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An Integrated Approach to Determine the Hydrocarbon Compositions and PVT Properties of Unconventional Gas Condensate Reservoirs

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Summary

Accurate determination of composition and PVT properties of hydrocarbons is paramount for formation evaluation, resource assessment, and optimizing field operations to maximize hydrocarbon recovery. However, it is often difficult to obtain representative hydrocarbon samples from tight and shale gas condensate reservoirs due to their low permeability. Low permeability can cause a large pressure drawdown between the reservoir and the wellbore or near wellbore region, leading to problems such as condensate liquid dropout in the wellbore or reservoir, and reduced producing condensate-gas ratios (CGRs). Downhole sampling has been employed to resolve this issue, but there is no guarantee that the samples obtained by this method will be representative.

In this study, we propose an integrated approach to reliably determine in-situ hydrocarbon compositions and associated PVT properties of tight and shale gas condensate reservoirs by incorporating core analyses and fluid sampling data. In the proposed workflow, fluid samples are recombined and analyzed at various gas-liquid ratios to tune an equation of state (EOS) model. That data is then incorporated with core porosity, residual hydrocarbon saturation, and residual hydrocarbon composition from core analyses. The integrated method yields an accurate estimation of native hydrocarbon fluid composition, which can be further optimized by EOS-based modeling to match observed laboratory and field data.

The proposed approach is illustrated and validated using a numerical compositional simulation of a hydraulically fractured horizontal gas condensate well in the Duvernay Formation. Residual oil from core analyses were recombined with produced gas at various bottom hole flowing pressures, which consistently yielded fluids with properties similar to the native reservoir fluid; showing <3% error for C1-C3 and C12+ concentrations, CGR, and in-situ gas density and <5% error for C8-C11 concentration.

The success of the proposed approach depends on reliable core analyses and wellhead fluid sampling. Influences of incorrect core data (e.g. erroneous composition and saturation due to mud contamination) on results are discussed and recommendations are provided for applying the proposed approach to better characterize reservoir fluid properties of unconventional gas condensate reservoirs.

Theory

For a condensate reservoir with native fluid PVT properties characterized by the phase diagram in Fig. 1, hydrocarbons flowing into the wellbore are representative of the native reservoir fluid when the flowing bottom hole pressure (BHP) is greater than the dew point (e.g. 25.5 MPa), but condensate liquid will condense in the wellbore during production if the wellhead pressure is below dew point and the flow rate is insufficient to uplift the liquids. If the BHP is below dew point pressure (e.g., <25 MPa), condensate enriched with heavy hydrocarbon (HC) components will form in the reservoir adjacent to the wellbore too. In either case, the produced wellstream fluids are leaner than the native reservoir fluid. A core recovered from the same reservoir may undergo a pressure-temperature path similar to the producing reservoir (Fig. 1), which also leads to the formation of condensate. However, for core, the condensate liquid will likely remain in the core while gas escapes out of the core. The quantity of the residual condensate liquid in the core is measured using the Dean Stark technique. The produced hydrocarbons and residual oil compositions can be recombined to give a good approximation of the native reservoir wellstream, when taking into account the measured core porosity, hydrocarbon saturations, and reservoir pressure and temperature. This study attempts to investigate the above hypothesis by numerical compositional simulations.

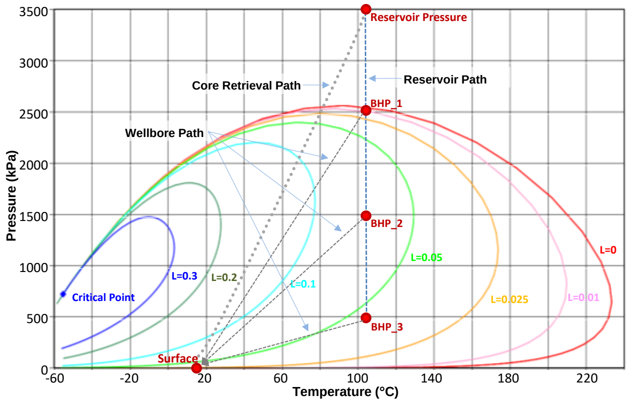

Figure 1. P-T phase diagram of the hydrocarbon fluid from a condensate Duvernay well.

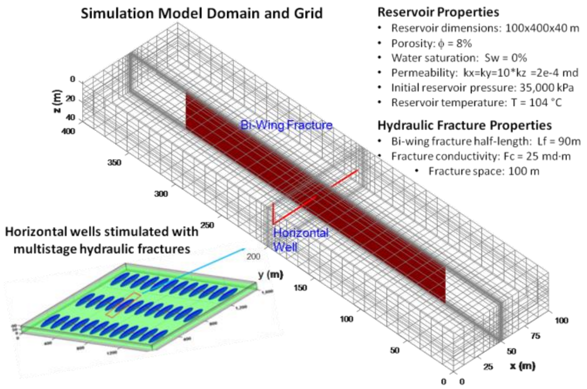
Simulation Model Domain and Grid
Reservoir Properties
Reservoir dimensions: 100x400x40 m
Porosity: ϕ = 8%
Water saturation: Sw = 0%
Permeability: kx=ky=10*kz =2e-4 md
Initial reservoir pressure: 35,000 kPa
Reservoir temperature: T = 104 °C
Hydraulic Fracture Properties
Bi-wing fracture half-length: Lf = 90m
Fracture conductivity: Fc = 25 md·m
Fracture space: 100 m
Bi-Wing Fracture
Horizontal Well
Horizontal wells stimulated with multistage hydraulic fractures
z (m)
y (m)
x (m)
0
20
40
400
350
300
250
200
150
100
50
0
100
75
50
25
0

Figure 2. Reservoir simulation model to study the compositional evolution of produced fluids.

To conduct the recombination, the pressure-volume-temperature (PVT) properties of the fluid should be established first, by analyzing various GORs of the produced gas and liquid, which allows the tuning of an equation of state (EOS) model. The tuned EOS can then be used to predict the PVT properties of different fluid compositions from the same reservoir or formation (e.g., Whitson & Sunjerga, 2012). Throughout this study, a hypothetical EOS is used to predict the PVT properties during simulations for consistency and simplicity.

Simulation Models

A compositional reservoir simulator MRST (Krogstad et al., 2015) was used to simulate the hydrocarbon production from a horizontal well stimulated with multi-stage hydraulic fractures (Fig. 2). However, only a sub-domain enclosing a single bi-wing fracture with symmetric boundaries was simulated in this study. Reservoir properties and model parameters are shown in Fig. 2. Locally refined grids were used to represent the horizontal wellbore and the high-conductivity hydraulic fracture. Phase change in production tubing was not considered; implying that anything flowed into the horizontal wellbore was produced to surface. The reservoir fluid properties were simulated with a PR EOS with the phase diagram depicted in Fig. 1, based on a hydrocarbon fluid of a Duvernay well. The same compositional simulator was expanded to simulate the hydrocarbon evolution in a core of 4 inches (10.2 cm) in diameter during its recovery from the coring point and afterwards; the variations of core temperature was also considered with thermal properties typical to sedimentary rocks.

Model Results

The results from one reservoir simulation case are shown in Fig. 3 & 5, and core retrieval simulation results are shown in Fig. 4 & 6. A stepwise decrease in BHP (i.e., 30, 25, 20, 15, 10, and 5 MPa) was applied to recover the hydrocarbons; each BHP was held for 2 days. After that, the well was shut in for 30 days and then re-started to flow with a BHP of 5 MPa for 2 years (Fig. 3a). As expected, the gas rate and GOR jumped as the BHP decreased from 30 to 5 MPa, but the gas rate decreased when BHP was held constant. On the other hand, the GOR remained relatively constant when the BHP remained relatively constant for either just 2 days or 2 years of production of different BHPs (Fig. 3b). The GOR was not restored to its initial value by the 30-day well shut-in after initial 12-day production. The produced wellstream fluids became more enriched with C1-C3 with lower BHPs (blue curves in Fig. 5a-b), whereas C4-C12+ became signficantly depleted (blue curves in Fig. 5c-f). As expected, the opposite occurred to the hydrocarbon fluids remained in the reservoir adjacent to the wellbore (red curves in Fig. 5a-5f).

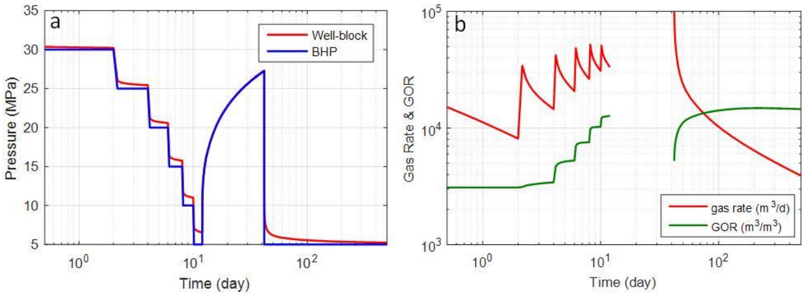

Figure 3. Well production simulation results: a) Well bottom-hole pressures (blue) and reservoir pressure adjacent to wellbore (red); b) Production gas rate (red) and associated gas-oil ratio (green).

The temperature path during core retrieval depends mainly on the recovery speed because heat transport in tight rock is dominated by conduction through rock matrix, and sedimentary rocks are relatively conductive to heat. The core pressure depends on not only the retrieval speed but also the core permeability (Fig. 4a & 4b). Oil saturation of the core likely reaches a maximum and then declines to a final constant (Fig. 4c), which is consistent with its P-T path illustrated in Fig. 1. Residual oil density increases as pressure and temperature decrease (Fig. 4d).

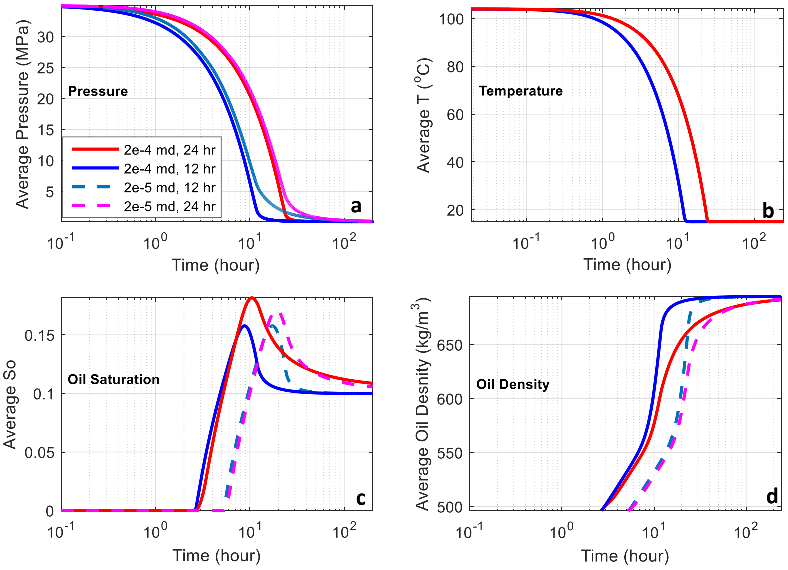

Figure 4. Core retrieval simulation results with two retrieval speeds and two permeabilities.

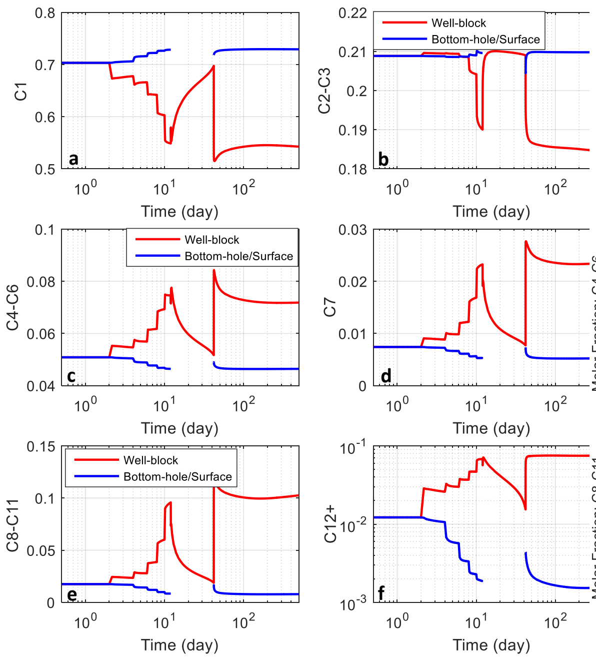

Figure 5. Compositional variation of produced hydrocarbon fluids from the reservoir

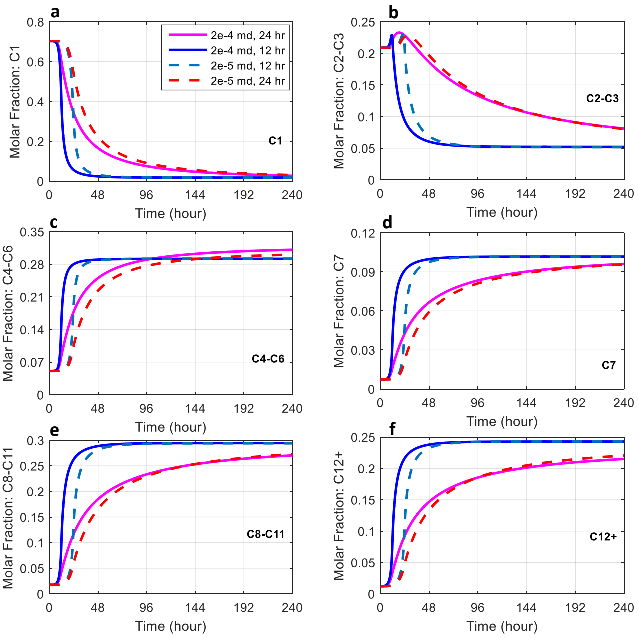

Figure 6. Compositional variation of hydrocarbon fluids remained in retrieved cores

The hydrocarbons remained in the retrieved cores of different permeability and recovery speeds became enriched in C4 – C12+ (Fig. 6c-f) and depleted in C1-C3 (Fig. 6a-b).

Based on the simulated condensate saturation and composition of the core with a permeability of 2e-4 md, reservoir fluids were reconstructed by adding more gas produced from the reservoir under different BHPs (Fig. 5) to fill up the core porosity to the reservoir pressure (35 MPa) and temperature (104 °C). The errors in mole fractions of the reconstructed fluids relative to the original fluid are consistently less than 3% for C1-C3 and C8-C12+ for all cases and relatively large errors for C4-C7 (Table 1). However, the gas-oil ratio and in-situ density of the re-constructed reservoir fluids have less than 3% errors for all cases studied, which is significantly better than the wellstream fluids produced under different BHPs, except for the case when the well was produced above the dew point pressure at a BHP of 30 MPa (Table 1).

Conclusions

The preliminary study results suggest that our proposed new method of integrating the residual oil of cores and the gas produced from wells can simulate the reservoir fluids well, especially for estimations of GOR and in-situ density and thus the resource in place of condensate and/or liquid rich shale gas reservoirs such as the Duvernay Formation.

Sampling Approach	Properties	GOR	Density	Total Hydrocarbon Composition (mole fractions)					
		m3/m3	kg/m3	C1	C2-C3	C4-C6	C7	C8-C11	C12+
	Original Fluid	3.11E+03	321	0.703	0.209	0.051	0.007	0.018	0.012
	Relative Error	%	%	%	%	%	%	%	%
Core Residual Oil + Well Stream Gas	30 Mpa	-3.1	-1.8	1.4	0.8	-22.0	-28.3	8.1	2.9
	25 Mpa	-2.9	-1.7	1.2	1.1	-21.2	-28.6	7.8	2.9
	20 Mpa	-2.3	-1.4	0.8	2.1	-18.2	-29.5	6.3	2.9
	15 Mpa	-1.9	-1.2	0.5	2.6	-15.9	-28.9	5.3	2.9
	10 Mpa	-1.9	-1.0	0.3	2.8	-14.3	-27.2	4.9	2.9
	5 Mpa	-2.0	-0.9	0.3	2.7	-13.5	-25.6	4.9	2.9
	5 Mpa (2 year)	-1.9	-0.9	0.3	2.7	-13.5	-25.7	4.8	2.9
Well Stream Only	30 Mpa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	25 Mpa	-10.6	1.4	0.4	0.0	-0.8	-2.1	-3.7	-12.9
	20 Mpa	-69.9	6.2	1.8	-0.1	-3.9	-10.4	-18.6	-53.2
	15 Mpa	-144.0	9.2	2.7	-0.1	-6.2	-17.5	-31.6	-72.6
	10 Mpa	-230.9	11.1	3.3	0.1	-7.9	-23.9	-43.4	-81.3
	5 Mpa	-310.5	12.1	3.6	0.4	-8.7	-28.4	-51.8	-84.7
	5 Mpa (2 year)	-358.7	12.5	3.7	0.5	-8.7	-29.1	-54.5	-86.9

Table 1. Summary of relative errors of recombined fluids as compared against the original fluids

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