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INTERPRETATION OF REDONDO CREEK FIELD PRESSURE BUILDUP TESTS

James B. Fallon

Union Oil Company of California
Santa Rosa, CA

Abstract

Recent pressure buildup analyses of Redondo Creek Field wells have been facilitated by identification of wellbore storage. The wellbore storage coefficient observed immediately after shut-in is controlled by the compressibility of the two-phase wellbore fluid, but the coefficient decreases when the wellbore storage is controlled by a rising liquid level. Identification of such phenomena aids in defining the correct radial flow regime of the pressure buildup response.

Introduction

The Redondo Creek Field is located within the Jemez Mountains in North Central New Mexico. The geothermal reservoir has been documented as containing a high temperature, low salinity water which is overlaid in a limited portion of the field by a steam-dominated zone (Union, 1978, and Atkinson, 1980). Union Oil Company of California has drilled nineteen wells in the field, four of which currently produce a two-phase mixture at commercial wellhead pressures; several others will produce at subcommercial wellhead pressures.

Figure 1 presents a wellbore schematic and pressure profile of a typical Redondo Creek well during production, shut-in, and transitional conditions. The flowing two-phase wellbore conditions change following shut-in to segregated liquid and vapor columns. These wellbore fluid behaviors have been associated with the wellbore storage regimes which dominate the early-time pressure response of all Redondo Creek pressure buildup tests. The initial wellbore storage coefficient is controlled by the compressibility of the initially two-phase wellbore fluid. Appendix A derives an approximate expression for the compressibility of a typical Redondo Creek two-phase wellbore fluid. This expression is dependent upon the volumetric heat content of the wellbore which in turn is dependent upon the volumetric steam fraction of the wellbore fluid and the assumed contributing heat content of the casing. A high volumetric heat content - large water fraction - results in a higher two-phase compressibility due to the increased energy available for phase change and hence a larger change in volume. The two-phase compressibility is up to an order of magnitude larger than the compressibility of steam.

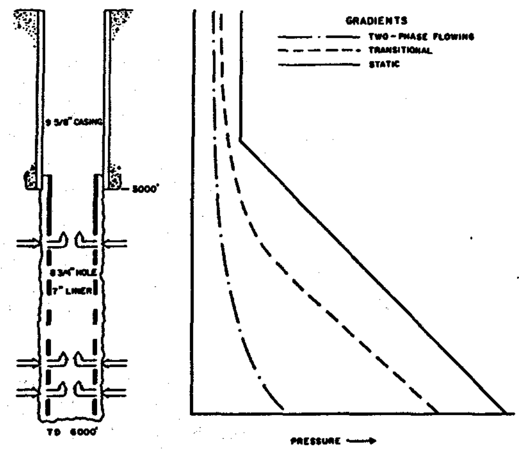

Figure 1 - Typical Redondo Creek Well; Casing Schematic and Pressure Profile During Production Shut-In and Transition.

Appendix B derives an expression for the total wellbore storage coefficient of a well which intersects a producing two-phase reservoir. Equation B-4 contains two factors which contribute to the total storage: a rising liquid level and wellbore fluid compressibility. The rising liquid level does not influence the observed wellbore storage until the wellbore liquid level rises above the pressure monitoring depth, at which time the magnitude of the wellbore storage factor will normally decrease. The duration of the compressibility storage will therefore be dependent upon the pressure monitoring depth and the steam quality of the fluid produced into the wellbore.

Identification of the different wellbore storage regimes has facilitated analysis of Redondo Creek buildup tests. Values of observed wellbore storage coefficients have been obtained from the unit slope of the log-log plot (Earlougher, 1977) where:

$$C = \frac{Wv\,\Delta t}{\Delta P}\ ft^3/psi \qquad (1)$$

W_v = volumetric production rate, $W_L v_L + W_g v_g$

Δt, ΔP = point on unit slope line

Comparison of the constant obtained from Equation 1 with the constant calculated from Equation B-4 has been used to classify wellbore storage regimes, identify wells which have intersected fractures, and obtain a qualitative estimate of the volumetric steam fraction produced from different zones in a well. While the intersection of fractures can be determined from the comparison, quantitative data concerning effective fracture volumes cannot be obtained because of the accompanying increase in two-phase compressibility due to increased effective heat content of the wellbore-fracture system.

Determination of the end of significant wellbore storage effects has helped to isolate reservoir characteristics. Once the wellbore storage effects have diminished, some Redondo Creek wells exhibit radial flow pressure fluctuations - an instability probably related to the reservoir equilibration of phases following a period of two-phase production. Whatever the physical mechanism, the instability appears to be aggravated by the withdrawal and reentry of wireline tools in and out of the wellbore.

The recent buildup tests conducted on four Redondo Creek wells will be used to illustrate this analytical tool. The Horner Analyses have assumed that all wells observed to have less than 30% wellhead mass steam fraction are dominated by a single-phase reservoir response. Wells with between 30% and 70% mass steam fraction have been considered as two-phase and analyzed in the manner proposed by Garg and Pritchett (1981). Analysis of wells with higher then 70% mass steam have combined this two-phase analysis with the ΔP^2 method commonly applied to a high compressibility, low pressure system.

Baca No. 15

Baca No. 15 produces from an upper steam-dominated zone and a lower liquid zone, with the well's high steam production originating almost entirely in the upper zone. The pressure response following the shut-in of Flow Test 3 (Figure 2) shows an initial wellbore storage dominated by the compressibility storage of the two-phase wellbore fluid. The contrast of the observed wellbore storage constant calculated from Equation 1 (167 ft^3/psi) with the calculated wellbore storage coefficient based upon the wellbore volume (28 ft^3/psi) suggests that the well intersects a large fracture network.

The abrupt decrease in wellbore storage observed in Figure 2 is a reflection of the wellbore liquid level reaching the pressure monitoring depth. The wellbore storage coefficient associated with the now dominant rising

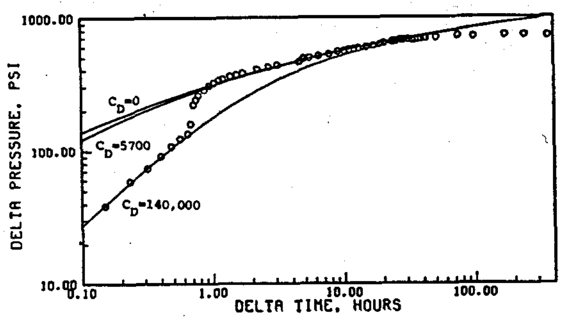

Figure 2 - Baca No. 15 Pressure Buildup Following Flow Test 3. P_{wf}=516 psig; s=-5.4; C_D=0, 5700, 140000.

liquid level is almost 25 times smaller than the earlier compressible storage coefficient.

Horner Analysis of the correct semilog straight line - reached almost immediately upon changing of dominant wellbore storage - results in an apparent kh of 3900 md-ft and a skin of -5.4 using a two-phase analysis (Figure 3). These values are consistent with the falloff testing results and the negative skin factor supports the wellbore storage indications of an intersected fracture network. The pressure stabilization at large shut-in times (Figures 2 and 3), characteristic of a constant pressure boundary, is attributed to the effect of the steam-dominating upper zone on the monitoring depth.

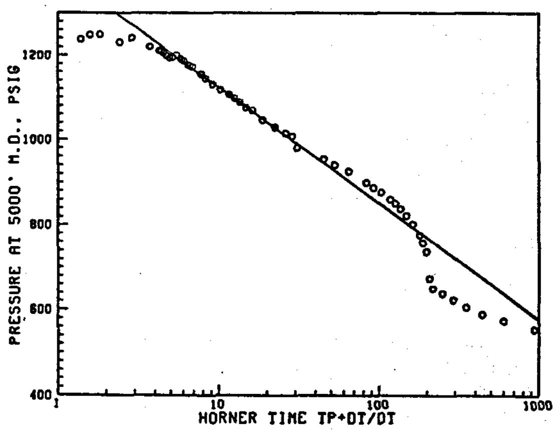

Figure 3 - Baca No. 15 Pressure Buildup Following Flow Test 3. t_p=140 hrs; m=275 psi/cycle; $P_{1\ HR}$=810 psig.

Baca No. 4

Baca No. 4 produces a limited amount of fluid from an upper steam-dominated zone, with the major production originating in a deeper zone producing a low steam-fraction fluid. The pressure responses following Flow Tests 4 and 5 are almost identical when displayed on a log-log plot (Figure 4). The early-time observed wellbore storage coefficient (28 ft^3/psi) compares favorably with the value calculated from Equation B-4 (25 ft^3/psi). This

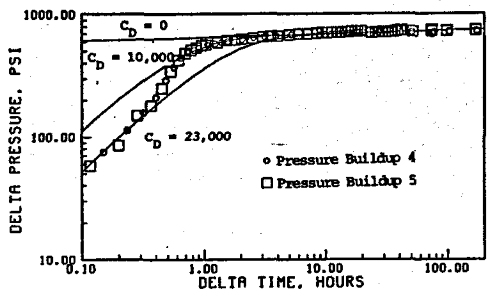

Figure 4 - Baca No. 4 Pressure Buildups Following Flow Tests 4 and 5. P_{wf}=500 and 470 psig; s=+10; C_D=0, 10000, 23000.

suggests that Baca No. 4 does not intersect significant reservoir fractures.

The decrease in wellbore storage coefficient observed in Figure 4 is not as abrupt as seen in Figure 2. The deep two-phase production of Baca No. 4 does not create as perfect a liquid interface as would be obtained from a well which produces nearly single-phase bottom zone fluid (Baca No. 15). The relatively small decrease in wellbore storage coefficient (2.3X) is due to the small effective wellbore volume contributing to the compressible storage and the small water fraction of the produced fluid.

Horner Analysis of the buildup data was complicated by reservoir pressure fluctuations (Figure 5). A single-phase analysis of the average pressure trend - designated by the straight line on Figure 5 - results in an apparent kh of 5200 md-ft and a skin of +10. These values are consistent with another Baca No. 4 pressure buildup analysis (Riney and Garg, 1981). The high skin factor is probably due to the reservoir flashing of fluid during production. The lack of fracture flow indications are consistent with the wellbore storage observations.

Baca No. 13

Baca No. 13 produces a moderate enthalpy fluid

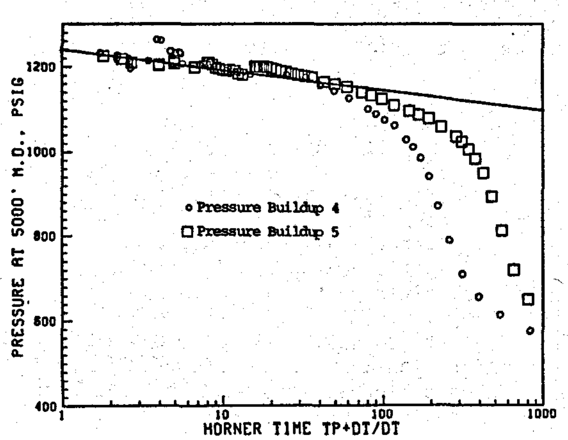

Figure 5 - Baca No. 4 Pressure Buildups Following Flow Tests 4 and 5. t_p=125 and 295 hrs; m=45 psi/cycle; $P_{1\ HR}$=1145 psig.

from at least two highly permeable zones in the deeper liquid reservoir. The well is completed with 9-5/8" casing from the surface to 3499' M.D. and a 7" liner hung from 3340' M.D. to 8200' M.D., the first 889 feet of which is blank with the remainder slotted. The pressure response following Flow Tests 7, 8 and 9 all had consistent, but unique, behaviors (Figure 6).

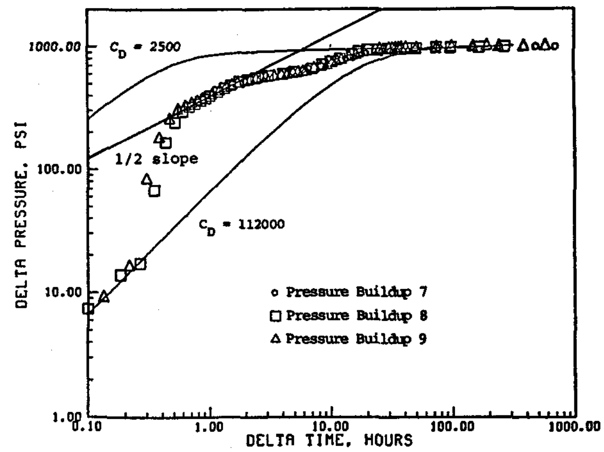

Figure 6 - Baca No. 13 Pressure Buildups Following Flow Tests 7, 8 and 9. P_{wf}=465 psig; s=+17; C_D=2500, 112000.

The initial pressure response is dominated by the compressibility of the two-phase wellbore fluid. The observed wellbore storage coefficient (135 ft^3/psi) differs from the theoretical value based upon the wellbore volume (48 ft^3/psi), suggesting the intersection of fractures. This is confirmed soon after the rising liquid level becomes the dominant wellbore storage factor. The associated decrease in wellbore storage coefficient creates the abrupt pressure rise observed in other wells, but before reaching the next wellbore storage regime or the semilog straight line (as observed in Baca Nos. 4 and 15) fracture flow begins to dominate the pressure response. This linear flow regime dominated the entire falloff pressure response following the Baca No. 13 injection test. The fracture must be located above the pressure monitoring depth and from temperature surveys has been tentatively identified near 4500' M.D..

The linear flow pressure response is interrupted by another wellbore storage phenomenon. When the wellbore liquid level reaches the 7" liner hanger, the water begins to spill over into the annulus of the blank liner section between the 7" liner and the 8-3/4" wellbore wall. Upon fill-up of this annulus the pressure response continues the transition to the semilog straight line, but not until the first 20 hours of the pressure buildup were dominated by either wellbore storage or fracture flow. Without identification of these wellbore storage regimes, the pressure buildup would have been interpreted as characteristic of a two-layer reservoir (Matthews and Russell, 1967).

The radial flow regimes of the three buildup tests are affected by the reservoir pressure fluctuations also observed in Baca No. 4. The Horner Analysis of the average pressure trend - designated by the straight line on Figure 7 - results in an apparent kh of 6400 md-ft and a skin of +17. The high skin factor is not consistent with the observed fracture phenomenon but is attributed to the extensive reservoir flashing of Baca No. 13.

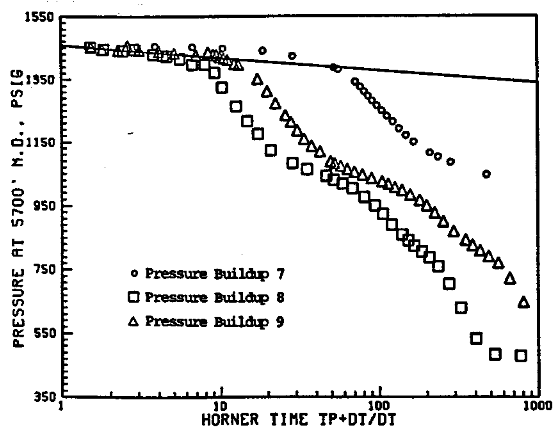

Figure 7 - Baca No. 13 Pressure Buildups Following Flow Tests 7, 8 and 9. t_p=1340, 130 and 309 hrs; m=43 psi/cycle; $P_{1\,HR}$=1352 psig.

Baca No. 21

Baca No. 21 is a shallow well (3000' M.D.) which produces a 95% steam fraction fluid. The anamolous pressure buildup behavior monitored following Flow Test 5 is a reflection of the anamolous behavior of the well in general. A static pressure gradient in Baca No. 21 reveals a high steam-fraction gradient without a liquid level, while a flowing gradient displays a liquid column below 2750'. Upon shut-in, the pressure response at 2750' is intially controlled by the wellbore storage of a rising liquid level as indicated in the close agreement between the observed storage coefficient (400 ft^3/psi) and the calculated storage coefficient (380 ft^3/psi). Depression of the liquid level to below the 2750' monitoring depth creates an increase in the effective wellbore storage coefficient. This depression is probably caused by several factors such as little water production combined with a quicker reservoir pressure recovery in the zone above 2750' than the zone below 2750'.

The magnitude of the second observed wellbore storage regime coefficient (2240 ft^3/psi) differs from the theoretical wellbore storage coefficient (50 ft^3/psi) based upon the wellbore volume suggesting that the wellbore has intersected a large fracture network. This appears to be confirmed by the excellent match of the log-log plot to the type-curve for a vertically fractured well with wellbore storage (Ramey, et al., 1975).

This match, shown on Figure 10, is clouded somewhat by reservoir pressure fluctuations and the failure of reaching the true radial flow regime. Analysis of the log-log type curve match indicates that Baca No. 21 has an apparent permeability of 2800 md-ft with an undetermined but negative skin factor.

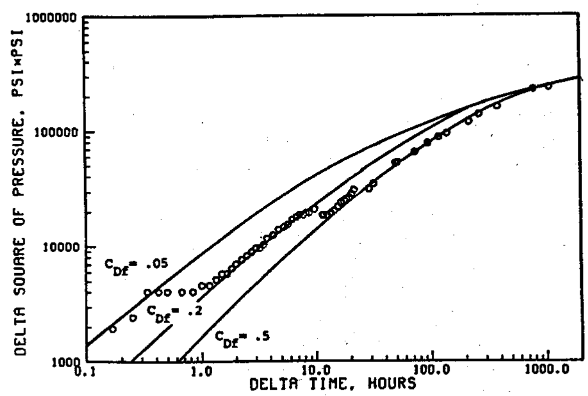

Figure 8 - Baca No. 21 Pressure Buildup Following Flow Test 5. Match With Type Curve for a Vertically-Fractured Well with Wellbore Storage (Finite-Difference Solution). C_{DF}=.05, .02, .5.

Summary

The results of the four pressure buildups discussed plus four other pressure buildup analyses are presented in Table 1. Derivation of an expression for the two-phase compressibility of a Redondo Creek wellbore fluid has been used in the calculation of the theoretical total wellbore storage coefficient. Comparison of this value with the observed wellbore storage coefficient has resulted in qualitative information which has been consistent with the results obtained from alternate methods of analysis. The correctly identified semilog straight lines have been analyzed and sometimes reveal significant reservoir pressure fluctuations which are probably associated with the equilibration of phases in the reservoir following a period of two-phase production.

Nomenclature

A	= cross sectional area of the wellbore, ft^2
C	= wellbore storage coefficient, ft^3/psi
C_c	= specific heat of casing, Btu/lb°F
C_g	= specific heat of steam, Btu/lb°F
C_h	= specific heat of reservoir, Btu/lb°F
C_L	= specific heat of liquid, Btu/lb°F
g	≅ gravitational constant, 32.2 ft/sec^2
g_c	= units conversion, 32.2 lb-ft/lbf-sec^2
P	= pressure, psia
V	= volume, ft^3
V_f	= wellbore fractional volume of fluid
V_g	= volume of steam in the wellbore, ft^3
V_L	= volume of liquid in the wellbore, ft^3

TABLE 1
SUMMARY OF REDONDO CREEK BUILDUP ANALYSES

WELL	TOTAL MASS FLOW RATE lb/hr	PRODUCED STEAM QUALITY OBSERVED WELLHEAD	PRODUCED STEAM QUALITY ASSUMED BOTTOMHOLE	WELLBORE STORAGE COEFFICIENT OBSERVED	WELLBORE STORAGE COEFFICIENT CALCULATED	kh md-ft	SKIN
Baca No. 4	161,100	30%	10%	28	25	5200	+10
Baca No. 13	187,200	25%	5%	135	48	6400	+17
Baca No. 15	282,700	34%	14%	167	28	3900	-5.4
Baca No. 19	158,600	20%	0%	1.2	1.1	3500	+1.4
Baca No. 20	56,100[1]	55.6%	35.6%	170	50	1850	-3.1
	46,700[2]	80%	60%	28	30	540	-6.7
Baca No. 21	35,300[3]	95%	85%	400	380	2800	—
	35,300[4]	95%	85%	2240	50		
Baca No. 24	281,300	20%	0%	7.4	2.6	9500	+2.4

1 - Before Stimulation
2 - After Stimulation
3 - First Storage Regime
4 - Second Storage Regime

$V_{2\phi}$ = volume of two-phase mixture in the wellbore, ft^3
β_t = total compressibility, psi^{-1}
β_g = compressibility of steam, psi^{-1}
β_L = compressibility of liquid, psi^{-1}
$\beta_{2\phi}$ = compressibility of two-phase flow, psi^{-1}
ρ = density, lb/ft^3
ρ_c = density of casing, lb/ft^3
ρ_g = density of steam, lb/ft^3
ρ_L = density of liquid, lb/ft^3

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Appendix A

Grant and Sorey (1979) obtained a simple formula for the total compressibility of two-phase reservoir which closely approximated the full expression. Expressed in simple engineering units, this formula is:

$$\phi\beta_t = (\rho C_h)(7.52)P^{-1.66},\ psi^{-1} \qquad \text{(A-1)}$$

The volumetric heat capacity of the reservoir, ρC_h, was a function of the rock heat capacity and the water heat capacity. If we consider a wellbore volume which contains volumes $V_f S_g$ of steam, $V_f(1-S_g)$ of water and $1 - V_f$ of casing, the heat capacity and the compressibility of the steam becomes significant. Equation A-1 can then be written as:

$$V_f\beta_t = \left(V_f S_g \rho_g C_g + V_f(1-S_g)\rho_L C_L + (1-V_f)\rho_c C_c\right)(7.52)P^{-1.66} + S_g\beta_g \qquad \text{(A-2)}$$

The contributing volumetric heat capacity of the casing for a typical Redondo Creek wellbore volume is assumed to only be dependent upon the innermost casing string depicted in Figure 1. With this assumption the average casing heat content contribution to the wellbore volume is:

$$\left(\frac{1-V_f}{V_f}\right) \rho_c C_c \cong 8.5 \text{ Btu/ft}^{3\circ}\text{F}$$

$$\beta_t = (S_g \rho_g C_g + (1-S_g)\rho_L C_L + 8.5)(7.52)P^{-1.66} + S_g \beta_g \quad \text{(A-3)}$$

Figure A1 displays the total wellbore compressibility factors obtained from Equation A-3 of a two-phase wellbore fluid as a function of pressure and volumetric fraction of steam. The discrepancy between the steam curve and the $S_g \cong 1.0$ curve is a reflection of the nonadiabatic conditions of the wellbore and the effect of an infitessimal amount of liquid present in the $S_g \cong 1.0$ condition. It is interesting to note that the compressibility increases with increasing liquid saturation in the wellbore. This is due to the increased heat content of the wellbore. An identical pressure change (and temperature change) will have a larger energy change and hence a larger mass will change phases in a high heat content system. The large associated volumetric change is the reason that a two-phase reservoir (high heat content) has a higher compressibility than a two-phase wellbore.

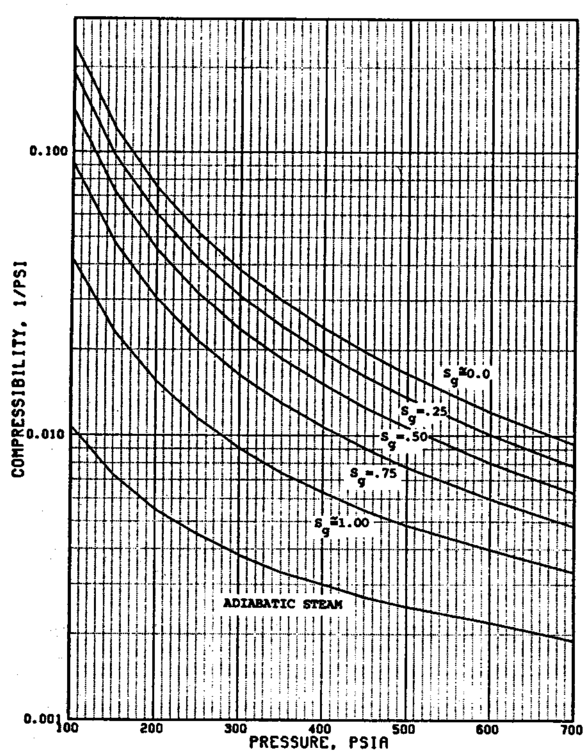

Figure A1 - Compressibility of a Two-Phase Wellbore Fluid; as a Function of Pressure and the Volumetric Fraction of Steam.

Appendix B

The wellbore storage (after-production) of a well is controlled by two effects: 1) the storage that results from the vertical movement of a gas-liquid interface and 2) the storage which results from the compression or expansion of the wellbore fluids (Earlougher, 1977). The wellbore storage coefficient is algebraically defined as:

$$C = \left(\frac{\Delta V}{\Delta P}\right)_{\text{Datum}} \quad \text{(B-1)}$$

Consider first the change in datum pressure due to water movement across the datum, ΔV_L. This volume will create a change in liquid interface elevation, $\Delta V_L/A$, which due to the hydrostatic gradient differences increases the datum pressure by:

$$\Delta P_1 = \frac{\Delta V_L}{A} \frac{(\rho_L - \rho_g)}{144} \frac{g}{gc} \quad \text{(B-2)}$$

Next consider the pressure change due to the compressibility of the wellbore fluids. The effective wellbore volume change created by the total production of fluids, ΔV, compresses the wellbore fluids. The total compressibility of each phase times that phase's wellbore volume results in:

$$\Delta P_2 = \frac{\Delta V}{V_g \beta_g + V_L \beta_L + V_{2\phi} \beta_{2\phi}} \quad \text{(B-3)}$$

The total wellbore storage will be dependent upon the total pressure change, $\Delta P_1 + \Delta P_2$.

$$C = \frac{\Delta V}{\Delta P_1 + \Delta P_2}_{\text{Datum}} =$$

$$\frac{\Delta V}{\frac{\Delta V_L}{A} \frac{(\rho_L - \rho_g)}{144} \frac{g}{g_c} + \frac{\Delta V}{V_g \beta_g + V_L \beta_L + V_{2\phi} \beta_{2\phi}}}$$

or

$$C = \frac{1}{\frac{\Delta V_L}{\Delta V} \frac{(\rho_L - \rho_g)}{144\ A} \frac{g}{gc} + \frac{1}{V_g \beta_g + V_L \beta_L + V_{2\phi} \beta_{2\phi}}} \quad \text{(B-4)}$$

Equation B-4 simplifies to the equations presented by Earlougher (1977) for a well with single-phase (liquid) production. If there is a water-gas interface:

$$C = \frac{A}{\frac{(\rho_L - \rho_g)}{144} \frac{g}{gc}} \text{ if } \frac{\rho_L - \rho_g}{144\ A} \gg \frac{1}{V_g \beta_g + V_L \beta_L + V_{2\phi} \beta_{2\phi}}$$

and for a wellbore completely filled with a single-phase fluid:

$$C = V \beta$$