

UPM 18070

Considerations for Multiphase Meter Table Preparation from Equation of State Fluid Model

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Abstract

The preparation of reservoir fluid models and the generation of appropriate tables for these models has been discussed previously. However recent experience with such an effort has indicated this topic at least needs clarification and identification of heuristics for model and table preparation. This talk will describe important aspects of the required PVT experimental data necessary for fluid model preparation. Then how to use typical experimental results to fashion appropriate property values for the tables based on the required input and desired outcome for the meter.

Most PVT studies are designed for reservoir simulation and engineering. These studies ignore many aspects important to facility engineers such as liquid volumes below bubble point pressure, and data at temperatures below the reservoir temperature. Temperature is a variable in pipelines more so than in a reservoir. Further data need to be taken to pressures as low as 750 psia.

The typical match focus on bubble point pressure is not so important since in reservoir studies this represents the onset of multiphase flow. This is not so important in pipeline flow where the volumes of liquid and gas at T and P as well as phase densities and viscosities are most important for flow. A case study will be used to demonstrate the complications of applying software to prepare tables of values appropriate for multiphase meters.

Introduction

The realities of multiphase flow forms the basis of flow assurance in subsea developments. A challenge in these developments is reservoir management which requires timely, relevant data regarding well and field performance hence accurate information on the volumes of oil, gas, and water produced during resource utilization. Multiphase meters can be a lower cost means of obtaining the required information.

Multiphase meters render the complex flowing phases into relevant volume of oil, gas, and water but these data are taken at flowing meter conditions. What is then needed is a method of converting the measured data into information relevant to reservoir management. The desired outcome would be volumes at STP. So one needs information on formation factors and relative gas produced from reservoir fluids at flowline conditions.

One solution to this need would be a set of conversion tables for various pressure and temperatures of fluid flow base on an equation of state representation of the produced reservoir fluid. It should be relatively strait forward to create such a model from data measured on representative reservoir fluid samples at a competent laboratory.

Building Reservoir Fluid Models

There are many methods for constructing reservoir fluid models. The view in this document is that there are enough components in the fluid model to forecast the desired fluid properties at the conditions of interest for this particular case. We wish the fluid model to be well grounded meaning the model adequately represents some basic reservoir fluid data as a function of the reservoir fluid composition. We will also need to have basic reservoir fluid data measurements to support our reservoir management requirements.

- Constant Mass Expansion – producing relative total volume V_r , fluid density D_o , fluid compressibility c_o , and relative liquid volume V_{liq} .
- Separator test – producing formation volume factor for oil and gas, Gas Oil Ratio, and residual oil density at STP
- Viscosity – single phase and two phase region liquid viscosity as a function of pressure.
- Differential Liberation or Constant Volume Depletion – B_o , B_g , D_g , R_s , D_o

PVT Test/Data Considerations When using and developing there are considerations regarding what is measured and what is not and how well the reported properties are actually known.

- For most PVT testing there are only two operations

- Constant mass expansion(PV)
- Constant Pressure Displacement to move material in and out of the phase cell.
- Key to fluid analysis is the flash to create ambient pressure gas and liquid samples for chromatographic analysis
 - Flashed oil molecular weight error is about ±5% at best
 - The reported GOR may have associated errors from the measurement of the gas volume ±5% at best
- The “+” fraction of the liquid may be in error ±5% and one does well to remember an inability to matchGOR data from separator tests and differential liberation may be due to an error in the analysis flash GOR or flashed liquid “+” fraction..
- The liquid phase volumes below the saturation pressure need to be measured to provide an experimental basis for the fluid model.
- The CME pressure volume data needs to include data points at pressures on the order of 500 to 1000 psia which are comparable to facility operating pressures.

Both CME and Viscosity experiments need to be run at temperatures below reservoir temperature. Since standard temperature is about 520 R and VLE varies with thermodynamic temperature, a change of 30°F only represents a 5% change in temperature (30/600). Such a small change may not produce a significant change in observed properties.

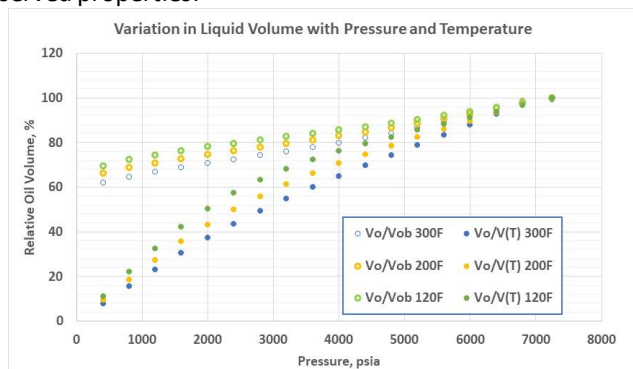


Figure 1 Liquid Volume versus Pressure at Different Temperatures

Figure 1 shows for a 30°API oil there is not a strong temperature effect on liquid volume.

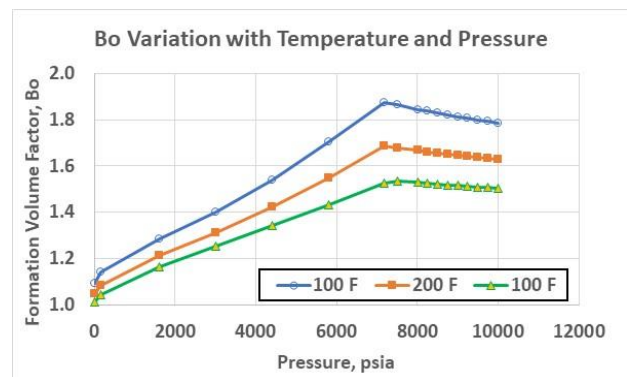


Figure 2 Variation of Bo with Temperature and Pressure

Figure 2 indicates a much greater temperature for Bo for the same oil. The Bo variation maximum is about twice the nominal thermal expansion for oils

$$(1/V) \cdot (dV/dT) \sim 5.5 \cdot 10^{-4} / ^\circ\text{F}.$$

- Recommend separator test conditions that can be executed in the vendor’s hardware.

Table 1 Example Separator Test

T, F	P, psia	V[o+g]	Vo	Bo	Δ[gas]
160	7500		14.76	1.554	0.00
135	1500	28.57	10.99	1.157	17.57
100	300	27.13	10.05	1.057	17.08
60	14.7	147.58	9.50	1.000	138.08

Table 1 illustrates how stage pressure and temperature can affect measurement accuracy. The initial charge would need to be reduced to about 15 cm³ to fit the experiment into a 150 cm³ phase cell. If the cell cross-sectional area is 8 cm² then the oil gas meniscus must be resolved to 0.1 mm to resolve 0.08 cm³ in volume. This resolution would produce an uncertainty of ± 1% in oil volume and Bo.

Fluid Model /Development.

Reservoir Fluid model development begins with a competent tool for equation of state simulation and modeling. It has been established for about 40 years that the general known phase’s diagrams for mixtures can be reproduced with a simple van der Waals equation (van Konynenburg and Scott, 1980). The most widely used modifications of the van der Waals equation are the Redlich-Kwong-Soave and Peng-Robinson equations of state both appearing in the early 1970s. Many advances in computer technology and fluid characterization have followed including



Figure 3 Composition Check for Distribution Function Application and Oil Base Mud contamination

The use of distribution functions to represent oil composition (Whitson, Behrens and Sandler) and the application of volume shift parameters to improve volumetric predictions (Peneloux, Rausey and Freze).

In Figure 3 we check for an exponential decay in a plot of weight percent or mole percent component. Based on Behren's and Sandler's treatment we would only need 2 or 3 components to represent the oil beginning at C13. We could then use a supplied detailed composition through C11 and applying the distribution function approach splitting the C12+ into two or three based on the plus fraction molecular weight and initial carbon number. We can also detect the presence of mud oil contamination of the reservoir fluid sample.

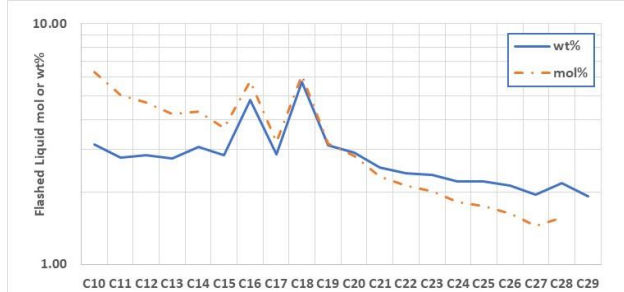


Figure 4 Component Distribution Plot Showing Mud Oil Contamination

The off-trend peaks of C15 and C18 shown in Figure 4 are due to the presence of mud oil in the sample. A plot of the reservoir fluid detailed composition versus carbon number or component assigned molecular weight also be used

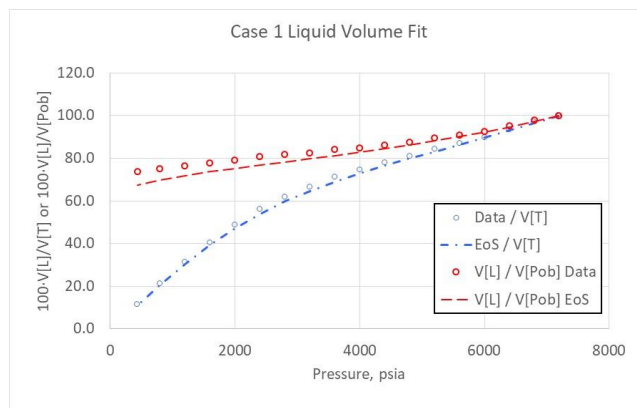


Figure 5 Variation of Oil Volume with Pressure and Temperature for $P < P_{ob}$

Figure 5 illustrates also that the needed oil hold-up error is apparently less when expressed as oil volume divided by total volume than when referenced against the bubble point volume. Given the low sensitivity of the oil volume, optimizing oil volume has proven difficult.

Figure 6 depicts an attempt to force a better match with oil

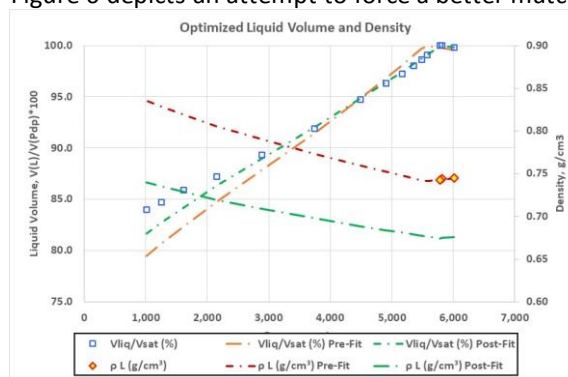


Figure 6 Optimization of Oil Volume

volume. The oil volume for much of $P > P_{ob}$ were omitted and a diminished weighting of the saturation pressure. The result was an improved oil volume at the expense of the reservoir fluid density.

Figure 7 shows the typical fit for oil viscosity variation with pressure and temperature. Note this match was obtained by emphasizing the single phase data versus the data at $P < P_{sat}$. In many cases the weakest data point is often the point reported for 14.7 psia. This point may not have been measured as part of the original depletion viscosity experiment. A major first step in fitting viscosity data is omission of the ambient pressure points.

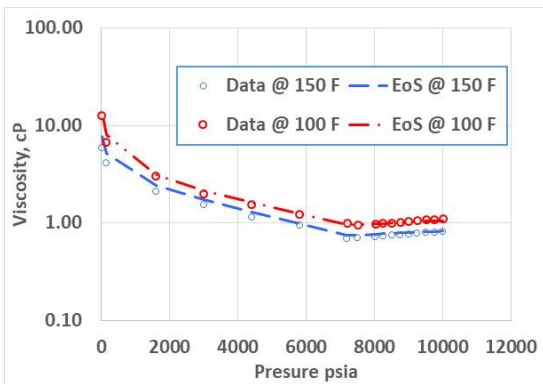


Figure 7 Viscosity versus Pressure and Temperature Results

Temperature Dependence Errors

In this work we have been able to create suitable reservoir fluid models by optimizing the saturation pressures and viscosities. Proper fluid characterization has been able to accomplish a density match (as well as compressibility and reduced modulus Y). The weakness in cubic equation of state temperature and pressure dependence has been avoided. Comparison of equation of state results with experiment we should compare against data from P.W. Bridgman "Physics of high Pressure" for benzene and n-octane, and from NIST Chemistry Web Book for toluene

Table 2 Percent Differences in Relative Volume Data versus PR78 EoS

		Temperature, C		
	benzene	0	50	95
psia	kg/cm ²			
25.0	0.0	0.00%	0.91%	1.00%
14,223.3	1,000.0		1.62%	2.97%
28,446.6	2,000.0			1.69%
42,669.9	3,000.0			0.05%
		Temperature, C		
	n-octane	0	50	95
psia	kg/cm ²			
25.0	0.0	0.00%	-1.16%	-1.60%
14,223.3	1,000.0	1.01%	-1.01%	-2.40%
28,446.6	2,000.0	3.31%	1.20%	-0.27%
42,669.9	3,000.0	5.62%	3.48%	2.02%

Errors on the order of the nominal error in B_0 ($\pm 2\%$) are present in the equation of state (EoS) model used to represent the data. The toluene data from NIST reveal a more interesting result.

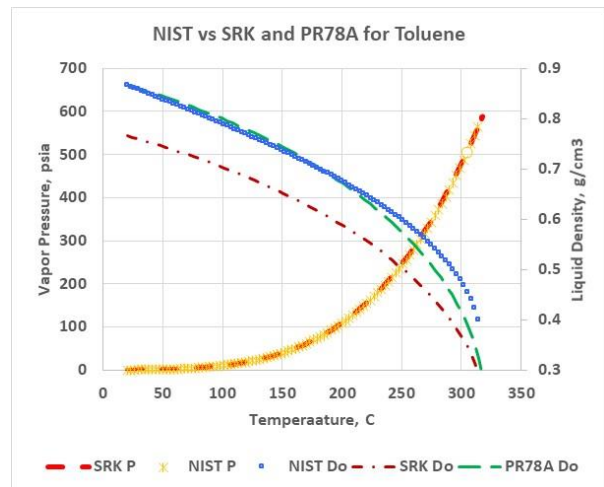


Figure 8 Comparison of NIST Density Data with SRK and PR78A EoS

Though the PR78A predictions are in good agreement with the NIST data at lower temperatures and this may help explain the good agreement found in the examples prepared for this talk, the problems caused by a fundamentally incorrect Z_{crit} persist as T approaches T_c . The SRK vapor pressure predictions are in good agreement with the NIST data.

Table Building

Once the fluid model is completed. It may be a time consuming task especially for those properties that require correction for separator conditions such as volume formation factors and gas liquid ratios. The phase fractions at the specified T and P through constant mass expansion or PT Flash calculation. The equilibrium gas, liquid, and water phases must then be flashed through production separators to populate the particular property table.

Figure 9 shows the stack or family of tables that help unlock the multiphase meter results in a way they can be used for reservoir management once application of the fluid model to the generation task is completed.



Figure 9 Ensemble of Meter Tables

Conclusions

The takeaways from this following sections:

1. Equation of State models that represent reservoir and fluid properties can be readily prepared.
2. These fluid models represent a coupling of fluid composition and fluid properties.
3. PVT data must be taken over a wide range of temperatures and pressures from near ambient to reservoir conditions.
4. The reservoir fluid composition can be represented in large part by a distribution function for the C10+ part of the reservoir fluid. This allows use of more accurate "+" fraction properties and a more accurate determination of the amount of the "+" fraction. Basic is the check of the analytical flash and the separator flash match.
5. Matching viscosity is best accomplished ignoring the ambient pressure points and focusing on the data for $P > P_{sat}$.
6. Recommendations: The optimization can be done step wise or globally. Optimization should be performed keeping track of whether or not variables remain within reasonable limits. Failure to do so could indicate problems with the fluid composition or the PVT experimental data. Though the modelling of the oil volumes at $P < P_{sat}$ expressed as $V_o/V_o[P_{obp}]$ seem usually when plotted at $V_o/V_o[0+g]$

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