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Research on the Mechanism of Gas Injection for Enhanced Production in High-Sulfur Gas Reservoirs (ICCUSC2025)

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ABSTRACT

The marine acidic gas in Zhongyuan Oilfield is mainly distributed in the Puguang gas field in northeastern Sichuan, with characteristics such as "burial permeability, high H_2S and CO_2 content, and strong edge and bottom water". As the gas field development enters the middle and lat-er stages, there are problems such as continuous decrease in formation pressure, water invasion, and increasingly serious sulfur deposition. Energy supplementation effects of gas injection with flue gas, tail gas, nitrogen, and CO_2. Experiments show that the production enhancement effects are comparable under different injected media; the displacement recovery efficiency of gas-displacing-gas is high, and under the condition of equal injection volume, the recovery efficiency differs by only 0.5% - 0.9%. Compared with depletion development to different abandonment pressures, gas injection can increase the recovery efficiency by 10-27 percentage points. Gas injection for energy supplementation prioritizes the production of main layers. When 0.7 PV is injected, the recovery factor basically reaches 93%. The poor layers are affected by the partial pressure and split gas volume, resulting in slow response to energy supplementation. However, their recovery factor continues to increase as the injected gas volume rises. The main mechanisms of enhanced oil recovery by gas injection in the Puguang Gas Field are energy supplementation and displacement. Capturing CO_2 and reinjecting it into gas reservoirs in high-sulfur gas fields can effectively improve oil recovery, and reinjecting tail gas can reduce carbon emissions, contributing to the achievement of the "dual carbon" goals.

Keywords: High-Sulfur Gas Reservoirs, Enhanced Production, Gas Injection, Mechanism Research

NONMENCLATURE

Abbreviations	
APEN	Applied Energy
Symbols	
n	Year 2025

1. INTRODUCTION

The Puguang Gas Field is China's first high-sulfur gas field put into development. It has maintained stable production for 15 years, with its output accounting for 25% of Sinopec's conventional natural gas production, a relatively high proportion. Its sustained high and stable production plays an important role in the large-scale development of natural gas. The Puguang Gas Field is currently mainly developed using the depletion method and has entered the middle and late stages of development. Its calibrated recovery factor is 65.0%, which is lower than that of some high-sulfur gas reservoirs with higher recovery factors abroad (77%-97%). Therefore, there is certain potential for improving the recovery factor of the gas field. In the middle and late stages of development, there exist development contradictions such as low pressure, water invasion and intensified sulfur deposition, which affect the recovery factor of the gas reservoir. It is urgent to tackle key problems in aggressive enhanced oil recovery technologies. Both the produced gas from the gas field and the tail gas from the purification system contain CO_2 (2 million tons per year), which has the potential to reduce carbon emissions and enhance oil recovery after being reinjected into the gas reservoir. An analysis of gas

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injection mining cases both domestically and internationally, such as in depleted gas reservoirs, ultra-low pressure gas reservoirs, and water-invaded gas reservoirs, shows that gas injection development can play a role in improving development effects. The Hungarian gas field is located in the Transdanubian region of Hungary. Due to the abundant natural CO_2 gas reservoirs near this gas field, a pilot test of CO_2 injection to enhance oil recovery was conducted on its Szintfeletti gas reservoir in the 1980s. The injected gas was impure CO_2, containing 20% CH_4, and the gas source was the adjacent natural CO_2 gas reservoir. When the CO_2 content in the produced gas exceeded 20%, the gas well was shut down. The recovery factor increased from 67% at the start of CO_2 injection to 78.6%. In the Hoflein condensate gas field in Austria, high-rate CO_2 injection (5-10%) at the edge of the field increased the reservoir pressure, leading to a rise in the production of gas and condensate. However, due to extremely low sweep efficiency, only a small amount of gas was displaced after CO_2 breakthrough. Moreover, the higher the CO_2 injection rate, the lower the cumulative gas production. Kela-2 is a typical edge-bottom water gas reservoir, currently suffering from severe water invasion (0.97 cubic meters per 10,000 cubic meters). High-permeability layers are developed in the eastern part, with a large water body, underdeveloped fractures, and a large amount of remaining gas in the water-flooded area, making it relatively suitable for gas injection. The well groups KL2-1 ~ KL2-10 ~ KL204 in the water-flooded area are selected for gas injection tests. After the success of the gas injection tests, the promotion of nitrogen (N_2) injection for enhanced recovery will be further carried out. It is planned to conduct 14 well times of gas injection from 2026 to 2030. After 2030, an overall secondary development of the gas reservoir will be carried out, with new wells deployed around the water-flooded area and N_2 injection implemented to displace the remaining gas, aiming to further improve the gas reservoir recovery factor, which is expected to reach 76%. There are several challenges in carrying out gas injection to enhance oil recovery in the Puguang Gas Field.

The understanding of the mechanisms by which gas injection in the middle and late stages of development can replenish energy, block water, control sulfur, and improve development effects is unclear. There is no practical experience in gas injection for high-sulfur gas reservoirs at home and abroad to draw on, and no reasonable technical policies such as injection modes, injection media, and injection-production ratios have been formed. The response characteristics and effects during the gas injection process, as well as the main controlling factors for enhancing oil recovery, are not clear.

2. EXPERIMENTAL OF ENHANCED OIL RECOVERY BY GAS INJECTION

2.1 Experimental Preparation Stage

2.1.1 Experimental Purpose and Scheme Design

The long-core gas flooding experiment is an indoor experiment that simulates the process of displacing original natural gas with gas during gas reservoir development. Its core purpose is to study the different dominant displacement mechanisms caused by property differences (such as viscosity contrast, gravity segregation, and diffusion) of various displacing gases, as well as the effects and influencing factors of improving gas reservoir recovery efficiency, including displacement pressure, gas flooding type, and core heterogeneity. Since natural gas is the main fluid in gas reservoirs, the experiment must focus on simulating the high pressure, specific temperature, and gas flow characteristics of the gas reservoir.

Key design parameters include the type of displacing gas medium, displacement pressure, displacement rate, and monitoring or collection indicators such as pressure distribution along the core, gas production rate, changes in gas components, recovery factor, and displacement front position.

2.1.2 Long-Core Preparation

Gas reservoir cores are typically carbonate rocks, and their properties related to gas flow need to be characterized with emphasis.

Measure the length, diameter, and pore volume (PV) of the long core (usually 100–500 cm in length and 5–10 cm in diameter); determine porosity using a helium porosimeter; measure absolute permeability using single-phase gas (e.g., nitrogen) displacement method (correction for gas slippage effect, i.e., Klinkenberg effect is required).

Oil washing and drying: If the core contains a small amount of formation oil, wash it with an organic solvent (e.g., toluene), then dry it in an oven at 105°C for 48 hours to remove moisture and residual organic matter.

Formation water saturation (optional): If there is connate water in the gas reservoir, saturate the core with simulated formation water (configured according to the salinity of the reservoir water) to establish connate water saturation (\\(S_{wi}\\)). The method is the same as that for oil reservoir cores (inject at constant pressure after vacuuming until no bubbles exit from the outlet).

2.1.3. Fluid Preparation

Fluids must match the actual fluid characteristics of the gas reservoir, including simulated reservoir natural gas and displacing gas.

Simulated reservoir natural gas: Prepare a mixed gas using a high-pressure gas distribution device according to the composition of the target reservoir's natural gas. Determine its density, viscosity, and compressibility under experimental conditions (using a PVT instrument).

Displacing gas: Select the gas designed for the experiment, and similarly determine its high-pressure physical parameters (viscosity, density, and miscibility pressure with the simulated natural gas).

2.1.4 Experimental Device Setup and Calibration

The experimental device must meet the requirements of high-pressure gas displacement.

Long-core holder: Resistant to high pressure and corrosion, capable of applying confining pressure (5–15 MPa higher than the displacement pressure), with reserved pressure monitoring interfaces along the length of the core.

Gas displacement system: Includes a constant-rate and constant-pressure injection pump (accuracy ±0.1%) and high-pressure intermediate containers (for storing simulated natural gas and displacing gas, with a volume of 500–1000 mL).

Monitoring and metering system: Includes pressure sensors (accuracy ±0.01 MPa) for monitoring pressures at the inlet, outlet, and along the core; a gas chromatograph for online or offline analysis of produced gas components to distinguish between displacing gas and original natural gas; as well as a gas flowmeter and a high-pressure separator.

Temperature control system: Includes a constant temperature oven (temperature control accuracy ±0.5°C) to ensure that the temperature of the core and intermediate containers is stable at the reservoir temperature.

After setup, high-pressure leak testing with nitrogen is required: pressurize the system to 1.2 times the experimental pressure, maintain the pressure for 2 hours, and a pressure drop $\leqslant 0.5$ MPa is considered qualified. Calibrate pressure sensors, flowmeters, and gas chromatographs.

2.2 Experimental Operation Process

2.2.1 Core Saturation with Simulated Natural Gas

Load the pretreated long core into the holder, apply confining pressure, turn on the temperature control to the target temperature, and stabilize for 2 hours. Replace the air in the core pores with simulated natural gas: first vacuum the core for 2 hours, then slowly inject simulated natural gas into the core through the intermediate container, control the injection pressure to the original reservoir pressure (e.g., 25 MPa), and saturate at constant pressure for 48 hours (to ensure that the gas fully enters the pores, including micropores and adsorption sites). Calculate the saturation amount based on the volume change of gas in the intermediate container and combined with the core pore volume to obtain the original gas saturation.

2.2.2 Execution of Gas Flooding Experiment

Record the initial state, including core inlet pressure, outlet pressure, temperature, and initial gas production. Set displacement parameters and select the displacement mode according to the experimental design.

Constant pressure displacement: Set the displacement pressure and stabilize the outlet pressure through a backpressure valve. Constant rate displacement: Set the gas injection rate (e.g. 0.5–2 mL/min, simulating on-site injection intensity) to ensure stable flow and avoid gas channeling caused by turbulence.

During gas displacement, start the displacement pump, inject displacing gas into the core inlet, continue displacement, and monitor in real time:

Record the pressure at each point along the core every 5–10 minutes (to determine the position of the displacement front; e.g., a sudden pressure drop indicates the front).

After the outlet gas passes through the separator (to remove trace water), measure the instantaneous gas production with a flowmeter, collect gas samples every 30 minutes, and analyze the components using a gas chromatograph (e.g., the proportion of displacing gas components to determine if breakthrough occurs).

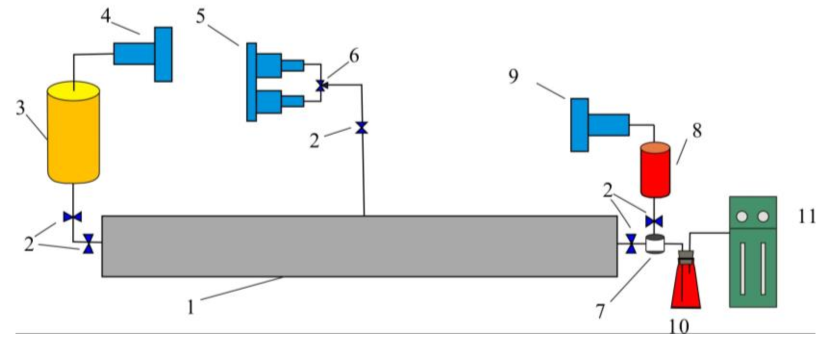
If gas channeling occurs (a sudden increase in gas production and the proportion of displacing gas > 90%), record the breakthrough time and continue displacement until the proportion of original natural gas in the produced gas is < 5% (considered the displacement endpoint).

2.2.3 Displacement Termination Conditions

Stop displacement when the proportion of the target natural gas component in the produced gas is $\leqslant 1\%$, or when the cumulative gas production no longer increases (change < 0.1% within 2 hours). Record the total displacement time, total injected gas volume, and total produced gas volume.

2.3 Data Recording and Analysis Stage

2.3.1 Raw Data Collation



1-Long core reservoir model, 2-needle valve, 3-piston container, 4-constant-rate and constant-pressure single-cylinder pump, 5-constant-rate and constant-pressure double-cylinder pump, 6-three-way valve, 7-backpressure valve,8-intermediate container, 9-backpressure tracking pump, 10-separator, 11-gas meter

Fig. 1. Flow chart of gas injection long core experimental device

Collate pressure data, gas production data, component data, etc. Plot curves of inlet pressure, outlet pressure, and pressure distribution along the core over time. Measure instantaneous gas production and cumulative gas production. Determine the changes in volume fractions of each component in the produced gas (e.g., methane, displacing gas) over time.

2.3.2 Calculation of Key Parameters

Natural gas recovery factor：

$$Eg = \frac{Cumulative\ produced\ natural\ gas\ volume}{\text{Original gas volume in core}} \times 100\%$$

Displacement efficiency:

$Ed = \frac{\text{Displaced natural gas volume}}{\text{Original gas volume}} \times 100\%$ (corrected by subtracting the mixed volume of displacing gas).

Gas breakthrough time and post-breakthrough recovery factor, Record the time when the proportion of displacing gas in the production first exceeds 10%, and calculate the difference in recovery factor before and after breakthrough (to evaluate the impact of gas channeling).

Displacement front advancement speed, Calculate the change in front position over time based on pressure distribution, and analyze the impact of heterogeneity on the front (e.g., front fingering caused by high-permeability zones).

2.4 Experimental Conclusion Stage

2.4.1 Device and Core Treatment

After stopping displacement, slowly reduce the system pressure (to avoid core rupture due to sudden pressure drop) and turn off the temperature control system. Remove the core; if residual gas analysis is required, conduct a desorption experiment (use a desorber to measure the residual natural gas adsorbed by the core). Clean intermediate containers, pipelines, and chromatographic sampling bottles to avoid residual gas contamination in subsequent experiments.

2.4.2 Result Analysis and Reporting

Plot key curves (e.g., recovery factor vs. displacement time, pressure distribution vs. core length, gas components vs. production volume) and summarize combined with experimental phenomena. Clarify displacement mechanisms, analyze influencing factors, and provide recommendations for on-site application.

3. MATERIAL AND METHODS

3.1 Materials

3.1.1 Core Samples

Long cores (98.5 cm in length, 2.5-2.6 cm in diameter) were collected from carbonate gas reservoirs, representing the target formation’s lithology and heterogeneity. Core properties, including porosity (measured via helium porosimetry), absolute permeability (corrected for Klinkenberg effect using nitrogen displacement), and pore volume (PV), were pre-characterized. Prior to experiments, cores were cleaned with toluene to remove residual fluid, dried at 105°C for 48 hours, and optionally saturated with simulated formation brine to establish connate water saturation via vacuum-pressurization.

3.1.2 FluidsSimulated Reservoir Gas

A gas mixture matching the target reservoir’s composition was prepared using a high-pressure gas blender. Its density, viscosity, and compressibility were measured with a PVT analyzer under experimental conditions.

Displacing Gases: High-purity gases (CO_2, N_2), flue gas, and tail gas were used as injected media. Their high-pressure properties (viscosity, density, and miscibility pressure with reservoir gas) were determined to ensure compatibility with simulation requirements.

Tab1. Long core pressure depletion development recovery factor table

Presure（MPa）	46.01	43.03	39.97	36.79	34.04	31.04	28.06	25.07	21.97	19.04	16.01	12.75	10.06	7.08	4.09
Eg（%）	0.00	2.76	5.93	9.69	13.07	17.02	21.26	25.81	30.86	35.85	41.76	47.68	53.25	59.06	64.91

Tab2. Comparison of energy supplement experimental data for different injected media

injected media	viscosity (mPa・s)	pressure difference (MPa)	breakthrough time (PV)	recovery factor (%)
nitrogen	0.024	0.08	0.50	75.95
flue gas	0.025	0.19	0.53	75.68
carbon dioxide	0.035	0.22	0.58	75.78
natural gas	0.019	-	-	-

Tab3. Recovery degree under different displacement pressures and displacement rates

injected media	displacement pressure(MPa)	injection rate(m/d)	pressure difference (MPa)	recovery factor (%)
carbon dioxide	18	0.3	0.20	73.72
carbon dioxide	22	0.3	0.22	75.78
carbon dioxide	30	0.3	0.24	78.11
carbon dioxide	46	0.3	0.30	78.65
carbon dioxide	22	0.9	0.60	77.81
carbon dioxide	22	1.5	1.10	78.10

3.2 Experimental Setup

A high-pressure core flooding system was assembled to simulate reservoir conditions.

Long-Core Holder. A corrosion-resistant, high-pressure vessel (⩾60 MPa) with confining pressure control (5-15 MPa above injection pressure) and pressure taps along the core length for spatial pressure monitoring.

Injection System. Constant-rate/constant-pressure pumps (±0.1% accuracy) and high-pressure intermediate containers (500–1000 mL) for storing reservoir gas and displacing gases.

Monitoring & Metering. Pressure sensors (±0.01 MPa) at inlet/outlet and core intervals; a gas chromatograph for online/offline compositional analysis; a mass flowmeter for measuring injection/production rates; and a high-pressure separator for dehydrating produced gas.

Temperature Control. A thermostatic oven (±0.5°C precision) to maintain reservoir temperature (e.g., 126°C) for cores and fluid containers.

System integrity was verified via leak testing (pressurization with N_2 to 1.2× experimental pressure, holding for 2 hours with ⩽0.5 MPa pressure drop). All instruments (sensors, flowmeters, chromatograph) were calibrated using standard gases and reference materials.

3.3 Experimental Procedures

3.3.1 Core Saturation with Reservoir Gas

Pretreated cores were loaded into the holder, and confining pressure was applied. After stabilizing at reservoir temperature for 2 hours, cores were evacuated for 2 hours, then saturated with simulated reservoir gas at original formation pressure (e.g., 65 MPa) for 48 hours to achieve initial gas saturation. Saturation was quantified via volume changes in intermediate containers, corrected for gas compressibility.

3.3.2 Gas Flooding ExperimentsInitial

Conditions: Inlet/outlet pressures, temperature, and baseline gas production were recorded.

Displacement Modes: Either constant-pressure (controlled via backpressure valve) or constant-rate (0.5-2 mL/min) injection was used to avoid turbulence-induced channeling.

Monitoring: Pressure profiles along the core were recorded every 5–10 minutes to track displacement front movement. Produced gas was sampled every 30 minutes for compositional analysis via gas chromatography. Breakthrough time was noted when displacing gas concentration exceeded 10% in produced fluids.

Termination: Experiments stopped when target gas (e.g., CH_4) in produced gas dropped to ⩽ 1% or cumulative production stabilized (<0.1% change over 2 hours). Total injection/production volumes and displacement duration were recorded.

3.4 Data Analysis

Raw data (pressures, production rates, gas compositions) were compiled to calculate key metrics:

Recovery Factor:

$$Eg = \frac{Cumulative\ produced\ gas\ volume}{\text{Initial gas volume in place}} \times 100\%$$

Displacement efficiency:

$Ed = \frac{\text{Displaced gas volume}}{\text{Initial gas volume in place}} \times 100\%$ (adjusted for displacing gas mixing).

Breakthrough Analysis: Recovery differences before/after breakthrough were analyzed to assess channeling impacts.

Frontal Velocity: Displacement front movement was derived from pressure profiles to evaluate heterogeneity effects (e.g., preferential flow in high-permeability zones).

Curves (recovery vs. time, pressure distribution, composition vs. production) were plotted to interpret displacement mechanisms and energy supplement effects of different injected media.

4. RESULTS

Physical Simulation Study on the Effect of Gas Injection for Energy Supplement.

Through physical simulation research on the energy supplement effect of gas injection in long cores, factors such as gas injection methods, gas injection media, gas injection timing, and gas injection rate were studied to evaluate the effect of gas injection for energy supplement and production enhancement in high-sulfur carbonate rocks, as well as the technical policies for production enhancement.

Through energy supplement experiments using CO_2 and flue gas, this study clarifies the impacts of gas injection timing, energy supplement pressure, and injection methods on development efficiency. The results provide a basis for numerical simulations and the formulation of field application plans.

Optimal Injection Timing: Early injection (before significant pressure depletion) enhances sweep efficiency by maintaining reservoir pressure and reducing gas slippage effects.

Pressure Thresholds: Recovery efficiency increases with injection pressure up to a critical point (e.g., minimum miscibility pressure for CO_2), beyond which gains plateau due to increased compression costs.

Injection Strategies: Continuous gas injection achieves higher initial recovery, while huff-n-puff cycles improve sweep in heterogeneous reservoirs by mitigating channeling.

These insights guide the design of efficient gas injection schemes, balancing recovery enhancement with operational feasibility.

5. DISCUSSION

Energy supplementation effects of gas injection with flue gas, tail gas, nitrogen, and CO_2. Experiments show that the production enhancement effects are comparable under different injected media; the displacement recovery efficiency of gas-displacing-gas is high, and under the condition of equal injection volume, the recovery efficiency differs by only 0.5% - 0.9%. Compared with depletion development to different abandonment pressures, gas injection can increase the recovery efficiency by 10 - 27 percentage points. In heterogeneous reservoirs, gas injection preferentially produces the main layers, and the recovery efficiency basically reaches 93% with an injection of 0.7 PV. The poor layers are affected by partial pressure and split gas volume, resulting in slow response to energy supplementation, but their recovery efficiency continues to improve as the injected gas volume increases.

Production by relying on natural energy and pressure reduction has brought the current formation pressure down to 22 MPa, with the natural gas recovery factor being only 31.34%. Under the condition of 22 MPa, energy supplementation by injecting carbon dioxide, flue gas, and nitrogen respectively results in little difference in the final recovery factor. This indicates that gas displacement is similar to piston displacement, and different injected media have little impact on the final recovery factor.

The earlier gas injection is conducted in a gas field, the higher the carbon dioxide injection pressure, the easier it is to enter tiny pores, the stronger the displacement capacity, and the better the energy supplement effect. The energy supplement effect at 46 MPa is 4.93 percentage points higher than that at 18 MPa.

The faster the gas injection rate, the better the energy supplementation effect. As the injection rate increases, the injection-production pressure difference increases, and the extent to which energy supplementation improves oil recovery increases.

Clarify the differences in the effect of interlayer gas injection for energy supplementation under the conditions of heterogeneous reservoirs and multi-layer commingled injection. For single-layer gas injection, permeability affects the effect of gas injection for energy supplementation; the effect of gas injection for energy supplementation in improving recovery efficiency in medium-high permeability layers is 6.21 percentage points greater than that in low permeability layers. In the initial stage of gas injection in the multi-layer gas injection for energy supplementation experiment, medium-high permeability reservoirs serve as preferential channels, and the recovery degree rises rapidly. When 0.66 times the pore volume is injected, the recovery efficiency reaches 70%, and the subsequent upward trend of recovery efficiency from gas injection for energy supplementation becomes very slow. During the process of gas injection for energy supplementation in low permeability layers, the recovery efficiency shows a linear upward trend all the time. Interlayer heterogeneity affects the upward trend of recovery efficiency improved by gas injection for energy supplementation; however, when the gas injection volume reaches 5.42 times the pore volume, the impact of heterogeneity on the final recovery efficiency of medium-high permeability and low permeability reservoirs is less than 0.25 percentage points.

A comparison of water invasion conditions under depletion production, nitrogen injection, CO_2 injection, and tail gas injection shows that CO_2 injection has the best water control effect.

The water control effect of CO_2 is better than that of tail gas and nitrogen, mainly because it is in a supercritical state in the Puguang formation, with a density close to that of liquid. However, nitrogen does not have similar density and viscosity characteristics.

6. CONCLUSIONS

The main mechanisms of enhanced oil recovery by gas injection in the Puguang Gas Field are energy supplementation and displacement.

Edge water invasion mainly enters high-permeability layers. After water breakthrough, the resistance of high-permeability layers increases significantly, with the recovery factor being only 42.79% when water flooding occurs, making gas injection for production enhancement very necessary. Edge water invades low-permeability layers slowly, resulting in a relatively high recovery factor of 55.04%. After water breakthrough in high-permeability layers, developing by injecting CO_2 at the outlet end of high-permeability layers can effectively supplement the energy of the gas reservoir, play a role in water control, and connect the CH_4 blocked by edge water.

The water control effect of CO_2 is better than that of tail gas and nitrogen. The main reason is that carbon dioxide is in a supercritical state in the Puguang formation, with a density close to that of liquid. However, nitrogen does not have similar density and viscosity characteristics.

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DECLARATION OF INTEREST STATEMENT

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. All authors read and approved the final manuscript.

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