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Effects of Completion Fluid Components on Reservoir Rock Matrix and Its Performance for Workover Applications

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Abstract
Formation damage from incompatible completion fluids remains a major challenge during workover operations, causing permeability impairment and reduced well productivity. This study investigates the effects of Sodium Chloride (NaCl), Potassium Chloride (KCl), and Calcium Chloride ($CaCl_2$) on sandstone reservoir matrices. Compatibility was evaluated using a laboratory sand-pack flooding apparatus. Brines were formulated at 5, 10 and 15 wt% and injected through fine (600 µm) and coarse (1.18 mm) sand packs at 80 °C; permeability was measured before and after exposure using Darcy's law. KCl produced the lowest average permeability reductions (3.2–12.9 %), NaCl the highest (13.5–33.3 %), and $CaCl_2$ intermediate values (13.2–34.1 %). KCl showed superior clay stabilization and minimal fines migration, while NaCl caused greater losses through weaker ion exchange and fines mobilization. $CaCl_2$ exhibited moderate performance with flocculation benefits but higher interaction in fine packs. KCl is recommended as the most effective brine for mitigating formation damage in clay-sensitive sandstones during workover operations.

Keywords: *Completion fluids · Reservoir matrix · Workover operations · Brine compatibility · Permeability reduction · Sandstone.*

1. Introduction

In oil and gas production, well efficiency declines over time due to geological, operational, and mechanical factors. Workover operations are essential to maintain or enhance well performance. Completion fluids stabilize the reservoir and regulate pressure, but incompatible interaction with sandstone or clay-rich matrices can cause clay swelling or permeability loss [1]. This study examines how NaCl, KCl, and $CaCl_2$ brines affect reservoir matrices to guide fluid selection for minimal formation damage.

Fluid–rock compatibility is critical to sustain productivity and extend reservoir life. Incompatible fluids in clay-rich sandstone can lead to swelling or scaling and costly remediation [2]. Brine-based fluids offer flexibility in salinity and ionic composition, yet tailoring them to specific reservoir conditions remains challenging [3].

Each brine interacts with the matrix through distinct mechanisms. NaCl expands the electrical double layer below the critical salt concentration (CSC), promoting clay swelling and fines migration [4], [5]. KCl stabilizes clays because K^+ has low hydration energy and fits into clay-lattice cavities, collapsing the double layer [6], [7]. $CaCl_2$ promotes divalent bridging and flocculation, but at high concentration may cause precipitation and damage in clay-rich systems [8], [9].

Compatible examples include KCl brines (2–7 wt%) in smectite- or illite-rich sandstones and formate brines in HTHP carbonates. Incompatible examples include fresh or low-salinity NaCl with montmorillonite (reductions often >50 %) and high-density $CaCl_2$ with sulfate-rich waters (gypsum/anhydrite scaling) [10], [11].

Most prior studies examined single-salt systems or limited conditions [4]–[9]. Side-by-side comparisons of NaCl, KCl and $CaCl_2$ under identical sand-pack, concentration and temperature conditions relevant to workovers are scarce. This study fills that gap by ranking the three brines across two grain sizes and three concentrations at 80 °C [15-20].

2.0 Experimental Procedures

2.1 Formulation of Brines

Brines of NaCl, KCl and $CaCl_2$ were formulated at 5, 10 and 15 wt%. For 5 wt%, 50.0 g salt was dissolved in 950.0 g distilled water; for 10 wt%, 100.0 g salt in 900.0 g water; for 15 wt%, 150.0 g salt in 850.0 g water. Solutions were stirred until fully dissolved (15–20 min), filtered through a 0.45 µm membrane, and checked for density and viscosity before injection.

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2.2 Sand-Pack Preparation

Fine (600 µm) and coarse (1.18 mm) sand packs were prepared in a cylindrical core holder (length 30 cm, diameter 3.8 cm; average porosity ≈ 35 %). Initial permeability was measured with distilled water at 0.01–0.05 atm using Darcy's law:

$$k = (Q\,\mu\,L) / (A\,\Delta P) \tag{1}$$

where k is permeability (mD), Q is flow rate (cm^3/min), µ is viscosity (cP), L is length (cm), A is cross-sectional area (cm^2), and ΔP is pressure drop (atm).

2.3 Simulated Reservoir Conditions and Apparatus

Tests were run at 80 °C (temperature-controlled oven) and atmospheric pressure (≈ 1 atm); confining pressure was not applied because the focus was chemical compatibility. Packs were first saturated with distilled water, then displaced by the test brine. The matrix was washed quartz sand (>98 % silica). The apparatus comprised a brine reservoir, constant-flow-rate pump, temperature-controlled core holder, upstream and downstream pressure transducers, optional back-pressure regulator, and effluent collection system.

3.0 Results and Discussion

Average permeability reductions are summarized in Table I. KCl showed the lowest reductions (3.2–12.9 %), indicating superior clay stabilization. NaCl produced higher reductions (13.5–33.3 %), linked to weaker ion exchange and fines mobilization, especially in fine packs. $CaCl_2$ gave intermediate values (13.2–34.1 %), performing better in coarse packs due to flocculation.

Table 2: Summary of average permeability reductions with error margins

Salt	Grain Size	5 % Avg Reduction (%)	10 % Avg Reduction (%)	15 % Avg Reduction (%)
NaCl	Fine	20.8 ± 1.2	25.9 ± 1.3	33.3 ± 1.5
NaCl	Coarse	13.5 ± 0.9	18.7 ± 1.0	24.7 ± 1.3
KCl	Fine	4.4 ± 0.5	8.9 ± 0.6	12.9 ± 0.7
KCl	Coarse	3.2 ± 0.4	6.4 ± 0.5	9.5 ± 0.6
$CaCl_2$	Fine	19.7 ± 1.1	29.6 ± 1.4	34.1 ± 1.6
$CaCl_2$	Coarse	13.2 ± 0.8	21.3 ± 1.2	25.9 ± 1.2

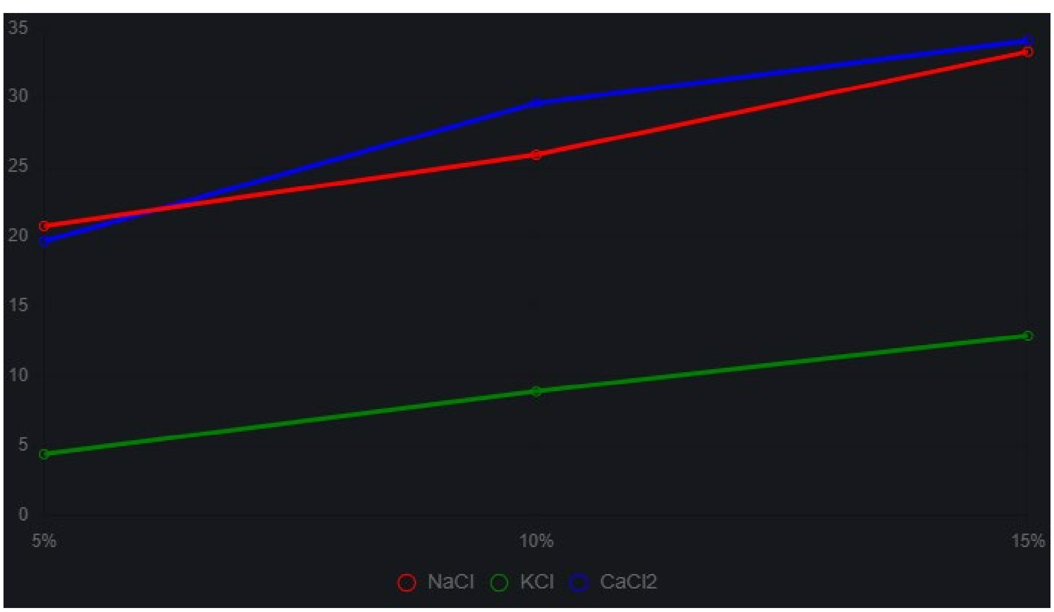

Figure 1: Permeability reduction trends in fine sand packs

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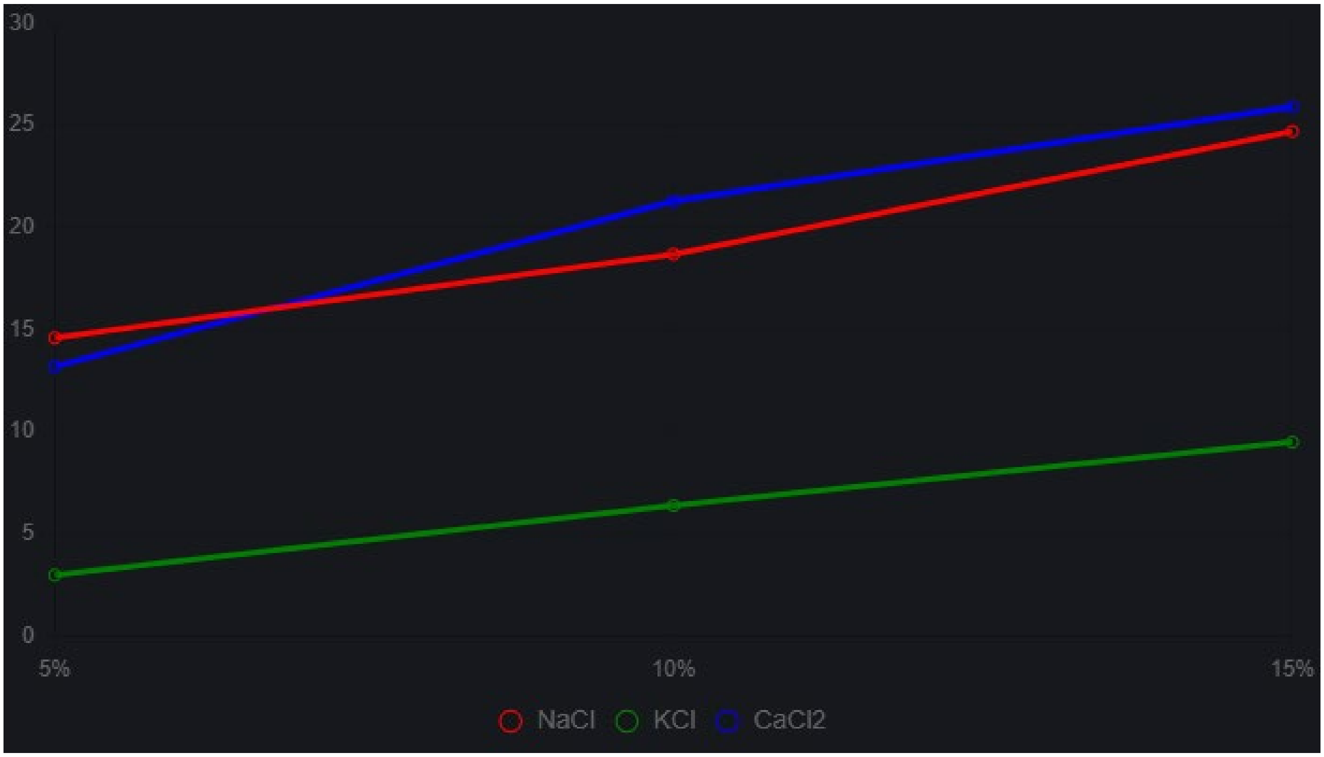

Figure 2: Permeability reduction trends in coarse sand packs

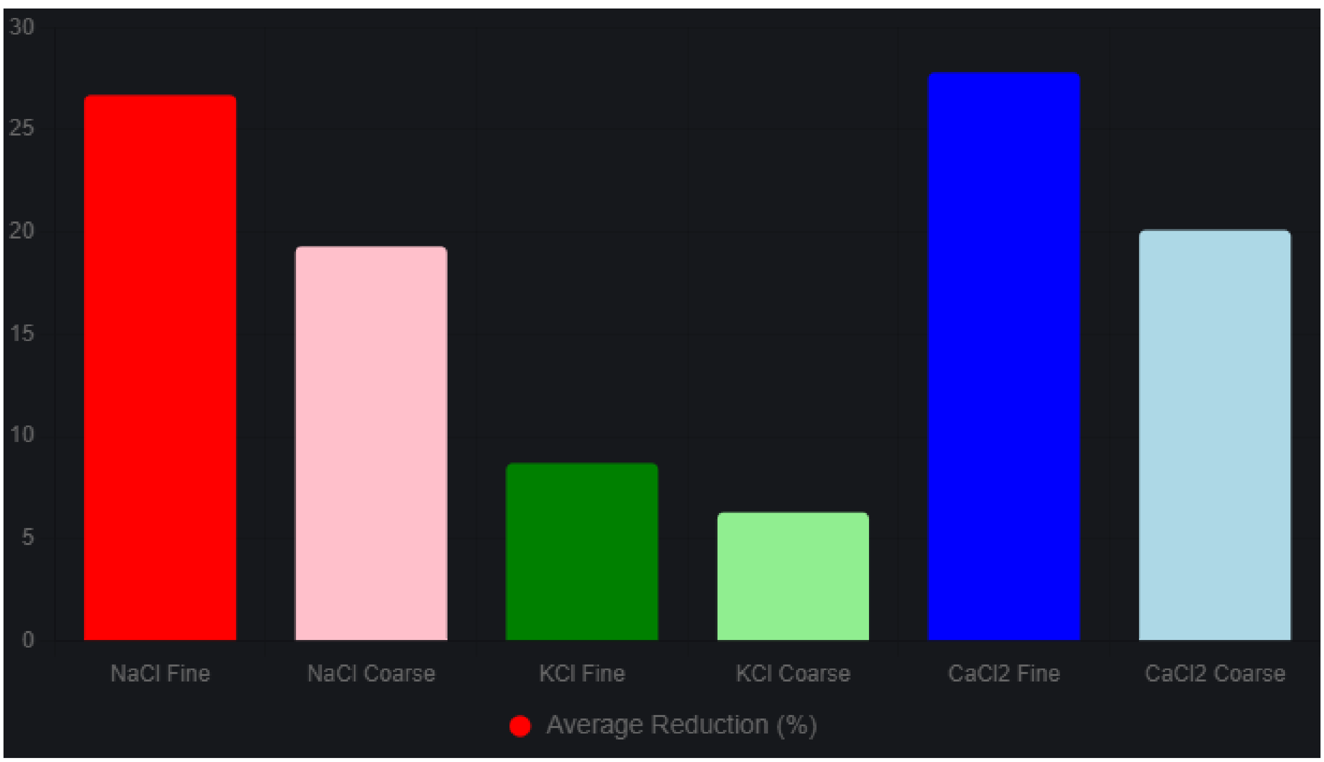

Figure 3: Average permeability reduction comparison

Results align with literature: KCl's K^+ ions reduce double-layer thickness [6], [7]; NaCl's Na^+ ions are less effective [5]; $CaCl_2$ provides bridging but can worsen swelling in high-clay systems [8]. Higher concentration and finer grains increased damage. Lever and Dawe [5] reported 15–40 % reduction for NaCl in Hopeman sandstone (consistent with 13.5–33.3 % here). Mehdizad et al. [7] found KCl above 3 wt% limited loss to <15 %, matching the maximum 12.9

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% obtained for 15 wt% KCl in fine packs. $CaCl_2$ studies [8], [9] report intermediate damage from competing flocculation and precipitation. The ranking KCl ≪ $CaCl_2$ ≈ NaCl under identical conditions is therefore robust.

Temperature (80 °C) enhanced ion mobility, consistent with endothermic swelling [12-15]. Coarse packs retained more permeability. Overall, KCl best preserves permeability by reducing clay hydration and stabilizing fines; NaCl causes greater decline through weaker stabilization; $CaCl_2$ is intermediate [21-25]. Fluid design should therefore consider mineralogy, grain size, formation-water chemistry and temperature [26-27].

4.0 Conclusion

Under the test conditions (80 °C, atmospheric pressure, fine and coarse quartz packs), KCl produced the lowest permeability reductions (3.2–12.9 %), NaCl the highest (13.5–33.3 %), and $CaCl_2$ intermediate values (13.2–34.1 %). KCl is recommended for clay-rich sandstones in workover operations. NaCl may suit less sensitive formations; $CaCl_2$ balances density and stabilization but requires caution in fine-grained reservoirs. These quantitative results guide fluid selection to minimize formation damage and sustain productivity.

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