[PS]A Successful Story of Integrating Geological Characterization, Reservoir Simulation, Assisted History Matching and EOR in Extremely Heterogeneous Reservoir*

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Abstract

Near shore oil reservoirs have become significantly depleted, forcing oil companies to explore deep-sea reservoirs with huge investments and the latest technology. However these projects are often very risky. Thus, the optimal solution is to explore shallow sea oil fields before proceeding to deep, high-risk areas.

The Lower Miocene reservoir of White Tiger Field is a sedimentary reservoir with high heterogeneity and complex geological characteristics. This reservoir was discovered twenty two years ago. There is an urgent need to study procedures for an increased and maximum oil recovery. A detailed geological understanding of the reservoir along with a reservoir simulation is needed to gain a detailed reservoir description and determine the optimal recovery method for this oil reservoir. These are essential to have successful operations as well as reducing uncertainties and improving the efficiency of oil field management. With a large database collected from initial production stages of over 50 wells, the authors developed an integrated static and dynamic workflow to forecast oil production under several production scenarios for this reservoir. The authors also proposed a successful assisted automatic history matching approach by combining global and local optimization to construct a reliable model for complex reservoirs. Finally, this paper provides a comparative evaluation of these effects of reservoir heterogeneity on a polymer flood. A series of compositional reservoir models were performed and analyzed by CMGTM simulator. The results showed improved recovery efficiencies for the diverse reservoir characteristics encountered in the high heterogeneous reservoir.

In additional, there are many phenomena that can decrease oil recovery efficiency and economic feasibility; however, the most important are reduction of permeability and chemical agent losses from adsorption by the rock, and precipitation by high salinity and

high-hardness brines. The smaller the polymer/surfactant adsorption, the smaller the amount of required chemical for injecting and the lower the cost. The simulated results indicate that polymer-surfactant adsorption depends greatly on concentration, shear rate and injected volume of chemical agent. However, there is a critical value of these parameters on the effect of polymer–surfactant adsorption; the effect to adsorption level is negligible when operated conditions are above or below these critical values. An optimum range of important factors were determined to reduce the effect of chemical adsorption, help minimize mass of chemical loss and improve economic efficiency of the polymer flooding processes.

Geological Framework Overview

The White Tiger Field is an offshore field located on an uplifted block in the central part of Cuu Long Basin, Vietnam continental self, 120 kms southeast of Vung Tau City in
Vietnam (Figure 1). This field belongs to the Vietsovpetro Joint Venture and is the first and largest oil field which produced industrially in Vietnam since 1986. This oil field includes a series of oil reservoirs distributed continuously from the Lower Miocene formation to the Pre-Cenozoic basement (Figure 2). Until the present, more than 215 wells have been drilled and completed in the White Tiger Field. The total cumulative export crude oil produced from White Tiger Field is over 186.1 million m^3 of oil (Vietsovpetro, 2007). For fields with a long production history, 3D dynamic simulations have been very useful in providing feedback to geologic modelers, which results in improved static models. In this study, we developed an integrated and dynamic workflow to determine the best economic solution to improve oil recovery from Lower Miocene reservoir of the White Tiger Field.

The Lower Miocene reservoir in the White Tiger Field is a sandstone reservoir, which is divided into two main structures: the Southern and Northern domes (combined center and southern blocks). This sequence belongs to the Bach Ho Formation and is developed over the field area from 2759m to 2998m depth. Lithological compositions consist dominantly of sandstone and siltstone and were aggregated by clay or carbonate-cement. Based on a petrographic analysis, the fine-grain sandstone proportions are mostly equal to medium-grain sandstone proportions. Its lithologic compositions contain 40-65% quartz, 10-25% feldspars, 2-5% micas, 2-13% fragments, and 12-15% clay or carbonate cements. The production sequence units of the Lower Miocene sequence, as determined from top to bottom, are sequence unit 23, 24, 25, 26, and 27. Oil was discovered quite high on the Northern and Southern domes. This reservoir is bounded by two seismic reflex sequences of SH-5 and SH-7.

The first oil flow was found in 1974 by well testing at well BH-1 in the center block. The natural temperature of the Lower Miocene reservoir, as measured by thermometer, is about 80-100 deg C at production and injection wells. The thermal gradient is 3.5 deg C per 100 meters from 1800m to 3600m depth. Porosity varies from 0-33.5%, with an average of 17.7%. According to the experimental results, the permeability of each cell in the model varies from 0.5 to 1650mD, averaging 239mD. The experimental equation for determining permeability from dynamic research of wells is as follows:

$K = 5*0.2*EXP(0.267*\{m\})$
$M = 2.18 - 1.68\ \eta sh$
$r = 0.71$

where m, ηsh are structural factor and clay ratio in reservoir rock.

Oil saturation was calculated by relative permeability curves and capillary pressure curves. It is suitable with the initial values in production calculation for each produced sequence and block.

Reservoir Simulation

Reservoir simulation models were built to integrate the reservoir characterization studies, geochemical analysis, surveillance data to optimize the near-term development plan, and evaluate potential recovery from the Miocene reservoir. A full-field reservoir simulation model has been adequate for reservoir management purposes in the stable production period. The authors used IMEXTM in CMG simulator to construct two reservoir models for Southern and Northern domes of the Miocene reservoir in the White Tiger Field (Figure 3). The PVT results were carefully conducted from laboratory testing and special core analysis data and water saturation endpoints were used to develop relative permeability curves for the production zones. Furthermore, well locations were originally selected to give reasonable pattern coverage over those regions where the oil accumulation was considered to be the greatest.

Assisted Automatic History Matching

Traditional history matching comprises the adjustment of reservoir parameters in the model until the simulated performance matches the measured data. This is a trial-and-error procedure; the qualities of history matching procedures depend so much on the knowledge and experience of the reservoir engineer. For a complex and heterogeneous reservoir, it usually takes a long time to match simulation results with production history data.

To reach success in reservoir simulation and improve history matching results compared with traditional methods, a number of previous works have concentrated on local gradient based optimization methods. These techniques are commonly used to solve the inverse problem and is quite efficient in converging to a local minimum in the objective function. However, there is no guarantee that this will be the global minimum. Besides that, some other authors have already proposed global minimization approaches in the field. Global optimization methods have been used to overcome some of the pitfalls of gradient based methods. But, global convergence – even to an approximation of the solution – usually requires a huge number of iterations, and convergence speed is usually low.

Regarding those limitations of both research tendencies, the authors proposed to combine the Simplex method with steepest descent algorithm to solve the history matching optimization problem. This solution can take full advantage of the gradient-based method (fast rate of convergence); it also minimizes the drawback when two algorithms are combined. The method was applied to modify the porosity and permeability distribution in the Miocene reservoir. In this test, the three-dimensional porosity and permeability distributions were selected to be the parameters that were modified. Other parameters were not modified and their values were the same as in the basic reservoir model. The porosity and permeability distributions obtained by the geological model are used as initial values for the iteration procedure. With the above methods, the objective function value significantly decreased even in the first iteration step. Finally, one hundred percent of oil cumulative production was matched between the model and actual data (Figures 4 and 5). Water cut and oil rate of model matched well. However, due to the complexity of energy mechanism support and vicinity of wells at some special region, it made field block pressure of the model at the initial production higher than production history data.

Analyze and Evaluate IOR for Lower Miocene Reservoir Well Pattern Optimization

Infill drilling is an efficient approach to improve oil recovery in mature fields. Some evidence presented in the previous section showed that some parts of the Southern Dome Miocene reservoir do not have enough production wells to gather all of the potential hydrocarbon reserves. Drilling a new well is impossible due to drilling costs and the limitations of the old platform. The most efficient solution is to reuse the old wells over the entire field area. It appeared that infill drilling locations selected with scientific criteria do improve oil recovery of a very heterogeneous reservoir. The authors did a series of simulations with different constraints and the results of three typical scenarios were:

♦ The first scenario (basic scenario): put 5 production wells into Southern Dome. The simulation results showed that the cumulative oil recovery significantly increased; however, the average reservoir pressure decreases very fast. This is a dangerous scheme because the reservoir pressure decreases fast and leads to modifying the production regime, and affects either the economic problem or production life-span of the reservoir.

♦ The second scenario: put 3 production wells and 1 injection well from basement sequence to operate in the Southern Dome Miocene reservoir. In this case, cumulative production is less than the first method by 0.18 million m^3 of oil, but the reservoir pressure increased to over 7.92 atm.

♦ The third scenario: put 3 production wells and 2 injection wells from basement sequence to operate in the Miocene reservoir. Accumulated oil production less than method 2, about 0.16 millions m^3 of oil, but the reservoir pressure increased 35.08 at compare to method 2 and 43 compare to method 3. This is good because the reservoir pressure increased significantly although production decreases. That can maintain the reservoir pressure at a good level and increase time for exploitation of the reservoir.

Most wells in the Northern Dome structure had high water content in product, and the oil recovery is 0.31 (a good value for a reservoir in sedimentary rocks). We cannot add more wells because production status can be worse. Therefore, the authors gave two different scenarios for Northern Dome objective: keep original well pattern and add one more well to assess the efficiency of oil recovery. The results of the infill well approach is indicated in (Figures 6 and 7).

Enhanced Oil Recovery by Polymer Flooding

After secondary recovery processing, such as waterflooding, residual oil remaining within porous media is difficult to displace. Flooding with polymers can reduce water mobility and improve oil recovery in unswept regions. The Miocene reservoir is extremely heterogeneous; thus, polymers can effectively suppress viscous channeling in small lens layers.

In polymer flooding, rheological properties of polymer solution determine the behavior of the displacing fluid; therefore, a detailed study was conducted by experiments in both the laboratory and commercial simulator to design the most suitable polymer solution for enhanced oil recovery in the Miocene formation. The authors applied parametric study in the laboratory and assess all important factors that affect the properties of polymer solution, such as pH, type of polymer, salt concentration, temperature, molecular weight and degree of hydrolysis. In addition, there are many phenomena that can decrease oil recovery efficiency and economic feasibility; however the most important are reduction of permeability and chemical agent losses from adsorption by the rock, precipitation by high salinity and high-hardness brines. The smaller the polymer/surfactant adsorption, the smaller the amount of chemical required for injecting and the lower the cost. The simulated results indicate that polymer adsorption depends greatly on concentration, shear rate and injected volume of the chemical agent. The polymer adsorption proportionally increases with polymer concentration, while it is not absolutely true in the case of injection pressure and injection rate (Figure 8). The effect to adsorption level is negligible when injection pressure is above 13,789.5 kPa (2,000 psi) or below 3,447.38 kPa (Figure 9). An optimum range of important factors were determined to reduce the effect of chemical adsorption and help minimize the mass of chemical loss and improve economic efficiency of the polymer flooding process. A sequential polymer flooding was applied with three main stages in order to reduce the cost:

♦ Stage 1: Inject with high polymer concentration.
♦ Stage 2: Inject with medium polymer concentration.
♦ Stage 3: Polymer taper process.

The simulation results (Figure 10) indicate that cumulative oil recovery of polymer flooding increases more than 1.39 times in comparison with water flooding. Water cut in production wells also decreases when polymer flooding is applied to the Miocene reservoir. Polymer flooding holds a promising future to enhance oil recovery from the Miocene reservoir.

Conclusion and Recommendation

Based on analysis and simulation, the results of this research project have lead to the following conclusions:

• This research achieved satisfactory results in integrating geological data and reservoir engineering. The author proposed an advance assisted automatic history matching to overcome the limitation of traditional history matching. It could be considered as a promising approach for complex geologically reservoirs.

• Infill wells are efficient in improving oil recovery from mature reservoirs. This method has high economic effect and is suitable for long-time production reservoirs such as in the White Tiger Field. The cumulative oil recovery significantly increased from 24.21% – 37.26 %.

• Polymer flooding showed an excellent result on enhanced oil recovery in highly heterogeneous reservoirs. The cumulative oil recovery by polymer flooding is higher than 1.39 times in comparison with water flooding. Polymer flooding also has better performance in controlling water cut in producing wells.

Acknowledgement

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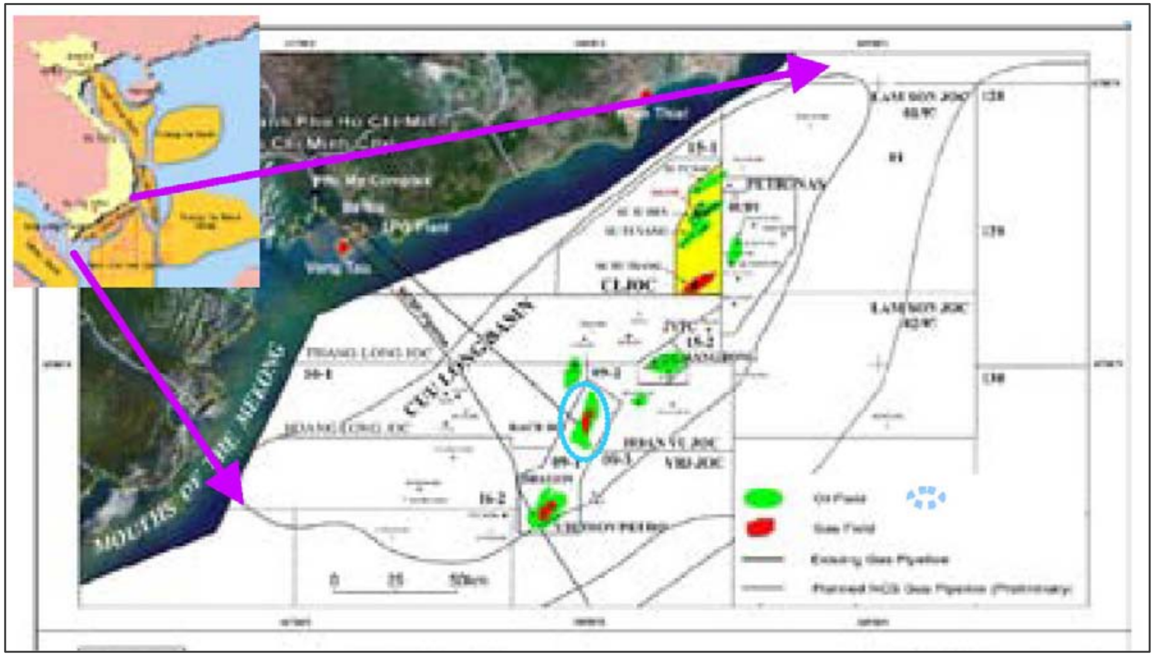

Figure 1. Location of White Tiger Field.

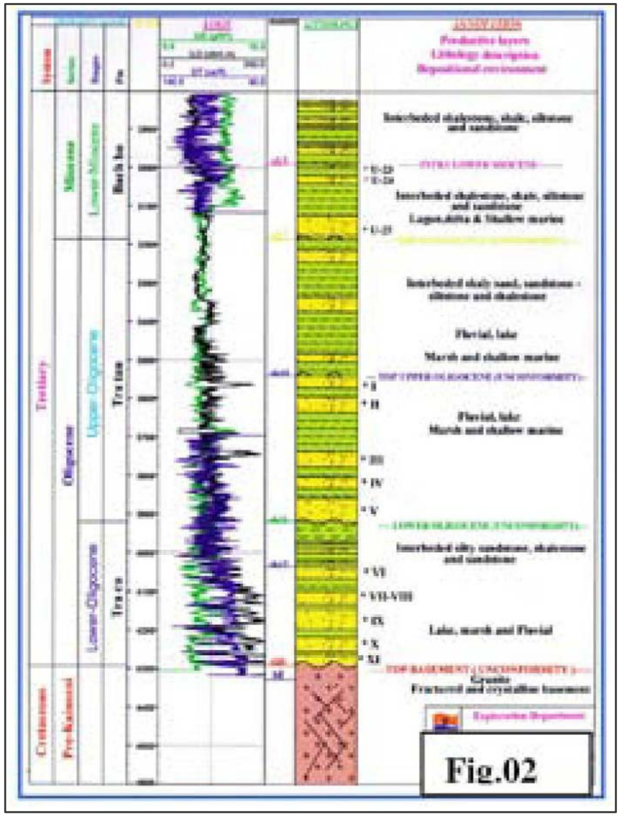

Figure 2. Stratigraphic sequence of the White Tiger Oil Field.

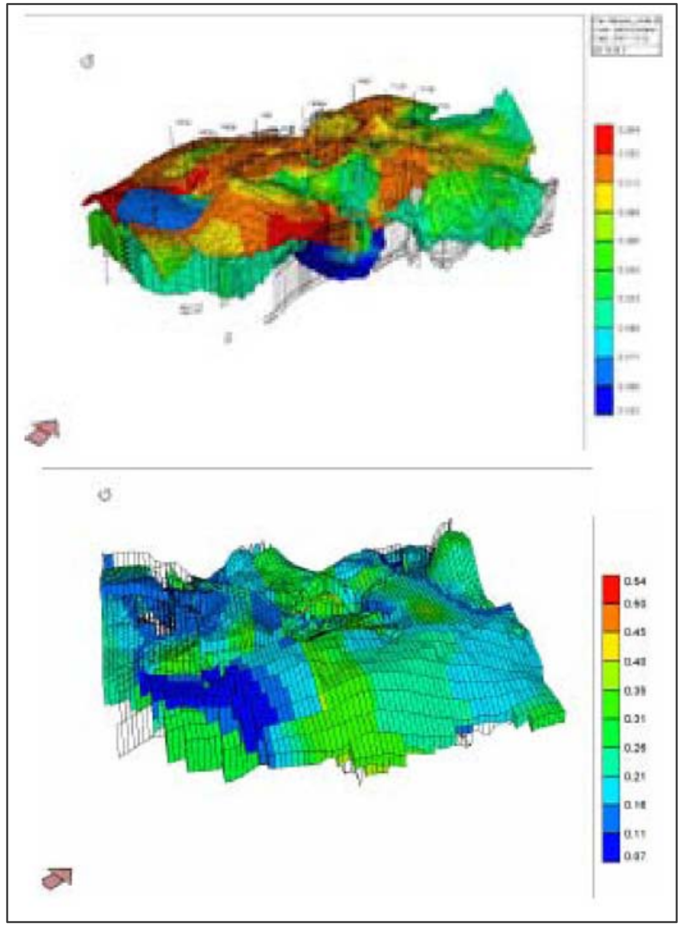

Figure 3. 3D porosity model of Southern and Northern domes.

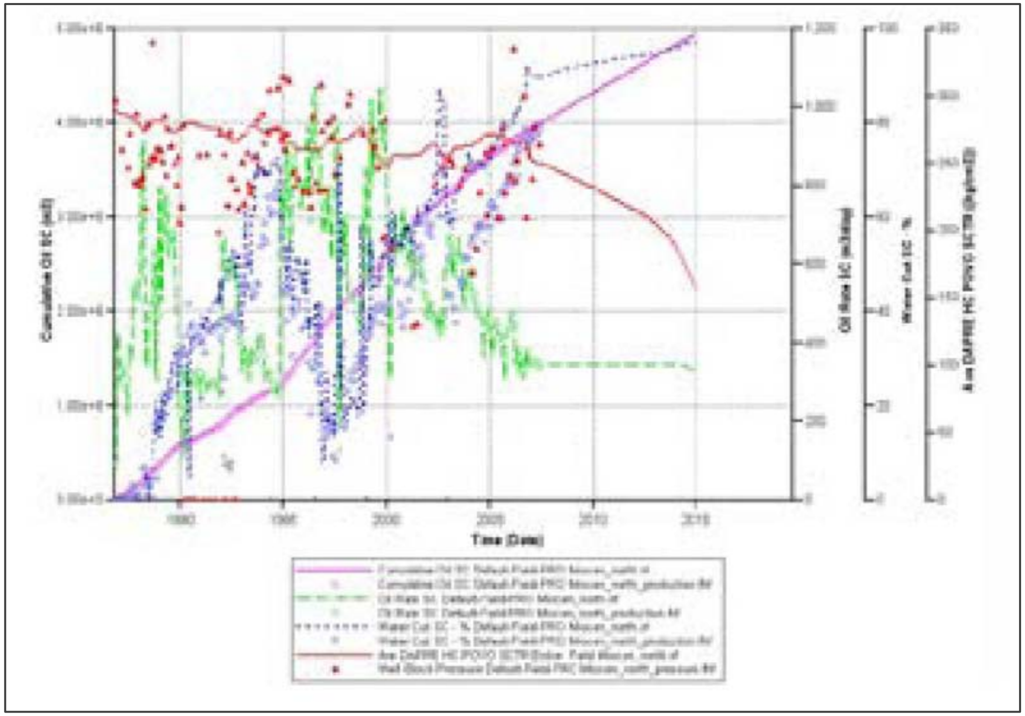

Figure 4. History matching results of Northern Dome structure.

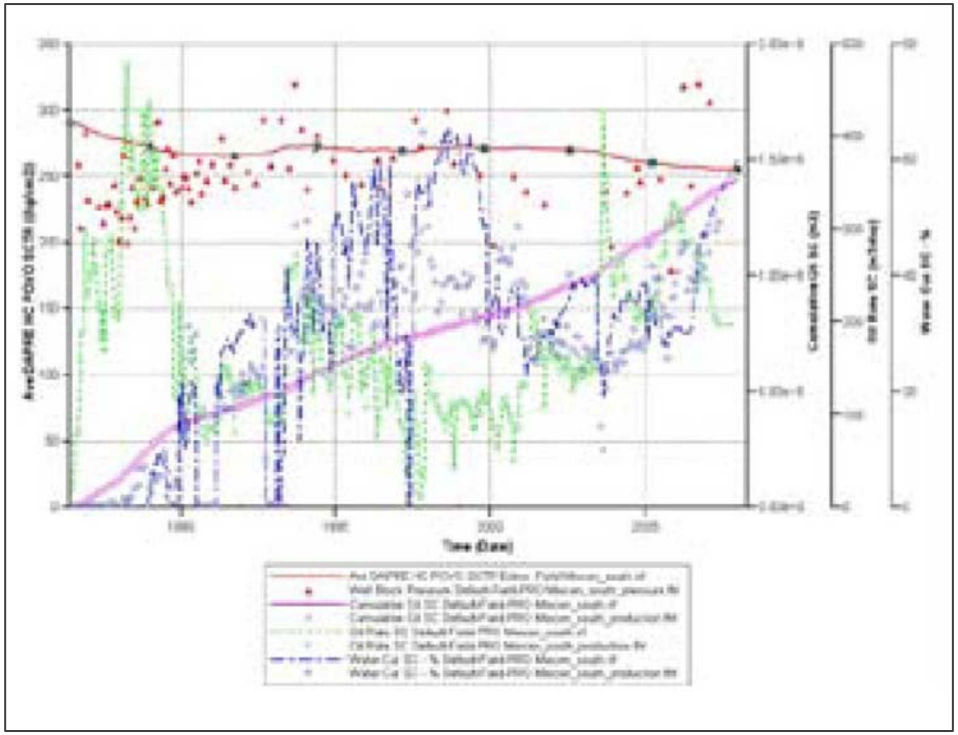

Figure 5. History matching results of Southern Dome structure.

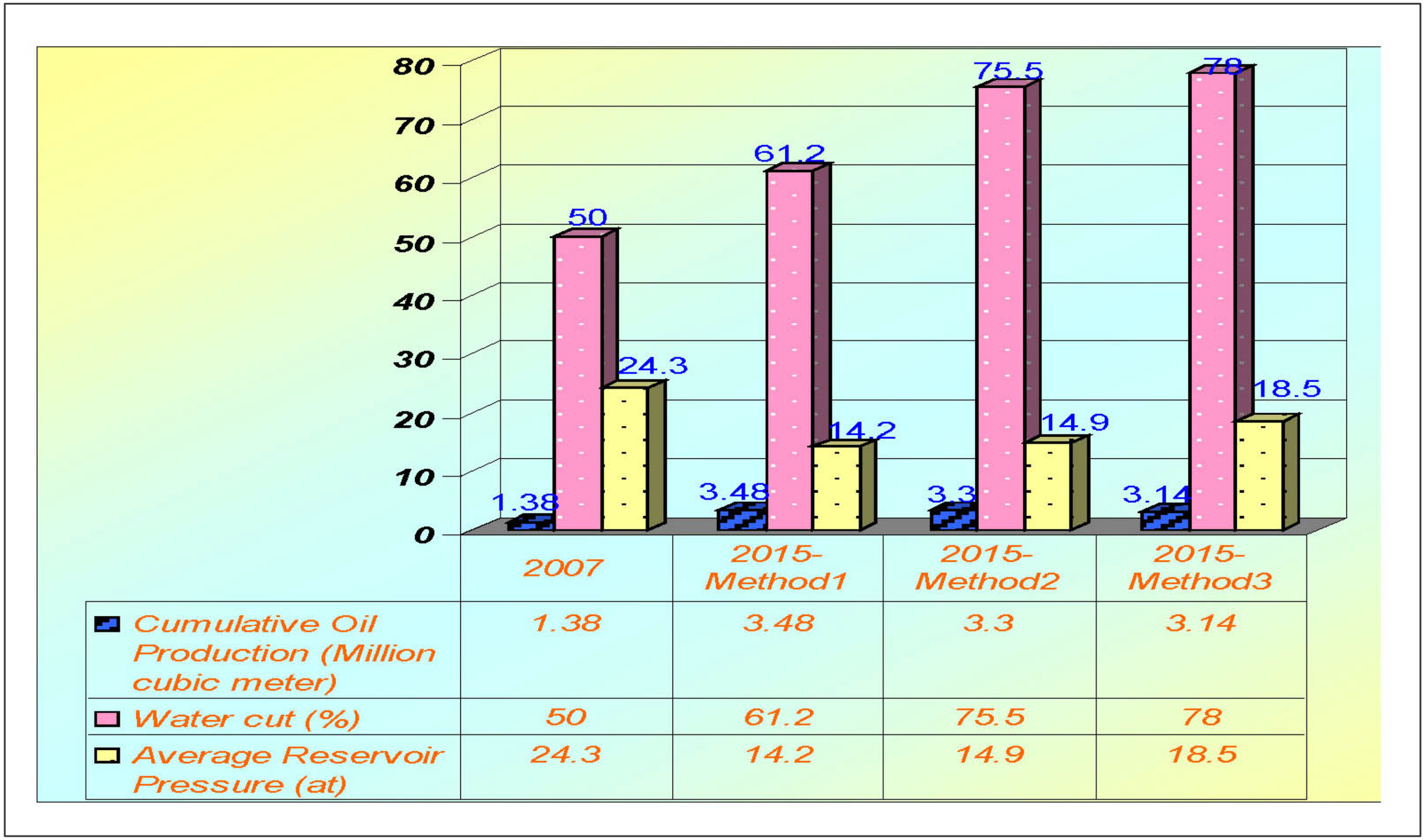

Figure 6. Impact of infill well in Southern Dome.

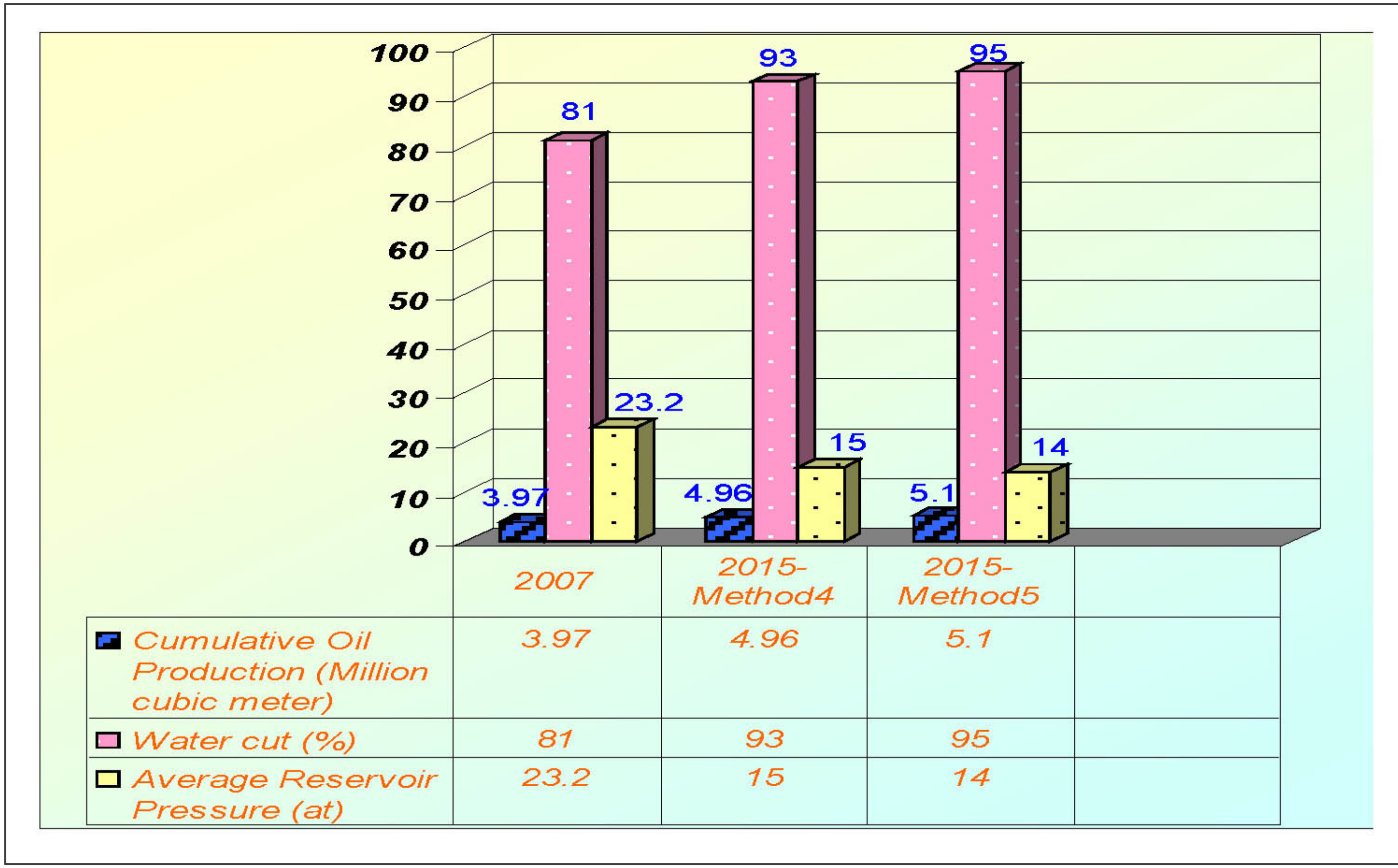

Figure 7. Impact of infill well in Northern Dome.

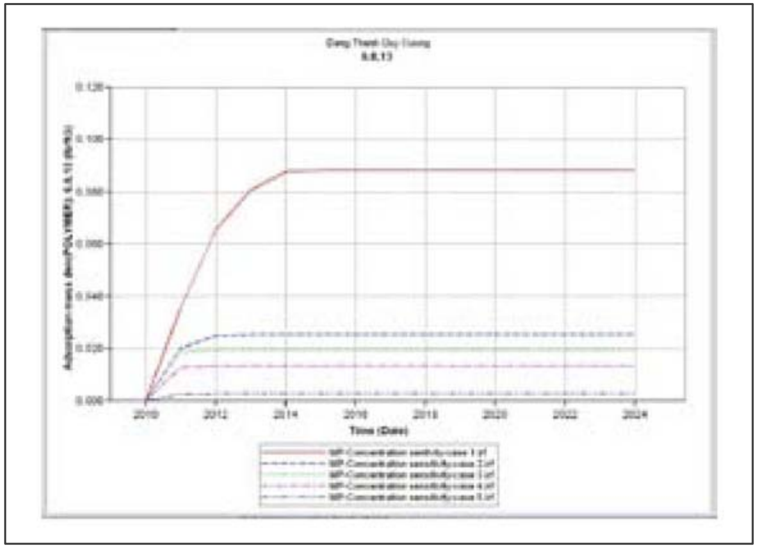

Figure 8. Effect of polymer concentration on adsorption.

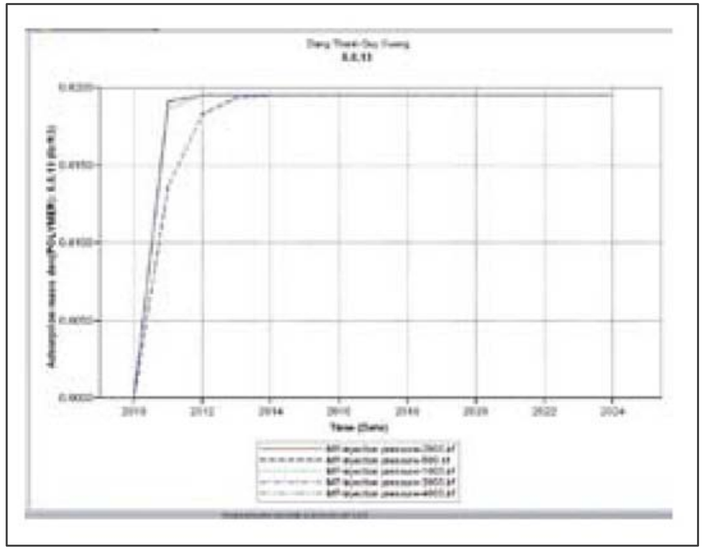

Figure 9. Effect of injection pressure on adsorption.

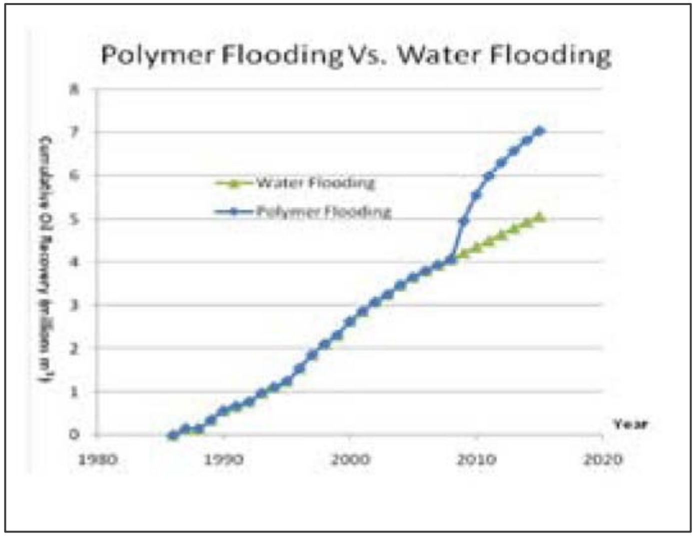

Figure 10. Comparison of polymer flooding and water flooding.