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Prediction the Effects of Acid Gas Flooding on Enhanced Oil Recovery

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ABSTRACT

CO_2 flooding is one of the main methods to enhance oil recovery under the background of carbon neutralization and carbon peak. In some fields, however, injected gas is mainly produced gas that contains a lot of acid gas. The EOR effect of acid gas flooding is rarely mentioned in the literature. Therefore, it is necessary to study the displacement process of acid gas flooding.

In this paper, acid gas composed of H_2S and CO_2 is studied. Oil samples from typical blocks of T reservoir are selected to study the EOR effect of acid gas. Under different displacement pressure, different proportions of acid gas were used to carry out slim tube experiments. The percentages of H_2S and CO_2 in acidic gases are 0%, 20%, 40%, 50%, 60%, 80% and 1, respectively. The experimental process is to fill the tube with crude oil and then flood the oil with acid gas with different proportions of H_2S and CO_2 content at a constant temperature. The ultimate recovery factor is the displacement efficiency, obtained at 1.2 pore volume gas injection or without oil production. Displacement experiments under different pressures were also carried out.

The results show that the displacement efficiency increases with the increase of displacement pressure at the same temperature, oil composition and gas composition. The experimental results also show that, at the same temperature, oil composition and displacement pressure, displacement efficiency increases with the increase of the proportion of acid gas in the injected gas.

The production gas of high sulfur gas field is injected back into the formation theoretically, and the effect of acid gas mixed displacement composed of H_2S and CO_2 is studied, which provides a new direction for the application of H_2S and CO_2.

Keywords: acid gas flooding; EOR; displacement pressure; displacement efficiency

1. INTRODUCTION

Globally, there has been an increasing focus on the management of carbon emissions in recent years due to the escalation of global warming. The use of CO_2 for increased oil recovery, which simultaneously fulfills the dual goals of expanding crude oil extraction rates and geological sequestration, has attracted a lot of interest in the petroleum industry. In order to achieve phase mixing with crude oil and increase the oil recovery factor, CO_2 is used for oil displacement. A lot of attention is paid to investigating phase behavior, miscibility, sweep efficiency, and displacement efficiency in the context of gas flooding. Through the study of visual injection experiment, it is found that excessive CO_2 injection is not conducive to enhanced oil recovery due to the effect of drainage and compression.[1] Phase behavior plays a more critical role in the gas flooding process. This is mainly attributed to the more pronounced mass transfer and compatibility effects resulting from multicomponent interactions.[2] During oil flooding, the injection of supercritical CO_2 into the PVT pool causes a chemical reaction that increases the acidity of the reservoir.[3] The transient flow mechanisms and interface mass transfer of specific dead-end pores have been detected using high-speed enhanced imaging cameras and microscopic simulation models. It has been found that the accumulation of supercritical CO_2 molecules gives heavy crude oil powerful dissolving ability.[4] Crude oil expansion, which improves its flowability by lowering viscosity and interfacial tension (IFT) between the rock and oil, is the main mechanism of CO_2 flooding in oil recovery. [5] Re-injecting H_2S and CO_2 into the system not only reduces greenhouse gas emissions while also having the ability to increase crude oil recovery and produce more fuel energy.[6] Gas-water alternating

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injection was shown to be more efficient than continuous gas injection or continuous water injection, according to a study of the method that used CO_2, acid gas (0.7CO_2 and 0.3CO_2), and natural gas with a high nitrogen content. An 81% recovery factor was achieved with the gas-water alternating injection, notably with the injection of acid gas.[7] Carbonated water flooding exhibits the advantages of both CO_2 flooding and water flooding. Based on multiple contact experiments, it has been found that carbonated water flooding demonstrates a significant expansion effect.[8] It has been found through comparing the efficacy of immiscible CO_2 flooding and carbonated water injection that the pressure differential is relatively small during CO_2 flooding. In contrast, the pressure differential rises when carbonated water is used for flooding. The recovery factor from flooding with carbonated water is 20% higher than the recovery factor from flooding with CO_2.[9] Gas injection using sour gas not only achieves zero greenhouse gas emissions, reduces costs associated with sour gas treatment, but also helps maintain reservoir pressure. Both CO_2 and H2S have the ability to reduce the miscibility pressure, with H_2S having the greater effect.[10] To determine the physical and geochemical interactions between acid gases and the mineral matrix as well as formation water, simulations of H_2S and CO_2 injection reactions and transport were carried out based on the mineral composition and hydrochemical characteristics of carbonate reservoirs in the Tarim Basin. Acid gas injection is considered viable in this area because to the small changes in the volume fractions of calcite and quartz relative to changes in porosity, and the rapid breakthrough of CO_2 can act as an early signal for acid gas breakthrough.[11] Oil and acid gases are miscible, thus miscible flooding techniques can be used together. In the reservoir layer, the surface tension between acid gases and water may be considerably lower than that between methane gas and water.[12] A number of intricate tests were carried out to assess the relative permeability of different rock types, including interbedded sandstone, carbonate rock, and shale, in two districts of Alberta, Canada, as part of an extensive research carried out under reservoir conditions. The experiments used supercritical pure CO_2 and H_2S as the fluids. Relative permeability values for each fluid and rock type were obtained from the measurements.[13] According to numerical modeling studies and sand-packed core displacement experiments, the greater solubility of H_2S relative to CO_2 causes the stripping of H_2S at the displacement front, which delays breakthrough. With an increase in gas diffusion coefficient, there is a greater delay in H_2S breakthrough.[14] The CO_2 MMP is a crucial variable in the process of utilizing CO_2 for increased oil recovery. The CO_2 MMP of the L reservoir was shown to be in good accord with laboratory experimental data using a one-dimensional CMG simulation model.[15] The mass transfer interaction between hydrocarbon gas and crude oil is favorable. The residual oil saturation in the area impacted by the hydrocarbon gas is very low during miscible phase behavior. It has been discovered through displacement tests utilizing mixed gases with various ratios of hydrocarbon gas and acid gas that the displacement efficiency rises as the ratio of acid gas increases in the injected gas. [16]

2. MATERIAL AND METHODS

2.1 Numerical Simulation Section

Under laboratory conditions, there is a significant risk of operation due to the high toxicity of H_2S in acid gas. In order to explore the law of acid gas displacement, numerical simulation is the method of choice in this paper.

This numerical simulation is intended to evaluate enhanced oil recovery performance using acid gases under various experimental settings in a lab setting.

2.2 Numerical Simulation Apparatu

The application of numerical modeling techniques involves constructing a fine-scale tube model to simulate the injection of different gases under various displacement pressures. The model is used to calculate the oil recovery when the injected pore volume reaches 1.2PV. The curve depicting the relationship between the recovery factor and the displacement pressure is then plotted. Through this analysis, the minimum miscibility pressure can be determined.

Tab.1.Slim-scale tube model parameters

Parameter	Amounts	Units
tube length	20	m
average inner diameter	0.006	m
porosity	0.35	%
displacement velocity	0.0012	m^3/day
permeability	17.589	mD

Table 1 is a list of the fine-scale tube model's individual parameters. Figure 1 shows the schematic representation of the tube model, with the color scale on the right side signifying the oil saturation. The grid size of the tube model is 40×1×1, with the plane sizes being 40×0.5m in the I direction, 1×0.006m in the J direction, and 1×0.006m in the K direction.

Fig.1.The schematic of slim-tube experiment

2.3 Materials

The compositional analysis result of the crude oil is given in Table 2. The injected gases which is shown in Table3 are used in the slim-tube experiments.

Tab.2.The compositional analysis result of the crude oil

Cn	Mole fraction	Cn	Mole fraction
H_2S	0.0027	C14	0.0207
CO_2	0.0101	C15	0.0186
N_2	0.0018	C16	0.0151
C1	0.1257	C17	0.0134
C2	0.0699	C18	0.0129
C3	0.0664	C19	0.0114
iC4	0.0235	C20	0.0089
nC4	0.0471	C21	0.0075
iC5	0.0282	C22	0.006
nC5	0.0514	C23	0.0055
C6	0.0769	C24	0.005
C7	0.0525	C25	0.0049
C8	0.0807	C26	0.0031
C9	0.032	C27	0.0029
C10	0.0404	C28	0.0019
C11	0.0316	C29	0.0011
C12	0.0255	C30+	0.0693
C13	0.0254	total	1

Tab.3.The compositional analysis result of the crude oil

$(1-n)CO_2$ $+nH_2S$	Gas 1	Gas 2	Gas 3	Gas 4	Gas 5	Gas 6	Gas 7
n	0	20%	40%	50%	60%	80%	1

Under various circumstances, the crude oil-filled fine tubes were displaced by the gas that was injected. In the experiment, the displacement efficiency of the mixed gas was assessed at various displacement pressures after infusing 1.2 pore volumes of gas or when no oil was being produced.

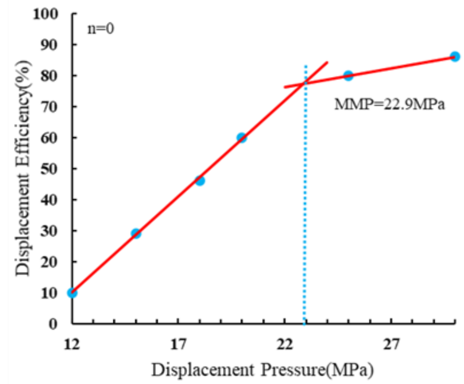
3. RESULTS AND DISCUSSIONS

In the slim-tube experiments, the reservoir fluid containing five different mixed gases was subjected to a range of displacement pressures, with the displacement efficiency being determined by the ultimate oil recovery rate. The results showed that the MMPs of the crude oil-hydrocarbon gas-acid system were around 17.1MPa, 17.5MPa, 18.2MPa, 18.5MPa, 19.1MPa, 19.4MPa, and 22.9MPa, respectively, when the proportion of CO_2 gas was 0%, 20%, 40%, 50%, 60%, 80%, and 100%

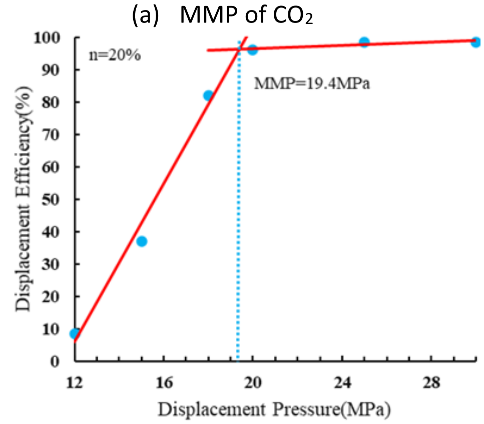
3.1 Minimum Miscibility pressure

Miscible gas flooding is widely used to enhance the oil recovery in many reservoirs. One key parameter for evaluating the applicability of reservoir processes is the MMP. Therefore, it is necessary to obtain the MMP of the reservoir by injecting a mixed gas containing acidic gases.

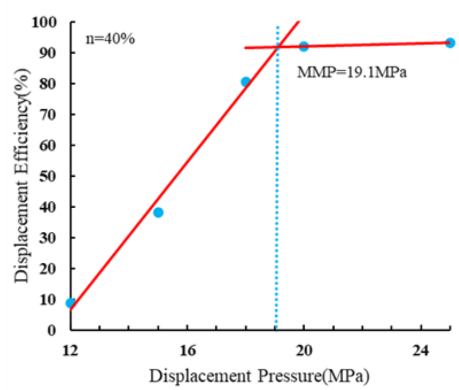
At reservoir temperature, MMPs were determined using five different mixed gases through tests in fine tubes. The process of obtaining MMPs is illustrated in Figure 2. In figure 2 seven charts can be compared to show how the blue dashed line gradually moves closer to the vertical axis as the fraction of acidic gases rises. This suggests that the MMP declines as the amount of acid gases increases. The results in Table 4 further bolster this view. This discovery can be explained by the mass transfer mechanism between the crude oil and the acidic gases, especially H_2S.



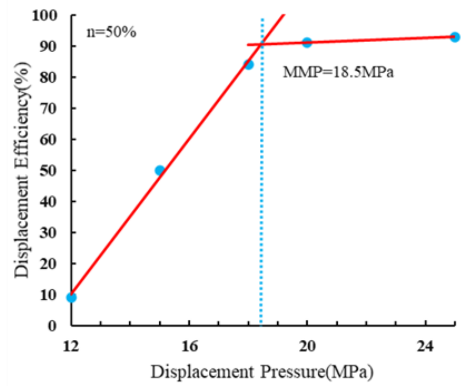
(a) MMP of CO_2



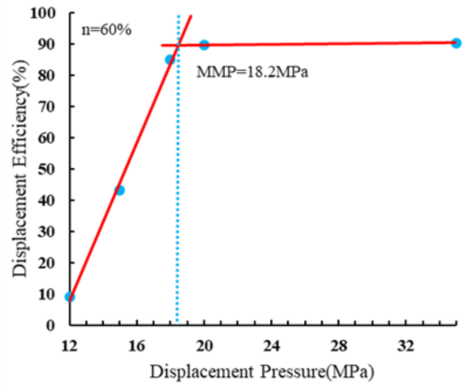
(b) MMP of 20% H_2S



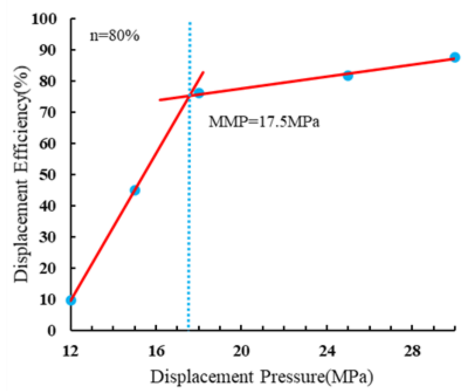
(c) MMP of 40% H_2S



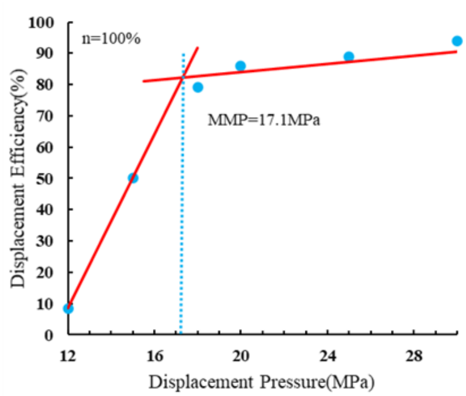
(d) MMP of 50% H_2S



(e) MMP of 60%



(f) MMP of 80%



(g) MMP of 100%

Fig.2.Measured the MMPs with different acid gas content under different displacement pressures

Tab.4.Measured the MMPs with different acid gas content

$((1-n)CO_2 + nH_2S$	0	20%	40%	50%	60%	80%	1
MMP(MPa)	22.9	19.4	19.1	18.5	18.2	17.5	17.1

Figure 3 depicts the curves of MMPs for acid gas flooding and different gas concentrations, confirming a certain linear relationship between MMPs and gas concentrations.The correlation coefficient is approximately 0.819.

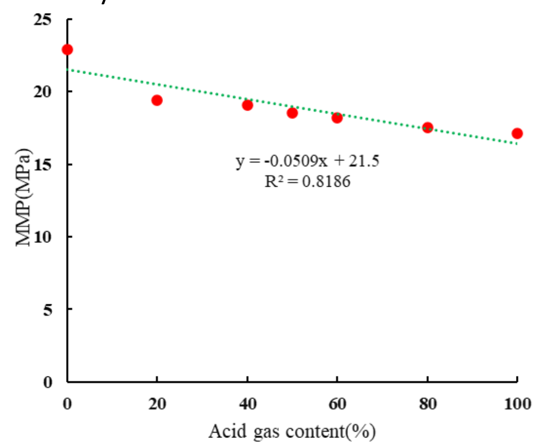


Fig.3.MMPs with different acid gas contents

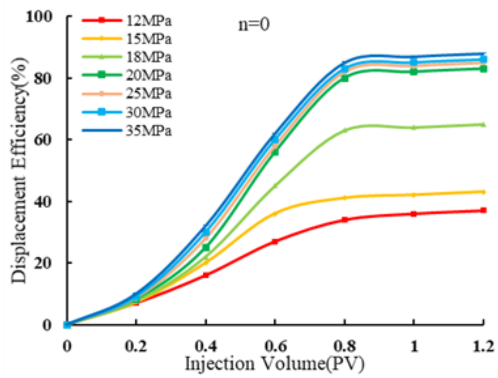
Therefore, acid gas flooding can achieve acid gas miscible displacement and improve oil recovery in reservoirs by incorporating H_2S gas into CO_2 displacement. This reduces the miscibility pressure of the acid gas significantly

3.2 Displacement Efficiency

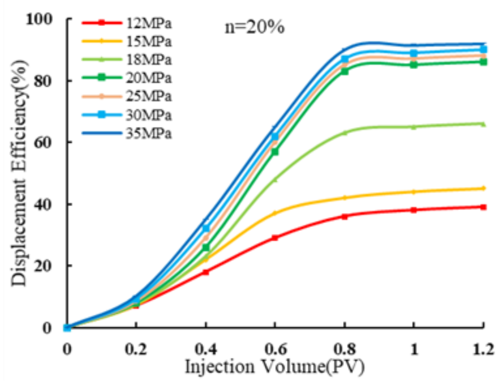
When acid gas is injected into the reservoir, there is a beneficial mass transfer between the acid gas and crude oil. Before the breakthrough of acid gas displacement front, the produced gas comes from the dissolved gas in the reservoir oil, and after the breakthrough, acid gas is produced along with the dissolved gas. During the displacement process, a combined condensing/vaporizing-gas drive mechanism is employed to enhance the recovery of acid gas with crude oil. In this process, displacement pressure and acid gas content are two important factors that affect the displacement efficiency.

3.3 Displacement Efficiency Versus Displacement Pressure

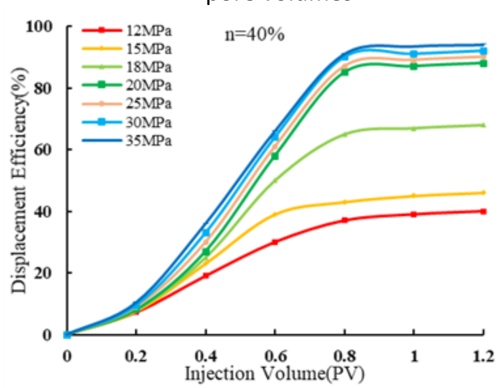
Figure 4 shows the relationship between the displacement efficiency and the injection volume of different acid gas contents under different displacement pressures. Obviously, the higher the displacement pressure, the higher the displacement efficiency, the later the gas breakthrough, and the higher the recovery rate. However, for the same injected volume after gas breakthrough, when the displacement pressure is greater than the MMP, the larger the displacement pressure, the smaller the trend of displacement efficiency increase; when the displacement pressure is less than the MMP, the greater the displacement pressure, the more obvious the increase of displacement efficiency. Comparing the displacement pressures in the figure, it can be observed that when the displacement pressure remains constant, the displacement efficiency increases with the increase of H_2S content. Analyzing figure 4 from the perspective of remaining oil, it can be found that the higher the H_2S content, the less remaining oil. The effect of changes in displacement pressure or injected acidic gas content on the remaining oil saturation is opposite to that on the displacement efficiency.



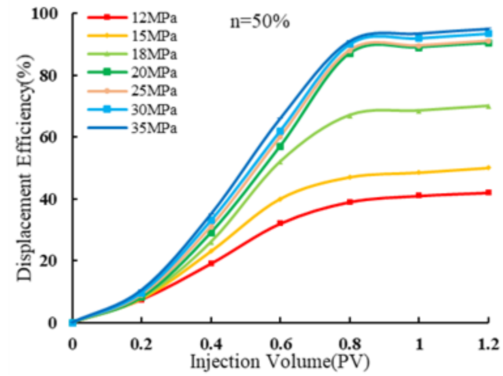
(a) Recovery efficiency of CO_2 injection at different pore volumes



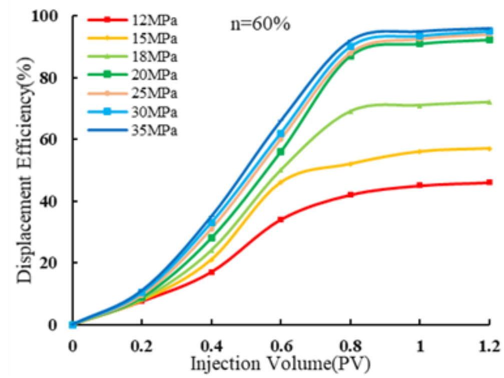
(b) Recovery efficiency of 20% H_2S injection at different pore volumes



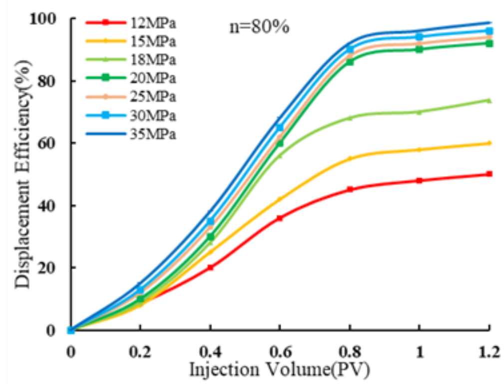
(c) Recovery efficiency of 40% H_2S injection at different pore volumes



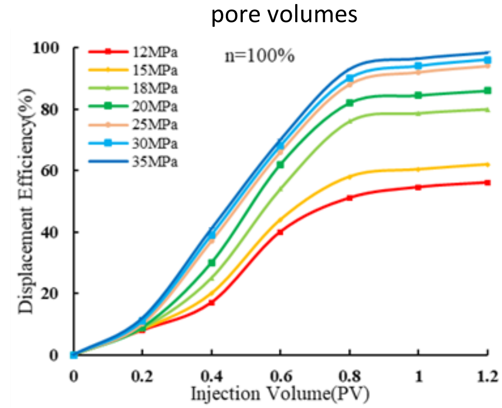
(d) Recovery efficiency of 50% H_2S injection at different pore volumes



(e) Recovery efficiency of 60% H_2S injection at different pore volumes



(f) Recovery efficiency of 80% H_2S injection at different pore volumes



(g) Recovery efficiency of H_2S injection at different pore volumes

Fig.4.Different recovery rates under displacement conditions

3.4 Displacement Efficiency Versus Acid Gas Content

Figure 5 illustrates the relationship between displacement efficiency and displacement pressure in acid gas flooding. It shows that the displacement efficiency increases as the displacement pressure increases when the acid gas content is constant.

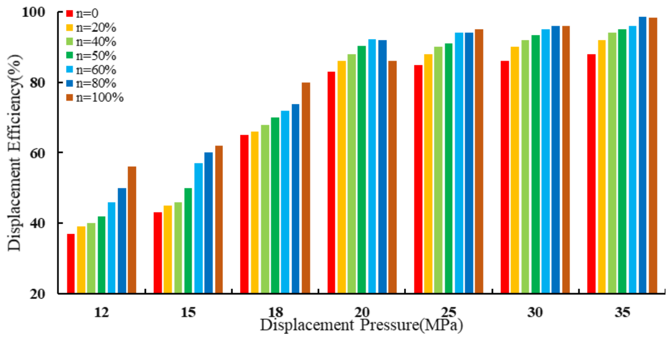


Fig.5.Displacement efficiency versus Displacement pressure

Figure 6 shows the relationship between displacement efficiency and H_2S gas percentage at a constant displacement pressure. It can be seen from Figure 6 that displacement efficiency increases with the increase of H_2S gas percentage when the displacement pressure is constant. From Figure 7, it can be seen that before reaching the mixing phase, displacement efficiency is roughly linearly related to H_2S gas percentage. When the displacement pressure is low, the slope of the curve is larger, and when the displacement pressure is high, the slope gradually decreases.

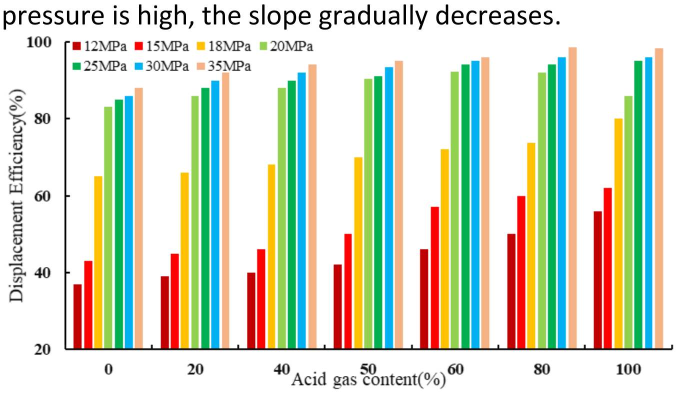


Fig.6.Relationship between displacement efficiency and H_2S content

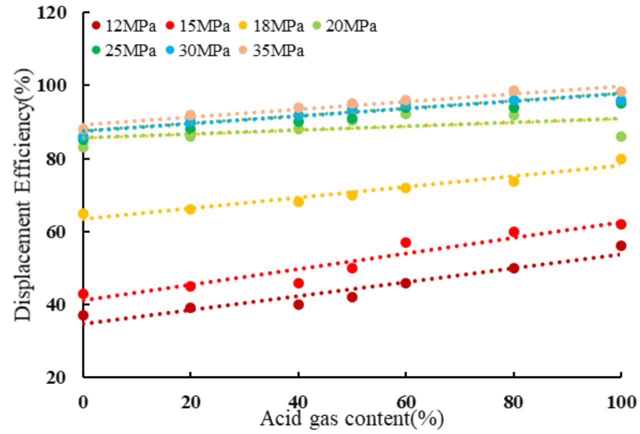


Fig.7.Relationship between displacement efficiency and H_2S content

Therefore, if the hydrocarbon gas or the produced gas contains acid gas, the mixed gases can be injected directly into the oil reservoir without separating the acid gas. This approach not only saves processing costs but also reduces environmental pollution. Additionally, it can improve the displacement efficiency more effectively and make better use of the acid gas storage. To prevent significant declines in displacement efficiency, increasing the displacement pressure and acid gas content within a certain range while injecting mixed gas is a good option.

4. CONCLUSIONS

This study performed a simulation experiment in a slim tube utilizing a mixture of gases with varying acid gas concentrations and displacement pressures.

MMP was anticipated when injecting crude oil with various acid gas levels. The MMP reduced as the H_2S level of the acid gas rose. When the MMP was higher than the reservoir or the displacement pressure criteria could not be reached during the CO_2 miscible flooding operation, adding some H_2S to the CO_2 will effectively lower the miscibility pressure.

When the displacement pressure is constant, the displacement efficiency increases with the increase of H_2S content in the acid gas mixture. Similarly, when the percentage of acid gas is constant, the displacement efficiency increases with the increase of displacement pressure. In addition, the higher the displacement pressure, the later the gas breakthrough time. The displacement efficiency is influenced by two important factors, namely displacement pressure and acid gas content. The displacement efficiency shows a linear relationship with the increase of H_2S content in the acid gas mixture.

This study opens up possibilities for mixing different levels of H_2S to achieve acid gas drive in CO_2 flooding in the future, which can improve the phase mixing and recovery efficiency. It provides a new approach to enhance oil recovery and reduce acid gas pollution, and is of significant importance.

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DECLARATION OF INTEREST STATEMENT

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

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