

MULTIPHASE, MULTICOMPONENT COMPRESSIBILITY IN GEOTHERMAL RESERVOIR ENGINEERING

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ABSTRACT

Coefficients of compressibilities below the bubble point were computed with a thermodynamic model for single and multicomponent systems. Results showed coefficients of compressibility below the bubble point larger than the gas coefficient of compressibility at the same conditions. Two-phase compressibilities computed in the conventional way are underestimated and may lead to errors in reserve estimation and well test analysis.

INTRODUCTION

The expansion properties of a two-phase liquid-vapor system are different from the corresponding properties of the individual phases. It is a common error to assume that the expansion properties of a two-phase system are a volumetric average of the liquid and gas properties. Martin derived an expression relating three phase flow (oil, gas, and water) to an equivalent single phase flow. This expression defined a Total System Compressibility that was a volumetric average of individual phase compressibilities and considered solution of gas in liquids. This expression is widely used in well test analysis and reservoir simulation. Although this approach appears reasonable for the segregated flow of the three phases, the true thermodynamic path for many expansion processes requires different averaging conditions.

Work by Grant and Sorey³ indicated that apparent system compressibility for two-phase systems in a porous medium could be much larger than gas compressibility for geothermal systems.

Thus the objective of this paper was to study two-phase compressibilities for single and multicomponent systems. In order to perform the study, the change in volume for the total mixture with respect to pressure was computed with a thermodynamic model for a flash system. The thermodynamic model included of a mass and energy balance, with appropriate thermodynamic relationships for enthalpy and equilibrium ratios utilizing the virial equation of state.

The total system effective compressibility for multiphase systems for different production modes was also computed in this study. The production modes included either gas production, or production according to relative permeability-saturation relationships.

Results from these calculations provide information on the multiphase coefficient of compressibility and the total system effective compressibility useful for the interpretation of well test analysis and other reservoir calculations. Theory and pertinent literature concerning the coefficient of compressibility and total system compressibility will be considered in the next section.

THEORY AND DEFINITIONS

The common kinds of compressibilities considered are: coefficient of isothermal compressibility, coefficient of adiabatic compressibility, total system compressibility, and two-phase apparent compressibility. A brief description of each follows.

Coefficient of Isothermal Compressibility

The isothermal compressibility is a point function, and can be calculated from the slope of an isotherm of a pressure versus specific volume curve, or from differentiation of an equation of state, and is defined as:

$$c = -(1/V)(dV/dp)_T \quad \dots \dots \dots \quad (1)$$

For the coexisting two-phase compressibility (gas and liquid), it can be shown from a p-V diagram, Fig. 1, that the inverse of the slope of an isotherm for the two-phase region will be larger than the corresponding reciprocal slope of either the gas or the liquid regions. We now turn to consideration of adiabatic compressibility.

Adiabatic Compressibility

Measuring the change in temperature and volume for a given small pressure change in a reversible adiabatic process provides enough information to calculate the adiabatic

compressibility, which is given by:

Keiffer⁵ in a study of the velocity of sound in liquid-gas mixtures, calculated sonic velocities for water-air and water-steam mixtures that were smaller than the sonic velocity of the gas phase. Sonic velocity can be related to adiabatic compressibility by the expression:

From Eq. 3, it is apparent that a small sonic velocity u_s corresponds to a large compressibility. The existence of gas or vapor bubbles in a liquid reduces the speed of sound in the liquid. This phenomenon was explained by suggesting that a two-phase system has the effective density of the liquid but the compressibility of a gas. This phenomenon is considered to be of importance in systems with the presence of bubbles from a process like gas leaving solution. It was suggested that sonic velocity measurements can be used to measure compressibility of a gas-liquid mixture.

Total System Compressibility

Perrine⁶ presented an empirical extension of single-phase pressure build-up methods to multiphase flow situations. He suggested that improper use of single-phase buildup analysis for multiphase flow could lead to errors in the estimation of static formation pressure, permeability and well condition. A theoretical foundation for Perrine's suggestion was established by Martin.² It was found that under certain conditions of small saturation and pressure gradients, the equations for multiphase fluid flow may be combined into an equation for effective single-phase flow. After some mathematical manipulations, Martin² developed to the following definition of total system isothermal compressibility:

$$C_t = S_o [-(1/B_o)(\partial B_o / \partial p) + (B_g/B_o)(\partial R_s / \partial p)] + S_w [-(1/B_w)(\partial B_w / \partial p) + (B_g/B_w)(\partial R_{sw} / \partial p)] + S_g [-(1/B_g)(\partial B_g / \partial p)] \dots \dots \dots (4)$$

Perrine⁶, Martin², and later Ramey⁷, showed that for multiphase buildup analysis, the parameter corresponding to isothermal compressibility in the dimensionless time group should refer to the total system compressibility of oil, gas, water, and reservoir rock, including changes of solubility of gas in liquid phases.

Two-Phase Apparent Compressibility

Grant and Sorey³ considered the fluid volume

change and heat evolved from rock in a phase change process with gas production to give an approximation of the adiabatic two-phase apparent compressibility. An example presented by Grant and Sorey³ showed a two-phase apparent compressibility that was 30 times larger than the gas compressibility at the same conditions.

From the proceeding, it appears that many fluid thermodynamic factors affect multiphase system compressibility. In view of the importance of this factor in petroleum reservoir engineering, the main objective of this study was to consider methods for an investigation of multiphase compressibility. We now consider the method used in this study.

METHOD OF SOLUTION

The method of solution to determine the coefficient of compressibility and the total system compressibility for a two-phase, single or multicomponent system will be discussed in the following section.

Coefficient of Compressibility

Compressibility computations were considered for either a single-component or multicomponent system with specified conditions of temperature, pressure, composition, and fractional vaporization for a flashing process allowing an increase in volume with a fixed decrease in pressure. To obtain the change in total volume with respect to pressure for single and multicomponent systems, the following procedure was used:

$$c = (1/V_{\text{mix}})(\Delta V_{\text{mix}}/\Delta p)_T \text{ or } H \quad \dots \dots \dots (5)$$

where:

$$V_{mix} = V_1 + x(V_g - V_1) \quad \dots \dots \dots (6)$$

Vapor-Liquid Equilibrium calculations for a given system of n components at a specified pressure, composition and temperature were performed with a thermodynamic flash model⁸ utilizing the virial equation of state, which is appropriate for polar compounds at pressures below 1440 psi (9927.36 kPa).⁹ Further details are given by Macias-Chapa.⁹

Total System Apparent Compressibility

In order to calculate the total system apparent compressibility in a similar fashion to that calculated by Grant and Sgrey³, the thermodynamic model was modified to perform a constant volume flash, after a small pressure drop within a given rock-fluid system. Below, or at the bubble point, there is a phase change in the system, allowing production from a fixed volume reservoir. The thermodynamic model was modified to include a porous medium contribution to the enthalpy balance. Two modes of production were allowed: gas production only and pro-

duction of both liquid and gas according to relative permeability-saturation relationship. The total system apparent compressibility is:

$$c_a = (1/V_{pore})(\Delta V_{prod.}/\Delta p) \quad \dots \dots \dots \quad (7)$$

where $\Delta V_{prod.}$ corresponds to the initial fluid volume after the flash minus the fluid volume remaining after production. The V_{pore} term represents the fixed pore volume. Figures 2 and 3 given a schematic representation of the two production modes considered in this study.

RESULTS

Results are presented for each system studied. First, the coefficient of compressibility is considered, then the production controlled systems.

Coefficients of compressibility below the bubble point were calculated for fluid systems ranging from geothermal fluids to hydrocarbon systems. The systems include pure water, water-carbon dioxide, several multicomponent hydrocarbon systems, and hydrocarbon-water systems. The systems containing pure water and water-carbon dioxide were treated as adiabatic. The hydrocarbon and the hydrocarbon-water systems were considered to be isothermal. Discussion of isothermal systems are given in Refs. 9 and 10.

H_2O and H_2O-CO_2 systems-Fig. 4 shows the adiabatic coefficient of compressibility of water-steam at an initial pressure of 1440 psi (9927.36 kPa) together with the coefficient of compressibility of steam at the same conditions computed with the virial equation of state. The adiabatic coefficient of compressibility for the two-phases is larger than the coefficient of compressibility for the steam at the same conditions, even for small steam qualities. Similar behavior was observed for runs made at initial saturation pressures of 576 psi (3970.94 kPa) and 133.92 psi (923.24 kPa), Fig. 5 and 6. These results are in agreement with thermodynamic theory (p-V diagram) and with studies^{1,5} of sonic velocities in liquid-gas mixtures. An explanation of this phenomenon¹ is that a liquid-gas system has nearly the density of the liquid but the compressibility of the gas, specially when the gas quantity is small. The effect of quality is more noticeable at low pressures.

In order to study a simple two-component system, carbon dioxide was added to water in the liquid phase. Contamination of a single component system causes a reduction in the coefficient of two-phase compressibility. Results for the adiabatic coefficients of compressibility for the H_2O-CO_2 systems showed the same general behavior as the H_2O system: The two-phase adiabatic coefficient

of compressibility was larger than the gas (H_2O-CO_2) coefficient of compressibility. A comparison of one-component, two-phase compressibility and two-component, two-phase compressibility with gas compressibility, Fig. 7, shows that the two-phase compressibility of a single-component system is larger than the two-phase compressibility of a two-component system, and also larger than the gas compressibility for the same conditions.

Total System Apparent Compressibility was computed for a pure water system at different saturation pressures and rock porosities in an adiabatic process for two modes of production: gas production (steam), and production from a geothermal system wherein both water and steam are produced as multiphase flow relative permeability relationships would dictate. Both modes of production are discussed in the following.

Gas Production

After a pressure drop, some of the initial liquid vaporizes. The amount of gas remaining in the system fills the volume that was occupied by the vaporized liquid. The rest of the gas is produced. Single-component water systems at different initial pressures were studied. These systems include a rock component evident through the enthalpy balance. Figure 8 presents results for a system of saturated water at an initial pressure of 576 psi (3970.94 kPa) in a 10% porosity rock.

The computed apparent compressibility is shown versus pressure. As the system depleted, the apparent compressibility increased. The values of apparent compressibility obtained in this process agreed with the values obtained by Grant and Sorey.³ The two-phase apparent compressibility was magnitudes larger than the gas (steam) compressibility at the same conditions.

Multiphase Production

For this production mode, liquid and gas were produced in proportion to relative permeabilities as determined from an average saturation. Figure 9 represents a system of saturated water at an initial pressure of 576 psi (3970.94 kPa) in a 25% porosity rock. Apparent compressibility is initially large because of a change in mass due to liquid production and liquid changing to gas. Apparent compressibility then decreases because gas saturation increases sufficiently to allow gas to be produced. Apparent compressibility was much larger than the gas (steam) compressibility at the same conditions throughout the two-phase reservoir condition. From the results shown in Figs. 8 and 9 for different modes of production, it can be seen that the apparent compressibility depends strongly on the manner in which a reservoir is produced.

CONCLUSIONS

A thermodynamic model has been used to compute coefficients of compressibility and apparent compressibility for both isothermal and adiabatic conditions. For the cases studied, it was observed that the compressibility of a two-phase system was always larger than the compressibility of the corresponding gaseous phase at the same conditions. The model used can yield information about coefficients of compressibility and apparent compressibility for well test analysis and simulation of reservoirs below the bubble point. Other equations of state appropriate for different fluids can be used in the model. In addition apparent compressibility could be larger than the coefficient of adiabatic two-phase compressibility, or the compressibility of the gaseous phase at the same conditions, and is also affected by the way fluids are removed from a given reservoir.

ACKNOWLEDGEMENTS

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NOMENCLATURE

B	= formation volume factor res B/std B; res $m^3/st m^3$
c	= coefficient of compressibility psi ⁻¹ ; kPa ⁻¹
H	= enthalpy BTU/lb; J/Kg
p	= pressure psi; kPa
S	= saturation, fraction of pore volume
T	= temperature °F; °C
u_s	= sonic velocity ft/s; m/s
V	= specific volume or total volume ft ³ /lb; m ³ /Kg
V_{mix}	= mixture volume ft ³ /lb; m ³ /Kg
V_{pore}	= pore volume ft ³ ; m ³
ΔV_{prod}	= change in volume due to production ft ³ ; m ³
x	= quality, mass of gas/mass total lb/lb; Kg/Kg
<u>Subscripts</u>	
a	= apparent
g	= gas
l	= liquid
o	= oil
s	= adiabatic
w	= water

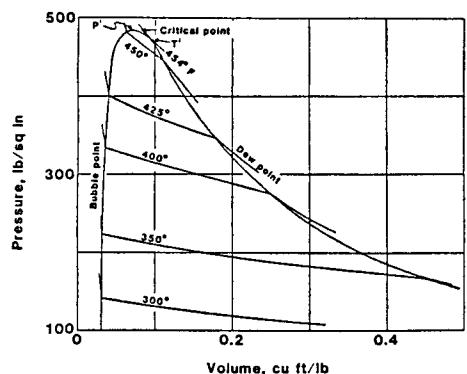


Fig. 1 Pressure vs specific volume, two component system n-heptane - n-pentane, from Sage B. H., and Lacey W.N4

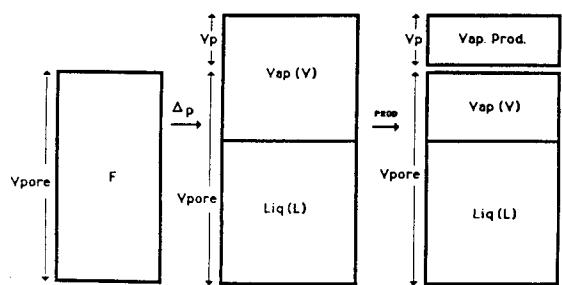


Fig. 2 Gas production mode

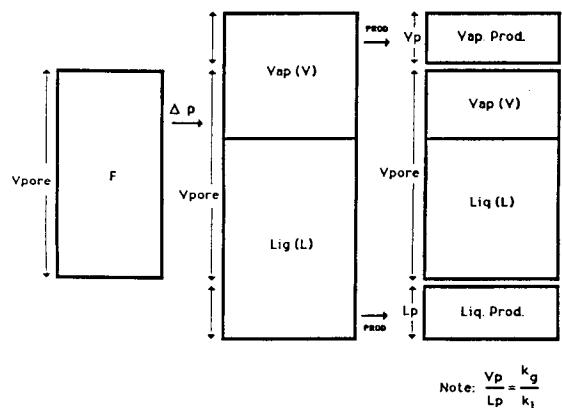


Fig. 3 Multiphase production mode (according to relative permeability-saturation relationship)

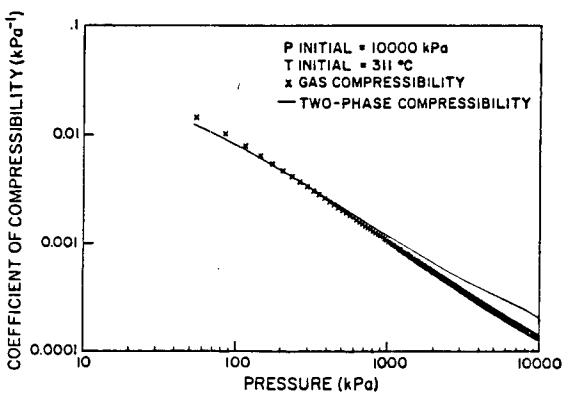


Fig. 4 Log-log graph of coefficient of adiabatic compressibility vs. pressure, pure water system.

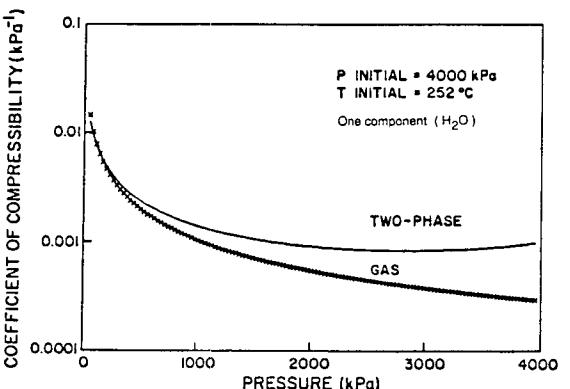


Fig. 5 Semilog graph of coefficient of adiabatic compressibility vs. pressure, pure water system.

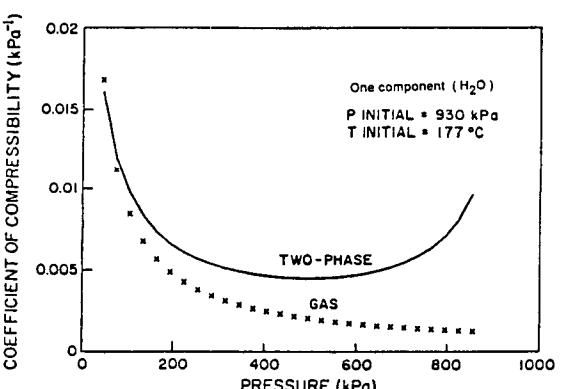


Fig. 6 Coefficient of adiabatic compressibility vs. pressure, pure water system.

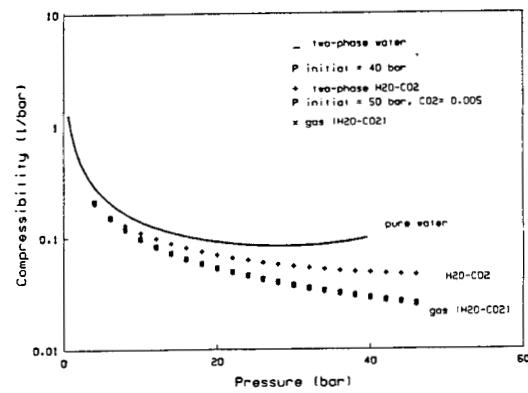


Fig. 7 Coefficient of adiabatic compressibility vs. pressure, pure water and $\text{H}_2\text{O}-\text{CO}_2$ systems.

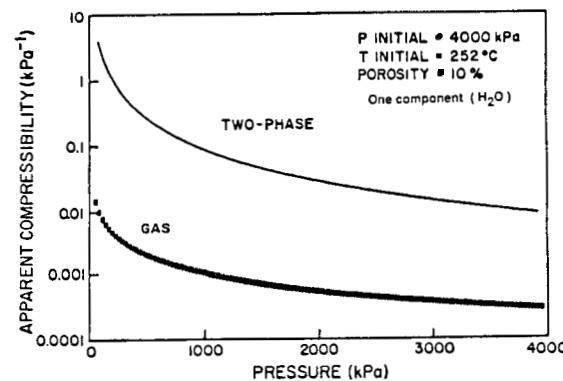


Fig. 8 Apparent compressibility vs. pressure for steam production from a 10 % porosity rock initially containing hot water.

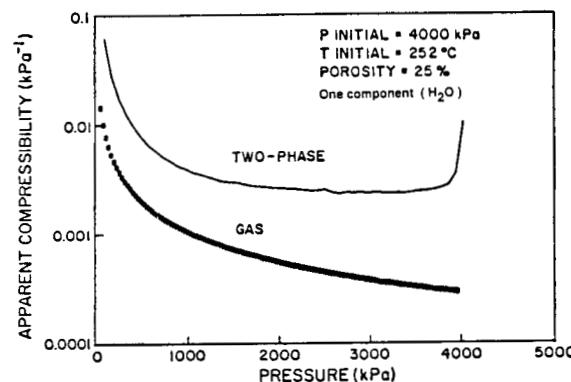


Fig. 9 Apparent compressibility vs. pressure for multiphase production from a 25% porosity rock initially containing hot water.