SIMULATION OF POLYMER FLOODING APPLIED FOR OIL FIELD IN PHITSANULOK BASIN

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Abstract

This paper examines 2 questions: (1) the study and comparison of oil recovery efficiency between the best case of waterflooding and polymer flooding by using the reservoir simulation technique and (2) the application of the discount cash flow to optimize the polymer flooding selection from each scenario under current Dubai oil prices. Three sizes of oil fields are modeled in an anticline reservoir structure with the original oil in place (OOIP) of 100, 30, and 5 million barrels respectively. Each oil field has many production methods using different polymer concentrations and injection periods. In the large size reservoir model A100, oil recovery has an increase from waterflooding of 3.86-7.24% OOIP. The polymer flooding has an internal rate of return (IRR) range from 28.40-43.76% and a profit to investment ratio (PIR) of 0.37-0.51; the best case scenario is the one that used a polymer concentration of 1000 ppm and an injection period of the 3rd-11th years and which has a net present value (NPV) of $170M. In the medium size reservoir model A30, oil recovery has an increase from waterflooding of 2.42-5.48% OOIP. The polymer flooding has an IRR range from 53.91-56.76% and a PIR of 0.36-0.40; the best case scenario is the one that used a polymer concentration of 1000 ppm and an injection period of the 3rd-10th years and which has an NPV of $53M. In the small size reservoir model A05, oil recovery has an increase from waterflooding of 4.39-4.62% OOIP. The polymer flooding has an IRR range from 20.95-21.73% and a PIR of 0.66-0.76, and the best case scenario is the one that used a polymer concentration of 600 ppm and an injection period of the 4th-20th years and which has an NPV of $15M.

Keywords: Recovery efficiency, polymer flooding, waterflooding, reservoir simulation

Introduction

The oil fields in the Phitsanulok Basin are located in the central part of Thailand. This study focused on the Sirikit oil field which is a part of the Phitsanulok Basin. The Sirikit oil field has been developed by primary and secondary oil recoveries which together have a production of 22978 bbl/d (Department of Mineral Fuels, 2009). For secondary recovery, water injection has been applied to maintain reservoir pressure with some successes; it is still a water breakthrough due to the high mobility ratio and heterogeneity of the geology that has actually occurred at the

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high water cut stage. It causes the poor performance of waterflooding. In order to improve the oil recovery, polymer flooding is an attractive alternative to conventional waterflooding. Minor modifications need to be made to waterflooding to enable polymer injection and recovery of additional oil. Additional polymers with flood water can increase the viscosity of the displacing phase (aqueous phase). The increased viscosity of water during polymer flooding causes a change of the water-oil fractional flow and an improvement in vertical and areal sweep efficiency. Thus more oil is recovered.

Characteristics of Petroleum Reservoirs

The Sirikit field is a main oil field in the Phitsanulok Basin and is the area of this study. The basin is an extensional Oligocene structure. The main reservoir intervals lie within the Oligocene-Miocene fluvio-lacustrine Lan Krabu Formation (Figure 1). The major reservoir facies are interpreted to be lacustrine mouth bars and fluvial distributary channels. The central area of the field is intensely faulted, whereas the western and eastern flanks are relatively undeformed. The field has an estimated stock tank oil initially in place of some 800 million barrels (MMbbl). The main reservoirs contain undersaturated light oil (39.4^{o}API) with the initial reservoir pressure of 3500 psi at a depth of 3850 m. The bubble point is lower than 1800 psi (Trisarn, 2006). Production started during 1982 and reservoir pressure quickly dropped to below the bubble point, which resulted in higher producing gas/oil ratios (GOR) and lower oil rates. The reservoir drive energy was determined to be limited to solution gas expansion, which is aided by gas-cap expansion in some reservoirs. To preserve this energy and to optimize oil recovery, GOR limitations were set for the different reservoirs. As early as 1982, a water injection scheme was suggested for the Sirikit oil field. Consequently, in 1995, full-scale water injection commenced on the eastern, unfaulted flank of the field (Bruce *et al.*, 1999). This study was a field development that investigated optimizing recovery and considered identifying unswept oil volumes.

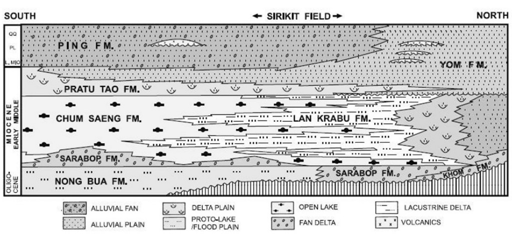

Figure 1. Schematic of general stratigraphy of the Phitsanulok Basin and the Sirikit field. The strata of interest are the Oligocene-Miocene lacustrine deltaics of the Lan Krabu Formation (Bruce *et al.*, 1999)

Enhanced Oil Recovery

The increased oil recovery efficiency by polymer flooding is proven to be workable in widespread distributions, especially in North America and China. In China, the study of enhanced oil recovery by chemical flooding has been carried out for more than 20 years (Han *et al.*, 1999) and has used both types of polymer which are Polyacrylamide (PAM) and Polysaccharide (Biopolymer or Xanthan Gum). The results from Chinese oil fields have proved that the polymer flooding technique can increase the oil recovery of the various reservoir types. This study used Xanthan Gum for the polymer flooding method, which has a better performance than PAM for the high temperature in the reservoir.

The objective of polymer flooding is to reduce the mobility ratio based on increasing the water viscosity. In some cases, the polymer solution reduces the permeability of the reservoir rock to

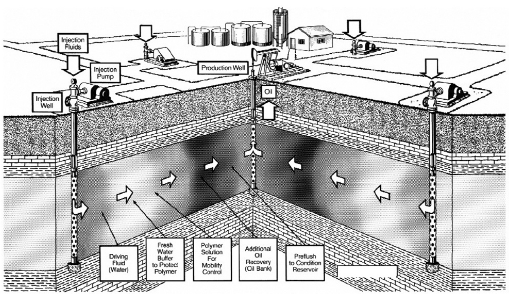

Figure 2. Schematic illustration of polymer flooding sequence, (Lake, 1989)

water. The mobility ratio between the displacing phase (polymer solution) and the displaced phase (oil) will be decreased; therefore, the oil water contact will move steadily in the formation from the injection well to the production well.

The polymer flooding into the reservoir to control the mobility of the injected phase can be shown in Figure 2, which shows a schematic of a typical polymer flood injection sequence: a preflush usually consists of low salinity brine; an oil bank is injected with the polymer; a fresh water buffer protects the polymer solution from backside dilution; and finally the water is driven.

Reservoir Simulation Model design

The performance prediction of water and polymer injection for the fields was built from the ECLIPSE OFFICE simulator model which confined the well pattern. Three sizes of oil fields are modeled with oil in place of 100, 30, and 5 million barrels respectively. The model sizes and dimensions are shown in Table 1. Each oil field has many production methods that use different polymer concentrations and various time intervals for injection. The properties of the reservoir are summarized in Table 2. The simulation pertained to a confined well pattern, the symmetry element being represented by a grid block of 25 x 25 x 8 blocks (5000 cells) for all models, which are shown in Figure 3. The polymer flooding pattern design for a comprehensive flooding simulation relies on the reservoir structure, drainage area, number of wells, and the production and injection activity. The summary of the water and polymer injection rates for each scenario are illustrated in Table 3.

The structural model A100 shows a peripheral flood injection pattern. There are 17 production wells and 8 injection wells located in and around the reservoir boundary. The appropriate spacing of each well is approximately 1000 ft. Model A30 also shows a peripheral flood injection pattern. There are 5 production wells and 4 injection wells located in and around the reservoir boundary. The appropriate spacing of each well is approximately 945 ft. Model A05 shows an inverted 3-spot flood injection pattern. There are a production well and 2 injection wells located at the reservoir crest and downdip of the reservoir boundary, respectively. The appropriate spacing of each well is approximately 350 ft.

The production and injection wells are located in the updip and downdip structure, respectively. The appropriate numbers of the wells are considered to be the optimum for oil recovery, injection of polymer slug, polymer concentration, and economic evaluation.

The structural model of the Sirikit oil field is very important for the maximal improvement of oil recovery. The field is geologically complex, being very faulted in a lacustrine environment and the heterogeneity of the various reservoirs. Trisarn (2006) found vertical heterogeneity of the porosity and permeability of the Sirikit L sand as shown in Figure 4.

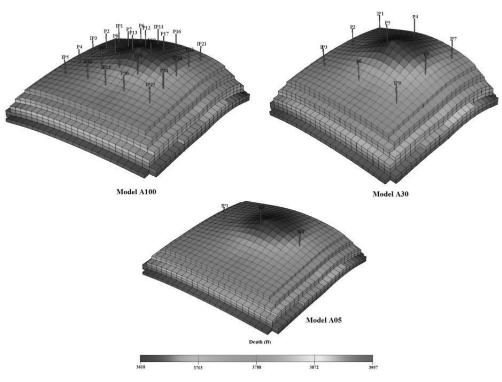

Figure 3. The model structure and confined well pattern of 3 reservoir sizes

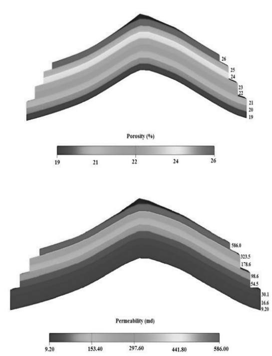

Figure 4. The reservoir sections show the vertical heterogeneities of the reservoir

Results and Discussion of Polymer Flooding Simulation

The waterflooding of each model was tested to find the best case as well as the highest oil recovery from the waterflooding. For all the models the results found that, for the waterflooding to have the highest oil recovery, it can be started within a reasonable time from the 3^{rd} year and water must be injected into the reservoir until the end of the project's life to support the reservoir pressure.

The results of the analysis obtained from the best case scenario of the waterflooding (base case) and the application of the polymer flooding technique in the 3 reservoir sizes of the oil field with different polymer concentrations and various times intervals for injection are shown in Table 4.

Table 1. Model sizes and dimensionst

Model	Dimension (ft)	Horizontal grid dimension (ft)	Area (acres)	Thickness (ft)
A100	6250 x 6250	250	896.75	100
A30	3375 x 3375	135	261.49	160
A05	1250 x 1250	50	35.87	56

Table 2. Summary of reservoir and fluid properties

Parameter	Properties
Depth	3850 ft
Temperature	203°F
Rock type	Consolidated Sandstone
Porosity	19-26%
Oil gravity	39.4°API
Oil viscosity	2.1 cp
Permeability	9.2-586 md
Average k_v/k_h	0.10
Datum depth	3850 ft
Initial static reservoir pressure	3500 psi
Oil formation volume factor	1.055-1.286 bbl/STB
Dissolved gas specific gravity	0.8
Bubble point pressure	1800 psi
Water-oil contact depth	3915 ft

Table 3. Injection rate of scenario tests with barrels of water per day (BWPD)

Model	Injection scenarios	Water injection (BWPD/well)	Polymer/water injection (BWPD/well)
A100	Waterflooding	1000	-
	Preflush by water		1000
	Polymer injection		1000
	Driving water		1000
A30	Waterflooding	500	-
	Preflush by water		500
	Polymer injection		500
	Driving water		500
A05	Waterflooding	200	-
	Preflush by water		200
	Polymer injection		200
	Driving water		-

There are shown the scenarios of polymer injection that could have the highest performance of oil recovery efficiency when compared with the best case of water injection. All scenarios have greater increments of oil from the polymer injection than that would be gained from water injection alone. Model A100's oil recovery has increased by 5.25, 4.60, 3.86, 6.37, 5.73, 4.98, 7.24, 6.58, and 5.83% of OOIP in scenarios 2 to 10, respectively. Model A30's oil recovery has increased by 4.25, 3.42, 2.42, 4.96, 4.01, 2.87, 5.48, 4.33, and 3.13% of OOIP in scenarios 2 to 10, respectively. Model A05's oil recovery has increased by 4.40, 4.48, 4.39, 4.56, 4.39, 4.57, 4.52, and 4.62% of OOIP in scenarios 2 to 9, respectively.

The results show that the polymer flooding can improve the water-swept coefficient and the volumetric sweep efficiency and that, consequently, the water cut in the reservoir decreased. As a result, the polymer flooding method can successfully adjust the mobility ratio between the polymer solution and the oil phase in the reservoir that is effectively prompt of oil recovery efficiency, which are shown Figures 5-7.

The effects of reducing the water cut and increasing the oil production rate are observed for all scenarios in each model. For example, for model A100 with a polymer concentration of 1000 ppm and a time interval injection for the 3rd-11th years, the oil production rate increases after injection of the polymer solution in June of the 6th year, and, at the end of the polymer flooding in the 11th year, the water cut of that reservoir decreases from 25.5% to 3.4% with a production rate increase from 2849 to 3667 bbl/day; in adition, the polymer flooding can maintain oil production at a higher rate than is obtained from waterflooding until June of the 21st year.

For a comparison between waterflooding and polymer flooding from model A100, the oil saturation distribution after polymer flooding by injection with a polymer concentration of 1000 ppm and with an injection slug size of 0.12 pore volume (PV) has been selected to compare with the waterflooding (Figures 8-9). Before polymer flooding, the oil saturation in all layers had been

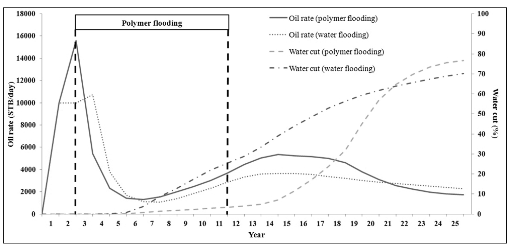

Figure 5. Production performance, model A100-polymer 1000 ppm-injected from the 3rd-11th years

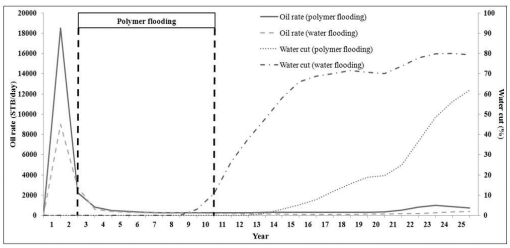

Figure 6. Production performance, model A30-polymer 1000 ppm-injected from the 3rd-10th years

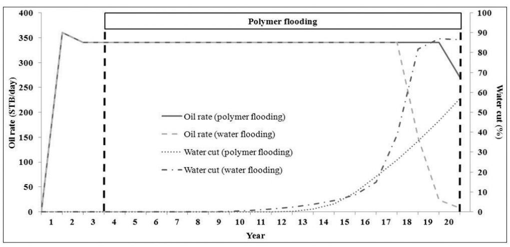

Figure 7. Production performance, model A05-polymer 600 ppm-injected from the 4th-20th years

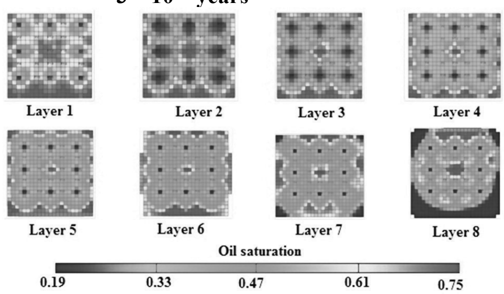

Figure 8. Oil saturation distribution after water-flooding at the end of the project life, model A100-no polymer injection

still very high. From the waterflooding, the oil saturation has decreased only in a small area around the wells. After polymer flooding, in most of the area where oil is in place and can be controlled by the injection wells and the production wells, the reservoir oil saturation has decreased to the residual oil saturation as more oil has been produced.

The comparison shows that oil saturation from polymer flooding has apparently decreased, especially in the upper 6 layers. The polymer flooding has clearly taken effect on improving the volumetric driving efficiency. On the other hand, the 2 lower layers have no effectiveness from polymer flooding because a reservoir with an aquifer may be difficult to flood, due to the flow of the polymer solution in the reservoir not being able to be regulated which is the difficulty in respect of the control of chemical loss.

Increasing the polymer concentration can increase the oil recovery; however, the concentration of polymer needs to be adjusted to a suitable injection rate to prevent the extreme adsorption mechanism on the rock surface and undesired blocking zones. If the polymer slug size is very small, there is almost no enhanced oil recovery. Most of the polymer has been adsorbed on the pore surface of the rock. In addition, a polymer injection with a concentration higher than the appropriate concentration will make a larger particle size which plugs the pore spaces. The oil recovery will be decreased due to the inaccessible pore volume that solid particles of polymer cannot flow through.

The polymer injection within a reasonable time will make for the highest oil recovery. The main importance to improvement of oil recovery is to maintain pressure in the reservoir for the stable pressure drop which controls the oil's optimum flow rate base on Darcy's Law. Therefore, the polymer injection in the early stage of waterflooding is important as mentioned above and the simulation also provides a suitable time period to start the polymer injection.

In a small reservoir that has only a small oil-bearing zone, such as model A05, an economical design of flooding may be not possible, because it is very difficult to flood with respect to the control of chemical loss. Thus, model A05 needs to be used with a lower polymer concentration injection with a long period of time to prevent adsorption and an undesired blocking zone. The effect of polymer injection and the increase in oil recovery are shown in Figure 10.

Economic Evaluation

Economic evaluation is the final step in this study on the application of polymer flooding for enhanced oil recovery. The objective of economic evaluation

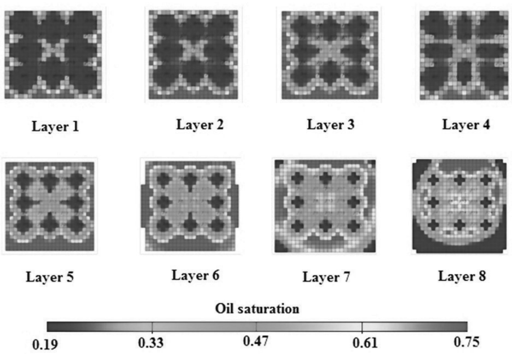

Figure 9. Oil saturation distribution after polymer flooding at the end of the project life, model A100-polymer 1000 ppm-injection from the 3rd-11th years

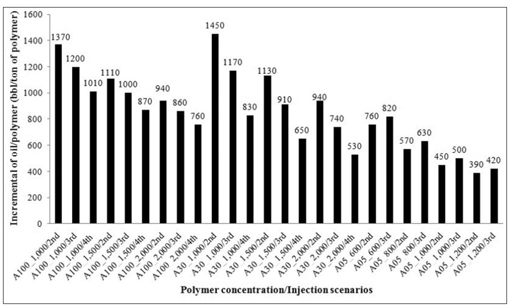

Figure 10. Effect of polymer injection (barrel oil/ ton of polymer)

is the commerciality of each model project resulting from the reservoir simulation. Table 5 lists the economic evaluation parameters used in this study.

The results of polymer flooding in each model are compared with the best case of the waterflooding using the same water/polymer solution injection rate (displacing phase). The results of the economic evaluation are shown in Table 6. This table contains the net present value (NPV), internal rate of return (IRR), and profit to investment ratio (PIR), all 8% discounted. For model A100, the scenario for water injection has the IRR after tax and 8% discounted of 33.49% and the PIR of 0.46, while the scenarios for polymer injection have the IRR after tax and 8% discounted ranging from 28.40-43.76% and the PIR from 0.37-0.51. Accordingly, the best operational case for model A100 is the scenario that used the polymer concentration of 1000 ppm and the time interval of injection for the 3^{rd}-11^{th} years, and which has the best NPV of $170M.

For model A30, the scenario for water injection has the IRR after tax and 8% discounted of 55.43% and the PIR of 0.39, while the scenarios for polymer injection have the IRR after tax and 8% discounted ranging from 53.91-56.76% and the PIR from 0.36-0.40. Accordingly, the best

Table 4. Basic data of polymer flooding

Model	Pattern	Injector/ Producer	Distance between injector and producer (ft)	Scenario No.	Polymer concentration (ppm)	Date of water/ polymer injection	Quantity of injected polymer (ton x PV)	Incremental oil recovery (%OOIP)
A100	Peripheral flood	8/17	1000	1	Water inj. (no-polymer)	3^{rd} -25^{th}	-	-
				2	1000	3^{rd} -11^{th}	4181x0.14	5.25
				3	1000	4^{th} -12^{th}	4181x0.14	4.60
				4	1000	5^{th} -13^{th}	4181x0.14	3.86
				5	1500	3^{rd} -11^{th}	6272x0.14	6.37
				6	1500	4^{th} -12^{th}	6272x0.14	5.73
				7	1500	5^{th} -13^{th}	6272x0.14	4.98
				8	2000	3^{rd} -11^{th}	8365x0.14	7.24
				9	2000	4^{th} -12^{th}	8365x0.14	6.58
				10	2000	5^{th} -13^{th}	8365x0.14	5.83
A30	Peripheral (no- polymer)	4/5	945	1	Water inj. (no- polymer)	3^{rd} -25^{th}	-	-
				2	1000	3^{rd} -10^{th}	929x0.12	4.25
				3	1000	4^{th} -11^{th}	929x0.12	3.42
				4	1000	5^{th} -12^{th}	929x0.12	2.42
				5	1500	3^{rd} -10^{th}	1394x0.12	4.96
				6	1500	4^{th} -11^{th}	1394x0.12	4.01
				7	1500	5^{th} -12^{th}	1394x0.12	2.87
				8	2000	3^{rd} -10^{th}	1858x0.12	5.48
				9	2000	4^{th} -11^{th}	1858x0.12	4.33
				10	2000	5^{th} -12^{th}	1858x0.12	3.13
A05	Inverted 3-spot	2/1	350	1	Water inj. (no-polymer)	3^{rd} -20^{th}	-	-
				2	600	3^{rd} -20^{th}	296x0.34	4.40
				3	600	4^{th} -20^{th}	279x0.34	4.48
				4	800	3^{rd} -20^{th}	395x0.34	4.39
				5	800	4^{th} -20^{th}	372x0.34	4.56
				6	1000	3^{rd} -20^{th}	494x0.34	4.39
				7	1000	4^{th} -20^{th}	465x0.34	4.57
				8	1200	3^{rd} -20^{th}	592x0.34	4.52
				9	1200	4^{th} -20^{th}	557x0.34	4.62

operational case for model A30 is the scenario that used the polymer concentration of 1000 ppm and the time interval of injection for the 3^{rd}-10^{th} year, and which has the best NPV of $53M.

For model A05, the scenario for water injection has the IRR after tax and 8% discounted of 21.72% and the PIR of 0.83, while the scenarios for polymer injection have the IRR after tax and 8% discounted ranging from 20.95-21.73% and the PIR from 0.66-0.76. Accordingly, the best operational case for model A05 is the scenario that used the polymer concentration of 600 ppm and the time interval of injection for the 4^{th}-20^{th} years, and which has the best NPV of $15M.

Conclusions and Recommendations

The heterogeneity of the geological conditions in the reservoirs causes the oil field to have a high water cut stage and low oil recovery efficiency using the waterflooding method. The results of the application of the polymer flooding method in the different sized oil fields with the various polymer concentrations by reservoir simulation found that polymer flooding can increase the oil recovery more than by using only the traditional waterflooding method, due to the polymer solution being able to improve the water swept coefficient and the volumetric sweep efficiency. In addition, these have reduced the water cut in the oil reservoirs of heterogeneous geological conditions. The "Xanthan Gum" polymer solution is used in these oil field simulations. A reservoir with quite a high temperature assures that this polymer solution can increase the water viscosity. Therefore, the mobility ratio between the polymer solutions and the oil will be decreased.

Consequently, for model A100 with the 1000 ppm polymer solution injection and injection period from the 3^{rd}-11^{th} years, there is an increased profit of 1370 barrels of oil production per ton of polymer injected, and the oil recovery efficiency will be increased by 5.25% OOIP more than the waterflooding method. For model A30, with the 1000 ppm polymer

Table 5. Economic evaluation parameter

Project parameters	A100	A30	A05
Dubai oil price (US$/bbl)	80	80	80
Income tax (%)	50	50	50
Inflation rate (%)	2	2	2
Real discount rate (%)	8	8	8
Sliding scale royalty (%)			
Production level (bbl/day)			
0-2000	5	5	5
2000-5000	6.25	6.25	6.25
5000-10000	10	10	10
10000-20000	12.5	12.5	12.5
>20000	15	15	15
Concession ($M)*	3.75	2.50	0.50
Geological and geophysical survey ($M)	5	4	1
Production facility ($M)	250	100	10
Drilling exploration & appraisal well ($M)	10.5	6	1
Drilling and completion production well ($M/well)	1.5	1.5	1.5
Facility cost of water injection well (US$/well)	60000	60000	60000
Facility cost of polymer injection well (US$/well)	62000	62000	62000
Maintenance cost of water injection well (US$/year)	80000	60000	40000
Maintenance cost of polymer injection well (US$/year)	80000	60000	40000
Abandonment cost (US$/well)	12500	12500	12500
Operating cost of production well (US$/bbl)	30	25	20
Operating cost of water injection (US$/bbl)	0.5	0.5	0.5
Operating cost of polymer injection (US$/bbl)	1.0	1.0	1.0
Polymer purchasing price including transportation (US$/kg)	7	7	7

*$M = Million US Dollar

solution injection and injection period from the 3rd-10th years, there is an increased profit of 1450 barrels of oil production per ton of polymer injected, and the oil recovery efficiency will be increased by 4.25% OOIP more than the waterflooding method. For model A05, with the 600 ppm polymer solution injection and injection period from the 4th-20th years, there is an increased profit of 820 barrels of oil production per ton of polymer injected, and the oil recovery efficiency will be increased by 4.48% OOIP more than the waterflooding method.

The polymer flooding would not be economically efficient when the field used an excess concentration of polymer, due to the large amount of polymer consumed. In this case, the polymer flooding will not make the operation profitable because of the higher cost than for waterflooding.

The heterogeneity effect of the porosity and absolute permeability variation needs to be applied and tested for an individual productive reservoir to make a reliable result from the simulation result.

The simulation models used in this study are conceptual models and do not represent the real performance of the oil field in the Phitsanulok Basin.

Table 6. Economic evaluation results summary

Model	Scenario No.	Time of water/ polymer injection (year)	Amount of polymer (ton)	Capital cost ($M)	NPV with8% discounted ($M)	IRR with8% discounted (%)	PIR with 8% discounted (Fraction)
A100	1	23	-	307.33	141.94	33.49	0.46
	2	9	4181	337.10	170.31	43.76	0.51
	3	9	4181	337.10	150.83	33.28	0.45
	4	9	4181	337.10	135.62	28.84	0.40
	5	9	6272	351.74	169.31	43.38	0.48
	6	9	6272	351.73	150.25	33.08	0.43
	7	9	6272	351.73	134.90	28.62	0.38
	8	9	8365	366.38	167.37	43.00	0.46
	9	9	8365	366.37	149.21	32.81	0.41
	10	9	8365	366.37	133.86	28.40	0.37
A30	1	23	-	126.54	49.60	55.43	0.39
	2	8	929	133.04	53.05	54.33	0.40
	3	8	929	133.04	50.83	55.31	0.38
	4	8	929	133.04	52.53	56.76	0.39
	5	8	1394	136.29	52.99	54.91	0.39
	6	8	1394	136.29	50.51	55.21	0.37
	7	8	1394	136.29	52.22	56.72	0.38
	8	8	1858	139.55	52.24	53.91	0.37
	9	8	1858	139.55	49.75	55.08	0.36
	10	8	1858	139.55	51.75	56.68	0.37
A05	1	18	-	17.15	14.26	21.72	0.83
	2	18	296	19.34	14.49	21.21	0.75
	3	17	279	19.22	14.69	21.73	0.76
	4	18	395	20.03	14.38	21.12	0.72
	5	17	372	19.87	14.61	21.67	0.74
	6	18	494	20.72	14.27	21.03	0.69
	7	17	465	20.52	14.51	21.61	0.71
	8	18	592	21.42	14.18	20.95	0.66
	9	17	557	21.17	14.42	21.54	0.68

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