New Chemical Treatment for Permanent Removal of Condensate Banking from Different Gas Reservoirs

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ABSTRACT: Condensate banking represents a challenging problem in producing the hydrocarbon from tight gas reservoirs. The accumulation of liquid condensates around the production well can significantly impair the gas flow rate. Gas injection and hydraulic fracturing are the common techniques used to avoid the condensate development by maintaining the reservoir pressure above the dew point curve. However, these treatments are associated with high operational costs and large initial investment. This study presents a new chemical treatment for removing the condensate banking using thermochemical solutions. The presented treatment can cause a permanent impact on the treated formations. Chemicals are injected to react downhole and generate in situ pressure and heat in certain conditions. The generated pressure can raise the gas pressure above the dew point, and the generated heat can change the phase of the liquid condensate to gas. Kinetic analysis indicates that thermochemical fluids can increase the temperature and heat by 85 °C and 369 kJ/mol, respectively. In addition, the impact of clay content on the efficiency of thermochemical treatment was studied using coreflooding experiments. A condensate removal of more than 60% was achieved using the huff and puff injection mode. A good correlation between the rock permeability and the condensate removal efficiency was observed. Higher condensate removal was obtained for the rock samples with high permeability values. Moreover, the presence of clay minerals in the treated rock showed a minor impact on the condensate removal, indicating that the injected chemicals are able to stabilize the clay minerals and avoid clay damage. This research shows that thermochemical treatment can remove more than 60% of the condensate damage for different types of tight sandstones. Huff and puff treatment was found to be a very practical approach to diminish the condensate banking from different sandstone rocks. Also, this work confirms that thermochemical treatment can be applied in the clayey formation for removing the condensate blockage without affecting the clay stability or inducing clay damage. Ultimately, this study introduces a new chemical treatment in the gas industry, and the used chemicals are effective, environmentally friendly, and not expensive.

1. INTRODUCTION

Natural gas is considered as one of the cleanest types of fossil fuels and one of the most eligible energy sources.1 Natural gas reservoirs represent important sources of energy around the world; they provide more than 30% of the consumed energy.2,3 However, several problems can encounter the supply of natural gas. In gas condensate reservoirs, condensate banking is one of the most critical problems that occur due to the reservoir depletion and reduce the gas recovery.4−6 During gas production, the reservoir pressure may decrease below the dew point pressure, and then a significant amount of the condensate liquid will develop and accumulate around the production well.4 The accumulated liquid will impede the flow of natural gas from the reservoir into the borehole, leading to a significant decrease in the well productivity.7−11 The severity of condensate damage depends on several factors, mainly the reservoir formation and the natural gas composition.6,12−15 Several treatments have been implemented to remove the condensate blocking and restore the gas production.16−20 These methods rely on creating conductive paths, altering the...
wettability condition, or increasing the pressure in the region around the wellbore to the level above the dew point pressure.\textsuperscript{21,22} Also, the condensate treatments are used to improve the flow condition and allow the easy production of the condensate liquid.\textsuperscript{23–25} The most common methods are gas recycling, hydraulic fracturing, and wettability alteration treatments.\textsuperscript{16,17} The applicability of these treatments depends on the reservoir characteristics and the reasons that lead to the development of the condensate blockage. For instance, wettability alteration treatments are applied to remove the condensate banking from strong liquid-wet formation.\textsuperscript{26} Several chemicals can be injected to alter the rock wettability from strong liquid-wet to the neutral wettability condition, which will improve the gas productivity for a long time.\textsuperscript{27} Hydraulic fracturing operations are implemented in the condition of extremely low permeability or significantly high capillary pressure.\textsuperscript{23,28} The induced fractures create conductive paths between the reservoir and the wellbore and then enhance the process of condensate removal.\textsuperscript{28} Gas recycling methods are used to pressurize the near-wellbore region to convert the condensate liquid into the gaseous state.\textsuperscript{29,30} However, gas recycling offers only a temporary improvement in the gas production, and the treatment needs to be repeated every 3–6 months.\textsuperscript{19,31}

Recently, thermochemical treatment was introduced as an effective method for removing the condensate banking and improving the formation productivity.\textsuperscript{16,19,32} Two reactive fluids are injected to react at the reservoir condition and produce a significant amount of heat and pressure. The in situ generated temperature and pressure can reach 500 °F and 5000 psi, respectively.\textsuperscript{33} The induced condition significantly changes the condensate behavior\textsuperscript{32} and creates multiple fractures.\textsuperscript{17} Consequently, it can mitigate the condensate damage and improve the formation deliverability for long-term applications.\textsuperscript{39,54} However, the generated heat and pressure can affect the well completion if they exceed the specification limit of the downhole equipment. Therefore, the chemical concentration and the treatment volume should be carefully determined to remove the condensate banking without damaging the well completion. Generally, increasing the chemical concentration or the injected volume can lead to an increase in the generated pressure and heat. Moreover, different injection modes can be applied to remove the condensate banking from the tight formation using thermochemical treatment. The chemical solutions can be injected using the continuous injection method or the huff and puff technique.\textsuperscript{17,53} In fact, the huff and puff method showed better performance than the continuous injection because the same condensate removal can be obtained using a less amount of the injected chemicals compared to the continuous injection method.\textsuperscript{17}

The performance of condensate removal techniques depends on several factors; one of these factors is the composition of treated formation. Indeed, the presence of certain minerals in the formation can affect the effectiveness of condensate removal methods. For example, if the treated formation contains clay minerals, it may restrict the applicability of several treatments due to the incompatibility between the injected fluids and clay minerals. Injection of non-native fluids into clayey formation can result in several types of formation damages such as clay swelling and fine migration and, consequently, can reduce the formation deliverability.\textsuperscript{35} Therefore, to avoid formation damage, the suitable treatment for removing the condensate banking should be selected based on the mineralogical composition of treated formation.

This paper presents the performance of thermochemical fluids in mitigating the condensate damage from several types of sandstone formations. Different sandstone rocks (Scioto, Kentucky, and Bandera) were used; coreflooding experiments were conducted using the huff and puff injection mode. Four cycles of injection and production periods were applied to remove the condensate liquid from the treated samples. The in situ generated pressures due to the thermochemical reaction were monitored, and the removed condensate per cycle was determined. The impact of rock mineralogy on the condensate removal was studied, and the relationship between the core permeability and the performance of thermochemical fluids was discussed.

2. RESULTS AND DISCUSSION

2.1. Condensate Removal in Scioto Sandstone.
Thermochemical fluids were injected into a Scioto rock sample to remove the condensate liquid and improve the rock conductivity. The used core sample has an average permeability of 0.89 mD, a porosity of 17.6%, and the total clay content (illite, kaolinite, and chlorite) of 23%. The thermochemical solutions were injected in four cycles using the huff and puff technique. Figure 1 shows the profiles of the removed condensate and the pore pressures at the core inlet and outlet. Injection of thermochemical fluids into the Scioto rock sample showed an effective performance in removing the condensate damage; 65% of the original condensate liquid was removed. The highest condensate removal was achieved during the first cycle; 56.4% of the liquid bank was removed. The second cycle provides moderate removal of the condensate bank with incremental condensate removal of 4.3%. While the third and fourth cycles of the huff and puff treatment showed lower condensate removal, 2.2 and 2.1% of the original condensate were removed during the third and fourth cycles, respectively. The profile of condensate removal indicates that two cycles of huff and puff treatment are sufficient to remove more than 60% of the condensate damage. Therefore, three cycles can be considered as the optimum number of huff and puff treatment to mitigate the condensate banking.

In addition, the profiles of inlet and outlet pressures, during the condensate removal treatment, indicate that the maximum

![Figure 1. Profiles of condensate removal and pore pressures during huff and puff treatment using a Scioto rock sample. More than 60% of the trapped condensate was removed using thermochemical fluids.](image-url)
A pressure of 1940 psi can be in situ generated due to the thermochemical reaction, as shown in Figure 1. In the first cycle, the inlet and outlet pressures increased to 890 psi, while in the second cycle, the pressures reached 1940 psi, which indicates that reducing the saturation of the condensate liquid can generate a higher pore pressure during the thermochemical treatment. Removing the condensate liquid from the pore medium provides more space for the injected chemicals to react and generate a higher pore pressure. The third cycle of huff and puff confirms that a higher pore pressure can be in situ generated, due to the thermochemical reaction, at lower condensate saturations. However, the fourth cycle shows lower pressure values; the maximum pressure during this cycle is 1680 psi, which is lower than the pressure generated during the third cycle by 230 psi. The decrease in the in situ generated pressure could be due to the presence of spent fluids inside the pore space, which have already reacted during the previous cycles of injection.

During thermochemical injection, a significant amount of heat is generated due to the reaction between the injected fluids. The generated heat can raise the condensate temperature up to 120 °C and therefore the condensate viscosity will reduce considerably. Increasing the temperature from around 80 to 120 °C will reduce the condensate viscosity by 39%; the condensate viscosities are 0.94 and 0.57 cP before and after thermochemical injection, respectively. Consequently, the condensate mobility will improve by a factor of 1.65. Furthermore, the in situ generated pressure due to the thermochemical reaction can efficiently contribute to mobilizing the trapped condensate liquid by increasing the pore pressure. In general, injection treatments can be used to pressurize the hydrocarbon reservoirs and hence increase the pressure. Increasing the drawdown pressure can improve the hydrocarbon flowing from the reservoir into the borehole. A similar mechanism can be achieved by injecting the thermochemical solutions into gas condensate reservoirs. The induced pressure during thermochemical treatment can increase the pressure around the wellbore and help in removing the condensate liquid. Also, the generated pressure can significantly affect the reservoir formations. For example, multiple fractures can be induced during the thermochemical treatment. In this work, NMR measurements were carried out before and after the chemical injections to evaluate the changes in rock samples. The effects of heat and pressure pulse generated during the thermochemical treatment on the clay minerals in the sandstone rocks are studied using the profiles of T2 relaxation time. Figure 2 shows the T2 relaxation time for a Scioto rock sample before and after the condensed treatment using thermochemical fluids. Multiple fractures were induced in the rock sample due to the in situ generated pressure during thermochemical treatment. The induced fractures are indicated by the second peak in the incremental porosity profile. As a result of the fracture generation, the cumulative porosity was increased from 17.6 to 18.4%. The generated fractures will significantly improve the pore connectivity and reduce the capillary pressure. The core permeability was increased by more than 50% due to the injection of thermochemical fluids. Ultimately, the generated heat and pressure during the thermochemical reaction can considerably change the condensate and rock properties and lead to efficient condensate removal.

2.2. Condensate Removal in Kentucky Sandstone.

Figure 3 shows the performance of thermochemical fluids in mitigating the condensate blockage for a Kentucky rock sample. For this sandstone sample, the core permeability is 0.64 mD, the cumulative porosity is 15.39%, and the clay content is 14%. The total condensate removal of 62.5% was achieved using four cycles of thermochemical injection. The cumulative condensate recovery is distributed as 42.2% during the first cycle, 11.2% during the second cycle, 6.94% during the third cycle, and 2.14% during the fourth cycle. The volume of removed condensate decreases as the cycle number increases, mainly due to the reduction in the remaining condensate volume with the cycle number. The profile of condensate removal indicates that three cycles of huff and puff treatment are required to mitigate the condensate banking, with a removal efficiency of more than 60% of the original condensate in place.

Also, Figure 3 shows the pressure profiles at the core inlet and outlet during the thermochemical treatment. For all cycles, the soaking and production durations were determined based on the pressure profiles. Sufficient time (20–60 min) was provided to allow the pore pressure to stabilize along the rock samples and to make sure that the thermochemical reaction is completed. The maximum pressure of 1350 psi was in situ generated during the fourth cycle of chemical injection, while the minimum generated pressure was 759 psi, which was
observed during the first cycle. Overall, the in situ generated pressure increases as the cycle number increases; this confirms the previous observation that a higher pressure can be in situ generated at low condensate saturation. Figure 4 shows the T2 profiles for a Kentucky rock sample before and after condensate removal using thermochemical fluids.

Figure 4. Incremental and cumulative porosity profiles for a Kentucky rock sample, before and after condensate removal using thermochemical fluids.

2.3. Condensate Removal in Bandera Sandstone. Thermochemical treatment was used to mitigate the condensate damage from a Bandera rock sample. The used sandstone sample has an absolute permeability of 13.12 mD, a porosity of 20.83%, and the total clay content of 12%. Figure 5 shows the performance of thermochemical solutions in removing the condensate liquid from Bandera sandstone. A cumulative condensate removal of 72.97% was achieved using four cycles of the huff and puff injection method. The highest incremental removal was obtained during the first cycle; the incremental condensate removal was 43.12%. On the other hand, the incremental condensate recoveries were 18.24, 8.29, and 3.32% during the second, third, and fourth cycles of huff and puff treatment, respectively.

Figure 5. Results of treatment of Bandera sandstone with thermochemical solutions. 72.9% of the condensate liquid was removed using four cycles of chemical injection.

Figure 5 also shows the in situ generated pressure due to the thermochemical reaction during all huff and puff cycles. In general, the pore pressure increases with injection cycles; the highest pressure was in situ generated during the fourth cycle of thermochemical injection. The in situ generated pressures were 948, 1556, 1843, and 2095 psi during the first, second, third, and fourth cycles of huff and puff treatment, respectively. The pressure profiles indicate that a significant pressure (up to 2000 psi) can be in situ generated during the thermochemical treatment. Also, during all production cycles, the outlet pressures are almost equal, and no pressure buildup was observed, indicating that no formation damage was induced during the thermochemical treatment. The changes in the Bandera rock sample due to thermochemical injection were investigated using NMR measurements. Figure 6 shows the T2 relaxation time for the Bandera sandstone sample before and after the thermal injection. The incremental porosity curve changed slightly, and the cumulative porosity increased from 20.83 to 21.90% after the treatment.

Figure 6. T2 relaxation time for the Bandera sandstone sample before and after the thermochemical treatment. The incremental porosity curve changed slightly, and the cumulative porosity increased from 20.83 to 21.90% after the treatment.

2.4. Comparison Study. Figure 7 shows the effectiveness of thermochemical fluids in mitigating the condensate damage for different sandstones. The cumulative condensate removal values are 65.03, 62.50, and 72.97% for Scioto, Kentucky, and Bandera rock samples, respectively. A good correlation and puff treatment, respectively. As expected, lower condensate removal was achieved during the fourth production cycle, which is attributed to the reduction in the remaining condensate volume inside the treated core sample. Although the fourth cycle provided 3.3% condensate removal, three cycles of huff and puff would be enough to mitigate the condensate. The main mechanism for removing the condensate bank from Bandera sandstone is the viscosity reduction. The in situ generated heat can reduce the condensate viscosity by a factor of 1.39; the fluid viscosities are 0.94 and 0.57 cP before and after thermochemical injection, respectively.
between the core permeability and the condensate removal efficiency was observed. Higher condensate removal was obtained for the rock sample with a higher permeability value. Injecting thermochemical fluids into the Bandera sample (a permeability of 13.12 mD) resulted in the highest condensate removal (72.97%). While treating Kentucky sandstone with thermochemical solutions showed the lowest condensate recovery, the core permeability for Kentucky rock was 0.64 mD and the condensate removal was 62.5%. The presence of clay minerals in the treated rock showed a minor impact on the condensate removal. More than 60% of the condensate liquid was removed from Scioto rock that has a clay content of more than 20%, indicating that the injected chemicals can stabilize the clay minerals and avoid clay damage. In fact, the thermochemical reaction produces a considerable amount of NaCl salt along with nitrogen gas (N₂) and steam (H₂O), as shown in eq 1. The presence of NaCl salt in the reaction products contributes to the stabilization of the clay minerals and protection against the clay damage.

Figure 8 shows the pressure profiles during thermochemical injection into Scioto, Kentucky, and Bandera rock samples.

The highest in situ generated pressure (2095 psi) was observed during the injection of thermochemical fluids into Bandera sandstone, while the lowest pressure of 774 psi was obtained by treating Kentucky samples with the thermochemical fluids. The pressure profiles reveal that a higher pressure can be generated by injecting thermochemical fluids into permeable sandstone (such as Bandera), and less pressure generation is associated with the tight formations (like Kentucky). The core permeabilities are 13.12 and 0.64 mD for Bandera and Kentucky rocks, respectively. Moreover, the pressure profiles confirm that no clay swelling or solid migration was induced during the thermochemical treatment because no pressure buildup was observed in the outlet core during all production cycles.

Figure 9 shows the incremental condensate removal against the cycle number. The incremental profiles indicate that three cycles of huff and puff treatment can be sufficient to mitigate the condensate banking. For all sandstone samples, more than 60% of the condensate liquid was removed using three injection cycles. However, in practical field applications, a greater number of huff and puff injection cycles might be required to mitigate the condensate banking in tight reservoirs. Tight formations are characterized by high capillary pressures that hold the formation fluids and restrain the flow of the condensate liquid toward the wellbore. The formation tightness can restrict the condensate removal; hence, more cycles of thermochemical injection would be required to alleviate the condensate damage and improve the hydrocarbon flow.

In addition, the impact of clay content on the performance of thermochemical solutions in removing the condensate damage from sandstone rocks is studied. Figure 10 shows a cross plot between the total clay content and condensate removal using thermochemical fluids. The clay content showed a minor impact on the performance of thermochemical treatment; a correlation coefficient of less than 0.2 was observed. For all rock samples, condensate removal of more than 60% was obtained regardless of the clay content, indicating the good performance of thermochemical solutions.
in stabilizing the clay mineral and avoiding the clay damage. Moreover, the relation between condensate removal and core permeability was investigated. Figure 11 shows the condensate removal against core permeability on the semilog scale. A good correlation was observed between the condensate removal and the log of core permeability; the correlation coefficient was 0.98. Increasing the core permeability showed higher condensate removal, which can be attributed to three reasons. First, the injected thermochemical fluids can penetrate for longer distances in the permeable rocks and then more condensate will be affected by the injected chemicals. Second, the higher permeability indicates a good pore connectivity; hence, the condensate liquid can easily flow with low pressure difference. Finally, high formation permeability reveals a lower capillary pressure, which means better flow condition for the liquid condensate. Ultimately, injecting thermochemical fluids into permeable formations can result in higher condensate removal compared to tight formations. Thermochemical treatment showed condensate removal of 72.9 and 62.5% from permeable and tight sandstones, respectively.

Ultimately, this study introduces a new chemical treatment for removing the condensate banking from different sandstone formations using thermochemical fluids. The used chemicals are effective, environmentally friendly, and not expensive. The proposed chemical treatment can be applied in the gas field to remove the trapped condensate and improve the gas production without inducing any formation damage, such as clay swelling or permeability impairment. Also, the in situ generation of temperature and pressure can reduce the energy losses and improve the treatment performance. The chemical concentration and the treatment volume can be selected to remove the condensate blockage without inducing sand production issues.

3. CONCLUSIONS

This paper presents the performance of thermochemical fluids in mitigating the condensate banking from three sandstone rocks. Core samples from Scioto, Kentucky, and Bandera formations were used, and coreflooding experiments were conducted using the huff and puff technique. The profiles of condensate recovery and pore pressure were utilized to assess the effectiveness of thermochemical fluids in alleviating the condensate damage. Based on this work, the following conclusions can be drawn:

- Thermochemical fluids are effective chemicals for removing the condensate bank from different sandstone formations; a condensate removal of 67% can be achieved on average.
- Injecting thermochemical fluids into clayey sandstone does not induce any formation damage, and no clay swelling or solid migration was observed for all treated samples.
- The produced salt from the thermochemical reaction can stabilize the clay minerals and avoid permeability impairment.
- A good correlation was observed between the condensate removal using thermochemical fluids and the log of core permeability, and the correlation coefficient was 0.98.
- Thermochemical treatment showed higher condensate removal for the permeable rocks, while moderate liquid removal was obtained for the tight sandstones.
- During thermochemical treatment, higher pressure can be in situ generated during the third and fourth injection cycles, due to the reduction of condensate saturation.
- Multiple fractures were induced due to the generated pressure during thermochemical injection, and the cumulative core porosity was increased for all rock samples.
- For different sandstone formations, three cycles of thermochemical treatment can be enough to mitigate the condensate damage, with a removal efficiency of more than 60%.

4. EXPERIMENTAL SECTION

4.1. Materials. In this study, three types of sandstone rocks (Scioto, Kentucky, and Bandera) were used, and the mineralogical compositions of these rocks are listed in Table 1. All samples showed high percentages of quartz; 70, 66, and 61% were observed for the Scioto, Kentucky, and Bandera rock samples, respectively. Scioto sandstone has the total clay content (illite, kaolinite, and chlorite) of 23%, while the clay contents of Kentucky and Bandera core samples are 14 and 12%, respectively. Bandera samples showed a considerable amount of iron, as indicated by the percentages of chlorite and ankerite, which are iron-rich minerals. The used rock samples have an average porosity of 17.94%, while the permeability values are 0.89, 0.64, and 13.12 mD for Scioto, Kentucky, and Bandera rock samples, respectively. Table 2 summarizes the petrophysical properties of all core samples used in this work.

**Table 1. Mineralogical Compositions of Scioto, Kentucky, and Bandera Rock Samples**

| minerals          | chemical Formula | rock composition (wt %) |
|-------------------|------------------|-------------------------|
| quartz SiO₂       |                  | Scioto 70 Kentucky 66 Bandera 61 |
| illite K₆[Al₂Si₃O₁₀(OH)₄] |                  | Scioto 18 Kentucky 14 Bandera 7.1 |
| potassium feldspar | KAlSi₃O₈        | Scioto 2 Kentucky 4 Bandera 100 |
| plagioclase NaAlSi₃O₆/CaAl₂Si₂O₈ |                  | Scioto 5 Kentucky 16 Bandera 23.3 |
| kaolinite Al₂Si₂O₅(OH)₄ |                  | Scioto 1 Kentucky 1.1 Bandera 2.4 |
| chloride Fe₃⁺Mg₂⁺Al₆[(Si₃Al)O₁₈(OH)₄] |                  | Scioto 4 Kentucky 2.5 Bandera 3.7 |
| ankerite Cu₃(Fe²⁺,Mg,Mn)₃(CO₃)₂₀ostenite |                  | Scioto 100 Kentucky 100 Bandera 100 |

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In addition, an actual condensate liquid was used in this work, and the viscosity and the American Petroleum Institute (API) gravity of this condensate were 1.8 cP and 48 API, respectively. Figure 12 shows the condensate viscosity and density at different temperatures. A logarithmic relationship was observed between the condensate viscosity and temperature ($R^2$ is 0.99), while a linear mathematical model can represent the relation between the condensate density and temperature. Moreover, thermochemical fluids that consist of sodium nitrite ($\text{NaNO}_2$) and ammonium chloride ($\text{NH}_4\text{Cl}$) were used. The used chemicals were stable and compatible with the high level of temperature and formation salinity. Acetic acid was injected with thermochemical fluids to change the system pH and activate the chemical reaction. Kinetic analysis was conducted to understand the performance of thermochemical fluids in different conditions. The impact of the system pressure and temperature and the presence of hydrocarbons on the generated pressure and heat from the thermochemical reaction was studied. A microreactor was used to carry out the kinetic study, and the profiles of pressure and temperature were monitored using a data acquisition system. Kinetic analysis of the used chemicals indicates that thermochemical fluids can increase the temperature and heat by 85 °C and 369 kJ/mol, respectively, on average. Also, the thermochemical reaction shows first-order behavior with an activation energy of 35 kJ/mol, while the reaction rate constant ($K_r$) varies between 0.0013 and 0.015 s$^{-1}$ based on the system temperature. The chemical reaction between sodium nitrite and ammonium chloride can be represented by eq 1:

$$\text{NH}_4\text{Cl} + \text{NaNO}_2 \rightarrow \text{NaCl} + 2\text{H}_2\text{O} + \text{N}_2 + \Delta H \text{ (heat)}$$

(1)

4.2. Experiments. A coreflooding system was used to perform the condensate removal treatment; thermochemical solutions were injected into the sandstone rocks to remove the condensate bank. The experimental setup consists of a core holder, an oven, injection pumps, back pressure regulators, and a data logging system. The coreflooding system was designed to withstand a pressure of up to 10 000 psi and a temperature of up to 400 °C, and the logging system could record the data every 5 s. The preparation of rock samples was conducted by saturating the core samples with the condensate liquid at high-pressure conditions. In this work, the worst-case scenario of complete condensate plugging was studied. All core samples were prepared for the chemical treatment by saturating the condensate liquid at high pressure for a sufficient time; thereafter, the thermochemical treatment was conducted. The treatment was performed by injecting the reactive fluids into the core samples to remove the condensate. The huff and puff technique was applied by injecting the thermochemical fluids into the core sample in four cycles. In each cycle, around 2 mL of the reactive fluids was injected, and the chemical concentrations and the injected volumes were kept constant for all flooding experiments. The chemicals were injected to react at the core inlet; then, the core sample was soaked for a suitable time (20–40 min) to allow the injected chemicals to interact with the trapped condensate and the rock matrix. Thereafter, the condensate liquid was produced. The pressure profiles and the removed condensate volume were

| sample ID | sample type | diameter (cm) | length (cm) | bulk volume (mL) | pore volume (mL) | porosity (%) | absolute permeability (mD) |
|-----------|-------------|---------------|-------------|-----------------|-----------------|--------------|---------------------------|
| S1        | Scioto      | 3.81          | 4.94        | 56.33           | 9.92            | 17.60        | 0.89                       |
| S2        | Kentucky    | 3.81          | 5.33        | 60.81           | 9.36            | 15.39        | 0.64                       |
| S3        | Bandera     | 3.81          | 5.33        | 60.81           | 12.67           | 20.83        | 13.12                      |
recorded with time. The duration of each injection cycle was determined based on the stability of pressure along the treated core sample, and the production period was determined based on the produced volume of the condensate liquid.

In addition, NMR (nuclear magnetic resonance) was used to characterize the rock samples before the condensate treatment. The rocks samples were prepared for the NMR measurements by cleaning the samples using the Soxhlet extraction apparatus; then, the samples were saturated with 3 wt % KCl brine at 3000 psi for 48 h. To minimize the NMR uncertainty, we applied the same experimental conditions for the NMR measurements before and after the chemical treatment. NMR measurements were performed on 3 wt % KCl brine-solution-saturated cores to measure the T2 relaxation time. The core samples were wrapped with a NMR-silent material using a tested operation to prevent any saturation loss during the test. All NMR measurements were carried out at ambient pressure and temperature. Figures 13 and 14 show the incremental and cumulative porosity profiles for all core samples used in this work. The T2 peaks are 22.38, 29.2, and 79.43 ms for the Scioto, Kentucky, and Bandera rock samples, respectively, which indicates that the Bandera sandstone sample has the largest pore throat among all core samples (Figure 13). The cumulative porosity profiles (Figure 14) show that the Kentucky (S2) sample has the lowest porosity value (15.4 porosity unit, p.u.), while Scioto and Bandera samples have cumulative porosities of 17.6 and 20.8 p.u., respectively.

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