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IMPROVED RECOVERY FROM GULF OF MEXICO RESERVOIRS**Volume III (of 4) Characterization and Simulation of Representative Reservoirs**

{Task 2, Refine SMI 73 Reservoir Characterization (Subtask 2.1, 2.2, 2.3, 2.4), Task 3, Refine South Pelto Reservoir Characterization (Subtask 3.1, 3.2), Task 4, Identify and Characterize Additional Representative Reservoirs (Subtask 4.1, 4.2), Task 6, Simulate Attic Gas Injection Processes (Subtask 6.1, 6.2), Task 7, Simulate Gas Injection Processes Using N₂, Flue Gas, and CO₂ (Subtask 7.1, 7.2), Task 8, Simulate Advanced Waterflood Processes (subtask 8.1, 8.2, 8.3)}

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Abstract

Significant innovations have been made in seismic processing and reservoir simulation. In addition, significant advances have been made in deviated and horizontal drilling technologies. Effective application of these technologies along with improved integrated resource management methods offer opportunities to significantly increase Gulf of Mexico production, delay platform abandonments, and preserve access to a substantial remaining oil target for both exploratory drilling and advanced recovery processes.

In an effort to illustrate the impact that these new technologies and sources of information can have upon the estimates of recoverable oil in the Gulf of Mexico, additional and detailed data was collected for two previously studied reservoirs: a South Marsh Island reservoir operated by Taylor Energy and a Gulf of Mexico reservoir operated by Mobil, whose exact location has been blind-coded at their request, and an additional third representative reservoir in the Gulf of Mexico, the KEKF-1 reservoir in West Delta Block 84 Field.

The new data includes reprocessed 2-D seismic data, newly acquired 3-D data, fluid data, fluid samples, pressure data, well test data, well logs, and core data/samples. The new data was used to refine reservoir and geologic characterization of these reservoirs. Further laboratory investigation also provided additional simulation input data in the form of PVT properties, relative permeabilities, capillary pressures, and water compatibility. Geological investigations were also conducted to refine the models of mud-rich submarine fan architectures used by seismic analysts and reservoir engineers. These results were also used, in part, to assist in the recharacterization of these reservoirs.

Executive Summary

B-65G Reservoir

The B-65G Reservoir is a long, north-south trending, steeply dipping sandstone, which pinches out just before encountering the piercement salt dome on its southeastern flank. Its dip rate averages 19 degrees. Structure and trapping are all results of the piercement salt dome. The location of the pinch-out of the sand along the salt face was the portion of the reservoir for which there was the least control. Overall, it is a clean sand that averages 66 feet in gross thickness and 53 feet in net sand thickness.

The reservoir has produced 6.2 MMSTB of oil, 8.5 BCF of gas (which also accounts for all gas injected back into reservoir) and 821 MBBLs of water. As previously characterized, four wells have produced from the reservoir; three injected 2 BCF of gas and one well injected no gas. A fifth downdip well, served as a primary gas injector and injected an additional 732 MMCF of gas. With the re-evaluation, two additional wells produced the reservoir.

Original oil-in-place calculations performed on the reservoir before 3-dimensional seismic data and other new information was incorporated assigned the reservoir approximately 10,100 acre-feet or an average net pay thickness of 38 feet over 267 acres. Porosity averages 28.5% and the original oil saturation was estimated at 73%, with an initial formation volume factor (FVF) of 1.3 res bbls/STB. Therefore, based on the old information and estimated volumetrically, the original in-place-oil was 12.6 MMSTB. Therefore, through March 1995, based upon volumetrics, 50% of the original oil-in-place had been produced.

A new structural and stratigraphic interpretation based upon the 3-dimensional seismic data was generated. The faults which were previously believed to exist were apparent in the seismic data, with the exception of one east-west fault which was believed to exist based upon past production and pressure data. The major down-to-the-south fault, which is the northern boundary of the B65 sand production, appeared to have more curvature (concave towards the platform in the map view) than previously believed. The smaller fault which previously was believed to be sealing is evident in the 3-dimensional seismic data. However, it appears to be non-sealing and this was later confirmed with simulation. A major down to the north fault, which was the southern boundary for the sand production previously believed to be south of the seal, also has more curvature (concave towards the platform in the map view) than previously believed. It

is also closer to a north-south trend which curves slightly east as opposed to the more east-west trend as it was previously mapped. The smaller east-west fault which dies out before reaching the salt dome appeared just as it was originally mapped. Two smaller faults which were believed to be under the platform were not visible due to the jumbled data image.

The reservoir appeared to shale out before actual contact with the salt dome was made. The shale out was fairly uniform along the boundary of the sand, yet seemed to push slightly away from the salt dome as it moved north along the salt dome. At the south end of the reservoir just north of the where the sand faults the salt dome contact shows the beginnings of a north-south trending steeply dipping down to the east fault. Overall, the reservoir was interpreted to be much larger than had previously been calculated by 6.4 million barrels, or an increase by a factor of 1.5.

A second reservoir simulation study was undertaken to incorporate new seismic data and confirm the new interpretations and characterizations for the B-65G Reservoir. Simulated vs. observed values for reservoirwide pressure, oil, water, and gas production matched very well, indicating the aquifer model and reservoir permeability were suitably chosen. In general, the well performance match was good as well, although some wells could not be matched satisfactorily. The results indicate that only 38% of the OOIP has been recovered.

Given the fluvial nature of the reservoir, drilling additional wells updip does not seem to hold much promise, as these wells are likely to fall outside of the channel system. As the reservoir re-pressurizes, existing wells should be periodically produced to recover newly segregated oil and gas.

The B-1 well was injected with 500 MCFD for 6 months and shut-in. The B-12 well was produced for an additional 54 months. Oil recovery over this time compared to the B-12 well producing with no enhancement, increased by 20%, for a ratio of 0.44 bbls of oil per MCF of gas injected. Water cut decreased by 3%. Additional gas injection improved the recovery proportionately. At a present gas price of \$2.90/mcf and a present oil price of \$25.00/bbl, and assuming no gas injected is recovered and operational costs are not increased dramatically, a profit increase (for use of the gas) of 3.8 times is realized by gas injection. Ultimate recovery was not increased in this particular reservoir, by using different gases.

U-8 Reservoir

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 reservoir can be described as a relatively flat, totally isolated fault block (surrounded on all sides by faults) with several non-sealing interior minor faults which serve to decrease drainage of the reservoir.

The actual water production, as was the case in the original study, 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. It was necessary to put the two top layers, A and B, into communication with one another within the reservoir. The structure map and the isolations of the southwestern portions of the unit, Area C, were factored into the reservoir model as before. There was no new data to support modifications to the geological interpretations from the previous study.

Essentially, the major occurrence and new piece of information which was obtained since the last report was the fact that the #10-20 had been reworked. The workover consisted of squeezing off with cement the lower perforations in an attempt to eliminate or reduce the water cut. It was unsuccessful within this capacity, however. The well still produces at a high water cut. Originally, the simulation was run with the assumption that Layer B had been isolated from Layer A to account for a successful workover.

However, a history match was unattainable using this scenario. Therefore, Lobe A was put back into communication with Lobe B within the reservoir and a history match was attained. The updated history match supports the theory that Lobe A and Lobe B are in communication within the reservoir. Several prediction runs were then performed and the following conclusions were made:

- Evidence still indicates that layers A and B of the U-8 Sand are in communication.
- The relative permeabilities were modified, based on new and updated information, to enable a history match to be obtained.
- Based on the predictive designs for water injection (1,700 STB/D), the best possible production scenario is in area A and the best possible injection area is in area H.
- Any major increase in the water injection rate above 1700 BWPD does not greatly improve the recovery and therefore is not economically justified.
- The horizontal well injection scheme for area H recovered 3.2 times more oil than a background continuing production scheme. However, the vertical well injection scheme for Area H recovered 3.15 times more oil. Therefore, a horizontal injector is not economically justified.

KEKF-1 Reservoir

The KEKF-1 reservoir is located in West Delta Block 84 Field. West Delta Block 84 Field is located off the coast of Plaquemines Parish, Louisiana, near the mouth of the Mississippi River. The field was discovered by Conoco in 1955. It was operated by Conoco until September, 1988 when S. Parish Oil Co. bought out Conoco's interest and took over operations. S. Parish Oil Co. resumed operations in the field for approximately one year when the lease was allowed to lapse. The field is presently being operated by West Delta Oil Co., which is in the process of re-working several wells to re-establish production. To date, however, the field is still shut-in. It is estimated that the total field originally contained 23.6 MMSTB of oil and 57.9 BCF of gas, from known productive sands. The field has produced 9.8 MMSTB of oil and 21 BCF of natural gas.

The KEKF-1 reservoir underwent a waterflood project during the 1970's, and is a good example of a reservoir which has undergone an expensive poorly designed waterflood which resulted in the loss of a large quantity of recoverable oil.

The KEKF-1 reservoir is limited on its north by a east-west trending normal fault, which dips to the south. It is bound on its east by a shale out. It is bound on its south by a partial sealing fault and a shale out. It is bound on its west by an original oil-water contact of 11,136 feet below sea level. It dips at approximately 6 degrees to the west and strikes north-south. The net effective sand thickness averages approximately 30 feet with a high of 66 feet penetrated in the #A3 well.

Original oil in place has been estimated to be 9.6 MMSTB or 1005 STB/ac-ft and original gas in place has been estimated to be KEKF-1 reservoir - 23.6 BCF.

The waterflood was targeting the KF-1 sand, not the KE-1 sand. It is believed that the operator at the time of the waterflood believed these two sands not to be in communication. Because of this, the waterflood was inefficient and poorly designed. If the possibility of communication between the KE and KF sands had been considered, the waterflood may have been more efficient. Assuming success from workovers a daily production rate of over 600 BOPD and 1.3 MMCFD of gas could be realized. At a 20% decline and a 15 year life, an additional 1.2 MMSTB of oil and 4.5 BCF of gas of proved developed reserves could be recovered from this reservoir.

SOUTH MARSH ISLAND 73 FIELD REINTERPRETATION OF GEOLOGIC CHARACTERIZATION BY USE OF 3-DIMENSIONAL SEISMIC DATA

by W. Clay Kimbrell¹, Stephen Norris², Hunter Coates³ and Jitendra Khandrika⁴

OVERVIEW

This is a continuation of a previous report, "Assist in the Recovery of Bypassed Oil From Reservoirs in the Gulf of Mexico - Volume III, Characterization of Representative Reservoirs - South Marsh Island 73, B35K and B65G Reservoirs" delivered under the U.S. Department of Energy (DOE) contract number DE-AC22-92BC14831.

Data

All necessary and available data were collected from Taylor Energy, which purchased the field from Exxon in 1993. All well logs, core analysis, historical, production and injection histories were available. Measured pressure-volume-temperature (PVT) data was calculated. Three-dimensional seismic data (3-D data) was acquired from a speculative survey performed by GECO-PRAKLA. Data acquired covered most of block 73 and portions of blocks 68,69,72 and 74 as shown in Figure 1. The 3-D data was processed by GECO-PRAKLA and provided to LSU via 8mm tape. Interpretation work was performed by LSU personnel primarily on a Sun Microsystems SPARC-20 workstation with some additional support provided by an Silicon Graphics INDIGO-2 workstation. The data was interpreted primarily using Landmark Graphics Seisworks 3D software.

Field History

The South Marsh Island Block 73 (SMI 73) Field is located approximately 77 miles south of Intercoastal City, LA in 135 feet of water in the Gulf of Mexico, Figure 2. The field was discovered in 1963 by Exxon when the #1 Well SMI 69 was drilled. Several other exploratory wells were drilled by Exxon and Shell on this block and the surrounding blocks. The field was subsequently developed by Shell (SMI 57 and 58) and Exxon (SMI 69, 72, and 73). Production from the field was initiated in 1964, and over time, a total of eight platforms were set and over 100 development wells were drilled. Taylor purchased the Exxon interest in SMI Blocks 69, 72, and 73 in 1993 and assumed operatorship.

The field is predominantly oil productive and production peaked in 1971 at a rate of 16,900 BOPD and 68.MMCFD. The field is currently producing almost 2,000 BOPD, 5 MMCFD and 2,600 BWPD, Figure 3. The productive zones have been established at depths between 5,000 feet and 11,500 feet. The cumulative production from the field as of January 92 totaled 67 million barrels of oil (MMBO), 276 billion cubic feet of gas (BCF), and 46 million barrels of water (MMBW). The gas from the field has not been sold; rather, it has been used for fuel or reinjected to improve oil recovery. The cumulative production from the Taylor blocks total 45 MMBO and 36 BCF.

¹ Louisiana State University, Department of Petroleum Engineering

² Ibid

³ Ibid

⁴ University of New Orleans, Department of Geology

Geco-Prakla
1325 S. DIARY ASHFORD
HOUSTON, TX 77077

SOUTH MARSH ISLAND

Area 2

NON-EXCLUSIVE 3D
BIN CENTER MAP

1" = 4,000'

UWAN 11
X = 543241.8 M
Y = 5182417.4 M
BASE ANGLE = 89.2°
ROW SIZE = 30 M
COL SIZE = 12.5 M

70

69

68

Outline of LSU Coverage

72

73

74

COL-3280

COL-3320

COL-3360

COL-3400

COL-3440

COL-3480

COL-3520

COL-3560

COL-3600

COL-3640

COL-3680

COL-3720

COL-3760

COL-3800

COL-3840

COL-3880

COL-3920

COL-3960

COL-4000

Figure 1 - LSU Acquired Geco-Prakla Seismic Data Coverage

LOCATION OF SMI BLOCK 73 FIELD IN THE GULF OF MEXICO

from Young, M. A., Salamy, S. P., Reeves, T. K., Kimbrell, W. C., Sawyer, W. K., "Characterization of Representative Reservoirs - South Marsh Island 73, B35K and B65G Reservoirs," Report prepared under U.S. Department of Energy DE-AC21-92BC14831 (October, 1993).

Figure 2 - Location Map of South Marsh 73

SOUTH MARSH ISLAND BLOCK 73 FIELD PRODUCTION STATISTICS

Discovery:	1964	(Exxon, SMI 69 #1)
Ownership:	Taylor	(SMI 69, 72, 73)
	Shell	(SMI 57, 58)
Initial Production:	1964	
Peak Production (1971):	16,900 BOPD, 68 MCFD	

Figure 3

Field and Reservoir Geology⁵

The SMI 73 Field is established by the simple piercement salt dome structure, as shown in Figure 4. The dome is relatively circular in shape, with a small area of overhang at the southeast corner. The current top-of-salt is approximately 364 feet below mean sea level. This dome formed in relatively shallow water, with salt movement having been initiated prior to the deposition of many of the key reservoir units. Sedimentation continued during the movement of the salt. The source for the main reservoir sands was apparently predominantly from the north and east. Drilling has been concentrated on the northern, eastern and southeastern portions of the structure, with twenty-five Miocene and Pliocene aged sands being productive from more than sixty reservoirs around those sides of the dome. Exploratory drilling on the western side of the structure indicates that area was on the lee side during deposition and was sheltered from most of the sand-laden currents. The rate of sediment influx appears to have been low and the material was very fine-grained during the deposition of most of the key reservoirs, with sands having been limited to deeper-water areas around the growing dome, and shale having been deposited atop the structure in a more-or-less starved environment. This helps to account for the facts that many of the reservoirs pinch out updip, toward the salt, and that most of the dome is wrapped in a shale sheath.

The B65G sand in the South Marsh Island area was deposited well offshore, in an open marine environment, in moderately deep water. The region had a hummocky, irregular bottom at the time of deposition, which controlled the flow of oceanfloor currents through the area. Salt movement took place concurrently with deposition of the reservoir sands and the enclosing shales. The syndepositional growth of the salt domes created a number of highs on the seafloor as sediments accumulated in the area.

Coarser-grained sediments were carried into the region by density currents, which spread out across the area, following channels along the deeper portions of the seafloor. Fine-grained sands were deposited in these deep areas between the domes, while shale and mud accumulated on the upslope areas and crests of the highs. The growing domes shielded some deeper portions

⁵ "Assist in the Recovery of Bypassed Oil From Reservoirs in the Gulf of Mexico - Volume III, Characterization of Representative Reservoirs - South Marsh Island 73, B35K and B65G Reservoirs" delivered under the U.S. Department of Energy (DOE) contract number DE-AC22-92BC14831, December 31, 1995.

of the seafloor from the density currents, with little sand reaching the lee side of the highs. Thus, sands and shale interfinger in a highly complex manner around the flanks of the domes, marking a period of sand pulses and density flows, alternating with periods of quiet deposition on the exposed side of the structure, and starved-basin conditions with fine-grained sediments on the sheltered side of the dome.

Reservoir Characteristics

The B-65G Reservoir is a long, north-south trending, steeply dipping sandstone, which pinches out just before encountering the piercement salt dome on its southeastern flank, as illustrated by the previously constructed structure map of the sand in Figure 5.⁶ Its dip rate averages 19 degrees. Structure and trapping are all results of the piercement salt dome. The location of the pinch-out of the sand along the salt face was the portion of the reservoir for which there was the least control.

Overall it is a clean sand that averages 66 feet in gross thickness and 53 feet in net sand thickness. Material balance calculations indicated that the reservoir contained about 12 MMSTB of oil. Its original reservoir pressure was 3457 psi at 7351 feet subsea. These and other reservoir characteristics have been summarized in Table 1.

Table 1
South Marsh Island Block 73 Field
B-65-G Reservoir Characteristics

Original Reservoir Pressure	3457 psi
Datum	7351 feet subsea
Average Porosity	28.5%
Original Water Saturation	23%
Average Thickness	37 feet
Areal Extent	267 acres
Average Horizontal Permeability	620 md
Average Horizontal/Vertical Permeability Ratio	0.1
Initial Gas-Oil Ratio	867 SCF/STB
Initial FVF	1.3 Res bbl/STB

Reservoir Production and Injection History

The reservoir has produced 7.2 MMSTB of oil, 8.7 BCF of gas (which also accounts for all gas injected back into reservoir) and 946 MBBLs of water over. As previously characterized, four wells had produced from the reservoir; three injected 2 BCF of gas and one well injected no gas. A fifth down-dip well, served as a primary gas injector and injected an additional 732 MMCF of gas. As re-evaluated and recharacterized within this study, two additional wells produced the reservoir.

The B-65G sand reservoir began production in October 1966 when the #B-1, #B-7, and #B-10D wells were put on line. The #B-12 was put on line in February 1967. The #B-9D (April

⁶ Ibid

Figure 5 - B-65G Reservoir Structure Map - previous

1967), and #B-17 (April 1971) were all drilled south of what was previously considered to be a sealing fault. However, with the new 3-dimensional seismic interpretation and the confirming simulation it is now believed that all of these wells produced from the same reservoir. Presently, the #B-12 and #B-1 wells are active in the B-65G Reservoir. The B-1 well is currently going through a gas injection stage. Table 2 shows the cumulative production and gas injection values through March 1995.

Table 2

Cumulative Production and Gas Injection, B-65G Reservoir

WELL	OIL-MSTB	GAS-MMCF	WATER-MBBLS	GASINJ-MMCF
B-1	1827	2115	259	672
B-7	1020	1576	1	0
B-10D	1325	792	220	11
B-12	2108	3980	341	1348
B-15	0	0	0	732
B17	400	21	49	0
B9	547	230	76	0
<hr/>				
<i>TOTAL</i>	<i>7227</i>	<i>8714</i>	<i>946</i>	<i>2763</i>

Original Oil-in-place Calculations

Original oil-in-place calculations performed on the reservoir before 3-dimensional seismic data and other new information was incorporated assigns the reservoir approximately 10,100 acre-feet or an average net pay thickness of 38 feet over 267 acres. Porosity averages 28.5% and the original oil saturation was estimated at 73%, with an initial formation volume factor (FVF) of 1.3 res bbls/STB. Therefore, based on the old information and estimated volumetrically, the original in-place-oil was 12.6 MMSTB. Based on re-evaluation and recharacterization, the original oil-in-place was 19 MMSTB. Therefore, through March 1995, based upon the previous study and volumetrics, 50% of the original oil-in-place had been produced. Based upon the re-evaluation and recharacterization, 38% of the original oil-in-place has been produced.

THREE-DIMENSIONAL DATA INTERPRETATION

Procedure

In general, the steps taken to interpret any 3-D data are six-fold: obtain the workstation, obtain the data, obtain interpretation software, load the data on the workstation, position or coordinate the data, and interpret the data. Amazingly for this study, due to the very high quality data obtained from Geco-Prakla and the superior software from Landmark, the last step - interpretation was the easiest task.

During the project, there were hardware problems, software problems and data problems; all mechanical in nature. Several months were spent just in tackling and solving these mechanical problems. The interpretation actually begins with the positioning or coordination of the data, which is where this discussion will begin.

Positioning of 3-D Data

The 3-D data obtained for this project, unfortunately, failed to incorporate a position coordinate. Therefore, it was necessary to use some other means to position the data to a coordinate platform. Digitized well markers had previously been installed based on the UTM coordinate system and therefore it was desirable to have the 3-D data follow the same system so that the digitized well data and 3-D data would overlay one another properly. In order to position the seismic data, the location of the B-platform in South Marsh Island was found on a hardcopy that was created before the seismic shoot. Using the northeast corner of Block 73, the distance to the platform was measured. The scale was then converted to that of the hardcopy for the seismic shoot. The B-platform location was pinpointed on the seismic data by the lack of data in the area of the platform, characterized by a "dead zone" where no data is obtained due to the structure. When the B-platform was located on the seismic hardcopy, its location was converted into line and trace numbers.

The Sun SPARC-20 workstation was used to find the X-Y coordinates for the B-platform. Using the map view in SeisWorks 3D, with the "show position" mode (which displays the line and trace position of the seismic data activated), the X-Y coordinates of the cursor appear at the bottom of the screen, as do the line and trace numbers. When the cursor was located at the exact line and trace numbers where the B-platform was located, the X-Y coordinates of the platform were read off the screen and then manually put into the workstation as the surface location of all the wells that originate from the B- platform.

Once the position of the B-platform was determined on the seismic map, it was determined that the horizontal scale of the wells did not agree with that of the 3-D data. In order to locate the B65 sand in the seismic data, two methods were used. The first was the use of the time-depth conversion, the B-10 well (which is almost vertical) and the "show position" mode in the seismic display. By using the line and trace and the time depth conversion in combination with the log of the B-10 well, the sand was located. The second method simply consists of a check pick by a geologist experienced with the sand and area. This pick was marked on the B-10 borehole in the seismic display.

Sand (Horizon) Interpretation

After it was determined which reflector represented the B65 sand, a methodological approach was used to map it. First, the sand was marked using the "interpret horizon" feature in the SeisWorks 3D software. The cursor was then placed at a certain point on a line on the screen and at the press of the "expert key G", a trace passing through that exact point appeared on the screen with a marker on it indicating the selected reflector. With this method, the reflector that was marked in the first line can be switched back to a different line perpendicular and once again there will be markers on the reflector. This method was used to make a grid throughout the sand,

which is very efficient because it effectively cuts down on jumping between reflectors unintentionally, as well as losing a reflector across a fault.

Once the grid was created, a SeisWorks 3D software function, "ZAP3", (which fills in any blank unmarked areas using a process called "autotracking") is used. Autotracking is the calculation of an output horizon from selected "seedpoints." Seedpoints are horizon interpretation picks that identify the event to be autotracked by location and seismic attribute. The autotracking software searches adjacent traces for picks with similar or identical seismic attributes. If the prospective picks meet user-defined tracking criteria, the new picks are converted to new seedpoints. In this manner, the horizon is propagated across the survey until no additional valid picks are found. There are two different seismic attributes which may be tracked, amplitude and phase. If tracking amplitude, the seed points are specified by their x, y and z locations and onset type. If tracking phase, the seed points are specified by x, y and z locations and phase angle. Amplitude was chosen to be tracked for this project.

The standard tracking mode was used in the "ZAP3" process. When tracking amplitudes, the standard mode autotracks in all four directions. It evaluates prospective picks in two ways:

1. A user-specified "Score" value that specifies how similar the prospective pick must be to the seedpoint.
2. A cross-check of the amplitudes to ensure that each prospective pick loop-ties with the initial seedpoint.

The score measures the difference in seismic attributes which are allowed for the points to be validated. For example, a score of 85 indicates that the new point must be about 85 percent the same as the seed point.

Fault Interpretation

Fault interpretation using SeisWorks 3D is similar in principle to that of horizon interpretation. A fault is picked in the seismic view and marked using the "fault interpretation" mode. Due to the nature of the faults in this area, the best method for interpretation was to mark the faults on every tenth trace. Once the faults and horizons were interpreted, the SeisWorks 3D software calculated the fault heaves using the specified horizon on both sides of the fault. This software also is useful in the creation of fault gaps because of the manner in which the fault heaves are displayed on the screen. They are displayed in the map view so that they appear as the horizontal displacement of the fault segments chosen. Once the fault was marked on every tenth line and the necessary heaves were calculated, the fault was triangulated using the "triangulate fault" function in the SeisWorks 3D software.

New Combined Three-Dimensional Seismic Interpretation

A new structural and stratigraphic interpretation based upon the 3-dimensional seismic data is shown in Figure 6. The faults which were previously believed to exist were apparent in the seismic data, with the exception of one east-west fault which was believed to exist based upon past production and pressure data. The major down-to-the-south fault which is the northern boundary of the B65 sand production appeared to have more curvature (concave towards the

platform in the map view) than previously believed. The major down to the north fault which is the southern boundary for the sand production also has more curvature (concave towards the platform in the map view) than previously believed. It is also closer to a north-south trend which curves slightly east as opposed to the more east-west trend as it was previously mapped. The smaller east-west fault which dies out before reaching the salt dome appeared just as it was originally mapped. Two smaller faults which were believed to be under the platform were not visible due to the jumbled data image.

The reservoir appeared to shale out before actual contact with the salt dome was made. The shale out was fairly uniform along the boundary of the sand, yet seemed to push slightly away from the salt dome as it moved north along the salt dome. At the south end of the reservoir just north of the where the sand faults the salt dome contact shows the beginnings of a north-south trending steeply dipping down to the east fault. Overall, the reservoir was interpreted to be much larger than had previously been calculated by 6.4 million barrels, or an increase by a factor of 1.5.

B-65G RESERVOIR SIMULATION STUDY

A 2nd reservoir simulation study was undertaken to incorporate new seismic data and confirm the new interpretations and characterizations for the B-65G Reservoir.

Fluid Properties

PVT data were generated by the use of fluid correlation's and were given in the previous report. In this study, the same values were used and are given in Figures 7 and 8. In order to honor the fluid properties previously calculated, it was assumed that the bubble point was 3457 psia, and the reservoir pressure was adjusted to preserve equilibrium conditions. This adjustment will not adversely affect the simulation results.

Rock Properties

The relative permeability curves from the previous report were not the most representative of a water wet, Gulf of Mexico reservoir. In particular, the relative permeability to water was considered to be unrealistically high. A more reasonable curve was used, honoring the water saturation observed from well logs. The curves used in the simulation are given in Figures 9 and 10.

Well Data

Production data was given for each producing well by Taylor Industries.

Structure, Gross Thickness, Net Thickness, Porosity, and Permeability Maps

The structure-stratigraphic map shown in Figure 6 was overlain with a 26 x 30 grid as shown in Figure 11. The new map added additional area to the reservoir. Gross and net sand thickness maps were derived from an initial interpretation by Exxon, and are shown in Figures 12 and 13. The maps show a fluvial depositional environment, with channeling affecting the fluid

Oil PVT Data

PVT TABLE 1

Figure 7- Oil PVT Data

Gas PVT Data

PVT TABLE 1

Figure 8 - Gas PVT Data

Figure 9 - Water-Oil Relative Permeability

Water-Oil Relative Permeability

ROCK TABLE

1

Figure 10 - Gas-Oil Relative Permeability

Gas-Oil Relative Permeability

ROCK TABLE

1

Figure 11 -Structure Map with Simulation Grid

Figure 12 - Vertical Gross Thickness Map

Figure 13 - Vertical Net Thickness Map

flow path. Porosity and permeability maps (Figures 14 and 15) were developed using observed values and the gross and net sand maps as a guide.

Aquifer

It was obvious from the observed pressure data that water influx was significant in this reservoir, as the pressure began to increase after peak production. A Carter-Tracy aquifer model was employed to simulate water influx, unlike the previous study which incorporated a steady-state aquifer influx model. Input values for the Carter-Tracy model can be found in the input data set in the Appendix. To honor the channeling, only the gridblocks in the last row in the upper left corner of the grid were permitted to influx water.

History-Match Results

Figure 16 shows simulated vs. observed values for pressure, oil, water, and gas production. Note the very good match of pressure, indicating the aquifer model and reservoir permeability were suitably chosen. Cumulative production is given in Figure 17. Individual well results are given in Figures 18 through 23. In general, the well performance match was good, although some wells could not be matched satisfactorily. The results indicate that almost 38% of the OOIP was recovered. The appendix contains the final fluids in place and cumulative production from the simulation model, as well as the initialization results.

Given the fluvial nature of the reservoir, drilling additional wells up dip does not seem to hold much promise, as these wells are likely to fall outside of the channel system. As the reservoir re-pressurizes, existing wells should be periodically produced to recover newly segregated oil and gas. Figures 24 and 25 show the initial and final oil saturation maps. Based upon these results, several predictive sensitivity study simulation runs were performed.

Predictive Sensitivity Studies and Conclusions

Predictive sensitivity studies were performed on the B-65 reservoir for several scenarios including continued production with no additional changes or enhancement and additional gas injection with separate emphasis on methane, flue gas, CO₂ and nitrogen. Results for the injection of different gases followed closely the results reached during laboratory investigations of these different injectants.

Continued Production with no Additional Enhancement

A simulation of the B-12 and B-1 wells was performed with no additional enhancement. The B-1 well recovered an additional 384,500 barrels of oil, while the B-12 well recovered an additional 89,600 barrels of oil.

Methane, Flue Gas, CO₂ and Nitrogen Injection

Simulations were performed to analyze the results of the injection of gases into the reservoir as an enhancement to its performance under conditions with not additional enhancement.

Figure 15 - Permeability Map

Figure 16 - Simulated versus Actual Fieldwide Production Rates

Fieldwide Production Rates

Figure 17 - Fieldwide Oil, Water, and Gas Cumulatives

Figure 18 - Production Rates, Well B-1

PRODUCTION RATES

WELL NAME b-1

Figure 19 - Production Rates, Well B-12

PRODUCTION RATES

WELL NAME b-12

Figure 20 - Production Rates, Well B-7.

PRODUCTION RATES

WELL NAME b-7

Figure 21 - Production Rates, Well B-9

PRODUCTION RATES

WELL NAME b-9

Figure 22 - Production Rates, Well B-10

PRODUCTION RATES

WELL NAME b-10

Figure 23 - Production Rates, Well B-17

PRODUCTION RATES

WELL NAME b-17

Figure 24 - Oil Saturation Map, Initial Conditions

6

b-19

0 25 50 75 100

Figure 25 - Oil Saturation Map, Final Conditions

6

b-19

100 75 50 25 0

At present, the B-1 and B-12 wells are the only existing completions available to the B-65 reservoir. Therefore, predictive analyses were restricted to the use of these two wells.

Several different gas injection/production scenarios were simulated, including each well used as a gas injector for different time periods, while the other produced, and both wells being used for different time periods as gas injectors/producers. The best increase in recovery of oil by use of gas injection enhancement for attic oil recovery were obtained with the B-1 well being used as a gas injector, while the B-12 well was used as a producer. The B-1 well is the most updip well between the B-1 well and the B-12 well. Gas was injected into the B-1 well and the B-12 well was utilized as a production well to analyze the differences and affects seen by gas injection for up-dip oil recovery. The B-1 well was injected with 500 MCFD for 6 months and shut-in. The B-12 well was produced for an additional 54 months. Oil recovery over this time compared to the B-12 well producing with no enhancement, increased by 20%, for a ratio of 0.44 bbls of oil per MCF of gas injected. Water cut decreased by 3%. Additional gas injection improved the recovery proportionately. At a present gas price of \$2.90/mcf and a present oil price of \$25.00/bbl, and assuming no gas injected is recovered and operational costs are not increased dramatically, a profit increase (for use of the gas) of 3.8 times is realized by gas injection. Ultimate recovery was not increased in this particular reservoir, by using different gases. Increased speed of recovery as a result of using different gases could not be properly simulated. Therefore, laboratory results as presented in Volume IV, which used actual B-65 reservoir oil, should be referred to for this analysis. Based upon these laboratory and simulation results, a major increase in reserves may be recovered by updip gas injection. Unfortunately, detailed operational cost analyses were not within the scope of this report. It is strongly recommended, from these results, that further studies are made in the form of cost/economic analyses and pilot case studies

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Figure 6 - B-65G Reservoir Structure Map - New 3-Dimensional Interpretation

Louisiana
State
University

Department of
Petroleum Engineering

65-G Reservoir, South Marsh Island 73 Field,
Louisiana

Geology by: Hunter Coates and W. Clay Kimbrell

August 12, 1996

Appendix A - Final Results from Simulation Run

```

*****
: SSI'S SIMBEST II SIMULATOR :                b65g sand                : DATE 15-Aug-96  TIME 16:24 :
: SCALAR VERSION 3.21I 9 S10 :                b65g sand                : SIMULATION RUN  PAGE   958 :
*****

```

+SIMULATION DATE 1 JAN 1995

SIMULATION TIME 10562.0 DAYS

MATRIX SYSTEM - TOTAL FIELD
=====

OVOL AVG PRESS (PSIA)
AT DEPTH 3027.

0-----
OFLUIDS IN PLACE
OIL (MSTB) 16354.
TOT GAS (MMSCF) 7975.
FREE GAS (MMSCF) 1170.
INERT GAS (MMSCF) 0.
WATER (MSTB) 84845.

0-----
OCUMULATIVE PROD
OIL (MSTB) 7716.
OIL (PCT IOIP) 32.050
HC. GAS (MMSCF) 6231.
INERT GAS (MMSCF) 0.
WATER (MSTB) 8656.

0-----
OCUMULATIVE INJ
HC. GAS (MMSCF) 2230.
INERT GAS (MMSCF) 0.
WATER (MSTB) 0.

0-----
ONET REGION INFLUX
OIL (MSTB) -4.
HC. GAS (MMSCF) -3.
INERT GAS (MMSCF) 0.
WATER (MSTB) 17299.

0-----
OBOUNDARY INFLUX
OIL (MSTB) 0.
HC. GAS (MMSCF) 0.
INERT GAS (MMSCF) 0.
WATER (MSTB) 17289.

0-----

Appendix B - Initialization Output

AMOUNT OF DYNAMIC MEMORY ALLOCATED(DOUBLE WORDS) 31203
 AMOUNT OF DYNAMIC MEMORY ALLOCATED(INTEGER WORDS) 2340

```

*****
*
*      SSSSSS          BBBBBBB
*  SS    SS          BB    BB
*  SS      IIIII M   M BB    BB EEEEE SSSSS TTTT
*      SS      I   MM MM BBBBBB E     S     T
*      SS      I   M M M BB    BB EEEEE SSS   T
*  SS    SS      I   M   M BB    BB E       S   T
*  SSSSSS IIIII M   M BBBBBBB EEEEE SSSSS   T
*
*
*              IIIII IIIII
*              I       I
*              I       I
*              I       I
*              IIIII IIIII
*
*
*              SCIENTIFIC SOFTWARE - INTERCOMP
*
*              INITIALIZATION MODULE
*
*  VERSION 3.21      APRIL , 1993      UPDATE I 9
*
*****

```

```

*****
* MODEL STATISTICS *
*
*
* MAX GRID CELLS    780 *
*
* MAX FRAC CELLS    1 *
*
* MAX COMPONENTS    3 *
*
* MAX WELLS          100 *
*
* MAX PERF / WELL    25 *
*
*****

```

\f

```
*****
: SSI'S SIMBEST II SIMULATOR :                INITIALISATION MODULE                : DATE 15-Aug-96  TIME 16:22 :
: VERSION  === 3.21 I 9      :                DATA SUMMARY                    : INITIALISATION  PAGE    1 :
*****
```

CARD	DATA CARDS	ERRORS DETECTED
====	=====	=====
1 : *C		
2 : *C		
3 : *C		
4 : *C	*****	
5 : *C	W O R K B E N C H *	
6 : *C	R E L E A S E 01.05.16 *	
7 : *C	I N I T I A L I Z A T I O N D E C K F O R S I M B E S T I I *	
8 : *C	*****	
9 : *C	* PROJECT: b65g sand *	
10 : *C	* * *	
11 : *C	* CASE: finegrid1 *	
12 : *C	* * *	
13 : *C	* DATE: 15-Aug-96 *	
14 : *C	* * *	
15 : *C	* TIME: 16:04:49 *	
16 : *C	* * *	
17 : *C	*****	
18 : *C		
19 : *C		
20 : *TITLE	b65g sand	
21 : *C		
22 : *C		
23 : *C		
24 : *C *PROJECT	b65g sand	
25 : *C *CASE	finegrid1	
26 : *C		
27 : *C		
28 : *CONTEXT	finegrid1	
29 : *C		
30 : *C		
31 : *C -----	START OF BASIC DATA	
32 : *C		
33 : *NOLIST		

\f

```
*****
```

: SSI'S SIMBEST II SIMULATOR :
: VERSION === 3.21 I 9 :
***** : DATE 15-AUG-96 TIME 16:22 :
: INITIALISATION PAGE 2 :

b65g sand

ARRAY DATA : FURTHER CONSISTENCY CHECKS
=====

** MULT EXPANSION **
ARRAY KY IS 1.000 * ARRAY KX

\f

***** :
: SSI'S SIMBEST II SIMULATOR :
: VERSION === 3.21 I 9 :
***** : DATE 15-AUG-96 TIME 16:22 :
: INITIALISATION PAGE 3 :

SCALAR DATA SUMMARY
=====

GEOMETRY	COORDINATE SYSTEM	..	..	..	..	CARTESIAN	X-Y-Z
-----	NUMBER OF BLOCKS IN X-DIRECTION	..	..	..	..	NX	30
	NUMBER OF BLOCKS IN Y-DIRECTION	..	..	..	..	NY	26
	NUMBER OF BLOCKS IN Z-DIRECTION	..	..	..	..	NZ	1
	TOTAL NUMBER OF BLOCKS	..	..	..	..	NB	780

OPTIONS	PROBLEM TYPE	..	..	..	..	..	BLK
-----	INPUT UNITS	..	..	..	..	..	ENGLISH
	OUTPUT UNITS	..	..	..	..	..	ENGLISH
	MATRIX SATURATION INTEGRATION SELECTED	..	..	..	..	..	SATCORM

MISCELLANEOUS DATA	WATER DENSITY AT STANDARD CONDITIONS	(GMS/CM3)	DMSTD	1.000
-----	WATER COMPRESSIBILITY	(1/PSI)	CW	.3000E-05
	WATER FORMATION VOLUME FACTOR	(RB/STB)	BWINIT	1.001
	WATER VISCOSITY	(CP)	VISW	.500
	RESERVOIR TEMPERATURE	(DEG. F)	TRSTD	160.00
	MATRIX COMPRESSIBILITY	(1/PSI)	CRM	.6000E-05
	INITIAL DATE	..	..	31-JAN-1966

STANDARD CONDITIONS	STANDARD PRESSURE	(PSIA)	PSTD	14.650
-----	STANDARD TEMPERATURE	(DEG. F)	TSTD	60.00

TABLES

NUMBER OF ROCK TYPES	NRTYPE	1
NUMBER OF FLUID TYPES	NOTYPE	1
NUMBER OF EQUILIBRATION REGIONS	NREGEQ	1

\f

```

*****
: SSI'S SIMBEST II SIMULATOR :                b65g sand                : DATE 15-Aug-96  TIME 16:22 :
: VERSION  ==== 3.21 I 9      :                : INITIALISATION  PAGE    4 :
*****

```

FLUID PROPERTIES - INPUT PVT TABLE 1

=====

OIL PROPERTIES

+-----+-----+-----+-----+-----+-----+						
I	API	36.0				I
I	VISCOSITY COMPRESSIBILITY	.1000E-03	1/PSI			I
+-----+-----+-----+-----+-----+-----+						
I	PRESSURE	I	SOL. GAS	I	VISCOSITY	I
I	PSIA	I	SCF/STB	I	CP	I
+-----+-----+-----+-----+-----+-----+						
I	14.70	I	6.3	I	1.7914	I
I	250.00	I	47.3	I	1.5942	I
I	500.00	I	85.1	I	1.4568	I
I	750.00	I	123.1	I	1.3291	I
I	1000.00	I	162.3	I	1.2179	I
I	1250.00	I	203.0	I	1.1402	I
I	1500.00	I	245.4	I	1.0706	I
I	1750.00	I	289.6	I	1.0032	I
I	2000.00	I	335.7	I	.9381	I
I	2250.00	I	383.9	I	.8763	I
I	2500.00	I	434.2	I	.8183	I
I	2750.00	I	486.7	I	.7646	I
I	3000.00	I	541.4	I	.7148	I
I	3250.00	I	598.6	I	.6689	I
I	3457.00	I	647.8	I	.6336	I
I	3500.00	I	658.2	I	.6266	I
I	3750.00	I	720.4	I	.5875	I
I	4000.00	I	785.2	I	.5512	I
I	4250.00	I	852.8	I	.5176	I
I	4500.00	I	923.2	I	.4863	I
I	4750.00	I	996.6	I	.4570	I
+-----+-----+-----+-----+-----+-----+						

```

I      5000.00  I      1073.2  I      .4295  I      1.4902  I      .1000E-05  I
+-----+-----+-----+-----+-----+-----+

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\f

```

*****
: SSI'S SIMBEST II SIMULATOR :                      b65g sand                      : DATE 15-Aug-96  TIME 16:22 :
: VERSION  ==== 3.21 I 9      :                      : INITIALISATION  PAGE    5 :
*****

```

FLUID PROPERTIES - INPUT PVT TABLE 1
=====

GAS PROPERTIES

+-----+-----+-----+-----+-----+-----+				
I	GAS DENSITY	.60		I
+-----+-----+-----+-----+-----+-----+				
I	PRESSURE	I	VOL. FAC	I
I	PSIA	I	RB/MSCF	I
+-----+-----+-----+-----+-----+-----+				
I	14.70	I	212.1994	I
I	250.00	I	12.2127	I
I	500.00	I	5.9771	I
I	750.00	I	3.9053	I
I	1000.00	I	2.8752	I
I	1250.00	I	2.2626	I
I	1500.00	I	1.8594	I
I	1750.00	I	1.5763	I
I	2000.00	I	1.3686	I
I	2250.00	I	1.2113	I
I	2500.00	I	1.0894	I
I	2750.00	I	.9930	I
I	3000.00	I	.9157	I
I	3250.00	I	.8528	I
I	3457.00	I	.8091	I
I	3500.00	I	.8008	I
I	3750.00	I	.7575	I
I	4000.00	I	.7209	I
I	4250.00	I	.6897	I
I	4500.00	I	.6628	I
I	4750.00	I	.6394	I
I	5000.00	I	.6188	I

\f

```
*****
: 6      PAGE  INITIALIZATION      :
: 22     DATE 15-Aug-96             : b65g sand
:                               : SS1'S SIMBEST II SIMULATOR
:                               : VERSION == 3.21 I 9
*****
```

MATRIX SATURATION FUNCTIONS

MATRIX ROCK TYPE 1

1	WATER-OIL SATURATION FUNCTIONS	1	GAS-OIL SATURATION FUNCTIONS	1	CONNATE WATER SATURATION .2000	1	THREE PHASE KRO CALCULATION METHOD IS MODIFIED STONE 2	1
1		1	RESIDUAL GAS SATURATION .0000	1		1		1

[illegible]

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*****
F
*****
: SSI'S SIMBEST II SIMULATOR : b65g sand :
: VERSION === 3.21 I 9 :
: DATE 15-AUG-96 :
: INITIALIZATION PAGE 7 :
*****

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[illegible]

•

0.3-

-0.7

4	.4<	<.5
3	.3<	<.4
2	.2<	<.3
1	.1<	<.2
0	.0<	<.1
BLANK		=0.

0.4-

-0.6

G
A
S
0.5-
S
A
T
N
0.6-

O
I
L
-0.5
S
A
T
N
-0.4

0.7-

-0.3

0.8-

-0.2

0.9-

-0.1

1.0-

-0.0

0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0

WATER SATN.

THREE PHASE OIL RELATIVE PERMEABILITY DATA FOR TABLE NUMBER 1

I	SG	SG	SG	SG	SG	SG	SG	SG	SG	I
I	.0000	.0500	.1000	.2000	.3000	.4000	.5000	.6000	.8000	I
I	SW	KRO	KRO	KRO	KRO	KRO	KRO	KRO	KRO	I
I	.200	1.0000	.7517	.6298	.4057	.2819	.1620	.0677	.0008	.0000
I	.300	.6808	.5009	.4101	.2430	.1388	.0267	.0000	.0000	.0000
I	.400	.4431	.3096	.2398	.1114	.0204	.0000	.0000	.0000	.0000
I	.500	.2700	.1668	.1109	.0077	.0000	.0000	.0000	.0000	.0000
I	.600	.1462	.0573	.0078	.0000	.0000	.0000	.0000	.0000	.0000
I	.700	.0579	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
I	.800	.0205	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
I	.900	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
I	1.000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000

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*****
: SSI'S SIMBEST II SIMULATOR :                      b65g sand                      : DATE 15-Aug-96  TIME 16:22 :
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EQUILIBRATION DATA TABLES

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I	EQUILIBRATION REGION					I	WATER-OIL CONTACT		I	GAS-OIL CONTACT		I
I	NUMBER	I	REFERENCE	I	REFERENCE	I	BUBBLE-POINT	I	DEPTH-SUBSEA	I	CAP PRESSURE	I
I		I	DEPTH-SUBSEA	I	PRESSURE	I	PRESSURE	I	FEET	I	PSIA	I
I		I	FEET	I	PSIA	I	PSIA	I		I		I
I		I		I		I		I		I		I
I	1	I	5400.000	I	2800.000	I	2800.000	I	6487.000	I	.000	I
I		I		I		I		I		I	.000	I

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*****
: SSI'S SIMBEST II SIMULATOR :                      b65g sand                      : DATE 15-Aug-96  TIME 16:22 :
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AQUIFER DATA SUMMARY

=====

AQUIFER NUMBER	AQUIFER TYPE	THREE PHASE	AUTOMATIC COEFFICIENT GENERATION	TOTAL AQUIFER INFLUX COEF.	PERMEABILITY THICKNESS (MD- FEET)	POROSITY THICKNESS (FEET)	EQUIVALENT AQUIFER RAD. (FEET)	ANGLE OF INFLUENCE (DEGREES)
1	CTAQ	NO	EDGE		25000.00	20.00	1000.00	45.00

AQUIFER INFLUX-EFFLUX INFORMATION

AQUIFER NUMBER	TYPE	THREE PHASE	INFLUX (PER CENT)	EFFLUX ALWAYS
1	CTAQ	NO	100.0	WATER
			.0	OIL
			.0	GAS

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*****
: SSI'S SIMBEST II SIMULATOR :                b65g sand                : DATE 15-Aug-96  TIME 16:22 :
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CARTER-TRACY AQUIFER INFLUENCE FUNCTION FOR AN INFINITE AQUIFER

=====

AQUIFER NUMBER	1
DIMENSIONLESS	DIMENSIONLESS
TIME	PRESSURE
.0000	.0000
.0100	.1120
.0500	.2290
.1000	.3150

+

```
*****
: SSI'S SIMBEST II SIMULATOR :                b65g sand                : DATE 15-Aug-96  TIME 16:22 :
: VERSION  ==== 3.21 I 9      :                : INITIALISATION  PAGE   11 :
*****
```

11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 100 101 102 103 104 105 106 107 108 109 110 111 112 113 114 115 116 117 118 119 120 121 122 123 124 125 126 127 128 129 130 131 132 133 134 135 136 137 138 139 140 141 142 143 144 145 146 147 148 149 150 151 152 153 154 155 156 157 158 159 160 161 162 163 164 165 166 167 168 169 170 171 172 173 174 175 176 177 178 179 180 181 182 183 184 185 186 187 188 189 190 191 192 193 194 195 196 197 198 199 200 201 202 203 204 205 206 207 208 209 210 211 212 213 214 215 216 217 218 219 220 221 222 223 224 225 226 227 228 229 230 231 232 233 234 235 236 237 238 239 240 241 242 243 244 245 246 247 248 249 250 251 252 253 254 255 256 257 258 259 260 261 262 263 264 265 266 267 268 269 270 271 272 273 274 275 276 277 278 279 280 281 282 283 284 285 286 287 288 289 290 291 292 293 294 295 296 297 298 299 300 301 302 303 304 305 306 307 308 309 310 311 312 313 314 315 316 317 318 319 320 321 322 323 324 325 326 327 328 329 330 331 332 333 334 335 336 337 338 339 340 341 342 343 344 345 346 347 348 349 350 351 352 353 354 355 356 357 358 359 360 361 362 363 364 365 366 367 368 369 370 371 372 373 374 375 376 377 378 379 380 381 382 383 384 385 386 387 388 389 390 391 392 393 394 395 396 397 398 399 400 401 402 403 404 405 406 407 408 409 410 411 412 413 414 415 416 417 418 419 420 421 422 423 424 425 426 427 428 429 430 431 432 433 434 435 436 437 438 439 440 441 442 443 444 445 446 447 448 449 450 451 452 453 454 455 456 457 458 459 460 461 462 463 464 465 466 467 468 469 470 471 472 473 474 475 476 477 478 479 480 481 482 483 484 485 486 487 488 489 490 491 492 493 494 495 496 497 498 499 500 501 502 503 504 505 506 507 508 509 510 511 512 513 514 515 516 517 518 519 520 521 522 523 524 525 526 527 528 529 530 531 532 533 534 535 536 537 538 539 540 541 542 543 544 545 546 547 548 549 550 551 552 553 554 555 556 557 558 559 560 561 562 563 564 565 566 567 568 569 570 571 572 573 574 575 576 577 578 579 580 581 582 583 584 585 586 587 588 589 590 591 592 593 594 595 596 597 598 599 600 601 602 603 604 605 606 607 608 609 610 611 612 613 614 615 616 617 618 619 620 621 622 623 624 625 626 627 628 629 630 631 632 633 634 635 636 637 638 639 640 641 642 643 644 645 646 647 648 649 650 651 652 653 654 655 656 657 658 659 660 661 662 663 664 665 666 667 668 669 670 671 672 673 674 675 676 677 678 679 680 681 682 683 684 685 686 687 688 689 690 691 692 693 694 695 696 697 698 699 700 701 702 703 704 705 706 707 708 709 710 711 712 713 714 715 716 717 718 719 720 721 722 723 724 725 726 727 728 729 730 731 732 733 734 735 736 737 738 739 740 741 742 743 744 745 746 747 748 749 750 751 752 753 754 755 756 757 758 759 760 761 762 763 764 765 766 767 768 769 770 771 772 773 774 775 776 777 778 779 780 781 782 783 784 785 786 787 788 789 790 791 792 793 794 795 796 797 798 799 800 801 802 803 804 805 806 807 808 809 810 811 812 813 814 815 816 817 818 819 820 821 822 823 824 825 826 827 828 829 830 831 832 833 834 835 836 837 838 839 840 841 842 843 844 845 846 847 848 849 850 851 852 853 854 855 856 857 858 859 860 861 862 863 864 865 866 867 868 869 870 871 872 873 874 875 876 877 878 879 880 881 882 883 884 885 886 887 888 889 890 891 892 893 894 895 896 897 898 899 900 901 902 903 904 905 906 907 908 909 910 911 912 913 914 915 916 917 918 919 920 921 922 923 924 925 926 927 928 929 930 931 932 933 934 935 936 937 938 939 940 941 942 943 944 945 946 947 948 949 950 951 952 953 954 955 956 957 958 959 960 961 962 963 964 965 966 967 968 969 970 971 972 973 974 975 976 977 978 979 980 981 982 983 984 985 986 987 988 989 990 991 992 993 994 995 996 997 998 999 1000 1001 1002 1003 1004 1005 1006 1007 1008 1009 1010 1011 1012 1013 1014 1015 1016 1017 1018 1019 1020 1021 1022 1023 1024 1025 1026 1027 1028 1029 1030 1031 1032 1033 1034 1035 1036 1037 1038 1039 1040 1041 1042 1043 1044 10

Y-DIR	I	X-DIR									
	I	1	2	3	4	5	6	7	8	9	10

[illegible]

Y-DIR	I	X-DIR
	I	11 12 13 14 15 16 17 18 19 20
- - - - -	I	
	I	
1 I		.3320E-01 .3313E-01 .2541E-01 .1979E-01 .2035E-01 .2092E-01 .2116E-01 .2117E-01 .2477E-01 .2683E-01
2 I		
3 I		
4 I		
5 I		
6 I		
7 I		
8 I		
9 I		
10 I		
11 I		

\text{E}

CARTER-TRACY AQUIFER INFLUENCE COEFFICIENTS FOR AQUIFER NUMBER 1 : (DIM.LESS)

[illegible]

12 I
13 I
14 I
15 I
16 I
17 I
18 I
19 I
20 I
21 I
22 I
23 I
24 I
25 I
26 I

\f

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*****
: SSI'S SIMBEST II SIMULATOR :                b65g sand                : DATE 15-Aug-96  TIME 16:22 :
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*****
```

MATRIX SYSTEM - SUMMARY OF INITIAL CONDITIONS

=====

TOTAL FIELD

INITIAL WATER IN PLACE	=	76201730. STB
INITIAL OIL IN PLACE	=	24073582. STB
INITIAL GAS IN PLACE	=	11979641. MSCF
INITIAL FREE GAS IN PLACE	=	0. MSCF
INITIAL HYDROCARBON VOLUME	=	29353067. RB
INITIAL AVERAGE PRESSURE	=	3221. PSIA
FIELD MATRIX PORE VOLUME	=	105519909. RB

\f

AVERAGE - MAXIMUM AND MINIMUM RESERVOIR PROPERTIES

PROPERTY	AVERAGE VALUE	MAXIMUM VALUE (I J K)	MINIMUM VALUE LOCATIONS
PORE VOLUME	.16749E+06	.96595E+06 (3, 4, 1)	.52367E+03 (26, 24, 1)
GROSS THICKNESS	.42076E+02	.97999E+02 (17, 14, 1)	.38980E+00 (26, 24, 1)
X DIRECTION TRANSMISSIBILITY	.51931E+01	.21268E+02 (10, 2, 1)	.67584E-02 (13, 20, 1)
Y DIRECTION TRANSMISSIBILITY	.19936E+02	.11041E+03 (2, 6, 1)	.20699E-01 (19, 5, 1)
ELEVATION	.64360E+04	.72955E+04 (6, 1, 1)	.55308E+04 (1, 26, 1)

USER PLEASE NOTE:

THE GREATER THE DISCREPANCY BETWEEN ANY MINIMUM AND MAXIMUM VALUE
THE HARDER THE PROBLEM MAY RUN

CARTER-TRACY TYPE AQUIFER DIAGNOSTICS
PROGRAM DEFAULT INFLUENCE FUNCTIONS

AQUIFER NUMBER	MAXIMUM TIME THAT THE AQUIFER WILL BE VALID - DAYS	MAXIMUM DIMENSIONLESS TIME
-------------------	--	----------------------------------

1 5680. 10000.

IF YOU PLAN ON RUNNING SIMULATION TIMES LONGER
THAN THE MAXIMUM TIME SHOWN HERE, YOU WILL HAVE
TO READ IN AN INFLUENCE FUNCTION TABLE THAT
COVERS A LONGER TIME SPAN

\f

*** END OF INITIALISATION ***

Dynamic Allocation OK.

Appendix C - Initialization Input

```

*C
*C
*C *****
*C *          W O R K B E N C H          *
*C *          R E L E A S E  01.05.16      *
*C *          I N I T I A L I Z A T I O N  *
*C *          D E C K F O R S I M B E S T   *
*C *          I I                          *
*C *****
*C *
*C *          P R O J E C T:  b65g sand      *
*C *
*C *          C A S E:
*C *
*C *          D A T E:      06-Aug-96        *
*C *
*C *          T I M E:      09:18:54        *
*C *
*C *****
*C
*C
*C *TITLE      b65g sand
*C
*C
*C
*C *PROJECT      b65g sand
*C *CASE
*C
*C
*C *CONTEXT      b65g sand
*C
*C
*C ----- START OF BASIC DATA
*C
*C *NOLIST
*C
*C *SATCORM
*C
*C *BLK
*C
*C *GRID      *XYZ      30      15      1
*C
*C          DWSTD      CW      BWINIT      VISW      TRRES
*C *MISC      .99955      3.00000E-06      1.0010      .50000      160.00
*C
*C *STDCON      14.650      60.000
*C
*C *IDATE      31 01 66
*C
*C
*C *OUTPUT      *TABLES
*C
*C
*C *WINIT      *SKIP
*C
*C *CRVAR      *MATRIX      *CONSTANT      6.00000E-06
*C
*C
*C ----- END OF BASIC DATA
*C
*C
*C ----- START OF TABULAR DATA
*C
*C
*C
*C          ROCK TABLE      1
*C
*C

```

*SATWO *MATRIX 1

*C

	SW	KRW	KROW
.2000	.0000	1.000	
.3000	2.6402E-02	.6808	
.4000	6.5663E-02	.4431	
.5000	.1089	.2700	
.6000	.1718	.1462	
.7000	.2878	5.7866E-02	
.8000	.4372	2.0520E-02	
.9000	1.000	.0000	
1.000	1.000	.0000	

*C

*SATGO *MATRIX 1

*C

	SL	KROG	KRG
.2000	.0000	1.000	
.4000	8.2079E-04	.4293	
.5000	6.7715E-02	.3094	
.6000	.1620	.2100	
.7000	.2819	.1168	
.8000	.4057	5.9781E-02	
.9000	.6298	3.0369E-02	
.9500	.7517	1.4637E-02	
1.000	1.000	.0000	

*C

*C

*C

*PVTO 1 3457.0

*API 36.000 *CO 1.00000E-06 *VCO 1.00000E-04

*C

	PRES	RSO	VO	BO
14.7	6.33	1.7914	1.0310	
250.0	47.31	1.5942	1.0429	
500.0	85.08	1.4568	1.0548	
750.0	123.10	1.3291	1.0676	
1000.0	162.28	1.2179	1.0815	
1250.0	202.96	1.1402	1.0966	
1500.0	245.35	1.0706	1.1129	
1750.0	289.56	1.0032	1.1306	
2000.0	335.71	.9381	1.1496	
2250.0	383.89	.8763	1.1699	
2500.0	434.18	.8183	1.1916	
2750.0	486.67	.7646	1.2147	
3000.0	541.45	.7148	1.2393	
3250.0	598.60	.6689	1.2653	
3457.0	647.78	.6336	1.2879	
3500.0	658.21	.6266	1.2928	
3750.0	720.38	.5875	1.3218	
4000.0	785.20	.5512	1.3523	
4250.0	852.78	.5176	1.3844	
4500.0	923.22	.4863	1.4180	
4750.0	996.65	.4570	1.4533	
5000.0	1073.17	.4295	1.4902	

*C

*C

*PVTG *BG 1 .60000

*C

	PRES	BG	VISG
14.7	212.19940	.01259	
250.0	12.21265	.01275	
500.0	5.97714	.01302	
750.0	3.90531	.01337	

1000.0	2.87524	.01379
1250.0	2.26263	.01428
1500.0	1.85938	.01483
1750.0	1.57626	.01545
2000.0	1.36856	.01613
2250.0	1.21130	.01686
2500.0	1.08938	.01763
2750.0	.99305	.01843
3000.0	.91572	.01926
3250.0	.85277	.02010
3457.0	.80910	.02080
3500.0	.80084	.02095
3750.0	.75749	.02179
4000.0	.72090	.02263
4250.0	.68968	.02346
4500.0	.66277	.02427
4750.0	.63937	.02508
5000.0	.61884	.02586

*C

*C

*C ----- END OF TABULAR DATA

*C

*C

*C ----- START OF GRID DATA

*C

*C

*C

*DXH *XVAR

413.525	413.525	413.525	413.525	413.525	413.525	413.525
413.525	413.525	413.526	413.525	413.525	413.525	413.525
413.525	413.525	413.525	413.525	413.525	413.525	413.526
413.525	413.526	413.526	413.526	413.526	413.525	413.526
413.526	413.526					

*C

*DYH *YVAR

270.708	270.708	270.708	270.708	270.708	270.708	270.708
270.708	270.708	270.708	270.708	270.708	270.708	270.708
270.708						

*C

*C

*HTOP *LAYER

*C

*C	*HTOP	FOR LAYER	1	J =	1			
6652.67	6790.19	6898.14	6979.15	7034.27	7060.12	7084.88	7100.63	
7066.92	7022.96	6982.30	6953.13	6934.44	6922.26	6911.73	6913.82	
6930.10	6945.27	6955.40	6960.15	6961.90	6963.31	6966.47	6971.61	
6982.56	6999.26	7010.51	7008.70	6990.87	6961.08			

*C

*C	*HTOP	FOR LAYER	1	J =	2			
6594.09	6735.44	6829.06	6887.52	6919.96	6923.46	6928.63	6934.21	
6921.26	6898.81	6869.40	6852.05	6846.22	6847.17	6850.65	6858.05	
6867.94	6876.21	6881.33	6883.70	6886.79	6892.83	6902.73	6915.50	
6934.18	6957.53	6971.47	6966.54	6939.30	6895.23			

*C

*C	*HTOP	FOR LAYER	1	J =	3			
6546.37	6697.22	6764.71	6800.27	6813.43	6800.11	6797.66	6790.02	
6787.72	6777.90	6757.30	6749.88	6754.91	6766.67	6781.41	6793.50	
6799.24	6801.95	6802.43	6802.56	6807.43	6819.42	6838.90	6865.54	
6897.36	6927.52	6942.12	6931.40	6891.88	6829.72			

*C

*C	*HTOP	FOR LAYER	1	J =	4			
6507.58	6671.61	6702.34	6716.71	6714.54	6692.51	6687.58	6693.65	
6673.72	6664.14	6651.17	6649.22	6658.02	6673.74	6693.27	6709.92	
6718.73	6720.53	6717.94	6716.41	6723.60	6742.53	6773.11	6816.35	
6864.16	6902.89	6919.98	6904.47	6851.29	6765.86			

*C

*C	*HTOP	FOR LAYER	1	J =	5			
6456.33	6642.02	6642.85	6637.72	6625.62	6606.33	6595.06	6581.09	
6566.62	6556.37	6548.56	6548.79	6555.63	6571.17	6592.22	6613.29	
6628.68	6632.16	6627.33	6624.30	6633.94	6659.76	6700.03	6757.31	
6821.76	6876.46	6903.30	6886.38	6818.32	6704.17			

*C	*HTOP	FOR LAYER	1	J =	6				
	6392.89	6606.50	6583.27	6558.86	6537.50	6520.92	6501.62	6472.88	
	6451.17	6435.06	6434.02	6438.61	6442.86	6458.65	6481.79	6508.14	
	6532.33	6538.43	6530.08	6524.02	6536.52	6570.39	6619.34	6688.16	
	6769.28	6845.83	6890.01	6878.07	6797.01	6648.16			
*C	*HTOP	FOR LAYER	1	J =	7				
	6330.28	6566.68	6519.09	6474.31	6441.13	6418.85	6392.14	6352.28	
	6320.14	6293.51	6304.19	6317.64	6319.86	6336.93	6361.78	6391.54	
	6423.03	6433.16	6426.23	6423.69	6440.51	6477.95	6530.33	6606.00	
	6701.28	6801.14	6875.70	6886.05	6794.28	6600.31			
*C	*HTOP	FOR LAYER	1	J =	8				
	6192.98	6447.48	6449.75	6383.80	6337.27	6304.96	6271.75	6226.52	
	6185.02	6146.70	6171.19	6197.82	6199.62	6214.04	6232.55	6254.18	
	6280.89	6299.26	6313.35	6334.49	6358.54	6387.29	6433.81	6510.21	
	6616.56	6740.62	6856.84	6906.27	6810.29	6565.98			
*C	*HTOP	FOR LAYER	1	J =	9				
	6057.00	6315.02	6368.04	6283.40	6222.68	6181.03	6146.02	6103.40	
	6055.18	6001.86	6039.95	6084.61	6088.07	6093.21	6095.06	6097.62	
	6110.36	6141.13	6190.05	6244.88	6277.60	6292.40	6327.07	6399.04	
	6513.01	6658.60	6810.23	6901.24	6842.47	6563.41			
*C	*HTOP	FOR LAYER	1	J =	10				
	6010.74	6246.96	6270.18	6172.28	6097.00	6045.96	6012.92	5980.03	
	5929.55	5861.77	5911.47	5972.13	5976.85	5972.66	5960.52	5949.79	
	5954.75	5993.33	6061.14	6131.53	6170.69	6181.48	6203.98	6266.61	
	6383.89	6547.78	6725.00	6855.24	6872.36	6526.38			
*C	*HTOP	FOR LAYER	1	J =	11				
	5954.05	6142.65	6163.43	6049.48	5958.39	5892.21	5839.30	5835.48	
	5807.66	5734.43	5790.33	5856.42	5859.37	5850.69	5834.57	5822.09	
	5827.54	5865.37	5930.10	5997.10	6040.58	6057.73	6070.01	6122.52	
	6244.36	6425.14	6623.11	6789.74	6890.10	6501.97			
*C	*HTOP	FOR LAYER	1	J =	12				
	5843.84	5988.71	6023.11	5911.29	5804.79	5716.97	5631.61	5574.52	
	5629.86	5618.75	5676.32	5739.30	5738.62	5727.70	5711.40	5700.41	
	5707.54	5741.98	5862.53	5971.99	5956.52	5931.58	5933.53	5985.43	
	6120.00	6311.76	6521.60	6716.80	6697.61	6131.16			
*C	*HTOP	FOR LAYER	1	J =	13				
	5712.83	5833.67	5866.63	5764.49	5646.02	5533.34	5421.38	5303.49	
	5308.40	5457.69	5559.59	5622.61	5618.60	5605.11	5587.47	5576.33	
	5670.31	5780.57	5950.05	6023.95	6000.90	5846.22	5765.38	5853.84	
	6007.47	6204.20	6420.38	6504.44	6165.96	5930.44			
*C	*HTOP	FOR LAYER	1	J =	14				
	5617.44	5722.82	5812.79	5677.37	5490.67	5353.99	5208.44	5056.21	
	5151.75	5295.04	5590.64	5680.94	5672.55	5655.55	5645.22	5742.71	
	5829.12	5910.94	5913.43	5930.24	5973.28	5942.17	5913.23	5824.65	
	5893.51	6096.08	6240.98	6107.01	5975.19	5896.41			
*C	*HTOP	FOR LAYER	1	J =	15				
	5555.77	5626.04	5750.90	5798.61	5597.93	5511.96	5398.71	5278.01	
	5428.09	5706.79	5853.19	5856.03	5845.07	5829.24	5825.91	5833.07	
	5819.97	5801.00	5797.93	5834.87	5896.40	5953.85	6005.11	5959.71	
	5923.70	5990.41	5987.80	5946.10	5911.83	5855.66			
*C									
*TH	*VALUE								
*C									
*C	*TH	FOR LAYER	1	J =	1				
	47.3487	49.0786	52.4403	57.7045	63.3255	67.9106	69.5521	69.9811	
	72.4462	74.4799	73.0174	68.9446	57.2122	42.1081	35.9308	34.9664	
	34.6264	36.3880	39.2908	40.8850	42.7618	44.6845	46.7226	51.2336	
	56.3109	59.2207	62.6002	64.0965	63.8319	63.2773			
*C	*TH	FOR LAYER	1	J =	2				
	58.4442	60.0958	62.8514	67.0627	70.9804	73.4504	72.5374	70.8284	
	72.8523	74.9284	73.2918	68.7136	60.4045	48.3161	37.1734	31.8079	
	29.2581	27.7982	28.1751	30.8478	34.4641	37.0253	38.4601	41.8272	
	46.3616	49.2663	52.2831	56.6821	60.5795	62.1823			
*C	*TH	FOR LAYER	1	J =	3				
	65.3701	67.2157	69.2392	72.1129	73.6167	73.7289	71.1447	68.1270	
	70.0533	73.1960	72.1453	68.5884	64.0558	56.4457	46.3669	34.9510	
	27.1605	24.0943	24.1242	27.3860	31.4189	33.5199	33.6322	34.1300	

	36.1672	38.8918	41.6643	47.1134	52.8191	55.8300		
*C	*TH	FOR LAYER	1	J =	4			
	69.6962	71.8564	73.2402	74.0413	72.1116	69.7015	66.0991	61.9009
	63.6014	68.8110	68.9579	66.9649	65.4849	61.3422	56.2389	41.7139
	28.9183	24.2536	23.9953	27.5455	31.4696	31.7049	29.5373	28.2319
	29.0783	31.8715	34.9919	37.6857	41.0436	44.9431		
*C	*TH	FOR LAYER	1	J =	5			
	71.3468	73.5712	73.9546	71.7295	65.5449	58.3424	51.5625	46.3966
	48.2292	59.2006	61.5980	60.0799	60.4461	56.1623	59.1755	49.0939
	34.6912	27.9948	26.9094	30.5347	34.1899	31.8539	26.9820	24.4771
	24.4719	26.7730	29.5563	30.4149	32.7989	38.0567		
*C	*TH	FOR LAYER	1	J =	6			
	69.9589	71.7171	70.2881	63.9159	53.3028	39.3679	27.5317	23.7390
	27.2532	45.6665	52.5603	52.7531	55.1695	50.9415	60.4155	57.4745
	43.9798	34.6179	31.9888	35.7211	39.9401	34.7407	26.6784	23.3350
	22.1909	23.2645	24.7118	25.5377	28.8884	35.1220		
*C	*TH	FOR LAYER	1	J =	7			
	65.3444	65.4522	61.5536	52.1873	40.4578	25.7685	14.0424	13.2953
	18.0186	33.2104	45.8647	53.6706	56.3717	54.1891	63.4446	66.3768
	56.3009	43.9724	39.3661	42.4252	44.8856	39.5489	31.9995	26.6780
	23.4939	22.8377	22.3181	22.1777	25.4460	31.7718		
*C	*TH	FOR LAYER	1	J =	8			
	56.9960	53.4521	46.7560	37.5081	29.6382	21.0971	14.0349	14.9754
	18.6164	24.3008	38.6324	52.2195	53.1433	53.3185	60.5861	73.1686
	72.8662	58.7816	52.1521	51.3760	42.3489	43.5122	46.6147	36.1230
	29.2728	26.3373	23.1465	20.7308	22.7829	28.7161		
*C	*TH	FOR LAYER	1	J =	9			
	48.0211	41.9484	34.6047	27.8908	24.4495	21.1480	17.5176	18.1811
	19.6077	20.6939	29.8543	38.4332	37.9719	42.7286	49.2140	73.9195
	86.2433	70.5658	61.9857	59.0989	43.4932	50.7980	63.2274	50.8852
	41.7007	35.4284	27.8146	21.7191	21.9804	27.3940		
*C	*TH	FOR LAYER	1	J =	10			
	41.1341	35.2694	29.6585	26.0100	24.5487	22.5560	19.7295	18.4887
	17.3086	16.5051	20.8205	25.2109	26.1068	33.0487	38.2360	61.1353
	73.7795	59.1652	53.7218	59.2974	58.1088	67.2951	76.5181	68.1104
	58.9394	49.0296	36.8083	26.6650	24.1600	28.3127		
*C	*TH	FOR LAYER	1	J =	11			
	35.1524	30.0080	25.7817	23.4017	20.5535	15.9517	11.7064	8.6505
	6.7103	6.1045	10.7923	18.3686	22.9996	26.4998	28.2384	38.9192
	43.1242	32.8616	32.4794	46.2758	60.8440	73.5678	80.0305	76.9755
	71.8270	63.6207	52.1055	39.2069	31.2946	32.2433		
*C	*TH	FOR LAYER	1	J =	12			
	29.6222	24.9318	21.1862	18.4449	12.8127	5.4370	1.7971	.4418
	.0000	.0921	2.3031	9.4519	14.6441	14.1834	12.0992	13.5607
	13.1780	8.5858	8.5141	18.4157	38.1919	59.1296	70.1751	72.4817
	73.6586	71.5786	65.6702	53.1472	40.4478	37.6412		
*C	*TH	FOR LAYER	1	J =	13			
	24.2361	19.7184	15.8345	11.9384	5.8122	.7688	.0000	.0000
	.0103	.0103	.0121	1.3423	2.8975	2.1704	.7037	.0565
	.0000	.0000	.0000	1.6816	14.1129	34.1772	45.0797	47.6657
	51.3719	58.7880	65.4367	60.7333	48.7329	43.2301		
*C	*TH	FOR LAYER	1	J =	14			
	18.8588	14.3084	10.0548	5.2360	1.0858	.0000	.0000	.0000
	.0103	.0103	.0000	.0000	.0000	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	2.4477	8.5729	12.9993	13.3539
	17.6223	34.1353	54.6146	60.7459	52.8041	46.6259		
*C	*TH	FOR LAYER	1	J =	15			
	13.6155	9.1460	4.9933	1.2425	.0000	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
	1.7259	12.6271	36.3274	52.1148	50.4880	46.4884		
*C								
*THNET	*VALUE							
*C								
*C	*THNET	FOR LAYER	1	J =	1			
	47.3434	49.0786	52.4403	57.6823	63.2045	67.0888	67.8986	67.8241
	69.9846	72.5392	72.7142	68.9446	57.2122	41.8303	35.7548	34.7945

	34.5375	36.3770	39.2802	40.8850	42.7618	44.6845	46.7226	51.2336
	56.3109	59.2197	62.5998	64.0962	63.8311	63.2750		
*C	*THNET	FOR LAYER	1	J =	2			
	58.4442	60.0774	62.7938	66.9744	70.5461	71.8249	69.9108	67.8159
	69.4013	72.2804	73.2918	68.7136	60.4045	48.1375	36.9415	31.8079
	29.2581	27.6257	27.8140	30.2543	33.7792	36.7093	38.4375	41.8057
	46.3466	49.2604	52.2831	56.6821	60.5794	62.1807		
*C	*THNET	FOR LAYER	1	J =	3			
	65.3701	67.1661	69.1104	72.0564	73.0096	71.5418	67.9744	64.8660
	66.2011	70.1539	72.1453	68.5884	64.0558	56.4457	46.3629	34.7921
	27.1379	23.5492	22.9600	25.4633	29.1745	32.3490	33.3975	34.0431
	36.1585	38.8918	41.6643	47.1130	52.8191	55.8289		
*C	*THNET	FOR LAYER	1	J =	4			
	69.6962	71.8564	73.2402	74.0413	71.9256	67.6896	63.1994	59.4800
	60.5069	65.9954	68.9579	66.9649	65.4849	61.3422	56.2389	41.3655
	28.7531	23.3349	22.0947	24.2204	27.1533	28.8585	28.6360	28.0768
	29.0783	31.8715	34.9919	37.6786	41.0436	44.9422		
*C	*THNET	FOR LAYER	1	J =	5			
	71.3468	73.5712	73.9546	71.7295	65.5449	58.3424	51.5625	46.3966
	48.2292	58.3866	61.5980	60.0799	60.4461	56.1623	59.1755	48.8402
	34.2978	26.8313	24.6512	26.3092	28.1529	27.4130	25.5000	24.4124
	24.4719	26.7730	29.5563	30.4102	32.7989	38.0567		
*C	*THNET	FOR LAYER	1	J =	6			
	69.9589	71.7171	70.2881	63.9159	53.2577	39.3679	27.5317	23.7390
	27.2532	45.6665	52.5603	52.7531	55.1695	50.9415	60.4155	57.2488
	43.7619	34.0811	30.4153	31.9952	33.3021	29.8452	25.6849	23.3350
	22.1909	23.2645	24.7118	25.5377	28.8884	35.1220		
*C	*THNET	FOR LAYER	1	J =	7			
	65.3444	65.4522	61.5536	52.1873	40.4578	25.7685	14.0424	13.2953
	18.0186	33.2104	45.8647	53.6706	56.3717	54.1891	63.4446	65.5035
	55.8244	43.9724	39.0169	41.1927	42.9694	38.1778	31.6789	26.6780
	23.4939	22.8377	22.3181	22.1777	25.4460	31.7718		
*C	*THNET	FOR LAYER	1	J =	8			
	56.9960	53.4521	46.7560	37.5081	29.6382	21.0971	14.0349	14.9754
	18.6164	24.3008	38.6324	52.2195	52.8751	51.3736	59.3223	68.1786
	65.3216	55.3046	51.7851	51.3760	42.3489	43.5122	46.3784	36.1230
	29.2728	26.3373	23.1163	20.7120	22.7778	28.7108		
*C	*THNET	FOR LAYER	1	J =	9			
	48.0211	41.9484	34.6047	27.8908	24.4495	21.1480	17.5176	18.1811
	19.6077	20.6939	29.0208	37.9835	36.2395	35.7049	46.4414	63.5099
	68.4962	61.6547	60.7911	59.0989	43.4932	50.7980	62.7744	50.5863
	41.6755	35.3763	27.7664	21.7038	21.9784	27.3857		
*C	*THNET	FOR LAYER	1	J =	10			
	41.1341	35.2694	29.6585	26.0100	24.5487	22.5560	19.7295	18.2809
	15.9911	15.4129	20.4592	25.2109	25.1454	26.2892	35.6389	53.0921
	59.7028	52.2816	52.6963	59.2974	58.1088	67.2951	75.2270	67.2581
	58.8118	49.0296	36.7953	26.6650	24.1600	28.3001		
*C	*THNET	FOR LAYER	1	J =	11			
	35.1524	30.0080	25.7817	23.3524	20.5535	15.9517	11.1735	7.2291
	5.2987	5.4292	10.7434	18.3686	22.7082	24.5582	27.3867	37.4001
	40.5286	31.6196	32.2685	46.2758	60.8440	73.3360	78.4268	76.1336
	71.6847	63.6207	52.1055	39.2069	31.2937	32.2198		
*C	*THNET	FOR LAYER	1	J =	12			
	29.6222	24.9318	21.1862	18.2688	12.8127	5.4370	1.7971	.3897
	.0000	.0921	2.3031	9.4519	14.6441	14.1834	12.0992	13.5607
	13.1780	8.5858	8.5141	18.3948	37.8388	58.4189	69.5538	72.1635
	73.5883	71.5786	65.6702	53.1465	40.4354	37.6015		
*C	*THNET	FOR LAYER	1	J =	13			
	24.2361	19.7184	15.8345	11.8344	5.8122	.7688	.0000	.0000
	.0000	.0000	.0000	1.3337	2.8975	2.1704	.7037	.0565
	.0000	.0000	.0000	1.6816	14.1129	34.1772	45.0797	47.6376
	51.3566	58.7880	65.4367	60.7313	48.7066	43.1694		
*C	*THNET	FOR LAYER	1	J =	14			
	18.8308	14.3084	10.0548	5.2360	1.0858	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	2.4378	8.5614	12.9993	13.3515
	17.6198	34.1353	54.6146	60.7311	52.7547	46.5379		

*C	*THNET	FOR LAYER	1	J =	15			
	13.3156	9.1348	4.9933	1.2382	.0000	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
	1.7250	12.6148	36.2995	52.0630	50.4024	46.3664		
*C								
*PHI	*VALUE							
*C								
*C	*PHI	FOR LAYER	1	J =	1			
	.2127	.2173	.2274	.2445	.2628	.2782	.2925	.3065
	.3183	.3288	.3333	.3168	.2533	.1901	.1806	.1848
	.1863	.1869	.1921	.1992	.2057	.2122	.2203	.2296
	.2382	.2473	.2569	.2624	.2649	.2682		
*C	*PHI	FOR LAYER	1	J =	2			
	.2473	.2524	.2614	.2769	.2923	.3030	.3117	.3195
	.3264	.3348	.3395	.3298	.2763	.2156	.1915	.1771
	.1712	.1673	.1688	.1756	.1823	.1881	.1942	.2026
	.2125	.2223	.2335	.2429	.2511	.2612		
*C	*PHI	FOR LAYER	1	J =	3			
	.2773	.2836	.2901	.3004	.3100	.3120	.3097	.3087
	.3137	.3239	.3332	.3383	.3128	.2646	.2161	.1820
	.1663	.1570	.1560	.1611	.1664	.1701	.1737	.1796
	.1880	.1967	.2057	.2159	.2287	.2441		
*C	*PHI	FOR LAYER	1	J =	4			
	.2980	.3055	.3085	.3102	.3059	.2947	.2811	.2703
	.2772	.2959	.3088	.3257	.3272	.3034	.2492	.1969
	.1703	.1533	.1496	.1534	.1565	.1571	.1575	.1609
	.1676	.1753	.1826	.1902	.2011	.2157		
*C	*PHI	FOR LAYER	1	J =	5			
	.3084	.3137	.3097	.3005	.2775	.2497	.2293	.2126
	.2202	.2591	.2718	.2896	.3143	.3142	.2887	.2244
	.1803	.1544	.1490	.1525	.1535	.1502	.1466	.1472
	.1522	.1591	.1654	.1710	.1785	.1902		
*C	*PHI	FOR LAYER	1	J =	6			
	.3054	.3055	.2919	.2717	.2377	.2024	.1810	.1657
	.1672	.2157	.2544	.2705	.2961	.3108	.3225	.2664
	.1988	.1643	.1584	.1633	.1634	.1550	.1451	.1413
	.1431	.1482	.1533	.1580	.1646	.1757		
*C	*PHI	FOR LAYER	1	J =	7			
	.2867	.2803	.2586	.2284	.1950	.1712	.1565	.1448
	.1377	.1681	.2343	.2667	.2738	.2859	.3164	.3104
	.2435	.1972	.1871	.1972	.2019	.1847	.1617	.1488
	.1435	.1438	.1461	.1494	.1566	.1687		
*C	*PHI	FOR LAYER	1	J =	8			
	.2599	.2452	.2167	.1853	.1632	.1535	.1483	.1428
	.1355	.1442	.1899	.2296	.2299	.2263	.2688	.3256
	.3085	.2645	.2430	.2593	.2766	.2534	.2124	.1776
	.1580	.1491	.1448	.1445	.1526	.1671		
*C	*PHI	FOR LAYER	1	J =	9			
	.2330	.2128	.1860	.1629	.1507	.1481	.1483	.1482
	.1468	.1483	.1610	.1963	.2043	.1790	.2048	.3006
	.3471	.3286	.3065	.3199	.3301	.3252	.2877	.2332
	.1934	.1708	.1535	.1444	.1517	.1694		
*C	*PHI	FOR LAYER	1	J =	10			
	.2104	.1901	.1691	.1546	.1490	.1489	.1497	.1502
	.1500	.1494	.1534	.1932	.2008	.1592	.1640	.2541
	.3294	.3164	.2920	.3070	.3216	.3322	.3271	.2976
	.2600	.2207	.1789	.1538	.1560	.1757		
*C	*PHI	FOR LAYER	1	J =	11			
	.1929	.1747	.1597	.1518	.1499	.1501	.1501	.1500
	.1498	.1487	.1471	.1583	.1663	.1523	.1532	.2004
	.2375	.2101	.1953	.2222	.2663	.2968	.3168	.3231
	.3135	.2846	.2315	.1848	.1724	.1886		
*C	*PHI	FOR LAYER	1	J =	12			
	.1798	.1641	.1533	.1494	.1494	.1500	.1499	.1495
	.0000	.1494	.1489	.1478	.1501	.1510	.1506	.1526
	.1505	.1388	.1353	.1582	.2026	.2505	.2806	.2947

	.3045	.3073	.2859	.2454	.2083	.2114		
*C	*PHI	FOR LAYER	1	J =	13			
	.1704	.1574	.1496	.1479	.1491	.1500	.0000	.0000
	.0000	.0000	.0000	.1488	.1492	.1472	.1403	.1244
	.0000	.0000	.0000	.1352	.1581	.1875	.2147	.2247
	.2384	.2689	.2940	.2893	.2534	.2403		
*C	*PHI	FOR LAYER	1	J =	14			
	.1641	.1539	.1489	.1485	.1501	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	.1370	.1484	.1605	.1633
	.1644	.1913	.2492	.2868	.2756	.2627		
*C	*PHI	FOR LAYER	1	J =	15			
	.1601	.1526	.1495	.1498	.0000	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
	.1335	.1451	.1944	.2601	.2742	.2727		
*C								
*KX	*VALUE							
*C								
*C	*KX	FOR LAYER	1	J =	1			
	213.13	218.02	227.92	243.75	258.75	268.66	274.81	279.17
	283.98	288.64	288.72	276.86	241.63	186.16	149.34	137.38
	153.33	169.92	184.52	196.22	205.11	215.79	227.11	234.10
	239.64	248.89	257.76	262.87	267.39	274.76		
*C	*KX	FOR LAYER	1	J =	2			
	246.83	251.37	258.20	268.72	276.85	280.89	281.94	282.20
	285.44	290.38	292.03	285.14	258.44	213.33	169.89	114.99
	78.37	80.26	98.01	125.97	146.53	160.38	178.89	199.37
	214.07	226.75	237.43	244.67	251.86	265.62		
*C	*KX	FOR LAYER	1	J =	3			
	270.77	274.78	277.57	281.46	283.69	283.54	279.26	275.10
	279.62	288.79	294.45	295.80	288.30	261.33	213.60	158.39
	79.15	17.46	12.48	31.62	56.18	91.21	120.73	142.24
	166.64	186.98	203.86	218.17	229.06	247.22		
*C	*KX	FOR LAYER	1	J =	4			
	282.09	287.11	287.64	285.55	280.68	275.77	266.33	257.45
	263.84	280.83	292.87	300.96	305.05	288.05	244.09	195.08
	138.35	64.79	24.33	11.16	10.50	22.58	43.82	67.55
	98.13	129.06	156.71	180.40	198.77	217.82		
*C	*KX	FOR LAYER	1	J =	5			
	284.87	290.16	288.41	280.58	265.62	246.37	228.67	214.19
	220.44	258.42	283.28	296.02	304.38	295.60	264.62	221.58
	174.30	121.69	82.84	67.40	64.30	50.16	28.40	21.82
	29.76	55.39	89.43	129.99	159.27	179.51		
*C	*KX	FOR LAYER	1	J =	6			
	280.14	284.23	279.64	264.10	236.68	203.96	184.82	172.03
	176.21	223.63	266.20	281.86	291.52	288.13	272.76	246.88
	200.46	161.80	142.53	140.41	143.78	129.87	98.77	68.95
	38.78	11.22	15.63	48.87	93.12	129.17		
*C	*KX	FOR LAYER	1	J =	7			
	267.95	268.11	255.35	228.09	196.45	177.84	170.14	165.11
	171.07	215.61	252.51	264.16	268.18	265.25	266.36	276.61
	245.68	199.70	189.20	196.21	199.91	184.87	156.61	123.02
	92.50	46.15	8.24	2.55	19.38	56.83		
*C	*KX	FOR LAYER	1	J =	8			
	249.41	241.43	217.37	187.50	169.23	166.98	168.79	168.40
	175.20	206.93	239.28	249.54	250.95	249.79	256.35	286.74
	288.00	253.34	239.36	250.98	262.55	244.21	208.15	172.25
	141.36	104.11	53.49	15.52	2.41	6.78		
*C	*KX	FOR LAYER	1	J =	9			
	228.55	213.63	190.51	171.13	162.56	164.32	166.31	164.03
	162.26	172.33	198.96	200.19	208.05	234.13	246.88	272.52
	296.79	295.64	291.20	298.45	308.98	300.98	273.64	230.26
	191.92	155.62	111.80	68.09	27.38	2.98		
*C	*KX	FOR LAYER	1	J =	10			
	209.65	194.76	177.47	165.16	160.43	158.75	153.36	144.80
	137.07	135.14	150.30	140.01	153.24	203.06	229.86	255.76

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*C
*C   REGION   DATUM   INITIAL
*C   PRESSURE   WOC   PCWOC   GOC   PCGOC   BPINI
*C
      1   5400.00   3057.00   6477.00   .00   .00   .00   2500.00
*C
*C ----- END OF EQUIL DATA
*C
*ENDJOB
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Appendix D - Recurrent Data Input

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*C
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*              W O R K B E N C H              *
*              R E L E A S E  01.05.16          *
*              RUN DECK FOR SIMBEST II         *
*****
*
*      PROJECT:  b65g sand                      *
*
*      CASE:
*
*      DATE:      02-Aug-96                      *
*
*      TIME:      14:23:21                      *
*
*****
*C
*C
*RTITLE  b65g sand
*C
*C
*C
*C *PROJECT      b65g sand
*C *CASE
*C
*C
*C CONTEXT      b65g sand
*C
*C
*WPLLOT      3
*C
*WMAP      10
*C
*C ----- START OF WELLBORE HYDRAULICS DATA
*C
*C ----- END OF WELLBORE HYDRAULICS DATA
*C
*NOLIST
*C
*C CENTRE      99      *GCNM__99
*C
*PRINT  *WELL  *REGION  *TIME
*WELL  2  *b-29  *MULT  99
*PERF  *S  2  *IJK  1  12  5  1  20607.
*WI  2  1000.0
*WELL  3  *b-3  *MULT  99
*PERF  *S  3  *IJK  1  15  3  1  12319.
*WI  3  1000.0
*WELL  5  *b-13  *MULT  99
*PERF  *S  5  *IJK  1  17  7  1  16356.
*WI  5  1000.0
*WELL  6  *b-27  *MULT  99
*PERF  *S  6  *IJK  1  17  7  1  16356.
*WI  6  1000.0
*WELL  9  *b-10  *MULT  99
*PERF  *S  9  *IJK  1  13  9  1  5870.6
*WI  9  1000.0
*WELL  10  *b-30  *MULT  99
*PERF  *S  10  *IJK  1  12  10  1  4379.4
*WI  10  1000.0
*WELL  11  *b-26  *MULT  99
*PERF  *S  11  *IJK  1  10  10  1  2899.9
*WI  11  1000.0
*WELL  13  *b-2  *MULT  99

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*PERF	*S	13		*IJK	1	9	13	1	.00000
*WELL		14	*b-8	*MULT	99				
*PERF	*S	14		*IJK	1	20	12	1	3521.8
*WELL		16	*b-18	*MULT	99				
*PERF	*S	16		*IJK	1	9	6	1	6601.3
*WELL		18	*b-16	*MULT	99				
*PERF	*S	18		*IJK	1	14	5	1	17644.
*WI		18		1000.0					
*WELL		19	*b-6	*MULT	99				
*PERF	*S	19		*IJK	1	9	11	1	857.81
*WELL		31	*b-25	*MULT	99				
*PERF	*S	31		*IJK	1	24	12	1	23844.
*WELL		32	*b-9	*MULT	99				
*PERF	*S	32		*IJK	1	21	9	1	14317.
*WELL		33	*b-20	*MULT	99				
*PERF	*S	33		*IJK	1	21	8	1	12571.
*WELL		35	*b-14	*MULT	99				
*PERF	*S	35		*IJK	1	3	9	1	8246.2
*WELL		37	*b-29st	*MULT	99				
*PERF	*S	37		*IJK	1	7	7	1	3139.5
*WELL		38	*b-27st1	*MULT	99				
*PERF	*S	38		*IJK	1	17	7	1	16356.
*WELL		40	*7	*MULT	99				
*PERF	*S	40		*IJK	1	8	2	1	21926.
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*PERF	*S	43		*IJK	1	30	11	1	7428.4
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*C							01	02	66
*C									
*TIME				28.000					
*C							28	02	66
*C									
*TIME				242.00					
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*C									
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*PROD	*O	9							
*PROD	*O	17							
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*C									
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*Q		9		141.533					
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*C									
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*C									
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*Q		9		132.548					
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*C									
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*Q	9	136.968			
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*C			
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*C			

*TIME		2189.0	
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FURTHER CHARACTERIZATION OF THE GULF OF MEXICO U-8 RESERVOIR

by W. Clay Kimbrell, *Louisiana State University*

Introduction

This report presents the information gained from the continued 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. A previous report was made on this reservoir under the U.S. Department of Energy (DOE) contract number DE-AC22-92BC14831, primarily in the form of a master's thesis by George Koperna.¹ The purpose of this continued research of this reservoir are as follows:

1. Refine the reservoir and geologic characterization of the U-8 reservoir by obtaining and analyzing additional data. Additional reservoir and geologic data includes updated fluid data, pressure data, well test data, and any newly available well logs and/or core data/samples. Laboratory investigations were included where necessary to improve simulator input.
2. Based on new data and characterization, simulate the performance of an advanced waterflooding project and perform predictive sensitivity studies to assess recovery potential and process improvements.

New data was obtained for this reservoir in the form of updated production records, well test data (which includes pressure, GOR, fluid data, and water cut), and core data.

Reservoir 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 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. The U-8 Sand reservoir has produced 2,115 MSTB of oil, 8,044 MMSCF of gas, and 1,379 MSTB of water, through November, 1995.

Reservoir Interpretation

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-

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).

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 structural and geological characterization of the U-8 reservoir is depicted in Figure 1. Also, shown on this figure are the well locations and areas which will be referred to later in this report. The reservoir can be described as a relatively flat, totally isolated fault block (surrounded on all sides by faults) with several non-sealing interior minor faults which serve to decrease drainage of the reservoir.

The U-8 was divided into three layers, with two intervening shaley zones as shown in Figure 2, which is a log section from the 10-20 well. The top, or A, layer was a relatively uniform blanket sand, between 12 and 15 feet thick. A shaley zone separates this unit from the underlying B sand, a much thicker, but more irregular, sand body. The actual water production, as was the case in the original study, 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. It was necessary to put the two top layers, A and B, into communication with one another within the reservoir. The structure map and the isolations of the southwestern portions of the unit, Area C, were factored into the reservoir model as before. There was no new data to support modifications to the geological interpretations from the previous study.

U-8 Reservoir Development History

The U-8 reservoir has been developed with three production wells and one exploration 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 an exploratory well. Field operations for this well included coring and geophysical well logging only.

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 #10-15) was a straight hole drilled to 12,324 feet. In February 1991, Well 10-15 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 #A-4) in the U-8 Sand in February 1988. The #A-4 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 #10-20) was drilled as a straight hole to a depth of 11,957 feet in July 1988. This well is currently the only well producing the U-8 reservoir. The plug-back 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 upper lobe, Lobe A, and the middle lobe, Lobe B. The U-8 reservoir originally did not flow in this well. Therefore, the perforations were washed, and a gravel pack was installed.

Figure 1 - U-8 Reservoir with well locations and areas of interest
(modified from Koperna, June 1994)

Figure 2 - Log of the 10-20 well depicting layers A through C

U-8 Reservoir Production History

In February 1991, well #10-15 was shut-in due to limited oil production and excessive gas and water production. To date, well #10-15 has produced 218 MBO, 836 MMSCF, and 330 MBW. Wells #A-4 and #10-20 produced until November and December 1992 when they were shut-in. Well #A-4 produced 517 MBO, 3101 MMCF, 356 MBW. Well #10-20 was put back on line January, 1993. It is presently the only well producing from the U-8 reservoir. To date, it has produced 1,380 MBO, 4,107 MMSCF, 693 MBW. Table 1 contains the cumulative reservoir fluid production. The production histories by well may be found in Figures 3 through 5.

Table 1: Cumulative Production for the U-8 Reservoir

WELL	CUMULATIVE OIL, MSTB	CUMULATIVE GAS, MMCF	CUMULATIVE WATER, MSTB
10-15	218	836	330
A-4	517	3,101	356
10-20	1,380	4,107	693
TOTAL	2,115	8,044	1,379

Figure 3 - A-4 Production History

Simulation of Well Histories

Using the oil production rate as an input, or the 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.

Essentially, the major occurrence and new piece of information which was obtained since the last report was the fact that the #10-20 had been reworked. The workover consisted of squeezing off with cement the lower perforations in an attempt to eliminate or reduce the water cut. It was unsuccessful within this capacity, however. The well still produces at a high water cut. Originally, the simulation was run with the assumption that Layer B had been isolated from Layer A to account for a successful workover. However, a history match was unattainable using this scenario. Therefore, Lobe A was put back into communication with Lobe B within the reservoir and a history match was attained. A copy of the final history match data set is found in Appendix A. History match results are illustrated in Figures 6 and 7. Figure 6 the simulated production values for oil, gas and water to the actual production values. Oil production was input as the control. Figure 7 compares the simulated reservoir pressure to the actual reservoir pressure. Both graphs illustrate a fair to good match.

Figure 6 - U8 Production History Match

Figure 7 - U8 Reservoir Pressure History Match

Predictive Study

This study targeted an enhanced recovery process which is commonly used in the Gulf of Mexico: waterflooding. All predictive study simulations were performed based on the updated history match achieved.

Predictive Study Setup

The following scenarios were made during the predictive study:

1. the maximum producing water-oil ratio was set at a maximum of 10 to allow the production wells to stay on-line for a reasonable amount of time
2. the maximum producing gas-oil ratio was set at 500,000 SCF/STB to allow the production wells to stay on-line for a reasonable amount of time
3. the minimum bottom hole pressure was set at 150 psi to allow the production wells to stay on-line for a reasonable amount of time
4. the field's water injection rate was set at a consistent level for both vertical and horizontal situations in order to compare and contrast the results

Waterflooding

Figures 8, 9 and 10 depict the ending oil, gas and water saturations, respectively, at the end of the BOAST III history match. Also, noted in these figures are zones as outlined in the previous study, Zones A through H. The highest amounts of remaining oil is found in the updip area A and the directly downdip area H. It was therefore decided to simulate an advanced waterflood concentrating on these two areas.

The initial predictive run, P1, was simply a continuation of the field production as it is presently, with only the 10-20 well producing. A second predictive run, P2, added the A-4 well to the 10-20 well. Both of these simulations, as well as the advanced waterflood simulations, were run with implicit pressure control. Therefore, comparisons for these different predictive scenarios will concentrate on qualitative rather than quantitative results.

After the first two predictive runs (P1 and P2), where there is no secondary production application, several advanced waterflood scenarios were simulated for comparison. The third and fourth simulation runs (P16 and P17) simulated a vertical injector well, injecting 1700 barrels of water per day, from grid block x-6, y-13, with two and one producing wells (10-20 + A-4 and 10-20), respectively. The fifth and sixth simulation runs (P18 & P19) simulated a horizontal injector well, injecting 1700 barrels of water per day, from grid block x-5-7, y-13, with two and one producing wells (10-20 + A-4 and 10-20), respectively. The seventh and eighth runs (P20 & P21) simulated a vertical injector well, injecting 1700 barrels of water per day, from grid block x-5, y-6, with two and one producing wells (10-20 + A-4 and 10-20), respectively. The ninth and tenth runs (P22 & P23) simulated a horizontal injector well, injecting 1700 barrels of water per day, from grid block x-5, y-5-7, with two and one producing wells (10-20 + A-4 and 10-20), respectively.

Results from these prediction runs have been depicted in Table 2. Interestingly, the best scenario for this particular reservoir, from this simulation study, is a vertical well injecting in Area H and producing from Area A from the 10-20 well. Oil recovery increases by a factor of 3.2 in comparison to the scenario of continuing as present with one well, the 10-20. Oil recovery increases by a factor of 2.6 in comparison to the scenario of continuing as present with two well, the 10-20 and the A-4.

A horizontal injector in the same area, is a close second in respect to oil recovery. However, when viewing the major increase in cost between putting a vertical well in place versus a horizontal well, the vertical injector is, by far, the most advantageous scenario.

Vertical and horizontal injectors placed between the 10-20 and A-4 wells, in Area A, resulted in the producing wells to reach a water/oil ratio of 10 very early. This resulted in a lower overall oil recovery and therefore a poor candidate scenario. Comparison results are illustrated in Figure 11.

Figure 8 - U8 Reservoir Oil Saturation at Present

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1	0.357	0.3347	0.4108	0.2748	0.2554	0.2664	0.2604	0.2608	0.2613	0.2609	0.2674	0	0	0	0
2	0.4584	0.4268	0.471	0.4109	0.2633	0.275	0.2664	0.2749	0.2746	0.2727	0.2583	0.1617	0.1492	0.1488	0
3	0.5851	0.5128	0.5413	0.4716	0.4035	0.3523	0.2836	0.3615	0.3821	0.3932	0.5251	0.1619	0.1492	0.1487	0
4	0.5456	0.4803	0.4792	0.5368	0.3887	0.5555	0.4311	0.4258	0.4236	0.4438	0.249	0.1623	0.1492	0.1487	0
5	0.5602	0.5903	0.5193	0.5601	0.4776	0.6202	0.5546	0.5091	0.4647	0.4659	0.4502	0	0	0	0
6	0.5	0.5398	0.5322	0.6119	0.622	0.6254	0.5493	0.4884	0.4667	0.4706	0.4455	0.3138	0.2958	0.2807	0.1551
7	0.4393	0.4997	0.5461	0.5686	0.5721	0.553	0.4659	0.459	0.4897	0.4799	0.4872	0.3795	0.3628	0.3586	0.3383
8	0.3196	0.5218	0.5559	0.5812	0.5818	0.5091	0.3042	0.3298	0.314	0.3171	0.5327	0.4287	0.4015	0.4203	0.4531
9	0.2988	0.4937	0.5202	0.5472	0.5573	0.4636	0.4195	0.4357	0.4175	0.3945	0.4751	0.5302	0.2874	0.3259	0.5233
10	0	0.4763	0.5061	0.4991	0.5138	0.4893	0.4031	0.4178	0.4038	0.417	0.4886	0.5504	0.2899	0.3536	0.5611
11	0	0.4476	0.5108	0.5047	0.4659	0.5136	0.4147	0.4448	0.4559	0.1592	0.5122	0.5819	0.3352	0.3753	0.6078
12	0	0.5218	0.541	0.5314	0.4707	0.4873	0.4204	0.4635	0.4852	0.5509	0.4863	0.571	0.5724	0.5659	0.5477
13	0	0	0	0.5758	0.4218	0.3921	0.4453	0.4566	0.4589	0.4558	0.3895	0.3849	0.3456	0.3301	0.3084
14	0	0	0	0	0	0	0.2804	0.2848	0.2857	0.2962	0.2975	0.216	0.2107	0.1726	0.1104
15	0	0	0	0	0	0	0	0	0	0.2457	0.1993	0.473	0	0	0
2	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	0.6257	0.6041	0.5818	0.626	0.5038	0.4769	0.4708	0.4882	0.4868	0.4747	0.4836	0	0	0	0
2	0.5986	0.5694	0.5662	0.5984	0.5421	0.5643	0.5272	0.5987	0.5989	0.5908	0.5842	0.2942	0.1681	0	0
3	0.5411	0.5538	0.5432	0.5775	0.6118	0.6261	0.6146	0.6084	0.5889	0.5561	0.4043	0.3008	0.1824	0.1622	0
4	0.5471	0.5957	0.5728	0.5555	0.6239	0.5971	0.6251	0.542	0.5054	0.4394	0.3887	0.3192	0.1824	0.1616	0
5	0.4474	0.547	0.5874	0.5703	0.579	0	0.5496	0.4513	0.4306	0.3801	0.434	0.2538	0	0.163	0
6	0.3557	0.4448	0.6263	0	0	0	0	0	0.4335	0.3772	0.4261	0.424	0.4249	0.3265	0.1608
7	0.3064	0.4037	0	0	0	0	0	0	0	0.3665	0.4053	0.237	0.2868	0.3166	0.4051
8	0.2505	0	0	0	0	0	0	0	0	0	0.414	0.2608	0.2761	0.2951	0.2987
9	0	0	0	0	0	0	0	0	0	0.2506	0.2742	0.3162	0.5055	0.4981	0.3975
10	0	0	0	0	0	0	0	0	0	0	0	0.4094	0.5588	0.5378	0.4319
11	0	0	0	0	0	0	0	0	0	0	0.3235	0.4075	0.6198	0.6051	0.476
12	0	0	0	0	0	0	0	0	0	0	0.2661	0.4151	0.3512	0.3134	0.2783
13	0	0	0	0	0	0	0	0	0	0	0.1047	0.0562	0.0175	0.0006	0.0011
14	0	0	0	0	0	0	0	0	0	0	0.0087	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0.014	0	0.3538	0	0
3	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	0.2043	0.13	0.0702	0.1184	0.1827	0.1409	0.1611	0.1216	0.1185	0.144	0.1654	0	0	0	0
2	0.3235	0.0675	0.0694	0.0889	0.246	0.1304	0.1536	0.1109	0.1225	0.1102	0.1058	0.0963	0.3397	0.1664	0
3	0.0857	0.1071	0.0654	0.0852	0.1553	0.1288	0.1348	0.0561	0.0696	0.0681	0.0084	0.0331	0.1928	0.284	0.2858
4	0.1884	0.2129	0.1242	0.0888	0.2232	0.0971	0.1062	0.0232	0.0766	0.0421	0.1924	0.0229	0.1793	0.2864	0.2747
5	0.0725	0.1645	0.1654	0.1162	0.1645	0.1067	0.0808	0.0686	0.1301	0.0433	0.0415	0.4824	0.179	0	0.1126
6	0.0693	0.0805	0.2855	0.2609	0.2038	0.1738	0.1296	0.0816	0.115	0.044	0.0529	0.0169	0.0241	0.2143	0
7	0.1067	0.0985	0.0709	0.0646	0.0607	0.0495	0.0411	0.1718	0.1646	0.0624	0.0659	0.0391	0.0395	0.0346	0.0557
8	0.1225	0.0682	0.0806	0.0838	0.1054	0.0596	0.0157	0.0237	0.0235	0.0144	0.0392	0.0383	0.0329	0.021	0.0341
9	0.0383	0.0585	0.0433	0.0373	0.038	0.0236	0.0389	0.0223	0.045	0.0328	0.0066	0.0127	0.076	0.0856	0.0277
10	0	0.0469	0.0433	0.0455	0.0438	0.0097	0.0173	0.0227	0.0089	0.0039	0.0612	0.0335	0.1393	0.0531	0.0268
11	0	0.0273	0.0573	0.0397	0.0293	0.0547	0.0189	0.0269	0.0026	0.153	0.0605	0.0023	0.2064	0.0998	0.0219
12	0	0.0862	0.0384	0.0373	0.0303	0.0341	0.0176	0.0239	0.0122	0.0156	0.0229	0.0564	0.0326	0.0276	0.0221
13	0	0	0	0.1224	0.0334	0.0261	0.0133	0.0381	0.0446	0.0276	0.0185	0.0275	0.0233	0.0129	0.0139
14	0	0	0	0	0	0	0.0219	0.02	0.0095	0.0182	0.0207	0.0111	0.0105	0	0.0068
15	0	0	0	0	0	0	0	0	0	0	0.0117	0.0013	0.032	0	0

Figure 9 - U-8 Reservoir Gas Saturation at Present

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1	0.3279	0.3613	0.2695	0.4372	0.4769	0.4558	0.4678	0.467	0.4661	0.4668	0.4539	0	0	0	0
2	0.2112	0.2514	0.1932	0.2695	0.4595	0.438	0.4554	0.4389	0.4393	0.4433	0.4715	0.6013	0.6138	0.6142	0
3	0.0429	0.1431	0.0987	0.1863	0.273	0.3359	0.4247	0.3118	0.2796	0.2585	0.0308	0.6011	0.6138	0.6143	0
4	0.098	0.194	0.1758	0.1009	0.2947	0.099	0.2554	0.2022	0.1791	0.1167	0.4839	0.6007	0.6138	0.6143	0
5	0.0241	0.0475	0.1343	0.0765	0.162	0.0337	0.0711	0.0446	0.0774	0.0489	0.1406	0	0	0	0
6	0.0283	0.0132	0.1472	0.0666	0.0522	0.0345	0.0393	0.0351	0.0741	0.0392	0.1352	0.3134	0.3952	0.4271	0.6079
7	0.0289	0.0207	0.0131	0.0104	0.0138	0.0091	0.0017	0.1658	0.0914	0.0292	0.0726	0.0847	0.1534	0.1759	0.2382
8	0.0303	0.0174	0.0261	0.019	0.0279	0.0091	0.0006	0.0045	0.0005	0.0003	0.0427	0.0797	0.1254	0.1232	0.0895
9	0.0007	0.0079	0.0192	0.0078	0.0117	0.0057	0.0032	0.0143	0.0013	0.0357	0.0111	0.0245	0.4144	0.375	0.0797
10	0	0.006	0.0189	0.0041	0.0055	0.0116	0.0012	0.0027	0.0001	0.0307	0.0168	0.0553	0.4182	0.3517	0.0629
11	0	0.0047	0.0229	0.0079	0.0034	0.0165	0.0016	0.0031	0.0001	0.6038	0.0267	0.0252	0.3782	0.3366	0.0482
12	0	0.0425	0.0184	0.0122	0.0039	0.0074	0.0019	0.0023	0.0003	0.0046	0.0109	0.0416	0.0143	0.0064	0.0035
13	0	0	0	0.0309	0.0023	0.0032	0.0143	0.0129	0.0124	0.0092	0.0065	0.0059	0.0067	0.0017	0.0006
14	0	0	0	0	0	0	0.0014	0.0011	0.0009	0.0015	0.004	0.0012	0.0054	0.0006	0.0002
15	0	0	0	0	0	0	0	0	0	0.0034	0.0002	0.0395	0	0	0
2															
1	0.0001	0	0	0.0001	0.1713	0.1932	0.22	0.1956	0.1942	0.2051	0.1831	0	0	0	0
2	0	0	0	0	0.1297	0.0885	0.1624	0.0588	0.0494	0.0374	0.0693	0.4387	0.5949	0	0
3	0	0	0	0	0	0	0.0339	0.0002	0	0	0	0.4279	0.578	0.6008	0
4	0	0	0	0	0	0	0	0	0.0001	0	0.2342	0.4065	0.5777	0.6014	0
5	0	0	0	0	0.0002	0	0.0001	0	0	0	0	0.5006	0	0.6	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0.005	0.2766	0.6022
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1892
9	0	0	0	0	0	0	0	0	0	0	0	0.0001	0.0001	0	0.2649
10	0	0	0	0	0	0	0	0	0	0	0	0.0002	0.0001	0	0.3598
11	0	0	0	0	0	0	0	0	0	0	0	0.0001	0.0001	0	0.0833
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3															
1	0.2093	0.0047	0.0003	0.0014	0.0121	0.1432	0.2292	0.1625	0.1474	0.1262	0.137	0	0	0	0
2	0.0247	0.0003	0.0008	0.0009	0.051	0.1004	0.1594	0.0349	0.0081	0.0016	0.0007	0.0007	0.348	0.5966	0
3	0.0013	0.002	0.0006	0.0014	0.015	0.0666	0.1055	0.001	0.0026	0.0007	0	0.0002	0.2104	0.4387	0.4428
4	0.0047	0.0566	0.0238	0.0103	0.1263	0.0343	0.0392	0.0003	0.0039	0.0003	0.0224	0.0103	0.2049	0.4081	0.4187
5	0.0011	0.0055	0.0126	0.0133	0.0938	0.0276	0.021	0.0034	0.0074	0.0006	0.0024	0.0582	0.584	0	0.3901
6	0.0021	0.0021	0.0163	0.0519	0.0531	0.0112	0.0315	0.0085	0.0056	0.0011	0.0048	0.0002	0.0002	0.1326	0
7	0.0074	0.0035	0.002	0.0018	0.0027	0.0012	0.0002	0.0185	0.0135	0.0016	0.0064	0.0005	0.0005	0.0001	0.0263
8	0.0239	0.0011	0.0022	0.0029	0.0053	0.0014	0.0001	0.0003	0.0001	0	0.0024	0.0008	0.0002	0.001	0.0003
9	0.0004	0.0004	0.0011	0.0007	0.001	0.0007	0.0003	0.0011	0.0001	0.0003	0.0016	0.0001	0.1884	0.1673	0.0004
10	0	0.0002	0.0012	0.0003	0.0004	0.0009	0.0001	0.0003	0	0	0.048	0.0043	0.2225	0.1809	0.0005
11	0	0.0001	0.0014	0.0007	0.0003	0.0022	0.0001	0.0005	0	0.2151	0.0027	0.0015	0.2141	0.1971	0.0008
12	0	0.0509	0.0005	0.0008	0.0003	0.0008	0.0001	0.0003	0.0001	0.0003	0.0008	0.0041	0.0006	0.0003	0.0002
13	0	0	0	0.1176	0.0004	0.0003	0.0021	0.0044	0.0066	0.0024	0.0005	0.0004	0.0002	0.0001	0.0001
14	0	0	0	0	0	0	0.0003	0.0002	0	0.0002	0.0004	0.0001	0.0001	0	0.0001
15	0	0	0	0	0	0	0	0	0	0	0.0003	0	0.0165	0	0

Figure 10 - U8 Reservoir Water Saturation at Present

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1	0.3151	0.3039	0.3197	0.288	0.2676	0.2777	0.2718	0.2722	0.2727	0.2723	0.2787	0	0	0	0	0
2	0.3303	0.3217	0.3357	0.3197	0.2772	0.287	0.2782	0.2862	0.2862	0.284	0.2702	0.237	0.237	0.237	0	0
3	0.372	0.3441	0.36	0.3421	0.3235	0.3118	0.2918	0.3267	0.3383	0.3482	0.4442	0.237	0.237	0.237	0	0
4	0.3564	0.3258	0.345	0.3623	0.3165	0.3455	0.3135	0.372	0.3973	0.4395	0.2671	0.237	0.237	0.237	0	0
5	0.4157	0.3622	0.3464	0.3635	0.3604	0.3461	0.3743	0.4464	0.4579	0.4852	0.4092	0	0	0	0	0
6	0.4717	0.447	0.3206	0.3214	0.3258	0.3401	0.4113	0.4764	0.4591	0.4902	0.4193	0.3728	0.309	0.2922	0.237	0
7	0.5318	0.4797	0.4408	0.421	0.4141	0.4379	0.5324	0.3752	0.4189	0.491	0.4402	0.5358	0.4838	0.4655	0.4236	0.237
8	0.6502	0.4608	0.418	0.3998	0.3903	0.4818	0.6951	0.6657	0.6855	0.6825	0.4247	0.4915	0.473	0.4564	0.4574	0.2726
9	0.7005	0.4984	0.4606	0.445	0.431	0.5307	0.5773	0.55	0.5812	0.5698	0.5138	0.4452	0.2982	0.2991	0.397	0.2562
10	0	0.5177	0.475	0.4968	0.4807	0.4991	0.5957	0.5795	0.5961	0.5524	0.4945	0.3943	0.2919	0.2947	0.3761	0.2447
11	0	0.5477	0.4663	0.4874	0.5307	0.4699	0.5837	0.5521	0.544	0.237	0.4611	0.393	0.2866	0.2881	0.344	0.2763
12	0	0.4357	0.4406	0.4564	0.5254	0.5053	0.5778	0.5343	0.5145	0.4444	0.5028	0.3874	0.4132	0.4277	0.4488	0.3656
13	0	0	0	0.3934	0.5758	0.6046	0.5404	0.5306	0.5287	0.535	0.604	0.6092	0.6477	0.6683	0.691	0.3738
14	0	0	0	0	0	0	0.7182	0.714	0.7134	0.7022	0.6986	0.7828	0.7839	0.8268	0.8894	0.7344
15	0	0	0	0	0	0	0	0	0	0	0.7509	0.8006	0.4876	1	0	0

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1	0.3742	0.3959	0.4182	0.3739	0.3248	0.3299	0.3092	0.3162	0.3189	0.3201	0.3333	0	0	0	0	0
2	0.4014	0.4306	0.4338	0.4016	0.3281	0.3472	0.3104	0.3425	0.3517	0.3717	0.3466	0.2671	0.237	0	0	0
3	0.4589	0.4462	0.4568	0.4225	0.3882	0.3739	0.3515	0.3914	0.4111	0.4439	0.5957	0.2713	0.2396	0.237	0	0
4	0.4529	0.4042	0.4272	0.4445	0.3761	0.4028	0.3749	0.4579	0.4945	0.5606	0.3771	0.2742	0.2399	0.237	0	0
5	0.5526	0.4529	0.4125	0.4297	0.4207	0	0.4503	0.5487	0.5694	0.6199	0.5659	0.2456	0	0.237	0	0
6	0.6443	0.5552	0.3737	0	0	0	0	0	0.5665	0.6228	0.5739	0.576	0.5701	0.3969	0.237	0
7	0.6935	0.5963	0	0	0	0	0	0	0	0.6335	0.5947	0.763	0.7132	0.6834	0.5949	0
8	0.7495	0	0	0	0	0	0	0	0	0	0.586	0.7392	0.7239	0.7049	0.7013	0.3671
9	0	0	0	0	0	0	0	0	0	0.7494	0.7258	0.6838	0.4944	0.5018	0.6024	0.3275
10	0	0	0	0	0	0	0	0	0	0	0	0.5906	0.4411	0.4621	0.5681	0.2957
11	0	0	0	0	0	0	0	0	0	0	0.6765	0.5925	0.38	0.3948	0.524	0.4117
12	0	0	0	0	0	0	0	0	0	0	0.7338	0.5849	0.6488	0.6866	0.7217	0.5382
13	0	0	0	0	0	0	0	0	0	0	0.8953	0.9438	0.9825	0.9994	0.9989	0.5797
14	0	0	0	0	0	0	0	0	0	0	0.9913	1	1	1	1	1
15	0	0	0	0	0	0	0	0	0	0	0.986	1	0.6462	1	0	0

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1	0.5864	0.8653	0.9295	0.8802	0.8052	0.7159	0.6097	0.7159	0.7341	0.7298	0.6976	0	0	0	0	0
2	0.6518	0.9322	0.9298	0.9103	0.703	0.7692	0.687	0.8542	0.8694	0.8883	0.8935	0.903	0.3123	0.237	0	0
3	0.913	0.8909	0.934	0.9134	0.8298	0.8046	0.7597	0.9429	0.9278	0.9312	0.9916	0.9666	0.5968	0.2773	0.2714	0
4	0.8069	0.7305	0.852	0.9008	0.6505	0.8686	0.8546	0.9766	0.9195	0.9576	0.7852	0.9669	0.6158	0.3055	0.3067	0
5	0.9263	0.83	0.822	0.8705	0.7417	0.8657	0.8981	0.9281	0.8625	0.9562	0.9561	0.4594	0.237	0	0.4973	0
6	0.9287	0.9174	0.6982	0.6871	0.7432	0.815	0.8389	0.9099	0.8794	0.955	0.9422	0.983	0.9757	0.6531	0	0
7	0.8859	0.898	0.9271	0.9336	0.9366	0.9493	0.8587	0.8097	0.8219	0.9361	0.9277	0.9604	0.9601	0.9653	0.918	0
8	0.8536	0.9307	0.9172	0.9133	0.8893	0.939	0.9843	0.976	0.9765	0.9856	0.9585	0.9609	0.9669	0.978	0.9655	0.8734
9	0.9613	0.9412	0.9555	0.962	0.961	0.9757	0.9609	0.9766	0.9548	0.9668	0.9918	0.9872	0.7356	0.7472	0.972	0.9076
10	0	0.9529	0.9555	0.9542	0.9558	0.9893	0.9826	0.977	0.9911	0.9961	0.8908	0.9622	0.6382	0.766	0.9726	0.8392
11	0	0.9725	0.9413	0.9595	0.9704	0.9432	0.981	0.9726	0.9974	0.6319	0.9368	0.9962	0.5796	0.7031	0.9773	0.974
12	0	0.8629	0.961	0.9619	0.9694	0.9651	0.9823	0.9758	0.9877	0.9841	0.9763	0.9395	0.9668	0.9721	0.9777	0.9812
13	0	0	0	0.76	0.9663	0.9736	0.9846	0.9575	0.9488	0.97	0.981	0.9722	0.9765	0.987	0.986	0.9786
14	0	0	0	0	0	0	0.9778	0.9799	0.9905	0.9816	0.9789	0.9888	0.9894	1	0.9932	0.9889
15	0	0	0	0	0	0	0	0	0	0	0.988	0.9987	0.9515	1	0	0

Figure 11 - Comparison of Predictive Runs

Conclusions

Prior to October 1996, the #10-20 well was producing with an 800 psi pressure drop across the gravel pack. Because the reservoir is pressure depleted, the well could not flow on gas lift without removing the damaged gravel pack. The well was also producing large quantities of water and it was believed that the water was coming from the lower perforations, or Lobe B.

Lobe A calculated low water saturations and should have been producing water free, while Lobe B calculated high water saturations on the original openhole logs. Recent TDT logs confirmed this belief by revealing a high gamma ray spike at the base of the perforations. The TDT logs did not show an increasing water saturation with time from the bottom of the sand, either. Therefore, in October, 1996 this well was worked over to remove the gravel pack, squeeze the lower perforations and return the well to production. However, after the workover, well #10-20 continued to produce high water rates. Therefore, the debate is whether the two lobes are in communication within the reservoir or if they are in communication through the wellbores only.

Recall that the previous simulation study, could not obtain a history match without putting Lobe A in communication with Lobe B within the reservoir. This has been the case for this updated, continuation study as well. A history match could not be obtained without having Lobe

A and Lobe B in communication. This explanation supports the continued high water cuts and the unsuccessful squeeze jobs.

Well #10-15 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. This may have been caused by the block squeeze breaking down because of decreasing reservoir pressure around the 2,600 day of production. This corresponds to a large increase in the water production rate of well #10-15. It could also be because Lobes A and B are in communication within the well bore.

Also, well #A-4 produced high water rates and it is the furthest well from high water saturation in Lobe A. This well also had a cement squeeze at the Lobe B depth from 12,013 feet to 12,022 feet. It is possible that this cement squeeze broke down as well because of diminishing pressure, but it is also possible that Lobes A and B are in communication within the reservoir.

The updated history match supports the theory that Lobe A and Lobe B are in communication within the reservoir. To summarize:

- Evidence still indicates that layers A and B of the U-8 Sand are in communication.
- The relative permeabilities were modified, based on new and updated information, to enable a history match to be obtained.
- Based on the predictive designs for water injection (1,700 STB/D), the best possible production scenario is in area A and the best possible injection area is in area H.
- Any major increase in the water injection rate above 1700 BWPD does not greatly improve the recovery and therefore is not economically justified.
- The horizontal well injection scheme for area H recovered 3.2 times more oil than a background continuing production scheme. However, the vertical well injection scheme for Area H recovered 3.15 times more oil. Therefore, a horizontal injector is not economically justified.

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WEST DELTA BLOCK 84 OFFSHORE, PLAQUEMINES PARISH, LOUISIANA KE-KF-1 RESERVOIR CHARACTERIZATION

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Introduction

This report presents the information gained from a characterization of a representative reservoir where an advanced waterflood project has been performed. The reservoir, KEKF-1, is located in West Delta Block 84 Field. West Delta Block 84 Field is located off the coast of Plaquemines Parish, Louisiana, near the mouth of the Mississippi River as shown in Figure 1. The field was discovered by Conoco in 1955. It was operated by Conoco until September, 1988 when S. Parish Oil Co. bought out Conoco's interest and took over operations. S. Parish Oil Co. resumed operations in the field for approximately one year when the lease was allowed to lapse. The field is presently being operated by West Delta Oil Co., which is in the process of re-working several wells to re-establish production. To date, however, the field is still shut-in. It is estimated that the total field originally contained 23.6 MMSTB of oil and 57.9 BCF of gas, from known productive sands. The field has produced 9.8 MMSTB of oil and 21 BCF of natural gas.

This report will attempt to describe and characterize the KEKF-1 reservoir, which underwent a waterflood project during the 1970's, in order to define potential proven remaining oil and gas reserves which may be recovered with minimal work and expense. It is a very good example of a reservoir which has undergone an expensive poorly designed waterflood which resulted in the loss of a large quantity of recoverable oil.

Available Data

The majority of the data was obtained from the Louisiana Department of Natural Resources (DNR) and the current and past operators. Data which was retrieved and included within this report are as follows;

- Production data - reported on a unit basis (several wells and reservoirs may be included in one report). Information includes oil and gas production for the unit.
- Individual well tests - taken approximately every quarter. Information includes daily production rates, gravities, flowing tubing pressures and sometimes shut-in tubing pressures and bottom hole pressures.
- Well histories - Information includes perforated intervals, directional surveys, casing programs, initial tests and other miscellaneous information.
- Electric well logs (primarily 1" scale)
- Various reports filed in regards to the KF-1 reservoir waterflood - Information included various information and maps on the KF-1 reservoir characteristics. Reports refer to the KF-1 reservoir, however, communication is believed to exist between the KF and KE sands at this particular locale and was treated as such. All future reference will be made to the KE-KF-1 reservoir.

Figure 1

For ease in discussion, the aforementioned data will be taken as accurate except as noted. Production information was manipulated in order to obtain an idea of the performance of individual reservoirs and wells. As much as a 40% error between the actual well production and the estimated well production from manipulation is possible when performing these manipulations. However, there was a fair amount of control and accurate test data for this case and so the error is believed to be at least within +/- 15%. In any case, these values should be viewed with caution and used in more of a qualitative manner rather than quantitative.

General Field Overview

The field contains four productive sands, which produce from 8 individual reservoirs containing a total 30 completions. Two of the sands in the area of the subject reservoir, the KE and KF, have been grouped together because they are considered to be in communication. There also exists numerous sands above and below these four known producing sands which have never been fully evaluated, leaving a large amount of upside potential to this acreage. The four sands from shallowest to deepest (7700' to 11900') and their separate reservoirs are as follows:

- GR sand - GR reservoir - 5 completions
- KE-KF sand - KE-KF-1 reservoir - 12 completions
KE-2 reservoir - 1 completion
KE-KF-5 reservoir - 2 completions
KE-6 reservoir - 6 completions
KE-8 reservoir - 1 completion (was included in KE-KF-1 production totals)
- KE-9 reservoir - 2 completions
- 11617 sand - 11617 reservoir - 2 completions

The reservoirs are trapped by structure, faulting and stratigraphic mechanisms. Drive mechanisms within all reservoirs consist of solution and gas cap expansion and some natural water drive. The reservoir which this report concentrates on, the KEKF-1, was waterflooded. It is not believed that the waterflooding was totally successful however, due to its design and length of flood. Data taken obtained for the KEKF-1 reservoir, are as follows:

- porosity is 30%,
- avg permeability is 600 md. (with a range of 1700 md to 10 md),
- avg initial water saturation 24.4%,
- avg API gravity is 36.1
- avg viscosity of the oil is 1.596 at 206 degrees F (average reservoir temperature),
- avg bubble point pressure is 5950 psi,
- avg initial solution GOR at bubble point is 1200 SCF/STB

Reservoir Description

The KEKF-1 reservoir is limited on its north by a east-west trending normal fault, which dips to the south. It is bound on its east by a shale out. It is bound on its south by a partial sealing fault and a shale out. It is bound on its west by an original oil-water contact of 11,136 feet below sea level. It dips at approximately 6 degrees to the west and strikes north-south. The net effective sand thickness averages approximately 30 feet with a high of 66 feet penetrated in the #A3 well. A structural-stratigraphic map of the KEKF-1 reservoir is depicted in Figure 2 and a type log, the #A-3 well, is shown in Figure 3.

Volumetrics and original Oil and Gas in Place - KEKF-1 Reservoir

Oil-water and gas-oil contacts were estimations based on all available data. There was not sufficient core and other data for exact placement of these depths in all cases. The contacts for the KEKF-1, KE-2 and KE-5 reservoirs were all taken from an old operator map obtained from DNR records. All other contacts are estimates only based on the performance of individual wells. Both the operator map and maps constructed from data are found at the end of this report. Acre-feet of bulk reservoir volume was obtained by planimeter and use of *Simpson's rule* as follows:

$$Vb = 10/3 * (Ao + 4(A1) + 2(A2) + 4(A3) + \dots + 4(An-1) + An) + Havgcap(An)$$

where Vb is in acre-feet

Original oil in place was calculated by

$$N = (Vbo * 7758 * Porosity * (1 - Sw)) / Boi$$

where N is in Stock tank barrels (STB) at standard conditions 14.7 psi and 60 degrees F

Original gas in place was calculated by

$$G = Vbg * 1539.846 * Pri / (z * Tf) + (N * Rsi)$$

where G is in MCF of gas at standard conditions
*Vbg * 1539.846 * Pri / (z * Tf) is free gas (gas cap) volume and*
*N * Rsi is solution gas volume*

Original oil in place is as follows:

KEKF-1 reservoir - 9.6 MMSTB or 1005 STB/ac-ft

Original gas in place is as follows:

KEKF-1 reservoir - 23.6 BCF (assuming an original gas-cap)

Figure 2

Louisiana
State
University

Department of
Petroleum Engineering

KEKF-1 Reservoir Structure-Stratigraphic Map
West Delta Block 84 Field, Louisiana

Geology by: W. Clay Kimbrell

August 12, 1996

Well Completions and Production

The KE-KF-1 reservoir has produced from the following wells:

- SL 2551 #1 serial # 55866
- SL 2551 #A1 serial # 112378
- SL 2551 #A3 serial # 117925
- SL 2551 #4 serial # 62347
- SL 2551 #12 serial #86079
- SL 2551 #15 serial #108695
- SL 2551 #A1D serial #117237
- SL 2551 #A4 serial #118328
- SL 2551 #A5 serial #118869
- SL 2551 #A11 serial #121874
- SL 2551 #A13 serial #122936
- SL 2551 #18 serial #167657
- SL 2551 #A8D serial #120630 (believed to be in separate reservoir)

Perforations and completion dates are shown in Table 1. Last tests for each of these wells are shown in Table 2. Corrected historical production for the overall reservoir is illustrated in graph form in Figure 4.

Estimated total production from this reservoir is 4.6 MMSTB of oil and 9.7 BCF of gas. This is 48% recovery of the in-place oil and 41% of the in-place gas. An efficient waterflood should recover at least 60% of the in-place oil and in some cases higher. This leaves 12% of the oil in place which should still be recoverable. In addition, because there is a known gas cap as well as dissolved gas associated with this reservoir, gas recovery should be near 60% also. Therefore, remaining *proved developed* reserves are estimated to be 1.2 MMSTB of oil and 4.5 BCF of gas from this reservoir.

Conclusions

The waterflood was targeting the KF-1 sand, not the KE-1 sand. It is believed that the operator at the time of the waterflood believed these two sands not to be in communication. Because of this, it is believed that the waterflood was inefficient and poorly designed. If the possibility of communication between the KE and KF sands had been considered, the waterflood may have been more efficient. The oil cut% vs cumulative oil production graphs for the #18 and #15 wells illustrated in Figures 5 and 6. There is no real evidence of water response in these wells. This would support the theory that no water from the downdip injection had reached these wells, much less swept the area around them.

Please refer to Table 2 once again. The last test on the #15 well on 6/87 was 98 BOPD, 806 SCF/STB, 225 psi FTP and 60% BS&W. After that, there is no additional production from this well and no explanation as to why. The last test on the #18 well on 2/90 is 350 BOPD, 110 psi FTP, and 40% BS&W. The last test on the well when Conoco operated was 319 BOPD. That's a total of 417 BOPD from these two wells alone. Assuming success from other additional

TABLE

WEST DELTA BLOCK 84
LL LIST - KE-KF-1

WELL	SERIAL #	INITIAL COMPLETION DATE	SAND	PERFS
2551 #1	55866	6/55	KE-KF-1	10857-864
2551 #15	108695	5/65	KE-KF-1	10960-986
2551 #A1	112378	10/65	KE-KF-1	11173-178
2551 #A1C	117237	10/66	KE-KF-1	11123-133
2551 #A3	117925	1/67	KE-KF-1	11264-269, 11227-32
2551 #A4	118328	2/67	KE-KF-1	11360-374
2551 #A5	118869	3/67	KE-KF-1	11147-156
2551 #A8C	120630	7/67	KE-KF-1	11324-30
2551 #A11	121874	11/67	KE-KF-1	11182-273
2551 #A13	122936	2/68	KE-KF-1	11422-61
2551 #18	167657	7/69	KE-KF-1	10941-964
2551 #4	62347	12/56	KE-KF-1	10913-25

TABLE 2

WEST DELTA BLOCK 84
 EAST WELL TEST - KE-KF-1

WELL	SERIAL #	STATUS	DATE	SAND	PERFS	TEST DATA							REASON OFF	
						BOPD	CHOKE	BS&W%	GOR	FTP	CP	API	PM	
L2551 #1	55866	P&A	9/64	KE-KF-1	10857-86	166	10	3	4175	1950	PKR	38.8	F	SANDED UP
L2551 #15	108695	SI	6/87	KE-KF-1	10960-98	98	128	60	806	225		34.6	GL	?
L2551 #A1	112378	SI	5/70	KE-KF-1	11173-17	231	15	12	182	600	PKR	35	F	ATTEMPTED TO PERF. UPPER LOBE IN 1973; UNSUCCESSFUL?; POSSIBLE REPERF?
L2551 #A1D	117237	SI	11/66	KE-KF-1	11123-13	53	11	6	838	315	PKR	37.3	F	LEFT KE PERFS OPEN(FELT TO BE UNPRODUCTIVE)
L2551 #A3	117925	SI	6/81	KE-KF-1	11264-26	2	64	99	4105	0		35.1	GL	?; SANDED UP OR WATER CONE?
			4/81	KE-KF-1	11264-26	2	64	93	950	0		35.1	GL	
			2/81	KE-KF-1	11264-26	64	64	80	950	250		35.1	GL	
			?	KE-KF-1	11227-32									
L2551 #A4	118328	SI	2/90	KE-KF-1	11360-37	45	OPEN	50	0	110		34.1	GL	VOORHIES STATES WELL DOWN FOR LONG TIME; TEST INCORRECT
L2551 #A5	118869	SI	3/67	KE-KF-1	11147-15	102	10	0	592	450		36	F	NEVER PRODUCED; CONVERTED TO WATER SOURCE
L2551 #A8D	120630	SI	9/69 12/71	KE-KF-1 KE-KF-1	11357-63 11324-30	74	7	46	552	850		33.1		?; REPERFED UPPER 12/71 SHUT-IN; LOOKS GOOD ON LOG, BUT NO TEST DATA; NO PROD. DOWNDIP IN KT, LOW PROD.?
L2551 #A11	121874	SI	12/82	KE-KF-1	11182-27	30	64	90	1450	250		30.1		
L2551 #A13	122936	SI		KE-KF-1	11422-61									WATER INJ. WELL
L2551 #18	167657	SI	2/90	KE-KF-1	10941-96	350	54	65	0	110		32	GL	STILL ACTIVE; PARISH REPORT, BOGUS?
			10/88	KE-KF-1	10941-96	271	442	40	62	300		35.5	GL	COMPARISON CONOCO REPORT
L2551 #4	62347	SI	3/79	KE-KF-1	10913-25	40	12	6	10400	1250		52.7		HIGH GOR?

Figure 4

WEST DELTA BLOCK 84
KE-KF-1 RESERVOIR CORRECTED PRODUCTION

WEST DELTA BLOCK 84 WOR VS. CUM OIL - SL#18 SN 167657

workovers on the #A-3, #4, #A4 and #12 a conservative daily production rate of over 600 BOPD and 1.3 MMCFD of gas could be realized. At a 20% decline and a 15 year life, an additional 1.2 MMSTB of oil and 4.5 BCF of gas of *proved developed reserves* could be recovered from this reservoir.

References

Craft B.C. and Hawkins M.F., Applied Petroleum Reservoir Engineering, Prentice-Hall, Inc., Englewood Cliffs, New Jersey, 1959.