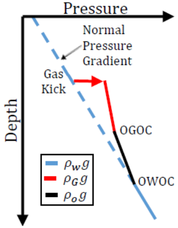
Conversions and Constants

1 kPa = 0.1450 psi	1 in = 2.54 cm	1 acre = 43,560 ft^2	1 m^3 = 6.2898 bbl	R = 459.67 + °F	1 cp = 1.0 mPa-s
1 MPa = 10 bar	1 ft = 0.3048 m	1 m^2 = 10.764 ft^2	1 bbl = 5.6146 ft^3	K = 273.15 + °C	
1 atm = 14.696 psi	1 mile = 5,280 ft		1 bbl = 42 US gal	°F = 1.8 °C + 32	
1 atm = 1.013 bar			1 ft^3 = 7.4805 gal		1 lb$_m$ = 453.592 g

1 Newton = 1 x 10^5 dynes	1 Darcy = 9.8692 x 10^{-9} cm^2	Standard Temperature = 60°F
1 dyne = 2.248 x 10^{-6} lb$_f$	1 Darcy = 1.0623 x 10^{-11} ft^2	Standard Pressure = 14.696 psia
1 g/cm^3 = 62.428 lb$_m$/ft^3	Euler (γ) = 0.5772 = ln(1.781)	Water density at SC = 62.37 lb$_m$/ft^3
1 mD/cp = 6.33 x 10^{-3} ft^2/psi-day	Gravitational Constant = 9.806 m/s^2	Molar Mass of Air = 28.966 g/mol
1000 kg/m^3 = 0.4335 psi/ft	Natural logarithm base = 2.71828	V_M^{IG} = 379.3 scf/lbmol @ 14.696 psia
1 kg/l = 8.347 lb$_m$/gal	Gas Constant = 8.314 Pa · m^3/mol K	Univ. Gas = 10.732 psia · ft^3/lbmol · R

Reservoir Pressure and Temperature



$$P = P_{surface} + \alpha_P z$$

$$z = \text{depth} \quad \alpha_P = \rho_f g$$

$$\alpha_P = \begin{cases} 0.433\ \frac{psi}{ft} & \text{if fresh } H_2O \\ 0.465\ \frac{psi}{ft} & \text{if brine} \end{cases}$$

$$T = T_{surface} + \alpha_T z$$

α_T is usually $0.01 - .02°F/ft$

Pressure Balance

$$P_{BH} = P_{dp} + 0.052\rho_m TVD \qquad \rho_m[=]\frac{lb_m}{gal}$$

$$P_{BH} = P_{csg} + 0.052\rho_m TVD$$

Reynold's Number

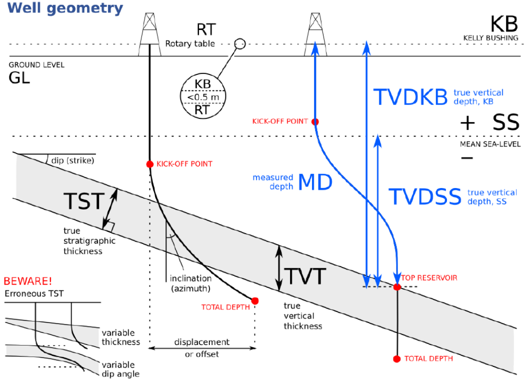
$$N_{Re} = 928\frac{Dv\rho}{\mu}$$

*units same as Pump Pressure

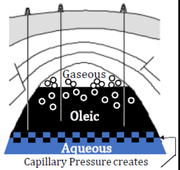
$N_{Re} < 2100$: Laminar Flow

$N_{Re} > 2100$: Turbulent Flow

Well geometry



Reservoir Fluids



Capillary Pressure creates transition zone between phases

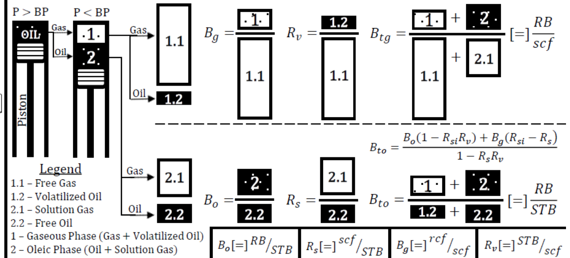
Component Concentrations

$$C_o = \frac{S_o}{B_o} + \frac{S_g}{B_g}R_v \qquad C_w = \frac{S_w}{B_w}$$

$$C_g = \frac{S_g}{B_g} + \frac{S_o}{B_o}R_s \qquad C_j[=]\frac{STB}{RB}$$

Reservoir Conditions — Isothermal | Surface Conditions

$$B_{tg} = \frac{B_g(1 - R_{vi}R_s) + B_o(R_{vi} - R_v)}{1 - R_s R_v}$$

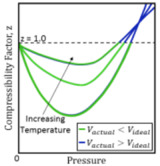


$$B_{to} = \frac{B_o(1 - R_{si}R_v) + B_g(R_{si} - R_s)}{1 - R_s R_v}$$

$B_o[=]^{RB}/_{STB}$ | $R_s[=]^{scf}/_{STB}$ | $B_g[=]^{rcf}/_{scf}$ | $R_v[=]^{STB}/_{scf}$

Compressibility Factor

$$PV = zNRT$$

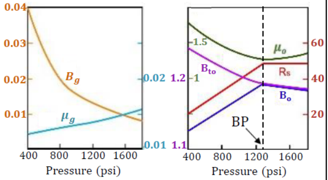


Relate B_g to z-factor

$$B_g = \frac{P^{SC}}{T^{SC}}\left(\frac{zT}{P}\right)[=]\frac{rcf}{scf}$$

$P[=]psia \quad T[=]R$

Pressure Dependent Fluid Properties



Specific Gravity

$$\gamma_o = \left(\frac{\rho_o}{\rho_w}\right)_{SC}$$

$$\gamma_g = \left(\frac{\rho_g}{\rho_{air}}\right)_{SC} = \frac{M_g}{M_{air}}$$

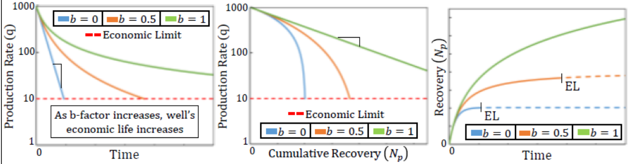
API Gravity

$$API° = \frac{141.5}{\gamma} - 131.5$$

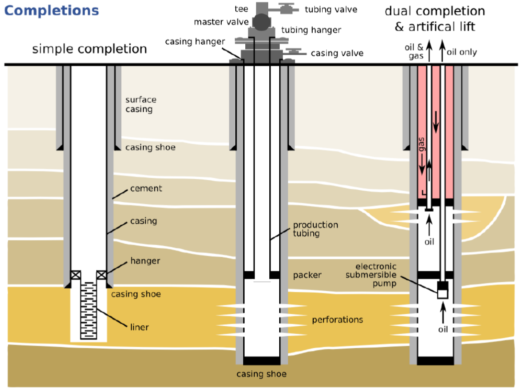
Decline Curve Analysis

$$\text{ODE: } -\frac{1}{q}\frac{dq}{dt} = D_i\left(\frac{q}{q_i}\right)^b;\ q = q_i\ @t = 0;\ \frac{D_i}{q_i^b}\int_{t=0}^{t} dt = -\int_{q_i}^{q}\frac{dq}{q^{b+1}} \qquad N_p = \int_{t=0}^{t} q(t)dt$$

(Arps, 1940)	b-factor	Rate (q)	Cumulative Recovery (N_p)	Decline Rate (D)
Exponential	$b = 0$	$q = q_i e^{-D_i t}$	$N_p = \frac{(q_i - q)}{D_i}$	$D = D_i$
Hyperbolic	$0 < b < 1$	$q = \frac{q_i}{(1 + bD_i t)^{1/b}}$	$N_p = \frac{q_i^b}{D_i(1-b)}\left(q_i^{1-b} - q^{1-b}\right)$	$D = D_i\left(\frac{q}{q_i}\right)^b$
Harmonic	$b = 1$	$q = \frac{q_i}{(1 + D_i t)}$	$N_p = \frac{q_i}{D_i}\ln\left(\frac{q_i}{q}\right)$	$D = D_i\left(\frac{q}{q_i}\right)$



Completions



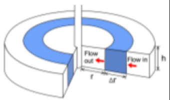
Single Phase Flow

Continuity Equation

Mass balance leads to Continuity Equation

$$\left(\begin{array}{c}\text{Mass of}\\ \text{fluid in}\end{array}\right) - \left(\begin{array}{c}\text{Mass of}\\ \text{fluid out}\end{array}\right) = \left(\begin{array}{c}\text{Fluid}\\ \text{accumulation}\end{array}\right)$$

$$-\nabla(\rho u) = \frac{\partial(\rho\phi)}{\partial t}$$



$$-\frac{\partial(\rho u_x)}{\partial x} = \frac{\partial(\rho\phi)}{\partial t} \qquad -\frac{1}{r}\frac{\partial(\rho r u_r)}{\partial r} = \frac{\partial(\rho\phi)}{\partial t}$$

Darcy's Law

$\Phi = P + \rho g h$	$u = \frac{q}{A}$	$u = -\frac{k}{\mu}\nabla\Phi$	Fluid flows from higher potential to lower potential (not pressure)

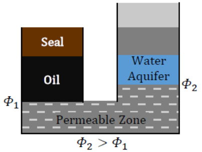
Φ = flow potential $\quad q$ = flow rate$[=]L^3/t$

u = fluid velocity$[=]L/t \quad \mu$ = viscosity

k = permeability$[=]L^2$

A = cross sectional area perpendicular to flow

A porous medium has a permeability of 1 Darcy if a pressure gradient of 1 atm/cm creates a velocity of 1 cm/sec for a 1 cp fluid.

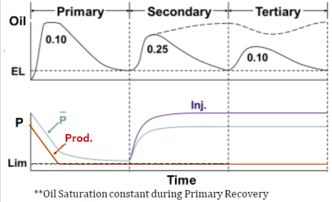


$\Phi_2 > \Phi_1$

Water flows towards oil zone

Improved Oil Recovery

Stages of Recovery



**Oil Saturation constant during Primary Recovery

IOR

Primary Recovery
- Natural Flow
- Artificial Lift
- Hydraulic Fracturing

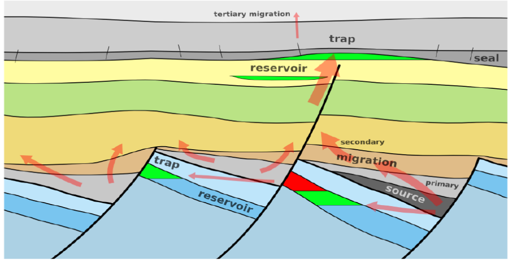
Secondary Recovery
- Waterflooding
- Pressure Maintenance

Tertiary Recovery (EOR)
- Thermal: - Steam, - Hot Water, - Combustion
- Gas Injection: - Carbon Dioxide, - Hydrocarbon, - Nitrogen Flue
- Chemical: - Alkali, - Surfactant, - Polymer
- Other: - Microbial, - Acoustic

IOR: Improved Oil Recovery

Adapted from SPE-SPE-8490B, 87864

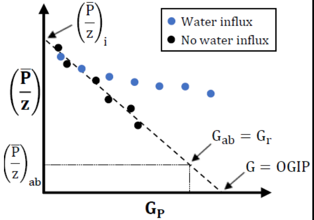
Conventional petroleum system



Predicting Gas Production

- Gas decline curves are harder to predict due to the high expansivity of gas
  - Can lead to an overestimation of total recovery
- Can use a P/z plot as another predictor
  - Developed from the Real Gas Law

P/z Plot – OGIP Estimation



$$\left(\frac{P}{z}\right) = \underbrace{\left(\frac{P}{z}\right)_i}_{\text{intercept}} - \underbrace{\left[\left(\frac{P}{z}\right)_i \frac{1}{G}\right]}_{\text{slope}} G_P \qquad RF = \frac{G_r}{G} \text{ Recovery factor}$$

Flow Assurance

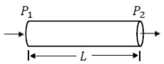
Common Issues

Damage Type	Detection Methods	Prevention Methods	Removal Methods
Calcium Carbonate Scale	Water analysis Physical sample	Scale inhibitor Scale squeeze	HCl acid job
Barium Sulfate Scale	Water analysis Physical sample	Scale inhibitor	Mechanical removal Re-perforation
Sodium Chloride	Water analysis Physical sample	Reduce pressure drop to reduce gas cooling	Fresh H_2O circulation Re-perforation
Emulsions and Sludge	Physical sample Lab analysis	Emulsion breaker	Emulsion breaker Mutual Solvent
Liquid Block Gas Well	Well history Lab analysis	Limit pressure drop at wellbore	Mutual solvents
Asphaltenes	Physical sample Oil analysis	Inhibitors Application of heat	Inhibitors Application of heat
Paraffin	Physical sample Oil analysis	Inhibitors Application of heat	Inhibitors Application of heat
Formation Fines	Physical sample	Limit production rate Gravel/frac pack	Re-perforation Small frac job
Clay Swelling	Lab analysis Production rate drop	Don't introduce incompatible water	Re-perforation Small frac job
Bacteria	Physical sample Lab culture	Don't introduce bacteria laden water	Bactericides

1-Dimensional Flow

Incompressible Fluid – Flowing at Steady State

Horizontal Flow

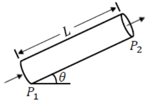


$$u = -\frac{k}{\mu}\frac{dP}{dx}$$

Continuity Equation reduces to $\rho\frac{\partial u}{\partial x} = 0$

$$\boxed{q = -\frac{kA}{\mu}\frac{\Delta P}{L}}$$

Non-Horizontal Flow

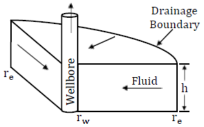


$$\Phi_2 = P_2$$

$$\Phi_1 = P_1 + \rho g(L\sin\theta)$$

$$u = -\frac{k}{\mu}\frac{\partial\Phi}{\partial x} \qquad \boxed{q = -\frac{kA}{\mu}\frac{\Delta\Phi}{L}}$$

Radial Flow



$$u = -\frac{k}{\mu}\frac{dP}{dr} \qquad A = 2\pi r h$$

$$q = -\frac{kA}{\mu}\frac{dP}{dr} = -\frac{2\pi kh(P_e - P_{wf})}{\mu\ln(r_e/r_w)}$$

Inflow Performance Relation (IPR)

Oil Productivity Index

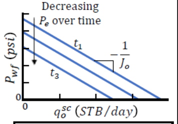
$$J_o = \frac{q_o^{sc}}{P_e - P_{wf}} [=] \frac{STB}{psi \cdot day}$$

Steady-state & radial flow

$$J_o = \frac{0.00708 k_o h}{B_o\mu_o\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2} + s\right]}$$

Only good for single phase flow

Single-Phase Oil IPR



If B_o, μ_o, k_o relatively constant, J_o is a constant

Gas Productivity Index

$$J_g = \frac{q_g^{sc}}{P_e^2 - P_{wf}^2} [=] \frac{Mscf}{psi^2 \cdot day}$$

Apply steady-state & radial flow

$$J_g = \frac{7.0225x10^{-4}(k_g h)}{\bar{\mu}_g \bar{z} T\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2} + s\right]}$$

Gas properties evaluated at $\bar{P}$

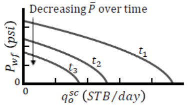
Two-Phase IPR ($P < P_{BP}$)

Empirical correlation (Vogel, 1968)

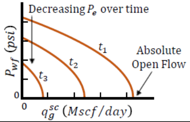
$$\frac{q_o}{q_{o,max}} = 1 - 0.2X - 0.8X^2$$

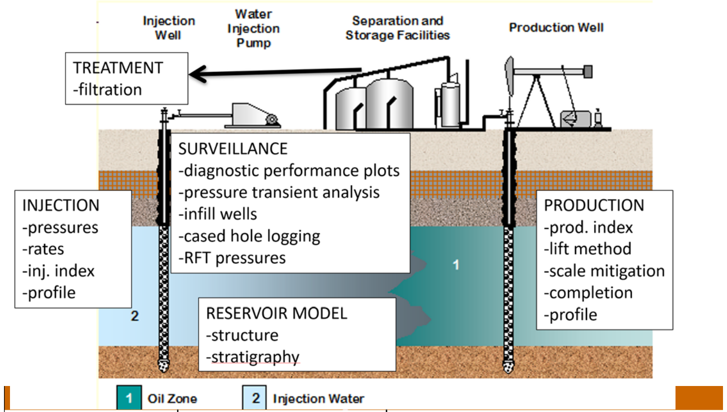
$$X = P_{wf}/\bar{P}$$

Can replace $\bar{P}$ with P_e



Gas IPR Curves





Multiphase Flow – Relative Permeability

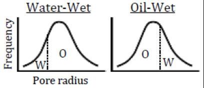
Darcy's Law

$$u_j = -\frac{kk_{rj}}{\mu_j}\left(\frac{dP_j}{dx}\right) \qquad j = \text{phase}$$

$$k_{rj} = \frac{k_j}{k} = \text{relative permeability}$$

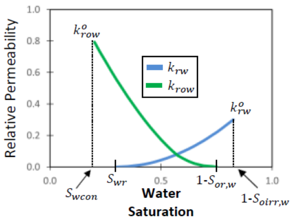
Wettability

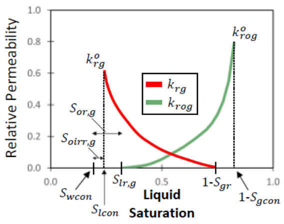
the strongest influence on k_{rj}



Non-wetting phase occupies larger pores so it flows easier

Relative Permeability Curves





Water-Wet Rock: $S_w > 0.5$ when curves intersect and $k_{rw}^o < k_{row}^o$ (inverse for Oil-Wet)

Artificial Lift

Common Issue	Rod Pump	ESP	Gas Lift
Sand	Fair	Fair	Excellent
Paraffin	Poor	Good	Poor
High GOR	Fair	Fair	Excellent
Deviated Hole	Poor	Fair	Good
Corrosion	Good	Fair	Fair
High Volume	Poor	Excellent	Good
Depth	Fair	Fair	Good
Simple Design	Yes	Yes	No
Casing Size	Fair	Good	Good
Flexibility	Fair	Poor	Good
Production Scale	Good	Poor	Fair
Onshore Usage	84%	2%	11%

Gas Lift much higher % offshore

Sedimentary Rock Properties

Class	Formation	Name	Mineralogy	ρ (g/cc)
Clastic	Rock fragments compacted and cemented together	Sandstone	Quartz	2.65
		Shale	Clay minerals	2.2-2.7
Carbonate	Dissolution and precipitation of calcite	Limestone	Calcite	2.71
		Dolomite	Dolomite	2.87
Evaporite	Evaporation of water	Gypsum	Gypsum	2.32
		Anhydrite	Anhydrite	2.98
		Salt	--	1.87-2.03
Organic	Accumulation of organic debris	Coal	--	0.64-0.93
		Peat	--	--
		Diatomite	--	0.224

Mechanism	Average Primary Recovery (% of OOIP)	Potential for Waterflooding
Fluid Expansion	3 to 10%	**Good**. Early start of waterflooding at P>Pbp or risk loss of reserves
Gravity Drainage	5 to 30% Additional	Up-dip gas injection may be a better choice if gravity drainage is the predominate mechanism.
Solution Gas Drive	10 to 15%	**Good**. This is the most commonly waterflooded reservoir.
Gas Cap Expansion	20 to 40%	Poor, if the gas cap is very large. Pressure maintenance by gas cap gas injection may be better. Peripheral waterflooding may be useful if care is taken not to move oil into the gas cap.
Water Drive	35 to 75%	Poor for reservoirs in communication with strong aquifers; however, peripheral injection may be necessary if voidage is greater than water influx.

Basic Definitions

$$\boxed{\text{Hooke's Law} \quad \sigma = -E\varepsilon}$$

$$\sigma = \frac{F}{A} \qquad \varepsilon = \frac{\Delta L}{L}$$

E = Young's Modulus [=] psi

ν = Poisson's Ratio

$$\nu = \frac{\text{transversal expansion}}{\text{axial compression}}$$

Linear Elasticity

Bulk modulus $K = \frac{E}{3(1-2\nu)}$

$$\varepsilon_i = \left(\frac{1+\nu}{E}\right)\sigma_i - \frac{\nu}{E}(\sigma_x + \sigma_y + \sigma_z)$$

$i = x,\ y,$ or z

Shear modulus $G = \frac{E}{2(1+\nu)}$

Subsurface Stresses

σ_v, σ_{Hmax}, σ_{Hmin} are the principal stresses

σ_v = vertical stress $\quad \sigma_v = \rho_b g h \quad \rho_b$ = bulk density

Neglecting tectonic stresses $\quad \boxed{\sigma_x = \sigma_y = \sigma_H = \left(\frac{\nu}{1-\nu}\right)\sigma_v + P_p\left(1 - \frac{\nu}{1-\nu}\right)}$

σ_H = horizontal stress $\quad P_p$ = pore pressure

Tectonic stresses create differences between σ_{Hmin} & σ_{Hmax}

Fracture orientation controlled by direction of σ_{Hmin}

$$A=[f_d(1-f_p)i\rho_w L_v/k_h \Delta T_s]\sqrt{\alpha t/\pi}$$

f_d = downhole steam quality, dimensionless fraction
f_p = fraction of injected heat produced, dimensionless

i = injection rate as volume of water converted to steam, cu ft/D [m^3/d]
k_h = thermal conductivity, Btu/ft-°F-D [J/m·K·d]
L_v = heat of vaporization of water, Btu/lbm [J/kg]

T = temperature, °F [K]

ρ = density, lbm/cu ft [kg/m^3]

M = volumetric heat capacity, Btu/cu ft-°F [J/m^3·K]

α = thermal diffusivity, sq ft/D [m^2/d]

Modified Theis

$$\Delta P = \frac{162.6Q\mu}{Kb}\left[log\frac{Kt}{\phi\mu C_t r^2} - 3.23\right]$$

Bernard Equation

$$P(r,t) = P_i + \frac{5575Q\mu}{KH}\left[\log t + \log\left(\frac{K}{\phi\mu C_t r^2}\right) - 3.23 + 0.87s\right]$$

Marx & Langenheim

$$T_s = 115.1 p_s^{0.225}$$

$$\rho_o = \frac{141.5}{°API + 131.5}62.4$$

$$t_D = \frac{42{,}048 k_h t}{h_t^2 \bar{M}_1}$$

$$h_{fg} = 865 - 0.207 p_s$$

$$h_f = 91 p_s^{0.2574}$$

$$\text{erfc}\sqrt{t_D} = (0.254829592K - 0.284496736K^2 + 1.421413741K^3 - 1.453152027K^4 + 1.061405429K^5)\cdot e^{-t_D}$$

where

$$K = \frac{1}{1+0.3275911\sqrt{t_D}}$$

The area steamed is from Marx and Langenheim :

$$A_s = \frac{\dot{Q}_{inj} h_n}{4k_h(t_s - t_f)1.2\times 43{,}560}\cdot\left(e^{t_D}\text{erfc}\sqrt{t_D} + 2\sqrt{t_D/\pi} - 1\right)$$

where

$$\dot{Q}_{inj} = 14.6 i_s\left[h_f + f_s h_{fg} - C_w(T_f - 32)\right]$$

$$\bar{M}_1 = (1-\phi)\rho_R C_R + \phi f_s(1-S_{or})\rho_s C_s + \phi S_{or}\rho_o C_o + \phi(\sqrt{1-f_s})(1-S_{or})\rho_w C_w$$

where

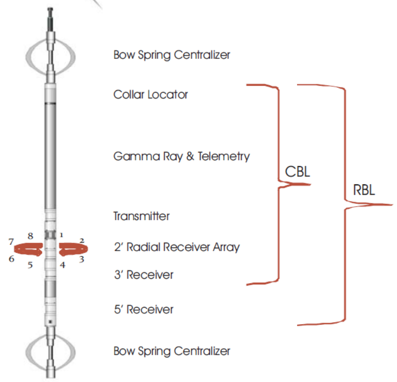
ρ_R = 165 lbm/cu ft,
C_R = 0.20 Btu/lbm-°F,
S_{or} = 0.15,
ρ_w = 62.4 lbm/cu ft,
$C_s \cong C_w$ = 1.0 Btu/lbm-°F,
C_o = 0.45 Btu/lbm-°F, and
$\rho_s \cong$ 0.*

VOIDAGE REPLACEMENT RATIO (VRR) = $\frac{\text{injected reservoir volumes}}{\text{produced reservoir volumes}}$

$$VRR = \frac{B_w(i_w)}{B_o(q_o) + B_w(q_w) + q_o(GOR - R_s)B_g}$$

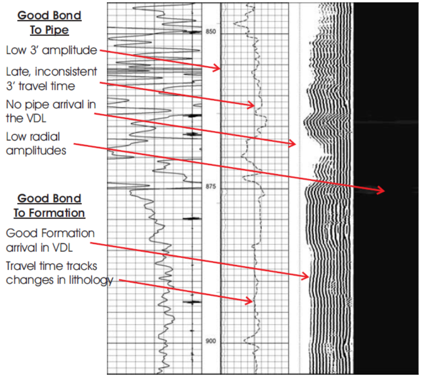
Cement Bond Log Quick Reference

Example Bond Tool



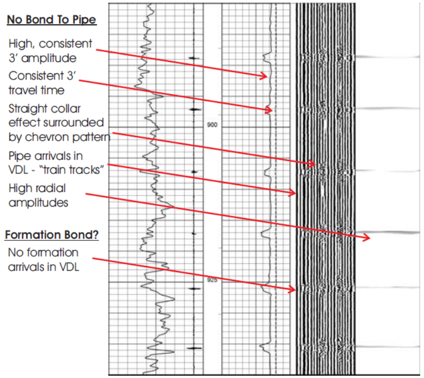
CBL - Cement Bond Log (GR-CCL, 3' & 5' receivers)
RBL - Radial Bond Log (CBL + Array of 8 Radials)

Good Bond To Pipe & Formation



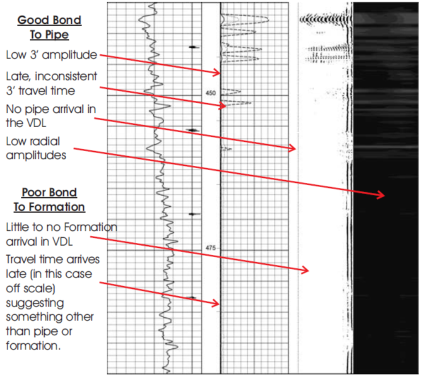
Good Bond To Pipe & Formation - Good bond to pipe is characterized by a low 3' amplitude, transit times of something other than pipe arrivals (which are consistent), lack of pipe arrival in the VDL and low 2' radial amplitudes (if RBL). Good bond to formation can be assumed if the VDL exhibits strong formation arrival suggesting good acoustic coupling between cement and the surrounding formation. Travel time will also track lithology.

Free Pipe



Free Pipe - No bond to pipe (free pipe) is characterized by a high, consistent 3' amplitude, consistent 3' travel time, high radial amplitudes, strong pipe arrivals (train tracks) and chevron patterns in VDL. No formation arrivals are present in the VDL as no cement is present to carry acoustic signal to formation and back to the receivers.

Good Bond to Pipe & Poor Bond to Formation



Good Bond To Pipe & Poor Bond To Formation - Good bond to pipe is characterized by a low 3' amplitude, transit times of something other than pipe arrivals (which are consistent), lack of pipe arrival in the VDL and low 2' radial amplitudes (if RBL). Poor bond to formation may be assumed if the VDL does not exhibit strong formation arrivals (may not be present at all). Must be aware if VDL is from 3' or 5' as mud may be confuses with formation.

Liquid	API
Extra Heavy Oil	8-10
Water	10
Heavy Oil	11-20
Medium Oil	21-29
Light Oil	30-39
Condensate	≥40

Gas	SG
Methane	0.5
Air	1.0
Ethane	1.0
Ethylene	1.0
Propane	1.5
Butane	2.0
Pentane	2.5
Gasoline Vapor	3.5