Study of the impact of injection parameters on the performance of miscible sour gas injection for enhanced oil recovery

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Abstract

Sour gas reservoirs have faced critics for environmental concerns and hazards, necessitating a novel outlook to how the produced sour gases could be either utilized or carefully disposed. Over the years of research and practice, several methods of sour gas processing and utilization have been developed, from the solid storage of sulfur to reinjecting the sour gas into producing or depleted light oil reservoir for miscible flooding enhanced oil recovery. This paper seeks to investigate the impact of injection parameters on the performance of sour gas injection for enhance oil recovery. In designing a miscible gas flooding project, empirical correlations are used and the key parameter which impacts the phase behavior is identified to be the minimum miscibility pressure (MMP). A compositional simulator was utilized in this research work to study the effect of injection parameters such as minimum miscibility pressure, acid gas concentration, injection pressure and injection rate on the performance of miscible sour gas injection for enhanced oil recovery. The findings showed that methane concentration had a significant impact on the MMP of the process. Additionally, an increase in acid gas concentration decreases the MMP of the process as a result of an increase in gas viscosity, consequently extending the plateau period resulting in late gas breakthrough and increased overall recovery of the process.

Keywords Sour gas · Minimum miscibility pressure · Enhanced oil recovery · Process parameters · Acid gas

Introduction

A major cause for concern in the development of sour gas reservoir is the disposal of the produced gas (Xue et al. 2019). The gases are usually sweetened using different methods. Amine extraction is one of the most commonly used methods in the petroleum industries (Bennion et al. 1999; Chen 2016). The separation process results in the production of a waste stream composing of acid gases (CO₂ and H₂S) and requires a huge capital and operation cost which has raised a cause of concern, given that the companies must

ensure their waste is eco-friendly before disposal (Bennion et al. 1999).

Over the years, a lot of strategies have been developed to handle acid gas mixture, with primary concerns being the reduction of the toxic hydrogen sulfide gas to an inert/non-toxic reactive product (Bennion et al. 1999). The most common technique is the Claus reaction process where gases containing H₂S are catalytically converted to elemental sulfur (Bennion et al. 1999). Also, a viable alternative is the reinjection of the produced gas into the reservoir as an enhanced recovery technique or for storage (Abou-Sayed et al. 2004; Bhatti et al. 2019; Ceragioli and Gianelli 2008; Ghodjani and Bolouri 2011; Hawez and Ahmed 2014; Nwidae et al. 2016). However, concerns have been raised as to possible leakages to the surfaces through faults or unsealing traps.

Sour gas injection for enhance oil recovery (EOR) is a viable option that presents a solution to many problems currently in the industry. It eliminates current taxation or future liability associated with emission or surface storage of sulfur (Abou-Sayed et al. 2004). EOR programs using gas injection have shown that sour gas has better sweep efficiency

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and voidage replacement ability compared to other gases used for miscible injection EOR. Therefore, this increases the amount of recoverable hydrocarbon (Abou-Sayed et al. 2004; Al-Hadhrami et al. 2007; Battistelli et al. 2011; Chugh et al. 2006; Metcalfe et al. 1973). This also translates to better economics as the cost of many surface treatments is eliminated, thus reducing the operational cost of the process.

This research work seeks to provide insight into the impact of injection parameters on the viability of miscible flooding of a light oil reservoir by the reinjection of sour gas (Abou-Sayed et al. 2004; Benham et al. 1960; Christiansen and Haines 1987; Eakin 1988; Elsharkawy et al. 1992; Green and Willhite 1998; Haynes et al. 2008; Holm and Josendal 1974; Khan et al. 2013; Lake 1989; Orr and Silva 1987; Orr et al. 1982). The reinjection of a rich waste acid gas stream directly into the producing light oil reservoir for the purpose of miscible flooding enhanced oil recovery using numerical simulation was studied putting into consideration the impact of certain injection parameters on the overall performance of the recovery process.

Methodology and model description

This section presents the reservoir model description, detailed methodologies and procedures used in achieving the aim and objectives of this research work. A comparative study of MMP using correlations was carried out. Base case light oil reservoir model was built using Eclipse 300 which is a compositional simulator, and the performance of sour gas injected was evaluated by varying the composition of acid gas injected in the oil recovery. The effect of the gas injection rate and injection parameter on the field production was also studied.

Base case model description

The reservoir model used in this study was based on the reservoir studies carried out by Battistelli et al. 2011. The fluid composition, porosity and initial water saturation are the same as reported. Other parameters such as permeability, grid, reservoir pressure and temperature were assumed. The base case model is a homogeneous reservoir with both porosity and permeability uniform in all directions, and the model was built using ECLIPSE 300 which is a compositional simulator. The model consists of two wells, one producer and one injector. The base case model has a length of 1320 ft, a width of 1320 ft and a thickness of 10 ft, and major reservoir parameters are summarized in Table 1. Peng–Robinson EoS is used in fluid characterization, and the component properties are summarized in Table 1. The injection fluid composition is shown in Table 2.

Reservoir model initialization

The reservoir model was initialized to determine the initial conditions of the reservoir. The gas–oil contact was set far above the reservoir so that only the hydrocarbon content is considered for study; the water–oil contact is set at 100 ft below the reference depth. Table 3 shows the reservoir model input parameters, while Table 4 shows the phase binary interaction parameters for the components contained in the oil mixture. Table 5 shows the oil, water and gas saturation functions.

Comparative study of MMP using correlations

This study made use of the existing pure and impure CO₂ stream MMP correlations published in the literature. Three injection scenarios (Table 6) were considered to evaluate the general trend on how MMP changes with a decrease in C₁ composition.

Table 1 Reservoir fluid composition and pseudo-component properties at 100 °C (212 °F) (Battistelli et al. 2011)

Component		Mole fraction	
<i>Reservoir fluid composition</i>			
H ₂ S		0.1500	
CO ₂		0.0500	
C1		0.4500	
C2		0.0500	
C3		0.0500	
C5		0.0500	
C6+		0.1000	
C9+		0.0939	
H2O		0.0061	
C6+		C9+	
<i>Pseudo-component properties</i>			
Molecular weight	93.00	Molecular weight	250.00
Specific gravity	0.29	Specific gravity	0.73

Table 2 Injection fluid composition

Component	Mole fraction
<i>Injection fluid composition at 100 °C</i>	
H ₂ S	0.0735
CO ₂	0.0744
C1	0.8384
C2	0.0130
C3	0.0007

Table 3 Reservoir model input parameters

Parameter	Value			
<i>Base case model input parameter</i>				
Grid				
Cells	Nx = 30, Ny = 30, Nz = 5			
Cells dimension	Dx = 44 ft, Dy = 44 ft, Dz = 2 ft			
Injection cells	Nx = 1, Ny = 1, Nz = 1			
Production cells	Nx = 30, Ny = 30, Nz = 5			
Porosity	0.2			
Permeability	K_v = 15 md, K_h = 15 md			
Reservoir temperature	212 °F			
Reservoir pressure	5169 psi			
Wellbore radius	0.3 ft			
Oil production rate	Unlimited			
Gas production rate	1000 Mscf/day			
Production well BHP	2000 psi			
Gas injection rate	2000 Mscf			
Injection well BHP	5200 psi			
Simulation time	800 days			
<i>Water properties</i>				
Compressibility (1/psi)	3.0×10^{-6}			
Density (lbm/ft3)	63			
Rock compressibility (1/psi)	4.0×10^{-6}			
Viscosity (cP)	0.31			
Component	Critical temperature (°F)	Critical pressure (Psi)	Molecular weight	Compressibility
<i>Component properties</i>				
CO ₂	548.460	1071.330	44.010	0.274077
H ₂ S	672.480	1296.170	34.0760	0.281954
H ₂ O	473.240	1447.640	18.010	0.275389
C ₁	343.080	667.781	16.043	0.284729
C ₂	549.770	708.342	30.070	0.284634
C ₃	665.640	615.758	44.097	0.276164
C ₅	838.620	487.169	72.151	0.268808
C ₆₊	957.030	469.530	93.000	0.272489
C ₉₊	1389.100	207.897	250.000	0.220257

First scenario

In this scenario, the injection gas consists of only CO₂ and C₁. Two different correlations used in this case were Yuan et al. correlation and Glaso correlation. MMP was calculated as C₁ composition decreases and CO₂ composition increases. MMP for pure CO₂ was calculated first using the two correlations: For Glaso correlation, the MMP is a function of reservoir temperature and intermediate component composition in the reservoir oil (C₂–C₆) (Glaso 1985), while for Yuan et al. correlation, the MMP is a function of the molecular weight of C₇₊, molar percentage of intermediates and reservoir temperature. The limitation of this correlation is that the oil used for the regression has a molecular weight

of C₇₊ in the range of 140–245, whereas the oil in the reservoir studied has M_{C7+} of 250. Also, the molar percentage of the intermediates is between 11.3 and 40.3% and reservoir temperature ranges from 120 to 300 °F (Yuan et al. 2004). The fraction of impure and pure MMP is calculated using the Yuan et al. correlation from which the impure MMP for the two correlations was calculated.

Second scenario

In this case, the injection gas consists of three components as listed in Table 6. The injection gas composition changes by decreasing C₁ and increasing H₂S and CO₂ compositions. CO₂ and H₂S compositions were increased equally. Two

Table 4 NA phase binary interaction parameters for the components contained in the oil mixture

NA-kij	CO ₂	H ₂ S	H ₂ O	C ₁	C ₂	C ₃	C ₅	C ₆₊	C ₉₊
CO ₂									
H ₂ S	0.0960								
H ₂ O	0	0							
C ₁	0.1000	0.0500	0						
C ₂	0.1000	0.0500	0	0					
C ₃	0.1000	0.0500	0	0	0				
C ₅	0.1000	0.0500	0	0	0	0			
C ₆₊	0.1000	0.0500	0	0.0326	0.0100	0.0100	0		
C ₉₊	0.1000	0.0500	0	0.0512	0.0100	0.0100	0	0	0

Table 5 Oil, water and gas saturation functions

S_W	K_{RW}	P_{COW}	S_O	K_{ROW}	K_{ROG}	S_G	K_{RG}	P_{COG}
0.200	0	0	0	0	0	0	0	0
0.240	0.003	0	0.300	0	0	0.050	0	0
0.280	0.010	0	0.330	0.005	0.005	0.100	0.004	0
0.320	0.023	0	0.360	0.018	0.018	0.150	0.015	0
0.360	0.040	0	0.390	0.038	0.038	0.200	0.033	0
0.400	0.063	0	0.420	0.064	0.064	0.250	0.059	0
0.440	0.090	0	0.450	0.096	0.096	0.300	0.093	0
0.480	0.123	0	0.480	0.133	0.133	0.350	0.133	0
0.520	0.160	0	0.510	0.175	0.175	0.400	0.181	0
0.560	0.203	0	0.540	0.223	0.223	0.450	0.237	0
0.600	0.250	0	0.570	0.275	0.275	0.500	0.300	0
0.640	0.303	0	0.600	0.333	0.333	0.550	0.370	0
0.680	0.360	0	0.630	0.395	0.395	0.600	0.448	0
0.720	0.423	0	0.660	0.462	0.462	0.650	0.533	0
0.760	0.490	0	0.690	0.533	0.533	0.700	0.626	0
0.800	0.563	0	0.720	0.609	0.609	0.750	0.726	0
0.840	0.640	0	0.750	0.69	0.690	0.800	0.834	0
0.880	0.723	0	0.780	0.775	0.775			
0.920	0.810	0	0.800	0.834	0.834			
0.960	0.903	0						
1.000	1.000	0						

Table 6 Different scenarios for MMP studies

Scenario	Component in injection gas	Com-position (%)
First scenario	CO ₂ + C ₁	100
Second scenario	CO ₂ + H ₂ S + C ₁	100
Third scenario	H ₂ S + C ₁	100

correlations were used for this study: Yuan et al. and Glaso correlation for the estimation of pure CO₂ MMP; for the impure/pure MMP fraction, Sebastian et al. and Yuan et al.

were used, while the impure MMP was calculated using Glaso and Yuan et al. correlation.

Third scenario

In this case, only H₂S and C₁ are present in the injection gas. The goal here is to understand how H₂S affects the MMP. Correlation for estimating hydrocarbon gas MMP and impure CO₂ stream was used to calculate the MMP. The Glaso correlation for hydrocarbon gas is the best option because it accounts for the change in C₁ composition in the injected gas which corresponds to the objective of this study. The Yuan et al. correlation was used for the impure CO₂ stream for comparison purpose.

Compositional variation of acid gas in the injection gas

It is important to determine how acid gas composition in the injection gas affects oil recovery as this will help to understand how the gas helps to improve recovery in a gas injection process. A 15-mole percent acid gas is used for the base case model with an equal composition for H_2S and CO_2 (i.e., 7.5% of H_2S and 7.5% CO_2). C_1 makes up 80% of the injection gas, 0.0061% water, while C_2 – C_5 makes up the remaining percentage as shown in Table 6. The composition of acid gas was varied subsequently from 15–20%, 30% and 40%. Also, three different cases were further considered to see the effect of injecting pure CO_2 (case one), a mix of 50% acid gas and 50% C_1 (case two) and pure acid gas having 50% CO_2 and 50% H_2S (case three) on the oil production rate and recovery efficiency, respectively, considering miscibility conditions.

Effect of gas injection rate

This study helps to also understand how gas injection rate affects various parameters such as oil recovery, oil production rate and how the volume of gas injected increases oil recovery. For this study, three rates were used to compare with the base case model. The injection was changed from 500 to 3000 Mscf to compare with the base case of 2000 Mscf.

Injection pressure effect

In this part of the study, the effect of injection pressure on the oil recovery from the model was investigated. Injection and production wells are completed in the first and fifth layer, respectively. For this investigation, two different pressures were used representing low case and high case to compare with the base case model.

For low case, an injection pressure of 2500 psia was used. This pressure was used to simulate immiscible gas injection, while for the high case, an injection pressure of 7500 psia was used which simulates first contact miscible injection. Based on the MMP study done, the estimated MMP using the equation of state analytical method in Eclipse PVTi is approximately 6200 psia for first contact miscibility and 5000 psia for multi-contact miscibility. Simulation runs were conducted at pressures below, equal to and greater than this pressure as stated above.

Since in vaporizing drive mechanisms, the pressure at the miscible front should be greater than the predicted miscible pressure, injection of gas at 5200 psi will raise the average reservoir pressure from initial pressure to the miscibility pressure of 5000 psi. Therefore, the injection pressure of

5200 psi seems to be the best candidate for the base case model.

Results and discussions

Comparative study of MMP using correlations

First scenario

The fraction of impure and pure MMP was calculated using the Yuan et al. correlation and Glaso correlation from which the impure MMP for the two correlations was calculated as seen in Table 7. Both correlations gave a similar trend; the MMP decreases as C_1 composition decreases as shown in Figs. 1 and 2. The decrease in the MMP as methane composition increased was due to the nature of methane gas. It is lighter and has a low viscosity. It will form a lesser density gas mixture. Utilization of only methane gas requires a very high MMP to attain miscibility for oil trapped in already depleted reservoir. But mixing it with CO_2 will lower the MMP required. This is indeed the very reason why there is a decrease in the MMP as the concentration of methane in the injection gas increases.

Second scenario

Table 8 shows the result of the MMP studies obtained from scenario two, while Figs. 3 and 4 show the results of the second scenario MMP study using the Glaso correlation and Yuan et al. correlation, respectively. Both figures show a linear relationship between C_1 composition and MMP. This scenario shows a trend similar to the first scenario which further confirms the effect of C_1 on MMP. Just as in the first scenario, the Glaso correlation has a more conservative result as compared to Yuan et al. correlation. Comparing the result of the two scenarios, the MMP of the second scenario is higher which is due to the presence of H_2S . CO_2 is denser

Table 7 Result of MMP studies for scenario one

CO_2 (%)	C_1 (%)	Glaso (Psi)	Yuan et al. (psi)
10	90	6799	7948
20	80	6392	7473
30	70	5987	6998
40	60	5580	6524
50	50	5174	6049
60	40	4768	5574
70	30	4362	5100
80	20	3956	4625
90	10	3550	4150
100	0	3144	3675

Fig. 1 Scenario 1 MMP change with C₁ composition using Glaso correlation

Fig. 2 Scenario 1 MMP change with C₁ composition using Yuan et al. correlation

Table 8 Result of MMP studies for scenario two

H ₂ S	CO ₂	C ₁	Glaso (Psi)	Yuan et al. (Psi)
5	5	90	7002	8185
10	10	80	6799	7948
15	15	70	6595	7710
20	20	60	6392	7473
25	25	50	6189	7236
30	30	40	5986	6998
35	35	30	5783	6761
40	40	20	5580	6524
45	45	10	5377	6286
50	50	0	5174	6049

than H₂S, and the addition of H₂S leads to an increment in the MMP as compared to scenario one. Similarly, an increment of the percentage of methane leads to an increment in the MMP.

Third scenario

Table 9 shows the results of the MMP studies obtained from scenario three, while Figs. 5 and 6 show the MMP trend for the third scenario using the Glaso correlation and Yuan et al. correlation, respectively. It is seen that the Glaso correlation gave a more realistic MMP as compared to Yuan et al. correlation. The MMP values obtained using the Yuan et al. correlation were higher than the ones obtained in scenario one and scenario two making it unrealistic. This is because Yuan et al. correlation is designed for a CO₂ stream with impurities which is not true for this case. However, the MMP trend obtained for this scenario using the Glaso correlation and Yuan et al. correlation was a parabolic trend unlike scenario one and scenario two where the trend obtained was a linear trend. This could be associated with the fact that both correlations used are not a perfect match for the case under investigation. The Glaso correlation is designed for gas injection with intermediates

Fig. 3 Scenario 2 MMP change with C_1 composition using Glaso correlation

Fig. 4 Scenario 2 MMP change with C_1 composition using Yuan et al. correlation

Table 9 Result of MMP studies for scenario three

H ₂ S	C ₁	Glaso (Psi)	Yuan et al. (Psi)
10	90	10020	28,175
20	80	7029	23,835
30	70	5027	19,928
40	60	3696	16,442
50	50	2823	13,366
60	40	2260	10,686
70	30	1908	8389
80	20	1700	6464
90	10	1590	4897
100	0	1546	3675

component (C_2 – C_6) of molecular weight of 34 which is not the case here. The MMP also increased with reduction in the composition of methane due to the nature and density of methane as observed in the first scenario.

Base case model description and initialization

The base case reservoir model used in this study is shown in Fig. 7. From the model initialization result, the initial field pressure of the reservoir was 5169 psi at a reference depth of 9840 ft, which corresponds to the top of the reservoir. From Table 3, a simple calculation shows that the reservoir has a pore volume of 620,160 rb, with an initial hydrocarbon pore volume of 496,128 rb. The original oil in place, water in place and gas in place were 216050 STB, 124,128 rb and 570.803 Mscf, respectively. The reservoir has an initial GOR of 2.642 Mscf/STB and FVF of 2.298 rb/STB.

Compositional variation of acid gas in the injection gas

Figure 8 shows the effect of acid gas compositional variation on oil recovery efficiency. The result shows that the increase in acid gas concentration leads to an increase in oil recovery.

Fig. 5 MMP trend with changing C_1 composition using Glaso correlation

Fig. 6 MMP trend with changing C_1 composition using Yuan et al. correlation

Fig. 7 Model diagram

An overall recovery of 86.81 and 78% was achieved when 40.30% and 20% acids gas composition, respectively, were used. It is also observed that the injection gas with the lower composition of acid gas had the earliest breakthrough time, while the injection gas with the highest composition had the

least breakthrough time. The increase in the recovery of oil and delay of the breakthrough time as the composition of the acid gas was increased was as a result of the increment in the density and viscous nature of the injection gas. The acid gas increased the density and viscosity of the injected gas.

Figure 9 shows how acid gas composition affects oil production rate. The result clearly shows that as the composition of acid gas increases the gas breakthrough time also increases. Initially, there was a decrease in the oil production rate, but after about 40 days of injecting the sour gas, the reservoir began to feel the effect of the injection leading to an increment in the production rate. The injection gas with 15% acid gas composition had the least breakthrough time, and the injection gas with 40% acid gas had the highest breakthrough time. This is because as the composition of acid gas increases in the injection gas, the viscosity of the injection gas also increases leading to a decrease in the mobility of the injected gas.

Figure 10 shows the effect of acid gas composition on the oil production rate. The first down dip is when the reservoir

Fig. 8 Comparison of the effect of acid gas composition on oil recovery efficiency

Fig. 9 Comparison of the effect of acid gas composition on oil production rate

is producing under natural depletion before injection starts. For the base case, as the pressure support starts at around day 100, there is a plateau gas production, while for 40% acid gas, the gas production did not stabilize until the gas breakthrough. Figure 11 shows the change in gas viscosity with the increased acid gas concentration. This gives a clearer picture of the production profile of both gas and oil. This figure shows that the gas viscosity increases as acid gas concentration is increased. The increase in gas viscosity is the consequence of miscible development resulting in a reduction of oil viscosity.

This reduction is the result of oil swelling or expansion of the under-saturated fluid by the addition of dissolved gas at higher pressures, which lightens the oil and consequently

decreases the oil viscosity. This is why 40% of the acid gas profile did not reach a plateau production until gas breakthrough. As a result, more gas dissolving in oil means less gas is coming out of solution.

Figures 12 and 13 show the oil production rate and recovery efficiency, respectively, for the different cases of injection gas compositions that were also considered. Case one was when only pure CO₂ was injected into the reservoir. When compared to the base case scenario, there was a 14.38% increase in the oil recovery efficiency. There was also an increase in the plateau period for the production rate profile, and this was due to the increase in the injection gas viscosity. For case two, the injection gas contains only C₁ (50%) and acid gas (50%). With the decrease in the C₁

Fig. 10 Comparison of the effect of acid gas composition on gas production rate

Fig. 11 Effect of acid gas composition on gas viscosity in the production block

composition in the injection gas as compared to the base case, there was 13.40% increase in the oil recovery. This was due to the increase in the injection gas viscosity, and as a result of this, it led to an increase in the sweep efficiency. The increase in the viscosity of the injection gas increased the plateau production period by 50 days as compared to the base case scenario.

Case three was characterized with the injection of pure acid gas into the reservoir with CO_2 and H_2S having equal proportion (50% CO_2 and 50% H_2S). This case had same recovery efficiency like when only pure CO_2 was used. It had a recovery of about 91%. But due to the viscous nature of acid gas, this case had a longer plateau period as compared

to case one when only pure CO_2 injection was carried out which resulted in an increase in the aerial sweep efficiency. Another advantage of this was that the acid gas achieved miscibility with the reservoir oil at lower pressure as compared to the pure CO_2 injection case.

Effect of gas injection rate

Figure 14 shows how the gas injection rate affects oil production rate. It was observed that there was an early gas breakthrough for rate 2000 and 3000 Mscf. This could be due to the increase in driven force as the injection rate increases. There was no noticeable change when the

Fig. 12 Oil production rate for the different injection gas composition

Fig. 13 Oil recovery efficiency for the different injection gas composition

injection rate increased above 2000 Mscf. This is because the injection well is constrained using two parameters (injection rate and pressure). Figure 15 shows the injection rate builds up over time. From the result, it is seen that the rate is gradually building up to the constrained rate and maintained throughout the simulation time for 500 Mscf and 1000 Mscf, while for 2000 and 3000 Mscf, the rate gradually builds up until the pressure support kicks in. But the rate does exceed 1500 Mscf which is maintained until the gas breakthrough after which rate starts declining until it reaches 1000 Mscf. This further shows that the current injection pressure does not support any rate above 1500 Mscf. The rate of decline in the oil production rate observed after breakthrough was due to the decrease in the pressure support.

Figure 16 is used to investigate how the volume of gas injected affects oil recovery efficiency. The result clearly

shows that the volume of gas injected is directly proportional to oil recovery efficiency. The result is consistent with the findings of Comberinati and Zammerilli (2000) which also showed an increment in oil production with increasing flood volume.

Injection pressure effect

Figure 17 shows the effect of gas injection pressure on oil recovery efficiency. It is clearly seen that there is an incremental oil recovery as a result of an increase in injection pressure. This increment in recovery is attributed to the fact that the higher the injection pressure, the more the tendency to attain miscibility. A noticeable change was observed due to the fact that the reservoir attained miscibility as the injection pressure was increased beyond 2500 psi. Figure 18 shows the oil production rate for different injection

Fig. 14 Comparison of effect of gas injection rate on oil production rate

Fig. 15 Gas injection rate versus time

Fig. 16 Cumulative gas injected versus oil recovery efficiency

pressures. It is seen that the attainment of miscibility and increment in the injection pressure lead to an increment in the production rate. According to the figure, for the high case, the pressure support was almost immediate, while

for the base case, the pressure support did not kick in until 52 days of continuous gas injection. The high case shows an early breakthrough time, but the difference as compared with the base case is marginal which further supports the

Fig. 17 Effect of gas injection pressure on oil recovery efficiency

Fig. 18 Effect of gas injection pressure on oil production rate

Fig. 19 Effect of gas injection pressure on the injection rate

argument that the economy may not support the incremental recovery from the high case.

Figure 19 shows the gas injection rate at different injection pressures. The figure shows how injection pressure affects the gas injection rate. For the high case model, a rate of 2000 Mscf was maintained until the gas breakthrough. After that, there was a steady decline in the rate until it

reached 1000 Mscf. This effect was seen during the injection rate study which further proves that the injection rate is directly proportional to injection pressure. This is due to the fact that high injection pressure means the driven force is high which translates to high gas velocity. It shows that for this study, the 1000 Mscf rate is the optimal injection rate.

Conclusion

- In conclusion, sour gas injection for enhanced oil recovery has supreme performance as compared to other gases used for miscible gas flooding EOR.
- Acid gas lowered the MMP of the process significantly resulting in more oil recovery and low operational cost for the process.
- Injection parameters such as the minimum miscibility pressure, acid gas concentration, injection pressure and injection rate had effect on the overall performance of the recovery process.
- The success of the miscible sour gas injection EOR can be attributed to the variation in fluid viscosities toward lower mobility ratios during injection. The injection gas lowers the oil viscosity substantially. This reduction is as the result of oil swelling or expansion of the under-saturated fluid by the addition of dissolved gas at higher pressures, which lightens the oil and consequently decreases the oil viscosity.
- The increase in the acid gas composition led to an increase in the oil recovery efficiency and the gas breakthrough time.

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Appendix

See Tables 7, 8 and 9.

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