

Review article

Review on miscible, immiscible, and progressive nitrogen injection for enhanced oil recovery

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ABSTRACT

Due to its relatively low cost, availability, safety, low environmental impact, and versatility, nitrogen emerges as a promising candidate for enhanced oil recovery. This article provides an overview of nitrogen injection applications within reservoirs, encompassing both miscible and immiscible conditions. Additionally, this work reviews unconventional nitrogen-based enhanced oil recovery methodologies, including the utilization of foam-assisted nitrogen and cold nitrogen injection. To adapt miscible injection for reservoirs characterized by lower pressure, the combination of nitrogen with hydrocarbon gasses or CO₂ presents a viable strategy. Notably, both miscible and immiscible nitrogen injection techniques demonstrate the potential to recover approximately 20 % of residual oil saturation. However, under conditions of high water cut, water alternating nitrogen injection surpasses regular immiscible nitrogen injection in terms of oil recovery. In the context of fractured rocks, foam-assisted water alternating nitrogen injection yields a 15 % higher oil recovery compared to conventional water flooding approaches. Intriguingly, nitrogen-based foams have been effectively deployed in field conditions to enhance the recovery of 920 cp oil from heterogeneous reservoirs, resulting in a remarkable up to 2.6-fold increase in oil flow rate. These compelling outcomes instigate a comparative investigation of the method's efficacy against the conventional chemical flooding technique. Furthermore, nitrogen exhibits remarkable potential for oil recovery from ultra-low permeability (198 nD) rocks, owing to its low molecular weight that facilitates penetration even into very small pores. Moreover, the injection of cold nitrogen (−26 °C) induces a substantial enlargement of fractures in low permeability rocks, accentuating its efficacy in this context.

1. Introduction

Among all approaches, gas injection has emerged as the most widely utilized enhanced oil recovery (EOR) technique, constituting nearly 60 percent of EOR production in the United States (Fahandezhsaadi et al., 2019). Conversely, other methods, are less appealing due to their limitations. For example, the application of chemical methods like polymer and ASP flooding may be challenging due to the high cost of chemicals, high reservoir temperature, brine salinity, and low permeability (Fahandezhsaadi et al., 2019).

The injection of N₂ is a well-known method of enhancing oil recovery (EOR), which can be either miscible or immiscible, depending on the pressure and oil composition (Economides et al., 2014; Taber et al., 1997).

There are 2 mechanisms of oil recovery by N₂ (Taber et al., 1997):

1-The transition of light fractions of oil into a gaseous state occurs

during the miscible displacement under high pressure.

2-Oil recovery is driven by filling the pore volume of a reservoir with inexpensive gas.

Besides that, it is possible to inject N₂ into reservoirs in large volumes due to its low cost compared to hydrocarbon gasses. Dean et al. (2018) have presented an enhanced oil recovery (EOR) agent evaluation approach for various gas and chemical EOR technologies. Different agents were compared based on sourcing options, pricing, as well as logistics. Among the options for immiscible gas injection, it was shown that N₂ is the most cost-effective. For instance, the cost of an N₂ generator is only \$500,000. Additionally, no pipeline costs are required for N₂, whereas with CO₂, approximately \$300,000 per mile were estimated for pipeline costs.

In some cases, N₂ injection can be a better choice than regular water flooding. For example, N₂ injection was preferred over water flooding in a fractured carbonate reservoir underlain by an infinite aquifer since

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water flooding was predicted to cause severe water cut increase and trapping of oil in the matrix due to a very high capillary pressure (Necmettin, 2003).

As for the history, projects on N_2 injection began as early as the 1940s. The main motivation for N_2 application has been to substitute hydrocarbon gases. One of the first projects on N_2 injection began in 1945 in West Texas tight reservoirs (Mogensen and Xu, 2020). Another early successful project of N_2 injection began in 1949, where N_2 was injected to assist gravity drainage, allowing for an increase in gas cap and reservoir pressure by 1.3 MPa (190 psi) and 1.2 MPa (176 psi), respectively, over five years. In fact, injecting 288 million m^3 /day of inert gas (90 % N_2 /10 % CO_2) during 1951–53 increased the oil production rate from ~15,000 bbls/day to 19,000 bbls/day (Stewart et al., 1955).

In 1981, an interesting paper was published showing that simultaneous injection of N_2 and water at 0.5 MPa (73 psi) into Berea sandstone can reduce oil saturation after water flooding from 40 % to 22 % (Slack and Ehrlich, 1981a). These results demonstrated that recovery of residual oil is possible even under immiscible conditions, as residual oil saturation strongly depends on three-phase relative permeability characteristics. N_2 miscible water alternating gas (WAG) injection was initiated in 1981 at Jay field and lasted for more than 33 years. The results of this project up until 2013 were published in (Meister et al., 2014). This field case proves that N_2 can be used continuously from the early to mature stages of the production period (Meister et al., 2014).

From October 2005 to January 2006, three injection wells were treated with a foaming agent and N_2 at Daqing field. The total volume of injected gas and fluid was equal to 9490 m^3 . As a result, during six months, 3486 t of oil were produced incrementally (He et al., 2010). The above examples demonstrate that N_2 has been used as an EOR agent since the 1940s and is suitable for a wide range of reservoir conditions, applicable at any production stage of the field.

Nevertheless, despite the advantages of N_2 -enhanced oil recovery (EOR), this approach often remains understudied. One contributing factor to this oversight is the elevated minimum miscibility pressure (MMP) of N_2 within oil. Indeed, most recent investigations have been carried out under high-pressure conditions, primarily aimed at inducing the necessary miscible flooding pressure to augment oil recovery (Hasan et al., 2023). However, the findings presented in this paper demonstrate that N_2 -based enhanced oil recovery (EOR) methods can be effective in both miscible and immiscible conditions. Another reason for the under-study of N_2 EOR, despite its benefits, could be that many reservoirs are in their final production stages with significant amounts of immobile oil. Traditionally chemical methods are used to recover this oil. However, some studies mentioned in this review suggest that even immiscible N_2 injection can mobilize some remaining immobile oil.

In recent years, several papers have been published to assess the advancements in N_2 EOR technology. For instance, (He et al., 2022) has showcased field cases illustrating the utilization of N_2 in assisting thermal heavy oil recovery and forming a secondary gas cap to facilitate downward oil movement. Notably, employing N_2 can lead to a reduction in the quantity of steam injection required.

Another paper explored N_2 injection as a cost-effective and water-saving alternative for fields in Africa. Drawing from the successful case study of the Cantarell oil field in Mexico, researchers developed a screening method tailored for African fields. As a result, they identified 48 oil fields in Algeria, 49 fields in Egypt, 50 fields in Libya, and 19 fields in Tunisia with significant potential for N_2 injection, potentially yielding up to a 10 % incremental recovery factor (Heucke, 2015).

Another significant paper by Sinanan and Budri (2012) examined the global history of N_2 EOR with a specific focus on its applications in Trinidad. The authors conducted an analysis of how reservoir properties influence recovery. Utilizing reservoir simulation, they highlighted the promising potential of N_2 injection for enhancing oil recovery in Trinidad's shallow onshore reservoirs. Their findings suggest that N_2 injection could serve as a practical and economic alternative for extending

the economic lifespan of mature fields. Indeed, it was demonstrated that immiscible N_2 injection has the potential to yield incremental oil recovery ranging from 10 % to 21 % over projects spanning 10–25 years, depending on factors such as formation dip, crude API, and porosity/permeability ratios.

This paper is different from the other review papers presented in the literature, as it reviews the injection of N_2 under both miscible and immiscible conditions, leveraging an analysis of outcomes from both laboratory and field experiments. Additionally, this review delves into the utilization of N_2 in conjunction with water or foam, exploring their efficacy in scenarios characterized by high water cut and for the recovery of viscous oil (approximately 900 cp) from heterogeneous reservoirs. Furthermore, the paper underscores the significance of employing N_2 for oil recovery from ultra-low permeability rocks. The low molecular weight of N_2 facilitates its infiltration into fine pores, enabling efficient oil displacement.

The information presented in the paper is meant to attract the attention of petroleum engineers to N_2 EOR as an effective and water-saving method.

2. Miscible N_2 injection

Depending on pressure at reservoir temperature and crude oil composition, N_2 injection can be miscible or immiscible. Miscibility is the point at which there exists no interface between the displacing phase and the reservoir oil i.e., two phases are considered miscible when they form a single-phase fluid regardless of the ratio at which they are mixed. The minimum pressure required for miscibility to occur between the injection gas and reservoir fluid, at reservoir temperature, is termed as the minimum miscibility pressure (MMP) (Fathinasab et al., 2015). Once MMP is achieved, N_2 and crude oil form single phase at first contact, usually at 36–50 MPa (5290–7347 psi). Since N_2 is a noble gas, there is no need for any exchange of components for the miscibility to develop.

It is a well-known fact that injecting N_2 into light and medium-density oil reservoirs enables higher miscibility and oil recovery. In fact, (Rushing et al., 1977) have demonstrated that lighter oils containing a specific amount of gas are more amenable to N_2 injection under high pressure.

The effect of N_2 injection pressure on recovery of 39° API oil can be seen from the Fig. 1 which illustrates the result of oil recovery by N_2

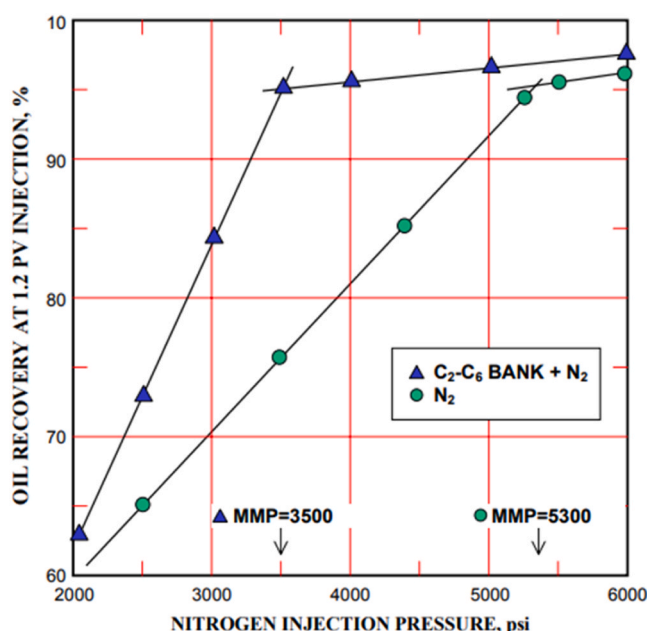


Fig. 1. Oil recovery vs N_2 injection pressure (Necmettin, 2003).

from 30-m-length sand pack filled with 44–125 μm sand particles and having permeability of 10 mD. As can be seen, the increase of injection pressure from 17 to 40 MPa (2500 to 5880 psi) resulted in oil recovery from 65 % to 96 % at 1.2 PVs injected. In fact, the minimum miscibility pressure for this oil was estimated at 36 MPa (5290 psi) (Necmettin, 2003).

Of note is that the miscibility pressure of N_2 with oil is 36–50 MPa (5290–7350 psi), which is 24–42 MPa (3530–6170 psi) higher than that of the hydrocarbon agent (Internet source).

However, as shown in Necmettin (2003), the injection of 0.05 PV of $\text{C}_2\text{--C}_6$ bank before N_2 reduced the minimum miscibility pressure from 36 to 23.8 MPa (5290 to 3450 psi), thereby saving the cost of compression. In fact, the injection of 0.05 PV $\text{C}_2\text{--C}_6$ gas followed by 0.05 PV of N_2 at 23.8 MPa (3450 psi) was proved to be more effective than the injection of 0.1 PV of pure N_2 at 37.4 MPa (5500 psi) (Necmettin, 2003).

In another study, the Minimum Miscibility Pressure (MMP) for N_2 was measured to be 66 MPa (9700 psi). However, injecting medium molecular weight hydrocarbons ($\text{C}_2\text{--C}_6$) along with N_2 reduced the MMP to 27.2 MPa (4000 psi) and increased oil recovery by 10 % compared to pure N_2 injection (Report No, 1989).

Another way to reduce the minimum miscibility pressure of N_2 in oil is to use it in combination with CO_2 . Fig. 2 shows the results of the minimum miscibility pressure of N_2 and CO_2 mixture versus the content of CO_2 (Mansour et al., 2021).

In fact, the utilization of lean gas, rather than N_2 , in conjunction with CO_2 , results in a lower Minimum Miscibility Pressure (MMP). For instance, a mixture of 0.5 CO_2 : 0.5 N_2 yields MMP of 31.7 MPa (4660 psi), whereas the combination of 0.5 CO_2 : 0.5 lean gas results in MMP of 23.8 MPa (3500 psi). Nevertheless, the elevated cost linked with lean gas might influence the decision to opt for N_2 as the preferred alternative (Mansour et al., 2021).

However, the price of N_2 is usually less than that of CO_2 and natural gas, and has the added benefit of being widely available and non-corrosive. In fact, N_2 demonstrated greater effectiveness compared to low salinity water and CO_2 in the recovery of residual oil from low permeability carbonate cores (0.3–2.2 mD). For instance, injecting 5 cm^3 of N_2 followed by 60 cm^3 of low salinity water into a core with a pore volume of 16.2 cm^3 resulted in the recovery of 24 % of the residual oil. In contrast, the injection of CO_2 and low salinity water, or low salinity water alone, only led to the production of 7.3 % or 7.1 % of the residual oil, respectively. The superior performance of N_2 was attributed to its enhanced injectability in low permeability rocks. In fact, the molecular weight of N_2 is smaller than that of CO_2 , enabling it to access the extremely fine pores of the cores that CO_2 cannot reach. Additionally, N_2 induces the vaporization of the lighter oil components (C_1 to C_6), and thus is more effective in recovering light oils (API = 35.7°) (Georges Lwisa and Abdulkhalek, 2018).

The results of computer simulation on a high-temperature carbonate

reservoir with a permeability of 2 mD and volatile oil also showed positive effects of N_2 application. The approach involved alternating injections of equal pore volumes of N_2 and water every six months. The use of N_2 in water alternating gas (WAG) injection strategy resulted in higher oil recovery rates compared to regular water flooding. In fact, the total oil recovery factor increased by 10 % due to the implementation of N_2 WAG (Xu et al., 2019).

Also, as was mentioned above, low cost and non-corrosive nature of N_2 make it a good alternative to CO_2 . For example, the injection of 70 % N_2 / 30 % CH_4 into the terrigenous gas-condensate saturated dome of the anticline structure in Fordoche Field (USA), with a permeability of 6 mD, for a duration of 2 years, led to a notable increase in light oil recovery. During this time no N_2 breakthrough was detected in production wells, though the concentration of N_2 in produced fluid increased by 4 %. However, the reduction in oil prices rendered the project uneconomical. It is worth noting that N_2 was chosen as an alternative to water flooding, which negatively affected oil permeability, and natural gas injection, which was not feasible due to commercial considerations (Mayne and Pendleton, 1986).

The presented examples describe the application of N_2 in conventional reservoirs. However, several recent studies demonstrate high potential of N_2 in unconventional reservoirs. For example, in the experiments with 198 nD shale cores the soaking of cores under N_2 pressure of 13.6 MPa (2000 psi) (miscible conditions) resulted in the recovery of 33.6 % of oil after 5 cycles (Fig. 3).

Cyclic tests revealed declining oil recovery in later cycles due to asphaltene precipitation, altering wettability and pore size. Higher N_2 injection pressure increased contact angle between brine and rock due to asphaltene-induced surface roughness (Fig. 4). Over cycles, asphaltene accumulation in larger pores transformed shale cores from weakly intermediate-wet (contact angle of ~ 83 deg) into strongly intermediate-wet systems (contact angle of 92–108 deg).

Of note is that N_2 injection can be also applied for the treatment of production wells in reservoirs containing heavy oils. For example, laboratory tests have shown that for heavy oil from the East Sarybulak field the increase of N_2 concentration in the mixture with reservoir oil from 0 to 1.36 m^3/t resulted in the decrease of the oil viscosity from 995 to 877 cp. Whereas the injection of N_2 into an oil saturated core at pressure drop decreasing from 3 to 0.8 MPa (440–117 psi) in the course of the experiment resulted in oil recovery of 35.9 % (Manikulov et al., 2016).

As a result, N_2 injection can be effectively applied for the recovery of oil, however its MMP is very high. The injection of $\text{C}_2\text{--C}_6$ gasses along with N_2 can reduce the MMP and increase oil recovery. Natural properties of N_2 make it an effective agent for tertiary oil recovery from low permeability carbonate rocks. Moreover, low cost and non-corrosive nature of N_2 makes it an appropriate alternative to CO_2 . Besides that,

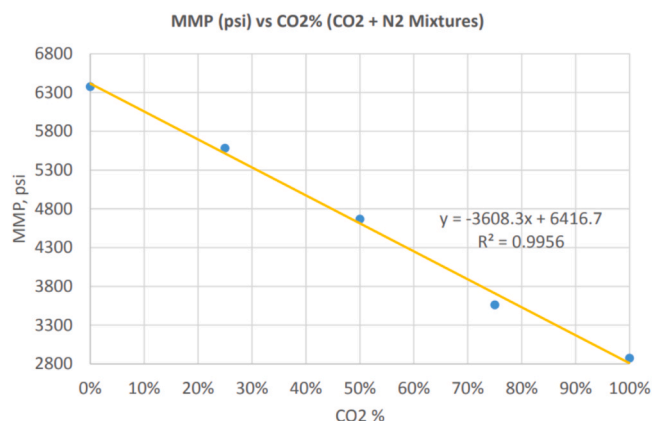


Fig. 2. MMP vs CO_2 content (Mansour et al., 2021).

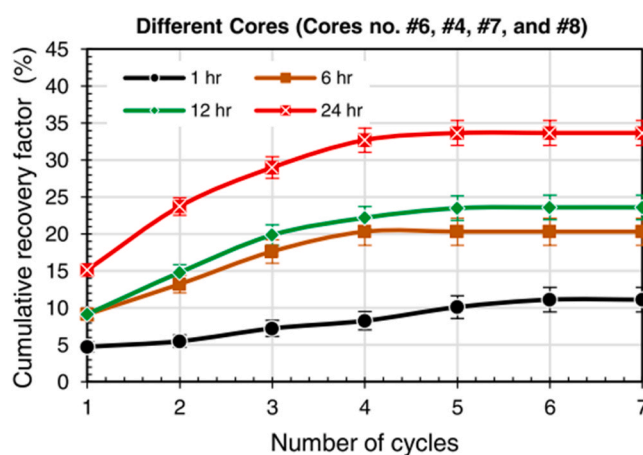


Fig. 3. Results of oil displacement by N_2 from 198 nD core (Elturki and Imqam, 2022).

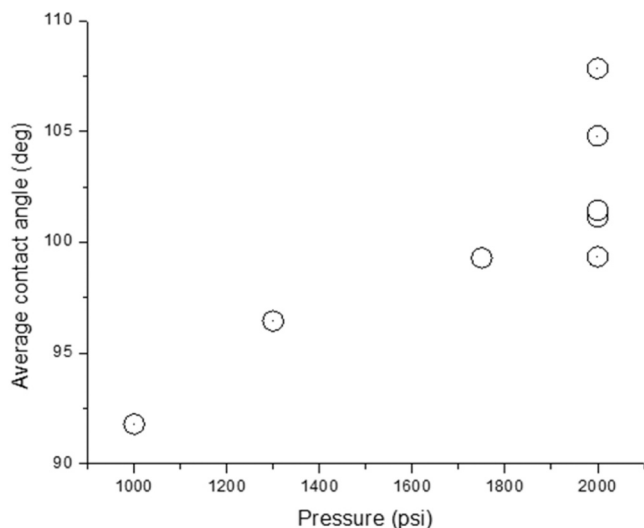


Fig. 4. The effect of N_2 injection pressure on the wettability change of the oil saturated shale (Elturki and Imqam, 2022).

N_2 can extract up to 33 % of oil from super low permeability rocks (198 nD), however this leads to the reduction of pore size due to the asphaltene precipitation.

3. Immiscible nitrogen injection

In cases where N_2 is injected at pressure below MMP, this is immiscible secondary

recovery pressure maintenance method that can be used for a wide range of conditions, as show in this section.

In the work of Janssen et al. (2018) several immiscible nitrogen injection schemes were compared by using Bentheimer sandstone cores. The injection of nitrogen into a 40-cm-long core with 2.88 D permeability, saturated with n-hexadecane, resulted in the increase of oil recovery by several percent, as the pressure increased from atmospheric to 6 MPa (880 psi). Even though the injection was done at pressure much less than MMP (35 MPa – 5140 psi), the increase of pressure may have resulted in the reduction of IFT (interfacial tension).

As has been shown in the work (Fahandezhsaadi et al., 2019) the difference between the injection pressure and the back pressure at which immiscible nitrogen injection is done has a strong effect on the oil recovery. The Fig. 5 shows oil recovery factor versus injected time registered during the injection of nitrogen into carbonate cores at pressure drop of 0.68 MPa (100 psi) (SARV-1) and 2.7 MPa (400 psi) (SARV-2) (Fahandezhsaadi et al., 2019).

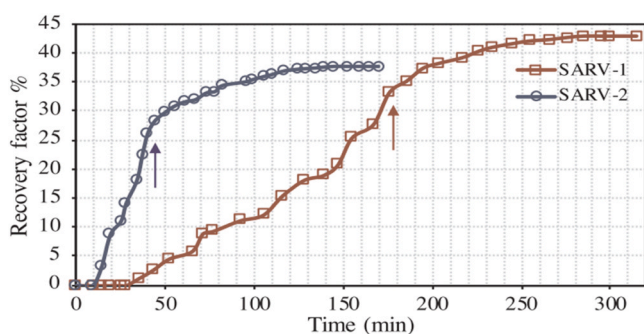


Fig. 5. Oil recovery factor versus injected time registered during the injection of nitrogen into carbonate cores at pressure drop of 0.68 MPa (100 psi) (SARV-1) and 2.7 MPa (400 psi) (SARV-2) (Fahandezhsaadi et al., 2019).

achieved in the experiment with a lower difference between the injection pressure and the back pressure (pressure drop of 0.68 MPa (100 psi)) (Fig. 5). This is explained by the delay in gas breakthrough and more stable oil displacement. However, within a given time interval before gas breakthrough, a larger pressure drop (2.7 MPa – 400 psi) resulted in higher oil recovery. These results imply the existence of an optimal pressure drop that can yield a relatively high oil recovery within a short period of time.

Besides optimal pressure drop, there is an optimal flow rate of nitrogen injection. For example, experimenting with 13-m-length slim tube filled with 5 Darcy sand and saturated with 1.06 cp oil has shown that the injection of nitrogen at 20, 30, and 36.6 cm^3/min at 10.2 MPa (1500 psi) resulted in 63.4 %, 69 %, and 51 %, respectively. Indicating that at some critical injection rate ORF by immiscible nitrogen injection starts to decrease (Siregar et al., 2007).

At this point, a question may arise: Besides the injected technological conditions like pressure drop and flow rate, do factors such as the timing of nitrogen injection (i.e., before or after water flooding) and the reservoir's depletion status also play a significant role? The following examples provide evidence that these factors have no detrimental effect on the outcome of immiscible nitrogen injection.

For example, the injection of nitrogen at the pressure inside of the injection line equal to 0.5 MPa (73 psi) into 1.94 D, 17-cm-length core after ~5 PVs of water flooding resulted in incremental ORF increase by 17 % (53 % in total) of n-hexadecane used as a model of oil (Janssen et al., 2018).

Besides that, six years of immiscible nitrogen injection for pressure maintenance show that this process can prolong the life of a depleted light oil (30° API) carbonate fractured high temperature (120 °C) reservoir. The reservoir produced 35 % of oil and 42 % of gas in 41 years. Nitrogen injection was started in 2008 at 5.38 million m^3/day in Oxiacaque field. The pressure increase effect was seen after two months in the injection block, after 6 years of injection was equal to 3.8 MPa (560 psi). Some of the fields located nearby also got affected by the injection. Fig. 6 shows that injecting sour gas and nitrogen was more effective for pressure maintenance compared to many years of water flooding. Notably, since 2009, a high nitrogen content has been added to the sour gas to control its quality for selling (Vazquez et al., 2014).

The project was challenged by the problem of gas breakout through the faulting system, which was solved by converting production wells into injection wells (Vazquez et al., 2014). This was a right decision because even though the presence of fractures provides higher oil recovery before the breakthrough of nitrogen, the ultimate oil recovery factor from fractured carbonate cores was 17 % lower than that from the original 6.27 mD and 8.39 mD non-fractured samples (Fig. 7) (Fahandezhsaadi et al., 2019).

Mobilization of residual oil can be achieved by simultaneously injecting water and nitrogen, even in cases where nitrogen and oil are immiscible and there is no noticeable swelling, viscosity reduction, or vaporization of the oil. For instance, conducting a simultaneous injection of water and nitrogen across a wide range of water-to-nitrogen ratios (0.045–30) led to a significant decrease in residual oil saturation within a Berea core subsequent to water flooding. The most notable outcome was observed when residual oil saturation reduced from 40 % to 22 % at a water-to-nitrogen ratio of 0.067 [cm^3/scm^3], maintained at an average pressure of 0.5 MPa (73 psi). This achievement is indeed remarkable. However, experimentation with unconsolidated sand yielded only a 2 % reduction in residual oil saturation. The conclusion drawn is that the effectiveness of oil recovery through this immiscible displacement mechanism is highly reliant on the relative permeability characteristics of the reservoir rock (Slack and Ehrlich, 1981b).

WAG injection in which immiscible nitrogen injection was alternated with water has been reported as an effective method to increase oil recovery. WAG injection consisting of 12 cycles of 1.3 PV nitrogen followed by 0.22 PV water at 0.5 MPa (73 psi) into 2.3 D, 17-cm-length sandstone core resulted in recovery of 35 %, 53 %, and 57 % of oil after

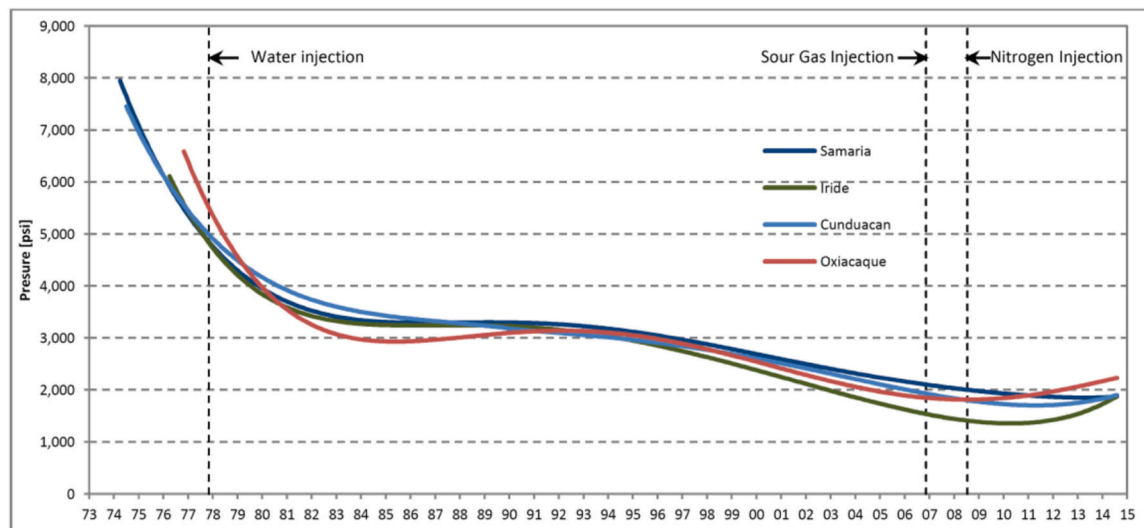


Fig. 6. Reservoir pressure vs time (Vazquez et al., 2014).

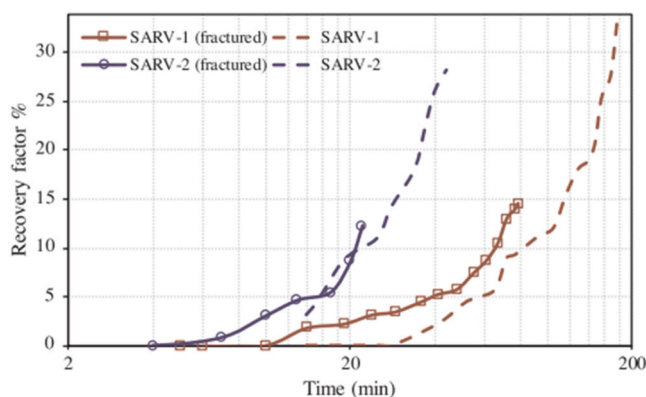


Fig. 7. Oil recovery by nitrogen from fractured and non-fractured cores (Fahandezhsaadi et al., 2019).

1st, 2nd, and 3rd cycles, respectively. In total 59 % of oil was displaced after 12 cycles. The best performance of WAG is explained by the increase in trapped gas saturation which may have occurred during the injection of water slug after nitrogen leading to the reduction of gas relative permeability and improved mobility factor between gas and oil (Janssen et al., 2018).

In another work the injection of water alternating sour and high-nitrogen ($\sim 85\%$ N_2) natural gas (WAG) into 21–22-cm-length 77–80 mD mixed-wetted carbonates saturated with 0.515 cp oil at 27 MPa (3970 psi) and 126 °C provided better result in comparison with continuous gas injection (CGI) and continuous water injection (CWI). In fact, in the WAG process the water slug was injected first at the volume of 0.2 HCPV (hydrocarbon pore volume). However, experimenting with fractured cores showed a significant reduction in the performance of WAG, CGI and CWI injection modes (Fig. 8). In fact, in a fractured core constant water injection outperformed WAG, which is in opposition to the results obtained by using non-fractured core (Wojnicki et al., 2020).

Immiscible nitrogen water-alternating-gas (WAG) injection has demonstrated its effectiveness under ultra-high water cut conditions. For instance, continuous N_2 injection into a 282 mD, 28.9-cm-length sandstone core sample, at a back pressure of 2 MPa (290 psi) after 1.2 PV of water flooding, resulted in a mere 5.27 % increase in the recovery of 1.82 cp model oil. In contrast, alternating injections of N_2 and water into a similar core sample led to an enhanced recovery of 15.62 % when the injected volume of water and gas in the cycle was 0.3 PV, with a gas-

to-water injection ratio of 2:1 (Kong et al., 2021).

Furthermore, the WAG injection method exhibited the ability to elevate the injection pressure by a factor of 2, as compared to that achieved during water flooding. This pressure increment facilitates the entry of gas and water into the pore spaces previously occupied by residual oil, thereby augmenting the microscopic sweep efficiency (Kong et al., 2021).

A key finding is that reducing injected PV (IPV) of water and gas in a cycle below 0.3 PV reduces oil recovery, likely due to ineffective slug formation. Similarly, exceeding 0.3 PV reduces recovery due to gas channeling. Therefore, 0.3 IPV was identified as optimal. Among different gas/water ratios (2:1; 1:2; 1:1; 3:1) 2:1 was shown to be the optimal variant (Table 1).

4. Progressive nitrogen injection applications

This section contains information on progressive N_2 injection applications published in recent years, such as the use of N_2 with foams and injecting cold N_2 to generate fractures.

Usually, nitrogen is employed for light oils. However, the synergistic use of nitrogen with foaming agents proves to be an effective method for producing viscous oil from heterogeneous reservoirs. For instance, injecting a foaming agent containing anionic-nonionic surfactant, PAM (polyacrylamide), and N_2 into a sand pack model led to significantly higher recovery of 700 cp oil compared to water flooding (Liu et al., 2016).

The application of this technology in field conditions was tested in an offshore oilfield situated in Bohai Bay, China. This oilfield is characterized by high oil viscosity (reaching up to 924 cp) and significant heterogeneity across its pay-zones. While water flooding had been implemented in the oilfield, the recovery factor remained below 20 %, and a high water cut (exceeding 85 %) was observed (Liu et al., 2016).

To evaluate the feasibility of the foam technique, a field pilot involving 2 injectors and 13 producers was conducted. Following foam injection, there was a notable increase in the wellhead injection pressure, and nearly all producers displayed positive responses. This was reflected in incremental oil recovery, and the average water cut decreased by 6.3 % over 8-month period of field operations. Notably, oil flow rates saw an increase of up to 2.6 times after the injection of 285 tons of foam agent and 3.16 million m^3 of nitrogen (Liu et al., 2016).

In another study, foam was generated in situ using 0.5 vol% of alpha-olefin sulfonate, which was dissolved in reservoir brine and then alternately injected with gas (FAWAG). This method proved capable of producing oil even from a fractured model at a higher rate than

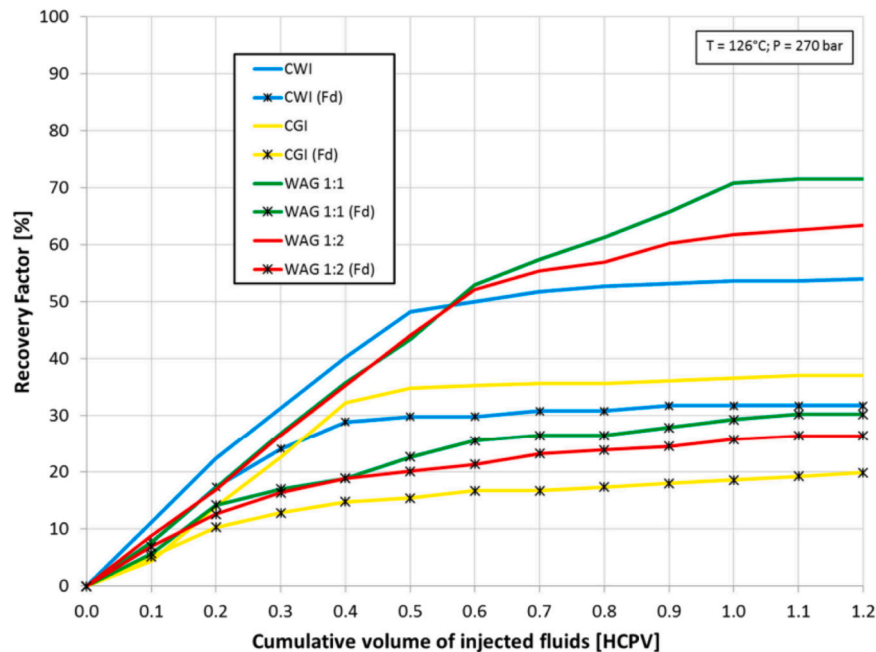


Fig. 8. Oil recovery from fractured and non-fractured cores (Wojnicki et al., 2020).

Table 1
The effect of technological parameters on the performance of WAG (Kong et al., 2021).

IPV	WAG ratio	Oil recovery after water flooding, %	Incremental oil recovery, %
0.3	2:1	38	15
0.2	2:1	38	10
0.4	2:1	38	13
0.5	2:1	38	12
0.3	1:2	37	10
0.3	1:1	37	11
0.3	3:1	38	12

achievable through constant gas injection or Water-Alternating-Gas (WAG). Specifically, a 0.2 HCPV foaming agent solution was injected alternately with gas (Wojnicki et al., 2020). As depicted in the Fig. 9, FAWAG has proven to be the most effective method for recovering oil from fractured cores. However, currently, there is insufficient field data available to conduct a thorough comparative analysis between nitrogen and foaming agent injection and conventional recovery methods like water flooding or gas injection.

In contrast, the presence of fractures is crucial for hydrocarbon production from low permeability reservoirs. In the study published by Elwegaa and Emadi (2019) it was demonstrated that an increase in the temperature difference between the injected gas and the rock sample

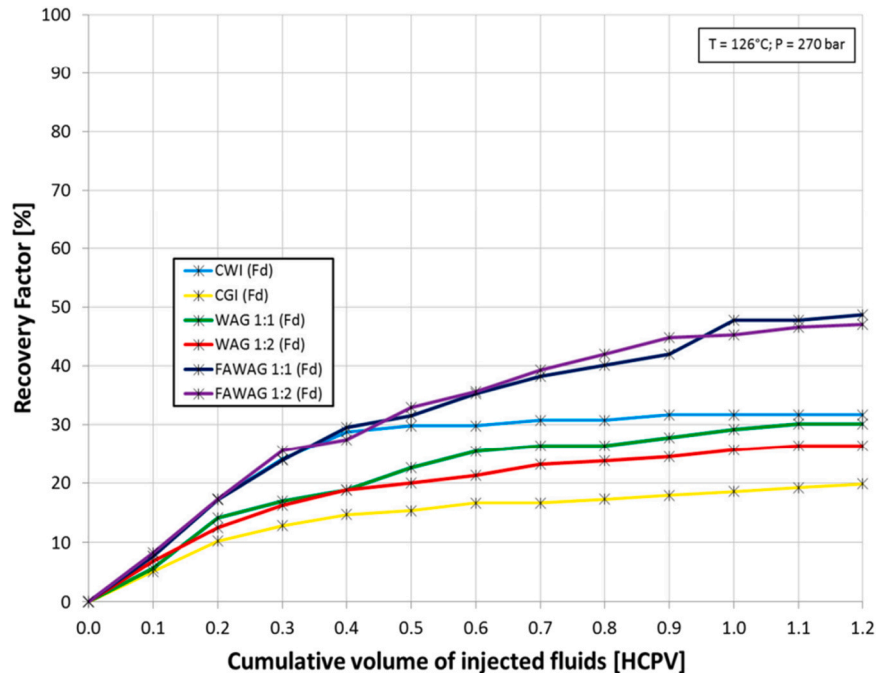


Fig. 9. Oil recovery from fractured cores by water (CWI), N₂ (CGI), WAG, or FAWAG methods (Wojnicki et al., 2020).

leads to an increase in the magnitude of thermal stress. Specifically, injecting cold N₂ at -26°C (-15°F) into hot formations results in the application of thermal stress amounting to 53 MPa (7790 psi), leading to the creation of new cracks and/or extension of existing ones. The CT scan results vividly illustrate that injecting cold nitrogen causes an expansion in the width of the pre-existing fracture, resulting in enhanced fracture conductivity and oil recovery factor (Fig. 10). In fact, the study of liquid nitrogen fracturing technology is rapidly growing, offering significant potential to enhance the effectiveness of unconventional oil and gas resources and to generate geothermal energy (Alameedy and Al-Behadili, 2023).

5. Conclusions

1-The findings indicate that even though the increase of nitrogen injection pressure below the minimal miscibility pressure leads to some enhancement in oil recovery, the high minimal miscibility pressure of nitrogen (36–50 MPa – 5290–7350 psi) remains a significant hurdle, necessitating continued exploration into innovative techniques for lowering this barrier.

2-Variou strategies to mitigate this challenge have been explored, including the injection of hydrocarbon gases alongside nitrogen and its combination with CO₂. Future studies could delve into optimizing injection strategies, such as the composition and sequencing of injected gas, to maximize oil recovery while minimizing operational costs and environmental impact. 3-The remarkable ability of nitrogen to reduce residual oil saturation – 24 % under miscible conditions, whereas CO₂ and low salinity water only yielded 7.1–7.3 %, and 18 % when using nitrogen and water under immiscible conditions – attracts attention to nitrogen's use instead of chemical EOR, such as ASP, which are problematic to apply due to the high cost of chemicals and accompanying issues with breaking emulsions and scale formation. 4-The low molecular weight of nitrogen enables access to fine pores, facilitating the recovery of 33 % of oil from 198 nD cores. Moreover, lowering nitrogen temperature enhances fracture size and oil recovery. This suggests the potential of nitrogen as a key factor in unlocking low permeability reservoirs.

5-The nitrogen water alternating gas (WAG) method holds promise for reservoirs in the final stages of production with ultra-high water cut. However, fractures can significantly compromise its effectiveness. Therefore, combining conformance control techniques like gel injection with the nitrogen WAG process shows potential for enhancing recovery in these reservoirs.

6-When producing from a fractured formation, foam-assisted nitrogen WAG should be considered as an alternative to water flooding, as it can yield a 15–17 % higher oil recovery factor. Additionally, the promising results of field pilot tests in recovering 700–920 cp oil from heterogeneous reservoirs prove that this method can be an alternative to thermal EOR, which is not always feasible, especially in thin formations due to high heat losses.

5.1. Based on the reviewed references, the following is recommended for better practices of nitrogen assisted EOR

1-Foam assisted nitrogen WAG or nitrogen injection in combination with in-depth conformance control techniques are potential solutions to deal with channeling and pre-mature breakthrough of oil recovery drive agent.

2-Experimentating with different nitrogen temperatures and pressures could further enhance fracture size and oil recovery, expanding its applicability in low permeability challenging reservoirs.

3-Comparative studies between nitrogen-based EOR techniques and other methods, such as polymer flooding or thermal EOR, are essential for identifying the most effective and economically viable solutions for specific reservoir conditions. This ongoing research will inform best practices and drive innovation in nitrogen-assisted EOR.

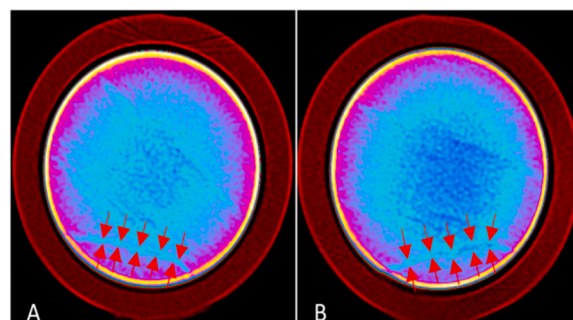


Fig. 10. Computer tomography results before (A) and after (B) thermal shock imposed by cold nitrogen (Elwegaa and Emadi, 2019).

CRediT authorship contribution statement

Nurbol Tileuberdi: Writing – review & editing, Writing – original draft, Funding acquisition, Conceptualization. **Iskander Gussenov:** Writing – original draft.

Declaration of Competing Interest

We have no conflicts of interest to disclose.

Data availability

Data will be made available on request.

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