RESERVOIR CHARACTERIZATION OF THE LOWER GREEN RIVER FORMATION, SOUTHWEST UINTA BASIN, UTAH

Deliverable 6.2

Numerical Simulation Models of the Lower Green River Formation Reservoirs

By

Milind D. Deo
University of Utah
Department of Chemical & Fuels Engineering

Contract DE-AC26-98BC15103

C. D. Morgan, Program Manager
Utah Geological Survey

Virginia Weyland, Contract Manager
U.S. Department of Energy
National Petroleum Technology Office

Submitting Organization: Utah Geological Survey
1594 West North Temple, Suite 3110
P.O. Box 146100
Salt Lake City, Utah 84114
(801) 537-3300
DISCLAIMERS

Utah Department of Natural Resources

Although this product represents the work of professional scientists, the Utah Department of Natural Resources, Utah Geological Survey, makes no warranty, expressed or implied, regarding its suitability for a particular use. The Utah Department of Natural Resources, Utah Geological Survey, shall not be liable under any circumstances for any direct, indirect, special, incidental, or consequential damages with respect to claims by users of this product.

United States Government

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

US/DOE patent clearance is not required prior to the publication of this document
LIST OF FIGURES

Figure 1: Lithofacies in some of the wells............................................................... 37
Figure 2: A northwest-southeast cross section through section 25 ..................... 38
Figure 3: The three surfaces along the cross section ............................................ 39
Figure 4: Lithotype distribution in the cross section shown in Figure 2 ............... 40
Figure 5: Porosity distribution in the cross section shown in Figure 2 ............... 41
Figure 6: Permeability distribution in the cross section shown in Figure 2 .......... 42
Figure 7: Porosity and permeability proportion curves and locations of upscaled
layer boundaries........................................................................................................ 43
Figure 8: Porosity distribution in the cross section shown in Figure 2 for the
upscaled reservoir ..................................................................................................... 44
Figure 9: Permeability distribution in the upscaled reservoir for the cross section
shown in Figure 2 ..................................................................................................... 45
Figure 10: Water saturation distribution in the upscaled reservoir for the cross
section shown in Figure 2 ....................................................................................... 46
Figure 11 Comparison of cumulative oil production in the MBNE field with total
water injection in D sands ...................................................................................... 47
Figure 12 Comparison of cumulative oil production in the MBNE field with 60%
water injection in D sands ...................................................................................... 48
Figure 13 Comparison of cumulative oil production in the MBNE field with 40%
water injection in D sands ...................................................................................... 49
Figure 14 Comparison of cumulative water production in the MBNE field with
40% water injection in D sands ............................................................................. 50
Figure 15 Comparison of cumulative gas production in the MBNE field with 40% water injection in D sands .......................................................... 51

Figure 16 Comparison of cumulative gas production in the MBNE field with 40% water injection in D sands .......................................................... 52

Figure 17 Cumulative oil production in the MBNE field; comparison of field production with simulation results .................................................. 53

Figure 18 Average rate of oil production in the MBNE field; comparison of field values with simulation results .................................................. 54

Figure 19 Cumulative water injection in the MBNE field; comparison of field values with simulation results .................................................. 55

Figure 20 Producing gas oil ratio in the MBNE field; comparison of field values with simulation results .................................................. 56

Figure 21 Cumulative gas production in the MBNE field; comparison of field production with simulation results .................................................. 57

Figure 22 Cumulative water production in the MBNE field; comparison of field production with simulation results .................................................. 58

Figure 23 Water cut in the MBNE field; comparison of field values with simulation results .......................................................... 59

Figure 24 Water cut in the MBNE field; comparison of simulation results with and without fractures .......................................................... 60

Figure 25 Cumulative water production in the MBNE field; comparison of simulation results with large fractures .......................................................... 61
Figure 26 Water cut in the MBNE field; comparison of simulation results with large fractures ................................................................. 62

Figure 27 Uteland Butte thickness map................................................................. 63

Figure 28 Production from all the 16 wells from the Uteland Butte field .......... 63

Figure 29 Thickness grid for the Brundage Canyon field............................... 64

Figure 30 Cumulative oil produced from the Brundage Canyon field............. 64

Figure 31 Pressure depletion map for the Brundage Canyon field................. 65

Figure 32 Comparison of the simulation data to the actual oil produced .......... 65
LIST OF TABLES

Table 1 Lithofacies assignments ................................................................. 33
Table 2 Thermodynamic properties of Monument Butte fluids..................... 34
Table 3 Comparison of cumulative production at the end of primary .......... 35
Table 4 Extended simulation predictions ..................................................... 36
ABSTRACT

Reservoir simulations of different fields in the Green River Formation are reported. Most extensive simulations were performed on the Monument Butte Northeast unit. Log data were used to construct detailed geostatistical models, which were upscaled to obtain reasonable number of grid blocks for reservoir simulation. Porosities, permeabilities, and water saturations required for reservoir simulation were thus generated. Comparison of the production results with the field data revealed that there was a phenomenogical deficiency in the model. This was addressed by incorporating hydraulic fractures into the models. With this change, much better agreement between simulation results and field data was obtained.

Two other fields, Brundage Canyon and Uteland Butte, were simulated in primary production. Only preliminary simulations were undertaken since a number of critical data elements were missing and could not be obtained from the operators. These studies revealed that the production performance of the Brundage Canyon field is much better than what can be predicted from simulations of a typical non-fractured, undersaturated reservoir. Uteland Butte field performance was that of a typical undersaturated reservoir.

INTRODUCTION

Fluvial-deltaic reservoirs contain a significant portion of the known world oil resources. Due to the sinuous nature of the sands, and complex geology, it is difficult to implement improved oil recovery in these reservoirs. However, the application of improved oil recovery is imperative to the commercial development of these reservoirs, since the primary recovery yields only 1% of the oil in place. The objective of this work
is to study the effectiveness of secondary oil recovery methods in lacustrine environments of the Green River Formation. This Tertiary-age formation is located in the Uinta Basin, in northeastern Utah, and is made up in part of productive sediments that formed deltas, at margins of an ancient lake. In addition to the deltas, oil is produced from sands formed in fluvial channels and offshore bars.

The Monument Butte Northeast (MBNE) unit located on the south flank of the Uinta Basin consists of 16 wells, eight injectors and the rest producers. Section 25 in the Monument Butte NE unit constitutes the field under study for this work. The reservoir has about 10 MMSTB of oil in place contained in two major sand bodies and several minor ones. The major sand bodies are the D and the C sand units, of which D sand layer has nearly 75% of the oil in place and will be studied in detail.

### Previous Work

The Green River Formation has produced in excess of 200 million barrels of oil, predominantly from three large fields: Red Wash, Wonsits Valley, and Walker Hollow located in the greater Red Wash area. These fields with their varied environments of deposition and their heterogeneous reservoirs did not appear to be good candidates for water flooding, but primary production of only 5% made the application of a secondary recovery a necessity. Three distinct units were targeted in the study: the Monument Butte unit, the Travis unit, and the Boundary unit. Wells in these units intersect 10 to 20 hydrocarbon-bearing sands, however, oil is usually produced from about 1 to 4 commercial sands. Monument Butte unit was the most developed of the three units and has 22 wells, eight injectors, and the rest producers. The unit contained about 9 million
barrels of original oil in place (OOIP) primarily in two sand layers, the D and the B. The primary production performance of the Monument Butte unit was typical of an undersaturated reservoir close to its bubble point. About 4.5% of the OOIP at a rate of 40 STB/day had been recovered when water flooding was initiated. The response to the water flood was extraordinary and nearly 10% of the OOIP had been recovered.

The geological model was developed from the log data obtained from the field. The thickness of the sands were assigned based on the isopach information and the perforated interval data for each well. The composition of the oil from specific wells was analyzed by simulated distillation on a capillary gas chromatographic column. The reservoir fluid properties such as the viscosities and gravities were measured in the laboratory. The bubble points and oil formation factors at different gas oil ratios were also measured. The black oil simulator, IMEX, developed by the Computer Modeling Group, was used for all the simulations. The reservoir was modeled using a variable thickness, variable depth option with several layers present. The simulator did an excellent job of matching overall reservoir performance. Further studies involved applying better geostatistics to represent heterogeneities in a fluvial-deltaic reservoir and representing reservoir images using stochastic simulations. The following conclusions were reached:

- a more rigorous geological approach is required, and
- incorporation of hydraulic fractures is important.

Thus the current approaches are:

- direct interpolation from high well density,
- a new geologically rigorous approach – HERESIM,
- incorporation of hydraulic fractures.
Later sections describe the better geological description of the MBNE unit and how hydraulic fractures were incorporated in the flow simulations. The history match of the model and predictions are also discussed.

**Geological Modeling of the Monument Butte NE unit**

An understanding of the internal architecture of the reservoir is required to improve reservoir management for oil recovery. Geophysical logs from 16 wells provide the basis to estimate the spatial distribution of facies type, permeability, porosity, and water saturation in the MBNE unit. These spatial distributions of porosity, permeability, and water saturation form the input parameters required to create a model for the fluid-flow simulations. Heresim3D, an integrated model for computer-aided reservoir description, is used to create the geological model for the MBNE unit. The different steps involved in creating a geological model are discussed in the following sections.

**Defining Model Boundaries and Lithostratigraphic units**

The log data from the field available at half-foot resolution, for each of the 16 wells, are transformed to an input file that can be read by the model. Once the well data (depths, lithofacies, porosity, permeability, and water saturation) are read, the domain, a regular three-dimensional grid, defining the reservoir is constructed in which the simulations of lithofacies and petrophysical parameters are performed. The lithofacies were based on the porosities. The lithofacies definitions are provided in Table 1. Lithofacies in four of the wells (10-25, 11-25, 12-25, and 13-25) (type logs) are shown in Figure 1.
The lithofacies are bounded by two surfaces, the top surface (10) and the bottom surface (20). Additional surfaces may be realized if the unit is considerably thick and large variations in the properties occur. The next step is to define the lithostratigraphic unit or litho-unit as it is called. The entire D sand unit is modeled as one litho-unit, defined by the upper and lower surfaces. Additional units are possible if more surfaces had been defined. The modeling grid must be defined before the characteristics of the litho-unit are studied. A northwest-southeast cross section through section 25 is shown in Figure 2. The surfaces for the defined cross section are shown in Figure 3.

**Model Gridding**

Petrophysical models are computed using a three-dimensional gridded volume with $\Delta x$ and $\Delta y$ equal to 132 feet and $\Delta z$ 0.5 feet. There are 40 cells each in the x and y direction and 65 cells in the z direction. For vertical gridding, two approaches are used: parallel and proportional gridding. Parallel gridding is used for the D sands with the bottom surface as the reference surface.

**Assignment of the Facies to the Lithotypes**

The lithofacies are distinguished by the porosity of the sands. Moreover, the permeability assigned to each block is computed from the porosity by using an empirical relation. A logarithmic relation is used in this case. Four lithofacies are identified in the sand. The assignment of the facies to the blocks is direct because a very fine grid is used and hence no averaging needs to be performed. After the lithofacies have been assigned to the blocks, the lithofacies are assigned to a particular lithotype. A lithotype is defined
as a set of lithofacies sharing the same properties. In this study, each lithofacies is assigned to a lithotype, thus creating four lithotypes.

**Proportion Curves and Variograms**

Proportion curves can be considered as a particular and original graphic representation of the stratigraphic sequence. They represent the percentage of each lithofacies at a given level in the lithostratigraphic unit. At each level, proportions are plotted using a standard stacked bar representation, as in a spreadsheet. Proportion curves serve as a tool to test the consistency between data and conceptual sedimentological interpretations, thus leading to better characterization. These curves are also a way to quantify geological parameters. Moreover, the curves are constraints for geostatistical simulations.

Variogram is a complementary tool that has both qualitative and quantitative interest. It is a direction-dependent mathematical function, which illustrates the variability of any parameter between two different points separated by a given distance. Variograms are also constraints for geostatistical simulations of lithofacies.

**Building the Petrophysical Model**

Once the proportional curves and the variograms have been generated, the global statistics are computed for each lithotype and saved as a statistical set. The petrophysical model is then constructed for each litho-unit. Since the porosity, water saturation, and permeability (Kx) data are available, the statistical model used to construct these
petrophysical properties for the reservoir is global statistics. $K_y$ and $K_z$ are assigned equal to $K_z$ due to isotropy. The model generated is saved as a petrophysical model.

**SIMULATIONS**

The lithology simulations are performed using the statistical set generated. A truncated Gaussian algorithm is used for these simulations. The petrophysical simulations are performed next, using the petrophysical model generated and by attributing all the petrophysical properties. The simulation results may be viewed for each slice in different ways. Litho-unit distribution in the same cross section (as Figure 2) is shown in Figure 4. Corresponding porosities and permeabilities are shown in Figures 5 and 6.

**Reservoir Construction, Gridding and Upscaling**

The reservoir is first defined by merging all the litho-units. The petrophysical data in each of these units are combined to form the entire reservoir. The simulation results for the entire reservoir can be viewed before gridding and upscaling. The domain over which upscaling is done must first be defined. At the current resolution, there are a total of about 65 layers, which would yield a total of 100,000 grid blocks. It would be possible to build a reservoir model with these many blocks; however, the awkward aspect ratio of grid blocks is expected to cause numerical instabilities. Hence, a series of reservoir models were built by upscaling the blocks vertically. A total of 13 vertical blocks were created. The proportion of porosity as a function of elevation is used to select locations of upscaled layers. Upscaled layers were selected at regular intervals. A standard upscaling procedure is used for the reservoir grid. The vertical layering is defined for each litho-
The vertical layering for the entire reservoir comprising of all the litho-units is displayed. The proportion of porosity as a function of elevation is shown in Figure 7. After defining the vertical layers, the two-dimensional areal grid is constructed using the upscaled layers. The origin location, the number of cells in the $x$ and $y$ direction, and their corresponding widths are defined. The final three-dimensional grid is generated next. A 20 x 20 grid, 264 feet wide in the $x$ and $y$ direction, is generated. The 13 vertical layers have variable thicknesses. The petrophysical properties, permeability, porosity, and water saturation, are upscaled to represent the 20 x 20 x 13 grid generated. Arithmetic averaging is used to upscale porosity and water saturation. Harmonic averaging is used to upscale permeabilities. The upscaled results are exported in a format suitable for the reservoir simulator. The upscaled cross sections for the section shown in Figure 2 are presented in Figures 8 (porosity), Figure 9 (permeability) and Figure 10 (water saturation). The basic quality of petrophysical property distribution is preserved in the upscaling process.

**Simulation Results**

A black–oil simulator, IMEX, developed by the Computer Modeling Group (CMG), was used for all of the Monument Butte NE unit reservoir simulations. As explained in the previous section, a Cartesian coordinate system was used to describe the Monument Butte unit with a multilayer, 20 by 20 areal grid to represent the reservoir. The total areal dimension of the field was 5200 by 5200 feet. The reservoir was modeled using a variable thickness, variable depth option with 13 layers present. Porosity, permeability, and water saturation computed in the geological model were used in constructing the
model for flow simulations. Since there was no free gas present in the reservoir initially, the oil saturations are just the difference between total saturation 1.0 and the water saturation. With the aforesaid reservoir description, the D sand was found to contain 7.52 MMSTB of OOIP. Reservoir fluid properties were the same as those computed and used in the previous work. The properties are summarized in Table 2.

The initial pressure in the reservoir was estimated to be between 2200 and 2300 psia. The bubble–point pressure of the reservoir crude at the initial GOR of about 450 to 500 scf/STB was around 2200 psia close to the reservoir pressure. As the first well was placed on production, the reservoir pressure began to drop, resulting in the formation of free gas in the reservoir. Gas being less viscous than oil, was preferentially produced and the production GOR increased. The average pressure had dropped to 2140 psia. As water was injected into the reservoir, the reservoir was pressurized and the production GOR declined to the current value of 488 scf/STB. The reservoir pressure was almost equal to the bubble–point pressure in most parts of the reservoir and well above the bubble point in the areas adjoining the injectors.

All the producers were operated at a bottom-hole pressure of 650 psia. Since injecting as much water into the reservoir as possible is important for a successful water flood and water injection in fluvial-deltaic reservoirs is always a concern, water injection was started quite early in the MBNE unit unlike the neighboring unit dealt with in the previous studies. The important deviation from conventional water floods is the injection strategy. Some of the largest producers were converted to injectors. To ensure a five–spot pattern, alternate producers were converted to injectors.
The field cumulative oil production and that predicted by the simulator are shown in Figure 11. The D sands contain nearly 76% of the OOIP and the remaining is in the C sands. To account for the production from D sands, simulations with different water injection rates were performed. Simulation runs with water injection rates of 60% and 40% of the original rates in each of the wells were performed. The cumulative oil production, as predicted by the simulations with 60% water injection (Figure 12) rate did not match the field oil production well.

The run with 40% water injection rate (Figure 13) matched approximately 82.8% of the total production from the field and the cumulative oil production profile matched the field results closely. This is approximately the production contribution expected from the D sands. The production match from individual wells was not matched well, though a satisfactory matched was obtained for some of the wells.

Figures 14 and 15 show the cumulative water and gas production profiles along with the corresponding field results. A pronounced variation between the field and simulation profiles was observed.

Figure 16 shows the water injection profile along with the field values. An excellent match was obtained between the simulation and the field results. However, the injection rate of 40% was lower than the amount that would have been injected into the D sands.

All the wells in the field and most of the greater Monument Butte belt are hydraulically fractured and have not been represented in these simulations. The following section deals with the inclusion of hydraulic fractures and its effects on matching history.
INCLUSION OF HYDRAULIC FRACTURES IN THE RESERVOIR MODEL

Introduction

Hydraulic proppant fracturing and gravel packing are common stimulation and stabilization treatments during completion, testing, and exploration of hydrocarbon reservoirs in the oil and gas exploration and production industry. Hydraulic fracturing is a method for increasing well productivity by fracturing the producing formation, and thus, increasing well drainage area. Thus, it can be defined as the process of creating a fracture or fracture system in a porous medium by injecting a fluid under pressure through a wellbore in order to overcome the native stress and to cause material failure of the porous medium. Briefly, it is the creation and preservation of the fracture in a reservoir rock. To fracture a rock, energy must be generated by injecting a fluid down a well and into the formation.

The purpose of natural sand or synthetic proppants of different type and grain size in hydraulic fracturing is to support the crack in order to keep it open against the closure stress acting in payzone depth and to maintain a highly conductive drainage path through the tight reservoir rock matrix for oil and gas flowing to the borehole, and in gravel packing to plug the perforation tunnels and to build a gravel mantle along the borehole wall in order to filter the hydrocarbons flowing into the wellbore and prevent payzone sand from moving. Hydraulic fracturing and gravel packing lead to enhanced oil and gas recovery from low permeability and weakly cemented to loose friable sandstones.

The next section explains how hydraulic fractures are represented in the simulator and its impact on the model to match history and forecast production.
Incorporating Hydraulic Fractures

All wells in this field and in most of the greater Monument Butte belt are hydraulically fractured. The objective of this study was to examine the impact of the presence of hydraulic fractures in the reservoir. The hydraulic fractures were inserted in blocks containing the wells. It is known (from stimulation simulations and through rock-mechanics considerations) that the hydraulic fractures are vertical, penny shaped, and extend about 200 feet beyond the wellbore on either side and span the entire thickness of the reservoir.

The following procedure was used to incorporate hydraulic fractures in the reservoir model. The grid blocks containing the wells were refined by local grid refinement. The hydraulic fracture was approximately 158.5 feet in length and its height spanned the perforated sand thickness. The fracture block was about 0.45 feet in width. This was the finest refinement that the simulator would allow. The width of the hydraulic fracture cannot be set to a finite value and is based upon the local grid refinement of a grid block approximately 264 feet in length and width. The block was refined into five blocks each in the x and y direction. The second third and the fourth blocks in the middle row in the j direction were further refined to five blocks in the i direction. The middle row of the resulting blocks was further refined and this procedure was carried out till the smallest refinement was slightly greater than the diameter of the well. With this refinement, there were a total of 12900 grid blocks. A fracture spanning nearly 200 feet on either side of the wellbore would have represented a more realistic picture, but the total number of resulting blocks would exceed the limits of the simulator.
The smallest refinement thus obtained was nearly 0.45 feet in width. All layers in which the wells were completed were refined to the dimensions stated above. Thus, the fracture was represented by the smallest refined block containing the well and one refined block on either side of the block containing the well. The fracture was represented by a high permeability zone and a permeability of 1000 md was assigned to each of the refined blocks representing the fracture. It should be noted that the matrix permeability varied over a range of about 0.1 to 150 md. The porosity was the same as the original refined block. All other properties were identical to the original simulation.

SIMULATION RESULTS

Comparison at the End of Primary Production

The initial pressure of 2300 psi dropped to around 2100 psi at the end of primary production. The presence of hydraulic fractures increased production in comparison to the model without fractures. The gas production rose significantly from 33.5 MMscf to 770.78 MMscf. The average gas production rate increased to 533.46 STB/day from 273.47 STB/day. The cumulative oil production increased to 77.09 MSTB from 59.2 MSTB in the model without the fractures. The gas saturation had increased to nearly 2%. The oil production rate increased to 641.88 STB/day from the previous value of 491.08 STB/day. The total water production had increased nearly tenfold from 0.266 MSTB to 2.99 MSTB, with the production rate too increasing tenfold from 3.66 STB/day to 32.158 STB/day. Table 3 summarizes the primary production from the field and simulation models with and without fractures.
In comparison to the field values, oil and gas production values were less than the corresponding field numbers. The water production matched quite well. The difference in values of the oil and gas production may be due to relative permeability data used in the model. The values used are the ones experimentally determined in the laboratory and used in previous work on the Monument Butte field, as stated earlier. Different sections of the reservoir may have different relative permeabilities, which have not been accounted for in the model. Another plausible reason is the size of the hydraulic fractures. Hydraulic fractures usually extend to around 200 feet on either side of the wellbore, but the ones represented in the model are only 158.5 feet in length. This was due to the limitation on the total number of blocks allowed by the simulator. To incorporate the required size, nearly 25,000 blocks would be necessary which is far more than that allowed by the simulator.

Moreover, the permeability of the fractures was assigned a value of 500 md. This value depends on the packing material and the packing pattern in the fracture.

**Further Comparisons and Analysis**

Water injection started on May 24, 1996. As water was injected into the reservoir, the reservoir pressure started to increase. The significant increase in gas production during primary production continued nearly at the same rate until about 600 days of production before more and more gas was driven into the solution, as only half of the injecting wells were opened by then. The production GOR reached a maximum of about 7000 scf/STB before declining to the current value of around 600 scf/STB as the reservoir continued being pressurized. The gas saturation increased to nearly 5% before starting to decrease. The reason for this was some of the biggest producers had just been
opened and some producers were opened after water injection had started in a couple of wells. The gas saturation decreased to the current value of 1.33% at the end of simulation period. The average oil saturation at the end of the period decreased to about 70%. As expected, the reservoir shows a large variation in oil saturation, ranging from 25% in the vicinity of the injectors to 70% in regions farther from the injectors.

Figure 17 shows the comparison of the field cumulative oil production and that predicted by the reservoir simulator. When some the producers were switched to injectors, the production profile started to flatten out, but when all the injectors were functional, the water flood rejuvenated oil production. The production from D sands matched nearly 88% of the total production from the field. Hereafter, all comparisons are made between 88% of the field value and that from the simulator. The remaining is attributed to the C sands. The cumulative production at the end of the simulation period was 408,690 STB and nearly 7.5% of the mobile oil had been recovered. Figure 18 shows the comparison of the field average rate of oil production and that from the simulations. A close match is obtained. The simulator does not do a good job of predicting the quick response to water flood observed in the field without fractures, but the response is closer in the model with hydraulic fractures. Thus, the inclusion of hydraulic fractures in the wells is very important in matching history and cannot be neglected. The simulator matched the actual water injection profile well. Figure 19 shows the water injection for the MBNE unit.

The mechanism of water flooding can be clearly understood by examining the instantaneous GOR as a function of time. The GOR is around 450 scf/STB at the beginning of primary production. The reservoir pressure falls below the bubble–point
pressure and the instantaneous GOR increases rapidly. As more and more free gas is produced in the reservoir and this gas is preferentially produced, the production GOR continues to increase reaching a value of about 7000 scf/STB. When all the injectors are functional, the reservoir is slowly pressurized; gas is driven back in to the reservoir and the production GOR declines.

Figure 20 shows the field production GOR and those predicted by the simulations. The simulator lags behind the field response to water flood. It takes more time in the simulation for the GOR’s to decline than in the field. This decline continues to the current value of around 600 scf/STB as stated earlier. Matching instantaneous GOR by reservoir simulation is complex since the value depends not only on the thermodynamics of oil and gas but also on the three–phase flow aspects of oil, water, and gas. Figure 21 shows the cumulative gas production is fairly tracked by the simulator. The simulator does a poor job matching the initial increase in gas production, as the reservoir initially declines below the bubble point. Once water flood was initiated, a close match in gas production is observed. As discussed earlier, a more realistic representation of the hydraulic fracture is bound to have a major effect on the amount of gas produced and an even closer match could be obtained.

The simulator does an excellent job of matching the cumulative water production. Figures 22 and 23 show the cumulative water production and the water cut as a percentage respectively. The water cut is much higher and closer to the field values in the model with hydraulic fractures. Figure 24 illustrates this point. There is a big variation in the water production and hence the water cut at the end of the simulation period. One reason may be due to existence of different regions with varying relative permeabilities.
The relative permeability data used were the ones measured in the laboratory. The relative permeability data were altered to obtain a satisfactory match between the simulation and the field results. Another reason for variation in water production may be due to the use of bottom hole constraint to model the data rather than respecting the individual water injection rates. This had to be followed because the local grid refinement used to model the hydraulic fractures gave rise to backflow problems. The size of the grid block was too small to inject the given rate of water.

To obtain a realistic representation of hydraulic fractures, and to overcome the limitations of the simulator, the length of the grid blocks containing the wells was changed to nearly 392 feet, quite close to the actual size of the fractures. The simulator does not allow the representation of grid blocks with different lengths for a given position in any coordinate direction. To circumvent this problem, the position of some of the wells had to be shifted by one block, so that position in the x direction was the same. Simulations were performed with this representation. The relative permeabilities were adjusted and refined to match the total water production.

The cumulative oil production during primary production had increased to nearly 85 MSTB. Water and gas production had increased significantly to about 6 MSTB and 100 MMSCF respectively. At the end of the time period, roughly the same amount of oil as in the previous case had been produced, but the water and gas production had increased significantly. Nearly 43 MSTB of water, 1300 MMSCF of gas had been produced and 1110 MSTB of water had been injected. The cumulative water production profile (Figure 25) did not match the field results well, the total water produced at the end of simulation matching field data notwithstanding. The water cut profile is shown in Figure 26.
Thus, the inclusion of hydraulic fractures increased oil production predominantly during primary production, but once water injection had started, there was not any pronounced influence on oil production. However, the water and gas production both increased phenomenally during primary production and at the end of the time period. The runs with more realistic representation of the fractures had decreased oil and water production while increasing gas production. The relative permeabilities had to be tuned to match oil and water production, but gas production and water injection increased slightly. Hence, the relative permeabilities play an influential role in obtaining a good history match.

While the simulator does an excellent job of matching the overall reservoir performance, it doesn’t do so in matching individual well performance. Heterogeneities and local production constraints play larger roles in individual well performances. In the current study, most of the individual well productions were matched within about 40% margin.

Summing up, the simulator does a good job in matching all the field quantities, but the overall contribution of 88% from the D sands appears to be higher than expected from that layer. Since the OOIP is nearly 75% of the total field and the D sand layer being the most productive one, a contribution of nearly 75 to 80% is reasonable. The primary reason for this being the fluvial reservoir modeled in this work is a subsystem that is a part of a much larger geologic system. The injected water may be leaving through the boundaries of the unit through sands channeling out of the unit. This is also the reason why the production rate predicted by the simulator is slightly higher than the ones observed in the field. Another reason is attributed to the paraffin deposition around the
vicinity of injection and production wells, which is not accounted for in the model. Thus, even though a reasonably good match is obtained by the simulator in matching reservoir performance, it should be used with caution to predict future performance.

**Extended Predictions**

The simulations were extended to the year 2010 using the same reservoir representation. Results are tabulated in Table 4. The simulations predict that by the year 2010, 1.53 MMSTB of oil would have been produced from the unit. This amounts to a recovery of 20% of the OOIP. The simulations project the water cut would have increased to 34%. With better representation of relative permeabilities, it is expected that the water cut would increase to around 60-70% and recover nearly 40-45% of the OOIP before the unit waters out. The model would have to be constantly monitored with field data and calibrated at a later time to ensure good prediction.

**Simulations of the Uteland Butte Field**

The purpose of this project was to make a baseline oil production prediction from the Uteland Butte Oil field. The computer program IMEX2001 facilitated this prediction, which is a black box simulator. This program enables the user to break up the oil field into a grid system and assign values of porosity, permeability, pressure, etc. for each individual block. The grid was simplified in the x and y plane into 15 x 15 matrix of equal size. Each of these blocks was approximately 225 feet by 225 feet.

The next step was to determine the thickness of each block. In this instance, the case was greatly simplified. It was assumed that the grid had only one block in the z
direction, and the thickness of the block was dependent upon how deep the wells were in the field. Most of the thickness values had to be estimated since there were only 19 wells with given thickness while 225 blocks needed to be assigned a thickness. If, for example, a well had a thickness of 10 feet, then the blocks around it that did not have wells would have thickness values close to that of 10 feet. To make reasonable estimations, some interpolation was done, and it was also assumed that the thickness at the edge of the grid eventually went to zero. After these calculations and estimations were performed, thickness values could be assigned. Figure 27 is the thickness grid generated by the simulator for the Uteland Butte field.

Now that the grid had been constructed, initial conditions had to be set. Several assumptions had to be made in this case, since it was not known at the time of this analysis what the initial conditions were. The assumptions that were made were a constant porosity of 0.13 for all of the blocks. The permeability was set to a constant of 5 md. The initial reservoir pressure was set to 3000 psi, while the Bubble Point was set to 3500. The initial oil saturation was 0.78, which meant that the initial water saturation was set to 0.22 for each of the blocks. Other values were assumed for well geometries and other important geometries and initial conditions.

The next part was to run simulations using the programs IMEX 2001. In order for a baseline to be constructed, a simulation had to be run for each well. In each case, only one well was opened and oil was collected for a time period from 1990 to 2005 (16 years). In each case, the amount of oil collected was different than for the other wells. The cumulative oil collected from each well is shown in Figure 28.
This figure shows that the program does indeed work and obtains reasonable working values of oil collected. In comparison with the actual oil collected, some of the values are quite close, while there are some values that are not that close. These errors are expected however, since there was no time frame given when the wells were open and when they were closed. In conclusion, a reasonable baseline was obtained from the field.

**Simulations of the Brundage Canyon Field**

The purpose of this simulation was to compare the results of the computer simulation to the actual data that was collected from Brundage Canyon. For purposes of simplification, the field was considered to be two layers on a 16 by 16 grid. Also from actual well data, porosity and thickness were assigned to each block. The grid is shown in Figure 29.

For this simulation, several simplifications needed to be made. One of these simplifications was that all of the blocks in the grid started with the same initial oil saturation. While this is not one hundred percent true, it is a fairly accurate assumption. The PVT table was also not altered for the experiment. Once again, for this simulation, only times were given when the wells were opened, but no data was supplied as to when the wells were shut in. This will lead to issues concerning well pressure, which will be discussed later.

The simulation was run with an initial oil pressure of 3000 psi and a bubble point of 2300 psi. The initial oil concentration was constant throughout the whole grid and was at the value of 0.7. When the simulation was run until the year 2006. The total oil collected is shown in Figure 30.
A good deal of oil is collected from the well, with an extra push of oil collected in about 1998. This can be accounted for several new wells being opened during that time period. But, as time goes on, less oil is collected and eventually the oil production stops. This is due to the lack of pressure that is in the well, which is caused by the continuous operation of the wells. The pressure grid shown in Figure 31 comes from the simulation and is for the year 2003.

The pressure from the well reaches readings as low as 700-psi, which is a significant pressure drop compared to the initial pressure of 3000-psi. Since there is not a considerable pressure gradient, no oil could be collected. One method to improve the computer simulation would be to have steam injected to the wells, or at least have the wells open and close when they actually did. Unfortunately, the data of when the wells were opened, not closed, was provided. If this information was given, the results could have been much more accurate.

Another major problem with the simulation was the initial conditions. It was not known what all of the initial conditions were. What were only known were the depths, porosity, and location of the wells. This leads to only a rough estimate of how much oil is collected. If proper data was given and correct PVT tables were provided, then a much better simulation could have been produced. In the case of this simulation, the output was not very close to the actual field data as shown in Figure 32.

As can be seen, the shape of the curves are similar (oil production increases and decreases at the same time for both graphs), but the curve from the simulation shows a much lower oil production than the oil that was actually collected, and then at the end of the simulation, it merely peters out and the oil production virtually stops. This error is
due to what has been discussed earlier. However, the data did show that the increase and
decrease of oil rate was predicted reasonably well, but not the magnitude. It is possible
that the field is fractured, allowing gas to segregate and maintain reservoir pressure.
CONCLUSIONS

1. The field data from the MBNE unit was transformed into a realistic geological model employing HERESIM, a geostatistical simulator. Previous studies used approximate models.

2. The results from the geostatistical simulations were used to build the reservoir model. The reservoir simulations were performed on IMEX (of CMG).

3. Simulations revealed that to obtain a good history match, representation of hydraulic fractures was necessary. This was in special reference to matching gas and water and improving oil recovery.

4. The cumulative oil produced at the end of primary production, was slightly greater than 50% of the field data. Incorporation of hydraulic fractures in the model immediately increased the oil production and it was within 10% of the field results. The overall oil profile matched excellently.

5. Cumulative gas production, that was nearly a third of the field values, increased phenomenally with the inclusion of hydraulic fractures. A good match was obtained.

6. Cumulative water production, which was only a tenth of the field values, increased significantly. A satisfactory match of the water cut and cumulative production was reached. The only disagreement was at the end of the simulation period, when the water production from the field increased sharply and the model could not match the results. This might be due to the presence of high permeability channels. Moreover, the uncertainties in the relative permeability play an important role in water production.
7. With a more realistic representation of the fractures, the gas production increased. The water production matched field values when the relative permeabilities were tuned a bit, but the production profile did not give a satisfactory match. The amount of oil produced too depended on these permeabilities and the permeability of the fractures. A higher permeability fracture caused backflow problems with flow and pressure constraints.

8. Water injection profile matched excellently in spite of using a pressure constraint on the injectors. The individual well profiles depend on local production and injection constraints and hence cannot be compared. However, most wells gave a satisfactory match within 40% of the field values.

9. From the observations stated above, hydraulic fractures play an important role in increasing oil during primary production; however, once water flooding had started, their effects on oil production weaken and are more pronounced on water and gas production. More simulations and analysis would be necessary to show whether fracturing the wells would increase production, if injection rate could be maintained in the wells.

10. A simple model for the Uteland Butte field appears to predict well the performance of the field. The undersaturated reservoir model for Brundage Canyon field fails miserably indicating that there is something fundamentally different about the field.
Table 1. Lithofacies assignments.

<table>
<thead>
<tr>
<th>Porosities</th>
<th>Lithofacies Designation</th>
</tr>
</thead>
<tbody>
<tr>
<td>-10-12.5</td>
<td>10</td>
</tr>
<tr>
<td>12.5-15</td>
<td>20</td>
</tr>
<tr>
<td>15-17.5</td>
<td>30</td>
</tr>
<tr>
<td>17.5-20 +</td>
<td>40</td>
</tr>
</tbody>
</table>
Table 2. Thermodynamic properties of Monument Butte fluids.

<table>
<thead>
<tr>
<th>p</th>
<th>rs</th>
<th>bo</th>
<th>eg</th>
<th>µ_o</th>
<th>µ_g</th>
</tr>
</thead>
<tbody>
<tr>
<td>14.7</td>
<td>0</td>
<td>1.0018</td>
<td>4.73</td>
<td>14.1</td>
<td>0.0055</td>
</tr>
<tr>
<td>500</td>
<td>115.128</td>
<td>1.0625</td>
<td>168.8</td>
<td>12.248</td>
<td>0.0057</td>
</tr>
<tr>
<td>1000</td>
<td>230.256</td>
<td>1.125</td>
<td>350.803</td>
<td>7.245</td>
<td>0.0061</td>
</tr>
<tr>
<td>1200</td>
<td>276.307</td>
<td>1.15</td>
<td>426.603</td>
<td>6.21</td>
<td>0.0062</td>
</tr>
<tr>
<td>1500</td>
<td>345.383</td>
<td>1.1875</td>
<td>541.8</td>
<td>5.348</td>
<td>0.0065</td>
</tr>
<tr>
<td>2000</td>
<td>450.511</td>
<td>1.25</td>
<td>850.991</td>
<td>4.14</td>
<td>0.0071</td>
</tr>
<tr>
<td>2500</td>
<td>575.639</td>
<td>1.3125</td>
<td>950</td>
<td>3.45</td>
<td>0.0077</td>
</tr>
<tr>
<td>3000</td>
<td>690.767</td>
<td>1.375</td>
<td>1140</td>
<td>3.105</td>
<td>0.0842</td>
</tr>
<tr>
<td>4000</td>
<td>921.022</td>
<td>1.5</td>
<td>1500</td>
<td>2.415</td>
<td>0.0907</td>
</tr>
<tr>
<td>6000</td>
<td>1370</td>
<td>1.75</td>
<td>2200</td>
<td>1.5</td>
<td>0.092</td>
</tr>
<tr>
<td>9000</td>
<td>2025</td>
<td>2.1</td>
<td>3200</td>
<td>1</td>
<td>0.093</td>
</tr>
</tbody>
</table>

p = pressure in psi  
rs = gas oil ration in SCF/STB  
bo = oil formation factor, reservoir barrel/stock tank barrel  
eg = gas formation volume factor, standard cubic feet/reservoir barrel  
µ_o = oil viscosity in centipose  
µ_g = gas viscosity in centipose
Table 3. Comparison of cumulative production at the end of primary.

<table>
<thead>
<tr>
<th>Fluids</th>
<th>Field</th>
<th>Simulation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>With fractures</td>
</tr>
<tr>
<td>Oil (MSTB)</td>
<td>99.97</td>
<td>77.093</td>
</tr>
<tr>
<td>Water (MSTB)</td>
<td>2.2926</td>
<td>2.9928</td>
</tr>
<tr>
<td>Gas (MMSCF)</td>
<td>148.96</td>
<td>70.782</td>
</tr>
</tbody>
</table>
Table 4. Extended simulation predictions.

<table>
<thead>
<tr>
<th>Year (March of)</th>
<th>Cumulative Oil Production (MSTB)</th>
<th>Recovery % OOIP</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001</td>
<td>514</td>
<td>6.84</td>
</tr>
<tr>
<td>2002</td>
<td>626</td>
<td>8.32</td>
</tr>
<tr>
<td>2003</td>
<td>744</td>
<td>9.89</td>
</tr>
<tr>
<td>2004</td>
<td>864</td>
<td>11.49</td>
</tr>
<tr>
<td>2005</td>
<td>984</td>
<td>13.09</td>
</tr>
<tr>
<td>2006</td>
<td>1091</td>
<td>14.51</td>
</tr>
<tr>
<td>2007</td>
<td>1206</td>
<td>16.04</td>
</tr>
<tr>
<td>2008</td>
<td>1318</td>
<td>17.53</td>
</tr>
<tr>
<td>2009</td>
<td>1440</td>
<td>19.15</td>
</tr>
<tr>
<td>2010</td>
<td>1532</td>
<td>20.37</td>
</tr>
</tbody>
</table>
Figure 1. Lithofacies in some of the wells.
Figure 2. A northwest-southeast cross section through section 25.
Figure 3. The three surfaces along the cross section.
Figure 4. Lithotype distribution in the cross section shown in Figure 2.
Figure 5. Porosity distribution in the cross section shown in Figure 2.
Figure 6. Permeability distribution in the cross section shown in Figure 2.
Figure 7. Porosity and permeability proportion curves and locations of upscaled layer boundaries.
Figure 8. Porosity distribution in the cross section shown in Figure 2 for the upscaled reservoir.
Figure 9. Permeability distribution in the upscaled reservoir for the cross section shown in Figure 2.
Figure 10. Water saturation distribution in the upscaled reservoir for the cross section shown in Figure 2.
Figure 11. Comparison of cumulative oil production in the MBNE unit with total water injection in D sands.
Figure 12. Comparison of cumulative oil production in the MBNE unit with 60% water injection in D sands.
Figure 13. Comparison of cumulative oil production in the MBNE unit with 40% water injection in D sands.
Figure 14. Comparison of cumulative water production in the MBNE unit with 40% water injection in D sands.
Figure 15. Comparison of cumulative gas production in the MBNE unit with 40% water injection in D sands.
Figure 16: Comparison of cumulative gas production in the MBNE unit with 40% water injection in D sands.
Figure 17. Cumulative oil production in the MBNE unit; comparison of field production with simulation results.
Figure 18. Average rate of oil production in the MBNE unit; comparison of field values with simulation results.
Figure 19. Cumulative water injection in the MBNE unit; comparison of field values with simulation results.
Figure 20. Producing gas oil ratio in the MBNE unit; comparison of field values with simulation results.
Figure 21. Cumulative gas production in the MBNE unit; comparison of field production with simulation results.
Figure 22. Cumulative water production in the MBNE unit; comparison of field production with simulation results.
Figure 23. Water cut in the MBNE unit; comparison of field values with simulation results.
Figure 24. Water cut in the MBNE unit; comparison of simulation results with and without fractures.
Figure 25. Cumulative water production in the MBNE unit; comparison of simulation results with large fractures.
Figure 26. Water cut in the MBNE unit; comparison of simulation results with large fractures.
Figure 27. Uteland Butte thickness map.

Figure 28. Production from all the 16 wells from the Uteland Butte field.
Figure 29. Thickness grid for the Brundage Canyon field.

Figure 30. Cumulative oil produced from the Brundage Canyon field.
Figure 31. Pressure depletion map for the Brundage Canyon field.

Figure 32. Comparison of the simulation data to the actual oil produced.