SPE-172003-MS

A New Approach for Optimization and Uncertainty Assessment of Surfactant-Polymer Flooding

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This paper was prepared for presentation at the Abu Dhabi International Petroleum Exhibition and Conference held in Abu Dhabi, UAE, 10–13 November 2014.

Abstract

Surfactant-Polymer (SP) flooding has become an attractive Enhanced Oil Recovery (EOR) method. Defining chemical concentrations, chemical types and an injection schedule, according to geological features of a reservoir and well pattern, is key to making decisions for reservoir management.

In this paper, we introduce an innovative approach for EOR optimization under geological uncertainty by integrating a reservoir geological property modelling and a robust optimizer. Multiple reservoir realizations are generated automatically by geology-driven modeling software and sent directly to an optimizer to analyze the effect of single or multi-parameters on objective functions such as cumulative oil production and net present value (NPV). Clay minerals play an important role in chemical flooding, but it is rarely included in the reservoir simulation. In this study, the distribution and proportion of clay are investigated in terms of facies and its relationship with porosity and permeability for a sandstone reservoir. Different facies and petrophysical properties are geostatiscally generated in a geologic manner that significantly improves the quality of history matching and optimization processes.

It is found that SP flooding has the highest oil recovery factor in comparison with waterflooding, polymer flooding and surfactant flooding, and it demonstrates good performances even in high clay content reservoirs. The optimal formulation of SP and polymer slugs and injection schedule were proposed. The effect of clay content in cumulative oil and NPV were addressed, in which the more clay content is the lower NPVs obtain. A comprehensive geological uncertainty analysis has been performed for: (1) facies distribution only; (2) facies distribution and proportion. The results indicated that NPV uncertainty is less than 2.25% for (1) and about 4.18% to 5.68% for (2).

The proposed optimization approach could be effectively applied to tertiary EOR techniques in various reservoir conditions under geological uncertainty. By integrating geological software, reservoir simulator and robust optimizer, it serves as a powerful tool for design and optimization of these processes.

SP flooding is definitely a complicated process, therefore, an innovative modeling and optimization approach for SP flooding described in this paper is needed to improve the prediction of process performance.

Introduction

Traditionally, water flooding is chosen to improve oil recovery and to maintain reservoir pressure. This is often an economical method and can be applied more easily than others, but water flooding can only help produce up to 20-40% initial oil in place. After water injection, the residual oil remains in the reservoir as a discontinuous phase and mainly in low permeable zones. Thus tertiary recovery has been studied to enhance oil recovery.

Chemical injection such as polymer, micelle, SP, and alkaline-surfactant-polymer flooding is considered as a tertiary recovery method. These flooding methods have shown that there is an increase of oil recovery in comparison with water flooding, and they can be economically applied for certain types of reservoirs. For example, actual field data in the Daqing Oil field showed that the production cost of polymer flooding is lower than water flooding (Demin et al., 2003; Yuming et al., 2013). However, chemicals always adsorb on rock surface or precipitate in the reservoir. If clay is present, it increases the chemical adsorption and reduces the effectiveness of the chemical injection process (Schamp and Huylebroeck, 1973; Theng, 1982; Deng et al., 2006; Zaitoun and Kohler, 1987; Chiappa et al., 1998). Zaitoun and Kohler (1987) showed that an increase in clay content both decreases permeability and increases polymer adsorption. Thus the effect of clay proportion and distribution on surfactant and polymer adsorption is also discussed in this paper. We pointed out the advantages of SP injection in clayey reservoirs compared with only polymer or surfactant injections.

It is known that defining chemical concentrations and chemical types, based on geological features of a reservoir and well pattern, is key to making decisions for reservoir management. In addition, identifying the time of injection for each chemical slug is also important in a project. Slug sizes also strongly affect oil production. We will discuss these important factors in this paper. A sensitivity analysis was conducted to test the effect of parameters such as salinity, surfactant concentration, polymer concentration, initial oil saturation, injection time, injection rate, well radius, polymer viscosity, and maximum polymer/surfactant adsorption mass on cumulative oil production and NPV for the simulated reservoir.

Finally, studying the effect of clay content on cumulative oil production and NPV for a SP flooding project is our main target. To investigate the effect of clay distribution and proportion in a sandstone reservoir on oil recovery and NPV for the SP injection project, we build a geological model, and then create a reservoir property model based on its facies and the relationship between facies and porosity and permeability via histograms and variograms. An optimization process was run by an optimizer which can link with the above reservoir property model. The reservoir model generates new realizations that are sent automatically to the optimizer. This way the clay distribution and proportion are considered in the optimization of the polymer-surfactant formulation and slug sizes. The maximum NPV is also calculated by accounting for geological uncertainty. Fig. 1 shows the flowchart of production optimization under geological uncertainty.

Reservoir Base Model

The reservoir contains 4,760 grid cells with dimensions of 8x17x35. Porosity and permeability vary in both horizontal and vertical directions (Fig. 2). Reservoir temperature is about 90^{0}C. Initial oil saturation and initial water saturation are 0.6 and 0.4, respectively. The fluid properties of this reservoir are showed in Table 1. The reservoir has no free gas.

SP Flooding and Injection Stages

We used a half inverted 7-spot injection pattern to simulate the SP flooding in a heterogeneous reservoir. All simulations were run by CMG's simulator STARS^{TM}. The model contains one injector and four producers with constraints shown in Table 2.

To balance the water injection volume and oil production volume, the production fractions for producers 1 and 2 are set to be 0.1667 and the production fractions of producers 3 and 4 to be 0.3333. The

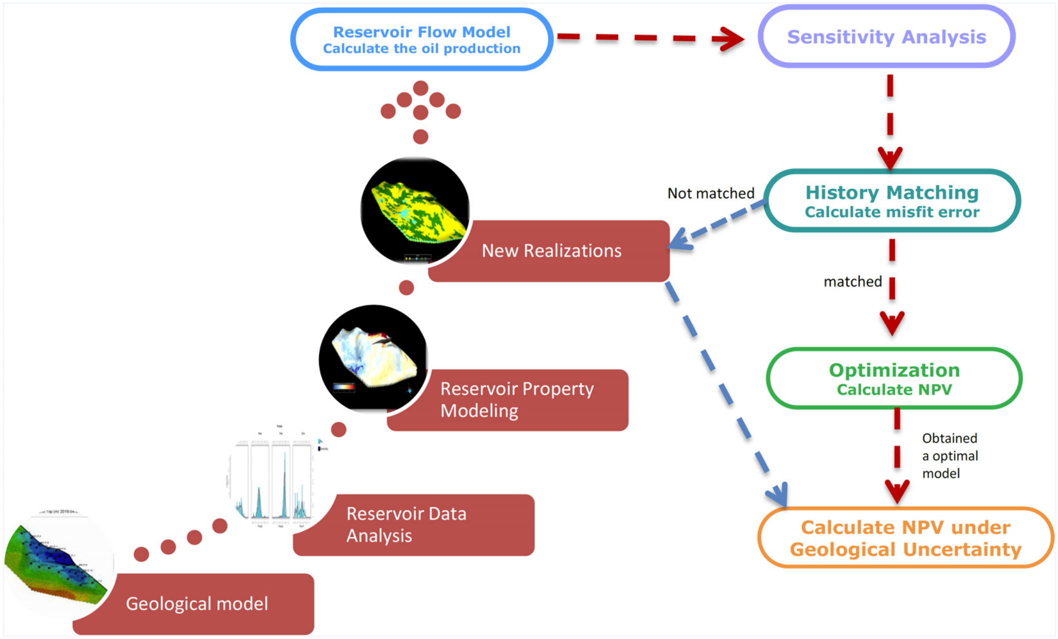


Figure 1—A Workflow of Production Optimization under Geological Uncertainty

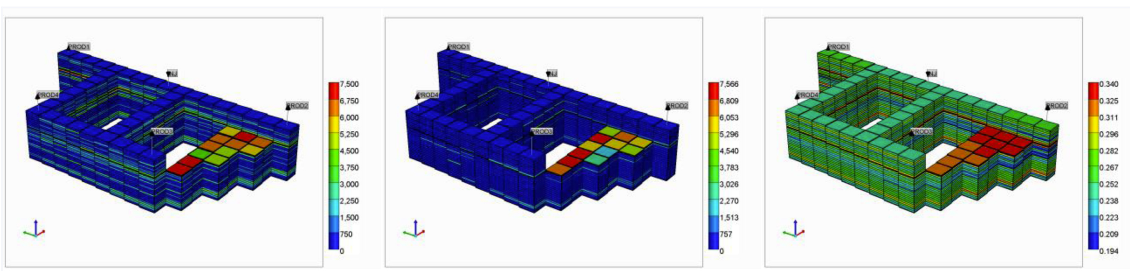


Figure 2—A 3D Porosity Model and Permeability Models in Directions *I* and *K*.

Table 1—Fluid Properties of Reservoir

Fluid Properties	Values
Water viscosity at reservoir temperature, cp	0.6
Water density, kg/m^3	987.96
Oil density at reservoir temperature, kg/m^3	887.45
Oil viscosity at reservoir temperature, cp	3.2
Water formation volume factor at reservoir pressure	0.9915
Oil formation volume factor at reservoir pressure	0.933

flood model was simulated with five injection stages (Table 3). Stage 1 corresponds to water injection for one year. Stage 2 corresponds to SP flooding for another year. This is the main period in our flooding project. The optimum formulation of this slug is proposed in this paper. Stage 3 consists of injection of a polymer slug for two years to create high viscous water that pushes the SP slug into the lower permeable zones. Stage 4 is also a polymer slug injection for one more year with lower polymer concentration (polymer tapering) with the goal to reduce polymer cost. Then, water is injected again in Stage 5 until the end of simulation. The injection date of each stage will also be analyzed with sensitivity analysis in next sections.

Table 2—Rate Constraints and Bottom-hole Pressure (BHP) Constraints for Injector and Producers

Constraints	BHP, kPa	Rates, m^3/d
Injectors	6,800	1,050
Producers		
1	1,200	1,150
2	1,200	1,150
3	1,200	1,150
4	1,200	1,150

Table 3—Summary of Injection Stages

	Injected Fluids	Mole Fraction		Injected Fluids	Mole Fraction
Stage 1	Water	1.0	Stage 4	Water	0.99999993
	Chloride	0.0		Chloride	0.0
	Polymer	0.0		Polymer	7.00E-08
	Surfactant	0.0		Surfactant	0.0
	Total	1.0		Total	1.0
Stage 2	Water	0.99349986	Stage 5	Water	1.0
	Chloride	0.005		Chloride	0.0
	Polymer	1.42E-07		Polymer	0.0
	Surfactant	1.50E-03		Surfactant	0.0
	Total	1.0		Total	1.0
Stage 3	Water	0.99999986			
	Chloride	0.0			
	Polymer	1.40E-07			
	Surfactant	0.0			
	Total	1.0			

Reservoir Simulation Results

For the SP flooding run, Fig. 3 shows 2D maps of polymer/surfactant adsorption, oil saturation and water viscosity in layer 17 at the end of simulation. The injected fluid covered the whole layer as we see that maximum oil saturation (0.36) is much lower than initial oil saturation (0.6). The adsorption speed of polymer and surfactant is similar in this layer, except for the adsorption mass.

We also ran the simulations for three other floods, i.e. water, polymer and surfactant flooding. Fig. 4 shows that the SP flooding gives the highest cumulative oil mass compared to others. Moreover, this method can also produce oil faster than others.

Fig. 5 explains why SP injection can produced more oil than the others. If we only inject water into the reservoir, water will move quickly toward high permeable zones (Figs. 5f and 5k). Whereas, SP injection controls the water viscosity behind the oil front and improves the sweep efficiency (Figs. 5b-5e). It is also better than single polymer or surfactant injection (Figs. 5h and 5g).

However, there are still some limitations and disadvantages if we only apply SP flood instead of others. First, the cost of injection is higher than the other methods because of the chemicals and facilities; therefore, we need to consider the benefits of this project (net present value). This will be studied and analyzed in the next section. Second, the reactions of chemicals are more complex and difficult to control. There is no guarantee that the field-scale implementations have similar recovery as the lab-scale experiment results. Thus we need to consider geological uncertainty in the production optimization process. Not only does the presence of clay reduce both porosity and permeability, which affects the prediction of the initial oil in place, but it also influences fluid flow, consequently oil production.

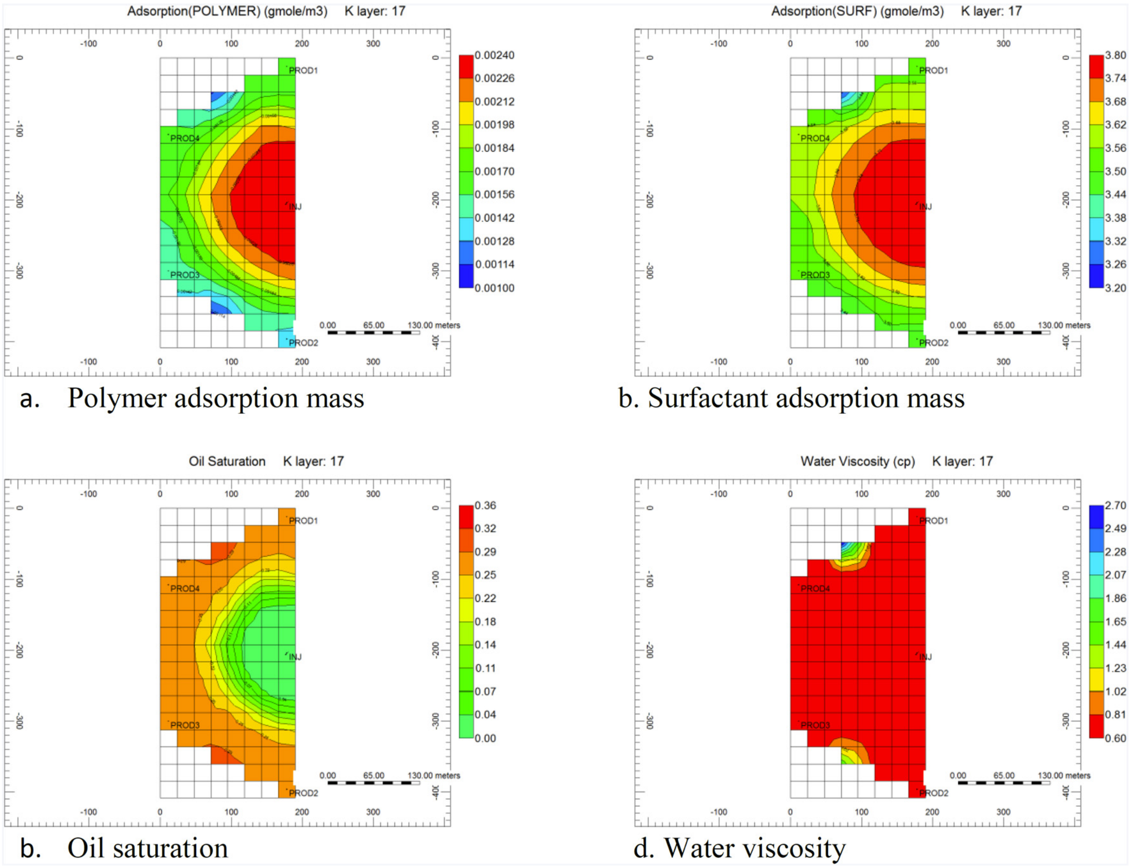


Figure 3—Results of SP Flooding Simulation for Layer 17

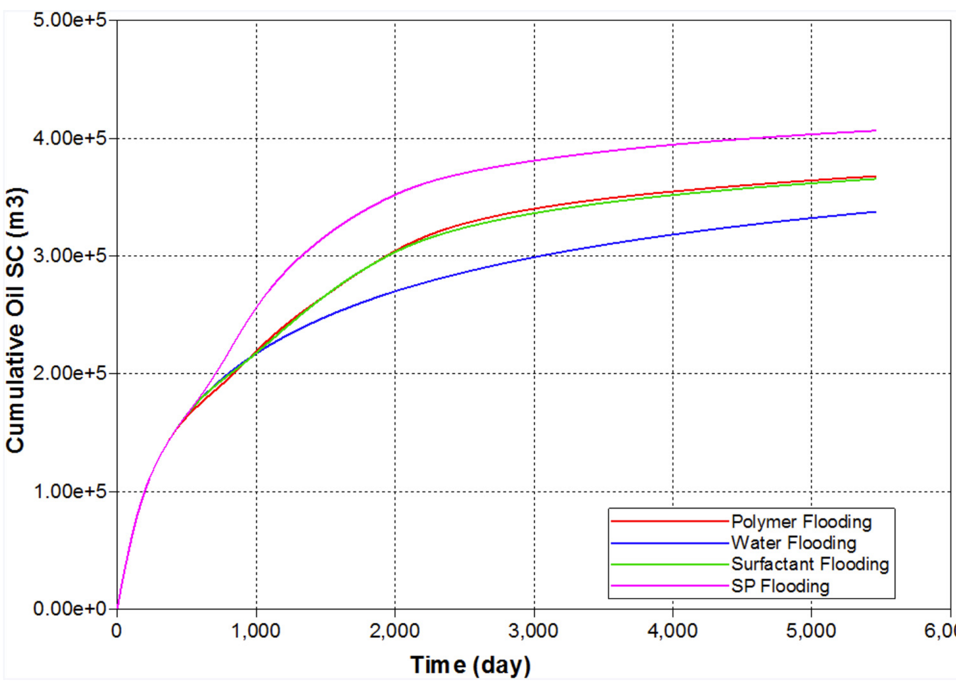


Figure 4—A Comparison of Cumulative Oil Mass among Four Methods: Water, Surfactant, Polymer and SP Flooding

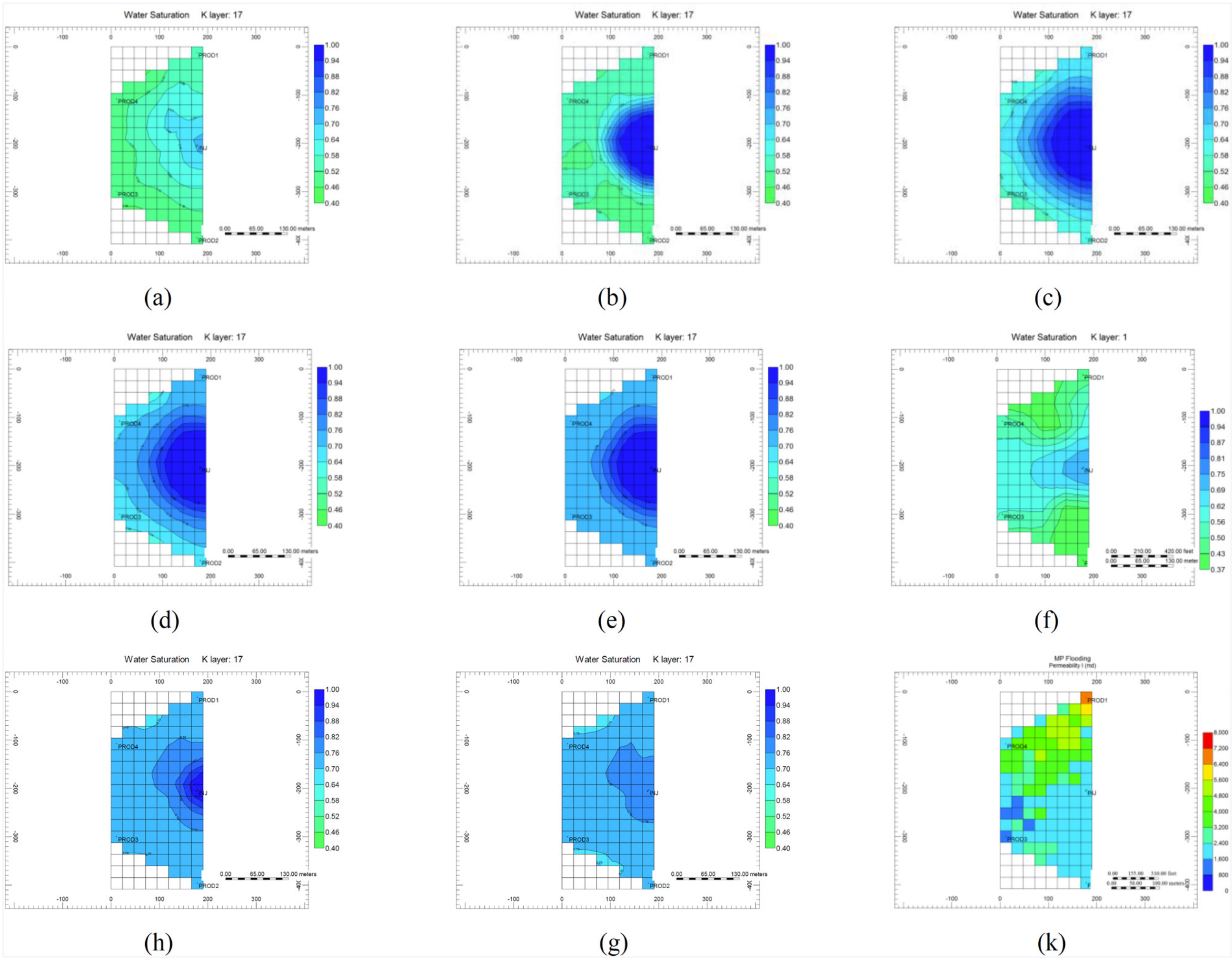


Figure 5—Comparison of Water Saturation of SP Flooding in Layer 17 at the end of First Water Injection (a), SP Injection (b), Polymer Drive (c), Polymer Taper (d), and Simulation End of SP Flood (e), Water Flood (f), Surfactant Flood (h), and Polymer Flood (g); Permeability Map of Layer 17 (k).

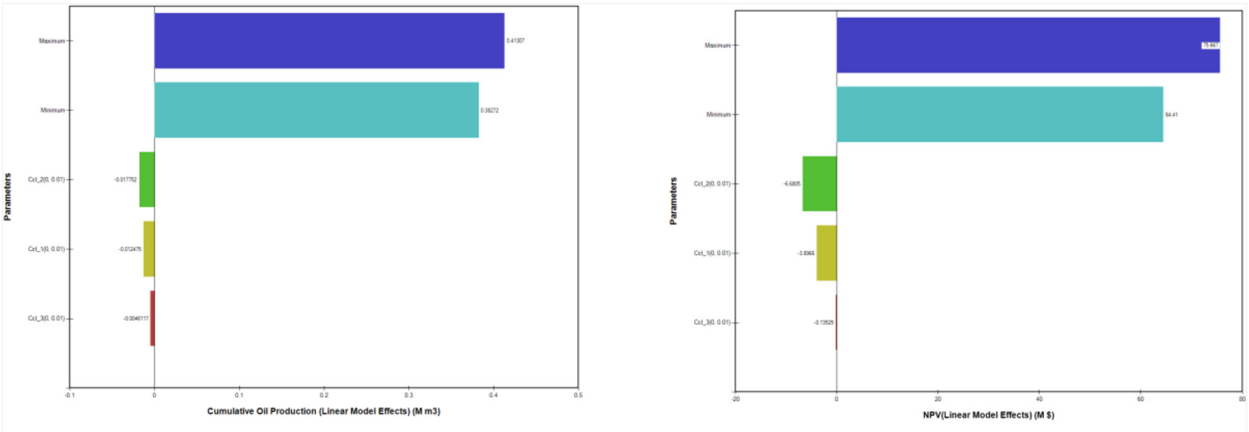
Sensitivity Analysis and Optimization

We started to run a sensitivity analysis from the base reservoir model with CMG's sensitivity analysis and optimization software CMOST^{TM} and the simulator STARS^{TM}. The concentrations of each chemical in SP and polymer slugs and the reservoir and injection conditions were changed to study its single effect on the cumulative oil production and the NPV for a project while we kept all other parameters constant. In addition, we ran some combined-parameter optimizations in order to find the optimal formulation for each slug, especially for a SP slug in a heterogeneous reservoir.

The new technology was applied to study the geological uncertainty (heterogeneity of the reservoir) for SP flooding. The link between a geological reservoir model and an optimizer helps us to generate the new properties automatically such as porosity and permeability that will be used in the sensitivity and uncertainty analysis process. In this section, we presented two optimal formulations of SP slugs and polymer slugs and analyzed the uncertainty of NPV as we consider the error of identifying of facies proportions and clay distribution in reservoir.

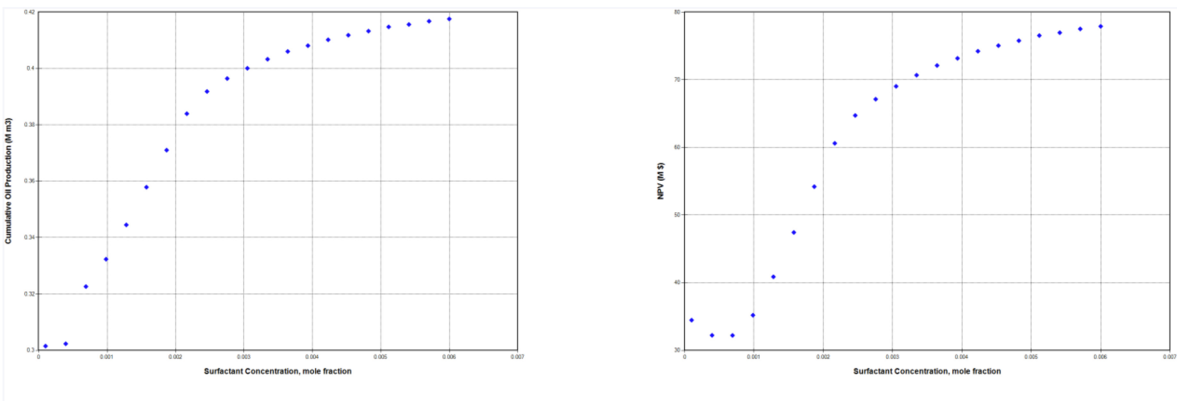
Sensitivity Analysis

Effect of injection salinity For all slugs, increasing chloride concentration decreases both cumulative oil production and NPV. Fig. 6 shows that the salinity of the polymer slug of Stage 3 has a strong influence



(a) (b)

Figure 6—Effect of Injection Salinity on Cumulative Oil Production (a) and NPV (b). Ccl_1, Ccl_2 and Ccl_3 are Chloride Concentrations for Slugs in Stages 2, 3 and 4, respectively.



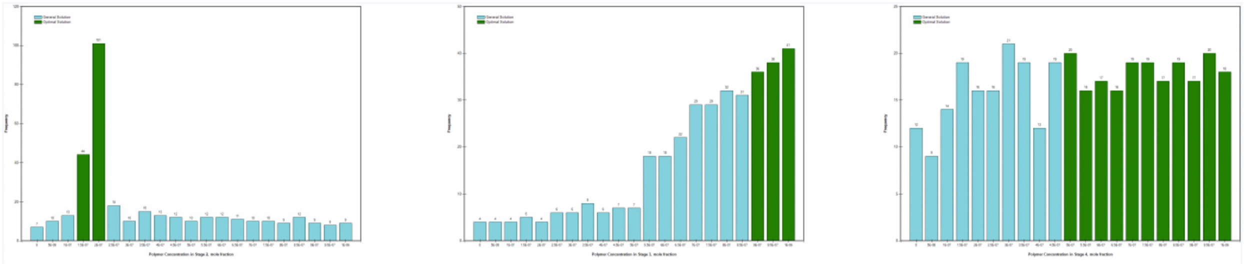
(a) (b)

Figure 7—Effect of Surfactant Concentration on Cumulative Oil Production (a) and NPV (b)

on the NPV and the cumulative oil production compared to the salinities of slugs in Stages 2 and 4. The maximum NPV reaches 75.667M$ when we use 0.001, 0.0, and 0.009 mole fraction of chloride for Stages 2, 3, and 4 respectively.

Effect of surfactant concentration Increasing surfactant concentration of a SP slug increases both cumulative oil production and NPV (Fig. 7). From the figure, we see that increasing surfactant concentration from 0.0001 to 0.0006 mole fraction decreases the NPV although the cumulative oil production increases. It can be explained that the revenue of the extra oil production cannot compensate for the extra expense of injection. However, if surfactant concentration is higher than 0.0007 mole fraction, the NPV will rapidly increase until reaching the critical value. Therefore, defining the optimal surfactant concentration of SP slug is an important key in success of injection project. For this run, the optimal NPV is about 77.895M$ as using 0.006 mole fraction of surfactant.

Effect of polymer concentration The optimal range of polymer mole fractions for Stage 2 is from 1.5e-7 to 2e-7, for Stage 3 is greater than 9e-7 and for Stage 4 is greater than 5e-7 (Fig. 8). In general, the sensitivity analysis results show that NPV increases with increasing polymer concentration (Fig. 9), especially polymer concentration in Stage 3. The maximum NPV is about 92.265M$ when we inject 1.5e-7, 1e-6 and 5e-7 mole fractions of polymer for Stages 2, 3 and 4, respectively.



(a) SP injection (b) Polymer drive (c) Polymer taper

Figure 8—The Optimal Polymer Concentrations for Three Stages

Effect of initial oil saturation Of course, the higher initial oil saturation is, the higher NPV can obtain. For our study case, the NPVs are negative if the initial oil saturation is lower than 0.45 (Fig. 10).

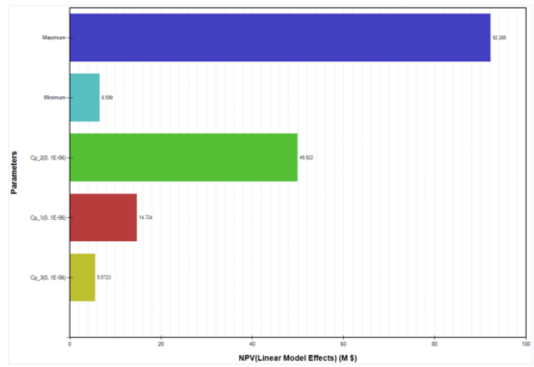


Figure 9—Tornado Plot: Polymer Concentration vs. NPV. Cp_1: Polymer Concentration in Stage 2, Cp_2: Polymer Concentration in Stage 3, Cp_3: Polymer Concentration in Stage 4.

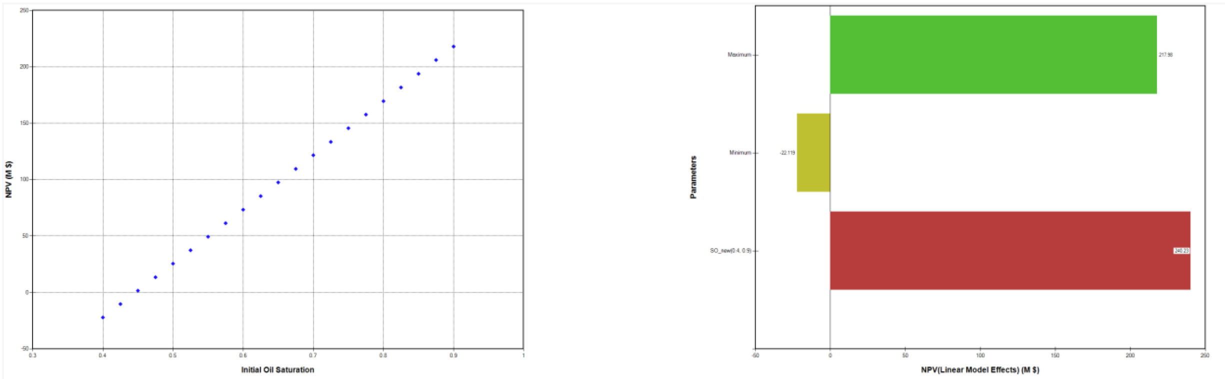
Effect of injection time For SP slug injection, the earlier starting injection date and the longer injection time lead to the higher oil recovery and NPV. However, delaying injections of a polymer slug in Stages 3 and 4 and water in Stage 5 will increase both cumulative oil production and NPV (Fig. 11). The results of simulation runs show that it is more profitable if we start SP injection as soon as possible. The optimal injection time for Stages 2, 3, 4 and 5 is 180, 531, 1,507 and 1,904 days, respectively. The maximum NPV is about 82.216M$.

Effect of injection rate Fig. 12 shows that increasing the injection rate increases both cumulative oil production and NPV until a critical point and decreases after this point. However, the maximum cumulative oil production was obtained at the injection rate (955m^3/d) much higher than that of the maximum NPV (290m^3/d). For the graph of NPV versus the injection rate, on both sides of the critical rate, the NPV decreases rapidly. Moreover, a higher injection rate allows the use of lower chemical concentrations and smaller slug sizes. This will reduce the cost of injection and make the project more benefits.

Effect of polymer viscosity Polymer viscosity is discussed here in terms of molecular weights. The solutions contain the same polymer concentration but the viscosities of these solutions are different if these polymers have different molecular weights. As we increase polymer viscosity or increase molecular weights, cumulative oil production first increases and then decreases (Fig. 13a). If the polymer viscosity is too high, it can be trapped near the wellbore, and reduce the fluid flow into the reservoir, and consequently oil recovery will decrease. There is the same trend for NPV, but the critical viscosity value of NPV (28cp) is higher than that one of cumulative oil production (23.5cp) (Fig. 13b).

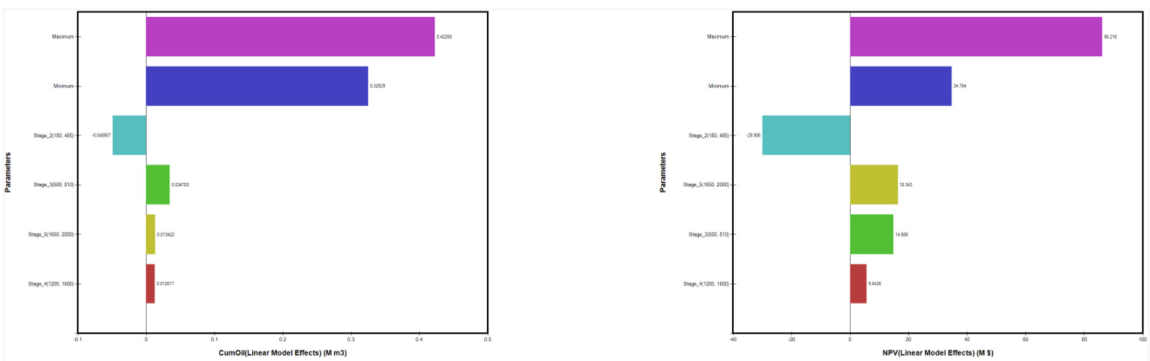
Combination of All Factors We also conducted a sensitivity analysis for all factors. Fig. 14 shows that the high impact factors on NPV are initial oil saturation, polymer concentration, surfactant concentration, water injection rate, injection period, and polymer viscosity. Increasing polymer or surfactant concentration will increase NPV whereas increasing injection rate or delaying injection date will decrease NPV. However, increasing polymer concentration substantially in SP slug would reduce the NPV.

Effect of Clay Content and Distribution To study the effect of heterogeneity of the reservoir and clay content, we generated multiple realization sets of reservoir properties including facies, porosity and



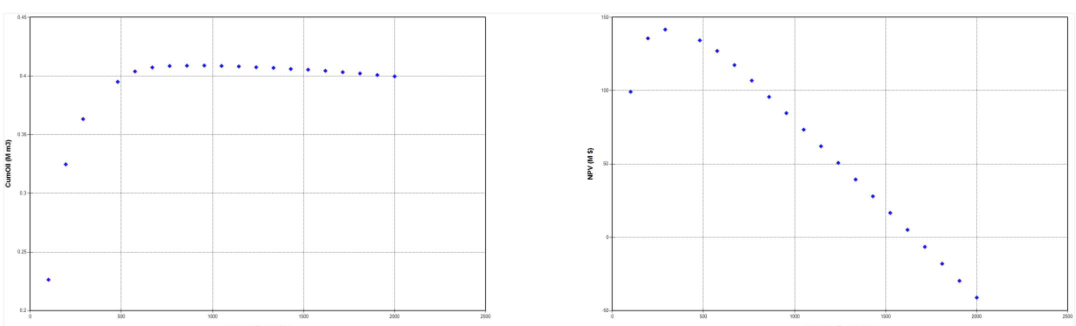
(a) NPV vs. Initial Oil Saturation (b) Tornado Plot: Initial Oil Saturation vs. NPV

Figure 10—Effect of Initial Oil Saturation on NPV



(a) (b)

Figure 11—Tornado Plot: Injection Times vs. Cumulative Oil Production (a) and NPV (b).



(a) (b)

Figure 12—Effect of Injection Rate on Cumulative Oil Production (a) and NPV (b)

permeability (Fig. 15). The base reservoir is assumed to contain three facies including coarse sand, medium sand and fine sand with volume proportion of 0.2, 0.5 and 0.3, respectively. The clay content has a strong relationship with the grain size of sands (Shahin et al., 2012). The higher clay content is, the lower grain size is and the lower porosity and permeability are. These values of sand proportion will be changed to generate not only do the models with different clay distributions with the same clay content but also models that have different clay proportions. The geological software GOCAD™ is used in conjunction with CMG's CMOST™ and STARS™ in this study. In addition, porosity and permeability are generated

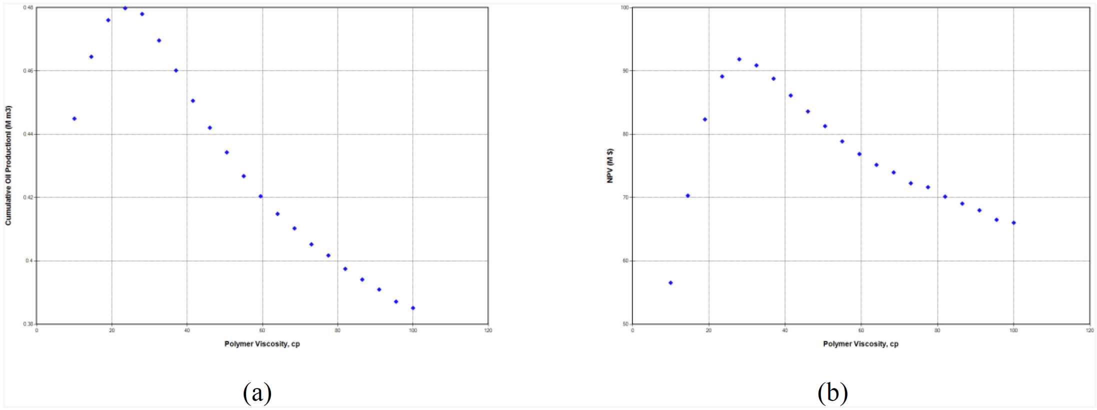


Figure 13—Effect of Polymer Viscosity on Cumulative Oil Production (a) and NPV (b)

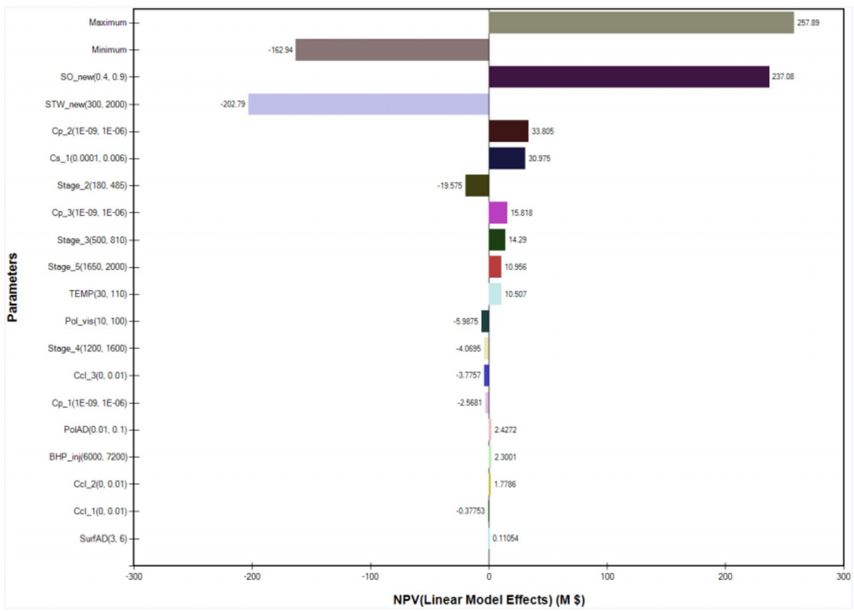


Figure 14—Tornado Plot of Linear Model Effects for NPV

based on the new facies, histograms and variograms. Table 4 shows the min, max and mean values of porosity and permeability for each facies in the simulated reservoir model.

The effect of clay content on NPV is very complex. It depends on many factors. Increasing clay content decreases both porosity and permeability. It also affects polymer and surfactant adsorption. Polymer and surfactant can adsorb on clay, which lead to a decrease of cumulative oil and NPV. Fig. 16 shows the results of simulation for three cases representing the effect of heterogeneity (clay content) on SP injection. Fig. 17 shows a comparison of cumulative oil production curves for each producer in the field.

Three cases were run with the same injection conditions and fluid properties. Table 5 presents the proportion of each facies for these three cases. Case 244 shows high porosity and permeability in the areas around producers 1, 4 and 3 (looking from the North and East sides of the reservoir), and has low porosity and permeability in the area around producer 2. In general, this reservoir has high porosity and permeability and has less clay content. In contract with case 244, cases 400 and 563 have higher clay content.

Case 400 shows high porosity and permeability in the areas around producers 2, 3 and 4 and low porosity and permeability in the area around producer 1. The injection well was drilled in a low porosity and permeability zone in compared to cases 244 and 563. Case 563 shows that the porosity and

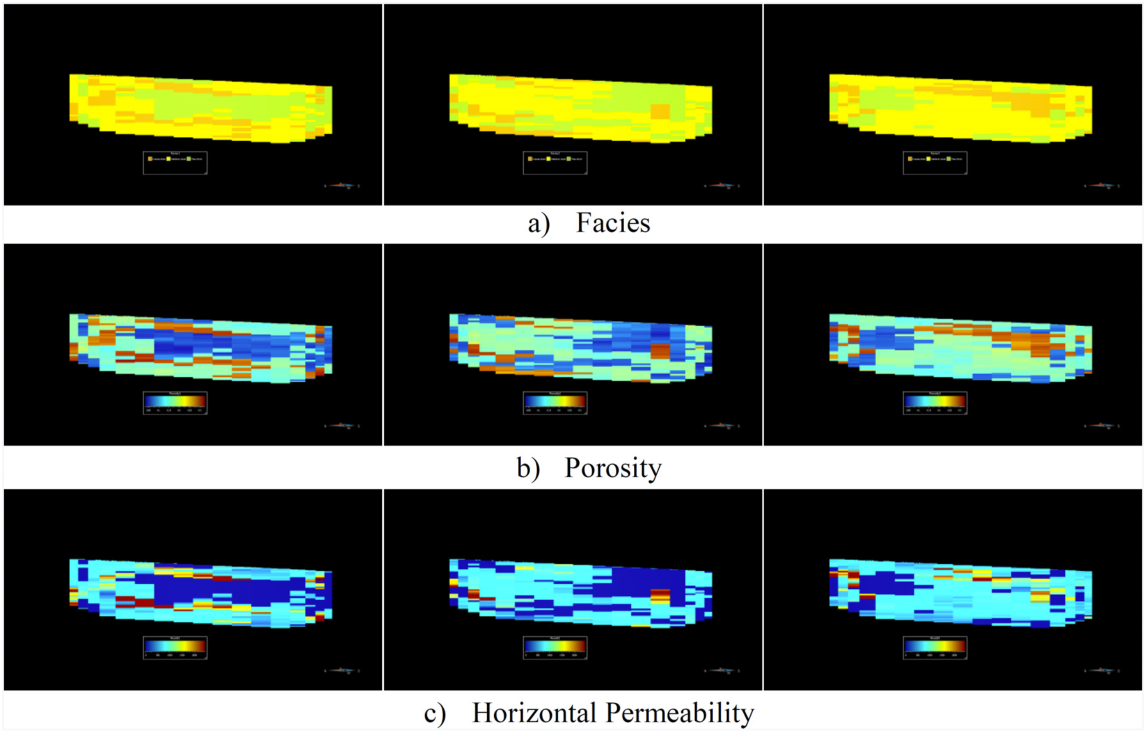


Figure 15—Several Generated Realizations with 0.2 Coarse Sand, 0.5 Medium Sand and 0.3 Fine Sand were viewed from West Side of the Model: a) Facies, b) Porosity and c) Horizontal Permeability

Table 4—Facies and its Properties in the Simulated Reservoir Model.

Properties	Porosity			Permeability		
Facies	Mean	Min	Max	Mean	Min	Max
Fine Sand	0.065	0.0099	0.1200	5.185	0.373	9.997
Medium Sand	0.170	0.1196	0.2203	734	68	1400
Coarse Sand	0.295	0.2410	0.3490	1535	268.136	8106.16

Table 5—Facies Proportion of Three Study Cases

Cases	244	400	563
Coarse Sand	0	0.21	0.18
Medium Sand	0.9	0.65	0.68
Fine Sand	0.1	0.14	0.14

permeability from the injection well to the areas around producers 1 and 2 are lower than those from the injection well to the areas around producers 3 and 4.

As the oil saturation map indicates (Fig. 16c), case 400 has higher residual oil saturation than cases 244 and 563. The oil is mainly in the north region around producer 1 which contains high clay content and has low porosity and permeability. The cumulative oil production curves for the four producers show that, the production well in the lowest clay content area has the highest cumulative oil production. For example, with producer 1, case 244 has the highest cumulative oil production among others because its porosity and permeability are higher than those of cases 400 and 563. The field cumulative oil production of case 400 is lower than that of other cases because it contains more clay and the injection well is perforated in a high clay content zone (Fig. 17; Table 5).

To quantify the effect of clay content (sand facies) on NPV, we ran a sensitivity analysis test for three sand facies. The proportions of each facies were set as sensitivity parameters. Fig. 18 shows that

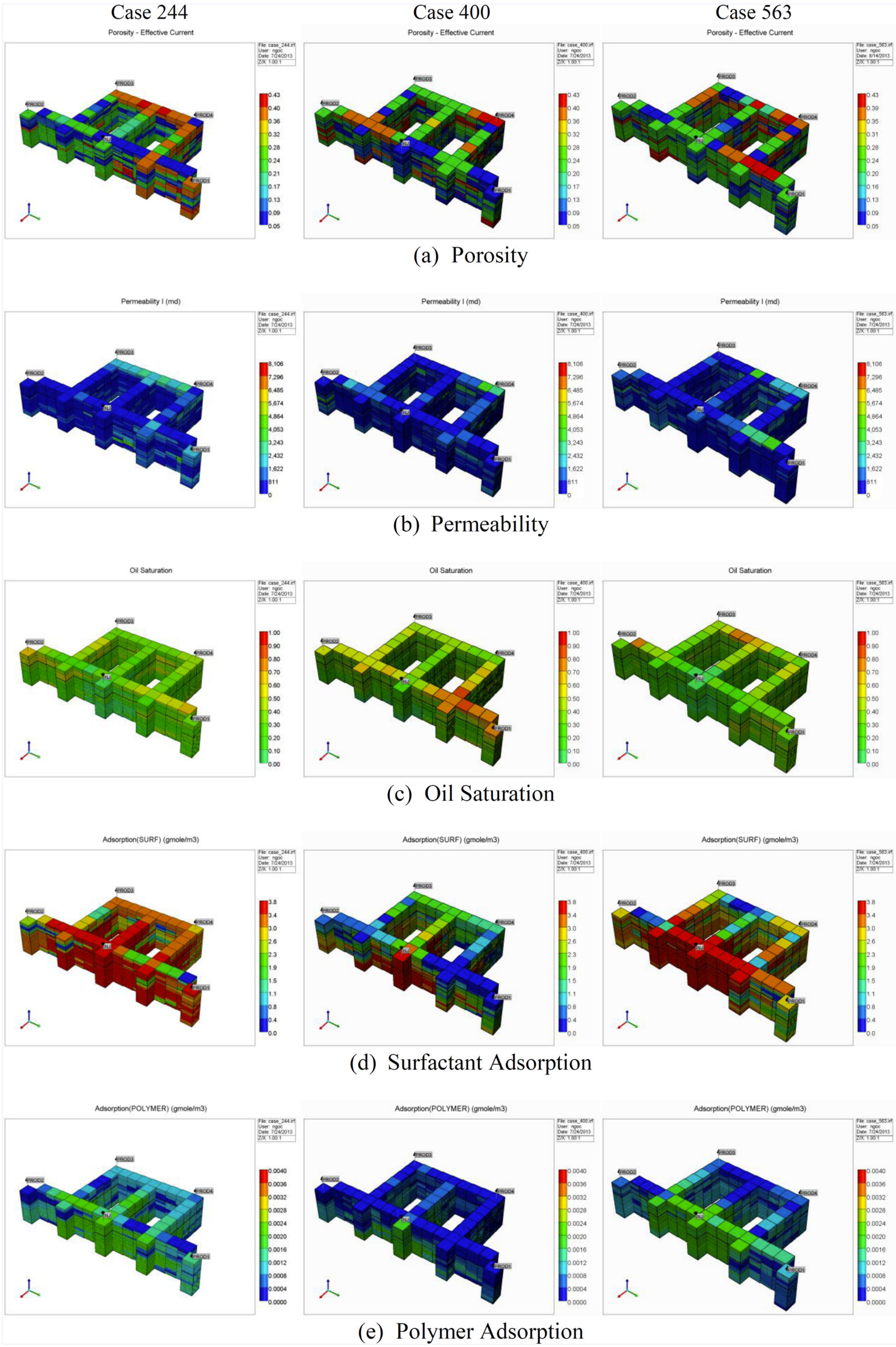


Figure 16—Simulation Results of SP Flooding for Three Cases (Different Porosity and Permeability).

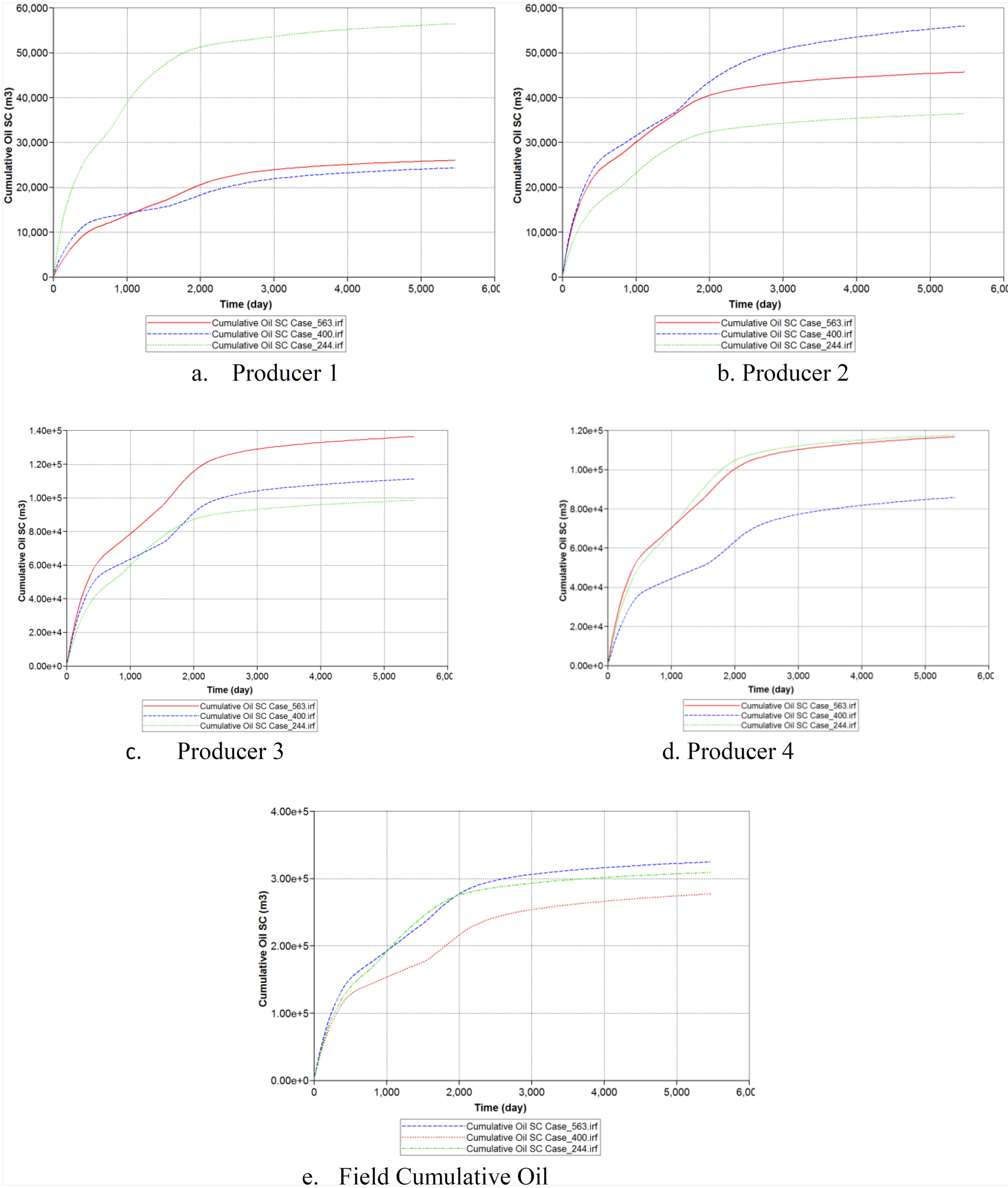


Figure 17—Cumulative Oil Production Curves of Each Producer in the Field.

increasing the fine-sand proportion or decreasing the medium-sand proportion decreases NPV. In other words, increasing clay content in the reservoir will decrease NPV. The results are presented with a constant coarse sand proportion. NPV is higher if the coarse sand proportion is higher.

Also, polymer and surfactant adsorption is strongly influenced by clay content. Surfactant and polymer adsorption mass is high in low porosity and permeability regions (Figs. 16d and 16e). Fig. 16 shows that the adsorbed-polymer/surfactant areas of cases 244 and 563 are larger than that of case 400. This means that the injection fluid of case 400 did not cover the whole reservoir. To compare the success of SP

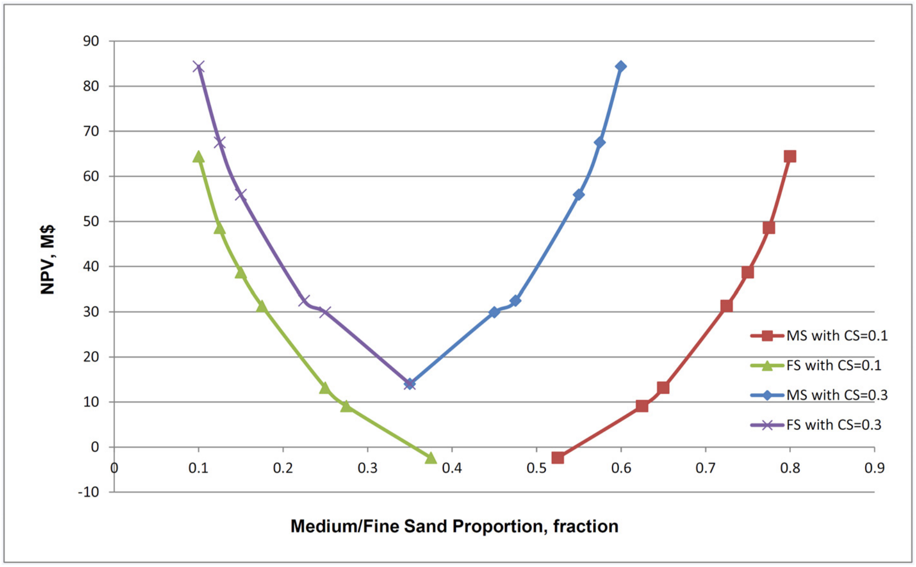


Figure 18—Graph of Facies Proportion versus NPV

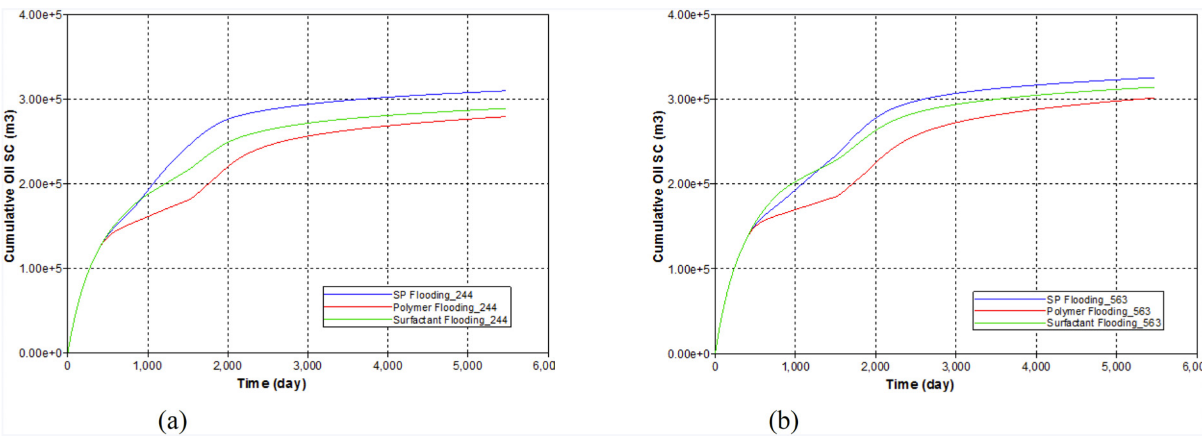


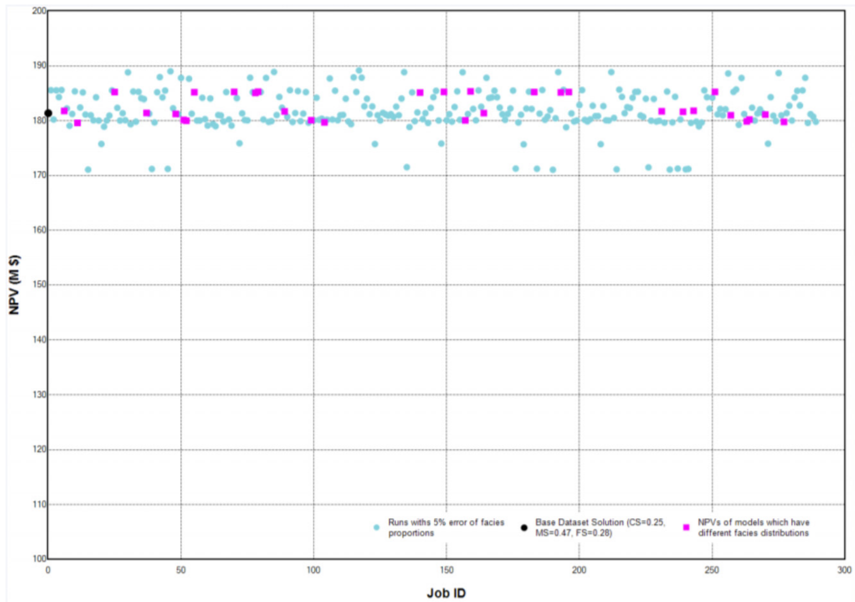
Figure 19—Comparison of Cumulative Oil Production of Three Flooding Methods (a) Case 244, (b) Case 563

Table 6—The Optimal Formulations of SP Slug, Polymer Slugs and Injection Schedule.

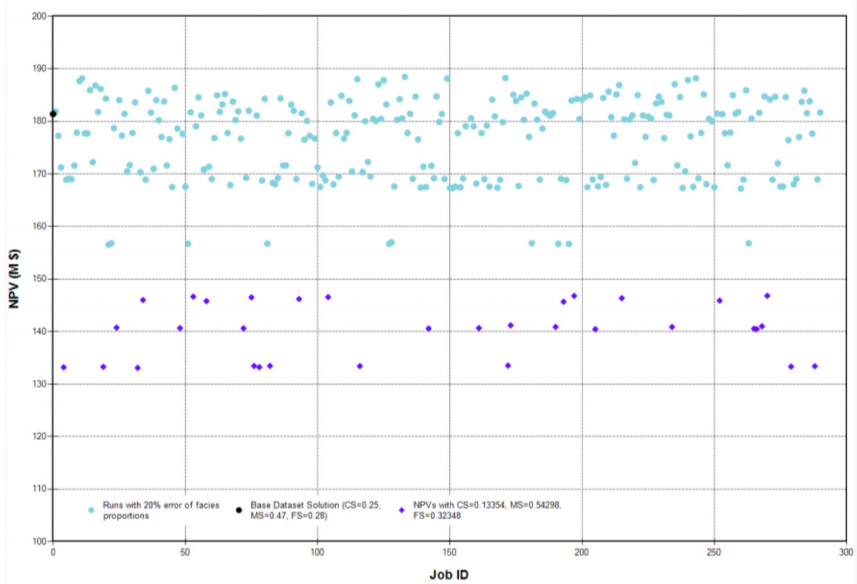
	Normal Optimization	Robust Optimization
Polymer concentration in SP slug, mole fraction	1.6084E-7	1.6084E-7
Surfactant concentration in SP slug, mole fraction	0.00482	0.004112
Polymer concentration in polymer drive slug, mole fraction	9.6004E-7	9.25075E-7
Polymer concentration in polymer taper slug, mole fraction	9.45055E-7	8.95105E-7
Chloride concentration in SP slug, mole fraction	0.00217	0.001675
Chloride concentration in polymer drive slug, mole fraction	0.0031	0.0014
Chloride concentration in polymer taper slug, mole fraction	0.00015	0.0001
Constraints of injection well		
BHP, Kpa	6960	7200
Injection rate, m^3/d	1320	1294.5
Injection Schedule		
SP injection time, days	241	210
Polymer drive injection time, days	686	624
Polymer taper injection time, days	1230	1230
Water injection time, days	1968	2000
Cumulative Oil Production, m^3	470,660.16	475,628.43

Table 7—Facies Proportion for calculating NPV uncertainty

Facies	New Models	Base case Model
Coarse Sand	0.1 - 0.4	0.25
Medium Sand	0.376 – 0.564	0.47
Fine Sand	0.224 – 0.336	0.28



a. NPVs of Runs with 5 Percent Error of Facies Proportions



b. NPVs of Runs with 20 Percent Error of Facies Proportions

Figure 20—NPVs of Different Clay Content and Distribution Models

injection with other methods, we ran polymer and surfactant flooding simulations for two cases. The SP flooding always produces more oil than polymer flooding and surfactant flooding (Fig. 19).

Optimization of SP slug and polymer slug

With the base reservoir conditions (0.2836 coarse-sand, 0.47 medium-sand and 0.2464 fine-sand), we ran an normal optimization to find the optimal formulation of SP slug, polymer slugs and injection schedule. The results are shown in Table 6. The SP slug consists of 1.6084×10^{-7} mole fraction polymer and 0.00482 mole fraction surfactant. The drive and taper slugs consist of 9.6004×10^{-7} and 9.45055×10^{-7} mole fraction of polymer. The SP slug should be injected into reservoir after 241 days of water flooding. Then, polymer is injected and tapered at 686 and 1230 days, respectively. Finally, the last water injection should start at 1968 days. The optimal cumulative oil production can be achieved about 470,660.16 m^3.

In addition, we created additional runs to calculate the effect of geological uncertainty on the optimal NPV's obtained above. This is performed in a closed loop workflow with CMOST™ invoking both GOCAD™ and STARS™. CMOST calls the reservoir property model GOCAD™ to generate reservoir realizations by changing facies proportions and distributions (Table 7). Clay content, porosity and permeability are also recalculated based on new facies distributions. Then, CMOST will run STARS and calculates the new NPV. The results of this uncertainty analysis show how the facies proportion (clay content) and distribution affect the optimal SP design obtained with the base case.

First, we look at the calculated NPVs of the models which have the same facies proportion as the base case but different facies distribution (pink dot, Fig. 20a). The NPV values range from 179.7M$ to 185.29M$. Thus, the uncertainty of the NPV optimization is less than 2.25%. Second, if the facies proportion of our simulation model has an uncertainty of five percent, the NPV of project may vary from 171.07M$ to 188.97M$ (Fig. 20a). The uncertainty of NPV optimization varies from 4.18% to 5.68%. Third, if we increase the facies proportion uncertainty to twenty percent, the calculated NPV will vary from 133.12M$ to 188.46M$. In this case, the uncertainty of NPV varies from 3.9% to 26.6% (Fig. 20b). As a result, the models which contain high clay proportion (violet dot, Fig. 20b), have NPVs lower than the optimum NPV of base case.

Recently, the robust optimization tool has been developed by CMG Ltd. Company to find the optimal objective with multiple realizations. From the uncertainty test, we selected five presentative realizations, which cover the range of NPVs of all run. The result of robust optimization is shown in Table 6. We can see that the optimal cumulative oil production of the robust optimization is higher than that one of normal optimization. By running robust optimization, we have ignored the geological uncertainty into finding the compatible chemical concentrations of the injected slugs and operational conditions in term of maximizing the oil production and the benefit of project. For the detail how robust tool help and improve the result of optimization, we will introduce in another paper soon.

Conclusions

1. We have constructed a geological model and a reservoir model in order to generate new reservoir property realizations that support sensitivity, optimization and uncertainty analysis.
2. The results of simulations have shown that the SP flooding recovers the highest oil production. This method can control water viscosity and diverts the injected fluid into low-permeable zones. The SP flooding always produces higher cumulative oil than polymer flooding or surfactant flooding even in the reservoirs that have high clay content.
3. The optimal formulations of the SP slug and the polymer slugs and injection schedule were identified.
4. We have proposed a method for studying the effect of geological uncertainties in the optimal SP design.
5. We have studied the effect of clay content on cumulative oil production and NPV in terms of facies and its relationship with porosity and permeability.
6. We have also identified most important factors on NPV by sensitivity analysis runs such as

polymer concentrations of each chemical slug, surfactant concentration, injection rate and time.

Acknowledgement

The authors thank the CMOST research group for their valuable advice and comments. We also thank Paradim for providing the GOCAD software and for their assistance in using GOCAD. This work is partly supported by NSERC/AIEES/Foundation CMG and AITF Chairs.

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