# SIMULATING THE STRATEGIES OF OIL FIELD DEVELOPMENT FOR ENHANCED OIL RECOVERY

by

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*Many years have passed in oil field development but primary challenges faced by the X reservoir are the rapid decline of formation pressure and the significant solution gas released from the formation, which impairs production. Based on these challenges, a compositional simulation model of the X reservoir was constructed and run to establish the future development plans. The basic reservoir data collection and processing, quality assurance of the data, characteristic pressure-volume-temperature (PVT) matching by ECLIPSE PVTi, and simulation of various adjustment strategies to forecast development plans, as well as data sensitivity analysis and optimization has been included in this study. In addition, to establish a desirable development plan, the simulation model is set-up in great consistency with the geological model resulted from the seismic and logging interpretations. Also, emphases are paid on establishing matches with the reported lab data from production wells by PVTi. Results revealed that the specific reservoir development plan intends to reinstate or maintain formation pressure of the X reservoir. All design and optimization studies are set to comprehend the reservoir with the numerical model.*

Key words*: field development, rock and fluid properties, oil production, gas production, water cut*

## Introduction

Oil is one of the most critical and noteworthy energy sources until now and has contributed an essential role in fulfilling energy requirements [1]. To meet the demand of oil for the next coming decades, it is essential to explore the new oil fields along with enhancing the oil production from existing producing wells. Even after achieving the latest techniques, in primary and secondary recovery, only one-third of the oil in the reservoir can be recovered [2-4]. After drilling in reservoir, initially reaches out at surface by using inherent pressure (primary recovery). As this initial pressure dissipates, the more oil is recovered by injecting local available seawater as an external source which is so called secondary recovery. Enhanced oil recovery (EOR) is a technique ascribe to that reservoir processes in which oil cannot reach the surface by using flooding techniques [5-8]. Chemical EOR is one of the foremost technique that is not frequently used to recover remaining and residual oil from reservoir due to certain reasons

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such as high prices of chemicals. In this technique, various chemicals are used *i. e.* polymers, surfactants and/or alkalis which maximize the macroscopic (volumetric sweep efficiency) and microscopic efficiency (displacement efficiency) [9, 14].

Hydrocarbon exploration and exploitation involves huge investments and risks. However, the industry's aims to devise ways of producing as much hydrocarbon as possible from any field discovered to ensure maximum returns from the investments [15]. So to achieve this goal, a good development plan is vital. It includes simulation studies of the reservoir, where the reservoir output will be tested at various methods of recovery, and production conditions will assess the optimal method that will yield as much crude as possible. It will also direct the design of surface facilities needed to handle the fluids that are generated [16].

In this work, a simulation study is done in the X reservoir (conventional sandstone reservoir). The primary issue being observed at the X reservoir is the rapid drop in formation pressure. As a result, the preliminary focus in development planning is on how to restore or maintain the formation pressure. A series of adjustment strategies based on water injection and gas recycling has been developed and simulated to establish future development plans.

## Field background

The X-oil field structure is located in the western area of the South Sumatra Basin, and Indonesia. The structure is a typically half-graben feature that became slightly re-inverted by later younger tectonism event in Plio-Pleistocene time. The paleo-high, composed granitic basement, where a thin reservoir developed on the crest, was cut through by northeast-southwest trending normal fault kept hydrocarbon trapped in the west structure. Fluvial sands of the reservoir Talang Akar on lapping and draping on the basement high to the crest of the paleo-high formed integrated structural and stratigraphic play trap.

## Simulation data preparations

### *Rock properties*

The realistic data were collected from approximately 5000 ft depth and of 5-800 mD (mid Depth) in absolute permeability. The average porosity is measured at 20%. The initial water saturation ranges from 16% to 50%. The relative permeability function used in the simulation was directly derived from a Corey relative permeability relationship [17]. The Corey exponents were chosen so that the simulated and observed relative permeability are in a sufficient agreement. In the simulation model, a digital table of the relative permeability can be set up after normalization. fig. 1 show the normalized permeability curves used in the simulation model for both high and low permeability group, respectively. These curves are then used as input in reservoir simulation runs. Similarly, for oil-gas relative permeability and oil-water capillary pressure functions, the same procedure, as in the oil-water relative permeability function, was applied to determine the best representative capillary pressure curves.

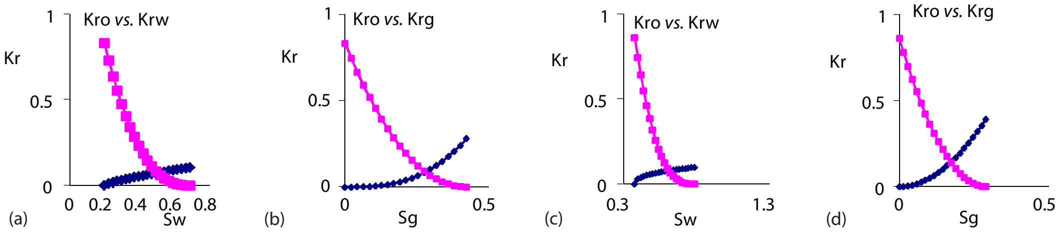


**Figure 1. (a) and (b) low, and (c) and (d) high permeability curve used in the simulation model**

*Reservoir conditions by labora tory data*

A combination of PVT Analysis was performed by using Schlumberger's PVTi program. The basic fluid composition was input as required for the calculation. The primary objective of the analyses is to generate a phase envelope diagram and identify the initial pressure and temperature condition at the X reservoir. The phase envelope curve of X was established based on the experimental analytical report from X-1 and X-2 wells, as shown in fig. 2. The summary of PVT data at reservoir condition and from separator test is described in tab. 1. In the PVTi matching, the pressure and temperature condition at surface separator is set at 14.5 PSIG and 60 °F, respectively. In short, with the PVT data matching and testing by PVTi, a compositional simulation is necessary at the X field. Eclipse E300 simulator, therefore, is used in this study. The oil and gas compressibility data was also from the experiments and described in tab. 2. The oil and gas viscosity and formation volume factor of oil and gas are shown in fig. 3. Since the later PVT regression will be performed on data from $X_1$ well by the PVTi program, formation volume factors are only analyzed with data from $X_1$. According to the SCAL data of Y oilfield, rock compressibility extends from a high value range of 12-20 and a low value range of 18-26 · $10^{-6}$ / Psi.

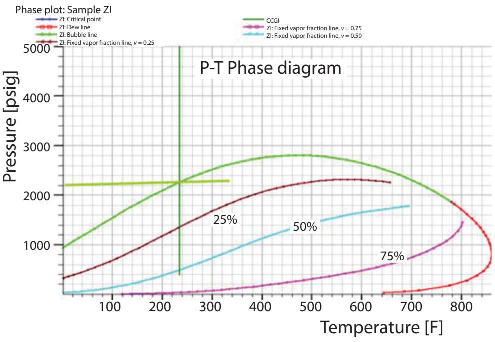


**Figure 2. Phase Envelope curve of X field**

**Table 1(a). Summary of PVT at reservoir condition**

| Name | X-1 | X-2 |
|---|---|---|
| Sample type | Separator | Separator |
| Production layer | A1 | A1, A2 |
| Mid depth (MD) ft | 5322 | 5331.5 |
| Mid depth (TVDSS) ft | 5204 | 5196 |
| Reservoir pressure (Psig) | 2270 | 2248 |
| Reseservoir temperature (°F) | 235 | 236 |
| Pb (Psig) | 2270 | 2122 |
| GOR (Scf/stb) at Pb (DV) | 1252 | 1259 |
| GOR (Scf/stb) at Pb (ST) | 976 | N/A |
| Density (lb/cuft) at Pb | 39.98 | 36.26 |
| Viscosity (cp) at Pb | 0.881 | 36.26 |

**Table 1(b). Summary of PVT at separator test**

| Name | X-1 | X-2 |
|---|---|---|
| Sample type | Separator | Separator |
| Production layer | A1 | A1, A2 |
| Mid depth (MD) ft | 5322 | 5331.5 |
| Mid depth (TVDSS) ft | 5204 | 5196 |
| Reservoir pressure (Psig) | 2270 | 2248 |
| Reservoir temperature (°F) | 235 | 236 |
| Pb (Psig) | 2270 | 2122 |
| GOR (Scf/stb) at Pb (DV) | 1252 | 1259 |
| GOR (Scf/stb) at Pb (ST) | 976 | N/A |
| Density (lb/cuft) at Pb | 39.98 | 36.26 |
| Viscosity (cp) at Pb | 0.881 | 36.26 |

**Table 2. The compressibility of oil**

| X-1 | | X-2 | |
|---|---|---|---|
| Pr | $10^{-6}$/Psi | Pr | $10^{-6}$/Psi |
| 4750 | 13.32 | 4750 | 12.26 |
| 4250 | 14.54 | 4250 | 13.35 |
| 3600 | 16.52 | 3750 | 14.66 |
| 2750 | 19.9 | 3050 | 17.19 |
| 2285 | 21.89 | 2361 | 20.59 |

The X reservoir has a connate gas cap with sufficient natural energy. As the development process progresses, a large amount of solution gas was released, which resulted in a complex phase variation in the reservoir. As a result, the compositional simulator was selected at the very beginning of this study. To validate the suitability of this approach at the X reservoir, specific property matching was performed by the ECLIPSE PVTi program.

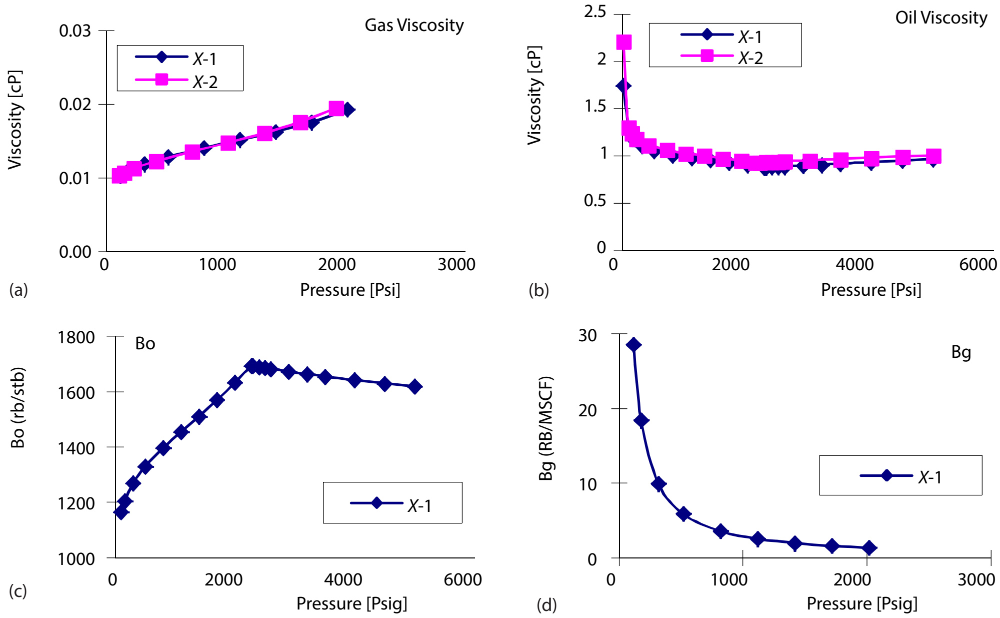


**Figure 3. Viscosity and formation volume factor of oil and gas curves**

## Initialization

After the completion of input data preparation for numerical simulation, model initialization was conducted to match the initial reserves in place. The crude-oil reserve is 45.47 MMstb, and gas 8.75 Bscf, respectively, from the original geological model. After the grid coarsening or model scale-up, the numerical simulation model gives 45.2 MMstb in oil and 7.8 Bscf in gas, respectively. In comparison, the errors are 0.59% in oil reserve, and 8.98% in gas. Consequently, the errors are within the acceptable range and the model conforms to the requirements of numerical simulation.

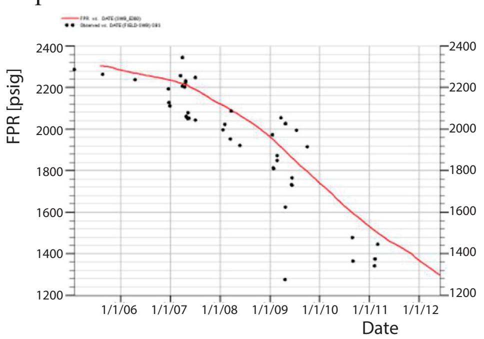


**Figure 4. The pressure data history matching of X field**

## History matching

The X field was put into production in September 2005. As of May 31, 2012, there are a total of twenty-three wells being drilled (including two sidetrack ones), of which seventeen wells have been put into production. At the end of May 2012, the twelve wells in operation have an oil production rate of 2238 bbl/day, gas 7454 Mscf/day, and liquid 2444 bbl/day. The cumulative oil, gas and liquid productions are 9.2 MMstb, 10.4 Bscf, and 9.403 MMstb, respectively. The water-cut

(WCUT) reached 6.38%. Overall, the recovery ratio is 20% for the X field. After the reserve matching performed in the initialization, the very first history matching work was conducted to match the overall pressure for the X reservoir. Figures 4 and 5 shows the matching result. Once the history matching was completed for the whole field. History matching for individuals well, including all the wells located in the X reservoir, was conducted in the same fashion.

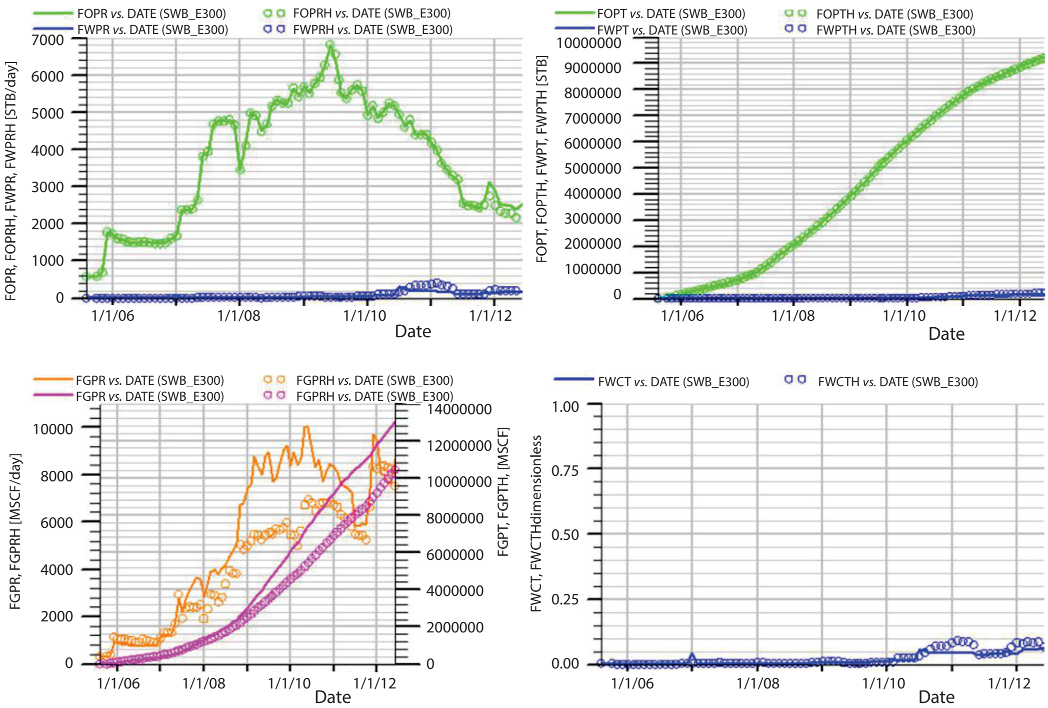


**Figure 5. The Produced data history matching of X field**

## Strategies plan

A series of adjustment strategies based on water injection and gas recycling has been developed and simulated. All the simulation runs start on January 1, 2013, and end on December 31, 2013, to forecast the reservoir performance. The current production scheme is maintained from June to December 2012.

To develop feasible plans, the following conditions are established as constraints in the simulation forecasts. For the whole field: minimum total oil production is 150 bbl/day, maximum water-cut is 95 percent, and maximum gas-oil ratio is up to 5 Mscf/stb. For individual well: minimum oil production is 5 bbl/day, maximum water-cut is 95 percent, maximum gas-oil ratio is up to 10 Mscf/stb, and minimum flowing bottom-hole pressure is 450 Psi. Table 3 listed the simulated results in detail. Specific adjustment measures employed include reperforation, well conversion, new sidetrack, vertical and horizontal drilling, gas recycling at gas cap, and optimization on water injection, oil and liquid production, and injection-production ratio. After all the simulation runs, the most effective measures were selected from various plans, and then combined into the recommended one.

**Table 3. Plan of development about *X* field**

| Name | Objective | Case | Sub-Case | Remark |
|---|---|---|---|---|
| Case 0 | | | Basecase | Do nothing |
| Case 1 | Basccase + Workover | Case 1-1 | Workover | Add perforation |
| | | Case 1-2 | Workover | Optimization add perforation |
| Case 2 | Case1-2 + Sidetrack | | Case 2 | Add perforation + Sidetrack |
| Case 3 | Case + Converted | Case 2-1 | Case 2-1 | Converted injector 4 |
| | | Case 2-2 | Case 2-2 | Converted injector 6 |
| Case 4 | Case 2 + Infill drilling | Case 4-1 (Vertical Well) | Case 4-1-1 | New well number 2 |
| | | | Case 4-1-2 | New well number 4 |
| | | | Case 4-1-3 | Optimization new well number |
| | | Case4-2 (Horizontal well) | Case 4-2-1 | Length 100 m |
| | | | Case 4-2-2 | Length 150 m |
| | | | Case 4-2-3 | Length 200 m |
| | | Case4-3 (Vertical and horizontal combination) | Case 4-3-1 | New well location + horizontal well 1 |
| | | | Case 4-3-2 | New well location + horizontal well 2 |
| Case 5 | Case 4 + Waterflood (Peripheral) | Case 4-1 + waterflood | Case 5-1-1 | Converted injector 4 |
| | | Case 4-2 + waterflood | Case 5-1-2 | Converted injector 4 |
| | | Case 4-3 + waterflood | Case 5-1-3 | Converted injector 4 |
| Case 6 | Case5 + Waterflood (Pattern) | Case4-1 + waterflood (Pattern) | Case 6-1-1 | Converted injector 4 |
| | | Case 4-2 + waterflood (Pattern) | Case 6-1-2 | Converted injector 4 |
| | | Case 4-3 + waterflood (Pattern) | Case 6-1-3 | Converted injector 4 |
| Case 7 | Case 7-1 | Case 7-1-1 | VRR = 0.6 | Optimization injection rata |
| | | Case 7-1-2 | VRR = 1.0 | |
| | | Case 7-1-3 | VRR = 1.5 | |
| | | Case 7-1-4 | VVR = 2, Until pressure = 1200, VVR = 1 | Optimization injection and pressure data |
| | | Case 7-1-5 | VVR = 2, Until pressure = 1700, VVR = 1 | |
| | | Case 7-1-6 | VVR = 3, Until pressure =1700, VVR = 1 | |
| | | Case 7-1-7 | VVR = 5,Until pressure = 1700, VVR = 1 | |

→

**Table 3. Continuation**

| Name | Objective | Case | Sub-Case | Remark |
|---|---|---|---|---|
| Case 7 | Case 7-2 | Case 7-2-1 | Liquid*0.6 | Optimization liquid rata |
| | | Case 7-2-2 | Liquid*1.0 | |
| | | Case 7-2-3 | Liquid*1.4 | |
| Case 8 | Case 8-1 | Case 8-1-1 | 60% gas recycling | |
| | | Case 8-1-2 | 100% gas recycling | Gas channeling seriously |
| | Case 8-2 | Case 8-2-1 | Light composition | Gas channeling seriously |
| | | Case 8-2-2 | Heavy composition | Gas channeling seriously |
| Case9 | Case 9 | | Recom waterflood + gas inject | Recom case |

## Results and discussions

### *Base case*

The base case maintained the production scheme on May 31, 2012, and extended to Decembar 31, 2012. In the actual simulation runs, the simulator terminated in June 2012 due to the filed-wide oil production dropped below 150 bbl/day. Table 3 lists the simulation results of the base case, while tab. 4 gives the production status of an individual well of the case.

**Table 4. Production data of base case**

| Case | Cum. oil [MMstb] | Cum. liquid [MMstb] | Cum. gas [Bscf] | Water cut [%] | RF [%] | Pressure [Psi] |
|---|---|---|---|---|---|---|
| Case 1 | 12.38 | 13.14 | 22.46 | 37.79 | 26.98 | 703 |

### *Reperforation*

Three production wells have been selected to simulate the effectiveness of reperforation after validating the production dynamics of individual wells in the X reservoir. Specifically, reperforation was conducted at A2 formation of vertical depth between 5120 and 5130 ft in X-4, at A2 formation of vertical depth between 5139 and 5145 ft in X-9, and at A2 formation of vertical depth between 5128 and 5132 ft in X-10, respectively. Table 5 gives the simulated cumulative oil production after the reperforation for X-4, X-9, and X-10 separately. Reperforation is much more effective at X-4 and X-10. Consequently, X-4 and X-10 were chosen for reperforation measures.

**Table 5. Reperforation results**

| Well name | Workover | Base case | Work over | Increased oil |
|---|---|---|---|---|
| | | Cum. oil (MMstb) | Cum. oil (MMstb) | MMstb |
| X-4 | Add perfforation of A2 | 0.94 | 1.08 | 0.14 |
| X-9 | Add perforation of A2 | 1.33 | 1.31 | 0.02 |
| X-10 | Add perforation of A2 | 1.21 | 1.29 | 0.08 |

### *Reperforation + Sidetrack*

By analyzing the saturation distribution map of remaining oil at the X reservoir, sidetrack drilling was designed to tackle the B1 formation of relative rich areas. The sidetrack well, X-16ST, is located at co-ordinates of $X$ = 981763.96 ft and $Y$ = 32404361.2 ft. The simulation predicted a cumulative oil production of 0.667 MMstb, cumulative gas production of 0.676 MMstb, and a water-cut of 7%.

### *Well conversion*

By converting oil production well into a water injector, natural reservoir energy can be supplemented. After simulation case studies, two well conversion strategies were established. In strategy one, four producers, *i. e.* X-5, X-11, X-17, and X-21, were converted into producers, while in strategy two, six were converted, *i. e.* X-3ST, X-5, X-11, X-14, X-17, and X-21. Tab. 6 gives the results. It can be seen that strategy one, four well conversions, is more suitable, in which the water injection rates were 3500, 3000, 3000, and 2000 bbl/day at X-5, X-11, X-17, and X-21, respectively. As a result, the four well conversions were recommended.

**Table 6. Converted simulated result**

| Case name | Cum. oil [MMstb] | Cum. liquid [MMstb] | Cum. water inject [MMstb] | Presure [Psi] |
|---|---|---|---|---|
| Converted 4 | 1.419 | 1.83 | 26.55 | 1240 |
| Converted 6 | 1.424 | 1.9 | 27.29 | 1240 |

### *Infill well + Conversion*

After incorporating the previous reperforation and sidetrack drilling measures, infill drilling was planned further to enhance the oil production capacity for the X field. Four new production wells were planned, *i. e.* NP1, NP2, NP3, and NP4. By comparing two strategies, one with NP1 and NP2 addition and another with NP1, NP2, NP3, and NP4 addition, simulation results lead to a suggestion of NP2, NP3, and NP4 addition. Table 7 lists the co-ordinates of the three new wells.

**Table 7. Co-ordinate of new well**

| Well name | $X$ [ft] | $Y$ [ft] |
|---|---|---|
| NP2 | 979889.97 | 32397836.32 |
| NP3 | 982089.72 | 32398288.18 |
| NP4 | 983139.54 | 32400329.28 |

In addition, a horizontal well was designed to replace the sidetrack well, X-16ST, and the new NP2. With different settings in varying numbers and locations and different combinations of vertical and horizontal wells, various simulation cases were studied. It has been concluded that adding infill wells alone cannot meet the production requirement at X under the natural depletion scheme. New infill drilling has to be complemented with well conversion. Therefore, infill drilling shall be considered together with a well conversion strategy. In combination with all of the aforementioned measures, reperforation, sidetrack drilling (X-16ST), well conversion (4 wells), and infill drilling (3 wells), an integrated water injection plan takes shape at X reservoir. Furthermore, a new sidetrack well, the NI15ST, is suggested to supplement the reservoir energy more with other converted wells. Table 8 lists the measures developed in this study.

*Sensitivity analysis*

After the water injection plan was determined for the X reservoir, it is necessary to conduct sensitivity analysis on the design parameters, including the injection-production ratio and the liquid production of each well. By setting three different injection-production ratios, 0.6, 1.0, and 1.5, simulation runs predicted that the ratio 1.0 can produce appropriately while maintaining formation pressure. Table 9 lists the simulation results under the three different ratios.

**Table 8. Waterflood measures**

<table>
<tr><th></th><th>Well name</th><th>Layer</th><th></th><th>Well name</th><th>Layer</th></tr>
<tr><td rowspan="2">Add perforation</td><td>X-4</td><td>A2</td><td rowspan="2">Sidetrack</td><td>X-16ST</td><td>B1</td></tr>
<tr><td>X-10</td><td>A2</td><td>NI15ST</td><td>A1</td></tr>
<tr><td rowspan="4">Converted</td><td>X-5</td><td>A1\A2\A3\B1</td><td rowspan="4">New well</td><td>NP2</td><td>A1</td></tr>
<tr><td>X-11</td><td>A1</td><td>NP3</td><td>A1</td></tr>
<tr><td>X-17</td><td>A1\A2</td><td>NP4</td><td>A1</td></tr>
<tr><td>X-21</td><td>A1\A2\A3</td><td>–</td><td>–</td></tr>
</table>

**Table 9. The VVR analysis**

| | Cum. oil [MMstb] | Cum. liquid [MMstb] | Cum. water inject [MMstb] | Pressure [Psi] |
|---|---|---|---|---|
| VVR:0.6 | 14.68 | 18.96 | 21.68 | 894 |
| VVR:1.0 | 14.87 | 23.59 | 33.35 | 1208 |
| VVR:1.5 | 14.77 | 25.42 | 41.79 | 2312 |

However, considering the formation pressure can drop significantly under natural depletion, it is more practical to set the injection-production ratio at 2.0 in the early production stage so that the formation of energy can be properly supplemented.

The liquid production rates of each individual wells were determined by dynamic analysis, a standard reservoir engineering method. These rates were then modified by 0.6 and 1.4 fold and specified in the simulation runs. Table 10 lists the computational results under different liquid production. Table 11 gives the optimized liquid rate for each production well.

**Table 10. Liquid analysis**

| | Cum. oil [MMstb] | Cum. liquid [MMstb] | Cum. water inject [MMstb] | Pressure [Psi] |
|---|---|---|---|---|
| Liquid*0.6 | 14.44 | 19.27 | 28.28 | 1227 |
| Liquid*1.0 | 14.91 | 23.72 | 33.05 | 1196 |
| Liquid*1.4 | 14.93 | 24.5 | 33.98 | 1166 |

**Table 11. Optimized liquid rate**

| Well name | Liquid [stb per day] | Well name | Liquid [stb per day] |
|---|---|---|---|
| X-1 | 200 | X-9 | 400 |
| X-2 | 450 | X-10 | 400 |
| X-4 | 400 | X-13 | 300 |
| X-7 | 250 | X-18 | 200 |
| X-8 | 200 | X-19 | 400 |

### *Gas recycling*

It is beneficial to re-inject the produced gas back into the reservoir because it can help to supplement the elastic energy inside the gas cap and increase the formation pressure. The X-8 is located at the gas cap of the X reservoir. Therefore, on the previously established development plan, two gas recycling schemes were designed at X-8, one with 100% gas reinjection and another with 60%. By comparing the simulation results from the two schemes, the 60% one was selected based on the economic concerns. Table 12 lists the simulation results.

**Table 12. Gas recycling**

| | Cum. oil [MMstb] | Cum. liquid [MMstb] | Cum. water inject [MMstb] | Cum. gas inject [Bscf] | Pressure [Psi] |
|---|---|---|---|---|---|
| 60% | 15.28 | 21.18 | 29.01 | 11.03 | 1293 |
| 100% | 16.23 | 19.33 | 11.09 | 225 | 1264 |

### *Economics and EOR program aspects*

The economics and EOR program are two significant aspects of field development plan [18]. It is difficult to develop the successful future strategies without analysis such aspect. Simulation work may help to evaluate the economics and EOR program for future development plan. Following parameters should be considered while evaluating the economics of oil field: oil reserves, oil price, gross revenue, capital investment, operating cost, government taxes, and contractor cost. The details of these parameters will be presented in future work.

## Conclusion

A final development plan is recommended here, in this plan, water injection with gas recycling at the cap is the focal point. In addition the measures of reperforation, well conversion, sidetrack drilling, infill production drilling, the recommended strategy suggested an initial injection-production ratio of 2.0 that followed by a reduced ratio of 1.0 and a 60% gas recycling at X-8. The authors would like to suggest the application of machine learning [19, 20] and two other people's paper about fluid saturation+machine learning (that you can find online) for better understanding integrating all the aforementioned measures and taking into consideration the sensitivity analysis results. Table 13 lists the simulated results of the whole field from the recommended plan, while tab. 14 gives the results of each individual well.

**Table 13. Recommended case**

| | Cum. oil [MMstb] | Cum. gas [Bscf] | Cum. liquid [MMstb] | fw [%] | Pressure [Psi] | Cum. gas Injected [Bscf] | Cum. water Injected [MMstb] |
|---|---|---|---|---|---|---|---|
| Recom case | 15.28 | 31.66 | 21.18 | 82.5 | 1293 | 11 | 29 |

In summary, a suitable development plan for X reservoir has been formulated by screening various designs. This plan has fully taken the advantage of connate gas cap existed at the X reservoir. Artificial waterflooding is assisted by the 60% gas recy cling, producer conversion, and addition of a sidetrack injector. It is believed that the recommended plan will lessen the formation pressure drop, and enhance the recovery ratio.

## Acknowledgment

The authors greatly appreciate the supports from National Science and Technology Major Project of China (2017ZX05009-005).

**Table. 14. New wells production data**

| | Cum. oil [MMstb] | Cum. gas [Bscf] | Cum. liquid [MMstb] |
|---|---|---|---|
| NP2 | 0.45 | 0.45 | 0.51 |
| NP3 | 0.61 | 0.58 | 1.82 |
| NP4 | 0.1 | 0.29 | 0.31 |
| X-16ST | 0.71 | 0.64 | 0.72 |
| X-1 | 1.21 | 1.59 | 1.44 |
| X-2 | 2 | 1.99 | 3.42 |
| X-4 | 1.74 | 9.75 | 1.77 |
| X-7 | 0.31 | 0.36 | 0.61 |
| X-9 | 1.61 | 2.62 | 2.21 |
| X-10 | 1.26 | 5.18 | 1.78 |
| X-13 | 0.96 | 0.93 | 1.26 |
| X-18 | 0.97 | 2.29 | 1.02 |
| X-19 | 1.19 | 1.41 | 2.09 |

## Nomenclature

Kr – relative permeability
Krg – relative permeability to gas
Kro – relative permeability to oil
md – millidarcy
Sw – water saturation
Sg – gas saturation

*Acronyms*

bbl/day – barrel per day
BSCF – billion standard cubic feet
Cum. oil – cumulative oil
GOR – gas-oil ratio
MD – measured depth
MMstb – million stock tank barrels
MSCF/d. – thousand standard cubic feet per day
Mscf/stb – thousand standard cubic feet per stock tank barrel
Pb – base pressure
PVT – pressure-volume-temperature
PVTi – power velocity time integral
SCAL– special core analysis
Res – resolution
Temp – temperature
TVD – true vertical depth
VRR – voidage-replacement ratio

*Relations between all American units used, and International units*

1 foot = 0.3048 m
1 Psig = 6894.76 Pa
1°F = –17.22 °C
1 Psi = 6894.76 Pa
1 cp =0.001 Pas$^{-1}$
1 lb/cu ft = 16.0185 kg/m$^3$

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