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The Effect of the Salinity of Injected Water and Reservoir Water on WAG Injection: A Study in an Iranian Reservoir

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The effect of salinity of injected water and reservoir water in water alternating gas injection in one of an Iranian reservoir was investigated. Usually in simulation works water salinity of reservoir or salinity of injected water may be ignored. Without applying salinity effect, it would cause estimated overall oil recovery to be different with real. Salinity of water phase would increase the viscosity of injected water also obviously the mobility ratio of oil. Because of this improvement in water mobility, more oil would be displaced toward production wells. The problem of increasing salinity of injected water is that too much salt may harm pump equipments. Over time, salt deposits in pumping devices may cause reduction in pumps efficiency and corrosion of pipes, thus injecting salty water would cause corrosion problems and pump failures. Since the salinity of the reservoir water in the study was not available so it was chosen in two modes: reservoir water without salt (Cs = 0) and with concentration of 140 kg/m^3 (Cs = 140). In this work 0.8 reservoir pore volume WAG was injected. Salinity of injected water was varied from zero to 4,800 kg/m^3; by increasing salinity of injected water, because of mobility ratio increment between water and oil, production efficiency would be increased. The economic dimension of this view must be examined. By considering reservoir water salinity, recovery would be increased in WAG injection.

Keywords: mobility control, recovery, relative permeability, reservoir simulation, salinity, water alternating gas injection (WAG)

INTRODUCTION

Water alternating gas (WAG) injection is a combining of two traditional technologies: waterflooding and gas injection. The method has applied larger and larger and its control and efficiency improvement is an acute problem (Bermudez et al., 2007).

Miscible gas-water injection was originally proposed by Caudle and Dyes in 1958. Their work showed that miscible simultaneous gas-water injection offered higher sweep efficiency than conventional water or gas injection. By using simultaneous gas-water injection process, 53% of

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oil in place was recovered at breakthrough and 98% was obtained when two reservoir volumes of fluid had been injected. On the other hand, by using gas injection, only 42% of oil in place was recovered at breakthrough and 62% when two reservoir volumes of fluid had been injected (Jiang et al., 2010). Although Caudle and Dyes (1958) suggested simultaneous water and gas injection for conformance control, however, later reviews suggested that water and gas were to be injected alternately (Rogers and Grigg, 2000). WAG has been applied with success in most examined fields in USA and Canada (Christensen and Stenby, 1998) by using many different types of gas, in either miscible or immiscible condition. The influence of CO_2 solubility in brine on CO_2 flooding was investigated by Yan and Stenby (2009). Jiang et al. (2010) concluded that the recovery factor of oil and the crude oil were found to increase slightly with the salinity of the injection brine due to the decrease in the CO_2 solubility in brines. The $CaCl_2$ in the injection brine was found to have similar effect as NaCl. Comparisons of WAG and continuous gas injection were also made on both model oil and crude oil (Jiang et al., 2010).

Salinity is defined in this simulator by molality: Cs = 1,000 ns/ms, where ns are the number of moles of salt and ms is the mass of the water. This may be related to the usual definition in terms of parts per million by mass. Sharma and Filco (2000) did experiments on the effect of brine salinity and crude-oil properties on oil recovery and residual saturations. They showed that the salinity of the displacing brine had no significant influence on the oil recovery. They concluded that the relative permeability curves obtained during drainage were also found to be insensitive to the salinity of the brine. However, the imbibitions relative permeability curves show strong salinity dependence.

BRINE CONSERVATION EQUATION

The distribution of brine is modeled by solving a mass conservation equation for the salt concentration in each grid block. Brine is assumed to exist solely in the water phase and is modeled internally as a water phase tracer using the equation

$$\frac{d}{dt}\left(\frac{VS_wC_s}{B_w}\right) = \sum\left[\frac{Tk_{rw}}{B_wS\mu_{s\,\mathrm{eff}}}\ (\delta P_w - \rho_w g D_z)\right]C_s + Q_wC_s \tag{1}$$

where ρ_w is water density, C_s is concentration of aqueous phase, $\mu_{s\,\mathrm{eff}}$ is effective viscosity of the salt, D_z is cell center depth, T is transmissibility, and V is block pore volume.

The salt concentrations are updated at the end of a time step after the inter block phase flows have been determined. If the salinity effect of flow properties is very long, salt concentrations updated simultaneously with the phase equations.

By considering salinity in reservoir simulation it will correct and modify the default equation of states by brine concentration.

The multicomponent brine option can be used to make the surfactant adsorption dependent on the salinity. Based on ion transport and exchanges an effective salinity is computed, and then used in surfactant adsorption isotherm. The effective salinity is an empirical quantity incorporating the association between the surfactant and divalent cations and calculated according to

$$C_{SE} = \frac{C_{-}}{1-\alpha^S X^S} \tag{2}$$

where C_{SE} is surfactant effective salinity, X^S is fraction of surfactant sites occupied by divalent cations, and α^{S} is user input effective salinity parameter, which is between zero and one.

TABLE 1
Rock and Reservoir Fluid Characteristics

Type of Reservoir	*Undersaturated*
Total thickness, m	10
Datum depth, m	2,925
Average reservoir pressure @ datum depth, bar	323.03
Reservoir temperature, K	372
API	36
Oil FVF, RM3/SM3	1.39
Gas FVF, RM3/SM3	0.0034
Oil saturation, %	74
Gas saturation, %	0
Total pore volume, MMRM^3	66.473

Field Description

The under study oil reservoir was an asymmetrical anticline with 7 km length and 5.5 km width that is located in one of Iranian oil field. The oil was light with 36° API gravity, gas oil ratio was 106.2590 SM^3/SM^3 and oil formation volume factor was 1.39 M^3/SM^3. Rock and reservoir fluid characteristics of the field of study have been illustrated in Table 1.

Model Description

In this study, different injection scenarios were simulated through commercial simulator (an ECLIPSE Module), a griding network of reservoir was designed using geological data (Figure 1).

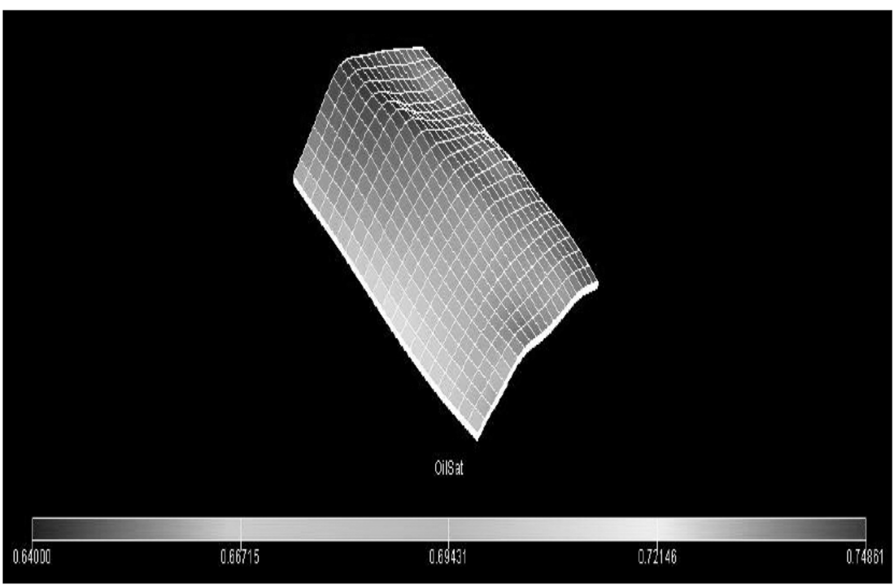

FIGURE 1 Three-dimensional view of reservoir model (initial condition).

TABLE 2
Model Characteristics

Number of cells in X-direction (Nx)	20
Number of cells in Y-direction (Ny)	20
Number of cells in Z-direction (Nz)	15
Number of cells	6,000
Y grid block size, m	1,130
Z grid block size, m	0.67
Permeability in x, y, and z directions, md	558
Porosity in x, y, and z directions, md	20.6

In this network, reservoir has been divided longitudinally and latitudinally into 20 and 20 grid blocks .15 grid blocks were defined for the reservoir in vertical direction (Table 2). Corner point method was used to grade the reservoir, which has more precision than block center method. Geological indications and the information related to drilling well showed no fracture in reservoir rock, therefore single porosity model was used for simulation of reservoir. Then reservoir static data including porosity, absolute permeability and NTG were calculated for all grid blocks using geological model of reservoir and upscaling techniques and were used as input data to ECLIPSE 100 software for simulation.

Reservoir rock has the same rock type in the model with 5×10^{-6} (1/bar) rock compressibility. On this basis, for each of five layers of reservoir, a type of rock was considered. Therefore water-oil (Figure 2) and gas-oil (Figure 3) relative permeability diagrams were used for simulation purpose. Pressure-volume-temperature tables also were prepared by using the results of experiments made on reservoir cores fluid.

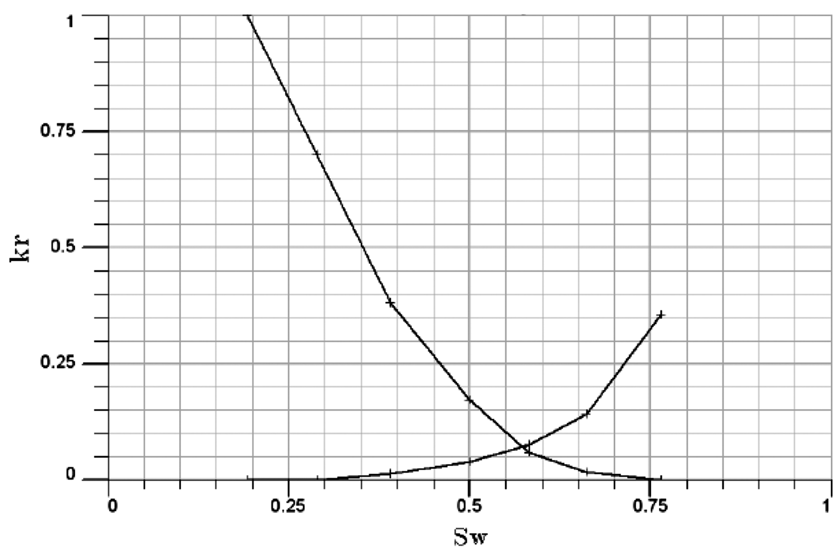

FIGURE 2 Water-oil relative permeability.

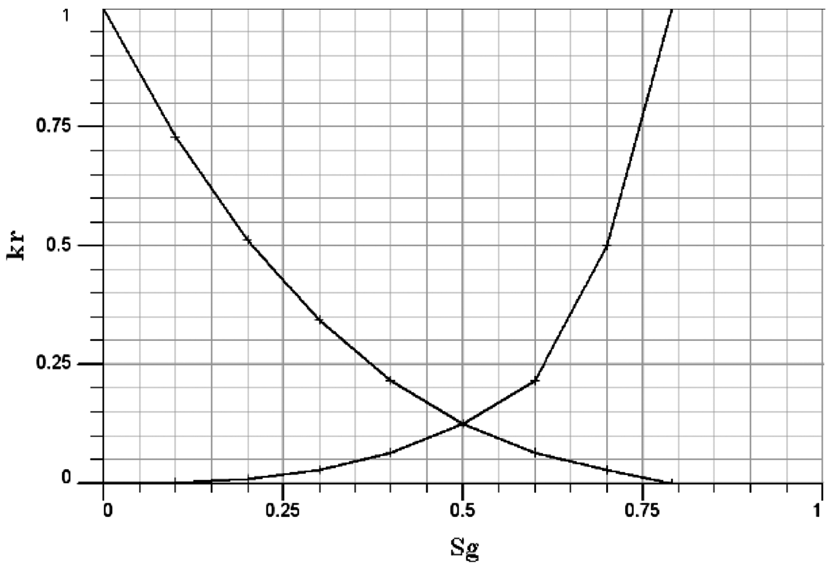

FIGURE 3 Gas-oil relative permeability.

SIMULATION OF INJECTION SCENARIOS

After model construction, WAG injection scenarios were designed and simulated and implemented by ECLIPSE 100 software. In designing the scenario of these enhanced oil recovery methods, two injection wells and two production wells were used, the well patterns kept the same for two scenarios. Water and gas rates were 3,500 m^3/day and 1,100,000 m^3/day respectively, water and gas had the same cycle times, which were 90 days for water injection and 30 days for gas injection, exactly 0.82 pore volumes of reservoir fluids injected to the reservoir other condition kept constant for both scenarios.

For reservoir simulation, two general manners considered: at first manner reservoir water was considered as pure water (i.e., concentration of reservoir water is zero) and at the second manner the water concentration of the reservoir was set to 140 kg/m^3.

At both scenarios, the salt concentration of injected water was increased and the effect of salt concentration on oil recovery for both manners was investigated.

Effect of Salinity in Mobility Improvement of Water

For investigating the effect of water salinity in mobility improvement of the displacing water, several salty waters with different water concentration was injected to the reservoir. Brine has more viscosity and density than fresh water so salt injection has more mobility than fresh water injection.

The result of simulation study has been shown in Figure 4. As it was shown in this figure, as the salt concentration of injected water increases, the total recovery of oil production was increased.

Because by using salty water, its viscosity would be increased and this incremental in the viscosity of water would increase the mobility of water and this water could push oil better through production wells. It seemed that increasing salt concentration of water phase in WAG injection would increase the total oil production recovery and the more stable displacing front of oil would be achieved.

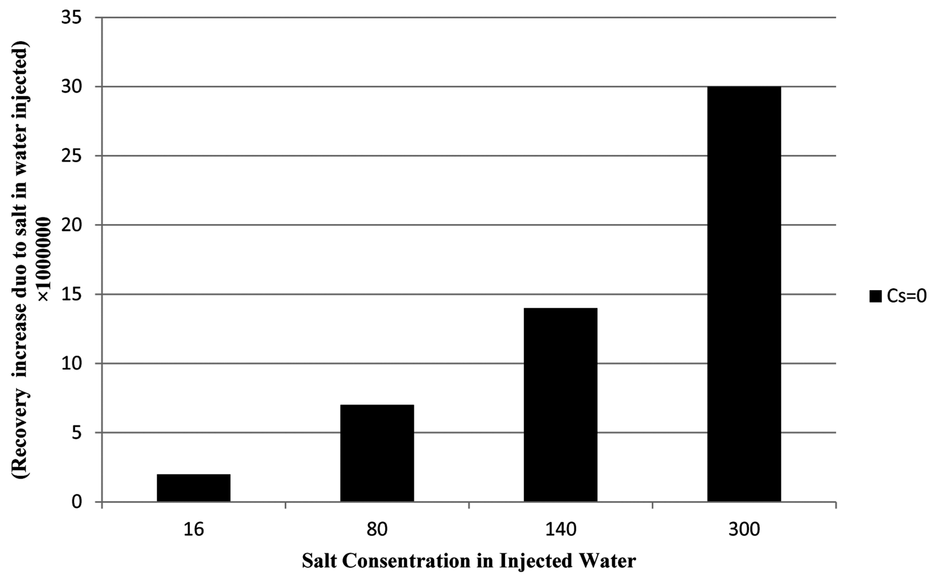

FIGURE 4 Recovery for different injected water salt concentration as a function of salt concentration in injected water.

Effect of Salt Concentration on Oil Recovery and Front Stability

Using salt in injected water would improve its mobility. In this section the effect of salt concentration of water injection phase was discussed. For this study different salt concentrations were used to be mixed in water injection phase. Water concentration was ranged between 16 and 4,800 kg/m^3 and to have a better comparison the lowest water concentration was considered as the base case of two dimensionless values:

Cd = dimensionless concentration value = (concentration/base concentration)
Base concentration = lowest concentrations = 16 kg/m^3
Rd = dimensionless recovery factor = [recovery/(recovery for zero salt concentration)

To find the optimized value for salt concentration in WAG injection, dimensionless recovery factor, Rd, was plotted in terms of the dimensionless concentration value, Cd, which is shown in Figure 5.

By a few increasing Cd from zero value to a optimized value, the Rd would increase so dramatically and after this optimized value the dimensionless recovery value has smooth increase.

To have a highest recovery, the concentration of the salt in the water must be considered in the optimized value. At the higher value of the salt concentration the salt may damage instruments such as pumps and also it may damage wellbore and cause decrease in the oil production.

Effect of Reservoir Water Salinity in Oil Recovery

To investigate the effect of the reservoir brine in oil production recovery, two reservoir water modes were considered, reservoir water with salt concentration of 140 kg/m^3, and in other mode reservoir water salinity was considered zero. The result of this investigating is shown in Figure 6. In this figure recovery incremental duo to salt in water injection phase was plotted versus different water injected salinity. Recovery incremental was calculated as recovery obtained in WAG injection by

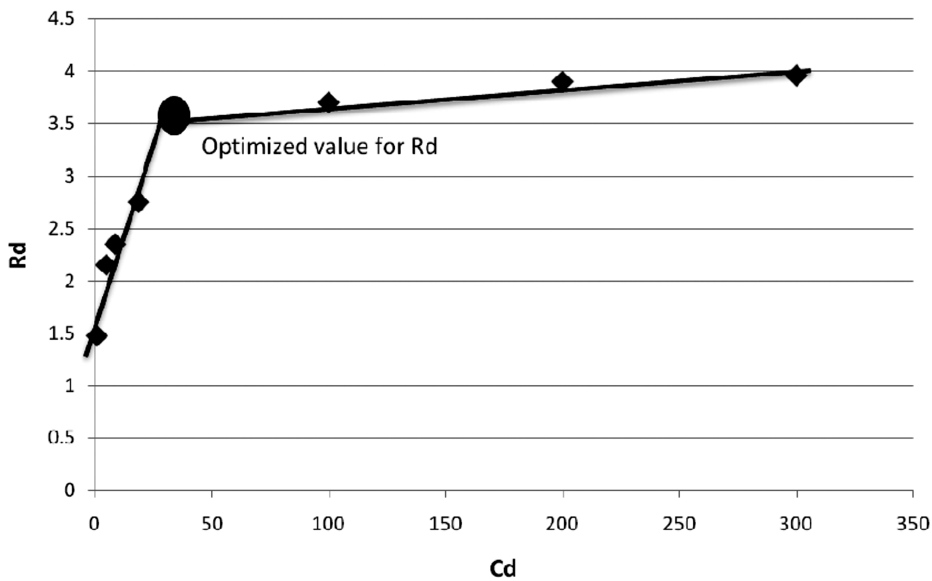

FIGURE 5 Dimensionless recovery factor (Rd) in terms of dimensionless concentration (Cd).

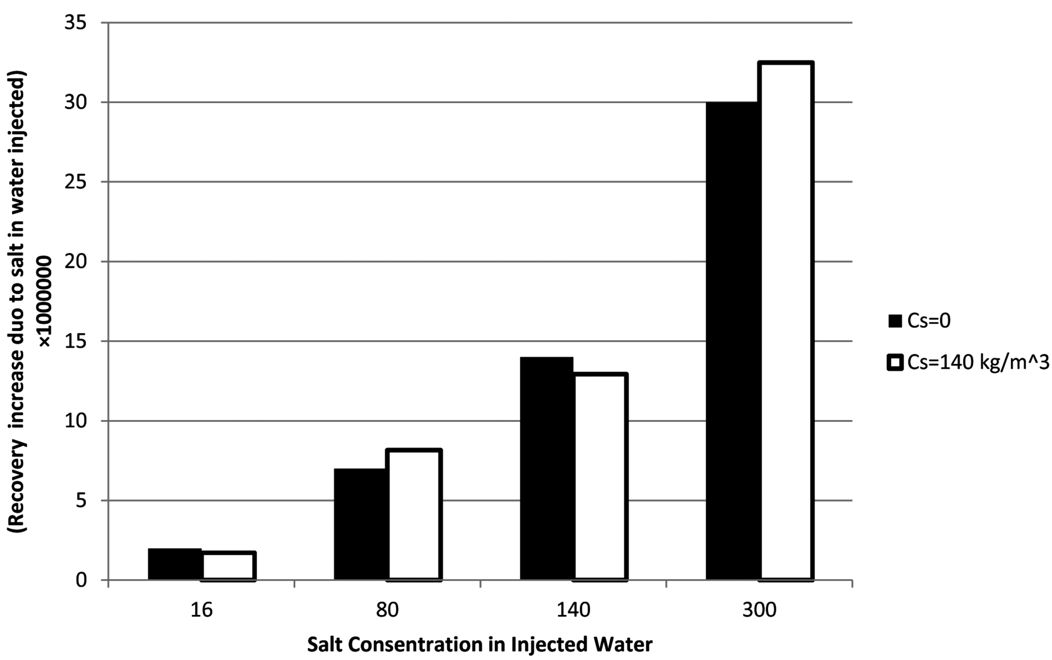

FIGURE 6 Effect of salt concentration in increasing water recovery in two scenarios.

considering injected water salinity minus recovery from fresh injected water in both modes. This recovery incremental was calculated for both modes and concluded that the recovery in second mode (when reservoir water salt concentration assumed not to be zero) is greater than the first condition so if it is possible and if the real reservoir water concentration and injected water salt has known so it is more accurate to consider this conditions in simulation studying. This difference in oil recovery for both modes was increased for increasing salt concentration of the injected water, so at higher water injection salinity it is more virtual to consider this effect.

CONCLUSION

Based on the studies of different parameters affecting WAG process the following was concluded:

1. It is important to consider the salt concentration of reservoir water in our studies; by not considering reservoir water salt concentration, the oil production recovery differs from real oil production.
2. Because the viscosity of salty water is higher than fresh water, mobility of salty water improves by increasing injected water salt concentration, and consequently oil production recovery increases.
3. Reservoir water salinity increases the oil production when WAG injection injected.

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