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Integrated Approach Towards the Application of
Horizontal Wells to Improve Waterflooding Performance

QUARTERLY REPORT

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1. OBJECTIVES

The overall purpose of the proposed project is to improve secondary recovery performance of a marginal oil field through the use of an appropriate reservoir management plan. The selection of plan will be based on the detailed reservoir description using an integrated approach. We expect that 2 to 5% of the original oil in place will be recovered using this method. This should extend the life of the reservoir by at least 10 years.

The project is divided into two stages. In Stage I of the project, we selected part of the Glenn Pool Field - Self Unit. We conducted cross borehole tomography surveys and formation micro scanner logs through a newly drilled well. By combining the state-of-the-art data with conventional core and log data, we developed a detailed reservoir description based on an integrated approach. After conducting extensive reservoir simulation studies, we evaluated alternate reservoir management strategies to improve the reservoir performance including drilling of a horizontal injection well. We observed that selective completion of many wells followed by an increase in the injection rate was the most feasible option to improve the performance of the Self Unit. This management plan is currently being implemented and the performance is being monitored.

Stage II of the project will involve selection of part of the same reservoir (Berryhill Unit - Tract 7), development of reservoir description using only conventional data, simulation of flow performance using developed reservoir description, selection of an appropriate reservoir management plan, and implementation of the plan followed by monitoring of reservoir performance.

By comparing the results of two budget periods, we will be able to evaluate the utility of collecting additional data using state-of-the-art technology. In addition, we will also be able to evaluate the application of optimum reservoir management plan in improving secondary recovery performance of marginal oil fields.

Successful completion of this project will provide new means of extending the life of marginal oil fields using easily available technology. It will also present a methodology to integrate various qualities and quantities of measured data to develop a detailed reservoir description.

2. STAGE I PROJECT MONITORING

During the summer of 1995, we started implementing the reservoir management plan in the Self Unit. Last quarter, after evaluating each individual well, we decided to install electrical submersible pumps to produce three wells. The other three wells required the use of rod pumps. Production from the field improved significantly once the pumps were installed. Over the last eighteen months, an average daily production has been approximately 45 bbls/day. Compared to a base line production of 13 bbls/day before the implementation, this is more than a 200% increase in production.

Part of the reservoir management plan is to increase the water injection rate. We have installed the injection pump and have started injecting water over the last eight months.

3. GEOLOGICAL DESCRIPTION (By Dennis R. Kerr and Liangmiao Ye)

3.1 Structure Study Southeast Glenn Pool Field

As part of the study, an additional well was drilled in Self Unit of the field. Preparation for drilling the Self 82 well included picking the top of the Inola limestone as the coring point. The offset wells were about 600 ft apart from the proposed Self 82 location. The coring point was picked at 1420 ft. drill depth. The actual top Inola is at 1453 ft in the Self 82 well. The coring point was picked independently by two geologists whose predictions were very similar. The 30-ft discrepancy between expected and actual depth of the Inola was most puzzling. We began to consider the possibility of localized structures developed within the broad structural closure of Glenn Pool field. In this last quarter, efforts were directed at considering this structural issue.

A study area was selected in Sections 27, 28, 33, and 34 of T17N R12E, located along the southeast margin of Glenn Pool field. This area was selected because there were suggestions that the structures might be related to large slump failures located along the incised valley margin.

Well logs (21 total) were copied from the existing project collection and from BLM Tulsa Office and Oklahoma Well Log Library of Tulsa. Well spacing ranges from 2,600 ft to less than 300 ft apart; well density is much higher in the N/2 Section 28 and W/2 Section 27. Structure cross section were compiled through the well network.

The interval of interest spanned from the Pink limestone to Brown limestone. The top Pink is about 260 ft above the Glenn sandstone. The top Brown is about 120 ft below the top of the Glenn sandstone. The interval thickness between top Brown and base Glenn is highly irregular as a result of erosional relief along the base of the Glenn. Structure maps were produced for top Pink, top Inola and top Brown.

The top Inola structure map provides evidence of localized structures similar to what would be expected for slumping. The relief within the study measured from well log tops is 50 ft over about 1 mile. Locally the relief is as high as 30 ft in 400 ft; relief comparable to that developed around the Self 82 well. From careful correlation, it is clear that stratigraphic section is faulted out of wells where the structural relief is high. The faults appear to be listric normal in geometry with associated antithetic faults and roll over anticlines. The normal faults trend northeast-southwest with open curvature to the northwest and down to the northwest separation. Less continuous antithetic faults mirror the normal faults. Structural separation is 30 ft across the listric faults with localized antithetic faults; 15 ft across listric faults without antithetic faults; 10 ft across the antithetic faults. Separation up through the Pink is only seen on the listric fault that courses through the W/2 of Section 27 and is extrapolated into the NW/4 Section 33.

The implication for reservoir compartments depends on the stratigraphic level within the Glenn sandstone. Faulting of the braided fluvial section probably has little effect in that fault gouge of this sand-rich interval is not likely to be a barrier to fluid flow. On the other hand, faulting of the meandering fluvial section could produce reservoir compartments in that fault gouge of this mud-rich interval will likely involve reservoir barriers/baffles. Thus, DGI A-E reservoir compartments could be developed locally in these listric faulted areas.

4. ENGINEERING DESCRIPTION (by Sanjay Paranj and Mohan Kelkar)

4.1 Introduction

Tract 7 is located north and east of Tract 9 and is also operated by Uplands Resources, Inc. The well density is higher as compared to Tract 9, and the unit has a history of good response to water flooding. The present well locations are shown in **Figure 1**. It is estimated that Tract 7 has close to 15 MMStb of Original Oil in place(OOIP). From Welch¹ it was noted that Tract 7 has produced about 3.9 MMStb through primary depletion and secondary recovery operations. This means that the total recovery is about 26% of the OOIP, implying there is still a lot of untapped potential in the reservoir as compared to Tract 9 which has a cumulative recovery closer to 40%. The well density being high, it is perhaps not advisable to drill new wells, but a plugging/recompletion program to exploit the upper zones may yield significant additional oil recovery.

Figure 1: Well base map for Tract 7 with the x, y dimensions in feet.

4.2 Data Input and Flow Simulation Technique

4.2.1 Facies Maps

The facies maps for all DGIs are generated using indicator using similar methodology as discussed in the previous quarterly report.² Several realizations are performed, and the realization which closely matches the map generated by the geologist, is chosen for petrophysical property estimation. In this work, this selection is done by visual observation. Automation of the selection of an optimal set of realizations is a topic of ongoing research.

4.2.2 Gamma Ray Logs

One of the major drawbacks of estimating porosity from gamma ray logs in mature fields is as follows. The engineer has to contend with the fact that calibration of the gamma ray tool is not uniform since the logs are performed by different service companies.

Open hole logs always give a higher gamma ray reading as compared to cased hole logs. Since gamma ray logs measure the natural radioactivity of the formation, cased hole logs are affected by the presence of the casing between the recording tool and the formation. Conceptually, if two different wells are logged with the same tool, a pure shale interval in the two wells would have the same reading of gamma ray API units. This is not observed in practice since the shale found at two different vertical sections may have different sand content, varying organic material content, contrasting compaction levels, all of which affect the value of the gamma ray readings.

If the raw values of gamma ray readings from different wells are translated to porosity without accounting for the facts mentioned above, it would lead to under or over estimation of porosity. It should be noted that the gamma ray to porosity regression correlation is one single relationship and the same relationship is used for all the wells uniformly. By itself, the correlation does not take into account the variations in the gamma ray readings between the wells. A procedure titled multi-well normalization is presented below which tries to resolve this problem.

4.2.3 Multiwell Normalization

The objective of the procedure is to bring the shale base line for different logs in alignment so that all deviations from this base line, which are indicative of sand, are referenced from a

common base datum, thus making the use of gamma ray-porosity relationship more reliable. It is observed that most of the wells in this study area are cored in the lower interval. Gamma-ray logs are transformed into porosity values for wells which are cored in the lower intervals. Then the gamma-ray derived porosity is compared with the core porosity. Only those gamma-ray logs are selected which demonstrate a good comparison. Foot by foot gamma-ray readings for such logs are pooled together to construct a probability density function (pdf) and this pdf is termed as the standard distribution. Individual well gamma-ray logs are then used to construct pdf(s) for the respective wells. The well pdf is then plotted against the standard distribution to determine the amount of linear shift in Gamma-ray absolute value required to bring the shale base lines in alignment.

Figure 2 exhibits the graphically the procedure. It can be observed that pdf curves exhibit two peaks, one for a range of gamma ray values between 15-60 units and the other centered around 90 API units. The first peak represents the range of possible gamma ray values representative of sand and splay. The range of values exhibited by the second peak is representative of shale. The underlying principle in shifting individual well pdfs is that even though the probability of occurrence of a gamma ray value representative of shale may not be the same in two different wells, the range of gamma-ray values which represent shale should be centered approximately around the same gamma ray reading. For well E-9 it was determined that a linear correction of -25 API units is appropriate. It can be seen that originally the center line of the shale peak, which was 125 API units, after adjustment is about 100 units. This is done for all the wells other than those which were used to generate the standard distribution.

Once the normalization procedure is completed the gamma ray values are averaged within each DGI at all wells. These average values are then kriged at all interwell locations DGI by DGI to produce areal maps of gamma ray readings with the simulated facies maps as external drift.

Figure 2: Well E-9 pdf plotted against the standard pdf. A linear shift of -25 API units is needed to bring the well E-9 shale peak in alignment with the shale peak of the standard distribution.

4.2.4 Porosity Estimation

The areal gamma ray maps are transformed into porosity maps by using the gamma ray-porosity relationships with the use of a random number to aid the reproduction of the scatter seen in the gamma-ray vs. porosity plots (Figure 3). The correlations were generated with the use of digitized gamma ray values and density-neutron log porosity values. It can be observed that the wells show a fairly consistent relationship. In this study a cutoff is used with respect to the gamma ray values beyond which transformation of gamma ray values to porosity is meaningless. The cutoff in this case was fixed as 140 API units. Beyond this range, the porosity is fixed as 1%.

Gamma Ray intensity vs. log porosity (well Self 79)

Gamma Ray intensity vs log porosity (well 7-113)

Figure 3: Gamma-ray vs. Porosity regression relationships for two wells logged in the Glenn sand reservoir.

4.2.5 Permeability Estimation

Regression relationships between $\log(K)$ and porosity are used to generate the permeability distribution from the porosity maps.

4.2.6 Thickness Estimation

The thickness maps for all DGIs are generated by using the ordinary kriging procedure at interwell locations. The thickness of all gridblocks for which the facies type is known as shale/flood plain mudstone is forced to zero. Since thickness is a continuous variable as opposed to facies which is a discrete variable kriging on thickness even with zero thickness points need not necessarily capture the facies boundary between sand and shale. It is therefore necessary to use explicit procedures to make the simulated facies and kriged thickness maps consistent with each other.

4.3 Flow Simulation Technique

The conventional history matching procedure involves reconstructing the well history from inception time to present time. A deterministic initial pressure and saturation profile is mapped, and then field flow performance is matched by tuning the input parameters. In this case study the saturation and pressure profiles are derived for the year 1993 and history matching is initiated at this time. This eliminates the need for reconstructing the well schedule history from inception time of the field. The history matching is performed for a short segment of time 1993-1997 during the course of which the input model is calibrated. It should be noted that the production and injection data were provided by the operator for this unit and is far more reliable than public sources of data.

The areal expanse of the Tract 7 is 160 acres. It was decided to divide the area into 66 ft x 66 ft gridblocks so that any DGI is split in 1600 gridblocks. The thickness of each gridblock is assigned to be the thickness of the DGI itself which was obtained by kriging at interwell locations. The system has 13 layers, which is the sum of all DGIs A through G and the intermediate shale layers between successive DGIs.

The PVT properties used for this case study are essentially the same as those used for the Chevron-William Berryhill unit study.²

The saturation profile derived from the resistivity logs derived earlier is scaled up so as to match the water cuts. It can be recalled² that the Tract 9 case study uses well test data to match the effective permeability calculated from the model with the effective permeability derived from the well test. In this simulation study, this approach could not be realized since only a single well was tested within this study area. Hence the reserves in place and the saturation multiplier used for Tract 9 were used as a guidelines for estimating the possible range of scaling coefficients of saturation.

- First, a multiplier of 1.4 which was used for Tract 9 was used for this study also. The ratio of oil phase effective permeability to water phase effective permeability is similar in both the study areas justifying use of the same multiplier.
- Second, a multiplier of 1.2 is chosen based on the fact that it is the lowest possible multiplier that would still yield a good history match with regard to the accuracy necessary in simulated water cuts.

It is known that reserves in place at the time when history matching is started (1993) is around 11.1 MMstb. It was proposed to use two multiplier coefficients 1.2 and 1.4 on the water phase saturation S_w based on which the reserves in place were calculated as 10.653 and 9.43 MMstb respectively. The objective is to get an idea of the incremental oil production obtainable with a worst case ($S_w \times 1.4$) and best case ($S_w \times 1.2$) scenario.

The pressure profile is guessed for DGI E, based on which all the other DGI pressure maps are generated assuming that the pressure difference between DGIs is equal to the hydrostatic head. The guess profile is then input into the simulator and the performance of this profile is gauged by determining if it satisfies the field injection and production rates. If not the pressure data are altered so as to be able to match the production and injection data. It should be noted that the BHP for producers (pumping wells) is about 20 psi and the BHP for the injectors is known to be 1250 psi. Hence there is only a certain range of input average reservoir pressure (year 1993) for

which the production data/injection data can be matched. This obviously assumes that there is no leverage with regard to alteration of the petrophysical property fields. If a typical fracture gradient of 0.75psi/ft is assumed, the formation fracture pressure is calculated as 1163 psi . It was found that the BHP of injectors is very close and sometimes above the fracture pressure. This is taken into account in the simulator by multiplying well transmissibility based on the instantaneous pressure difference between BHP and the calculated fracture pressure.

It should be noted that the single well test (well 7-111) that was performed in this study area demonstrated an average reservoir pressure of 1050 psi. It is also known that the row of injectors located in the southern part of the study area take in water at very high pressures only. Considering these facts there is enough reason to believe that the average reservoir pressure is high and close to about 1000 psi. Well 7-111 produces the highest volume of fluid and contributes one half of the total liquid production at any given time.

4.4 Results and Conclusions

The completion density in this study area is largely skewed towards DGI G (**Figure 4**). Considering the well density in Tract 7, it was decided that a plugging/recompletion program is the most appropriate future implementation. All perforations in DGI G are plugged, and then DGIs B-F are recompleted. Recompletion of DGI A is avoided since the permeability for this layer is observed to be smaller as compared to all other DGIs. Independent simulations were conducted with two different S_w scaling factors mentioned before.

Figure 4: Histogram showing the concentration of perforations in DGI G.

4.4.1 Scenario $S_w \times 1.2$

This is the optimistic scenario wherein it is deemed sufficient that the resistivity log derived saturation profile, when scaled up by a factor 1.2, is adequate to bring it in tune with the initial time of history matching(1993). It should be noted that the saturation profile captures the global profile of the reservoir but the relative highs and lows predicted in this profile need not necessarily be valid. Extending this logic, it could be said that when the unit is considered as one unified system, the flow simulation gives an approximate idea of how the system would behave in response to a stimulus, but there is no guarantee that wells at selected locations will honor the simulated performance in truth. The reduction in water cut for this scenario is about 2%, and the incremental production obtainable after implementation of the plug/recompletion program is about 375 bbl/d. The simulated response is shown in **Figure 5**.

Figure 5: Oil production, water cut plot for the scenario $S_w \times 1.2$

4.4.2 Scenario $S_w \times 1.4$

This is the pessimistic scenario, wherein the effect of a very large multiplying coefficient for the S_w profile at 1993 is simulated, and is contrasted against the previous case. It can be observed that the incremental oil production is still quite high but the reduction in water cut is small after implementation of the plug/recompletion program. The governing factor for a proposal to be viable or not, is the possible reduction in water cut coupled with the incremental oil production that could be obtained. In this case, oil production increases since more total fluid (oil+water) is being withdrawn. The high rates of total liquid withdrawal also result in increase of lifting or operating costs. It should be noted that, before implementation of the recompletion program, the wells were primarily producing from one DGI. But after implementation of the program fluid is withdrawn from DGIs B-F yielding more total liquid production.

It can be observed from **Figure 6** that the water cut shows a decrease of about 0.2% at best. It will be shown later in the economic analysis chapter that the incremental oil production does not generate enough revenue to offset the increase in lifting costs. If the saturation profile in reality is close to the saturation profile estimated in this scenario, then it can be concluded that a plug/recompletion program is not economically viable.

Figure 6: Oil production, water cut plot for the scenario $S_w \times 1.4$

4.5 Economic Analysis of Tract 7

Only two scenarios were incorporated in the analysis of Tract 7. The forecasting was performed for observing the response of plug/recompletion program but the simulation itself was initiated with two different base maps of resistivity log derived water saturation maps. This was accomplished by using two scaling coefficients for saturation namely $S_w \times 1.2$ and $S_w \times 1.4$. **Figure 7** presents the rate of return and the net present value charts for the two scenarios. The unit has 37 active wells for which the approximate plug/recompletion cost is \$500,000. It can be observed that if the water saturation profile is scaled up by a factor of 1.4, the plug/recompletion program is unfeasible as indicated by the zero rate of return and negative net present value. Conversely, if in reality the saturation profile corresponds to the resistivity log derived profile scaled up by a factor of 1.2, the implementation of the plug/recompletion program will be largely successful. These two extremes could be considered as the bounding cases for actual field implementation.

Figure 7: Rate of return and net present value charts for Tract 7.

4.6 Summary

- Owing to the high well density and completion skew towards the lower zones in Tract 7, the most appropriate program is plug/recompletion. The bounding extremes have been defined by performing simulations with different saturation profiles for the time instant when history matching is started.

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