VOLUME IV

**CHARACTERIZATION OF REPRESENTATIVE RESERVOIRS - GULF OF MEXICO
FIELD, U-8 RESERVOIR**

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Table of Contents

Title Page

Table of Contents

List of Figures

List of Tables

Nomenclature

Abstract

Executive Summary

Section 1: Introduction

Section 2: Field and Reservoir History

2.1 Field Development History

2.2 Reservoir Geologic History

2.3 Reservoir Interpretation

2.4 Well Completion Scenarios

2.5 U-8 Sand Production History

2.6 Material Balance Calculations

Section 3. Model Validation

Section 4. Model Input Data Analysis

4.1 Model Grid Dimensions

4.2 Porosity, Water Saturation, and Permeability Distribution

4.3 Relative Permeability Curves

4.4 PVT Data Analysis

4.5 Layer Flow Index (PID) Calculations

4.6 Simulation of Well Histories: Recurrent Data

4.7 Water-Oil Ratio and Gas-Oil Ratio Constraints

Section 5. History Matching

5.1 Model Volumetric Predictions

5.2 Simulation

5.3 Discussion of Results

Section 6. Predictive Study

6.1 Introduction

6.2 Predictive Study Setup

6.3 Waterflooding

6.4 Gas and Water Injection

6.5 Horizontal Well Production Scenario

6.6 Discussion of Results

Section 7. Conclusions

Bibliography

Appendix A. History Matching Results

Appendix B. Thesis by George J. Koperna, Jr.: "Reservoir Characterization and Performance Predictions for the U-8 Sand Reservoir"

Appendix C. Well Completion Schematics

Appendix D. PVT Data

Appendix E. Petrophysical Study

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List of Figures

- 2.2.1 Original U-8 Sand Reservoir Interpretation
- 2.2.2 Initial U-8 Sand 3-D Seismic Interpretation
- 2.3.1 Current U-8 Sand 3-D Seismic Interpretation
- 2.5.1 Shut-In Reservoir Pressure
- 2.5.2 Daily Production Rates for Well #2
- 2.5.3 Daily Production Rates for Well #3
- 2.5.4 Daily Production Rates for Well #4
- 2.6.1 Reservoir Voidage Prediction Using the Material Balance Software Package
- 3.0.1 BOAST3 Reservoir Modeling Validation Results
- 4.3.1 Wylie's Approximation for k_{rw}
- 4.3.2 Wylie's Approximation for k_{rg}
- 4.3.3 Original and Modified Relative Permeability Curves
- 4.4.1 Capillary Pressure Data
- 6.3.1 Oil Saturation Prior to Secondary Recovery for Lobe A as Predicted by BOAST3
- 6.3.2 Oil Saturation Prior to Secondary Recovery for Lobe B as Predicted by BOAST3
- 6.3.3 Predictive Study Injection Well Areas
- A-1 Run One: No Communication Between Lobes A and B Except at the Well Blocks
- A-2 Run Two: Permeability Adjustment to Account for Fault in Reservoir
- A-3 Run Three: Use Modified Relative Permeability Curves, Mod k_{rw} #1 & Mod k_{rg} #1
- A-4 Run Four: Use Modified Relative Permeability Curves, Mod k_{rw} #2 & Mod k_{rg} #2
- A-5 Run Five: Use Modified Relative Permeability Curves, Mod k_{rw} #2 & Mod k_{rg} #1
- A-6 Run Six: Final History Match
- A-7 Run Six: Water Production Rate as the Recurrent Data Set Input

List of Tables

- 2.4.1 U-8 Sand Zonation
- 2.5.1 Cumulative Production For The U-8 Reservoir
- 4.5.1 P_i Values For Each Lobe
- 5.1.1 Initial Fluid Volumes
- 6.3.1 Incremental Oil Recovery as a Result of Waterflooding

Nomenclature

2-D	two dimensional
3-D	three dimensional
bbl	reservoir barrel
bbl/d	barrels per day
bcf	billion cubic feet
B_o	oil formation volume factor
dx	x-direction gridblock thickness
dy	y-direction gridblock thickness
dz	z-direction gridblock thickness
ft	feet
GOR	gas-oil ratio
k_{av}	average horizontal permeability
k_{rg}	gas relative permeability (SPE standard unit)
k_{ro}	oil relative permeability (SPE standard unit)
k_{rw}	water relative permeability
k_x	permeability in the x direction
k_y	permeability in the y direction
k_z	vertical permeability
mbo	thousand barrels of oil
mbw	thousand barrels of water
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmstb	million stock tank barrels
MOD	modified
mstb	thousand stock tank barrels
OOIP	original oil in place
PI	productivity index
PID	layer flow index
psia	pounds per square inch absolute
PVT	Pressure, volume, and temperature
R	horizontal permeability ratio
r_e	external radius
r_o	estimated reservoir radius
r_w	wellbore radius
s	skin factor
S^*	Wyllie's normalized saturation
scf	standard cubic feet
S_o	oil saturation
S_{wi}	irreducible water saturation
WOR	water-oil ratio
μ_o	oil viscosity

Abstract

A reservoir study was performed using a publicly available black oil simulator to history match and predict the performance of a Gulf of Mexico reservoir. The work was performed by BDM Federal, Inc., in support of the Louisiana State University Bypassed Oil Study, which is funded by the U.S. Department of Energy (DOE) under contract number DE-AC22-92BC14831.

The first objective of this simulation study was to validate the Black Oil Applied Simulation Tool version three for personal computers (BOAST3-PC) model to ensure the integrity of the simulation runs. Once validation was completed, a field history match for the Gulf of Mexico U-8 oil reservoir was attempted. A verbal agreement was reached with the operator of this reservoir to blindcode the name and location of the reservoir. In return, the operator supplied data and assistance in regards to the technical aspects of the research. On the basis of the best history match, different secondary recovery techniques were simulated as a predictive study for enhancing the reservoir productivity.

Executive Summary

The U-8 reservoir, located offshore of Louisiana in the Gulf of Mexico, is the specific focus of this study. A verbal agreement was reached with the operator of this reservoir to blindcode the name and location of the reservoir. In return, the operator supplied data and assistance in regards to the technical aspects of the research. The section of the reservoir that is under study has been developed with three production wells and one exploration/study well penetrating nearly 12,000 ft into the U-8 Sand formation. The U-8 Sand reservoir has produced over 1,800 MSTB of oil, 6,900 MMSCF of gas, and 870 MSTB of water. Secondary recovery techniques are being designed to extract the remaining hydrocarbons from the reservoir.

This reservoir lies on the northeast side of a major fault radiating from a large salt tongue. Several smaller faults splay out from this major fault, forming the boundaries of the reservoir unit. Two minor faults cut the interior of the reservoir block. These minor faults partially isolate portions of the reservoir block, creating long migration pathways from sections of the reservoir to the producing wells.

Companies A and B have penetrated the U-8 Sand with four wells. Company A controls the northern section of the block, while Company B has been developing the southern section. One of Company A's wells, the #1, was logged through the U-8, but was not completed. The other three wells have been productive.

The U-8 was divided into three layers, with two intervening shaley zones. The top, or A, layer was a relatively uniform blanket sand, between 12 and 15 feet thick. A shaley zone isolated this unit from the underlying B sand, a much thicker, but more irregular, sand body. The upper unit appears to be completely oil-saturated at all of the penetration points. Whether this unit waters out at some point down dip is unknown, but the production and pressure data imply that the entire layer may be oil-filled. The B sand shows a relatively shallow oil-water contact. The total capacity of this layer is much greater than that of the A Layer, but much of the layer is filled with water.

The deepest zone, the C layer, is also very thick. It has an oil-water contact, showing that the deeper sections are waterfilled. The C layer is also irregular in thickness. The isopach data for the B and C layers suggest that they were deposited during a period of active fault

movements. The sands appear to pile up against the main boundary faults, as if they are compensating for active fault displacements.

The shaley zones between the layers are thin, but they have apparently formed effective barriers to fluid migration, as demonstrated by the differing oil-water contacts in each of the layers. Some of the production data have suggested that water has migrated from layer to layer since oil production began. Fluid may also be leaking into the reservoirs around improperly completed well bores or along the bounding fault planes.

The primary, contiguous area of the reservoir was split into three layers and laid out in a custom-designed grid pattern to account for local reservoir properties. Parameters such as structural position, thickness, porosity and permeability were determined for each block. The geologic and engineering data were used in concert to produce a model and production scenario that best fit the actual history of the U-8 reservoir.

Although production records dated as far back as November 1982 are on file for the U-8 reservoir, reservoir fluids were not withdrawn until March 1983 from Company B's #2 well. This was due to reservoir tests conducted on the well prior to production. During well #2's producing period, two more wells came on line in the U-8 reservoir. In February 1988, Company A turned well #3 on line, and, in July 1988, Company B placed well #4 on line. These three wells were producing freely until mid-1989 when all production was choked back to conserve the rapidly depleting reservoir pressure.

In February 1991, well #2 was shut-in due to limited oil production and excessive gas and water production. To date, well #2 has produced 218 MBO, 836 MMSCF, and 330 MBW.

Wells #3 and #4 produced until November and December 1992 when they were shut-in. Well #3 produced 517 MBO, 3101 MMCF, 356 MBW, and well #4 produced 1,091 MBO, 2987 MMSCF, 193 MBW.

Company A's A-1 well, located in the north side of the field, was drilled into the U-8 Sand in January 1981 as a test well for the reservoir. Coring operations were conducted, as well as extensive geophysical well logging. The log interpretation indicated that the U-8 Sand's B lobe was missing.

Material balance estimations were carried out by Company B using MBAL, a material balance software package owned and operated by that company. To estimate the fluid volumes in place, PVT data were correlated for the reservoir.

Company B implemented PVTGOR, a PVT correlation software package, to generate PVT data for the entire U-8 reservoir. These correlations were based on a PVT study completed for well #4. Once this task was completed, the field PVT data were placed into MBAL. MBAL can use both PVT data and production data to determine the reservoir volumetrics and any aquifer water encroachment into the reservoir.

A plot was generated from the MBAL software package. By inspecting the plot, two lines of different slope appear. The intersection of these two lines at 5,300 psia represents the estimated bubble point pressure, which is the pressure at which the gas begins to come out of solution within the reservoir. MBAL also predicted the OOIP in the U-8 reservoir to be 17.3 MMSTB at a GOR of 850 SCF/BBL.

The input data file needed to run the BOAST3 model was derived extensively from information provided by Company A. The information included production (oil, gas, and water) and reservoir pressure data that had been compiled over the life of the reservoir.

Petrophysical well data was provided and analyzed to obtain porosity, water saturation, and permeability values for model input.

Careful review of the geology led to the determination that the U-8 Sand could be described through the use of a three-layer model representing the three lobes within the U-8 Sand reservoir. Thus, a 16 by 15 by 3 model system was created and overlain upon structural and isopach maps to obtain elevation and thickness values for each reservoir grid block. By reading the top layer's elevation values for the reservoir, the simulator computed the elevations for the second and third layers from the uppermost layer's elevation and the subsequent layers' thicknesses.

Petrophysical data was used in combination with the geologic interpretation to yield porosity, water saturation, and permeability distributions for the entire reservoir.

The permeability distribution within the system was constructed to be one constant value of k_x , k_y , and k_z for each layer. The vertical permeability values controlled the level of interlayer communication. Based upon the geologic interpretation, layers one and two were allowed to communicate; however, layer three was shut out of the reservoir by reducing the value of k_z to a very small number, effectively reducing it to zero. For each layer, the values of k_x and k_y were equal and that of k_z was lower than the other two. The horizontal and vertical permeabilities were different for each layer.

The relative permeability data obtained from Company A were derived from a gas reservoir adjacent to the area under study. These data were the only available relative permeability data for the area and, hence, were used for early reservoir simulation. Eventually, the relative permeability data were modified to achieve a better history match.

As the history matching process reached a point at which no other practical data manipulation was possible, the relative permeability data were reviewed to determine the relevance to the U-8 Sand. Because the data were obtained from a gas, rather than an oil, reservoir, the given relative permeability data were not applicable to the U-8 Sand.

Therefore, the actual field data were reviewed to determine key inflection points during production. These points were then viewed during simulation runs to determine the computed gas and water saturations corresponding to the inflection points. The relative permeability curves were then altered at these saturations to achieve the final relative permeability modifications.

The PVT data were gathered from an intensive study conducted on well #4. The PVT data that were gathered from well #4 were used to generate a field-wide PVT data set using Company B's PVTCOR software. Information obtained included viscosity, formation volume factor, and density for oil, gas, and water at varying pressures. The gas-oil ratio and the z-factor were also obtained. Capillary pressure data were provided by Company B for input into the model. The compiled data were applied to the entire reservoir.

Using the oil production rate as an input, or a known parameter, an implicit rate calculation scheme was used to accurately simulate past reservoir history. The oil rate was averaged over designated periods of time for each of the three producing wells with each time period represented by an individual recurrent data set. Reservoir pressure, water production, and gas production were predicted and compared to actual field history.

The maximum allowable water-oil ratio (WOR) and gas-oil ratio (GOR) are input by the user and control the model behavior. When the maximum WOR or GOR is reached, the model will shut-in the layer that is producing the highest WOR or GOR at the time. If more

than one layer exhibits the same maximum WOR or GOR at the same time, the deepest layer is shut-in first. For this system, a WOR cut-off of 2.0 and a GOR cut-off of 500,000.0 were used.

The model predicted a value of OOIP significantly smaller than the value obtained through the material balance study, therefore the thickness and water saturation contours were modified slightly to achieve a more correct volumetric estimate.

When volumetric alterations to the simulation input file were completed, the model calculated the OOIP for lobes A and B at 15.95 MMSTB. This value was viewed as a conservative estimate of the OOIP calculated by Company B.

During the history matching process, some of the early U-8 Sand reservoir geologic interpretations were found to be in error. The actual water production could not be modeled based upon the premise that each lobe was a reservoir unit, itself cut off from communication with the other lobes by the shale stringers running between them. Evidence that indicates that layers A and B are in communication include a cement block squeeze conducted in Well #2 that did not stop excessive water production and high water production from well #3, which is located the farthest away from the A lobe high water saturated areas. These effects could be due to liquid removal from the reservoir which upsets the equilibrium reservoir conditions, leading to a complete breakdown of the seal between lobes A and B, as well as a breakdown of the cement block squeeze in Well #2.

Also, the block squeeze in Well #2 may have possibly broken down due to decreasing reservoir pressure around the 2,600th day of production. This time corresponds to a large increase in the water production rate in well #2. Thus, some damage apparently occurred around each of the wells to allow vertical communication between lobes A and B. This would account for some of the large amount of water production.

The given reservoir relative permeability data were determined to be inappropriate for the U-8 Sand reservoir because the data were obtained from an adjacent gas reservoir that is isolated from the U-8 Sand. The relative permeability data were modified to achieve a history match because these data were believed to be the least reliable.

Once a history match was obtained, the data set was converted to run on the basis of a given water rate. The results of this run showed that the altered relative permeabilities were very close to the actual field relative permeabilities. The oil-rate-based simulation run and the water-rate-based simulation run were similar. Also, the vertical permeability values were found to be within the accepted range for the Gulf of Mexico ($0.1k_x < k_z < 0.5k_x$, with $k_x = k_y$) at $0.4k_x$.

During the predictive case study simulations, the production scenario was altered. Since Well #2 has had a troubled productive history, the predictive study was conducted based on the decision that this well would be cemented or shut-in and that a new well would be drilled. The new well, well #5, would be drilled exactly midway between wells #2 and #4. Drilling well #5 has at least one major advantage. The excessive formation damage that has occurred around well #2 has allowed large quantities of water production. Well #5 would be placed farther away from the water-oil-contact. Therefore, the well would be moved farther away from the 100 percent water saturated zones of the reservoir, possibly reducing the water production.

These assumptions were made during the predictive study: 1) the production time is ten years; 2) the producing water-oil ratio was set at 1,000 to allow the production wells to stay on-line; 3) the producing gas-oil ratio was set at 5,000,000 SCF/STB to allow the production wells to stay on-line; 4) Well #3 would come on-line after one year of water injection (about the time

that the oil front would reach the well; 5) the field's water injection rate (based upon a decision by the reservoir's operator) would be approximately 5,000 STB/D; and 6) the field's gas injection rate would be 500 MCF/D.

Based upon the oil saturation profiles established for lobes A and B, potential sites were targeted and denoted using A, B, C, D, and H. Waterflooding operations were carried out based on the previous assumptions and decisions. Area B showed the greatest additional oil recovery when simulated under the given setup.

For a combination scheme of gas injection and waterflooding, the setup was: inject gas at a rate of 500 MCF/D for 300 days through a vertical well; shut in the reservoir for ninety days; and inject water at a rate of 5,000 STB/D for ten years through a horizontal well. Area A was chosen to be the site for gas injection and areas B and C were selected for waterflooding based upon their performance during the waterflooding portion of the predictive study. The results showed a considerable reduction in overall additional oil recovery. The combination gas injection/waterflood for areas A and C produced an additional oil recovery of only 2,296 MSTB. The combination gas injection/waterflood for Areas A and B produced an additional oil recovery of only 3,018 MSTB.

Each of these projected additional oil recoveries is considerably (approximately 400 to 500 MSTB) less than the waterflooding-only recoveries for horizontal wells. This could be due to the possible redistribution of oil into zones of high water saturation, which translates into losing the oil for good as it becomes irreducible.

For a horizontal well production scenario, the original production wells (#3 and #4) and well #5 were converted to water injectors, which allowed the placement of a horizontal production well in area H. The water injection wells were designed to inject water at a total field rate of 5,100 STB/D and the horizontal production well was designed for a 1,500-ft horizontal section. After one year, field production operations began. The total ten-year oil production from the horizontal well was 3,269 MSTB.

Given the standard industry design for water injection (5,100 STB/D), the best possible production scenario is a ten-year waterflooding operation in area B. However, if the injection rate can be increased, and even doubled, the additional oil recovery may be increased by 33% in the vertical injection well scenario and by 37% in the horizontal well scenario (at 10,200 STB/D).

The reservoir simulation study using BOAST3 has been validated, and the results achieved in this study have been shown to be accurate and correct. The results have led to the development of a set of technically feasible solutions to improve oil production from the U-8 Sand reservoir.

Section 1: Introduction

This report presents the results of the simulation study of the U-8 reservoir in the Gulf of Mexico. A verbal agreement was reached with the operator of this reservoir to blindcode the name and location of the reservoir. In return, the operator supplied data and assistance in regards to the technical aspects of the research. Section 2.0 highlights the field and reservoir history and describes the reservoir geology and production history. The BOAST3 validation test criteria and the validation test results are contained within section 3.0. Section 4.0 describes the development of the model's input data; specifically, reservoir rock and rock-fluid properties and the gridding of

the system are discussed. Section 5.0 covers the history match process that was used during the study. Finally, the predictive study results are summarized in section 6.0.

Work on this study led to the completion of a master's thesis.¹ The thesis encompassed the entire reservoir simulation study and is included in Appendix B.

Section 2: Field and Reservoir History

2.1 Field Development History

The U-8 reservoir, located offshore of Louisiana in the Gulf of Mexico, is the specific focus of this study. The section of the reservoir that is under study has been developed with three production wells and one exploration/study well penetrating nearly 12,000 ft into the U-8 Sand formation. Company A's well (further reference herein to this well will be to A-1), located in the north side of the field, was drilled in January 1981 as a test well. Field operations for this well included coring and geophysical well logging.

In November 1982, the first production well was completed in the U-8 sand reservoir. Company B's well (further reference herein to this well will be to #2) was a straight hole drilled to 12,324 feet. In February 1991, Well B was shut-in due to high water and gas production rates.

Company A drilled the second production well (further reference herein to this well will be to #3) in the U-8 Sand in February 1988. The #3 well was drilled to a total depth of 12,140 feet. In November 1992, this well was shut-in due to high water and gas production rates and diminishing reservoir pressure.

Company B's second well (further reference herein to this well will be to #4) was drilled as a straight hole to a depth of 11,957 feet in July 1988. The well is currently under production.

The U-8 Sand reservoir has produced over 1,800 MSTB of oil, 6,900 MMSCF of gas, and 870 MSTB of water. Secondary recovery techniques are being designed to extract the remaining hydrocarbons from the reservoir.

2.2 Reservoir Geologic History

The subject field is located on the north side of a large salt tongue. This tongue has risen diagonally through the surrounding sediments, creating an extremely complex fault pattern. The disturbance patterns in the sediments around salt tongues can be much more complicated than those generally seen around typical salt dome structures. Salt domes, by definition, rise more or less vertically through the overlying beds. They tend to produce a relatively standardized set of sedimentation and fault patterns, which have been studied extensively. As salt flows into the dome structure, sediments thin over high areas. As salt withdraws from these areas, sediments thicken, and surrounding beds collapse into the vacated area. This activity produces somewhat standardized radial and concentric sets of faults.

¹ Koperna, G., "Reservoir Characterization and Performance Predictions For The U-8 Sand Reservoir," Master's Thesis, West Virginia University Department of Petroleum and Natural Gas Engineering, (June, 1994).

In the case of salt tongues, the salt moves upward at an angle. Beds can be rapidly elevated by the advancing salt and plowed out of the way in front of the tongue. The plowing action causes extremely complex faulting, with vertical, inclined, and horizontal offsets. Above the salt, the beds are raised and stretched, producing extension faulting. Once the salt has moved through an area, the fault plane traversed by the salt partially or completely closes. The beds, which had been elevated by the salt, subside once the salt has passed. The patterns of salt movement vary over time, following the path of least resistance at any moment. The direction of movement and rate of climb through the overlying sediments continuously change as a salt tongue advances. The structural patterns in the area that was studied have been formed by this type of disturbance.

The U-8 Sand is the unit studied for this project (Figure 2.2.1). This reservoir lies on the northeast side of a major fault radiating from a large salt tongue. Several smaller faults splay out from this major fault, forming the boundaries of the reservoir unit. Two minor faults cut the interior of the reservoir block. These minor faults partially isolate portions of the reservoir block, creating long migration pathways from sections of the reservoir to the producing wells.

As previously discussed, Companies A and B have penetrated the U-8 Sand with four wells. Company A controls the northern section of the block, while Company B has been developing the southern section. One of Company A's wells, the A-1, was logged through the U-8 but was not completed. The other three wells have been productive.

Early interpretations of the reservoir were based on two dimensional (2-D) seismic lines shot in the 1970s and 1980s. The original structural interpretation of the area showed a saddle-shaped structure with a dome at each end. The productive wells were placed to produce from the crest of the northern dome and from an area just south of the low point on the saddle.

As the study area was developed, additional information was gathered, and three dimensional (3-D) seismic surveys were run. Using seismic workstations, Company B processed the data. The results showed a much more complicated picture than had originally been envisioned.

The first interpretation of the U-8 Sand using 3-D data is shown in Figure 2.2.2. The major faults surrounding the block have been reinterpreted, and the internal structure of the U-8 is shown as being much more complex. The two-dome shape is much less obvious. The "dome" at the south end is now an irregularly shaped high, formed largely by faulting. The new interpretation does not clearly indicate if a migration path exists from this area to the production wells.

The production from Company B's wells did not fit the pattern that would have been predicted based on this interpretation. Logs were collected from the wells that penetrated the U-8 Sand, and a meeting was held in Company B's offices to analyze the characteristics of the reservoir.

2.3 Reservoir Interpretation

The U-8 was divided into three layers, with two intervening shaley zones. The top, or A, layer was a relatively uniform blanket sand, between 12 and 15 feet thick. A shaley zone isolated this unit from the underlying B sand, a much thicker, but more irregular, sand body. The upper unit appears to be completely oil-saturated at all of the penetration points. Whether this unit waters out at some point down dip is unknown, but the production and pressure data imply that

Figure 2.2.1 - Original U-8 Sand Reservoir Interpretation

Figure 2.2.2 - Initial U-8 Sand 3-D Seismic Interpretation

the entire layer may be oil-filled. The B sand shows a relatively shallow oil-water contact. The total capacity of this layer is much greater than that of the A Layer, but much of the layer is filled with water.

The deepest zone, the C layer, is also very thick. It has an oil-water contact, showing that the deeper sections are waterfilled. The C layer is also irregular in thickness. The isopach data for the B and C layers suggest that they were deposited during a period of active fault movements. The sands appear to pile up against the main boundary faults, as if they are compensating for active fault displacements.

The shaley zones between the layers are thin, but they have apparently formed effective barriers to fluid migration, as demonstrated by the differing oil-water contacts in each of the layers. Some of the production data have suggested that water has migrated from layer to layer since oil production began. Fluid may also be leaking into the reservoirs around improperly completed well bores or along the bounding fault planes.

Figure 2.3.1 shows the latest 3-D seismic structural interpretation of the U-8 Sand. The data have been further refined, and better picks made on some of the reflectors. The details on the structure have changed. The "saddle" form is even less obvious. Potential migration patterns have been revised. Analysis of reflection patterns and strength on the southern high suggest that there is very little oil potential in this area. The revised structure map and the isolation of the southwestern portions of the unit were factored into the new reservoir model.

The primary, contiguous area of the reservoir was split into three layers and laid out in a custom-designed grid pattern to account for local reservoir properties. Parameters such as structural position, thickness, porosity and permeability were determined for each block. The geologic and engineering data were used in concert to produce a model and production scenario that best fit the actual history of the U-8 reservoir.

2.4 Well Completion Scenarios

The following is a summary of the completion methods/scenarios implemented in the four wells in the reservoir. Table 2.4.1 contains the lobe zonations for each well in the U-8 Sand. Well completion schematics for each of the three production wells may be found in Appendix C.

Company A's A-1 well, located in the north side of the field, was drilled into the U-8 Sand in January 1981 as a test well for the reservoir. Coring operations were conducted, as well as extensive geophysical well logging. The log interpretation indicated that the U-8 Sand's B lobe was missing.

Table 2.4.1: U-8 Sand Zonation

WELL	LOBE A (FT)	LOBE B (FT)	LOBE C (FT)
1	11,853-11,867	MISSING	11,867-11,930
2	11,873-11,897	11,897.5-11,914	11,914.5-11,962
3	12,000-12,015	12,015.5-12,032	12,032.5-12,122
4	11,844-11,858	11,858.5-11,870	11,870.5-11,913

Figure 2.3.1 - Current U-8 Sand 3-D Seismic Interpretation

Company B's #2 well was the first production well completed in the U-8 Sand reservoir. The well was a straight hole drilled to 12,324 feet and plugged back to 11,930 feet. The U-8 Sand was block squeezed with 100 sacks of cement from 11,900 feet to 11,904 feet to separate the water zones from the hydrocarbon bearing portions of the formation. The A lobe was perforated with eight five-inch perforations from 11,873 feet to 11,888 feet. In late 1988, a total of ten gas lift valves were installed, three in the top three mandrels and seven in the bottom seven mandrels. Currently, the well is configured with gas lift and a through-tubing recompletion from the G-8U Sand to the U-8 Sand. Currently, the #2 well is shut-in due to high water and gas production rates.

Based upon the well log analysis conducted for well #2, an additional pay zone was determined to exist. This zone, the G-8U Sand, lies between 9,314 feet and 9,328 feet. The pay interval was circulation squeezed from 9,254 feet to 9,348 feet; however, the circulation squeeze failed to test after the cement was drilled out. The top and bottom set of perforations were squeezed with an additional 58 and 114 sacks of cement each. Again, the top set of perforations would not test. The top set of perforations were squeezed two additional times with a total of 180 sacks of cement. The G-8U Sand was left behind pipe as a plugback alternative.

Drilled to a total depth of 12,140 feet, Company A's #3 well was the second production well to go on line. The well was cement squeezed from 12,013 feet to 12,022 feet, and 12 perforations were made in the A lobe from 12,002 feet to 12,012 feet. In 1989, the U-8 Sand was gravel packed and gas lift operations were implemented. The U-5 Sand was left behind pipe for future potential production. Currently, this well is shut-in due to high water and gas production rates as well as diminishing reservoir pressure.

Company B's #4 well was drilled as a straight hole to a depth of 11,957 feet. The plugback depth was 11,920 feet. The U-8 Sand was perforated from 11,844 feet to 11,862 feet, with 12 four-inch perforations allowing production from both the A and B lobes. The U-8 Sand did not flow. Therefore, the perforations were washed, and a gravel pack was installed. Two potential pay intervals, the U-5 (from 11,610 feet to 11,680 feet) and the U-6 (from 11,728 feet to 11,736 feet), were left behind pipe for future production. The well is currently producing under gas lift.

2.5 U-8 Reservoir Production History

Although production records dated as far back as November 1982 are on file for the U-8 reservoir, reservoir fluids were not withdrawn until March 1983 from Company B's #2 well. This was due to reservoir tests conducted on the well prior to production. During well #2's producing period, two more wells came on line in the U-8 reservoir. In February 1988, Company A turned well #3 on line, and, in July 1988, Company B placed well #4 on line. These three wells were producing freely until mid-1989 when all production was choked back to conserve the rapidly depleting reservoir pressure.

Because the reservoir pressure had been drawn down approximately 3,000 psia over the productive life of the reservoir, as illustrated in Figure 2.5.1, large amounts of gas were forced out of solution and produced. In February 1991, well #2 was shut-in due to limited oil production and excessive gas and water production. To date, well #2 has produced 218 MBO, 836 MMSCF, and 330 MBW.

Figure 2.5.1: Shut-In Reservoir Pressure

Wells #3 and #4 produced until November and December 1992 when they were shut-in. Well #3 produced 517 MBO, 3101 MMCF, 356 MBW, and well #4 produced 1,091 MBO, 2987 MMSCF, 193 MBW. Table 2.5.1 contains the cumulative reservoir fluid production. The production rates by well may be found in Figures 2.5.2 through 2.5.4.

Table 2.5.1: Cumulative Production for the U-8 Reservoir

WELL	CUMULATIVE OIL, MSTB	CUMULATIVE GAS, MMCF	CUMULATIVE WATER, MSTB
2	218	836	330
3	517	3,101	356
4	1,091	2,987	193
TOTAL	1,826	6,924	879

Figure 2.5.2: Daily Production Rates For Well 10-15

Figure 2.5.3: Daily Production Rates For Well A-4

Figure 2.5.4: Daily Production Rates For Well 10-20

2.6 Material Balance Calculations

Material balance estimations were carried out by Company B using MBAL, a material balance software package owned and operated by that company. To estimate the fluid volumes in place, PVT data were correlated for the reservoir.

Company B implemented PVTCOR, a PVT correlation software package, to generate PVT data for the entire U-8 reservoir. These correlations were based on a PVT study completed for well #4. The PVT data is located in Appendix D. Once this task was completed, the field PVT data were placed into MBAL. MBAL can use both PVT data and production data to determine the reservoir volumetrics and any aquifer water encroachment into the reservoir.

Figure 2.6.1 was generated from the MBAL software package. By inspecting the plot, two lines of different slope appear. The intersection of these two lines at 5,300 psia represents the estimated bubble point pressure, which is the pressure at which the gas begins to come out of solution within the reservoir. MBAL also predicted the OOIP in the U-8 reservoir to be 17.3 MMSTB at a GOR of 850 SCF/BBL.

Figure 2.6.1: Reservoir Voidage Prediction Using the Material Balance Software Package

Section 3: Model Validation

BOAST3-PC must be compared to an already existing reservoir simulator before it can be viewed as a descriptive reservoir tool. A Society of Petroleum Engineers (SPE) technical paper by Aziz S. Odeh was published in the *Journal of Petroleum Technology*.² This paper provides the results of a comparison of several reservoir simulators; the methodology that Odeh describes in the paper was used to evaluate BOAST3-PC. Also the thorough overview of the BOAST3 model that is given in the South Marsh Island Simulation Study Project Report (USDOE 1993) was also considered in the evaluation of the model.

² Odeh, Aziz S., "Comparison of Solutions to a Three-Dimensional Black-Oil Reservoir Simulation Problem," *Journal of Petroleum Technology*, (January, 1981). pp. 13 - 25.

Odeh's paper fully describes a gas injection-oil production system and the reservoir's rock and fluid properties. Odeh used the data from this system in several reservoir simulators that are available in the petroleum industry. Contributing companies included Exxon, Mobil, Shell, Intercomp Resource Development, and Scientific Software Corp. (SSC). The results of Odeh's study showed very good agreement between each company's simulation results and the results obtained from the field study. This published model comparison study should provide an adequate basis for evaluating the BOAST3 model.

A data set was created for use in the BOAST3 model. The system in question is a ten-by-ten-by-three grid system with a gas injection well and an oil production well system. The results of the simulation runs are shown in Figure 3.0.1.

The oil production rate (STB/D) was plotted versus time, in years, and compared to the results of Odeh's study. BOAST3's simulation results lie within the industry envelope given in Odeh's study and show a good correlation to the results given by mainframe simulators used in industry.

Figure 3.0.1 also reveals the correlation results for plots of gas to oil ratio (GOR), in cubic feet per stock tank barrel, versus time (years). After year three on the plot, all of the BOAST3 values are significantly higher than those obtained using the industry models; the deviation in values indicates a poor correlation. This problem can be attributed to BOAST3 calculating high gas saturations in the producing well's grid block, and, hence, predicting high gas production, a problem which was also inherent in BOAST2. In the near future, an attempt will be made to modify BOAST3 so that the problem of high GOR values will be resolved.

Section 4: Model Input Data Analysis

The input data file needed to run the BOAST3 model was derived extensively from information provided by Company A. The information included production (oil, gas, and water) and reservoir pressure data that had been compiled over the life of the reservoir. Petrophysical well data was provided and analyzed to obtain porosity, water saturation, and permeability values for model input.

4.1 Model Grid Dimensions

Careful review of the geology led to the determination that the U-8 Sand could be described through the use of a three-layer model representing the three lobes within the U-8 Sand reservoir. Thus, a 16 by 15 by 3 model system was created and overlain upon structural and isopach maps to obtain elevation and thickness values for each reservoir grid block. By reading the top layer's elevation values for the reservoir, the simulator computed the elevations for the second and third layers from the uppermost layer's elevation and the subsequent layers' thicknesses.

4.2 Porosity, Water Saturation, and Permeability Distribution

Having been supplied with a petrophysical study, included as Appendix E, for each well, the petrophysical data was used in combination with the geologic interpretation to yield porosity, water saturation, and permeability distributions for the entire reservoir. Since the reservoir was

(a) Oil Production Rate Comparison

(b) Gas-Oil Ratio Comparison

Figure 3.0.1 - BOAST3 Reservoir Modeling Validation Results

described as undersaturated (i.e., no initial gas saturation), the initial oil saturation was determined by subtracting the water saturation for each grid block from one ($S_o = 1 - S_w$).

The permeability distribution within the system was constructed to be one constant value of k_x , k_y , and k_z for each layer. The vertical permeability values controlled the level of interlayer communication. Based upon the geologic interpretation (see section 2.3), layers one and two were allowed to communicate; however, layer three was shut out of the reservoir by reducing the value of k_z to a very small number, effectively reducing it to zero. For each layer, the values of k_x and k_y were equal and that of k_z was lower than the other two. The horizontal and vertical permeabilities were different for each layer.

4.3 Relative Permeability Curves

The relative permeability data obtained from Company A were derived from a gas reservoir adjacent to the area under study. These data were the only available relative permeability data for the area and, hence, were used for early reservoir simulation. Eventually, the relative permeability data were modified to achieve a better history match.

As the history matching process reached a point at which no other practical data manipulation was possible, the relative permeability data were reviewed to determine the relevance to the U-8 Sand. Because the data were obtained from a gas, rather than an oil, reservoir, the given relative permeability data were not applicable to the U-8 Sand.

As an initial step, a literature search revealed four possible sources of relative permeability approximations. The first approximation, from a paper authored by J. Naar in December 1961, could not be used because of limitations associated with the available data. Also, insufficient data were available to use the Knopp, Honarpour, et al., and Hirasaki approximation (Honarpour, Koederitz, and Harvey, 1986). This computation requires data that can be obtained only through fluid imbibition core analysis. A third means of calculating relative permeability, found in Amyx, Bass, and Whiting (1960), pertains to field determination of relative permeability ratios. This technique combines production data with PVT data to determine the relative permeability ratio, k_{rg}/k_{ro} . Although all the needed data are available, the combined data derived from the approximation are not suitable for input data in the simulation. Therefore, this approximation was also deemed unusable.

Finally, a correlation for two- and three-phase relative permeability calculations by Wylie (Slider 1983) was used to approximate the relative permeability data. The equations used were for an unconsolidated sand that was well sorted. Although the U-8 Sand does not exactly meet this geologic description, the description was the closest of the available choices. The resulting set of equations for k_{rw} and k_{row} are:

$$S^* = S_o / (1 - S_w) \quad (3)$$

$$k_{ow} = (S^*)^3 \quad (4)$$

$$k_{rw} = (1 - S^*)^3 \quad (5)$$

³ Slider, H. C., "Worldwide Practical Petroleum Reservoir Engineering Methods, Penwell Publishing Company, Tulsa, Oklahoma, (1983) pp. 691-692.

⁴ Ibid

⁵ Ibid

Where S_o and S_{wi} are the oil saturation and irreducible water saturation, respectively, expressed as fractions. Similarly, the expressions for k_{rg} and k_{rog} are:

$$S^* = (S_w - S_{wi}) / (1 - S_{wi}) \quad (6)$$

$$k_{rog} = (1 - S^*)^3 \quad (7)$$

$$k_{rg} = (S^*)^3 \quad (8)$$

Where S_w is the water saturation expressed as a fraction.

When computed and simulated, the calculated relative permeability data led to extremely small production values for the reservoir. Compared to the given laboratory data, all of the calculated values were significantly smaller. These smaller relative permeability values, in turn, caused the simulated production values to be smaller. Therefore, the only way to increase the production values was to modify the relative permeability data manually. Figures 4.3.1 and 4.3.2 illustrate Wylie's approximations.

Figure 4.3.1: Wylie's Approximation For Krw

⁶ Ibid

⁷ Ibid

⁸ Ibid

Figure 4.3.2: Wylie's Approximations For Krg

Figure 4.3.3 shows the relative permeability curves generated using both the original (denoted by ORIG) relative permeability data obtained from Company B and the modified (denoted by MOD) relative permeability data for water and gas relative permeabilities.

Alterations to the original relative permeability data were made by studying previous history matching efforts, detailed in section 5.0. For example, the production data obtained during simulation runs were found to have excessive gas and limited water production, an effect probably caused by using the relative permeability curves for the adjacent gas bearing reservoir.

Therefore, the actual field data were reviewed to determine key inflection points during production. These points were then viewed during simulation runs to determine the computed gas and water saturations corresponding to the inflection points. The relative permeability curves were then altered at these saturations to achieve the final relative permeability modifications denoted by MOD K_{rw} #2 and MOD K_{rg} #2 on Figure 4.3.3.

4.4 PVT Data Analysis

The PVT data were gathered from an intensive study conducted on well #4. The PVT data that were gathered from well #4 were used to generate a field-wide PVT data set using Company B's PVTCOR software. Information obtained included viscosity, formation volume factor, and density for oil, gas, and water at varying pressures. The gas-oil ratio and the z-factor were also obtained. The PVT data are contained in Appendix D.

Capillary pressure data were provided by Company B for input into the model. The compiled data were applied to the entire reservoir. Figure 4.4.1 illustrates the capillary pressure curves.

(a) Gas-Oil Relative Permeability Curves

(b) Water-Oil Relative Permeability Curve

Figure 4.3.3 - Original and Modified Relative Permeability Curves

Figure 4.4.1: Capillary Pressure Data

4.5 Layer Flow Index (PID) Calculations

Each well lobe must have a characteristic layer flow index (PID). The equation used to determine PID is rather cumbersome and contains terms, such as r_e and $K_{ro}/\mu_o B_o$, that are rarely exactly known for multiphase-flowing wells. Thus, the layer flow index value may be approximated using the productivity index (PI) for non-fractured wells. The equation is:

$$PI = \frac{0.00708 \cdot k_{av} d_s}{\ln(r_o/r_w) + s} \quad (9)$$

Where the following variables may be equated as:

$$r_o = \frac{0.28 \cdot (R^{1/2} \cdot d_1^2 + R^{1/2} \cdot d_2^2)^{1/2}}{R^{1/4} + R^{-1/4}}$$

$$k_{av} = (k_x \cdot k_y)^{1/2}$$

$$d_s = dz$$

$$d_1 = dx$$

$$d_2 = dy$$

$$R = k_y/k_x$$

⁹ Peaceman, D.W.; "Interpretation of Well-Block Pressures in Numerical Simulation", Society of Petroleum Engineer's Journal, (1978) pp. 183-194.

The calculated PI values are shown in Table 4.5.1.

Table 4.5.1: PI Values for Each Lobe			
WELL	LOBE A	LOBE B	LOBE C
2	15.52	25.83	126.75
3	9.87	60.08	115.08
4	4.21	1.62	50.73

4.6 Simulation of Well Histories: Recurrent Data

Using the oil production rate as an input, or a known parameter, an implicit rate calculation scheme was used to accurately simulate past reservoir history. The oil rate was averaged over designated periods of time for each of the three producing wells with each time period represented by an individual recurrent data set. Reservoir pressure, water production, and gas production were predicted and compared to actual field history.

4.7 Water-Oil Ratio and Gas-Oil Ratio Constraints

The maximum allowable water-oil ratio (WOR) and gas-oil ratio (GOR) are input by the user and control the model behavior. When the maximum WOR or GOR is reached, the model will shut-in the layer that is producing the highest WOR or GOR at the time. If more than one layer exhibits the same maximum WOR or GOR at the same time, the deepest layer is shut-in first.

For this system, a WOR cut-off of 2.0 and a GOR cut-off of 500,000.0 were used.

Section 5: History Matching

5.1 Model Volumetric Results

As the reservoir data were assembled into the input data set, several pre-history matching simulations were made. These simulation runs were completed to reveal any material balance or reservoir volumetric problems that might occur.

Petrophysical data, seismic data, water saturation and lobe thickness contours were created for each layer within the U-8 Sand based upon the geologic interpretation of the well logs. These data were then assigned to the corresponding grid blocks in each layer. Once completed, the reservoir model was run to find the initial fluid volumes.

Material balance calculations had been performed by Company B for the U-8 Sand. Based upon Company B's calculations, the original oil in place (OOIP) was computed to be 17.4

MMSTB for lobes A and B only. Therefore, when the model predicted a value of OOIP significantly smaller than this value, the thickness and water saturation contours were modified slightly to achieve a more correct volumetric estimate.

When volumetric alterations to the simulation input file were completed, the model calculated the OOIP for lobes A and B at 15.95 MMSTB. This value was viewed as a conservative estimate of the OOIP calculated by Company B. The following table shows values of initial fluid in place as calculated by BOAST3.

Table 5.1.1: Initial Fluid Volumes				
Fluid in Place	Lobe A	Lobe B	Lobe C	Total
Oil (MMSTB)	14.40	1.55	2.67	18.62
Water (MMSTB)	11.68	7.23	45.16	64.07
Solution Gas (BCF)	11.82	1.26	2.19	15.27

5.2 Simulation

Plots for all six runs are included in Appendix A. An important point is that the model was run under a constant oil rate for each well. This rate for the given time period was determined from actual production data provided by Company B. Thus, cumulative oil will always match. The most critical parameter to match, cumulative water production, became evident with the first run. The plot for Run No. 1 shows the first complete data set run. The original geologic interpretation was used (i.e., no communication between lobes A and B, except around the wells where vertical communication was allowed). Although the cumulative gas production matched well, the cumulative water production was approximately half of the actual production.

Also some of the very early volumetric runs performed indicated that the water production could not be modeled while lobes A and B were not in communication. As stated in the earlier geological overview, the B lobe contained a shallow oil-water contact and also had a much greater capacity than did the A lobe. Hence, since the A lobe has a small quantity of water in place and that much of the B lobe is saturated with water, some of the water production must be originating from the B lobe.

Evidence of communication between lobes A and B is revealed in the well completions section of this report (see section 2.4). As previously discussed, well #2 was block squeezed with 100 sacks of cement from 11,900 feet to 11,904 feet to separate the water-bearing lobes, B and C, from the hydrocarbon-bearing lobe, A. Although the block squeezed was tested successfully, the well still produced large amounts of water, water that could not be produced from the A lobe alone.

Input data modifications were then made to Run No. 1. Among these, the model was modified to account for a fault, which is located through the middle of the U-8 Sand. The plot for Run No. 2 shows the results of this simulation, which reveal, as expected, that the reservoir pressure declined as the cumulative water and cumulative gas values increased. The pressure

value is closer to the actual field value. However, although the cumulative water increased by 100 MSTB, the amount is still significantly lower than it should be.

An important point in describing these runs is that the only data not provided was the permeability in the z direction (k_z) for each lobe within the U-8 Sand. It was determined that the range of k_z was one tenth to one half the relative permeability in the x or y directions ($0.1k_x < k_z < 0.5k_x$, with $k_x = k_y$).

The k_z value is important because it controls the communication between the three lobes within the reservoir. In the cases in which the data suggested no communication between the lobes, k_z was set to nearly zero in the B lobe (k_z in the A lobe is set at $0.5k_x$). In the cases in which the data indicated communication between the lobes, k_z is set to a value within the previously described range for each layer.

Run No. 2 was altered several times by increasing the degree of communication between lobes A and B. Each run revealed that the cumulative water production could not be attained. Thus, the relative permeability data was reviewed to determine if any alterations or approximations could be made. Section 2.0 describes the outcome of this review.

Run No. 3 was made using the first modified relative permeability data set. Although the cumulative water production remained constant, both the reservoir pressure and the cumulative gas production increased. These results led to increasing the communication between lobes A and B in an attempt to achieve a better history match.

These simulation runs failed to result in a satisfactory set of history matches; therefore, the relative permeability curves were altered once more. This time, a second relative permeability modification was used. Also, that the water production could not be matched unless lobes A and B were in communication became increasing apparent. An arbitrary value of k_z was chosen from the previously described range.

Run No. 4 was made using these additional changes, and the results show a decrease in pressure and increases in cumulative water and gas production. Again, k_z was altered within the range of reliable values in an attempt to achieve a better history match. The larger the value of k_z that was used led directly to a further decrease in the reservoir pressure, eventually reaching a much lower value than the actual pressure measured in the reservoir. Correspondingly, large amounts of gas were being produced due to the large pressure drop.

Because of the increased gas production, Run No. 5 was made using the second set of water relative permeability modifications and the first set of gas relative permeability modifications. Initially, the results showed rather close approximations to the actual reservoir pressure, cumulative gas production, and cumulative water production.

The plot of Run No. 6 shows a modification of Run No. 5 in which the k_z value was increased to $0.4 k_x$ in the B lobe. Although the cumulative gas production is slightly higher than the actual production, the cumulative water production and reservoir pressure match well. The input data set for this run is included in Appendix A.

To check the modified relative permeability data set, Run No. 6 will be rerun based on a constant water rate (instead of a constant oil rate). This run is yet another attempt to achieve a history match. A figure that illustrates this run is included in Appendix A.

5.3 Discussion of Results

During the history matching process, some of the early U-8 Sand reservoir geologic interpretations were found to be in error. The actual water production could not be modeled based upon the premise that each lobe was a reservoir unit, itself cut off from communication with the other lobes by the shale stringers running between them. Evidence that indicates that layers A and B are in communication include a cement block squeeze conducted in Well #2 that did not stop excessive water production and high water production from well #3, which is located the farthest away from the A lobe high water saturated areas. These effects could be due to liquid removal from the reservoir which upsets the equilibrium reservoir conditions, leading to a complete breakdown of the seal between lobes A and B, as well as a breakdown of the cement block squeeze in Well #2.

Also, the block squeeze in Well #2 may have possibly broken down due to decreasing reservoir pressure around the 2,600th day of production. This time corresponds to a large increase in the water production rate in well #2. Thus, some damage apparently occurred around each of the wells to allow vertical communication between lobes A and B. This would account for some of the large amount of water production.

The given reservoir relative permeability data were determined to be inappropriate for the U-8 Sand reservoir because the data were obtained from an adjacent gas reservoir that is isolated from the U-8 Sand. The relative permeability data were modified to achieve a history match because these data were believed to be the least reliable.

Once a history match was obtained, the data set was converted to run on the basis of a given water rate. The results of this run showed that the altered relative permeabilities were very close to the actual field relative permeabilities. The oil-rate-based simulation run and the water-rate-based simulation run were similar.

Finally, the vertical permeability values were found to be within the accepted range for the Gulf of Mexico ($0.1k_x < k_z < 0.5k_x$, with $k_x = k_y$) at $0.4k_x$.

Section 6: Predictive Study

6.1 Introduction

Several types of secondary recovery techniques are available to be used in any oil reservoir. The type of recovery technique depends on various parameters, such as the type of production-drive mechanism, the oil's chemical makeup, and economics. This study will target two enhanced recovery processes that are commonly used in the Gulf of Mexico: waterflooding and gas injection. All predictive study simulations were performed based on the history match achieved in section 5.2.

6.2 Predictive Study Setup

During the predictive case study simulations, the production scenario was altered. Since Well #2 has had a troubled productive history, the predictive study was conducted based on the decision that this well would be cemented or shut-in and that a new well would be drilled. The new well, well #5, would be drilled exactly midway between wells #2 and #4. Drilling well #5 has

at least one major advantage. The excessive formation damage that has occurred around well #2 has allowed large quantities of water production. Well #5 would be placed farther away from the water-oil-contact. Therefore, the well would be moved farther away from the 100 percent water saturated zones of the reservoir; possibly reducing the water production.

These assumptions were made during the predictive study: 1) the production time is ten years; 2) the producing water-oil ratio was set at 1,000 to allow the production wells to stay on-line; 3) the producing gas-oil ratio was set at 5,000,000 SCF/STB to allow the production wells to stay on-line; 4) Well #3 would come on-line after one year of water injection (about the time that the oil front would reach the well; 5) the field's water injection rate (based upon a decision by the reservoir's operator) would be approximately 5,000 STB/D; and 6) the field's gas injection rate would be 500 MCF/D.

Most important, the additional wells to be drilled for secondary recovery processes, whether injection or production, would be drilled based upon the oil saturation profile for lobes A and B (Figures 6.2.1 and 6.2.2). Based upon the oil saturation profiles established for lobes A and B, potential sites were targeted and denoted using A, B, C, D, and H (see Figure 6.2.3).

6.3 Waterflooding

Waterflooding operations were carried out based on the assumptions and decisions described in section 6.2. Predictive simulations were carried out in areas B, C, and D (see Figure 6.2.3). Within each area a group of three vertical well water injectors, each injecting at a rate of 1,700 STB/D, was simulated. Also within each of these areas, one horizontal well, with a 1,500 ft. horizontal wellbore, was simulated at an injection rate of 5,100 STB/D. The results are shown in Table 6.3.1.

Table 6.3.1: Incremental Oil Recovery as a Result of Waterflooding		
Area	Vertical Injectors	Area
B	3,727 MSTB	3,525 MSTB
C	2,644 MSTB	2,692 MSTB
D	2,304 MSTB	2,284 MSTB

Area B showed the greatest additional oil recovery when simulated under the given setup. An additional run was implemented using the data from Area B. The water injection rate was doubled to determine if the additional oil recovery would vary significantly over the industry mandated injection rate (5,100 STB/D). The results were 4,941 MSTB of recovered oil in the three vertical well injector scenarios and 4,847 MSTB in the horizontal injector scenario. These results indicate that, if the operator injected water at a rate higher than 5,000 STB/D, the productivity could be greatly improved.

Figure 6.2.1 - Oil Saturation Prior to Secondary Recovery For Lobe A
as Predicted by BOAST3

Figure 6.2.2 - Oil Saturation Prior to Secondary Recovery For Lobe B
as Predicted by BOAST3

Figure 6.2.3 - Predictive Study Injection Well Areas

6.4 Gas and Water Injection

For a combination scheme of gas injection and waterflooding, the setup was:

- Inject gas at a rate of 500 MCF/D for 300 days through a vertical well;
- Shut in the reservoir for ninety days; and
- Inject water at a rate of 5,000 STB/D for ten years through a horizontal well.

Area A (see Figure 6.2.3) was chosen to be the site for gas injection and areas B and C were selected for waterflooding based upon their performance during the waterflooding portion of the predictive study.

The results showed a considerable reduction in overall additional oil recovery. The combination gas injection/waterflood for areas A and C produced an additional oil recovery of only 2,296 MSTB. The combination gas injection/waterflood for Areas A and B produced an additional oil recovery of only 3,018 MSTB.

Each of these projected additional oil recoveries is considerably (approximately 400 to 500 MSTB) less than the waterflooding-only recoveries for horizontal wells. This could be due to the possible redistribution of oil into zones of high water saturation, which translates into losing the oil for good as it becomes irreducible.

6.5 Horizontal Well Production Scenario

For this scenario, the original production wells (#3 and #4) and well #5 were converted to water injectors, which allowed the placement of a horizontal production well in area H (Figure 6.2.3). The water injection wells were designed to inject water at a total field rate of 5,100 STB/D and the horizontal production well was designed for a 1,500-ft horizontal section. After one year, field production operations began. The total ten-year oil production from the horizontal well was 3,269 MSTB.

6.6 Discussion of Results

Given the standard industry design for water injection (5,100 STB/D), the best possible production scenario is a ten-year waterflooding operation in area B (Figure 6.2.3). However, if the injection rate can be increased, and even doubled, the additional oil recovery may be increased by 33% in the vertical injection well scenario and by 37% in the horizontal well scenario (at 10,200 STB/D).

The three vertical wells are more dispersed in area B than is the single horizontal well. Therefore, the same injected rate of water sweeps a greater area through the higher oil saturated zone in the case of the vertical wells, resulting in the greater additional oil production. As the water injection rate increases, the horizontal well, because of its length, has a higher sweep efficiency than the vertical wells. Increasing the sweep efficiency increases the oil production.

Several incentives were available to justify a horizontal production well. In converting the old production wells into injection wells, only two new wells needed to be drilled. Also, in cases of high anisotropy ratios (k_x/k_y) and thin formations, horizontal production wells characteristically lead to better oil recovery. Therefore, area H, where the formation thins as it

reaches the righthand reservoir boundary, is a prime candidate for a horizontal well. Another benefit that horizontal production wells offer is the prevention of possible water coning problems.

Compared to the additional oil recovery in area B (Figure 6.2.3), the horizontal well production scheme for area H resulted in a favorable return (3,269 MSTB in ten years). Additional oil recovery ranged from 88% using vertical wells to 93% using the horizontal well at the same field injection rate (5,100 STB/D).

Section 7: Conclusions

The reservoir simulation study using BOAST3 has been validated, and the results achieved in this study have been shown to be accurate and correct. The results have led to the development of a set of technically feasible solutions to improve oil production from the U-8 Sand reservoir.

To summarize:

- Evidence indicates that layers A and B of the U-8 Sand are in communication.
- The given reservoir relative permeability data were not appropriate for the U-8 Sand reservoir. The relative permeabilities were modified to enable a history match to be obtained.
- The vertical permeability values were found to be within the accepted range for the Gulf of Mexico ($0.1k_x < k_z < 0.5k_x$, with $k_x = k_y$) at $0.4k_x$.
- Based on the standard industry design for water injection (5,100 STB/D), the best possible production scenario is in area B (Figure 6.2.3).
- If the water injection rate is doubled to 10,200 MSTB/D, the additional oil recovery may be increased by 33% (1,214 MSTB) in the vertical well scenario and by 37% (1,320 MSTB) in the horizontal well scenario.
- The horizontal well production scheme for area H recovered 3,269 MSTB in ten years. Additional oil recovery ranged from 88% using vertical wells (area B) to 93% using the horizontal well (area B) at the same field injection rate (5,100 STB/D).
- In addition to the technical findings of this study, an economic analysis based on injection well type(s) and injection rate(s) should be considered to determine the optimum combination of both well type and water injection rate.

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APPENDIX A
HISTORY MATCHING RESULTS

(a) Average Reservoir Pressure (psia) vs. Time (Days)

(b) Cumulative Gas Production (MMCF) vs. Time (Days)

(c) Cumulative Water Production (MSTB) vs. Time (Days)

(d) Cumulative Oil Production (MSTB) vs. Time (Days)

Figure A-1: Run One: No Communication Between Lobes A and B Except at Well Blocks (• Actual Data - Simulated Results)

(a) Average Reservoir Pressure (psia) vs. Time (Days)

(b) Cumulative Gas Production (MMCF) vs. Time (Days)

(c) Cumulative Water Production (MSTB) vs. Time (Days)

(d) Cumulative Oil Production (MSTB) vs. Time (Days)

Figure A-2: Run Two: Permeability Adjustment to Account For Fault in Reservoir (• Actual Data - Simulated Results)

(a) Average Reservoir Pressure (psia) vs. Time (Days)

(b) Cumulative Gas Production (MMCF) vs. Time (Days)

(c) Cumulative Water Production (MSTB) vs. Time (Days)

(d) Cumulative Oil Production (MSTB) vs. Time (Days)

Figure A-3: Run Three: Use Modified Relative Permeability Curves
Mod K_{rw} #1 and Mod K_{rg} #1 (• Actual Data - Simulated Results)

(a) Average Reservoir Pressure (psia) vs. Time (Days)

(b) Cumulative Gas Production (MMCF) vs. Time (Days)

(c) Cumulative Water Production (MSTB) vs. Time (Days)

(d) Cumulative Oil Production (MSTB) vs. Time (Days)

Figure A-4: Run Four: Use Modified Relative Permeability Curves
Mod K_{rw} #2 and Mod K_{rg} #2 (• Actual Data - Simulated Results)

(a) Average Reservoir Pressure (psia) vs. Time (Days)

(b) Cumulative Gas Production (MMCF) vs. Time (Days)

(c) Cumulative Water Production (MSTB) vs. Time (Days)

(d) Cumulative Oil Production (MSTB) vs. Time (Days)

Figure A-5: Run Five: Use Modified Relative Permeability Curves
Mod K_{rw} #2 and Mod K_{rg} #1 (• Actual Data - Simulated Results)

(a) Average Reservoir Pressure (psia) vs. Time (Days)

(b) Cumulative Gas Production (MMCF) vs. Time (Days)

(c) Cumulative Water Production (MSTB) vs. Time (Days)

(d) Cumulative Oil Production (MSTB) vs. Time (Days)

Figure A-6: Run Six: Final History Match
(• Actual Data - Simulated Results)

(a) Average Reservoir Pressure (psia) vs. Time (Days)

(b) Cumulative Gas Production (MMCF) vs. Time (Days)

(c) Cumulative Water Production (MSTB) vs. Time (Days)

(d) Cumulative Oil Production (MSTB) vs. Time (Days)

Figure A-7: Run Six: Water Production Rate as the Recurrent Data Set Input (• Actual Data - Simulated Results)

APPENDIX B

**RESERVOIR CHARACTERIZATION AND PERFORMANCE PREDICTIONS FOR
THE U-8 SAND RESERVOIR**

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Vol. 4-Pt. 2*