TITLE: IMPROVED OIL RECOVERY IN MISSISSIPPIAN CARBONATE RESERVOIRS OF KANSAS -- NEAR TERM -- CLASS 2

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Contractor Name and Address:	The University of Kansas Center for Research Inc.
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Reporting Period:	September 18, 1994 -- March 15, 1997
Report:	Continuation Application and Project Evaluation

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ABSTRACT

This annual report describes progress during the second year of the project entitled “Improved Oil Recovery in Mississippian Carbonate Reservoirs in Kansas”. This project funded under the Department of Energy’s Class 2 program targets improving the reservoir performance of mature oil fields located in shallow shelf carbonate reservoirs. The focus of this project is development and demonstration of cost-effective reservoir description and management technologies to extend the economic life of mature reservoirs in Kansas and the mid-continent. As part of the project, several tools and techniques for reservoir description and management were developed, modified and demonstrated. These include: 1) a new approach to subsurface visualization using electric logs (“Pseudoseismic”); 2) a low-cost easy-to-use spreadsheet log analysis software (PfEFFER); and 3) an extension of the BOAST-3 computer program for full field reservoir simulation. The world-wide-web was used to provide rapid and flexible dissemination of the project results through the Internet.

Included in this report is a summary of significant project results at the demonstration site (Schaben Field, Ness County, Kansas). These results include an outline of the reservoir description based on available and newly acquired data and reservoir simulation results. Detailed information is available on-line through the Internet. Based on the reservoir simulation, three infill wells will be drilled to validate the reservoir description and demonstrate the effectiveness of the proposed reservoir management strategies. The demonstration phase of the project has just begun and will be presented in the next annual report.

EXECUTIVE SUMMARY

The Kansas Class 2 project involved a demonstration project in a Osagian and Meramecian (Mississippian) shallow shelf carbonate reservoir in west-central Kansas. Cumulative production from Mississippian carbonate reservoirs located beneath the regional sub-Pennsylvanian unconformity in Kansas is over 1 billion barrels distributed over a large number of small to medium size reservoirs. Many of these reservoirs and production units are operated by small independent producers. Extremely high water cuts and low recovery factors place continued operations at or near their economic limits.

Application of cost-effective reservoir description and management strategies can significantly extend the economic life of these mature peritidal carbonate fields and recover incremental reserves. Equally important is innovative dissemination of the data, methodologies, and results to foster wider application of demonstrated technologies by the numerous operators of similar fields throughout the northern Mid-continent and US. Producibility problems in Kansas Meramecian and Osagian dolomite reservoirs include inadequate reservoir characterization, drilling and completion design problems, and non-optimal primary recovery.

The project entailed integration of existing data, drilling and coring of three new wells through the reservoir interval. Descriptive core analysis, petrophysical and petrographic analysis (e.g. capillary pressure and NMR), calibration of logs and core data, and integration of existing well data into a computerized three dimensional visualization/simulation that was used to develop a digital reservoir model and management plan for the Osagian and Meramecian rocks at the Schaben site. Analysis indicates significant potential incremental reserves through targeted infill and horizontal drilling in this major producing trend.

At the Schaben demonstration site, integrated reservoir characterization provided the basis for development of a descriptive reservoir model and the framework for simulation. A publicly accessible and comprehensive digital reservoir database using existing and newly acquired data was distributed through the Internet. New data from the three new wells provided insight into fundamental reservoir parameters (e.g., core plug NMR analysis to determine effective porosity and relationship to facies). As part of the Kansas Class 2 project a number of cost-effective tools and techniques for reservoir description were developed, modified and demonstrated. These include: 1) a new approach to subsurface visualization using electric logs ("Pseudoseismic"); 2) a low-cost easy-to-use spreadsheet log analysis software (PfEFFER); and 3) an extension of the BOAST-3 computer program for full field reservoir simulation. The Kansas Digital Petroleum Atlas model was used to provide rapid and flexible dissemination of the project results through the Internet.

The most significant Kansas Class 2 project results are 1) development of an on-line comprehensive digital reservoir database; 2) acquisition of additional core, electric log and test data; 3) construction of an integrated geologic reservoir characterization using cost-effective approaches to data analysis; 3) full-field reservoir characterization and simulation using publicly available or low-cost software; 4) identification of potential incremental reserves that can be accessed through targeted infill and possible horizontal drilling; 5) development of a regional database for evaluation of potential for horizontal and targeted infill drilling in similar Mississippian reservoirs of Kansas; and 6) new models for innovative technology transfer.

An improved understanding of Mississippian subunconformity reservoirs in Kansas has been developed and new cost-effective techniques have been demonstrated for the identification of incremental reserves at the Schaben Field demonstration area and at similar reservoirs throughout Kansas and the Mid-continent

1.0 INTRODUCTION

The Kansas Class 2 project is an effort to introduce Kansas producers to potentially useful technologies and to demonstrate these technologies in actual oil field operations. In addition, advanced technology was tailored specifically to the scale appropriate to the operations of Kansas producers. The majority of Kansas production is operated by small independent producers that do not have resources to develop and test advanced technologies (90% of the 3,000 Kansas producers have less than 20 employees). For Kansas producer's, access to new technology is important for sustaining production and increasing viability. A major emphasis of the project is collaboration of university scientists and engineers with the independent producers and service companies operating in Kansas to accelerate adaptation and evaluation of new technologies. An extensive technology transfer effort is being undertaken to inform other operators of the project results. In addition to traditional technology transfer methods (for example, reports; trade, professional, and technical publications; workshops; and seminars), a public domain relational database and computerized display package are available through the Internet. The goal is figuratively to provide access to data and technology to independent producers in their office.

Project design, methodologies, data, and results are being disseminated through focused technology transfer activities. These activities include development of cost-effective technologies and software (e.g. PfEFFER, “Pseudoseismic”), open-file reports; publication in trade, professional, and technical publications; workshops and seminars; and the establishment of public access through the Internet to the data, technologies and project results domain relational database and computerized display package. The target audience includes other operators in the demonstration area, operators of other Mississippian sub-unconformity dolomite reservoirs in Kansas, operators of analogous shallow shelf carbonate reservoirs in the Mid-continent, and technical personnel involved in reservoir development and management.

1.1 OBJECTIVES AND SIGNIFICANCE

The majority of Mississippian production in Kansas occurs at or near the top of the Mississippian section just below the regional sub-Pennsylvanian unconformity. These reservoirs are a major source of Kansas oil production and account for approximately 43% (21 million barrels in 1994) of total annual production (Carr et al., 1995a, Figure 1.1). Cumulative production from Mississippian reservoirs in Kansas exceeds 1 billion barrels. Many of these reservoirs and production units are operated by small independent producers. Extremely high water cuts and low recovery factors place continued operations at or near their economic limits.

This project addresses producibility problems in the numerous Kansas fields such as the Schaben field in Ness County that produce from Meramecian and Osagian dolomites beneath the sub-Pennsylvanian unconformity. Producibility problems in these reservoirs include inadequate reservoir characterization, drilling and completion design problems, and non-optimal primary recovery. Tools and techniques will facilitate integrated, multi-disciplinary reservoir characterization. Application of cost-effective reservoir description and management strategies can significantly extend the economic life of these mature peritidal carbonate fields and recover significant incremental reserves. Equally important is innovative dissemination of the data, methodologies, and results to foster wider application of demonstrated technologies by the numerous operators of similar fields throughout the northern Mid-continent and US.

1.2 SITE DESCRIPTION

The Schaben demonstration site consists of 1,720 contiguous acres within Schaben field, located in Township 19 South--Range 21 West, Township 20 South--Range 21 West, and Township 19 South--Range 22 West, Ness County, Kansas (Figure 1.2). The leases comprising the demonstration sites are highlighted in Figure 1.2. This site is located in the upper shelf of the Hugoton Embayment of the Anadarko Basin and produces oil from dolostones and limestones of the lower Meramecian Warsaw Limestone and Osagian Keokuk Limestone (Mississippian) at depths of 4,350-4,410 feet.

Schaben field, discovered in 1963, consists of 78 completed oil wells spaced primarily on 40-acre locations (Figure 1.3). Cumulative field production as of September, 1996 was 9.1 million barrels of oil (BO), and daily field production was 326 BOPD from 51 wells (Figure 1.2). Wells in the Schaben demonstration site have cumulatively produced 3,593,609 BO, with current (June 1993) daily production totaling 141 BOPD from 29 wells. In addition to production from the Mississippian, one well produces oil from the Cherokee Group and the Fort Scott Limestone, however, the relative volume of oil produced from these secondary zones is small. The Schaben demonstration site contains 6 plugged and abandoned oil wells, 27 actively producing oil wells, and 2 water disposal wells.

The Schaben Field demonstration site is located on the western flank of the Central Kansas uplift at the western edge of the Mississippian Osagian subcrop beneath the sub-Pennsylvanian unconformity (figures 1.4 - 1.6).

1.3 PARTICIPATING ORGANIZATIONS

University of Kansas Center for Research Inc., the University of Kansas Energy Research Center, the Kansas Geological Survey, and the Tertiary Oil Recovery Project of Lawrence Kansas, and Ritchie Exploration Inc. of Wichita, Kansas are participating in the project. Total cost sharing in the project is 50 percent.

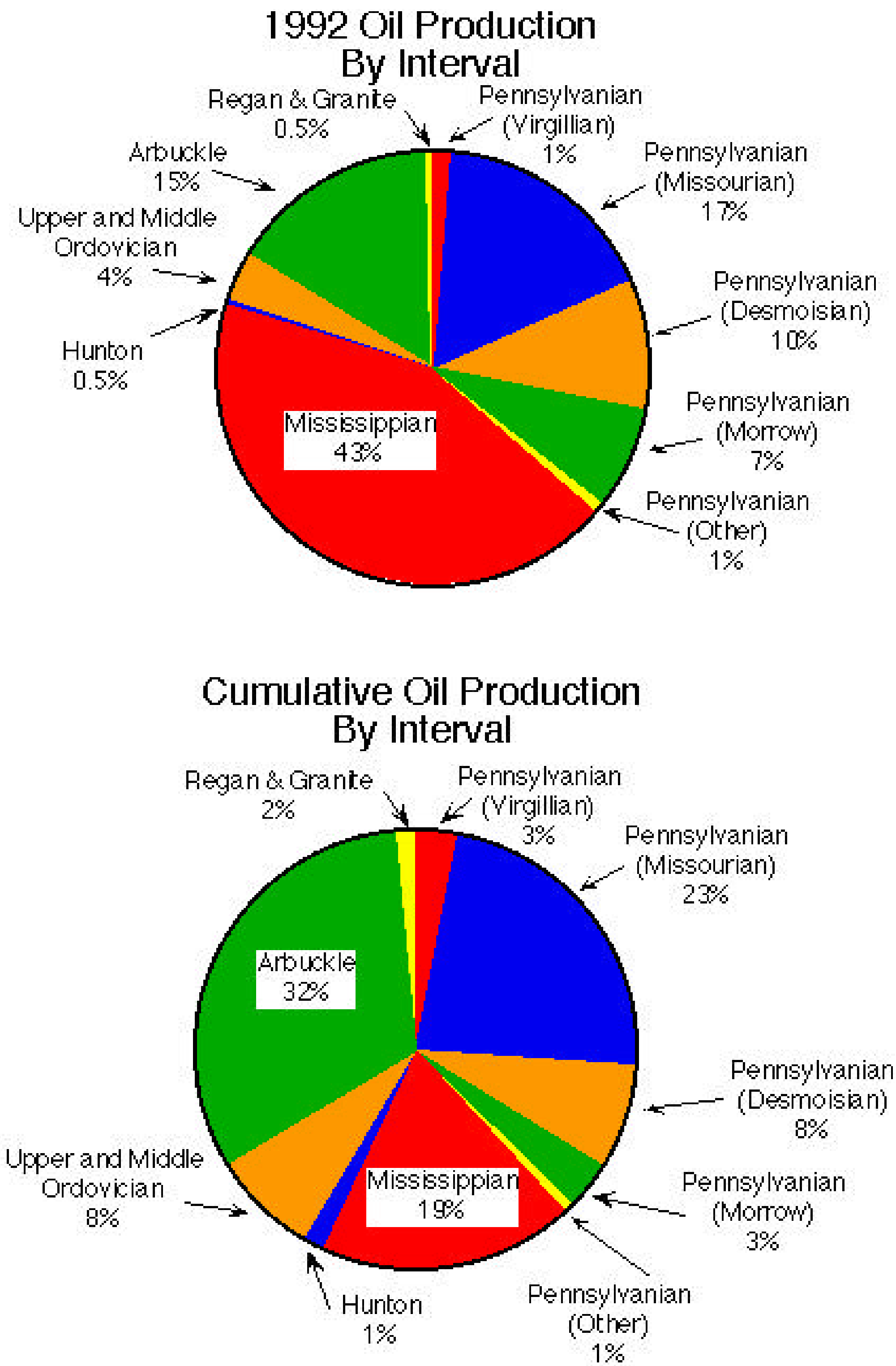

FIGURE 1.1 Kansas annual and cumulative oil production from Carr et al. 1995a. Mississippian reservoirs comprise one of the largest producing intervals in the state. Also available on-line through the Internet (http://www.kgs.ukans.edu/PRS/publication/OFR95_42/tim1.html).

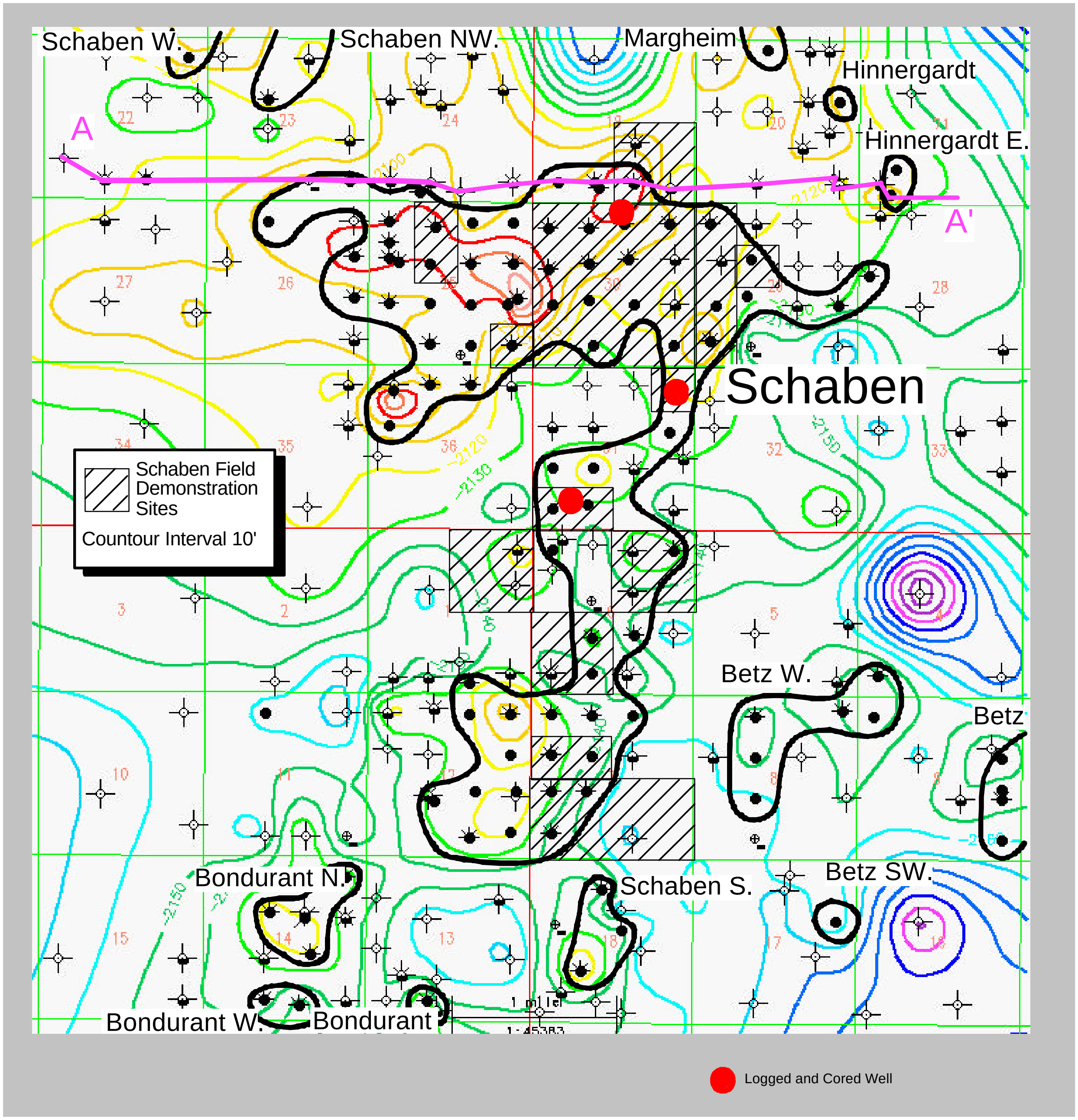

FIGURE 1.2. Schaben Field demonstration site with structure on top of the Mississippian Limestone. The Schaben Field outline and location of leases involved in demonstration are indicated. Location of the three wells, drilled, logged and cored as part of the demonstration project, are also indicated.

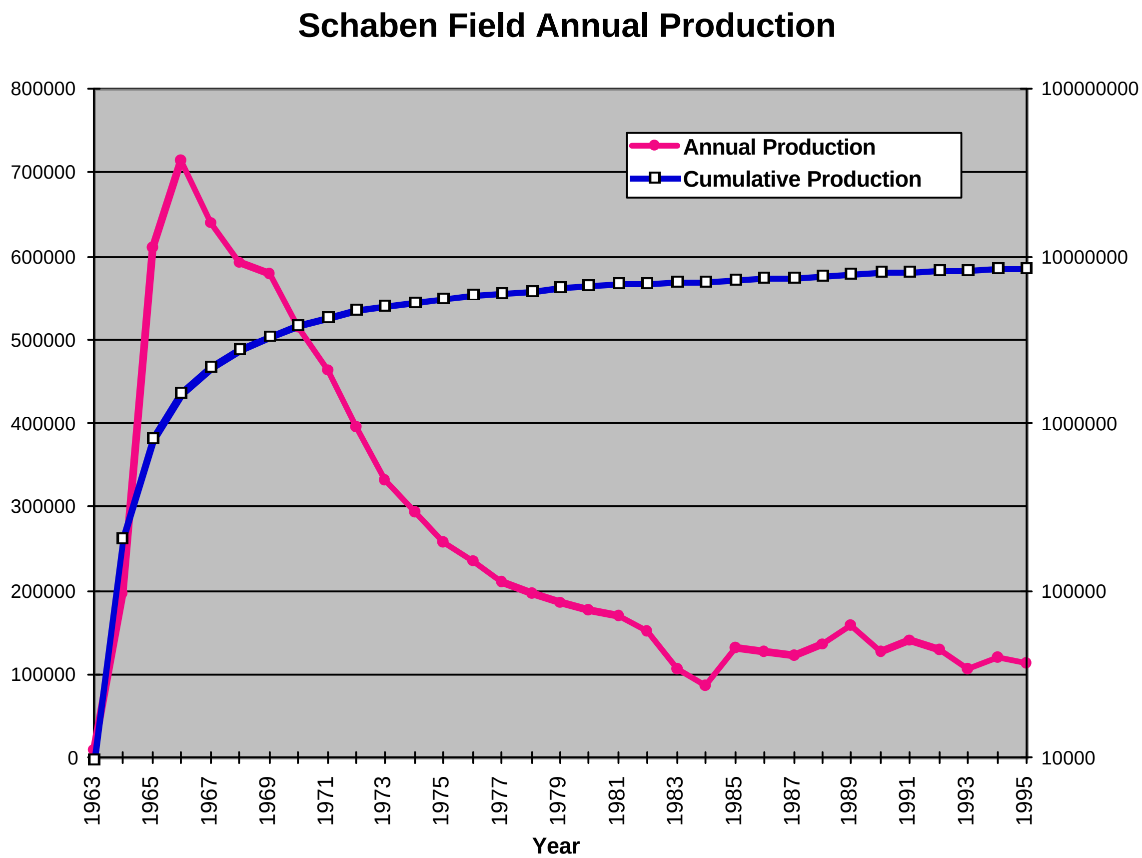

FIGURE 1.3. Annual and cumulative field production for the Schaben Field Ness County, Kansas.

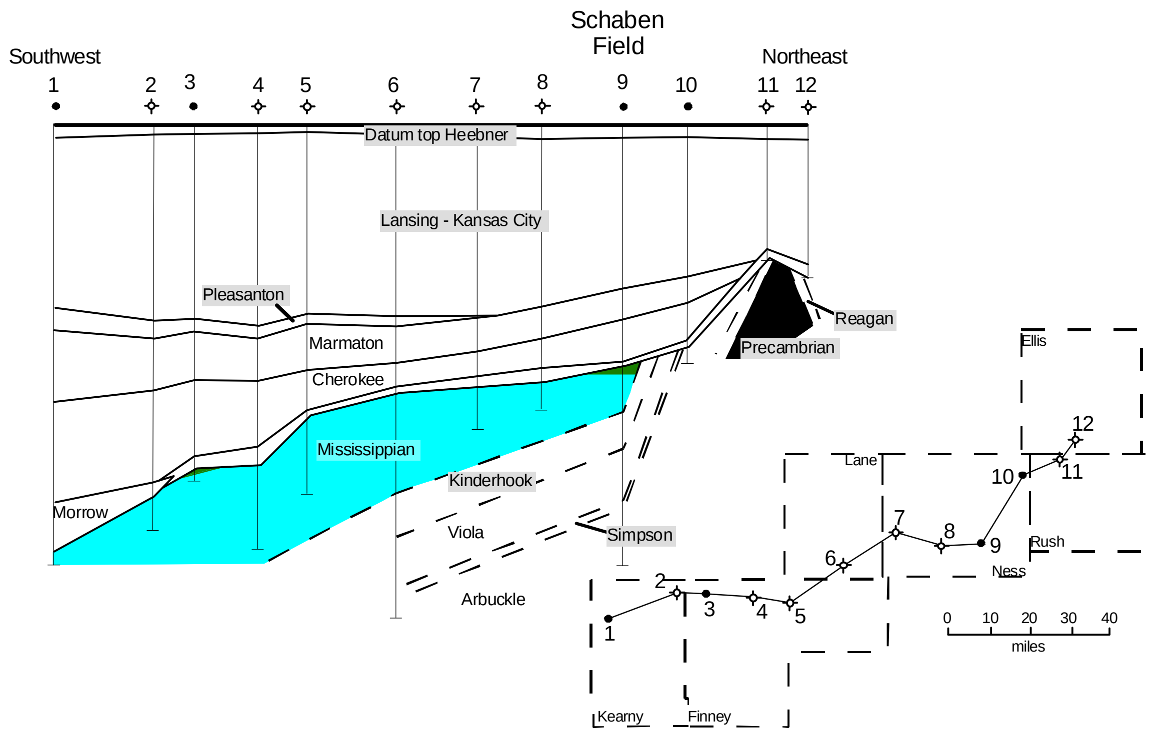

Figure 1.4. Regional southwest-northeast cross-section showing relation of Mississippian and older rocks to the pre-Pennsylvanian unconformity. Location of the Schaben Field demonstration site is indicated by the shaded area at the top of the Mississippian at well 9. Modified from Goebel and Merriam (1957).

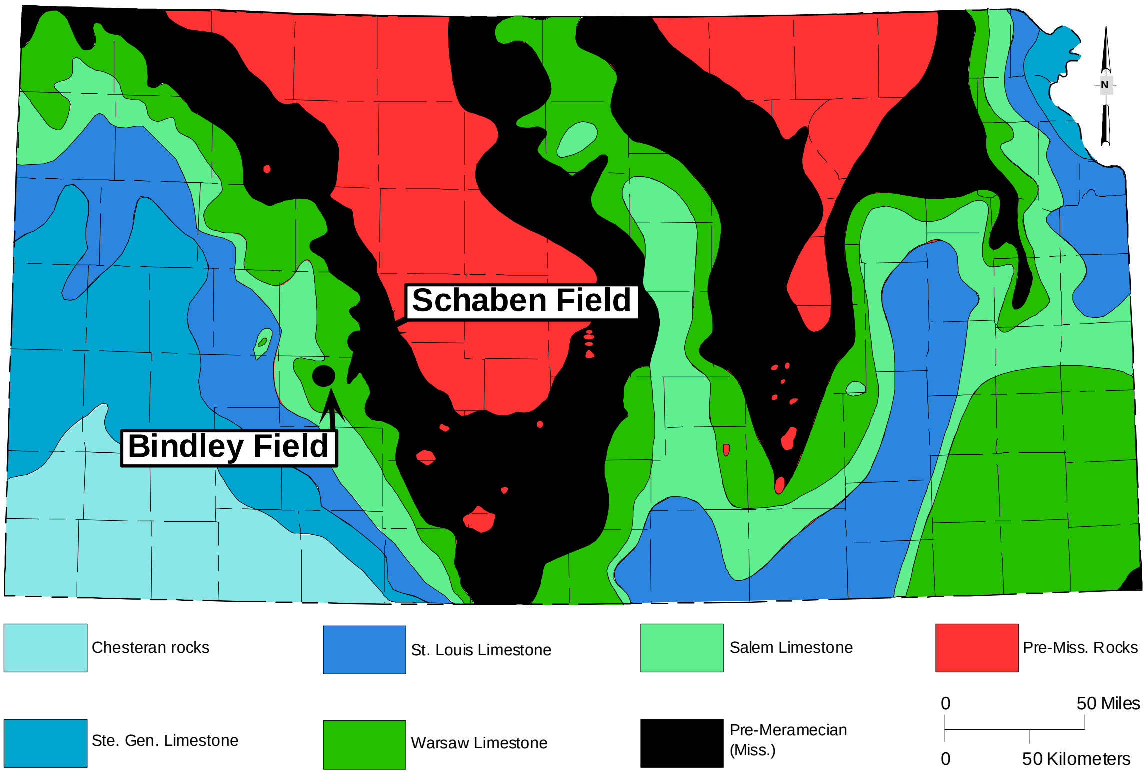

FIGURE 1.5. Mississippian subcrop map beneath the Pennsylvanian unconformity showing location of Schaben Field. Mississippian units beneath the unconformity become progressively older and are absent on the Central Kansas uplift.

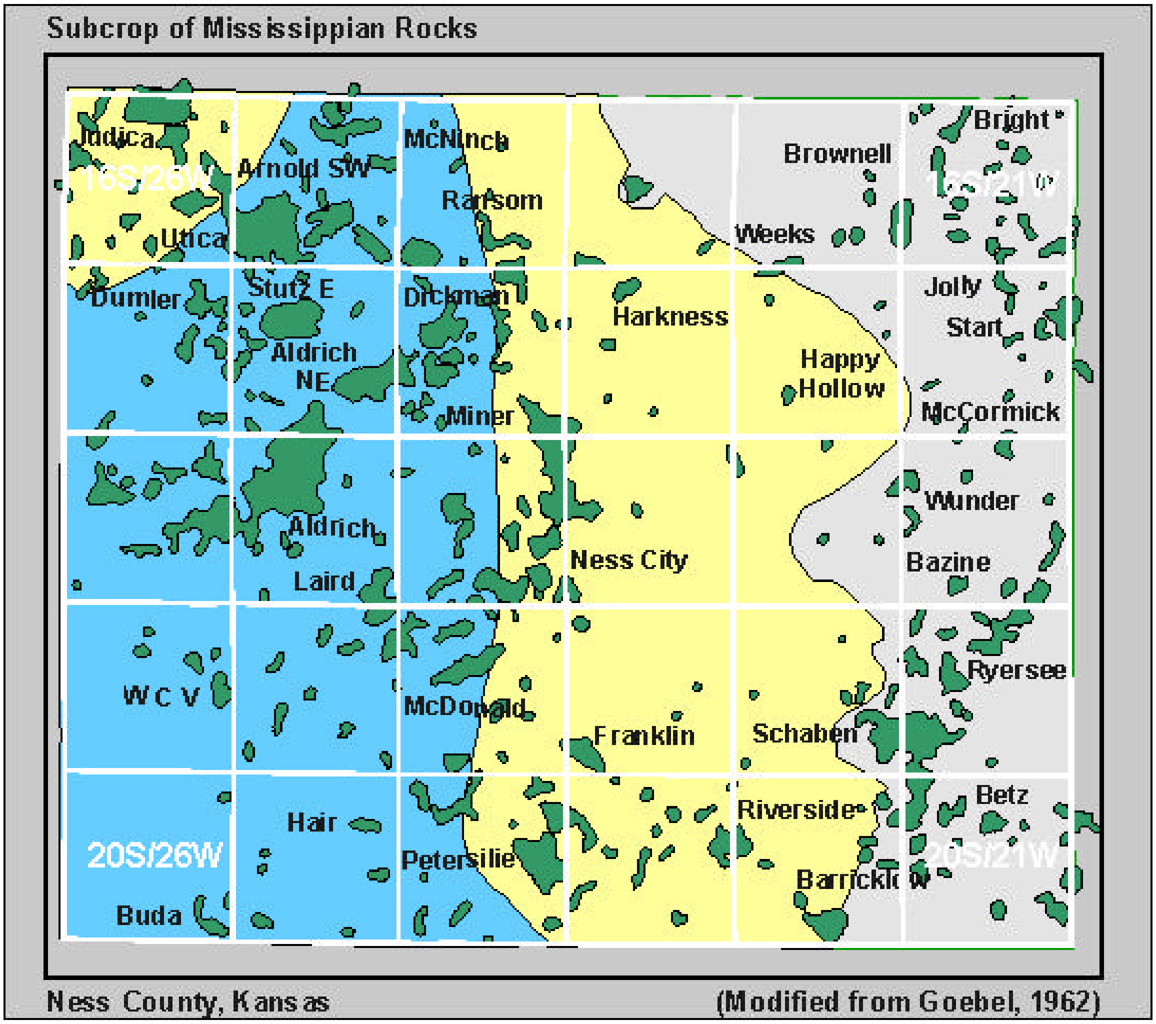

FIGURE 1.6. Mississippian subcrop map and structure on top of the Mississippian for Ness County Kansas. Field outlines for Mississippian production are shown. Schaben Field is located in the southeast corner of the county. Map available on-line through the Internet (http://www.kgs.ukans.edu/DPA/County/ness.html).

2.0 DISCUSSION

The general goal of the project is the application of existing cost-effective recovery technologies to extend the economic life of selected fields producing from shallow shelf carbonate reservoirs, and the innovative dissemination of the data, methodologies, and results for the purpose of fostering wider application of demonstrated technologies to other fields. The specific goal is to identify areas of unrecovered mobile oil in Osagian and Meramecian (Mississippian) dolostone reservoirs in western Kansas through integrated, multi-disciplinary reservoir characterization, and the demonstration of incremental primary recovery at the Schaben Field Demonstration Site.

At the Schaben site, integrated, descriptive reservoir characterization provides the basis for development of a reservoir model. Descriptive reservoir characterization entails integration and creative application of existing data, drilling and coring three new wells through the reservoir interval. Descriptive core analysis, petrophysical and petrographic analysis, calibration of logs and core data, and integration of existing well data into a computerized three dimensional visualization/simulation used to develop a descriptive reservoir model for the Osagian and Meramecian rocks at the Schaben site. This model will be compared to the existing model at the Bindley site to provide a broad foundation of modern geologic and engineering analysis for demonstration of incremental primary recovery through deepening and recompletion of existing wells and targeted infill drilling in this major producing trend.

Acquisition and consolidation of geologic, digital log, and production data are complete and all data have been entered into a database management and analysis system. Data for 267 wells distributed of 36 sections in and surrounding the Schaben project area were collected, edited and loaded into a computer database. Digital well logs for 209 of the 267 wells were obtained and loaded into the database. All digital data is available through a common computer database for use in constructing geologic maps and cross-sections and reservoir analysis (Figure 6).

Log analyses, core analyses and descriptions are underway 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 should be possible with the techniques being used in the Schaben Field project.

2.1 FIELD ACTIVITIES

Three wells were drilled, cored, logged and tested to gather modern data for reservoir characterization. The well history for each of the wells is summarized below.

Ritchie 4 Moore "B-P" Twin
NW NE Sec. 30-T19S-R21W
Ness County, Kansas

Spudded 4/25/95. Reached TD of 4450' (log) 5/5/95. Cored Pennsylvanian conglomerate-Mississippian limestone from 4370-82' and 4390-4443. Ran Halliburton Dual Introduction Laterolog Log before running 5 1/2" casing to 4452'. Ran BPB Neutron 2, sonic, and spectral logs through casing. Final perfs 4412-17' (top Mississippian 4385'). Last one hour swab test before running tubing recovered 14.2 barrels of fluid (23% oil).). Current production is 250 barrels of fluid (6% oil) or 15 barrels of oil per day.

The core from the 4 Moore was analyzed from 4390.4-4399.4', 4410.3-4411.9, 4418.5-4442.8', and of 4443.2' for air and Klickenberg permeability, helium porosity, grain density, water saturation and oil saturation. Eight whole core samples were also analyzed. The core was slabbed, photographed, and described in detail. Thin sections were made of selected reservoir lithologies. Selected core plugs were sent out for magnetic resonance and oil-brine capillary measurements. The core was measured on a 1/4 foot spacing for permeability attributes using a mini-permeameter.

Ritchie 1 Foos "A-P" Twin
NE SW SW Sec. 31-T19S-R21W
Ness County, Kansas

Spudded 8/4/95. Reached TD of 4445' (log) 8/12/95. Cored Mississippian limestone from 4387-4441.5'. Ran BPB Induction Shallow Focused, Neutron-Photo Density, sonic, micro-resistivity, and spectral logs. Ran drill stem test from 4412-24'. Recovered 160' very slightly oil specked water. Ran 5 1/2" casing to 4444'. Final perfs 4394-95.5' (top Mississippian 4388'). Last one hour swab test before running tubing recovered 25.46 barrels of fluid (8% oil). Current production is 105 barrels of fluid (24% oil) or 25 barrels of oil per day.

The core from the 1 Foos was analyzed from 4393.3-4431.6' for air and Klickenberg permeability, helium porosity, grain density, water saturation and oil saturation. Nine whole core samples were also analyzed. The core was slabbed, photographed, and described in detail. Thin sections were made of selected reservoir lithologies. Selected core plugs were sent out for magnetic resonance and oil-brine capillary measurements. The core was measured on a 1/4 foot spacing for permeability attributes using a mini-permeameter.

Ritchie 2 Lyle Schaben "P"
400’ FNL and 400” FEL, NE/4 Sec. 31-T19S-R21W
Ness County, Kansas

Spudded 2/14/96. Reached TD of 4500' (log) 2/23/96. Cored Mississippian limestone from 4409-4466'. Ran BPB Induction Shallow Focused, Neutron-Photo Density, sonic, micro-resistivity, and spectral logs. Ran drill stem test from 4318-4401'. Recovered 30' mud with an oil scum. Ran 5 1/2" casing to 4494'. Final perfs 4400-04' (top Mississippian 4389'). Last one hour swab test before running tubing recovered 12.52 barrels of fluid (22% oil). Current production is 150 barrels of fluid (35% oil) or 53 barrels of oil per day.

The core from the 2 Lyle Schaben was analyzed from 4409-4466' for air and Klickenberg permeability, helium porosity, grain density, water saturation and oil saturation. Selected whole core samples were also analyzed. The core was slabbed, photographed, and described in detail. Thin sections were made of selected reservoir lithologies. Selected core plugs were sent out for magnetic resonance and oil-brine capillary measurements. The core was measured on a 1/4 foot spacing for permeability attributes using a mini-permeameter.

2.2 DATA ANALYSIS AND RESULTS

Acquisition and consolidation of geologic, digital log, and production data are complete and all data are entered into a database management and analysis system (Figure 2.1). Database contains data from 267 wells distributed over 36 sections in and surrounding the Schaben project area. Digital well logs for 209 of the 267 wells were obtained and loaded into the database. All digital data is available through a common computer database for use in constructing geologic maps and cross-sections, and for reservoir analysis (Figure 6). Data is accessible on-line through the Internet (http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.html).

2.2.1 Field Mapping

The Schaben digital database was used to construct a geologic model for the demonstration site and the surrounding region. On the basis of present geologic analysis, the Mississippian is an erosional karst surface. The combination of a karsted erosional surface, the influences of original depositional facies and subsequent diagenesis have had a significant control on development and preservation of reservoir quality. Mississippian (Osagian and Meramecian) reservoirs such as those present at Schaben are extremely heterogeneous. The reservoir is expected to consist of numerous vertically and laterally segregated compartments. Subsequent engineering analysis and simulation support the geologic interpretation.

Structure and isopach maps for the Schaben Field demonstration area were generated for all important stratigraphic intervals (e.g., Figure 2.2). All maps are accessible through the Internet (http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.html). Using the digital well-logs and other well data, a complete network of consistently interpreted north-south and east-west cross-sections was constructed (e.g., Figures 2.3-2.6). All cross-sections display geologic tops, original oil-water contacts and other well data (e.g., logs, perforations, DST's, casing). Stratigraphic correlation was based on traditional log correlation and the results of the "pseudoseismic" analysis (see section 2.2.3). All cross-sections are accessible on-line through the Internet (http://www.kgs.ukans.edu/DPA/Schaben/CrossSect/crossSectH.html).

Production data were generated for each well in the Schaben Field demonstration area using oil sales records that are reported at the lease level. Water production was available for only a limited number of leases and wells. Annual productivity test reported to the Kansas Corporation Commission were used to allocate oil and water production to individual wells. Oil production at the well level and water production at the lease and individual wells were estimated and subject to some error. The errors in this estimation procedure were evaluated where oil and water production were recorded for individual wells. On an annual basis the uncertainty in estimated fluid production appears small. All production data and plots are accessible on-line through the Internet using a clickable field map or custom search routines (e.g., figures 2.7- 2.9).

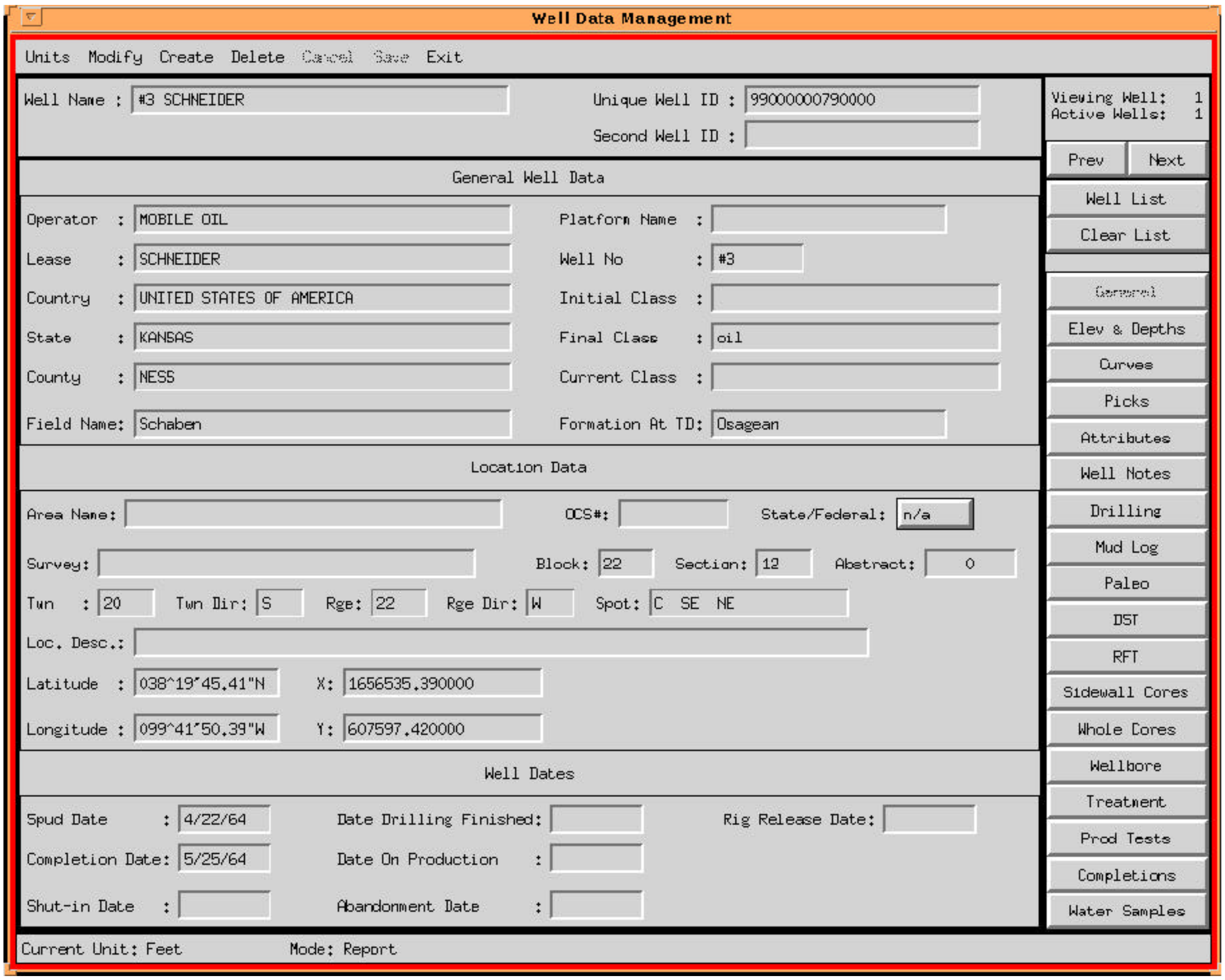

FIGURE 2.1. Sample screen from Schaben Field computer database of well data and logs. Additional data is accessed through buttons on left side of screen. Data is available through the Internet (http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.html).

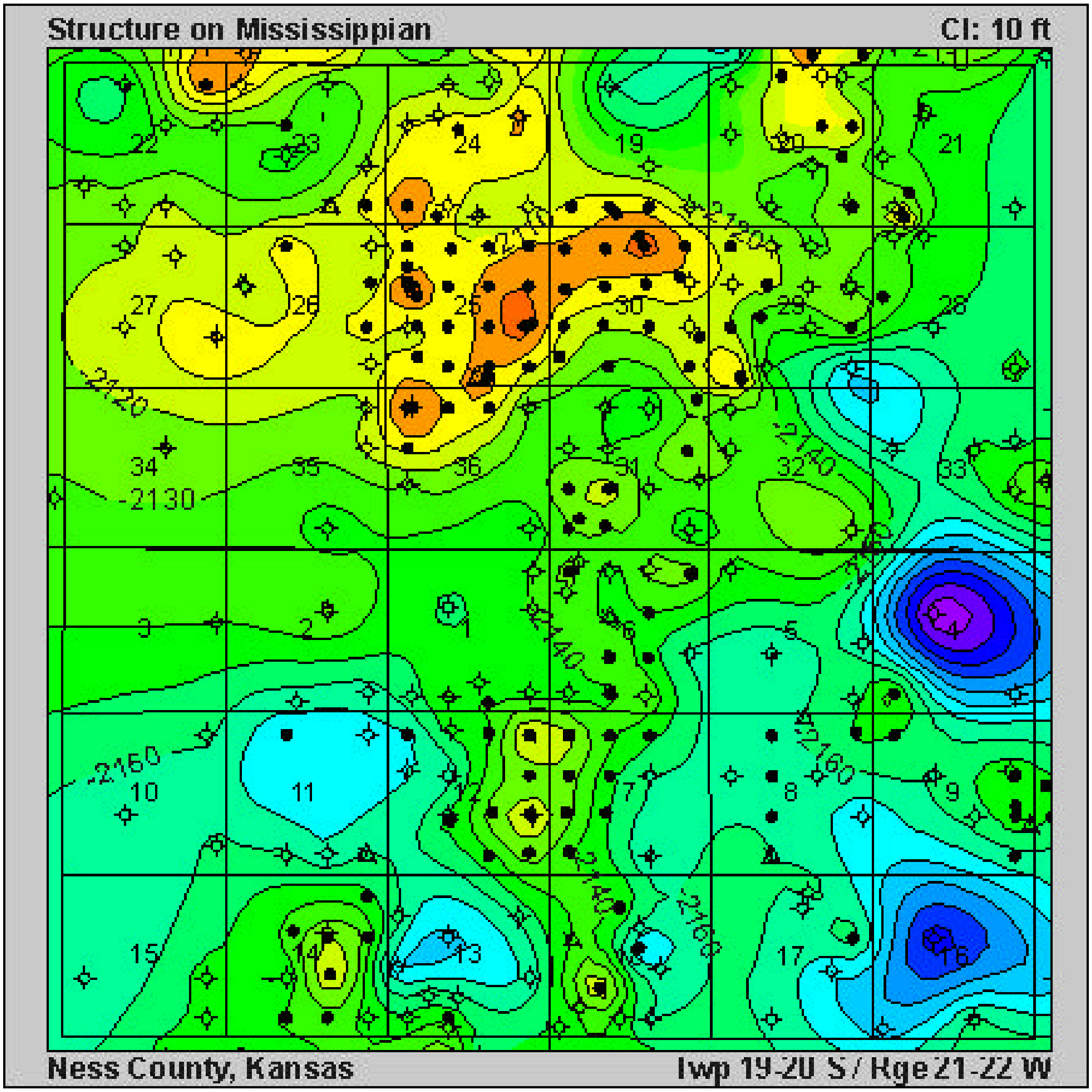

FIGURE 2.2. Structure map on the Mississippian erosional surface over Schaben Field demonstration area. Map shows irregular karst surface on top of Mississippian (Osagian). A selection of structure and isopach maps are accessible through the Internet. Figure was copied directly from the Internet (http://www.kgs.ukans.edu/DPA/Schaben/Geology/schabenGeol4.html).

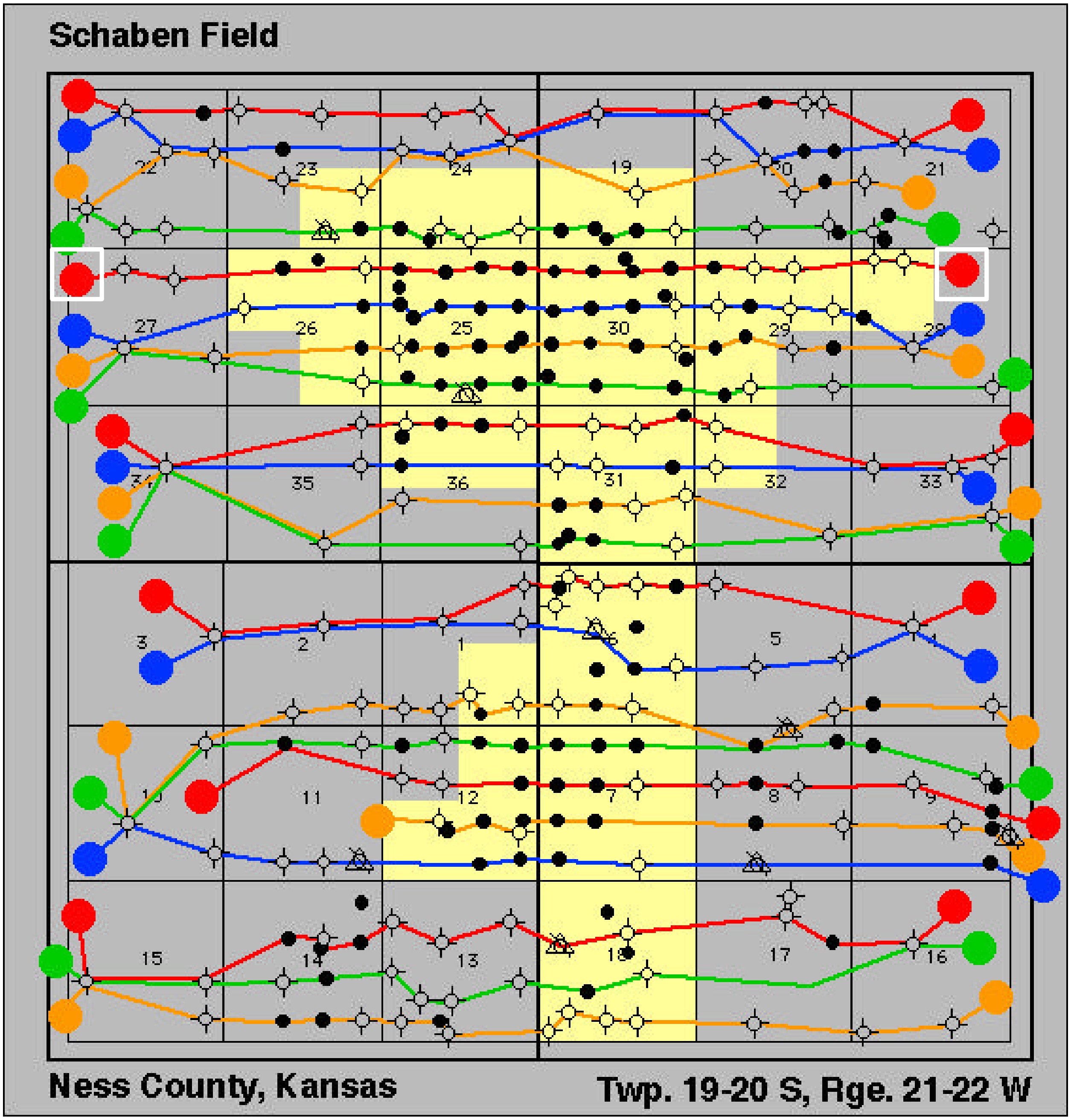

FIGURE 2.3. Map showing east-west cross-sections over Schaben Field demonstration area (http://www.kgs.ukans.edu/DPA/Schaben/CrossSect/crossSectH.html). Map is a graphical user interface and all cross-sections can be accessed on-line by clicking on the appropriate circle. Cross-section shown in Figure 2.4 is highlighted with white squares.

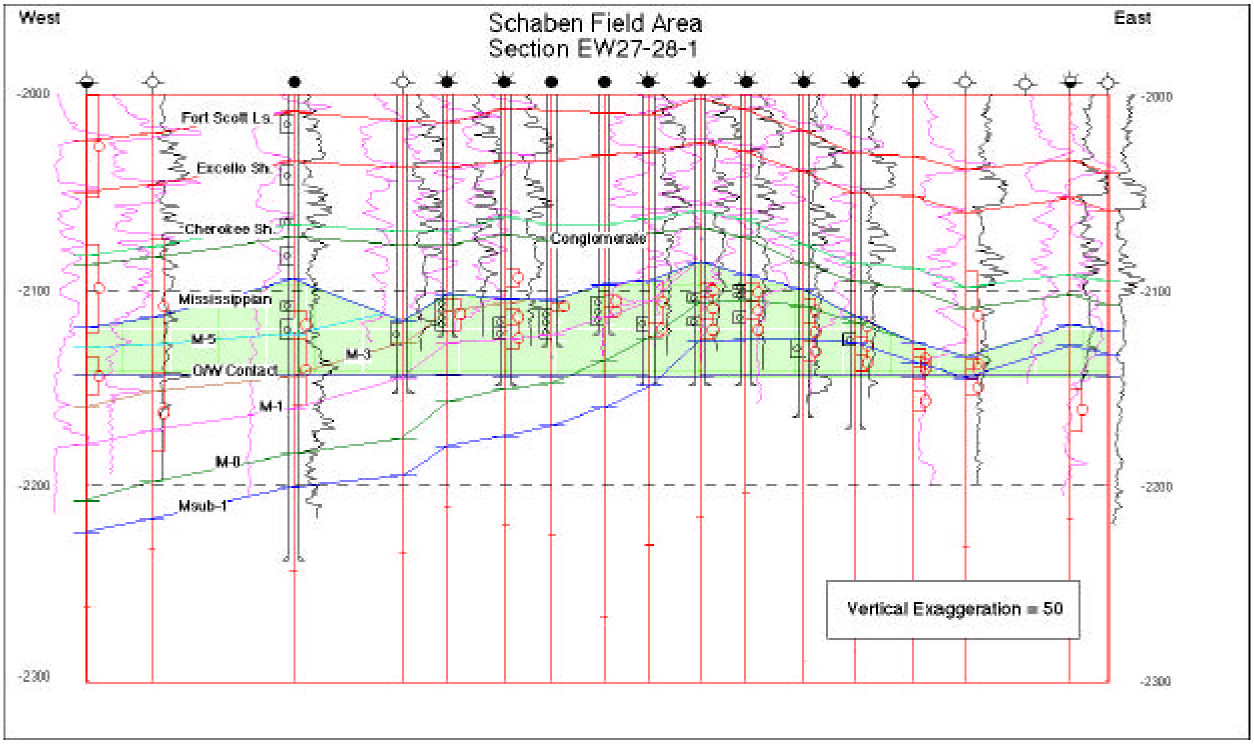

FIGURE 2.4. A selected east-west cross-section across the Schaben Field demonstration area (Cross-section EW27-26-1). Section is accessible on-line through the graphical user interface shown in Figure 2.3. Cross-section shows geologic tops, original oil-water contact and other well data (e.g., perforations, DST's, casing). Cross-section is copied directly from the Internet (http://www.kgs.ukans.edu/DPA/Schaben/CrossSect/EW27281.html).

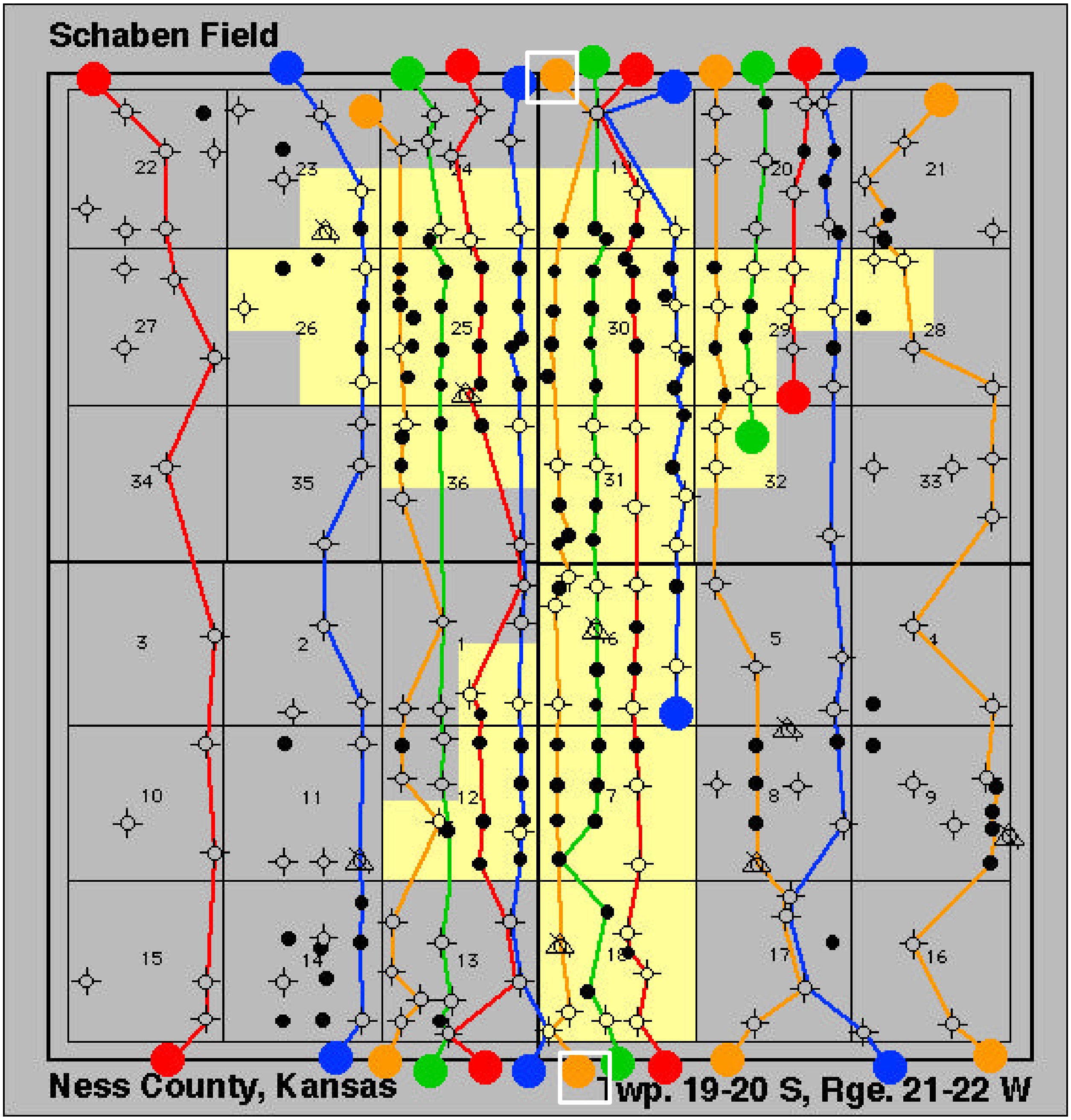

FIGURE 2.5. Map showing north-south cross-sections over Schaben Field demonstration area (http://www.kgs.ukans.edu/DPA/Schaben/CrossSect/crossSectV.html). Map is a graphical user interface and all cross-sections can be accessed on-line by clicking on the appropriate circle. Cross-section shown in Figure 2.6 is highlighted with white squares.

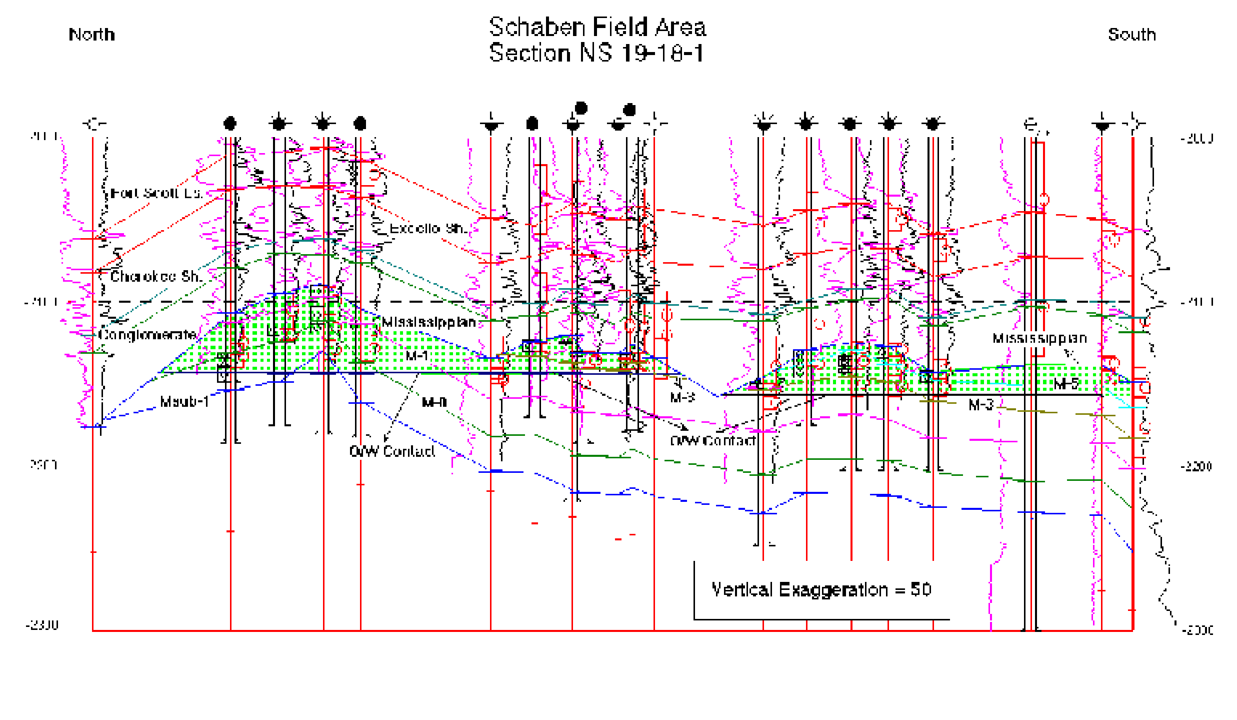

FIGURE 2.6. A selected north-south cross-section across the Schaben Field demonstration area (Cross-section 19-18-1). Section is accessible on-line through the graphical user interface shown in Figure 2.5. Cross-section shows geologic tops, original oil-water contact and other well data (e.g., perforations, DST's, casing). Cross-section is copied directly from the Internet (http://www.kgs.ukans.edu/DPA/Schaben/CrossSect/NS19-18-1.html)

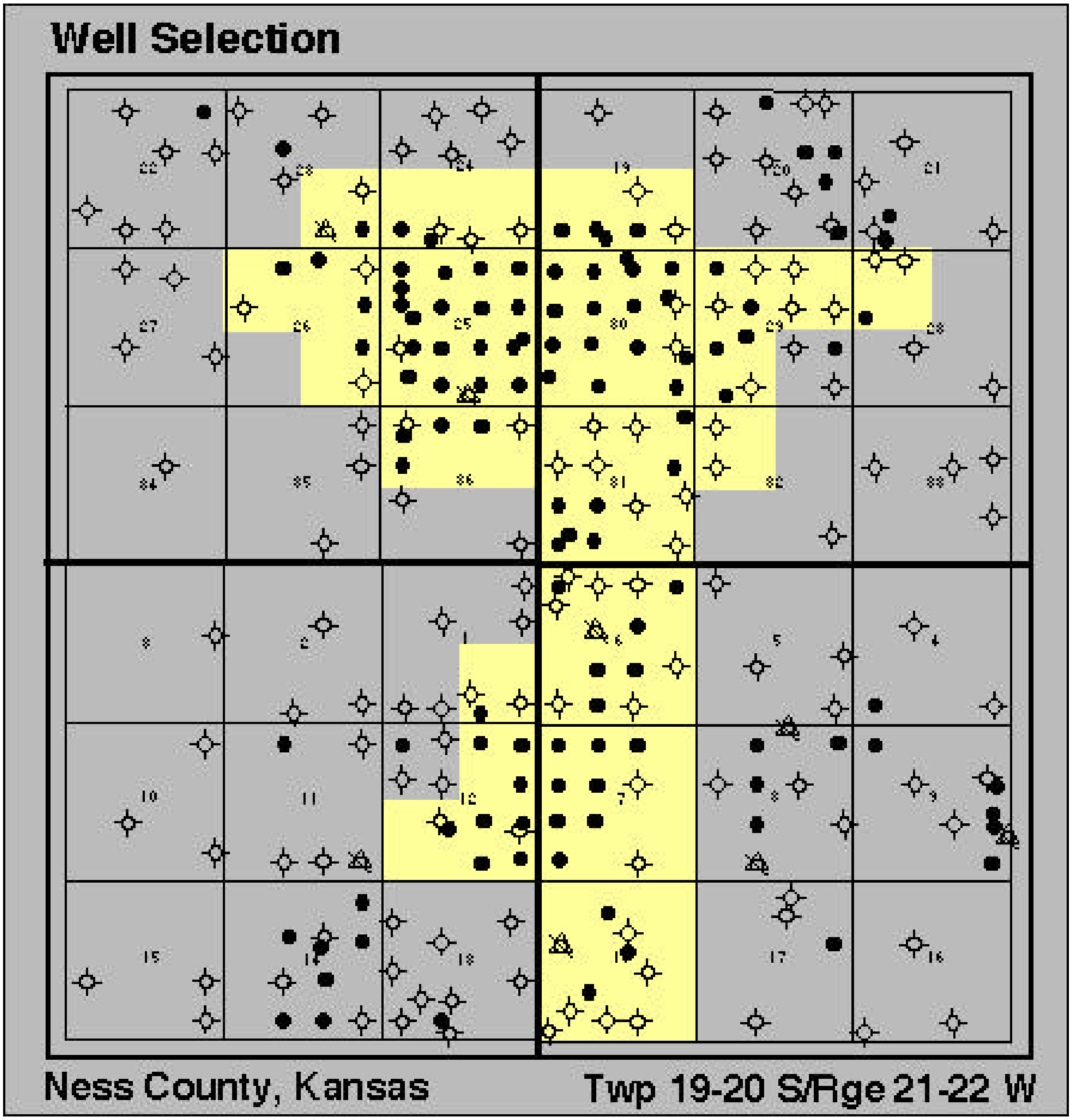

FIGURE 2.7. Map of Schaben Field demonstration area showing location of wells used in the study.. Map is a graphical user interface and all well data can be accessed on-line by clicking on the appropriate well symbol (http://www.kgs.ukans.edu/DPA/Schaben/Wells/schabenWell1.html). Well data can also be accessed by searching on geographic location or API number.

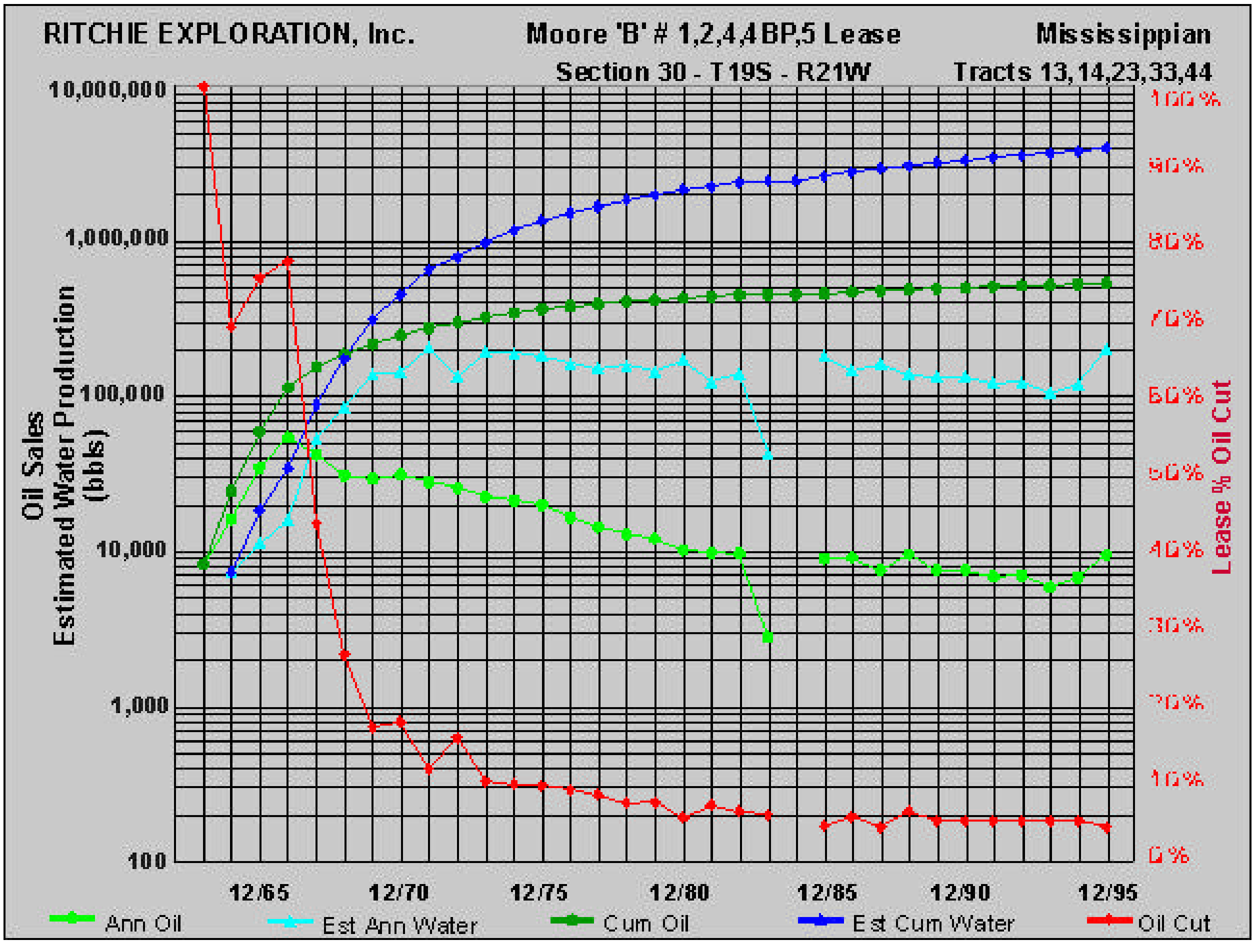

FIGURE 2.8. Fluid production plot for Moore "B" Lease. Oil production is from sales records. Water production is estimated from annual productivity tests. Plots and data are for all wells in the Schaben demonstration area are accessible through the Internet.
http://www.kgs.ukans.edu/DPA/Schaben/Wells/Pro/MooreBpro.html

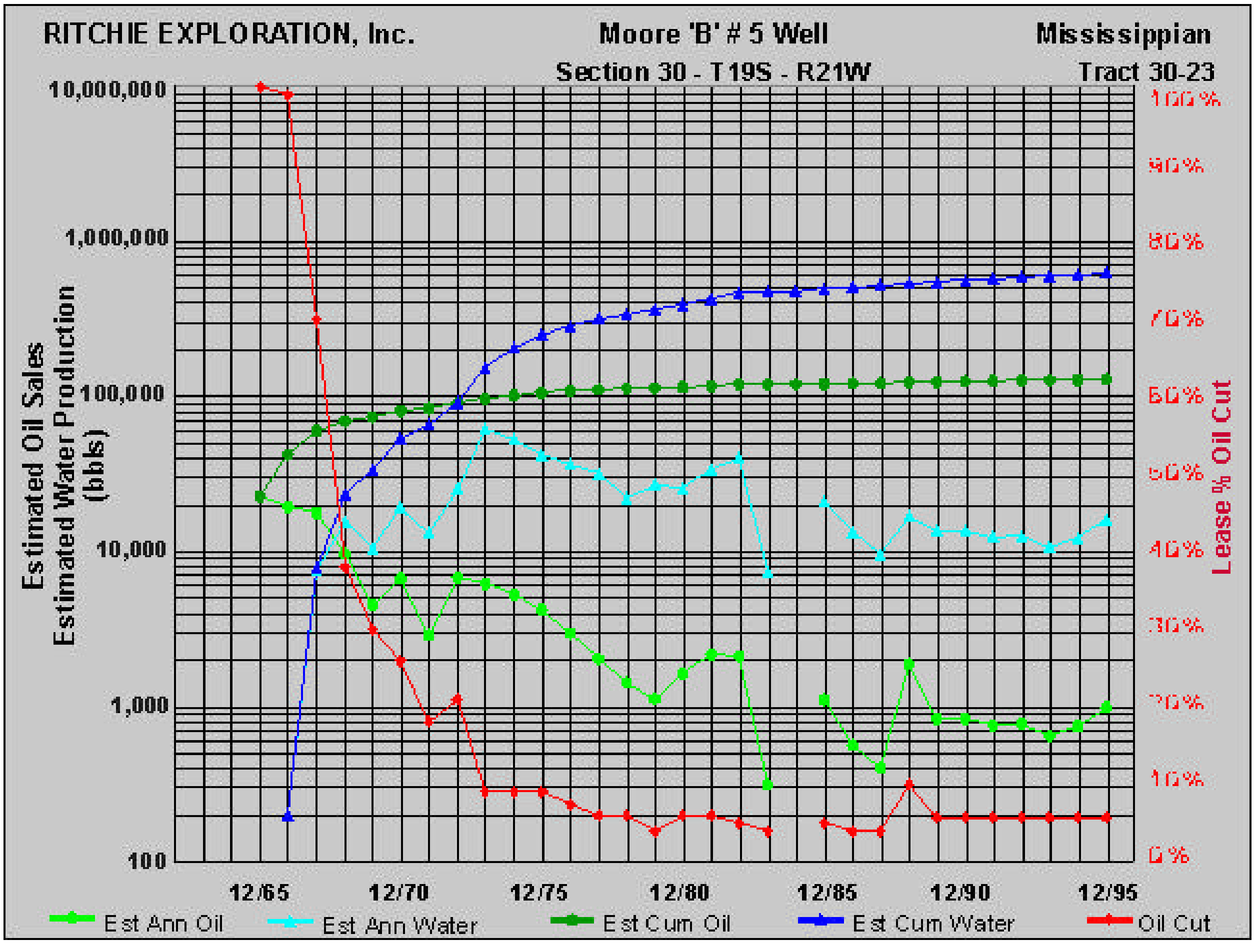

FIGURE 2.9. Fluid production for selected well on the Moore B Lease. Oil and water production are estimated from lease data using annual productivity tests. Plots and data are for all wells in the Schaben demonstration area are accessible through the Internet (http://www.kgs.ukans.edu/DPA/Schaben/Wells/Pro/SCHB14pro.html).

2.2.2 Petrophysical Analysis

2.2.2.1 NMR Analysis

The magnetic resonance technique has rapidly evolved in only the last five years, but offers answers to questions that have puzzled the petroleum industry for years (Akkurt, 1990; Keller, 1990; Kleinberg and Horsfield, 1990; Kenyon, 1992: SPWLA, 1995). The magnetic resonance equipment measures the relaxation rate of hydrogen protons in porous reservoirs when excited by an applied magnetic field. The T2 relaxation time can be related to surface to volume ratio and ultimately to porosity and bulk volume irreducible.

Nuclear Magnetic Resonance (NMR) measurements were determined on 18 core plugs from the three Schaben Field wells drilled under the DOE grant. The magnetic resonance data were used to determine the fluid filled porosity, free fluid porosity, bound water porosity, pore size, grainsize, and irreducible water saturation. NMR data are interpreted as indicating pore size while the capillary pressure indicates pore throat size. After the plug is cleaned and evacuated it is saturated with a brine similar to the reservoir water. The NMR data are then obtained from the saturated core plug. The brine saturated core sample is placed into a "Core Analyzer". The relaxation times (T2) were determined at 5000 points at an inter-echo spacing of 1.2 milliseconds. The core plugs are then placed in a high speed centrifuge to determine the capillary pressure data. At selected pressures, for instance 70 and 100 psi (air-brine), the core plugs are again analyzed by the NMR lab equipment. Centrifuging is then continued until some maximum pressure (1000 psi air-brine) is reached. The final NMR data are then recorded.

Technology advances in the field of NMR logging change daily with new publications and modified techniques (e.g., Chandler et al., 1994, Murphy, 1995). Our work in the Schaben Field used only laboratory measurements. Although recent advances have occurred in wireline open hole measurements and laboratory measurements, our discussion will pertain only to the interpretation of laboratory data.

The most significant change in interpretation of reservoirs is in the determination of the T2 cutoff. The T2 cutoff is the point of division between free fluid or effective porosity, and bound water or ineffective porosity. As a result early field testing, an initial cutoffs of 33 milliseconds for sandstone and 94-100 milliseconds for carbonates were determined. Recent experience with NMR measurements indicates that the cutoff for sandstone remains at approximately 33 milliseconds, but the cutoff for carbonates varies widely from 7 to 100 milliseconds.

The laboratory technique of making NMR measurements with the plug saturated with water similar to reservoir water and then centrifuging to revolutions equivalent to pre-determined pressures are a great aid in locating the T2 cutoff and evaluating the reservoir. The Numar technique for determining the T2 cutoff is where the saturated cumulative porosity crosses the desaturated incremental porosity. Schlumberger believes the cutoff is best indicated by the point of divergence between the saturated cumulative and the desaturated cumulative curves. These "rules of thumb" are not always precise and require the interpreter to make subjective judgments using all available data.

Service company literature indicates that the T2 value from NMR data can be used to determine permeability. Experience in the Schaben Field, which has a very heterogeneous carbonate lithology, indicates that the numerous permeability equations have two short-comings in that they rely on values for T2 and/or porosity. There is normally no direct relationship between porosity and permeability and the value for T2 is not always precise.

The pressure value where NMR data is measured is determined by the lithology and height of oil/gas column. In the Schaben field with its heterogeneous lithology and pay column of only 35-50 feet, the maximum effective pressure is only about 10-40 psi (air/brine). Therefore, the pressure recommended for NMR reservoir evaluation is 70 psi (air/brine), which is equivalent to 350 psi (air/mercury).

Comparison of the reservoir characteristics in laboratory samples using NMR data with air/brine capillary pressure data and thin section petrography is excellent. The use of mercury/air capillary pressure data would increase the resolution of the pore geometry, but would contaminate the core for future use and make it impossible to gain NMR data.

The use of NMR analysis within the Schaben Field can be illustrated by the analyses of three core plugs: the Moore 2 (4394.8'), the Moore 12 (4423.5'), and the Moore 24 (4437.8'). The M-2 is an example of a poor reservoir (Figure 2.10). The M-2 sample has a core porosity of 7.6% and a core permeability of 0.036 md. The T2 cutoff is at 5-7 milliseconds. NMR analysis indicates a total porosity of 7.34%, and a bound water porosity of 4.63%. Thus, the effective or free fluid porosity is only 2.71%. Figure 2.10 illustrates that almost all of the bound water porosity has a T2 value of less than 7 milliseconds, and places it in the zone of microporosity similar to that in shale. Even the free fluid or effective porosity never exceeds 20 milliseconds, and even the best reservoir quality in the core plug has very fine pores.

The M-12 is an example of an excellent very fine crystalline unimodal homogeneous dolomite. The M-12 sample has a porosity of 19.8%, and a permeability of 8.54 md. NMR analysis indicates a total porosity of 19.89% and a bound water porosity of 3.21%. Thus, the effective or free fluid porosity is 16.68 %. The saturated incremental porosity curve (Figure 2.11) is almost totally between a T2 value of 35 to 200 milliseconds. Using a T2 cutoff of 35 milliseconds indicates that the reservoir has a homogeneous unimodal pore geometry. The absence of pores above 200 milliseconds indicates that the reservoir has no vugular porosity, and is verified by examination of thin-sections.

The M-24 is an example of a very fine crystalline bimodal dolomite with a core porosity of 14.7% and a core permeability of 149 md. The T2 cutoff is at 50 milliseconds (Figure 2.12). The NMR analysis indicates a total porosity of 14.74%, a bound water porosity of 6.09% and a free fluid or effective porosity of 8.65%. The saturated incremental porosity curve indicates that the dolomite reservoir has a T2 value from 50 to 2000 milliseconds. Analysis would indicate that the T2 values between 50 and 200-225 milliseconds represent a dolomite with fine pores and that T2 values exceeding 200 milliseconds represent large vugular porosity, some of which is not effective. Comparisons with thin sections confirm the NMR observations.

The NMR data from these three core plugs were determined at a pressure of 1000 psi (air-brine) and are therefore too optimistic for the Schaben Field where data should have been analyzed at about 70 milliseconds. However this does not affect the interpretation to any significance.

Another good example is to compare the capillary pressure, NMR, and thin sections of Schaben 22 and 27 core plugs. Schaben 27 has little to no effective porosity (9.86%, total 17.27% from NMR while Schaben 22 has excellent effective porosity (11.38%, total 18.82% from NMR). Comparison of the thin sections indicates that the Schaben 22, although appearing very similar to the Schaben 27, has a much higher amount of effective porosity. The primary difference is that Schaben 22 is a mottled, wispy mudstone wackestone, while Schaben 27 is a very homogeneous mudstone. The capillary pressure curves of the two core plugs verify that Schaben 22 has a greater percentage of effective porosity.

The reservoir data, determined by the NMR, capillary pressure, and thin sections, were used to determine reservoir parameters used in the reservoir evaluation and simulation.

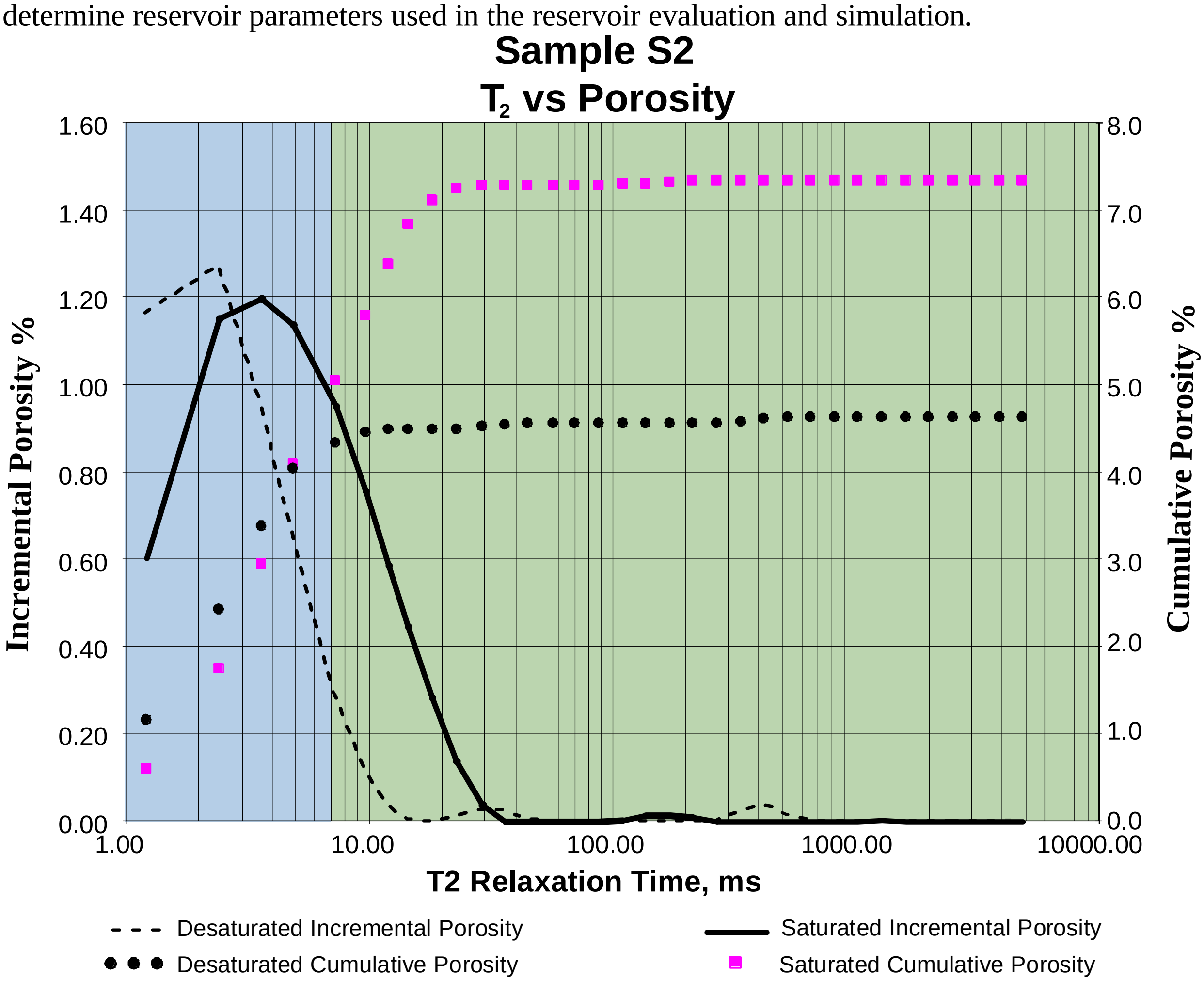

FIGURE 2.10. NMR analysis from Sample 2 (4394.8') in the Moore "B-P" Twin. The T2 cutoff is at 5-7 milliseconds. NMR analysis indicates a total porosity of 7.34%, and a bound water porosity of 4.63%. Thus, the effective or free fluid porosity is only 2.71%.

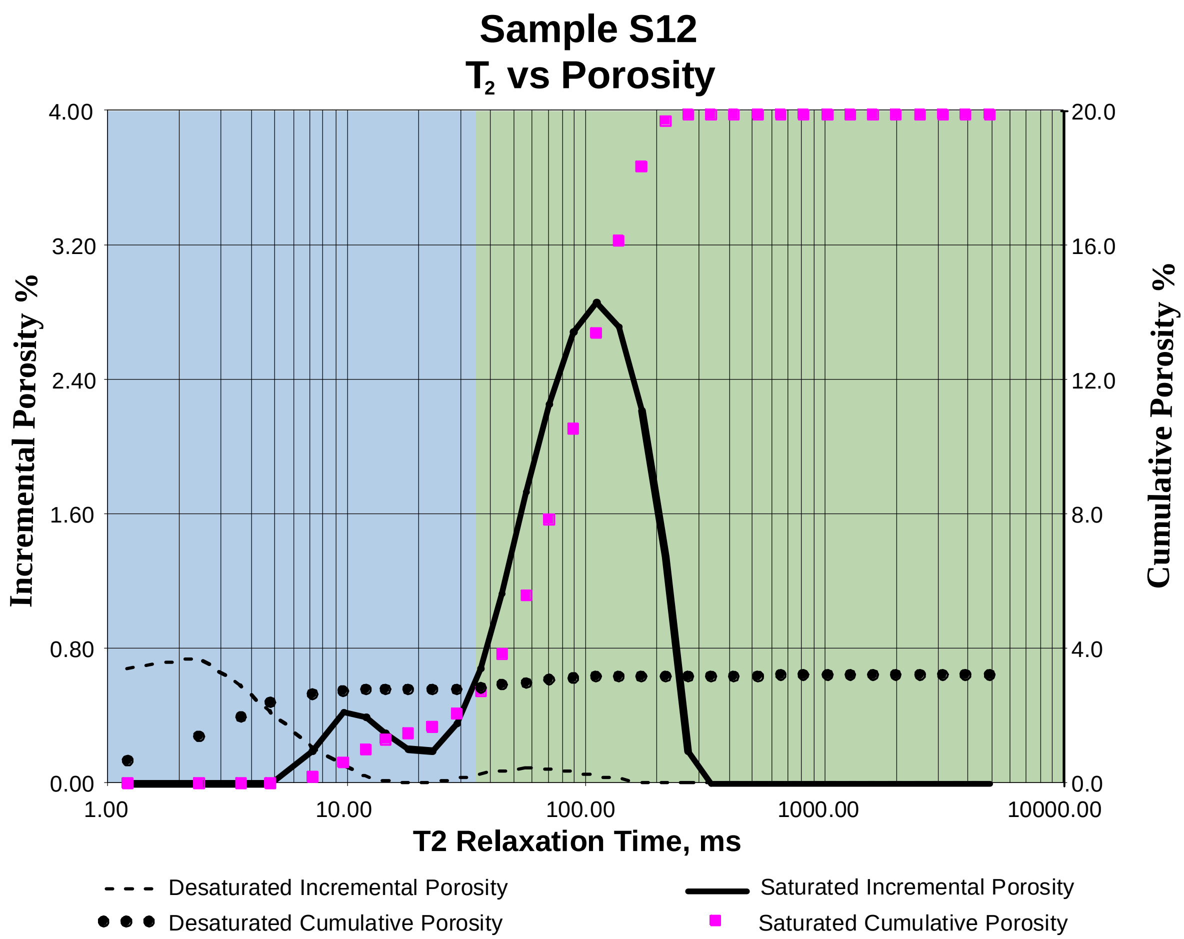

FIGURE 2.11. NMR analysis from Sample 12 (4423.5') in the Moore "B-P" Twin. The M-12 is an example of an excellent very fine crystalline unimodal homogeneous dolomite with a porosity of 19.8%, and a permeability of 8.54 md. NMR analysis indicates a total porosity of 19.89% and a bound water porosity of 3.21%. Thus, the effective or free fluid porosity is 16.68 %.

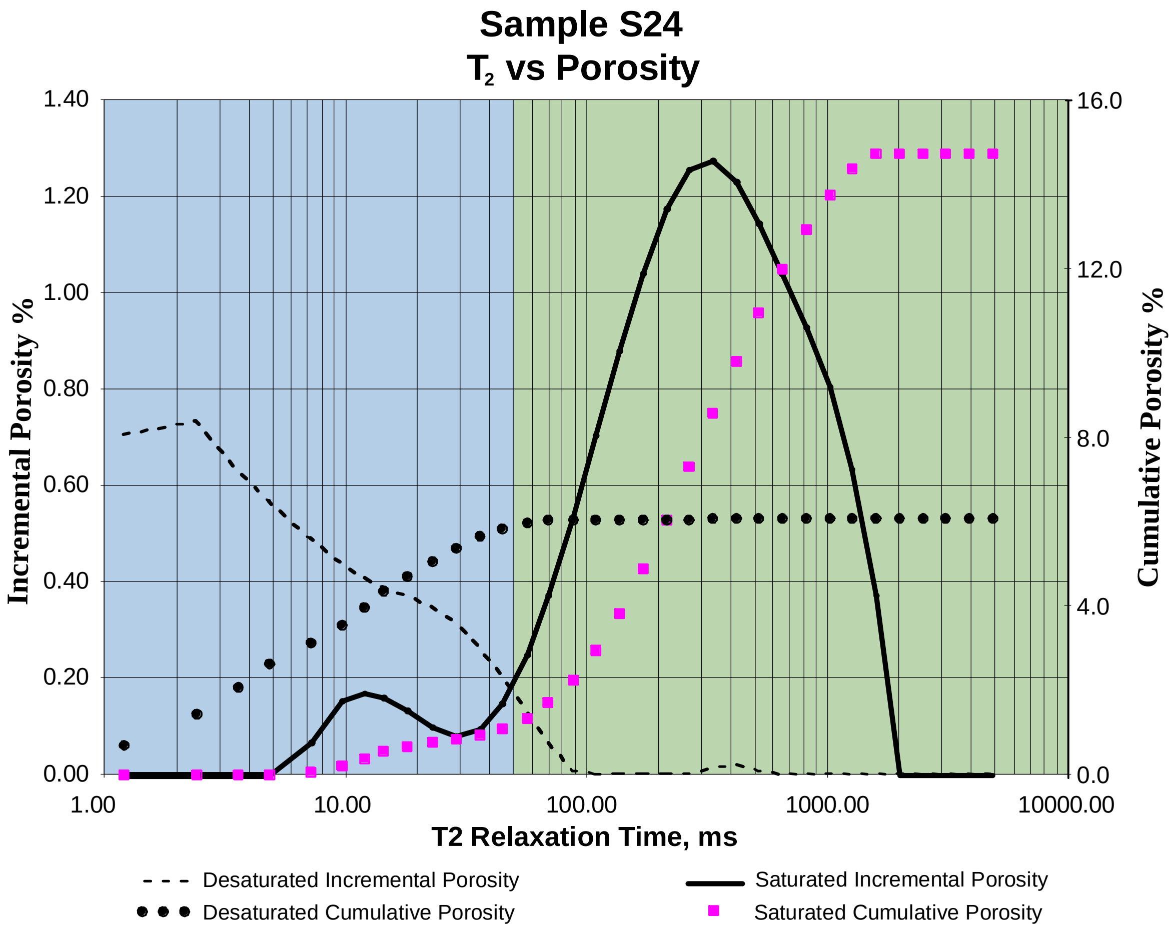

FIGURE 2.12. NMR analysis from Sample 24 (4437.8') in the Moore "B-P" Twin. The M-24 is an example of a very fine crystalline bimodal dolomite with a core porosity of 14.7% and a core permeability of 149 md. The T2 cutoff is at 50 milliseconds (Figure 2.12). The NMR analysis indicates a total porosity of 14.74%, a bound water porosity of 6.09% and a free fluid or effective porosity of 8.65%.

2.2.2.2 Capillary Pressure

Air-brine capillary pressure measurements were taken on 18 core plugs from the three Schaben Field wells drilled under the DOE grant program. These were taken using a high speed centrifuge. Capillary pressures were taken to study the pore geometry, the height of oil column, the irreducible water saturation, and the effective porosity. These measurements were taken in association with a Nuclear Magnetic Resonance (NMR) study. Air-mercury capillary pressure measurements, which are less expensive, were not done because of the mercury contamination that would not permit NMR measurements to be made.

Air-brine capillary measurements were made primarily at pressures of 7, 10, 20, 40, 70, 100, 200, 400, 700, and 1000 psi. However, if we take the normal maximum carbonate pore size cutoff of 0.5 microns, any pressure higher than 40 psi will not be of value in the reservoir evaluation. The Schaben Field has only a 35-50 foot oil column that is equivalent to about 10 psi (air-brine). Thus, in reality, no pore-size less than about 2.0 microns will be effective.

The capillary pressure data, therefore, indicates that the Schaben Field will have a water saturation of approximately 50% even though the “irreducible” water saturation of some of the reservoir can be as low as 20% at 1000 psi (air-brine). This low saturation would be in non-effective microporosity.

The air-brine capillary data indicates that the Schaben reservoir is primarily unimodal in pore size within a very fine crystalline dolomite. Pore size histograms made from the capillary data shows that most of the effective reservoir has macro porosity (2-10 microns). A few of the core plugs have a bi-modal porosity, yet NMR data indicates that many of the larger vugs are not effective unless they are connected by microfractures.

The use of capillary measurements remains as an under utilized reservoir evaluation tool. Results in the Schaben Field using capillary measurements in association with NMR data and petrography using thin sections were very useful in understanding the reservoir.

2.2.2.3 Minipermeameter

In order to analyze the degree of vertical stratification present in Schaben Field, permeability values were measured in all three cores using a portable field permeameter (minipermeameter). The values obtained using the minipermeameter were compared with permeability analyses of plugs taken from the core at the same interval. Core plug measurements were collected at an interval spacing of approximately 1.0 foot whereas the minipermeameter measurements were collected at an interval spacing of 0.25 feet (3 inches). Because a larger volume of the rock was tested, core plug permeability values were thought to be more accurate than minipermeameter results. Regression analysis allowed us to establish a correlation line between the minipermeameter and core plug permeability results and minipermeameter values were corrected to the equation of this line.

Vertical profiles of minipermeameter and core plug permeability values from the reservoir interval of the Ritchie Exploration, #1 Foos AP Twin are shown in Figure 2.13. The minipermeameter profile demonstrates that a high degree of vertical stratification is present in the reservoir interval. Comparison of the minipermeameter profile to the core plug profile indicates that core plug permeability values were sampled at a spacing insufficient for representing the vertical stratification present in the Mississippian reservoir at Schaben Field. The same type of vertical stratification of flow units is present in the reservoir interval of the Ritchie Exploration, #4 Moore BP Twin and #2 Lyle Schaben P cores (figures 2.14, 2.15).

A plot of minipermeameter values, simplified depiction of facies, fracturing, brecciation and other features as related to these values, and locations of oil staining are shown for the Ritchie Exploration, #1 Foos AP Twin (Figure 2.16).

Further discussion of minipermeameter measurements and the relationship to facies and diagenetic features is given in section 2.2.4.

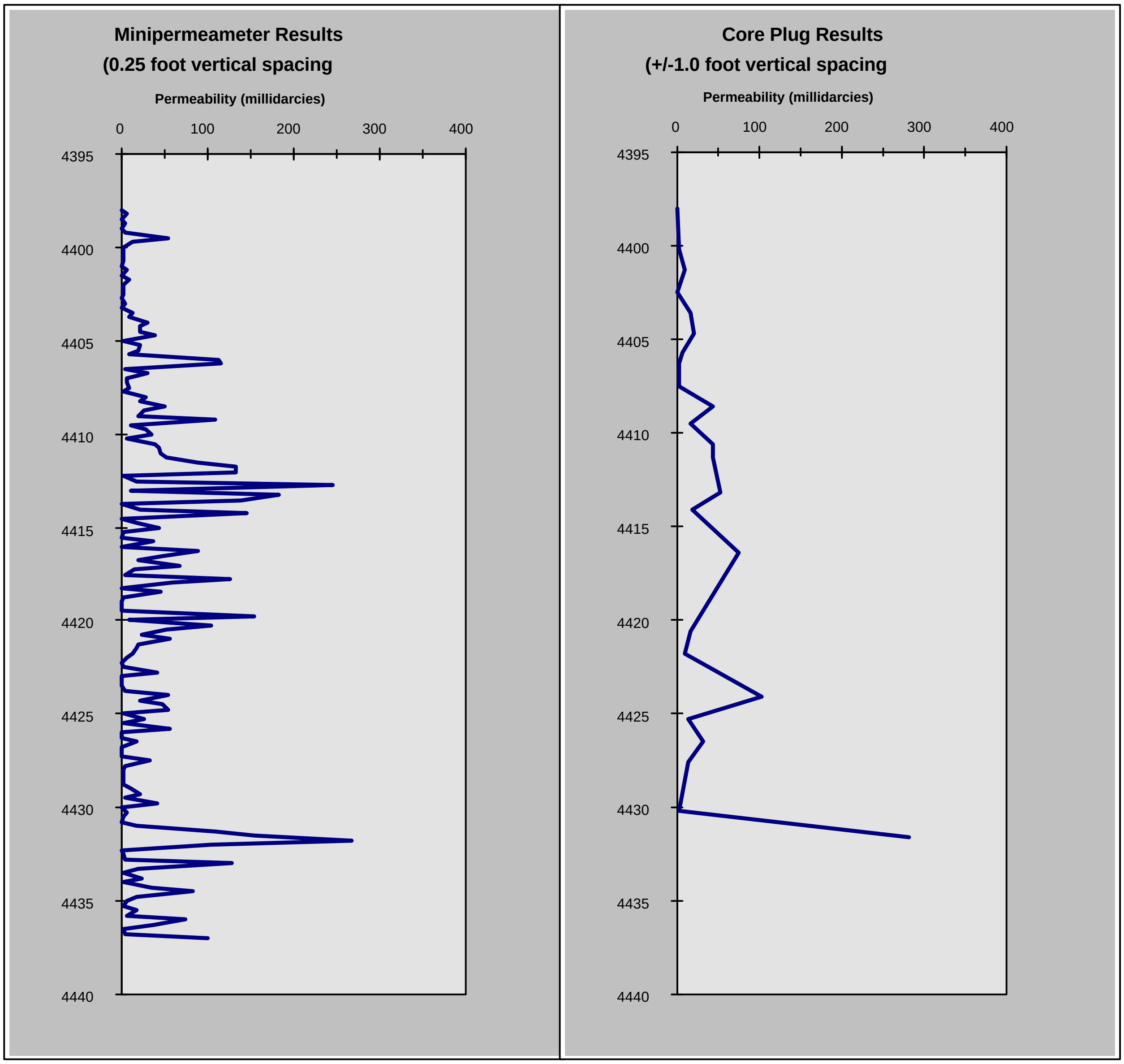

FIGURE 2.13. Vertical profiles of minipermeameter and core plug permeability values from the reservoir interval of the Ritchie Exploration, #1 Foos AP Twin. The minipermeameter profile demonstrates that a high degree of vertical stratification is present in the reservoir. Comparison of the minipermeameter profile to the core plug profile indicates that core plug permeability values were sampled at a spacing insufficient for representing the vertical stratification present in the Mississippian reservoir at Schaben Field

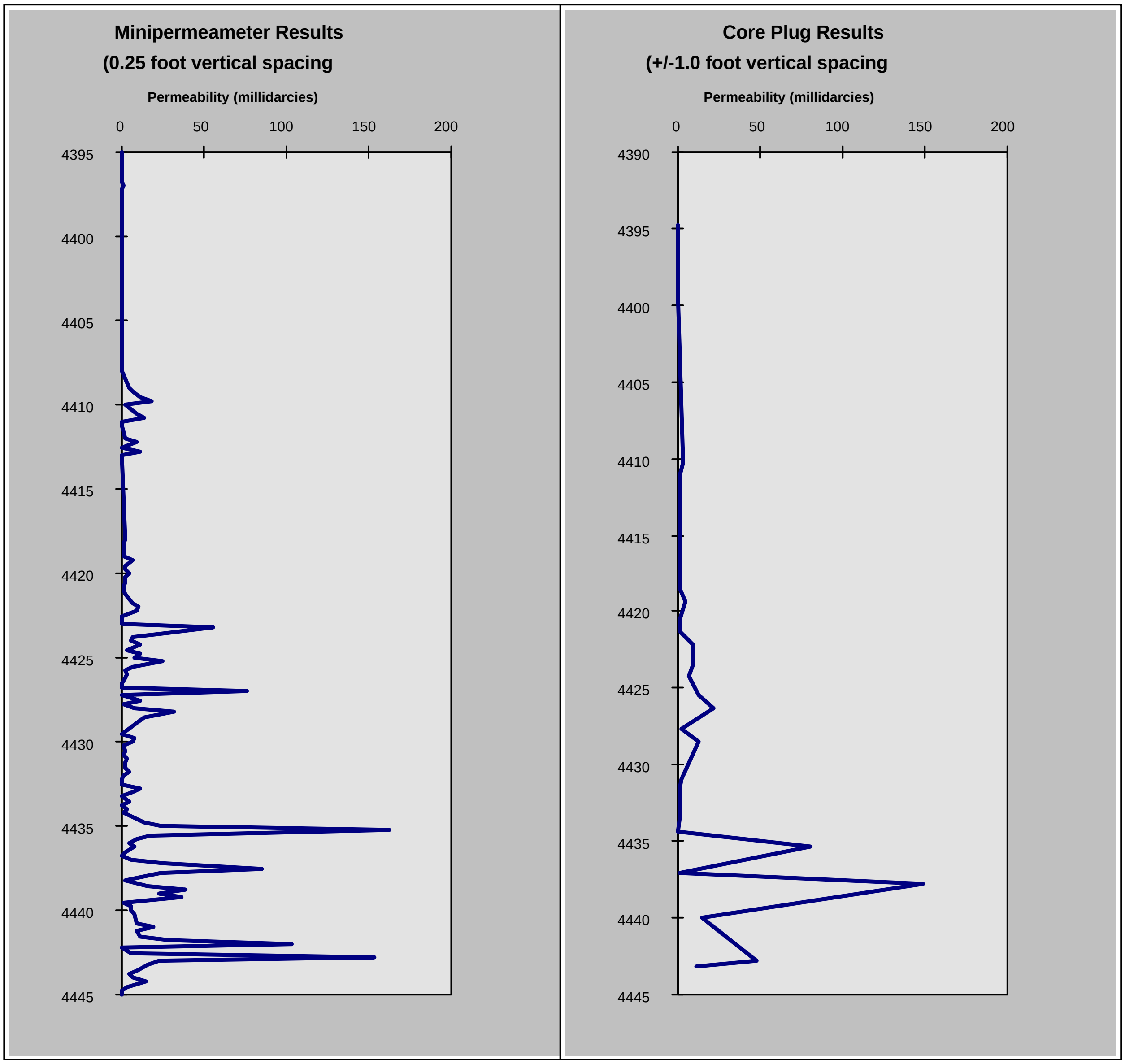

FIGURE 2.14. Vertical profile of minipermeameter values from the reservoir interval of the Ritchie Exploration, #4 Moore BP Twin. The minipermeameter profile demonstrates that a high degree of vertical stratification is present in the reservoir. Comparison of the minipermeameter profile to the core plug profile indicates that core plug permeability values were sampled at a spacing insufficient for representing the vertical stratification present in the Mississippian reservoir at Schaben Field.

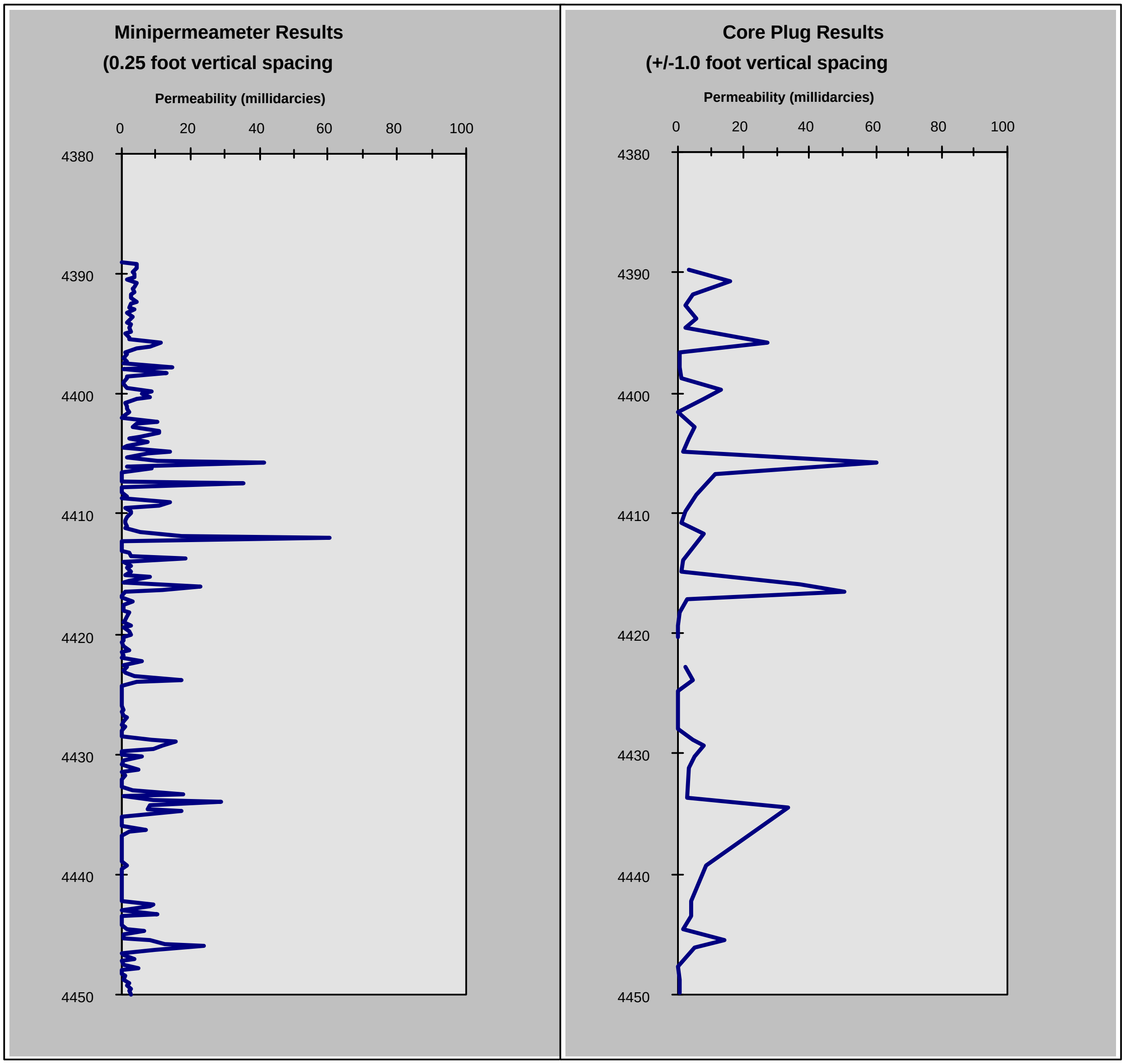

FIGURE 2.15. Vertical profile of minipermeameter values from the reservoir interval of the Ritchie Exploration, #2 Lyle Schaben. The minipermeameter profile demonstrates that a high degree of vertical stratification is present in the reservoir. Comparison of the minipermeameter profile to the core plug profile indicates that core plug permeability values were sampled at a spacing insufficient for representing the vertical stratification present in the Mississippian reservoir at Schaben Field.

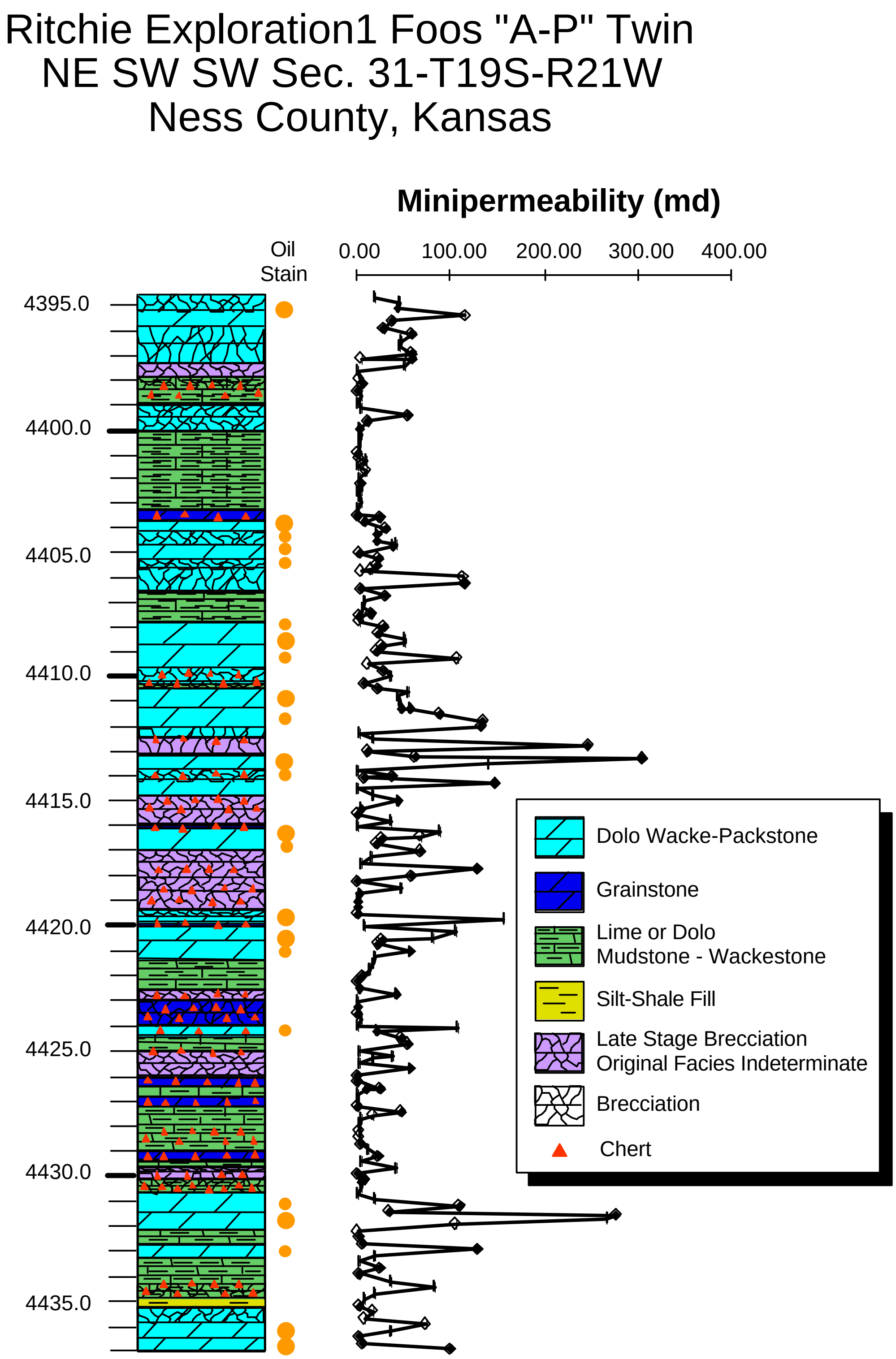

FIGURE 2.16. Graphical core description showing facies discussed in text for the Ritchie Exploration, #1 Foos AP Twin compared with the vertical profile of minipermeameter values. Depositional facies appear to influence permeability development and the reservoir is very vertically heterogeneous. Individual facies are discussed in text.

2.2.2.4 PfEFFER

Petrophysical analysis and reservoir evaluation used a new computer package (PfEFFER) that was developed in conjunction with this project. Prototype software was tested and successfully applied in Schaben Field, and grew out of the "Super-Pickett" crossplot that was initially developed and applied as part of other DOE funding (DOE/BC/14434-13). PfEFFER stands for "Petrofacies Evaluation of Formations For Engineering Reservoirs" (Doveton et al., 1995). PfEFFER v. 1 was released January 2, 1996 as a commercial spreadsheet-based well-log analysis program developed and distributed through the Kansas Geological Survey. PfEFFER v. 1 software was developed as a separate project with one year of additional funding provided by twelve major and small independent companies. Additional funding for development of an enhanced PfEFFER is being provided by industry and BDM/Oklahoma. PfEFFER was designed as a means to obtain timely, inexpensive, but reliable and consistent reservoir characterization using the limited available information, staff, and technical resources (a major problem identified by independent producers).

PfEFFER is an interactive spreadsheet-based program that is designed to run as an add-in to Excel version 5.0 or later and is written in Visual Basic. The minimum logs required are a porosity log and a resistivity log. The focal point of the analytical routines and graphical displays is the "Super Pickett" crossplot, an extension of the standard log-log porosity/resistivity plot. The special features in this crossplot include: tracking the pattern of data points by depth, and annotation of the crossplot with bulk volume water and permeability lines in addition to the standard water saturation lines. Color is used in the data shown on the "Super Pickett" crossplot to display attributes such as well log data, completion information, and other derived data. Color ranges are automatically or manually selected to highlight and emphasize reservoir components, adding new perspectives to the reservoir. Proportions of complex lithologies can be solved with the "RU" option, Rhomaa Umaa plot, if neutron/density porosity and PEF logs are available. A variety of lithologies can be selected and easily changed through menu choices to modify the matrix coefficients. Explicit lithological information can be displayed as attributes on the Pickett crossplot or shown as compositional profiles keyed to depth. Lithology solutions can be presented as attribute colors on the crossplot or the information can be presented along with other depth-related information as a vertical depth display by activating the "LOG" button and corresponding dialog boxes and menus. Log traces can be combined on single or multiple tracks. Additional details can be found in Doveton et al. (1995, 1996).

Well log analyses of the Schaben Field uses the PfEFFER Version 1.0 computer program. Logging suites in the Schaben Field are as diverse as the reservoir. There are about 41 wells that have only the Microlateralog to use in determining porosity, 46 wells have only the uncalibrated neutron for determining porosity, 56 wells with sonic porosity logs, and 23 wells with a combination density neutron porosity. Using the PfEFFER program, we have been able to determine reservoir parameters that are reasonably accurate and comparable, no matter which porosity tools were run. Petrophysical results indicate that the reservoir is highly stratified vertically, of variable lithology (limestone, dolomite, and chert), and has high BVW (Bulk Volume Water). PfEFFER analysis on all wells in the Schaben Field demostration area with an adequate suite of logs provided the input parameters for reservoir simulation. Examples of PfEFFER plots and petrophysical interpretations for the three new wells drilled as part of the project are attached (Appendices A - C). The petrophysical results from the PfEFFER analyses are being tied into advanced core analysis (for example, Minipermeability, Capillary Pressure and NMR).

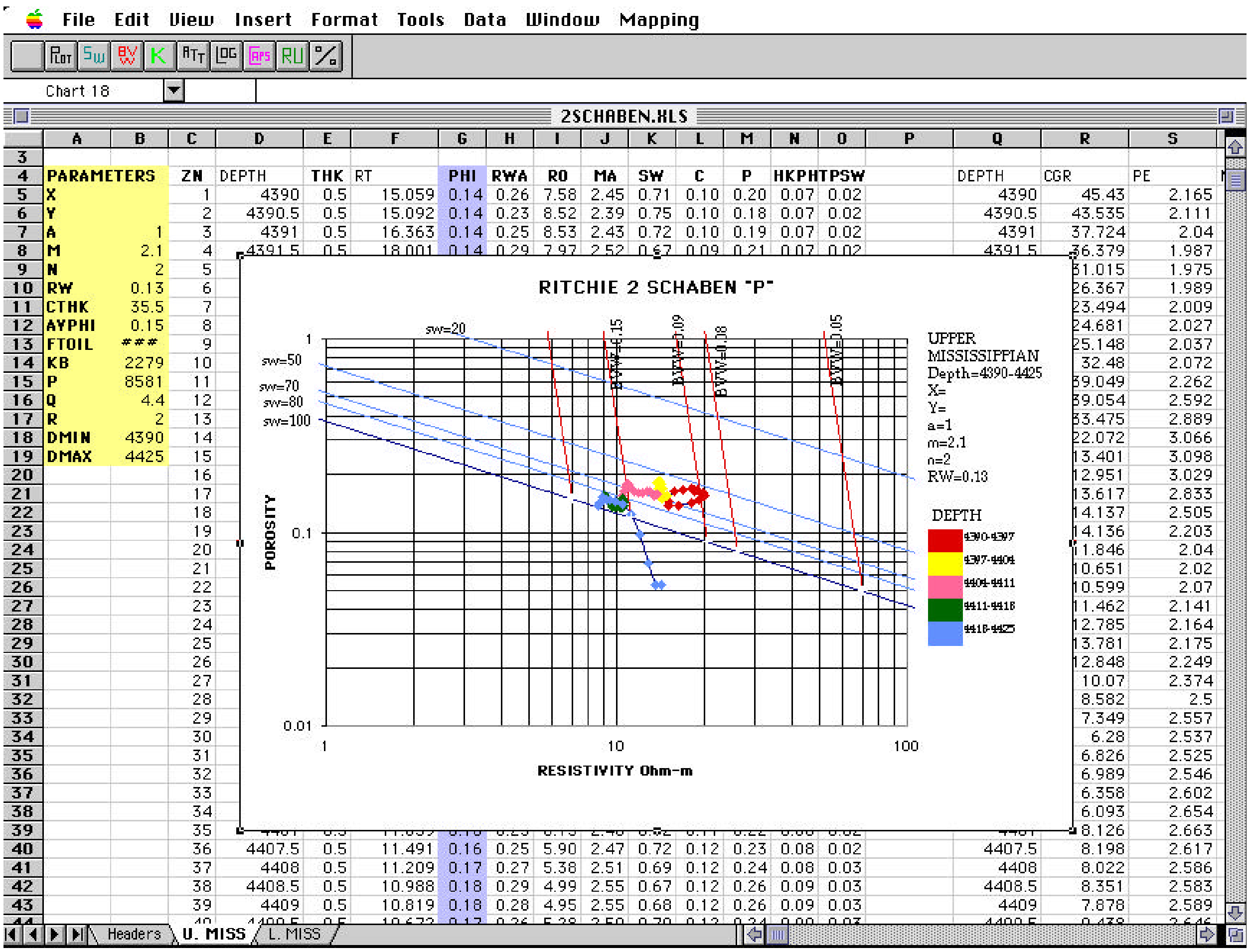

FIGURE 2.17. PfEFFER spreadsheet showing data and structure of the program. The focal point of the PfEFFER analytical routines and graphical displays is the "SuperPickett" crossplot, an extension of the standard log-log porosity/resistivity plot. Specific parameters obtained from the PfEFFER crossplots include minimum bulk volume water and associated porosity and water saturations, permeability estimates, resistivity gradients reflecting hydrocarbon transition zones and depth of possible free water levels, and reservoir zonation/permeability barriers and associated heterogeneities

2.2.2.5 Pseudoseismic Analysis

Additional petrophysical/seismic procedures were developed to modify, load, and display well log data from Schaben Field as a 3D "pseudoseismic" volume (figures 7 - 9). The pseudoseismic volume can be displayed and interpreted on any commercial geophysical workstation (PC or UNIX). At Schaben the "pseudoseismic" approach was used to recognize and map previously unknown small faults and subtle stratigraphic heterogeneities within the reservoir units. The pseudoseismic approach adapts technologies and leverages previously existing data (i.e., electric logs). The pseudoseismic approach developed at Schaben has been presented and published through technical meetings, industry newsletters and technical publications (Carr et al. 1995b; Hopkins et al., 1996; Hopkins and Carr, in press),. Copies of abstracts and manuscripts are attached as appendices (D-F). Numerous producing companies have inquired concerning software and assistance in using the 3D pseudoseismic approach in their projects.

Genesis of a seismic approach to wireline logs arose from efforts to use the computer workstation to integrate geologic and geophysical approaches to subsurface analysis, and the challenge of trying to apply computer-aided exploration and development techniques to mature producing areas that are dominated by well data such as the Schaben demonstration site. Wireline well logs resemble seismic traces in many respects. Fundamentally, both wireline log data and seismic data are simple x-y series. The wireline log records amplitude in the depth domain, and the seismic trace records amplitude in the time domain. Wireline well logging tools record various rock properties and output these data as a depth series. Ultimately, the goal of seismic processing is to approach on a trace-by-trace basis the resolution of geophysical well logs. If wireline logs can be transformed to more closely resemble the seismic trace one can interpret wireline logs within existing seismic interpretation software. This change in approach is labeled *pseudoseismic* . The pseudoseismic approach significantly increases the scope, power, and resolution of the interpretation.

In a series of papers during the 1980's John Doveton and Dave Collins of the Kansas Geological Survey proposed a color image transformation that achieves a significant improvement in the stratigraphic interpretation of wireline log data (Collins and Doveton, 1986, 1989). When well designed, such a transformation of wireline log data from multiple wells can maximize both spatial and compositional information contents, and provide a readily interpretable image of the subsurface geology. They introduced the concept of a color cube subdivided into a series of discrete cells to represent the log data. The planes between cells were selected to coincide with coordinate values that discriminate between lithologies, porosity levels, or shale mineralogy. The transformation operates as an automatic classification device that provides visual meaning. The color image transformation was used to construct single well displays and a single cross-section across western Kansas. The cross-section was constructed on a well-by-well basis, and resembles in many ways a standard 2D seismic display (See: Doveton, 1994, p. 43).

The pseudoseismic approach uses a similar transform of a single curve or combination from multiple tools (e.g., gamma ray, density and neutron) to generate a color coded "crossplot log" for each well as the single trace input to the pseudo-seismic approach. The key is to take the transformed log data and treat it as either 2D or 3D "seismic" data. The actual conversion of digitized well data to pseudo-seismic data is accomplished by a conversion program to transform wire-line or transformed wireline log data into a binary SEGY file.

LAS and SEGY formats are "standard" formats for digital well log and seismic data, respectively. SEGY was designed primarily as a format for recording and processing seismic data. This format consists of a 3600 byte reel header containing general information about the seismic line or survey. The first 3200 bytes of the SEGY reel header are in ASCII and the remaining 400 bytes are binary. Following the reel header are the binary trace data. Each trace also has its own header (240 bytes binary) and is followed by the seismic trace data (Barry, Cavers, and Kneale, 1975). The data are arranged serially. A common starting point (the seismic datum) and time increment (sample interval) are assigned to all traces. The data appear as a listing of numbers, time increasing at an equal interval from left to right across rows and downwards between rows. The data one encounters within a seismic trace are normally seismic reflection amplitudes, or, loosely, waves.

LAS formatted well log data contrast strongly in appearance with SEGY seismic data. LAS was developed to insure that there was a standard digital well log format that anyone with a computer could read (Canadian Well Logging Society's LAS Committee, 1993). The entire well log data set is in ASCII and can be opened like any ASCII file. The data structure is relatively straight forward. The well header contains LAS version, general well, logging parameter, and curve information. The curve data following the header is set up much like a spread sheet. Depth values appear in the far left column followed by one or more data points for that depth, corresponding to the various well logging tools run in that well.

The pseudoseismic transform "maps" LAS header and curve data onto corresponding SEGY data fields creating a file formatted like seismic reflection data. Coding of the pseudo-seismic transform uses a "C" program (Appendix F). The transform reads LAS files containing one curve (depth-value pairs) plus the well header. For instance, if it was desired to transform neutron-porosity readings from LAS to SEGY, files must exist which contain only the well log header and depth-porosity pairs. It is also required that all the digital well logs have the same sample interval. The transform program reads the LAS files, writes portions of the curve header to specific locations in the SEGY trace header, and writes the log data to the SEGY trace data field (Table 1). Data from the well header that are used in the trace header are location (X, Y or latitude and longitude) and kelly bushing elevation. Many of the fields in the reel and trace headers are filled with null values because they have little relevance to well log data. For instance, there are SEGY fields set aside for filter parameters and vibrator sweep characteristics. Data handling and loading are made somewhat easier by using SEGY data fields in the standard manner.

The pseudo-seismic transform combines data from many individual wells and creates a 2-D or 3-D data set. In doing so, the program also assigns a datum for the data set (the largest K. B. value), pads the tops and bottoms of well logs to ensure the "traces" are of equal length and writes this information to a binary SEGY file. Trace spacing is determined from well spacing based on the nearest neighbors to an arbitrary spacing unit (e.g., an 80 acre bin or a 330 foot spacing). Transformation of well locations to trace spacing can be computed rounding to the nearest whole spacing unit or bin. Areas without wells can be represented by empty bins or blank traces. The net result is that the SEGY file contains a structural volume created from geophysical well logs.

After the transform, the ASCII well log data looks like a binary seismic data set. This allows the data set to be loaded into a seismic workstation for display, manipulation, and interpretation purposes. It also facilitates the compiling of very large digital well log data bases, which eases data handling burdens. For example, a cross-section containing 300 gamma-ray traces (one well per mile) was constructed for a project at the Kansas Geological Survey (Figure **???**). If this cross-section had been constructed using 4 inch wide paper logs, at a scale of 4 inches per mile, the section would have been a 100 feet long. A section of this monumental proportions would be unwieldy and impractical. However, as a pseudo-seismic line it contains only 300 traces, about as many traces as a 3 mile seismic reflection line shot with 55 foot C. D. P. spacing, and is readily manipulated or interpreted.

Using a seismic approach to well data can significantly ease the data handling burdens through use of computerized techniques designed for interpretation and display of seismic data. The use of interpretation and processing packages developed for seismic data offers flexibility in displaying and picking horizons, and opens new opportunities for increasing the efficiency of stratigraphic interpretation. The change in approach from the traditional well-by-well examination to treating the wireline logs in a field or basin as a data volume permits comprehensive study and cost-effective analysis of data sets that were previously considered intractable.

The examples from the Schaben demonstration site uses gamma ray logs to map small faults and subtle stratigraphic geometries in the Pennsylvanian rocks overlying the Mississippian reservoirs. Data was “binned” at a 40 acre spacing resulting in a volume that covers approximately six square miles with a trace every 1320 feet (Figure **???**). The “hot” Pennsylvanian core shale make excellent markers that can be traced using the gamma-ray log across the demonstration site (Figure **???**). The pseudoseismic technique was used to effeciently map internal Mississippian markers across the Schaben Field demonstration area.

WELL LOG HEADER & OTHER INFORMATION	SEGY BYTE NUMBERS FOR REEL HEADER	DESCRIPTION
1	3213-3214	Number of traces per record, always 1 for curve data
1000, 2000, ...	3217-3218	Sample interval in feet *1000
XXX	3221-3222	Number of samples per curve
1	3225-3226	Data format: 4 byte floating point
1	3227-3228	Number of traces per record or C. D. P.
1 or 2 ...	3255-3256	Measurement system: 1 = metres 2 = feet
WELL HEADER & OTHER INFORMATION	SEGY BYTE NUMBERS IN TRACE HEADER	DESCRIPTION
1, 2, 3, ...	1-4	Trace sequence number, numbers increase for each curve.
K. B. elevation	41-44	Elevation of well, used to place wells in correct relative vertical position.
Max K. B. elevation	53-56	elevation used as datum
X coordinate or Longitude	81-84	Survey coordinates
Y coordinate or Latitude	85-88	Survey coordinates
1 or 2	89-90	Coordinate units: 1 = length (metres or feet) 2 = seconds of arc
XXX	115-116	Maximum number of samples
1000, 2000 ...	117-118	Sample interval in feet *1000

Table 1: Data field and header information and the corresponding SEGY reel and trace header byte numbers. Not all SEGY fields are used in the transform. The unused fields are filled with null values.

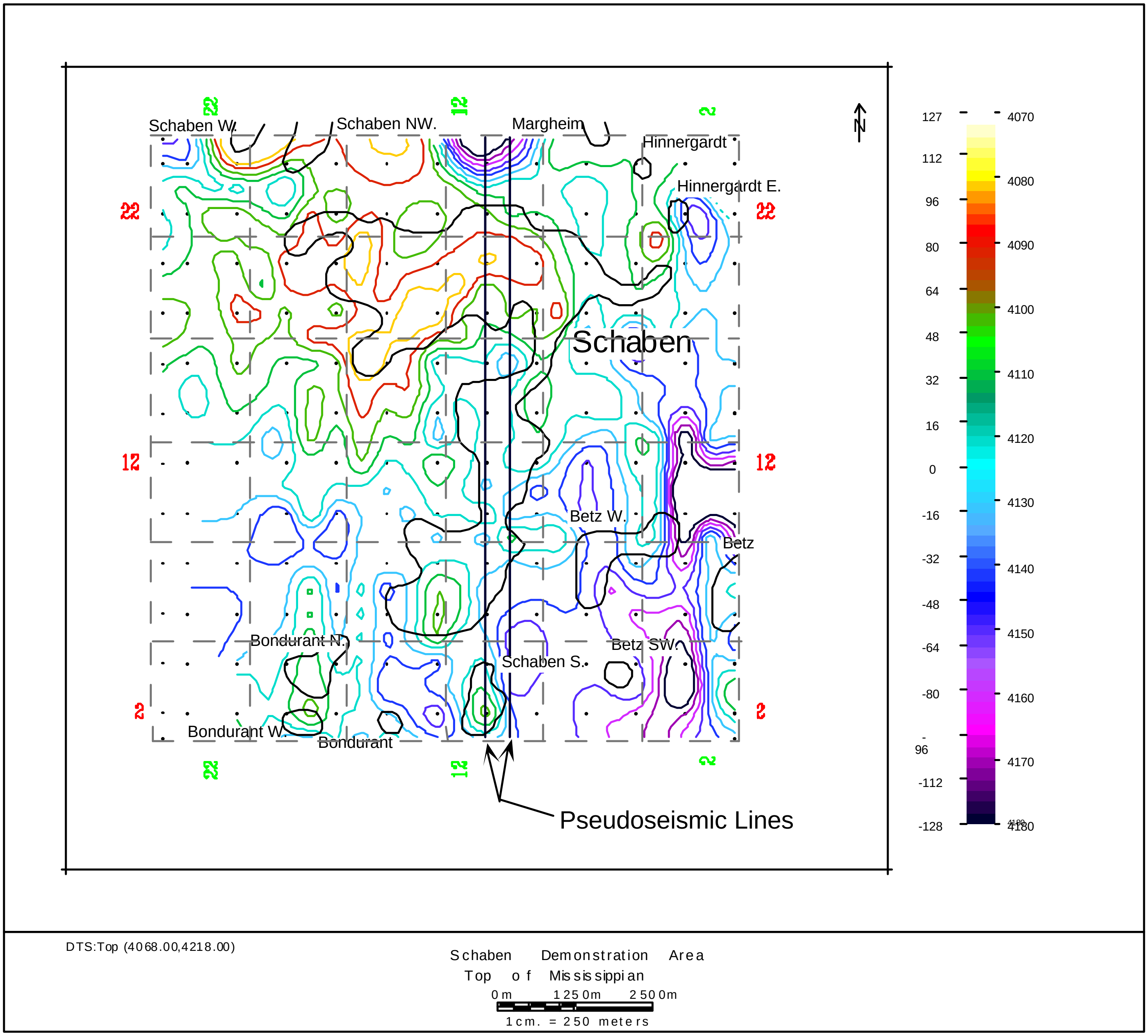

FIGURE 2.18. Map of selected pseudoseismic surface (Top of Mississippian) from the Schaben demonstartion site 3D *pseudoseismic* volume. Note correspondence to contour map generated from well tops (Figure 2.2). Location of selected pseudoseismic profiles are shown (figures 2.19 and 2.20). Hotter colors represent higher subsea depths.

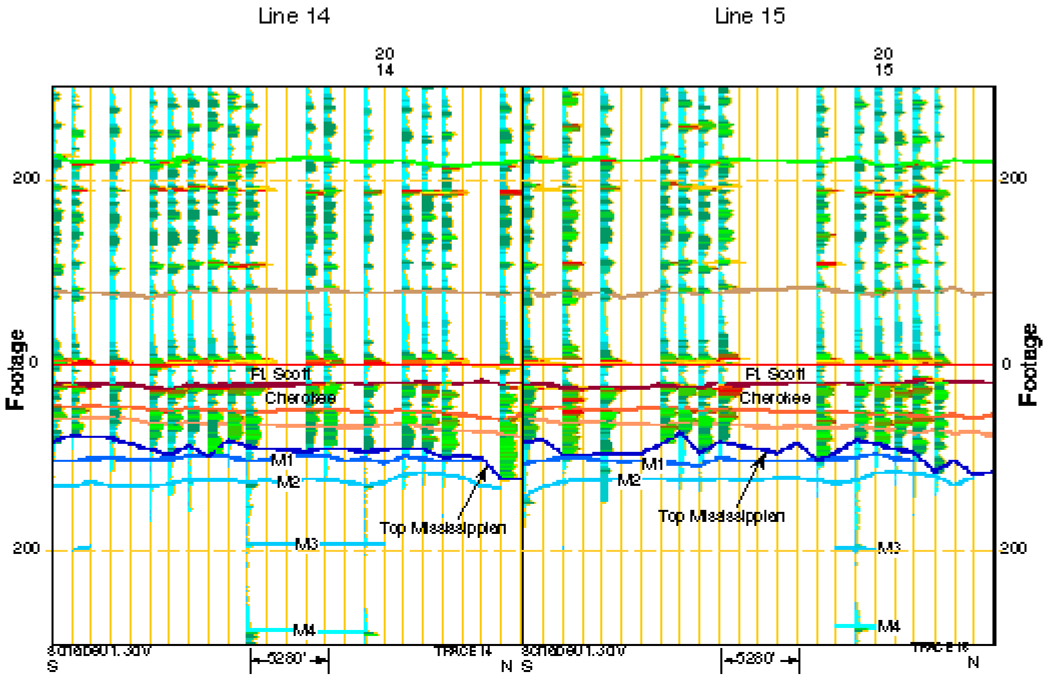

FIGURE 2.19 A group of two north south pseudoseismic profiles of gamma-ray across Schaben Field. Individual profiles extracted from the Schaben demonstration site 3D volume are datumed on the top of the Fort Scott and are 1320' apart. Volume contains data from over 200 wells and is “binned” at forty-acre spacings. Note the east to west truncation of Mississippian markers and the irregular nature of the Mississippian erosional surface. Location of profiles shown on figure 2.18.

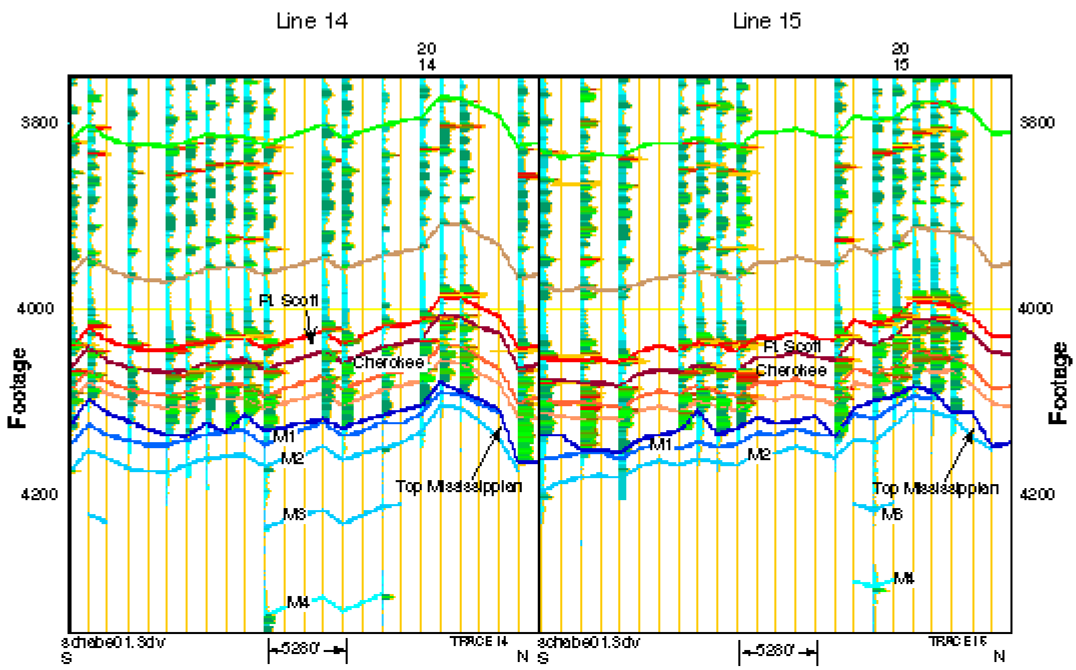

FIGURE 2.20. A group of two north south pseudoseismic profiles of gamma-ray across Schaben Field. Individual profiles extracted from the Schaben demonstration site 3D volume are structurally datumed and are 1320' apart. Volume contains data from over 200 wells and is “binned” at forty-acre spacings. Note consistent east to west offset of shale markers on both profiles across the demonstration site. Location of profiles shown on Figure 2.18.

2.2.4 Lithofacies, Depositional Environment, Paragenesis: Controls on Reservoir Facies
The following discussion is based on examination of the three cores recovered from the Schaben Field demonstration area. All core photographs are avaialble online at http://www.kgs.ukans.edu/DPA/Schaben/CoreScans/Core.html

Depositional Facies

Dolomite or Lime Mudstone-Wackestone (MW).--This facies is typically light gray to olive green in color or dark gray to brown. Typically this facies is laminated, or wavy to wispy laminated. Locally it is massive. Laminations are imparted locally by interbedded green shale-siltstone and by horsetail stylolites (Plate 1A). Much of this facies has a mottled texture apparently imparted by burrowing organisms and locally microscopic fracturing. Other features include soft sediment deformation. Fenestral fabric, indicating early subaerial exposure, occurs locally. Identifiable skeletal grains are rare; sponge spicules (mostly monaxon) and their molds are locally identifiable and appear to be the most common grain type with echinoderm and bryozoan, brachiopod, gastropods, peloid, and glauconite locally present. The sponge spicules are locally concentrated in layers or in “pockets” presumably as a function of currents and reworking by burrowing organisms. Rare concentrations of very fine grained (~ 100 µm) detrital quartz grains also likely occur from reworking by burrowing organisms. This facies is typically tight or has moldic, intercrystalline, and vuggy porosity (up to ~25%, visual estimate) locally developed; mottling texture and lamination locally results in variable tight and porous areas at a thin section scale. Dolomite occurs as very finely crystalline to micrite size (~20 µm to <100 µm), subhedral to anhedral crystals; euhedral crystals are locally developed and more commonly identified in areas with intercrystalline porosity. This facies often contains silica that replaced evaporite crystals, nodules and coalesced nodules that form layers. Silica also locally replaces matrix and grains in this facies.

Sponge Spicule-Rich Dolomitic or Lime Wackestone-Packstone (SWP).--This facies is defined because of its abundance in all three cores, especially in the upper portions of each core and because of its importance as a reservoir facies. This facies is dark to light gray, olive green, tan, or brown in color. Mottled, wispy horizontal laminated, and wavy horizontal laminated textures are common. This facies is typically characterized by mottling from burrowing organisms (Plate 1B). Laminations are imparted locally by interbedded green-gray shale-siltstone and by horsetail stylolites. Sponge spicules (mostly monaxon) and their molds (Plate 1C) are the most common grain type and commonly the exclusive grain type. Echinoderm, bryozoan, gastropod, and peloid grains occur more rarely. The sponge spicules are locally concentrated in layers or in “pockets” as a function of depositional processes (currents) and reworking by burrowing organisms. Moldic, intercrystalline, and vuggy porosity is locally abundant (up to ~65%, visual estimate). Fenestral fabric occurs locally. Some primary porosity is solution enlarged forming vugs. The mottling texture and concentration of grains in layers locally results in variable tight and porous areas at a thin section scale. Dolomite occurs as very finely crystalline to micrite size (~20 µm to <100 µm), subhedral to anhedral crystals; euhedral crystals are locally developed and more common in areas with intercrystalline porosity. This facies commonly contains chert after replacement of evaporite crystals, nodules and coalesced nodules that form layers. Chert also replaces matrix and grains (Plate 1D, Plate 2A). A breccia fabric is common from dissolution and collapse of evaporites and due to early differential compaction between brittle chert and soft dolomitic matrix. This facies is the most common to contain oil staining.

Echinoderm-Rich Dolomitic or Lime Wackestone-Packstone-Grainstone (EWPG).--This facies occurs in all three cores and is most abundant in the lower parts of the cores. This facies is typically dominated by echinoderm fragments but also contains abundant sponge spicules, bryozoan fragments, brachiopods, coral fragments, gastropods, ostracods, ooids, peloids, grapestone, calcispheres, oncolites, and other unidentifiable skeletal debris. Very fine to fine-grained detrital quartz grains occur locally. Where replaced by silica, the grain textures may be preserved or are molds filled with chert, silica or calcite cement (Plate 2B). Grainstones locally have an isopachous chalcedony cement that coats grains and lines primary pores (Plate 2B). Where still dolomitic, the grains are typically preserved as molds (Plate 2C). Horizontal laminations and low-angle cross laminations are locally preserved. Some intervals show sorting of grains into fine grained layers and coarser-grained layers. Other intervals show normal grading of grains. Locally, grains in this facies show compromise boundaries, overly close packing, grain breakage and flat, horizontal alignment of skeletal fragments, but typically there is not much over compaction or other evidence for much early compaction.

Where still dolomite, this facies is characteristically tan to dark brown in color and typically has a wispy laminated or mottled texture; locally it has a massive texture. Locally, interbedded skeletal rich layers (more porous) and skeletal poor layers (tighter) result in an alternating porous and tight layering within this facies. Porosity in this facies can exceed 35% (visual estimate). Common porosity types include moldic, moldic reduced, intercrystalline, and vugs. Oil staining occurs commonly in this facies where still mostly dolomitic. Dolomite is typically very finely crystalline (~50 µm or less) but locally exceeds 150 µm. Crystals are typically subhedral to euhedral. Some of the crystals are zoned with a clear to turbid (locally calcian) center and clear dolomite rim. Some dedolomite textures were identified. Locally, calcite cement and neomorphic spar occlude porosity and replace original textures; some areas have dolomite rhombs, or silica “floating” in calcite.

This facies commonly has been partially or pervasively replaced with porcelanous (tight) or tripolitic (porous) chert/megaquartz. Abundant vuggy and microcrystalline porosity occur within tripolitic chert areas (Plate 2D) and both tripolitic and porcelanous chert typically contains micro- and mega-fracture porosity. Only locally are vugs developed within chert areas and partially or fully filled with silica cement . Fenestral pores either partially or fully filled with silica cement occur locally.

Other Lithologies and Features

Chert/Chalcedony/Megaquartz Replacement.--Silica replacement of original lithologies is abundant throughout all three cores and replaces all facies types described above. Silica replacement occurs either as pervasive or partial replacement of original facies, textures or grains. The silica is typically white to light gray in hand sample and has a porcelanous or tripolitic texture. Typically, several stages of silica replacement and cementation can be identified microscopically. A typical sequence shows a first stage of brown/black chert replacing facies and grains, a second stage of isopachous brown chalcedony cement, and a third stage of megaquartz replacement or cementation. This sequence is repeated at least two times stratigraphically.

The abundance of silica replacement is likely at least partially due to the abundance of sponge spicules. Silica locally preferentially replaces spicules imparting a wispy texture or replaces the matrix surrounding the spicules and leaves the spicules as molds. Much of the chert replacement appears to follow original burrow mottling and networks. The silica replacement is typically tight and forms impermeable layers where replacement is massive and porcelanous. Where the silica replacement is tripolitic the chert contains abundant microcrystalline porosity. Chert areas commonly exhibit a fracture and brecciated texture due to early differential compaction between brittle chert areas and surrounding matrix areas that were still soft (Plate 3A, 3B), and from later fracturing related to subaerial exposure and later burial compaction. Variable micro-and macro-fracture porosity results from these processes.

Silica also occurs as replacement of original evaporite crystals, isolated nodules, horizontal layers of isolated or laterally coalescing nodules, or as horizontal layers of vertically elongate nodules. This silica replacement is typically dark gray in color and has more associated vuggy porosity. Some of these nodules preserve a bladed or radiating bladed crystal morphology (Plate 3C), bladed and twined morphology or zebraic chalcedony texture (Plate 3D) when viewed with a petrographic microscope, indicating replacement of an original evaporite mineral (anhydrite or gypsum). Typically, the original evaporite crystals and nodules display replacement by clear to dark brown chert followed by dissolution/corrosion/erosion forming an irregular surface by precipitation of megaquartz cement in remaining pore space (Plate 4A).

<u>Sandstone/Siltstone/shale</u>.--This facies is typically green to gray in color. It is wavy to wispy laminated and locally displays low-angle lamination. This facies is composed predominantly of very-fine grained sand (~100 µm) to silt-sized (<50 µm) quartz grains. Intergranular porosity is locally developed (> 20% locally, visual estimate). This facies occurs as fracture fill (Plate 4B) and breccia matrix. The shale locally occurs as wispy layers in dolomitic mudstone or wackestone facies (Plate 1A).

<u>Breccia and Fracturing</u>.--Brecciation and fracturing are ubiquitous throughout the three cores. Fracturing and brecciation results in fracture and mosaic breccias, with textures ranging from little to no rotation on clasts (indicating in-situ brecciation) (Plate 4C), to matrix-supported and clast-supported chaotic breccias that represent mixtures of autochthonous and allochthonous materials resedimented by gravitationally driven processes (Plate 4D).

Fracturing and brecciation occur on macroscopic and microscopic (Plate 5A) scales. Fracture fill and breccia matrix includes shale, subangular to rounded, silt- to coarse-grained size detrital quartz, chert, megaquartz, chalcedony grains, carbonate micrite, carbonate grains, and skeletal grains. Clasts (ranging from rounded to angular) include chert/chalcedony/megaquartz fragments, clasts of original carbonate facies, replacive poikilotopic calcite clasts, coarse calcite cement fragments, and rubble of red and greenish limy clay. Porosity associated with fracturing and brecciation is quite variable, ranging from tight to very porous, and depends on amount of fracturing and brecciation, “openness” of fractures, types and grain size of fracture fill, and types and grain size of breccia clasts and matrix. Interparticle, intercrystalline, vuggy and fracture porosity are common porosity types in breccia matrix.

Brecciation and fracturing were caused by a variety of processes interacting at different times. Some areas reveal several generations of fracturing, brecciation, cementation and sediment fills. The overprinting of these different events results in complex fabrics. Relatively early silica replacement resulted in layers and areas that were cemented versus surrounding original matrix that was still soft. Early compaction resulted in differential brittle and soft deformation between the chert and surrounding matrix which imparted a fracture and breccia fabric. Displacive growth of chert nodules in soft dolomitic sediment resulted in soft sediment deformation textures and some brecciation. Some breccia was locally caused by depositional processes (e.g. current rip-up). Other brecciation and fracturing were caused by early (intra-Mississippian) subaerial exposure, dissolution and collapse of evaporites, post-Mississippian subaerial exposure, and late burial compaction that resulted in brittle deformation of all lithologies.

Depositional Environment

A general upward facies change is discernible in all three cores. Echinoderm facies predominates in the bases of all the cores (up to 4435' in Moore, up to 4428' in Schaben and up to 4436' in Foos). Although other facies occur as well, importantly, evidence of evaporites is generally lacking. The upper portions of all cores (above 4435' in Moore, above 4428' in Schaben and above 4436' are dominated by the sponge spicule-rich and mudstone/wackestone facies and contain abundant evidence of evaporites. Figure 2.21 shows correlation of the cores that was made with the aid of well logs. Although dips are accentuated by structural elements, the correlations and general facies trends indicate deposition on a ramp with the Moore core at the updip area, Schaben in the middle, and the Foos core in a downdip area. The abundance of the echinoderm facies with abundant other diverse fauna, abundance of burrowing organisms and only rare occurrence of evaporites in the basal portions of the cores suggest deposition in relatively normal to somewhat restricted marine environments. In contrast, the abundance of mudstone, wackestone and spicule-rich facies, relative rarity of echinoderm-rich facies, and abundance of evaporites in upper portions of the cores suggest deposition in restricted, evaporitive ramp or lagoon environments. However, the abundance of burrow mottling indicates conditions sufficient to support organisms that reworked the sediment. The morphology and alignment of the evaporite crystals, nodules, and layers likely indicates formation in a supratidal to shallow subaqueous setting at or just below the sediment/water interface (Warren, 1989). Local fenestral fabric indicates at least intermittent subaerial exposure.

Overall, each core shows an upward shoaling trend leading up to the post-Mississippian subaerial exposure event. Correlations reveal lateral facies shifts accross the ramp through time with the evaporitic ramp to lagoon environment existing earliest in the Moore core (correlating with open to restricted marine ramp environments in the Schaben and Foos cores) and shifting down ramp through time in response to the relative sea level drop leading to the eventual post-Mississippian subaerial exposure event.

The echinoderm-rich facies are mostly characteristic of a shallow subtidal shelf setting. The lamination, cross lamination, normal grading, packing of grains, grain breakage, and scoured contacts evidence at least intermittent high energy. In the normal to restricted portion of the ramp, this facies likely represents deposition from storm and turbidity currents or from migration of subtidal shoals or banks. Local fenestral fabrics in the echinoderm facies, especially in the evaporite ramp or lagoon portion of the section, indicate at least local subaerial exposure in a supratidal setting. The echinoderm-rich facies in this part of the ramp may represent shelfward migration of a subtidal shoal or shelfward deposition from tide or storm currents. The sponge spicule dolowackestone-packstone and dolomudstone-wackestone facies are likely indicative of a low energy and slightly more restricted setting as compared to the echinoderm-rich facies. In this environment sponges thrived and likely formed sponge "gardens" or "mounds" (Rogers et al., 1995). Wispy and wavy horizontal lamination, alternating grain-rich and grain-poor layers, some apparent normally graded beds and local interbeds of grainstone in mudstone to packstone indicate transport and reworking of sediment by currents likely generated from tides or storms.

The change between the normal to restricted marine ramp and the evaporitic ramp to lagoon in the Schaben core is marked by a sharp contact at 4424' (MO sufrace). This surface and the strata immediately below for several meters show significant alteration. A coarse calcite cement and replacive poikilotopic calcite is associated with the MO surface and occurs variably throughout strata below this surface to the bottom of the core (Plate 5B). This cement is very important for making these strata relatively tight compared to overlying strata. The cement does not occur in strata above the MO surface. There is a similar cement at the very top of the Schaben core (Plate 5C) but it only affects strata in the upper five feet of the core and is presumably related to the post-Mississippian subaerial exposure event. Strata from about 4390' to 4424' do not contain any coarse poikilotopic calcite cement. In addition, the strata below the MO surface contain local fenestral fabric (Plate 5D), autobreccia, clay-rich "crusts" (most now chertified) with abundant horizontal fenestrae interlaminated with fine-coarse grained detrital quartz layers, locally abundant glauconite, pyrite, fractures and breccia with dolomite, clay, detrital quartz matrix locally cemented with coarse calcite cement (Plate 6A), dolomite facies clasts, chalcedony, megaquartz and chert clasts, and, locally, poikilotopic calcite clasts (Plate6B). In addition, round or oblong to elongate areas altering original facies occur for several meters below the surface. These areas are characterized by a central area filled with poikilotopic calcite that is surrounded by a halo of iron staining and local fenestral fabric (Plate 6C). Some of these areas show associated microscopic horizontal and downward "branching" of microfractures. These altered areas may reflect the presence of land plant roots. The fenestral fabric, crusts, autobreccia, coarse calcite and poikilotopic cement, possibly associated with meteoric water, are consistent with subaerial exposure as well. An early, intra-Mississippian exposure event at the MO surface versus the alteration and features being related to the post-Mississippian exposure event is supported by several cross-cutting relationships. Below the MO surface, original dolomitic facies and silica replaced facies are fractured and brecciated and infilled with dolomite matrix, detrital quartz and replacive silica clasts. These facies and previously fractured and brecciated areas are crosscut by coarse calcite-filled fractures, replaced by poikilotopic calcite, and the previously fractured and brecciated areas are locally cemented by the poikilotopic calcite (Plate 6A). These fabrics, including the coarse calcite cement and poikilotopic calcite, are crosscut by fractures filled with dolomite (Plate 6D) and locally, evaporite crystals and evaporite nodules from facies overlying the

MO surface. These dolomite-filled fractures contain clasts of poikilotopic cement (Plate 6B, 6D) and clasts of replacive silica (Plate 6A). Importantly, none of these features are identified above the MO which strongly suggests a subaerial exposure event at the MO surface prior to deposition of overlying strata. The MO surface in the Schaben core appears to correlate with an area of siliciclastic-rich and shallow water carbonate rubble and missing strata in the Moore core (~4400-4410') (Figure 2.21). This may represent extreme erosion in the updip Moore core during the MO subaerial exposure event. The Foos core does not extend down to the level that correlates with the MO surface in the Schaben core.

Paragenetic Sequence

The following is a preliminary paragenetic sequence of depositional and diagenetic events for the strata from the Schaben field based on macroscopic and standard petrographic observations of cross-cutting relationships. Although in general this paragenetic sequence is thought to be applicable to all three cores, further analyses utilizing cathodoluminescence, fluid inclusion data, XRD, SEM and geochemical analyses will be necessary to determine the details of timing, environment and lateral continuity of the different events. This preliminary paragenetic sequence is given here to highlight the complexity of events that have affected Schaben field strata and, in turn, affected reservoir properties.

1) Deposition of pre-MO surface sediments.

2) Local syntaxial overgrowths on echinoderm fragments. Some minor early compaction in grainstone facies.

3) Dolomitization dominated by very finely crystalline (<10-50 µm) dolomite characteristic of early dolomitization possibly associated with reflux or mixing zone.

5) Dissolution of grains, silica cementation and replacement of dolomite facies and grains. Early silica cementation and replacement is evidenced by silica replacement closely following burrow networks, brittle fracturing of silica areas and fractures in silica filled with surrounding dolomite, displacive growth of silica nodules and soft-sediment deformation of surrounding dolomite. A typical sequence of silica replacement and cementation events is as follows:

A) pervasive chertification of matrix and many grains.

B) dissolution, erosion and corrosion of grains and matrix

C) precipitation of brown, isopachous to equant pore lining or filling chalcedony cement (lines or fills molds, shelter pores, and interparticle pores). This cement does not typically line or fill echinoderm molds possibly indicating later dissolution of echinoderms (Plate 2B).

D) Clear megaquartz pore filling cement; this cement also fills echinoderm molds (Plate 2B).

6) Subaerial exposure at MO surface results in following events and features in underlying strata:

A) fracturing, brecciation, dissolution (Plate 6).

B) development of crusts, fenestral fabric (Plate 5D, 6C), autobreccia.

C) infill of fractures with various dolomite, detrital quartz, clay, and replacive silica matrix and clasts (Plate 6A).

D) fracturing and precipitation of coarse calcite cement in fractures and calcite cementation of fracture matrix (Plate 6A); replacement of dolomite facies (Plate 6B) and replacive silica with poikilotopic calcite. Some dedolomite.

E) possible early precipitation of glauconite (reducing conditions).

7) Deposition of post MO surface facies including abundant evaporites crystals and nodules.

8) Dolomitization dominated by very finely crystalline (<10-50 µm) dolomite characteristic of early dolomitization associated with reflux or mixing zone. Predominance of evaporites is supportive of reflux mechanism.

9) Dissolution of grains and evaporite minerals, silica cementation and replacement of dolomite facies and grains. In addition to previously cited evidence for early silica cementation and replacement, additional evidence includes replacement of radiating bladed evaporite crystal and nodule textures without much breakage or compaction (Plate 3C). The typical sequence of silica replacement fabrics and cements is similar to previously described. In addition, evaporite crystals and nodules were replaced with a generally clear to light brown chert followed by a corrosion/erosion event in which crystals and nodules have a dark brown (Fe-stained?) irregular surface that is overlain by clear megaquartz cement that fills or partially fills remaining porosity (Plate 4A). Evidence for several sequences of silica replacement and cementation include fractures in pre MO surface strata that crosscut all silica replacement fabrics and cements and are filled with a sequence of chert and or chalcedony cement followed by megaquartz cement.

10) Fracturing and brecciation, including collapse breccia from dissolution of evaporites (Plate 7A). Fractures extend into pre-MO surface strata where they crosscut all previous dolomite and chert facies as well as coarse calcite cement and poikilotopic replacive calcite (Plate 6B, 6D, 7C). The fractures are filled with dolomite and, locally, evaporite crystals and nodule fragments from post MO surface sediment and contain clasts of calcite cement, replacive poiklotopic calcite, replacement silica, and silica cement.

11) Post-Mississippian subaerial exposure, resulting in the following:

A) Additional fracturing and brecciation

B) Infiltration of clay and detrital siliciclastic grains

C) Precipitation of coarse calcite cement and replacive poikilotopic calcite (Plate 5C).

12) Burial resulting in the following:

A) Precipitation of coarser (up to 150 µm) baroque dolomite (Plate 7B).

B) Precipitation of pyrite and glauconite.

C) Compaction resulting in stylolites and brittle fracturing of all facies (Plate 7C).

Although reservoir characteristics in strata underlying major subaerial exposure unconformities, such as the Schaben field, are thought to be controlled by processes associated with subaerial exposure, the value of sorting out the different depositional and diagenetic events in these types of fields as listed above is demonstrated by comparing minipermeameter measurements and locations of oil stains in relationship to core data (Figure 2.22). An original depositional facies control for favorable reservoir strata is shown by the predominance of the highest minipermeameter readings and most oil shows occurring in spicule-rich facies that originally had abundant evaporites present and, less commonly, echinoderm-rich wackestones/packstone facies. Burrow mottling was very important in creating and locating fluid flow networks for later diagenetic fluids that resulted in variable porous and non-porous areas on macroscopic and microscopic scales. Early diagenetic events such as dolomitization, dissolution, silica cementation and replacement, associated fracturing and brecciation and poikilotopic calcite replacement and cementation were important for reservoir architecture. Dissolution of grains and dolomitization created the moldic, intercrystalline and vuggy porosity important for favorable reservoir facies. Early silica cementation and replacement was important in creating the vertical heterogeneity illustrated by minipermeameter measurements and oil staining patterns (Figure 2.22) Whereas silica replacement and cementation tend to result in relatively tight and pervasive replacement in echinoderm-rich facies, the silica replacement and cementation in spicule-rich facies tends to be more variable, especially where evaporites were replaced and tend to contain more moldic and vuggy porosity. The poikilotopic cement associated with the MO subaerial exposure event was extremely important in occluding porosity in underlying strata in the Schaben field as reflected by the low minipermeameter readings and relative lack of oil staining. Both early and late fracturing and brecciation variously enhanced or destroyed reservoir characteristics as indicated by minipermeameter measurements and oil stain patterns (Figure 2.22). Certainly the late fracture and breccia matrix porosity that remained open are important for creating effective porosity when intersecting favorable reservoir facies.

In summary, historically, topographic highs just underlying the post-Mississippian unconformity are viewed as the most favorable locations for petroleum exploration and production. This study shows that the dipping Mississippian ramp strata, accentuated by structural uplift, were differentially eroded at the post-Mississippian unconformity resulting in paleotopographic highs (buried hogbacks, Figure 2.3). The sedimentologic, stratigrahic and paragenetic portion reported in this section indicate that the most favorable areas for successful production may be where spicultic-rich facies containing abundant evaporites intersect fractures associated with the post-Mississippian unconformity and form the topographic highs. In contrast, areas in which echinoderm-rich facies intersect fractures associated with the unconformity and form topographic highs may not be as favorable reservoirs, especially for pre-MO strata.

Clearly, additional studies are necessary to evaluate and confirm the details of paragenesis and determine more fully the relationship of the different events to reservoir architecture. This detailed understanding not only has important implications for Schaben field, but for other similar Mississippian reservoirs in Kansas such as Glick field (Osagian, Rogers et al., 1995), Western Sedgwick basin (Osagian; Thomas, 1982), Bindley field (Warsaw, Ebanks, 1991; Johnson and Budd, 1994) and other similar Mississippian strata outside of Kansas (e.g. Madison Group strata from the Williston Basin of Southeast Saskatchewan, pers. comm. Paul Gerlach).

PLATE 1:
A) Dolomite Mudstone-Wackestone facies. Wispy lamination imparted by clay and horsetail stylolites. This facies is typically tight. Plane polarized light.
B) Sponge Spicule-rich Dolomite Wackestone-Packstone facies. Burrow mottling has created variably tight and porous (blue) areas with abundant moldic and intercrystalline porosity. Plane polarized light.

C) Sponge Spicule-rich Dolomite Wackestone-Packstone facies with abundant sponge spicule moldic and intercrystalline porosity. Plane polarized light.
D) Sponge Spicule-rich Dolomite Wackestone-Packstone facies. In this sample the sponge spicules are siliceous and only a minor amount of intercrystalline porosity is present. Plane polarized light.

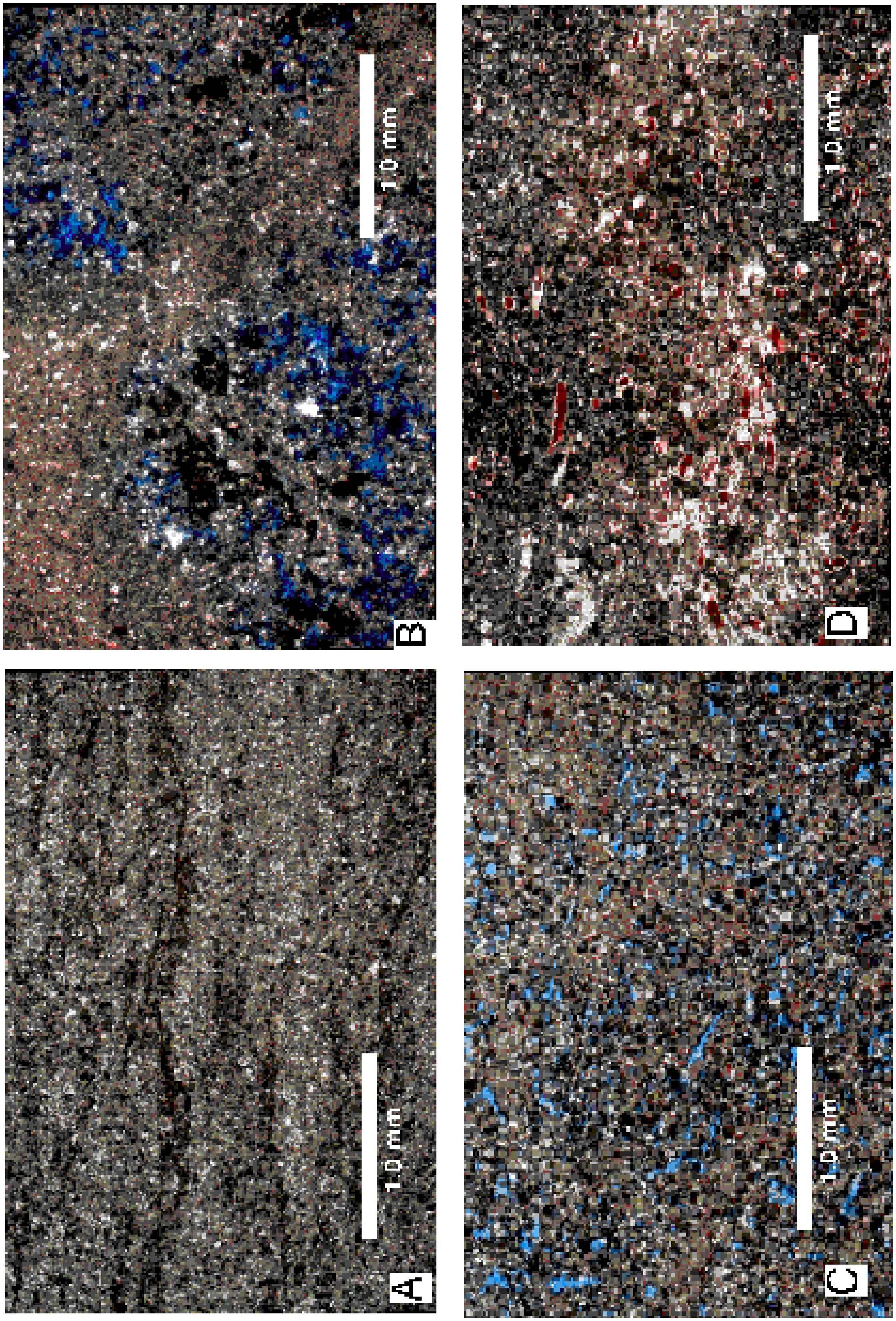

Plate 1

PLATE 2:

A) Sponge Spicule-rich Dolomite Wackestone-Packstone facies. In this sample sponge spicules have been dissolved leaving molds (blue areas) and the surrounding matrix has been replaced by chert. Note the upper left corner of this photomicrograph has not been replaced by chert and is dolomitic. Plane polarized light.

B) Echinoderm-rich Wackestone-Packstone-Grainstone facies. Echinoderm, brachiopod, and other skeletal fragments in this sample have been entirely replaced and cemented by silica. Red arrow points to initial chert replacement, white arrow points to brown isopachous chalcedony cement that lines primary pores, and the green arrow points to clear pore-filling micro-megaquartz cement. Plane polarized light.

C) Echinoderm-rich Dolomitic Wackestone-Packstone-Grainstone facies. Echinoderm fragments and other skeletal fragments, including sponge spicules (white arrow), have been dissolved leaving abundant moldic porosity (blue areas). Plane polarized light.

D) Echinoderm-rich Wackestone-Packstone-Grainstone facies. This is an example of porous (tripolitic) chert texture. The grains in this sample have been preserved by chert replacement and surrounding matrix has been dissolved leaving abundant interparticle, vuggy, and some intercrystalline porosity. Plane polarized light.

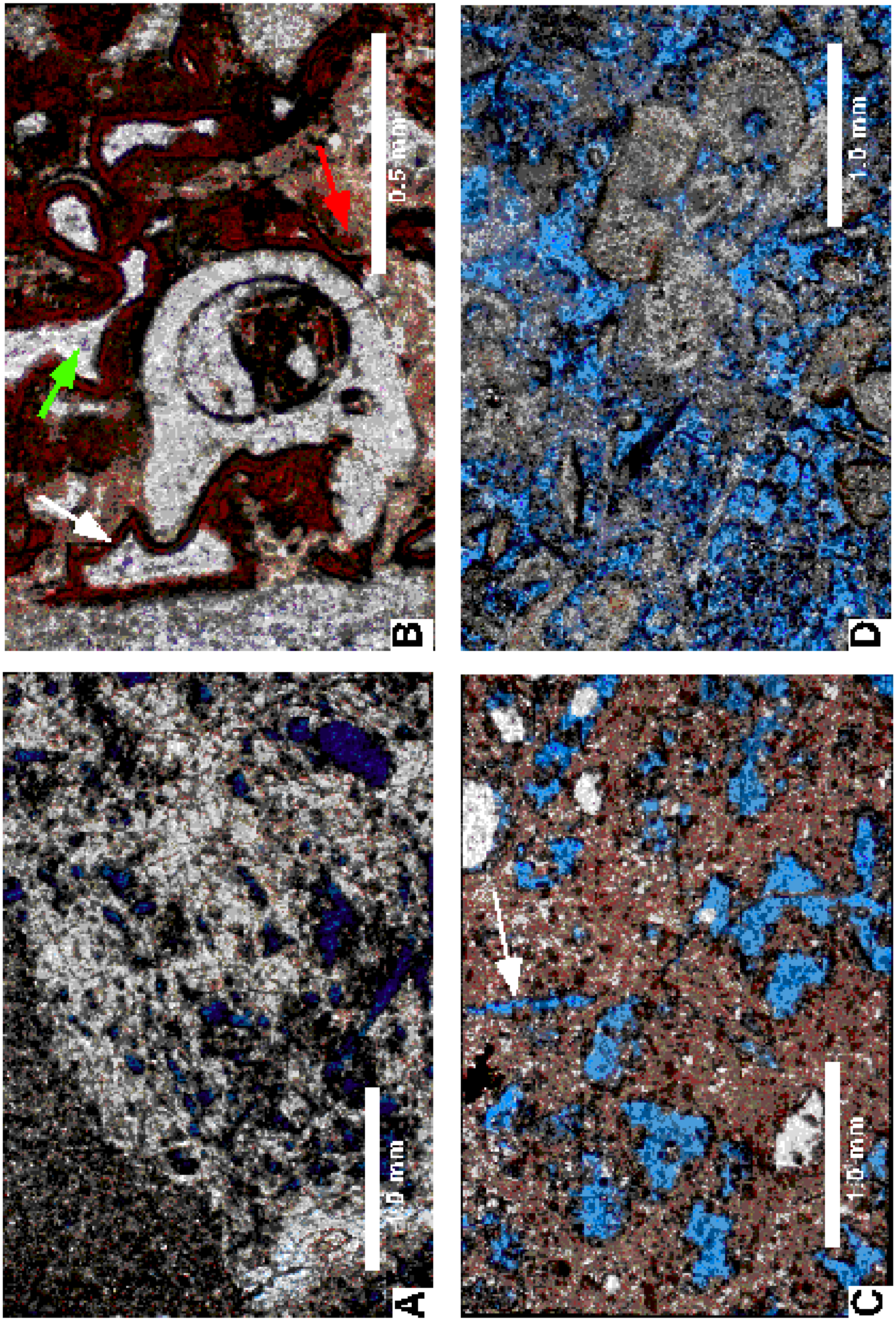

Plate 2

PLATE 3:

A) Chert and chalcedony filled fracture in dolomitic mudstone-wackestone facies. Note the fracture was subsequently fractured and the surrounding dolomitic matrix fills in around fractured areas without brittle fracture. Plane polarized light.

B) Partial chert replacement of Sponge Spicule-rich Dolomite Wackestone-Packstone facies. Some sponge-spicule molds (blue areas) can be identified in chert areas. Note brittle fracturing of chert and infill by surrounding dolomitic matrix indicating early chert replacement and differential compaction. Plane polarized light.

C) Silica-replaced bladed and radiating bladed texture of original evaporite (anhydrite/gypsum) minerals. This sample exhibits displacive growth of crystals and formation of nodules in dolomitic sediment. Preservation of the radiating crystal/nodule texture suggests early replacement by silica prior to any significant compaction. Plane polarized light.

D) Zebraic chalcedony pore-filling cement which is assorted with evaporite minerals. Crossed nicols.

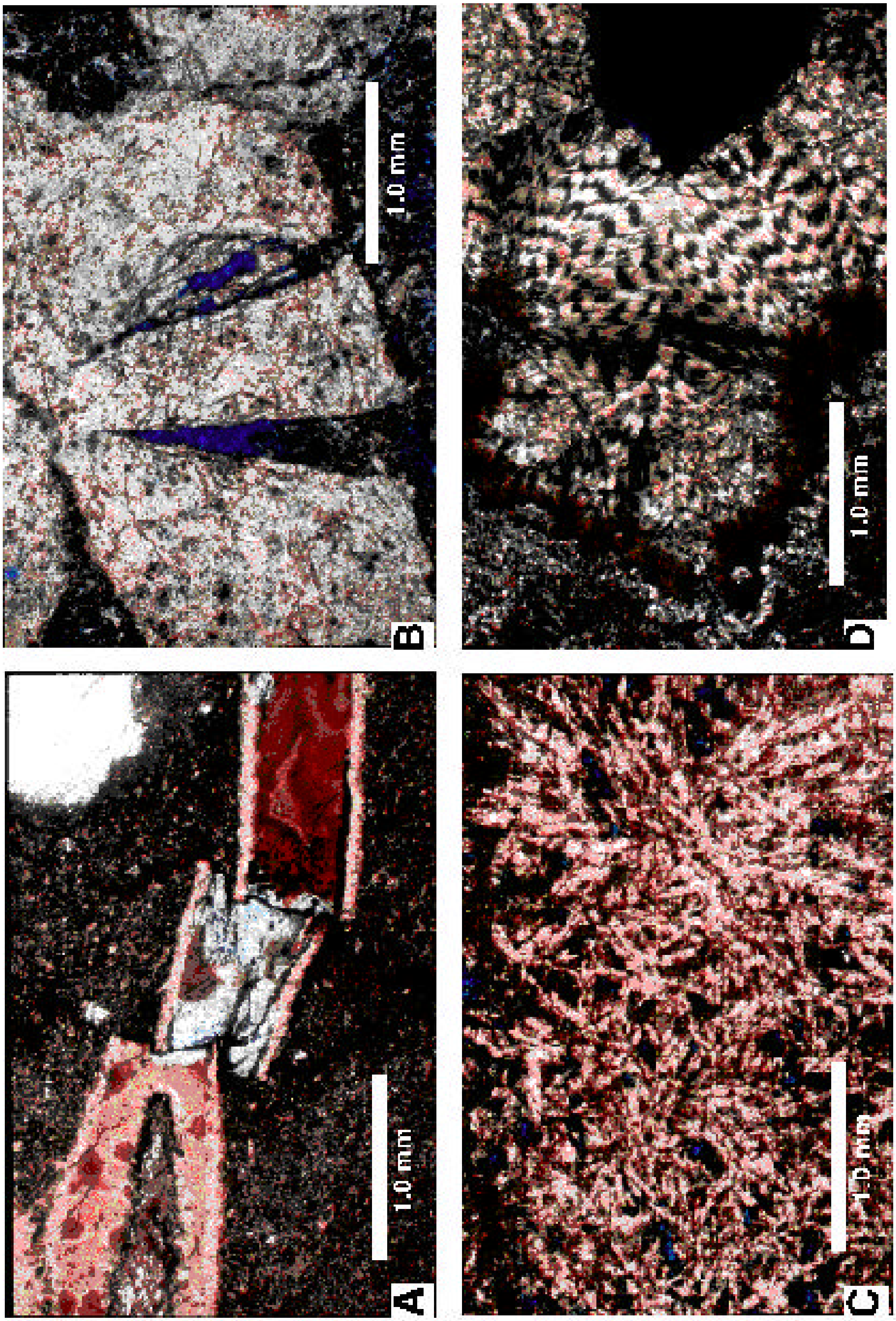

Plate 3

PLATE 4:

A) Replacement of original evaporite crystals and nodule by clear to brown chert (white arrow). This was followed by a dissolution/corrosion/erosion event (blue arrow). Remaining porosity was filled by clear megaquartz cement (black arrow). Plane polarized light.

B) Dolomitic matrix cut by a fracture filled with chert and detrital quartz. Plane polarized light.

C) Autobreccia fabric indicative of in-place brecciation. Plane polarized light.

D) Chaotic breccia fabric with subround to round detrital quartz and megaquartz cement grains and angular to subangular chert fragments in dolomitic and chert matrix. Plane polarized light.

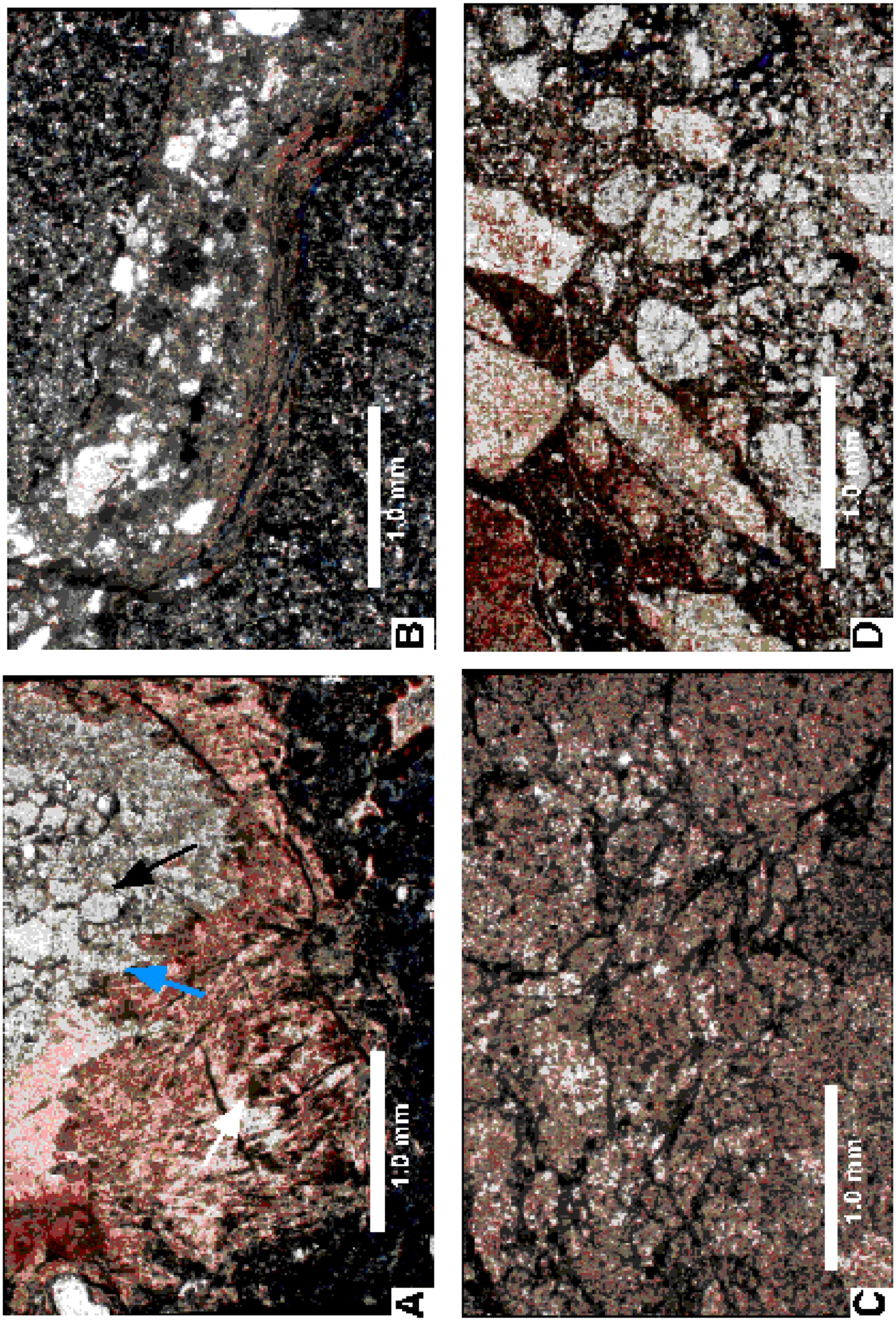

Plate 4

PLATE 5:

A) Echinoderm-rich Dolomitic Wackestone-Packstone-Grainstone facies. Note that grain molds and intercrystalline porosity (blue areas) are lined with oil and connected by fractures (white arrows). Plane polarized light.

B) Coarse calcite cement and poikilotopic calcite (red-stained areas) that is common below the MO. White arrow points to a dolomite rhomb “floating” in calcite. Plane polarized light.

C) Poikilotopic replacive calcite just below post-Mississippian unconformity. Here the calcite replaces sponge spicule-rich facies. The dark areas (white arrow) are extinction patterns of poikilotopic calcite. Crossed nicols.

D) Dolomitic matrix below the MO surface with abundant fenestral pores (white areas). Note one pore filled with coarse calcite cement (red-stained area). Plane polarized light.

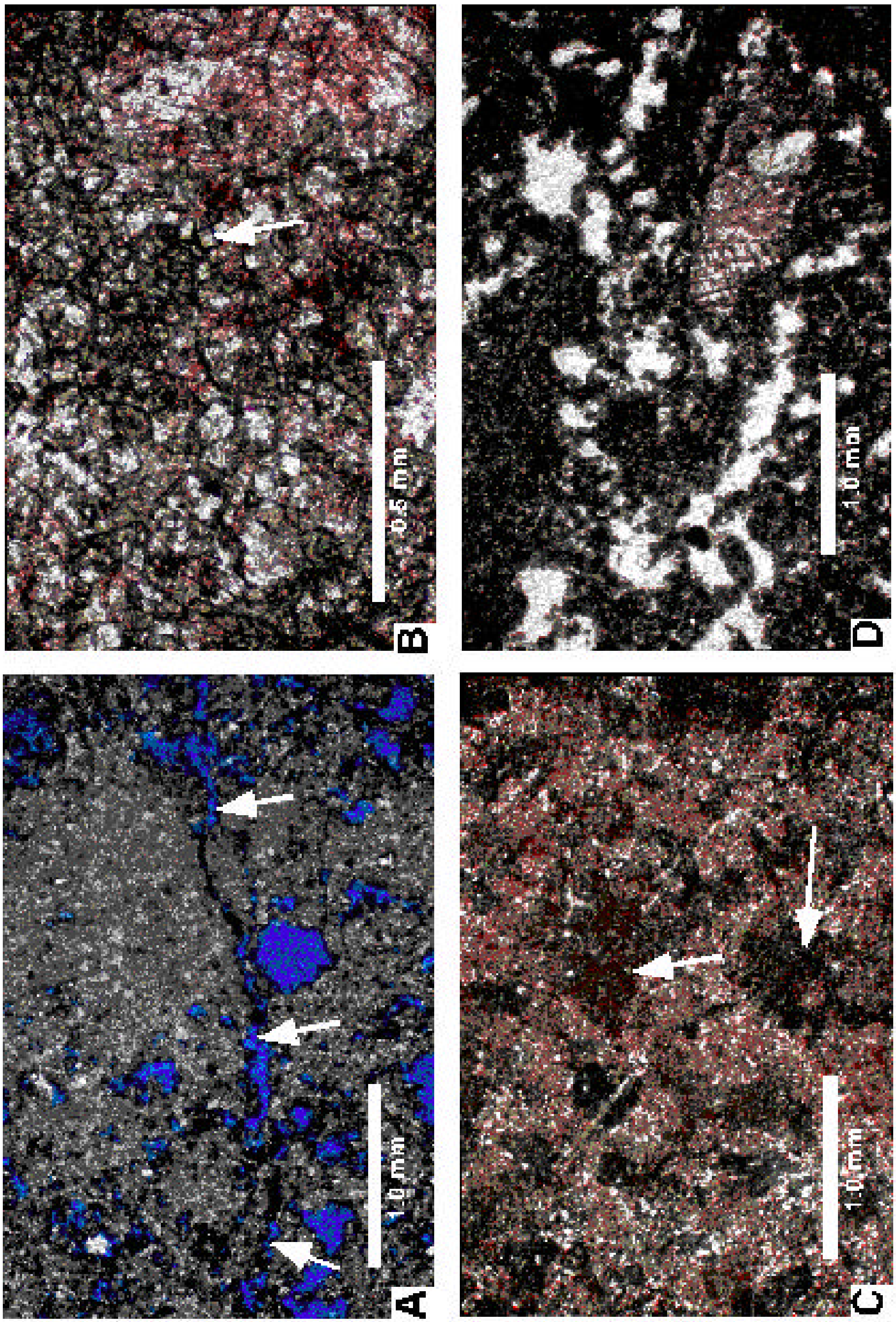

Plate 5

PLATE 6:

A) Fracture below the MO surface filled with dolomite, clay, detrital quartz (white arrow) clasts and matrix that is cemented by coarse calcite cement (blue arrow). Plane polarized light.

B) Fracture below the MO surface that contains angular poikilotopic calcite clasts (red-stained) and detrital quartz in very finely crystalline dolomitic matrix. Plane polarized light.

C) Altered facies below the MO surface. Some altered areas are characterized by a central area filled with coarse calcite cement (white arrow) surrounded by a halo rich in iron and fenestral pores (white areas) in dolomitic and replacive poikilotopic calcite matrix. Plane polarized light.

D) Poikilotopic calcite replaced facies (red-stained areas) below the MO surface that were subsequently fractured. The fracture is filled with very finely crystalline dolomite from above the MO surface and locally contains clasts of poikilotopic calcite (white arrow). Note the truncated coarse calcite cement filled fracture in the poikilotopic calcite area in the bottom right portion of the photomicrograph. Plane polarized light.

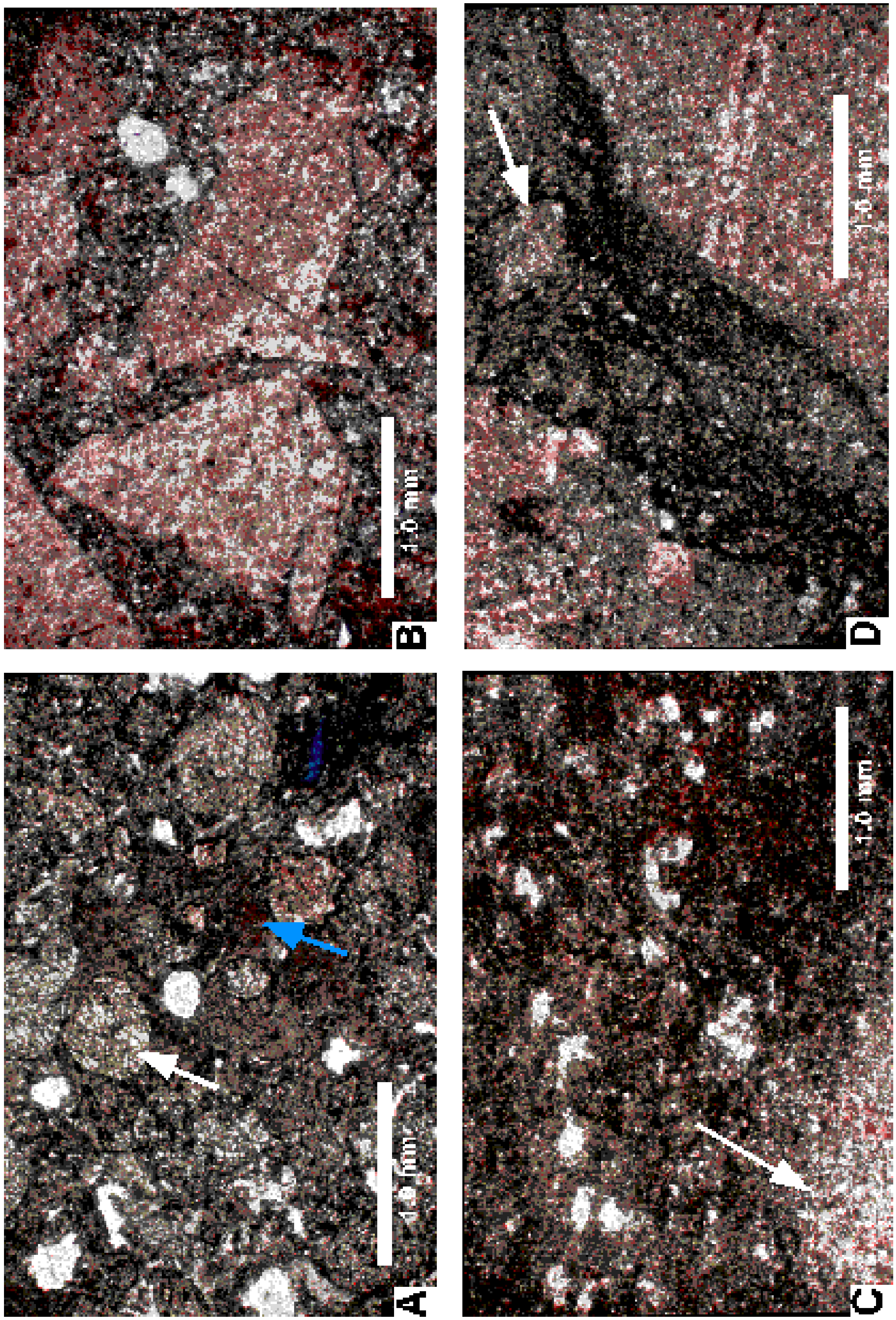

Plate 6

PLATE 7:

A) Silica replaced evaporite mineral blades and nodule cut by later fracture partially filled with very finely crystalline dolomite and evaporite matrix containing evaporite nodule clasts. Plane polarized light.

B) Late stage baroque dolomite (white arrow points to rhomb) and glauconite cement (red arrow). Plane polarized light.

C) Coarse calcite cement and poikilotopic calcite areas (1) cut by fracture filled with Fe-rich dolomite (2). Later open fractures (3) crosscut all previous facies and events. Plane polarized light.

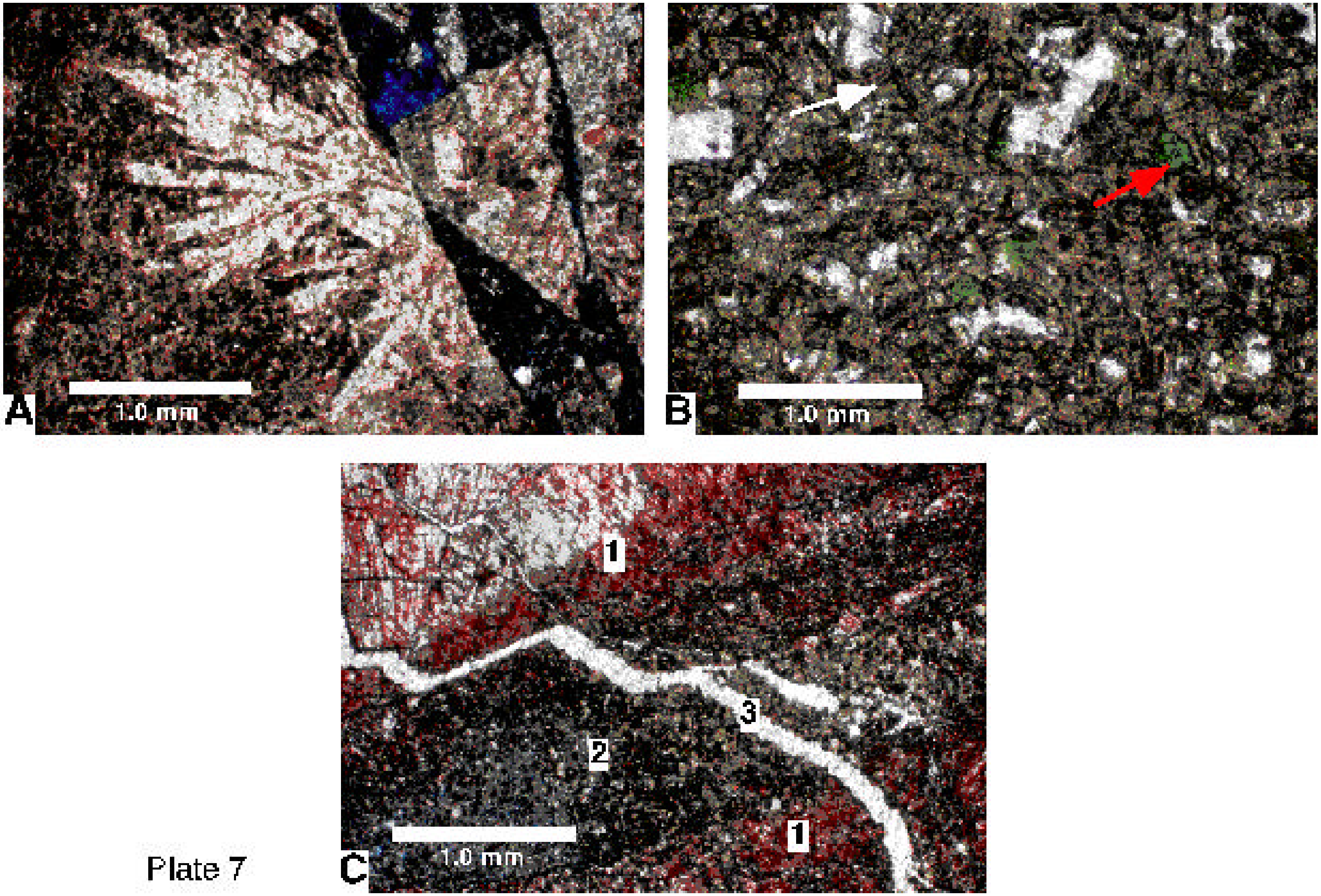

Plate 7

2.3 RESERVOIR MODEL
2.3.1 Field Data and Full Field Reservoir Parameters

FIELD DATA

GENERAL DATA

State:	Kansas
County:	Ness
Location:	Township 19 South--Range 21 West, Township 20 South--Range 21 West, and Township 19 South--Range 22 West
Discovery Date:	September 4, 1963
Discovery Well(s):	Cities Service Oil Company, #1 Moore 'B' SE SE 30-T19S-R21W Mississippian Oil, 4494' RTD
Field Size:	8,880 acres
Wells	
Total:	90
Operating (1996):	67
Abandoned:	25

RESERVOIR DATA

Producing Formation(s):	Mississippian (Osagian)
Lithology:	Dolomite, Chert, Limestone
Average Depth:	4400’ (-2100’ subsea)
Original Oil/Water Contact	-2145’ subsea
Average Porosity:	17.5 %
Permeability Horizontal (Estimated):	6.5md to 167.0 md
Permeability Vertical (Estimated):	0.15 times horizontal permeability
Archie Equation Parameters:	a=1, m=2, n=2, Rw =0.13
Temperature:	115 F
Original Field Pressure:	1100 psi
Present Field Pressure:	1100 psi

PRODUCTION DATA

Original Oil In Place (Volumetrics): 40 - 50 MMBO
Cumulative Oil Production (mm/yy): 9.1 MMBO (September 1996)
Estimated Recovery Factor: 17%
Present Oil Production:
Cumulative Produced Water (Estimated):
Present Produced Water (Estimated):

FLUID PROPERTIES:

Crude Oil

API Gravity	40
Viscosity at P_{BP}:	2.5 cp
Initial Solution Gas-Oil Ratio:	50 cu. ft/bbl

Formation Volume Factor at Pi: 1.037 RB/STB
Bubble Point Pressure: 225 psia

Gas
Viscosity at P_{BP}: 0.0108 cp
Formation Volume Factor at P_{BP}: 0.0123 RB/SCF

Produced Water:
Total Dissolved Solids: 30,000 ppm
Viscosity at P_{BP}: 0.65 cp

FULL FIELD SIMULATION PARAMETERS

1. Number of grid blocks:

A first step in a simulation study is establishing a pattern of grids that is able to properly define the reservoir. Any mapping or gridding software can be used for this purpose. In this study, the Geographix mapping and gridding package was used to generate the grid maps of porosity, saturation, permeability, pressure, and pay thickness.

Grid sizes were selected such that there were 5 grid blocks between wells. This spacing was thought to be sufficient to represent the reservoir. Also, the effects of numerical dispersion in BOAST 3 are reduced if there are about 4 to 5 grid cells between the wells. Figure 2.23 shows the location of wells in the grid pattern generated for Schaben field.

Sub-surface petrophysical cross-sections in Schaben field show that the original oil column has migrated across multiple correlated zones within the Mississippian. This suggests that the oil migrated into the anticlinal structure through a fracture system rather than by capillarity. The presence of fractures in the cores, obtained from the 3 recently drilled wells, confirms a fracture system within the reservoir. Also, reservoir heterogeneity is a typical characteristic for most Mississippian carbonate reservoirs. However, limited petrophysical and core data in the Schaben field do not allow a complex description of the reservoir. Fluid production data over the life of the field shows an increasing rate of water production with time. DST results from recently drilled wells indicate that the current reservoir pressure is close to the original reservoir pressure. These observations suggest a strong recharge of the reservoir by an underlying aquifer. Considering these observations, the Schaben field simulation was simplified as a two-layer model in the z direction that included a reservoir layer with an underlying aquifer layer.

2. Grid block dimensions:

The grid block dimensions are 220 feet by 220 feet and are same for both the reservoir layer and the aquifer. From petrophysical logs covering the Mississippian at the Schaben demonstration site, it is difficult to distinguish between productive and non-productive zones, therefore gross and the net pay thickness is assumed to be equal. Gross/net pay was selected from petrophysical logs as the interval from the top of the reservoir to the oil water contact (OWC) at -2145 feet subsea. Figure 2.24 shows the gross/net pay thickness of layer 1. OWC was established from DST data, production test data, and petrophysical analysis. All petrophysical analyzes were generated using PfEFFER (see section 2.2.2.4). A uniform aquifer thickness of 100 feet was assumed in this study. Petrophysical logs from some of the deep wells surrounding the Schaben field show an approximate aquifer thickness of 100 feet.

3. Dip angle:
The regional dip of the Mississippian formation across the demonstration area is a quarter of 1 degree (0.25^o). Given the negligible regional dip angle, a zero dip angle was used in this simulation study.

4. Depth to the top of the grid blocks in the top most layer.
The depth to the top of layer 1 (pay-zone) is the distance between the datum of sea level and the top of the reservoir. This interval was obtained from the petrophysical logs. Figure 2.25 is a map showing the depth to the top of the reservoir from a datum of sea level.

5. Reservoir Porosity and Permeability:
The PfEFFER log analysis package (see Section 2.2.2.4) was used to determine the total reservoir porosity at each well. Calculated porosity at each well is the average value obtained over the net pay interval. Porosity values in Schaben field were obtained from a wide suite of logs, both old and new, and run over a period of 35 years. For the simulation, porosity obtained from the log calculations was labeled total porosity and assumed to be made up of both micro- and macro-porosity. Based on core analysis, under reservoir pressures the micro-pores do not appear to contribute to fluid flow within the reservoir, and are saturated with immobile water. Under reservoir pressures, it was assumed that the fluid-flow took place only through macro-pores. Hydrocarbons are assumed to reside only in the macro-pores. Correlation between core porosity and macro-porosity, at reservoir pressure, was obtained from the NMR studies on 18 core plugs selected from wells drilled as part of the project (Figure 2.26). Based on the results of core studies, core porosity was assumed to equal to the log porosity. Since the pore volume making up the macro-pores is believed to contribute solely to the fluid-flow in the reservoir, the macro-porosity was used as the effective porosity in the simulation. Figure 2.27 is the effective porosity map of Schaben field.

A horizontal matrix permeability to effective porosity cross-plot (Figure 2.28) was obtained from laboratory measurements on 104 cores plugs taken from cores of the three most recently drilled wells. The permeability range observed from core plugs is 1.3 to 33.4md.. As mentioned earlier, fluid-flow in Schaben field is influenced by a fracture-matrix system. Examination of the permeability obtained from DST tests in 5 wells indicate average permeability values ranging between 73 to 246md. Matrix permeabilities appear to underestimate the effective permeability in the reservoir. Simulation runs using only the matrix permeability were unable to support the historical production rates of oil and water. Sensitivity analysis and history matching from iterative simulation runs resulted in the use of an effective horizontal permeability that was five times the matrix permeability (Figure 2.29). The permeabiulity values adjusted for the simulation are similar to observed values from Mississippian DST test and ranged from 6.5 to 167.0 md.

Horizontal permeability measurements were obtained from approximately 150 core plugs, taken from cores of seven different wells, was available. A plot of maximum horizontal matrix permeability against the direction 90^{O} to the maximum resulted in a slope near 1 (Figure 2.30). Based on this plot, it was assumed that the horizontal permeability in the X and Y directions is equal.

In fractured reservoirs, an assumption is often made that the vertical permeability is one tenth that of the horizontal permeability. A histogram plot of the ratio of horizontal and vertical permeability from 48 core plugs from the Schaben demonstration site is shown as figure 2.31. The highest frequencies are between the permeability ratios of 0.05 and 0.2 with a mean value of 0.15. Initial simulation runs used a horizontal to vertical matrix permeability ratio of 0.1. Sensitivity analysis and production history matching from iterative simulation runs were used to adjust the vertical permeability to 0.15 times the horizontal permeability (Figure 2.32).

6. Relative Permeability & Capillary Pressure:

Data relating relative permeability ratio (K_{rw}/K_{ro}) at different water saturations were available from standard laboratory core plug measurements from the well #1 Moore D. This relative permeability ratio curve was used to generate relative permeability curves (i.e., K_{ro} vs. S_w and K_{rw} vs. S_w). Initial simulation runs were carried out using these relative permeability curves. However, the end points and the shape of both the curves were modified in order to match the historical production data of the field. The final relative permeability data used in the simulation were obtained from the exercise of history matching over a period of 34 years (Figure 2.33).

Eighteen core plugs from the pay zone were selected from the cores of three different wells, and capillary pressure tests were carried out on them. The irreducible water saturation was obtained from the relative permeability data. From the series of 18 capillary pressure curves, the curve showing an asymptotic rise closest to the irreducible water saturation was selected as the representative capillary pressure curve.

7. PVT data:

Historical production data from Schaben demonstration site indicates that gas production was never significant during the history of the field. Thus, a solution gas-oil-ratio of 50 cu. ft/bbl was assumed in this study. The gas gravity was assumed to be 0.7 (air=1.0). Production records show that the average API tank gravity of the oil is 40 degrees and the average reservoir temperature is 115^{o}F.

A bubble point pressure of 225 psia was calculated from standard correlations. The subsea depth corresponding to this bubble point pressure was -2100 feet. This is the average subsea depth of the reservoir across the field. The oil viscosity above and below the bubble point was calculated with the help of standard correlations. The viscosity of dead oil at reservoir temperature was determined as 2.5 cp, with a slope of oil viscosity above bubble point of 0.000495 cp/psi.

The oil formation volume factor at bubble point and above the bubble point was also calculated using standard correlations. The oil formation volume factor at bubble point was determined as 1.037 RB/STB with a slope of oil formation volume factor above bubble point of -0.000005 RB/(STB.psi).

Water analyzes available from wells in the Schaben demonstration area indicate average total dissolved solids are 30,000 ppm. Correlations were used to calculate the water viscosity corrected to average reservoir temperature and pressure (Water viscosity = 0.65 cp). Standard correlations were also used to calculate the formation volume factor of water at pressures above the bubble point.

The calculated average reservoir porosity for all the grid blocks is 17.5%. This average porosity was used to determine the total rock compressibility of the reservoir from standard correlations (Total rock compressibility = $3.8*10^{-6}$ psi^{-1}).

Gas formation volume factor and gas viscosity was calculated at bubble point pressure, and also at pressures above the bubble point with the help of standard correlations. The gas viscosity at bubble point was determined as 0.0108 cp with a slope above bubble point of 0.0123 RB/scf.

The stock tank properties of oil, gas and water used in the simulation are:

density of oil = 51.46 lb/cu. ft;
density of water = 64.55 lb/cu. ft;
density of gas = 0.0535 lb/cu. ft.

8. Oil saturation:

Since the Schaben field has not produced significant volumes of gas, the sum of water and oil saturation was assumed to be unity. Initial water saturation at individual wells was determined from well log analysis using the PfEFFER log analysis package (see Section 2.2.2.4). Total water saturation as calculated at individual wells and effective porosity as determined from log calculations and NMR analysis (Figure 2.26) were used to create a effective oil saturation (1-water saturation) map for the Schaben demonstration area. Effective oil saturation in each 220' X 220' grid cell was obtained by dividing the total volume of oil present in each grid by the effective pore volume of that grid (Figure 2.27). This effective oil saturation was then normalized so that no grid cell had a value of effective oil saturation more than 75% (Figure 2.34). This normalization was carried out because the relative permeability curves indicate that the water stops moving at saturations below 25%.

9. Water saturation:

The water saturation in the effective porosity of each grid cell was obtained by subtracting the effective oil saturation from 1.

10. Pressure:

The average DST shut-in pressures in the Mississippian reservoir at Schaben Field were used to generate an initial reservoir pressure map (Figure 2.35). The reservoir pressure map showed that most of the reservoir had pressures above 1100 psi. However, two regions at the periphery of the field showed pressures in the region of 400 psi. These anomalously low pressures were removed from the analysis and the final map normalized so that all the grid cells had a minimum pressure of 1100 psi. (Figure 2.35).

11. Aquifer:

Schaben field appears to have an active bottom water drive. Simulation was based on a two layer model with the bottom layer acting as the aquifer. The aquifer in this simulation was designed solely to supply the necessary water required to recharge the reservoir layer and maintain reservoir pressure over time. An uniform porosity of 25% was used for the aquifer. The aquifer porosity was obtained from the well logs of Humburg #1. This is one of the few deep wells in the field with an adequate electric log suite across the aquifer. Oil flow in the reservoir is restricted to the upper layer, and is unaffected by the aquifer permeability. Vertical permeability in the aquifer plays a critical role in controlling the water production at the wells. A good field match was obtained (within 18% of what is believed to be the water production in the field) when a value of 25md was assumed as the horizontal permeability of the aquifer along with a vertical permeability ranging between 0.1 to 4.5md. As in the reservoir layer, aquifer permeability in the X and Y direction was assumed to be equal. The aquifer pressure was assumed to be higher than the maximum pressure value in the reservoir, and was assigned a constant value of 1400 psi.

12. Limiting factors imposed on the simulation:

Maximum number of time steps allowed in the run = 9999
Limiting maximum water/oil ratio = 100
Limiting maximum gas/oil ratio = 1000
Limiting minimum field average pressure = 100 psi
Limiting maximum field average pressure = 2000 psi
Maximum saturation change permitted over a time step = 0.3
Maximum pressure change permitted over a time step = 200 psi