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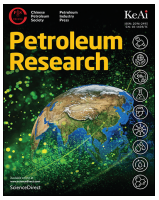

Full Length Article

Asphaltene deposition during miscible and immiscible gas injection in tight heavy oil reservoir: Implications for formation damage

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ABSTRACT

Gas injection is frequently used to displace the trapped oil. However, this may lead to deposition of asphaltene, which can profoundly block the pores and throats of the porous media, resulting in reduced porosity and permeability. The rock lithology, composition of the injected fluids, pressure, and temperature are among the parameters that may influence asphaltene deposition. This study investigated the asphaltene precipitation/deposition while injecting rich hydrocarbon gas into a heavy oil reservoir. The experiments were conducted under two conditions: miscible and immiscible gas injections. Two rich hydrocarbon gases with different compositions were used, and experiments were conducted under reservoir conditions. Experiments were performed in carbonate cores previously saturated with heavy live oil. The extent of formation damage was assessed by measuring asphaltene deposition during the flooding of miscible and immiscible rich hydrocarbon gases into the core plugs. The outlet oil samples from the core flooding were analyzed using molecular weight measurements, UV spectroscopy, and the IP143 method. During the miscible flooding process, where rich hydrocarbon gas was injected into live oil at 210 °F, the molecular weight of the outlet oil samples decreased by 53%. The porosity and permeability of the carbonate core in miscible flooding at 210 °F, after washing with cyclohexane, showed a reduction of 13.6% in porosity and 42.8% in permeability. In the course of immiscible flooding with rich hydrocarbon gas, the outlet oil at 104 °F decreased by 48.3% in molecular weight, 35.5% in absorption coefficient, and 30.7% in asphaltene content. The porosity and permeability of the carbonate core in immiscible flooding decreased by 11.8% and 43.25%, respectively. The results showed that both miscible and immiscible injection processes reduce the porosity and permeability of carbonate cores. The damage was particularly severe during the miscible flooding.

1. Introduction

There is a growing interest in the injection of various fluids, including gases, for enhanced oil recovery (EOR), as many oil reservoirs have exceeded their natural depletion period. Gas injection is a common method used for EOR (Hajizadeh et al., 2020). It is performed under either miscible or immiscible conditions, depending on the reservoir's temperature, pressure, and oil characteristics (Memon et al., 2012). The miscible gas injection applies at or above the minimum miscible pressure (MMP) to ensure that the gas dissolves in the oil. Immiscible gas injection is performed at pressures below MMP, where gas remains undissolved in oil (Almobarak et al., 2021; Li et al., 2022). In miscible gas injection, oil and gas are usually combined to make a single phase, which could facilitate oil displacement. Oil composition, reservoir temperature, and pressure are parameters that affect the miscible injection and displacement of oil (Alamooti and Malekabadi, 2018; Bahadori, 2018a). Injecting miscible gas into the oil also causes swelling of the oil, which may lead to lower fluid density and viscosity. Thus,

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the oil flows more efficiently in the production wells (Fanchi, 2010). In the course of gas injection, asphaltene deposition often occurs in the reservoir and near the wellbore region (Bahadori, 2018b; Zekri et al., 2007).

Asphaltenes contain the most polar and heaviest compounds found in crude oil, characterized by a complex molecular structure. Their properties vary from one crude oil to another (Mahmoudvand et al., 2019). The use of solvents such as liquefied petroleum gas (LPG), natural gas liquids (NGL), CO_2, and natural gas in EOR processes can lead to asphaltene deposition. In addition, solvent injection leads to changes in reservoir pressure, which causes asphaltene deposition (Doryani et al., 2018; Mansoori, 1997; Mousavi Dehghani et al., 2007). The instability of asphaltenes due to their chemical properties and phase behavior causes challenges in producing oil from the reservoir. Deposition of the asphaltene in wells and surface facilities causes operational challenges (Mohammed et al., 2021a,b; Park and Ali Mansoori, 1988). Asphaltene deposition in oil reservoirs would inevitably result in reduced porosity and permeability, as well as wettability alterations, ultimately compromising the oil flow assurance (Andersen, 1995).

Researchers experienced asphaltene deposition during water-alternating-gas (WAG) injection in an Abu Dhabi oil field, showing that hydrocarbon-rich gas interacting with reservoir fluid would destabilize asphaltene. It was also observed that the injection of rich gas with a high liquid-gas ratio (LGR) resulted in exacerbated deposition of asphaltenes (Negahban et al., 2005). The study of an oil field in Kuwait also showed that in miscible injection, the rate of asphaltene precipitation rises with the increase in the LGR of the injected gas. The richness of the injected gas can affect the volume of asphaltene precipitation. Both simulation and experimental results indicated that asphaltene precipitation is higher when the LGR of injection gas is increased (Memon et al., 2012a). The injection of miscible gas into Iran's Kopal field was investigated. The results indicated a significant correlation between asphaltene precipitation and the richness of injected carbon dioxide (Dahaghi et al., 2008).

The experimental results indicated that the asphaltene flocculation process changes with gas injection, resulting in the formation of larger flocculated particles (Dashti et al., 2020). Gas injection, under miscible and immiscible conditions, profoundly affected the asphaltene deposition near the injection well (Elturki and Imqam, 2022). This emphasizes the importance of thorough experimental and theoretical analyses before gas injection. Factors like the rock type, oil acidity, and the properties of porous media can impact this process. Flocculated asphaltenes can adsorb on the rock surface, causing lower rock porosity and permeability (Bahmaninia et al., 2021a; Elturki and Imqam, 2022). During the injection of miscible gases, asphaltenes deposit on the rock surface and react with it, leading to changes in the rock's wettability. The wettability and permeability of fluid-rock systems are affected by asphaltene deposition (Mousavi Dehghani et al., 2007).

The flocculation and adsorption mechanisms of asphaltene during CO_2 gas injection under miscible and immiscible conditions have been studied in relation to asphaltene precipitation. For instance, Elturki and Imqam (2022) reported that flocculation and adsorption processes are highly influenced by gas injection characteristics in terms of type, composition, and thermodynamic conditions. They also reported that challenges related to asphaltene deposition become particularly more critical when gas injection occurs under miscible conditions. Variation in pressure and temperature during CO_2 injection causes asphaltene deposition, which would otherwise reduce permeability and decrease recovery efficiency in reservoirs with very low permeability.

Surface characteristics of the porous media in terms of wettability have a profound impact on asphaltene deposition. Utilizing nanoparticles as adsorbents can potentially provide an effective solution to control asphaltene deposition in reservoirs. Extensive studies have been conducted on asphaltene adsorption on various rock surfaces and nanoparticles. One such study (Ansari et al., 2023) analyzed asphaltene adsorption onto iron oxide and calcium nanoparticles in both the presence and absence of water. The results demonstrated a significant effect of the aqueous phase on asphaltene adsorption. Several factors, including dolomite rock features, fluid flow conditions, and the chemical composition of asphaltene, influence the adsorption process on dolomite rock surfaces. Ansari et al. (2022, 2023) also showed that these parameters would greatly influence the extent of asphaltene adsorption and the severity of associated deposition problems in reservoirs, emphasizing the need to consider rock properties and operational conditions. Asphaltene adsorption on quartz surfaces is also affected by factors such as quartz particle size and concentration, asphaltene composition, flow conditions, and the presence of the aqueous phase. Bacteria may also influence asphaltene deposition and wettability alteration on dolomite and quartz surfaces. Their ability to modify surface properties and reduce the damage caused by asphaltene deposition broadens the scope of available chemical and physical mitigation strategies (Soleimani et al., 2023).

Carbon dioxide gas injection into oil reservoirs has received significant attention due to its ability to reduce viscosity and enhance oil recovery (Ghorbani et al., 2019). However, asphaltene precipitation remains a considerable challenge. Recent studies have used nanoparticles as inhibitors to prevent asphaltene deposition (Azizkhani and Gandomkar, 2020). Previous studies have primarily focused on inhibitors under experimental conditions or CO_2 injection. For instance, the effect of asphaltene concentration on the minimum miscibility pressure (MMP) of the CO_2/oil system shows a direct correlation between increasing asphaltene content and MMP (Ghorbani et al., 2020). Similarly, a CO_2 solvent inhibitor aims to reduce asphaltene deposition during immiscible gas injection by adding a chemical solvent, thereby lowering deposition rates (Gandomkar et al., 2023). In contrast, the present study does not focus on chemical inhibitors. Instead, it provides a detailed analysis of the parameters associated with hydrocarbon gas injection, such as gas richness, temperature, and miscibility conditions, examining their direct effects on asphaltene deposition within the core samples.

Many studies pertinent to gas injection investigated the effects of nitrogen and carbon dioxide on asphaltene deposition. Moreover, most experiments used dead oil for the flooding experiments. Additionally, core flooding experiments usually involved rock samples that had high porosity and high permeability (Dahaghi et al., 2008; Fassihi et al., 2020; Memon et al., 2012a; Mousavi Dehghani et al., 2007; Negahban et al., 2005). This study investigates the injection of hydrocarbon gas at different richness levels at miscible and immiscible conditions into the heavy oil of the Asmary reservoir located in southern Iran. The Asmary reservoir was undersaturated, which means the primary mechanism for the production of oil is fluid and rock expansion. The miscible injection process has been applied in this reservoir for more than a decade, but concerns have gradually been raised due to asphaltene deposition. Live oil samples from the bottom hole were collected using a single-phase sampling method under reservoir conditions. The samples were then used in flooding experiments conducted under both miscible and immiscible conditions. The objective was to determine the optimal level of hydrocarbon gas richness to enhance production and also to decrease formation damage. The aim was also to identify the ideal levels of hydrocarbon gas

richness to improve production performance and minimize formation damage.

The impact of hydrocarbon gas injection under reservoir conditions using live oil samples can help to optimize the gas injection process and reduce damage. Accordingly, this study examined the potency of asphaltene precipitation and deposition occurrences by sampling live oil from the reservoir well, conducting core flooding experiments with different hydrocarbon gases, field tests, and various analytical methods. The main advantages and innovations of this study include using live heavy oil under reservoir conditions, which provides more practical and generalizable results. There is a systematic comparison of hydrocarbon gas injection with varying gas richness under miscible and immiscible conditions. This area has seen limited prior research in the literature. Experiments are conducted under reservoir conditions, accompanied by accurate measurements of molecular weight, optical absorption, and specific tests to quantify asphaltene precipitation. The study also investigates the effects of high temperature and pressure (up to 210 °F) on the intensity of asphaltene precipitation under various gas injection conditions, which is rarely reported in harsh reservoir environments.

2. Materials and methods

2.1. Experimental setup and procedure

The gas injection tests were conducted using a core flood system, as depicted in Fig. 1. The carbonate core was used from the Asmary formation. This set of experiments aimed to study asphaltene deposition during rich hydrocarbon gas injection under reservoir conditions. The system involved an oven, a core holding device, an injection pump, fluid cylinders, a back pressure regulator (BPR), a needle valve, and a data acquisition system. The core flooding setup was carefully constructed to conduct tests at high temperatures and pressures, resembling experiments under reservoir conditions.

Validated experimental procedures were utilized in this investigation, including the saturation of carbonate core samples with formation water, saturation with dead oil, and replacement with live oil. Additionally, the injection of hydrocarbon-rich gases has been validated and documented elsewhere (Ghorbani et al., 2019). The cores were located inside a desiccator and subjected to a vacuum for 5 h to ensure they were fully saturated with formation water. This procedure effectively removed any air trapped in the rock pores. Formation water entered through a flow line connected to the desiccator, and the vacuum assisted its penetration into the cores. After maximum saturation was reached, the cores were submerged in formation water and located in an oven at a temperature of 176 °F for 21 days. The cores were then saturated with the dead oil through flooding until 3 PV was achieved. Finally, the irreducible water saturation and initial oil saturation values are determined based on the amount of produced water from the core. These procedures are aligned with standard core flooding tests conducted by (Gandomkar and Kharrat, 2012). Thereafter, the cores underwent an aging process and were returned to the oven under the same conditions.

The flooding test was initiated by gradually injecting a specific amount of dead oil into an oil-saturated core, using BPR to create a pressurized core flooding system. Following this, live oil was injected into the core to replace the dead oil under a pressure that was higher than the saturation pressure of the live oil. BPR was maintained at the core output under constant pressure and temperature conditions. A total volume of live oil equivalent to two pore volumes was injected into the core saturated by dead oil at a flow rate of 0.3 cc/min. Subsequently, hydrocarbon gas was injected into the core saturated with live oil at a flow rate of 0.1 cc/min. The gas injection continued until the pressure at both ends of the core stabilized, with approximately three times the pore volume of hydrocarbon gas being injected. Fluid samples were collected during the flooding tests using three lidded containers with a capacity of 1.8 cc. Gas was injected into the core to produce oil, which was then captured in containers until a breakthrough occurred. In total, three fluid samples were collected for each flooding test in sequences of approximately 0.4 PV, 0.6 PV, and 1.2 PV, respectively. The samples were then analyzed for their molecular weight, optical spectrophotometry, and asphaltene content. The sample collection was repeated for all flooding tests.

This work presents a case study based on field conditions. The carbonate core samples used in this research closely resemble reservoir rocks in terms of porosity and permeability. Bottom hole fluid samples were also utilized in the experiments to accurately represent reservoir fluids, enabling chemical and physical

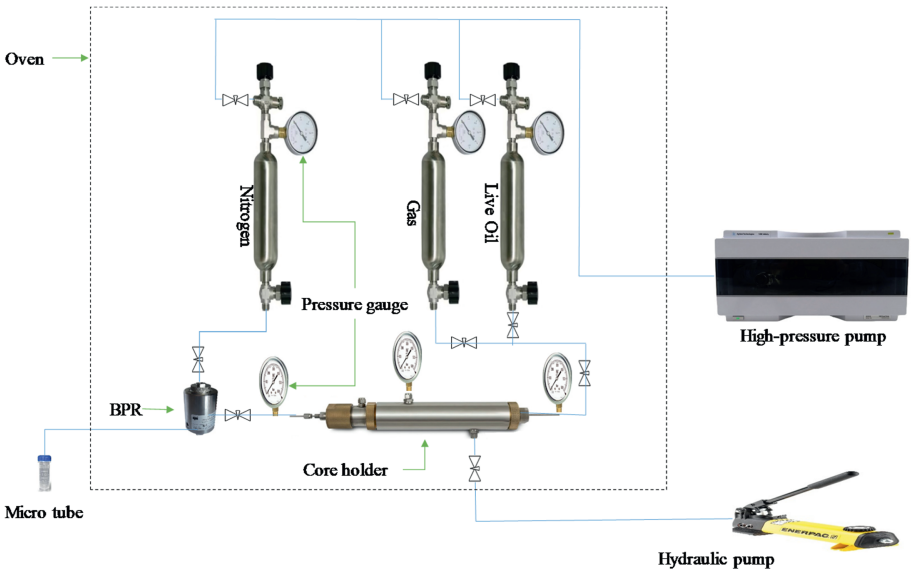

Fig. 1. Schematic of the core flooding setup for hydrocarbon gas injection.

reactions to occur under reservoir conditions. Since miscible injection was performed in the studied reservoir, hydrocarbon-rich gases with liquid-to-gas ratios of 380 and 450 bbl/MMSCF—similar to the injection gases in the field—were used. Utilizing these hydrocarbon gases ensured that the results of the flooding experiment closely match field conditions. Moreover, the experiments were conducted under reservoir temperature and pressure conditions to ensure the results are relevant to the studied reservoir. These conditions confirmed that the outcomes of the core experiments apply to the reservoir, which facilitated the optimization of the injection process and established the impacts of asphaltene deposition.

The miscible gas injection has been in operation in the studied reservoir for over a decade, during which the gas richness has been measured at 450 bbl/MMSCF. Nonetheless, the production of rich hydrocarbon gas using NGL is a costly process. As a result, the reservoir and operation conditions, along with miscibility pressure, were analyzed to select a gas with a richness of 380 bbl/MMSCF (LGR = 380 bbl/MMSCF) for comparison with a gas richness of 450 bbl/MMSCF. The detailed conditions for the flooding tests are outlined in Table 1 (core samples of A and B will be explained in the following section). Core flooding experiments were performed in five different scenarios using carbonated core samples. The injection parameters established for each phase were aimed at optimizing both miscible and immiscible gas injection mechanisms. Core samples were used to investigate formation damage by injecting rich hydrocarbon gas with an LGR of 450 and 380 bbl/MMSCF at temperatures of 104 °F and 210 °F. Given the harsh conditions at 210 °F and for the sake of screening, several tests were first conducted at 104 °F. Once the screening was accomplished, several selected core flooding tests were performed based on the extent of formation damage and reservoir pressure conditions.

2.2. Sample preparation

The core samples were cut into smaller pieces to create core plugs with a length of 0.23 ft and a diameter of 0.125 ft. An ultrasonic bath was used to eliminate any remaining debris from core plugs and rock slabs, which were then dried in the oven for a day. The rock samples were washed with a toluene and methanol mixture using a Soxhlet apparatus to remove impurities. Finally, the permeability and porosity of the core plugs were measured. The end-capillary effect, which is caused by capillary forces at the ends of core samples, can influence flow distribution and the outcomes of core flooding experiments. In this study, considering the dimensions of the cores used along with the injection fluid rate and controlled experimental conditions, the end-capillary effect was found to be meagre. According to the scaling criteria presented by Rapoport et al. (1953), which have been followed in previous studies (Motealleh et al., 2012; Nematzadeh et al., 2012), the Rapoport-Leas scaling criterion ($L^* V^* \mu \geq 1$) was calculated with values ranging from 1.6 to 1.7 (Rapoport and Leas, 1953). This confirms that the capillary end effect in the flooding experiments is negligible. The specifications of the cores used in the gas injection tests are specified in Table 2.

2.3. Materials

A bottom-hole sample of live oil was obtained at reservoir pressure and temperature through single-phase sampling from an oil reservoir in the south of Iran. The Asmary reservoir contained undersaturated oil, with fluid and rock expansion as the primary mechanisms for oil production. The reservoir temperature was 210 °F with a pressure of 4250 psi, indicating an API gravity of 24, which confirmed it was a heavy oil reservoir. Under these reservoir conditions, the saturation pressure was recorded to be 2500 psi. Limestone core samples were obtained from the outcrop. The samples, comparable to the reservoir rocks from the Asmary formation, were collected for core flooding. The formation water sample was obtained from the reservoir through a separator test at the wellhead, and its composition was analyzed to saturate the cores with formation water. The composition of the formation water is provided in Table 3. The measured salinity of the formation water was 200669 ppm.

Normal heptane was purchased from Daejung, South Korea, and was utilized as an asphaltene precipitator. Toluene from Merck, Germany, was used as a solvent for asphaltene in the Soxhlet apparatus. Additionally, cyclohexane was used to wash cores within the Soxhlet apparatus. The composition of dry gas and reservoir oil is analyzed using gas chromatography. The colloidal instability index (CII) is a crucial parameter for assessing the tendency of crude oils to asphaltene deposition. When the CII value approaches or exceeds 0.9, then the crude oil is considered unstable and increases the likelihood of asphaltene precipitation (Gandomkar and Reza Nasriani, 2020). This study analyzed the SARA fractions of dead oil, as presented in Table 4, and the calculated CII was 1.03. Since this value is greater than 0.9, the investigated oil is prone to asphaltene precipitation. The IP143 method was used for the SARA analysis.

Vinci technology was used to combine dry gas and NGL to produce rich hydrocarbon gas. This procedure was followed to make the LGRs of 380 and 450 barrels per million cubic feet, as detailed in Table 5. Various gas compositions were evaluated according to their miscibility pressure, considering the reservoir's pressure and temperature conditions to facilitate gas miscible injection. Gas compositions for injection, with a richness of 380–450 barrels per million cubic feet, have been identified to establish optimal conditions for miscible injection in the studied oil field.

Table 1
Flooding conditions of A and B core samples during miscible and immiscible gas injection.

Core Sample	Type	Injection method	Injection gas	BPR (psi)	Miscible pressure (psi)	Temperature (°F)
A	Carbonate rock	Miscible	Rich hydrocarbon gas (LGR = 450 bbl/MMSCF)	2987	2600	104
B	Carbonate rock	Immiscible	Rich hydrocarbon gas (LGR = 450 bbl/MMSCF)	2059	2600	104
A	Carbonate rock	Miscible	Rich hydrocarbon gas (LGR = 380 bbl/MMSCF)	3755	3300	104
B	Carbonate rock	Immiscible	Rich hydrocarbon gas (LGR = 380 bbl/MMSCF)	2276	3300	104
B	Carbonate rock	Miscible	Rich hydrocarbon gas (LGR = 380 bbl/MMSCF)	4480	4200	210

Table 2
Specifications of the investigated cores.

Core Sample	Lithology	Porosity	Permeability (mD)	Length (ft)	Diameter (ft)
A	Carbonate	24.11	16.04	0.23	0.125
B	Carbonate	26.30	19.83	0.23	0.125

Table 3
Formation water characteristics.

Component	NaCl	Ca	Mg	SO_4^-	HCO_3^-	Cl^-
Concentration (mg/L)	62004	13090	1615	500	490	123000

Table 4
SARA analysis of dead oil in weight percentage.

Saturates	Aromatics	Asphaltenes	Resins
45.5	43.6	5.2	5.7

3. Results and discussion

Core flooding experiments under miscible and immiscible conditions were conducted using two samples of hydrocarbon gas enriched with NGL (Table 5). The experiments involved carbonate cores under both miscible and immiscible conditions. Hydrocarbon gases with richness of 380 (LGR = 380 bbl/MMSCF) and 450 (LGR = 450 bbl/MMSCF) were used for flooding tests at temperatures of 104 °F and 210 °F.

3.1. Core flooding with hydrocarbon gas of LGR = 450 bbl/MMSCF

The experimentswere conducted following the specifications detailed in Table 6. The preparation was for both miscible and immiscible injections using hydrocarbon gas (LGR = 450 bbl/MMSCF) at a temperature of 104 °F. The MMP measured at 104 °F is 2600 psi, based on the results of the slim tube test (Safaei, 2022).

Fig. 2 demonstrates the pressure difference between cores A and B. In the miscible injection process within core A, gas enters the core sample and gradually dissolves into the oil. As oil is produced, the pressure variation between the two ends of the core decreases. During this process, the gas dissolves in the live oil, reducing its viscosity and allowing the gas and oil to flow together as a single phase. As a result, the pressure drop across both sides of the A core continues to decline until a gas breakthrough occurs. These changes can be observed in core A. In contrast, during the immiscible injection process in core B, gas injection increases its relative permeability, leading to higher oil production from the core. In this scenario, the movement of gas within the core helps to displace the oil further. After the gas breakthrough occurs, the pressure change between the two ends of the core decreases as the injected gas continues to displace the oil. Fig. 2 also confirms that during gas injection, an increase in the pressure difference was observed at both ends. This increase may be attributed to the interaction of hydrocarbon gas with oil inside the core, leading to the formation of asphaltene deposits. The gas injection continued until the pressure differentials on both sides of the cores stabilized, with an injection of approximately three pore volumes.

3.1.1. Porosity and permeability

After miscible flooding in core sample A and immiscible flooding in core sample B, the cores were washed with cyclohexane in a Soxhlet extractor for seven days. After this, the core samples were dried in an oven at 176 °F for three days, during which their permeability and porosity were measured. The deposited asphaltene in the cores could not be dissolved in cyclohexane but remained in the cores. Thereafter, toluene was used in a Soxhlet extractor for seven days to dissolve the deposited asphaltene. The cores were then placed in an oven at 176 °F for another three days. Finally, their permeability and porosity were measured. Table 7 presents the permeability and porosity of cores A and B. The initial permeability and porosity of core sample A were measured as 26.3% and 19.83 mD, respectively. After washing with cyclohexane, both porosity and permeability experienced a reduction, dropping to 21.64% and 12.95 mD, which would indicate a reduction of 18% in porosity and 35% in permeability. After the core was further washed with toluene, both porosity and

Table 5
Composition of gas and oil used in the flooding tests.

Component	Reservoir oil composition	Reservoir dry gas composition	Natural gas liquid composition	hydrocarbon gas (LGR = 380 bbl/MMSCF) composition	hydrocarbon gas (LGR = 450 bbl/MMSCF) composition
	(mole%)	(mole%)	(mole%)	(mole%)	(mole%)
H_2S	0.00	0.01	0.00	0.01	0.01
N_2	0.13	9.52	0.83	1.25	1.22
CO_2	0.15	1.59	0.77	6.00	5.54
C1	33.89	80.02	4.16	50.54	47.45
C2	8.43	1.96	55.23	24.03	26.06
C3	8.70	0.66	29.97	11.42	13.07
iC4	1.98	0.34	4.33	1.17	1.55
nC4	2.82	0.52	4.01	1.51	1.34
iC5	0.97	0.58	0.31	0.47	0.43
nC5	1.16	0.36	0.26	0.32	0.31
C6	1.78	1.95	0.08	1.17	1.10
C7	2.15	1.47	0.01	1.45	1.36
C8	4.39	0.84	0.04	0.56	0.50
C9	2.21	0.17	0	0.10	0.10
C10	1.58	0	0	0	0
C11	1.04	0	0	0	0
C12+	28.62	0	0	0	0

Table 6
Conditions for conducting the flooding test of A and B carbonate cores.

Core Sample	Type	Injection method	Injection gas	BPR (psi)	Miscible pressure (psi)	Temperature (°F)
A	Carbonate rock	Miscible	Hydrocarbon gas (LGR = 450 bbl/MMSCF)	2987	2600	104
B	Carbonate rock	Immiscible	Hydrocarbon gas (LGR = 450 bbl/MMSCF)	2059	2600	104

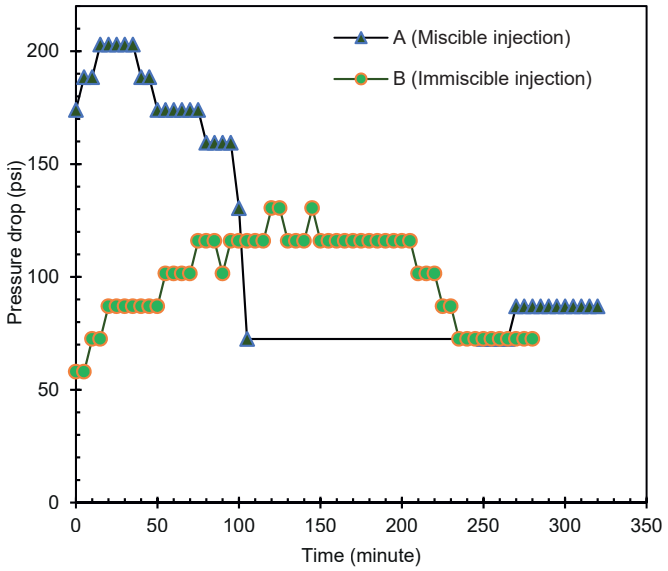

Fig. 2. Pressure drop at the ends of cores over time during hydrocarbon gas injection by LGR 450 bbl/MMSCF at 104 °F.

permeability returned to their original values. The differences in porosity and permeability observed between the cyclohexane and toluene washes during the miscible flooding test can be attributed to asphaltene deposition in core sample A.

For core sample B, after immiscible flooding and washing with cyclohexane, the porosity and permeability decreased to 22.42% and 13.2 mD, respectively. This result indicates a 7% decrease in porosity and an 18% decrease in permeability. Toluene was used to wash the core sample B, after which the porosity and permeability retained their initial values. The variations in permeability and porosity between washing with cyclohexane and toluene have again been related to asphaltene deposition in the core during the immiscible flooding process in core B. During the flooding process, the reductions in permeability and porosity in core sample A are larger than those in core sample B.

3.1.2. Asphaltene content

The asphaltene content in the dead oil was measured to be 5.2 wt%. During the miscible flooding process in core sample A, the asphaltene content in the oil samples extracted from the core was determined using the IP143 method. Three fluid samples collected during the flooding test, as explained in the preceding section, were stored in three lidded containers, each with a volume of 1.8 cc. As gas was injected into the core at the output section of BPR, the produced oil was collected in these containers. To measure asphaltene content, 0.5 cc of oil was used for each sample. The asphaltene contents in samples 1, 2, and 3 were measured as 3.76%, 3.38%, and 3.41% by weight, respectively. When the asphaltene content of the output samples from the flooding test was compared with that of the dead oil, there was a 34% reduction in asphaltene content compared to sample 3. During the immiscible flooding process in core sample B, three samples were again collected and stored in three 1.8 cc lidded containers, similar to those used for core sample A. The asphaltene contents in samples 1, 2, and 3 were 4.43%, 3.68%, and 3.61% by weight, respectively. This results in a 30% decrease in sample 3 compared to the dead oil.

Fig. 3 illustrates the asphaltene content changes observed in the collected samples. The reduced asphaltene content suggests that asphaltene was deposited within cores A and B during the core flooding. The results indicate a reduction in asphaltene content, implying that a larger quantity of asphaltene is deposited in the cores as gas injection progresses. Additionally, the samples subjected to miscible injection demonstrate lower asphaltene contents than those undergoing immiscible injection, indicating that a greater amount of asphaltene was deposited in the core during the miscible injection process.

3.1.3. UV–Vis spectrophotometry

A Dynamical DB20-S UV-VIS spectrophotometer with a quartz cuvette was used to measure the light absorption of oil samples collected during the flooding test. In this method, a light beam passes through the oil, and the compounds in the sample absorb light at specific wavelengths. The oil sample is opaque and has a high concentration, which necessitates dilution. To achieve this, the crude oil was mixed with specific proportions of toluene. The optimal dilution concentration is determined at the point at which the absorption number significantly decreases. In this case, the dilution ratio of toluene to the oil sample was found to be 24:1. The absorption rate of the dead oil sample after dilution with toluene was measured at 3.204. Fluid samples from the miscible flooding of core A were stored in three containers. An oil sample with a volume of 0.3 cc was taken to determine the absorption value. The recorded absorption spectra of the samples were 2.01, 1.953, and 2.028. The miscible flooding process led to a 37% reduction in absorption in sample 3. For immiscible flooding of core B, oil samples were collected in three 1.8 cc containers, similar to those used for core A. To determine the absorption values, 0.3 cc of oil

Table 7
Porosity and permeability measurements of core samples A and B.

Carbonate core	Porosity	Permeability (mD)	Description
A	26.30	19.83	Initial condition
A	21.64	12.95	Washing with cyclohexane in hydrocarbon gas injection (LGR = 450 & T = 104 °F)
A	26.20	19.28	Washing with toluene in hydrocarbon gas injection (LGR = 450 & T = 104 °F)
B	24.11	16.04	Initial Condition
B	22.42	13.20	Washing with cyclohexane rich hydrocarbon gas injection (LGR = 450 & T = 104 °F)
B	24.11	15.19	Washing with toluene rich hydrocarbon gas injection (LGR = 450 & T = 104 °F)

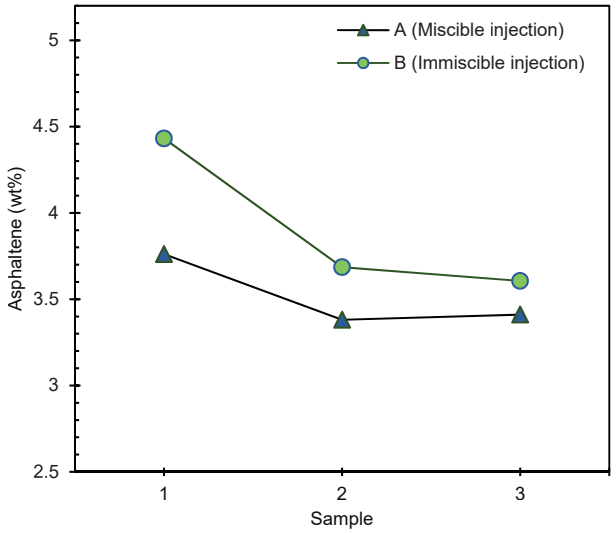

Fig. 3. Asphaltene contents in the collected samples of 1, 2, and 3 during hydrocarbon gas injection at LGR 450 bbl/MMSCF and 104 °F.

was taken from each sample. The absorption values for the three fluid samples were 2.202, 2.141, and 2.124, which indicates a 33% reduction in absorption for the final sample.

Fig. 4 illustrates the propensity of absorbance for the flooding tests. As the immiscible gas injection progressed in core B, asphaltene deposition in the porous media became severe. The absorption coefficients of the samples decreased, indicating an increase in asphaltene deposition. On the contrary, during the miscible gas injection process in core A, the absorption coefficients of the samples generally decreased, except for sample 3, which exhibited an increasing trend. During the miscible injection process, there was a noticeable increase in the accumulation of asphaltene. By the end of the injection process, sample 3 had accumulated a greater amount of asphaltene. This suggests that asphaltene deposition within the core influences fluid movement and production, resulting in a higher asphaltene concentration in sample 3.

In the preceding section, it was noted that the asphaltene deposition during the miscible gas injection process in core A

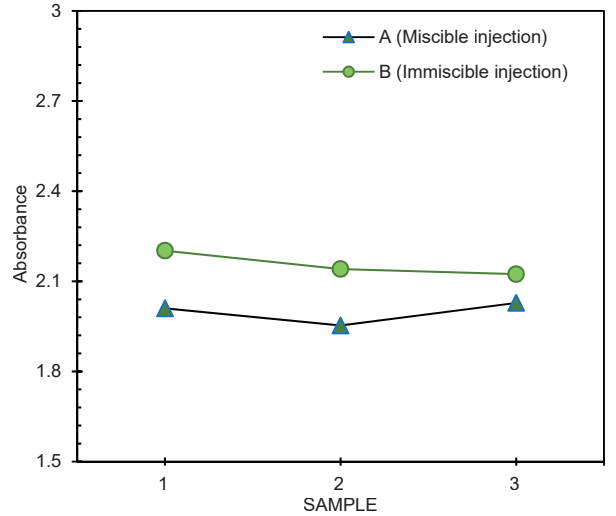

Fig. 4. Absorbance of the collected samples 1, 2, and 3 during hydrocarbon gas injection at LGR 450 bbl/MMSCF and 104 °F.

proved to be more effective than that observed during the immiscible injection process in core B. This observation is supported by the results presented in this section.

3.1.4. Molecular weight measurements

A cooling trap designed by Vinci was utilized to determine molecular weight using the freezing point method. The molecular weight of the dead oil has been determined to be 281 g/mol. Fluid samples from the gas flooding were collected as described in the previous section using 0.6 cc of oil for each sample to assess the molecular weight. The molecular weights of the collected samples during the miscible flooding of core sample A were measured at 150, 141, and 134 g/mol. This analysis indicates a great reduction of 52% in molecular weight in sample 3 when compared to the dead oil. Asphaltenes have a molecular weight distribution ranging from 400 to 1500 g/mol. However, determining both the average and extreme values is challenging due to the aggregation of molecules within the solution (Podgorski et al., 2013). Asphaltenes have a profoundly higher molecular weight than other oil components. The asphaltene deposition in the core reduced the molecular weight of the output fluid sample. Additionally, during the immiscible injection into core sample B, three fluid samples were analyzed, resulting in molecular weights of 161 g/mol, 147 g/mol, and 144 g/mol. These findings indicate a decrease of approximately 49% in molecular weight for sample 3 during the immiscible flooding process for core sample B, compared to that of the dead oil.

Fig. 5 illustrates the changes in the molecular weight over time. The decrease in molecular weight of both cores indicates increased asphaltene deposition through gas injection in carbonate cores A and B. A lower molecular weight indicates a greater asphaltene deposition in the core. The presented results in this section highlight that asphaltene deposition during the miscible injection process is noticeably more significant than that during the immiscible injection process. This conclusion was supported by the analysis of the samples, as discussed in the previous sections.

3.2. Core flooding by hydrocarbon gas of LGR = 380 bbl/MMSCF

Core samples of A and B were prepared following the specifications detailed in Table 8 for injection with rich hydrocarbon gas at temperatures of 104 °F and 210 °F. This process considered both miscible and immiscible conditions to evaluate the formation damage that could occur during hydrocarbon gas injection. Slim tube tests were initially performed to determine the miscibility pressure. The results showed that the miscibility pressure of live oil combined with rich hydrocarbon gas, at a ratio of 380 barrels per million cubic feet, was 3300 psi at 104 °F and 4200 psi at 210 °F (Safaei, 2022).

The formation water was used to saturate the core sample, and it was thermally aged at 176 °F for 21 days. Subsequently, the samples were flooded with dead oil and aged for 21 days. Core sample An underwent a miscible flooding test at a back pressure of 3755 psi. Dead oil was injected until the desired pressure was achieved, which facilitated the emergence of the first oil droplet. Then, live oil was injected to displace dead oil at 2 PV, with a flow rate of 0.3 cc/min. This was followed by hydrocarbon gas at a rate of 0.1 cc/min. Core sample B was prepared for an immiscible flooding test under a back pressure of 2276 psi. Dead oil was injected until the core chamber attained the specified back pressure, after which live oil was injected to displace the dead oil following the same flow rate and conditions as implemented for the core sample of A. Upon completion of the aging process, core sample B was prepared for a miscible test at 210 °F. Dead oil was injected until the pressure reached 4480 psi; at this point,

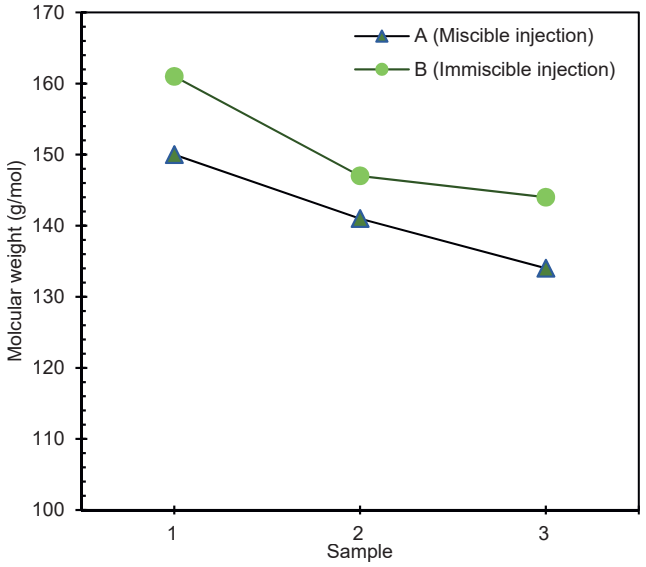

Fig. 5. Molecular weights of the collected samples 1, 2, and 3 during hydrocarbon gas injection at LGR = 450 bbl/MMSCF and 104 °F.

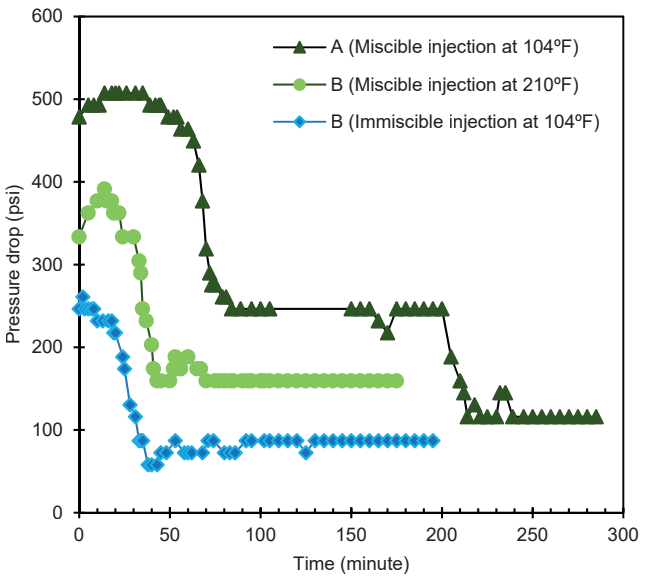

Fig. 6. Pressure drop at the ends of cores over time during hydrocarbon gas injection at LGR 3800 bbl/MMSCF, conducted at 104 °F and 210 °F.

production began using the previously specified injection rates for both live oil and hydrocarbon gas.

Fig. 6 shows the pressure drop at both ends of the cores as a function of time during hydrocarbon gas injection into live oil. Injecting hydrocarbon gas into live oil initially results in no production, causing a rapid increase in pressure without any output due to insufficient gas injection. As gas injection continues and pressure rises, the gas penetrates the core further, allowing oil to flow and production to start. Over time, the enhanced gas relative permeability improves oil production as gas saturation rises, leading to greater output from the cores.

During the miscible gas injection in core A, gas was injected into the live oil and dissolved. This dissolution causes the oil to expand but also decreases its viscosity and density. Together, these changes promote the flow of gas and oil as a single phase. As oil is extracted from the system, the pressure differential decreases until a gas breakthrough occurs, as illustrated in Fig. 6. On the contrary, the immiscible injection process in core B increases the gas's relative permeability, enabling the gas to displace oil and effectively enhance production. Once a gas breakthrough occurs, the pressure begins to decline as the gas continues to push out the oil. At a temperature of 210 °F in core B during the miscible injection process, gas dissolves into the oil, leading to oil swelling and reduced viscosity. This effect facilitates the combined flow of gas and oil. The pressure differential decreases until a gas breakthrough occurs, as shown in core B. The figure illustrates a decrease in the pressure difference across the core leading up to the gas breakthrough. The continued gas production further reduced the pressure differential. During the gas injection phase, a significant pressure difference was observed, likely due to the interaction between hydrocarbon gas and oil, which led to the formation of asphaltene deposits. This injection process continued until pressure stabilization was achieved at approximately three pore volumes of the injected cores.

During the injection of hydrocarbon gas into the core samples, oil was produced and collected in containers until a breakthrough was observed. Fluid samples from the carbonate cores used in the flooding tests were collected in 1.8 cc containers, as explained before, at specific pore volumes. The samples were subsequently analyzed for their optical spectrophotometry, asphaltene content, and molecular weight.

3.2.1. *Porosity and permeability*

Cores A and B were washed with toluene using a Soxhlet extractor to prepare for the flooding tests. The initial measurements of porosity and permeability for core A were determined to be 26.2% and 19.28 mD, respectively. Core B exhibited an initial porosity of 24.11% and a permeability of 15.19 mD. After the washing and aging process, miscible flooding was conducted in core A, while immiscible flooding was conducted in core B at 104 °F. Following the flooding tests, both cores were washed with cyclohexane, followed by measurements of porosity and permeability. After cyclohexane treatment, the values of porosity and permeability in core A decreased to 23.38% and 14.63 mD, respectively, indicating a 10% reduction in porosity and a 24% reduction in permeability. For core B, porosity decreased to 21.26% and permeability to 12.32 mD, indicating a reduction of 12% in

Table 8
Conditions for core flooding tests of the A and B carbonate cores.

Core Sample	Type	Injection method	Injection gas	BPR (psi)	Miscible pressure (psi)	Temperature (°F)
A	Carbonate rock	Miscible	Hydrocarbon gas (LGR = 380 bbl/MMSCF)	3755	3300	104
B	Carbonate rock	Immiscible	Hydrocarbon gas (LGR = 380 bbl/MMSCF)	2276	3300	104
B	Carbonate rock	Miscible	Hydrocarbon gas (LGR = 380 bbl/MMSCF)	4480	4200	210

porosity and 19% in permeability, respectively. Toluene was also used in a Soxhlet extractor to clean core sample B for an additional flooding test under miscible conditions at 210 °F. This process resulted in changes to the porosity and permeability that were close to the initial conditions (see Table 9).

After the cleaning and aging processes, a second miscible flooding was conducted for core B at 210 °F. After the flooding tests, core sample B was washed with cyclohexane. The porosity and permeability measurements then revealed a reduction of 13.6% and 42.8%, respectively. Asphaltene deposition during flooding likely affected the porosity and permeability changes in carbonate cores A and B, as demonstrated in Table 9. During the flooding experiment, porosity and permeability decreased more significantly with miscible injection than with immiscible injection. The most notable decline was observed in core B during miscible injection at 210 °F, where high temperature and pressure led to increased asphaltene deposition. Previous studies showed that viscosity significantly influences the rate of asphaltene aggregation, as low viscosity results in faster aggregation (Enayat et al., 2020; Maqbool et al., 2011). As temperature increases, viscosity is expected to decrease, resulting in a higher diffusion rate of asphaltene particles. Consequently, the rate of asphaltene aggregation increases, leading to a rapid rise in the precipitation rate (Bjorøy et al., 2012).

3.2.2. Asphaltene content

To measure the asphaltenes content, 0.5 cc of oil was used for each sample, following the procedure that has been outlined before. Fluid samples were collected and conserved in three sealed containers in each flooding experiment. During the miscible flooding process in core sample A, the asphaltene contents of samples 1, 2, and 3 were measured as 4.19%, 3.65%, and 3.52% by weight, respectively. The asphaltene content of the dead oil was calculated to be 5.2% by weight. The asphaltene content in sample 3 was 32% lower compared to the dead oil. During the immiscible flooding process with core sample B, the asphaltene contents of samples 1, 2, and 3 were measured as 4.53%, 3.97%, and 3.75% by weight, respectively. When comparing the asphaltene content of sample 3 from this flooding test with that of dead oil, a lower asphaltene content of 27% was noted. In the miscible flooding process conducted at 210 °F using core sample B, the asphaltene contents of samples 1, 2, and 3 were measured as 3.59%, 3.15%, and 3.04%, respectively. This indicates 41.5% lower asphaltene content in sample 3 compared to that of the dead oil.

Fig. 7 illustrates the variation of asphaltene weight percentage in the collected samples. In core B, miscible flooding at 210 °F resulted in the highest asphaltene deposition in the porous media. In contrast, immiscible flooding at 104 °F resulted in the lowest level of deposition. The data from the samples indicate a decrease in asphaltene content, suggesting that a larger volume of asphaltene was deposited within the porous media of cores A and B. Samples obtained via miscible injection exhibit lower asphaltene contents than those derived via immiscible injection. This indicates that a greater degree of asphaltene deposition occurs in porous media during miscible injection.

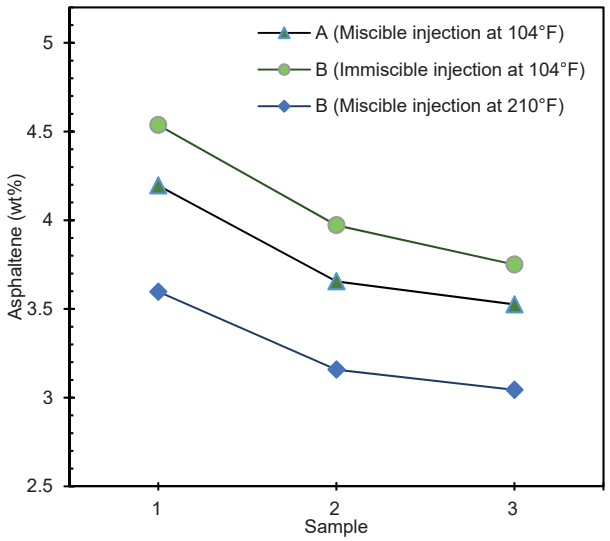

Fig. 7. Asphaltene content in the collected samples of 1, 2, and 3 during hydrocarbon gas injection at LGR 380 bbl/MMSCF, and 104 °F and 210 °F.

3.2.3. UV–Vis Spectrophotometry

During each flooding test, fluid samples were collected in three lidded containers. A total of 0.3 cc of oil was used for each sample to determine absorption values in accordance with the procedure outlined in the section on UV–Vis Spectrophotometry. Fluid samples from the miscible flooding of core A were collected in three containers. The recorded absorption values for these samples were 2.1, 2.075, and 2.019, indicating a 36% reduction in sample 3 compared to the absorption of dead oil. For the immiscible flooding of core B, similar methods were applied to those used for core A. The absorption values for the three fluid samples from core B were 2.33, 2.21, and 2.06, which confirmed 35% lower absorption for sample 3. During miscible flooding at 210 °F, the absorption values for fluid samples 1, 2, and 3 from core B were 2.007, 1.943, and 1.854, respectively. These results show a profound reduction of 42.1% in sample 3, resulting in the lowest recorded absorption in this series of experiments.

Fig. 8 shows how the absorbance changes for the collected samples. During the immiscible gas injection in core B, asphaltene deposition within the porous media became increasingly notable. The absorption coefficients of the samples tended to decrease, indicating a rise in asphaltene deposition. Conversely, although the miscible gas injection in core A also resulted in an overall decline in absorption coefficients, this was marked by a significant increase in asphaltene deposition. Notably, the maximum asphaltene deposition occurred during the miscible flooding at 210 °F in core B. The substantial reduction in the absorption coefficient reflects that more asphaltene has been deposited in the core. Additionally, as noted earlier, the volume of asphaltene deposited during miscible injection at 210 °F was considerably

Table 9
Porosity and permeability measurements of core samples A and B.

Carbonate core	Porosity	Permeability (mD)	Description
A	26.20	19.28	Initial condition: cleaning with toluene
A	23.38	14.63	Washing with cyclohexane in a rich hydrocarbon gas injection (LGR = 380 & T = 104 °F)
B	24.11	15.19	Initial Condition: Cleaning with Toluene
B	21.26	12.32	Washing with cyclohexane in a rich hydrocarbon gas injection (LGR = 380& T = 104 °F)
B	24.15	16.12	Initial Condition: Cleaning with Toluene
B	20.86	9.32	Washing with cyclohexane in a rich hydrocarbon gas injection (LGR = 380 & T = 210 °F)

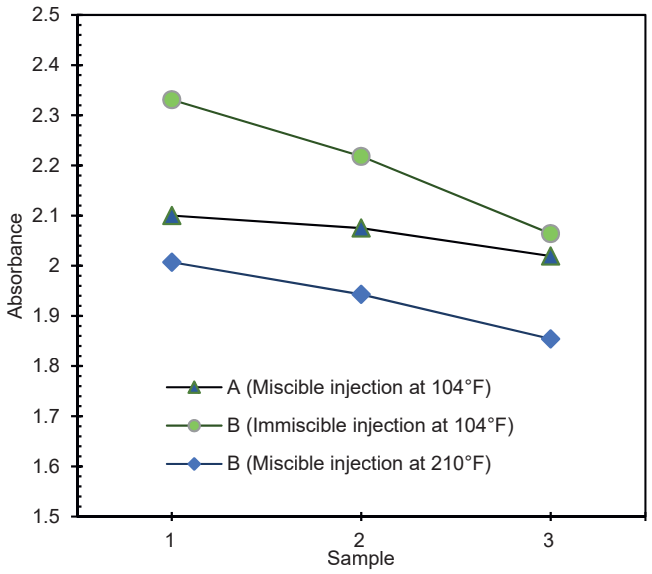

Fig. 8. Variation of absorbance for samples 1, 2, and 3 during hydrocarbon gas injection at LGR 380 bbl/MMSCF, conducted at 104 °F and 210 °F.

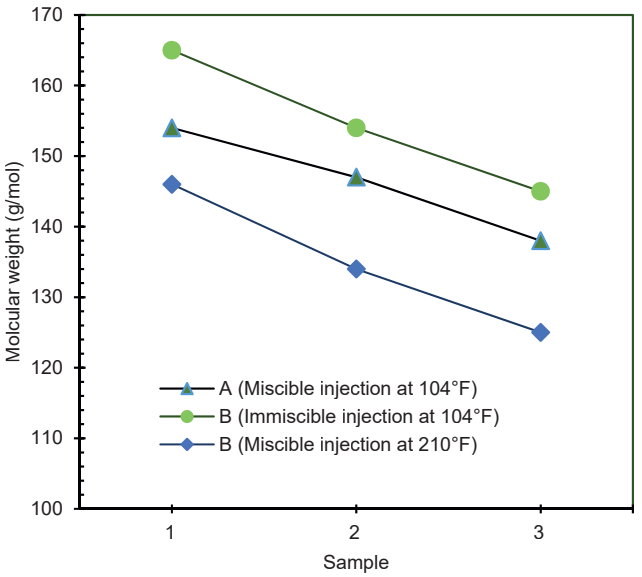

Fig. 9. Molecular weights of the collected core samples of A and B.

higher than that observed during immiscible injection.

3.2.4. Molecular weight measurements

Fluid samples from the gas flooding process were analyzed to determine their molecular weight. Each sample required 0.6 cc of oil, as detailed in the previous section on molecular weight measurements, for the miscible flooding of core sample A. The molecular weights of the collected samples were 154, 147, and 138 g/mol. This indicates a 51% reduction in sample 3 when compared to the molecular weight of the dead oil. During the immiscible injection into core sample B, three fluid samples were analyzed. The molecular weights of the collected samples were 165, 154, and 145 g/mol, indicating a 48% lower molecular weight in sample 3. During miscible gas flooding conducted at 210 °F, the molecular weights of fluid samples 1, 2, and 3 from core B were recorded to be 146, 134, and 125 g/mol, respectively. The data points show a 53% reduction in sample 3.

Fig. 9 shows the changes in the molecular weight of cores A and B for various samples. The trend charts show a consistent decrease in molecular weight, indicating increased asphaltene deposition during the gas injection. The observed reduction in molecular weight highlights the profound deposition of asphaltene in core samples during the experiments. In particular, the maximum asphaltene deposition occurred during the miscible flooding process at a temperature of 210 °F in core B. Additionally, as noted in the section "Asphaltene Content," the volume of asphaltene deposited during miscible injection at 210 °F was significantly higher than that recorded during the immiscible injection.

Hydrocarbon gas injection under miscible conditions led to more severe asphaltene precipitation than that under immiscible gas injection. This phenomenon can be explained from thermodynamic and physicochemical perspectives. Under miscible conditions, the gas completely mixes with the oil, causing changes in the oil composition, swelling, and a reduction in viscosity. These changes disturb the phase equilibrium, which would otherwise decrease the solubility of asphaltenes, resulting in increased precipitation of asphaltenes (Alvarado and Manrique, 2010). As a result, asphaltenes become unstable in the oil phase, which promotes their aggregation and latter deposition (Najjar et al., 2024). The formation of larger flocculated particles accompanies the asphaltene precipitation process under miscible conditions (Moradi et al., 2012). These particles can significantly block the pore throats and reduce the permeability and porosity of the rock. In contrast, under immiscible conditions, gas dissolves less in the oil, which limits instability and precipitation of asphaltenes. Additionally, asphaltene precipitation causes significant changes in rock wettability, which are more pronounced under miscible conditions. This alteration then impacts fluid flow within the reservoir and can reduce the efficiency of the injection process (Mohammed et al., 2021a,b). The mechanisms are well established by the experimental data presented in this work, including the reduction in oil molecular weight, changes in UV–Vis absorbance, and decreases in core permeability and porosity.

Porosity and permeability measurements at the core scale are generally accurate and reliable, although heterogeneities in reservoir layers can profoundly affect the results. Heterogeneity in the rock types and properties, asymmetric distribution of asphaltene deposition, and fluid flow dispersion cause core-scale experimental results to be non-uniform and not directly generalizable to all locations in the reservoir. This study used live oil and hydrocarbon gas injected in the field at the core scale. To make the data applicable at the reservoir scale, samples should be taken from different rock types of the reservoir, followed by upscaling to the reservoir scale.

3.3. Comparison of gas injection at richness levels of 380 and 450 bbl/MMSCF

The injection of hydrocarbon gases into a heavy oil reservoir may lead to phase changes and alteration of chemical equilibrium. Gas injection can also alter the reservoir pressure, which may decrease the solubility of asphaltene. This would, in turn, cause the precipitated asphaltene particles to join together and form aggregates. Asphaltene deposition caused by asphaltene instability under gas injection conditions involves the formation of aggregated particles, their movement and adsorption within the porous media, and ultimately the accumulation and blockage of the pore throat. This process has been experimentally demonstrated in this study using various analytical methods such as molecular weight measurement, light absorption, and calculation of asphaltene

content. Additionally, the permeability and porosity of the core sample in the core flooding process before and after core flooding are measured.

As stated earlier, the miscible injection process has been used in the Asmary reservoir for over a decade, with the gas richness recorded at 450 bbl/MMSCF. As it is well-known, the extraction of rich gas from NGL comes at high costs. Having considered this fact along with other factors such as reservoir pressure, miscibility pressure, and operating conditions, a gas with a richness of 380 bbl/MMSCF was selected for comparative analysis against the gas with a richness of 450 bbl/MMSCF, which has been used in the aforementioned oil field for a long time. The experimental results show that injecting hydrocarbon gas at a richness of 450 bbl/MMSCF under both miscible and immiscible conditions leads to profound asphaltene deposition. During hydrocarbon gas injection at a richness of 380 bbl/MMSCF, a much lower deposition of asphaltene was experienced. It has also been proven to be more economical than using gas with a richness of 450 bbl/MMSCF. As a result, hydrocarbon gas with a richness of 380 bbl/MMSCF was injected under reservoir conditions at a temperature of 210 °F. The results indicate that higher temperatures and pressures lead to more significant deposition of asphaltenes.

Then, suppose one denotes the asphaltene content (AC) in the dead oil as ACdead oil and similarly the asphaltene content in the collected oil samples as ACcollected sample. In that case, the extent of asphaltene deposition can be defined as ($AC_{dead\ oil}$ - $AC_{collected\ sample}$)/$AC_{dead\ oil}$. Fig. 10 shows the extent of asphaltene deposition during different flooding tests. During the gas injection, the extent of asphaltene deposition increases gradually as the volume of hydrocarbon gas injection rises. Asphaltene deposition is influenced by the solubility of hydrocarbon gases in crude oil and the oil's capacity to transport asphaltene (Pi et al., 2025). Asphaltene deposition is notably more significant during miscible injection than immiscible injection. The experimental results indicate that gas injection with a richness of 450 bbl/MMSCF at 104 °F resulted in greater asphaltene deposition compared to gas with a richness of 380 bbl/MMSCF.

Gas with a richness of 380 bbl/MMSCF leads to less asphaltene deposition and is more economical than using gas hydrocarbons with a richness of 450 bbl/MMSCF since NGL is used to make rich hydrocarbon gas, which is quite costly. Thus, hydrocarbon gas was injected with a richness of 380 bbl/MMSCF under reservoir conditions at a temperature of 210 °F. The extent of asphaltene deposition during miscible injection at 210 °F is profoundly higher than that observed during other gas injection processes investigated in this study. The results show that increased temperature and pressure lead to greater deposition of asphaltenes.

As stated earlier, this study presents several advantages, including the use of live oil samples from the reservoir. Moreover, carbonate cores were used for experiments and core flooding under reservoir conditions, which resulted in attaining more reliable results. The effect of injecting hydrocarbon-rich gases with varying compositions under miscible and immiscible injection conditions was investigated, allowing a better understanding of the asphaltene precipitation process and the resulting damage. Analytical methods, including molecular weight measurement, UV–Vis absorption, and determination of asphaltene content in oil samples produced from the core flooding process, provide a comprehensive framework to evaluate the intensity and dynamics of asphaltene precipitation.

Having said that, this study also has some shortcomings, including its focus on low-permeability carbonate rocks and heavy oil samples, which may limit the applicability of the results to other oil reservoirs. Moreover, since the primary goal was to investigate asphaltene precipitation during gas injection in heavy oil reservoirs, methods to inhibit asphaltene deposition, such as using anti-asphaltene additives, were not explored. The limitations of the study include the fact that experiments and core flooding tests were conducted at the experimental scale, and further studies are needed to fully understand asphaltene deposition under reservoir field conditions. Additionally, factors like long-term reservoir pressure variations due to production and field pressure depletion were not comprehensively considered.

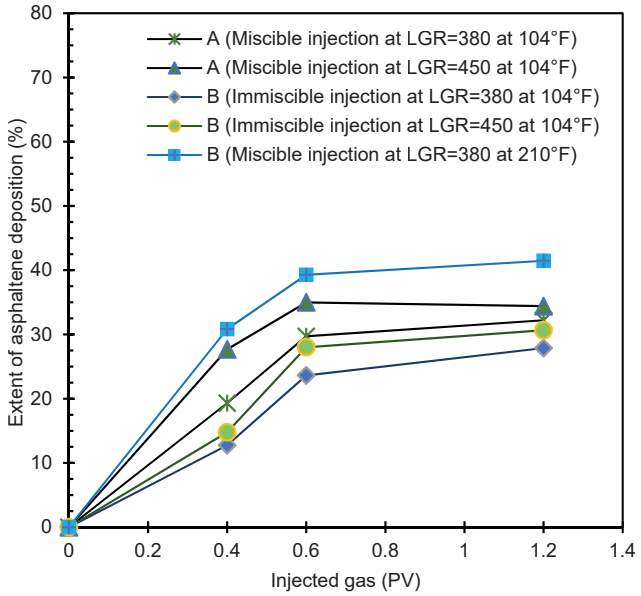

Fig. 10. Extent of asphaltene deposition during different gas flooding under miscible and immiscible conditions.

Using rich hydrocarbon gases as injection fluid at high temperature and pressure facilitates applying agents such as chemical solutions and nanoparticles to mitigate asphaltene precipitation and deposition. At higher temperatures and pressures, the solubility of rich hydrocarbon gases increases, allowing nanoparticles to disperse more easily in the injection fluid (Sodeifian and Sajadian, 2018). To mitigate the damage caused by asphaltene deposition at the field scale, the following methods are recommended for future studies.

- Solvent preflush: Injecting aromatic solvents such as normal heptane, toluene, or cyclohexane before gas injection can help prevent the initial formation of asphaltene deposits and clean the rock pores. This method reduces blockages by increasing asphaltene solubility (Fassihi et al., 2020).
- Use of chemical Inhibitors: Introducing chemical compounds that inhibit asphaltene precipitation in the injection fluid reduces asphaltene aggregation and deposition, thereby improving reservoir performance (Bahmaninia et al., 2021b).
- Water-Alternating-Gas (WAG) Injection: This technique helps control pressure and phase composition in the reservoir. It prevents severe fluctuations in phase equilibrium and reduces asphaltene deposition (Memon et al., 2012b)
- Adjustment of Injection gas richness: Using gases with lower richness (e.g., LGR around 380 bbl/MMSCF instead of 450 bbl/MMSCF) can help reduce asphaltene precipitation and operational costs while maintaining process efficiency
- These strategies can enhance gas injection effectiveness and reduce asphaltene deposition in conjunction with controlled experiments and optimization based on reservoir conditions.

4. Conclusions

During the flooding experiments, hydrocarbon gases with LGR of 380 and 450 bbl/MMSCF were injected into live oil into two core samples. Different gas flooding tests were performed under both miscible and immiscible conditions at two temperatures of 104 °F and 210 °F. In addition, the asphaltene content, molecular weight, and UV–Vis spectrophotometry of three collected oil samples were measured to determine the extent of asphaltene deposition. The experimental results showed that.

- Permeability and porosity of the core samples were reduced, but more noticeably during miscible gas injection. Accordingly, asphaltene deposition was more severe during miscible injection compared to immiscible injection for both gas compositions.
- Injection of a heavier hydrocarbon gas (450 bbl/MMSCF) during core flooding led to more asphaltene deposition than that of lighter hydrocarbon gas (380 bbl/MMSCF).
- Injecting hydrocarbon gas with a richness of 380 bbl/MMSCF into live oil under miscible conditions at a reservoir temperature of 210 °F resulted in profound asphaltene deposition since a 42.8% reduction in permeability of the core sample of B was observed.
- The use of lighter hydrocarbon gas during the immiscible core flooding process at 104 °F resulted in less asphaltene deposition.
- More asphaltene deposition should be expected regardless of gas richness and miscibility as temperature increases.

The results of this study highlight the need to optimize hydrocarbon gas injection conditions in terms of gas type and richness to effectively reduce the potency of asphaltene deposition in heavy oil reservoirs. Optimizing these parameters can significantly prevent damage to the porosity and permeability of reservoirs, thereby enhancing oil recovery efficiency. The findings provide practical guidelines for oil companies to select optimal injection strategies and reduce costs related to asphaltene deposition control. The development of more accurate predictive models and conducting large-scale field experiments are considered the main objectives for future research. Moreover, the integration of these results with technologies such as chemical inhibitors and nanoparticles can provide a better solution for managing asphaltene deposition. These approaches may improve production stability and reduce operational downtime.

CRediT authorship contribution statement

N. Shakibasefat: Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **M.R. Malayeri:** Writing – review & editing, Validation, Supervision. **M. Riazi:** Writing – review & editing, Validation, Supervision.

Declaration of competing interest

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.

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Abbreviations

API	American Petroleum Institute
BPR	Back Pressure Regulator
EOR	Enhanced Oil Recovery
LPG	Liquefied Petroleum Gas
LGR	Liquid-Gas Ratio (bbl/MMSCF)
MMP	Minimum Miscible Pressure
MMSCF	Million Standard Cubic Feet
NGL	Natural Gas Liquids
PV	Pore Volume
SARA	Saturates, Aromatics, Resins, and Asphaltenes analysis
UV–Vis	Ultraviolet–Visible Spectrophotometry

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