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ASSIST IN THE RECOVERY OF BYPASSED OIL FROM RESERVOIRS IN THE GULF OF MEXICO

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Abstract

The objective of this research is to assist the recovery of non-contacted oil from known reservoirs on the Outer Continental Shelf in the Gulf of Mexico. Thus far, research has consisted of data collection from Minerals Management Service (MMS), literature and operators; detailed studies of several screened reservoirs; modification of three public domain simulators; development of a predictive model; and design and construction of several laboratory experiments for studying attic oil recovery.

The methodology for data collection from MMS, literature and operators is keyed on 208 sands containing 1,289 reservoirs, representing 60% of the original oil in place (OOIP) in the Gulf of Mexico. This data collection has been completed after several delays concerning confidentiality agreements between MMS, DOE, and LSU and its subcontractors.

Secondary recovery by downdip gas injection in steeply dipping oil reservoirs has been widely used successfully since the 1950's. Methane and nitrogen have been the primary gases used. Reservoirs which had been subjected to this type of recovery or had the potential to be subjected to this type of recovery were screened for detailed studies. Three reservoirs were identified which possessed the proper criteria and which had data available for detailed studies, the B-35-K and B-65-G reservoirs of South Marsh Island Block 73 Field and Reservoir 3 of Field 2, which was blind-coded by operator request.

Detailed data sets for simulating these reservoirs were created. This included the review and analysis of the geology of the reservoirs to define reasonable grid configurations for use in the simulator and review of well histories, including production, gas injection, and pressure data.

History matching and prediction runs have been completed on the B-35-K reservoir, history matching has been completed on the B-65-G reservoir and history matching is almost completed on Reservoir 3. Prediction runs on the B-35-K reservoir indicated an economical amount of oil to be recovered by additional injection of gas. The most efficient gas cycles, injection amounts and injection rates were also identified by the prediction runs.

Modifications on three public domain computer reservoir simulators, BOAST II mainframe, BOAST II PC and MASTER, were underway. Modifications consisted of developing a code to handle steeply dipping oil reservoirs and a radial grid format for near wellbore studies. Modifications for steeply dipping reservoirs have been successfully implemented and tested against commercial simulators in the PC version of BOAST II, renamed BOAST III. At present, modifications to BOAST II for radial grid systems are producing acceptable results in a 2-D model. A paper was presented at the 1994 ACM Symposium on Applied Computing in Phoenix, Arizona, March 6-8, 1994 on these results. Modifications have also been succesfully implemented in the MASTER simulator. It is presently undergoing industry testing for validity.

Laboratory investigations continued but were slowed by several unforeseen incidences involving broken apparatus and inability to recieve parts due to the California earthquake.

Executive Summary

The objective of this research is to assist in the recovery of non-contacted oil from known reservoirs on the Outer Continental Shelf in the Gulf of Mexico. Mature offshore reservoirs, declining oil reserves, declining production, and other natural forces currently are accelerating the abandonment of offshore oil resources and production platforms. As these offshore wells are plugged and the platforms are abandoned, an enormous volume of remaining oil is permanently abandoned. Significant quantities of this oil could be recovered using advanced technologies now available if the resource can be identified.

The methodology for data collection from Minerals Management Service (MMS), literature and operators is keyed on 208 sands containing 1,289 reservoirs. These sands contain 60% of the original oil in place (OOIP) in the Gulf of Mexico. This data collection has been completed after several delays concerning confidentiality agreements between MMS, DOE, and LSU and its subcontractors.

From these sources, a list of high-priority fields/reservoirs were compiled, and additional information were perused on these fields/reservoirs for detailed studies. Operators of these fields/reservoirs were contacted to determine their interest in providing data or other assistance.

Secondary recovery by downdip gas injection in steeply dipping oil reservoirs has been widely used successfully since the 1950's. Methane and nitrogen have been the primary gases used. Reservoirs which had been subjected to this type of recovery or had the potential to be subjected to this type of recovery were screened for detailed studies.

Taylor Energy Company provided data on South Marsh Island 73 Field. From further review of this field, two reservoirs were selected for detailed studies, the B-35 Sand Reservoir K and the B-65 sand Reservoir G. The production and pressure history for both of these reservoirs was matched. Several simulations were then run to refine the history match of the reservoir performance and to predict the incremental oil production which could result from future gas injection into the reservoirs. Prediction runs on the B-35-K reservoir indicated

an economical amount of oil to be recovered by additional injection of gas. The most efficient gas cycles, injection amounts and injection rates were also identified by the prediction runs.

ARCO, Amoco, Texaco and Chevron all responded and were very helpful. However, upon reviewing their reservoirs which had been screened, it was determined that they did not fit the anticipated criteria and further studies were not warranted.

During the second quarter, Mobil Exploration and Producing U.S., Inc. (Mobil) provided data on Field 2, which LSU and subcontractors agreed to blind code. Amoco, a partner with Mobil in the same field, also contributed data on this same field. From this data, a third reservoir was chosen for detailed studies, Reservoir 3.

Modifications on two public domain computer reservoir simulators, BOAST II and MASTER, continued. Modifications to develop a code to handle steeply dipping oil reservoirs in the PC version of BOAST II were completed. The new PC version was renamed BOAST III. Modifications to BOAST III also include post-processing programs. BDM began the process of verifying both the BOAST III and MASTER (which had been previously modified in the year prior) models through comparison of model output to published model results for an attic gas injection process in a steeply dipping reservoir.

Modifications for a radial grid for use on near wellbore studies continued with good results in 2-D. Attempts to reproduce the results of small-scale 2-D experiments produced in the Department of Petroleum Engineering were successful. A paper was presented at the 1994 ACM Symposium on Applied Computing in Phoenix, Arizona, March 6-8, 1994 on these results.

Laboratory investigations continued but were slowed by several unforeseen incidences involving broken apparatus and inability to recieve parts due to the California earthquake.

Introduction

The objective of this research is to assist in the recovery of non-contacted oil from known reservoirs on the Outer Continental Shelf in the Gulf of Mexico. Mature offshore reservoirs, declining oil reserves, declining production, and other natural forces are currently accelerating the abandonment of offshore oil resources and production platforms. As these offshore wells are plugged and the platforms are abandoned, an enormous volume of remaining oil is permanently abandoned. Significant quantities of this oil could be recovered using advanced technologies now available if the resource can be identified.

Much of the remaining oil offshore is trapped in formations that are extremely complex due to intrusions of salt domes. Conventional seismic processing techniques cannot clearly image these traps or the full extent of oil-bearing segments near the salt domes; therefore, substantial volumes of oil may have remained un-contacted by previous drilling. Recently, however, significant innovations have been made in seismic processing and mathematical migration of seismic signal. In addition, significant advances have been made in deviated and horizontal drilling technologies and applications. These technological advances make it possible to reprocess existing seismic data to identify non-contacted portions of the reservoirs, which can then be contacted using advanced technologies such as drilling to kick out new wells from existing wells. Effective application of these technologies, along with improved recovery methods, offers opportunities to increase significantly Gulf of Mexico production, delay platform abandonments, and preserve access to a substantial remaining oil target for enhanced recovery and other advanced recovery processes.

This project will proceed under three broad phases: analysis, supporting research, and technology transfer.

In the analysis phase, TORIS-level data will be collected on the major fields located in the piercement salt dome province of the Gulf of Mexico Outer Continental Shelf. Representative reservoirs will be studied in detail in order to evaluate undeveloped and attic oil reserve potential. These detailed investigations will be used to calibrate the TORIS level predictive models. The recovery potential of advanced secondary and enhanced oil recovery processes and the exploitation of undeveloped and attic oil zones for salt dome reservoirs in the Gulf of Mexico will be assessed.

Supporting research will focus on the modification of public domain reservoir simulation models to accurately simulate the conditions encountered in the piercement salt dome province of the Gulf of Mexico. Laboratory research will focus on the development of fluid relationships that will be used in the simulation of miscible and immiscible processes in the project area.

During the final phase of the project a significant effort is planned to transfer the results of this project to potential users of the technology. Technology transfer activities will also provide feedback channels that will help keep the analysis and supporting research focused on the most important problems associated with this project.

Project Description and Objectives

The objective of the project is to estimate the potential reserve additions that could result from the application of advanced secondary and enhanced oil recovery technologies and the exploitation of undeveloped and attic oil zones in Gulf of Mexico oil fields that are related to piercement salt domes. A task list follows.

1. Develop a detailed work plan. This plan will include detailed task assignments, scheduled outlines of data collection and field assessment methodologies, and integration of the laboratory work into reservoir simulation as well as TORIS model development efforts. This task will include the selection and orientation of a peer review committee and planning for the integration of the data collection efforts with the work being performed by the Texas Bureau of Economic Geology to develop a Gulf of Mexico oil and gas atlas.

2. Collect TORIS-level data. TORIS level reservoir data will be collected on the major oil fields in the piercement salt dome province offshore of Louisiana. This

data will be generated or extracted from data available through the Department of Interior Minerals Management Service, Louisiana Geological Survey, published operator case studies, and other available sources. It will be necessary to negotiate an interagency agreement to protect the confidentiality of the MMS data.

3. Modify public reservoir models. Readily available public reservoir simulation models (BOAST II and/or MASTER) will be modified to simulate accurately the conditions encountered in steeply dipping high permeability reservoirs. The modifications will also involve the development and integration of radial grid systems suitable for the investigations proposed in the project. The existing models will be evaluated, modified, and validated against commercial reservoir models.

4. Perform laboratory research. A program of laboratory research will be undertaken to study and develop fluid relationships that will be utilized in the reservoir simulation of miscible and immiscible processes in steeply dipping reservoirs. The investigations will focus on developing three phase-relative permeability relationships, defining minimum miscibility pressures for various injectants, defining critical velocities of gas front movement in gravity stable miscible displacement processes, and determining the impact of the various injectant gases on miscible and immiscible processes.

5. Develop TORIS predictive models. TORIS-level predictive models for miscible and immiscible processes and for undeveloped and attic oil zones in steeply dipping reservoirs will be developed. These models will be calibrated using the modified reservoir simulation models developed in Task 3 and the results of the laboratory investigations of Task 4. The methodology used in the modeling will be subject to peer review.

6. Characterize representative reservoirs. Selected representative reservoirs

will be studied in detail in order to evaluate undeveloped and attic reserve potential. A detailed geological and reservoir characterization of these reservoirs will be performed using available geological, geophysical, and reservoir data, some of which will be provided by operators.

7. Define production potential. The production potential for undeveloped and attic oil zones in representative fields will be determined using material balance and reservoir simulation studies. The modified reservoir simulation models from Task 3 will be utilized in the reservoir simulation efforts.

8. Integrate and complete regional assessment of production potential. The results of the detailed geological and reservoir engineering studies of Task 6 and 7 will be integrated with the TORIS models developed in Task 5 for calibration purposes. Cost and economic data will also be integrated in the models.

9. Install TORIS models at BPO. The TORIS models developed by this research program will be installed at the Bartlesville project office. Economic parameters developed in Task 8 will be utilized to assess the recovery potential for the application of advanced secondary recovery and enhanced oil recovery processes and the exploitation of undeveloped and attic oil zones for salt dome reservoirs in the Gulf of Mexico. Documentation of the database development task, laboratory and simulation tasks, the detailed field analysis tasks, and the TORIS models will be prepared and presented as a summary report of the project.

10. Conduct technology transfer. This technology will be transferred to the industry through publications and a workshop.

Project Status

Data Collection

During the first quarter and in order to collect data from Minerals Management Service (MMS) in the most efficient and accurate manner, efforts were shifted from keying on the 118 reservoirs which had >2.5 MMBBLS reserves and >60% produced to date (i.e. large, incorrectly mapped reservoirs) to 208 sands in 46 fields which contained 1,289 reservoirs. This represents 60% of the original oil in place (OOIP) for the entire offshore Gulf of Mexico.

ICF Resources, Inc., a subcontractor on the project, concentrated on data pertinent to Bay Marchand 2 Field, first, since this is the largest and most prolific field in the offshore Gulf Coast. Upon completion of the data collection on Bay Marchand 2 field, ICF personnel began collecting data on South Marsh 73 field and other pertinent fields. Taylor Energy Co., the main operator of South Marsh 73 field, agreed to provide a substantial amount of data for the project. Therefore, efforts at MMS were coordinated with the Taylor data collection efforts. MMS will provide, through DOE, the content of FRRE Database for the 1,289 reservoirs. ICF's on-site personnel will compile measurements of fault blocks from maps, data elements from MER and other hard copy files, and key reservoir properties from hard copy files for the purpose of cross-checking the FRRE Database.

LSU collected the Taylor data. LSU also collected data from other operators. ARCO Oil and Gas Co. has provided some excellent data on the South Pass 60 and 61 field areas. Amoco provided an information package for sands in Eugene Island 208 after obtaining approval from their partner, Texaco.

During the second quarter, Mobil Exploration and Producing U.S., Inc. (Mobil) provided data on Field 2, which LSU and subcontractors have agreed to blind code. Amoco, a partner with Mobil in the same field, also contributed data on this same field.

During the third and fourth quarters, ICF completed its data collection from MMS. This data is now being input into the TORIS model. Any remaining data will be collected from several operators on an "as need basis".

Data Validation and Map Measurements

During the fourth quarter, maps collected at the MMS office in New Orleans were planimetered and measured in order to verify and cross-check data in the FRRE database and to obtain reservoir size, shape, dip and relative well position data for use in TORIS process models. Measurements of estimated salt diameter and updip areas are also being derived. Production data was read from the tapes obtained in New Orleans and reformatted for use in TORIS. There were errors in some of the tapes and these are being corrected.

Model Development

Conceptual work is in progress on the development of the models required to assess unrecovered oil, continue primary recovery of existing mapped oil, updip attic oil recovery, and miscible and immiscible CO_2 injection recovery.

Preliminary model designs have been tested against subsets of the data and model refinements are underway. This effort included a literature search on topics related to enhanced oil recovery in offshore Gulf of Mexico reservoirs.

Supporting Cost Data Collection

Efforts to supplement existing TORIS data with drilling, workover and facility costs related to past enhanced oil recovery efforts in the offshore Gulf of Mexico area began. Data on CO_2 sources was collected and byproduct CO_2 costs were estimated for use in the economic model.

Data Analysis

Secondary recovery by downdip gas injection in stepply dipping oil reservoirs has been widely used successfully since the 1950's[illegible]. Methane and nitrogen have been the primary gases used [9, 10]. Reservoirs which had been subjected to this type of recovery or had the potential to be subjected to this type of recovery were screened for detailed studies. Three reservoirs were identified which possessed the proper criteria and which had data available for detailed studies.

SOUTH MARSH ISLAND BLOCK 73 FIELD

LSU and BDM Federal, Inc. (name changed from BDM International, Inc.) (BDM), a subcontractor for the project, began analysis of data obtained from Taylor Energy on the South Marsh Island (SMI) Block 73 Field in the Gulf of Mexico during the first quarter of 1993. The location of SMI 73 Field is offshore Vermilion and Iberia Parishes, Louisiana. The field was originally discovered by Exxon in 1964 with peak production reaching 16,900 barrels of oil per day (BOPD) and 68 million cubic feet of gas per day (MMCFD) in 1971. It is currently producing 1800 BOPD and 4.6 MMCFD. Of the five offshore blocks which the field covers (69, 72, 73, 57, 58), Taylor Energy has purchased three (69, 72 and 73) while Shell retains ownership of the other two. Structurally, the field consists of a piercement salt dome with its associated faults and shale-out trapping

Two reservoirs were identified from this data as having the proper characteristics for detailed studies, the B-35-K and B-65-G reservoirs. Both the SMI 73 B-35 K and the B-65 Sand reservoirs are excellent examples of steeply dipping salt dome related oil reservoirs. Detailed data sets for simulating the B-35 K and B-65 reservoirs were created. This included the review and analysis of the geology of the reservoirs to define reasonable grid configurations for use in the simulator and review of well histories, including production, gas injection, and pressure data. BDM concentrated on the B-35 K reservoir, and LSU concentrated on the B-65 reservoir.

B-35-K Sand Reservoir

Initial efforts were placed primarily on the B-35 K Sand reservoir for several reasons. The data was easily accessible, because Taylor Energy was also reviewing this reservoir for possible gas injection. All other data were still in boxes and unorganized because of the recent purchase of the field by Taylor from Exxon. Also, production from the B-35 K reservoir had exceeded the mapped reserves as a result of poor definition of either the up-dip limit or the original oil/water contact, or both. Recovery to date from the B-35 K reservoir represents 86% of the initially defined original oil in place. Volumetric analysis of this additional potential was performed to define a reservoir volume that resulted in a reasonable percentage recovery. This reservoir also provided an opportunity to simulate attic gas injection, since numerous gas injection cycles were conducted. As mentioned earlier, the operator intends to conduct additional cycles. Therefore, the simulation was utilized to help define the following: optimum injection rate and volume, an anticipated shut-in time necessary for optimum gas migration, and a more accurate estimate of the up-dip oil volumes.

The B-35-K Sand Reservoir is located on the southeastern flanks of the salt dome and has produced from 4 wells. Relative permeability data was modelled initially after Combs and Knezek and Strickland and Morse[11,12,13]. PVT data were taken from several empirical correlations described by Glaso, Beggs, Robinson, Sutton and Farshad[14,15,16,17].

Numerous simulation runs to refine the history match of the B-35-K Sand reservoir performance and to predict the incremental oil production which could result from future gas injection into the reservoir were performed.

The history match of the production performance of the B-35-K Reservoir was refined through the modification of the water-oil relative permeability, the down-dip location of the estimated oil-water contact, and the estimated attic volume of the reservoir. Using the final values for these variables in the model, the primary performance of the reservoir was accurately matched, as was the performance of the reservoir as a result of the five attic gas injection cycles. The gas production, oil production, and pressure data were relatively easy to match. However, to obtain a match of the water production history, it was necessary to include an attic volume of approximately 846 acre-feet (1.3 million BO) and to assume that the oil-water contact was approximately 60 feet below the proven oil limit of the reservoir.

The location of the oil-water contact had a significant impact on the production performance of the simulator. Because the sand thickens in the down-dip direction, the original oil-in-place of the reservoir increases significantly as the oil-water contact is pushed down-dip. Downward movement of the oil-water contact also slows the water production rate because the water level is moved away from the production well take points. By moving the contact in the simulator to a level 60 feet below the proven oil limit, an optimum match of water production performance was achieved.

Because the sand appears to thin in the up-dip direction, the attic volume had less impact on the simulated performance. An attic volume is necessary to obtain the history match, but the exact volume is difficult to define since both the up-dip and down-dip limits are unknown. In other words, there are multiple combinations of oil-water contact and attic volume that will yield a reasonable history match.

Using the final history match assumptions, the volumetric original oil-in-place for the reservoir is calculated at 6.3 million barrels of oil, meaning that 48% recovery has been realized to date.

Using the final history match assumptions, various model sensitivy tests were conducted to examine the results of additional gas injection into the reservoir through the A-6 well. These sensitivites were conducted to evaluate the impact of gas injection rate, post-injection shut-in period, gas injection volume, and gas injection cycle staging.

The first sensitivity was conducted to evaluate the impact of gas injection rate on the incremental oil recovery. The data indicates that lower injection rates improve the performance of the gas injection cycle by accelerating the production response after the shut-in period. In addition, the incremental recovery is higher for the lower injection rates. These effects could be attributed to the efficiency of the process at lower gas injection rates due to reduced gas fingering and a higher segregation rate.

The impact of post injection shut-in time was also evaluated. The cases evaluated used a total injection volume of 150 million cubic feet of gas at 500 mcfd in one stage, and the shut-in period varied between 0 and 6 months. Although the results of the three cases are similar, the 3-month shut-in case has slightly accelerated oil production, and the 6-month shut-in case has slightly higher incremental recovery. Economic analysis of the results will probably indicate that the 3-month shut-in case is economically optimum.

Comparison of the four cases shows that production is slightly accelerated at higher injection volumes and that incremental oil recovery tends to be higher for the larger injection volumes. However, there appears to be a point of diminishing returns, as there is very little difference for cases between 300 and 400 million cubic feet. The optimum gas injection volume is probably in the range of 150 to 300 million cubic feet of gas.

An additional sensitivity was conducted to investigate the results of gas injection cycle staging. The effects of two and three injection stages were compared to the 150 million cubic feet injection volume case where the injection rate was 500 mcfd and the shut-in period after injection was 3 months. The first case assumes that injection occurs in two stages: (1) half of the gas is injected followed by a 3-month shut-in period and 6 months of production; (2) the remaining half of the gas is injected with production initiated after a 3-month shut-in period. The next case assumes that the gas volume is injected in three stages, with similar shut-in and production stages in between.

A 2-stage injection scenario is probably optimum because the production duration between the first and second stages was only 6 months, contributing to the gas segregation phenomena and, thereby, contributing to the oil recovery enhancement with lower associated water production rate than for one stage.
To help improve oil recovery from the reservoir through additional attic gas injection cycles the results of this study offer a set of technically feasible solutions:

1. The injection rate sensitivities indicate that relatively low injection rates accelerate the production response from

additional gas injection cycles due to improved segregation of the gas in the attic. The ultimate incremental recovery is improved only slightly at higher gas injection rates. An injection rate of about 500 mcfd appears to be reasonable for this reservoir.

2. The injection volume sensitivities show that production is slightly accelerated at higher injection volumes and that incremental oil recovery tends to be higher, but there is a point of diminishing returns. The optimum gas injection volume appears to be between 150 and 300 million cubic feet.

3. The post-injection shut-in time sensitivity indicates that a 3-month shut-in time yields an optimum incremental oil recovery.

4. The incremental volume staging sensitivity indicates that higher incremental recovery can be achieved by dividing the total injection cycle into two stages, with a short production stage between the two. This improved recovery is most likely due to better segregation of the injected gas in the attic.

<u>B-65-G Sand Reservoir</u>

The B-65-G Sand reservoir, in South Marsh 73 Field, was chosen to be modelled for calibration studies because of its numerous gas injection cycles from different locales, longetivity of its production and access to data.

Four wells produced from the reservoir; three injected some quantity of gas and one well injected no gas. A fifth downdip well, served as a primary gas injector, with no production from this reservoir.

Material balance studies of this reservoir followed closely the techniques described by Havlena and Odeh[18,19], who described the material balance as an equation of a straight line. The material balance studies support the theory that the reservoir has a small gas cap and a moderate amount of water drive.

The reservoir model was developed by integrating geologic and engineering data. The reservoir is a long, north-south trending, steeply dipping sandstone, which pinches out just before encountering a piercement salt dome. Structure and trapping are all results of the piercement salt dome. The sandstone produces in several reservoirs within the field, including two which are adjacent to the B-65-G reservoir. It was believed that these two adjacent reservoirs are isolated from the B-65-G reservoir by faulting, because of differences observed in the bottomhole pressure histories of producing wells. This was later confirmed by computer simulation. Originally, it was believed that the reservoir was subject to a fairly strong water drive. However, upon performing material balance studies it was found to have a very weak and limited water drive. Also, initially, the computer simulation of this reservoir was performed using a data set which did not contain a gas cap. While attempting to arrive at a history match it was necessary to include a small gas cap. This was in agreement with material balance studies. Also, the updip volume of the reservoir had to be reduced substantially from the initial volume, in order to obtain a history match. Overall, the simulation conferred superbly with the results of the material balance work.

The reservoir consists of approximately 7,000 acre-feet with an average net thickness of 27 feet. Porosity averages 28.5% and the original oil saturation was estimated at 75%. Material balance calculations and simulation work indicates that the reservoir was originally at its bubble point with a small gas cap and contained about 12 MMSTB of oil. It's original reservoir pressure was 3457 psi at -7351 feet subsea. Simulation work assumed that this original reservoir pressure was the bubble point.

The reservoir produced 6.2 MMSTB of oil, 3.4 BCF of gas (this accounts for all gas injected back into reservoir also) and 820 MBBLS of water over a period of 27 years.

The model consisted of 12 rows and 12 columns, oriented northeast-southwest over the reservoir. Grid block lengths averaged 425 feet and grid block widths averaged 224 feet. Grid block dimensions around well bores were about 150 feet by 150 feet.

The sand was subdivided into three flow-unit layers. These flow-unit layers were defined by alternating layers of low and high permeability (alternating sand-shale sequences) as observed on electric logs. Average values for porosity and permeability were assigned to each layer initially. Vertical permeability was taken to be 1/10 of the horizontal permeability. While attempting to obtain a history match, detailed modifications were made to these values. On average, the layers were 22 feet in gross thickness and 10 feet in net thickness.

PVT data and initial relative permeability curves used at the beginning of the simulation were based on values calculated using empirical methods as described earlier. These relative permeability curves were later modified slightly in order to obtain a history match.

It was anticipated that because the reservoir initially had a gas cap in place, the amount of gas injection which took place and the performance of the wells that no additional oil reserves remained to be recovered. Only the remaining gas cap remained to be blowndown. Several predictive runs under varying scenarios are being run at present to confirm this.

Primarily, the study of this reservoir indicates that BOAST III is able to accurately describe the history of a steeply dipping reservoir with a past gas injection project.

Also, through history matching and predictive simulation runs, it has been shown that the gas injection cycles were very successful in moving attic oil down to be produced by the downdip wells in the B-65-G reservoir in South Marsh Island Block 73 Field.

FIELD 2

Reservoir 3, Field 2

Evaluation included well log analysis, pressure and production data analysis, evaluation of PVT data and development of preliminary model grid schemes. Well logs and log analysis were used to define the optimum layering for use in the simulator. Subsequently, net sand isopach maps were prepared for each of these layers. 3-D geophysical data was used to define the structural interpretation for use in the geologic model. Proprietary material balance programs were used to evaluate the production and pressure history of the reservoir. Through an iterative process, the optimum PVT properties were defined for use in the simulator. The material balance programs defined the aquifer size and strength and established the original oil in place vale that was in agreement with the material balance work. A history match of this reservoir is almost completed. LSU and its subcontractors are working closely and simultaneously with Mobil in modelling this reservoir. All groups are presently reviewing results to date.

Predictive Modeling Phase

The determination of the methodology for the predictive modeling phase of the project is about 50% complete. The design of the blueprint began in February 1993, and the computer coding began in March 1993.

Modifications of BOAST II

BOAST III

Modifications to BOAST for modelling steeply dipping reservoirs were successfully implemented into the PC based BOAST II program. The modified PC program, BOAST III, was and is being used to model the Taylor and Mobil reservoirs.

Mainframe BOAST II

Separate modifications to the mainframe BOAST II code consisting of implementation of a radial grid system and inclusion of a gravity term also continued. This will be a 3-D, two-phase model that includes capillary and gravity forces. This model will then be scaled up, added to BOAST II, and compared to some other known field results.

The near wellbore region simulation models must properly represent the near wellbore reservoir properties, the completion interval, and the multiphase flow into the well, especially coning and stratified flow. Modelling this region requires an extremely fine grid in the neighborhood of the well, and this rapidly became a large scale computer problem. An accurate near wellbore regional simulator can be used for better well management. Well management can include setting of well rates or pressures, operating policies, production levels, etc. An accurate simulation can influence the decision to work-over or recomplete a well, to install artificial lifts, and/or to control water and gas production rates.

The need for an accurate and feasible way to model the simulation of flow near the well led to the development of a hybrid approach to reservoir simulation. In this technique, a Cartesian grid is used for the entire reservoir with arbitrary fine meshes in the near wellbore regions that can include one or more blocks of the Cartesian grid.

Multiphase flow near the well can be more accurately modelled with finite element methods coupled with adaptive, dynamic grid refinements in the region of high activity (maximum change). Timed portions of the current finite element program on large-scale problems, have shown that the mesh refinement algorithms require an extremely small amount of time while the solution of the systems of equations consume approximately 90% of the total computation time. To use dynamic grid refinement techniques in three dimensions, it was necessary to construct a unique finite element which, apparently, has not been used before.

The number of elements required for the near well portion of the reservoir using this approach can be very large. However, this approach is intended to improve the treatment of wells by use of this fine mesh in the well region and a normal (large) rectangular grid elsewhere in the reservoir. This will substantially improve the treatment of wells in BOAST II. The rectangular grid that is currently used in BOAST II will remain. The flow equations for the two regions are to be solved with different levels of implicitness; the simultaneous solution (implicit) method is to be applied to the well regions and the explicit saturation (IMPES) technique that is currently used in BOAST II will remain in the reservoir region.

The use of a hybrid grid scheme in reservoir simulation was introduced by Pedrosa and Aziz[illegible]; however, their scheme was also to improve the treatment of wells. LSU's scheme is different because it will use

BOAST,

* Finite element methods in the well region,
* Adaptive grid refinements in the region of high activity, and
* Modern PDE solvers for the well region.

Finite element methods (FEM) are very useful in solving problems in which the unknown function varies sharply in a localized region. FEM meshes are constructed so that smaller elements are placed in regions of high activity while larger elements are placed in regions where there is little activity. An adaptive refinement technique has been developed that automates the process of refining the mesh where it is needed most and, in transient problems, allows mesh refinement to occur in different regions near the well as the solution evolve. The use of FEM with adaptive refinement techniques should permit radial flow results near the well because of the fineness of the grid.

A program for water and oil FEM with adaptive refinement techniques for the well region has been developed, and this program is being tested against experimental results obtained by Lance Hebert in the LSU Department of Petroleum Engineering for coning and sweep efficiency problems[21]. When an agreement exists between the program results and the experimental results, the near well model will be added to BOAST II and real field test simulations will be executed.

Although coning traces were produced similar to those in the Lance Hebert thesis, oscillations are still a problem. Testing on much simpler hypothetical problems produces oscillation-free results, but at the expense of heavy mesh refinement along the oil-water interface. It is believed that extensive mesh refinement in the Hebert problem would also produce oscillation-free results, but more work needs to go into speeding up the calculations and reducing the memory requirements. Distribution of the workload and memory across a cluster of RS6000's has been accomplished, utilizing PVM for interprocess communication. On an 'unloaded' system, the speed-ups have been excellent. However, it is currently limited to four nodes on the cluster at a time, usually sharing the nodes with other users, so it is difficult to achieve any speed-up under these conditions. It is anticipated that the code will be ported to a 128-node Cray T3D later in the spring for testing in an MPP environment. The parallel version of the code is suitable for 1, 2, and 3D problems utilizing static meshes. Currently, the implementation of our dynamic mesh routines on the parallel architectures are being studied, recognizing the fact that efficient load-balancing will become a major issue. Finally, much of the work from the past few years is being written up as a doctoral dissertation, with the intention of publishing parts of it - particularly the parallel implementation. A paper was presented at the 1994 ACM Symposium on Applied Computing in Phoenix, Arizona, March 6-8, 1994 on these results. Testing of this method on areal sweep efficiencies is continuing and should be completed soon.

MASTER Modification

LSU and BDM have modified the MASTER reservoir simulation model for use in simulating miscible gas injection processes in steeply dipping reservoirs. The simulation code has been modified to include the dip feature, and the program has been successfully installed and operated on in-house PCs. BDM began the process of verifying the model by comparing the model output to published model results for an attic gas injection process in a steeply dipping reservoir. The model is also being tested within the industry solving a real problem. Results of this test have not been completed.

Attic Oil Critical Parameters

The apparatus for experiments for the study of attic oil recovery techniques was tested. Problems arose with sand plugging in various ports and are currently being solved. A delay arose with the delivery of a valve from a company in California due to the earthquake.

Planned Activities

Planned activites include completing TORIS database and modelling work, finishing write-ups on detailed reservoir studies, completing laboratory work and implementation of same into TORIS model and completion of all remaining deliverables of the project.

Summary

During March, 1993, ICF continued data collection with Minerals Management Service (MMS). LSU also continued collecting data from several operators and modifying BOAST II for the integration of radial grid systems and the building of the experimental apparatus designed for studying the recovery of attic oil. BDM continued modifying the MASTER reservoir simulation model for use in simulating miscible gas injection processes in steeply dipping reservoirs. In addition, a meeting was held between LSU, BDM and ICF to discuss progress.

During April and May, 1993, ICF continued data collection with MMS. LSU continued collecting data from operators and modifying BOAST II for the integration of radial grid systems and the building of the experimental apparatus designed for studying the recovery of attic oil. LSU and BDM began the analysis of data obtained from Taylor Energy in South Marsh 73 Field. A meeting was also held with representatives from Mobil Exploration and Producing U.S., Inc. (Mobil), BDM, ICF and LSU to discuss obtaining data from Mobil. In addition, Amoco Production Company agreed to provide data to the project.

During June, 1994, the production and pressure history for Taylor Energy's B-35K reservoir in South Marsh Island 73 Field was matched. Several simulations were then run to refine the history match of the reservoir performance and to predict the incremental oil production which could result from future gas injection into the reservoir. Mobil Exploration and Producing U.S., Inc. (Mobil) agreed to provide data one of their fields. Amoco Production Company provided data on their Eugene Island 208 Field.

During July, 1993, data collection from MMS continued and was 90% complete. Mobil provided data on one of their fields, Field 2, which LSU and subcontractors have agreed to blind code. Amoco, a partner with Mobil in the same field, also contributed data. Material balance and computer simulations studies of the B-65-G Sand reservoir, in South Marsh 73 Field, continued. Modifications to BOAST for modelling steeply dipping reservoirs were successfully implemented into the PC based BOAST II program. The modified PC program, BOAST III, was and is being used to model the Taylor reservoirs. Separate modifications to the mainframe BOAST II code also continued. The apparatus for experiments for the study of attic oil recovery techniques was tested. Problems arose with sand plugging in various ports and are currently being solved.

During August, 1993, data collection from MMS continued and was 95% complete. Work continued on Field 2 and South Marsh Island 73 Field. Reservoir 3 of Field 2 was selected from Mobil's data for detailed study.

During September, 1993, data collection from MMS was completed. Data collection from operators was 95% complete. Remaining collection concerns general trend input and statistical data. Data analysis continued on Reservoir 3 in Field 2. Material balance and computer simulations studies of the B-65-G Sand reservoir, in South Marsh 73 Field, continued. A rough history match was obtained on the reservoir. Work continued on refining the match for use in predictive runs. Modifications to BOAST continued with no unforseen problems or delays. An abstract was submitted and accepted by the SPE/DOE EOR Conference to present some of the research findings. The apparatus for experiments for the study of attic oil recovery techniques was being tested. Modifications to MASTER continued with no unforseen problems or delays.

During October, 1993, analysis continued on Reservoir 3 in Field 2. The input dataset continued to be generated. All data was input and initial history match runs were conducted. Material balance and computer simulations studies of the B-65-G Sand reservoir, in South Marsh 73 Field, also continued.

During November, 1993, statistical data concerning successes, failures and observations with 3-D seismic was obtained from several industry companies, including Amoco, Texaco, Chevron and Mobil. Analysis continued on Reservoir 3 in Field 2. Attempts to history match continued. A history match was obtained for the B-65-G Sand reservoir, in South Marsh 73 Field.

During December, 1993 and January, 1994, a reasonably close match of the historical oil, water, gas, and pressure was achieved for Reservoir 3 of Field 2, but additional simulation runs will be conducted. Material balance and computer simulations studies of the B-65-G Sand reservoir, in South Marsh 73 Field, also continued. A copy of a modified copy of the PC version of BOAST II, BOAST III, was being validated against a proprietary industry simulator at this time. Modifications to MASTER have been completed and are currently undergoing testing.

During February, 1994, a draft of documentation of the match results for Reservoir 3 in Field 2 were being circulated to the operator and others for review. Documentation for the simulation of the B-65-G Sand reservoir, in South Marsh 73 Field, also was being prepared. A paper was presented at the 1994 ACM Symposium on Applied Computing in Phoenix, Arizona, March 6-8, 1994 on the results of some of the BOAST modifications. Experiments for the study of attic oil recovery techniques are currently underway. A delay arose with the delivery of a valve from a company in California due to the earthquake.

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Publications

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