# The *Class* Act

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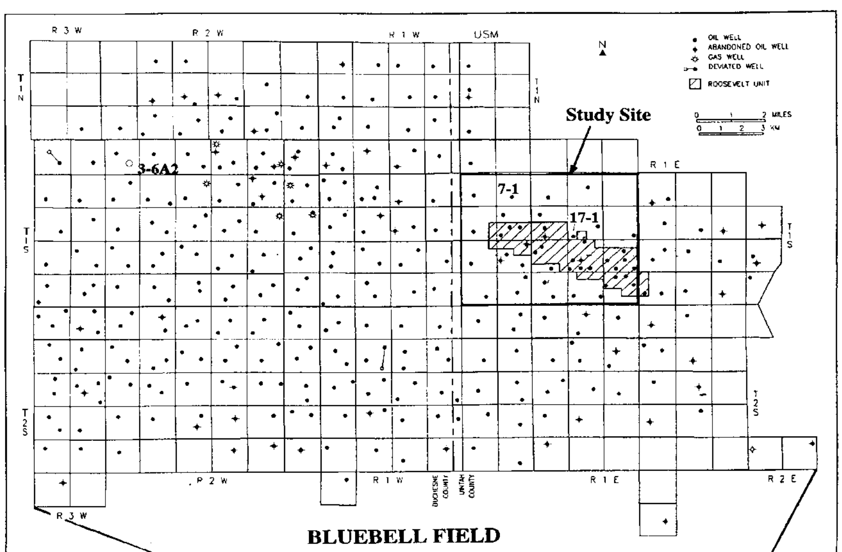
## Application of the Bed Isolation Completion Technique in a Mature Well in the Bluebell Field, Uinta Basin, Utah

By Craig Morgan, Utah Geological Survey

The oil well demonstration program for the DOE Class I project entitled *Increased Oil Production and Reserves From Improved Completion Techniques in the Bluebell Field, Uinta Basin, Utah* was carried out by Quinex Energy Corporation, Bountiful, Utah. The Bluebell field has more than 300 active wells in a 249 square-mile area. Bluebell field is one of three contiguous fields (Bluebell, Altamont, and Cedar Rim) with production from the Eocene Green River and Colton Formations, at a drill depth of about 12,000 to 14,000 feet (**Figure 1**). Wells in the Bluebell field are initially completed and periodically recompleted by treating tens of beds at a time in a shotgun fashion.



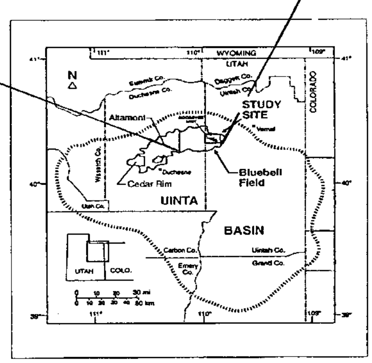




**Figure 1 Location of Bluebell field, Duchesne and Unitah Counties, Utah.** Demonstration wells 7-1, 17-1, and 3-6A are labeled. Study site is the area characterized in detail prior to the well-demonstration program.

Identifying which beds in a well are oil productive, water productive, thief, or nonproductive has always been a problem in the Bluebell field. Economics of production don't allow for individual testing of beds, and so the shotgun completion method is used. The demonstration was intended to increase our knowledge of the effects of the current completion practices and show ways to improve those practices, resulting in an increase of primary oil recovery and extending the life of the wells. The demonstration consisted of three parts:

**1.** The recompletion of the Michelle Ute 7-1 well using a three-stage, high-diversion, high-pressure, acid treatment. Each stage was an appoximately 500-foot vertical interval with over 10 beds perforated in each interval.

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**2.** The recompletion of the Malnar Pike 17-1 well by acidizing four separate beds using a bridge plug and packer to isolate individual beds in a well with over 60 beds previously perforated.

**3.** The logging and completion of a new well, the Chasel 3-6A2.

The Malnar Pike well was completed in 1987 flowing 640 BOPD and 550 MCFGPD. The cumulative production before the demonstration (September 31, 1997) was 111,304 BO and 95,970 MCFG, with an average daily rate of 18 BOPD. The objective of the Malnar Pike recompletion was to use cased-hole logs to select individual beds for treatment and to determine the effectiveness of treating at the bed scale an older well, which is near its limit in Bluebell field.

Dual burst thermal decay time (TDT) and dipole shear anisotropy (anisotropy) logs were used to identify beds for treatment, and an isotope tracer log was used for post-treatment evaluation (**Figure 2**). Four separate treatments were applied. The beds were isolated using a bridge plug at the base and a packer at the top of the test interval. The first two treatments resulted in communication above and below the test interval. Swab tests recovered acid water from both intervals after the treatment. The third and fourth treatments

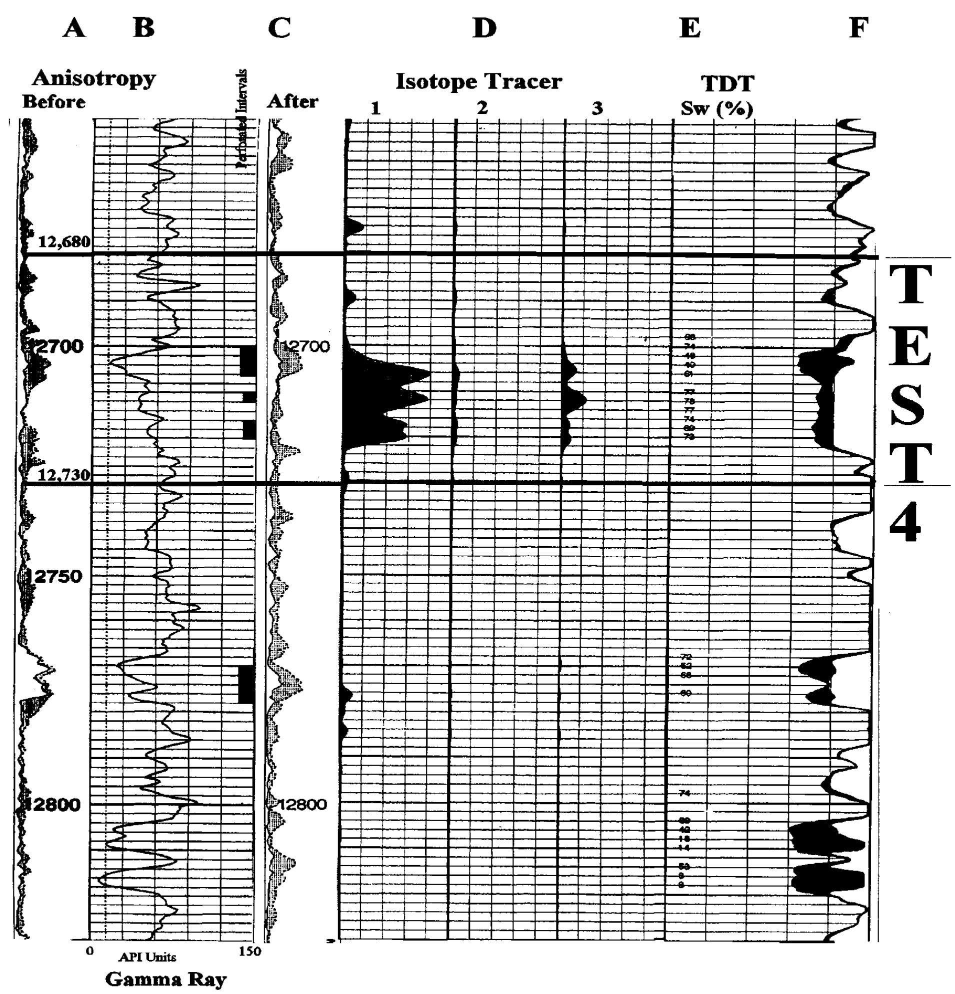


**Figure 2** Portions of the cased-hole logs run in the Malnar Pike 17-1 well showing test interval 4. (A) is a portion of the dipole shear anisotropy log run before the acid treatment. The greater the separation of the two lines (shaded in), the greater the density of the fractures. (B) is a gamma-ray curve for correlation and bed identification. (C) is the anisotropy log run after the acid treatment. (D) is from the isotope tracer log with different tracers labeled 1, 2, and 3. The larger the curve, the more isotope was left behind the casing, which helps determines where the acid went. (E) is percent water saturation calculated from the TDT log. (F) is a diagrammatic display of oil (black) and water (white) in the pore volume of the rock as calculated from the TDT log.

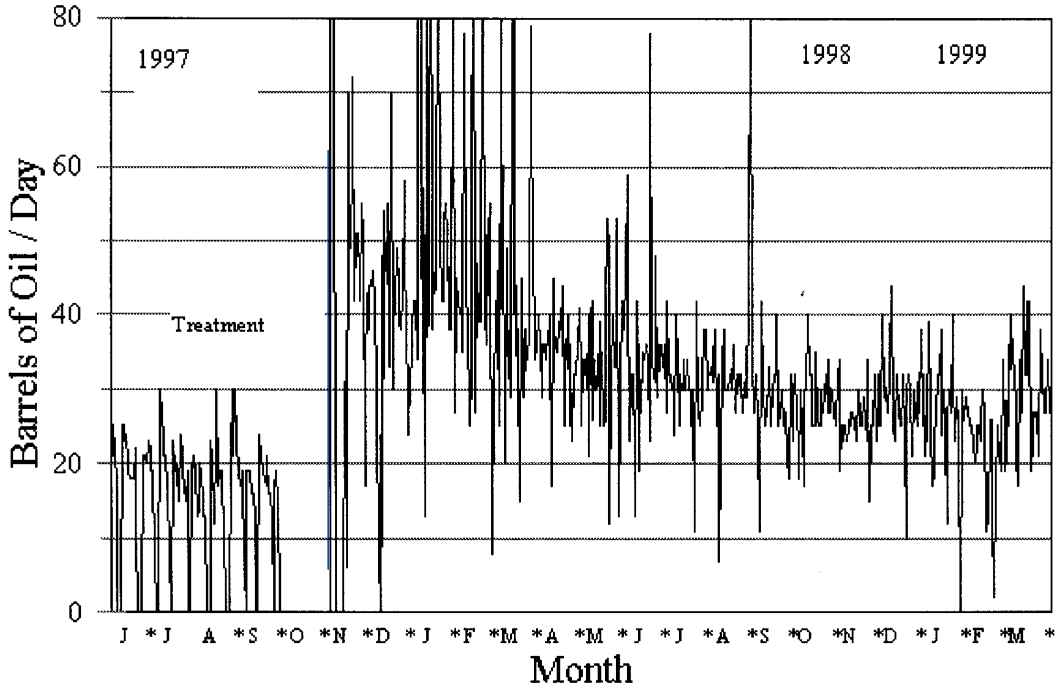


**Figure 3** Daily oil production from the Malnar Pike 17-1 well four months before and 16 months after recompletion. Most of the large spikes (60 BOPD or more) in production are due to hot oil treatments. Data source: Quinex Energy Corporation.

were mechanically sound and resulted in an increase in the daily oil production (**Figure 3**).

A bridge plug was placed above the first and second intervals because the operator felt these intervals would produce water. The daily oil-production rate did increase as a result of the treatment of the third and fourth intervals. The incremental increase in the oil production was typical to less than in most recompletions in the Bluebell field.

Originally the recompletion plan was to do the treatments with a dual-packer tool so that all four treatments could be done in a day. The operator decided to use the bridge plug and packer method, which is mechanically safer but took about two weeks, greatly increasing the cost.

As a result, the incremental increase will probably not pay for the cost of the treatment.

Communication above and below the test intervals was a major problem. The Malnar Pike well has numerous perforations that have been acidized several times, increasing the potential for communication behind the casing. It is likely that conventional acid treatments (typically treating a 500- to 1500-foot interval) of older wells in the Bluebell field cause a similar problem. Much of the acid may be moving vertically through the cement and not into the formation.

The bed-scale completion technique can be an effective treatment if good cased-hole data is gathered, especially in older wells where the incremental increase in oil no longer justifies the expense of the larger single- or multi-staged recompletions. The bed-scale completion should be done using a dual packer tool to reduce cost. The anisotropy and TDT logs should be used to select beds that are fractured and have relatively low water saturation. Both the upper and lower packer should be placed between perforated beds that are at least 50 feet apart to reduce the risk of communication behind the casing.

# Application of Advanced Reservoir Characterization, Simulation, and Production Optimization Strategies to Maximize Recovery in Slope and Basin Clastic Reservoirs, West Texas (Delaware Basin)

By Shirley P. Dutton, Bureau of Economic Geology, The University of Texas at Austin, and William A. Flanders, Transpetco Engineering

Slope and basin clastic reservoirs in sandstones of the Delaware Mountain Group in the Delaware Basin of West Texas and New Mexico contained more than 1.8 billion barrels (Bbbl) of oil at discovery. Recovery efficiencies of these reservoirs have averaged only 14% since production began in the 1920s and, thus, a substantial amount of the original oil in place remains unproduced. Many of these mature fields are nearing the end of primary production and are in danger of abandonment unless effective, economic methods of enhanced oil recovery can be implemented. The goal of this project is to demonstrate that reservoir characterization, by means of outcrop characterization, subsurface field studies, and other techniques, which are then integrated with reservoir simulation, can optimize enhanced oil recovery (EOR) projects in Delaware Mountain Group reservoirs.

The original objectives of the reservoir-characterization phase of the project were to (1) provide a detailed model of the architecture and heterogeneity of two representative fields of the Delaware Mountain Group–Geraldine Ford and Ford West–which produce from the Bell Canyon and Cherry Canyon Formations, respectively; (2) choose a demonstration area in one of the fields; and (3) simulate a $CO_2$ flood in the demonstration area. After completion of the study of Geraldine Ford and Ford West fields, the original industry partner decided not to continue.

A new industry partner, Orla Petco, Inc., is now participating in the project, and the reservoir-characterization phase has been expanded to include the East Ford unit, which is immediately adjacent to the Ford Geraldine unit and produces from a branch of the same Ramsey sandstone channel. Abundant subsurface data were available from the Ford Geraldine unit for reservoir characterization, including cores from 83 wells, core analyses from 152 wells, and 3-D seismic over the entire unit. In contrast, the smaller subsurface database from the East Ford unit is more typical of most Delaware sandstone fields. Reservoir characterization of the East Ford unit provided an excellent opportunity to test the transferability of the geologic model and log-interpretation methods developed during characterization of the Ford Geraldine unit (Dutton et al., 1997, 1998) to another field in the Delaware sandstone play.

East Ford field, discovered in 1960, produces from both the Ramsey and Olds sandstones in the upper Bell Canyon Formation in Reeves County, Texas. Oil production peaked at 965 bbl of oil per day (BOPD) in May 1966. Original oil in place (OOIP) in the Ramsey sandstone was estimated to be 19.8 million barrels (MMbbl). Cumulative production from the Ramsey sandstone by the end of primary recovery was 2.9 MMbbl, which represents 14.6% of OOIP.

The geologic model that was developed by studying Bell Canyon sandstones in outcrop and in the Ford Geraldine unit (Dutton et al., 1997) was used as a guide to interpret the reservoir at the East Ford unit. Ramsey sandstones at the East Ford unit are interpreted as having been deposited by sandy high- and low-density turbidity currents. The sands were deposited on the basin floor in a channel-levee system with attached lobes. The deposits formed a complex about 2,500 to 4,000 ft wide, similar in dimension to the channel-levee and lobe system that was studied in outcrop. Individual channels within the complex were approximately 1,000 to 1,500 ft wide and 15 to 30 ft deep. Levee deposits thin away from the channel over a distance of about 1,000 to 1,500 ft. Lobe sandstones, deposited at the mouths of the channels, form broad, tabular deposits that were partly incised and replaced by prograding channels. The ability to apply the geologic model developed for the Ford Geraldine unit to another Delaware sandstone field was expected because of the uniform depositional conditions throughout the basin. Furthermore, the Ramsey sandstone in the East Ford unit is a branch of the channel that forms the Ford Geraldine reservoir, and a high degree of similarity should be expected

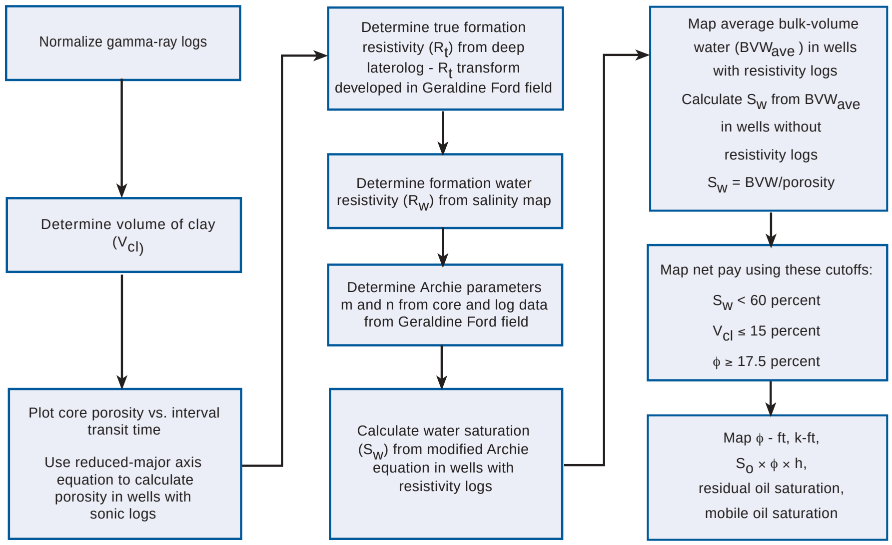


**Figure 4** Flow chart of petrophysical analysis

between the two reservoirs.

In the study of the Ford Geraldine unit, special techniques were used to maximize the information that could be derived from the old geophysical logs (Asquith et al., 1997). We used the petrophysical techniques developed during that earlier study to map reservoir properties in the East Ford unit (**Figure 4**). The first step in the petrophysical analysis was to construct a cross plot of interval transit time (ITT) versus core porosity in order to determine log-to-core porosity transforms. Core porosity was plotted versus core permeability to establish a porosity versus permeability transform. Additional tasks included (1) normalizing gamma-ray logs and determining volume of clay and (2) mapping water resistivity ($R_w$) across the unit. Because special core analyses were not available from East Ford cores, Archie parameters m (cementation exponent) and n (saturation exponent) determined for the Ford Geraldine unit were applied to the East Ford unit. Similarly, the transform developed in the Ford Geraldine unit for converting the deep laterolog to $R_t$ when an $R_{xo}$ device is unavailable was applied to the East Ford unit.

Most aspects of the log-interpretation methodology developed for the Ford Geraldine unit were used successfully in the East Ford unit. The approach that had been used to interpret water saturation from resistivity logs, however, had to be modified because in some East Ford wells the log-calculated water saturation was too high and inconsistent with the actual production. In addition, the use of bulk-volume water mapping to determine water saturation in wells without resistivity logs (Asquith et al., 1997) did not yield results consistent with production. A cross plot of valid log-calculated water saturation versus water-cut data from initial-potential tests provided a transform that was used to estimate water saturation from water-cut data in wells without good resistivity logs.

The result of the petrophysical characterization was a set of maps of porosity, permeability, net pay, water saturation, porous hydrocarbon volume, and other reservoir properties across the unit. The maps of average porosity, average permeability, and net pay (**Figure 5**) for the Ramsey sandstone in the East Ford unit exhibit a strong north-south trend that follows the positions of the Ramsey 1 and 2 sandstone channels.

Compositional simulation of a $CO_2$ flood in a quarter five-spot pattern in the Ramsey sandstone indicates that 10 to 30% of remaining oil in place in the East Ford unit, or 1.7 to 5 MMbbl, is recoverable through $CO_2$ flood. Phase II will apply the knowledge gained from the reservoir characterization to increase recovery from the East Ford unit through an enhanced-recovery program ($CO_2$ flood). Detailed comparison will be made between production from the East Ford unit during the $CO_2$ flood with the predictions that were made during Phase I on the basis of simulations. This comparison will provide an important opportunity for testing the accuracy of reservoir-

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characterization and flow-simulation studies as predictive tools in resource preservation of mature fields. Through technology transfer, the knowledge gained in the study of the East Ford and Ford Geraldine units can be applied to increase production from the more than 100 other Delaware Mountain Group reservoirs in West Texas and New Mexico, which together contain 1,558 MMbbl of remaining oil.

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Asquith, G. B., Dutton, S. P., Cole, A. G., Razi, M., and Guzman, J. I., 1997, Petrophysics of the Ramsey sandstone, Ford Geraldine Unit, Reeves and Culberson Counties, Texas: West Texas Geological Society Publication No. 97-102, p. 71–74.

Dutton, S. P., Asquith, G. B., Barton, M. D., Cole, A. G., Gogas, J., Malik, M. A., Clift, S. J., and Guzman, J. I., 1997, Application of advanced reservoir characterization, simulation, and production optimization strategies to maximize recovery in slope and basin clastic reservoirs, West Texas (Delaware Basin): The University of Texas at Austin, Bureau of Economic Geology, annual report prepared for the U.S. Department of Energy, (DE98000456), DOE/BC/14436-4, 187 p.

Dutton, S. P., Malik, M. A., Clift, S. J., Asquith, G. B., Barton, M. D., Cole, A. G., Gogas, J., and Guzman, J. I., 1998, Geological and engineering characterization of Geraldine Ford field, Reeves and Culberson Counties, Texas: The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the U.S. Department of Energy, (DE98000477), DOE/BC/14936-10, 115 p.


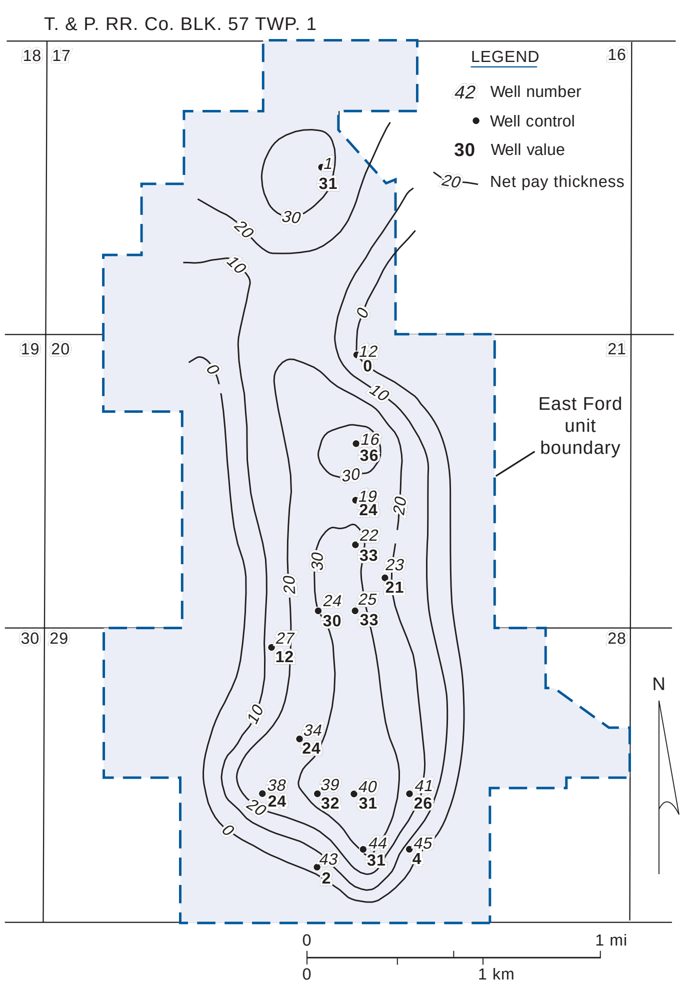


**Figure 5** Map of net pay of the Ramsey sandstone in the East Ford unit, Reeves County, Texas

# The *Class* Act

**The *Class* Act** is a biannual newsletter devoted to providing information about **DOE's Reservoir Class Program**.

For more information on Class Program projects, contact **Herb Tiedemann** at **DOE's National Petroleum Technology Office**:

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If you have a project that you would like to preview in an issue of **The *Class* Act**, please contact Viola Rawn-Schatzinger.

# Cost-Effective Technology for Independent Oil and Gas Producers

By Timothy R. Carr, Kansas Geological Survey and
University of Kansas Energy Research Center

The majority of Kansas production is operated by the small independent oil and gas producer (90% of the 3,000 Kansas producers have fewer than 20 employees). The independent producer does not have the extensive resources and ready access to a research lab to develop and test advanced technologies. For the Kansas oil and gas industry, access to new technology remains a critical component to sustained production and increased economic viability. A major emphasis of the Kansas Class II project was collaboration of University of Kansas Energy Research scientists and engineers with Kansas independent producers and service companies. The goal was to develop and modify cost-effective new technologies and to accelerate adaptation and evaluation of these technologies.

The Kansas Class II project introduced a number of potentially useful technologies and demonstrated these technologies in actual oil field operations. Advanced technology was tailored specifically to the scale appropriate to the operations of Kansas producers. An extensive technology transfer effort remains ongoing to inform other operators of project results. In addition to traditional technology transfer methods (e.g., reports, publications, workshops, and seminars), a public domain relational database and online package of project results are available through the Internet. The goal is to provide the independent access to project data and technology on the desktop.

## Project Background

The demonstration project is being conducted in a cooperative manner with independent oil operators at the demonstration site. Ritchie Exploration, Inc. of Wichita operates leases that were the focus of the demonstration. However, a number of major operators in the Schaben field have contributed data to the project, and tested and adopted project results. Other major operators in Schaben field include Pickrell Drilling Co., Inc. of Wichita and American Warrior, Inc. of Garden City.

Schaben field, located in Ness County on the western flank of the Central Kansas uplift, was discovered in 1963 and is typical of Mississippian production in Kansas. The majority of Mississippian production occurs at or near the top of the Mississippian, just below a regional sub-Pennsylvanian unconformity. These reservoirs are a major source of Kansas oil production and account for approximately 43% of total annual production. Cumulative production from Mississippian reservoirs in Kansas exceeds 1 billion barrels. Today, small independent producers operate many of these Mississippian reservoirs and production units. Extremely high water cuts and low recovery factors place continued operations at or near their economic limits. Cumulative Schaben field production was 9.1 million barrels of oil (BO), and daily field production was 326 BOPD from 51 wells before the demonstration project.

## Cost-Effective Technology for Independent Producers

The Kansas project addresses producibility problems common to numerous Kansas fields. Producibility problems in these reservoirs include old and missing data, inadequate reservoir characterization, drilling and completion design problems, and non-optimal primary recovery. Work using cost-effective techniques for reservoir characterization and simulation at Schaben field has demonstrated its value to independent operators. All of the major operators at Schaben have adopted the results of the reservoir management strategy developed as part of the study, and have located and drilled additional infill locations and targeted recompletions. At the Schaben Demonstration Site, the additional infill locations and recompletions have resulted in an incremental

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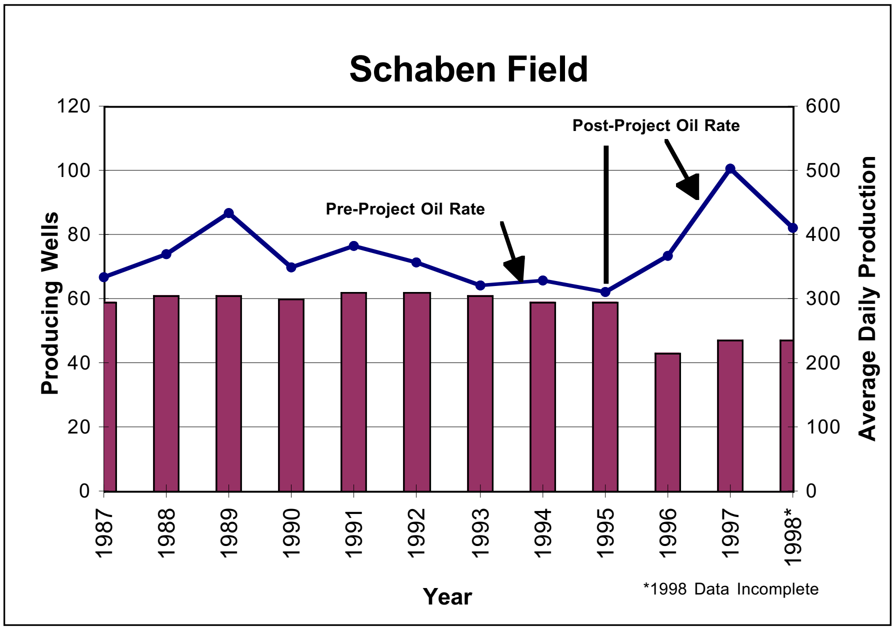


**Figure 6** Plot of average daily production (line) and producing wells (bars) from the Schaben Demonstration Area showing producing rates before and after initiation of demonstration project. Increase in production is from a smaller number of producing wells. Additional current production data for the Schaben Field and individual leases are available at http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.html

production increase of 200 BOPD (**Figure 6**).

As part of the Budget Period 1, an integrated descriptive geologic reservoir characterization provided the basis for development of a quantitative reservoir model. Descriptive reservoir characterization entailed integration and creative application of existing vintage data, and drilling and coring three new wells through the reservoir interval.

Core analysis (including NMR), petrophysical analysis, calibration of logs and core data were integrated with existing well data into a computerized three-dimensional visualization. Procedures and computer code were developed to modify, load, and display well logs using seismic workstations for an improved 3D visualization using available wireline log data (http://www.kgs.ukans.edu/PRS/publication/OFR97-22/ofr9722.html). Geologic, engineering and production data, including maps, cross-sections, and core analyses were brought into a common set of relational databases. Much of the data from Schaben field is available on-line at reservoir, lease, and well levels (http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.html).

Log analyses, core analyses, and petrographic descriptions were completed to better understand the pore geometry of the carbonate reservoir in the Schaben Field. All of the complexities existing in an evaluation of an extremely heterogeneous reservoir are present in the producing reservoir in the Schaben field. Determination of pore size, throat size, irreducible water saturation, permeability, effective porosity, and movable oil was possible using cost-effective techniques on existing data. As an example, NMR and capillary pressure data on 18 core plugs were used to determine the fluid filled porosity, free fluid porosity, bound water porosity, pore size, grainsize, and irreducible water saturation. (**Figure 7**).

Another aspect of the project involved development of a low-cost PC-based petrophysical analysis package (PfEFFER). The program, available to oil operators as a add-in to Microsoft Excel, is a cost-effective and practical tool for the real-time, interactive log analysis. Spreadsheet database and graphic

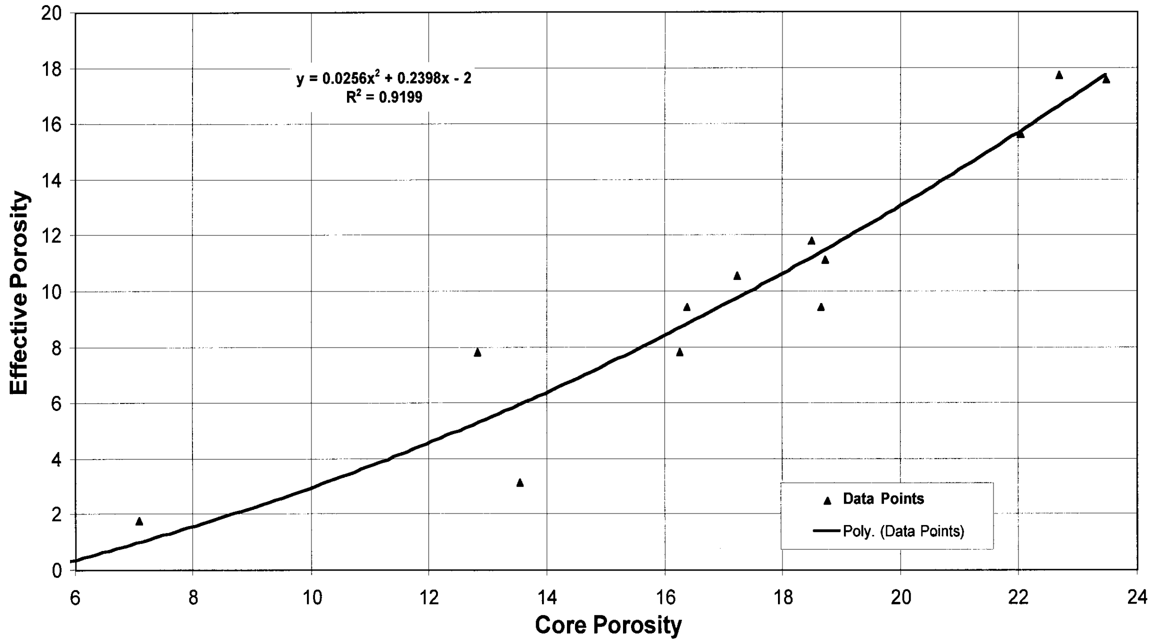


**Figure 7** Plot of core porosity and effective macro-porosity, (at reservoir pressure), was obtained from NMR analysis on 18 core plugs selected from wells drilled as part of the project. The results were used to adjust porosity determined from logs to derive effective porosity input to the simulation model. Additional details are available online at http://www.kgs.ukans.edu/PRS/Info/webPubs97-24.html

features allow both rapid interaction and comparative evaluation of multiple interpretations or best case/worst case extremes. In addition, multiple wells and zones are easily managed. A project file can be generated that assembles reservoir parameter, grids them, and displays them as 2D maps or 3D surfaces.

After completion of a quantitative reservoir characterization, the US DOE Boast 3 Reservoir Simulation Package was adapted for use at the full field scale. Interfaces to the Boast freeware were developed to use low-cost, commonly available, programs as pre- and post-processors (e.g., using Microsoft Excel to generate post-processor displays). A short course on the results of the reservoir simulation was given several times and is under development for the Web (initial product is available at http://www.kgs.ukans.edu/General/Tutorial/Boast3/findex.html). The result was a full field reservoir simulation model and management tool that the independent producer can run on a desktop PC using freeware and a spreadsheet (**Figure 8**).

## Technology Transfer

Project design, methodologies, data, and results are disseminated to independent operators through focused technology transfer activities. These activities include development of cost-effective technologies and software (e.g., PFEFFER and Pseudoseismic), open-file reports, publications, workshops and seminars, and public access through the Internet to the data, technologies, and project results. In addition to traditional workshops, electronic short courses covering important technologies are being developed for distribution on the North Mid-Continent PTTC Internet Site (http://www.kgs.ukans.edu/ERC/PTTC1/pttccourse.html). The target audience includes other operators in the demonstration area, operators of numerous other Mississippian subunconformity dolomite reservoirs in Kansas, operators of analogous

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shallow shelf carbonate reservoirs in the Mid-Continent, and technical personnel involved in reservoir development and management.

## Summary

All technologies used have been adapted to be cost-effective for independent operators in mature fields. Technologies include petrophysical analysis (PfEFFER), visualization (Pseudoseismic), core analysis using NMR, numerical simulation on a PC, and Internet technology transfer. Work using cost-effective technologies for reservoir characterization and simulation at Schaben Field has demonstrated their value for independent operators. All of the major operators at Schaben have adopted the results of the reservoir management strategy developed as part of the study, and have located and drilled approximately 20 infill locations. Overall results of the incremental wells are very favorable and show the value of reservoir description and simulation (**Figure 6**). The procedures continued to be transferred to a number of other independent operators through publication, presentations, hands-on computer workshops, and the Internet.♦

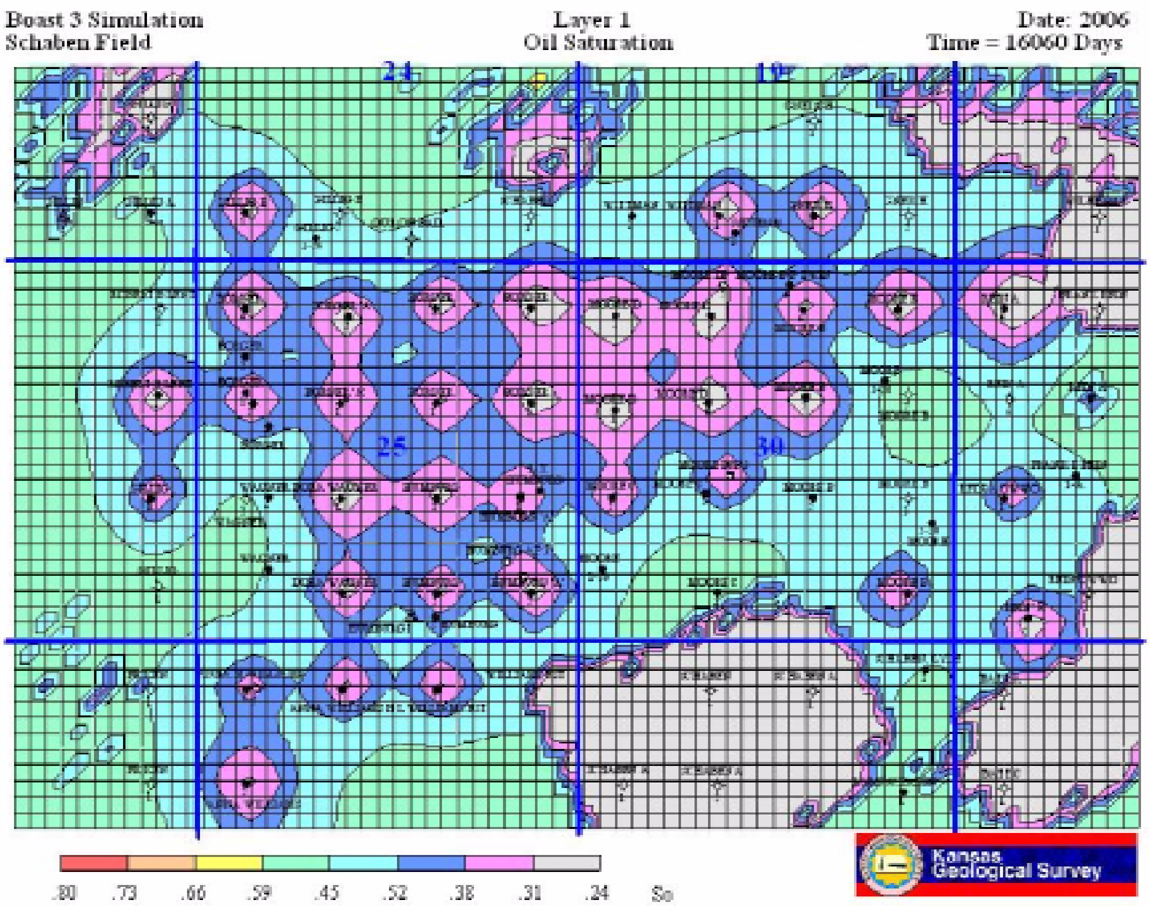


**Figure 8** Sample map showing Boast 3 results and spreadsheet post-processing from full field reservoir simulation for Schaben Field (predicted remaining oil saturation in year 2006 with addition of infill wells). Additional results and discussion of the use are available online at http://www.kgs.ukans.edu/PRS/Info/webPubs97-24.html and http://www.kgs.ukans.edu/General/Tutorial/Boast3/findex.html

# Workshops/Conferences

**June 3, 1999, PTTC Workshop, Midland, TX,** "Microbial Enhanced Oil Recovery North Blowhorn Creek Unit", Jim Stephens, Lewis Brown, and Alex Vadie.

***June 27-30, 1999, Oil and Gas Conference, "Technology Options for Producers Survival," Dallas , Texas:**

***Workshop*****—**Software Programs

- The Reservoir Characterization Advisor, Paul Knox, University of Texas, BEG; Class I 14959
- PfEFFER Logging Analysis Package, Tim Carr, John Doveton, Kansas Geological Survey; Class II 14987

***Presentations***

- Air Injection in a Gulf Coast Light Oil Field, Travis Gillham, BP-Amoco; Class I 14963
- Overview of the $CO_2$ Pilot in the Spraberry Trend Area, Todd Yokum, Pioneer Natural Resources; Class III 14942
- Improved Oil Recovery in Fluvial–Dominated Deltaic Reservoirs of Kansas, Don Green, Kansas Geological Survey; Class I 14957
- Increased Oil Production and Reserves Utilizing Secondary/Tertiary Recovery Techniques on Small Reservoirs in the Paradox Basin, Utah, Thomas C. Chidsey, Utah Geological Survey; Class II 14988
- Cost-Effective Techniques for Improved Oil Recovery in Mississippian Carbonate Reservoirs of Kansas, Timothy R. Carr, Kansas Geological Survey; Class II 14987
- A Low Cost Solution for Enhanced Waterflood Performance, James O. Stephens, Hughes Eastern Corporation; Class I 14962
- Exploration Methods and Basin Analysis, James Wood, Michigan Technological University; Class II 14983
- New Techniques for Using Old Logs in Reservoir Characterization, Shirley P. Dutton, University of Texas Bureau of Economic Geology; Class III 14936
- Major Pennsylvanian Fluvial-Deltaic Light Oil Reservoir Systems in Oklahoma, Jock A. Campbell, Oklahoma Geological Survey; Class I 14956
- Incorporating Seismic Attribute Porosity into a Flow Model of the Grayburg Reservoir in the Foster-South Cowden Field, Robert Trentham, Laguna Petroleum Corporation; Class II 14982
- Improvement in Performance of a Mature Oil Field Through Horizontal Well Drilling, Mohan Kelkar, University of Tulsa; Class I 14951
- Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico, Mark Murphy, Strata Production Company; Class III 14941
- Controlling Unconsolidated Sand Formations Using Steam, Scott Hara, Tidelands Oil Production Company: Class III 14939

***Poster Presentations***

- $CO_2$ Flood Utilizing Horizontal Injection Wells, Rex Owen, Phillips Petroleum Company; Class II 14991
- Interpretation of Complex Structure in a Limited-Quality 3D Seismic Image, Bob A. Hardage, Bureau of Economic Geology, The University of Texas at Austin; (in part) Class III 14941
- Bed-Isolation Treatments of a Mature Well in the Bluebell Field of the Uinta Basin, Utah, That Has Undergone Numerous High Volume Shot-Gun Completions, Craig Morgan, Utah Geological Survey; Class I 14953

**August 8-11, 1999, Rocky Mountain Section Meeting, Bozeman, Montana,** "Mule field in the Paradox Basin of Southeastern Utah: A case study for small carbonate buildups, horizontal drilling and carbon dioxide flooding", T. C. Chidsey, Jr. and D. E. Eby.

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## 1999 HART'S OIL AND GAS AWARDS

**Gulf Coast Section**

*Best Advanced Recovery Project*

Hughes Eastern Corp.
Principal Investigators: Jim Stephens
Lewis Brown, Alex Vadie
North Blowhorn Creek Field, Alabama

**Permian Basin Section**

*Best New Technology*

Strata Production Company
Principal Investigators: Mark Murphy,
Bruce Stubbs
Nash Draw Field, New Mexico

**Pacific Section**

*Best Advanced Recovery Project*

University of Utah
Principal Investigator: Steven Schamel
Midway-Sunset Field, California

**Pacific Section**

*Best Field Improvement Project*

City of Long Beach/Tidelands Oil
Principal Investigators: Scott Hara, Don Clarke
Wilmington Field, California

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