Секция «Разработка месторождений нефти и газа»

Chemical method (foam surfactant) to restrict gas inflow into a well

Научный руководитель – Ганиева Гузель Рафиковна

Гильметдинов Ильмир Дамирович

Студент (магистр)

Казанский (Приволжский) федеральный университет, Институт геологии и нефтегазовых технологий, Казань, Россия

E-mail: igilmetdinov@gmail.com

Rationale development of the reservoir with a massive gas cap is relevant for a lot of oil and gas companies around the world. The main problems of such challenge are the formation of gas cones, which lead to gas breakthroughs to production wells. This process reduces technical and economic indicators and does not allow to achieve high values of oil gas recovery factor. A significant part of Russia hydrocarbon reserves are oil and gas condensate fields, in the oil rims of which about 6 billion tons of oil are concentrated. At the same time, the oil reserves of such fields are used effectively, which is often with a negative load of gas from the gas cap. Due to the complexity of development, oil reserves of oil and gas condensate fields are classified as hard-to-recover. [1]

The use chemical methods to create blocking agents are an alternative method to reduce excessive gas or water inflow during oil production. Also it allows to reduce value of residual oil saturation. Several articles were reviewed on the topic of methods for limiting gas inflows into wells. Harsh conditions of oil reservoirs require surfactant candidates with high cloudpoint temperatures in the presence of concentrated brine in order to prevent surfactant precipitation. [2] In addition, the foam coarsens, coalesces, and decays faster as a response to the reduction of foamability and foam viscosity at high temperatures and salinities. [3]

The foam generation is tested in steady-state coreflooding experiments at various gas and liquid flow rates, temperatures, pressures, and salinities. The strength of foam moving through porous media is related to the magnitude of pressure gradient measured along the medium. [4] The finer the texture of generated foam and the smaller foam bubbles, the higher the pressure gradient and apparent viscosity. [5] The constant velocity foam scan is performed in order to measure pressure gradient (dP) and calculate apparent viscosity at specific foam quality (gas fraction).

Foam quality is a gas fractional flow rate of the total flow rate f(g):

where liquid injection flow rate q(i) and gas injection rate q(g) are calculated at normal pressure.

The apparent viscosity μ is calculated using Darcy formula:

where k is the permeability of the core, u is the total Darcy velocity, ΔP is the pressure drop (dP) over the core, and L is the length of the core.

Typically, the apparent viscosity first increases linearly with foam quality and then decreases sharply. Thus, two distinct flow regimes can be determined in the plot: low-quality regime (low gas fraction) with strong foam and high-quality regime (high gas fraction) with weak foam separated by the transition foam quality, which is characterized by the maximum pressure drop and apparent viscosity

In the low-quality regime, the pressure gradient increases as the gas saturation rises because of bubble trapping and the foam volume increase. The bubble size is controlled by the pore size, and the reduction in gas mobility is greatest. In the high-quality regime, the pressure gradient decreases with increase in foam quality mainly due to coalescence of the gas bubbles. Foam collapses at the transition between two regimes which designates the critical capillary pressure close to the rupture pressure of a single foam film. If foam quality rises to a very high level, foam presents the morphology of “gas slug” instead of gas bubbles. [6]

The experiments were carried out simulating reservoir conditions: temperature 15 °C (using thermal oven) and pressure 79 bar (using back pressure regulator - BPR), oil used in the tests was also taken from the field. The core samples were saturated with water, then the core was flooded with kerosene and then with oil. After that, the sample remained for the aging. After this preparation, experiments were carried out. High-permeability and low-permeability samples were used in the process. The tests will be carried out in the presence of gas flow and without, with various gas blocking agents (gels, foam gels, foams, other surfactants with polymers) in order to determine the best GBA and determine its characteristics and properties during oil production

Источники и литература

1) V.A. Lushpeev; N.A. Rovnik; D.S. Tananykhin; V. Shpurov. Efficiency assessment of gas discharge limitation technologies while simulating oil fringes using the naviga-tor bundle. Territory “NEFTEGAS”, 2019, 1–2, P. 80–88.
2) Al Sumaiti, A.; Shaik, A. R.; Mathew, E. S.; Al Ameri, W. Tuning foam parameters for mobility control using CO2 foam: field application to maximize oil recovery from a high temperature high salinity layered carbonate reservoir. Energy Fuels, 2017, 31 (5), P. 4637−4654.
3) Kapetas, L.; Vincent Bonnieu, S.; Danelis, S.; Rossen, W.R.; Farajzadeh, R.; Eftek-hari, A.A.; Mohd Shafian, S.R.; Kamarul Bahrim, R.Z. Effect of temperature on foam flow in porous media. J. Ind. Eng. Chem., 2016, 36, P. 229−237.
4) Farajzadeh, R.; Andrianov, A.; Krastev, R.; Hirasaki, G. J.; Rossen, W. R. Foam−oil interaction in porous media: implications for foam assisted enhanced oil recovery. Adv. Colloid Interface Sci., 2012, 183−184, P. 1−13.
5) Osei-Bonsu, K.; Shokri, N.; Grassia, P. Fundamental investigation of foam flow in a liquid-filled Hele-Shaw cell. J. Colloid Interface Sci., 2016, 462, P. 288−296.
6) Rudyk S., Al-Khamisi S., Al-Wahaibi Y., Afzal N. Internal Olefin Sulfonate Foam Coreflooding in Low-Permeable Limestone at Varying Salinity. Energy Fuels, 2019, 33, P. 8374−8382