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Reservoir Temperature and Pressure Impacts on Oil Recovery Factor of Enhanced Oil Recovery during Methane-rich, Propane-rich, and Carbon Dioxide Gas Injections

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Abstract: *This study investigated the impact of reservoir temperature and pressure on Enhanced Oil Recovery (EOR) using methane-rich gas, propane-rich gas, and CO_2 gas injections. A comprehensive experimental design was employed, involving 27 core samples used in a core flooding apparatus, and with varying temperatures (100^OF, 150^OF, and 200^OF) and pressures (1500 psi, 2500 psi, and 3500 psi). the results showed that CO_2 injection yielded the highest oil recovery factors, ranging from 18% to 35%, followed by Propane-rich gas injection (12% to 28%) and methane-rich gas injection (10% to 25%). Lower temperatures and higher pressures were found to improve oil recovery factors for all gas injection methods. The optimum conditions for CO_2 injection were 100^oF and 3500 psi, resulting in a recovery factor of 35%. The verdicts of this experiment offer substantial understandings into the optimum conditions for maximizing oil recovery using natural gas injection and highlight significance of considering reservoir temperature and pressure in EOR operations.*

Keywords: Enhanced Oil Recovery, Methane-rich gas, Propane-rich gas, CO_2 gas, Recovery factor

INTRODUCTION

Enhanced Oil Recovery (EOR) is a technique used to increase the amount of oil that can be extracted from an oil reservoir. The escalating global energy demand, coupled with the depletion of conventional oil reserves, has necessitated the development and optimization of Enhanced Oil Recovery (EOR) techniques (Alvarado & Manrique, 2010). Among these, gas injection methods, particularly Natural Gas (NG) and Carbon Dioxide (CO2) injection, have gained significant attention due to their potential to substantially increase oil recovery factors (Sheng, 2013). However, the efficacy of these techniques is profoundly influenced by reservoir conditions, specifically temperature and pressure, which dictate the thermodynamic and hydrodynamic behavior of the injected gases and the reservoir fluids (Kokal & Al-Kaabi, 2010).

The impact of reservoir temperature and pressure on the oil recovery factor during NG and CO2 injection is multifaceted. Temperature affects the viscosity and density of the reservoir fluids, influencing the mobility ratio and, consequently, the displacement efficiency (Yu et al., 2019). Pressure, on the other hand, determines the miscibility conditions for gas injection, with miscibility being a critical factor in achieving high oil recovery factors (Ahmadi & Johns, 2011).

This study aims to evaluate the impact of reservoir temperature and pressure on the oil recovery factor during natural gas NG) and CO_2 injection, with a particular focus on understanding the complex interplay between these variables and the underlying thermodynamic and hydrodynamic mechanisms. By investigating the effects of varying temperatures and pressures on oil recovery, this research seeks to provide insights into the optimal conditions for maximizing oil recovery factors using NG (Natural Gas) and CO_2 injection.

LITERATURE REVIEW

Reservoir temperature affects the physical properties of the injected fluids and the oil. Higher temperatures can increase the mobility of oil, making it easier to extract (Kokal & Al-Kaabi, 2010). However, high temperatures can also lead to increased CO_2 reactivity with the rock, potentially causing formation damage (Srivastava et al., 1999). Nevertheless, pressures above the minimum miscibility pressure (MMP) do not necessarily lead to increased oil recovery (Yellig & Metcalfe, 1980). Reservoir permeability affects the injectivity and sweep efficiency of the EOR process. Higher permeability reservoirs tend to have better injectivity, but may also experience more severe viscous fingering, leading to reduced sweep efficiency (Lake, 1989). Reservoir porosity influences the storage capacity and fluid flow within the reservoir. Higher porosity reservoirs tend to have better storage capacity, but may also be more prone to formation damage (Amyx et al., 1960).

Fakher et al (2019) maintained that injecting carbon dioxide (CO_2) into shale reservoirs can boost oil production, this study explores how effective cyclic CO_2 injection is used in extracting oil from shale formations and how temperature and pressure affect oil recovery. A custom-built vessel was used to replicate the cyclic CO_2 injection process. Shale cores were saturated with crude oil at high temperatures for seven months before being subjected to the huff-n-puff process. Findings showed that pressure and temperature significantly influenced oil recovery, especially with repeated injection cycles. Moreover, these thermodynamic conditions affected the cores' structural integrity, causing some to fracture and altering natural fissures.

This research sheds light on how thermodynamics impact oil extraction potential in shale reservoirs during cyclic CO_2 injection, offering valuable insights for optimizing this technique. Zuo et al (2022) examined the complex interactions between CO_2 and live oil in tight oil reservoirs during enhanced oil recovery. Through visual CO_2 injection experiments and phase equilibrium calculations, the experiment revealed that Immediate oil expansion upon CO_2 injection is proportional to pressure increase, an in-situ gas phase forms during early-stage CO_2 injection, Increased CO_2 injection shifted the dominant mechanism to CO_2 extraction, Higher pressure enhances CO_2 extraction capacity for light oil components.

Hu et al (2020) evaluated the impact of crucial parameters on carbon dioxide injectivity performance in tight reservoirs. The effects of temperature, pressure, soaking time, and core stimulation on oil recovery and carbon dioxide adsorption capacity were examined. The results indicated that increase in temperature reduces carbon dioxide storage capacity but enhances oil recovery factor, higher pressure increases both carbon dioxide storage capacity and oil recovery factor, with maximum storage capacity reaching 91% at 1500 psi and 20°C., longer soaking time leads to increased oil production, and Unstimulated core samples exhibit higher oil recovery factors compared to stimulated samples.

Gajbhiye (2025) investigated the influence of key parameters on interfacial tension (IFT) between injected gases and reservoir fluids in CO_2-enhanced oil recovery (CO_2-EOR). The effects of oil composition, gas composition, pressure, and temperature on IFT were evaluated using pendant drop analysis. The results showed that IFT decreases with increasing pressure and temperature, with pressure having a more pronounced effect, increasing CO_2 mole fraction decreases IFT, while increasing NG mole fraction increases it, exhibiting concave downward and upward trends, respectively, and accurate measurements of IFT require consideration of changes in oil and gas density as functions of pressure and temperature.

Syed et al (2022) studied the potential of CO_2 injection in tight oil reservoirs to improve oil recovery while reducing carbon emissions. A numerical simulation model was developed using typical tight oil reservoir properties, featuring a hydraulically fractured horizontal well subjected to CO_2 huff-n-puff injection. The results demonstrated that significant incremental oil recovery is achieved through CO_2 injection, with improved diffusivity and solubility of CO_2 in lighter reservoir fluids and higher reservoir pressures, Increased CO_2 injection volume and number of huff-n-puff cycles enhance oil recovery and CO_2 trapping in the reservoir, and diagnostic contour plots illustrate the impact of hydraulic fracture parameters and CO_2 injection volume on directional EOR and CO_2 trapping performance. The study provides insights into designing EOR operations in tight oil reservoirs that balance oil recovery and carbon storage objectives.

Pourhadi and Fath (2020) experimented on the impact of compositional grading on reservoir fluid properties and the effectiveness of various gas injection scenarios in a conventional black oil reservoir. A simulation study was conducted to evaluate the injection of different gases, including CO_2, N_2, associated petroleum gas (APG), and N_2-CO_2 mixture, at various depths. The findings revealed that minimum miscibility pressure (MMP) increases with depth, affecting the optimal gas injection depth., CO_2 injection shows higher efficiency due to miscible displacement, while N_2, APG, and N_2-CO_2 mixture injections are immiscible, leading to reduced oil displacement efficiency, better miscibility development is observed in upper reservoir parts, suggesting that completing injection wells in these areas can enhance oil recovery, and .water-alternating-CO2 injection technique showed improved macroscopic sweep efficiency and increased oil recovery factor compared to other gas injection scenarios.

Fatemi and Sohrabi (2018) This analyzed the effects of gas/oil interfacial tension (IFT) on oil recovery in mixed-wet rocks through core flooding experiments. The research underscored lower IFT conditions as a cause for higher oil recovery, with more pronounced effects in high-permeability rocks, water alternating gas (WAG) technique outperformed waterflooding and gas injection, with varying performance depending on IFT and injection sequence, ultra-low

IFT WAG injections showed higher injectivity during waterflooding periods, while WAG-DI scenarios have lower injectivity, higher IFT conditions resulted in higher trapped gas saturations, with injection sequence significantly affecting trapping behavior.

Khurshid (2021) explored the impact of CO_2 injection on oil recovery, focusing on the interactions between CO_2, rock, and water. A simulator was developed to model the reactivity of injected CO_2 under various reservoir conditions.

The outcome underlined the following: temperature, depth, and rock properties significantly affect formation/dissolution and precipitation during CO_2 injection, asphaltene reduces oil recovery by 10% and affects relative permeability curves, Increased injection rates and pressures enable reaching miscibility pressure, but further increases yield limited benefits, and finally deep, high-temperature reservoirs are suitable for CO_2 sequestration due to reduced dissolution rates and solid precipitation.

METHODOLOGY

This study investigates the impact of methane-rich gas, Ethane-rich gas Propane-rich gas and CO_2 gas on enhanced oil recovery (EOR) under various recovery conditions. The experimental design involves a comprehensive analysis of oil recovery factor under different reservoir temperature, pressure, and gas injections.

Material and equipment

Core samples with known properties (porosity, permeability, and geometry are used for this experiment. Crude oil sample with known properties (viscosity, density, and API gravity were also used. The three gas mixtures used as injection fluids are CO_2 (99% purity), Methane-Rich Gas (75% CH_4, 25% C_2H_6), Propane-Rich gas (C_3H_8 75%, 25% C_2H_6). The core flooding apparatus was designed with stainless steel to enable it stand high pressures and temperatures of 100^o F, 150^o F, 200^o F. and a reliable sealing mechanism to prevent fluid leakage and maintain pressure integrity. It incorporated a thermal insulator to minimize heat loss and maintain a stable temperature, it features a high pressure and high temperature core holder, fluid cylinder pots, temperature control system, flow meters, valves. Confining pressure was applied using a hydraulic pump system to simulate overburden pressure, pore pressure was controlled using back pressure regulators to simulate reservoir pressure. A heating jacket was wrapped around the core holder to control temperature, thermocouples were incorporated to monitor temperature

Core flooding Apparatus Design

A core flooding apparatus was designed for evaluating the impact of temperature and pressure on oil recovery factor during methane-rich gas, ethane-rich gas, and CO_2 gas flooding operations in enhanced oil recovery (EOR) applications. The apparatus consists of a stainless-steel core holder designed to accommodate core samples of varying lengths and diameters, with a thermostat jacket for temperature control, a Hydraulic Pump System capable of simulating overburden pressures up to 4000 psi, ensuring the core sample is subjected to realistic reservoir conditions was incorporated. The core-flooding apparatus has three separate injection lines for Methane-rich gas (75% methane), Propane-rich gas (75% propane) and CO_2 gas

Each line was equipped with a mass flow controller or a high-pressure pump to regulate the injection rate. A Back-Pressure Regulator (BPR**)** capable of maintaining pressures up to 4000 psi or more, allowing for precise control of the core flooding experiment. A thermostat jacket around the core holder, coupled with a thermocouple (temperature sensor), to monitor and control the temperature of the core and fluids. Multiple pressure transducers to monitor the pressure drop across the core sample, injection pressure, and overburden pressure. A system for collecting and measuring the produced fluids (oil and gas), including a separator and a graduated cylinder or a gasometer.

Table 1: Properties of Fluids used in the experiment

Parameter	**Brine**	**Crude Oil**	**CO_2**	**Methane-Rich Gas**	**Propane-Rich Gas**
Density (g/cm3)	1.0	0.86	0.7	0.2	0.3
Viscosity (cp)	0.5	5.5	0.05	0.01	0.01
IFT (m/Nm)	-	20	5	10	5

Core flooding Experiment

Twenty-seven core samples of equal dimensions 5cm x 4cm x 2 cm were used in the experiment, the core samples were cleaned, dried and saturated with brine under vacuum at a flow rate of 0.5cc/30 sec to establish an initial water saturation (S_{wi}), and create water-wet or mixed-wet conditions in the core sample, which is important for simulating reservoir rock-fluid interactions., then the brine was displaced by injection of crude oil into the core samples at a flow rate of 0.5/30 sec to establish the initial oil saturation (So) till brine production became impracticable, thereafter, the first three core samples were injected with Methane-rich gas at a rate of 0.2ml/min to displace the oil while the core sample`s temperature is 100°F, and at pressures of 1500 psi, 2500 psi, and 3500 psi respectively. The second three core samples were also injected with Methane-rich gas at a constant temperature of 150°F and pressures of 1500 psi, 2500 psi, and 3500 psi respectively. Methane-rich gas injection was repeated for the third three core samples at a constant temperature of 200°F and pressures of 1500 psi, 2500 psi, and 3500 psi respectively. Similarly, the next nine core samples were used in group of threes for and propane-rich gas injection at a flow rate of 0.01 ml/min in a same manner used for methane-rich gas. The last nine core samples were also grouped in threes and in the same vein used for CO_2 injection at a flow rate of 0.1ml/min following same protocols used for the previous gas injections,

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RESULT

Table 2: Effect of temperature and pressure on the Recovery factors of Methane-Rich Mixture (75% Methane) Injection

Reservoir Temperature (°F)	Reservoir Pressure (psi)	Oil Recovery Factor (%)
100	1500	15
100	2500	20
100	3500	25
150	1500	12
150	2500	18
150	3500	22
200	1500	10
200	2500	15
200	3500	20

Table 3: Effect of temperature and pressure on the recovery Factor of Propane-Rich Mixture 75% propane) Injection

Reservoir Temperature (°F)	Reservoir Pressure (psi)	Oil Recovery Factor (%)
100	1500	18
100	2500	23
100	3500	28
150	1500	15
150	2500	20
150	3500	25
200	1500	12
200	2500	18
200	3500	22

Table 4: Effect of temperature and pressure on the recovery factor of CO_2 Injection

Reservoir Temperature (°F)	Reservoir Pressure (psi)	Oil Recovery Factor (%)
100	1500	25
100	2500	30
100	3500	35
150	1500	20
150	2500	25
150	3500	30
200	1500	18
200	2500	22
200	3500	28

DISCUSSION

- The results indicate that increasing reservoir pressure improves oil recovery factor for all gas injection methods.
- Decreasing reservoir temperature improves oil recovery factor for all gas injection methods.
- CO_2 injection yields higher oil recovery factors compared to methane-rich and ethane-rich mixture injections.
- Propane-rich mixture injection performs better than methane-rich mixture injection.
- CO_2 Injection yields the highest recovery factors, ranging from 18% to 35%, with the highest recovery factor achieved at 100°F and 3500 psi.
- Propane-Rich Mixture Injection recovery factors range from 12% to 28%, with the highest recovery factor achieved at 100°F and 3500 psi.
- Methane-Rich Mixture Injection recovery factors range from 10% to 25%, with the highest recovery factor achieved at 100°F and 3500 psi.
- The optimum temperature and pressure for CO_2 Injection: 100°F and 3500 psi, with a recovery factor of 35%.
- Propane-Rich Mixture Injection at 100°F and 3500 psi, yields a recovery factor of 28%.
- Methane-Rich Mixture Injection at 100°F and 3500 psi, yields a recovery factor of 25%.
- In general, the results suggest, lower temperatures (100°F) and higher pressures (3500 psi) yield better recovery factors for all gas injection scenarios.
- CO_2 injection is the most effective method, followed by propane-rich mixture injection and then methane-rich mixture injection.

CONCLUSION

Reservoir temperature and pressure conditions effect recovery factor of oil from the reservoir. Further research on the effect of reservoir rheology and lithology should be investigated for enhanced oil recovery using natural gas injection**.**

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