Exploitation and Optimization of Reservoir Performance in Hunton Formation, Oklahoma

TECHNICAL PROGRESS REPORT

Submitted by

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Objectives

The main objectives of the proposed study are as follows:

• To understand and evaluate an unusual primary oil production mechanism which results in decreasing (retrograde) oil cut (ROC) behavior as reservoir pressure declines.

• To develop better, produced water, disposal techniques so as to minimize lifting costs, surface separation costs and water disposal costs.

• To improve calculations of initial oil in place so as to determine the economic feasibility of completing and producing a well.

• To optimize the location of new wells based on understanding of geological and petrophysical properties heterogeneities.

• To evaluate various secondary recovery techniques for oil reservoirs producing from fractured formations.

• To enhance the productivity of producing wells by using new completion techniques.

These objectives are important for optimizing field performance from West Carney Field located in Lincoln County, Oklahoma. The field, which was discovered in 1980, produces from Hunton Formation in a shallow-shelf carbonate reservoir. The early development in the field was sporadic. Many of the initial wells were abandoned due to high water production and constraints in surface facilities for disposing excess produced water. The field development began in earnest in 1995 by Altex Resources. They had recognized that production from this field was only possible if large volumes of water can be disposed. Being able to dispose large amounts of water, Altex aggressively drilled several producers. With few exceptions, all these wells exhibited similar characteristics. The initial production indicated trace amount of oil and gas with mostly water as dominant phase. As the reservoir was
depleted, the oil cut eventually improved, making the overall production feasible. The decreasing oil cut (ROC) behavior has not been well understood. However, the field has been subjected to intense drilling activity because of prior success of Altex Resources.

In this work, we will investigate the primary production mechanism by conducting several core flood experiments. After collecting cores from representative wells, we will study the wettability of the rock and simulate the depletion behavior by mimicking such behavior under controlled lab conditions.

The excess water production also requires careful attention to optimize the performance of the reservoir. The excess water requires expensive surface handling facilities, increased lifting costs, additional disposal expense and reduction in well productivity due to increased hydrostatic head. To improve the water handling, we will examine implementation of downhole separator. If installed successfully, much of the water can be disposed of in the Arbuckle Formation which is below the Hunton Formation. This will reduce the produced water cut as well as size of the surface facilities. Instead of using conventional water knock out, we intend to use liquid-liquid compact separators (LLCS). This will reduce installation and operating costs of surface water separation.

Another difficulty in producing from the Hunton Formation is the inability to correctly predict the well locations. At present, the locations of wells have been determined in a haphazard manner without significant geological consideration. To develop the entire field, it is imperative that the depositional model be clearly understood and quantified. This can be done by collecting core samples, running modern imaging logs and describing the geological facies in some detail. This will allow us to quantify the geological model, enabling a geostatistical description of lithofacies. By quantifying uncertainties in the model, the future well locations can be optimized.

West Carney Field is at the beginning of an exploitation phase. All the wells are under primary production. However, the pressure in the reservoir is decreasing and eventually some additional mechanism will have to be used to recover the remaining resources. For proper exploitation of the reservoir, it is best that we examine alternate methods of secondary recovery. One possible method we
are going to investigate is huff-n-puff of gas injection. We will investigate both CO₂ and flue gas as possible injection fluids.

Economic feasibility of producing oil from this field also depends on the initial oil in place. The prior experience in this field indicates that the initial oil saturation is difficult to determine based on conventional well logs. To remedy this problem, we will run a single well tracer test. The tracer test has the ability to investigate a much bigger volume than the log data and will be able to determine the initial oil saturation more accurately.

The overall project goal would be to validate our hypothesis and to determine the best method to exploit reservoirs exhibiting ROC behavior. To that end, we will collect and analyze core samples, and run a single well tracer test during the Budget Period I. We will continue to drill vertical wells during this period. Once we understand the mechanism and are able to quantify the geological model, in Budget Period II we will drill several, additional wells. Depending on the feasibility, we will equip some of the vertical wells with downhole separator, as well as surface compact separator. This will allow us to compare the new technology with the existing one. In the Budget Period III, we will monitor the field performance and revise and refine our models to further optimize the performance.

To ensure that the technology developed in this project is communicated to a wide cross-section of interested individuals, we will undertake an aggressive technology transfer program. This will include publishing and presenting papers at various technical meetings, publishing a semi-annual newsletter and conducting technical workshops for small operators and independents at the end of Budget Periods II and III.
Summary of Technical Progress

The summary of progress is divided into three sections. The first section discusses the field activities. The second section discusses the geological progress and the last section deals with the engineering work progress.

Field Activities

The field activities continued during this period. The field is being developed rapidly, and eight wells were drilled by Marjo Operating Company during this period. All of these wells were cored. In addition to drilling new wells, the production from the existing wells is being carefully monitored.

Geological Analysis

In this quarter, the geological analysis for the Hunton Project continued with the analysis of the data from the 14 cored wells. The focus was mainly concentrated on log analysis and our objective was to correlate the pore types with the log data and also study the production characteristics of the different wells based on this correlation.

In the last quarterly report, we described the geological classification of various facies and pore types. Briefly, the pore types are divided into:

1. Vuggy
2. Coarse grained
3. Fine grained
4. Fractures

We short-listed some techniques for log analysis from the literature. In continuation with our investigation with the Pickett plot approach, mentioned in the last quarterly report, we used the Buckles plot.
In this approach we examined the Bulk Volume Water (BVW) for clues to producibility when related pore character. The equation for the BVW can be written as:

\[ c = \phi \cdot S_{wi} \]

The equation states that the product of connate water and porosity is constant. Therefore, if we plot porosity vs. saturation on a graph, if the saturation is equal to connate water saturation, then all the points, for a given pore size, should fall on the same curve. On the other hand, for a given porosity, if the water saturation is higher than the connate water saturation, the points will fall above the curve. This type of plot is typically used to determine transition zone between oil and water zones. We used it to determine where mobile water is located.

Figures below show the buckles plot for the four different pore types mentioned previously. Figures 1 and 2 represent Buckle’s plot for vugs and coarse matrix. These figures clearly indicate that saturation of water at higher porosities is significantly higher than indicated by connate water saturation. In contrast, Figure 4 shows the same plot for fine matrix. This plot shows that most of the points lie on a constant value of c, indicating that water saturation is close to connate water. This also implies that most of the oil resides in small pores. Figure 3, which represents the same plot for fractures indicates a plot which is similar fine matrix, but has more values indicating higher saturation. This can be explained by the fact that most of the fractures are located within fine matrix reservoir. However, some of the fractures are filled with water after depletion indicating higher water saturation. In essence, fractures may have high conductivity but low storativity, so they may not significantly contribute to storage of oil Based on these four plots, we can reasonably conclude that fine matrix is storing most of the hydrocarbons, whereas coarse matrix and vugs are mostly storing water.
Figure 1: Buckle Plot for Vugs

BUCKLES PLOT coarse
Figure 2: Buckle Plot for Coarse Matrix

Figure 3: Buckle Plot for Fractured Rock
Figure 4: Buckle Plot for Fine Matrix

Engineering Analysis

The overall engineering analysis is divided into two parts. In the first part, we discuss the progress we have made regarding understanding of primary mechanism by which oil is produced. In the second part, we discuss the methods we are developing to evaluate the existing well performance so that we can estimate dynamic reservoir properties as well as the reserves estimates from the current wells. Eventually, by evaluating an individual well performance, we intend to improve our reservoir model for flow simulation.

Flow Simulation

One of the main objectives of this project is to establish primary mechanism by which oil is being produced from the field. Unless we understand the mechanism, we will not be able to extrapolate the behavior at other wells as well as other reservoirs. To that end, we are testing alternate reservoir models, and simulating the behavior to match with the observed production data. Marjo Operating
Company’s lease is divided into two parts by a major fault. The two sides of the lease have different initial reservoir pressure. The east side has an initial pressure of 500 psi while the west side has an initial pressure of 1500 psi. The Hunton thickness is also different in the two parts. East side has a thickness of around 30ft while the west side has about 45ft of thickness. In our model we considered 18 wells on the west side and there are 6 producing wells on the east side.

**Model Description**

As explained above, the field was divided into two parts and simulation results were generated separately for them. Apart from the initial pressure and the total thickness, the remaining properties were kept the same for both the sides.

We assumed a black oil model and the PVT properties were such that the bubble point was 1600 psi. Two sets of relative permeability values were included in the model. Top two layers having hydrocarbons had one set of relative permeability while the bottom layer having water had different relative permeability values. We assumed a thickness of gas layer to be 5 ft, thickness of oil layer to be 17 ft, and the thickness of water layer to be 13 ft. We used 51 x 105 grid blocks on the west side and 52 x 79 grid blocks on the east side to areally cover the reservoir. Each grid block had 200 ft side in both the directions. The permeability and porosity of each layer was adjusted to match the observed results. We assumed a uniform vertical permeability for all the layers.

**History Matching**

We used water rate as a constraint in history matching the results. To do history matching we used the ECLIPSE automatic history matching software (SimOpt). The purpose of history matching is to minimize the objective function iteratively to obtain a better match. To calculate gradients we need to input the data and assign weight to different data points. The observed data used in this case was: water cut and GOR for all the wells. The data points at different times were given different weight factors according to the quality of the data in order to achieve better match.
The parameters adjusted to get a good history match include the permeabilities in x, y and z directions as well as pore volumes. Individual well matches were obtained by adjusting the skin factors for each well. Layout of the grid blocks and the well locations are shown in Fig. 5.
Fig. 5: Grid Layout in the Model
Results

Using the three-layer model and the input values discussed above we generated results using simulation techniques. Figures 6 and 7 show the overall matches for oil and gas production respectively. We used the water production as operating constraint in running the simulation. Therefore, oil and gas rates were considered as matching parameters. As can be seen from these plots, the match between the observed and the simulated rates is reasonable.

Figure 6: Match between predicted and observed oil production
We also compared the results on individual well basis. Although the match is not as good as what we observed on a global basis, it was able to capture the overall trend in the data as shown here in Figures 8-10 for Boone Well. Note that the match is based on daily rate, which is very hard to capture. Also, we did not try to make local variations in the reservoir properties to match the individual well performance. Therefore, overall, the match is quite satisfactory.

We will continue to refine our reservoir model to incorporate relative permeability characteristics based on lab data. In addition, we will also build a reservoir model based on geological rock types to incorporate reservoir heterogeneties.
Figure 8: Comparison between simulated and observed oil rate for Boone well

Figure 9: Comparison between simulated and observed gas rate for Boone well
Production Data Analysis

In addition to working on simulating the flow behavior of the reservoir, we are also interested in evaluating the existing production data to better understand the reservoir performance. To that end, we are developing an interactive computer program to quickly analyze the production data from individual wells.

So far, we have developed analytical solutions for the homogeneous model for the following cases:

1. Constant pressure production for an infinite reservoir
2. Constant pressure production for a bounded reservoir
3. Constant rate production for an infinite reservoir
4. Constant rate production for a bounded reservoir

The program we have developed currently uses the constant pressure solutions, but will eventually be modified to handle varying rate and pressure production (field case).
The program is able to give estimates of the following:

1. Permeability
2. External radius
3. System compressibility
4. Skin factor.

The required input for the program is the following:

1. Porosity
2. Viscosity
3. Formation volume factor
4. Initial Pressure
5. Wellbore flowing pressure
6. Wellbore radius
7. Reservoir thickness

It also requires guesses for the parameters to be estimated as well as upper and lower bounds. With this data the program will generate a match for the real production data. The program incorporates an outlier routine which enables outliers to be determined and eliminated as well as a confidence interval routine which determines the confidence intervals for the estimated parameters.

The program appears to be giving good estimates for k, ct, re, and sf. More work needs to be done to find out what is considered a good estimate (i.e. initial guess, min and/or max).
The following are pictures of the program:

**Input Screen:**

![Image of the program interface with various input fields and tables displaying reservoir characteristics and fluid properties.]
Imported Production Screen:

The data to be imported should be in the format of:

- Time [Unit]: Days
- Rate [STB/Day]

The file can be read width, or a deleted type.

- Units of Time: Days
- Number of Data Points: 50
Graphical Output:

We will continue to improve the program and expect to show the results of the field data analysis by the end of next quarter report.

**Technology Transfer**

A web page, dedicated to the project has been developed and is on line at [http://www.tucrs.utulsa.edu](http://www.tucrs.utulsa.edu). The web page contains information about the project, team members and publications and reports produced as a result of the project. The first newsletter has been published and mailed to 3,500 independent operators in Oklahoma and Texas. The newsletter is also available on the web page. In addition, several field trips to the field have been sponsored to expose people to the project.
References