_{MI})(1 + (0.015\,L_b))) + (42(MW_X)(V_s))} \tag{4.16}$$

Where: MW_{MX} = Maximum mud weight possible in ppg with weight material inventory

Example: Calculate the maximum mud weight with the following data:

Mud system volume:	2000 bbl
Current mud weight:	12.0 ppg
Weight material-base liquid mixture weight:	25.8 ppg
Base liquid mud weight:	8.34 ppg
Weight material inventory:	1000 sks

$$MW_{MX} = \frac{((100(1000))(25.8)(1 + (0.015(8.34)))) + (42(25.8)(2000)(12.0))}{((100(1000))(1 + (0.015(8.34)))) + (42(25.8)(2000))}$$

$$MW_{MX} = \frac{(2,902,500) + (26,006,400)}{(112,500) + (2,167,200)}$$

$$MW_{MX} = \frac{28,908,900}{2,279,700} = 12.68 \approx 12.7\ \text{ppg}$$

is the maximum mud weight that can be mixed with only 1000 sacks of weight material in the rig inventory with a 2000 bbl system of 12.0 ppg mud.

4.1.7 SI Units Calculation

$$W_M = \frac{(1000\,SG_{WM})(\rho_n - \rho_o)}{(1000\,SG_{WM}) - \rho_n} \tag{4.17}$$

Where: W_M = Weight material required in kg/m^3
ρ_o = Original mud weight in kg/m^3
ρ_n = New mud weight in kg/m^3

Example: Calculate the amount of 4.2 barite required to increase the mud density of 1 m^3 of mud volume from 1440 to 1680 kg/m^3.

$$W_M = \frac{(1000(4.2))(1680 - 1440)}{1000(4.2) - 1680}$$

$$W_M = 400\ \text{kg/m}^3$$

4.2 Mud Weight Reduction with Base Liquid Dilution

4.2.1 Mud Weight Reduction with Base Liquid

$$V_a = \frac{V_m(\rho_o - \rho_n)}{\rho_n - L_b} \tag{4.18}$$

Where: V_a = Volume of base liquid in bbl added to reduce the mud weight

Example: Determine the number of barrels of fresh water weighing 8.34 ppg required to reduce the mud weight of 100 bbl of water-base mud (WBM) from 14.0 to 12.0 ppg:

$$V_a = \frac{100(14.0 - 12.0)}{12.0 - 8.33}$$

$$V_a = \frac{200}{3.67}$$

V_a = 54.5 bbls of water are required

Example: Determine the number of barrels of base oil weighing 6.7 ppg required to reduce the mud weight of 100 bbl of synthetic-base mud (SBM) from 14.0 to 12.0 ppg:

$$V_a = \frac{100(14.0 - 12.0)}{12.0 - 6.7}$$

$$V_a = \frac{200}{5.3}$$

V_a = 37.7 bbls of base oil are required

Note: Adding this much base oil to 100 bbl of SBM may increase the oil/water ratio (OWR) too much, so the dilution volume may need to be added as a mixture of base oil and water with the same OWR as the active mud system. To calculate the volume of mixture required, calculate the mud weight of the mixture, then calculate a new V_a value.

$$MW_X = (f_o(\rho_{bo})) + (f_w(\rho_w)) \tag{4.19}$$

Where: f_o = Fraction of base oil in mixture
ρ_{bo} = Mud weight of base oil in ppg
f_w = Fraction of water in mixture
ρ_w = Mud weight of water in ppg

Example: Determine the mud weight of the base oil/water mixture required to reduce the mud weight of 100 bbl of synthetic-base mud (SBM) from 14.0 to 12.0 ppg and maintain a 75/25 OWR:

Base oil mud weight = 6.7 ppg (SG 0.80)

$$MW_X = (0.75(6.7)) + (0.25(8.34))$$
$$MW_X = 7.1 \text{ ppg}$$

$$V_a = \frac{100(14.0 - 12.0)}{12.0 - 7.11}$$

$$V_a = \frac{200}{4.89}$$

$$V_a = 40.9 \text{ bbls}$$

Therefore (40.9 (0.75)) or 30.7 bbl of base oil will be required to mix with (40.9 (0.25)) or 10.2 bbl of water to reduce the mud weight and keep the OWR the same.

4.3 Mixing Fluids of Different Densities

4.3.1 The Material Balance Formula

$$((V_f)(\rho_f)) = ((V_1)(\rho_1)) + ((V_2)(\rho_2)) \tag{4.20}$$

Where: V_f = Final volume in bbl, gal, etc.
ρ_f = Final mud weight in ppg, lb/ft.^{3}, etc.

V_1 = Volume of fluid 1 in bbl, gal, etc.
ρ_1 = Mud weight of fluid 1 in ppg, lb/ft.^{3}, etc.
V_2 = Volume of fluid 2 in bbl, gal, etc.
ρ_2 = Mud weight of fluid 2 in ppg, lb/ft.^{3}, etc.

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

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

$$\begin{aligned}
300(11.5) &= ((300 - x)11.0) + (14.0x) \\
3450 &= ((3300 - 11.0x)) + (14.0x) \\
3450 - 3300 &= 3.0x \\
150 &= 3.0x \\
x &= 50 \text{ bbl of 14.0 ppg mud.} \\
300 - 50 &= 250 \text{ bbl of 11.0 ppg required.}
\end{aligned}$$

To check the volumes are correct:

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

To check the final mud weight:

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

Example 2: No limit is placed on volume:

Determine the final mud weight when the following two muds are mixed together:

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

$$800\,\rho_f = (400(11.0)) + (400(14.0))$$

$$\rho_f = \frac{(4400) + (5600)}{800} = \frac{10,000}{800}$$

$$\rho_f = 12.5\text{ ppg}$$

4.4 Oil-Based Mud Calculations

4.4.1 Calculate the Starting Volume of Liquid (Base Oil Plus Water) Required to Prepare a Desired Final Volume of Mud

Example: Prepare 100 bbl of 16.0 ppg mud with a 75/25 OWR using a 0.80 SG base oil and fresh water (no salt added):

(a) Calculate the base oil-water mixture mud weight from Equation (4.19):

$$MW_X = (0.75(6.7)) + (0.25(8.34)) = 7.1\text{ ppg}$$

(b) Calculate the starting volume using Equation (4.5):

$$V_s = \frac{(8.34(4.2)) - 16.0}{(8.34(4.2)) - 7.1}(100)$$

$$V_s = \frac{19.0}{27.9}(100) = 68.1\text{ bbls of a base oil-water mixture with an OWR of 75/25.}$$

(c) Calculate the volume of weight material in bbl:

$$V_{WM} = V_f - V_s \tag{4.21}$$

Where: V_{WM} = Volume of weight material in bbl

(d) Calculate the sacks of weight material required for the 100 bbl of mud:

$$W_M = V_{WM}(3.5(SG_{WM})) \tag{4.22}$$

Where: W_M = Number of 100 lb sacks of weight material required for 100 bbl of mud

Continue the *Example*:

100 − 68.1 = 31.9 bbl of weight material
V_{WM} ((3.5)(4.2)) = 575 sacks of weight material

4.4.2 Oil/Water Ratio from Retort Data

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

(a) Calculate the % of base oil in the OWR mixture:

$$O_{OWR} = \frac{O_{\%}}{(O_{\%} + W_{\%})} 100 \tag{4.23}$$

Where: O_{OWR} = Oil content in the OWR in %
$O_{\%}$ = Oil content in the mud in %
$W_{\%}$ = Water content in the mud in %

(b) Calculate the % of water in the OWR mixture:

$$W_{OWR} = \frac{W_{\%}}{(O_{\%} + W_{\%})} 100 \tag{4.24}$$

Example: Calculate the OWR of a mud that has the following data:

Oil content by volume:	51%
Water content by volume:	17%
Solids content by volume:	32%

$$O_{OWR} = \frac{51}{(51 + 17)} 100 = 75$$
$$W_{OWR} = \frac{17}{(51 + 17)} 100 = 25$$

The OWR is 75/25.

4.4.3 Change the OWR

Note: If the OWR is to be ***increased***, add oil; if it is to be ***decreased***, add water.

(a) To increase the oil content in the OWR, the current water content will be changed to a new volume percent in the OWR:

$$V_{nw} = \frac{W_o}{W_n} \tag{4.25}$$

Where: V_{nw} = New volume of base oil-water mixture in bbl when holding the water content constant
W_o = Old water content, bbl in 100 bbl of mud
W_n = New water content in % (decimal)

(b) The amount of oil to add is calculated by the following:

$$O_a = V_{nw} - V_o \tag{4.26}$$

Where: O_a = Volume of oil to be added in bbl
V_o = Old volume of base oil-water mixture in bbl

(c) To increase the water content in the OWR, the current oil content will be changed to a new volume:

$$V_{no} = \frac{O_o}{O_n} \tag{4.27}$$

Where: V_{no} = New volume of base oil-water mixture in bbl when holding the base oil content constant
O_o = Old oil content, bbl in 100 bbl of mud
O_n = New oil content in % (decimal)

(d) The amount of water to add is calculated by the following:

$$W_a = V_{no} - V_o \tag{4.28}$$

Where: W_a = Volume of water to be added in bbl

Example 1: Increase the OWR from 75/25 to 80/20:

Given:	Oil content by volume:	51%
	Water content by volume:	17%
	Solids content by volume:	32%
	OWR:	75/25

In 100 bbl of this mud, there are 68 bbl of liquid (oil plus water). To increase the OWR, 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 old liquid volume, but it will represent *only* 20% of the new liquid volume.

$$V_{nw} = \frac{17}{0.20}$$

V_{nw} = 85 bbls of new liquid volume after adding base oil to 100 bbl of mud volume.

O_a = 85 − 68 = 17 bbls of base oil to be added per 100 bbl of mud

Check the calculations.

$$O_{OWR} = \frac{51 + 17}{(68 + 17)} 100 = 80$$

The new OWR is 80/20.

Example 2: Change the OWR from 75/25 to 70/30:

As in Example 1, 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:

$$V_{no} = \frac{51}{0.70} = 72.8 \approx 73 \text{ bbls}$$

$W_a = 73 - 68 = 5$ bbls of water added per 100 bbl of mud.

Check the calculations.

$$W_{OWR} = \frac{17 + 5}{(68 + 5)} 100 = 30$$

The new OWR is 70/30.

4.5 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: Calculate the volume of saltwater in %:

$$W_s = \left[\left(5.88 \times 10^{-8} \mathrm{Cl}^{1.2}\right) + 1\right](W_{\%}) \tag{4.29}$$

Where: W_s = Volume of saltwater in %
Cl = Chloride content measured from the filtrate in ppm
$W_{\%}$ = Volume of water in mud from the retort in %

Step 2: Calculate the volume of the suspended solids in %:

$$S_s = 100 - O_{\%} - W_s \tag{4.30}$$

Where: S_s = Volume of suspended solids in %
$O_{\%}$ = Oil content in %

Step 3: Calculate the ASG of the saltwater:

$$W_{ASG} = \left[\left(1.94 \times 10^{-6}\right)\left(\mathrm{Cl}^{0.95}\right)\right] + 1 \tag{4.31}$$

Where: W_{ASG} = Average specific gravity of the saltwater

Step 4: Calculate the ASG of the solids suspended in the mud:

$$S_{ASG} = \frac{(12\,MW) - ((W_s)(W_{ASG})) - ((O_{\%})(O_{ASG}))}{S_s} \tag{4.32}$$

Where: S_{ASG} = Average specific gravity of suspended solids in the mud
$O_{\%}$ = Volume of oil in the mud in %
O_{ASG} = Specific gravity of base oil being used in mud (0.84 for diesel; 0.80 for IO)

Step 5: Calculate the ASG of solids *without* salt in the water phase:

$$S_{fASG} = \frac{(12\,MW) - (1\,W_{\%}) - ((O_{\%})(O_{ASG}))}{S_s} \tag{4.33}$$

Where: S_{fASG} = Average specific gravity of solids without salt in the water phase

Step 6: Calculate the volume of low gravity solids (LGS) in %:

$$LGS = \frac{(S_s)(WM_{SG} - S_{ASG})}{1.6} \tag{4.34}$$

Where: LGS = Volume of LGS in %

Step 7: Calculate the amount of LGS in lb/bbl:

$$LGS_{ppb} = 9.1\,LGS \tag{4.35}$$

Where: LGS_{ppb} = Amount of LGS in lb/bbl

Step 8: Calculate the volume of the weight material in %:

$$HGS = S_s - LGS \tag{4.36}$$

Where: HGS = Volume of high specific gravity weight material in %

Step 9: Calculate the amount of high specific gravity weight material in pounds (lb):

$$HGS_{ppb} = HGS(3.5(SG_{WM})) \quad (4.37)$$

Where: HGS_{ppb} = Amount of high specific gravity weight material in lb/bbl

Step 10: Calculate the amount of bentonite (high quality LGS) in the mud:

If the cation exchange capacity (CEC) of the formation clays and the methylene blue test (MBT) of the mud are known:

(a) Calculate the amount of bentonite in the mud in lb/bbl:

$$B_{ppb} = \left[\frac{1}{\left(1 - \left(\frac{F_{CEC}}{65}\right)\right)}\right]\left(M_{MBT} - 9\left(\frac{F_{CEC}}{65}\right)\right)LGS \quad (4.38)$$

Where: B_{ppb} = Amount of bentonite in the mud in lb/bbl
F_{CEC} = CEC of the formation solids
M_{MBT} = MBT of the mud

(b) Calculate the volume of bentonite in the mud in %:

$$B_{\%} = \frac{B_{ppb}}{9.1} \quad (4.39)$$

Where: $B_{\%}$ = Amount of bentonite in the mud in %

If the CEC of the formation clays are *not known*:

(a) Calculate the volume of bentonite in %:

$$B_{\%} = \frac{(M_{MBT} - LGS)}{8} \quad (4.40)$$

(b) Calculate the amount of bentonite in the mud in lb/bbl:

$$B_{ppb} = 9.1(B_{\%}) \qquad (4.41)$$

Step 11: Calculate the volume of drill solids in %:

$$DS_{\%} = LGS - B_{\%} \qquad (4.42)$$

Where: $DS_{\%}$ = Volume of drill solids in %

Step 12: Calculate the amount of drill solids in the mud in lb/bbl:

$$DS_{ppb} = 9.1(DS_{\%}) \qquad (4.43)$$

Where: DS_{ppb} = Amount of drill solids in lb/bbl

Example: Mud weight = 16.0 ppg
Chlorides = 73,000 ppm
MBT of mud = 30 lb/bbl
CEC of shale = 7 lb/bbl

Retort analysis:

Water = 57.0% by volume
Oil = 7.5% by volume (0.84 ASG diesel oil)
Solids = 35.5% by volume (4.2 ASG barite)

Step 1: Calculate the volume of the saltwater in %:

$$W_s = \left[\left(5.88 \times 10^{-8}\left(73,000^{1.2}\right)\right) + 1\right](57)$$

$$W_s = [0.0403055 + 1](57)$$

$$W_s = 59.297 \approx 59.3 \text{volume of salt water in } \%$$

Step 2: Calculate the volume of suspended solids in %:

$S_s = 100 - 7.5 - 59.3 = 33.2\%$ of suspended solids in the mud

Step 3: Calculate the ASG of the saltwater:

$$W_{\text{ASG}} = \left[\left(1.94 \times 10^{-6}\right)\left(73{,}000l^{0.95}\right)\right] + 1$$
$$W_{\text{ASG}} = [0.0809018] + 1$$
$$W_{\text{ASG}} = 1.0809$$

Step 4: Calculate the **ASG** of the solids suspended in the mud:

$$S_{\text{ASG}} = \frac{(12(16.0)) - ((59.3)(1.0809)) - ((7.5)(0.84))}{33.2}$$
$$S_{\text{ASG}} = \frac{121.6}{33.2}$$
$$S_{\text{ASG}} = 3.66$$

Step 5: Because a high chloride example is being used, Step 5 is omitted.

Step 6: Calculate the volume of LGS in %:

$$\text{LGS} = \frac{(33.2)(4.2 - 3.66)}{1.6}$$

LGS = 11.2% volume of LGS in the mud

Step 7: Calculate the amount of LGS in lb/bbl:

$\text{LGS}_{\text{ppb}} = 9.1(11.2) = 101.9$ ppb of LGS in the mud

Step 8: Calculate the volume of the weight material in %:

HGS = 33.2 − 11.2 = 22.0% volume of barite weight material

Step 9: Calculate the amount of high specific gravity weight material in pounds (lb/bbl):

$$\text{HGS}_{\text{ppb}} = 22.0(3.5(4.2))$$

$\text{HGS}_{\text{ppb}} = 323.4$ ppb of barite (HGS) in the mud

Step 10: Calculate the amount of bentonite in the mud in lb/bbl:

$$B_{\text{ppb}} = \left[\frac{1}{\left(1 - \left(\frac{7.0}{65}\right)\right)}\right]\left(30.0 - 9\left(\frac{7.0}{65}\right)\right)11.2$$

$$B_{\text{ppb}} = (1.121)(2.262)(11.2)$$

$B_{\text{ppb}} = 28.4\,\text{lb/bbl}$ of bentonite in the mud.

Step 11: Calculate the volume of bentonite in the mud in %:

$B_{\%} = \frac{28.4}{9.1} = 3.12\%$ volume of bentonite in the mud.

Step 12: Calculate the volume of drill solids in %:

$DS_{\%} = 11.2 - 3.12 = 8.1\%$ volume of drill solids in the mud.

Step 13: Calculate the amount of drill solids in the mud in lb/bbl:

$DS_{\text{ppb}} = 9.1(8.1) = 73.7\,\text{lb/bbl}$ amount of drill solids in the mud.

4.6 Solids Fractions (Barite Treated Muds)

4.6.1 Calculate the Maximum Recommended Solids Fraction in % Based on the Mud Weight

$$S_{RM} = (2.917\,MW) - 14.17 \tag{4.44}$$

Where: S_{RM} = Maximum recommended solids content in % by volume
MW = Mud weight in ppg

4.6.2 Calculate the Maximum Recommended LGS Fraction in % Based on the Mud Weight

$$LGS_{RM} = \left(\frac{S_{RM}}{100} - \left[0.3125\left(\left(\frac{MW}{8.34}\right) - 1\right)\right]\right)200 \tag{4.45}$$

Where: LGS_{RM} = Maximum recommended low gravity solids fractions, % by volume

Example: Calculate the maximum recommended solids content and LGS content in % with a 14.0 ppg water-based mud:

$$S_{RM} = (2.917(14.0)) - 14.17$$

$S_{RM} = 26.7\%$ maximum recommended solids content in the mud.

$$LGS_{RM} = \left(\frac{26.7}{100} - \left[0.3125\left(\left(\frac{14.0}{8.34}\right) - 1\right)\right]\right)200$$

$$LGS_{RM} = 0.2667 - (0.3125(0.6787))(200)$$

$$LGS_{RM} = (0.2667 - 0.2121)(200)$$

$LGS_{RM} = (0.0566)(200) = 11.3\%$ maximum recommended LGS content in the mud.

4.7 Dilution of Mud System

4.7.1 Calculate the Volume of Dilution in bbl Required to Reduce the Solids Content in the Mud System

$$V_{dm} = \frac{V_s(LGS - LGS_{RM})}{(LGS_{RM} - LGS_a)} \quad (4.46)$$

Where: V_{dm} = Volume of dilution with base liquid or mud in bbl
LGS_a = Low gravity solids from bentonite or chemicals added to the mud in %

Example: Calculate the volume of dilution required to change the LGS content from 6% to 4% in 1000 bbl of mud with fresh water:

$$V_{dm} = \frac{1000(6.0 - 4.0)}{(4.0 - 0.0)}$$

$$V_{dm} = \frac{2000}{4.0} = 500 \text{ bbls of water required}$$

Example: Calculate the volume of dilution with a 2% bentonite slurry required to change the LGS content from 6% to 4% in 1000 bbl of mud:

$$V_{dm} = \frac{1000(6.0 - 4.0)}{(4.0 - 2.0)}$$

$$V_{dm} = \frac{2000}{2.0} = 1000\,\text{bbls of volume with the bentonite slurry.}$$

4.7.2 Displacement—Barrels of Water/Slurry Required

$$V_{dmr} = \frac{V_s(LGS - LGS_{RM})}{(LGS - LGS_a)} \tag{4.47}$$

Where: V_{dmr} = Volume of mud in bbl to be jetted and base liquid or slurry to be added to maintain constant circulating volume

Example: Calculate the volume of mud jetted or dumped to change the LGS content from 6% to 4% and maintain the mud system volume at 1000 bbl:

$$V_{dmr} = \frac{1000(6.0 - 4.0)}{(6.0 - 0.0)}$$

$$V_{dmr} = \frac{2000}{6.0} = 333.3\,\text{bbls to be displaced with the dilution volume.}$$

Example: Calculate the volume of mud jetted or dumped to change the LGS content from 6% to 4% with a 2% bentonite slurry and maintain the mud system volume at 1000 bbl:

$$V_{dmr} = \frac{1000(6.0 - 4.0)}{(6.0 - 2.0)}$$

$$V_{dmr} = \frac{2000}{4.0} = 500\,\text{bbls to be displaced with the dilution volume.}$$

4.8 Evaluation of Hydrocyclones

4.8.1 Calculate the Mass of Solids (for an Unweighted Mud) and the Volume of Water Discarded by One Cone of a Hydrocyclone (Desander or Desilter) with a Water-Based Mud

$$H_s = \frac{(\mathrm{MW}) - 8.34}{13.37} \tag{4.48}$$

Where: H_s = Volume fraction of solids discarded by the hydrocyclone (decimal)

4.8.2 Calculate the Mass Rate of Solids in gal/h

$$S_{MR} = (19{,}530\,H_s)\left(\frac{V_Q}{t}\right) \tag{4.49}$$

Where: S_{MR} = Mass rate of solids discharged by one cone of a hydrocyclone in lb/h
V_Q = Volume of slurry collected in quarts
t = Time required to collect sample slurry in seconds

4.8.3 Calculate the Volume of Liquid Ejected by One Cone of a Hydrocyclone in gal/h

$$V_H = 900(1 - H_s)\left(\frac{V_Q}{t}\right) \tag{4.50}$$

Where: V_H = Volume of liquid ejected by one cone of a hydrocyclone in gal/h

Example: Calculate the evaluation of a single hydrocyclone cone with the following data:

Average mud weight of slurry sample collected:	16.0 ppg
Sample collection time:	45 s
Volume of slurry sample collected:	2 quarts

(a) Calculate the volume fraction of solids discharged:

$$H_s = \frac{(16.0) - 8.34}{13.37}$$

$$H_s = 0.573$$

(b) Calculate the mass rate of solids discharged:

$$S_{MR} = (19,530(0.573))\left(\frac{2.0}{45}\right)$$

$$S_{MR} = 497.4\,\text{lb/h of solids discarded}$$

(c) Calculate the volume rate of liquid ejected by one cone:

$$V_H = 900(1 - 0.573)\left(\frac{2}{45}\right)$$

$$V_H = 900(0.427)(0.0444)$$

$$V_H = 17.1\,\text{gal/h volume of liquid ejected by one cone}$$

4.9 Evaluation of Centrifuge

4.9.1 Evaluate the Centrifuge Underflow

(a) Calculate the underflow mud volume in gal/min:

$$C_U = \frac{[C_F(\text{MW} - C_O)] - [C_D(C_O - \text{MW}_D)]}{(\text{MW}_U - C_O)} \tag{4.51}$$

Where: C_U = Centrifuge underflow volume in gal/min
C_F = Volume of mud feed into centrifuge in gal/min
C_O = Centrifuge overflow mud weight in ppg
C_D = Volume of dilution in gal/min
MW_D = Mud weight of dilution liquid in ppg
MW_U = Mud weight of underflow in ppg

(b) Calculate the fraction of old mud in underflow in %:

$$C_{OM} = \frac{(SG_{WM}(L_b)) - (MW_U)}{(SG_{WM}(L_b)) - MW + \left(\frac{C_D}{C_F}((SG_{WM}(L_b)) - MW_D)\right)} \tag{4.52}$$

Where: C_{OM} = Volume fraction of mud in underflow in %

(c) Calculate the mass rate of clay (LGS) going into the mixing pit in lb/min:

$$C_{UC} = \frac{LGS_{ppb}(C_F - (C_U(C_{OM})))}{42} \tag{4.53}$$

Where: C_{UC} = Amount of clay in the centrifuge underflow in lb/min

(d) Calculate the mass rate of additives in the underflow going into the mixing pit in lb/min:

$$C_{UA} = \frac{A(C_F - (C_U(C_{OM})))}{42} \tag{4.54}$$

Where: C_{UA} = Mud additives in the underflow going into the mixing pit in lb/min
A = Additive content in lb/bbl

(e) Calculate the base liquid flow rate going into mixing pit in gal/min:

$$C_{UL} = \frac{(C_F((3.5\,SG_{WM}) - MW)) - (C_U((3.5\,SG_{WM}) - MW_U)) - (0.6129\,C_{UC}) - (0.6129(C_{UA}))}{(3.5\,SG_{WM}) - L_b} \tag{4.55}$$

Where: C_{UL} = Volume of base liquid flow rate going into the mixing pit in gal/min

(f) Calculate the mass rate of weight material (barite) going into the mixing pit in lb/min:

$$C_{UB} = C_F - C_U - C_{UL} - \left(\frac{C_{UC}}{21.7}\right) - \left(\frac{C_{UA}}{21.7}\right)(3.5\,SG_{WM}) \quad (4.56)$$

Where: C_{UB} = Amount of weight material going into the mixing pit in lb/min

Example: Calculate the following data:

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 barite into mixing pit

Mud density into centrifuge	= 16.2 ppg
Mud volume into centrifuge	= 16.5 ppg
Dilution water density	= 8.34 ppg
Dilution water volume	= 10.5 gal/min
Underflow mud density	= 23.4 ppg
Overflow mud density	= 9.3 ppg
Clay content of mud	= 22.5 lb/bbl
Additive content of mud	= 6 lb/bbl

(a) Calculate the underflow mud volume in gal/min:

$$C_U = \frac{[16.5(16.2 - 9.3)][10.5(9.3 - 8.34)]}{(23.4 - 9.3)}$$

$$C_U = \frac{113.85 - 10.08}{14.1}$$

$$C_U = 7.4\,\text{gal/min}$$

(b) Calculate the fraction of old mud in underflow in %:

$$C_{OM} = \frac{(4.2(8.34)) - (23.4)}{(4.2(8.34)) - 16.2 + \left(\frac{10.5}{16.5}((4.2(8.34)) - 8.34)\right)}$$

$$C_{OM} = \frac{11.6}{18.8 + (0.63636(26.66))}$$

$$C_{OM} = 0.324\%$$

(c) Calculate the mass rate of clay (LGS) going into the mixing pit in lb/min:

$$C_{UC} = \frac{22.5(16.5 - (7.4(0.324)))}{42}$$

$$C_{UC} = \frac{22.5(14.1)}{42}$$

$$C_{UC} = 7.55\,\text{lb/min}$$

(d) Calculate the mass rate of additives in the underflow going into the mixing pit in lb/min:

$$C_{UA} = \frac{6.0(16.5 - (7.4(0.324)))}{42}$$

$$C_{UA} = \frac{6.0(14.1)}{42}$$

$$C_{UA} = 2.01\,\text{lb/min}$$

(e) Calculate the base liquid flow rate going into mixing pit in gal/min:

$$C_{UL} = \frac{(16.5((3.5(4.2)) - 16.2)) - (7.4((3.5(4.2)) - 23.4)) - (0.6129(7.55)) - (0.6129(2.0))}{(3.5(4.2)) - 8.34}$$

$$C_{UL} = \frac{218.5}{26.66} = 8.20\,\text{gal/min}$$

(f) Calculate the mass rate of weight material (barite) going into the mixing pit in lb/min:

$$C_{UB} = 16.5 - 7.4 - 8.2 - \left(\frac{7.55}{21.7}\right) - \left(\frac{2.0}{21.7}\right)(35)$$

$$C_{UB} = 0.4599(35) = 16.1\ \text{lb/min}$$

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CHAPTER FIVE

Cementing Calculations

5.1 Cement Additive Calculations

Step 1: Calculate the weight of additive per sack of cement in lb:

$$W_{ca} = (V_{a\%})(94.0) \quad (5.1)$$

Where: W_{ca} = Weight of cement additive in lb
$V_{a\%}$ = Volume percent of additive for cement mixture
94.0 = Pounds of cement in one sack (sk)

Step 2: Total water requirement for each sack of cement in gal/sk:

$$V_{cwt} = V_{cw} + V_{aw} \quad (5.2)$$

Where: V_{cwt} = Total volume of water required for each sack of cement in gal/sk
V_{cw} = Volume of water required for cement portion in gal/sk (Table 5.1)
V_{aw} = Volume of water required for additive portion in gal/sk (Table 5.1)

Step 3: Calculate the volume of the cement slurry in gal/sk:

$$V_{cs} = \left(\frac{94.0}{(SG_{cmt})(8.33)}\right) + \left(\frac{W_{ca}}{(SG_a)(8.33)}\right) + V_{cwt} \quad (5.3)$$

Where: V_{cs} = Volume of cement slurry in gal/sk
SG_{cmt} = Specific gravity of dry cement
SG_a = Specific gravity of dry additive
8.33 = Density of fresh water in lb/gal

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Table 5.1
Water Requirements and Specific Gravity of Common Cement Additives

Material	Water Requirement (gal/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
Common cement additives		
Attapulgite	1.3 for 2% gel in cement	2.89
Cement Fondu	4.5	3.23
Lumnite cement	4.5	3.20
Trinity Lite-weight cement	9.7	2.80
Bentonite	1.3 for 2% gel in cement	2.65
Calcium carbonate powder	0	1.96
Calcium chloride	0	1.96
Cal-Seal (gypsum cement)	4.5	2.70
CFR-1	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 for 10% in cement	2.10
Diacel LWL	0 (up to 0.7%) 0.8:1/1% in cement	1.36
Gilsonite	2 for 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 1b/ft.^{3}	2.20
Perlite 6	6/38 1b/ft.^{3}	–
Pozmix® A	4.6-5.0	2.46
Salt (NaCl)	0	2.17
Sand Ottawa	0	2.63
Silica flour	1.6 for 35% flour 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

Step 4: Calculate the yield of the cement slurry in ft.^{3}/sk:

$$Y_{cs} = \left(\frac{V_s}{7.48}\right) \tag{5.4}$$

Where: Y_{cs} = Yield of cement slurry mixture in ft.^{3}/sk
7.48 = Volume of fresh water in gal/ft.^{3}

Step 5: Calculate the cement slurry density in lb/gal:

$$W_{cs} = \left(\frac{94.0 + W_{ca} + (8.33(V_{cwt}))}{V_s}\right) \tag{5.5}$$

Where: W_{cs} = Weight of cement slurry in lb/gal

Example: Using a Class A cement plus 4% bentonite with normal mixing water, calculate the following:

1. Amount of bentonite to add in lb/sk
2. Total water volume required for the slurry in gal/sk
3. Slurry yield in ft.^{3}/sk
4. Slurry weight in lb/gal

Step 1: Calculate the weight of the bentonite additive:

$$W_{ca} = (0.04)(94.0) = 3.76\,\text{lb/sk}$$

Step 2: Calculate the total water requirement per sack of cement used:

$$V_{cwt} = 5.2 + 2.6 = 7.8\,\text{gal/sk}$$

Step 3: Calculate the total volume of the cement slurry:

$$V_{cs} = \left(\frac{94.0}{(3.14)(8.33)}\right) + \left(\frac{3.76}{(2.65)(8.33)}\right) + 7.8 = 11.56\,\text{gal/sk}$$

Step 4: Calculate the yield of the cement slurry:

$$Y_{cs} = \left(\frac{11.56}{7.48}\right) = 1.55\,\text{ft.}^3/\text{sx}$$

Step 5: Calculate the cement slurry density:

$$W_{cs} = \left(\frac{94.0 + 3.76 + (8.33(7.8))}{11.56}\right) = 14.08\,\text{lb/gal}$$

5.2 Water Requirements

Step 1: Calculate the weight of cement additive materials in lb/sk:

$$W_{cam} = 94.0 + (8.33(V_{cwt})) + (94.0(V_{\%})) \tag{5.6}$$

Where: W_{cam} = Weight of cement additive materials in lb/sk

Step 2: Calculate the water requirement for the slurry using material balance equation:

$$(D_1)(V_1) = (D_2)(V_2) \tag{5.7}$$

Where: D_1 = Density of item 1 in consistent units
V_1 = Volume of item 1 in consistent units
D_2 = Density of item 2 in consistent units
V_2 = Volume of item 2 in consistent units

Example: Using a Class H cement plus 6% bentonite to be mixed at 14.0 1b/gal.

Calculate the following:

1. Bentonite requirement in lb/sk
2. Water requirement in gal/sk
3. Slurry yield in ft.^{3}/sk
4. Check the slurry weight in lb/gal

Step 1: Calculate the weight of cement additive materials:

$$W_{cam} = 94.0 + (8.33(x)) + (94.0(0.06)) = 99.64 + (8.33x)\ \text{lb/sk}$$

Step 2: Calculate the volume of cement slurry:

$$V_{cs} = \left(\frac{94.0}{(3.14)(8.33)}\right) + \left(\frac{5.64}{(2.65)(8.33)}\right) + x = 3.86 + x\ \text{gal/sk}$$

Step 3: Calculate the water requirement using the material balance equation:

$$\begin{aligned}
(99.64 + 8.33x) &= (3.86 + x)(14.0)\\
(99.64 + 8.33x) &= (54.04 + 14.0x)\\
(99.64 - 54.04) &= (14.0x - 8.33x)\\
(45.6) &= (5.67x)\\
\frac{45.6}{5.67} &= x\\
8.04 &= x \approx 8.0\ \text{gal/sk water requirement per sack of cement}
\end{aligned}$$

Step 4: Calculate the yield of the cement slurry:

$$Y_{cs} = \left(\frac{3.6 + 0.26 + 8.0}{7.48}\right) = 1.59\ \text{ft.}^3/\text{sk}$$

Step 5: Recheck the cement slurry density:

$$W_{cs} = \left(\frac{94.0 + 5.64 + (8.33(8.0))}{11.86}\right) = 14.0\ \text{lb/gal}$$

5.3 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:	Cement	= 240 sk
	Slurry density	= 13.8 lb/gal
	Mixing water	= 8.6 gal/sk
	Bentonite to be *pre-hydrated*	= 1.5%

Step 1: Calculate the volume of mixing water required in gal:

$$V_{\text{cwt}} = (240)(8.6) = 2064\,\text{gal}$$

Step 2: Calculate the total weight of mixing water in lb:

$$W_{\text{mw}} = (2064)(8.33) = 17,193\,\text{lb}$$

Where: W_{mw} = Total weight of mixing water in lb

Step 3: Calculate the amount of bentonite required in lb:

$$W_{\text{ben}} = (17,193)(0.015) = 258\,\text{lb}$$

Where: W_{ben} = Weight of bentonite required in lb

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

Cement program:	Cement	= 240 sk
	Halad (fluid loss)	= 0.50%
	CFR-2 (dispersant)	= 0.40%

Step 1: Calculate the weight of the cement:

$$W_{\text{cmt}} = (240)(94) = 22,560\,\text{lb}$$

Step 2: Calculate the weight of the fluid loss additive:

$$\text{Halad} = (22,560)(0.005) = 112.8\,\text{lb}$$

Step 3: Calculate the weight of the dispersant:

$$CFR-2=(22,560)(0.004)=90.24\,\text{lb}$$

5.4 Weighted Cement Calculations

Step 1: Calculate the amount of high density additive required per sack of cement to achieve a required cement slurry density in lb:

$$W_{ca}=\frac{(((W_{cs})(11.207983))/SG_{cmt})+((W_{cs})(V_{cwt}))-94.0-((8.33)(W_{cs}))}{\left(1+\left(\frac{V_{wa}}{100}\right)\right)-\left(\frac{W_{cs}}{(SG_a)(8.33)}\right)-\left((W_{cs})\left(\frac{V_{wa}}{100}\right)\right)} \tag{5.8}$$

Where: W_{ca} = Additive required per sack of cement in lb
W_{cs} = Required cement slurry density in lb/gal
SG_{cmt} = Specific gravity of cement
V_{cwt} = Water requirement of cement in gal/sk
V_{wa} = Water requirement of additive in gal/sk
SG_a = Specific gravity of additive (Table 5.2)

Example: Calculate how much hematite (in lb/sk) is 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

Table 5.2
Weighting Agents for Cement

Additive	Water Requirement (gal/94 lb/sk)	Specific Gravity
Hematite	0.34	5.02
Ilmenite	0	4.67
Barite	2.5	4.23
Sand	0	2.63

$$W_a = \frac{(((17.5)(11.207983))/3.14) + ((17.5)(4.3)) - 94.0 - ((8.33)(4.3))}{\left(1 + \left(\frac{0.34}{100}\right)\right) - \left(\frac{17.5}{(5.02)(8.33)}\right) - \left((17.5)\left(\frac{0.34}{100}\right)\right)}$$

$$W_a = \frac{(62.4649) + (75.25) - 94.0 - (35.819)}{(1.0034) - (0.418494) - (0.0595)} = \frac{(7.8959)}{(0.525406)}$$

$$= 15.1 \text{ lb per sack of cement}$$

5.5 Calculations for the Number of Sacks of Cement Required

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

Step 1: Calculate the following capacities:

(a) Annular capacity in ft.^{3}/ft.:

$$V_{acf} = \left(\frac{D_h^2 - D_p^2}{183.35}\right) \tag{5.9}$$

Where: V_{acf} = Annular capacity in ft.^{3}/ft.

(b) Casing capacity in ft.^{3}/ft.:

$$V_{cc} = \left(\frac{D_i^2}{183.35}\right) \tag{5.10}$$

Where: V_{cc} = Casing capacity in ft.^{3}/ft.

(c) Casing capacity in bbl/ft.:

$$V_{pc} = \left(\frac{D_i^2}{1029.4}\right)$$

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

$$SR_L = \frac{(L_{cmt})(V_{ac})(1 + (V_{\%e}/100))}{Y_L} \tag{5.11}$$

Where: SR_L = Cement required for LEAD job in sk
L_{cmt} = Length of section to be cemented in ft.
$V_{\%e}$ = Excess volume for job in %
Y_L = Yield of LEAD cement in ft.^{3}/sk

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

$$SR_{Ta} = \frac{(L_{cmt})(V_{ac})(1 + (V_{\%e}/100))}{Y_T} \tag{5.12}$$

Where: SR_{Ta} = Cement required in annulus for the TAIL job in sk
Y_T = Yield of TAIL cement in ft.^{3}/sk

$$SR_{Tc} = \frac{(L_{cmt})(V_{cc})}{Y_T} \tag{5.13}$$

Where: SR_{Tc} = Cement required inside the casing for the TAIL job in sk

Step 4: Calculate the total sacks of TAIL cement required:

$$SR_{Tt} = SR_{Ta} + SR_{Tc} \tag{5.14}$$

Step 5: Calculate the casing capacity down to the float collar:

$$V_{fc} = (V_{pc})(L_{fc}) \tag{5.15}$$

Where: V_{fc} = Casing capacity down to the float collar in bbl
L_{fc} = Length of casing from the surface to the float collar in ft.

Step 6: Calculate the number of strokes required to bump the plug:

$$S_{bp} = \left(\frac{V_{pc}}{O_p}\right) \tag{5.16}$$

Where: S_{bp} = Strokes to bump the plug

Example: Calculate the following based on the data listed below:

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	= 17½ in.
Casing—54.5 lb/ft.	= 13⅜ in.
Casing ID	= 12.615 in.
Float collar (number of feet above shoe)	= 44 ft.
Pump (5½ in. by 14 in. duplex @ 90% eff)	= 0.112 bbl/stk

Cement program:

LEAD cement (13.8 1b/gal)	= 2000 ft.
Slurry yield	= 1.59 ft.^{3}/sk
TAIL cement (15.8 1b/gal)	= 1000 ft.
Slurry yield	= 1.15 ft.^{3}/sk
Excess volume	= 50%

Step 1: Calculate the following capacities:

(a) Annular capacity in ft.^{3}/ft.:

$$V_{ac} = \left(\frac{17.5^2 - 13.375^2}{183.35}\right) = 0.6946\,\text{ft.}^3/\text{ft.}$$

(b) Casing capacity in ft.^{3}/ft.:

$$V_{cc} = \left(\frac{12.615^2}{183.35}\right) = 0.8679\,\text{ft.}^3/\text{ft.}$$

(c) Casing capacity in bbl/ft.:

$$V_{pc} = \left(\frac{12.615^2}{1029.4}\right) = 0.1545\,\text{bbl/ft.}$$

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

$$\text{SR}_\text{L} = \frac{(2000)(0.6946)(1 + (50/100))}{1.59} = 1311\,\text{sk}$$

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

$$\text{SR}_\text{Ta} = \frac{(1000)(0.6946)(1 + (50/100))}{1.15} = 906\,\text{sk}$$

$$\text{SR}_\text{Tc} = \frac{(44)(0.8679)}{1.15} = 33\,\text{sk}$$

$$\text{SR}_\text{Tt} = 906 + 33 = 939\,\text{sk}$$

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

$$V_{fc} = (0.1545)(3000 - 44) = 456.7\,\text{bbl}$$

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

$$S_{bp} = \left(\frac{456.7}{0.112}\right) = 4078\,\text{stks}$$

5.6 Calculations for the Number of Feet to Be Cemented

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

Step 1: Calculate the following capacities:

(a) Annular capacity in ft.^{3}/ft.:

$$V_{ac} = \left(\frac{D_h^2 - D_p^2}{183.35} \right)$$

(b) Casing capacity in ft.^{3}/ft.:

$$V_{cc} = \left(\frac{D_i^2}{183.35} \right)$$

Step 2: Calculate the slurry volume in ft.^{3}:

$$V_{cs} = (ST_t)(Y_s) \tag{5.17}$$

Where: V_{cs} = Volume of cement slurry in ft.^{3}

Step 3: Calculate the amount of cement to be left in casing in ft.^{3}:

$$V_{cc} = \left(L_{csg} - D_{st} \right)(V_{cc}) \tag{5.18}$$

Where: V_{cc} = Volume of cement left in casing in ft.^{3}

Step 4: Calculate the height of cement in the annulus in ft.:

$$H_{cmt} = \frac{(V_s - V_{cc})/V_{ac}}{1 + (V_{\%e}/100)} \tag{5.19}$$

Where: H_{cmt} = Height of cement slurry in the annulus in ft.

Step 5: Calculate the depth of the top of the cement slurry in the annulus in ft.:

$$D_{tcmt} = (L_c - L_{cmt}) \tag{5.20}$$

Where: D_{tcmt} = Depth of the top of the cement slurry in the annulus in ft.

Step 6: Calculate the volume of mud required to displace the cement in bbl:

$$V_{dcmt} = (L_p - L_{as})(V_p) \tag{5.21}$$

Where: V_{dcmt} = Volume of mud required to displace cement slurry in bbl
L_{as} = Length of distance between cementing tool and casing shoe in ft.

Step 7: Calculate the number of strokes required to displace the cement slurry:

$$S_{dcmt} = \left(\frac{V_{dcmt}}{O_p}\right) \tag{5.22}$$

Where: S_{dcmt} = The number of strokes required to displace the cement

Example: Calculate the following from the data listed below:

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

Data: Casing setting depth = 3000 ft.
Hole size = 17½ in.
Casing (54.5 lb/ft.) = 13⅜ in.
Casing ID = 12.615 in.
Drill pipe (5.0 in., 19.5 1b/ft.) = 0.01776 bbl/ft.
Pump (7 × 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: Calculate the following capacities:

(a) Annular capacity between casing and hole in ft.^{3}/ft.:

$$V_{ac} = \left(\frac{17.5^2 - 13.375^2}{183.35}\right) = 0.6946\,\text{ft.}^3/\text{ft.}$$

(b) Casing capacity in ft.^{3}/ft.:

$$V_{cc} = \left(\frac{12.615^2}{183.35}\right) = 0.8679\,\text{ft.}^3/\text{ft.}$$

Step 2: Calculate the cement slurry volume in ft.^{3}:

$$V_{cs} = (500)(1.15) = 575\,\text{ft.}^3$$

Step 3: Calculate the amount of cement, ft.^{3}, to be left in the casing:

$$V_{cc} = (3000 - 2900)(0.8679) = 86.79\,\text{ft.}^3$$

Step 4: Calculate the height of the cement in the annulus in ft.:

$$H_{cmt} = \frac{(575 - 86.79)/0.6946}{1 + (50/100)} = 468.58\,\text{ft.}$$

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

$$D_{\mathrm{tcmt}} = (3000 - 468.58) = 2531.42\,\mathrm{ft.}$$

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

$$V_{\mathrm{dcmt}} = (3000 - 100)(0.01766) = 51.5\,\mathrm{bbl}$$

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

$$S_{\mathrm{dcmt}} = \left(\frac{51.5}{0.136}\right) = 379\,\mathrm{stks}$$

5.7 Setting a Balanced Cement Plug

Step 1: Calculate the following capacities:

(a) Calculate the annular capacity between pipe or tubing and hole or casing in ft.^{3}/ft.:

$$V_{\mathrm{ac}} = \left(\frac{D_{\mathrm{h}}^2 - D_{\mathrm{p}}^2}{183.35}\right)$$

(b) Calculate the annular capacity between pipe or tubing and hole or casing in ft./bbl:

$$V_{\mathrm{acf}} = \left(\frac{1029.4}{D_{\mathrm{h}}^2 - D_{\mathrm{p}}^2}\right)$$

(c) Hole or casing capacity in ft.^{3}/ft.:

$$V_{\mathrm{cc}} = \left(\frac{D_{\mathrm{i}}^2}{183.35}\right)$$

(d) Drill pipe or tubing capacity in ft.³/ft.:

$$V_{\text{dpc}} = \left(\frac{D_i^2}{183.35}\right)$$

(e) Drill pipe or tubing capacity in bbl/ft.:

$$V_{\text{pcb}} = \left(\frac{D_i^2}{1029.4}\right)$$

Step 2: Calculate 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:

$$\text{SR}_{\text{plug}} = \frac{(L_{\text{plug}})(V_{\text{acf}})(1 + (V_{\%e}/100))}{Y_{\text{cs}}} \tag{5.23}$$

Where: SR_{plug} = Cement required for a given length of plug in sk
L_{plug} = Length of plug in ft.
V_{acf} = Hole or casing capacity in ft.³/ft.
$V_{\%e}$ = Excess volume for job in %
Y_{cs} = Yield of cement slurry in ft.³/sk

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

OR

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

$$L_{\text{plug}} = \left(\frac{((\text{SR}_{\text{plug}})(Y_{\text{cs}})/V_{\text{ac}})}{\left(1 + \left(\frac{V_{\%e}}{100}\right)\right)}\right) \tag{5.24}$$

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

Step 3: Calculate the spacer volume (usually water) to be pumped behind the cement slurry to balance the plug in bbl:

$$V_{\text{spacer behind}} = \left(\frac{V_{\text{ac}}}{\left(1 + \left(\frac{V_{\%\text{e}}}{100}\right)\right)} \right) \left(V_{\text{spacer ahead}}\right) \left(V_{\text{pc}}\right) \tag{5.25}$$

Where: $V_{\text{spacer behind}}$ = Volume of spacer pumped behind cement plug in bbl
$V_{\text{spacer ahead}}$ = Volume of spacer pumped ahead of cement plug in bbl

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

Step 4: Calculate the plug length before the pipe is withdrawn in ft.:

$$L_{\text{plug}} = \frac{\left(\text{SR}_{\text{plug}}\right)\left(Y_{\text{cs}}\right)}{\left(\left(\left(V_{\text{ac}}\right)\left(1 + \left(\frac{V_{\%\text{e}}}{100}\right)\right)\right) + \left(V_{\text{pf}}\right)\right)} \tag{5.26}$$

Where: SR_{cmt} = Cement required for plug in sk

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

Step 5: Calculate the fluid volume required to spot the plug in bbl:

$$V_{\text{displace}} = \left(L_{\text{p}} - L_{\text{plug}}\right)\left(V_{\text{pc}}\right) - V_{\text{spacer behind}} \tag{5.27}$$

Where: V_{displace} = Volume of fluid required to spot the plug in bbl
L_{p} = Length of pipe or tubing in ft.

Example 1: A 300 ft. plug is to be placed at a depth of 5000 ft. The open-hole size is 8½ in. and the drill pipe is 3½ in.—13.3 1b/ft.; ID—2.764 in. Ten barrels of water will be pumped ahead of the slurry. Use a slurry yield of 1.15 ft.^{3}/sk. Use 25% as the excess for the 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: Calculate the following capacities:

(a) Annular capacity between drill pipe and hole in ft.^{3}/ft.:

$$V_{ac} = \left(\frac{8.5^2 - 3.5^2}{183.35}\right) = 0.3272\,\text{ft.}^3/\text{ft.}$$

(b) Annular capacity between drill pipe and hole in ft./bbl:

$$V_{acf} = \left(\frac{1029.4}{8.5^2 - 3.5^2}\right) = 17.1569\,\text{ft./bbl}$$

(c) Hole capacity in ft.^{3}/ft.:

$$V_{cc} = \left(\frac{8.5^2}{183.35}\right) = 0.3941\,\text{ft.}^3/\text{ft.}$$

(d) Drill pipe capacity in bbl/ft.:

$$V_{pb} = \left(\frac{2.764^2}{1029.4}\right) = 0.00742\,\text{bbl/ft.}$$

(e) Drill pipe capacity in ft.^{3}/ft.:

$$V_{pf} = \left(\frac{2.764^2}{183.35}\right) = 0.0417\,\text{ft.}^3/\text{ft.}$$

Step 2: Calculate the number of sacks of dry cement required:

$$SR_L = \frac{(300)(0.3941)(1 + (25/100))}{1.15} = 129\,\text{sk}$$

Step 3: Calculate the spacer volume (water) to be pumped behind the cement slurry to balance the plug in bbl:

$$V_{\text{spacer behind}} = \left(\frac{17.1569}{\left(1 + \left(\frac{25}{100}\right)\right)}\right)(10)(0.00742) = 1.018\,\text{bbl}$$

Step 4: Calculate the plug length before the pipe is withdrawn in ft.:

$$L_{\text{plug}} = \frac{(129)(1.15)}{\left(\left((0.3272)\left(1 + \left(\frac{25}{100}\right)\right)\right) + (0.0417)\right)} = 329\,\text{ft.}$$

Step 5: Calculate the volume of the displacing fluid required to spot the plug in bbl:

$$V_{\text{displace}} = [(5000 - 329)(0.00742)] - 1.0 = 33.6\,\text{bbl}$$

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 8½ in., hole. Use 1.15 ft.^{3}/sk for the cement slurry yield. The capacity of 8½ in. hole = 0.3941 ft.^{3}/ft. Use 50% as excess slurry volume:

$$L_{\text{plug}} = \left(\frac{(((100)(1.15))/0.3941)}{\left(1 + \left(\frac{50}{100}\right)\right)}\right) = 194.5\,\text{ft.}$$

5.8 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: 9⅝ in. casing—43.5 1b/ft. in 12¼ in. hole:

Well depth		= 8000 ft.
Cementing program:		
LEAD slurry	2000 ft.	= 13.8 1b/gal
TAIL slurry	1000 ft.	= 15.8 1b/gal
Mud weight		= 10.0 lb/gal
Float collar (no. of feet above shoe)		= 44 ft.

Step 1: Calculate the total hydrostatic pressure of cement and mud in the annulus:

(a) Hydrostatic pressure of mud in annulus in psi:

$$HP_{ma} = (10.0)(0.052)(5000) = 2600\ \text{psi}$$

(b) Hydrostatic pressure of LEAD cement in psi:

$$HP_L = (13.8)(0.052)(2000) = 1435\ \text{psi}$$

(c) Hydrostatic pressure of TAIL cement in psi:

$$HP_T = (15.8)(0.052)(1000) = 822\ \text{psi}$$

(d) Total hydrostatic pressure in annulus in psi:

$$HP_{ta} = (2600 + 1435 + 822) = 4857\ \text{psi}$$

Step 2: Calculate the total pressure inside the casing in psi:

(a) Pressure exerted by the mud in psi:

$$HP_m = (10.0)(0.052)(8000 - 44) = 4137\,\text{psi}$$

(b) Pressure exerted by the cement in psi:

$$HP_{cmt} = (15.8)(0.052)(44) = 36\,\text{psi}$$

(c) Total pressure inside the casing in psi:

$$HP_{csg} = (4137 + 36) = 4173\,\text{psi}$$

Step 3: Calculate the differential pressure in psi:

$$P_d = (4857 - 4173) = 684\,\text{psi}$$

5.9 Hydraulicing Casing

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

Step 1: Calculate the difference in the pressure gradient between the cement and the mud in psi/ft.:

$$PG_d = (W_{cmt} - W_m)(0.052) \tag{5.28}$$

Where: PG_d = Difference in the pressure gradient between the cement and the mud in psi/ft.

Step 2: Calculate the differential pressure (DP) between the cement and the mud in psi:

$$DP = (PG_d)\left(L_{csg}\right) \tag{5.29}$$

Where: DP = Differential pressure between the cement and the mud in psi
L_{csg} = Length of the casing in ft.

Step 3: Calculate the area of the casing below the shoe in sq. in.:

$$A_{bcs} = \left(D_c^2\right)(0.7854) \tag{5.30}$$

Where: A_{bcs} = Area below the casing shoe in sq. in.
D_c = Diameter of casing in in.

Step 4: Calculate the upward force (F) in lb. This is the weight or total force acting at the bottom of the shoe:

$$F_{up} = (A_{bcs})(DP) \tag{5.31}$$

Where: F_{up} = Upward force on casing in lb

Step 5: Calculate the downward force (W) in lb. This is the weight of the casing:

$$F_{down} = \left(W_{csg}\right)\left(L_{csg}\right)(BF) \tag{5.32}$$

Where: F_{down} = Downward force or weight of the casing in lb
W_{csg} = Weight of the casing in lb/ft.

Step 6: Calculate the difference in these forces in lb:

$$F_d = \left(F_{down} - F_{up}\right) \tag{5.33}$$

Where: F_d = Differential force in lb

Step 7: Calculate the pressure required to balance these forces so that the casing will not hydraulic out of the hole (move upward) in psi:

$$P_b = \left(\frac{F_d}{A_{bcs}}\right) \tag{5.34}$$

Where: P_b = Pressure to balance forces in psi

Step 8: Calculate the mud weight increase required to balance the pressure in lb/gal:

$$W_{mb} = \left(\frac{(P_b/0.052)}{L_{csg}}\right) \tag{5.35}$$

Where: W_{mb} = Mud weight increase required to balance pressure in lb/gal
L_{csg} = Length of casing in ft.

Step 9: Calculate the new mud weight in lb/gal:

$$W_{mn} = (W_m + W_{mb}) \tag{5.36}$$

Where: W_{mn} = New mud weight to balance pressure in lb/gal

Check the forces with the new mud weight with the following equations:

(a) $\text{PG} = (W_{cmt} - W_m)(0.052)$
(b) $\text{DP} = (\text{PG})(L_{csg})$
(c) $F_{up} = (A_{bcs})(\text{DP})$
(d) $F_d = (F_{down} - F_{up})$

Example: Calculate the forces and new mud weight with the following data:

Casing size = 13⅜ in. – 54 lb/ft.
Cement weight = 15.8 lb/gal
Mud weight = 8.8 lb/gal
Buoyancy factor = 0.8656
Well depth = 164 ft.

Step 1: Calculate the difference in pressure gradient between the cement and the mud in psi/ft.:

$$PG = (15.8 - 8.8)(0.052) = 0.364\,\text{psi/ft.}$$

Step 2: Calculate the differential pressure between the cement and the mud in psi:

$$DP = (0.364)(164) = 60\,\text{psi}$$

Step 3: Calculate the area of the casing below the shoe in sq. in.:

$$A_{bcs} = \left(13.375^2\right)(0.7854) = 140.5\,\text{in.}^2$$

Step 4: Calculate the upward force (F) in lb. This is the weight or total force acting at the bottom of the shoe:

$$F_{up} = (140.5)(60) = 8430\,\text{lb}$$

Step 5: Calculate the downward force (W) in lb. This is the weight of the casing:

$$F_{down} = (54.5)(164)(0.8656) = 7737\,\text{lb}$$

Step 6: Calculate the difference in these forces in lb:

$$F_d = (7737 - 8430) = -693\,\text{lb}$$

The resultant force is **NEGATIVE!**

Therefore: Unless the casing is tied down or stuck, it will "hydraulic" out of the hole (move upward).

Step 7: Calculate the pressure required to balance these forces so that the casing will not hydraulic out of the hole (move upward) in psi:

$$P_b = \left(\frac{693}{140.5}\right) = 4.9\,\text{psi}$$

Step 8: Calculate the mud weight increase required to balance the pressure in lb/gal:

$$W_{\text{mb}} = \left(\frac{(4.9/0.052)}{164}\right) = 0.57 \approx 0.6\,\text{lbm/gal}$$

Step 9: Calculate the new mud weight in lb/gal:

$$W_{\text{mn}} = (8.8 + 0.6) = 9.4\,\text{lbm/gal}$$

Check the forces with the new mud weight:

(a) $\text{PG} = (15.8 - 9.4)(0.052) = 0.3328\,\text{psi}$
(b) $\text{DP} = (0.3328)(164) = 54.58\,\text{psi}$
(c) $F_{\text{up}} = (140.5)(54.58) = 7668\,\text{lb}$
(d) $F_{\text{d}} = (7737 - 7668) = +69\,\text{lb}$

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CHAPTER SIX

Well Hydraulics

6.1 System Pressure Losses

6.1.1 Determine the Pressure Loss in the Surface System in psi

$$\Delta P_{SC} = (C_{SC})(MW)\left(\frac{Q}{100}\right)^{1.86} \tag{6.1}$$

Where: ΔP_{SC} = Pressure loss in surface system in psi
C_{SC} = Constant for surface system from Table 6.1
Q = Pump output in gpm

6.1.2 Determine the Pressure Loss in the Drill String in psi

(a) Determine the fluid velocity down the pipe in ft./s:

$$V_p = \frac{(0.408)(Q)}{D_{IDp}^2} \tag{6.2}$$

Where: V_p = Fluid velocity down the drill string in ft./s
D_{IDp} = Internal diameter of the pipe in in.

(b) Determine the n value for the pipe (flow behavior index) in the pipe:

$$n_p = 3.32 \log\left(\frac{\theta 600}{\theta 300}\right) \tag{6.3}$$

Where: n_p = Flow behavior index for the pipe (dimensionless)
$\theta 600$ = Viscometer reading at 600 rpm
$\theta 300$ = Viscometer reading at 300 rpm

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Table 6.1
Surface System Cases

Case	Standpipe (ft. × ID in.)	Hose (ft. × ID in.)	Swivel (ft. × ID in.)	Kelly (ft. × ID in.)	C_{SC}
1	40.0 × 3.0	45.0 × 2.0	4.0 × 2.0	40.0 × 2.25	1.00
2	40.0 × 3.5	55.0 × 2.5	5.0 × 2.5	40.0 × 3.25	0.36
3	45.0 × 4.0	55.0 × 3.0	5.0 × 2.5	40.0 × 3.25	0.22
4	45.0 × 4.0	55.0 × 3.0	6.0 × 3.0	40.0 × 4.00	0.15
5	100.0 × 5.0	85.0 × 3.5	22.0 × 3.5		0.15

Ref: Table 4 of API RP 13D, June, 2006, p. 28.

(c) Determine the K value (consistency factor) in the pipe in Poise:

$$K_p = \frac{5.11(\theta 600)}{1022^{n_p}} \tag{6.4}$$

Where: K_p = Consistency factor in Poise

(d) Determine the effective viscosity in the pipe in cP:

$$\mu_{ep} = 100(K_p)\left[\frac{96(V_p)}{D_{IDp}}\right]^{n_p-1} \tag{6.5}$$

Where: μ_{ep} = Effective viscosity in the pipe in cP

(e) Determine the Reynolds number for the pipe:

$$Re_p = \frac{928(V_p)(D_{IDp})(MW)}{(\mu_{ep})\left[\frac{3n_p+1}{4n_p}\right]^{n_p}} \tag{6.6}$$

Where: Re_p = Reynolds number for the pipe (dimensionless)

(f) Determine the Reynolds number for the change from laminar to transitional flow for the pipe:

$$Re_L = 3470 - 1370(n_p) \tag{6.7}$$

Where: Re_L = Reynolds number for the change from laminar to transitional for the pipe (dimensionless)

(g) Determine the Reynolds number for the change from transitional to turbulent flow for the pipe:

$$Re_T = 4270 - 1370(n_p) \quad (6.8)$$

Where: Re_T = Reynolds number for the change from transitional to turbulent flow for the pipe (dimensionless)

(h) Determine the type of flow, then determine the friction factor:

1. If the $Re_p < Re_L$, select the laminar flow equation to determine the friction factor:

$$f_p = \frac{16}{Re_p} \quad (6.9)$$

2. If the $Re_p > Re_T$, use the turbulent flow equation to determine the friction factor:

$$f_p = \frac{((\log(n_p) + 3.93)/50)}{Re_p^{\frac{([1.75 - \log(n_p)])}{7}}} \quad (6.10)$$

3. If the $Re_L < Re_p < Re_T$, use the transitional flow equation to determine the friction factor:

$$f_p = \left[\frac{Re_p - Re_L}{800}\right]\left[\frac{(\log(n_p) + 3.93)/50}{Re_T^{\frac{([1.75 - \log(n_p)])}{7}}} - \frac{16}{Re_L}\right] + \frac{16}{Re_L} \quad (6.11)$$

(i) Determine the pressure loss for the interval:

$$\Delta P_{pI} = \frac{(f_p)\left(V_p^2\right)(\mathrm{MW})}{25.8(D_{IDp})}(L_I) \quad (6.12)$$

Where: ΔP_{pI} = Pressure loss in the pipe for the internal in psi
L_I = Length of the interval in ft.

6.1.3 Determine the Pressure Loss at the Bit in psi

$$\Delta P_b = \frac{156.5\left(Q^2\right)(\mathrm{MW})}{\left[\left(D_{J1}^2\right) + \left(D_{J2}^2\right) + \left(D_{J3}^2\right) + \cdots + \left(D_{Jn}^2\right)\right]^2} \tag{6.13}$$

Where: ΔP_b = Pressure loss at the bit in psi
Q = Pump output in gpm
MW = Mud weight in ppg
D_J = Diameter of the bit nozzles #1, #2, and #3 in 32nds of an inch (rounded to the nearest whole number).

6.1.4 Determine the Pressure Loss in the Annulus in psi

(a) Determine the fluid velocity in the Annulus in ft./s:

$$V_a = \frac{(0.408)(Q)}{\left(\left(D_h^2\right) - \left(D_p^2\right)\right)} \tag{6.14}$$

Where: V_a = Fluid velocity in the annulus in ft./s
D_h = Diameter of the hole or the internal diameter of the casing in in.
D_p = Outside diameter of the pipe in in.

(b) Determine the *n* value for the pipe (flow behavior index) in the annulus:

$$n_a = 0.5 \log\left(\frac{\theta 300}{\theta 3}\right) \tag{6.15}$$

Where: n_a = Flow behavior index for the pipe (dimensionless)
$\theta 300$ = Viscometer reading at 300 rpm
$\theta 3$ = Viscometer reading at 3 rpm

(c) Determine the *K* value (consistency factor) the annulus in Poise:

$$K_a = \frac{5.11(\theta 300)}{511^{n_a}} \tag{6.16}$$

Where: K_a = Consistency factor in Poise

(d) Determine the effective viscosity in the annulus in cP:

$$\mu_{ea} = 100(K_a)\left[\frac{144(V_a)}{D_h - D_p}\right]^{n_a - 1} \tag{6.17}$$

Where: μ_{ea} = Effective viscosity in the annulus in cP

(e) Determine the Reynolds number for the annulus:

$$Re_a = \frac{928(V_a)\left(D_h - D_p\right)(MW)}{(\mu_{ea})\left[\frac{2n_a + 1}{3n_a}\right]^{n_a}} \tag{6.18}$$

Where: Re_a = Reynolds number for the annulus (dimensionless)

(f) Determine the Reynolds number for the change from laminar to transitional flow for the annulus:

$$Re_L = 3470 - 1370(n_a) \tag{6.19}$$

Where: Re_L = Reynolds number for the change from laminar to transitional for the annulus (dimensionless)

(g) Determine the Reynolds number for the change from transitional to turbulent flow for the annulus:

$$Re_T = 4270 - 1370(n_a) \tag{6.20}$$

Where: Re_T = Reynolds number for the change from transitional to turbulent flow for the annulus (dimensionless)

(h) Determine the type of flow, then determine the friction factor:

1. If the $Re_a < Re_L$, select the laminar flow equation to determine the friction factor:

$$f_a = \frac{24}{Re_a} \tag{6.21}$$

2. If the $Re_a > Re_T$, use the turbulent flow equation to determine the friction factor:

$$f_a = \frac{((\log(n_a) + 3.93)/50)}{Re_a^{([1.75 - \log(n_a)]/7)}} \tag{6.22}$$

3. If the $Re_L < Re_a < Re_T$, use the transitional flow equation to determine the friction factor:

$$f_a = \left[\frac{Re_a - Re_L}{800}\right]\left[\frac{((\log(n_a) + 3.93)/50)}{Re_T^{([1.75 - \log(n_a)]/7)}} - \frac{24}{Re_L}\right] + \frac{24}{Re_L} \quad (6.23)$$

(i) Determine the pressure loss for the interval:

$$\Delta P_{aI} = \frac{(f_p)\left(V_p^2\right)(\text{MW})}{25.8\left(D_h - D_p\right)}(L_I) \quad (6.24)$$

Where: ΔP_{aI} = Pressure loss in the pipe for the internal in psi
L_I = Length of the interval in ft.

6.1.5 Determine the Downhole Density of the Base Oil or Brine in the Mud at Depth of Interest in ppg

This calculation is made for a specific depth location in the well at the conditions that occur at that depth. To determine the ESD for the entire well, values must be calculated for each depth interval and integrated in a stepwise procedure down to the total well depth.

(a) Determine the volume of salt in a 19.3% (v/v) brine phase of the mud in %:

$$V_{salt} = \left(\left(13.091 \times 10^{-4}\right)(\text{CaCl}_2)\right) + \left(\left(8.44 \times 10^{-5}\right)(\text{CaCl}_2)^2\right) \quad (6.25)$$

Where: V_{salt} = Volume of CaCl2 salt in the brine in %
$CaCl_2$ = Weight percent of calcium chloride in %

(b) Determine the volume of brine in the mud in %:

$$V_B = V_{salt} + V_W \quad (6.26)$$

Where: V_B = Volume of brine in the mud in %
V_W = Volume of water in the mud from the retort test in %

(c) Determine the corrected volume of solids in the mud in %:

$$V_{CS} = (V_S) - \left(\frac{(0.056704)(V_W)}{100}\right) \tag{6.27}$$

Where: V_{CS} = Volume of corrected solids in the mud in %
V_S = Volume of solids determined in the retort test of the mud in %
V_W = Volume of water determined in the retort test of the mud in %

(d) Determine the density of the base oil or brine in the mud in ppg:

$$\mathrm{MW_O} \text{ or } \mathrm{MW_B} = \left[\left(a_1 + ((b_1)(P)) + \left((c_1)\left(P^2\right)\right)\right) + \left(\left(a_2 + ((b_2)(P)) + \left((c_2)\left(P^2\right)\right)\right)(T)\right)\right] \tag{6.28}$$

Where: $\mathrm{MW_O}$ = Density of the base oil at depth of interest in ppg
$\mathrm{MW_B}$ = Density of the brine at depth of interest in ppg
a_1 = Density correction coefficient from Table 6.2 for pressure in ppg
b_1 = Density correction coefficient from Table 6.2 for pressure in ppg/psi
c_1 = Density correction coefficient from Table 6.2 for pressure in ppg/psi^2
P = Pressure at depth of interest in psi
a_2 = Density correction coefficient from Table 6.2 for temperature in ppg/°F
b_2 = Density correction coefficient from Table 6.2 for temperature in ppg/psi/°F
c_2 = Density correction coefficient from Table 6.2 for temperature in ppg/psi^2/°F
T = Temperature at depth of interest in °F

Table 6.2
Temperature and Pressure Coefficients for Determining Fluid Density

	$CaCl_2$ (19.3% w/w)	Diesel	Mineral Oil	Internal Olefin	Paraffin
Pressure coefficients					
a_1 (ppg)	9.9952	7.3183	6.9912	6.8538	6.9692
b_1 (ppg/psi)	1.77×10^{-5}	5.27×10^{-5}	2.25×10^{-5}	2.23×10^{-5}	3.35×10^{-5}
c_1 (ppg/psi^2)	6×10^{-11}	-8×10^{-10}	-1×10^{-10}	-2×10^{-10}	-5×10^{-10}
Temperature coefficients					
a_2 (ppg/°F)	-2.75×10^{-3}	-3.15×10^{-3}	3.28×10^{-3}	-3.39×10^{-3}	3.46×10^{-3}
b_2 (ppg/psi/°F)	3.49×10^{-8}	7.46×10^{-8}	1.17×10^{-7}	1.12×10^{-7}	-1.64×10^{-8}
c_2 (ppg/psi^2/°F)	-9×10^{-13}	-1×10^{-12}	-3×10^{-12}	-2×10^{-12}	2×10^{-13}

Ref: Table 3 of API RP 13D, June, 2006, p. 26.

(e) Determine the static density of the mud at a specific depth in the well in ppg:

$$ESD_{DI} = \frac{((V_O/100)(MW_O)) + ((V_B/100)(MW_B)) + ((V_S/100)((S_{ASG})(8.34)))}{\left(\frac{V_T}{100}\right)} \quad (6.29)$$

Where: ESD_{DI} = Equivalent static density at depth of interest in ppg
V_O = Volume of oil in the mud from the retort test in %
V_S = Volume of solids in the mud from the retort test in %
S_{ASG} = Average specific gravity of the solids from Equation (3.32) in gm/cm^3
V_T = Total of volume of mud tested in the retort in %

6.2 Equivalent Circulating "Density" ECD (ppg) [USCS/British]

Definition: ECD takes into account the friction loss in the annulus due to circulation of the drilling mud (pumps on).

$$ECD = \left(\frac{\Delta P_a}{0.052 \times D_{TVD}}\right) + MW \tag{6.30}$$

Where: ECD = Equivalent circulating density in ppg
ΔP_a = Annulus friction pressure loss in psi
D_{TVD} = Total vertical depth in ft.
MW = Mud weight in ppg

Example: Circulation friction pressure loss in annulus is 200 psi, MW is 9.6 ppg, and TVD is 10,000 ft.

$$ECD = \left(\frac{200.0}{0.052(10{,}000)}\right) + 9.6$$

$$ECD = 10.0\,\text{ppg}$$

6.2.1 Equivalent Circulating "Density" ECD (N/Liter) and ECD (SG) [SI-Metric]

Definition: ECD takes into account the friction loss in the annulus due to circulation of the drilling mud (pumps on).

$$ECD = \left(\frac{\Delta P_a}{1000 \times D_{TVD}}\right) + MW \tag{6.31}$$

Where: ECD = Equivalent circulating density in N/liter
ΔP_a = Annulus friction pressure loss in N/m^2
D_{TVD} = Total vertical depth in m
MW = Mud weight in N/liter

Example: Circulation friction pressure loss in annulus is 1,380,000 N/m^2, MW is 11.3 N/liter, and H is 3048 m.

Note: Pressure can also be written as 1.38 M Pa (where $M = 10^6$, $P_a = \text{N/m}^2$).

$$\text{ECD} = \left(\frac{1,380,000}{1000(10,000)}\right) + 11.3$$

$$\text{ECD} = 11.8\ \text{N/liter}$$

Definition: ECD takes into account the friction loss in the annulus due to circulation of the drilling mud (pumps on).

$$\text{ECD} = \left(\frac{\Delta P_a}{9810 \times D_{TVD}}\right) + \text{MW} \tag{6.32}$$

Where: ECD = Equivalent circulating density in specific gravity (SG)
ΔP_a = Annulus friction pressure loss in N/m^2
D_{TVD} = Total vertical depth in m
MW = Mud weight in SG

Example: Circulation friction pressure loss in annulus is 1,380,000 N/m^2, mud SG is 1.15, and H is 3048 m.

$$\text{ECD} = \left(\frac{1,380,000}{9810(3408)}\right) + 1.15$$

$$\text{ECD} = 1.20$$

6.2.2 ECD with Cuttings

$$\text{ECD}_C = \left(\left(1 - \left(\frac{V_{Ca}}{100}\right)\right)(\text{ESD}_a)\right) + \left(\left(\frac{V_{Ca}}{100}\right)((G_C)(8.34))\right) + \left(\frac{(\Delta P_{aT})}{(0.052)(D_{TVD})}\right) \tag{6.33}$$

Where: ECD_C = Equivalent circulating density with cuttings in the annulus in ppg
V_{Ca} = Volume of cuttings in the annulus in %
ESD_a = Equivalent static density in the annulus in ppg
G_C = Specific gravity of the cutting in gm/cm^3
ΔP_{aT} = Total pressure loss in the annulus in psi

Example: Determine the system pressure loss and the ECD with the following:

Data: Mud type = synthetic base mud (internal olefin)
Mud weight = 12.0 ppg
Oil/water ratio = 80/20
Oil content (retort) = 64% v/v
Water content (retort) = 16% v/v (brine content = 16.97% v/v)
Solids content (retort) = 20% v/v (corrected solids = 19.03% v/v)
Solids ASG = 3.82 gm/cm^3
Calcium chloride content = 19.3% w/w
θ600 reading = 66
θ300 reading = 40
Plastic viscosity = 26 cP
Yield point = 14 lb/100 ft.^{2}
θ3 reading (gel strength) = 8 lb/100 ft.^{2}
Bit size = 9⅞ in. (3 × 12/32nds jets)
Open hole length = 3000 ft.
Casing size = 10¾ in. (45.5 lb/ft., ID = 9.950 in.)
Casing length (measured) = 12,000 ft. (TVD = 11,500 ft.)
Drill pipe size = 5.0 in. (19.5 lb/ft., ID = 4.276 in.)
Drill pipe tool joint size = 6⅝ in. (pin + box length = 19 in.)
Drill collar size = 8.0 in. (147 lb/ft., ID = 3.0 in.)
Drill collar length = 650 ft.
Cutting size = 0.625 in. (equivalent spherical diameter)
Pump output = 400 gpm
Pump pressure = 2950 psi
Surface case = 4 (C_{SC} = 0.15)
Geothermal gradient = 1.0 °F/100 ft.

1. Determine the pressure loss in the surface system in psi:

$$\Delta P_{SC} = (0.15)(12.0)\left(\frac{400}{100}\right)^{1.86} = 23.7\,\text{psi}$$

2. Determine the pressure loss in the drill pipe in psi:

   (a) Determine the fluid velocity down the drill pipe in ft./s:

$$V_p = \frac{(0.408)(400)}{4.276^2} = 8.925\,\text{ft./s}\,(535.5\,\text{ft./min})$$

   (b) Determine the *n* value for the pipe (flow behavior index) in the drill pipe:

$$n_p = 3.32\log\left(\frac{66}{40}\right) = 0.722$$

   (c) Determine the *K* value (consistency factor) in the drill pipe in Poise:

$$K_p = \frac{5.11(66)}{1022^{0.722}} = 2.265\,\text{Poise}$$

   (d) Determine the effective viscosity in the drill pipe in cP:

$$\mu_{ep} = 100(2.265)\left[\frac{96(8.925)}{4.276}\right]^{0.722-1} = 51.9\,\text{cP}$$

   (e) Determine the Reynolds number for the drill pipe:

$$Re_p = \frac{928(8.925)(4.276)(12.0)}{(51.9)\left[\frac{3(0.722)+1}{4(0.722)}\right]^{0.722}} = 7662.8$$

(f) Determine the Reynolds number for the change from laminar to transitional flow for the drill pipe:

$$Re_L = 3470 - 1370(0.722) = 2480.9$$

(g) Determine the Reynolds number for the change from transitional to turbulent flow for the drill pipe:

$$Re_T = 4270 - 1370(0.722) = 3280.9$$

(h) The type of flow is turbulent, go to Equation (6.10) and determine the friction factor:

If the $Re_p > Re_T$, use the turbulent flow equation to determine the friction factor:

$$f_p = \frac{((\log(0.722) + 3.93)/50)}{7662.8^{([1.75-\log(0.722)]/7)}} = 0.006760$$

(i) Determine the pressure loss for the drill pipe interval:

$$\Delta P_{pI} = \frac{(0.006760)(8.925^2)(12.0)}{25.8(4.276)}(15{,}000 - 650) = 840.5\ \text{psi}$$

3. Determine the pressure loss for the drill collars.

(a) Determine the fluid velocity down the drill collars in ft./s:

$$V_p = \frac{(0.408)(400)}{3.0^2} = 18.13\ \text{ft./s}\ (1088\ \text{ft./min})$$

(b) Determine the n value for the pipe (flow behavior index) in the drill collars:

$$n_p = 3.32 \log\left(\frac{66}{40}\right) = 0.722$$

(c) Determine the K value (consistency factor) in the drill collars in Poise:

$$K_{\mathrm{p}} = \frac{5.11(66)}{1022^{0.722}} = 2.265\,\text{Poise}$$

(d) Determine the effective viscosity in the drill collars in cP:

$$\mu_{\mathrm{ep}} = 100(2.265)\left[\frac{96(18.13)}{3.0}\right]^{0.722-1} = 38.6\,\text{cP}$$

(e) Determine the Reynolds number for the drill collars:

$$Re_{\mathrm{p}} = \frac{928(18.13)(3.0)(12.0)}{(38.6)\left[\frac{3(0.722)+1}{4(0.722)}\right]^{0.722}} = 14{,}684$$

(f) Determine the Reynolds number for the change from laminar to transitional flow for the drill collars:

$$Re_{\mathrm{L}} = 3470 - 1370(0.722) = 2480.9$$

(g) Determine the Reynolds number for the change from transitional to turbulent flow for the drill collars:

$$Re_{\mathrm{T}} = 4270 - 1370(0.722) = 3280.9$$

(h) The type of flow is turbulent, go to Equation (6.10) and determine the friction factor:

If the $Re_{\mathrm{p}} > Re_{\mathrm{T}}$, use the turbulent flow equation to determine the friction factor:

$$f_{\mathrm{p}} = \frac{((\log(0.722) + 3.93)/50)}{14{,}684^{([1.75-\log(0.722)]/7)}} = 0.005671$$

(i) Determine the pressure loss for the drill collars interval:

$$\Delta P_{\mathrm{pI}} = \frac{(0.005671)\left(18.13^2\right)(12.0)}{25.8(3.0)}(650) = 187.8\,\text{psi}$$

4. Determine the pressure loss at the bit in psi:

$$\Delta P_{\mathrm{b}} = \frac{156.5\left(400^2\right)(12.0)}{\left[\left(12^2\right) + \left(12^2\right) + \left(12^2\right)\right]^2} = 1610\,\mathrm{psi}$$

5. Determine the pressure loss in the annulus.

5A. Determine the pressure loss in the drill pipe/casing annulus in psi:

(a) Determine the fluid velocity in the drill pipe/casing annulus in ft./s:

$$V_{\mathrm{a}} = \frac{(0.408)(400)}{\left(\left(9.950^2\right) - \left(5.0^2\right)\right)} = 2.205\,\mathrm{ft./s}\,(132.3\,\mathrm{ft./min})$$

(b) Determine the n value for the pipe (flow behavior index) in the drill pipe/casing annulus:

$$n_{\mathrm{a}} = 0.5\log\left(\frac{40}{8}\right) = 0.3495$$

(c) Determine the K value (consistency factor) the drill pipe/casing annulus in Poise:

$$K_{\mathrm{a}} = \frac{5.11(40)}{511^{0.3495}} = 23.1\,\mathrm{Poise}$$

(d) Determine the effective viscosity in the drill pipe/casing annulus in cP:

$$\mu_{\mathrm{ea}} = 100(23.1)\left[\frac{144(2.205)}{9.95 - 5.0}\right]^{0.3495-1} = 154.2\,\mathrm{cP}$$

(e) Determine the Reynolds number for the drill pipe/casing annulus:

$$Re_{\mathrm{a}} = \frac{928(2.205)(9.95 - 5.0)(12.0)}{(154.2)\left[\frac{2(0.3495) + 1}{3(0.3495)}\right]^{0.3495}} = 665.9$$

(f) Determine the Reynolds number for the change from laminar to transitional flow for the drill pipe/casing annulus:

$$Re_L = 3470 - 1370(0.3495) = 2991.2$$

(g) Determine the Reynolds number for the change from transitional to turbulent flow for the drill pipe/casing annulus:

$$Re_T = 4270 - 1370(0.3495) = 3791.2$$

(h) The type of flow is laminar, go to Equation (6.21) to determine the friction factor:

If the $Re_a < Re_L$, select the laminar flow equation to determine the friction factor:

$$f_a = \frac{24}{665.9} = 0.03604$$

(i) Determine the pressure loss for a 1 foot drill pipe/casing annulus interval:

$$\Delta P_{aI} = \frac{(0.03604)\left(2.205^2\right)(12.0)}{25.8(9.95 - 5.0)}(1) = 0.0165\,\text{psi/ft.}$$

Note: The pressure drop around the tool joints will be different from the drill pipe tube in the casing interval. A pressure drop for the total tool joint length in the casing should be calculated and added to the annular pressure drop total.

5B. Determine the pressure loss in the tool joint/casing annulus in psi:

(a) Determine the fluid velocity in the tool joint/casing annulus in ft./s:

$$V_a = \frac{(0.408)(400)}{\left(\left(9.95^2\right) - \left(6.625^2\right)\right)} = 2.96\ \text{ft./s}\,(177.7\,\text{ft./min})$$

(b) Determine the n value for the pipe (flow behavior index) in the tool joint/casing annulus:

$$n_a = 0.5 \log\left(\frac{40}{8}\right) = 0.3495$$

(c) Determine the K value (consistency factor) the tool joint/casing annulus in Poise:

$$K_a = \frac{5.11(40)}{511^{0.3495}} = 23.1\ \text{Poise}$$

(d) Determine the effective viscosity in the tool joint/casing annulus in cP:

$$\mu_{ea} = 100(23.1)\left[\frac{144(2.96)}{9.950 - 6.625}\right]^{0.3495-1} = 98.3\ \text{cP}$$

(e) Determine the Reynolds number for the tool joint/casing annulus:

$$Re_a = \frac{928(2.96)(9.95 - 6.625)(12.0)}{(98.3)\left[\frac{2(0.3495)+1}{3(0.3495)}\right]^{0.3495}} = 1402.2$$

(f) Determine the Reynolds number for the change from laminar to transitional flow for the tool joint/casing annulus:

$$Re_L = 3470 - 1370(0.3495) = 2991.2$$

(g) Determine the Reynolds number for the change from transitional to turbulent flow for the tool joint/casing annulus:

$$Re_T = 4270 - 1370(0.3495) = 3791.2$$

(h) The type of flow is laminar, go to Equation (6.21) to determine the friction factor:

If the $Re_a < Re_L$, select the laminar flow equation to determine the friction factor:

$$f_a = \frac{24}{1402.2} = 0.01712$$

(i) Determine the pressure loss for a 1 foot tool joint/casing annulus interval:

$$\Delta P_{aI} = \frac{(0.01712)(2.96^2)(12.0)}{25.8(9.95 - 6.625)}(1) = 0.0141 \text{ psi/ft.}$$

Determine the number of connections are inside the casing interval:

The number of connections = (12,000/31) = 387. The pin and box length equals 19 in. Therefore, there are ((19)(387)/12) = 612.75 ≈ 613 ft. of tool joints that can be treated as another section of pipe in the annulus. The total pressure drop in the drill pipe/casing annulus is equal to:

$$((12,000 - 613)(0.0165)) + ((613)(0.0141)) = 196.5 \text{ psi}$$

6. Determine the pressure loss in the drill pipe/open hole annulus in psi:

(a) Determine the fluid velocity in the drill pipe/open hole annulus in ft./s:

$$V_a = \frac{(0.408)(400)}{\left((9.875^2) - (5.0^2)\right)} = 2.25 \text{ ft./s } (135.0 \text{ ft./min})$$

(b) Determine the n value for the pipe (flow behavior index) in the drill pipe/open hole annulus:

$$n_a = 0.5 \log\left(\frac{40}{8}\right) = 0.3495$$

(c) Determine the K value (consistency factor) the drill pipe/open hole annulus in Poise:

$$K_a = \frac{5.11(40)}{511^{0.3495}} = 23.1 \text{ Poise}$$

(d) Determine the effective viscosity in the drill pipe/open hole annulus in cP:

$$\mu_{ea} = 100(23.1)\left[\frac{144(2.25)}{9.875 - 5.0}\right]^{0.3495-1} = 150.7\,\text{cP}$$

(e) Determine the Reynolds number for the drill pipe/open hole annulus:

$$Re_a = \frac{928(2.25)(9.875 - 5.0)(12.0)}{(150.7)\left[\frac{2(0.3495) + 1}{3(0.3495)}\right]^{0.3495}} = 684.7$$

(f) Determine the Reynolds number for the change from laminar to transitional flow for the drill pipe/open hole annulus:

$$Re_L = 3470 - 1370(0.3495) = 2991.2$$

(g) Determine the Reynolds number for the change from transitional to turbulent flow for the drill pipe/open hole annulus:

$$Re_T = 4270 - 1370(0.3495) = 3791.2$$

(h) The type of flow is laminar, go to Equation (6.21) to determine the friction factor:

If the $Re_p < Re_L$, select the laminar flow equation to determine the friction factor:

$$f_a = \frac{24}{684.7} = 0.0351$$

(i) Determine the pressure loss for a 1 foot drill pipe/open hole annulus interval:

$$\Delta P_{aI} = \frac{(0.0351)\left(2.25^2\right)(12.0)}{25.8(9.875 - 5.0)}(1) = 0.0170\,\text{psi/ft.}$$

The pressure drop in the drill pipe/open hole annulus is: ((3000 − 650)(0.0170) = 40.0 psi

7. Determine the pressure loss in the drill collar/open hole annulus in psi:

   (a) Determine the fluid velocity in the drill collar/open hole annulus in ft./s:

   $$V_a = \frac{(0.408)(400)}{((9.875^2) - (8.0^2))} = 4.87\,\text{ft./s}\,(292.2\,\text{ft./min})$$

   (b) Determine the *n* value for the pipe (flow behavior index) in the drill collar/open hole annulus:

   $$n_a = 0.5\log\left(\frac{40}{8}\right) = 0.3495$$

   (c) Determine the *K* value (consistency factor) the drill collar/open hole annulus in Poise:

   $$K_a = \frac{5.11(40)}{511^{0.3495}} = 23.1\ \text{Poise}$$

   (d) Determine the effective viscosity in the drill collar/open hole annulus in cP:

   $$\mu_{ea} = 100(23.1)\left[\frac{144(4.87)}{9.875 - 8.0}\right]^{0.3495-1} = 48.97\,\text{cP}$$

   (e) Determine the Reynolds number for the drill collar/open hole annulus:

   $$Re_a = \frac{928(4.87)(9.875 - 8.0)(12.0)}{(48.97)\left[\frac{2(0.3495) + 1}{3(0.3495)}\right]^{0.3495}} = 1754.1$$

   (f) Determine the Reynolds number for the change from laminar to transitional flow for the drill collar/open hole annulus:

   $$Re_L = 3470 - 1370(0.3495) = 2991.2$$

(g) Determine the Reynolds number for the change from transitional to turbulent flow for the drill collar/open hole annulus:

$$Re_{\mathrm{T}} = 4270 - 1370(0.3495) = 3791.2$$

(h) The type of flow is laminar, go to Equation (6.21) to determine the friction factor:

If the $Re_{\mathrm{a}} < Re_{\mathrm{L}}$, select the laminar flow equation to determine the friction factor:

$$f_{\mathrm{a}} = \frac{24}{1754.1} = 0.01368$$

(i) Determine the pressure loss for a 1 foot drill collar/open hole annulus interval:

$$\Delta P_{\mathrm{aI}} = \frac{(0.01368)\left(4.87^2\right)(12.0)}{25.8(9.875 - 8.0)}(1) = 0.0805\,\mathrm{psi/ft.}$$

The pressure drop in the drill collars/open hole annulus is: $((650)(0.0805)) = 52.3\,\mathrm{psi}$

The total pressure drop for the drill string/open hole annulus is: $(40.0) + (52.3) = 92.3\,\mathrm{psi}$

The total pressure drop for the annulus is: (196.5) + (92.3) = 288.8 psi

The total pressure drop for the system is:

$$(23.7) + (840.5) + (187.8) + (1610) + (52.3) + (40.0) + (196.5) = 2950.8\,\mathrm{psi}$$

8. Determine the downhole density of the base oil or brine in the mud a depth of interest of 6000 ft. in ppg.

   (a) Determine the volume of salt in a 19.3% (v/v) brine phase of the mud in %:

$$V_{\mathrm{salt}} = \left(\left(13.091 \times 10^{-4}\right)(13.9)\right) + \left(\left(8.44 \times 10^{-5}\right)(13.9)^2\right) = 0.056704\%$$

(b) Determine the volume of brine in the mud in %:

$$V_B = ((0.056704)(16.0)) + 16.0 = 16.91\%$$

(c) Determine the corrected volume of solids in the mud in %:

$$V_{CS} = (20.0) - \left(\frac{(5.6704)(16)}{100}\right) = 19.09\%$$

(d) Determine the density of the internal olefin in the mud in ppg:
Use a pressure of (6000)(0.052)(12.0) = 3744 psi and a temperature of (1.0)(60) + (80) = 140 °F.

$$\begin{aligned} MW_O = \big[&(6.8538 + \left(\left(2.23 \times 10^{-5}\right)(3744)\right) + \\ &\left(\left(-2 \times 10^{-10}\right)\left(3744^2\right)\right)) \\ &+ \left(\left(-3.39 \times 10^{-3} + \left(\left(1.12 \times 10^{-7}\right)(3744)\right)\right.\right. \\ &+ \left.\left.\left(\left(-2 \times 10^{-12}\right)\left(3744^2\right)\right)\right)(140)\right)\big] = 6.515\,\text{ppg} \end{aligned}$$

(e) Determine the density of the Brine in the mud in ppg:

$$\begin{aligned} MW_B = \big[&(9.9952 + \left(\left(1.77 \times 10^{-5}\right)(3744)\right) \\ &+ \left(\left(6 \times 10^{-11}\right)\left(3744^2\right)\right)) + ((-2.75 \times 10^{-3} \\ &+ \left(\left(3.49 \times 10^{-8}\right)(3744)\right) \\ &+ \left(\left(-9 \times 10^{-13}\right)\left(3744^2\right)\right))(140))\big] = 9.694\,\text{ppg.} \end{aligned}$$

(f) Determine the static density of the mud at a specific depth of 6000 ft. in the well in ppg:

$$ESD_{DI} = \frac{\begin{array}{c}((64/100)(6.410288)) + ((16.91/100)(9.5597)) \\ + ((19.09/100)((3.82)(8.34)))\end{array}}{\left(\frac{100}{100}\right)}$$

$$= 11.8\,\text{ppg}$$

9. ECD with cuttings

Example: Determine the ECD with cuttings with the following conditions:

Data: ESD at the casing shoe = 12.0 ppg
Volume of cuttings in the annulus = 4.5%
Specific gravity of the cutting = 2.5 gm/cm^3
Pressure loss in the annulus = 196.5 psi
Casing shoe depth = 12,000 ft.

$$ECD_C = \left(\left(1 - \left(\frac{4.5}{100}\right)\right)(12.0)\right) + \left(\left(\frac{4.5}{100}\right)((2.5)(8.34))\right) + \left(\frac{(196.5)}{(0.052)(12,000)}\right)$$
$$= 12.71 \text{ ppg}$$

6.3 Surge and Swab Pressure Loss

This technique is based on converting the drill pipe speed into equivalent mud velocity in the annulus. The time to run or pull the middle joint in a stand through the rotary table is measured in seconds from the box to the pin. This mud velocity caused by the displacement of the pipe is then used in the annular pressure loss equations to determine an equivalent mud weight in ppg.

Method 1:

1. Determine n:

$$n = 3.32 \log \frac{\theta 600}{\theta 300} \tag{6.34}$$

2. Determine K:

$$K = \frac{\theta 300}{511^n} \tag{6.35}$$

3. Determine velocity, ft./min:

   For plugged flow:

$$v = \left[0.45 + \frac{{D_p}^2}{D_h^2 - D_p^2}\right] V_p \qquad (6.36)$$

   For open pipe:

$$v = \left[0.45 + \frac{D_p^2}{D_h^2 - D_p^2 + \mathrm{D}_i^2}\right] V_p \qquad (6.37)$$

4. Maximum pipe velocity:

$$V_m = 1.5 \times v \qquad (6.38)$$

5. Determine pressure losses:

$$\mathrm{Ps} = \left(\frac{2.4m}{D_h - D_p} \times \frac{2n+1}{3n}\right)^n \times \frac{\mathrm{KL}}{300(D_h - D_p)} \qquad (6.39)$$

Nomenclature:

N = Dimensionless
K = Dimensionless
$\theta 600$ = 600 viscometer dial reading
$\theta 300$ = 300 viscometer dial reading
v = Fluid velocity, ft./min
V_p = Pipe velocity, ft./min
V_m = Maximum pipe velocity, ft./min
P_s = Pressure loss, psi
L = Pipe length, ft.
D_h = Hole diameter, in.
D_p = Drill pipe or drill collar OD, in.
D_i = Drill pipe or drill collar ID, in.

Example: Determine surge pressure for plugged pipe:

Data: Well depth = 15,000 ft.
Hole size = 7⅞ in.
Drill pipe OD = 4½ in.
Drill pipe ID = 3.82 in.
Drill collar = 6¼ in. OD × 2¾ in. ID
Drill collar length = 700 ft.
Mud weight = 15.0 ppg

Viscometer readings:

$\theta 600 = 1400$

$\theta 300 = 80$

Average pipe running speed = 270 ft./min

1. Determine *n*:

$$n = 3.32 \log \left(\frac{140}{80} \right)$$

$$n = 0.8069$$

2. Determine *K*:

$$K = \frac{80}{511^{0.8069}}$$

$$K = 0.522$$

3. Determine velocity, ft./min:

$$V = \left[0.45 + \frac{(4.5)^2}{7.875^2 - 4.5^2} \right] 270$$

$$V = (0.45 + 0.484)270$$

$$V = 252 \text{ft./min}$$

4. Determine maximum pipe velocity, ft./min:

$$V_m = 252 \times 1.5$$
$$V_m = 378\,\text{ft./min}$$

5. Determine pressure loss, psi:

$$Ps = \left(\frac{2.4 \times 378}{7.875 - 4.5} \times \frac{2(0.8069) + 1}{3(0.8069)}\right)^{0.8069} \times \frac{(0.522)(14{,}300)}{300(7.875 - 4.5)}$$

$$Ps = (268.8 \times 1.1798)^{0.8069} \times \frac{7464.6}{1012.5}$$

$$Ps = 97.098 \times 7.37$$

$$Ps = 716\,\text{psi surge pressure}$$

Therefore, this pressure is added to the hydrostatic pressure of the mud in the well bore. If, however, the swab pressure is desired, this pressure would be subtracted from the hydrostatic pressure.

Example: Determine surge pressure for open pipe:

1. Determine velocity, ft./min:

$$v = \left[0.45 + \frac{4.5^2}{7.875^2 - 4.5^2 + 3.82^2}\right]270$$

$$v = \left(0.45 + \frac{5.66}{56.4}\right)270$$

$$v = (0.45 + 0.100)2700$$

$$v = 149\,\text{ft./min}$$

2. Maximum pipe velocity, ft./min:

$$V_m = 149 \times 1.5$$
$$V_m = 224\,\text{ft./min}$$

3. Pressure loss, psi:

$$Ps = \left(\frac{2.4 \times 224}{7.875 - 4.5} \times \frac{2(0.8069) + 1}{3(0.8069)}\right)^{(0.8069)} \times \frac{(0.522)(14{,}300)}{300(7.875 - 4.5)}$$

$$Ps = (159.29 \times 1.0798)^{0.8069} \times \frac{7464.6}{1012.5}$$

$$Ps = 63.66 \times 7.37$$

$$Ps = 469\,\text{psi surge pressure}$$

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), nor open-ended.

A. Surge pressure around drill pipe:

1. Estimated annular fluid velocity (v) around drill pipe:

$$v = \left[0.45 + \frac{D_p^2}{D_h^2 - D_p^2}\right] V_p \tag{6.40}$$

2. Maximum pipe velocity (V_m):

$$V_m = v \times 1.5 \tag{6.41}$$

3. Calculate n:

$$n = 3.32 \log \frac{\theta 600}{\theta 300} \tag{6.42}$$

4. Calculate K:

$$K = \frac{\theta 300}{511^n} \tag{6.43}$$

5. Calculate the shear rate (γm) of the mud moving around the pipe:

$$\gamma_m = \frac{2.4 \times V_m}{D_h - D_p} \tag{6.44}$$

6. Calculate the shear stress (τ) of the mud moving around the pipe:

$$\tau = K(\gamma_m)^n \tag{6.45}$$

7. Calculate the pressure (Ps) decrease for the interval:

$$\text{Ps} = \frac{3.33\tau}{D_h - D_p} \times \frac{L}{1000} \tag{6.46}$$

B. Surge pressure around drill collars:

1. Calculate the estimated annular fluid velocity (v) around the drill collars:

$$v = \left[0.45 + \frac{D_p^2}{D_h^2 - D_p^2}\right] V_p \tag{6.47}$$

2. Calculate maximum pipe velocity (Vm):

$$V_m = v \times 1.5 \tag{6.48}$$

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flowrate (Q):

$$Q = \frac{V_m\left[(D_h)^2 - (D_p)^2\right]}{24.5} \tag{6.49}$$

4. Calculate the pressure loss for each interval (Ps):

$$Ps = \frac{0.000077 \times MW^{0.8} \times Q^{1.8} \times PV^{0.2} \times L}{(D_h - D_p)^3 \times (D_h + D_p)^{1.8}} \tag{6.50}$$

C. Total surge pressures converted to mud weight: total surge (or swab) pressures:

$$\text{psi} = \text{Ps(drill pipe)} + \text{Ps(drill collars)} \tag{6.51}$$

D. If surge pressure is desired:

$$\text{SP, ppg} = \text{Ps} \div 0.052 \div \text{TVD, ft} + \text{MW, ppg} \tag{6.52}$$

E. If swab pressure is desired:

$$\text{SP, ppg} = \text{Ps} \div 0.052 \div \text{TVD, ft.} - \text{MW, ppg} \tag{6.53}$$

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/100 sq ft.
Hole diameter	= 7⅞ in.
Drill pipe OD	= 4½ in.
Drill pipe length	= 14,300 ft.
Drill collar OD	= 6¼ 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:

$$v = \left[0.45 + \frac{(4.5)^2}{7.875^2 - 4.5^2}\right]270$$

$$v = [0.45 + 0.4848]270$$

$$v = 253\ \text{ft./min}$$

2. Calculate maximum pipe velocity (Vm):

$$\text{Vm} = 253 \times 1.5$$

$$\text{Vm} = 379\ \text{ft./min}$$

Note: Determine n and K from the plastic viscosity and yield point as follows:

PV + YP = θ300 reading
θ300 reading + PV = θ600 reading

Example: PV = 60
YP = 20
60 + 20 = 80 (θ300 reading)
80 + 60 = 140 (θ600 reading)

3. Calculate n:

$$n = 3.32 \log\left(\frac{140}{80}\right)$$

$$n = 0.8069$$

4. Calculate K:

$$K = \frac{80}{511^{0.8069}}$$

$$K = 0.522$$

5. Calculate the shear rate (γm) of the mud moving around the pipe:

$$\gamma\text{m} = \frac{2.4 \times 379}{(7.875 - 4.5)}$$

$$\gamma\text{m} = 269.5$$

6. Calculate the shear stress (τ) of the mud moving around the pipe:

$$\tau = 0.522(269.5)^{0.8069}$$

$$\tau = 0.522 \times 91.457$$

$$\tau = 47.74$$

7. Calculate the pressure decrease (Ps) for the interval:

$$\text{Ps} = \frac{3.33(47.7)}{(7.875 - 4.5)} \times \frac{14,300}{1000}$$

$$\text{Ps} = 47.064 \times 14.3$$

$$\text{Ps} = 673\,\text{psi}$$

B. Around drill collars:

1. Calculate the estimated annular fluid velocity (v) around the drill collars:

$$v = (0.45 + 1.70)270$$

$$v = 581\,\text{ft./min}$$

2. Calculate maximum pipe velocity (Vm):

$$\text{Vm} = 581 \times 1.5$$

$$\text{Vm} = 871.54\,\text{ft./min}$$

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flowrate (Q):

$$Q = \frac{871.54\left(7.875^2 - 6.25^2\right)}{24.5}$$

$$Q = \frac{20{,}004.567}{24.5}$$

$$Q = 816.5$$

4. Calculate the pressure loss (Ps) for the interval:

$$\text{Ps} = \frac{0.000077 \times 15.0^{0.8} \times 816^{1.8} \times 60^{0.2} \times 700}{(7.875 - 6.25)^3 \times (7.875 + 6.25)^{1.8}}$$

$$\text{Ps} = \frac{185{,}837.9}{504.12}$$

$$\text{Ps} = 368.6\,\text{psi}$$

C. Total pressures:

$$\text{psi} = 672.9\,\text{psi} + 368.6\,\text{psi}$$

$$\text{psi} = 1041.5\,\text{psi}$$

D. Pressure converted to mud weight, ppg:

$$\text{ppg} = 1041.5\,\text{psi} \div 0.052 \div 15{,}000\,\text{ft.}$$
$$\text{ppg} = 1.34$$

E. If surge pressure is desired:

$$\text{Surge pressure, ppg} = 15.0 + 1.34\,\text{ppg}$$
$$\text{Surge pressure} = 16.34\,\text{ppg}$$

F. If swab pressure is desired:

$$\text{Swab pressure, ppg} = 15.0 - 1.34\,\text{ppg}$$
$$\text{Swab pressure} = 13.66\,\text{ppg}$$

6.4 Critical Velocity and Pump Rate

1. Determine n:

$$n = 3.32 \log \frac{\theta 600}{\theta 300} \tag{6.54}$$

2. Determine K:

$$K = \frac{\theta 600}{1022^n} \tag{6.55}$$

3. Determine x:

$$x = \frac{81{,}600(K)(n)^{0.387}}{\left(D_h - D_p\right)^n \mathrm{MW}} \tag{6.56}$$

4. Determine critical annular velocity:

$$\mathrm{AVc} = (x)^{1 \div (2-n)} \tag{6.57}$$

5. Determine critical flow rate:

$$\mathrm{GPMc} = \frac{\mathrm{AVc}\left({D_h}^2 - {D_p}^2\right)}{24.5} \tag{6.58}$$

Nomenclature:

n = Dimensionless
K = Dimensionless
x = Dimensionless
$\theta 600$ = 600 viscometer dial reading
$\theta 300$ = 300 viscometer dial reading

D_h = Hole diameter, in.
D_p = Pipe or collar OD, in.
MW = Mud weight, ppg
AVc = Critical annular velocity, ft./min
GPMc = Critical flow rate, gpm

Example: Mud weight = 14.0 ppg
$\theta 600$ = 64
$\theta 300$ = 37
Hole diameter = 8½ 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:

$$x = \frac{81,600(0.2684)(0.79)^{0.387}}{(8.5 - 7.0)^{0.79} \times 14.0}$$
$$x = \frac{19,967.413}{19.2859}$$
$$x = 1035$$

4. Determine critical annular velocity:

$$AVc = (1035)^{1 \div (2-0.79)}$$
$$AVc = (1035)^{0.8264}$$
$$AVc = 310\,\text{ft./min}$$

5. Determine critical flow rate:

$$GPMc = \frac{310(8.5^2 - 7.0^2)}{24.5}$$
$$GPMc = 294\,\text{gpm}$$

6.5 Equivalent Spherical Diameter for Drilled Cuttings Size Used in Slip Velocity Equations

Step 1: Determine the length, width, and thickness dimension of the cutting in in.

Step 2: Convert these measurements to eights of-an-inch.

Step 3: Determine the volume of the cutting:

$$V_C = (L)(W)(T) \tag{6.59}$$

Where:

V_C = Volume of the cutting in eights of-an-inch
L = Length of the cutting
W = Width of the cutting
T = Thickness of the cutting

Step 4: Determine the equivalent spherical diameter from Table 6.3 to use in the slip velocity equation.

Table 6.3
Equivalent Spherical Diameter for Cuttings

Volume $\left(\frac{\text{Inches}}{8}\right)$	Equivalent Diameter (Inches)	Equivalent Diameter (Decimal)
1	1/8	0.125
4	1/4	0.250
14	3/8	0.375
34	1/2	0.500
65	5/8	0.625
110	3/4	0.750
180	7/8	0.875
270	1	1.000
380	9/8	1.125
520	5/4	1.250
700	11/8	1.375
900	3/2	1.500

Example: Determine the equivalent spherical diameter for the following:

Step 1: Determine the length, width, and thickness dimension of the cutting in in.

Data: Length = 1 in.

Width = ½ in.

Thickness = ¼ in.

Step 2: Convert these measurements to eights of-an-inch.

Length = 8

Width = 4

Thickness = 2

Step 3: Determine the volume of the cutting:

$$V_C = (8)(4)(2) = 64$$

Step 4: Determine the equivalent spherical diameter from Table 6.3 to use in the slip velocity equation.

The equivalent spherical diameter for 64 is (approximately) ⅝ in. or **0.625** to use as the particle size in the slip velocity equation.

6.6 Slip Velocity of Cuttings in the Annulus

These calculations provide 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./min:

$$AV = \frac{24.5 \times Q}{D_h^2 - D_p^2} \tag{6.60}$$

Cutting slip velocity, ft./min:

$$Vs = 0.45\left(\frac{PV}{(MW)(D_p)}\right)\left[\sqrt{\frac{36,800}{\left(\frac{PV}{(MW)(Dp)}\right)^2} \times (D_p)\left(\frac{DenP}{MW} - 1\right) + 1} - 1\right] \tag{6.61}$$

Where: Vs = Slip velocity, ft./min
PV = Plastic viscosity, cps
MW = Mud weight, ppg
D_p = Diameter of particle, in.
DenP = Density of particle, ppg

Example: Using the following data, determine the annular velocity, ft./min; the cuttings slip velocity, ft./min, and the cutting net rise velocity, ft./min:

Data: Mud weight (MW) = 11.0 ppg
Plastic viscosity (PV) = 13 cps
Diameter of particle = 0.25 in.
Density of particle = 22.0 ppg (8.33 ppg × specific gravity, 2.64)
Flow rate = 520 gpm
Diameter of hole = 12¼ in.
Drill pipe OD = 5.0 in.

Annular velocity, ft./min:

$$AV = \frac{24.5 \times 520}{12.25^2 - 5.0^2}$$

$$AV = 102\,\text{ft./min}$$

Cutting slip velocity, ft./min:

$$Vs = 0.45\left(\frac{13}{(11.0)(0.25)}\right)\left[\sqrt{\frac{36,800}{\left(\frac{13}{(11.0)(0.25)}\right)^2} \times (0.25)\left(\frac{22.0}{11.0} - 1\right) + 1} - 1\right]$$

$$Vs = 0.45(4.727)\left[\sqrt{\frac{36,800}{(4.727)^2} \times (0.25)(1) + 1} - 1\right]$$

$$Vs = 2.12715\left(\sqrt{412.6839} - 1\right)$$

$$Vs = 2.12715 \times 19.3146$$

$$Vs = 41.085\,\text{ft./min}$$

Cutting net rise velocity:

Annular velocity	=	102 ft./min
Cutting slip velocity	=	− 41 ft./min
Cutting net rise velocity	=	61 ft./min

Method 2:

1. Determine *n*:

$$n = 3.32 \log \frac{\theta 600}{\theta 300} \tag{6.62}$$

2. Determine K:

$$K = \frac{\theta 300}{511^n} \tag{6.63}$$

3. Determine annular velocity, ft./min:

$$\mathrm{AV} = \frac{24.5 \times Q}{{D_\mathrm{h}}^2 - {D_\mathrm{p}}^2} \tag{6.64}$$

4. Determine viscosity (μ):

$$\mu = \left(\frac{2.4v}{D_\mathrm{h} - D_\mathrm{p}} \times \frac{2n+1}{3n}\right)^n \times \left(\frac{200K\left(D_\mathrm{h} - D_\mathrm{p}\right)}{v}\right) \tag{6.65}$$

5. Slip velocity (Vs), ft./min:

$$\mathrm{Vs} = \frac{(\mathrm{DenP} - \mathrm{MW})^{0.667} \times 175 \times \mathrm{DiaP}}{\mathrm{MW}^{0.333} \times \mu^{0.333}} \tag{6.66}$$

Nomenclature:

n = Dimensionless
K = Dimensionless
x = Dimensionless
$\theta 600$ = 600 viscometer dial reading
$\theta 300$ = 300 viscometer dial reading
Q = Circulation rate, gpm
D_h = Hole diameter, in.
D_p = Pipe or collar OD, in.
v = Annular velocity, ft./min
μ = mud viscosity, cps
DensP = Cutting density, ppg
DiaP = Cutting diameter, in.

Example: Using the data listed below, determine the annular velocity, cuttings slip velocity, and the cutting net rise velocity:

Data:

Mud weight (MW)	= 11.0 ppg
Plastic viscosity (PV)	= 13 cps
Yield point (YP)	= 10 lb/100 sq.ft.
Diameter of particle	= 0.25 in.
Density of particle	= 22.0 ppg
Hole diameter	= 12¼ in.
Drill pipe OD	= 5.0 in.
Circulation rate	= 520 gpm

1. Determine n:

$$n = 3.32 \log\left(\frac{36}{23}\right)$$

$$n = 0.64599$$

2. Determine K:

$$K = \frac{23}{511^{0.64599}}$$

$$K = 0.4094$$

3. Determine annular velocity, ft./min:

$$v = \frac{24.5 \times 520}{12.25^2 - 5.0^2}$$

$$v = \frac{12,740}{125.06}$$

$$v = 102\,\text{ft./min}$$

4. Determine mud viscosity, cps:

$$\mu = \left(\frac{2.4 \times 102}{12.25 - 5.0} \times \frac{2(0.64599) + 1}{3 \times 0.64599}\right)^{0.64599} \times \left(\frac{200 \times 0.4094 \times (12.25 - 5.0)}{102}\right)$$

$$\mu = \left(\frac{244.8}{7.25} \times \frac{2.92}{1.938}\right)^{0.64599} \times \left(\frac{593.63}{102}\right)$$

$$\mu = (33.6 \times 1.1827)^{0.64599} \times 5.82$$

$$\mu = 10.82 \times 5.82$$

$$\mu = 63 \text{ cps}$$

5. Determine cutting slip velocity, ft./min:

$$Vs = \frac{(22.0 - 11.0)^{0.667} \times 175 \times 0.25}{11.0^{0.333} \times 63^{0.333}}$$

$$Vs = \frac{4.95 \times 175 \times 0.25}{2.222 \times 3.97}$$

$$Vs = \frac{216.56}{8.82}$$

$$Vs = 24.55 \text{ ft./min}$$

6. Determine cutting net rise velocity, ft./min:

$$\begin{aligned} \text{Annular velocity} &= 102.00 \text{ ft./min} \\ \text{Cutting slip velocity} &= \underline{-24.55 \text{ ft./min}} \\ \text{Cutting net rise velocity} &= 77.45 \text{ ft./min} \end{aligned}$$

6.7 Carrying Capacity Index

Determine the carrying capacity index (CCI) developed to indicate hole cleaning efficiency in vertical and low-angle wells.

Step 1: Determine the flow behavior index (*n*) for the Herschel-Bulkley fluids model:

$$n_{HB} = 3.32 \log_{10} \frac{\left(2\left(\overline{PV}\right) + \left(\overline{YP}\right)\right)}{\left(\overline{PV} + \overline{YP}\right)} \quad (6.67)$$

Where: nHB = Flow behavior index for the Herschel-Bulkley fluids model
PV = Plastic viscosity in cP
YP = Yield point in lb/100 ft.^{2}

Step 2: Determine the consistency factor (K) for the Herschel-Bulkley fluids model:

$$K_{HB} = \left(511^{1-n_{HB}}\right)\left(\overline{PV} + \overline{YP}\right) \quad (6.68)$$

Where: K_{HB} = Consistency factor for the Herschel-Bulkley fluids model in lb/100 ft.^{2}

Step 3: Determine the carrying capacity index:

$$CCI = \frac{(MW)(K_{HB})(V_a)}{400,000} \quad (6.69)$$

Where: CCI = Carrying capacity index (dimensionless)
MW = Mud weight in ppg
K_{HB} = Consistency factor in lb/100 ft.^{2}
V_a = Annular velocity in ft./min

Example: Determine the carrying capacity index with the following:
Data: Mud weight = 10.0 ppg
Annular velocity = 125 ft./min
Plastic viscosity = 18 cP
Yield point = 15 lb/100 ft.^{2}

Step 1: Determine the flow behavior index (n) for the Herschel-Bulkley fluids model:

$$n_{HB} = 3.32 \log_{10} \frac{\left(2\left(\overline{18}\right) + (15)\right)}{(18 + 15)} = 0.6277$$

Step 2: Determine the consistency factor (K) for the Herschel-Bulkley fluids model:

$$K_{HB} = \left(511^{1-0.6277}\right)(18+15) = 336.4\,\text{lb}/100\,\text{ft.}^2$$

Step 3: Determine the carrying capacity index:

$$\text{CCI} = \frac{(10.0)(336.4)(125)}{400{,}000} = 1.05$$

Note: A CCI of 1.0 or greater indicates excellent hole cleaning. If the CCI is less than 0.5 then the hole cleaning is poor. If the ROP is above 200 ft./h, a CCI of 2.0 or above will indicate good cleaning.

6.8 Pressure Required to Break Circulation

Pressure required to break the mud's gel strength inside the drill string in psi.

Step 1: Calculate the pressure required to break the mud's gel strength inside the drill string:

$$P_{gsds} = \left(\frac{(L_{ds})\left(\tau_{gs}\right)}{300D_i}\right) \tag{6.70}$$

Where: P_{gsds} = Pressure required to break gel strength inside the drill string in psi
τ_{gs} = 10 min gel strength of drilling fluid in lb/100 ft.^{2}
D_i = Inside diameter of drill pipe in inches
L_{ds} = Length of drill string in ft.

Step 2: Calculate the pressure required to break the mud's gel strength in the annulus:

$$P_{gsa} = \left(\frac{L_{ds}\tau_{gs}}{300(D_h - D_i)}\right) \tag{6.71}$$

Where: P_{gsa} = Pressure required to break gel strength in the annulus in psi
D_h = Diameter of the annulus in inches

Step 3: Calculate the total pressure required to break circulation:

$$P_{gst} = \left(P_{gsds} + P_{gsa}\right) \tag{6.72}$$

Where: P_{gst} = Pressure required to break circulation in the well in psi

Example: Calculate the pressure required to break circulation in the well with this:

Data: Gel strength (10 or 30 min) = 18 lb/100 ft.^{2}
Drill string = 6⅝ × 5.965 in.
Hole size = 12¼ in.
Depth (MD) = 15,000 ft.

Step 1: Calculate the pressure required to break the mud's gel strength inside the drill string:

$$P_{gsds} = \left(\frac{(15{,}000)(18)}{300(5.965)}\right) = 150.9 \approx 151.0\,\text{psi}$$

Step 2: Calculate the pressure required to break the mud's gel strength in the annulus:

$$P_{gsa} = \left(\frac{(15{,}000)(18)}{300(12.25 - 6.625)}\right) = 160\,\text{psi}$$

Step 3: Calculate the total pressure required to break circulation:

$$P_{gsa} = (151 + 160) = 311\,\text{psi}$$

Calculate the effective gel strength based on the actual pressure required to break the circulation

$$\tau_{egs} = \frac{300(P_{bc})(D_i(D_h - D_{ds}))}{(L_{ds})(D_i + D_h - D_{ds})}$$

Where: τ_{egs} = Effective gel strength based on pressure required to break circulation in lb/100 ft.^{2}
P_{bc} = Actual pressure required to break circulation in the well in psi

Example: Calculate the effective gel strength with the following:

Data: Pressure required to break circulation = 475 psi
Drill string length = 15,000 ft.
Hole size = 12¼ in.
Drill string size = 6⅝ × 5.965 in.

$$\tau_{egs} = \frac{300(475)(5.965(12.25 - 6.625))}{(15{,}000)(5.965 + 12.25 - 6.625)} = 27.5\,\text{lb}/100\,\text{ft.}^2$$

6.9 Initial Gel Strength Guidelines for Top Hole Drilling in High Angle Wells (After Zamora)

$$\tau_I = 8.75[(D_C)(((C_{SG})(8.34)) - \text{MW})]^{0.5} \tag{6.73}$$

Where: τ_I = Initial gel strength in lb/100 ft.^{2}
D_C = Equivalent spherical diameter of cutting in in.
C_{SG} = Specific gravity of cutting in gm/cm^3 (Shallow formations may range from 2.5 to 2.0 gm/cm^3).
MW = Mud weight in ppg

Example 1: Determine the initial gel strength recommended for the following conditions:

Data: D_C = 0.625 in. (Gumbo particle with soft clay).
C_{SG} = 2.0 gms/cm^3
MW = 9.5 ppg

$$\tau_I = 8.75[(0.625)(((2.0)(8.34)) - 9.5)]^{0.5} = 18.5 \approx 19\,\text{lb}/100\,\text{ft.}^2$$

Example 2: Determine the initial gel strength recommended for the following conditions:

Data: $D_C = 0.125$ in. (sand particle).
$C_{SG} = 2.5$ gms/cm^3
MW $= 9.5$ ppg

$$\tau_I = 8.75[(0.125)(((2.5)(8.34)) - 9.5)]^{0.5} = 10.4 \approx 11\,\text{lb}/100\,\text{ft.}^2$$

6.10 Bit Nozzle Selection—Optimized Hydraulics

These series of formulas will determine the correct jet sizes when optimizing for jet impact or hydraulic horsepower and optimum flow rate for two or three nozzles.

1. Nozzles area, sq. in.:

$$\text{Nozzle area, sq. in.} = \frac{N_1^2 + N_2^2 + N_3^2}{1303.8} \tag{6.74}$$

2. Bit nozzle pressure loss, psi (Pb):

$$\text{Pb} = \frac{\text{gpm}^2 \times \text{MW, ppg}}{10{,}858 \times \text{nozzle area, sq. in.}} \tag{6.75}$$

3. Total pressure losses except bit nozzle pressure loss, psi (Pc):

$$\text{Pc}_1 \& \text{Pc}_2 = \text{circulating pressure, psi} - \text{bit nozzle pressure loss, psi} \tag{6.76}$$

4. Determine slope of line M:

$$M = \frac{\log(\text{Pc}_1 \div \text{Pc}_2)}{\log(Q_1 \div Q_2)} \tag{6.77}$$

5. Optimum pressure losses (P_{opt})

(a) For impact force:

$$P_{opt} = \frac{2}{M+2} \times P_{max} \tag{6.78}$$

(b) For hydraulic horsepower:

$$P_{opt} = \frac{1}{M+1} \times P_{max} \tag{6.79}$$

6. For optimum flow rate (Q_{opt}):

(a) For impact force:

$$Q_{opt}, \text{gpm} = \left(\frac{P_{opt}}{P_{max}}\right)^{1 \div M} \times Q_1 \tag{6.80}$$

(b) For hydraulic horsepower:

$$Q_{opt}, \text{gpm} = \left(\frac{P_{opt}}{P_{max}}\right)^{1 \div M} \times Q_1 \tag{6.81}$$

7. To determine pressure at the bit (Pb):

$$\text{Pb} = P_{max} - P_{opt} \tag{6.82}$$

8. To determine nozzle area, spin.:

$$\text{Nozzle area, sq. in.} = \sqrt{\frac{{Q_{opt}}^2 \times \text{MW, ppg}}{10{,}858 \times P_{max}}} \tag{6.83}$$

9. To determine nozzle, 32nd in. for three nozzles:

$$\text{Nozzles} = \sqrt{\frac{\text{nozzle area, sq. in.}}{3 \times 0.7854}} \times 32 \tag{6.84}$$

10. To determine nozzle, 32nd in. for two nozzles:

$$\text{Nozzles} = \sqrt{\frac{\text{nozzle area, sq. in.}}{2 \times 0.7854}} \times 32 \qquad (6.85)$$

Example: Optimize 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
Jet sizes	= 17-17-17
Pump pressure 1	= 3000 psi
Pump rate 1	= 3000 psi
Pump pressure 2	= 420 gpm
Pump rate 1	= 420 gpm
Pump pressure 2	= 1300 psi
Pump rate 2	= 275 gpm

1. Nozzle area, sq. in.:

$$\text{Nozzle area, sq. in.} = \frac{17^2 + 17^2 + 17^2}{1303.8}$$

$$\text{Nozzle area, sq. in.} = 0.66497$$

2. Bit nozzle pressure loss, psi (Pb):

$$Pb_1 = \frac{420^2 \times 13.0}{10{,}858 \times 0.664979^2}$$

$$Pb_1 = 478 \text{ psi}$$

$$Pb_2 = \frac{275^2 \times 13.0}{10{,}858 \times 0.664979^2}$$

$$Pb_2 = 205 \text{ psi}$$

3. Total pressure losses except bit nozzle pressure loss (Pc), psi:

$$\text{Pc}_1 = 3000 - 478\ \text{psi}$$
$$\text{Pc}_1 = 2522\ \text{psi}$$
$$\text{Pc}_2 = 1300 - 205\ \text{psi}$$
$$\text{Pc}_2 = 1095\ \text{psi}$$

4. Determine slope of line (M):

$$M = \frac{\log(2522 \div 1095)}{\log(420 \div 275)}$$
$$M = \frac{0.3623309}{0.1839166}$$
$$M = 1.97$$

5. Determine optimum pressure losses, psi (P_{opt}):

(a) For impact force:

$$P_{\text{opt}} = \frac{2}{1.97 + 2} \times 3000$$
$$P_{\text{opt}} = 1511\ \text{psi}$$

(b) For hydraulic horsepower:

$$P_{\text{opt}} = \frac{1}{1.97 + 1} \times 3000$$
$$P_{\text{opt}} = 1010\ \text{psi}$$

6. Determine optimum flow rate (Q_{opt}):

(a) For impact force:

$$Q_{\text{opt}},\ \text{gpm} = \left(\frac{1511}{3000}\right)^{1 \div 1.97} \times 420$$
$$Q_{\text{opt}} = 297\ \text{gpm}$$

(b) For hydraulic horsepower:

$$Q_{opt}, \text{gpm} = \left(\frac{1010}{3000}\right)^{1 \div 1.97} \times 420$$

$$Q_{opt} = 242 \text{ gpm}$$

7. Determine pressure losses at the bit (Pb):

(a) For impact force:

$$\text{Pb} = 3000 - 1511 \text{ psi}$$

$$\text{Pb} = 1489 \text{ psi}$$

(b) For hydraulic horsepower:

$$\text{Pb} = 3000 - 1010 \text{ psi}$$

$$\text{Pb} = 1990 \text{ psi}$$

8. Determine nozzle area, sq. in.:

(a) For impact force:

$$\text{Nozzle area, sq. in.} = \sqrt{\frac{297^2 \times 13.0}{10{,}858 \times 1489}}$$

$$\text{Nozzle area, sq. in.} = \sqrt{0.070927}$$

$$\text{Nozzle area} = 0.26632 \text{ sq. in.}$$

(b) For hydraulic horsepower:

$$\text{Nozzle area, sq. in.} = \sqrt{\frac{242^2 \times 13.0}{10{,}858 \times 1990}}$$

$$\text{Nozzle area, sq. in.} = \sqrt{0.03523}$$

$$\text{Nozzle area} = 0.1877 \text{ sq. in.}$$

9. Determine nozzle size, 32nd in.:

(a) For impact force:

$$\text{Nozzles} = \sqrt{\frac{0.26632}{3 \times 0.7854}} \times 32$$

$$\text{Nozzles} = 10.76$$

(b) For hydraulic horsepower:

$$\text{Nozzles} = \sqrt{\frac{0.1877}{3 \times 0.7854}} \times 32$$

$$\text{Nozzles} = 9.03$$

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:

$$0.76 \times 3 = 2.28 \text{ rounded to } 2$$

$$\text{so}: 1 \text{ jet} = 10/32\text{nds}$$

$$2 \text{ jet} = 11/32\text{nds}$$

(b) For hydraulic horsepower:

$$0.03 \times 3 = 0.09 \text{ rounded to } 0$$

$$\text{so}: 3 \text{ jets} = 9/32\text{nd in.}$$

10. Determine nozzles, 32nd in. for two nozzles:

(a) For impact force:

$$\text{Nozzles} = \sqrt{\frac{0.26632}{2 \times 0.7854}} \times 32$$

$$\text{Nozzles} = 13.18 \text{ sq. in.}$$

(b) For hydraulic horsepower:

$$\text{Nozzles} = \sqrt{\frac{0.1877}{2 \times 0.7854}} \times 32$$
$$\text{Nozzles} = 11.06\,\text{sq.in.}$$

6.11 Hydraulic Analysis

This sequence of calculations is designed to quickly and accurately analyze various parameters of existing bit hydraulics.

1. Annular velocity, ft./min (AV):

$$\text{AV} = \frac{24.5 \times Q}{\text{Dh}^2 - \text{Dp}^2} \tag{6.86}$$

2. Jet nozzle pressure loss, psi (Pb):

$$\text{Pb} = \frac{156.5 \times Q^2 \times \text{MW}}{\left[(N_1)^2 + (N_2)^2 + (N_3)^2\right]^2} \tag{6.87}$$

3. System hydraulic horsepower available (Sys HHP):

$$\text{SysHHP} = \frac{\text{surface, psi} \times Q}{1714} \tag{6.88}$$

4. Hydraulic horsepower at bit (HHPb):

$$\text{HHPb} = \frac{Q \times \text{Pb}}{1714} \tag{6.89}$$

5. Hydraulic horsepower per square inch of bit diameter:

$$\text{HHPb/sq. in.} = \frac{\text{HHPb} \times 1.27}{\text{bit size}^2} \tag{6.90}$$

6. Percent pressure loss at bit (% psib):

$$\%\text{psib} = \frac{\text{Pb}}{\text{surface, psi}} \times 100 \tag{6.91}$$

7. Jet velocity, ft./s (Vn):

$$\text{Vn} = \frac{417.2 \times Q}{(N_1)^2 + (N_2)^2 + (N_3)^2} \tag{6.92}$$

8. Impact force, lb, at bit (IF):

$$\text{IF} = \frac{(\text{MW})(\text{Vn})(Q)}{1930} \tag{6.93}$$

9. Impact force per square inch of bit area (IF/sq. in.):

$$\text{IF/sq. in.} = \frac{\text{IF} \times 1.27}{\text{bit size}^2} \tag{6.94}$$

Nomenclature:

AV = Annular velocity, ft./min
Q = Circulation rate, gpm
Dh = Hole diameter, in.
Dp = Pipe or collar O.D., in.
MW = Mud weight, ppg
N_1; N_2; N_3 = Jet nozzle sizes, 32nd in.
Pb = Bit nozzle pressure loss, psi
HHP = Hydraulic horsepower at bit
V_n = Jet velocity, ft./s
IF = Impact force, lb
If/sq. in. = Impact force lb/sq. in. of bit diameter

Example: Mud weight = 12.0 ppg
Circulation rate = 520 gpm
Nozzle size 1 = 12–32nd in.
Nozzle size 2 = 12–32nd in.
Nozzle size 3 = 12–32nd in.
Hole size = 12¼ in.
Drill pipe OD = 5.0 in.
Surface pressure = 3000 psi

1. Annular velocity, ft./min.

$$AV = \frac{24.5 \times 520}{12.25^2 - 5.0^2}$$

$$AV = \frac{12,740}{125.0625}$$

$$AV = 102\,\text{ft./min}$$

2. Jet nozzle pressure loss:

$$Pb = \frac{156.5 \times 520^2 \times 12.0}{\left(12^2 + 12^2 + 12^2\right)^2}$$

$$Pb = 2721\,\text{psi}$$

3. System hydraulic horsepower available:

$$SysHHp = \frac{3000 \times 520}{1714}$$

$$SysHHp = 910$$

4. Hydraulic horsepower at bit:

$$HHPb = \frac{2721 \times 520}{1714}$$

$$HHPb = 826$$

5. Hydraulic horsepower per square inch of bit area:

$$HHP/sq.\,in. = \frac{826 \times 1.27}{12.25^2}$$

$$HHP/sq.\,in. = 6.99$$

6. Percent pressure loss at bit:

$$\%\,psib = \frac{2721}{3000} \times 100$$

$$\%\,psib = 90.7$$

7. Jet velocity, ft./s:

$$V_n = \frac{417.2 \times 520}{12^2 + 12^2 + 12^2}$$

$$V_n = \frac{216{,}944}{432}$$

$$V_n = 502\,\text{ft./s}$$

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:

$$IF/sq.\,in. = \frac{1623 \times 1.27}{12.25^2}$$

$$IF/sq.\,in. = 13.7$$

6.12 Minimum Flowrate for PDC Bits

$$\text{Minimum flowrate, gpm} = 12.72 \times \text{bit diameter, in.}^{1.47} \tag{6.95}$$

Example: Determine the minimum flowrate for a 12¼ in. PDC bit:

$$\text{Minimum flowrate, gpm} = 12.72 \times 12.25^{1.47}$$

$$\text{Minimum flowrate, gpm} = 12.72 \times 39.77$$

$$\text{Minimum flowrate} = 505.87\ \text{gpm}$$

6.13 Critical RPM: RPM to Avoid Due to Excessive Vibration (Accurate to Approximately 15%)

$$\text{Critical RPM} = \frac{33{,}055}{L^2} \times \sqrt{\text{OD}^2 + \text{ID}^2} \tag{6.96}$$

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.

$$\text{Critical RPM} = \frac{33{,}055}{31^2} \times \sqrt{5.0^2 + 4.276^2}$$

$$\text{Critical RPM} = \frac{33{,}055}{961} \times \sqrt{43{,}284}$$

$$\text{Critical RPM} = 34.3965 \times 6.579$$

$$\text{Critical RPM} = 226.296$$

Note: As a rule of thumb, for 5.0 in. drill pipe, do not exceed 200 RPM at any depth.

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CHAPTER SEVEN

Drilling and Completion Calculations

7.1 Control Drilling: Maximum Drilling Rate (MDR) When Drilling Large Diameter Holes (14¾ in. and Larger) in ft./h

$$MDR = \frac{67(MW_o - MW_i)(R_c)}{D_h^2} \quad (7.1)$$

Where: MDR = Maximum drilling rate in ft./h
MW_o = Mud weight out in ppg
MW_i = Mud weight in in ppg
R_c = Rate of circulation in gpm

Example: Determine the MDR, ft./h, 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 = 17½ in.

$$MDR = \frac{67(9.7 - 9.0)(530)}{17.5^2}$$

$$MDR = \frac{24,857}{306.25} = 81.16 \text{ ft./h}$$

7.2 Mud Effects on Rate of Penetration

The following are based on curve fits obtained in laboratory tests as reported by Chilingarian.

http://dx.doi.org/10.1016/B978-0-12-803417-0.00007-X

A. Determine the effect on the ROP with a change in the plastic viscosity:

$$ROP_2 = \left(ROP_1 \times 10^{0.003\left(\overline{PV}_1 - \overline{PV}_2\right)}\right) \quad (7.2)$$

Where: ROP_2 = New rate of penetration in ft./h
ROP_1 = Current rate of penetration in ft./h
PV_1 = Current plastic viscosity in cP
PV_2 = New plastic viscosity in cP

Example: Determine the effect on the ROP with a change in the plastic viscosity:

Data: Current rate of penetration = 100 ft./h
Current plastic viscosity = 24 cP
New plastic viscosity = 36 cP

$$ROP_2 = \left(100 \times 10^{0.003(24-36)}\right) = 92 \text{ ft./h}$$

B. Determine the effect on the ROP with a change in the plastic viscosity:

$$ROP_2 = \left(ROP_1 \times 10^{0.051\left(\overline{V}_{B1} - V_{B2}\right)}\right) \quad (7.3)$$

Where: ROP_2 = New rate of penetration in ft./h
ROP_1 = Current rate of penetration in ft./h
V_{B1} = Original volume of bentonite in the mud in %
V_{B2} = New volume of bentonite in the mud in %

Example: Determine the effect on the ROP with a change in the volume percent of bentonite in the mud:

Data: Current rate of penetration = 100 ft./h
Current Bentonite volume = 2.0% (v/v)
New Bentonite volume = 4.0% (v/v)

$$ROP_2 = \left(100 \times 10^{0.051(2.0-4.0)}\right) = 79.1 \text{ ft./h}$$

C. Determine the effect on the ROP with an increase in the total solids content in the mud:

$$ROP_2 = \left(ROP_1 \times 10^{0.0066\left(V_{S1} - V_{S2}\right)}\right) \quad (7.4)$$

Where: ROP_2 = New rate of penetration in ft./h
V_{S1} = Original volume of total solids in the mud in %
V_{S2} = New volume of total solids in the mud in %

Example: Determine the effect on the ROP with an increase in the total solids in the mud:

Data: Current rate of penetration = 100 ft./h
Current total solids volume = 10.0% (v/v)
New total solids volume = 12.0% (v/v)

$$ROP_2 = \left(100 \times 10^{0.0066(10.0-12.0)}\right) = 97.0 \text{ ft./h}$$

D. Determine the effect on the ROP with a decrease in the filtrate of the mud:

$$ROP_2 = (ROP_1)\left(\frac{V_{F2} + 35}{V_{F1} + 35}\right) \quad (7.5)$$

Where: ROP_2 = New rate of penetration in ft./h
V_{F1} = Original volume of the filtrate in cm^3/30 min
V_{F2} = New volume of the filtrate in cm^3/30 min

Example: Determine the effect on the ROP with a decrease in the filtrate of the mud:

Data: Current rate of penetration = 100 ft./h
Current filtrate volume = 14.0 cm^3/30 min
New filtrate volume = 8.0 cm^3/30 min

$$ROP_2 = (100)\left(\frac{8.0 + 35}{14.0 + 35}\right) = 87.8 \text{ft./h}$$

E. Determine the effect on the ROP with a change in the oil content (volume of oil < 30%) of the mud:

$$ROP_2 = (ROP_1)\left[\frac{\sin((10.6)(V_{O2}) - 48.3) + 10.33}{\sin((10.6)(V_{O1}) - 48.3) + 10.33}\right] \quad (7.6)$$

Where: ROP_2 = New rate of penetration in ft./h
V_{O1} = Original volume of oil in the mud in %
V_{O2} = New volume of oil in the mud in %

Example: Determine the effect on the ROP with a change in the oil content (volume of oil < 30%) of the mud:

Data: Current rate of penetration = 100 ft./h
Current oil volume = 5.0%
New oil volume = 8.0%

$$ROP_2 = (100)\left[\frac{\sin((10.6)(8.0) - 48.3) + 10.33}{\sin((10.6)(5.0) - 48.3) + 10.33}\right] = 281.2 \text{ ft./h}$$

F. Determine the effect on the ROP with a change in total fluid properties of the mud for depths ranging from 8000 to 12,000 ft.:

$$ROP_2 = (ROP_1)\left(e^{0.382(\rho_1 - \rho_2)}\right) \quad (7.7)$$

Where: ROP_2 = New rate of penetration in ft./h
ρ_1 = Original mud weight in ppg
ρ_2 = New mud weight in ppg

Example: Determine the effect on the ROP with a change in total fluid properties of the mud:

Data: Current rate of penetration = 100 ft./h
Current mud weight = 12.0 ppg
New mud weight = 14.0 ppg

$$ROP_2 = (100)\left(e^{0.382(12.0 - 14.0)}\right) = 46.6 \text{ ft./h}$$

7.3 Cuttings Concentration % by Volume

A. Determine the net transport efficiency of the cuttings in the annulus in %:

$$NT_E = \frac{(V_a - V_{CS})}{V_a}(100) \tag{7.8}$$

Where: NT_E = Transport ratio of the cuttings (dimensionless)
V_a = Fluid velocity in the annulus in ft./min
V_{CS} = Slip velocity of the cuttings in ft./min

Example: Determine the net transport efficiency of the cuttings with the following conditions:

Data: Annular velocity = 117.5 ft./min
Slip velocity of cuttings = 40.5 ft./min

$$NT_E = \frac{(117.5 - 40.5)}{117.5}(100) = 65.5\%$$

B. Determine the volume of cuttings in the annulus based on the rate of penetration in %:

$$C_a = \frac{\left(D_h^2\right)(\text{ROP})}{448.4(Q)\left(\dfrac{NT_E}{100}\right)}(100) \tag{7.9}$$

Where: C_a = Concentration of cuttings in annulus in %
D_h = Diameter of hole in in. (Normally, the bit size, but some enlargement can be added if needed).
ROP = Rate of penetration in ft./h
Q = Pump output in gpm
NT_E = Net transport efficiency in %

Example: Determine the volume of cuttings in the annulus with the following conditions:

Data: Bit size = 12¼ in.
Rate of penetration = 50 ft./h
Pump output = 800 gpm
Transport ratio = 65.5%

$$Ca = \frac{(12.25^2)(50)}{448.4(800)\left(\frac{65.5}{100}\right)}(100) = 3.2\%$$

C. Determine the mud weight in the annulus based on the concentration of cuttings:

$$MW_a = ((G_C)(8.34))\left(\frac{C_a}{100}\right) + \left((MW)\left(1 - \left(\frac{C_a}{100}\right)\right)\right) \quad (7.10)$$

Where: MW_a = Mud weight in the annulus based on the concentration of cuttings in ppg
G_C = Specific gravity of the cuttings in g/cm^3
MW = Mud weight in use in ppg

Example: Determine the mud weight in the annulus based on the concentration of cuttings with the following:

Data: Mud weight = 12.0 ppg
Specific gravity of cuttings = 2.5 g/cm^3
Volume of cuttings in annulus = 3.2%

$$MW_a = ((2.5)(8.34))\left(\frac{3.2}{100}\right) + \left((12.0)\left(1 - \left(\frac{3.2}{100}\right)\right)\right)$$
$$= 12.28 \text{ ppg}$$

D. Determine the maximum rate of penetration needed to limit the annular mud weight and prevent loss of circulation in the top hole section of the well.

$$ROP = \frac{(Q)(FG - MW_a)}{(D_h^2)((0.0057(C_{SG})) - (0.00068(FG)))} \quad (7.11)$$

Where: ROP = Rate of penetration in ft./h
FG = Fracture gradient in ppg
MW = Mud weight in ppg
C_{SG} = Specific gravity of cuttings in g/cm^3

Example: Determine the maximum penetration rate to limit the annular mud weight below the fracture gradient in ft./h:

Data: Bit size = 17½ in.
Fracture gradient = 10.0 ppg
Mud weight = 9.5 ppg
Cutting specific gravity = 2.0 g/cm^3
Pump output = 800 gpm

$$\text{ROP} = \frac{(800) - (10.0 - 9.5)}{\left(17.5^2\right)((0.0057(2.0)) - (0.00068(10.0)))} = 284 \text{ ft./h}$$

E. Determine the rate of penetration required to maintain a certain volume percent of cuttings in the annulus. (Assuming 100% cuttings transport up the annulus).

$$\text{ROP}_\text{M} = \frac{(C_\text{a})(Q)}{\left(\frac{\left(D_\text{h}^2\right)}{1470}\right)(1 - C_\text{a})} \tag{7.12}$$

Where: ROP_M = Maximum instantaneous rate of penetration in ft./h

Example: Determine the rate of penetration required to maintain a certain volume percent of cuttings in the annulus.

Data: Bit size = 17½ in.
Volume of cuttings = 4%
Pump output = 800 gpm

$$\text{ROP}_\text{M} = \frac{(0.04)(800)}{\left(\frac{\left(17.5^2\right)}{1470}\right)(1 - 0.04)} = 160 \text{ ft./h}$$

7.4 "*d*" Exponent

Formula 1: The "*d*" exponent is derived from the general drilling equations:

$$R + N = a\left(\frac{W^d}{D}\right) \tag{7.13}$$

Where: R = Penetration rate in ft./h
N = Rotary speed in rpm
a = Rock drillability constant (dimensionless)
W = Weight on bit in lb
d = Exponent in general drilling equation (dimensionless)

Formula 2: The "*d*" exponent equation:

$$d = \frac{\log\left(\frac{R}{60\text{N}}\right)}{\log\left(\frac{12W}{1000D}\right)} \tag{7.14}$$

Where: d = "*d*" exponent (dimensionless)
R = Penetration rate in ft./h
N = Rotary speed in rpm
W = Weight on bit in 1000 lb
D = Bit size in in.

Example: R = 30 ft./h
N = 120
W = 35,000 lb
D = 8½ in.

$$d = \frac{\log\left(\frac{30}{60(120)}\right)}{\log\left(\frac{12(35)}{1000(8.5)}\right)}$$

$$d = \frac{\log\left(\frac{30}{7200}\right)}{\log\left(\frac{420}{8500}\right)}$$

$$d = \frac{\log(0.0042)}{\log(0.0494)}$$

$$d = \frac{(-2.377)}{(-1.306)} = 1.82$$

Formula 2: The corrected "*d*" exponent equation:

The "*d*" exponent is influenced by mud weight variations, so modifications have to be made to correct the changes in the mud weight:

$$d_c = d\left(\frac{9.0}{MW_a}\right) \tag{7.15}$$

Where: d_c = corrected "*d*" exponent (dimensionless)
9.0 = Normal mud weight in ppg
MW_a = Actual mud weight in ppg

Example: d = 1.64
MWa = 12.7 ppg

$$d_c = 1.64\left(\frac{9.0}{12.7}\right) = 1.16$$

7.5 Cost per Foot

$$C_f = \frac{B + (C_r(R_t + T_{rt}))}{F} \tag{7.16}$$

Where: C_f = Cost per foot in \$
B = Bit cost in \$

C_r = Rig cost in \$ per hour
R_t = Rotating time in hours
T_{rt} = Round trip time in hours
F = Footage per bit in ft.

Example: Determine the drilling cost per foot in \$, using the following:

Data: Bit cost = \$2500
Rig cost = \$900/h
Rotating time = 65 h
Round trip time = 6 h (for depth—10,000 ft.)
Footage per bit = 1300 ft.

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

$$C_f = \frac{66,400}{1300} = 51.08 \ \$/\text{ft.}$$

7.6 Rig Loads

A. Determine the dead line tension for the drill line.

Step 1: Determine the total hook load on the hoist in lb:

(a) Determine the buoyant weight of the casing in lb:

$$W_{cs} = (W_c)(L_c)(\text{BF}) \tag{7.17}$$

Where: W_{cs} = Buoyant weight of the casing in lb
W_c = Casing weight in lb/ft.
L_c = Length of casing in ft.
BF = Buoyancy factor $\left[\frac{(65.5 - \text{MW})}{65.5}\right]$

(b) Determine the total hook load on the hoist in lb:

$$L_{hoist} = (W_{cs}) + (W_{block}) \tag{7.18}$$

Where: L_{hoist} = Total hook load on the hoist in lb
W_{block} = Traveling block weight in lb

(c) Determine the dead line tension in lb:

$$T_{dl} = \frac{(L_{hoist} + MOP)}{n} \tag{7.19}$$

Where: T_{dl} = Dead line tension in lb
MOP = Maximum overpull in lb
n = Number of lines in the derrick

Step 2: Determine the static fast line tension in lb:

$$T_{fls} = T_{dl} \tag{7.20}$$

Where: T_{fls} = Static fast line tension in lb

Step 3: Determine the dynamic fast line tension in lb:

(a) **Method 1** (calculation):

$$T_{fld1} = \frac{(L_{hoist} + MOP)}{n(1 - (0.02(n)))} \tag{7.21}$$

Where: T_{fld1} = Dynamic fast line tension in lb

(b) **Method 2** (alternate calculation):

$$T_{fld2} = \frac{(L_{hoist} + MOP)}{n(0.98^n)} \tag{7.22}$$

Where: T_{fld2} = Dynamic fast line tension in lb

Step 4: Determine the Safety Factor for the drill line:

(a) Standard calculation using the dead line data:

$$SF_{dl} = \frac{T_A}{T_{dl}} \tag{7.23}$$

Where: SF_{dl} = Standard safety factor using the deal line data
T_A = Allowable hoist line tension in lb

(b) Conservative safety factor for the drill line using the Method 1 dynamic fast line tension:

$$SF_{fldl} = \frac{T_A}{T_{fld1}} \tag{7.24}$$

Where: SF_{fld1} = Standard safety factor using the deal line data

(c) Conservative safety factor for the drill line using the Method 2 dynamic fast line tension:

$$SF_{fld2} = \frac{T_A}{T_{fld2}} \tag{7.25}$$

Where: SF_{fld2} = Standard safety factor using the deal line data

B. Determine the static load for the derrick in lb:

$$L_{mast} = \left[\frac{(n+2)}{n}\right](L_{hoist}) \tag{7.26}$$

Where: L_{mast} = Buoyed weight of casing string and traveling block in lb

Note: This value should be compared to the rated load of the derrick.

C. Determine the static load of the rig substructure in lb:

(a) Determine the air weight of the drill collars and drill pipe stored on the pipe rack in lb:

$$L_{sb} = [(W_{DC})(L_{DC})] + [(W_{HW})(L_{HW})] + \left[\left(W_{dp}\right)\left(L_{dp}\right)\right] \tag{7.27}$$

Where: L_{sb} = Air weight of the drill string on the pipe rack in lb
WDC = Weight of drill collars in lb/ft.
LDC = Length of the drill collars in ft.
WHW = Weight of the heavy weight drill pipe in lb/ft.
LHW = Length of the heavy weight in ft.
Wdp = Weight of the drill pipe in lb/ft.
Ldp = Length of the drill pipe in ft.

(b) Determine the Buoyed Weight of the Casing Set in the Slips in lb:

$$L_{rt} = W_{cs} \tag{7.28}$$

Where: L_{rt} = Buoyed weight of the casing set in the slips in lb

(c) Determine the total load on the substructure in lb:

$$L_{SS} = (L_{sb}) + (L_{rt}) \tag{7.29}$$

Example: Determine the line tension and rig load with the following:

Data:

Mud weight	= 12.0 ppg
Buoyancy Factor	= 0.8168
Casing weight	= 68 lb/ft. (N-80)
Casing length	= 12,000 ft.
Traveling block	= 50,000 lb
Maximum overpull	= 100,000 lb
Allowable cable tension	= 396,000 lb
Number of lines	= 12
Drill collar weight	= 147.0 lb/ft.
Drill collar length	= 810 ft.
Heavy weight pipe	= 50.3 lb/ft.
Heavy weight pipe length	= 900 ft.
Drill pipe weight	= 22.61 lb/ft.
Drill pipe length	= 10,290 ft.

Step 1: Determine the total hook load on the hoist in lb:

(a) Determine the buoyant weight of the casing in lb:

$$W_{cs} = (68.0)(12,000)(0.8168) = 666,508.8 \text{ lb}$$

(b) Determine the total hook load on the hoist in lb:

$$L_{hoist} = (666,508.8) + (50,000) = 716,508.8 \text{ lb}$$

(c) Determine the dead line tension in lb:

$$T_{dl} = \frac{(716,508.8 + 100,000)}{12} = 68,042.4 \text{ lb}$$

Step 2: Determine the static fast line tension in lb:

$$T_{\text{fls}} = 68{,}042.4 \text{ lb}$$

Step 3: Determine the dynamic fast line tension in lb:

(a) **Method 1** (calculation):

$$T_{\text{fld1}} = \frac{(716{,}508.8 + 100{,}000)}{12(1 - (0.02(12)))} = 89{,}529.5 \text{ lb}$$

(b) **Method 2** (alternate calculation):

$$T_{\text{fld2}} = \frac{(716{,}508.8 + 100{,}000)}{12\left(0.98^{12}\right)} = 86{,}709.5 \text{ lb}$$

Step 4: Determine the safety factor for the drill line:

(a) Standard calculation using the dead line data:

$$\text{SF}_{\text{dl}} = \frac{396{,}000}{68{,}042.4} = 5.82$$

(b) Conservative safety factor for the drill line using the **Method 1** dynamic fast line tension:

$$\text{SF}_{\text{fldl}} = \frac{396{,}000}{89{,}529.5} = 4.42$$

(c) Conservative safety factor for the drill line using the **Method 2** dynamic fast line tension:

$$\text{SF}_{\text{fld2}} = \frac{396{,}000}{86{,}709.5} = 4.57$$

D. Determine the static load for the derrick in lb:

$$L_{\text{mast}} = \left[\frac{(12 + 2)}{12}\right](716{,}508.8) = 835{,}926.9 \text{ lb}$$

Note: This value should be compared to the rated load of the derrick.

E. Determine the static load of the rig substructure in lb:

(a) Determine the air weight of the drill collars and drill pipe stored on the pipe rack in lb:

$$L_{sb} = [(147.0)(810)] + [(50.3)(900)] + [(22.61)(10,290)]$$
$$= 396,996.9 \text{ lb}$$

(b) Determine the buoyed weight of the casing set in the slips in lb:

$$L_{rt} = 666,508.8 \text{ lb}$$

(c) Determine the total load on the substructure in lb:

$$L_{SS} = (396,996.9) + (666,508.8) = 1,063,505.7 \text{ lb}$$

7.7 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

7.7.1 Round Trip Ton-Miles (RT_{TM})

$$RT_{TM} = \frac{\left(\left(W_{bdp}\right)(D)\left(L_{ps} + D\right)\right) + ((2D)((2W_{tb}) + W_{bdc}))}{(5280)(2000)} \tag{7.30}$$

Where: RT_{TM} = Round trip in ton-miles
W_{bdp} = Buoyed weight of drill pipe in lb/ft.
D = Depth of hole in ft.
L_{ps} = Length of one stand of drill pipe (average) in ft.
W_{tb} = Weight of traveling block or top drive assembly in lb

W_{bdc} = Buoyed weight of drill collars in mud minus the buoyed weight of the same length of drill pipe in lb
2000 = Number of pounds in one short ton
5280 = Number of ft. in one mile

Example: Calculate the round trip ton-miles with the following data:

Data:

Mud weight	= 12.6 lb/gal
Measured depth	= 15,000 ft.
Drill pipe size	= 6⅝ in., (25.20 lb/ft, S-135)
Drill collar weight	= 147 lb/ft.
Drill collar length	= 500 ft.
Traveling block assembly	= 100,000 lb
Average length of one stand	= 92 ft. (treble)

Step 1: Calculate the Buoyancy Factor:

$$BF = \left(\frac{65.5 - 12.6}{65.5}\right) = 0.8076$$

Step 2: Calculate the buoyed weight of the drill pipe in mud in lb/ft.:

$$W_{dp} = (25.2)(0.8076) = 20.59 \text{ lb/ft.}$$

Step 3: Calculate the buoyed weight of the drill collars in the mud minus the buoyed weight of the same length of drill pipe in lb:

$$W_{dc} = ((500)(147)(0.8076)) - ((500)(25.2)(0.8076))$$
$$= 49,183 \text{ lb}$$

Step 4: Calculate the round trip ton-miles:

$$RT_{TM} = \frac{((20.59)(15,000)(92 + 15,000)) + ((30,000)(200,000 + 49,183))}{(5280)(2000)}$$

$$= 1149.3 \text{ ton-miles}$$

7.7.2 Drilling or "Connection" Ton-Miles

The ton-miles calculation used for the drilling operation is expressed in terms of the work performed making round trips. These are the actual ton-miles of work required to drill down the length of a joint of drill pipe ($\approx$30 ft.), plus picking up, connecting, and starting to drill with the next joint.

To determine connection or drilling ton-miles, multiply three times the difference between the ton-miles for the current round trip minus the ton-miles for the previous round trip:

$$TM_D = 3(TM_2 - TM_1) \tag{7.31}$$

Where: TM_D = Drilling or "connection" ton-miles
TM_2 = Ton-miles for one round trip—depth where drilling stopped before coming out of the hole
TM_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

$$TM_D = 3(1175.2 - 1149.3) = 77.7 \text{ ton-miles}$$

7.7.3 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 two 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:

$$TM_C = 2(TM_4 - TM_3) \tag{7.32}$$

Where: TM_C = Ton-miles while coring
TM_4 = Ton-miles for one round trip—depth where coring stopped before coming out of the hole
TM_3 = Ton-miles for one round trip—depth where coring started

7.7.4 Ton-Miles Setting Casing

The calculation of the ton-miles for setting casing is determined just like the one for drill pipe, but with the buoyed weight of the casing being used. The result is multiplied by one-half because setting casing is a one-way (½ round trip) operation. Ton-miles for setting casing can be determined from the following formula:

$$TM_{CSG} = \frac{0.5\left(\left(W_{csgb}\right)(D)\left(L_{csg} + D\right)\right) + ((D)(W_b))}{(5280)(2000)} \tag{7.33}$$

Where: TM_{CSG} = Ton-miles setting casing
W_{csgb} = Buoyed weight of casing in lb/ft.
L_{css} = Length of one joint of casing in ft.
W_b = Weight of traveling block assembly in lb

7.7.5 Ton-Miles While Making Short Trips

The ton-miles of work performed on short trip operations are also expressed in terms of round trips. Analysis shows that the ton-miles of work done in making a short trip are equal to the difference in round trip ton-miles for the two depths in question.

$$TM_{ST} = (TM_6 - TM_5) \tag{7.34}$$

Where: TM_{ST} = Ton-miles for short trip
TM_6 = Ton-miles for one round trip at the deeper depth, the depth of the bit before starting the short trip
TM_5 = Ton-miles for one round trip at the shallower depth, the depth that the bit is pulled up to at the end of the short trip

7.7.6 Cutoff Practices for Rotary Drilling Line

Refer to Section 6 in API RP 9B for recommended cutoff lengths for drill line based on ton-mile calculations.

7.7.7 Calculate the Length of Drill Line Cutoff

$$DL_{co} = \left(\frac{RT_{TM}}{CO_G}\right) \tag{7.35}$$

Where: DL_{CO} = Drill line cutoff in ft.
CO_G = Cutoff goal from Table 7.1

Table 7.1
Ton-Mile Goal per Foot of Rope[a]

Drum Diameter (in.)	Rope Diameter							
	1 in.	**1⅛ in.**	**1¼ in.**	**1⅜ in.**	**1½ in.**	**1⅝ in.**	**1¾in.**	**2 in.**
18	6.0	9.0						
19	6.0	9.0						
20	7.0	9.0						
21	7.0	10.0						
22	7.0	10.0						
23	8.0	10.0	13.0					
24	8.0	10.0	13.0	17.0				
25	8.0	10.0	14.0	17.0				
26	9.0	11.0	14.0	17.0				
27	9.0	12.0	15.0	18.0				
28		12.0	15.0	18.0				
29		12.0	15.0	18.0				
30		13.0	16.0	19.0	20.0			
31			16.0	19.0	21.0			
32			17.0	20.0	22.0			
33			17.0	20.0	23.0			
34			18.0	21.0	24.0			
35				21.0	25.0			
36				22.0	25.0	28	30	
42								32
48								
60								

[a]Premium ropes such as plastic impregnated can provide additional service.

Using the ton-miles calculated in Step 4 of Section 7.5.1, calculate the amount of drill line to be cut.

Data: Drum circumference = 42 in.
Drill line diameter = 2 in.
Ton-miles calculated = 1149.3

$$DL_{co} = \left(\frac{1149.3}{32}\right) = 35.9 \text{ ft.}$$

7.8 Hydrostatic Pressure Decrease When Pulling Pipe Out of the Hole

7.8.1 When Pulling DRY Pipe

Step l: Determine the number of barrels displaced when pulling **DRY** pipe in bbl:

$$V_d = S_n \times L_s \times P_d \tag{7.36}$$

Where: V_d = Volume of displaced mud when pulling **DRY** pipe in bbl
S_n = Number of stands
L_s = Average length per stand in ft.
P_d = Pipe displacement in bbl/ft.

Example: Determine volume of barrels displaced when pulling **DRY** pipe out of the hole.

Data: S_n = 5 stands
L_s = 92 ft./std.
P_d = 0.0075 bbl/ft.

$$V_d = 5 \times 92 \times 0.0075 = 3.45 \text{ bbl}$$

Step 2: Determine the hydrostatic pressure decrease when pulling **DRY** pipe in psi:

$$HP_d = \left(\frac{B_d}{C_a - P_d}\right) \times 0.052 \times MW \tag{7.37}$$

Where: HP_d = Hydrostatic pressure decrease when pulling **DRY** pipe in psi

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

Data: V_d = 3.45 bbl from Step 1
C_a = 0.0773 bbl/ft.
P_d = 0.0075 bbl/ft.
MW = 11.5 ppg

$$HP_d = \left(\frac{3.45}{0.0773 - 0.0075}\right) \times 0.052 \times 11.5 = 29.56 \text{ psi}$$

7.8.2 When Pulling WET Pipe

Step 1: Determine volume of barrels displaced when pulling **WET** pipe out of the hole.

$$V_w = S_n \times L_s \times (P_d + C_p) \tag{7.38}$$

Where: V_w = Volume of
C_p = Capacity of pipe in bbl/ft.

Example: Determine the volume of barrels displaced when pulling **WET** pipe out of the hole.

Data: S_n = 5 stands
L_s = 92 ft./std.
P_d = 0.0075 bbl/ft.
C_p = 0.01776 bbl/ft.

$$V_w = 5 \times 92 \times (0.0075 + 0.01776) = 11.62 \text{ bbl}$$

Step 2: Determine the hydrostatic pressure decrease in psi:

$$HP_w = \frac{B_d}{C_a - \left(P_d + C_p\right)} \times 0.052 \times MW \tag{7.39}$$

Where: HP_w = Hydrostatic pressure decrease when pulling **WET** pipe in psi
C_a = Capacity of casing or open hole in bbl/ft.

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

Data: S_n = 5 stands
L_s = 92 ft./std.
P_d = 0.0075 bbl/ft.
C_p = 0.01776 bbl/ft.
C_a = 0.0773 bbl/ft.
MW = 11.5 ppg

$$HP_w = \frac{11.6196}{0.0773 - (0.0075 + 0.01776)} \times 0.052 \times 11.5$$

$$HP_w = \frac{11.6196}{0.05204} \times 0.052 \times 11.5$$

$$HP_d = 133.52 \text{ psi}$$

7.9 Loss of Overbalance Due to Falling Mud Level

7.9.1 Feet of Pipe Pulled DRY to Lost Overbalance

$$L_{pd} = \frac{O_{bL} \times (C_a - P_d)}{MW \times 0.052 \times P_d} \tag{7.40}$$

Where: L_{pd} = Length of pipe pulled DRY in ft.
O_{bL} = Amount of overbalance LOST in psi

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

Data: $O_b = 150$ psi
$C_a = 0.0773$ bbl/ft.
$P_d = 0.0075$ bbl/ft.
MW = 11.5 ppg

$$L_{pd} = \frac{150 \times (0.0773 - 0.0075)}{11.5 \times 0.052 \times 0.0075}$$

$$L_{pd} = \frac{10.47}{0.004485} = 2334.45 \text{ ft.}$$

7.9.2 Feet of Pipe Pulled WET to Lose Overbalance

$$L_{pw} = \frac{O_b \times \left(C_a - C_p - P_d\right)}{\text{MW} \times 0.052 \times \left(C_p + P_d\right)} \tag{7.41}$$

Where: L_{pw} = Length of pipe pulled WET in ft.

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

Data: $O_b = 150$ psi
$C_a = 0.0773$ bbl/ft.
$C_p = 0.01776$ bbl/ft.
$P_d = 0.0075$ bbl/ft.
MW = 11.5 ppg

$$L_{pw} = \frac{150 \times (0.0773 - 0.01776 - 0.0075)}{11.5 \times 0.052 \times (0.01776 + 0.0075)}$$

$$L_{pw} = \frac{150 \times 0.05204}{11.5 \times 0.052 \times 0.02526}$$

$$L_{pw} = \frac{7.806}{0.0151055} = 516.8 \text{ ft.}$$

7.9.3 Metric Calculations

Formula 1: DRY PIPE in bar/m

$$HP_d = \frac{MW \times P_d \times 0.0981}{(C_a - P_d)} \tag{7.42}$$

Where: HP_d = Hydrostatic pressure drop tripping with **DRY** pipe in bar/m
MW = Mud weight in kg/l
P_d = Pipe displacement in l/m
C_a = Casing or open hole capacity in l/m

Formula 2: DRY PIPE in bar/m

$$HP_d = \frac{MW \times P_d \times 0.0981}{(C_a - P_d)} \tag{7.43}$$

Where: HP_d = Hydrostatic pressure drop tripping with **DRY** pipe in bar/m
MW = Mud weight in bar/m

Formula 3: WET PIPE in bar/m

$$HP_d = \frac{MW \times (P_d + C_p) \times 0.0981}{C_a} \tag{7.44}$$

Where: HP_d = Hydrostatic pressure drop tripping with **DRY** pipe in bar/m
MW = Mud weight in kg/l
P_d = Pipe displacement in l/m
C_p = Capacity of pipe in l/m
C_a = Casing or open hole capacity in l/m

Formula 4: WET PIPE in bar/m

$$HP_d = \frac{MW \times (P_d + C_p) \times 0.0981}{C_a} \tag{7.45}$$

Where: HP_d = Hydrostatic pressure drop tripping with **WET** pipe in bar/m
MW = Mud weight in bar/m
P_d = Pipe displacement in l/m
C_p = Capacity of pipe in l/m
C_a = Casing or open hole capacity in l/m

Formula 5: Mud level drop for POOH with drill collars

$$L_{ddc} = \frac{L_{dc} \times P_d}{C_a} \tag{7.46}$$

Where: L_{ddc} = Length of mud level drop to pull drill collars out of the hole in meters.
L_{dc} = Length of drill collars in meters

7.9.4 SI Unit Calculations

Formula 1: DRY PIPE in kPa/m

$$\Delta P_d = \frac{MW \times P_d}{102 \times (C_a - P_d)} \tag{7.47}$$

Where: ΔP_d = Pressure drop tripping DRY pipe in kPa/m

Formula 2: WET PIPE in kPa/m

$$\Delta P_w = \frac{MW \times (P_d + P_c)}{102 \times C_a} \tag{7.48}$$

Where: ΔP_w = Pressure drop tripping WET pipe in kPa/m

Formula 3: Mud level drop for POOH with drill collars

$$L_{ddc} = \frac{L_{dc} \times P_d}{C_a} \tag{7.49}$$

Where: P_d = Pipe displacement in m^3/m
C_p = Capacity of pipe in m^3/m

7.10 Lost Circulation

Loss of Overbalance

Step 1: Calculate the number of feet of fluid (water for WBM; base oil for OBM/SBM) added to the top of the annulus:

$$L_f = \frac{V_f}{9.71 \times 10^{-4}\left(D_b^2 - D_p^2\right)} \tag{7.50}$$

Where: L_f = Length of fluid added to the top of the annulus in ft.
V_f = Volume of fluid added to the top of the annulus in bbl

Step 2: Calculate the reduction in bottomhole pressure (BHP) due to the unweighted fluid added to the top of the annulus:

$$P_{BHP} = (L_f)(W_{ma} - W_f)(0.052) \tag{7.51}$$

Where: P_{BHP} = Decrease in bottom hole pressure in psi
W_{ma} = Weight of mud in annulus in lb/gal
W_f = Weight of fluid added to the top of the annulus in lb/gal

Step 3: Calculate the equivalent mud weight at TVD due to fluid added to the top of the annulus:

$$W_{mc} = W_{ma} - \left(\frac{\left(\frac{P_{BHP}}{0.052}\right)}{D_{TV}}\right) \tag{7.52}$$

Where: W_{me} = Equivalent mud weight in lb/gal
D_{TV} = Total vertical depth in ft.

Example: Calculate the equivalent mud weight due to the addition of unweighted fluid to the top of the annulus with the following data:

Data: Mud weight = 12.5 lb/gal
Water added = 150 bbl (required to fill the annulus)
Weight of water = 8.33 lb/gal
TVD = 10,000 ft.
Riser ID = 18¾in.
Drill pipe size = 6⅝ × 5.965 in.

Step 1: Calculate the length of annulus covered by the volume of water added:

$$L_f = \frac{325}{9.71 \times 10^{-4}\left(18.75^2 - 6.625^2\right)} = 1087.9 \approx 1088\,\text{ft.}$$

Step 2: Calculate the reduction in bottom hole pressure:

$$P_{BHP} = (1088)(12.5 - 8.55)(0.052) = 223.5 \approx 224 \text{ psi}$$

Step 3: Calculate the equivalent mud weight at the TVD:

$$W_{me} = 12.5 - \left(\frac{\left(\frac{224}{0.052}\right)}{10{,}000}\right) = 12.07 \text{ lb/gal}$$

7.10.1 Determine the Equivalent Mud Weight in ppg That Will Balance the Formation Losing Mud Volume

Step 1: Determine the level of the mud in the annulus in ft by adding water to fill up the casing:

$$L_w = \left(\frac{V_w}{C_a}\right) \tag{7.53}$$

Where: L_w = Length of water added to annulus in ft.
V_w = Volume of water added to the annulus in bbl
C_a = Capacity of the annulus in bbl/ft.

Step 2: Determine the mud weight equivalent at the depth of the loss of circulation in ppg:

$$MW_e = \frac{((L_w)(G_w)) + ((D_m - L_w)((MW)(0.052)))}{((D_m)(0.052))} \quad (7.54)$$

Where: MW_e = Mud weight equivalent at depth of lost circulation in ppg
G_w = Gradient of water added to annulus (Fresh = 0.433 psi/ft.; Sea Water = 0.455 psi/ft.)
D_m = Measured depth of interest (normally the casing shoe) in ft.
MW = Mud weight in use when loss occurred in ppg

Example: Determine the equivalent mud weight in ppg with the following conditions:

Data: Casing size = 9⅝ in. (43.5 lb/ft., ID = 8.755 in.)
Casing length = 3500 ft.
Annulus capacity = 0.0502 bbl/ft.
Drill pipe size = 5.0 in. (19.5 lb/ft.)
Fresh water added = 25 bbl
Mud weight = 12.2 ppg

Step 1: Determine the level of the mud in the annulus in ft. by adding water to fill up the casing:

$$L_w = \left(\frac{25}{0.0502}\right) = 498 \text{ ft.}$$

Step 2: Determine the mud weight equivalent at the depth of the loss of circulation in ppg:

$$MW_e = \frac{((498)(0.433)) + ((3500 - 498)((12.2)(0.052)))}{((3500)(0.052))}$$
$$= 11.65 \text{ ppg}$$

7.10.2 Determine the Depth of the Fluid Level with Loss of Circulation in Natural Fractured Formations

$$D_{fl} = \frac{(\Delta W_{ds})}{[(DP_{aw})(1 - BF)]} \tag{7.55}$$

Where: D_{fl} = Depth of fluid level in ft.
ΔW_{ds} = Increase in string weight caused by a loss of buoyancy in lb
DP_{aw} = Adjusted weight of the drill pipe including tool joints in lb/ft.
BF = Buoyancy Factor

Example: Determine the depth of the fluid level with the following:

Data: Fractured formation depth = 7575 ft.
Mud weight = 11.8 ppg
String weight increase = 5000 lb
Drill pipe weight = 20.9 lb/ft.
Buoyancy Factor = 0.8183

$$D_{fl} = \frac{(5000)}{[(20.9)(1 - 0.8183)]} = 1316.6 \text{ ft.}$$

7.10.3 Determine the Amount of Mud Loss That Can Occur Before the Well Begins to Flow from a Gas-Bearing Formation

Step 1: Determine the length of fluid drop before taking a kick in ft.:

$$L_m = \frac{(P_{ob})}{(G_m)} \tag{7.56}$$

Where: L_m = Maximum length of fluid drop before taking a gas kick in ft.
P_{ob} = Pressure of overbalance in psi
G_m = Mud gradient in psi/ft.

Step 2: Determine the volume of mud that can be lost before the well kicks in bbl:

$$V_m = (L_m)(C_a)$$

Where: V_m = Volume of mud that can be lost before the well kicks in bbl
C_a = Capacity of the annulus in bbl/ft.

Example: Determine how much mud can be lost with the following conditions:

Data: Planned overbalance = 250 psi
Casing size = 9⅝ in. (47 lb/ft.)
Annulus capacity = 0.0489
Drill pipe size = 5.0 in.
Mud weight = 12.0 ppg
Mud gradient = 0.624 psi/ft.

Step 1: Determine the length of fluid drop before taking a kick in ft.:

$$L_m = \frac{(250)}{(0.624)} = 400.6 \text{ ft.}$$

Step 2: Determine the volume of mud that can be lost before the well kicks in bbl:

$$V_m = (400.6)(0.0489) = 19.6 \text{ bbl}$$

7.11 Core Analysis Techniques

7.11.1 Extraction and Saturation Determinations (Dean Stark Analysis)

Step 1: Determine the pore volume and porosity.

(a) Determine the pore volume in cm^3:

$$V_p = \frac{(W_{SC} - W_e)}{\rho_w} \tag{7.57}$$

Where: V_p = Volume of pore in cm^3
W_{SC} = Weight of saturated core in g
W_e = Weight of dried core in g
ρ_w = Specific gravity of water in g/cm^3

(b) Determine the porosity of the core in %:

$$\varnothing = \frac{(V_p)}{(V_b)}(100)$$

Where: $\varnothing$ = Core porosity in %
V_b = Bulk volume of the core in cm^3

Step 2: Determine the water saturation in the core in %:

$$S_w = \frac{(V_w)}{(V_p)}(100) \tag{7.58}$$

Where: S_w = Water saturation in %
V_w = Volume of water extracted from the core in cm^3

Step 3: Determine the oil saturation in %:

$$S_O = \frac{(W_{sc} - W_{dc} - (V_w(\rho_w)))}{(V_p)}(100)$$

Where: S_O = Oil saturation in %
W_{sc} = Weight of the saturated sample in g
W_{dc} = Weight of the dry core in g

Step 4: Determine the gas saturation in %:

$$S_g = (1.0 - S_w - S_O)(100) \tag{7.59}$$

Where: S_g = Gas saturation in %

7.12 Temperature Correction for Brines

7.12.1 Determine the Clear Brine Fluid Weight to Be Mixed at the Surface to Balance the Required Bottomhole Pressure at the Bottomhole Temperature Conditions

Step 1: Select the appropriate weight loss factor in ppg/°F:

Table 7.2: Brine Weight Loss Factor

Brine Weight (ppg)	Weight Loss (ppg/°F)
8.4–9.0	0.0017
9.1–11.0	0.0025
11.1–14.5	0.0033
14.6–17.0	0.0040
17.1–19.2	0.0045

Step 2: Determine the brine weight to be mixed at surface conditions in ppg:

$$MW_{SB} = (MW_f) + [(T_f - T_S)(F_{WL})] \tag{7.60}$$

Where: MW_{SB} = Brine weight at surface temperature in ppg
MW_f = Formation mud weight in ppg
T_f = Formation temperature at total depth in °F

T_S = Surface temperature in °F
F_{WL} = Brine weight loss factor in ppg/°F

Example: Determine the brine weight to be mixed at surface conditions in ppg:

Data: $MW_f = 11.4$ ppg
$T_f = 180$ °F
$T_S = 80$ °F
$F_{WL} = 0.0033$ ppg/°F

$$MW_{SB} = (11.4) + [(180 - 80)(0.0033)] = 11.7 \text{ ppg}$$

7.13 Tubing Stretch

A. Determine the tubing stretch from the weight of the string:

$$S_W = \frac{(W_T)(D_{TVD})\left(\frac{L_{tbg}}{2}\right)}{(A_p)(3.0 \times 10^7)} \tag{7.61}$$

Where: S_W = Tubing stretch due to the weight of the string in ft.
W_T = Weight of the tubing (plus connection) in lb/ft.
D_{TVD} = Total vertical depth in ft.
L_{tbg} = Measured length of the tubing in ft.
A_p = Cross-sectional area of the tubing in in.^{2}

B. Determine the tubing stretch from the expansion of the tube due to internal pressure:

$$S_E = \frac{(0.6)\left[\left(\frac{(A_{OD})((MW)(0.052)(D_{TVD}))}{2}\right) - \left(\frac{(A_{ID})((MW)(0.052)(D_{TVD}))}{2}\right)\right](L_{tbg})}{(A_{pw})(3.0 \times 10^7)} \tag{7.62}$$

Where: S_E = Tubing stretch from the expansion due to internal pressure in ft.
A_{OD} = Cross-sectional area of the OD of the tubing in in.^{2}
MW = Mud weight in ppg
A_{ID} = Cross-sectional area of the ID of the tubing in in.^{2}
A_{pw} = Cross-sectional area of the tubing wall in in.^{2} (OD – ID)

C. Determine the tubing stretch from buoyancy of the tubing in ft.:

$$S_B = \frac{(-(MW)(0.052)(D_{TVD}))(A_{Pw})(L_{tbg})}{(A_{Pw})(3.0 \times 10^7)} \tag{7.63}$$

Where: S_B = Tubing stretch from the buoyancy in the completion fluid in ft.

D. Determine the tubing stretch from temperature changes in the well in ft.:

(a) Determine the Δ temperature in the well:

$$\Delta T = \frac{(T_{BH} - T_{surface})}{2} \tag{7.64}$$

Where: ΔT = Temperature change in the well in °F
T_{BH} = Bottom hole temperature in °F
$T_{surface}$ = Surface temperature in °F

(b) Determine the tubing stretch from the temperature change in the well in ft.:

$$S_T = (6.9 \times 10^{-6})(\Delta T)(L_{tbg}) \tag{7.65}$$

Where: S_T = Tubing stretch from temperature changes in the well in ft.

E. Determine the total tubing stretch in the well:

$$S_{total} = (S_W) + (S_E) + (S_B) + (S_T) \tag{7.66}$$

Example: Determine the tubing stretch with the following conditions:

Data: Depth TVD = 10,000 ft.
Measured depth = 12,000 ft.
Mud weight = 8.34 ppg
Tubing size = 2⅞ in. (8.7 lb/ft., ID = 2.259 in.)
Cross-sectional area of the tubing OD = 6.49 in.^{2}
Cross-sectional area of the tubing ID = 4.01 in.^{2}
Cross-sectional area of the tubing wall = 2.48 in.^{2}
Surface temperature = 80 °F
Bottom hole temperature = 275 °F

A. Determine the tubing stretch from the weight of the string:

$$S_W = \frac{(8.7)(10,000)\left(\frac{12,000}{2}\right)}{(2.48)\left(3.0 \times 10^7\right)} = 7.02 \text{ ft.}$$

B. Determine the tubing stretch from the expansion of the tube due to internal pressure:

$$S_E = \frac{(0.6)\left[\left(\frac{(6.49)((8.34)(0.052)(10,000))}{2}\right) - \left(\frac{(4.01)((8.34)(0.052)(10,000))}{2}\right)\right](12,000)}{(2.48)\left(3.0 \times 10^7\right)}$$

$$= 1.04 \text{ ft.}$$

C. Determine the tubing stretch from buoyancy of the tubing in ft.:

$$S_B = \frac{(-(8.34)(0.052)(10,000))(2.48)(12,000)}{(2.48)\left(3.0 \times 10^7\right)} = -1.73 \text{ ft.}$$

D. Determine the tubing stretch from temperature changes in the well in ft.:

(a) Determine the Δ temperature in the well:

$$\Delta T = \frac{(275 - 80)}{2} = 97.5\,°\text{F}$$

(b) Determine the tubing stretch from the temperature change in the well in ft.:

$$S_T = \left(6.9 \times 10^{-6}\right)(97.5)(12,000) = 8.07 \text{ ft.}$$

E. Determine the total tubing stretch in the well:

$$S_{\text{total}} = (7.02) + (1.04) + (-1.73) + (8.07) = 14.4 \text{ ft.}$$

7.14 Directional Drilling Calculations

7.14.1 Directional Survey Calculations

The following are the two most commonly used methods to calculate directional surveys:

1. Angle Averaging Method

$$\text{North} = \text{MD} \times \sin\frac{(I_1 + I_2)}{2} \times \cos\frac{(A_1 + A_2)}{2} \tag{7.67}$$

$$\text{East} = \text{MD} \times \sin\frac{(I_1 + I_2)}{2} \times \sin\frac{(A_1 + A_2)}{2} \tag{7.68}$$

$$\text{Vert} = \text{MD} \times \cos\frac{(I_1 + I_2)}{2} \tag{7.69}$$

2. Radius of curvature method

$$\text{North} = \frac{\text{MD}(\cos I_1 - \cos I_2)(\sin A_2 - \sin A_1)}{(I_2 - I_1)(A_2 - A_1)} \times \left(\frac{180}{\pi}\right)^2 \tag{7.70}$$

$$\text{East} = \frac{\text{MD}(\cos I_1 - \cos I_2)(\cos A_1 - \cos A_2)}{(I_2 - I_1)(A_2 - A_1)} \times \left(\frac{180}{\pi}\right)^2 \tag{7.71}$$

$$\text{Vert} = \frac{\text{MD}(\sin I_2 - \sin I_1)}{(I_2 - I_1)} \times \left(\frac{180}{\pi}\right) \tag{7.72}$$

Where: MD = Course length between surveys in measured depth (ft.)
I_1 = Inclination (angle) at upper survey (°)
I_2 = Inclination (angle) at lower survey (°)
A_1 = Direction at upper survey
A_2 = Direction at lower survey

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 (°)	4	8
Azimuth (°)	10	35

1. Angle averaging method:

$$\text{North} = 300 \times \sin\frac{(4+8)}{2} \times \cos\frac{(10+35)}{2}$$
$$= 300 \times \sin(6) \times \cos(22.5)$$
$$= 300 \times 0.14258 \times 0.923879$$
$$\text{North} = 28.97 \text{ ft.}$$

$$\text{East} = 300 \times \sin\frac{(4+8)}{2} \times \sin\frac{(10+35)}{2}$$
$$= 300 \times \sin(6) \times \sin(22.5)$$
$$= 300 \times 0.14258 \times 0.38268$$
$$\text{East} = 12.0 \text{ ft.}$$

$$\text{Vert} = 300 \times \cos\frac{(4+8)}{2}$$
$$= 300 \times \cos(6)$$
$$= 300 \times 0.99452$$
$$\text{Vert} = 298.35 \text{ ft.}$$

2. Radius of curvature method:

$$\text{North} = \frac{300(\cos 4 - \cos 8)(\sin 35 - \sin 10)}{(8-4)(35-10)} \times \left(\frac{180}{\pi}\right)^2$$

$$= \frac{300(0.99756 - 0.990268)(0.57357 - 0.173648)}{4 \times 25} \times \left(\frac{180}{3.1416}\right)^2$$

$$= \frac{0.84629}{100} \times 57.3^2$$

$$= 0.008746 \times 3283.3$$

$$\text{North} = 28.72 \text{ ft.}$$

$$\text{East} = \frac{300(\cos 4 - \cos 8)(\cos 10 - \cos 35)}{(8-4)(35-10)} \times \left(\frac{180}{\pi}\right)^2$$

$$= \frac{300(0.99756 - 0.990268)(0.9848 - 0.81915)}{4 \times 25} \times \left(\frac{180}{3.1416}\right)^2$$

$$= \frac{300(0.0073)(0.16565)}{100} \times \left(\frac{180}{3.1416}\right)^2$$

$$= \frac{0.36277}{100} \times 57.3^2$$

$$= 0.0036277 \times 32.83.3$$

$$\text{East} = 11.91 \text{ ft.}$$

$$\text{Vert} = \frac{300(\sin 8 - \sin 4)}{(8-4)} \times \left(\frac{180}{\pi}\right)$$

$$= \frac{300(0.13917 \times 0.069756)}{4} \times \left(\frac{180}{3.1416}\right)$$

$$= \frac{300(0.069414)}{4} \times (57.3)$$

$$= 5.20605 \times 57.3$$

$$\text{Vert} = 298.3 \text{ ft.}$$

7.14.2 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.

Figure 7.1 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

To calculate the deviation/departure (CD) (ft.):

$$CD(\text{ft.}) = \sin 1 \times BD \tag{7.73}$$

Example: Kick off point (KOP) is a distance 2000 ft. from the surface. MD is 8000 ft. Hole angle (inclination) is 20°. Therefore, the distance from KOP to MD = 6000 ft. (BD):

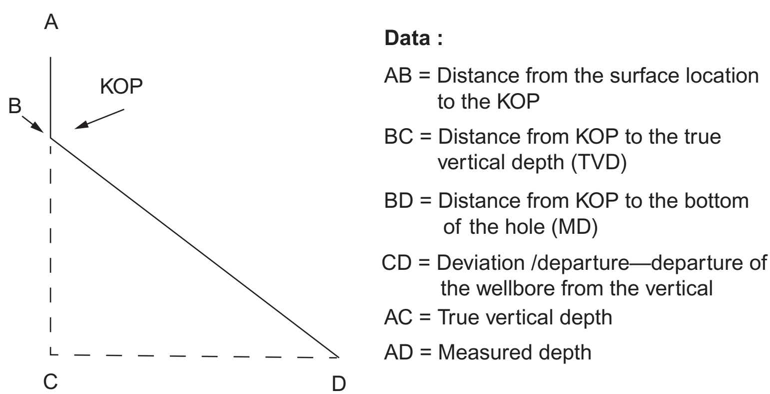

Figure 7.1 Deviation/departure.

$$\text{CD(ft.)} = \sin 20 \times 6000 \text{ ft.}$$
$$= 0.342 \times 6000 \text{ ft.}$$
$$\text{CD} = 2052 \text{ ft.}$$

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:

$$\text{DLS} = \left\{ \cos^{-1}[(\cos I_1 \times \cos I_2) + (\sin I_1 \times \sin I_2) \times \cos(A_2 - A_1)] \right\} \times \frac{100}{\text{CL}} \tag{7.74}$$

$$\text{For metric calculation, substitute} \times \frac{30}{\text{CL}} \tag{7.75}$$

Where: DLS = Dogleg severity, degrees/100 ft.
CL = Course length, distance between survey points (ft.)
I_1 = Inclination (angle) at upper survey (ft.)
I_2 = Inclination (angle) at lower survey (ft.)
A_1 = Direction at upper survey (°)
A_2 = Direction at lower survey (°)
"Azimuth = Azimuth change between surveys (°)

Example:

	Survey 1	**Survey 2**
Depth (ft.)	4231	4262
Inclination (°)	13.5	14.7
Azimuth (°)	N 10 E	N 19 E

$$\text{DLS} = \left\{ cos^{-1}[(\cos 13.5 \times \cos 14.7) + (\sin 13.5 \times \sin 14.7 \times \cos(19 - 10))] \right\} \times \frac{100}{31}$$

$$\text{DLS} = \left\{ cos^{-1}[(0.9723699 \times 0.9672677) + (.2334453 \times .2537579 \times .9876883)] \right\} \times \frac{100}{31}$$

$$\text{DLS} = \left\{ cos^{-1}[(.940542) + (.0585092)] \right\} \times \frac{100}{31}$$

$$\text{DLS} = 2.4960847 \times \frac{100}{31}$$

$$\text{DLS} = 8.051886^\circ/100 \text{ ft.}$$

Method 2:

This method of calculating dogleg severity is based on the tangential method:

$$\text{DLS} = \frac{100}{L[(\sin I_1 \times \sin I_2) \times (\sin A_1 \times \sin A_2 + \cos A_1 \times \cos A_2) + (\cos I_1 \times \cos I_2)]} \quad (7.76)$$

Where: DLS = Dogleg severity, degrees/100 ft.
L = Course length (ft.)
I_1 = Inclination (angle) at the upper survey (°)
I_2 = Inclination (angle) at the lower survey (°)
A_1 = Direction at the upper survey (°)
A_2 = Direction at the lower survey (°)

Example:

	Survey 1	**Survey 2**
Depth	4231	4262
Inclination (°)	13.5	14.7
Azimuth (°)	N 10 E	N 19 E

$$DLS = \frac{100}{31[(\sin 13.5 \times \sin 14.7) \times (\sin 10 \times \sin 19 + \cos 10 \times \cos 19) + (\cos 13.5 \times \cos 14.7)]}$$

$$DLS = \frac{100}{30.97}$$

$$DLS = 3.229°/100 \text{ ft.}$$

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:

$$P = W \times \cos 1 \tag{7.77}$$

Where: P = Partial weight available for bit
cos = cosine
I = Degrees inclination (angle)
W = Total weight of collars

Example: W = 45,000 lb
I = 25°
P = 45,000 × cos25
P = 45,000 × 0.9063
P = 40,784 lb

Thus, the available weight on bit is 40,784 lb.

7.14.3 Determining True Vertical Depth

The following is a simple method of correcting for the TVD on directional wells. This calculation will provide 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:

$$TVD_2 = \cos 1 \times CL + TVD, \tag{7.78}$$

Where: TVD_2 = New true vertical depth (ft.)
cos = cosine
CL = Course length—number of feet since last survey
TVD_1 = Last true vertical depth (ft.)

Example: TVD (last survey) = 8500 ft.
Deviation angle = 40°
Course length = 30 ft.

Solution: $TVD_2 = \cos 40 \times 30$ ft. + 8500 ft.
$TVD_2 = 0.766 \times 30$ ft. + 8500 ft.
$TVD_2 = 22.98$ ft. + 8500 ft.
$TVD_2 = 8522.98$ ft.

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CHAPTER EIGHT

Air and Gas Calculations

Note 1: This chapter has unit system consistent equations, not field equations. The equations may be worked using either the USCS or the SI. If USCS is used, pressure is (lb/ft.^{2} abs), specific weight (lb/ft.^{3}) or specific gravity, temperature (°Rankin), and depth (ft.). If SI is used, pressure is (N/m^2 abs), specific weight (N/m^3) or specific gravity, temperature (Kelvin), and depth (m). API standard conditions are 14.696 psia (~14.7 psia), 59 °F, and 0% humidity.

Note 2: Flow problems with gas require that the calculations be carried out from a flow state that is known (usually at the exit). This requires that the calculations proceed from that known position in the flow to subsequent upstream positions until the injection pressure and temperature are determined.

8.1 Static Gas Column

$$P_{bh} = P_{wh} e^{\left(\frac{S_g}{R}\right) H / T_{av}} \tag{8.1}$$

Where: P_{bh} = Bottomhole pressure (lb/ft.^{2} abs)
P_{wh} = Wellhead pressure at surface (lb/ft.^{2} abs)
H = TVD of the well (ft.)
S_g = Specific gravity of the gas
R = Engineering gas constant at API standard conditions (53.36 ft. lb/lb °R)

Example: Determine the approximate bottomhole shut-in pressure of a well filled with natural gas with an $S_g = 0.7$ and a TVD = 10,000 ft. The wellhead pressure is reading 1800 psig, and the average temperature in the well is determined to be 139 °F. The wellhead surface location is approximately sea level.

Material in Chapter 8 was Contributed by William Lyons.

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$$p_{wh} = 1800 + 14.7 = 1814.7\,\text{psia}$$

$$p_{wh} = 1814.7(144) = 261{,}317\,\text{lb/ft.}^2\,\text{abs}$$

$$T_{av} = 139° + 460° = 599\,°\text{R}$$

$$P_{bh} = (261{,}317)\text{e}^{\frac{\left(\frac{0.7}{53.36}\right)(10{,}000)}{(599)}} = (261{,}317)(1.244)$$
$$= 325{,}078\,\text{lb/ft.}^2\,\text{abs}$$

$$p_{bh} = \frac{325{,}078}{144} = 2258\,\text{psia}$$

or

$$p_{bh} = 2258 - 14.7 = 2243\,\text{psig}$$

8.2 Direct Circulation: Flow Up the Annulus (from Annulus Bottomhole to Exit)

Unlike incompressible hydraulic flow calculations, compressible gas flow calculations must begin with a known pressure and temperature. This is usually at the exit to the system (top of annulus). In this case, the exit conditions are known, since the flow exits the annulus into the atmosphere at the surface. In essence, the calculation will proceed from the exit, then upstream to the bottom of the annulus. The bottomhole pressure in the annulus is

$$P_{bh} = \left[\left(P_{ex}^2 + b_a T_{av}^2\right)\text{e}^{\frac{2a_a H}{T_{av}}} b_a T_{av}^2\right] \tag{8.2}$$

Where: P_{ex} = Exit pressure at the top of the annulus at the surface (lb/ft.^{2} abs) and

$$a_a = \left(\frac{S_g}{R}\right)\left[1 + \left(\frac{\dot{w}_s}{\dot{w}_g}\right)\right]$$

$$b_a = \frac{f_a}{2g\left(D_h - D_p\right)}\left(\frac{R}{S_g}\right)^2 \frac{\dot{w}_g^2}{\left(\frac{\pi}{4}\right)^2\left(D_h^2 - D_p^2\right)^2}$$

$$f_a = \left[\frac{1}{2\log_{10}\left(\frac{D_h - D_p}{\epsilon}\right) + 1.14}\right]^2$$

$\varepsilon = 0.0005$ ft. (absolute roughness of inside of casing and outside of pipe)
$g = 32.2$ ft./s^2
D_h = Inside diameter of annulus (ft.)
D_p = Pipe outside diameter (ft.)

$$\dot{w}_s = \gamma_g Q_g$$

Where: Q_g = Gas flow rate (ft.^{3}/s)

$$\gamma_g = \frac{P_g S_g}{RT_g}$$

$$\dot{w}_s = \left(\frac{\pi}{4}\right) D_h^2 (62.4)(2.7)\left(\frac{\text{ROP}}{3600}\right)$$

Example: Determine the approximate bottomhole annulus pressure in a well being drilled with a 6⅛ in. drill bit on a drill string made of API 5.0 in., 19.50 lb/ft. nominal weight (i.d. =4.276 in.) drill string run inside an API 7⅝ in. casing, 39.00 lb/ft. nominal weight (i.d. = 6.625 in.). The well is being drilled at an ROP of 60 ft./h, and the drill fluid is inert air with a volumetric flow of 2000 SCFM that is produced by the nitrogen generator ($S_g = 0.97$). The well is vertical with a depth of 10,000 ft., and the surface location is near sea level at mid-latitudes in North America. The geothermal gradient at this drilling location is approximately 0.016° per ft.

$t_{ex} = t_{at}$ (use average temperature)
$t_{ex} = 59\,°\text{F}$ (API standard temperature)
$t_{bh} = 59° + 0.016°(10,000)$
$t_{bh} = 219\,°\text{F}$

$$t_{av} = \left(\frac{59° + 219°}{2}\right) = 139\,°\text{F}$$

$T_{av} = 139° + 460° = 599\,°\text{R}$
$p_{ex} = p_{at}$

$$p_{ex} = 14.7\,\text{psia (API standard pressure)}$$

$$P_{ex} = 14.7(144) = 2116.8\,\text{lb/ft.}^2\,\text{abs}$$

$$t_{ex} = t_{at}$$

$$t_{ex} = 59\,°\text{F}$$

$$T_{ex} = 59° + 460° = 519\,°\text{R}$$

$$\gamma_g = \frac{(2116.8)(0.97)}{(53.36)(519)} = 0.0741\,\text{lb/ft.}^3$$

$$q_g = 2000\ \text{SCFM}$$

$$Q_g = \frac{q_g}{60} = \frac{2000}{60} = 33.3\,\text{ft.}^3/\text{s}$$

$$\dot{w}_g = (0.0741)(33.3) = 2.471\,\text{lb/s}$$

$$\dot{w}_s = \left(\frac{\pi}{4}\right)\left(\frac{6.125}{12}\right)^2 (62.4)(2.7)\left(\frac{60}{3600}\right) = 0.575\,\text{lb/s}$$

$$a_a = \left(\frac{0.97}{53.36}\right)\left[1 + \left(\frac{0.575}{2.471}\right)\right] = 0.0224$$

$$D_c = \frac{6.625}{12} = 0.552\,\text{ft.}$$

$$D_p = \frac{5.0}{12} = 0.417\,\text{ft.}$$

$$f_a = \left[\frac{1}{2\log_{10}\left(\frac{0.552-0.417}{0.0005}\right) + 1.14}\right]^2 = 0.0278$$

$$b_a = \frac{0.0278}{2(32.2)(0.552-0.417)}\left(\frac{53.36}{0.97}\right)^2 \frac{(2.471)^2}{\left(\frac{\pi}{4}\right)^2\left[(0.552)^2-(0.417)^2\right]^2}$$

$$= 5532.9$$

$$P_{abh} = \left[(2116.8)^2 - (5532.9)(599)^2 e^{\frac{2(0.0224)10,000}{599}} - (5532.9)(599)^2\right]^{0.5}$$

$$P_{abh} = 47,106.3\,\text{lb/ft.}^2\,\text{abs}$$

$$p_{abh} = \left(\frac{47,106.3}{144}\right) = 327.1\,\text{psia}$$

or

$$P_{abh} = 312.4\,\text{psig}$$

8.3 Direct Circulation: Flow Down the Inside of the Drill Pipe (from the Bottom of the Inside of the Drill String to the Injection at the Top of the Drill String)

In nearly all air and gas drilling operations, the drill bit nozzles are not jetted. Therefore, there is little or no pressure loss through the drill bit open orifices, and it can be assumed that the pressure and temperature at the bottom of the annulus will be approximately the same as the pressure and temperature at the bottom of the inside of the drill pipe just above the drill bit. The injection pressure into the inside of the drill string is

$$P_{\text{in}} = \left[\frac{P_{\text{ai}}^2 + b_{\text{i}} T_{\text{av}}^2 \left(e^{\frac{2a_{\text{i}}H}{T_{\text{av}}}} - 1\right)}{e^{\frac{2aH}{T_{\text{av}}}}}\right]^{0.5} \tag{8.3}$$

Where: P_{ai} = Pressure above the drill bit inside the drill string at the bottom of the well (lb/ft.^{2} abs) and

$$a_{\text{i}} = \left(\frac{S_{\text{g}}}{\text{R}}\right)$$

$$b_{\text{i}} = \frac{f_{\text{i}}}{2gD_{\text{i}}}\left(\frac{\text{R}}{S_{\text{g}}}\right)^2 \frac{\dot{w}_{\text{g}}^2}{\left(\frac{\pi}{4}\right)^2 D_{\text{i}}^4}$$

$$f_{\text{i}} = \left[\frac{1}{2\log_{10}\left(\frac{D_{\text{i}}}{\varepsilon}\right) + 1.14}\right]^2$$

ε = 0.0005 ft. (absolute roughness of inside the drill pipe)

g = 32.2 ft./s^2

D_{i} = Inside drill pipe diameter (ft.)

Example: For the previous example, determine the approximate pressure of the nitrogen generator-produced inert air injected into the top of the inside of the drill string (the inside diameter of the drill string is 4.276 in.).

$$p_{abi} = 327.1\,\text{psia}$$

or

$$P_{abi} = 327.1(144) = 47{,}106.3\,\text{lb/ft.}^2\,\text{abs}$$

$$a_i = \left(\frac{0.97}{53.36}\right) = 0.0182$$

$$D_i = \frac{4.276}{12} = 0.356\,\text{ft.}$$

$$f_i = \left[\frac{1}{2\log_{10}\left(\frac{0.356}{0.0005}\right) + 1.14}\right]^2 = 0.0213$$

$$b_i = \frac{0.0213}{2(32.2)(0.356)}\left(\frac{53.36}{0.97}\right)^2 \frac{(2.471)^2}{\left(\frac{\pi}{4}\right)^2(0.356)^4} = 1727.2$$

$$P_{in} = \left[\frac{(47,106.3)^2 + (1712.8)(599)^2\left(e^{\frac{2(0.0182)(10,000)}{599}} - 1\right)}{e^{\frac{2(0.0182)(10,000)}{599}}}\right]^{0.5}$$

$$P_{in} = 38{,}617.9\,\text{lb/ft.}^2\,\text{abs}$$

$$P_{in} = \left(\frac{38{,}617.9}{144}\right) = 268.2\,\text{psia}$$

or

$$p_{in} = 253.5\,\text{psig}$$

8.4 Reverse Circulation: Flow Up the Inside of Tubing String

Reverse circulation is often used in gas and condensate well workover operations. In such operations, it is necessary to flow nitrogen-generated inert air down the annulus between the inside of the casing and the outside of the production tubing and up through the inside of the production tubing. In this manner, the pressure at the bottom of the well is reduced, which in turn allows the natural gas or condensate to flow from the formation and intermix with the injected inert air and proceed up the tubing to the surface. As the flow from the formation increases, the inert air flow can be reduced as the formation begins to flow naturally through the production tubing and the tubing head choke. The flow from the bottom of the inside of the tubing to the surface is

$$P_{\mathrm{bt}} = \left[\left(P_{\mathrm{th}}^2 + b_{\mathrm{it}} T_{\mathrm{av}}^2\right) \mathrm{e}^{\frac{2a_{\mathrm{it}}H}{\mathrm{e}T_{\mathrm{av}}}} b_{\mathrm{it}} T_{\mathrm{av}}^2\right] \tag{8.4}$$

Where: P_{bt} = Pressure above the drill bit inside the drill string at the bottom of the tubing ($\mathrm{lb/ft.}^2$ abs) and

$$a_{\mathrm{ti}} = \left(\frac{S_{\mathrm{g}}}{\mathrm{R}}\right)$$

$$b_{\mathrm{ti}} = \frac{f_{\mathrm{i}}}{2gD_{\mathrm{ti}}} \left(\frac{\mathrm{R}}{S_{\mathrm{g}}}\right)^2 \frac{\dot{w}_{\mathrm{tg}}^2}{\left(\frac{\pi}{4}\right)^2 D_{\mathrm{ti}}^4}$$

$$\dot{w}_{tg} = \dot{w}_{g1} + \dot{w}_{g2}$$

$$f_{\mathrm{ti}} = \left[\frac{1}{2\log_{10}\left(\frac{D_{\mathrm{ti}}}{\varepsilon}\right) + 1.14}\right]^2$$

$\varepsilon = 0.0005$ ft. (absolute roughness of inside the drill pipe)

$g = 32.2\ \mathrm{ft./s^2}$

D_{ti} = Inside tubing diameter (ft.)

Example: Determine the approximate inside bottom pressure at the bottom of the tubing string. The production tubing string is API 2⅞ in., 6.50 lb/ft. nominal weight (i.d. = 2.441 in.), and is hung in a 10,000 ft. vertical well inside API 7⅝ in. casing, 39.00 lb/ft. nominal weight (i.d. = 6.625 in.). A flow of 500 SCFM nitrogen-generated inert air ($S_{\mathrm{g}} = 0.97$) is injected into the top of the annulus between the inside of the casing and the outside of the tubing. The flow continues to the bottom of the annulus and then flows up the inside of the tubing to the tubing head and to the choke at the surface. The tubing head pressure is to be kept at a constant 100 psig via the choke as the natural gas production is initiated with the reverse circulation operation. The temperature at the wellhead during circulation is estimated to be the surface ambient (standard API) temperature (59 °F). The natural gas ($S_g = 0.7$) producing formation has the potential to flow at a rate of up to 700 SCFM (or 1,008,000 SCFD). This illustrative example will show the calculations for a 200 SCFM of natural gas production rate. The geothermal gradient at this drilling location is approximately 0.016° per ft. The well is located at sea level at midlatitudes in North America.

$$q_{g1} = 500\,\text{SCFM}\,(\text{inert air})$$

$$q_{g2} = 200\,\text{SCFM}\,(\text{natural gas})$$

$$S_{g1} = 0.97$$

$$S_{g2} = 0.7$$

$$p_{at} = 14.7\,\text{psia}$$

$$p_{th} = 100\,\text{psig}$$

$$P_{th} = 100 + 14.7 = 114.7\,\text{psia}$$

$$P_{th} = 114.7(144) = 16,516.8\,\text{lb/ft.}^2\,\text{abs}$$

$$T_{th} = t_{at}\,(\text{use average atmospheric temperature})$$

$$t_{bh} = t_{at} + 0.016°(10,000)$$

$$t_{bh} = 219\,°\text{F}$$

$$t_{av} = \left(\frac{59° + 219°}{2}\right) = 139\,°\text{F}$$

$$T_{av} = 139° + 460° = 599\,°\text{R}$$

$$T_{API} = 59° + 460° = 519\,°\text{R}$$

$$\gamma_{g1} = \frac{(2116.8)(0.97)}{(53.36)(519)} = 0.0741\,\text{lb/ft.}^3$$

$$q_{g1} = 500\,\text{SCFM}$$

$$Q_{g1} = \frac{q_{g1}}{60} = \frac{500}{60} = 8.33\,\text{ft.}^3/\text{s}$$

$$\dot{w}_{g1} = (0.0741)(8.33) = 0.618\,\text{lb/s}$$

$$\gamma_{g2} = \frac{(2116.8)(0.7)}{(53.36)(519)} = 0.0535 \text{lb/ft.}^3$$

$$Q_{g2} = \frac{q_{g2}}{60} = \frac{200}{60} = 3.33 \text{ft.}^3\text{/s}$$

$$\dot{w}_{g2} = (0.0535)(3.33) = 0.178 \text{lb/s}$$

$$\dot{w}_{tg} = 0.618 + 0.178 = 0.796 \text{lb/s}$$

$$a_{ti} = \left(\frac{0.97}{53.36}\right) = 0.0182$$

$$d_{ti} = 2.441 \text{in.}$$

$$D_{ti} = \frac{2.441}{12} = 0.203 \text{ft.}$$

$$f_{ti} = \left[\frac{1}{2\log_{10}\left(\frac{0.203}{0.0005}\right) + 1.14}\right]^2 = 0.0247$$

$$b_{ti} = \frac{0.0247}{2(32.2)(0.203)}\left(\frac{53.36}{0.97}\right)^2 \frac{(0.796)^2}{\left(\frac{\pi}{4}\right)^2(0.203)^4} = 3427.3$$

$$P_{bt} = \left[(16,516.8)^2 - (3427.3)(599)^2 e^{\frac{2(0.0182)10,000}{599}} - (3427.3)(599)^2\right]^{0.5}$$

$$P_{bt} = 39,078.5 \text{lb/ft.}^2 \text{abs}$$

$$p_{bt} = \left(\frac{39,078.5}{144}\right) = 271.4 \text{psia}$$

or

$$p_{bt} = 271.4 - 14.7 = 256.7 \text{psig}$$

8.5 Reverse Circulation: Flow Down the Annulus

The pressure at the bottom of the tubing is known and is approximately the pressure at the bottomhole pressure in the annulus. In essence, the calculation will proceed from the bottom of the annulus upstream to determine the injection pressure at the top of the annulus. The injection pressure at the top of the annulus is

$$P_{in} = \left[\frac{P_{ba}^2 + b_a T_{av}^2 \left(e^{\frac{2a_a H}{T_{av}}} - 1\right)}{e^{\frac{2a_a H}{T_{av}}}}\right]^{0.5} \tag{8.5}$$

Where: P_{ba} = Pressure at bottom of annulus (lb/ft.^{2} abs) and

$$a_a = \left(\frac{S_g}{R}\right)$$

$$b_a = \frac{f_a}{2g(D_c - D_{to})}\left(\frac{R}{S_g}\right)^2 \frac{\dot{w}_{g1}^2}{\left(\frac{\pi}{4}\right)^2 \left(D_c^2 - D_{to}^2\right)^2}$$

$$f_a = \left[\frac{1}{2\log_{10}\left(\frac{D_c - D_{to}}{\varepsilon}\right) + 1.14}\right]^2$$

ε = 0.0005 ft. (absolute roughness of inside of casing and outside of pipe)

g = 32.2 ft./s^2

D_c = Inside diameter of annulus casing (ft.)

D_{to} = Tubing outside diameter (ft.)

$$\dot{w}_{g1} = \gamma_{g1} Q_{g1}$$

Where: Q_g = Gas flow rate (ft.^{3}/s)

$$\gamma_g = \frac{P_g S_g}{R T_g}$$

Example: Using the data from the above example, determine the approximate annulus injection pressure into the well that has been worked over and is being put back into production.

$$d_{to} = 2.875 \text{in.}$$

$$D_{to} = \frac{2.875}{12} = 0.240 \text{ft.}$$

$$D_c = \frac{6.625}{12} = 0.552\,\text{ft.}$$

$$t_{in} = t_{at}$$

$$t_{in} = 59\,°\text{F}$$

$$T_{ex} = 59° + 460° = 519°$$

$$\gamma_{g1} = \frac{(2116.8)(0.97)}{(53.36)(519)} = 0.0741\,\text{lb/ft.}^3$$

$$Q_{g1} = \frac{500}{60} = 8.33\,\text{ft.}^3/\text{s}$$

$$\dot{w}_{g1} = (0.0741)(8.33) = 0.618\,\text{lb/s}$$

$$a_a = \left(\frac{0.97}{53.36}\right) = 0.0182$$

$$f_a = \left[\frac{1}{2\log_{10}\left(\frac{0.552-0.240}{0.0005}\right) + 1.14}\right]^2 = 0.0221$$

$$b_a = \frac{0.0221}{2(32.2)(0.552-0.240)}\left(\frac{53.36}{0.97}\right)^2 \frac{(0.618)^2}{\left(\frac{\pi}{4}\right)^2\left[(0.552)^2-(0.240)^2\right]^2}$$

$$= 547.9$$

$$P_{in} = \left[\frac{(39,078.5)^2 + (547.9)(599)^2\left(e^{\frac{2(0.0182)(10,000)}{599}} - 1\right)}{e^{\frac{2(0.0182)(10,000)}{599}}}\right]^{0.5}$$

$$P_{in} = 30,360.2\,\text{lb/ft.}^2\,\text{abs}$$

$$p_{in} = \left(\frac{30,360.2}{144}\right) = 210.8\,\text{psia}$$

or

$$p_{in} = 210.8 - 14.7 = 196.1\,\text{psig}$$

Table 8.1 gives the results of the above calculations for a natural gas flow of 0 SCFM, 100 SCFM, and 200 SCFM.

Table 8.1
Natural Gas Flow Versus Injection Pressure

q_{ng} (SCFM)	p_{in} (psig)
0	168.9
100	182.1
200	196.1

8.6 Reverse Circulation: Adjusting for Reservoir Pressure

If the inert air is injected into the top of a well annulus that is under pressure from the reservoir, then the compressor (and nitrogen generator) system will have to overcome the static pressure at the top of the annulus in order to initiate flow.

Example: Let us assume that the static annulus pressure is given by the example in number 1 above. Figure 8.1 shows an example inflow performance relationship (IPR) of the static well given

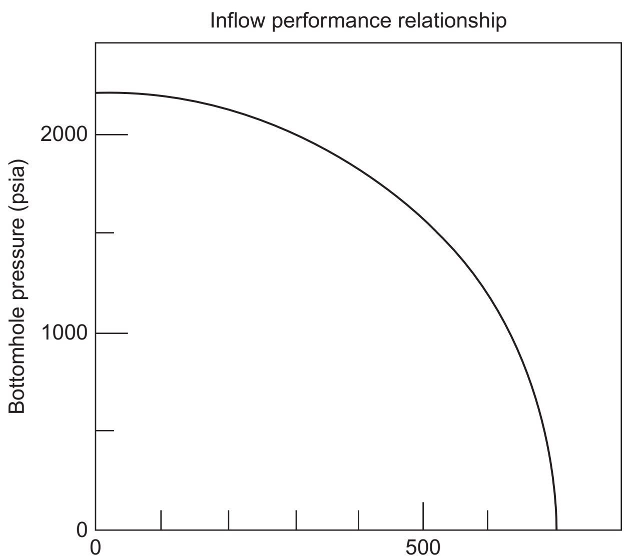


Figure 8.1 IPR for example well.

Table 8.2
Approximate Compressor Injection Pressures

q_{ng} (SCFM)	p_{res} (psia)	p_{th} (psia)	p_{th} (psig)	p_{com} (psig)
0	2258	1814.7	1800.0	1968.9
100	2240	1800.7	1786.0	1968.1
200	2150	1728.3	1713.6	1909.7

in number 1. With no flow from the reservoir ($q_{ng} = 0$), the compressor system would have to inject inert air at

$$p_{inr} = 168.9 + 1800.0 = 1968.9\,\text{psig}$$

where the injection pressure is taken from Table 8.1.
Table 8.2 gives the approximate bottomhole pressures and tubing head pressures for the natural gas flow rates given in Table 8.1. From Figure 8.1, the flowing reservoir pressure and its associated tubing head pressure can be estimated.

Table 8.2 shows that the inert air compressor injection pressures will decrease as the natural gas begins to flow up the production tubing to the surface as the well is brought into production. These injection pressures will require a 1000 SCFM primary compressor (either helical screw type or reciprocating piston) and nitrogen generator filter unit and a booster compressor (which must be a reciprocating piston). The nitrogen generator "rule of thumb" is that only about 50% of the primary compressed air will be available after the 1000 SCFM of compressed air flows through the nitrogen generator filter unit. This leaves just 500 SCFM to be injected by the booster compressor into the well.

Appendix A

Table A.1
Drill Pipe Capacity and Displacement (English System)

Size OD (in.)	Size ID (in.)	Weight (lb/ft.)	Capacity (bbl/ft.)	Displacement (bbl/ft.)
2⅜	1.815	6.65	0.00320	0.00228
2⅞	2.150	10.40	0.00449	0.00354
3½	2.764	13.30	0.00742	0.00448
3½	2.602	15.50	0.00658	0.00532
4	3.340	14.00	0.01084	0.00471
4½	3.826	16.60	0.01422	0.00545
4½	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
5½	4.778	21.90	0.02218	0.00721
5½	4.670	24.70	0.02119	0.00820
5 9/16	4.859	22.20	0.02294	0.00712
6⅝	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.)
3½	2.0625	25.3	0.00421	0.00921
4	2.25625	29.7	0.00645	0.01082
4½	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:

$$\text{Capacity}(\text{bbl/ft.}) = \frac{\text{ID}(\text{in.})}{1029.4}$$

$$\text{Displacement}(\text{bbl/ft.}) = \frac{\left(D_{\text{h}}(\text{in.})^2 - D_{\text{p}}(\text{in.})^2\right)}{1029.4}$$

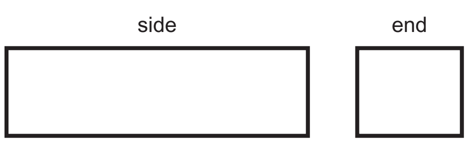
Weight (lb/ft.) = displacement (bbl/ft.) × 2747 lb/bbl

Table A.3
Drill Pipe Capacity and Displacement (Metric System)

Size OD (in.)	Size ID (in.)	Weight (lb/ft.)	Capacity (lb/ft.)	Displacement (lb/ft.)
2⅜	1.815	6.65	1.67	1.19
2⅞	2.150	10.40	2.34	1.85
3½	2.764	13.30	3.87	2.34
3½	2.602	15.50	3.43	2.78
4	3.340	14.00	5.65	2.45
4½	3.826	16.60	7.42	2.84
4½	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
5½	4.778	21.90	11.57	3.76
5½	4.670	24.70	11.05	4.28
5⁹/₁₆	4.859	22.20	11.96	3.72
6⅝	5.965	25.20	18.03	4.21

A.1 Tank Capacity Determinations

A.1.1 Rectangular Tanks with Flat Bottoms



$$\text{Volume}(\text{bbl}) = \frac{\text{length}(\text{ft.}) \times \text{width}(\text{ft.}) \times \text{depth}(\text{ft.})}{5.61}$$

Example 1: Determine the total capacity of a rectangular tank with a flat bottom using the following data:

Length = 30 ft.
Width = 10 ft.
Depth = 8 ft.

$$\text{Volume (bbl)} = \frac{30\,\text{ft.} \times 10\,\text{ft.} \times 8\,\text{ft.}}{5.61}$$

$$\text{Volume (bbl)} = \frac{2400}{5.61}$$

$$\text{Volume} = 427.84\ \text{bbl}$$

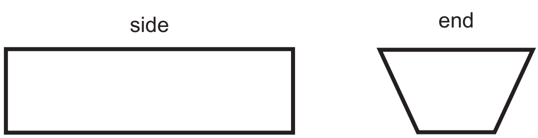
Example 2: Determine the capacity of this same tank with only 5½ ft. of fluid in it:

$$\text{Volume (bbl)} = \frac{30\,\text{ft.} \times 10\,\text{ft.} \times 5.5\,\text{ft.}}{5.61}$$

$$\text{Volume (bbl)} = \frac{1650}{5.61}$$

$$\text{Volume} = 294.12\ \text{bbl}$$

A.1.2 Rectangular Tanks with Sloping Sides



$$\text{Volume (bbl)} = \frac{\text{length (ft.)} \times [\text{depth (ft.)}(\text{width}_1 + \text{width}_2)]}{5.62}$$

Example: Determine the total tank capacity using the following data:

Length = 30 ft.
Width (top) = 10 ft.
Width (bottom) = 6 ft.
Depth = 8 ft.

Table A.4
Drill Collar Capacity and Displacement

OD	ID Capacity	1½ (in.) .0022	1¾ (in.) .0030	2 (in.) .0039	2¼ (in.) .0049	2½ (in.) .0061	2¾ (in.) .0073	3 (in.) .0087	3¼ (in.) .0103	3½ (in.) .0119	3¾ (in.) .0137	4 (in.) .0155	4¼ (in.) .0175
4 in.	#/ft.	36.7	34.5	32.0	29.2	–	–	–	–	–	–	–	–
	Disp.	0.0133	0.0125	0.0116	0.0106								
4¼ in.	#/ft.	42.2	40.0	37.5	34.7	–	–	–	–	–	–	–	–
	Disp.	0.0153	0.0145	0.0136	0.0126								
4½ in.	#/ft.	48.1	45.9	43.4	40.6	–	–	–	–	–	–	–	–
	Disp.	0.0175	0.0167	0.0158	0.0148								
4¾ in.	#/ft.	54.3	52.1	49.5	46.8	43.6	–	–	–	–	–	–	–
	Disp.	0.0197	0.0189	0.0180	0.0170	.0159							
5 in.	#/ft.	60.8	58.6	56.3	53.3	50.1	–	–	–	–	–	–	–
	Disp.	0.0221	0.0213	0.0214	0.0194	0.0182							
5¼ in.	#/ft.	67.6	65.4	62.9	60.1	56.9	53.4	–	–	–	–	–	–
	Disp.	0.0246	0.0238	0.0229	0.0219	0.0207	0.0194						
5½ in.	#/ft.	74.8	72.6	70.5	67.3	64.1	60.6	56.8	–	–	–	–	–
	Disp.	0.0272	0.0264	0.0255	0.0245	0.0233	0.0221	0.0207					
5¾ in.	#/ft.	82.3	80.1	77.6	74.8	71.6	68.1	64.3	–	–	–	–	–
	Disp.	0.0299	0.0291	0.0282	0.0272	0.0261	0.2048	0.0234					
6 in.	#/ft.	90.1	87.9	85.4	82.6	79.4	75.9	72.1	67.9	63.4	–	–	–
	Disp.	0.0328	0.0320	0.0311	0.0301	0.0289	0.0276	67.9	0.0247	0.0231			
6¼ in.	#/ft.	98.0	95.8	93.3	90.5	87.3	83.8	80.0	75.8	71.3	–	–	–
	Disp.	0.0356	0.0349	0.0339	0.0329	0.0318	0.0305	0.0291	0.0276	0.0259			

6½ in.	#/ft.	107.0	104.8	102.3	99.5	96.3	92.8	89.0	84.8	80.3	–	–	–
	Disp.	.0389	0.0381	0.0372	0.0362	0.0350	0.0338	0.0324	0.0308	0.0292			
6¾ in.	#/ft.	116.0	113.8	111.3	108.5	105.3	101.8	98.0	93.8	89.3	–	–	–
	Disp.	0.0422	0.0414	0.0405	0.0395	0.0383	0.0370	0.0356	0.0341	0.0325			
7 in.	#/ft.	125.0	122.8	120.3	117.5	114.3	110.8	107.0	102.8	98.3	93.4	88.3	–
	Disp.	0.0455	0.0447	0.0438	0.0427	0.0416	0.0403	0.0389	0.0374	0.0358	0.0340	0.0321	
7¼ in.	#/ft.	134.	131.8	129.3	126.5	123.3	119.8	116.0	111.8	107.3	102.4	97.3	–
	Disp.	0.0487	0.0479	0.0470	0.0460	0.0449	0.0436	0.0422	0.0407	0.0390	0.0372	0.0354	
7½ in.	#/ft.	144.0	141.8	139.3	136.5	133.3	129.8	126.0	121.8	117.3	112.4	107.3	–
	Disp.	0.0524	0.0516	0.0507	0.0497	0.0485	0.0472	0.0458	0.0443	0.0427	0.0409	0.0390	
7¾ in.	#/ft.	154.0	151.8	149.3	146.5	143.3	139.8	136.0	131.8	127.3	122.4	117.3	–
	Disp.	0.0560	0.0552	0.0543	0.0533	0.0521	0.0509	0.0495	0.0479	0.0463	0.0445	0.0427	
8 in.	#/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.	0.0600	0.0592	0.0583	0.0573	0.0561	0.0549	0.0535	0.0520	0.0503	0.0485	0.0467	0.0447
8¼ in.	#/ft.	176.0	173.8	171.3	168.3	165.3	161.8	158.0	153.8	149.3	144.4	139.3	133.8
	Disp.	0.0640	0.0632	0.0623	0.0613	0.0601	0.0589	0.0575	0.0560	0.0543	0.0525	0.0507	0.0487
8½ in.	#/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.	0.0680	0.0672	0.0663	0.0653	0.0641	0.0629	0.0615	0.0600	0.0583	0.0565	0.0547	0.0527
8¾ in.	#/ft.	199.0	196.8	194.3	191.5	188.3	184.8	181.0	176.8	172.3	167.4	162.3	156.8
	Disp.	0.0724	0.0716	0.0707	0.0697	0.0685	0.0672	0.0658	0.0613	0.0697	0.0609	0.0590	0.0570
9 in.	#/ft.	210.2	208.0	205.6	202.7	199.6	196.0	192.2	188.0	183.5	178.7	173.5	168.0
	Disp.	0.0765	0.0757	0.0748	0.0738	0.0726	0.0714	0.0700	0.0685	0.0668	0.0651	0.0632	0.0612
10 in.	#/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.	0.0950	0.0942	0.0933	0.0923	0.0911	0.0898	0.0084	0.0869	0.0853	0.0835	0.0816	0.0796

$$\text{Volume (bbl)} = \frac{30\text{ft.}\,[8\text{ft.}(10 + 6\text{ft.})]}{5.62}$$

$$\text{Volume (bbl)} = \frac{30 \times 128\text{ ft.}}{5.62}$$

$$\text{Volume} = 683.3\text{ bbl}$$

A.1.3 Circular Cylindrical Tanks

$$\text{Volume (bbl)} = \frac{3.14 \times r^2 \times \text{height (ft.)}}{5.61}$$

Example: Determine the total capacity of a cylindrical tank with the following dimensions:

Height = 15 ft.
Diameter = 10 ft.

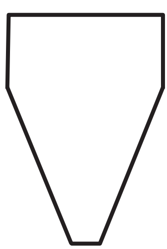
Note: The radius (r) is one-half of the diameter:

$$\text{Volume (bbl)} = \frac{3.14 \times 5\text{ft.}^2 \times 15\text{ft.}}{5.61}$$

$$\text{Volume (bbl)} = \frac{1177.5}{5.61}$$

$$\text{Volume} = 209.89\text{ bbl}$$

A.1.4 Tapered Cylindrical Tanks



(a) Volume of cylindrical section:

$$V_c = 0.1781 \times 3.14 \times r_c^2 \times h_c$$

(b) Volume of tapered section:

$$V_t = 0.059 \times 3.14 \times h_t \times \left(r_c{}^2 + r_b{}^2 + r_b r_c\right)$$

Where: V_c = Volume of cylindrical section, bbl
r_c = Radius of cylindrical section, ft.
h_c = Height of cylindrical section, ft.
V_t = Volume of tapered section, bbl
h_t = Height of tapered section, ft.
r_b = 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:
$V_c = 0.1781 \times 3.14 \times 6.0^2 \times 5.0$
$V_c = 100.66$ bbl

(b) Volume of tapered section:
$V_t = 0.059 \times 3.14 \times 10$ ft. $\times (6^2 + 1^2 + 1 \times 6)$
$V_t = 1.8526\ (36 + 1 + 6)$
$V_t = 1.8526 \times 43$
$V_t = 79.66$ bbl

(c) Total volume:
bbl = 100.66 + 79.66 bbl
bbl = 180.32

A.1.5 Horizontal Cylindrical Tank

(a) Total tank capacity:

$$\text{Volume (bbl)} = \frac{3.14 \times r^2 \times L(7.48)}{42}$$

(b) Partial volume:

$$\text{Volume}\left(\text{ft.}^3\right) = L\left[0.017453 \times r^2 \times \cos^{-1}\left(\frac{r-h}{r}\right) - \sqrt{2hr - h^2} \times (r-h)\right]$$

Example 1: Determine the total volume of the following tank:

Length = 30 ft.
Radius = 4 ft.

(a) Total tank capacity:

$$\text{Volume (bbl)} = \frac{3.14 \times 4^2 \times 30 \times 7.48}{42}$$

$$\text{Volume (bbl)} = \frac{11{,}279.574}{42}$$

$$\text{Volume} = 268.56 \text{ bbl}$$

Example 2: Determine the volume if there are only 2 ft. of fluid in this tank: ($h = 2$ ft.)

$$\text{Volume}\left(\text{ft.}^3\right) = 30\left[0.017453 \times 4^2 \times \cos^{-1}\left(\frac{4-2}{4}\right) - \sqrt{2 \times 2 \times 4 - 2^2} \times (4-2)\right]$$

$$\text{Volume}\left(\text{ft.}^3\right) = 30\left[0.0279248 \times \cos^{-1}(0.5) - \sqrt{12} \times (4-2)\right]$$

$$\text{Volume (ft.}^3) = 30\ (0.279248 \times 60 - 3.464 \times 2)$$

$$\text{Volume (ft.}^3) = 30 \times 9.827$$

$$\text{Volume} = 294 \text{ ft.}^3$$

To convert volume, ft.^{3}, to barrels, multiply by 0.1781.
To convert volume, ft.^{3}, to gallons, multiply by 7.4805.

Therefore, 2 ft. of fluid in this tank would result in:

Volume (bbl) = 294 ft.^{3} $\times$ 0.1781
Volume = 52.36 bbl

Note: This is only applicable until the tank is half full ($r - h$). After that, calculate the 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 centimeters	6.45
Square inches	Square millimeters	645.2
Square centimeters	Square inches	0.155
Square millimeters	Square inches	1.55×10^{-3}
Circulation rate		
Barrels/min	Gallons/min	42.0
Cubic feet/min	Cubic meters/s	4.72×10^{-4}
Cubic feet/min	Gallons/min	7.48
Cubic feet/min	Liters/min	28.32
Cubic meters/s	Gallons/min	15,850
Cubic meters/s	Cubic feet/min	2118
Cubic meters/s	Liters/min	60,000
Gallons/min	Barrels/min	0.0238
Gallons/mm	Cubic feet/min	0.134
Gallons/min	Liters/min	3.79
Gallons/min	Cubic meters/s	6.309×10^{-5}
Liters/min	Cubic meters/s	1.667×10^{-5}
Liters/min	Cubic feet/min	0.0353
Liters/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}
Kilograms	Pounds	2.20
Newtons	Pounds	0.2248

To Convert from	to	Multiply by
	Length	
Feet	Meters	0.305
Inches	Millimeters	25.40
Inches	Centimeters	2.54
Centimeters	Inches	0.394
Millimeters	Inches	0.03937
Meters	Feet	3.281
	Mud weight	
Pounds/gallon	Pounds/ft.^{3}	7.48
Pounds/gallon	Specific gravity	0.120
Pounds/gallon	Grams/cm^3	0.1198
Grams/cm^3	Pounds/gallon	8.347
Pounds/ft.^{3}	Pounds/gallon	0.134
Specific gravity	Pounds/gallon	8.34
	Power	
Horsepower	Horsepower (metric)	1.014
Horsepower	Kilowatts	0.746
Horsepower	Foot-pounds/s	550
Horsepower (metric)	Horsepower	0.986
Horsepower (metric)	Foot-pounds/s	542.5
Kilowatts	Horsepower	1.341
Foot-pounds/s	Horsepower	0.00181
	Pressure	
Atmospheres	Pounds/sq. in.	14.696
Atmospheres	Kilograms/sq. cm	1.033
Atmospheres	Pascals	1.033×10^5
Kilograms/sq. cm	Atmospheres	0.9678
Kilograms/sq. cm.	Pounds/sq. in.	14.223
Kilograms/sq. cm.	Atmospheres	0.9678
Pounds/sq. in.	Atmospheres	0.0680
Pounds/sq. in.	Kilograms/sq. cm	0.0703
Pounds/sq. in.	Pascals	6.894×10^3

To Convert from	to	Multiply by
	Velocity	
Feet/s	Meters/s	0.305
Feet/min	Meters/s	5.08×10^{-3}
Meters/s	Feet/min	196.8
Meters/s	Feet/s	3.28
	Volume	
Barrels	Gallons	42
Cubic centimeters	Cubic feet	3.51×10^{-5}
Cubic centimeters	Cubic inches	0.06102
Cubic centimeters	Cubic meters	10^{-6}
Cubic centimeters	Gallons	2.642×10^{-4}
Cubic centimeters	Liters	0.001
Cubic feet	Cubic centimeters	28,320
Cubic feet	Cubic feet	1728
Cubic feet	Cubic meters	0.02832
Cubic feet	Gallons	7.48
Cubic feet	Liters	28.32
Cubic inches	Cubic centimeters	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	Liters	0.01639
Cubic meters	Cubic centimeters	10^{6}
Cubic meters	Cubic feet	35.31
Cubic meters	Gallons	264.2
Gallons	Barrels	0.0238
Gallons	Cubic centimeters	3785
Gallons	Cubic feet	0.1337
Gallons	Cubic inches	231
Gallons	Cubic meters	3.785×10^{-3}
Gallons	Liters	3.785
	Weight	
Pounds	Tons (metric)	4.535×10^{-4}
Tons (metric)	Pounds	2205
Tons (metric)	Kilograms	1000

Appendix C
Average Annual Atmospheric Conditions

This appendix gives the graphic representation of the average atmospheric conditions for midlatitudes (30-60 °N) of the North American continent. Figure C.1 gives the average annual atmospheric pressure of air for midlatitudes of the North American continent as a function of surface elevation location above mean sea level. These average annual atmospheric pressures are of critical importance in predicting the actual weight rate of flow of air (or other gases) at an actual drilling location. Figure C.1(a) is given in USCS units, and Figure C.1(b) is given in SI units.

Figure C.2 gives the average annual atmospheric temperature of air for midlatitudes of the North American continent as a function of surface elevation location above mean sea level. These average annual atmospheric temperatures are of critical importance in predicting the approximate geothermal temperature at an actual drilling location. Figure C.2(a) is given in USCS units, and Figure C.2(b) is given in SI units.

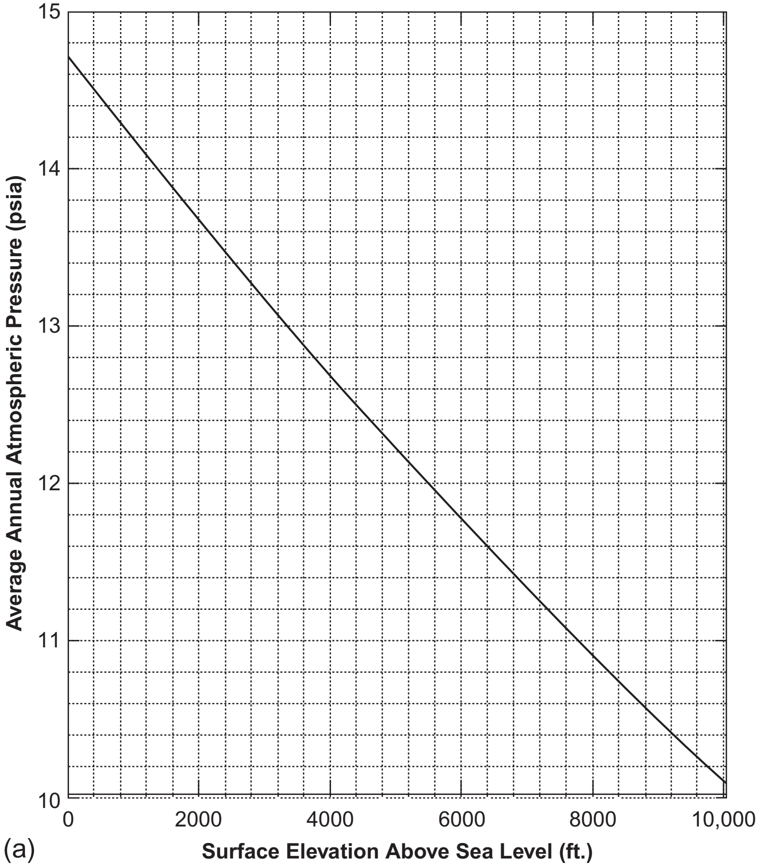


Figure C.1 (a) Average annual atmospheric pressure versus surface elevation above mean sea level (USCS units).

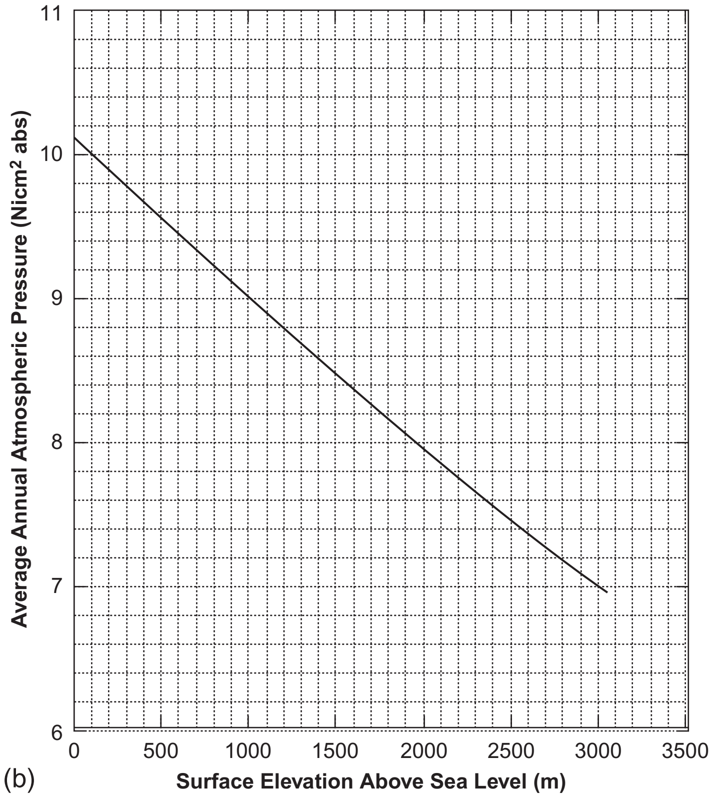


Figure C.1 (b) Average annual atmospheric pressure versus surface elevation above mean sea level (SI units).

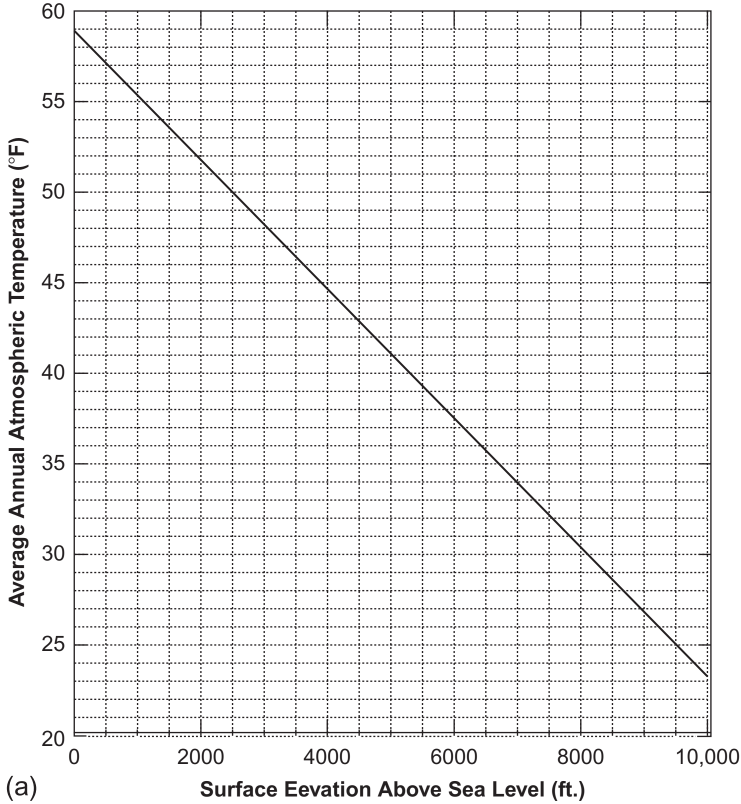


Figure C.2 (a) Average annual atmospheric temperature versus surface elevation above sea level (USCS units).

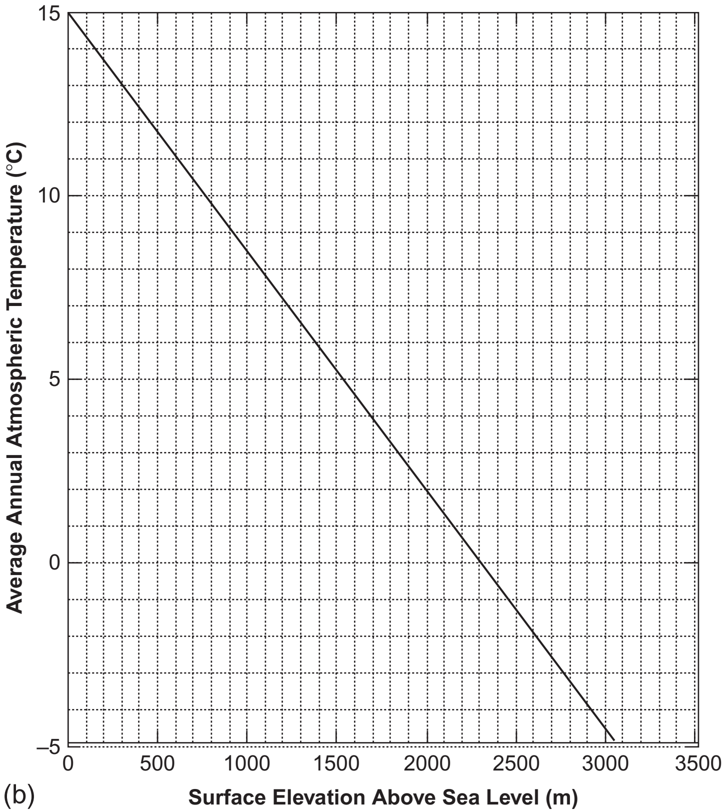


Figure C.2 (b) Average annual atmospheric temperature versus surface elevation above sea level (SI units).

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