INCREASED OIL PRODUCTION AND RESERVES UTILIZING SECONDARY/TERTIARY RECOVERY TECHNIQUES ON SMALL RESERVOIRS IN THE PARADOX BASIN, UTAH

Thomas C. Chidsey, Jr. (nrugs.tchidsey@state.ut.us; 801-537-3364)
Utah Geological Survey
P.O. Box 146100
Salt Lake City, Utah 84114-6100

U.S. Department of Energy
National Petroleum Technology Office, Tulsa, Oklahoma
Class II Oil Program, Contract Number DE-FC22-95BC14988

INTRODUCTION

Over 400 million barrels of oil have been produced from shallow-shelf carbonate reservoirs in the Pennsylvanian (Desmoinesian) Paradox Formation in the Paradox basin of Utah, Colorado, and Arizona. With the exception of the giant Greater Aneth field, 100 plus oil fields in the basin typically contain 2 to 10 million barrels of original-oil-in-place per field. To date, none of these small fields have been the site of secondary/tertiary recovery (carbon dioxide- [CO_2-] miscible flood) techniques used in large carbonate reservoirs. Most of these fields are characterized by extremely high initial production rates followed by a very short production life (primary) and hence early abandonment. At least 200 million barrels of oil are at risk of being left behind in these small fields because of inefficient recovery practices and undrained heterogeneous reservoirs.

The Utah Geological Survey (UGS), the prime contractor, led a multidisciplinary team consisting of the UGS, Harken Southwest Corporation (Harken), and several subcontractors. This research was performed under the Class II Oil Program of the U.S. Department of Energy, National Petroleum Technology Office in Tulsa, Oklahoma.

During Budget Period I, we described the geological and reservoir characteristics of five small algal mound fields in the Paradox basin of southeastern Utah (figure 1), and conducted reservoir modeling and simulation on two of the project fields. The activities for Budget Period II, the field demonstration, will be: (1) implement a pilot CO_2 flood on a selected field, (2) monitor testing and production, (3) evaluate demonstration techniques and economic feasibility, (4) determine which project techniques are suitable for use in similar fields in the Paradox basin and throughout the U.S., and (5) technology transfer.

OBJECTIVE

The primary objective of this multi-year project is to enhance domestic oil production and increase reserves through detailed reservoir characterization and simulation. This objective will be accomplished via case studies of small fields in the Paradox basin of southeastern Utah, conducting a field demonstration

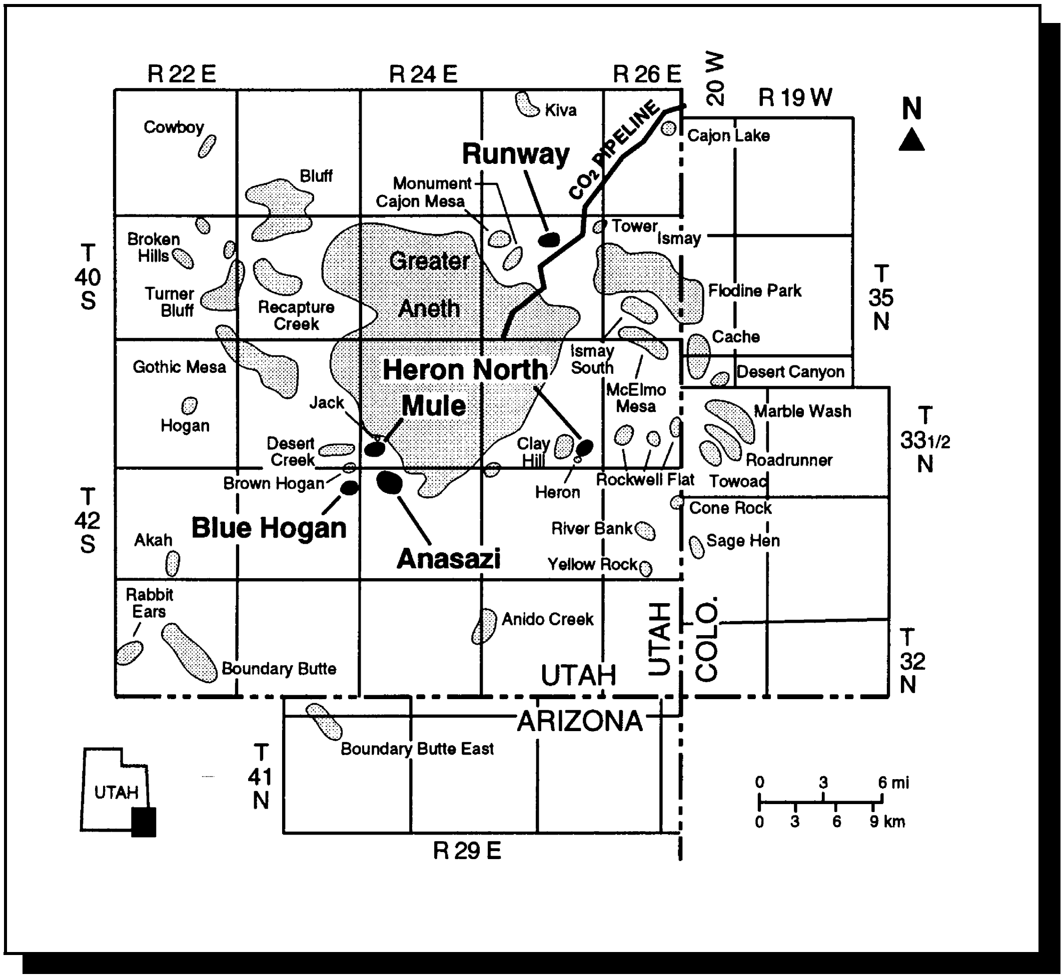

Fig. 1. Location of project fields (dark-shaded areas with names in bold type) in southwestern Paradox basin on the Navajo Nation, San Juan County, Utah.

of secondary/tertiary recovery techniques, and transferring results of developed technologies to industry. If this project demonstrates a technique with economic feasibility, the technique can be applied to about 100 additional small fields in the Paradox basin alone, and result in increased recovery of 150 to 200 million bbl of oil.

The objectives of Phase I were to characterize five, shallow-shelf carbonate reservoirs in the Paradox Formation and choose the best candidate for a pilot demonstration project for either a waterflood or CO_2-flood project. The objectives of Phase II, the field demonstration, are to test the conclusions of Phase I with a pilot CO_2 flood and monitor field performance. These activities will take place within the Navajo Nation.

The final objectives of this project will be to transfer the results and recommendations developed to the petroleum industry and other researchers through a petroleum extension service, creation and distribution of digital databases, technical workshops and seminars, field trips, technical presentations at national and regional professional meetings, and publications in newsletters and various technical or trade journals.

APPROACH AND PROJECT DESCRIPTION

Introduction

The geological and reservoir characteristics of five fields (Anasazi, Blue Hogan, Heron North, Mule, and Runway) within the Navajo Nation, San Juan County, Utah, were quantitatively determined to rank each field's suitability for enhanced recovery projects. These fields represent typical, small, shallow-shelf carbonate reservoirs producing oil and gas from the Desert Creek zone of the Paradox Formation. Our study included: (1) analyzing regional facies and outcrop analogs, (2) drilling development wells (one horizontal), (3) determining reservoir heterogeneity, quality, and lateral continuity or compartmentalization, (4) determining diagenetic fabrics and history, (5) extensive mapping of reservoirs, (6) determining field reserves, (7) laboratory testing and analogies to large- scale waterflood/CO_2 flood, and (8) reservoir modeling and simulation on two of the project fields.

Geological and Reservoir Characterization

Reservoir data, cores and cuttings, geophysical logs, various reservoir maps, and other information from the project fields and regional exploratory wells were collected. Well locations, production reports, completion tests, core analysis, formation tops, and other data were compiled and entered in a database developed by the UGS.

Three generalized facies belts were mapped in the Desert Creek zone of the Paradox Formation utilizing representative core and modern geophysical logs: (1) open-marine, (2) shallow-shelf and shelf-margin, and (3) intra-shelf, salinity-restricted facies (figure 2). Outcrops of the Paradox Formation Ismay zone along the San Juan River of southeastern Utah, provided small-scale analogues of the reservoir heterogeneity, flow barriers and baffles, and lithofacies geometry observed in the fields. These analogues include a phylloid-algal mound, (2) a "reef wall," and (3) a carbonate detrital wedge and fan. These outcrop characteristics were incorporated in the reservoir simulation models.

Geological characterization on a local scale focused on reservoir heterogeneity, quality, and lateral continuity, as well as possible compartmentalization within each of the five project fields. Structure contour maps on the top of the Desert Creek zone of the Paradox Formation and gross Desert Creek interval isopach maps were constructed for the project fields. These maps were combined to show carbonate buildup trends, define limits of field potential, and indicate possible combination structural and stratigraphic traps. Basic reservoir parameters and production histories for each field were also compiled and summarized. The typical vertical sequence, or cycle, of lithofacies from each field, as determined from conventional core, was tied to its corresponding log response. Diagenetic histories of the various Desert Creek reservoirs were determined from petrographic examination of thin sections from representative samples of conventional cores from each field. The petrographic descriptions were used to rank each field's suitability for enhanced recovery projects.

A team of geologists, reservoir engineers, and geophysicists from Harken evaluated potential development locations (for both vertical and horizontal wells) for the project fields. Project development

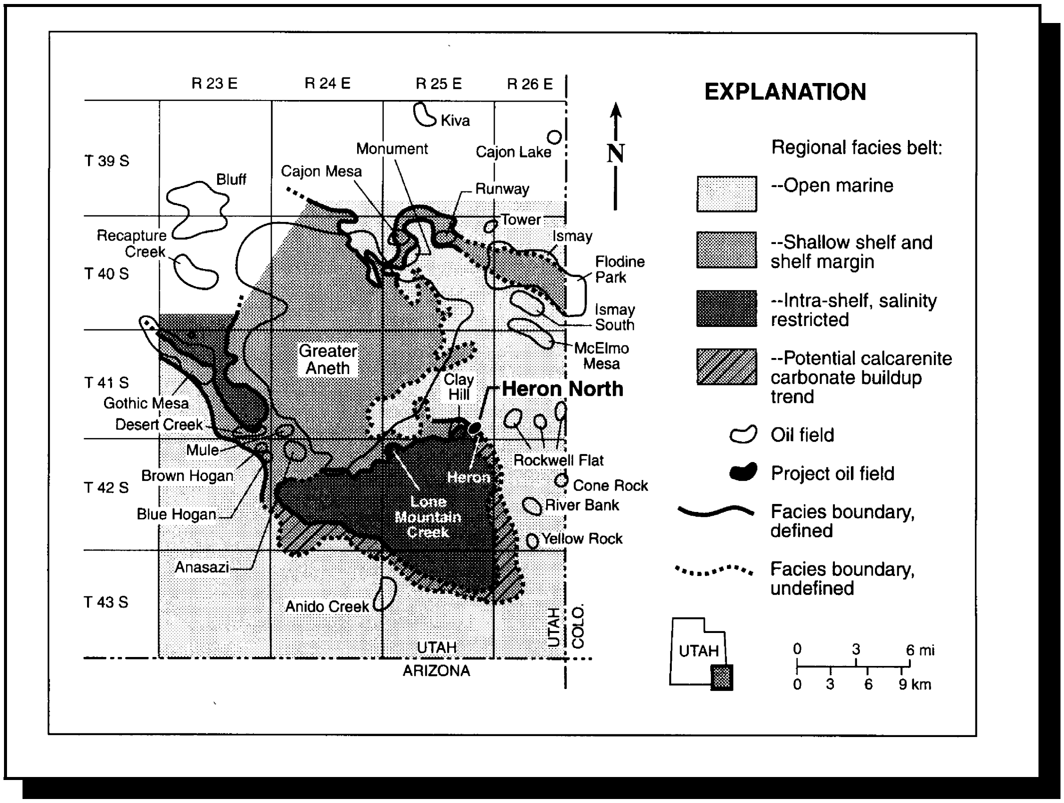

Figure 2. Generalized regional facies belts for the Desert Creek zone, Pennsylvanian Paradox Formation, southeastern San Juan County, Utah.

wells were designed to increase the well density from one well per 80 acres to one well per 30 to 40 acres. Additional seismic data were used to determine the extent of the algal mound in Mule field, and the orientations and lengths of horizontal development drilling. The data obtained from these new wells enabled the project team to assess: (1) the frequency of reservoir compartment changes (reservoir heterogeneity) in a given area, (2) the amount of communication between compartments, (3) how a waterflood or CO_2 flood will flow from one compartment to another, and (4) the areal extent of an average compartment.

Reservoir Modeling and Simulation

Two fields, Anasazi and Runway (figure 1), were selected for detailed geostatistical modeling and reservoir simulation in order to determine which field was the best candidate for a pilot waterflood or CO_2-flood demonstration project. Detailed quantitative reservoir descriptions, coupled with geostatistical modeling and composition simulations, were used to predict field performances under CO_2 flooding and waterflooding recovery processes. The internal architecture of the reservoir between the wells was modeled using a marked-point (Boolean) process for emplacement of constituent lithotypes (figure 3). Emplacement sequences were established and the relative lithotype proportions varied stochastically. The pair-wise, block-exchange process for simulating Desert Creek reservoir porosity between the field wells was carried out using the well-known stochastic relaxation technique known as simulated annealing.

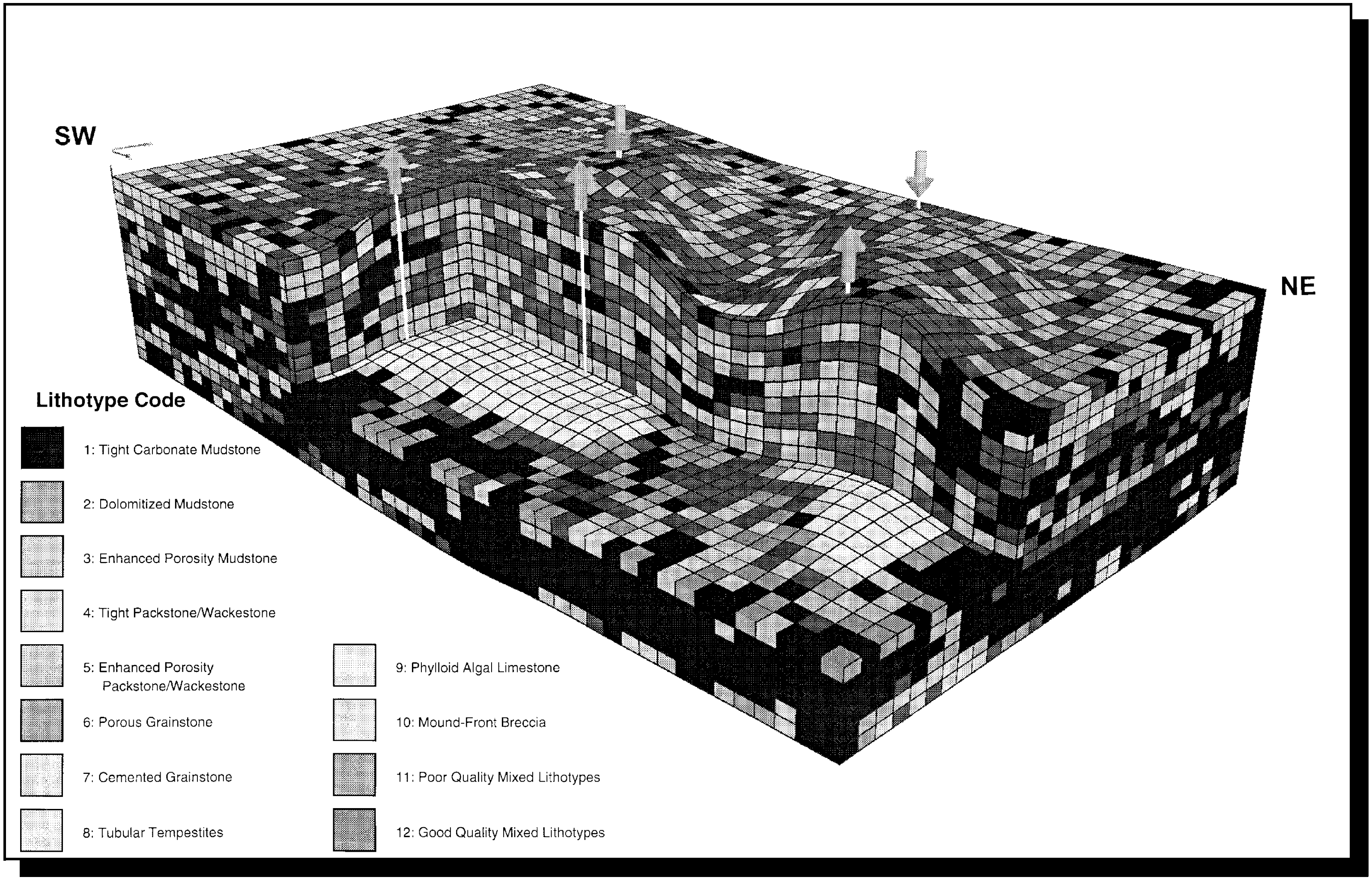

Figure 3. Block diagram displaying distribution of lithotypes in the reservoir simulation model, Anasazi field. Arrows directed up are producing oil wells, arrows directed down are CO_2 injectors. The layers consist of a 30 by 50 block grid (1,500 blocks per layer or a total of 22,500 blocks). The layer at the bottom of the "cut away" is the boundary between mound-core and supra-mound intervals.

Sensitivity studies were conducted which indicated that most of the variation in effective reservoir properties could be retained with careful scaling of porosity and permeability. Lithotypes were assigned to gridblocks in 15 layers. Porosity was volume-averaged for the 15-layer model, and effective permeability was computed by solution of the pressure equation using the field-scale reservoir simulator.

Compositional simulation was used to history match (model) predicted production to actual past production performance of the fields, as well as to predict the performance of continued primary depletion and various CO_2 floods (figure 4). The simulation study employed the stochastically generated reservoir description. The reservoir fluid was characterized via an equation-of-state calibrated using CO_2-swelling tests conducted on crude oil from Anasazi field and the original, black oil, pressure-volume-temperature data for both fields. Gas-oil and water-oil relative permeability, capillary pressure, and rockpore volume compressibility data were generated for the principal productive facies.

PROJECT RESULTS

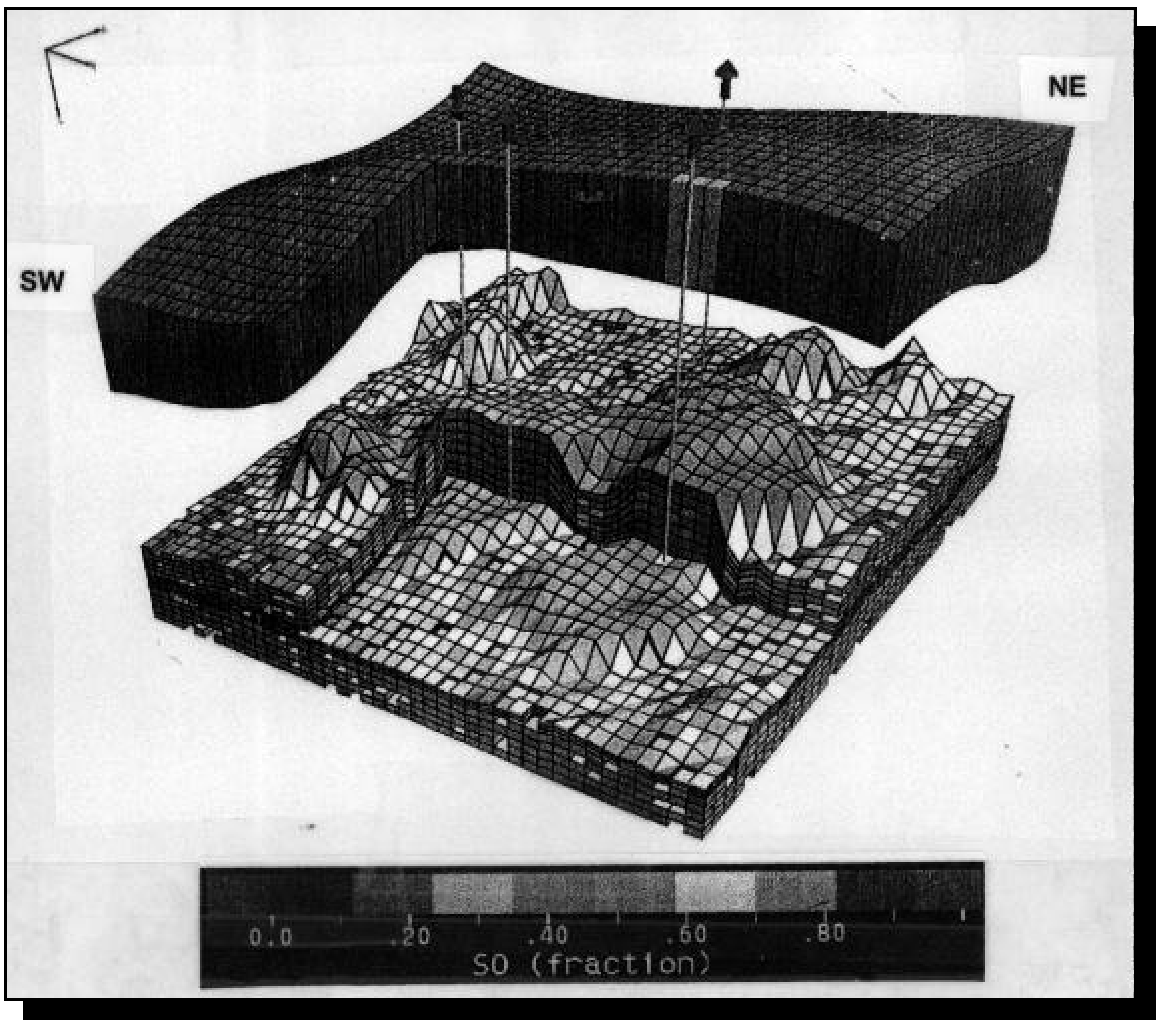

Fig. 4. Block diagram displaying reservoir oil saturation distribution after 4 years of CO_2 injection. Shown is a "cut away" through one of the proposed horizontal injector wells and the Runway Nos. 10G-1 and 10E-2 production well locations. SO (fraction) is the oil saturation.

Geological and Reservoir Characterization

Regional Geological Setting

Facies belts and patterns are critical to the understanding of the heterogeneity and reservoir capacity of each of the five project fields evaluated for the demonstration project. In addition, the analysis of the vertical facies sequence in each field area was important in order to infer lateral relationships and overall depositional geometries of the reservoir facies, and the intervals that would tend to compartmentalize production. All five project fields, as well as the other Desert Creek fields in the region, are located within the shallow-shelf and shelf-margin facies belt (figure 2). This facies belt includes shallow-shelf carbonate buildups, platform-margin calcarenites, and platform-interior carbonate muds and sands. The regional lithofacies map indicated a relatively untested belt of shallow-shelf, calcarenite carbonate deposits (figure 2). This narrow, but long, belt of calcarenite lithofacies is between open marine lithofacies and the margins of intra-shelf, salinity-restricted lithofacies. Heron North field (figures 1 and 2), one of five project fields, is an excellent example of the type of field which potentially lies within this 20-mi-long lithofacies belt. Carbonate buildups located within the open-marine and intra-shelf, salinity-restricted facies belts typically have poor reservoir quality.

Field correlations of wells within the Desert Creek interval were critical to predicting reservoir development and continuity. In addition, sequence stratigraphic analysis of the excellent outcrops along the San Juan River just west of the study area helped to determine the factors which control facies and reservoir development. Outcrop study showed that morphologically, the buildups consist of large, northwest-trending algal banks separated by interbank troughs or channels. Smaller, secondary algal mounds and intermounds define the upper surfaces of the algal banks. By analogy, the presence of certain facies in a well core might serve as a proximity indicator for a more prospective drilling target. Reservoir-quality porosity may develope in troughs, detrital wedges, and fans identified from core and facies mapping. If these deposits are in communication with mound-reservoir facies in the subsurface, they could serve as conduits facilitating the sweep efficiency of secondary/tertiary recovery projects. However, the relatively small sizes and the abundance of intermound troughs over short distances, as observed along the river, suggests caution should be used when correlating these facies between development wells. Facies that appear correlative and connected from one well to another may actually be separated by low-permeability facies which inhibit flow and decrease production potential.

The results of these field investigations were incorporated into the geological constraints on facies distributions in the geostatistical models. Reservoir models for possible water and CO_2 floods of small Paradox basin fields were developed to determine the most effective secondary/tertiary recovery method. The models included lithologic fabrics, flooding surfaces, and inter-mound troughs, based on the mound complex exposed in the San Juan River Canyon.

Field-Scale Geologic Analysis

Field-scale geologic analysis was used to identify reservoir and non-reservoir rock, determine potential units suitable for water- and/or CO_2-flood projects, and compare field to non-field areas. The typical vertical sequence, or cycle, of lithofacies from each field, as determined from conventional core, was graphically tied to its corresponding log response. Structure contour maps on the top of the Desert Creek zone of the Paradox Formation and isopach maps of the gross Desert Creek interval were constructed for the project fields. These maps were combined to show carbonate buildup trends, define limits of field potential, and indicate possible combination structural and stratigraphic traps.

From these analyses, productive carbonate buildups were divided into three types: (1) phylloid algal, (2) coralline algal, and (3) bryozoan. Hydrocarbons are stratigraphically trapped in porous and permeable lithotypes within the mound-core and supra-mound intervals of Desert Creek carbonate buildups. Primary oil recovery is about 40 percent in mound-core intervals but 15 percent or less in the supra-mound intervals. In these traps, determining the nature, location, and extent of reservoir heterogeneity was the key to increasing oil recovery.

Three factors create reservoir heterogeneity within productive mound-core and supra-mound intervals: (1) variations in lithotypes, (2) mound relief and flooding surfaces, and (3) diagenesis. The extent of these factors, and how they are combined, affect the degree to which they create barriers to fluid flow. The mound-core intervals, the most homogenous part of these buildups, are dominated by bafflestones. The overlying supra-mound intervals exhibit the greatest heterogeneity with multiple combinations of lithotypes and various lithofacies thicknesses.

Most shallow-shelf/shelf margin carbonate buildups in the study area had topographic relief which was subaerially exposed when sea level dropped. This produced four major diagenetic environments: (1) a fresh water (meteoric) vadose zone (above the water table, generally at or near sea level), (2) a meteoric phreatic zone (below the water table), (3) a marine phreatic zone, and (4) a mixing zone. Neomorphism, leaching/dissolution, and fresh water cementation took place within the vadose and meteoric phreatic zones. Both the meteoric phreatic zone and marine phreatic zone were dynamic, changing with sea level fluctuations. These phreatic zones were separated by a mixing zone (fresh and sea water) which also changed with sea level fluctuation. Early dolomitization took place in the mixing zone. That portion of the carbonate buildup facing the open-marine environment was generally a steep-wall complex where early-marine cements were deposited from invading sea water pumping through the system. The other side of the mound typically bordered a hypersaline lagoon. The dense brine from the lagoon seeped into the phreatic zone, a process termed seepage reflux, forming both early replacement dolomite and dolomite cement.

Core data, log data, pressure data, production data, PVT data, and oil-water relative permeability data were collected or determined to characterize the reservoirs in three dimensions. Permeability, porosity, heterogeneities, fractures, boundaries, layers, ineffective pay, and reservoir fluid and flow characteristics were cataloged and correlated from well to well across each field. Production histories were also plotted for each field. Primary recovery and original oil in place were determined from volumetric reserve calculations, material balance calculations, and decline curve extrapolations. The information and plots compiled were merged with geological characterization data and incorporated into reservoir statistical models and simulations.

Drilling of Development Wells

Seismic interpretation and mapping indicated that the mound buildup at Anasazi field (figure 1) extended to the west of the previously developed areas. A new well at a more westerly location could also serve as an Anasazi water/CO_2 injection well in the future. A new seismic program was also permitted and conducted in the Mule field (figure 1). The additional seismic data were used to determine the extent of the algal-mound buildup in the field and the orientations and lengths of any horizontal development drilling.

These seismic data were interpreted and incorporated into the overall interpretation of the southwest Aneth region.

During the first project year, one development well was drilled in the Anasazi field, the Anasazi No. 6H-1 well. Evaluation of the core suggests the well missed the main buildup or mound-core interval (algal-bafflestone reservoir) and penetrated poorer quality mound-flank deposits (mixed carbonate fabrics that are brecciated, slumped, and chaotic) instead. However, the dolomites in the upper part of the buildup or supra-mound may be connected to the upper Anasazi reservoirs in the rest of the field. Selected plugs from the reservoir were used to determine oil/water and gas/oil relative permeability measurements; the results were incorporated into the Anasazi reservoir flow simulation model. The Anasazi No. 6H-1 well was completed at a daily rate of 31.3 barrels of oil, 25 thousand cubic feet of gas, and 7.5 barrels of water per day in the Desert Creek and Ismay zones.

The Mule No. 31 K-1 sidetrack, with a horizontal displacement of 939 feet in a northwest direction, was the first horizontal test of a small algal buildup in the Paradox basin. Drill cuttings and the mud log (no geophysical logs were run) indicated the well intersected possible intercrystalline porosity zones in the supra-mound interval of the buildup facies, lagoonal overwash deposits (?), and mound-front facies. The well was completed at a rate of 149 barrels of oil and 223 barrels of water per day, respectively.

Reservoir Modeling and Simulation

The key to increasing ultimate recovery from the Anasazi and Runway fields (and similar fields in the basin), is to design either waterflood or CO_2-miscible flood projects capable of forcing oil from high-storage-capacity but low-recovery supra-mound units into the high-recovery mound-core units. The results of statistical models were used in reservoir simulations to test and design those types of projects. The secondary/tertiary recovery techniques simulated (with appropriate variations) were waterflooding and CO_2-miscible flooding, as well as a combination of the two (water alternating gas [WAG]).

Geostatistical Models

The geometry, lithology, internal architecture and reservoir properties of the Anasazi and Runway mound complexes were developed from a variety of data sources. Data sources included seismic, well logs, core, outcrop data, and well test results. This data and its interpretation were used to construct geostatistically based architectural representations of a number of different reservoir models, or realizations, and the associated properties of the facies contained in the architectural elements (figure 3).

The reservoir production history, and the various stages of depletion, were defined using production data, mechanistic, and full field simulation studies. Fluid property data were used to calibrate equation of states, which were subsequently used to conduct CO_2 process mechanistic studies and compositional simulation studies to define CO_2 miscibility conditions.

A complete review of existing well test data, and new interpretations of this data, were completed. Interpretations provided new insight into fluid flow among the principal rock types, and quantitative data to support reservoir characterization. Utilizing new reservoir property data, the calibrated equation of states and number of different geostatistically based reservoir models, a compositional simulator was used to history match past reservoir production performances. The reservoir properties that required modification to obtain history matches were reviewed, and the final predicted performances compared with historical data.

Using the history-matched simulator, continued primary production depletion was predicted. The simulator was used to predict performances of both CO_2 floods (figure 4) and waterfloods. The influence of the number of injectors, injector location, injector-well configuration (vertical versus horizontal), and production well operating conditions were assessed for both CO_2 floods and water flooding. In addition, the operating pressure required to maintain CO_2-crude oil miscibility and the impact of re-injecting unprocessed (CO_2 and hydrocarbons not separated) produced gas on CO_2 flood performance were assessed. Simulation results indicate that CO_2 flooding is superior to water flooding in terms of total oil recovery. Simulation results provided data to determine the CO_2 gas volume required and overall project injection requirements. Also, the field performance was simulated to compare the scenarios of continued CO_2 injection versus CO_2 injection followed by reservoir blowdown.

Reservoir Mechanistic Studies

Based on the calibrated equation of states, multiple contact phase behavior calculations, and one-dimensional compositional studies, it was concluded that:

1. The Anasazi and Runway crudes can be miscibility displaced by CO_2.

2. The CO_2 - crude mass transfer process can be characterized as a vaporizing gas drive process where the injected CO_2, via a multiple contact process, is enriched in intermediate components vaporized or extracted from the in-place oil.

3. Using oil compositions representative of the original oil and depleted oil in Anasazi, miscible displacement occurs over the pressure range of 2,400 to 3,100 pounds-per-square-inch absolute (psia). A pressure of 3,100 psia was used as a guideline for full field simulation studies assessing CO_2 injection. Using oil compositions representative of the original oil, miscible displacement will require a pressure in excess of 3,000 psia for Runway.

Two-dimensional, mechanistic, reservoir performance studies modeling the primary depletion stages of the Anasazi reservoir provided the following insights into basic reservoir prediction mechanisms for both reservoirs:

1. The initial Anasazi reservoir production behavior can be characterized as liquid expansion processes followed by a solution gas drive. The solution gas drive is accompanied by free-gas segregation into the supra-mound interval and the development of a secondary gas cap. The latter stage of production is characterized by secondary gas cap expansion and gravity drainage of oil from the supra-mound interval into the underlying core-mound interval (the dolomite/limestone unit).

2. The limestone unit (core-mound interval) contributes the major portion of production (>99 percent), but is continually recharged from the overlying supra-mound interval.

3. Vertical permeability is a key parameter that controls reservoir processes. The extent and nature of the supra-mound/core-mound (dolomite/limestone) communication plays a controlling role in reservoir performance.

Anasazi Reservoir Performance Predictions

The history-matched simulator was used to predict the production performance of the Anasazi reservoir under continued primary depletion, assess the potential of CO_2 flooding, and identify operating conditions needed to maximize CO_2 enhanced recovery (figure 5). In addition, the potential of water flooding was assessed. Major results of the predicted reservoir performances are presented below

1. The projected primary production through January 1, 2012 is 2.55 million stock tank barrels (STB). This represents 54 percent of the original oil in place (OOIP) in the mound complex proper and 22.3 percent of the OOIP in the total system.

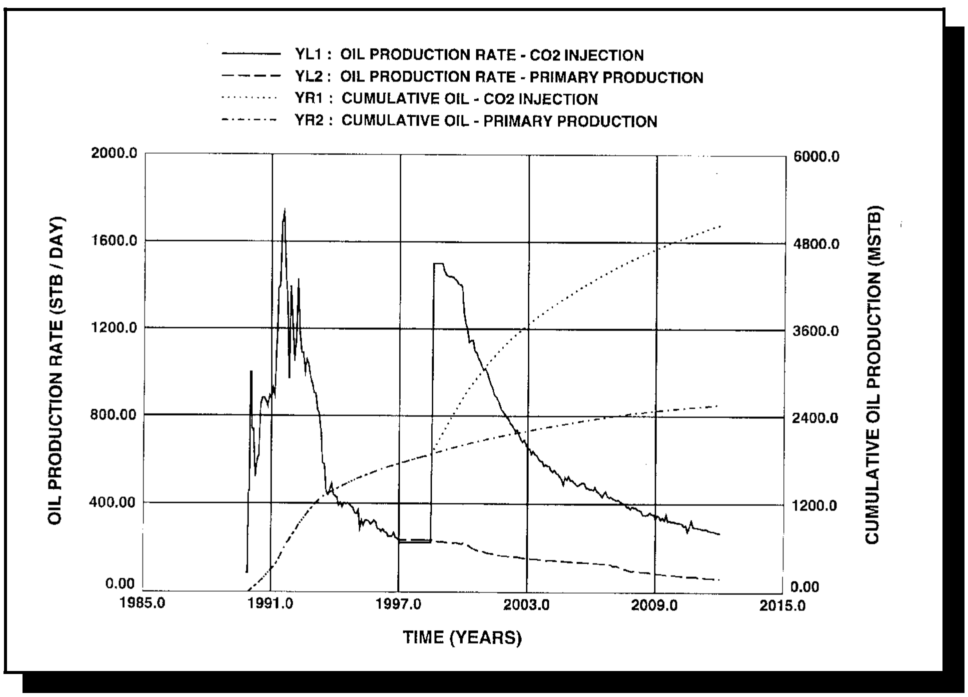

Figure 5. Oil recovery - primary depletion versus continuous CO_2-flood injection/flood recovery, Anasazi field.

2. An optimized CO_2 flood is predicted to recover a total 4.21 million STB. This represents an increase of 1.65 million STB over predicted primary depletion recovery as of January 1, 2012. The projected 4.21 million STB of oil production represents in excess of 89 percent of the OOIP in the mound complex and 36.8 percent of the OOIP of the total system modeled. The incremental recovery of 1.65 million STB requires the injection of the 35.0 billion standard cubic feet (BSCF) of gas and the purchase of 11.5 BSCF of CO_2.

3. Projected maximum CO_2 enhanced oil recovery will require pressurization of the reservoir to over 2,700 psia (core-mound core pressure in excess of 2,500 psia). This is the projected average operating pressure needed to provide miscibility, given past production and compositional changes.

4. Optimum recovery from CO_2 flooding will require one injector for each mound.

5. Vertical injection wells with injection restricted to the supra-mound interval provide the best recovery. Horizontal CO_2 injection wells have poorer recovery associated with early CO_2 break through.

6. Conditioning of produced gas to remove hydrocarbons prior to re-injection is not required to maintain miscible conditions in the reservoir and obtain high oil recovery.

7. The subject reservoir can maintain current production levels during reservoir fill-up without adversely impacting the CO_2 enhanced recovery process.

8. Comparison of continuous CO_2 injection versus CO_2 injection followed by blowdown favors continuous injection, since it is projected to recover 800,000 STB more oil than the case using blowdown.

9. Predicted waterflooding recovery was substantially below the projected CO_2-flood performance. The best waterflooding exhibited an incremental increase in oil recovery over primary production of 618,000 STB of oil versus the 1.65 million STB of additional recovery for the best CO_2 flood.

10. The low mobility of water (relative CO_2) and the corresponding poor injectivity of water injectors would require producers to operate at low bottom hole pressure to enhance water influx and improve water flood response time. Low reservoir pressure would result in three phase flow contributing to lower oil production rates and recovery.

11. Carbon dioxide flooding is favored over water flooding because:

    a. higher oil recovery is possible,

    b. substantially higher oil mobility which improves oil flow (CO_2) exhibited a maximum constrained rate of 1,500 STB/day versus a maximum waterflood rate of less than 400 STB/day,

    c. project life is shorter, and

    d. the possibility of return to primary depletion is possible after injecting CO_2; this is unlikely after injection of water.

Two additional simulation prediction cases (A and B) were run to assess the sensitivity CO_2 performance at Anasazi field to reductions in the CO_2 injection rate and to serve as the basis for the final economic assessment of CO_2 flooding. The principal operating parameters and simulation-related data used for these simulation cases were:

- CO_2 injection starts on January 1, 2000.

- Simulation case A uses an injection rate of 2.0 million standard cubic feet of gas per day (MMSCFGPD)/well and case B uses an injection rate of 4.0 MMSCFGPD/well. Injection was simulated through one well in each of the two mound lobes.

- Production wells Anasazi No. 1, Anasazi No. 5L-3, and Sahgzie No. 1 were allowed to produce at the rate in effect on January 1, 2000 during reservoir fill-up.

- Produced gas was recycled to reduce CO_2 make-up gas purchases. Thus, no conditioning was employed.

- CO_2 injection was continuous from the start of injection until January 1, 2012.

The data show that for case A, the incremental oil recovery above primary was 951,000 STB as of January 1, 2012. This required injection of 17.5 BSCF of CO_2 and produced gas and purchase of 10.1 BSCF of CO_2. Simulation prediction results indicate that a CO_2 injection rate of 2.0 million SCFGPD/well would not be sufficient to meet ongoing production needs of the operator and generate acceptable economic returns. It would however, increase recovery by close to 1.0 million STB of oil over predicted primary recovery as of January 1, 2012.

The data show that for case B, the incremental oil recovery above primary was 1,654,000 STB as of January 1, 2012. This required injection of 35.0 BSCF of CO_2 and produced gas, and purchase of 11.5 BSCF of CO_2. Specifically, using a 4.0 million SCFGP/day/well injection rate from two injectors, the CO_2 flood will recover 4.21 million STB. This represents an increase of 1.65 million STB over predicted primary recovery as of January 1, 2012. The projected 4.21 million STB represents more than 89 percent of the OOIP in the mound complex and 36.8 percent of the OOIP in the total system modeled.

Runway Reservoir Performance Predictions

The history-matched simulator was used to predict the performance of the Runway reservoir under continued primary depletion, and assess the potential of CO_2 flooding (figure 6). Major results of the predicted reservoir performances are presented below.

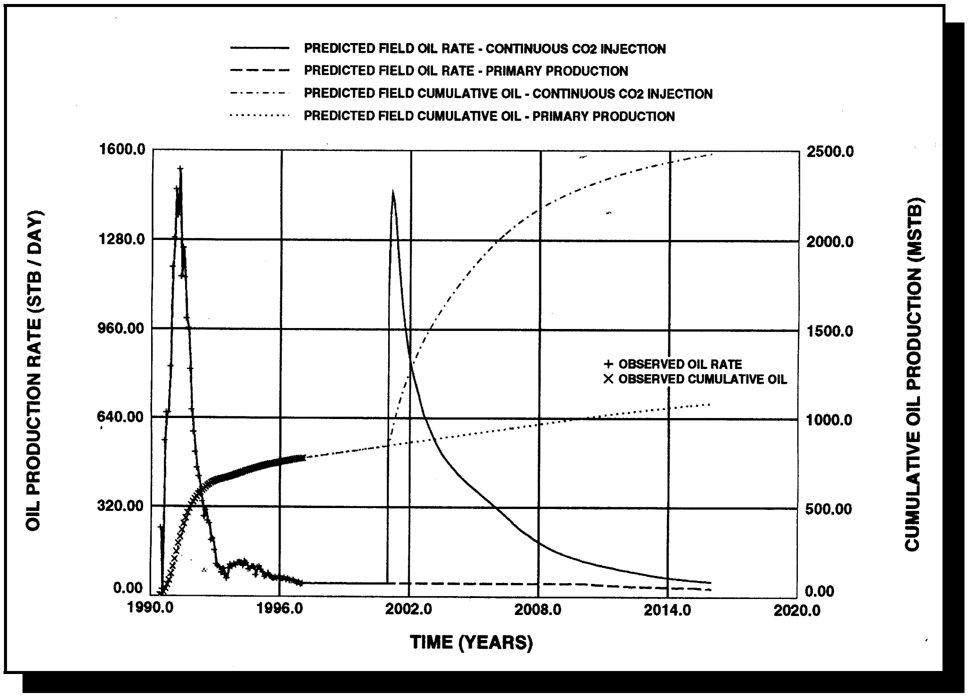

Fig. 6. Oil recovery - primary depletion versus continuous CO_2-flood injection/flood recovery, Runway field.

1. The projected primary production through January 1, 2012 is 1.032 million STB. This represents 31 percent of the OOIP in the mound complex proper and 21 percent of the OOIP in the mound and off-mound areas and the platform interval.

2. Of the limited number of prediction cases completed, the best CO_2 flood is predicted to recover a total 2.4 million STB. This represents an increase of 1.58 million STB over predicted primary depletion recovery as of January 1, 2012. The projected 2.4 million STB of oil production represents 71 percent of the OOIP in the mound complex and 48 percent of the oil in place of the total system modeled, excluding the Ismay. The incremental recovery of 1.58 million STB requires the injection of 51.0 BSCF of gas and the purchase of 8.7 BSCF of CO_2.

3. Projected maximum CO_2 enhanced oil recovery will require pressurization of the reservoir to over 3,000 psia. This is the projected average operating pressure needed to provide miscibility, given past production and compositional changes.

4. Optimum recovery from CO_2 flooding may only require one horizontal injector.

5. The reservoir can maintain current production levels during reservoir fill-up without adversely impacting the CO_2 enhanced recovery process.

6. Additional prediction cases are needed to assess the impact of operating the CO_2 flood at various injection rates. The 8.0 MMSCFPD case resulted in marginal economics despite reasonable overall oil recovery.

Economic Assessments of CO_2 Floods

__Anasazi Field:__ Using reservoir simulation-based performance predictions and current CO_2 flood implementation costs, detailed economic assessments were conducted for a number of different CO_2 flood options. These studies indicated that:

1. A CO_2 flood of the Anasazi reservoir has robust economics. With U.S. Department of Energy (DOE) participation the project would have a rate-of-return (ROR) of 62 percent, a payout of 35 months, a profitability index (PI) of 15 to 1, and a discounted (10 percent) net-present-value (NPV) in excess of $12,500,000. Harken's capital outlay would be $1,728,000. Even without DOE participation the economics remain robust with a ROR of 48 percent, a payout of 39 months, a PI of 8 to 1, and a discounted NPV of over $11,000,000. The capital requirements would be $3,146,000.

2. Leasing the compressor on a five year contract basis is better economically than purchasing the compressor. Leasing improves the ROR by approximately $1.0 million.

3. The benefit from processing produced gas to separate CO_2 from the hydrocarbons and using the hydrocarbons for fuel and sales are offset by the large capital investment required for a membrane separation facility. Thus, re-injection of all produced gas without conditioning is economically more attractive than implementing a CO_2 flood with gas processing.

4. The difference between a minimum and maximum cost option for installation of flow/injection lines and the CO_2 supply is approximately $1,000,000. However, the economics are still robust. With DOE cost sharing, the ROR is 56 percent with a PI of 11.5 to 1.

5. Comparison of the economics of a process using blowdown after six years of CO_2 injection versus the continuous CO_2 injection case indicates that the ROR and the PI are not significantly different, but the NPV is substantially decreased (approximately $1.4 million). The lower NPV is a result of lower oil recovery for the blowdown case (800,000 STB less than the continuous injection case).

Production data and injection gas requirements, including CO_2 make-up purchases, from case B information were used to assess, from an economic standpoint, the financial merits of CO_2 flood with a 8.0 MMCFGPD total injection rate commencing January 1, 2000. The economic assessment was conducted assuming the following conditions: (1) leased compressor (option 1 - $19,500/option 2 - $23,500 [same compressor with a different engine]), (2) CO_2 supply line construction using the minimum costs option ($825,000), (3) no gas processing, and (4) cost sharing by the DOE. This assessment concludes that CO_2 flooding provides both an adequate flood response and an acceptable economic ROR of 32 percent and

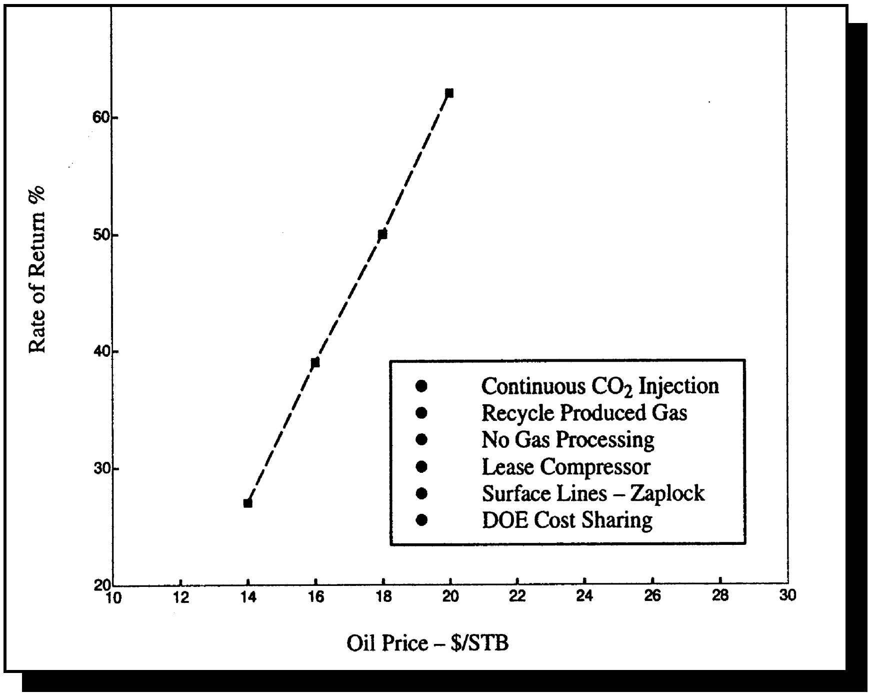

Figure 7. Rate of return versus price of oil, Anasazi field Co_2 flood at high rate.

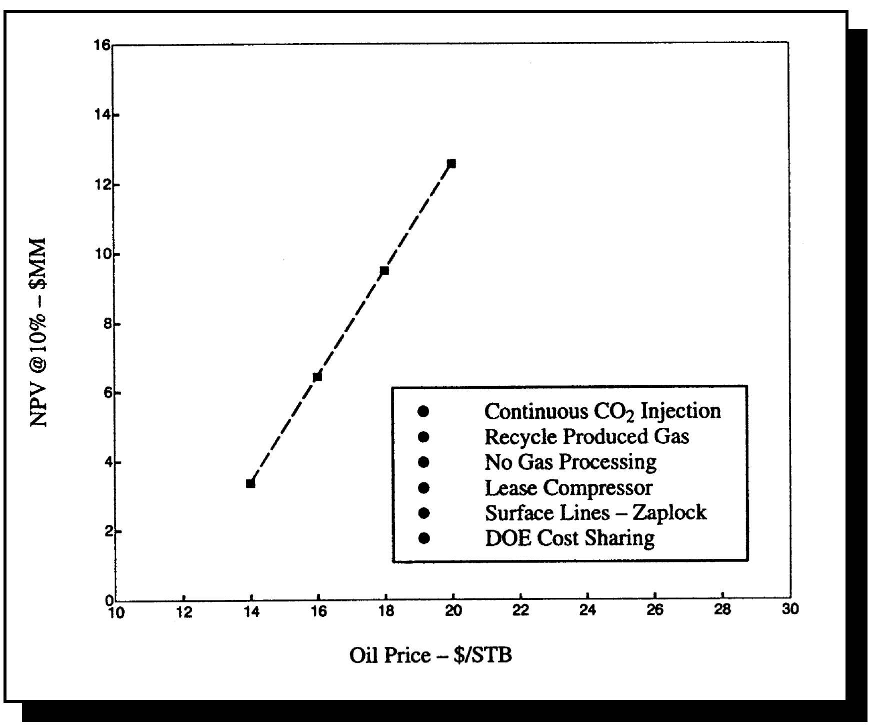

Figure 8. Net present value versus price of oil, Anasazi field CO_2 flood at high rate.

a payout of 36 months. A discounted (10 percent) NPV of $5.9 million could be realized by implementing a CO_2 flood under the proposed conditions. Harken's capital outlay with DOE participation would be $1,493,000.

In summary, if the CO_2 flood performs as predicted, it is a financially robust process for increasing the reserves of the Anasazi reservoir. However, the ROR and NPV are very sensitive to oil prices (figures 7 and 8). Therefore economics should be rerun before installation of injection facilities.

Runway Field: Using reservoir simulation-based performance predictions and current CO_2 flood implementation costs, detailed economic assessments were conducted for five different CO_2 flood options. This set of studies indicated that:

1. A CO_2 flood of the Runway reservoir has acceptable economics. With DOE participation the project would have a ROR of 30 percent, a payout of 32 months, a PI of 5 to 1, and a discounted (10 percent) NPV in excess of $3,100,000. Harken's capital outlay would be $1,532,000. Even without DOE participation the economics remain acceptable with a ROR of 21 percent, a payout of 39 months, a PI of 2.8 to 1, and a discounted NPV of almost $2,000,000. The capital requirements would be $2,789,000.

2. Based on the Anasazi study, leasing a compressor rather than purchase was adopted for the Runway evaluation.

3. The difference between a minimum and maximum cost option for installation of flow/injection lines and the CO_2 supply is approximately $233,000. However, the economics are still acceptable. With DOE cost sharing, the ROR is 29 percent with a PI of 4.8 to 1, and a discounted NPV of $2,900,000.

4. Most economic evaluations exhibited negative cash flows in the year 2008, when operating costs exceed revenues. At this point the projects were terminated. However, the reservoir process should have been changed from continuous CO_2 injection to blowdown and the economics re-run. The additional recovery from blowdown, without the operating costs associated with CO_2 injection, would improve economic returns. Thus, additional prediction runs should be completed to assess the conversion to blowdown on economics.

In summary, if the CO_2 flood performs as predicted, it is a financially acceptable process for increasing the reserves of the Runway reservoir. However, the ROR and NPV are very sensitive to oil prices (figures 9 and 10). Therefore economics should be rerun before installation of injection facilities.

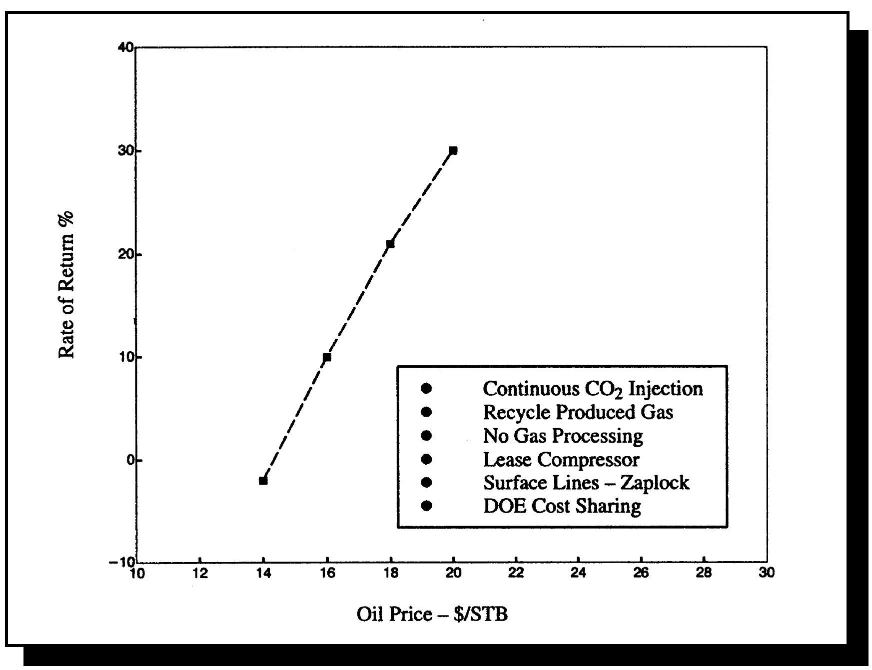

Figure 9. Rate of return versus price of oil, Runway field CO_2 flood at high rate.

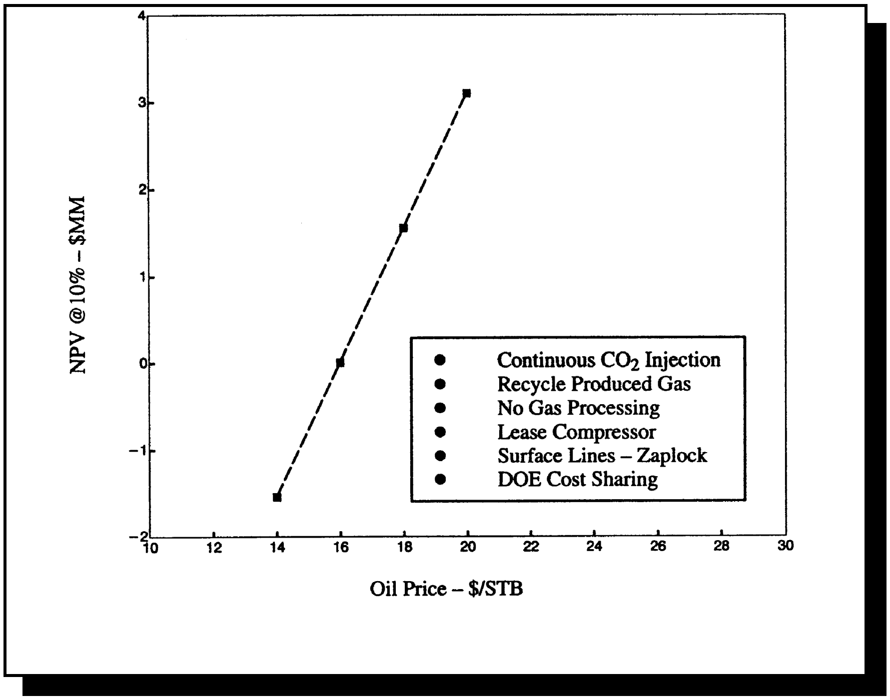

Figure 10. Net present value versus price of oil, Runway field CO_2 flood at high rate.

Conclusions, and Reserve and Recovery Determinations for Project Fields

The results of the Anasazi and Runway studies can be used to qualitatively assess the CO_2 recovery potential of other Paradox basin small, algal-mound reservoirs containing fluids with similar properties. However, the experience gained in history matching and predicting the performance of the Anasazi and Runway reservoirs indicates that the overall mound geometry and internal facies architecture is critical to matching and predicting performance.

The cumulative production for the five project fields as of January 1, 1999, is summarized on table 1. Heron North field is currently shut-in. Primary recovery and OOIP (table 2) were determined from volumetric reserve calculations, material balance calculations, and decline curve extrapolations, as well as refined geologic characterization. These volumetric calculations were made by evaluating well logs and reservoir aerial extent (as defined by seismic data), coupled with reservoir geometry. Material balance and decline curve calculations utilized the production and pressure history. Knowing the OOIP and the primary recovery, the amount of oil left behind was calculated. Lastly, utilizing the results from the simulation studies of Anasazi and Runway fields, sweep efficiencies for CO_2 flooding and the ultimate enhanced recovery were estimated for all project fields (table 2). Using the average predicted oil recovery rate of 71.8 percent (percent recovery of remaining oil in place after primary recovery) for the Runway and Anasazi reservoirs, the projected additions to reserves if CO_2 is also applied to all the project fields is over 8.2 million STB of oil.

Table 1. Cumulative production from project fields.

Project Field	Cumulative Production*		
	Oil (bbl)	Gas (MCF)	Water (bbl)
Anasazi	1,883,393	1,625,892	29,942
Blue Hogan	311,842	303,938	1,903
Heron North	206,446	328,713	34,820
Mule	410,792	273,247	31,710
Runway	801,889	2,675,307	5,987

* As of January 1, 1999; source - Utah Division of Oil, Gas and Mining.

Table 2. Reserve and recovery determinations.

Project Field	OOIP* (MSTB)	Primary Recovery		ROIP** (MSTB)	CO_2 Flood Projected Recovery (MSTB)	CO_2 Flood Recovery % ROIP
		Oil (MSTB)	Gas (MCF)			
Anasazi†	4,706	2,000	1,890,000	2,706	2,208	81.6
Blue Hogan	2,530‡	321	968,000	2,209	1,586	71.8
Heron North	2,640‡	216	2,650,000	2,424	1,740	71.8
Mule	2,000‡	454	288,000	1,546	1,110	71.8
Runway	3,372	825	2,830,000	2,547	1,577	61.9

* Original oil in place (thousand stock tank barrels [MSTB]), mound-core and supra-mound intervals (includes platform interval in Runway)

** Remaining oil in place

† High rate case starting CO_2 flood January 1, 2000

‡ Estimate based on approximate volumetric data

TECHNOLOGY TRANSFER

Project materials, results, and objectives were displayed at 13 professional society meetings and conventions. The UGS sponsored two workshops displaying core and results of the reservoir modeling. The UGS also conducted a field trip to the outcrops which served as reservoir analogs, and to field facilities. Thirteen technical papers with project results were presented at various professional society conventions and 25 papers were published in professional journals, guidebooks, and periodicals.

The UGS established a web site on the Internet with a Paradox basin project home page (http://utstdpwww.state.ut.us/~ugs/paradox.htm). The UGS also maintains a database which includes those companies or individuals (over 300) specifically interested in the Paradox basin project and who receive the UGS *Survey Notes* and *Petroleum News* periodicals.

BENEFITS

The benefits expected from the project are: (1) increased recoverable reserves by identifying untapped compartments created by reservoir heterogeneity, (2) increased deliverability through a CO_2-miscible flood in other small fields in the Paradox basin, (3) stimualtion of exploration for field extensions and new fields along identified reservoir trends and Paradox basin fairways, (4) use of project technology in other basins with similar types of reservoirs, (5) prevention of premature abandonment of numerous small fields, (6) reduction of development costs by more closely delineating minimum field size and other parameters necessary to a successful flood, (7) more productive use of limited energy investment dollars, and (8) increased royalty income to the Navajo Nation; Federal, state, and local governments; and fee owners. Project benefits could apply to other areas in the Rocky Mountain region, the Michigan and Illinois basins, and the Midcontinent region.

Budget Period I of the project showed that a CO_2 flood, not a waterflood, would be best technically, as well as economically feasible. For Anasazi field, an optimized CO_2 flood is predicted to recover a total 4.21 million STB of oil. This represents an increase of 1.65 million STB of oil over predicted primary depletion recovery as of January 1, 2012. The projected 4.21 million STB of oil production represents in excess of 89 percent of the OOIP in the mound complex and 36.8 percent of the OOIP of the total system modeled. For Runway field, the best CO_2 flood is predicted to recover a total 2.4 million STB. This represents an increase of 1.58 million STB of oil over predicted primary depletion recovery as of January 1, 2012. The projected 2.4 million STB of oil production represents 71 percent of the OOIP in the mound complex and 48 percent of the OOIP of the total system modeled, excluding the Ismay reservoir.

FUTURE ACTIVITIES

<u>Phase II</u> will be a CO_2-miscible flood demonstration project on Anasazi field, as determined from the characterization study. This technique was identified as having the greatest potential for increased well productivity and ultimate recovery. The demonstration project will include:

(a) conducting a CO_2 injection test(s),

(b) acquiring a CO_2 source for the flood project,

(c) acquiring a fuel gas source for the compressor,

(d) rerunning project economics,

(e) drilling a development well(s), vertically or horizontally, to facilitate sweep during the pilot flood,

(f) purchasing and installing injection facilities,

(g) flood management, monitoring field performance, and evaluation of results, and

(h) determining the feasibility of transferring the project technologies to similar fields in the Paradox basin and throughout the U.S.

The results of this project will continue to be transferred to industry and other researchers through a petroleum extension service, creation of digital databases for distribution, technical workshops and seminars, field trips, technical presentations at national and regional professional meetings, maintaining a project home page on the Internet, and publication in newsletters and various technical or trade journals.

ACKNOWLEDGMENTS

This research is performed under the Class II Oil Program of the U.S. Department of Energy, National Petroleum Technology Office, Tulsa, Oklahoma, contract number DE-FC22-95BC14988. The Contracting Officer's Representative is Gary D. Walker, NPTO, Tulsa, OK. Budget Period I, the Geological and Reservoir Characterization was February 9, 1995 - August 31, 1998. Budget Period II, the Field Demonstration is September 1, 1998 - August 31, 2002.

Additional funding is being provided by the industry partner and subcontractor Harken Southwest Corporation, Houston, Texas, David Gibbs, Vice President, Engineering and Development, and Richard O. Cottle, Vice President, Engineering; and the Utah Office of Energy and Resource Planning, Jeff Burks, Director.