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Methodology to Make Technical and Economic Comparison between Infill Well Drilling and Polymer Flooding

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Abstract: *In the North Sea average recoveries are reported to be above 40% of initial oil in place. The Norwegian Petroleum Directorate in 2001 set a target of 50% recovery for the Norwegian sector of the North Sea and it was envisioned that EOR techniques could be used to achieve this target. However, many oil companies rely primarily on infill well drilling to increase recovery factors as their default option because with the information that they have they can target new wells to recover bypassed oil. EOR techniques involve a greater degree of uncertainty in predicating recovery factors, and therefore, risk and economic assessments are more difficult to perform Awan et al. (2008).*

Addition of polymer to injection water increases the viscosity of the water and hence reduces the mobility of the displacing fluid, increasing the microscopic sweep efficiency. Macroscopic sweep efficiency is also improved by the reduction in channelling in heterogeneous reservoirs. Initially the polymer slug is displaced primarily into the high permeability zones so the mobility in these high permeability zones is reduced disproportionally. Subsequently injected fluid will increasingly displace hydrocarbons from the low permeability zones, improving overall sweep efficiency.

Infill well drilling does not impact microscopic sweep efficiency but seeks to improve the macroscopic sweep efficiency by targeting oil that has not been swept by water. Due to gravity effects this bypassed oil is often to be found near the top of the reservoir and referred to as attic oil.

This paper is going to concentrate on polymer flooding as an EOR technique to compare with infill well drilling. A probability distribution tool, such as a Monte Carlo simulation, is used to identify the impact of input variables on the economic outcomes, such as mean, standard deviations, P10, P50, and P90.

Flow charts (Fig. 1) were developed in this study following the work of Gharbi (2005) describing the steps used for the polymer flooding project optimizationand then making a comparison with infill drilling to maximise recovery from mature assets. Then a range of reservoir simulation scenarios were run to test possible recovery outcomes; these outcomes will then provide input data that were used in the probabilistic economic evaluation tool.An economic assessment is made of the costs and risks of the various options together with expected return under a range of economic scenarios.

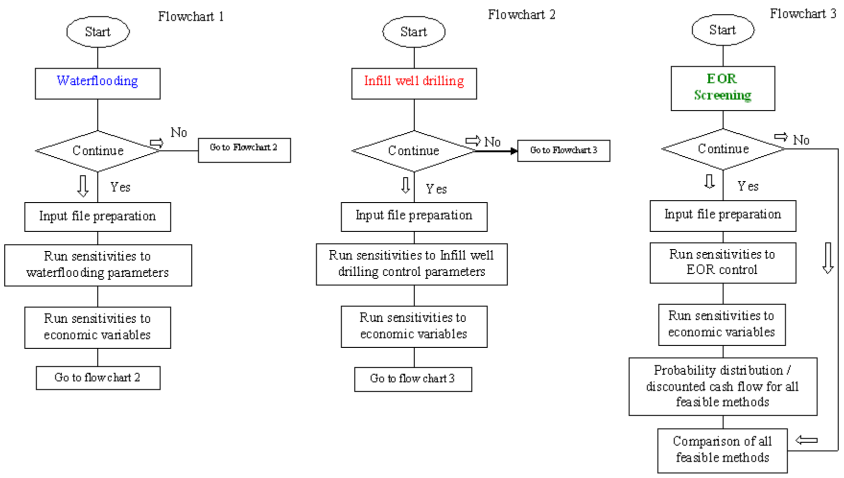

Figure1. *Flow chart for the expert system (following Gharbi 2005)*

1. Introduction

At present, the world-wide production statistics indicate that the ultimate recovery from light and medium gravity oils by conventional (primary/secondary) recovery methods is around 25-35 % of the

OOIP, while from heavy oil deposits, on average only 10 % OOIP is recoverable. Hence a substantial fraction of oil in place is non-recoverable by conventional methods, and these remaining reserves may become the target for EOR to increase the recovery fraction Zekri et al. (2000).

Polymer flood may be used to enhance oil recovery from a reservoir by improving reservoir sweep and reducing the amount of injection fluid needed to recover a given amount of oil. Polymer floods work by adding low concentrations of water-soluble polymers to injection water to increase the injectant viscosity. This is done to more closely match the injectant viscosity to that of the in situ oil, and thus achieve a more favourable mobility ratio and sweep efficiency Kaminsky et al. (2007).

An optimization methodology technique was developed to assist in choosing between polymer flooding and infill well drilling by combining Reservoir Engineering and Petroleum Economics.The approach used in this paper involves, performing reservoir simulation calculations to estimate additional oil recovery, and then making a comparison with a similar scenario, but where infill drilling has been used to maximise recovery instead, and provide these as input to an economic model. The output of the economic model will be net present value (NPV) or some other economic parameters, such as return on investment (ROI). This approach was done for polymer flooding, but the approach could be used for other EOR techniques also.

The production data obtained from the simulationresults were imported into an economic model in orderto evaluate the project profitability of a particular design.The economic model required thefollowing variables: (1) time (yr), (2) polymer/water injected, (3) cumulative oil recovery, and (4) totalfluid production (bbls).

It is useful to perform fractional flow analysis of any reservoir system to identify whether it is suitable for any particular recovery process, before a decision is made to undertake detailed reservoir simulation studies.The fractional flow of water relative to total liquid flow (f_w), ignoring gravity and capillary pressure, is giving by;

$$f_w = \frac{1}{1 + \frac{K_{ro}}{K_{rw}} . \frac{\mu_w}{\mu_o}}$$

Figure 2 and 3 show typical plots of normalised relative permeabilities and the corresponding fractional flow curve for this synthetic system.

An important parameter in determining the effectiveness of a waterflood is the end point mobility ratio. The mobility ratio for the synthetic system is greater than 1 which is unfavourable but at approximately 2 is not severe. In addition, the permeability ratio between high and low permeability layers is 10:1. Therefore this is a case that might benefit from polymer flooding although the benefit would only be marginal, and would very much depend on the cost of materials, etc. Although there are reservoirs which are candidates for polymer flooding which have similarly low oil viscosities (<5 cP), Visual inspection of the waterflood identified areas of unrecovered (bypassed) oil. These resulted from combination of the viscous and the gravitational forces, and the system heterogeneity, and meant that late field recovery was occurring at high water cuts, but with significant recoverable reserves still in place. The main factors were an average permeability ratio between zones of 5 to 1 and inter-well distance of 1125 ft and formation thickness 150 ft.

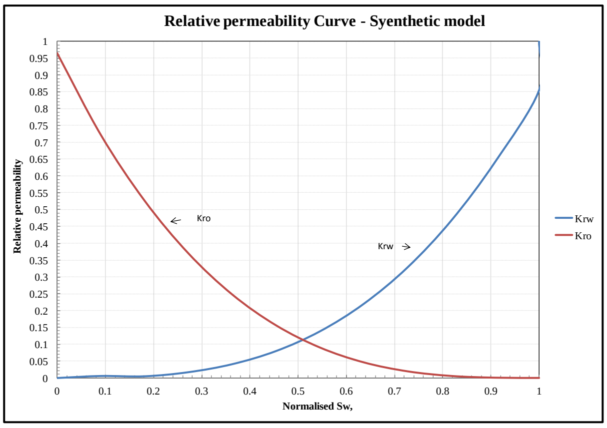

Figure2. *Typical permeability curve for the Synthetic Model*

Fractional flow plots for the two cases are shown in Figure 3 and the results obtained by applying Welge's graphical technique, at breakthrough, are listed below:

The producing water cut at flood front (f_{wbt}) and the saturation at flood front before water breakthrough (S_{wbt}) are calculated. Then the average saturation at $f_w = 1$, behind flood front after water breakthrough can be evaluated.

Figure 3 indicates that for waterflooding, the leading edge of the flood front has a water saturation of 60%. The leading edge of the flood front for polymer flooding has a higher water saturation of 88%.

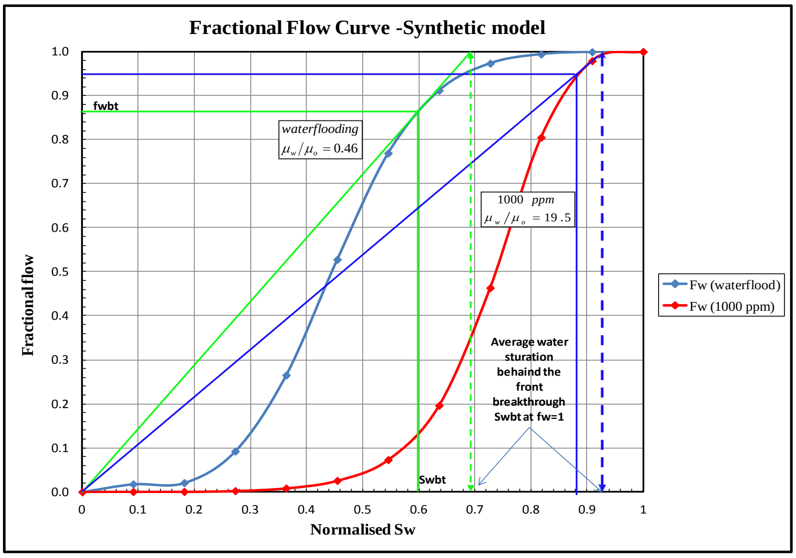

Figure3. *Typical plots of fractional flow curve for the Synthetic Model*

The results of the fractional flow can be summarized in Table1 and Table2:

In the waterflooding case the oil-water viscosity ratio is greater than 1 ($\mu_o/\mu_w = 2.2$), leading to a slightly unfavourable mobility ratio (M=2), and so oil is bypassed at early breakthrough of water. The oil recovery at breakthrough is 60% of the mobile oil.

In the polymer flooding case ($\mu_o/\mu_w = 0.05$), the mobility ratio is less than one – i.e. is favourable. The oil recovery can be increased to over 88% recovery of mobile oil at breakthrough by addition of polymer at 1000 ppm polymer concentration.

The results obtained by applying Welge's graphical technique, at breakthrough, are listed below in Table1:

Table1. *Oil recoveries and saturation at breakthrough for Buckley-Leverett method*

case	S_{wbt}	Reservoir	Surface	$\overline{\overline{S_{wbt}}}$	N_{pdpt} (PV)
		f_{wbt}	f_{wsbt}		
WF	0.60	0.86	1.02	0.69	0.60
1000 ppm	0.88	0.92	0.925	0.93	0.83

Values of M and M_s (the mobility ratio at the shock front) for waterflooding and polymer flooding for 1000 ppm polymer concentration are listed below in Table2.

Table2. *Values of the shock front and end point relative permeabilities calculated using fractional flow.*

case	S_{wf}	$\frac{\mu_o}{\mu_w}$	$K_{rw}(S_{wf})$	$K_{ro}(S_{wf})$	M_s	M
WF	0.60	2.2	0.18	0.06	0.47	2
1000	0.88	0.05	0.58	0.0007	0.03	0.05

To calculate the water saturation profile, firstly the relative permeability ratio K_{ro}/K_{rw} versus water saturation is plotted on a semi log scale to determine the values, and then the fractional flow derivative has to be calculated. For this case, Figure shows the fractional flow (f_w) and the fractional flow derivative (dF_w/dS_w) versus the water saturation (S_w) for the waterflooding scenario. Figure shows the same for polymer flooding at polymer concentration of 1000 ppm.

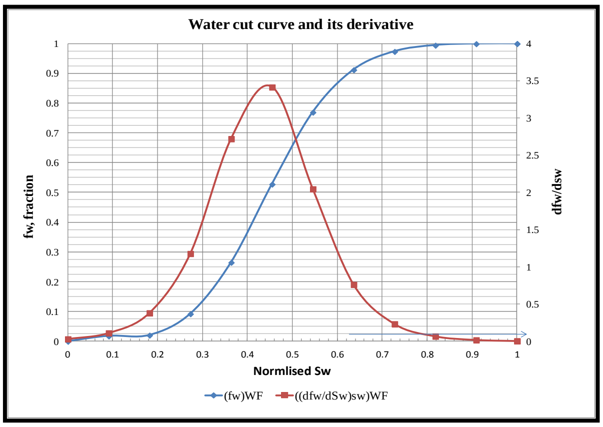

Figure4. *F_w and dF_w/dS_w vs S_w (waterflooding)*

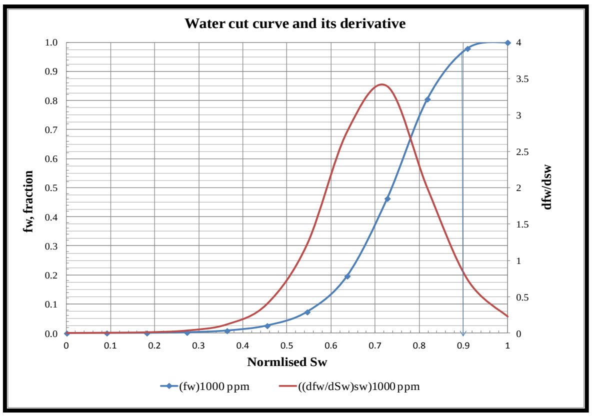

Figure5. *F_w and dF_w/dS_w vs S_w (polymer flood at 1000ppm)*

Figure shows the shock front at which the water saturation rapidly increases from S_{wc} to S_{wf}. Behind the flood front there is an increase in saturation from S_{wf} to $1\text{-}S_{or}$. The time to breakthrough for waterflooding is 0.83PV and the time to breakthrough for polymer flooding is 0.91PV.

This analysis indicates that the mobility ratio is not highly unfavourable, and thus for the waterflood the recovery at water breakthrough is 60% of mobile oil in place. However, the mobility ratio is unfavourable, and thus there is an opportunity to use polymer to increase sweep efficiency and recovery, and use of polymer at a concentration of 1000 ppm could increase the recovery at water breakthrough to 83%. Caution should be used with this type of analysis for a variety of reasons. It is assumed that in the polymer flood case all the water has the viscosity of the polymer solution. However, in front of the polymer slug there will be banking of connate water, and this banked connate water will not be viscosified, and so the recovery when this water breaks through will probably be less than 83%. Also, addition of polymer will entail additional cost. The question that has to be addressed is whether the potential improvement in sweep efficiency and ultimate recovery merits the additional investment. This analysis indicates that there is value in performing the reservoir simulation and economic calculations to address this question.

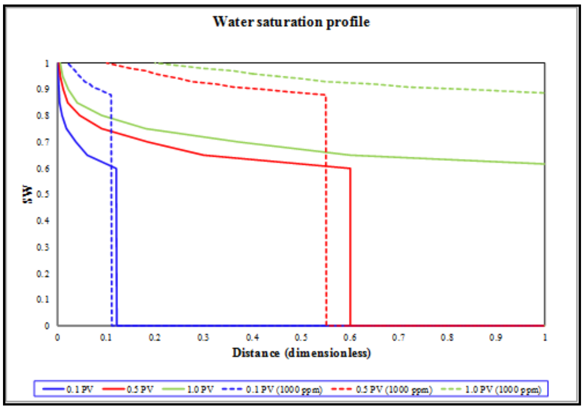

Figure6. *Water saturation profile as a function of distance and time*

Polymer is sometimes included in surfactant flooding. The reason for this is that addition of surfactant can reduce the residual oil saturation, mobilising more oil, but it tends to result in a mobility ratio that is more unfavourable than for the conventional waterflood. As an example, Figure shows the fractional flow curve for surfactant injection, and compares it to the waterflooding and polymer flooding scenarios already presented. It is clear that water breakthrough occurs at a lower water saturation. In this calculation, the water and oil viscosities have not been changed relative to the base case waterflooding scenario – only the impact of the surfactant on the relative permeability curves has been included. Figure shows that the flood front advancers more quickly. The subsequent increase in water saturation is more gradual. At the production well, this would translate into early water breakthrough (at 0.65 PVI, compared to 0.83 PVI for the waterflooding case), and a more gradual increase in water cut after breakthrough, compared to the conventional waterflood.

At high flow rates, as occurs near the injection wells, the addition of polymer may have an impact in reducing residual oil saturation somewhat. However, rather than improving only the microscopic sweep efficiency, as surfactant flooding does, polymer flooding primarily acts by increasing the microscopic and the macroscopic sweep efficiency, giving better conformance control and a more piston like displacement. Polymer and surfactant flooding should not be considered as mutually exclusive, and thus addition of polymer to a surfactant flood is used to reduce the impact of early breakthrough that would otherwise occur if only surfactant is used.

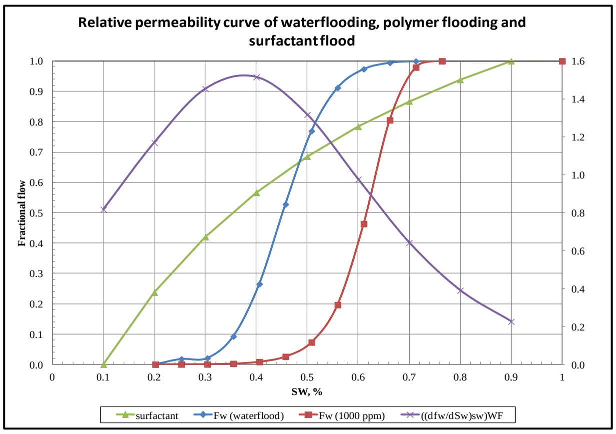

Figure7. *Shows the fractional flow curve for surfactant injection, and compares it to the waterflooding and polymer flooding scenarios*

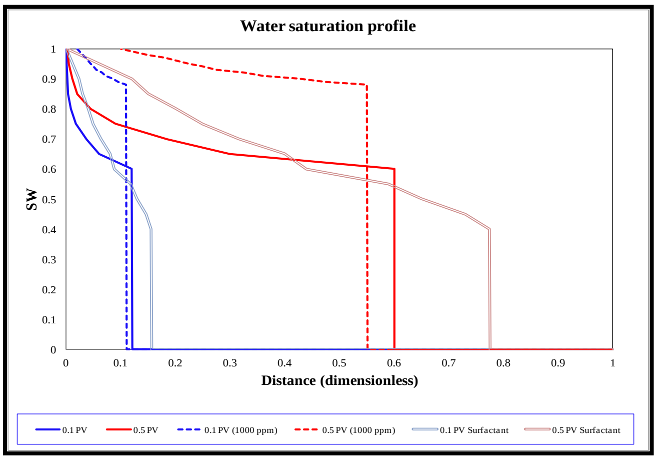

Figure8. *Water saturation profile as a function of distance and time for surfactant injection, and compares it to the waterflooding and polymer flooding scenarios*

2. Development of the Reservoir Simulation Methodology

2.1. Reservoir Simulation Model 1 for Polymer Flood (Simple Two Well Synthetic Model) and Economic Model

Having identified that the reservoir simulation study should be conducted, the following input control parameters were included in the modelFigure 9. In the base case, polymer flooding was assumed for

10 years after two years of waterflooding,and sensitivity calculations performed:

- The injecting well was controlled by an injection rate of 2000 bbl/day.
- Concentration of polymer: 100, 200, 500,1000 and 1500 ppm
- Three contiguous periods of injection:
  - Period of waterflooding (variable)
  - Period of polymer flooding (variable)
  - Period of waterflooding until reach 90% water cut.

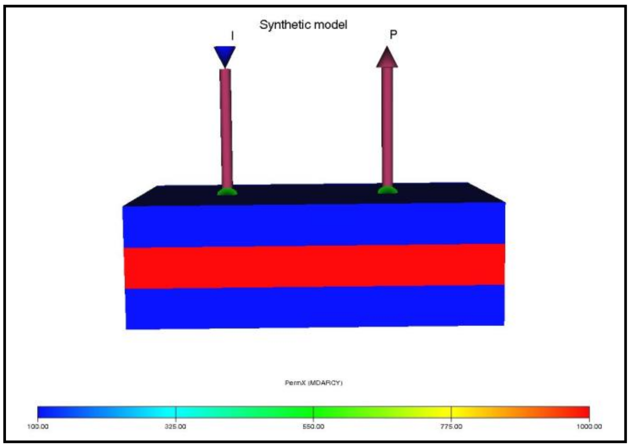

Figure9. *Synthetic model, with high permeability layer in the middle.*

The procedure for the reservoir simulation calculations is as follows:

- 50 sensitivities have been run with polymer concentrations of 100, 200, 500, 1000, 1500 ppm for various durations (see below).
- Three contiguous stages (total time up to 24 years):
  - Stage 1: Water flood
  - Stage 2: Polymer flood
  - Stage 3: Water flood for up to 12 years, depending on WCT
- Stage 1 commences in Year 1, and last for year 2.
- Stage 2 lasts between 1 and 10 years.
- The following output is generated
  - Field oil production total (FOPT)
  - Field water production total (FWPT)
  - Field water injection total (FWIT)
  - Field polymer injection total (WCIT)
  - Field polymer production total (WCPT)

Ten scenarios are presented in this paper for the concentration of 1000 ppm. The injection rate during polymer flooding remained the same as during the conventional water flood. The oil production rate was higher under polymer injection than it was for water flooding until 2020 for all the cases.

The incremental oil is measured as the difference between waterflood and polymer flood oil recoveries and is shownin Figure 10. The case with no polymer injection at all gave the poorest recovery which is 44.9 %, and the various options for timing of polymer injection gave intermediate levels of oil recovery. The oil production rates calculated in the various scenarios are used as input for the economic modelling. However, the key question is not which sensitivity leads to the highest oil recovery, but which one results in the best economic performance. In the following tables and figure are presented oil recoverey data as Field Oil Efficiency (FOE), which is defined as the cumulative oil recovery to date divided by the initial oil in place, and is always afraction between 0 and 1.

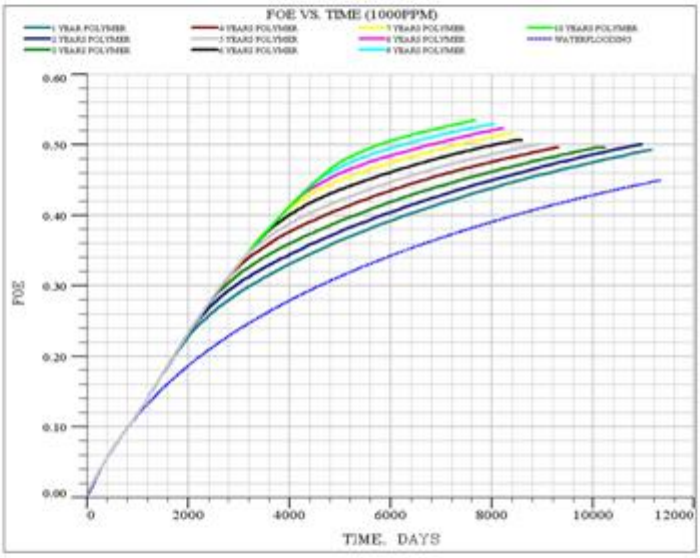

Figure10. *Field Oil Efficiency (FOE) for polymer concentration of 1000 ppm*

Economic analysis is an essential aspect of a reservoir management study. The economic performance of a prospective project is often the deciding factor in determining whether or not a project is undertaken. Consequently, it is important to be aware of basic economic concepts and factors that may affect the economic performance of the project. Economic sensitivity analysis should be performed on key input variables such as oil price, the price of polymer injection, capital expenditure (CAPEX), operating expenditure (OPEX), and oil recovery. The aim is to develop sensitivity analysis graphs for different variables to assess future plans in terms of EOR projects and economics.

Cash Flow = Revenue – Capital expenditure – Operating expenditure…..…………………….......… (1)

The point in time on the graph when the cumulative DCF reaches to zero after the project has begun is the payback period. The payback period is defined as the time taken, from the start of the project, to reach this position.

The discount rate that, applied to all cash flows, returns a zero NPV is called the Internal Rate of Return (IRR). The Internal Rate of Return and playback period are measures of the economic viability of a project.Table 1shows the constant parameters in the economic model.

Table1. *Parameters used in the economic model*

Start of Polymer Injection	*2011*	*Units*
Oil Prices	*30 - 50*	*$/bbl*
Capex	*1*	*mm$*
Discount Rates	*10*	*%*
Present Incremental Oil Production Cost	*8.00*	*$/bbl*
Present Water Injection Cost	*2.00*	*$/bbl*
Present Water Production Cost	*2.00*	*$/bbl*
Present Polymer Cost	*1.50*	*$/lb*
Polymer Concentration	*1000*	*ppm*
Present Incremental Polymer Injection Cost	*0.50*	*$/bbl*
Present Incremental Polymer Production Cost	*0.50*	*$/bbl*

Figures11&13 show discounted cash flow (DCF)by years at discounted rate of 10 %, and$30 and $50 oil prices, respectively. *Figures 12&14* show typical plots of cumulative discounted cash flow (CDCF) as a function of time at $30 and $50 oil prices. The early time of the plot (2009 to 2011) indicates negative NPV; this part of the project is dominated by Capital expenses.After 2011 the eventual growth to positive NPV is due to the generation of revenue in excess of expense. The payback period is approximately 1.2 years after the polymer flooding was started.

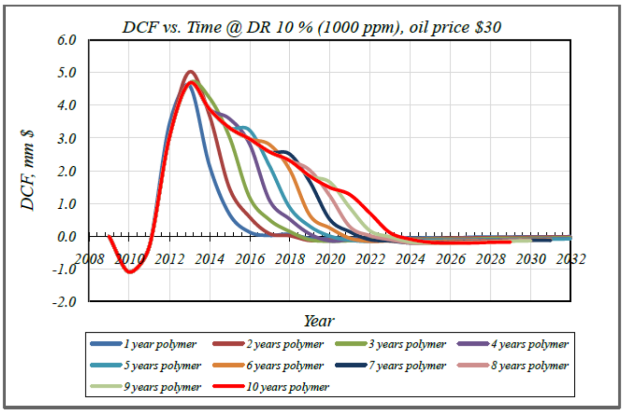

Figure11. *DCF for oil price of $30*

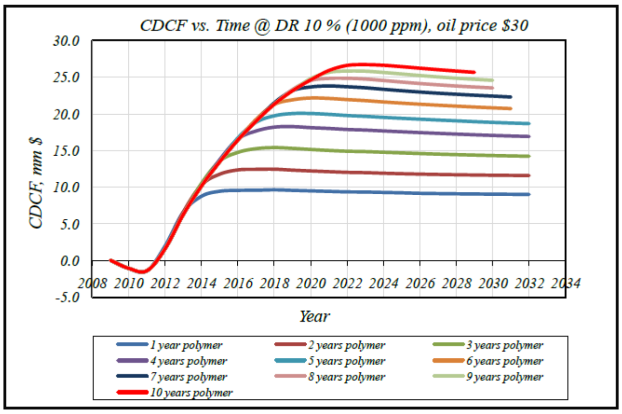

Figure12. *CDCF for oil price of $30*

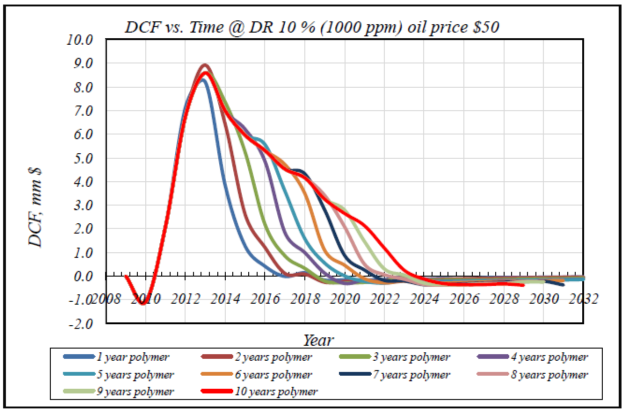

Figure13. *DCF for oil price of $50*

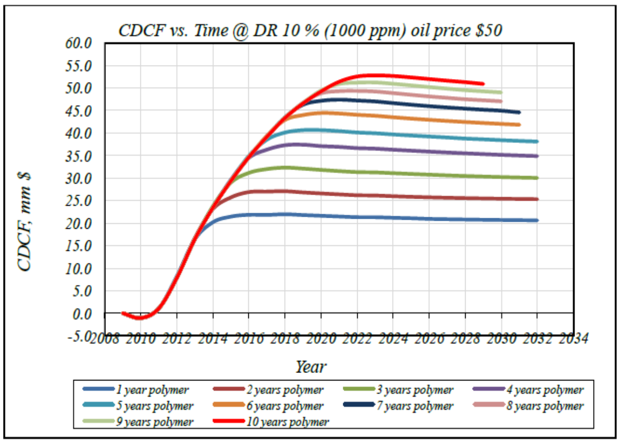

Figure14. *CDCF for oil price of $50*

2.2. Reservoir Simulation Model 2 For Polymer Flood (Simple Three Well Synthetic Model) and Economic Model

A new production well wasadded to the model in 2011to compare the recovery factor between infill well drilling and polymer flooding in terms of production. The distance between the oil production well (p) and the new infill well is 450 ft (137 m)(Figure 15).

The injection rate during the new infill wellscenario remains the same as during the conventional water flood. The oil production rate continues higher with thenew infill well than it did for water flooding until 2023,and then the model stopped from running because of the water cut limitation exceeding 90 %.

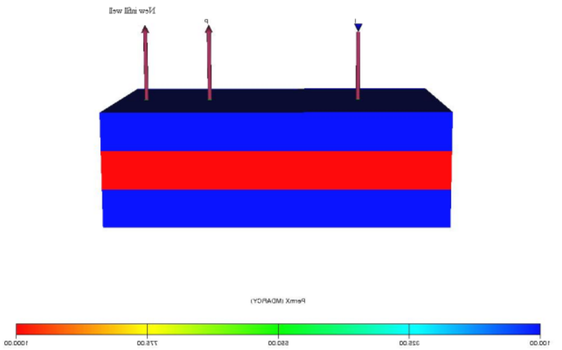

Figure15. *Synthetic model, with new infill well*

*Figures16& 18*show discounted cash (DCF) flow by years at discounted rate of 10 %, and \$30 and \$50 oil prices, respectivily. *Figures17& 19*show a typical plots of cumulative discounted cash flow (CDCF) as a function of time at \$30 and \$50 oil prices. The early time of the plot indicates positive NPV, because the very quickly additional investment is much lower than for polymer flooding.

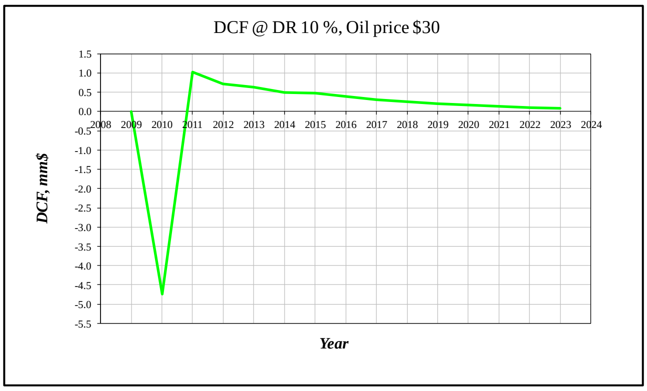

Figure16. *DCF for infill well vs. waterflooding*

Figure17. *CDCF for infill well vs. waterflooding*

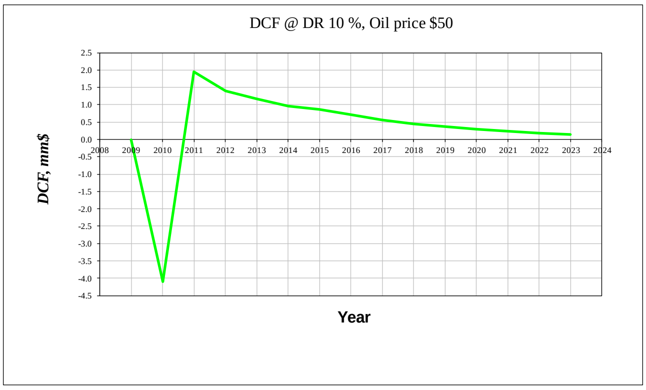

Figure18. *DCF for infill well vs. waterflooding*

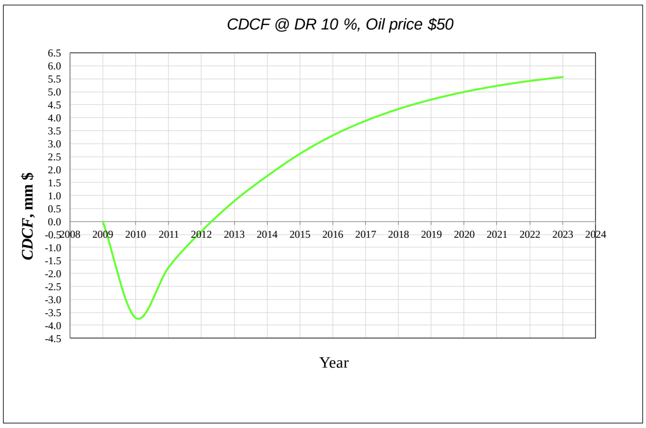

Figure19. *CDCF for infill well vs. waterflooding*

3. CONCLUSIONS

The development of this modelling technique is still ongoing. However, the method that has been developed so far, and as applied to the synthetic dataset, has led to the following interim conclusions:

- This project has focused on the development of a method to test theeconomic viability of polymer flooding compared to infill well drilling, but can be modified to suit other enhanced oil recovery methods.
- The technique involves running a range of reservoir simulation scenarios to test possible recovery outcomes; these outcomes then provide input data that is used in a probabilistic economic evaluation tool.
- The method has been applied to a synthetic scenario, which has demonmstrated the impact that oil price can have on the decision making process.
- For example, with relatively early application of polymer flooding at a concentration of 1000 ppm,the method shows that in this case polymer flooding is clearly more economically attaractivethan infill well drilling.

FUTURE WORK

This work is ongoing, and further results will be published in the future.While initial development work has been conducted using a simplisitic 2 or 3 well synthetic model, the method will be applied and tested with field scale models as part of the conclusion of this project. Futher work includes the following plan:

- Investigate the impact in delaying the start of polymer flooding to identify whether it is better to start polymer flooding earlier or later in the life of the project.
- These calculation are performed routinely, and are included in this paper only as a lead in to the future work, where instead of considering a few economic calculations based on a limited set of reservoir engineering scenarios, then consider a method to compare ranges of economic scenarios based on ranges of reservoir simulation sensitivity calculations, to derive a more comprehensive

overview of the comparison between different recovery methods, is presented in full, taking full account of the combination of reservoir and economic uncertainties.

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