

Well Engineering Quick Reference

41 formulas for well control, circulation, bit hydraulics, cementing, casing loads, drilling performance and reservoir engineering, each with units, assumptions, a reproducible worked example and a reference.

Educational use only. This guide explains calculations with synthetic teaching data. It does not replace approved well programs, operator and drilling contractor procedures, applicable standards or the judgment of qualified engineers. Where they differ, the approved documents prevail.

Conventions

Item	Convention in this guide
Units	US oilfield units: psi, ppg (lbm per US gal), ft, in, US gal/min, bbl. 1 oilfield barrel (bbl) = 42 US gal = 5.6146 ft ³ .
Pressure	psig (gauge, relative to atmospheric) for wellbore pressures unless stated; psia (absolute) for reservoir PVT and inflow.
Depth	TVD (true vertical depth) for hydrostatic heads and pressure differences; MD (measured depth) or physical section length for volumes. TVD measured from the stated datum (top of the fluid column at surface in the examples).
Volumes	Standard conditions (STB, scf) are distinguished from reservoir conditions (RB, reservoir ft ³).
Force and mass	Weights of strings are forces, in lbf; nominal pipe weight in lbf/ft.
Constants	0.052 psi per ppg per ft. Internal capacity = $ID^2 / 1029.4$ and annular capacity = $(D_h^2 - OD^2) / 1029.4$ give bbl/ft when diameters are in inches (the diameter term is divided by 1029.4). 24.5 (annular velocity), 0.3208 (nozzle velocity) and 1714 (hydraulic horsepower) assume US gal/min.
Rounding	Calculations use unrounded values; only displayed results are rounded. Chained examples show enough digits to be reproduced.
Links	“Reference” cites technical sources (numbered list at the end). “Read more” links to a PetroSmart Academy article on the topic.

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Then: glossary and technical references.

A. Hydrostatics and well control

Static and circulating pressure relations used in well control calculations. They illustrate the arithmetic only; kill sheets, MAASP and shut-in decisions follow the approved well control procedures of the operator and drilling contractor.

01 Hydrostatic pressure

$$P_h = 0.052 \times MW \times TVD$$

Where	P_h : hydrostatic pressure, psi (gauge, relative to atmospheric pressure at the fluid surface); MW: mud weight, ppg; TVD: true vertical depth below the top of the fluid column, ft; 0.052: psi per ppg per ft.
Assumptions / limitations	Uniform or representative fluid density over the column; TVD and pressure referred to the same datum (here the top of the fluid column at surface). With a surface pressure P_s applied, total pressure at depth is $P_s + P_h$.
Example	MW = 10.5 ppg, TVD = 10,000 ft, no surface pressure.
Result	$P_h = 5,460$ psi
Reference	[1]; [2] (see list at the end)
Read more	petrosmartacademy.com/2025/09/well-control-in-petroleum-engineering.html

02 Pressure gradient of a fluid column

$$G = 0.052 \times MW$$

Where	G: hydrostatic pressure gradient, psi/ft; MW: mud weight, ppg.
Assumptions / limitations	Uniform density; the gradient applies per foot of vertical height (TVD), not of measured length.
Example	MW = 10.5 ppg.
Result	$G = 0.546$ psi/ft
Reference	[1]; [2] (see list at the end)
Read more	petrosmartacademy.com/2025/09/well-control-in-petroleum-engineering.html

03 Equivalent mud weight

$$EMW = P / (0.052 \times TVD)$$

Where	EMW: equivalent mud weight, ppg; P: pressure at the point considered, psig, referred to the same datum as TVD; TVD: true vertical depth of the point, ft.
Assumptions / limitations	Expresses any pressure at depth as the density of a static column from the datum to that depth; it does not imply that a fluid of that density is in the hole.
Example	P = 6,000 psig at TVD = 10,000 ft.
Result	$EMW = 11.54$ ppg
Reference	[1]; [2] (see list at the end)
Read more	petrosmartacademy.com/2025/09/well-control-in-petroleum-engineering.html

04 Equivalent circulating density (ECD)

$$ECD = MW + \Delta P_{ann} / (0.052 \times TVD)$$

Where	ECD, MW: ppg; ΔP_{ann} : frictional pressure loss in the annulus between the point considered and surface, psi; TVD: true vertical depth of the point, ft.
Assumptions / limitations	Surface back-pressure taken as zero. Only annular friction acts on the open hole: losses inside the string and across the bit are excluded. An imposed back-pressure (for example with managed pressure drilling) is added separately when evaluating the equivalent density at the point.
Example	MW = 10.5 ppg, ΔP_{ann} = 300 psi from the point to surface, TVD = 10,000 ft, no back-pressure.
Result	ECD = 11.08 ppg
Reference	[3]; [2] (see list at the end)
Read more	petrosmartacademy.com/2025/05/drilling-fluid-additives-enhancing.html

05 Formation pressure estimated from SIDPP

$$P_f = SIDPP + 0.052 \times OMW \times TVD$$

Where	P_f : formation pressure, psig; SIDPP: stabilized shut-in drillpipe pressure, psi; OMW: original mud weight in the drillstring, ppg; TVD: true vertical depth of the kicking zone (taken as bit TVD), ft.
Assumptions / limitations	Estimate only. Requires a stabilized and representative SIDPP, a drillstring full of a known, uniform fluid, and hydraulic communication between the string and the formation (no float valve holding pressure, no trapped pressure).
Example	SIDPP = 500 psi, OMW = 10.5 ppg, TVD = 10,000 ft.
Result	$P_f \approx 5,960$ psig
Reference	[2]; [1] (see list at the end)
Read more	petrosmartacademy.com/2025/04/well-control-system-mastering-kick.html

06 Kill mud weight

$$KMW = OMW + SIDPP / (0.052 \times TVD)$$

Where	KMW, OMW: ppg; SIDPP: stabilized shut-in drillpipe pressure, psi; TVD: true vertical depth of the bit or kicking zone, ft.
Assumptions / limitations	Same assumptions as card 05. Numerical rounding and any safety margin are two separate decisions: the operational rounding rule and any margin are set by the applicable well control procedure.
Example	OMW = 10.5 ppg, SIDPP = 500 psi, TVD = 10,000 ft.
Result	KMW = 11.461538 ppg; rounded to 11.5 ppg for this exercise (rounding convention, no margin added)
Reference	[2]; [1] (see list at the end)
Read more	petrosmartacademy.com/2025/04/well-control-system-mastering-kick.html

07 Initial circulating pressure (ICP)

$$\text{ICP} = \text{SCR} + \text{SIDPP}$$

Where	ICP: pump pressure at the start of the kill, psi; SCR: circulating pressure measured at the selected kill rate (slow circulating rate pressure), psi; SIDPP: stabilized shut-in drillpipe pressure, psi.
Assumptions / limitations	Constant kill rate equal to the rate at which SCR was recorded, with comparable hydraulic conditions. One step of a kill method, not a complete well control procedure. Subsea wells require separate treatment of choke line friction.
Example	SCR = 600 psi at the kill rate, SIDPP = 500 psi.
Result	ICP = 1,100 psi
Reference	[2]; [1] (see list at the end)
Read more	petrosmartacademy.com/2025/04/well-control-system-mastering-kick.html

08 Final circulating pressure (FCP)

$$\text{FCP} = \text{SCR} \times \text{KMW} / \text{OMW}$$

Where	FCP: pump pressure once kill mud reaches the bit, psi; SCR: circulating pressure at the kill rate with OMW, psi; KMW, OMW: ppg.
Assumptions / limitations	Approximation that scales frictional pressure with the density ratio at constant rate; rheology changes are ignored. Not a complete well control procedure; subsea choke line friction needs specific treatment.
Example	SCR = 600 psi, KMW = 11.5 ppg (rounded value from card 06), OMW = 10.5 ppg.
Result	FCP = 657.1 psi, about 657 psi
Reference	[2]; [1] (see list at the end)
Read more	petrosmartacademy.com/2025/04/well-control-system-mastering-kick.html

09 Influx gradient

$$L_i = V_{\text{pit}} / C_a; G_i = G_{\text{mud}} - (\text{SICP} - \text{SIDPP}) / H_i$$

Where	V_{pit} : pit gain, bbl; C_a : annular capacity around the bottom of the string, bbl/ft; L_i : influx length along the hole, ft; H_i : vertical height of the influx, ft; $G_{\text{mud}} = 0.052 \times \text{MW}$, psi/ft; SICP: stabilized shut-in casing pressure, psi; G_i : influx gradient, psi/ft.
Assumptions / limitations	Constant annular section, representative pit gain, stabilized and interpretable pressures. L_i equals H_i only in the vertical case shown; in a deviated well H_i is taken from the trajectory over the influx interval. Gas dissolved in oil- or synthetic-based mud, migration and volume uncertainty limit the result. A low gradient is a possible indication of gas under these assumptions; it does not identify the fluid on its own.
Example	Vertical well, $V_{\text{pit}} = 20$ bbl, 8.5 in hole around 5 in pipe ($C_a = 0.045900$ bbl/ft), SICP = 650 psi, SIDPP = 500 psi, MW = 10.5 ppg.
Result	$L_i = H_i \approx 435.725$ ft; $G_i \approx 0.201746$ psi/ft (about 0.20 psi/ft)
Reference	[1] (see list at the end)
Read more	petrosmartacademy.com/2025/04/well-control-system-mastering-kick.html

10 Maximum allowable annular surface pressure (MAASP)

$$\text{MAASP} = (\text{EMW}_{\text{lim}} - \text{MW}) \times 0.052 \times \text{TVD}_{\text{shoe}}$$

Where	EMW_{lim} : limiting equivalent mud weight at the shoe derived from the formation strength test retained for the well (leak-off test, LOT, or formation integrity test, FIT), ppg; MW: current uniform mud weight in the annulus, ppg; TVD_{shoe} : true vertical depth of the casing shoe from the same datum, ft.
Assumptions / limitations	Static estimate with a homogeneous mud column, the shoe assumed to be the weakest point. A LOT result, a FIT pressure and a demonstrated fracture pressure are different quantities and must not be interchanged. The operational value also accounts for the fluids actually in the annulus, circulation and equipment pressure limits. Recalculate whenever the mud weight or other relevant conditions change.
Example	$\text{EMW}_{\text{lim}} = 14.0$ ppg from a LOT, $\text{MW} = 10.5$ ppg, $\text{TVD}_{\text{shoe}} = 5,000$ ft.
Result	MAASP = 910 psi
Reference	[2]; [1] (see list at the end)
Read more	petrosmartacademy.com/2025/09/well-control-in-petroleum-engineering.html

B. Capacities and circulation

Geometric volumes and theoretical circulation times. Volumes use measured length (MD) of each section; vertical depth (TVD) is used only for hydrostatic heads.

11 Pipe internal capacity

$$C_p = ID^2 / 1029.4$$

Where	C_p : internal capacity, bbl/ft; ID: inside diameter, in. 1029.4 converts a diameter squared in in ² into bbl/ft ($\pi/4 \div 144 \div 5.6146$).
Assumptions / limitations	Uniform ID; tool joints and upsets ignored. For a string of several sections, $V = \Sigma(C_i \times L_i)$ with L_i the measured length of each section.
Example	5 in drillpipe, ID = 4.276 in.
Result	$C_p \approx 0.01776$ bbl/ft
Reference	[1] (see list at the end)
Read more	petrosmartacademy.com/2025/03/mastering-circulating-system-functions.html

12 Annular capacity

$$C_a = (D_h^2 - OD^2) / 1029.4$$

Where	C_a : annular capacity, bbl/ft; D_h : hole diameter (open hole) or casing inside diameter (cased hole), in; OD: outside diameter of the inner pipe, in.
Assumptions / limitations	Gauge hole and uniform pipe OD; washouts, tool joints and BHA changes are ignored. For several sections, $V = \Sigma(C_{ai} \times L_i)$ with L_i in measured length.
Example	8.5 in hole, 5 in pipe.
Result	$C_a \approx 0.04590$ bbl/ft
Reference	[1] (see list at the end)
Read more	petrosmartacademy.com/2025/03/mastering-circulating-system-functions.html

13 Steel (metal) displacement

$$D_s = (OD^2 - ID^2) / 1029.4; \text{ closed-end displacement } D_{ce} = OD^2 / 1029.4$$

Where	D_s : volume of steel per foot, bbl/ft; D_{ce} : steel plus internal volume when the pipe is pulled or run closed (wet), bbl/ft; OD, ID: in.
Assumptions / limitations	Plain pipe body; tool joints add displacement. Hole fill calculations use D_s when pulling dry and D_{ce} when pulling wet; mixing them up gives the wrong fill volume.
Example	5 in pipe, ID = 4.276 in.
Result	$D_s \approx 0.00652$ bbl/ft; $D_{ce} \approx 0.02429$ bbl/ft
Reference	[1]; [2] (see list at the end)
Read more	petrosmartacademy.com/2025/03/mastering-circulating-system-functions.html

14 Triplex pump output per stroke

$$Q_p = 0.000243 \times d_l^2 \times L_s \times E$$

Where	Q_p : actual output, bbl/stroke; d_l : liner diameter, in; L_s : stroke length, in; E : volumetric efficiency as a fraction ($E = 0.95$ for 95%). 0.000243 is the rounded constant for a single-acting triplex (exact value 0.00024286).
Assumptions / limitations	Single-acting triplex pump. With $E = 1$ the formula gives the theoretical displacement; the actual output per stroke is lower. For real applications use an efficiency verified on the rig.
Example	6 in liner, 12 in stroke, $E = 0.95$.
Result	$Q_p = 0.0997272$ bbl/stroke (about 0.0997)
Reference	[1] (see list at the end)
Read more	petrosmartacademy.com/2025/03/mastering-circulating-system-functions.html

15 Annular velocity

$$AV = 24.5 \times Q / (D_h^2 - OD^2)$$

Where	AV : mean annular velocity, ft/min; Q : flow rate, US gal/min; D_h , OD : in.
Assumptions / limitations	Theoretical mean velocity for the section considered. It does not by itself ensure hole cleaning, which also depends on geometry, inclination, rheology, pipe rotation and cuttings transport.
Example	$Q = 500$ US gal/min, 8.5 in hole, 5 in pipe.
Result	$AV \approx 259$ ft/min
Reference	[1] (see list at the end)
Read more	petrosmartacademy.com/2025/03/mastering-circulating-system-functions.html

16 Bottoms-up time

$$t_{bu} = V_{ann} / (Q / 42), \text{ with } V_{ann} = \sum(C_{ai} \times L_i)$$

Where	t_{bu} : minutes; V_{ann} : annular volume from bit to surface, bbl; C_{ai} : annular capacity of section i , bbl/ft; L_i : measured length of section i , ft; Q : US gal/min; 42 US gal per bbl.
Assumptions / limitations	Theoretical volumetric displacement time. Actual cuttings or tracer arrival is later because of slip velocity, washouts and hole cleaning efficiency.
Example	One section: 10,000 ft MD of 8.5 in hole around 5 in pipe ($C_a = 0.045900$ bbl/ft, card 12), $Q = 500$ US gal/min.
Result	$V_{ann} \approx 459.0$ bbl; $t_{bu} \approx 38.56$ min, about 39 min
Reference	[1] (see list at the end)
Read more	petrosmartacademy.com/2025/03/mastering-circulating-system-functions.html

C. Bit hydraulics

Simplified nozzle relations for a bit with several nozzles of known size. Use the bit manufacturer's data and coefficients when they are available.

17 Total nozzle flow area

$$A_n = \sum (\pi/4) \times (d_n/32)^2$$

Where A_n : total flow area, in²; d_n : nozzle size expressed as the number of 32nds of an inch (for a 14/32 in nozzle, $d_n = 14$).

Assumptions / limitations Round nozzles of nominal size.

Example Three 14/32 in nozzles.

Result $A_n \approx 0.450990 \text{ in}^2$

Reference [1] (see list at the end)

Read more petrosmartacademy.com/2025/05/drilling-fluid-additives-enhancing.html

18 Pressure drop across the bit nozzles

$$\Delta P_b = MW \times Q^2 / (12,032 \times C_d^2 \times A_n^2)$$

Where ΔP_b : psi; MW: ppg; Q: US gal/min; A_n : in²; C_d : nozzle discharge coefficient (dimensionless). $12,032 \approx 1 / (8.311 \times 10^{-5})$.

Assumptions / limitations Simplified nozzle model with a discharge coefficient $C_d = 0.95$, a common assumption. The frequently quoted form $MW \times Q^2 / (12,031 \times A_n^2)$ has no C_d and corresponds to $C_d = 1$. Use the bit manufacturer's coefficients when available.

Example MW = 10.5 ppg, Q = 500 US gal/min, $A_n = 0.450990 \text{ in}^2$ (card 17), $C_d = 0.95$.

Result $\Delta P_b \approx 1,188.5 \text{ psi (with } C_d = 1: \approx 1,072.6 \text{ psi)}$

Reference [1] (see list at the end)

Read more petrosmartacademy.com/2025/05/drilling-fluid-additives-enhancing.html

19 Hydraulic horsepower at the bit

$$HHP_b = \Delta P_b \times Q / 1714$$

Where HHP_b : hydraulic hp; ΔP_b : psi; Q: US gal/min.

Assumptions / limitations Uses the bit pressure drop of card 18.

Example $\Delta P_b = 1,188.53 \text{ psi}$ (card 18), Q = 500 US gal/min.

Result $HHP_b \approx 346.7 \text{ hp}$

Reference [1] (see list at the end)

Read more petrosmartacademy.com/2025/05/drilling-fluid-additives-enhancing.html

20 Nozzle velocity

$$V_n = 0.3208 \times Q / A_n$$

Where	V_n : mean velocity through the nozzles, ft/s; Q: US gal/min; A_n : in ² .
Assumptions / limitations	Ideal mean velocity Q / A_n ; independent of C_d in this simplified form.
Example	$Q = 500$ US gal/min, $A_n = 0.450990$ in ² (card 17).
Result	$V_n \approx 355.7$ ft/s
Reference	[1] (see list at the end)
Read more	petrosmartacademy.com/2025/05/drilling-fluid-additives-enhancing.html

21 Hydraulic horsepower per square inch of bit area (HSI)

$$HSI = HHP_b / ((\pi/4) \times D_{bit}^2)$$

Where	HSI: hp/in ² ; HHP_b : hp (card 19); D_{bit} : bit diameter, in.
Assumptions / limitations	Comparative indicator only; no universal target value is implied.
Example	$HHP_b = 346.71$ hp (card 19), $D_{bit} = 8.5$ in (area 56.745 in ²).
Result	$HSI \approx 6.11$ hp/in²
Reference	[1] (see list at the end)
Read more	petrosmartacademy.com/2025/05/drilling-fluid-additives-enhancing.html

D. Cementing

Volume arithmetic for a single primary cement job. The cementing program approved for the well defines the volumes, excess, displacement criteria and limits.

22 Annular slurry volume with excess

$$V_{\text{ann}} = C_a \times L \times (1 + e)$$

Where	V_{ann} : annular slurry volume of the section, bbl; $C_a = (D_h^2 - OD^2) / 1029.4$, bbl/ft; L: measured length of the cemented section, ft; e: excess as a fraction (e = 0.30 for 30% excess).
Assumptions / limitations	Annular volume of one section only. The total slurry also includes the shoe track, any rathole and other planned volumes, counted separately. The excess depends on the geometric basis (bit size or caliper) and the data available; 30% on bit size is an assumption of this exercise.
Example	12.25 in open hole, 9 5/8 in casing (OD 9.625 in), L = 1,000 ft MD, e = 0.30.
Result	$C_a \approx 0.055782$ bbl/ft; $V_{\text{ann}} \approx 72.51645$ bbl
Reference	[4]; [1] (see list at the end)
Read more	petrosmartacademy.com/2025/10/cement-excess-calculating-safety-margin.html

23 Number of sacks of cement

$$N = V \times 5.6146 / Y$$

Where	N: number of sacks; V: slurry volume, bbl; 5.6146 ft ³ per bbl; Y: yield of the selected slurry formulation, ft ³ /sack.
Assumptions / limitations	The yield must correspond to the slurry formulation used. The calculated requirement and the whole number of sacks are distinct; neither includes an operational allowance, which is set by the cementing program.
Example	V = 72.51645 bbl (card 22), Y = 1.18 ft ³ /sack.
Result	Calculated requirement ≈ 345.04 sk; rounded up to whole sacks: 346 sk, before any additional operational allowance
Reference	[4] (see list at the end)
Read more	petrosmartacademy.com/2025/04/cementing-calculations-in-petroleum.html

24 Mix water volume

$$V_w = N \times w / 42$$

Where	V_w : mix water for the slurry, bbl; N: number of sacks; w: mix water requirement of the formulation, US gal/sack; 42 US gal per bbl.
Assumptions / limitations	Mix water and yield must come from the same formulation. This is formulation water only; water for spacers, washes, line flushing and dead volume is counted separately.
Example	N = 346 sacks (whole sacks, card 23), w = 5.2 US gal/sack.
Result	$V_w \approx 42.84$ bbl (theoretical value for 345.04 sk: 42.72 bbl)
Reference	[4] (see list at the end)
Read more	petrosmartacademy.com/2025/04/volume-of-mix-water-required-for-cement.html

25 Displacement volume to the float collar

$$V_d = \sum(C_i \times L_i); \text{ for one uniform string } V_d = C_{\text{csg}} \times \text{MD}_{\text{fc}}$$

Where	V_d : displacement volume from the top plug at surface to the float collar, bbl; C_i : internal capacity of section i, bbl/ft; L_i : measured length of section i, ft; MD_{fc} : measured depth of the float collar below the counting point, ft.
Assumptions / limitations	Counting starts when the top plug leaves the cementing head at surface. Surface lines and cementing head volume are excluded in this example; include them if the counting point is at the pump. The simple product is valid only for a uniform casing capacity.
Example	9 5/8 in, 47 lb/ft casing (ID 8.681 in, capacity 0.073208 bbl/ft) to the float collar at 7,920 ft MD.
Result	$V_d \approx 579.803096$ bbl (about 580 bbl)
Reference	[4]; [1] (see list at the end)
Read more	petrosmartacademy.com/2025/04/cementing-calculations-in-petroleum.html

26 Theoretical displacement strokes to the float collar

$$N_{\text{stk}} = V_d / Q_p$$

Where	N_{stk} : strokes; V_d : displacement volume, bbl (card 25); Q_p : actual pump output, bbl/stroke (card 14).
Assumptions / limitations	Theoretical value from unrounded inputs. It does not by itself instruct the crew to keep pumping until the plug bumps: displacement criteria, overdisplacement limits and pressure limits come from the approved cementing program.
Example	$V_d = 579.803096$ bbl; $Q_p = 0.0997272$ bbl/stroke.
Result	$N_{\text{stk}} \approx 5,813.89$ strokes, about 5,814
Reference	[4] (see list at the end)
Read more	petrosmartacademy.com/2025/05/number-of-strokes-required-to-displace.html

27 Differential hydrostatic pressure of the cement column

$$\Delta P = 0.052 \times (\rho_{\text{slurry}} - \rho_{\text{mud}}) \times \Delta \text{TVD}_{\text{cement}}$$

Where	ΔP : psi; ρ_{slurry} , ρ_{mud} : ppg; $\Delta \text{TVD}_{\text{cement}}$: vertical height of the cement column, ft.
Assumptions / limitations	Compares two fluid columns over the same vertical interval; friction, gel strength and other pressure contributions are excluded.
Example	$\rho_{\text{slurry}} = 15.8$ ppg, $\rho_{\text{mud}} = 10.5$ ppg, $\Delta \text{TVD}_{\text{cement}} = 1,000$ ft.
Result	$\Delta P \approx 275.6$ psi, about 276 psi
Reference	[4]; [1] (see list at the end)
Read more	petrosmartacademy.com/2025/04/cementing-calculations-in-petroleum.html

E. Simplified casing load examples

These cards illustrate elementary loads and ratios. They are not a complete casing design, which also covers combined loads, connections, wear, temperature, corrosion and the load cases defined by company standards.

28 Buoyancy factor

$$BF = 1 - MW / 65.5$$

Where	BF: dimensionless; MW: ppg; 65.5 ppg: density of steel.
Assumptions / limitations	Valid for a string fully immersed in one homogeneous fluid, with the same fluid inside and outside under hydrostatic conditions. Different internal and external densities or end pressure effects require a full force balance.
Example	MW = 10.5 ppg.
Result	BF ≈ 0.839695 (displayed 0.840)
Reference	[1]; [5] (see list at the end)
Read more	petrosmartacademy.com/2025/09/tension-criterion-in-casing-design.html

29 Buoyed weight of a casing string

$$W_b = w \times L \times BF$$

Where	W_b : buoyed weight, a force in lbf; w: nominal weight per foot, lbf/ft; L: string length, ft; BF from card 28 (unrounded).
Assumptions / limitations	Apparent weight under the conditions of card 28 only; it is not automatically the actual hook load, which also depends on friction, pressure effects and fluids in place.
Example	w = 47 lbf/ft, L = 8,000 ft, BF = 0.839695.
Result	$W_{air} = 376,000$ lbf; $W_b \approx 315,725$ lbf (about 315.7 klbf)
Reference	[1]; [5] (see list at the end)
Read more	petrosmartacademy.com/2025/09/tension-criterion-in-casing-design.html

30 Simplified collapse load: full evacuation

$$\Delta P_c = 0.052 \times MW_{ext} \times D$$

Where	ΔP_c : differential collapse load, psi; MW_{ext} : external mud weight, ppg; D: TVD of the point considered, ft.
Assumptions / limitations	Simplified scenario: homogeneous external mud column and zero internal pressure, both on the same gauge basis. This is a load, not a collapse resistance; this single calculation does not verify the casing.
Example	$MW_{ext} = 10.5$ ppg, D = 8,000 ft TVD (shoe).
Result	$\Delta P_c = 4,368$ psi at the shoe
Reference	[5]; [1] (see list at the end)
Read more	petrosmartacademy.com/2025/06/collapse-design-in-casing.html

31 Simplified burst load at surface: gas to surface

$$P_{i,surf} = P_{res} - G_{gas} \times D$$

Where	$P_{i,surf}$: internal pressure at surface, psig; P_{res} : reservoir pressure, psig, at TVD D; G_{gas} : gas gradient, psi/ft; D: TVD of the reservoir, ft.
Assumptions / limitations	Assumed constant gas gradient for this example: 0.1 psi/ft. It is not a universal value and not necessarily conservative; real evaluations depend on gas composition, pressure, temperature and the load scenario. External backup taken as zero at surface.
Example	$P_{res} = 6,000$ psig at $D = 8,000$ ft TVD, $G_{gas} = 0.1$ psi/ft.
Result	$P_{i,surf} = 5,200$ psig
Reference	[5]; [1] (see list at the end)
Read more	petrosmartacademy.com/2025/06/burst-design-in-casing.html

32 Design factor

$$DF = \text{Rating} / \text{Load}$$

Where	Rating: resistance of the pipe for the failure mode considered, psi; Load: the corresponding load, psi.
Assumptions / limitations	Rating and load must refer to the same failure mode and conditions. Connections, wear, temperature derating and combined loads are checked separately. Minimum design factors are defined by company standards; none is implied here.
Example	Assumed burst rating for the exercise: 8,150 psi (not attributed to any grade); load 5,200 psig from card 31.
Result	$DF \approx 1.567$ (about 1.57)
Reference	[5] (see list at the end)
Read more	petrosmartacademy.com/2025/08/design-criteria-for-casing-balancing.html

F. Drilling performance and cost

Indicators used to compare bit runs, parameters and trajectories.

33 Drilling cost per foot for a bit run

$$C_f = (B + R \times (t + T)) / F$$

Where	C_f : cost per foot, USD/ft; B: bit cost, USD; R: rig spread rate, USD/h; t: rotating time, h; T: trip time, h; F: footage drilled, ft.
Assumptions / limitations	Simplified cost of one bit run for comparing bits and parameters; it is not the total well cost, which includes casing, cementing, logging, completion and other services.
Example	B = USD 15,000, R = USD 1,250/h (USD 30,000/day), t = 25 h, T = 8 h, F = 1,200 ft.
Result	$C_f = \text{USD } 46.875/\text{ft}$, about USD 46.88/ft
Reference	[1] (see list at the end)
Read more	petrosmartacademy.com/2025/01/drilling-cost-calculations-optimizing.html

34 Mechanical specific energy (MSE)

$$\text{MSE} = \text{WOB} / A_b + (120 \times \pi \times N \times T) / (A_b \times \text{ROP})$$

Where	MSE: psi; WOB: weight on bit, lbf; A_b : bit area, in ² ; N: rotary speed at the bit, rpm; T: torque at the bit, ft·lbf; ROP: rate of penetration, ft/h.
Assumptions / limitations	Torque and speed must represent the same system consistently. With a downhole motor, the motor speed and the torque delivered at the bit must be accounted for, and surface measurements differ from bit conditions. MSE is an efficiency indicator, not a direct, universal measure of rock strength.
Example	WOB = 25,000 lbf, 8.5 in bit ($A_b = 56.745 \text{ in}^2$), N = 120 rpm, T = 5,000 ft·lbf, ROP = 100 ft/h.
Result	$\text{MSE} \approx 40,302 \text{ psi}$
Reference	[6]; [7] (see list at the end)
Read more	petrosmartacademy.com/2025/01/drilling-parameters-and-optimization.html

35 Dogleg severity (DLS)

$$\cos \beta = \cos I_1 \cos I_2 + \sin I_1 \sin I_2 \cos(A_2 - A_1); \text{DLS} = \beta \times 100 / \Delta \text{MD}$$

Where	β : dogleg angle, degrees; I: inclination, degrees; A: azimuth, degrees; ΔMD : measured distance between the two survey stations, ft; DLS: °/100 ft.
Assumptions / limitations	Trigonometric functions evaluated with angles converted consistently (degrees to radians in software); β converted back to degrees before computing DLS. The result is the average curvature between the two stations.
Example	Station 1: I = 20°, A = 45°; station 2: I = 23°, A = 49°; $\Delta \text{MD} = 100 \text{ ft}$.
Result	$\beta \approx 3.33743^\circ$; $\text{DLS} \approx 3.34^\circ/100 \text{ ft}$
Reference	[1] (see list at the end)
Read more	petrosmartacademy.com/2026/04/dogleg-severity-analysis-key-to.html

G. Reservoir and production

Volumetric, inflow, PVT, decline and injection relations in their simplest forms.

36 Original oil in place, volumetric

$$N = 7758 \times A \times h \times \phi \times (1 - S_w) / B_{oi}$$

Where	N: oil initially in place, STB; 7758: bbl per acre-ft; A: area, acres; h: net oil pay thickness, ft; ϕ : porosity, fraction; S_w : water saturation, fraction; B_{oi} : initial oil formation volume factor, RB/STB.
Assumptions / limitations	Representative average properties. N is oil initially in place, not recoverable reserves, which depend on recovery and commercial criteria (SPE-PRMS).
Example	A = 640 acres, h = 50 ft, $\phi = 0.22$, $S_w = 0.25$, $B_{oi} = 1.25$ RB/STB.
Result	N ≈ 32,769,792 STB, about 32.77 million STB
Reference	[8]; [9] (see list at the end)
Read more	petrosmartacademy.com/2024/10/understanding-original-oil-in-place.html

37 Productivity index

$$J = q_o / (\bar{P}_r - P_{wf})$$

Where	J: STB/d/psi; q_o : oil rate, STB/d; $\bar{P}_r$: average reservoir pressure, psia; P_{wf} : flowing bottomhole pressure, psia, both at the same datum.
Assumptions / limitations	An indicator valid for the test conditions; it does not imply a universal linear relation, especially with multiphase flow below the bubble point.
Example	$q_o = 1,500$ STB/d, $\bar{P}_r = 3,000$ psia, $P_{wf} = 2,200$ psia.
Result	J = 1.875 STB/d/psi, about 1.88
Reference	[8] (see list at the end)
Read more	petrosmartacademy.com/2024/09/nodal-analysis-in-petroleum-engineering.html

38 Pseudo-steady-state radial inflow

$$q_o = 0.00708 \times k \times h \times (\bar{P}_r - P_{wf}) / [\mu_o \times B_o \times (\ln(r_e/r_w) - 0.75 + S)]$$

Where	q_o : STB/d; k: permeability, md; h: net thickness, ft; $\bar{P}_r$: average reservoir pressure in the drainage area, psia; P_{wf} : psia; μ_o : cp; B_o : RB/STB; r_e : drainage radius, ft; r_w : wellbore radius, ft; S: skin factor (dimensionless); ln: natural logarithm. $0.00708 = 2\pi \times 0.001127$ for these field units.
Assumptions / limitations	Pseudo-steady state, idealized circular drainage area centred on the well, single-phase oil, representative constant properties.
Example	k = 50 md, h = 40 ft, $\bar{P}_r - P_{wf} = 800$ psi, $\mu_o = 1.2$ cp, $B_o = 1.25$ RB/STB, $r_e = 1,490$ ft, $r_w = 0.354$ ft, S = 0.
Result	$q_o \approx 994.34$ STB/d
Reference	[8] (see list at the end)
Read more	petrosmartacademy.com/2024/09/nodal-analysis-in-petroleum-engineering.html

39 Gas formation volume factor

$$B_g = 0.02827 \times z \times T / p$$

Where	B_g : reservoir ft ³ /scf; z : gas deviation factor; T : reservoir temperature, °R (°F + 459.67); p : reservoir pressure, psia.
Assumptions / limitations	Constant based on standard conditions of 14.696 psia and 60 °F (519.67 °R). For RB/scf divide by 5.6146 ($B_g = 0.005035 \times z \times T / p$).
Example	$z = 0.88$, $T = 180 + 459.67 = 639.67$ °R, $p = 3,000$ psia.
Result	$B_g \approx 0.00530448$ reservoir ft³/scf (0.0009448 RB/scf)
Reference	[10]; [8] (see list at the end)
Read more	petrosmartacademy.com/2024/09/gas-formation-volume-factor-bg-key.html

40 Exponential decline

$$q = q_i \times \exp(-D t); N_p = 365 \times (q_i - q) / D$$

Where	q, q_i : rates, STB/d; D : nominal exponential decline rate, 1/year; t : years; N_p : cumulative production over t , STB; 365 days per year.
Assumptions / limitations	Exponential (constant D) behaviour and stable, interpretable operating conditions over the period.
Example	$q_i = 1,000$ STB/d, $D = 0.25$ per year, $t = 2$ years.
Result	$q \approx 606.53$ STB/d; $N_p \approx 574,465$ STB
Reference	[11] (see list at the end)
Read more	petrosmartacademy.com/2024/10/decline-curve-analysis-key-tool-in.html

41 Voidage replacement ratio (VRR)

$$VRR = \Sigma(\text{injected volumes at reservoir conditions}) / \Sigma(\text{produced volumes at reservoir conditions})$$

Where	Simplified form used here: $VRR = q_{wi} B_w / (q_o B_o + q_{wp} B_{wp})$, rates in STB/d over the same period, B in RB/STB.
Assumptions / limitations	Numerator and denominator at consistent reservoir conditions. A rate ratio (instantaneous) and a cumulative ratio over a period are different quantities. Free gas is neglected in this example; it must be added when significant, without double counting the dissolved gas already included in B_o . $VRR = 1$ does not guarantee pressure maintenance everywhere in the reservoir.
Example	$q_{wi} = 12,000$ STB/d ($B_w = 1.02$); $q_o = 8,000$ STB/d ($B_o = 1.25$); $q_{wp} = 2,000$ STB/d ($B_{wp} = 1.01$); free gas neglected.
Result	$VRR \approx 1.0183$, about 1.02
Reference	[12]; [8] (see list at the end)
Read more	petrosmartacademy.com/2024/11/voidage-replacement-ratio-vrr.html

Glossary

Term	Meaning
BHA	Bottomhole assembly
Bg	Gas formation volume factor, reservoir ft ³ /scf or RB/scf
Bo	Oil formation volume factor, RB/STB
Boi	Initial oil formation volume factor, RB/STB
Bw	Water formation volume factor, RB/STB
DLS	Dogleg severity, °/100 ft
ECD	Equivalent circulating density, ppg
EMW	Equivalent mud weight, ppg
FIT	Formation integrity test: pressure test to a planned value below leak-off
ID	Inside diameter, in
KMW	Kill mud weight, ppg
LOT	Leak-off test: pressure test until the formation starts to take fluid
MAASP	Maximum allowable annular surface pressure, psi
MD	Measured depth, along the hole, ft
MSE	Mechanical specific energy, psi
MW	Mud weight (fluid density), ppg
OD	Outside diameter, in
OMW	Original mud weight, ppg
ppg	Pounds per US gallon (density)
psia / psig	Absolute pressure / gauge pressure (relative to atmospheric)
RB	Reservoir barrel
ROP	Rate of penetration, ft/h
scf	Standard cubic foot (14.696 psia, 60 °F in this guide)
SCR	Slow circulating rate pressure: circulating pressure at the selected kill rate, psi
SICP	Shut-in casing pressure, psi
SIDPP	Shut-in drillpipe pressure, psi
Skin (S)	Dimensionless pressure drop factor for near-wellbore damage or stimulation
STB	Stock-tank barrel
TVD	True vertical depth, ft
WOB	Weight on bit, lbf

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Standards and formula sheets are revised over time; check that the edition you use is the one in force for your project. The IWCF sheet cited is in SI units; the relations are the same with 0.00981 kPa per $(\text{kg/m}^3 \cdot \text{m})$ in place of 0.052.

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