УДК 622.276.63

МОДЕЛИРОВАНИЕ КИСЛОТНОЙ ОБРАБОТКИ ТЕРРИГЕННОЙ ПОРОДЫ В ТЕРМОБАРИЧЕСКИХ УСЛОВИЯХ

–––––––

SIMULATION OF ACID TREATMENT OF TERRIGENOUS ROCK UNDER THERMOBARIC CONDITIONS

Антонов Сергей Михайлович
кандидат химических наук, ведущий инженер НИО
моделирования физико-химического воздействия на пласт,
ТО «СургутНИПИнефть» ПАО «Сургутнефтегаз»,
старший преподаватель института химии,
Тюменский государственный университет
s.m.antonov@utmn.ru

Гарипова Карина Фауадисовна
техник ООО «Корэтест Сервис», исследовательский центр,
магистрант института химии,
Тюменский государственный университет
stud0000195761@study.utmn.ru

Киселев Константин Владимирович
кандидат химических наук, начальник НИО
моделирования физико-химического воздействия на пласт,
ТО «СургутНИПИнефть» ПАО «Сургутнефтегаз»
kiselev_kv@mail.ru

Русейкина Анна Валерьевна
кандидат химических наук, доцент, профессор
кафедры органической и экологической химии
института химии,
Тюменский государственный университет
a.v.rusejkina@utmn.ru

Андреев Олег Валерьевич
доктор химических наук, профессор, заведующий
кафедрой неорганической и физической химии
института химии,
Тюменский государственный университет
o.v.andreev@utmn.ru

Аннотация. В данной работе представлены результаты обработки моделей терригенного пласта различными кислотными растворами в термобарических условиях. Рассчитаны коэффициенты проницаемости моделей пласта до и после проведения кислотных обработок, а также проведен визуальный анализ керна. По результатам экспериментов выбран наиболее подходящий кислотный раствор для проведения кислотной обработки терригенного коллектора.

Ключевые слова: терригенный коллектор, кислотная обработка, модель пласта, глинокислота, изопропиловый спирт.

Antonov Sergey Mikhaylovich
Ph. D., Lead Engineer of Research
Department of Simulation of Physical
and Chemical Impact on the Reservoir,
Tyumen branch of «SurgutNIPIneft»,
«Surgutneftegas» PJSC,
Senior Lecturer of Institute of Chemistry,
Tyumen State University
s.m.antonov@utmn.ru

Garipova Karina Fauadisovna
Technician of Research Center
«Coretest Service» LLC,
Undergraduate of Institute of Chemistry,
Tyumen State University
stud0000195761@study.utmn.ru

Kiselev Konstantin Vladimirovich
Ph. D., Head of Research Department
of Simulation of Physical and Chemical
Impact on the Reservoir,
Tyumen branch of «SurgutNIPIneft»,
«Surgutneftegas» PJSC
kiselev_kv@mail.ru

Ruseykina Anna Valerievna
Ph. D., Docent, Professor of the Department
of Organic and Ecological Chemistry,
Institute of Chemistry,
Tyumen State University
a.v.rusejkina@utmn.ru

Andreev Oleg Valerievich
D. Sc., Professor, Head of the Department
of Inorganic and Physical Chemistry,
Institute of Chemistry,
Tyumen State University
o.v.andreev@utmn.ru

Annotation. The results of treatment of a terrigenous reservoir models with various acid solutions under thermobaric conditions are presented in this paper. The permeability coefficients of reservoir models are calculated before and after acid treatments, and a visual analysis of the core was also carried out. The most suitable acid solution for acid treatment of the terrigenous reservoir was chosen based on the results of the experiments.

Keywords: terrigenous reservoir, acid treatment, reservoir model, clay acid, isopropyl alcohol.

Reduction of resources of oil fields in Western Siberia led to the need to develop hard-to-recover reserves. The Tyumen formation (formation JS_2) belongs to them in this area [1]. The potential of geological reserves of the Tyumen formation ranges from 3 to 4.5 billion tons of oil [2]. However, low increases in oil production are obtained during the operation of wells. Low permeability ($3–5 \cdot 10^{-3}$ μm^2) and layered reservoir heterogeneity are the main reason for reducing in oil. Also, the decrease in permeability of the near-wellbore zone occurs in the process of construction and repair of wells [3].

Low permeability of rocks and clogging of the near-wellbore zone lead to reduce hydrodynamic connection between production wells and injection wells. Various acid solutions for treating the near-wellbore zone are used to improve the productivity of wells. However, technological approaches of acid the impact on the formation have not been formed due to the small experience in the development of analogous oil fields similar in structure [4].

A series of filtration experiments was carried out to select an effective acid solution. An increase in the fluid conductivity of the rock was an indicator of effectiveness. The experiments were carried out on multiprofile module system ACRS-831Z (Coretest system, USA) under thermobaric conditions (pore pressure P = 10 MPa, reservoir pressure P = 42 – 44 MPa, reservoir temperature t = 82 °C). Solutions of the composition Hydrochloric acid+Surfactant (HCl – 22 wt %, Surfactant – 3 wt %), Clay Acid+Surfactant (HCl – 22 wt %, HF – 3 wt %, Surfactant – 3 wt %) and Cosolvent + Clay Acid + Surfactant (HCl – 16 wt %, HF – 3 wt %, Surfactant – 3 wt %, Isopropyl alcohol – 20 wt %) were chosen for experiment. Core samples from the JS_2 formation (fine-grained silty sandstone) were used. Cylindrical samples had dimensions of length and diameter l = d = 3 cm, helium gas permeability in the range $K = 3{,}79 – 9{,}32 \cdot 10^{-3}$ μm^2, porosity ø = 16,22 – 17,11 %. The reservoir model was composed of 3 samples. Fluid injection rate of solutions to the reservoir model was Q = 6 cm^3/h. Drilling fluid filtrate (polyacrylamide Survey D_1 – 1,0 wt %; biopolymer Xanthan Gum – 1,0 wt %; filtration stabilizer Survey FL – 2,0 wt %; Clay powder – 8,0 wt %; NaOH – 0.1 wt %) was used as a clogging agent.

The permeability assessment test was based on the pressure difference created by fluids injected into the reservoir model at the ends of a core sample. First, a reservoir oil model was pumped through the core and oil permeability ($K_1 \cdot 10^{-3}$, μm^2) was determined; then drilling fluid filtrate was injected, and afterwards oil phase permeability ($K_2 \cdot 10^{-3}$, μm^2) was determined. The next stage involved acid treatment, followed by the determination of oil permeability of the reservoir model (K_3, $K_4 \cdot 10^{-3}$, μm^2). Also, the calculation of the coefficient of decrease and increase in permeability relative to the initial value of K_1 : $(1 – K_3(K_4) / K_1) \cdot 100$ % and $(K_3 / K_{2–1}) \cdot 100$ % was made [5].

Rock permeabilities were assessed in terms of the Darcy linear filtration law:

$$K = \frac{\mu \cdot l \cdot Q}{\Delta P \cdot F}, \tag{1}$$

where K – rock permeability, m^2; Q – fluid volume rate per unit time, m^3/s; μ – dynamic viscosity of the fluid, N · s/m^2; l – carbonate reservoir model length, m; ΔP – pressure difference at the ends of reservoir model, N/m^2; F – filtration area, m^2.

The results of filtration experiments are presented in table 1. Treatment of the JS_2 reservoir models with drilling fluid filtrate led to a decrease in oil permeability by 2,2 – 2,4 times. Also this shown in the graphs of pressure gradient changes versus injected pore volumes of solutions. He increased from initial values GradP = 20 – 60 atm/m to GradP = 96 – 210 atm/m (fig. 1). Treatment of the reservoir model with the first volume of acid solution of Hydrochloric acid+Surfactant led to a slight increase permeability. This is due to the partial dissolution of the filtrate drilling fluid, but the low reactivity of HCl on in relation to the minerals of the JS_2 formation. Injection of the second volume of solution $V = 4{,}18\ V_{pore}$ also wasn't led to the restoration of reservoir model permeability. Filtering the first volume of Clay Acid + Surfactant led to an increase in permeability with $K = 1{,}09 \cdot 10^{-3}$ μm^2 up to $K = 3{,}13 \cdot 10^{-3}$ μm^2. Injection of the second volume acid solution led to significant ($K > 1000 \cdot 10^{-3}$ μm^2) increase in rock permeability. This is explained by the dissolution of the aluminosilicate framework of the rock by hydrofluoric acid and the formation dissolution channel. Injection of an acid solution of Cosolvent + Clay Acid + Surfactant into the reservoir model also led to a significant ($K > 1000 \cdot 10^{-3}$ μm^2) increase rock permeability. Smallest volume of solution $V = 3{,}73\ V_{pore}$ was spent on this treatment. Injection the second volume of acid solution was not required.

Table 1 – Filtration characteristics of the reaction between terrigenous core models and acid fluids

Acid solution	V_{pore}	K_1, μm^2 · 10^{-3}	K_2, μm2 · 10^{-3}	K_3 (K_4), μm^2 · 10^{-3}	%
Hydrochloric acid + Surfactant	8,19	4,03	1,69	2,73	32,25
Clay Acid + Surfactant	7,22	2,61	1,09	>1000	>915
Cosolvent+Clay Acid + Surfactant	2,89	1,44	0,66	>1000	>1280

Visual analysis of the core was carried out after filtration experiments (fig. 2). Formation of highly permeable dissolution channels in models treated with acidic solutions Clay Acid + Surfactant and Cosolvent + Clay Acid + Surfactant was confirmed. The formation of dissolution channels with a diameter of 1–4 mm was noted in the model treated with an acid solution of Cosolvent + Clay Acid + Surfactant. This points to high reactivity of the alcohol-acid composition. This led to the destruction of the rock matrix and the removal a layer of frame grains of sandstone (quartz, feldspar) by the filtration flow from models.

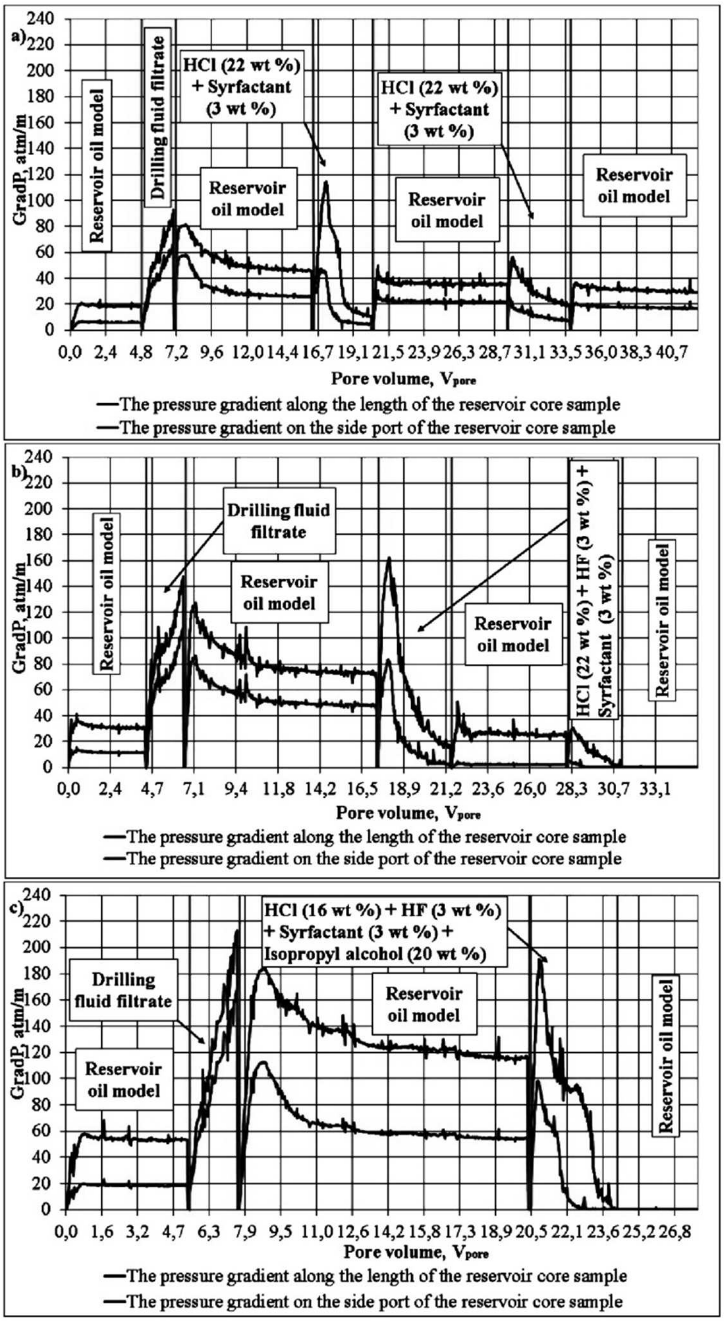

Figure 1 – Pressure gradients at the ends of the reservoir core sample upon the injection of oil, drilling fluid filtrate, and (a) Hydrochloric acid + Surfactant, (b) Clay Acid + Surfactant and (c) Cosolvent + Clay Acid + Surfactant

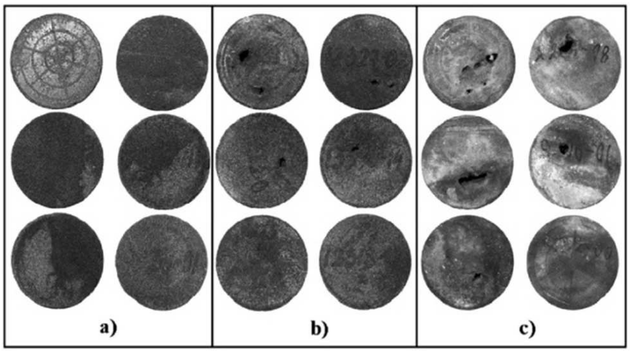

Figure 2 – End surfaces of terrigenous core models after the rock was treated with (a) Hydrochloric acid + Surfactant, (b) Clay Acid + Surfactant and (c) Cosolvent + Clay Acid + Surfactant

Thus, in a series of experiments, it was confirmed a significant decrease of the permeability of the JS_2 reservoir models after their treatment with process fluid (drilling fluid filtrate). Treatment of the reservoir model with Hydrochloric acid + Surfactant did not lead to the restoration of rock permeability. Treatment of reservoir models with Clay Acid + Surfactant and Cosolvent + Clay Acid + Surfactant solutions led to the formation of highly permeable dissolution channels. However, the smallest volume of the solution is required when acidizing the reservoir model with a solution of Cosolvent + Clay Acid + Surfactant. The profitability of use is achieved due to this, despite the presence of isopropyl alcohol in the composition. The efficiency and profitability of the treatment determine the priority use of the acid solution of Cosolvent + Clay Acid + Surfactant on oil deposits of the Tyumen formation (formation JS_2).

Литература:

1. Перспективы выработки трудноизвлекаемых запасов нефти на территории ХМАО-ЮГРЫ / А.А. Севастьянов [и др.] // Нефть и газ: опыт и инновации. – 2017. – Т. 1. – № 1. – С. 15–21.
2. Скоробогатов В.А. Юрский продуктивный комплекс Западной Сибири: прошлое, настоящее, будущее // Научно-технический сборник Вести газовой науки. – 2017. – № 3. – С. 36–58.
3. Анализ факторов, влияющих на эффективность методов ОПЗ пород-коллекторов Тюменской свиты юрских отложений / И.Б. Дубков [и др.] // Бурение и нефть. – 2008. – № 3. – С. 17–19.
4. Кондаков А.П., Гусев С.В., Нарожный О.Г. Результаты большеобъемных обработок призабойной зоны нагнетательных скважин месторождений ОАО «Сургутнефтегаз» // Нефтяное хозяйство. – 2016. – № 9. – С. 74–77.
5. Andreev O.V., Antonov S.M., Kiselev K.V. Kinetics of reaction between gelled HCl and Dolomite Ca_1, $16Mg_0$, $84(CO_3)_2$ and filtration of gelled acid in a reservoir core sample // International Journal of Oil, Gas and Coal Technology. – 2017. – Vol. 14. – № 4. – P. 369–379.

References:

1. Production prospects of hard-to-recover oil reserves on the territory of Khanty-Mansiysk autonomous Okrug-YUGRA / A.A. Sevastianov [et al.] // Petroleum and Gas: Experience and Innovation. – 2017. – Vol. 1. – № 1. – P. 15–21.
2. Skorobogatov V.A. Jurassic productive complex of Western Siberia: past, present and future // Scientific-Technical collection book Vesti Gazovoy Nauki. – 2017. – № 3. – P. 36–58.
3. Analysis of the factors influencing efficiency of methods of down-the-hole treatment of the rock-collectors of Tyumen horizon of Yursky deposits / I.B. Dubkov [et al.] // Drilling and oil. – 2008. – № 3. – P. 17–19.
4. Kondakov A.P., Gusev S.V., Narozhnyi O.G. The results of large-volume matrix acidizing treatments in injection wells in JS2 formations at the Surgutneftegas OJSC fields // Oil industry. – 2016. – № 9. – P. 74–77.
5. Andreev O.V., Antonov S.M., Kiselev K.V. Kinetics of reaction between gelled HCl and Dolomite Ca_1, $16Mg_0$, $84(CO_3)_2$ and filtration of gelled acid in a reservoir core sample // International Journal of Oil, Gas and Coal Technology. – 2017. – Vol. 14. – № 4. – P. 369–379.