

Comprehensive Experimental Study on Fluid Phase Behavior and Reservoir Microstructure of Ultra-Deep Condensate Gas Reservoirs in Block A

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Abstract: The efficient development of ultra-deep condensate gas reservoirs in the Block A Block is hindered by two major factors: the complex fluid phase behavior under high-temperature and high-pressure (HTHP) conditions and strong reservoir heterogeneity, hence the necessity for a systematic experimental study. Therefore, the authors integrated three well-suited laboratory techniques: high-pressure PVT phase analysis, constant-rate mercury injection (CRMI), and oil-water relative permeability measurements, and applied them to fluid samples and corresponding core plugs from three representative wells (Block A 83, Block A 21, and Block A 6). The PVT results conclusively established that all three fluids are typical condensate gases with clearly distinguishable critical parameters, most notably critical condensate pressure ranging from 41.60 MPa to 55 MPa. The study examined the fluid phase behavior and phase envelopes, thereby clearly identifying the varying risks of retrograde condensation. CRMI analysis was used to systematically quantify the microscopic pore-throat structures, from which the dominant throat radius range controlling fluid flow was determined. Oil-water relative permeability curves were then employed to obtain reliable endpoints: irreducible water saturation and residual oil saturation, both crucial for assessing water displacement efficiency. Most importantly, the paper rigorously links fluid phase behavior and microscopic reservoir architecture to macroscopic flow capacity, thus providing solid experimental basis and direct practical guidance for optimizing development strategies in the Block A Block, especially regarding pressure maintenance and well placement.

Keywords: Block A Block; Condensate Gas Reservoir; Phase Behavior Analysis;

Constant-Rate Mercury Injection; Relative Permeability; High-Temperature and High-Pressure (HTHP)

1. Introduction

1.1 Research Background and Significance

The Block A Block is well known for its ultra-deep (often >8000 m) carbonate oil and gas reservoirs under extreme conditions of high temperatures (often >150°C) and high pressures (often >70 MPa) [1], and among the hydrocarbon resources in this area, condensate gas reservoirs are both significant in volume and technically challenging to exploit efficiently [2]. The fundamental problem lies in the complex phase behavior of condensate fluids: when the bottom-hole flowing pressure drops below the dew-point pressure during production, liquid hydrocarbons (condensate) drop out in the reservoir, leading to severe formation damage, reduced gas productivity, and major economic losses [3]. Compounding this issue is the strong heterogeneity of the fractured-cavity carbonate reservoirs, which results in highly variable pore-throat structures that directly affect fluid flow paths, sweep efficiency, and ultimately the recovery factor [4].

Because a proper understanding of the dynamic fluid phase characteristics and the static reservoir micro structure is fundamental, systematic experimental investigations under simulated reservoir conditions are absolutely necessary. Data on fluid phase envelopes, critical parameters, microscopic pore-throat size distribution, and multi phase flow characteristics all serve as the basis for reliable reservoir simulation, accurate production forecasting, and the rational design of development strategies, including pressure maintenance by gas injection or Huff-n-Puff operations [5,6].

1.2 Current Research Status

Internationally, research on HTHP condensate

gas reservoirs focuses on accurate equation-of-state(EOS)characterization and tuning using advanced algorithms and comprehensive PVT data [7], experimental measurement of phase envelopes under extreme conditions[8],and the study of multi phase flow in complex porous media [9]. Advanced techniques like CRMI and digital rock physics are widely used to characterize nanoscale pore-throat systems in tight and unconventional reservoirs, providing more accurate capillary pressure curves and spatial connectivity information than conventional mercury intrusion porosimetry [10,11]. Similarly, relative permeability measurements under reservoir conditions, especially for gas-condensate systems, are crucial for understanding displacement dynamics and condensate banking [12]. In China, significant research efforts have been directed towards the unique geological and engineering challenges of ultra-deep carbonate reservoirs in the Tarim Basin [13,14]. While significant progress has been made in these areas, integrated studies that simultaneously

analyze fluid phase behavior, microscopic structure, and flow capacity for specific ultra-deep carbonate reservoirs like those in Block A are still limited and highly valuable.

1.3 Research Objectives and Technical Approach

This study aims to conduct a comprehensive experimental evaluation of the fluid and rock properties from the Block A Block's condensate gas reservoirs. The specific objectives are:(1)to determine the precise phase behavior and classify the hydrocarbon fluids from three key wells using HTHP PVT analysis;(2)to characterize the microscopic pore-throat structure of the reservoir cores using CRMI; and(3)to evaluate the oil-water flow capacity through relative permeability measurements. The integrated analysis of these three datasets seeks to establish correlations between fluid properties, rock micro structure, and flow performance, thereby providing direct insights for field development. The technical workflow is illustrated in Figure 1.

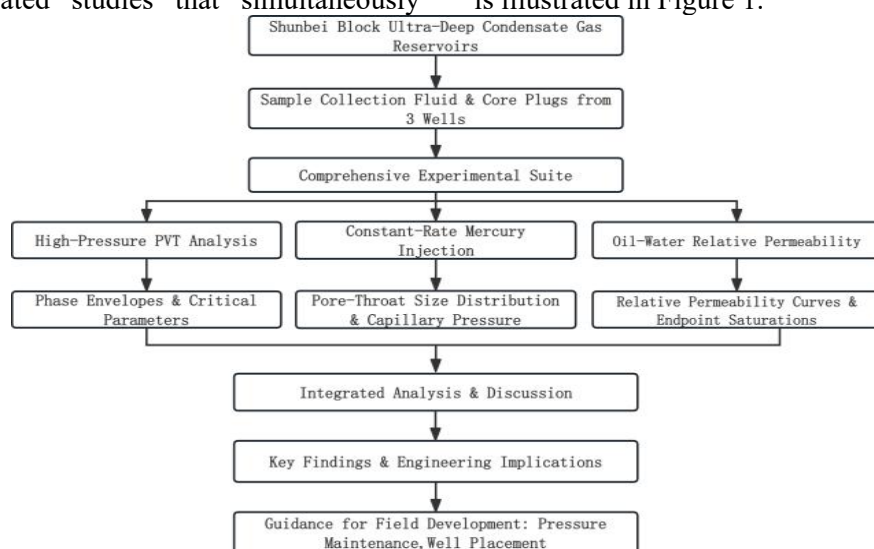


Figure 1. Technical Workflow of the Integrated Experimental Study

2. Experimental Samples and Methodology

2.1 Sample Information

A total of 12 samples, comprising hydrocarbon fluid(well stream)samples and associated reservoir core plugs from three wells(Block A

83,Block A 21,Block A 6),were analyzed. The testing program included PVT phase analysis, CRMI, and oil-water relative permeability measurements. The sample submission and testing were completed between February and June 2023.Detailed information is summarized in Table 1.

Table 1. Experimental Sample Information.

No.	Well Name	Sample Type	Submission Date	Test Item
1	Block A 83	Hydrocarbon Fluid	2023-02-08	PVT Phase Behavior Analysis
2	Block A 83	Reservoir Core Plug	2023-02-08	Constant-Rate Mercury Injection(CRMI)
3,4	Block A 83	Reservoir Core Plug	2023-02-08/04-12	Oil-Water Relative Permeability
5	Block A 21	Hydrocarbon Fluid	2023-03-15	PVT Phase Behavior Analysis

6	Block A 21	Reservoir Core Plug	2023-03-15	Constant-Rate Mercury Injection(CRMI)
7,8	Block A 21	Reservoir Core Plug	2023-03-15/04-12	Oil-Water Relative Permeability
9	Block A 6	Hydrocarbon Fluid	2023-04-12	PVT Phase Behavior Analysis
10	Block A 6	Reservoir Core Plug	2023-04-12	Constant-Rate Mercury Injection(CRMI)
11,12	Block A 6	Reservoir Core Plug	2023-04-12	Oil-Water Relative Permeability

2.2 Experimental Equipment and Procedures

2.2.1 High-temperature and high-pressure full-visualized PVT phase analysis

Experiments were conducted using a full-visualized PVT system with a maximum working pressure of 200Mpa and temperature of 200°C, with a cell volume of 250ml. The system offers high

precision (pressure: 0.01%FS, temperature: 0.1°C, volume: 0.0001 ml) and features electromagnetic stirring and 0-180° rotation. The experimental procedure included: (1) recombination of the well stream fluid based on separator gas and oil compositions to match the reported wellhead GOR; (2) Constant

Composition Expansion (CCE) tests at reservoir temperature to determine dew-point pressure and volumetric behavior; (3) determination of the full phase envelope by measuring bubble/dew points at multiple temperatures.

2.2.2 Constant-rate mercury injection (CRMI) test

A core test ASPE-730 constant-rate mercury injection apparatus was employed. Its key advantage over conventional mercury intrusion porosimetry (MIP) is the ultra-low and constant injection rate (0.00005 ml/min), which allows for the quasi-static measurement of capillary pressure and distinguishes between pore body and pore throat volumes. The instrument can detect throat radii as small as 0.12 μm. The test involves incrementally increasing the mercury pressure at a constant volumetric rate and recording the pressure and volume injected, from which detailed pore-throat radius distributions and capillary pressure curves are derived. 2.2.3 Oil-Water Relative Permeability Test

The experiments were performed using a core

Table 2. Key Phase Behavior Parameters for Condensate Gases from the Block A Block.

Well Name	Block A 83	Block A 21	Block A 6
Critical Pressure (MPa)	23.4	13.64	36.62
Critical Temperature (°C)	44	87.7	-26.6
Critical Condensate Pressure (MPa)	41.6	55.38	46.39
Critical Condensate Temperature (°C)	344	275.4	321.6
C ₁ +N ₂ Content (%)	81.35	82.36	84
C ₂ -C ₆ +CO ₂ Content (%)	13.09	12.62	9.23
C ₇ + Content (%)	5.56	5.03	6.77

flooding system consisting of a dual-cylinder precision syringe pump (flow rate: 0-10 ml/min), a Hassler-type core holder (rated for 70 MPa, accommodating 25 mm diameter × 80 mm long cores), a back-pressure regulator (0-70 MPa), and a data acquisition system (MOXA 168). The tests were conducted in a constant-temperature oven at reservoir temperature. The unsteady-state method was used: brine and oil were sequentially injected at a constant rate, and the effluent volumes and pressure differential across the core were recorded to calculate relative permeabilities using the JBN method.

2.3 Experimental Venue and Quality Control

All experiments were conducted at the professional laboratories of Dayue Huashuo Petroleum Technology Co., Ltd., Karamay, Province A, China, located at No. 29 Zhungaer Road (Rock and Mineral Lab) and Room 201-3-03, Jingliu Road (Conventional Lab) in Karamay. The use of calibrated, high-precision equipment and standardized procedures ensured the reliability and authority of the experimental data.

3 Results and Analysis

3.1 Condensate Gas Phase Behavior and Classification

3.1.1 Phase envelopes and key parameters

The PVT analysis confirmed that the hydrocarbon fluids from all three wells exhibit typical characteristics of condensate gases. The phase envelopes (Pressure-Temperature diagrams) were constructed, and key thermodynamic parameters were extracted. A comparative analysis is presented in Table 2 and Figure 2.

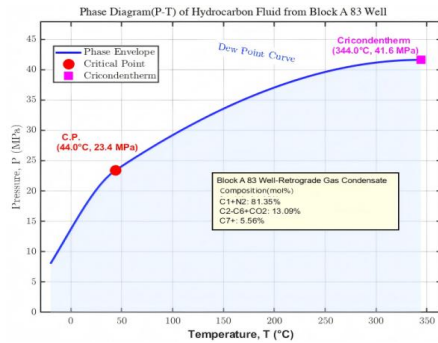


Figure 2. Comparative Phase Envelopes (P-T diagram) for Block A 83, 21, and 6 Wells, Highlighting Critical Points(C) and Critical Condensate Points (CC).

The data clearly show significant differences. Block A 83 has a moderate critical condensate pressure (41.60MPa). Its phase envelope is relatively wide.

Block A 21 possesses the highest critical condensate pressure (55.38MPa) but the lowest critical pressure, indicating a fluid highly sensitive to pressure changes near the dew-point line.

Block A 6 has an extremely low critical temperature (-26.6°C), with its critical point located far left on the phase envelope.

3.1.2 Fluid classification and triangular diagram analysis

The compositional analysis shows that the methane-plus-nitrogen(C₁+N₂)content exceeds 80%for all wells, while the heptane-plus(C₇⁺)fraction is below 10%.According to standard hydrocarbon fluid classification schemes(e.g., using a C₁+N₂,C₂-C₆+CO₂,C₇⁺ternary diagram), these compositional characteristics definitively classify the fluids as condensate gases. Plotting the compositions on the ternary diagram (Figure 3) visually confirms that all three samples fall squarely within the condensate gas region

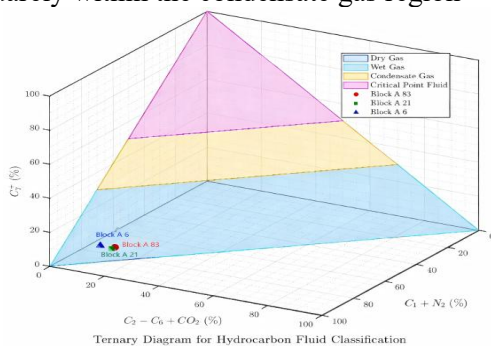


Figure 3.Ternary Diagram for Hydrocarbon Fluid Classification. The Data Points for Block A 83, 21, and 6 Wells are All Located Within the Condensate Gas Region.

3.2 Characteristics of Reservoir Micro-Pore-Throat Structure (CRMI)

The CRMI tests provide detailed quantification of the pore-throat system. A typical result includes a pore-throat radius distribution histogram and a cumulative mercury saturation curve (Figure 4). Key parameters derived from the analysis are summarized in Table 3.

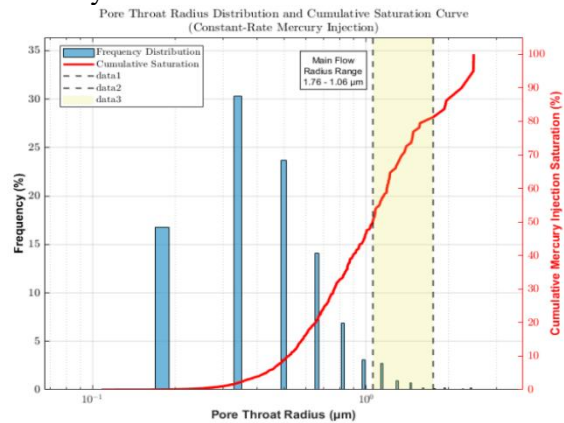


Figure 4. Pore-Throat Radius Distribution Frequency and Cumulative Mercury Saturation Curves of Typical Core Sample from Block A 83

Table 3. Key Micro Structural Parameters from Constant-Rate Mercury Injection Analysis

Parameter	Value	Unit
Maximum Mercury Injection Saturation(S_{Max})	85.7	%
Average Throat Radius(R_{avg})	1.19	μm
Median Throat Radius(R_{50})	1.06	μm
Displacement Pressure(P_d)	43.24	psi
Main Controlling Throat Radius Range	0.5-2.0	μm

The analysis indicates that the reservoir pore-throat system is characterized by a relatively wide distribution. The main flow paths are controlled by throats within the 0.5-2.0 μm radius range. The displacement pressure reflects the capillary threshold pressure needed to initiate mercury intrusion into the largest connected throats.

3.3 Evaluation of Reservoir Oil-Water Flow Capacity (Relative Permeability)

The oil-water relative permeability curves for the core samples were successfully obtained (Figure 5).Key endpoint parameters crucial for reservoir engineering calculations were extracted:

(1)Irreducible Water Saturation (S_{wi}): ~25%

(2) Residual Oil Saturation (S_{orw}): ~30%

(3) Endpoint Oil Permeability at ($K_{ro}@S_{wi}$): ~0.85

(4) Endpoint Water Permeability at S_{orw} / ($K_{rw}@S_{orw}$): ~0.12

(5) Cross point Saturation: ~55% Water Saturation

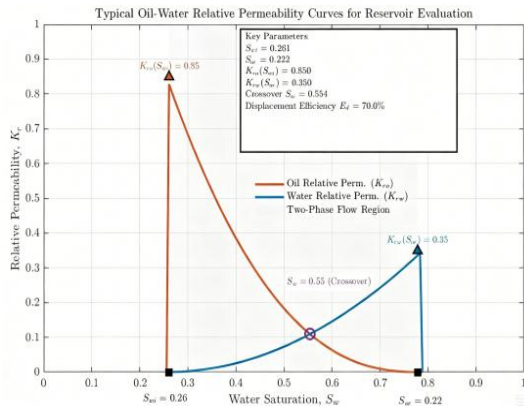


Figure 5. Typical Oil-Water Relative Permeability Curves for the Block A Reservoir Cores.

The curves exhibit characteristics of mixed-wet to oil-wet carbonate rock: a relatively rapid decline in oil relative permeability as water saturation increases, and a low endpoint water relative permeability. The significant residual oil saturation suggests challenges in achieving high displacement efficiency through water flooding alone.

4. Integrated Discussion and Development Implications

4.1 Impact of Fluid Phase Behavior Differences on Development Strategy

The different phase behavior of the three wells has very clear and important operational implications: Block A 21, which has the highest critical condensate pressure (55.38MPa), is by far the most susceptible to retrograde condensation if the bottom-hole pressure drops below this value, so maintaining flowing pressure above the dew point is absolutely critical for this well, necessitating earlier and more aggressive pressure maintenance actions (e.g., gas injection). In contrast, Block A 83 and 6 have lower critical condensate pressures and therefore have a slightly larger operating window, but both still require careful monitoring and control. The phase envelopes are thus invaluable inputs for compositional reservoir simulation to optimize production rates and design gas injection schemes.

4.2 Analysis of "Pore-Throat-Fluid-Flow" Synergistic Relationships

From an integrated viewpoint one can clearly see the possible correlations.

1. Because the CRM-defined main throat radius range (0.5-2.0 μm) determines which pore spaces are readily accessible to flowing fluids, it directly follows that condensate droplets formed in pores linked by throats smaller than this range are likely to be trapped, thus aggravating condensate blockage

2. Because the endpoint water permeability ($K_{rw}@S_{orw}$) measured in the relative permeability tests is quite low, it is clear that once water breaks through, well productivity will drop sharply. This behavior is very naturally explained by the pore-throat structures: water flows preferentially through large pores/throats and bypasses oil in the smaller ones

3. Because a condensate fluid undergoing liquid dropout is combined with a pore system containing a large amount of small throats (which have high capillary forces), the composite effect leads to complex three-phase (gas-condensate-water) flow, hence a reduction in recovery efficiency

4.3 Recommendations for Efficient Development of the Block A Block

Based on the integrated experimental evidence, the following engineering recommendations are proposed:

1. Use differentiated pressure management techniques by first implementing a well-specific pressure maintenance strategy and then injecting gas preferentially in wells such as Block A 21 whose pressures are near their dew point.

2. Consideration of Wettability Alteration: Given the relative permeability curves indicating possible oil-wet tendencies, investigating chemical treatments to alter wettability to more water-wet conditions could improve water flood efficiency and reduce residual oil saturation.

3. Since the quantified pore-throat distributions can be naturally and usefully integrated into geological and simulation models, it is logical to use them to predict fluid flow paths and sweep efficiency, thus aiding in well placement and completion design in heterogeneous zones.

4. Because the in-situ process has not yet been adequately studied, it is clear that future

experimental work should involve measurements of gas-condensate relative permeability under reservoir conditions to determine directly the effect of condensate dropout on gas deliver ability

5. Conclusions

1. The hydrocarbon fluids from Block A 83, 21, and 6 wells are definitively classified as condensate gases, as confirmed by PVT phase envelopes and compositional analysis ($C_1+N_2>80\%$, $C_7^+<10\%$). However, their key phase parameters (e.g., critical condensate pressure ranging from 41.60 to 55.38MPa) differ significantly, indicating varying sensitivities to pressure depletion and thus necessitating customized development strategies for each well or zone.

2. The constant-rate mercury injection analysis successfully quantified the microscopic pore-throat structures of the reservoir cores. The main fluid flow pathways are controlled by throat radii in the range of 0.5 to 2.0 μm . This parameter is critical for understanding capillary-controlled processes, including condensate dropout and trapping.

3. From the oil-water relative permeability experiments, reliable two-phase flow parameters were obtained: an irreducible water saturation of $\sim 25\%$, a residual oil saturation of $\sim 30\%$, and a low endpoint water relative permeability (~ 0.12), which therefore provide a clear quantification of fluid flow capacity and efficiency, making them extremely valuable for numerical simulation and production forecasting. The present paper gives a very sound experimental basis for studying the fluid-rock interactions in the Block A Block's ultra-deep condensate gas reservoirs, but it is also clearly and honestly acknowledged that the limited number of samples restricts the ability to fully characterize the field heterogeneity. Therefore, future work should enlarge the sample set and perform experiments under true HTHP conditions with gas-condensate multi phase flow.

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