

Assessing the Impact of Capillary Pressure and Critical Properties Shift on the PVT Behavior of Hydrocarbons in Tight and Shale Reservoir

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Abstract

The research paper presents a comprehensive study of the effects of confinement on the PVT properties of hydrocarbon fluids in tight and shale reservoirs. A literature review highlights the previous studies on this topic and identifies the lack of attention paid to the critical properties shift due to confinement. To investigate this effect, a simple synthetic hydrocarbon oil composition was chosen, and its PVT properties were studied under different confinement conditions. The bubble point pressure, gas solubility, oil density, viscosity, and formation volume factor were observed at different pore radii and reservoir temperatures across a range of pressures. The critical properties were modified due to confinement, and a modified flash calculation was used to account for the capillary pressure in the two-phase region. The results of the study demonstrate that confinement leads to a depression in bubble point pressure, lower oil viscosity and density at the bubble point, higher gas solubility and formation volume factor, and lower oil viscosity below the bubble point. In contrast, the oil properties above the bubble point are minimally affected. These findings highlight the significance of considering both capillary pressure and critical properties shift in studying the PVT behavior of hydrocarbon fluids in tight reservoirs.

Keywords: Confinement effects; Critical properties shift; Capillary pressure; Oil PVT properties; Shale oil.

1. Introduction

Shale oil and gas production have played a significant role in achieving energy independence for many countries in recent years, despite the fact that shale and tight reservoirs pose a significant obstacle to profitable production due to their remarkably low permeability and porosity, which inhibit the flow of hydrocarbons and render their economic extraction difficult [1]. The pore size and geometry of rock formations profoundly impact the characteristics of reservoir fluids, including viscosity, density, formation volume factor, and compressibility [2]. The distribution of pore types in shales varies depending on the specific shale formation. In the Barnett Shale the majority of the porosity was associated with nanopores (less than 50 nm in diameter), accounting for up to 60% of the total porosity. The remaining porosity was attributed to micropores (50 nm to 2 μm) and mesopores (2 μm to 50 μm), with micropores accounting for up to 20% and mesopores for up to 15% of the total porosity. The remaining porosity was attributed to macropores (greater than 50 μm), which accounted for less than 5% of the total porosity [3].

When a fluid is confined in a pore space, it experiences surface interactions with the solid walls, which can alter its thermodynamic properties. These surface interactions can lead to a reduction in the available space for the fluid molecules to move, which in turn can affect the entropy of the system. This effect is more pronounced when the pore size is comparable to or smaller than the size of the fluid molecules. In such cases, the confinement can significantly increase the fluid's surface area and alter the interactions between the fluid molecules, leading to changes in its thermodynamic properties [4-5]. In general, the confinement effect occurs when the pore size to molecule size ratio is less than 20 [6]. Pore throat diameters in shale

gas formations typically range from 0.5 to 100 nm [7], whereas the chain diameter of straight hydrocarbons falls within the 0.4 to 0.6 nm range [8]. The confinement effect is more significant in nanopores and diminishes in macro-pores where molecules are far from the pore wall and molecule-molecule interaction is more dominant.

The thermodynamic properties of a fluid can be significantly affected when confined in a nanopore space. The critical properties of a fluid are some of the most important properties that change when a fluid is confined in a pore space. Recent studies have shown that confinement can cause significant changes in critical properties of fluids in shale reservoirs. A study by Ma *et al.* [9] investigated the effect of pore proximity on phase behavior and fluid properties in shale formations. The study used molecular dynamics simulations to investigate the behavior of methane in shale nanopores of different sizes and shapes. The results showed that the critical temperature and pressure of methane were affected by the proximity of the pore walls, with the critical temperature and the critical pressure decreasing as the pore size decreased [9]. The shift in the critical point is due to the reduction in the number of particles in the confined fluid, which leads to a decrease in the attractive interactions and a reduction in the critical temperature and pressure [10].

Capillary pressure is a significant factor that influences the phase behavior of shale oil and gas condensate reservoirs. It refers to the pressure difference between two immiscible fluids that are in contact with a porous medium, such as shale rocks [11]. Capillary pressure varies with the pore size, shape, and wettability of the pore surface. In petroleum reservoir engineering, capillary pressure is an essential factor in determining fluid distribution, fluid phase behavior, and the ultimate recovery of hydrocarbons [12].

The capillary pressure in shale reservoirs can lead to the trapping of fluids in the pores, affecting their distribution and leading to changes in the thermodynamic equilibrium of the fluids. This can result in changes to the bubble point, dew point, and other phase behavior properties of the fluids. Furthermore, capillary pressure result in the formation of two distinct phases with different pressures and compositions, which are not typically accounted for in classical thermodynamic models. This can make it difficult to accurately predict the behavior of the fluids in the reservoir and can lead to errors in estimations of important properties such as fluid composition, phase behavior, and fluid flow. In order to address this issue, modifications to the current available techniques have been developed that account for capillary pressure effects and improve the accuracy of fluid behavior predictions in shale reservoirs [4-5].

Kamari, Li, and Sheng conducted a study on the effect of rock pore sizes on the PVT properties of oil and gas condensate in shale and tight reservoirs. They made modifications to the conventional flash calculations, incorporating the impact of capillary pressure and critical properties shift, and concluded that pore size has a significant impact on various PVT properties such as bubble point and dew point pressures, interfacial tension, viscosities, and densities of Eagle Ford shale oil and gas condensates. [2]. In a related study, Li and Sheng investigated the phase behavior of Wolfcamp shale oil by incorporating a modified flash calculation with the Peng-Robinson equation of state (PR-EOS) and the Young-Laplace equation to account for capillary pressure effects. They observed substantial deviations from the expected bulk behavior, which they attributed to the impact of nanopore radius. [13].

To date, the majority of research has concentrated on analyzing the influence of critical properties shift and adsorption effects on gas properties, as well as the capillary pressure effect on the phase behavior of shale oils. My study, on the other hand, will be unique in that it will explore the combined impact of critical properties shift and capillary pressure on oil composition. It will focus on observing the impact of reduced pore radius or size on oil formation volume factor, density, viscosity, and gas solubility. This will enable a more comprehensive understanding of the behavior of shale oil reservoirs under varying conditions.

2. Calculation methodology

The objective of this research paper is to assess the impact of capillary pressure and critical properties shift on the PVT properties of shale oil. The study aims to investigate the degree to which PVT properties are affected or deviated from these properties across various pore radii,

pressures, and temperatures. This will be accomplished through a series of steps, which are detailed as follows:

2.1. Step1: Preparation of compositional data for the study

Collecting and preparing the necessary data is essential for conducting a thermodynamic modeling study. The initial step involves selecting the relevant hydrocarbon compositions and identifying the required properties of each pure component that will be utilized in the modeling process. These properties can be obtained from a variety of sources, such as published literature, databases, or experimental measurements [14].

Table 1 presents the compositional data for a hypothetical shale oil that will be used in this study. The table contains the molar composition of the oil composition, molecular weight, critical pressure, critical temperature, acentric factor, critical compressibility factor, critical volume, and parachor which is a dimensionless compound-specific constant used in calculating the interfacial tension [15]. Table 2 lists the binary interaction coefficients to be employed when modeling the properties of the oil using the Peng-Robinson equation of state. Binary interaction coefficient is a thermodynamic parameter used in equations of state to account for the deviation from ideal behavior in mixtures of two different chemical species. The BIC describes the interaction between the two components of the mixture and reflects their mutual influence on each other's thermodynamic properties, such as their vapor pressures, fugacities, and activity coefficients [16]. Reservoir temperatures will be systematically varied at different pore radii to thoroughly study the impacts of confinement on oil composition.

Table 1. Compositional data for hypothetical shale oil sample

Component	xi	Mw (lbm/lbm.mol)	Pc (psia)	Tc (°R)	ω	Zc	Vc ft ³ /lb.mol	Parachor
C1	0.1	16.04	667.8	343	0.0115	0.2884	1.59	77
n-C4	0.25	58.12	550.7	765.3	0.1928	0.2736	4.08	189.9
n-C8	0.65	114.2	360.6	1,023.90	0.3978	0.2587	7.882	351.5

Table 2. Peng-Robinson equation of state binary interaction coefficient for shale oil sample [24]

Component	C1	n-C4	n-C8
C1	0	0.025	0.04
n-C4	0.025	0	0.005
n-C8	0.04	0.005	0

2.2. Step2: Calculating bulk oil PVT properties

The second step in this study involves calculating the bulk oil PVT properties using the Peng-Robinson equation of state and mixing rules i.e., under no confinement. The parameters for the Peng-Robinson equation of state are calculated using mixing rules, which use the critical properties of the pure components in the hydrocarbon mixture. Once these parameters are calculated, the equation can be used to accurately predict the thermodynamic properties of the hydrocarbon mixture. The equation of state is utilized to compute the equilibrium ratios and liquid compressibility factor, enabling the simulation of oil PVT properties for a range of reservoir pressures and temperatures during reservoir depletion.

The generalized form of the cubic equation of state is applied in this study as follows [8, 17-18]:

$$P = \frac{RT}{V - b} - \frac{a}{V^2 + ubV + wb^2} \quad (1)$$

where P is the pressure, psia; V is the molar volume, ft³·lbmol⁻¹; T is the temperature, °R; R is the universal gas constant an equals 10.731 psi·ft³·lbmol⁻¹·°R⁻¹, u = 2, w = 1, a, and b are calculated according to Peng- Robinson as follows [18]:

$$a = \frac{0.457R^2T_c^2}{P_c} \left[1 + f_\omega \left(1 - T_r^{\frac{1}{2}} \right) \right]^2 \quad (2)$$

$$b = \frac{0.07780RT_c}{P_c} \quad (3)$$

$$f_\omega = 0.37464 + 1.54226\omega - 0.2699\omega^2 \quad (4)$$

where T_c is the critical temperature, °R; P_c is the critical pressure, psia; T_r is the reduced temperature; ω is the acentric factor.

To apply this equation of state to hydrocarbon mixtures, mixing rules are used to calculate the equation of state parameters, such as the interaction energy parameter (a) and the co-volume parameter (b).

$$a_m = \sum_j \sum_i y_i y_j (a_i a_j)^{\frac{1}{2}} (1 - K_{ij}) \quad (5)$$

$$b_m = \sum_i y_i b_i \quad (6)$$

where K_{ij} is the binary interaction coefficient. Which accounts for the deviations from ideal behavior due to interactions between unlike molecules.

The conventional method of determining the bubble point pressure and other PVT properties using an equation of state is employed to compute the bulk properties of the hydrocarbon mixture, which is subsequently used for comparative analysis with the properties of the confined oil that will be calculated in the following steps.

2.3. Step 3: Accounting for confinement effects and modifying flash calculations

Step 3.1: The critical properties of the pure components are initially adjusted using the correlations developed by Ma et al. and Jin et al. to account for the impact of confinement on hydrocarbon critical properties. These correlations are presented below [9, 11] :

$$\Delta T_c = \frac{T_{cb} - T_{cz}}{T_{cb}} = 1.1775 \left(\frac{D}{\sigma_{eff}} \right)^{-1.338} \quad \text{for } \left(\frac{D}{\sigma_{eff}} \right) \geq 1.5 \quad (7)$$

$$\Delta T_c = \frac{T_{cb} - T_{cz}}{T_{cb}} = 0.6 \quad \text{for } \left(\frac{D}{\sigma_{eff}} \right) < 1.5 \quad (8)$$

$$\Delta P_c = \frac{P_{cb} - P_{cz}}{P_{cb}} = 1.5686 \left(\frac{D}{\sigma_{eff}} \right)^{-0.783} \quad (9)$$

$$\sigma_{eff} = 0.244 \sqrt[3]{\frac{T_{cb}}{P_{cb}}} \quad (10)$$

Step 3.2: To begin, an appropriate trial value for the bubble point pressure (P_b) must be assumed. To ensure accuracy and reasonability, the Wilson equation can be used to calculate K_i , as outlined below [19].

$$P_b = \sum_{i=1}^{N_c} z_i P_{ci} e^{\left[5.37(1+\omega_i) \left(1 - \frac{T_{ci}}{T} \right) \right]} \quad (11)$$

Using the assumed bubble point pressure obtained from Equation 11, the equilibrium ratio of each component in the hydrocarbon mixture can be calculated as follows:

$$K_i = \frac{P_{ci}}{P_b} e^{\left[5.37(1+\omega_i) \left(1 - \frac{T_{ci}}{T} \right) \right]} \quad (12)$$

Step 3.3: Performing flash calculations involves using the equilibrium ratio calculated in Step 3.2 to determine the vapor and liquid compositions of the mixture. This is typically done by solving the Rachford-Rice equation, which is an algebraic equation that relates the vapor and liquid compositions of a mixture at equilibrium. The solution to the Rachford-Rice equation

provides the number of moles of vapor and liquid in the equilibrium mixture, as well as the mole fractions of each component in the vapor and liquid phases as follows [20]:

$$f(n_l) = \sum_i^{N_c} \frac{Z_i(1 - K_i)}{K_i + (1 - K_i)n_l} = 0 \quad (13)$$

$$x_i = \frac{Z_i}{n_L + (1 - n_L)K_i} \quad (14)$$

$$y_i = \frac{Z_i K_i}{n_L + (1 - n_L)K_i} \quad (15)$$

Step 3.4: In this step, the parameters (a_L and b_L) associated with the liquid phase equation of state applied in this study are determined as follows [16, 21]:

$$a_L = \sum_j \sum_i x_i x_j (a_i a_j)^{\frac{1}{2}} (1 - K_{ij}) \quad (16)$$

$$b_L = \sum_i x_i b_i \quad (17)$$

Next the liquid compressibility factor is determined as follows [16]:

$$Z_L^3 - (1 + B_L^* - u B_L^*) Z_L^2 + (A_L^* + w B_L^{*2} - u B_L^* - u B_L^{*2}) Z_L - A_L^* B_L^* - w B_L^{*2} - w B_L^{*3} = 0 \quad (18)$$

where

$$A_L^* = \frac{a_L P}{R^2 T^2} \quad (19)$$

$$B_L^* = \frac{b_L P}{RT} \quad (20)$$

It should be noted that the equation presented above has three roots. The smallest positive root is considered as the compressibility factor for the liquid phase (Z_L) [21]. Subsequently, the molecular weight for both the gas and liquid phases must be calculated.

Step 3.5: In this step, the interfacial tension and capillary pressure will be calculated to account for the pressure difference between the gas phase and liquid phase. The excess pressure in the gas phase is typically higher than the pressure in the liquid phase due to the smaller pore size in shale formations. The capillary pressure can be calculated using the Young-Laplace equation, while the interfacial tension can be calculated applying Weinaug and Katz correlation as follows [22].

$$\sigma = \sum_{i=1}^n [(P_{ch})_i (A x_i - B y_i)]^4 \quad (21)$$

$$A = \frac{\rho_o}{62.4 M_o} \quad (22)$$

$$B = \frac{\rho_g}{62.4 M_g} \quad (23)$$

$$P_{cap} = \frac{2\sigma}{r} \quad (24)$$

It is important to note that all properties related to the vapor phase must be calculated at the vapor phase pressure, which is adjusted to account for the capillary pressure using the following equation:

$$P_V = P_L + P_{cap} \quad (25)$$

Step 3.6: In this step, the parameters (a_v and b_v) associated with the vapor phase equation of state applied in this study are determined as follows [16, 21]:

$$a_v = \sum_j \sum_i y_i y_j (a_i a_j)^{\frac{1}{2}} (1 - K_{ij}) \quad (26)$$

$$b_v = \sum_i y_i b_i \quad (27)$$

Next the vapor compressibility factor is determined as follows [16]:

$$Z_v^3 - (1 + B_v^* - u B_v^*) Z_v^2 + (A_v^* + w B_v^{*2} - u B_v^* - u B_v^{*2}) Z_v - A_v^* B_v^* - w B_v^{*2} - w B_v^{*3} = 0 \quad (28)$$

Step 3.7: In this step, the fugacity and fugacity coefficient for each component in both phases are computed using the calculated values of pressure, temperature, and composition. The fugacity is a measure of the chemical potential of a component in a mixture and reflects the deviation from ideal behavior, while the fugacity coefficient is a measure of the deviation from ideal gas behavior in the vapor phase. The calculation of fugacity and fugacity coefficient is essential for accurate modeling of phase behavior and equilibrium ratios [16, 21].

The fugacity coefficient of the components in the liquid phase is calculated as follows [16].

$$\ln \Phi_i^L = \frac{b_i}{b_L} (Z_L - 1) - \ln(Z_L - B_L^*) + \frac{A_L^*}{B_L^* \sqrt{u^2 - 4w}} \times \left(\frac{b_i}{b_L} - \delta_i^L \right) \ln \frac{2Z_L + B_L^* (u + \sqrt{u^2 - 4w})}{2Z_L + B_L^* (u - \sqrt{u^2 - 4w})} \quad (29)$$

where

$$\frac{b_i}{b_L} = \frac{T_{ci}/P_{ci}}{\sum x_i T_{ci}/P_{ci}} \quad (30)$$

$$\delta_i^L = \frac{2a_i^{1/2}}{a_L} \sum_j x_j a_j^{1/2} \times (1 - K_{ij}) \quad (31)$$

The fugacity coefficient of the components in the vapor phase is calculated as follows [16].

$$\ln \Phi_i^V = \frac{b_i}{b_v} (Z_v - 1) - \ln(Z_v - B_v^*) + \frac{A_v^*}{B_v^* \sqrt{u^2 - 4w}} \times \left(\frac{b_i}{b_v} - \delta_i^V \right) \ln \frac{2Z_v + B_v^* (u + \sqrt{u^2 - 4w})}{2Z_v + B_v^* (u - \sqrt{u^2 - 4w})} \quad (32)$$

where

$$\frac{b_i}{b_v} = \frac{T_{ci}/P_{ci}}{\sum x_i T_{ci}/P_{ci}} \quad (33)$$

Fugacity of each component in the liquid and vapor phase are calculated as follows [16]:

$$f_i^L = x_i P_L \Phi_i^L \quad (34)$$

$$f_i^V = x_i P_v \Phi_i^V \quad (35)$$

Step 3.8: In this step, we check for equilibrium.

The system is in equilibrium when the following is true for all components:

$$f_i^L = f_i^V \quad i = 1, 2, \dots, NC \quad (36)$$

If the equation above is not satisfied, a new value of K_i must be selected using the following equation. The previous steps must be repeated until the system reaches equilibrium.

$$K_i^{k+1} = \left(\frac{f_i^L}{f_i^V} \right)^k \quad (37)$$

Step 3.9: In this step, the validity of the assumed bubble point pressure (P_b) obtained from Equation (11) is checked. If the relationship below is not satisfied, a new value of P_b is assumed according to Equation (39), and the calculations from Step 3.3 to Step 3.8 are repeated until the relationship is met [16, 21].

$$\sum_{i=1}^{NC} Z_i K_i = 1 \quad (38)$$

$$P_b^{n+1} = P_b^n \sum \frac{\Phi_i^L x_i}{\Phi_i^V} - P_{cap} \quad (39)$$

Step 3.10: The final step is organized for calculating all oil PVT properties after equilibrium is reached. Correlations developed by Lohrenz, Bray and Clark [23] have been employed in the thermodynamic modelling performed in this study for prediction of viscosity of liquid phase. Figure 1 provides a succinct overview of the methodology used in this study to assess the effects of confinement on shale oil.

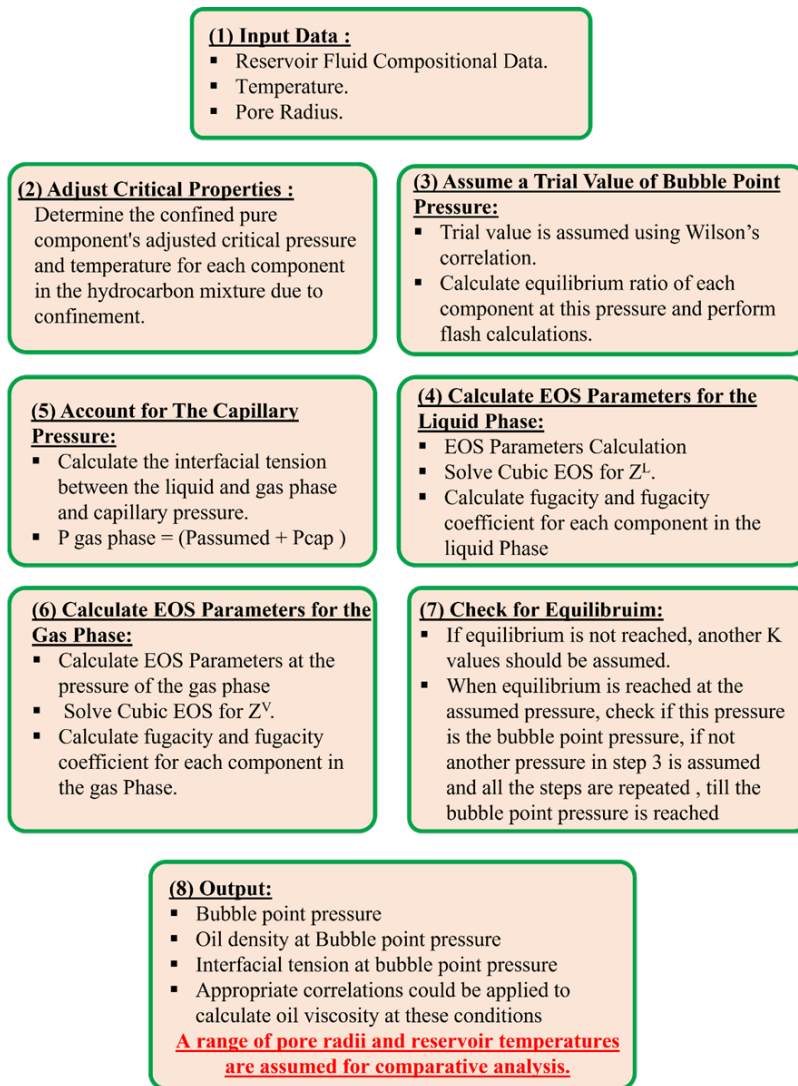


Figure 1 Schematic representation of the proposed approach for incorporating the impact of critical properties shift and capillary pressure on shale oil PVT properties

3. Results and discussion

This study investigates the impact of capillary pressure and critical properties shift on shale reservoirs over a range of reservoir pressures and temperatures for different pore radii, using compositional data from Table 1.

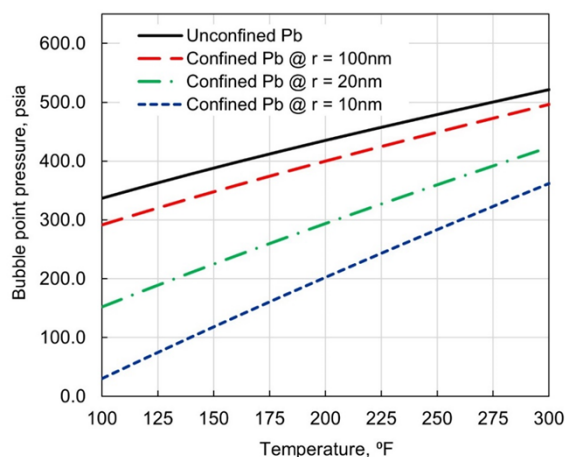


Figure 2. Bubble point pressure calculated for the shale oil sample at various pore radii across a wide range of reservoir temperatures

against the formation of gas bubbles, and as a result, a lower pressure is needed for gas to come out of solution in the confined space of small pores. Moreover, the depression is higher at lower reservoir temperatures due to reduced thermal vibrations causing particles to move more coherently. As a result, confinement effects can be more pronounced as the limited motion of particles is amplified and can result in collective behavior.

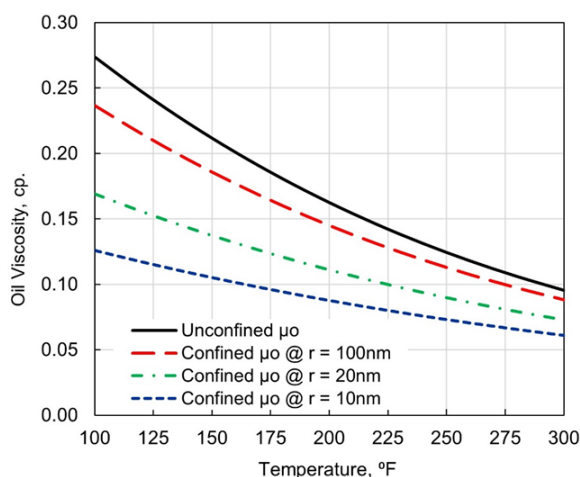


Figure 3. Oil viscosity at bubble point pressure for the shale oil sample calculated for different pore radii across wide range of reservoir temperatures

The bubble point pressure exerts a crucial impact on the phase behavior, fluid characteristics, and flow dynamics in reservoirs, making it a crucial parameter for determining reserves, production rates, and reservoir performance. The influence of capillary pressure and the shift in critical properties on the bubble point pressure of shale oil samples at varying reservoir temperatures and pore radii is demonstrated in Figure 2. It is observed that the bubble oil is depressed due to confinement, the degree of depressions increases with decreasing the pore radius, this may be attributed to the small pore size that leads to high capillary pressures. This increased capillary pressure effectively reduces the bubble point pressure of the hydrocarbons. The capillary pressure acts

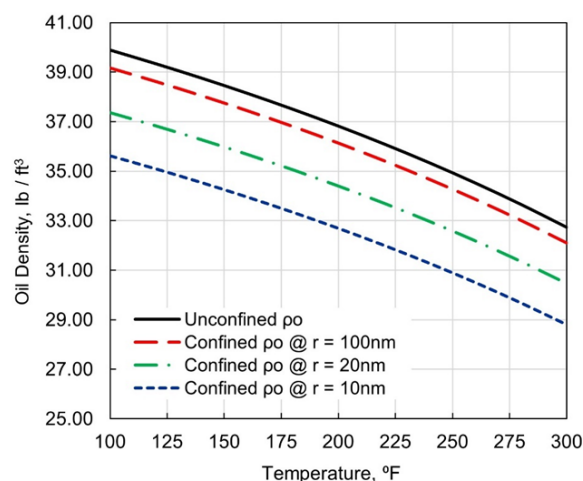


Figure 4. Oil density at bubble point pressure for the shale oil sample calculated for different pore radii across wide range of reservoir temperatures

Figure 3 through Figure 6 display the calculated oil viscosity, oil density, first bubble of gas density, and interfacial tension, respectively at the bubble point pressure, for the shale oil sample at various pore radii and over a wide range of reservoir temperatures. It is observed that confinement results in a reduction in oil viscosity at the bubble point. This is attributed to the fact that the bubble point pressure is reached at a lower pressure when confined, as previously mentioned. At lower pressures, viscosity decreases. Furthermore, confinement

causes the gas phase to remain in the oil phase for a longer period of time, resulting in a decrease in oil viscosity. The oil density and gas density of the first bubble of gas at the bubble point pressure also decrease due to confinement for the same reasons that cause the oil viscosity to decrease. However, the degree of deviation is not significantly affected by the reservoir temperature, unlike oil viscosity. The oil/gas interfacial tension at the bubble point pressure is also observed to decrease due to confinement. This can be attributed to the fact that confinement makes it more difficult for the vapor phase to exist by depressing the bubble point pressure. When the vapor phase is formed, the interfacial tension is lower as it tends to come back to the liquid phase.

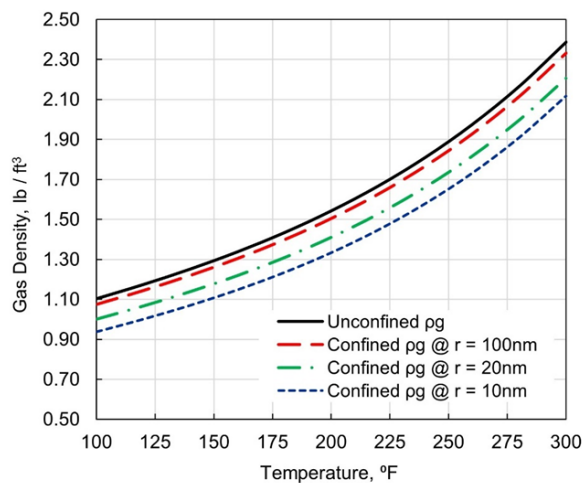


Figure 5. Density of the first bubble of gas formed at bubble point pressure for the shale oil sample calculated for different pore radii across wide range of reservoir temperatures

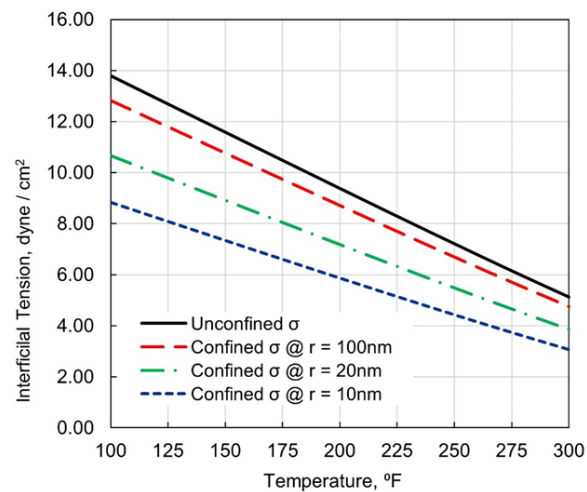


Figure 6. Interfacial tension of the first between the bubble of gas formed at bubble point pressure and the liquid phase for the shale oil sample calculated for different pore radii across wide range of reservoir temperatures

A trend analysis of the confinement effects on shale oil bubble point pressure is presented. The aim is to examine the influence of confinement on the oil properties as the pore radius of the porous media changes. The results show that the confinement effect on shale oil properties becomes more significant as the pore radius of the porous media decreases. Figure 7 depicts the correlation between pore radius and bubble point pressure of the reservoir system at three different temperatures. The outcomes indicate that the bubble point pressure diminishes as the pore radius decreases, with confinement having a more pronounced effect at lower temperatures.

An equation of state besides appropriate correlations can be utilized to simulate and calculate the unconfined and confined oil PVT properties, which include the oil formation volume factor, gas solubility, and oil viscosity, for a range of reservoir pressures. These properties are computed assuming a reservoir temperature of 250°F. Figure 8, Figure 9, and Figure 10 display the simulation results for gas solubility, oil formation volume factor, and oil viscosity, respectively, under no confinement, 100 nm pore radius, and 10 nm pore radius for the synthetic oil composition. It should be noted that above the bubble point pressure, there is no significant deviation in the properties. However, below this pressure, the PVT properties of oil deviate depending on the pore radius. It is observed that below the bubble point pressure, the gas solubility is higher in the confined fluid, indicating that it is difficult for the gas phase to come out of the solution and remains in the liquid phase due to confinement. Additionally, the oil formation volume factor is higher, indicating high shrinkage, as the trapped gas in the liquid phase rapidly comes out of the solution when the fluid is out of the reservoir, taking more molecules to the vapor phase. As predicted, the oil viscosity is lower due to gas which remains in solution, which eventually lowers the oil viscosity.

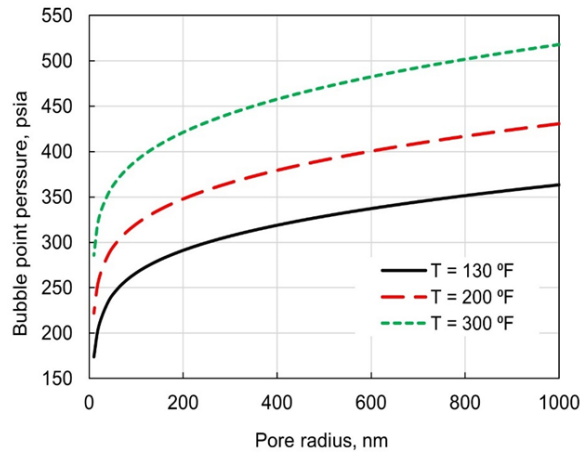


Figure 7. Trend analysis of the bubble point pressure as a function of pore radius for the shale oil composition at various temperatures, including 130°F, 200°F, and 300°F

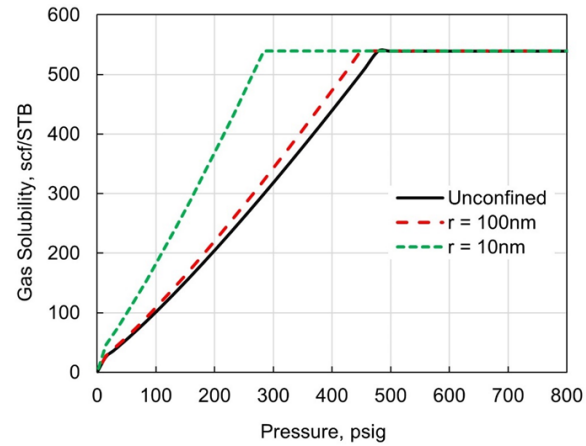


Figure 8. Unconfined and confined gas solubility at pore radii of 100 nm and 10 nm as a function of pressure, for the shale oil composition at a reservoir temperature of 250°F

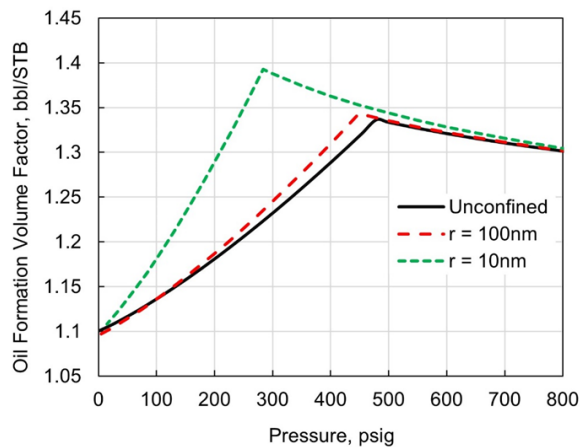


Figure 9. Unconfined and confined oil formation volume factor at pore radii of 100 nm and 10 nm as a function of pressure, for the shale oil composition at a reservoir temperature of 250°F

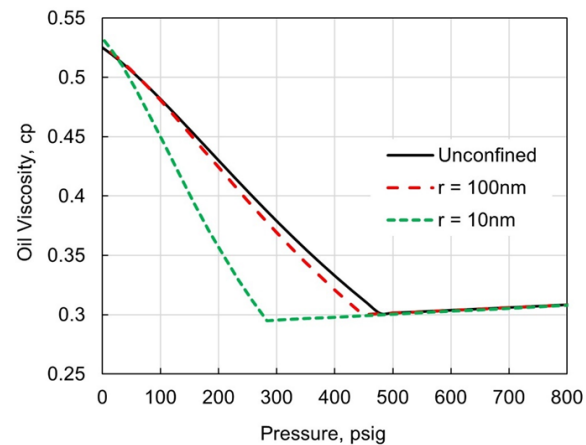


Figure 10. Unconfined and confined oil viscosity at pore radii of 100 nm and 10 nm as a function of pressure, for the shale oil composition at a reservoir temperature of 250°F

4. Conclusion

The results of this study demonstrate the significant impact of capillary pressure and critical properties shift on the PVT behavior of hydrocarbon fluids in shale reservoirs. The study shows that confinement causes a depression in the bubble point pressure, resulting in lower oil viscosity and density at the bubble point, higher gas solubility, and formation volume factor, and lower oil viscosity at any pressure below the bubble point. The degree of depression increases with decreasing pore radius, and the effect is more pronounced at lower reservoir temperatures. The study also highlights that the confinement effect on shale oil properties becomes more significant as the pore radius of the porous media decreases. The observed deviations in oil PVT properties due to capillary pressure and critical properties shift can have a significant impact on the reservoir performance and production rates. The oil and gas production rates from the reservoirs can be different from what is expected, which can affect the overall profitability of the project. Therefore, it is crucial to consider these effects when designing and operating shale reservoirs. These findings highlight the importance of considering capillary pressure and critical properties shift in modeling and simulation studies.

Nomenclature

a	parameter in Peng-Robinson equation of state
$a_{L/V}$	parameter in Peng-Robinson equation of state
b	parameter in Peng-Robinson equation of state
$b_{L/V}$	parameter in Peng-Robinson equation of state
$A_{L/V}^*$	parameter in cubic equation of state
$B_{L/V}^*$	parameter in cubic equation of state
f_i^L	fugacity of component i in the liquid phase
f_i^V	fugacity of component i in the vapor phase
K_{ij}	binary interaction coefficient
K_i	K-values of component i
MW	molecular weight, $Ib/Ib.mole$
n_V	mole fraction of vapor
n_L	mole fraction of liquid
NC	number of components
ρ_L	density of the bulk liquid phase, Ib/ft^3
ρ_V	density of the bulk vapor phase, Ib/ft^3
P	reservoir pressure, $psia$
P_b	bubble point pressure, $psia$
P_{cap}	capillary pressure, $psia$
P_{ci}	critical pressure of component i , $psia$
P_L	liquid pressure, $psia$
P_V	vapor pressure, $psia$
r	pore radius, nm
P_{ch}	parachor constant for each component
R	universal gas constant
T	reservoir temperature, Rankine
T_r	reduced temperature
T_{ci}	critical temperature of component i , Rankine
V	mole volume of component i , $ft^3/Ib.mole$
V_c	critical volume
ω	acentric factor of component i
x_i	mole fraction of component i in the vapor phase
y_i	mole fraction of component i in the liquid phase
z_i	overall mole fraction of component i
Z	compressibility factor
σ	interfacial tension at the vapor-liquid phase, $dyne/cm^2$
Φ_i^L	fugacity coefficient of component i in the liquid phase
Φ_i^V	fugacity coefficient of component i in the vapor phase
ΔT_c	shift in critical temperature
ΔP_c	shift in critical pressure
σ_{eff}	effective molecular diameter, nm
D	Pore diameter
T_{cz}	confined critical temperature, Rankine
P_{cz}	confined critical pressure, $psia$

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