A comparison of different methods for generating pressure-volume-temperature (PVT) properties of volatile oil and gas-condensate reservoir fluids determined that PVT properties generated with the Whiston and Torp method agree the best with full equation-of-state (EOS) compositional simulation.

Besides the comparison with the EOS compositional simulation, the study also compared the initial-oil-in-place (IOIP) calculations with the generalized material-balance equation.

The study included a wide range of fluid characteristics from nine reservoir fluid systems: six gas condensate, two volatile oil, and one wet gas.

**Material balance**

Material-balance calculations are useful for analyzing reservoir performance, estimating oil and gas reserves, and predicting future reservoir performance.

Schlumberger in 1936 was among the first to formulate and apply material-balance analysis. In time, the industry created more sophisticated material-balance models, each attempting to provide greater generality.

In 1963, Havlena and Odeh presented techniques for interpreting the material-balance equation as a straight line that facilitates graphical techniques.

The two-hydrocarbon component or zero-dimensional material-balance model still applies only to black oil or dry-gas reservoirs. As volatile oil and gas-condensate exploitation increases, the industry needs to change these limitations.

Walsh addressed this limitation and developed a generalized material-balance equation to treat the full spectrum of reservoir fluids. The key is the use of the volatile oil-gas ratio \( R_v \) expressed in units of stock-tank cubic meters/standard cubic meters or stock-tank barrels/standard cubic feet (stb/scf). This variable effectively describes the amount of volatilized oil in the reservoir gas phase. \( R_v \) is a function of both reservoir-fluid composition and the separator configuration, which is typically designed for maximum liquid recovery.

A comparison among different methods of generating the modified black oil (MBO) PVT properties determined the accuracy of three models. PVT properties considered include the oil-formation volume factor \( B_o \), solution gas-oil ratio \( R_o \), gas-formation volume factor \( B_g \), and \( R_g \).

The study determined the accuracy of the methods through a comparison of the MBO simulation with straight-line material-balance calculations, followed with a comparison of the generated MBO PVT properties to the results

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**Table 1**

<table>
<thead>
<tr>
<th>Reservoir Fluid Samples</th>
<th>VO 1</th>
<th>VO 2</th>
<th>GC 1</th>
<th>GC 2</th>
<th>GC 3</th>
<th>GC 4</th>
<th>GC 5</th>
<th>GC 6</th>
<th>WG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir temperature, °F</td>
<td>249</td>
<td>246</td>
<td>312</td>
<td>186</td>
<td>268</td>
<td>268</td>
<td>238</td>
<td>256</td>
<td>312</td>
</tr>
<tr>
<td>Initial reservoir pressure, psig</td>
<td>NA</td>
<td>5,056</td>
<td>14,216</td>
<td>5,726</td>
<td>NA</td>
<td>6,000</td>
<td>7,000</td>
<td>14,216</td>
<td>18,050</td>
</tr>
<tr>
<td>Initial producing gas-oil ratio, scf/stb</td>
<td>1,991</td>
<td>2,000</td>
<td>3,413</td>
<td>6,987</td>
<td>4,278.5</td>
<td>NA</td>
<td>4,697</td>
<td>8,280</td>
<td>29,743</td>
</tr>
<tr>
<td>Stock tank oil gravity, °API</td>
<td>45.5</td>
<td>51.2</td>
<td>45.6</td>
<td>58.5</td>
<td>NA</td>
<td>NA</td>
<td>46.5</td>
<td>50.7</td>
<td>41.6</td>
</tr>
<tr>
<td>Saturation pressure, psig</td>
<td>4,527</td>
<td>4,823</td>
<td>5,210.3</td>
<td>4,000</td>
<td>5,410</td>
<td>6,815</td>
<td>6,010</td>
<td>5,465.3</td>
<td>12,485</td>
</tr>
</tbody>
</table>

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of the compositional simulation. The methods investigated were the Whitson and Torp (W&T), 6 Coats, 7 and Walsh and Towler 1 correlations. References 10-11 provide additional details on the calculations.

Fluid samples
The study included nine reservoir-fluid samples: six gas condensates (GC), two volatile oils (VO), and one wet gas (WG).

This article gives detailed results for three of the samples, one from each fluid type. The samples are from reservoirs representing different locations and depth and cover a wide range of characteristics (Table 1). 11

Figs. 1a-1b show the calculated MBO PVT properties (R 6 and R 7 ) and (B 6 , and B 7 ) with the W&T method for Sample VO 1. Both the Walsh and Coats methods apply only to gas-condensate fluids.

Figs. 1c-1f show the calculated MBO PVT properties (R 6 , R 7 ) and (B 6 , and B 7 ) with W&T, Coats, and Walsh methods for samples GC 1 and WG. These figures indicate that the W&T and Coats methods produce identical results for R 6 , R 7 , and B 6 with some differences at higher pressures only for B 6

The Walsh method was poorest in each case. For Sample GC 1, only the R 6 and B 6 curves have values similar to those generated with the W&T and Coats methods. The R 6 curve is overestimated and B 6 is underestimated.

For sample WG, the Walsh method underestimates the R 6 and B 6 and overestimated B 6 and R 6.

For calculating the W&T and Coats values, the study used the EOS modeling program PVTi 12 after first matching PVT experiment results with the PR- EOS model. 13

For the Walsh calculations, the study used a spreadsheet, as Walsh suggests in Reference 7, and found that this method provides inaccurate results because it is restricted to the pressure levels found in constant-volume depletion (CVD) experiments.

MBO PVT
Various authors have shown that MBO simulation is adequate for depletion studies of volatile oil and gas condensate fluids. 9 14 15

Our study used a numerical simulation test problem to compare the different MBO PVT generation methods.

Compositional simulation provided the basis for comparing MBO simulation results for different PVT generation methods.

The test case is a single-well, one-dimensional radial flow, with 20-md absolute permeability and 20% porosity. The simulation included 70 radial grid blocks and was run from the initial pressure to depletion without pressure maintenance.

The run assumed an initial 12% water saturation with the water remaining immobile throughout the simulation. Initial reservoir pressure was set higher than the saturation pressure of the fluid system being simulated.

Figs. 2a and 2b compare the MBO and compositional simulation results for Sample VO 1. The results indicate that the W&T method almost completely matches the compositional simulation results. The Coats and Walsh methods were not used for this volatile oil case because both apply only to gas-condensate calculations. The PVT software does not produce Coats results for pressures below the bubblepoint, as McCy recommends. 14

Figs. 2c and 2d compare MBO and compositional simulation results for

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Material balance calculations

The study did not include the Walsh method for the simulation cases because it provided poorer results. The Walsh method is based on a few pressure points from CVD experimental data.

The study used the same comparisons for the other fluid samples with similar results.\textsuperscript{11}

\textbf{Material-balance comparisons}

The study used a general spreadsheet to compare W&T, Coats, and Walsh PVT methods with the generalized material-balance calculation (GMBC).\textsuperscript{4, 5}

The general form of the material-balance equation, Equation 1 (see equation box) for oil reservoirs and Equation 2 for gas reservoirs, is a straight-line equation for initially undersaturated, volumetric reservoirs when the calculations neglect formation and water compressibility.

The compositional simulation test case used initial oil in place (IOIP) of 1 billion stb, while the W&T, Coats, and Walsh PVT generation methods provided the required PVT data, except for the volatile oil where only the W&T method generated the PVT data.

The best-fit lines and their slopes were computed with the least squares methods and the slopes of the lines yielded the IOIP.

Fig. 4a shows the GMBC results as a straight line with the W&T method for...
Sample VO 1. The line fits the calculated points well and its slope is 0.9935, or a 0.65% error in IOIP. The GMBC with the W&T, Coats, and Walsh methods for GC 1 (Fig. 4b) indicates that the line fits well. The slope of the line is 0.9776, or a 2.24% error in IOIP.

For Coats, the straight line fits the calculated points with a slope of 1.0797 (7.79% error of IOIP). For the Walsh method, however, the line fits the calculated points poorly and has a 47.77% error.

Fig. 4c provides the results of the GMBC as a straight line for the W&T, Coats, and Walsh methods for the WG sample. The W&T (4.64% error) and Coats, (2.35% error) correlated well while the Walsh method has a poor correlation.

The same procedure was followed for the remaining six samples (Table 2) and the W&T methods provided the...
Equations

For oil reservoirs

\[ F = NE \]

\[ \text{Where: } F = \frac{B_o (1 - R_w) + R_o - R_w B_o}{1 - R_o R_w}, \]

\[ E_o = \frac{E_o - B_o + B_o (R_o - R_w) + R_w (B_o - B_o) R_w}{1 - R_o R_w} \]

and \( G = NR \).

For gas reservoirs

\[ F = GE \]

\[ \text{Where: } E_o = \frac{E_o - B_o + B_o (R_o - R_w) + R_w (B_o - B_o) R_w}{1 - R_w R_o} \]

and \( N = GR \).

Nomenclature

- \( B_o \): Gas formation volume factor, bbl/scf
- \( B_p \): Initial gas formation volume factor, bbl/scf
- \( B'_p \): Oil formation volume factor, bbl/bbl
- \( N \): Net gas expansion term, reservoir bbl/scf
- \( R_o \): Net gas expansion term, reservoir bbl/scf
- \( C_o \): Total hydrocarbon fluid withdrawal, reservoir bbl
- \( G \): Original gas in-place (OGIP), scf
- \( C \): Cumulative gas produced, scf
- \( N \): Initial oil in-place (IIP), stock-tank bbl
- \( E \): Cumulative oil produced, stock-tank bbl
- \( R \): Cumulative produced oil-gas ratio, scf/stock-tank bbl
- \( R_w \): Initial solution gas-oil ratio, scf/stock-tank bbl
- \( R_o \): Initial oil-gas ratio, stock-tank bbl/scf

References

12. ECLIPSE Program, Schlumberger Inc.

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