CHAPTER II

LITERATURE REVIEW

Several WAG studies including core flood experiments, analytical methods, reservoir simulation, and field trials have been carried out and reported improvement in oil recovery. Most of these studies include the optimization of the WAG process which were carried out in specific reservoirs. Due to the heterogeneity of each reservoir, these studies produced different results. These different outcomes mean optimized WAG parameters in one reservoir are not the optimized values when used in another reservoir.

Christensen *et al.* (1998) studied compositional effect and relative permeability hysteresis. In this work, they simulated a reservoir in the North Sea. Killough relative permeability hysteresis model was used in compositional reservoir simulation and Larsen and Skauge hysteresis model was used in black oil simulation. A number of simulations were performed using a water-gas ratio from 4 to 0.25 and a slug size from 3 to 12 months. The results showed that the WAG process gives a recovery factor approximately 7% higher than water injection and that a WAG process with a water-gas ratio of 0.5 gives the highest recovery factor of 37.8%. Moreover, there is slightly difference in oil recovery between the two hysteresis models. The authors concluded that the slug size has little influence on oil recovery compared to water-gas ratio

Larsen and Skauge (1999) stated that simulation of WAG process using three-phase relative permeability hysteresis matches quite well with core-flood experiment. The matching process was done on oil, water and gas production. The authors used reservoir simulation to model a WAG process in a reservoir in North Sea by varying the slug size from 1 to 2, 3, 4, 5, 6, 12, and 36 months using a water-gas ratio of 1:1 and varying the water-gas ratio from 2:1 to 4:1, 1:2 and 1:4 using a slug size of 3 months. From the study, they suggested that the water-gas ratio of 1:1 yields the maximum recovery (50.2%) for the 6 month slug size and the water-gas ratio of 2:1 yields the highest recovery (53.5%) for 3 month slug size.

Surguchev *et al.* (1992) presented the result of optimization of WAG process in a stratified reservoir in the North Sea using reservoir simulation. Relative permeability and capillary pressure hysteresis were used to validate the injection scheme. They also referred to the modified equation of Blackwell *et al.* (1960). The Blackwell equation calculates the minimum gas-water ratio at which the process can be considered as WAG injection. If the gas-water ratio is less than the minimum value, the process will simply be considered as waterflooding. Moreover, this equation can be used only in multi-layered reservoir. In this work, the result showed that the optimum water-gas ratio is 1:1 at 300 days of gas slug. Other ratios used were 0:1, 1:3, 2:3, 3:2, and 2:1. Finally, they concluded that the efficiency of WAG injection in the high permeable layer is high and increasing of gas slug size improves the recovery in low permeable reservoir.

Christie *et al.* (1993) studied the effect of viscous fingering and improvement of recovery factor from WAG process. The recovery of homogeneous and isotropic reservoir was investigated in both 2 and 3-dimensional simulators. This study concentrated on comparing three WAG injection strategies that are 4:1 water-gas ratio, 100% miscible flood, and matched velocity (water and solvent travel at the same speed). Matched velocity was calculated by Todd and Longstaff models. They suggested the matched velocity provides optimum stabilization at high rate. At a lower rate, recovery factor is maximum when the water-gas ratio is lower than matched velocity ratio.

Pritchard *et al.* (1993) used the compositional reservoir simulator to optimize WAG process in Judy Creek reservoir. They stated that the use of a simulator provides a more rigorous analysis to optimize WAG parameters such as bank size, cycle time, and water-gas ratio. The results showed good performance for using high injection rates at low WAG ratios in the early stages of the flood followed by the increased water-gas ratio during later solvent injection. Properly sized banks and timing of the injected chase gas can also optimize oil recovery.

Madarapu *et al.* (2002) studied the enhanced oil recovery in Schrader Bluff reservoir. Different modes of injections such as continuous gas injection and WAG process were performed in compositional reservoir simulation. Water-gas ratio and slug size with different compositions of gas were optimized.

Some WAG process uses CO_2 as an injected gas. For instance, Bredikovetsky *et al.* (1996) developed a mathematical model to optimized water alternated CO_2 injection. The model doesn't take into account of some factors that could be critical for recovery factor such as heterogeneity, gravity segregation, and viscous fingering.

The authors assumed 1-dimensional fractional flow and incompressible fluid. They divided the WAG process into 6 regimes representing different values of water-gas ratio. It was concluded that the optimum water-gas ratio is the condition of equality of water and gas velocities in the injected flux. Concerning slug size, there exists a critical maximum gas slug volume which prevents the appearance of the unstable front of the displacement of oil bank by the injected gas

Jerauld *et al.* (1993) studied timing of miscible hydrocarbon gas injection after waterflooding. They mentioned that timing of gas injection is the controlling factor in maximizing oil recovery. The reservoir model was created with two horizontal producers and one horizontal injector. The impact of waterflooding before WAG process was investigated. They founded that maximum WAG recovery can be achieved when WAG process starts at the point where the water flood front is roughly 64 % across the model. The water-gas ratio and slug size were also optimized in this work. The simulation results indicated that water-gas ratio of 1 shows the maximum incremental recovery and the effect of slug size on recovery factor changes with the water-gas ratio. The higher water-gas ratio with larger slug size produces the higher incremental oil recovery.

In order to properly construct the reservoir model, the suitable saturation function have to be input. Akervoll *et al.* (2000) presented WAG experiments with x-ray CT in-situ saturation measurements of the gas, oil and water phases in a normal size single core plug, and simulation of the experiments with hysteresis in a reservoir simulator to analyze the physical behavior. Relative permeability and capillary pressure functions can be obtained by performing history matching of the experimental data and the corresponding values calculated by simulation. For the experiment, the WAG injection sequences are 1) water injection at the bottom of the core at a very low rate, 2) equilibrium gas injection at the top of the core at a very low rate, 3) water injection at the bottom of the core at a medium rate to mobilize the residual oil, 4) gas injection at a high rate to displace residual oil, and 5) water injection at a very high rate to obtain the end-point saturation.

Since hysteresis model will be incorporated in the reservoir models in this study, it is necessary to review the literature of this issue. Bennion *et al.* (1998) stated that hysteresis of relative permeability has a positive effect on WAG process because the interfering effects between gas and liquid are used to retard the speed of gas migration. Since water tends to preferentially flow into higher permeability channels of the reservoir, it will selectively reduce the permeability to gas. Due to mobility effect, it is more difficult for gas to displace water from this zone than to flow into lower permeability zone. Therefore, it will improve the overall performance.

Kossack (2000) discussed available models of commercial reservoir simulation for hysteresis effect in water-wet system and the interaction of these models with the standard three phase relative permeability and capillary pressure. WAG process was simulated with several combinations of hysteresis model and wetting phase options for water-wet system. He suggested that using the available 2 phase models or WAG hysteresis model needs suitable imbibition and drainage curves. The end points of the curves must be consistent and the orientation of the curves with respect to each other must be correct. In addition, he showed the effect of various hysteresis options by simulating 13 grid block reservoir model. Five WAG cycles were simulated starting with 30 days of water injection followed by 30 days of gas injection. The results indicated the difference oil production rate for different hysteresis models. Finally, he recommended that WAG long core displacement using should be done in laboratory, and the fluids should be injected for 5 or 6 cycles. The experiment should then be simulated and history matched in order to determine the proper hysteresis model.

Bredikovetsky *et al.* (1996) presented a mathematical model of miscible WAG process with hysteresis. The system of the governing equations consists of the material balance of the water phase and gas component. They assumed gas and oil are totally miscible, and relative permeabilities are independent of gas concentration in the oil phase. They emphasized that the proposed model is not valid from the point of view of oil recovery estimation but the model produces a valuable information about the propagation of water slugs and water drive during the miscible WAG injection.

From all the previous works stated, no author has performed optimization of WAG process by varying reservoir properties. Therefore, it is decided in this thesis to study this topic in detail.