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Investigation on Nitrogen Foam Assisted Steam Flooding with Sand Production

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Abstract: Foam performances including interfacial tension, foam volume, half-life period and plugging ability are investigated in laboratory. A numerical model is built to simulate sand production during thermal recovery. The changes of reservoir permeability and steam breakthrough time after sand production are analyzed. Based on experimental results, an integrated model which considers foam generation, coalescence, oil acceleration on foam decay and sand production is built to study nitrogen foam assisted steam flooding with sand production. Simulation results show that foam can improve areal sweep efficiency and delay steam breakthrough time significantly. However, the adverse effect is that foam will intensify the sand production due to its high sand-carrying ability.

Keywords: Nitrogen foam, steam flooding, sand production, breakthrough time, numerical simulation, laboratory experiment

1 Introduction

Heavy oil takes a large share of oil reservoirs in the world. Thermal recovery is still the most popular development style due to the high sensitivity to temperature of oil viscosity. As the initial stage of thermal recovery, huff and puff can only get 10%-20% of the oil recovery. At the same time, along with the round increase of huff of puff, oil steam ratio will decrease gradually and economic benefit will become poor. Steam flooding which is the succeeding development style of huff and puff shows great potential to develop heavy oil reservoirs [Liu (1998); Zhang (1999); Cornelius, Willman, Runberg, Powers, and Valleroy (1961)].

However, many heavy oil reservoirs have shallow burial depth and poor cementation. Sand production is easy to happen for this kind of reservoirs which will make the reservoir more heterogeneous and intensify steam channeling [Dusseault (1993); Yi (2002)]. Meanwhile, high temperature of the injected steam may weak

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the cementation and aggravate sand production. After steam breakthrough, the injected steam will flow to the adjacent production well quickly along the channeling paths and the huge heat loss will make the project uneconomic [Han, Bruno, and Dusseault (2007); Zhou, Jiang, and Feng (2004)].

Foam has long been used to enhance oil recovery due to its special properties. Holm found that after the co-injection of gas and the foaming agent, liquid flows as a continuous phase and gas flows to occur by a sometimes very slow process of continually breaking and re-forming the liquid films. This will lead to a significant reduction of gas relative permeability and make foam highly applicable in steam channeling control, water coning prevention and gas storage [Coffin and Aquitaine (1993)]. By experimental methods, many researchers also found that foam can increase the gas apparent viscosity by a big margin. This viscosifying ability of foam for gas is also helpful to increase the sweep efficiency for gas flooding projects [Ozkan and Raghavan (1990); Chaperon (1996)].

For this paper, firstly static and dynamic tests of foam are done by experimental methods in order to get the key parameters which are essential in the following numerical models. The static tests include foam volume, half-life period and interfacial tension tests and the dynamic test is the plugging ability tests of foam under different temperatures. Secondly, a sand production model is built to study the physical property changes during steam flooding. Finally, an integrated mechanism model which considers foam generation, coalescence, oil acceleration on foam decay and sand production is built to study nitrogen foam assisted steam flooding with sand production.

2 Foam performance tests

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Steam flooding is a temperature variant process and the variance of temperature will have a great influence to the foam performance. In order to get a comprehensive understanding about the foam performance during steam flooding, foam volume test, half-life period test and foam blocking ability test are all done under different temperatures.

2.1 Interfacial tension test

Mass concentrations of the foaming agent solutions are set to 0.1wt%, 0.2wt%, 0.3wt%, 0.4wt%, 0.5wt%, 0.6wt% and 1.0wt% respectively. An interfacial tension meter is used to accomplish these tests. Experimental results are shown in Figure 1. From this figure, we can see that the foaming agent can lower the interfacial tension by a big margin and if the mass concentration exceeds 0.5wt%, the interfacial tension will have a slight increase, i.e., the critical micelle concentration of the foaming agent solution is 0.5wt%.

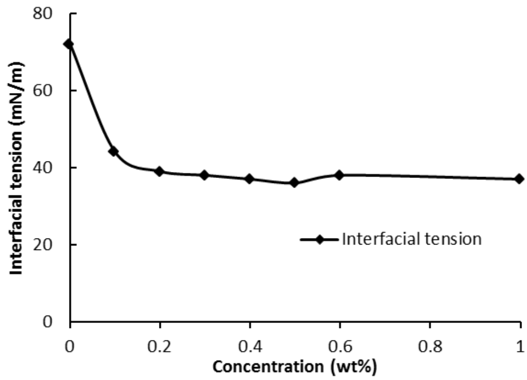


Figure 1: The relationship between interfacial tension and mass concentration

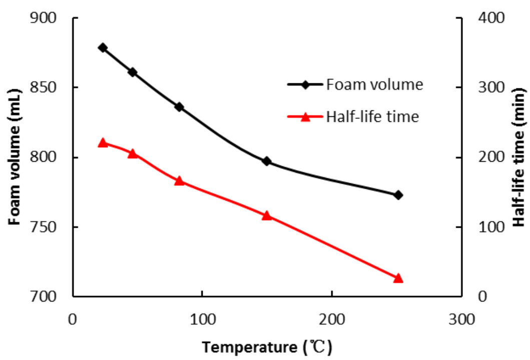


Figure 2: The relationship between temperature, foam volume and half-life time

2.2 *Foam volume and half-life period tests under different temperatures*

Mass concentration of the foaming agent solution is set to 0.5wt%. 150mL of the foaming agent solution is poured into a high temperature high pressure reactor and then 150mL of the nitrogen gas is injected into the foaming agent solution. Foam volume and half-life period are measured and the test is repeated under temperature 25°C, 45°C, 80°C, 150°C and 250°C respectively. The results of these tests are shown in Figure 2. From this figure, we can see that along with the increase of temperature, the foam volume and half-life period are both decrease gradually.

However, the magnitude of the drop for foam volume is only 11.7% and that for half-life volume is up to 59.1%, i.e., half-life period is more sensitive to temperature. This means under high temperature the foaming ability of the foaming agent can be kept well while the stability of the foam will have a big discount. Nevertheless, it is a decay and regeneration process for foam in porous media and the effectiveness of foam can last for a long time so good performances are still respected in the later plugging ability tests.

2.3 Plugging ability tests under different temperatures

The higher the temperature, the faster the evaporation of water in the liquid film and foam will decay when the liquid film become thin to a certain extent. So generally speaking, under high temperature the stability and plugging ability of foam will become weak. In order to study the influence of temperature on the plugging ability of foam, tests are done under 25°C, 45°C, 80°C, 150°C, 250°C and 300°C respectively. For all tests, mass concentration of the foaming agent, gas liquid ratio and back pressure are set to 0.5wt%, 1:1 and 1.5MPa respectively. At first water and nitrogen gas are co-injected to a sand pack whose permeability is 1,470 mD at a constant rate and when stable, the differential pressure is recorded as the base differential pressure. Then the foaming agent solution and nitrogen gas are co-injected to this sand pack and when stable, the differential pressure is recorded again as the working differential pressure. The ratio of the working differential pressure and the base differential pressure is the resistance factor of foam. Experimental results are shown in Figure 3. From this figure, we can see that temperature has a significant influence on the plugging ability of foam. Along with the increase of temperature, the base differential pressure goes up gradually and the resistance factor goes down on the contrary. Though the drop is dramatic, the resistance factor still reaches 34.24 at 250°C. This is enough for mobility control during steam flooding.

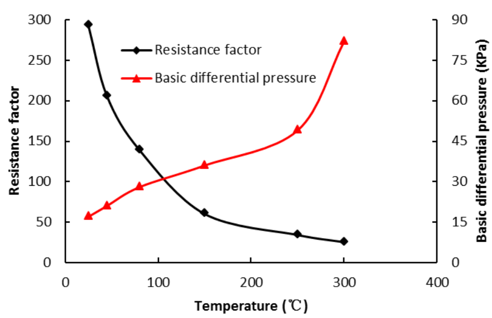


Figure 3: The relationship between temperature, resistance factor and basic differential pressure

3 Steam flooding with sand production

Sand production may occur with heavy oil production in unconsolidated sand formations. For some heavy oil reservoirs, sands are cemented only by asphalt or colloid. When steam flooding is carried out, the mobility of asphalt and colloid will be improved by a big margin and sand will be produced along with the flowing asphalt and colloid. After sand production, high permeability channels will form and steam channeling is easy to happen.

3.1 The built of the sand production model

A two dimensional sand production model is built using the STARS module of CMG software. In this model, sands are divided into three categories including flowing sands, moveable sands and matrix sands. Flowing sands represent the sands which are flowing along with oil; moveable sands represent the sands which are immovable before production and can convert to flowing sands due to pressure drop and thermal damage and matrix sands represent the sands which are immovable under any conditions. The conversion from moveable sands to flowing sands is realized by employing a kinetic reaction equation and the reaction rate which is related to pressure, temperature, cementation, oil viscosity and so on can be controlled according to the geological condition of the formation of interest. After sand production, formation porosity will change and permeability is calculated using Carmen-Kozeny formula according to the porosity. The basic parameters of the formation which referred to Jinglou block in Henan oilfield (located at Nanyang, Henan province, China), Sinopec are listed in Table 1.

Table 1: Reservoir parameters used in this study

Property	Value	Property	Value
Horizontal permeability	1,500 mD	Grid top depth	900 m
Vertical permeability	450 mD	Pay zone thickness	10 m
Porosity	0.3	Oil viscosity(R.C.)	1,324 cp
Initial Temperature	$48°C$	Oil density	$985kg/m^3$
Initial Pressure	9,000 Kpa	Net gross ratio	1
Oil saturation	0.712	Poisson's ratio	0.3
Water saturation	0.288	Young's elastic modulus of formation	400 MPa

The model includes two wells. The initial stage is three cycles' huff and puff for both wells. For each cycle, each well is injected steam for 10 days; soaks for 2 days and produces for 5 months. The steam injection rate is $100m^3/d$ for the first cycle and it will increase 10% per cycle in the later two ones. After steam stimulation, steam flooding is carried out. The left well is for injection and the right well is for production. Production-injection ratio and steam injection strength are set to 1.2 and 1.6t/(d·m·ha) respectively.

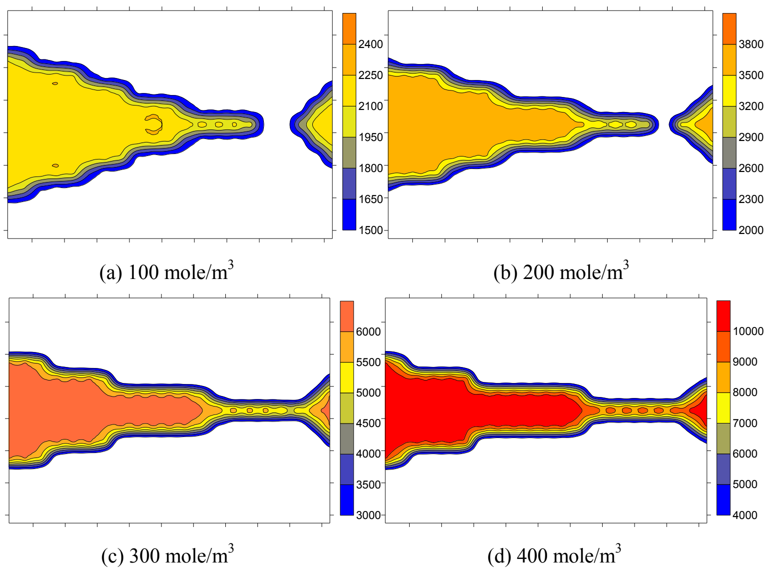


Figure 4: Permeability distributions at 1000d with different proportions of moveable sand

3.2 *Physical changes caused by sand production*

Sand production volume can be adjusted by the proportion of moveable sands and the reaction rate. Figure 4 shows the permeability distributions at 1000d for 4 different proportions of moveable sands. From this figure, we can see that high permeability channels mainly consist in the mainstream line and the near-wellbore area. This is because at the stage of huff and puff, production system shifts between injection and production in a short period. Thermal damage caused by high temperature steam and the repeated rising and declining of reservoir pressure will lead to large amount of sand production. After three cycles' huff and puff, two round shaped high permeability zones are formed at the near-wellbore area. For steam flooding process, high pressure and high temperature caused by the continuously injected steam will lead to sand dissolution and shedding and the flowing sands will be flooded from the injection well to the production well. Along with the steam injection, high permeability channels will extend from the injection well to the production well. At the same time, steam channeling through the high permeability channels will intensify sand production due to thermal damage. While for non-mainstream line area, blockage will occur due to sand migration and the effective permeability will decrease accordingly. The blank area of contour map (a) in Figure 4 whose permeability is lower than the original reservoir permeability indicates the damaged area. The opposite effects for mainstream line area and non-mainstream line area will intensify reservoir heterogeneity and steam channeling.

3.3 The effect of sand production on steam breakthrough

Figure 5 shows the bottom hole temperature of the right production well for different proportions of moveable sands. For each curve, there is an inflection point at steam flooding process. At this point, the channeling paths have been formed between the injection well and the production well and the injected steam will flow to the production well at a fast speed along the channeling paths. After this point, bottom hole temperature will rise quickly to nearly the steam temperature and the channeling of steam will lower the oil steam ratio and cause a huge heat loss. So the time at which the inflection point occurs can be recognized as the steam breakthrough time at steam flooding process. From figure 5, we can see that sand production will shorten the steam breakthrough time by a big margin and the more the sand production, the shorter the steam breakthrough time.

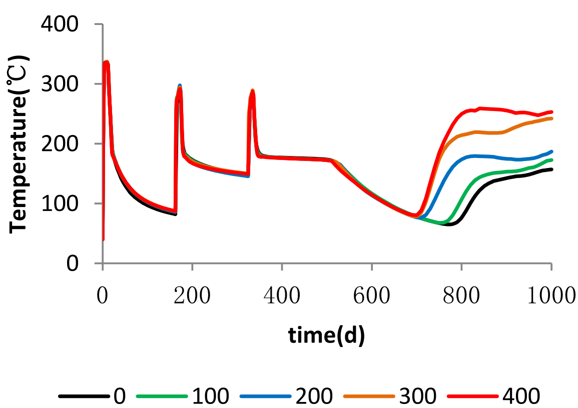


Figure 5: Bottom hole temperatures with different moveable sand proportions

4 Numerical simulation of foam assisted steam flooding with sand production

As figure 5 shows that, steam breakthrough will occur when continuous high temperature steam is injected into the reservoir. After breakthrough, the huge heat loss will make the project more and more uneconomic. Foam which can be seen as a gas viscosifying agent has long been used in gas mobility control in oil recovery processes. When foam flows in porous media, the shape of foam will deform if the pore throat radius changes. Jamin effect will occur due to this deformation and the flow resistance of gas will increase greatly. At the same time, the presence of oil will affect the stability of foam significantly so the injected foam which will flow along high permeability channels first will form strong plugging due to low oil saturations of these channels. On the contrary, in low permeability zones, oil will accelerate foam decay and effective plugging is hardly to form. This selective plugging ability can even the steam-front profile and delay the steam breakthrough time. Furthermore, the foaming agent injected is a kind of surfactant with strong activity. It can lower the interfacial tension significantly and alter the wettability of the rock to some extent so a part of oil which is in bond state at steam flooding process can be displaced after the injection of foam. In order to simulate all above-mentioned mechanisms, an integrated model which considers foam generation, coalescence, oil acceleration on foam decay and sand production is built to study nitrogen foam assisted steam flooding with sand production.

The experimental results of interfacial tension test are imported to express the decrease of interfacial tension after foam injection. Foam generation and decay rate are set by reference to foam volume and half-life period and the decrease of gas relative permeability is set according to the results of blocking ability tests. For huff and puff stage, only steam is injected and when steam flooding stage begins, foam is co-injected with steam. The proportion of steam and foam is 2:1; gas-liquid ratio is 1:1; mass concentration of the foaming agent is 0.5wt%. For better comparison, the total injected fluid volumes of steam flooding and foam assisted steam flooding are the same. Simulation results are analyzed taking the model whose moveable sand concentration is 300 mole/m^3 for example.

4.1 The effect of foam on areal sweep efficiency

Figure 6 is the comparison of oil saturation distributions at 1000d for steam flooding and foam assisted steam flooding. From this figure, we can see that foam can improve the areal sweep efficiency significantly. On one hand, due to the plugging of foam, steam can spread to a larger area so the width of the blue area for foam assisted steam flooding is bigger than that for steam flooding. On the other hand, the foaming agent can also improve the displacement efficiency so foam flooded area has lower oil saturation and the length of the blue area for foam assisted steam flooding is bigger than that for steam flooding too.

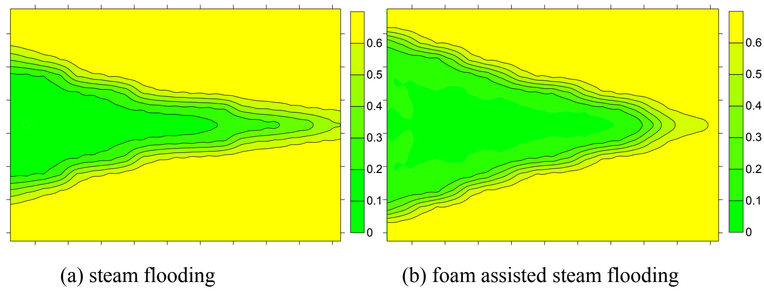


Figure 6: Oil saturation distributions for two development styles

4.2 The effect of foam on steam breakthrough time

Figure 7 shows the bottom hole temperature of the production well for two development styles. From this figure, we can see that the co-injection of steam and nitrogen foam can delay the steam breakthrough time greatly and the rise speed of temperature for foam assisted steam flooding after steam breakthrough is slower than that for steam flooding.

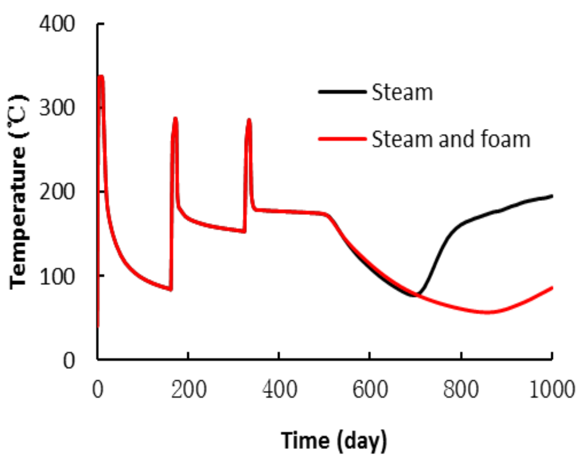
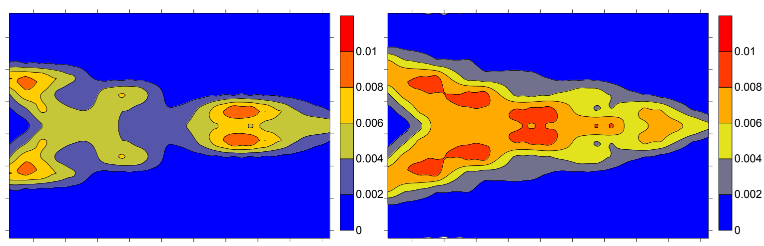


Figure 7: Bottom hole temperature for two development styles

4.3 The effect of foam on sand production

Figure 8 shows the mole fraction of the flowing sands at 1000d for two development styles. From this figure, we can see that foam assisted steam flooding will cause more serious sand production. The reason mainly includes two aspects. One is that for foam assisted steam flooding, the areal sweep efficiency is improved so sand production area is larger than that of steam flooding. The other is that sand-carrying capability of foam is much stronger than that of steam due to its high viscosity so when foam is co-injected with steam, more sands will be carried out along with foam. This is the adverse effect of foam assisted steam flooding.



(a) steam flooding (b) foam assisted steam flooding

Figure 8: Mole fraction of flowing sand for two development styles

5 Conclusions

1. Physical experiments shows that the foaming agent can reduce oil-water interfacial tension by a big margin; along with the rise of temperature, both foam volume and half-life period will decrease and half-life period is more sensitive to temperature; the plugging ability is also sensitive to temperature while the resistance factor still reaches 34.24 at 250°C so a good performance still can be expected.

2. Sand production will intensify the heterogeneity of the reservoir. The mainstream line area is stress concentrated so sand production is more serious at this area. High permeability channels spread from the injection well to the production well. After sand production, steam channeling will be more serious and steam breakthrough time will be shorted by a big margin.

3. The co-injected foam can form an effective plugging to the high permeability channels and more steam will flow to low permeability zones instead. After foam injection, steam profile and areal sweep efficiency can be improved and steam breakthrough time will be delayed by a big margin.

4. Due to the high sand-carrying ability of foam, more sands will be produced. This will increase the wear of tools and the workload of oil purification. This is the adverse effect of foam assisted steam flooding.

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