HETEROGENEOUS SHALLOW-SHELF CARBONATE BUILDUPS IN THE PARADOX BASIN, UTAH AND COLORADO: TARGETS FOR INCREASED OIL PRODUCTION AND RESERVES USING HORIZONTAL DRILLING TECHNIQUES

SEMI-ANNUAL TECHNICAL PROGRESS REPORT
April 6, 2002 - October 5, 2002

Edited and Compiled
by

Thomas C. Chidsey, Jr., Principal Investigator/Program Manager,
Utah Geological Survey

December 2002

Contract No. DE-FC2600BC15128

Gary D. Walker, Contract Manager
U.S. Department of Energy
National Petroleum Technology Office
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ABSTRACT

The Paradox Basin of Utah, Colorado, Arizona, and New Mexico contains nearly 100 small oil fields producing from carbonate buildups within the Pennsylvanian (Desmoinesian) Paradox Formation. These fields typically have one to 10 wells with primary production ranging from 700,000 to 2,000,000 barrels (111,300-318,000 m^3) of oil per field and a 15 to 20 percent recovery rate. At least 200 million barrels (31.8 million m^3) of oil will not be recovered from these small fields because of inefficient recovery practices and undrained heterogeneous reservoirs.

Several fields in southeastern Utah and southwestern Colorado are being evaluated as candidates for horizontal drilling and enhanced oil recovery from existing, vertical, field wells based upon geological characterization and reservoir modeling case studies. Geological characterization on a local scale is focused on reservoir heterogeneity, quality, and lateral continuity, as well as possible reservoir compartmentalization, within these fields. This study utilizes representative cores, geophysical logs, and thin sections to characterize and grade each field's potential for drilling horizontal laterals from existing development wells. The results of these studies can be applied to similar fields elsewhere in the Paradox Basin and the Rocky Mountain region, the Michigan and Illinois Basins, and the Midcontinent region.

This report covers research activities for the first half of the third project year (April 6 through October 5, 2002). This work included capillary pressure/mercury injection analysis, scanning electron microscopy, and pore casting on selected samples from Cherokee and Bug fields, Utah. The diagenetic fabrics and porosity types found at these fields are indicators of reservoir flow capacity, storage capacity, and potential for enhanced oil recovery via horizontal drilling.

The reservoir quality of Cherokee and Bug fields has been affected by multiple generations of dissolution, anhydrite plugging, and various types of cementation which act as barriers or baffles to fluid flow. The most significant diagenetic characteristics are microporosity (Cherokee field) and micro-boxwork porosity (Bug field), as shown from pore-throat radii histograms, and saturation profiles generated from the capillary pressure/mercury injection analysis, and identified by scanning electron microscopy and pore casting. These porosity types represent important sites for untapped hydrocarbons and primary targets for horizontal drilling.

Technology transfer activities consisted of exhibiting a booth display of project materials at the Rocky Mountain Section meeting of the American Association of Petroleum Geologists, a technical presentation, and publications. The project home page was updated for the Utah Geological Survey Internet web site.

EXECUTIVE SUMMARY

The project's primary objective is to enhance domestic petroleum production by demonstration and transfer of horizontal drilling technology in the Paradox Basin of Utah and Colorado. If this project can demonstrate technical and economic feasibility, then the technique can be applied to approximately 100 additional small fields in the Paradox Basin alone, and result in increased recovery of 25 to 50 million barrels (4-8 million m^3) of oil. This project is designed to characterize several shallow-shelf carbonate reservoirs in the Pennsylvanian (Desmoinesian) Paradox Formation, choose the best candidate field(s) for a pilot demonstration project to drill horizontally from existing vertical wells, monitor well performance(s), and report associated validation activities.

The Utah Geological Survey heads a multidisciplinary team to determine the geological and reservoir characteristics of typical, small, shallow-shelf, carbonate reservoirs in the Paradox Basin. The Paradox Basin technical team consists of the Utah Geological Survey (prime contractor), Colorado Geological Survey (subcontractor), Eby Petrography & Consulting Inc. (subcontractor), and Seeley Oil Company (subcontractor and industry partner). This research is funded by the Class II Oil Revisit Program of the U.S. Department of Energy, National Petroleum Technology Office (NPTO) in Tulsa, Oklahoma. This report covers research activities for the first half of the third project year (April 6 through October 5, 2002).

This work included capillary pressure/mercury injection analysis, scanning electron microscopy, and pore casting on selected samples from Cherokee and Bug fields, Utah. From these, and other, project evaluations, untested or under-produced reservoir compartments can be identified as targets for horizontal drilling. The results of this study can be applied to similar reservoirs in many U.S. basins.

Capillary pressure/mercury injection analysis for Cherokee field indicates a relatively high injection pressure is required to occupy greater than the last 70 percent of the pores. A steep saturation profile indicates greater microporosity that corresponds to the lower initial flowing potential and productivity, but high potential for untapped reserves. Half of the pore size distribution for the Cherokee reservoir fall in the microporosity realm. The pore throat radius for the Bug reservoir, show that some zones also have significant microporosity (micro-boxwork porosity) while other zones are dominated by moldic porosity. As in Cherokee field, relatively high injection pressures in Bug field are required to occupy greater than the last 70 percent of the pores. The steeper saturation profiles indicate the presence of micro-box-work porosity and thus, excellent horizontal drilling targets.

Scanning electron microscope and/or pore casting analyses helped disclose the diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of Cherokee and Bug fields. All samples exhibit microporosity in the form of intercrytalline (primarily in Cherokee field) or micro-boxwork porosity (primarily in Bug field). Dissolution has contributed to porosity in most samples by creating moldic, vuggy, and channel porosity. Anhydrite, calcite, smectite clays, and pyrobitumen are present in some samples. The dominant cement occluding porosity and permeability in the Cherokee wells is anhydrite. The general diagenetic sequence for samples studied by SEM and pore casting analyses was: (1) deposition of calcite cement, (2) dissolution, (3) dolomitization, (4) dissolution, (5) fracturing, (6) calcite cementation, (7) quartz cementation, (8) clay deposition, (9) anhydrite cementation, and (10) pyrobitumen emplacement.

The diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of Cherokee and Bug fields are indicators of reservoir flow capacity and storage capacity. The microporosity in Cherokee field and the micro-boxwork porosity in Bug field represent important sites for untapped hydrocarbons and possible targets for horizontal drilling using stacked, parallel horizontal laterals from existing vertical wells.

Technology transfer activities consisted of exhibiting a booth display of project materials at the 2002 Rocky Mountain Section meeting of the American Association of Petroleum Geologists in Laramie, Wyoming. An oral technical presentation was made at the convention on porosity development in Cherokee field, Utah. The project home page was updated for the Utah Geological Survey Internet web site. The project team members submitted an abstract to the American Association of Petroleum Geologists for presentation at the 2003 annual national convention in Salt Lake City, Utah. They also planned a project short course, co-sponsored by the U.S. Department of Energy, for that meeting. Project team members published an abstract and semi-annual reports detailing project progress and results.

INTRODUCTION

Project Overview

Over 400 million barrels (64 million m^3) of oil have been produced from the shallow-shelf carbonate reservoirs in the Pennsylvanian Paradox Formation in the Paradox Basin of southeastern Utah and southwestern Colorado (figure 1). The two main producing zones of the

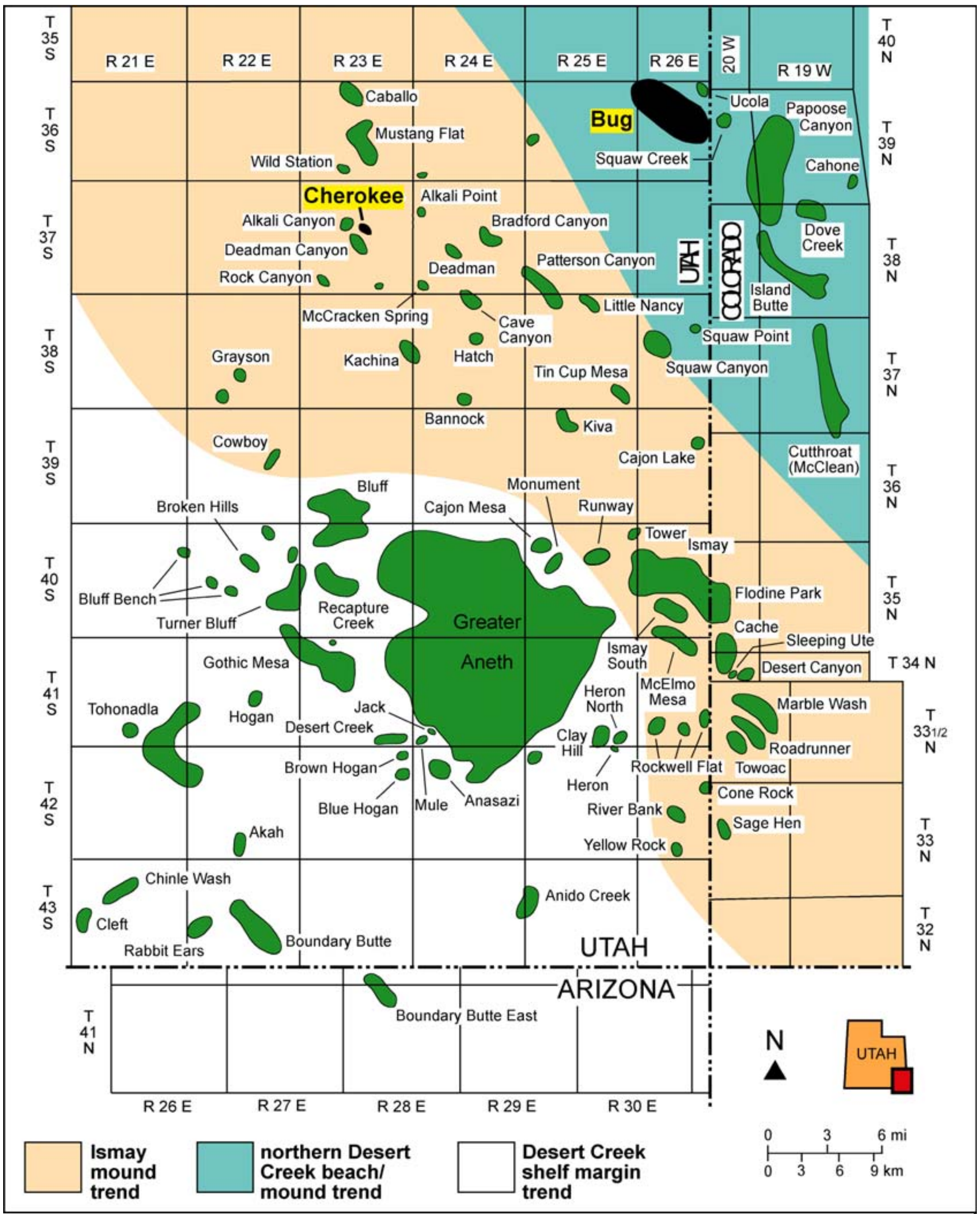

Figure 1. Map showing the project study area and fields within the Ismay and Desert Creek producing trends in the Blanding sub-basin, Utah and Colorado.

Paradox Formation are informally named the Ismay and the Desert Creek (figure 2). The Ismay zone is dominantly limestone comprising equant buildups of phylloid-algal material with locally variable small-scale subfacies (figure 3A) and capped by anhydrite. The Ismay produces oil from fields in the southern Blanding sub-basin (figure 1). The Desert Creek zone is dominantly dolomite comprising regional, nearshore, shoreline trends with highly aligned, linear facies tracts (figure 3B). The Desert Creek produces oil in fields in the central Blanding sub-basin (figure 1). Both the Ismay and Desert Creek buildups generally trend northwest-southeast. Various facies changes and extensive diagenesis have created complex reservoir heterogeneity within these two diverse zones.

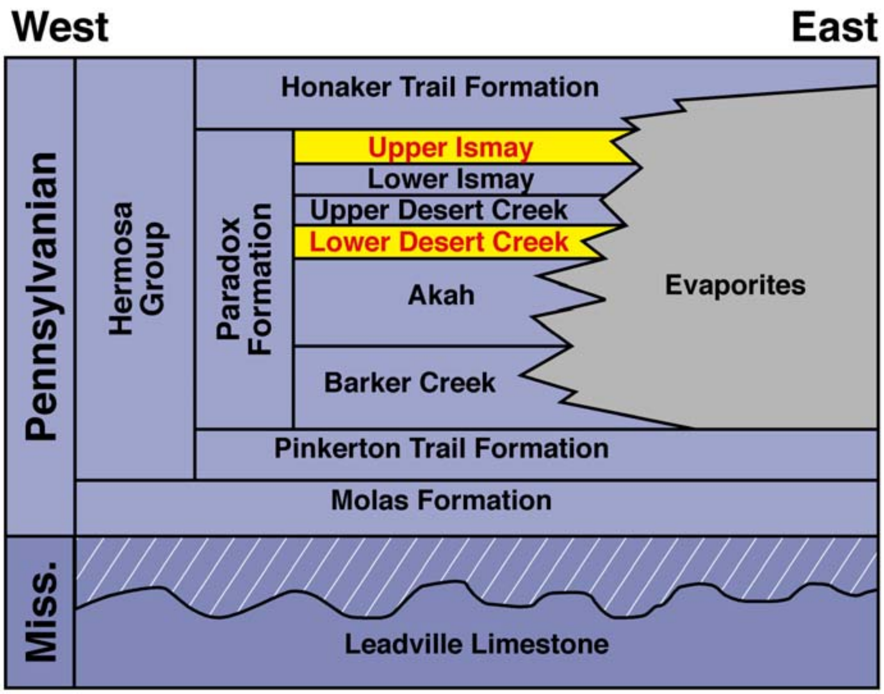

Figure 2. Pennsylvanian stratigraphy of the southern Paradox Basin including informal zones of the Paradox Formation.

With the exception of the giant Greater Aneth field, the other 100+ oil fields in the basin typically contain 2 to 10 million barrels (0.3-1.6 million m^3) of original oil in place. Most of these fields are characterized by high initial production rates followed by a very short productive life (primary), and hence premature abandonment. Only 15 to 25 percent of the original oil in place is recoverable during primary production from conventional vertical wells.

An extensive and successful horizontal drilling program has been conducted in the giant Greater Aneth field. However, to date, only two horizontal wells have been drilled in small Ismay and Desert Creek fields. The results from these wells were disappointing due to poor understanding of the carbonate facies and diagenetic fabrics that create reservoir heterogeneity. These small fields, and similar fields in the basin, are at high risk of premature abandonment. At least 200 million barrels (31.8 million m^3) of oil will be left behind in these small fields because current development practices leave compartments of the heterogeneous reservoirs undrained. Through proper geological evaluation of the reservoirs, production may be increased by 20 to 50 percent through the drilling of low-cost single or multilateral horizontal legs (figure 4) from existing vertical development wells. In addition, horizontal drilling from existing wells minimizes surface disturbances and costs for field development, particularly in the environmentally sensitive areas of southeastern Utah and southwestern Colorado.

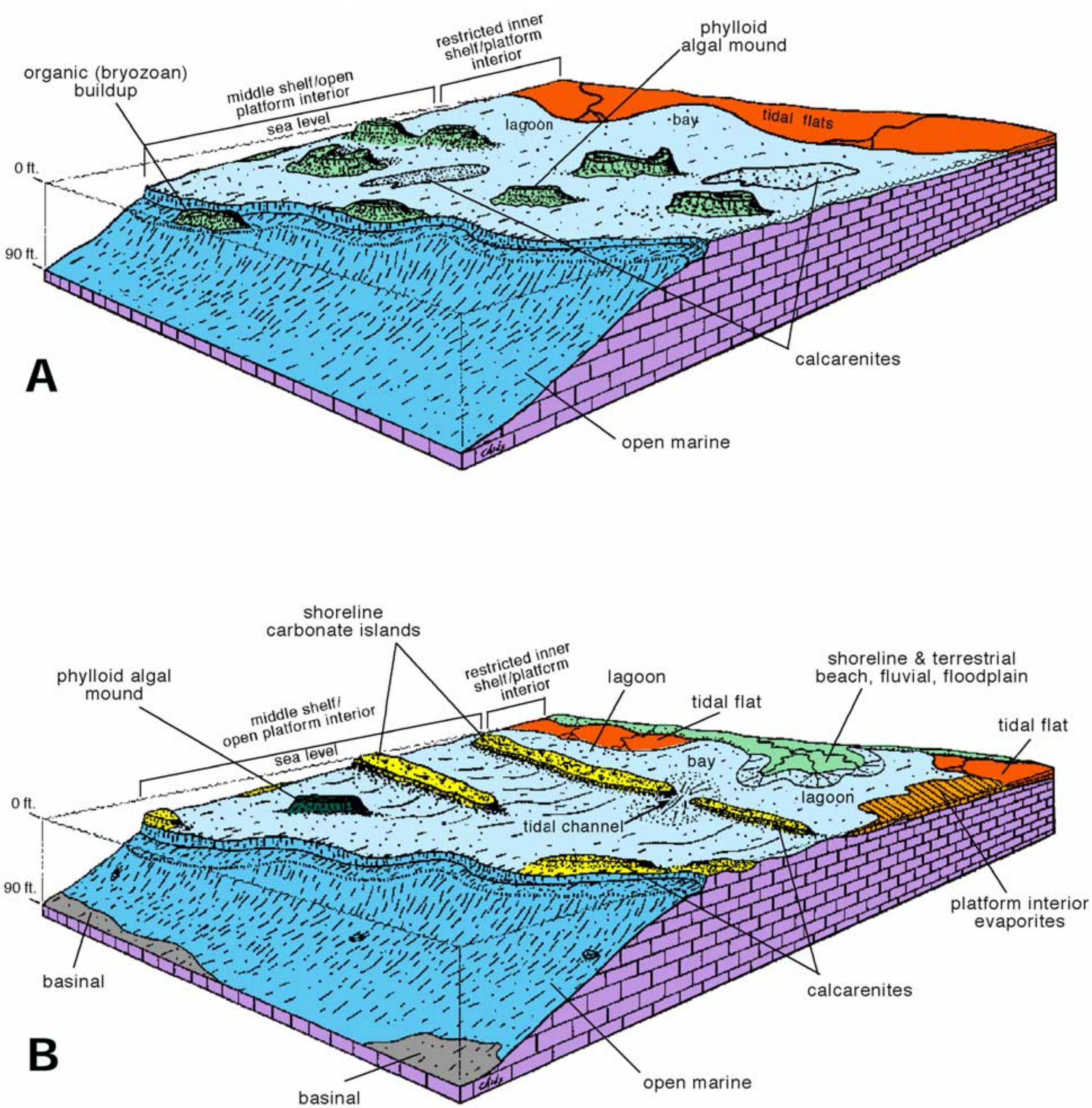

Figure 3. Block diagrams displaying major depositional facies, as determined from core, for the Ismay (A) and Desert Creek (B) zones, Pennsylvanian Paradox Formation, Utah and Colorado.

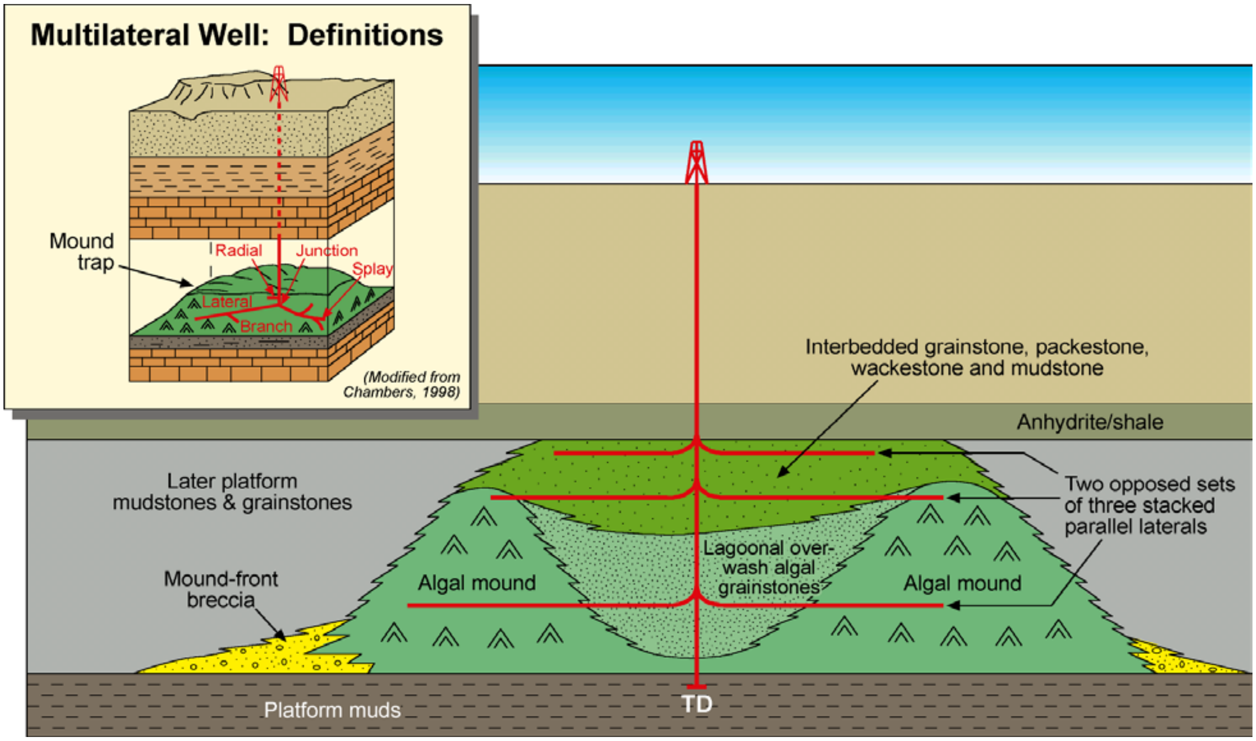

Figure 4. Schematic diagram of Ismay zone drilling targets by multilateral (horizontal) legs from an existing field well.

The Utah Geological Survey (UGS), Colorado Geological Survey (CGS), Eby Petrography & Consulting, Inc., and Seeley Oil Company have entered into a cooperative agreement with the U.S. Department of Energy (DOE) as part of its Class II Oil Revisit Program. A three-phase, multidisciplinary approach will be used to increase production and reserves from the shallow-shelf carbonate reservoirs in the Ismay and Desert Creek zones of the Paradox Basin.

<u>Phase 1</u> is the geological and reservoir characterization of selected, diversified small fields, including Cherokee and Bug fields in San Juan County, Utah (figure 1), to identify those field(s) having the greatest potential as targets for increased well productivity and ultimate recovery in a pilot demonstration project. This phase will include: (a) determination of regional geological setting; (b) analysis of the reservoir heterogeneity, quality, lateral continuity, and compartmentalization within the fields; (c) construction of lithologic, microfacies, porosity, permeability, and net pay maps of the fields; (d) determination of field reserves and recovery; and (e) integration of geological data in the design of single or multiple horizontal laterals from existing vertical wells.

<u>Phase 2</u> is a field demonstration project of the horizontal drilling techniques identified as having the greatest potential for increased field productivity and ultimate recovery. The demonstration project will involve drilling one or more horizontal laterals from the existing vertical field well(s) to maximize production from the zones of greatest potential.

<u>Phase 3</u> includes: (a) reservoir management and production monitoring, (b) economic evaluation of the results, and (c) determination of the ability to transfer project technologies to other similar fields in the Paradox Basin and throughout the U.S.

Phases 1, 2, and 3 will have continuous, but separate, technical transfer activities including: (a) an industry outreach program; (b) a core workshop/seminar in Salt Lake City; (c) publications and technical presentations; (d) a project home page on the Utah Geological Survey and Colorado Geological Survey Internet web sites; (e) digital databases, maps, and reports; (f) a summary of regulatory, economic, and financial needs; and (g) annual meetings with a Technical Advisory Board and Stake Holders Board.

Project Benefits and Potential Application

The overall benefit of this multi-year project would be enhanced domestic petroleum production by demonstrating and transferring an advanced-oil-recovery technology throughout the small oil fields of the Paradox Basin. Specifically, the benefits expected from the project are: (1) increasing recovery and reserve base by identifying untapped compartments created by reservoir heterogeneity; (2) preventing premature abandonment of numerous small fields; (3) increasing deliverability by horizontally drilling along the reservoir's optimal fluid-flow paths; (4) identifying reservoir trends for field extension drilling and stimulating exploration in Paradox Basin fairways; (5) reducing development costs by more closely delineating minimum field size and other parameters necessary for horizontal drilling; (6) allowing for minimal surface disturbance by drilling from existing vertical field wells; (7) allowing limited energy investment dollars to be used more productively; and (8) increasing royalty income to the federal, state, and local governments, the Ute Mountain Ute Indian Tribe, and fee owners. These benefits may also apply to other areas including: algal-mound and carbonate buildup reservoirs on the eastern and northwestern shelves of the Permian Basin in Texas, Silurian pinnacle and patch reefs of the Michigan and Illinois Basins, and shoaling carbonate island trends of the Williston Basin.

The results of this project are transferred to industry and other researchers through establishment of Technical Advisory and Stake Holders Boards, an industry outreach program, digital project databases, and project web page. Project results will be disseminated via technical workshops and seminars, field trips, technical presentations at national and regional professional meetings, and papers in various technical or trade journals.

GEOLOGICAL CHARACTERIZATION OF CASE-STUDY FIELDS, SAN JUAN COUNTY, UTAH - RESULTS AND DISCUSSION

Two Utah fields were selected for local-scale evaluation during Budget Period I of the project: Cherokee in the Ismay trend and Bug in the Desert Creek trend (figure 1). This evaluation included data collection, core photography and description, determination of a typical vertical sequence from conventional core tied to its corresponding log response, reservoir mapping, determination of diagenetic fabrics from thin sections, and plots of core plug porosity versus permeability of these fields, as described in Chidsey and others, 2001. Capillary pressure/mercury injection analysis, scanning electron microscopy (SEM), and pore casting were also conducted on selected samples from Cherokee and Bug fields, and the results are described in this report.

The geological characterization of these fields is focused on reservoir heterogeneity, quality, and lateral continuity, as well as possible compartmentalization. From these evaluations, untested or under-produced compartments can be identified as targets for horizontal drilling. The models resulting from the geological and reservoir characterization of these fields can be applied to similar fields in the basin (and other basins as well) where data might be limited.

Case-Study Fields

Cherokee Field

Cherokee field (figure 1) is a phylloid-algal buildup capped by anhydrite that produces from porous algal limestone and dolomite in the upper Ismay zone. The net reservoir thickness is 27 feet (8.2 m), which extends over a 320-acre (130 ha) area. Porosity averages 12 percent with 8 millidarcies (md) of permeability in vuggy and intercrystalline pore systems. Water saturation is 38.1 percent (Crawley-Stewart and Riley, 1993).

Cherokee field was discovered in 1987 with the completion of the Meridian Oil Company Cherokee Federal 11-14, NE1/4NW1/4 section 14, T. 37 S., R. 23 E., Salt Lake Base Line and Meridian (SLBL&M); initial flowing potential (IFP) was 53 barrels of oil per day (BOPD) (8.4 m^3), 990 thousand cubic feet of gas per day (MCFGPD) (28 MCMPD), and 26 barrels of water (4.1 m^3). There are currently four producing (or shut-in) wells and two dry holes in the field. The well spacing is 80 acres (32 ha). The present field reservoir pressure is estimated at 150 pounds per square inch (psi) (1,034 Kpa). Cumulative production as of July 1, 2002, was 181,421 barrels of oil (28,846 m^3), 3.63 billion cubic feet of gas (BCFG) (0.1 BCMG), and 3,358 barrels of water (534 m^3) (Utah Division of Oil, Gas and Mining, 2002). The original estimated primary recovery is 172,000 barrels of oil (27,348 m^3) and 3.28 BCFG (0.09 BCMG) (Crawley-Stewart and Riley, 1993). The fact that both these estimates have been surpassed suggests significant additional reserves could remain.

Bug Field

Bug field (figure 1) is an elongate, northwest-trending carbonate buildup in the lower Desert Creek zone. The producing units vary from porous dolomitized bafflestone to packstone and wackestone. The trapping mechanism is an updip porosity pinchout. The net reservoir thickness is 15 feet (4.6 m) over a 2,600-acre (1,052 ha) area. Porosity averages 11 percent in moldic, vuggy, and intercrystalline networks. Permeability averages 25 to 30 md, but ranges from less than 1 to 500 md. Water saturation is 32 percent (Martin, 1983; Oline, 1996).

Bug field was discovered in 1980 with the completion of the Wexpro Bug No. 1, NE1/SE1/4 section 12, T. 36 S., R. 25 E., SLBL&M, for an IFP of 608 BOPD (96.7 m^3), 1,128 MCFGPD (32 MCMPD), and 180 barrels of water (28.6 m^3). There are currently eight producing (or shut-in) wells, five abandoned producers, and two dry holes in the field. The well spacing is 160 acres (65 ha). The present reservoir field pressure is 3,550 psi (24,477 Kpa). Cumulative production as of July 1, 2002, was 1,619,605 barrels of oil (257,517 m^3), 4.47 BCFG (0.13 BCMG), and 3,174,487 barrels of water (504,743 m^3) (Utah Division of Oil, Gas and Mining, 2002). Estimated primary recovery is 1,600,000 bbls (254,400 m^3) of oil and 4 BCFG (0.1 BCMG) (Oline, 1996). Again, since the original reserve estimates have been surpassed and the field is still producing, significant additional reserves likely remain.

Capillary Pressure/Mercury Injection Analysis

Capillary pressure/mercury injection analysis evaluates reservoir fluid saturation, and relates pore aperture size and distribution to porosity and permeability (Pittman, 1992). These data were used to assess reservoir potential and quality by: (1) determining the most effective pore systems for oil storage versus drainage, (2) identifying reservoir heterogeneity, (3) predicting potential untested compartments, (4) inferring porosity and permeability trends, and (5) matching diagenetic processes, pore types, mineralogy, and other attributes to porosity and permeability distribution.

High-pressure, mercury-injection porosimetry (MIP) measurements were conducted on five core samples (table 1). The core samples include: (1) a dolomitic, peloidal packstone to grainstone with anhydrite replacement and bitumen plugging from the Cherokee no. 22-14 well, (2) a micritic dolomitic mudstone to wackestone with a large amount of bitumen from the Cherokee no. 33-14 well, (3) a dolomitic phylloid-algal bafflestone with both early marine cement and leaching from the May Bug no. 2 well (6,304 feet [1,921 m]), (4) a dolomitic phylloid-algal bafflestone with internal sediment and leaching, also from the May Bug no. 2 well (6,315 feet [1,925 m]), and (5) a dolomitic phylloid-algal bafflestone with both early marine cement and leaching from the Bug 4 well.

Table 1. Well core-plug samples selected for capillary pressure/mercury injection analysis.

Sample Depth (feet)	Well Name	Porosity (%)	Grain Density (g/cm^3)
5768.7	Cherokee 22-14	24.38	2.875
5781.2	Cherokee 33-14	20.89	2.934
6304.0	May Bug 2	11.06	2.865
6315.0	May Bug 2	22.24	2.834
6289.7	Bug 4	12.45	2.857

Methods

Core plugs were obtained from the two Cherokee wells and three of the eight Bug wells that were cored. Core plugs were no more than 2 inches (5 cm) in length. Prior to MIP testing, the samples were dried in a low-temperature convection oven, and then ambient helium porosity and grain density measurements were conducted on each sample (table 1). These porosity values, along with the volume of mercury injected into each sample, were used to calculate cumulative saturation. The samples were also visually examined for open fractures that can contribute to anomalous results at low injection pressures. None of the samples tested contained open fractures or coring-induced cracks.

Results and Interpretation

All samples tested exhibited 100 percent mercury saturation at pressures less than 10,000 psi (68,950 Kpa) injection pressure. The selected reservoir rock samples vary in porosity from 11 to 24 percent, and have grain densities of 2.8 to 2.9 g/cm^3. Pore-throat-radius histograms and saturation profiles are presented in figures 5 through 11.

Cherokee field: The pore-throat-radius histograms for both the Cherokee no. 22-14 and Cherokee no. 33-14 wells (figures 5 and 6), show that half of the pore size distribution falls under 2.0 microns, or in the microporosity realm. For the Cherokee no. 22-14 well, the distribution of pore-throat radii appears to be trimodal. Mode 1 ranges from 7.0 to 3.6 microns (the modal class [the most abundant radii in the mode] is 4.0 microns), and accounts for 3.8 to 8 percent of the pore space, with 30 percent of the pores saturated on the cumulative injection curve. Mode 2 ranges from 2.4 to 1.04 microns (the modal class is 1.6 microns), and accounts for 10 to 15 percent of the pore space, also with 30 percent of the pores saturated on the cumulative injection curve. Mode 3 ranges from 0.7 to 0.13 microns (the modal class is 0.7 microns), and accounts for the remaining pore space, but with 20 percent of the pores saturated on the cumulative injection curve. Modes 1 and 2 account for 60 percent of the injection and need 16 percent porosity to be effective for oil and gas production. Mode 3 needs 19.5 percent porosity to be effective for oil (1.0 micron radii) and gas (0.5 micron radii) production. The measured porosity is 24.4 percent.

For the Cherokee no. 33-14 well, the distribution of pore-throat radii appears to be unimodal. The primary mode ranges from 3.0 to 1.04 microns (modal class is 2.0 microns), accounts 6 to 15 percent of the pore space, but only 40 percent saturation of the cumulative curve at 2.0 microns. Thus of the two wells, the Cherokee no. 33-14 is a poorer producer than the Cherokee no. 22-14. This primary mode needs 15.5 percent porosity to be effective for oil and 19.5 percent porosity for gas production. The measured porosity is 20.1 percent.

The saturation profile for the Cherokee no. 22-14 well shows mode 1 covers 2 to 30 percent of the mercury saturation (percent of the pore volume) and requires injection pressure of 2 to 20 psi (14-138 Kpa) (figure 7). Mode 2 covers 30 to 70 percent of the mercury saturation and requires injection pressure of 20 to 40 psi (138-276 Kpa), and is the most important in terms of contribution to production. The first 50 percent of the mercury saturation requires 28 psi (193 Kpa) and is thus a good pore system; the second 45 percent requires 400 psi (2,758 Kpa). Most pores are filled under 1,000 psi (6,895 Kpa).

The saturation profile for the Cherokee no. 33-14 well shows the primary mode covers 2.5 to 70 percent of the mercury saturation and requires injection pressure of 15 to 70 psi (103-483 Kpa) (figure 7). The first 50 percent of the mercury saturation requires 45 psi (310 Kpa); the second 45 percent requires 600 psi (4,137 Kpa).

Both wells show that a relatively high injection pressure is required to occupy more than the last 70 percent of the pores (figure 7). The Cherokee no. 33-14 well has a steeper saturation profile than the Cherokee no. 22-14 indicating a greater amount of microporosity, and corresponding to the lower IFP (336 BOPD [53 m^3/D] and 349 MCFGPD [10 MCMGPD] for the Cherokee no. 33-14 well compared to 688 BOPD [109 m^3/D] and 78,728 MCFGPD [2,230 MCMGPD] for the Cherokee no. 22-14 well). However, the well has a high potential for untapped reserves.

Bug field: Three capillary pressure/mercury injection tests were run on samples from Bug field: two from the May Bug no. 2 well (6,304 feet [1,921 m] and 6,315 feet [1,925 m]), and one from the Bug no. 4 well. For the 6,304-foot sample from the May Bug no. 2 well, the distribution of pore-throat radii is trimodal (figure 8). Mode 1 ranges from 10 to 20 microns (the modal class is 10.65 microns), and accounts for 2 to 4 percent of the pore space, with 20 percent of the pores saturated on the cumulative injection curve. Mode 2 ranges from 6.9 to 4.5 microns (the

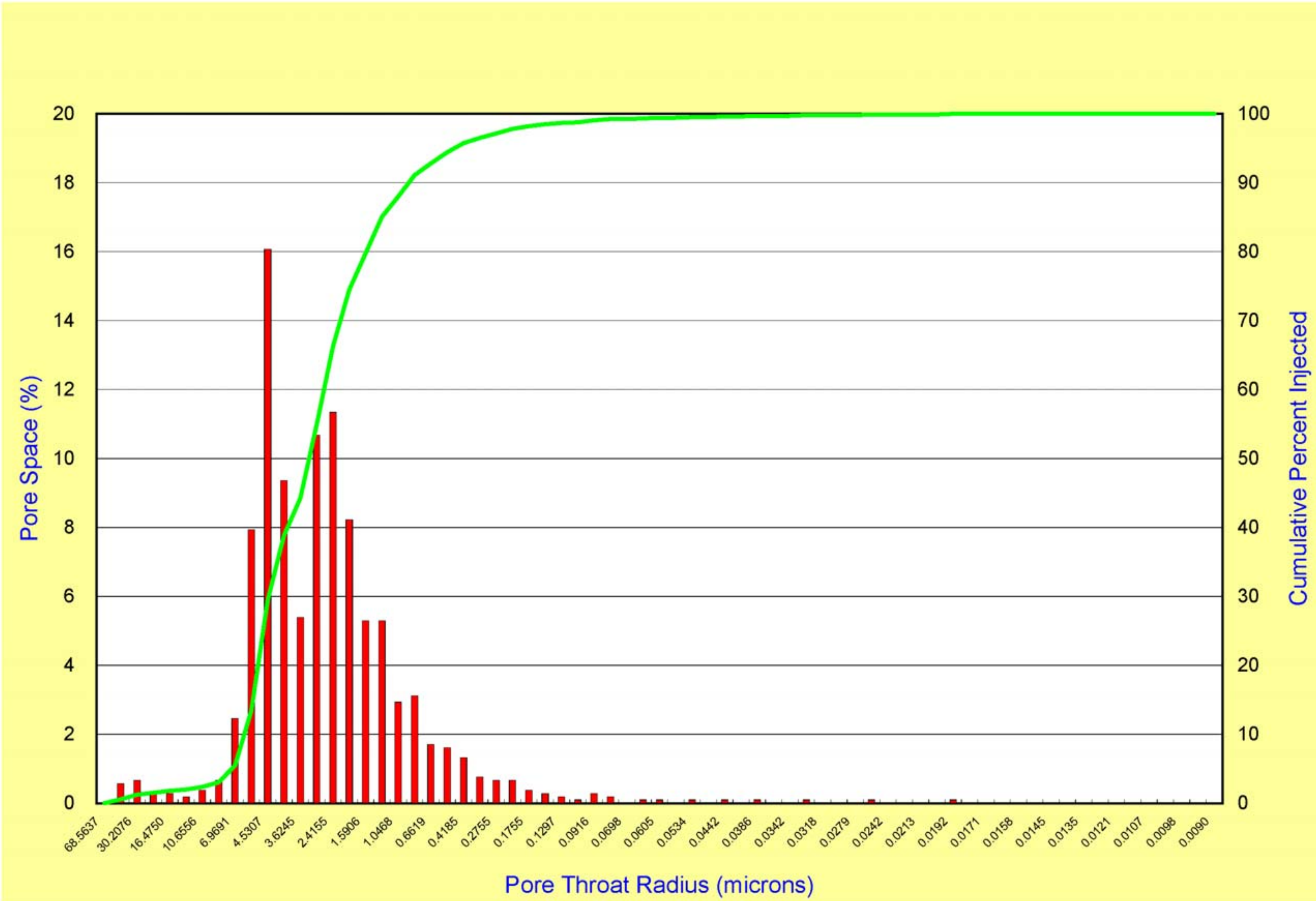

Figure 5. Pore throat radius histogram – sample depth, 5,768.7 feet – Cherokee no. 22-14 well.

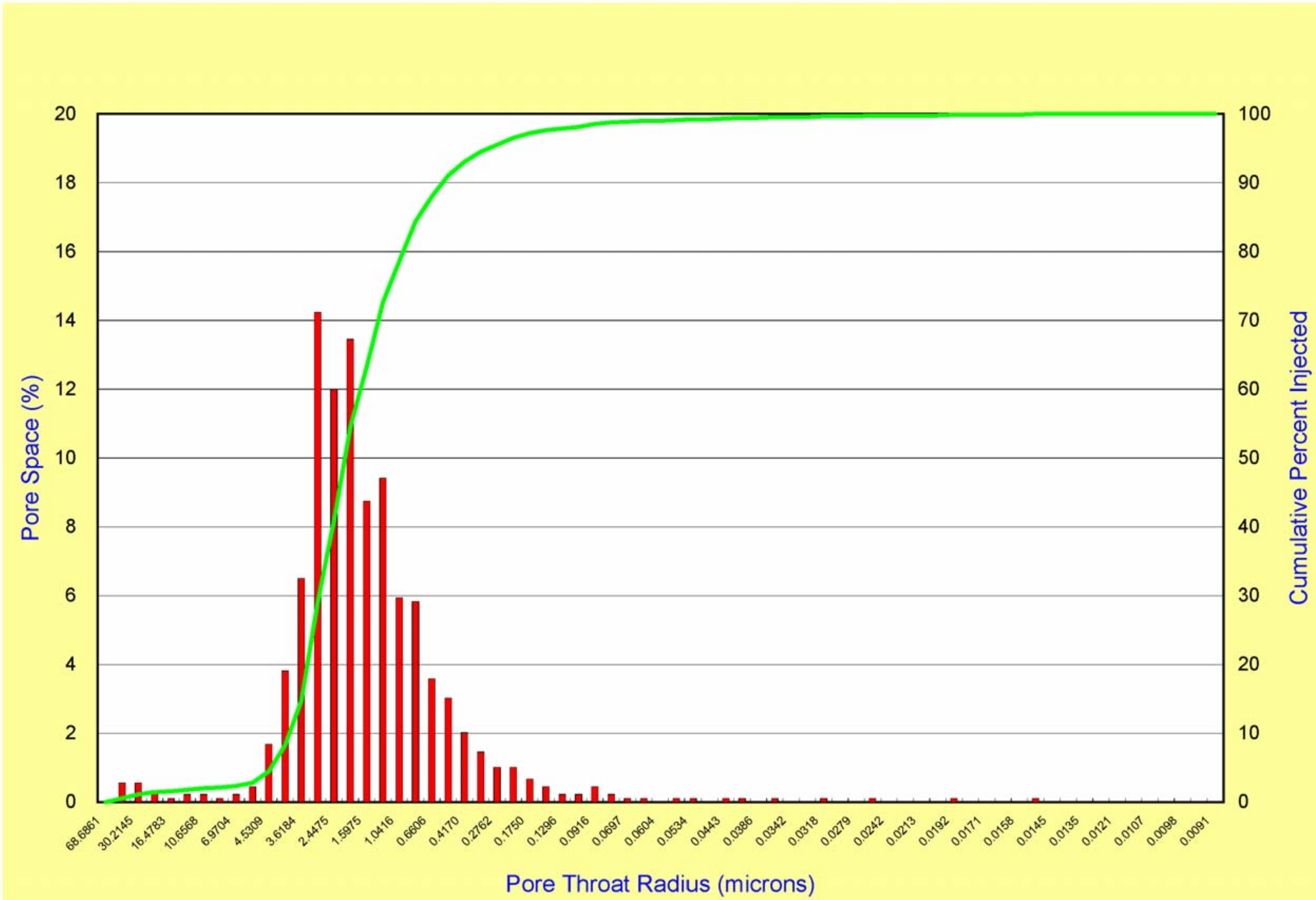

Figure 6. Pore throat radius histogram – sample depth, 5,781.2 feet – Cherokee no. 33-14 well.

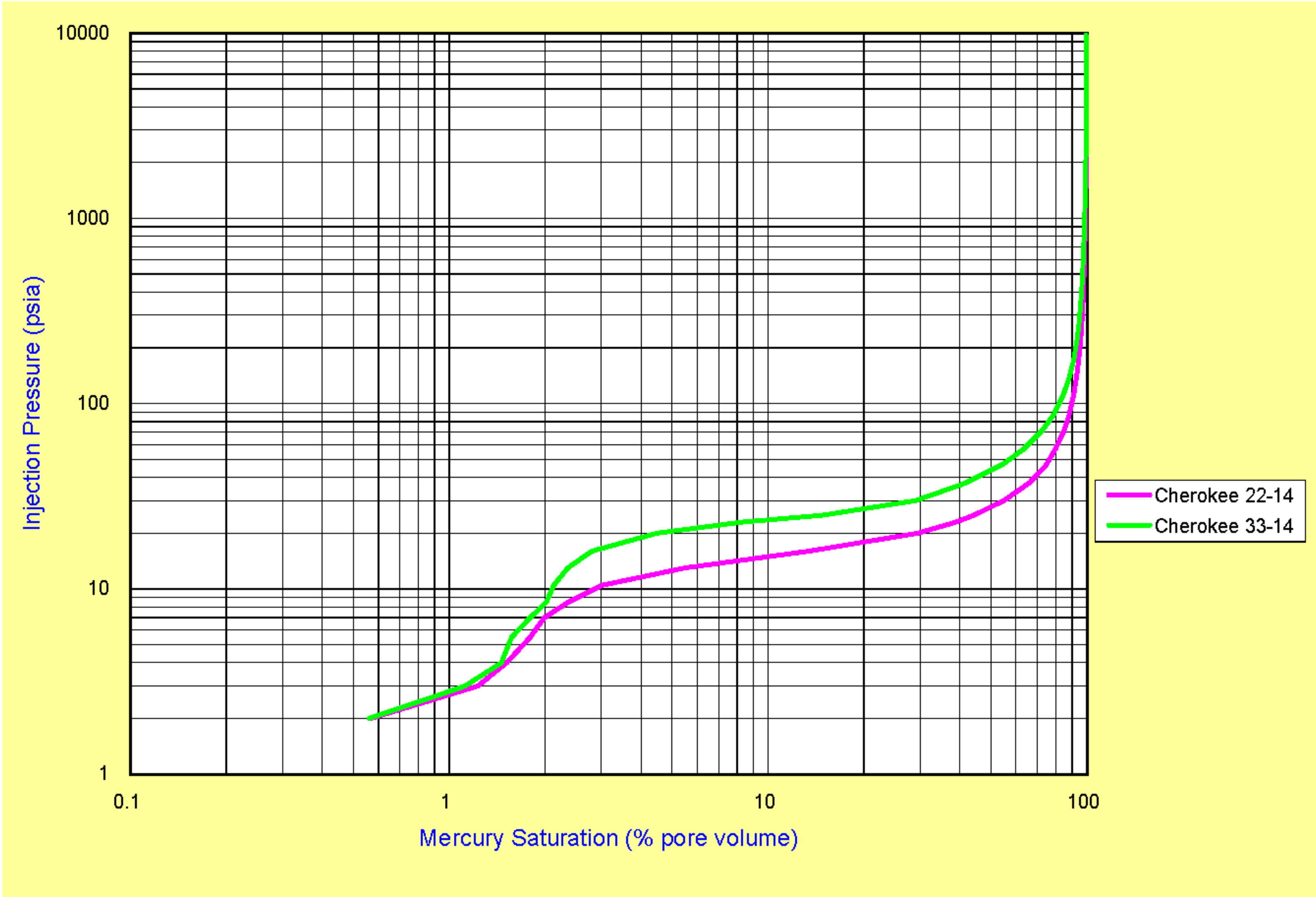

Figure 7. Saturation profiles, Cherokee no. 22-14 and Cherokee no. 33-14 wells.

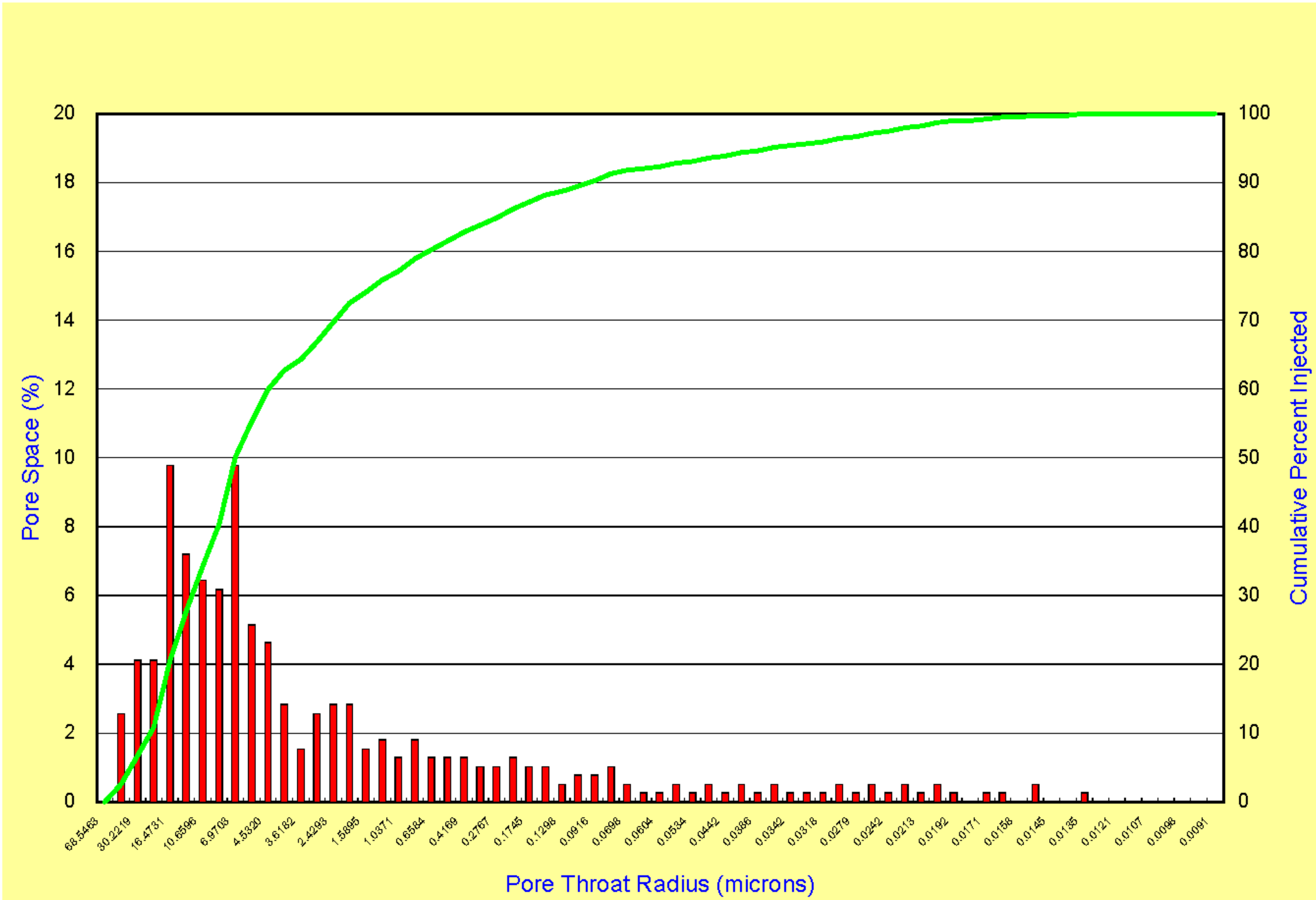

Figure 8. Pore throat radius histogram – sample depth, 6,304 feet – May Bug no. 2 well.

modal class is 5.0 microns), and accounts for 10 to 12 percent of the pore space, with 10 percent of the pores saturated on the cumulative injection curve. The minor mode 3 ranges from 3.0 to 1.5 microns (the modal class is 2.0 microns), and accounts for 13 to 15 percent of the pore space, also with 10 percent of the pores saturated on the cumulative injection curve. Modes 1 and 2 account for 30 percent of the injection and need 16 percent porosity to be effective for oil and 17.5 percent porosity for gas production. The measured porosity is 11.1 percent.

For the 6,315-foot sample from the May Bug no. 2 well, the distribution of pore-throat radii appears to be unimodal (figure 9). The primary mode ranges from 4.5 to 1.5 microns (modal class is 2.3 microns), and accounts 2 to 17 percent of the pore space, with 75 percent saturation of the cumulative curve. This primary mode needs 18 percent porosity to be effective for oil and 19.5 percent porosity for gas production. The measured porosity is 22.2 percent.

The distribution of pore-throat radii in the Bug no. 4 well is trimodal (figure 10). Mode 1 ranges from 5.5 to 3.6 microns (the modal class is about 4.0 microns), and accounts for 4.2 to 6.3 percent of the pore space, with 10 percent of the pores saturated on the cumulative injection curve. Mode 2 ranges from 2.4 to 1.0 microns (the modal class is 1.6 microns), and accounts for 8.3 to 10.3 percent of the pore space, also with 10 percent of the pores saturated on the cumulative injection curve. Mode 3 ranges from 1.0 to 0.4 microns (the modal class is 0.66 microns), and accounts for 12.3 to 14.3 of the remaining pore space, again with 10 percent of the pores saturated on the cumulative injection curve. Modes 1 and 2 account for 20 percent of the injection and need 11 percent porosity to be effective for oil production. Mode 3 needs 18 percent porosity to be effective for gas production. The measured porosity is 12.3 percent.

The saturation profile for the 6,304-foot sample from the May Bug no. 2 well shows mode 1 covers 1 to 60 percent of the mercury saturation and requires injection pressure of 1 to 20 psi (7-138 Kpa) (figure 11). Mode 2 covers 60 to 75 percent of the mercury saturation and requires injection pressure of 20 to 50 psi (138-345 Kpa). The first 50 percent of the mercury saturation requires 15 psi (103 Kpa); the second 45 percent requires 400 psi (2,758 Kpa).

The saturation profile for the 6,315-foot sample from the May Bug no. 2 well shows the primary mode covers 6 to 60 percent of the mercury saturation and requires injection pressure of 15 to 30 psi (103-207 Kpa) (figure 11). The first 50 percent of the mercury saturation requires 28 psi (193 Kpa); the second 45 percent requires 400 psi (2,758 Kpa).

The saturation profile for the Bug no. 4 well shows mode 1 covers 4 to 28 percent of the mercury saturation and requires injection pressure of 3 to 20 psi (21-138 Kpa) (figure 11). Mode 2 covers 45 to 70 percent of the mercury saturation and requires injection pressure of 40 to 150 psi (276-1,034 Kpa). Mode 3 covers 88 to 92 percent of the mercury saturation and requires injection pressure of 500 to 1,500 psi (3,448-10,343 Kpa). The first 50 percent of the mercury saturation requires 55 psi (379 Kpa); the second 45 percent requires 2,000+ psi (13,782+ Kpa).

As in Cherokee field, relatively high injection pressures are required to occupy more than the last 70 percent of the pores (figure 11). The steeper saturation profiles indicate a significant amount of micro-boxwork porosity, and thus, an excellent target for horizontal drilling.

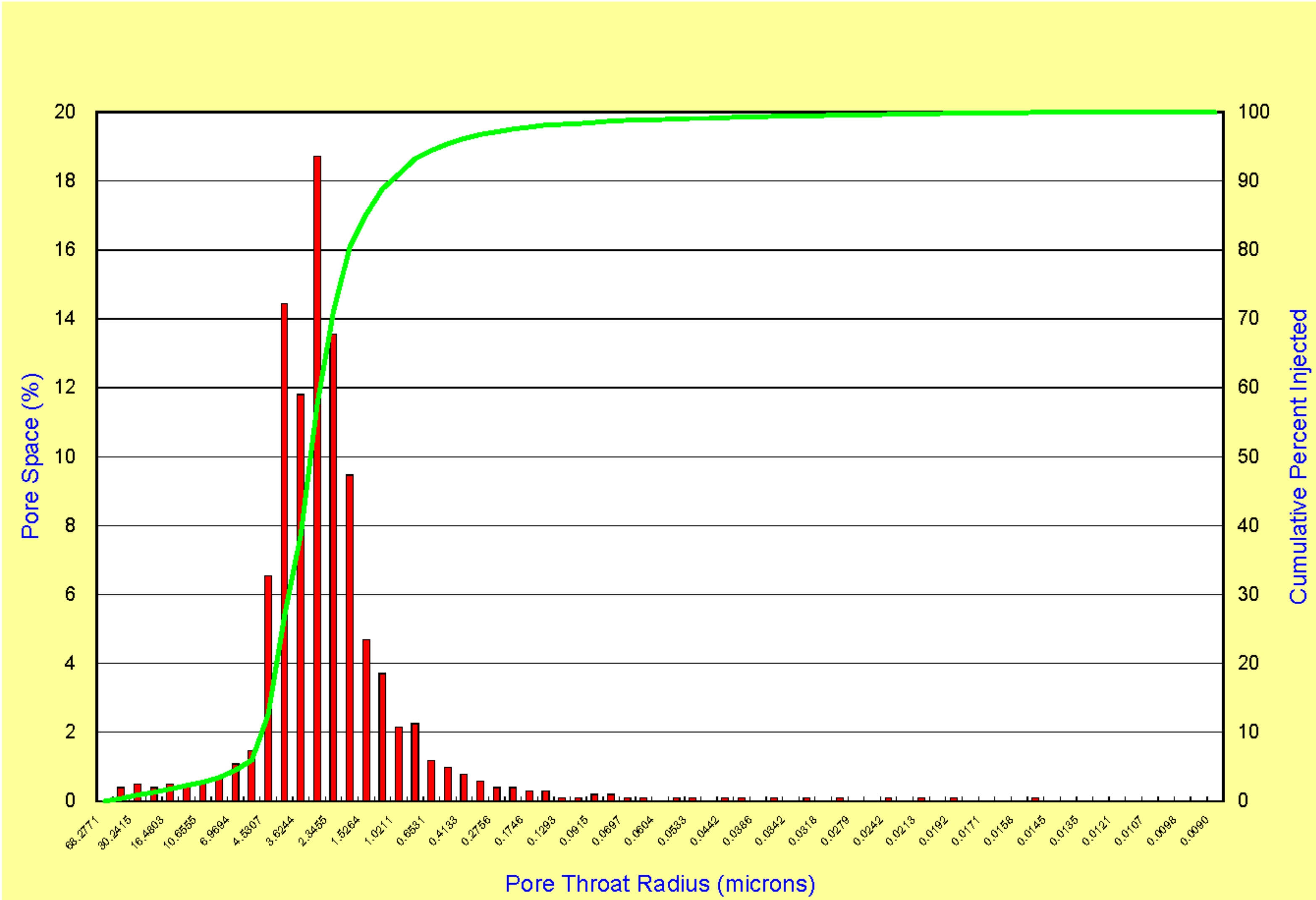

Figure 9. Pore throat radius histogram – sample depth, 6,315 feet – May Bug no. 2 well.

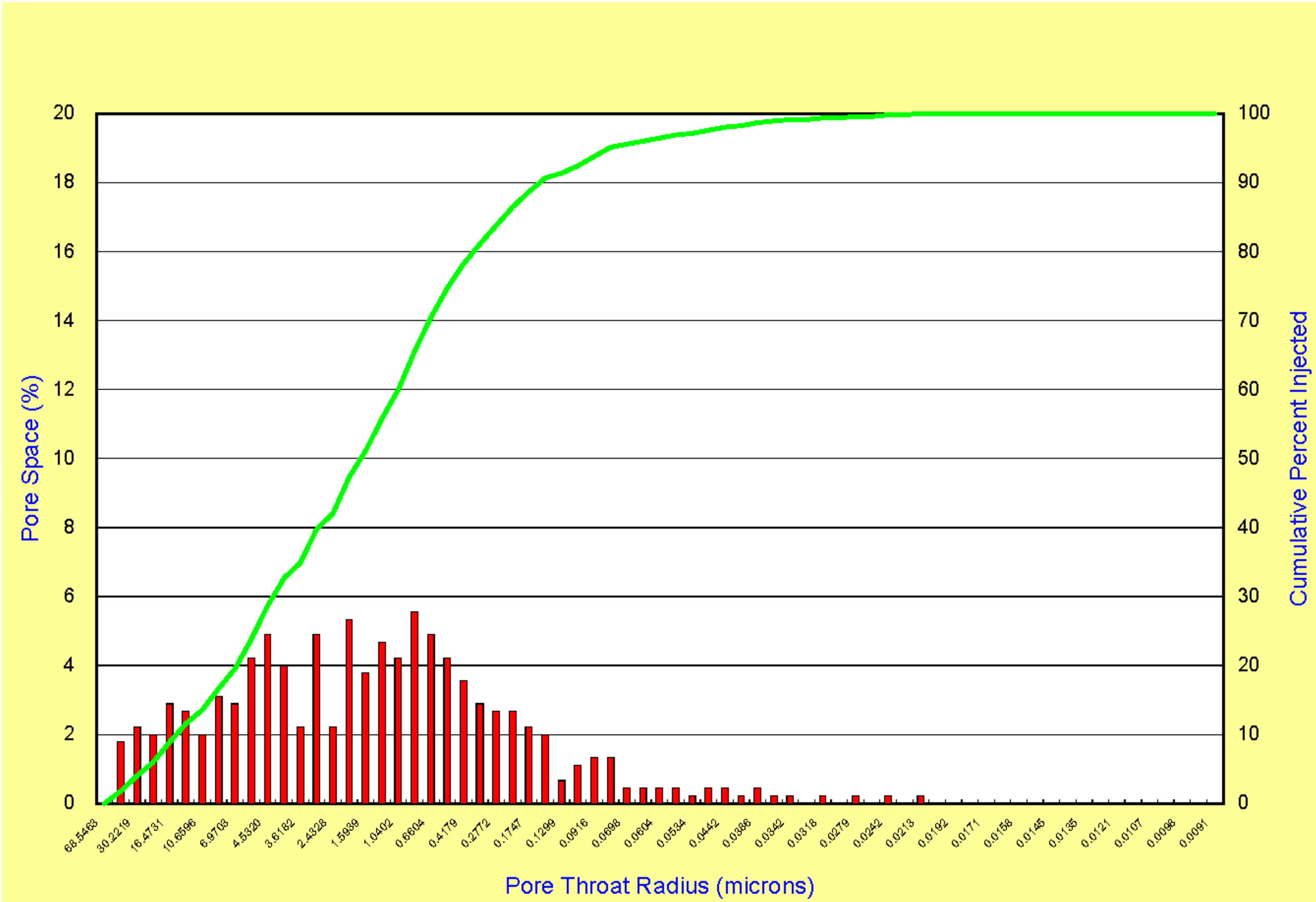

Figure 10. Pore throat radius histogram – sample depth, 6,289.1 feet – Bug no. 4 well.

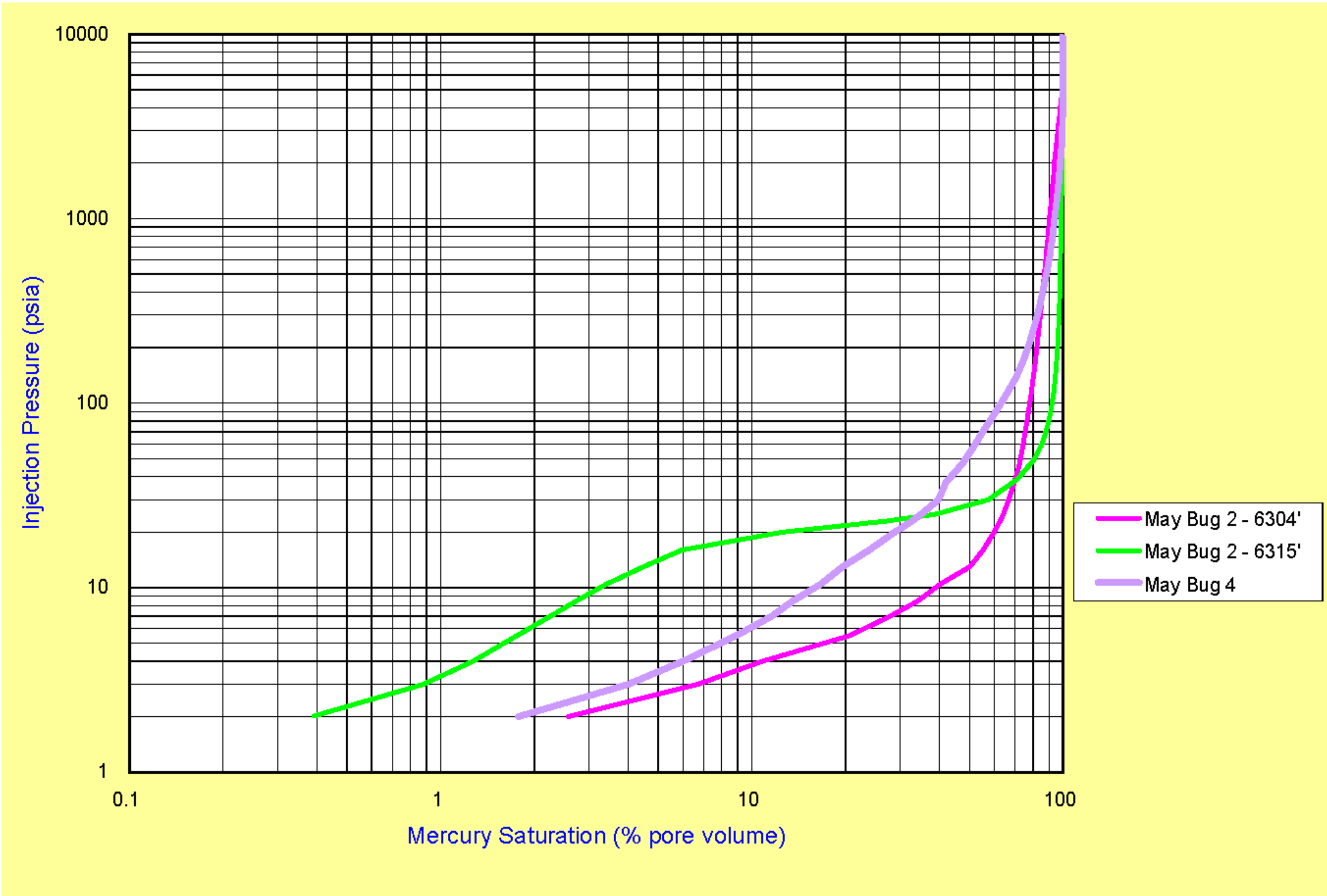

Figure 11. Saturation profiles, May Bug no. 2 and Bug no. 4 wells.

Scanning Electron Microscopy and Pore Casting

The diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of Cherokee and Bug fields can be indicators of reservoir flow capacity, storage capacity, and potential for horizontal drilling. In order to determine the diagenetic histories of the various Ismay and Desert Creek reservoirs, representative samples were selected from the suite of 44 samples taken from conventional cores of each field (table 1), which were used for thin sections. Carbonate fabrics were determined according to Dunham's (1962) and Embry and Klovan's (1971) classification schemes. A scanning electron microscope (SEM) was used to photograph: (1) typical preserved primary and secondary pore types and pore throats, (2) cements, (3) sedimentary structures, (4) fractures, and (5) pore plugging anhydrite, halite, and bitumen.

Pore casting is a special technique where the carbonate matrix of an epoxy impregnated thin section blank is dissolved by hydrochloric acid. What remains is only the epoxy that represents the entire pore system of the sample (pores and pore throats). The pore cast is then coated with gold, and studied and photographed with the SEM (the same method as if it were the actual thin section blank).

Reservoir diagenetic fabrics and porosity types of these carbonate buildups were analyzed to: (1) determine the sequence of diagenetic events, (2) predict facies patterns, and (3) provide input for reservoir modeling studies. Diagenetic characterization focussed on reservoir heterogeneity, quality, and compartmentalization within the two fields. All depositional, diagenetic, and porosity information will be combined with each field's production history in order to analyze each horizontal drilling candidate's potential for success. Of special interest is the determination of the most effective pore systems for oil drainage versus storage.

Scanning electron microscope and/or pore casting analyses were conducted on eight thin section blanks from core samples that displayed particular characteristics of interest (table 2). The objectives of this study were to: (1) characterize the cements present, (2) characterize the types of porosity present, and (3) identify diagenetic events. The results are summarized in table 3. Porosity types and associated abbreviations included in this report are from Choquette and Pray (1970) (figure 12). Some porosity descriptions provided here vary from those determined by thin section analysis reported by Chidsey and others (2001). The descriptions presented in this report are from SEM examination and measurement only.

Table 2. List of samples examined in this study and the characteristics of interest.

Well	Depth	SEM	Pore Casting	Characteristics of Interest
Cherokee 22-14	5768.7	X	X	Microporosity dolomite with bitumen
Cherokee 22-14	5827.7	X		Moldic porosity and micro-crystalline dolomite
Cherokee 33-14	5773.9	X		Dolomite, microporosity and moldic porosity, relatively low porosity and permeability
Cherokee 33-14	5781.2	X	X	Microporosity only dolomite, high porosity and permeability
May Bug 2	6304	X	X	Micro-boxwork dolomite/hollow dolomite fabric
May Bug 2	6312B	X		B - (second sample) botryoidal cement/dolomite
May Bug 2	6315A	X	X	A – yellow internal sediment/dolomite
Bug 4	6289.7	X	X	Microporosity/with bitumen and micro-boxwork dolomite
TOTAL	-	8	5	-

Table 3. Summary of porosity, cement, and diagenetic characters of samples examined.

WELL	**Cherokee 22-14**		**Cherokee 33-14**		**May Bug 2 ****			**Bug 4**
DEPTH (ft)	5768.7'	5826.7'	5773.9'	5781.2'	6304.0'	6312.0' B	6315.0' A	6289.7'
POROSITY								
Intergranular (Micro) (BC)	X	X	X	X	X	X	X	X
Dissolution (MO)	X	X	X			X		
Dissolution (VUG)	X				X	X		X
Dissolution (CH)	X	X	X					X
Fractures	X				X			X
CEMENTS								
Anhydrite	X	X	X			X		X
Calcite		X	X			X		
Quartz		X	X	X		X		
Dolomite					X			
Smectite	X	X	X					
Pyrobitumen	X	X	X	X				
DIAGENESIS								
Botryoidal Calcite Deposition					X	X	X	X
Dolomitization	X	X	X	X	X	X	X	X
Dissolution	X	X	X	X	X	X		X
Calcite Cementation		X	X					
Quartz Cementation		X	X	X		X		
Smectite Deposition	X	X	X	X				
Anhydrite Cementation	X	X	X			X		X
Pyrobitumen Emplacement	X	X	X	X				
Fracturing					X			

** Limited observation of the 6312-foot B specimen.

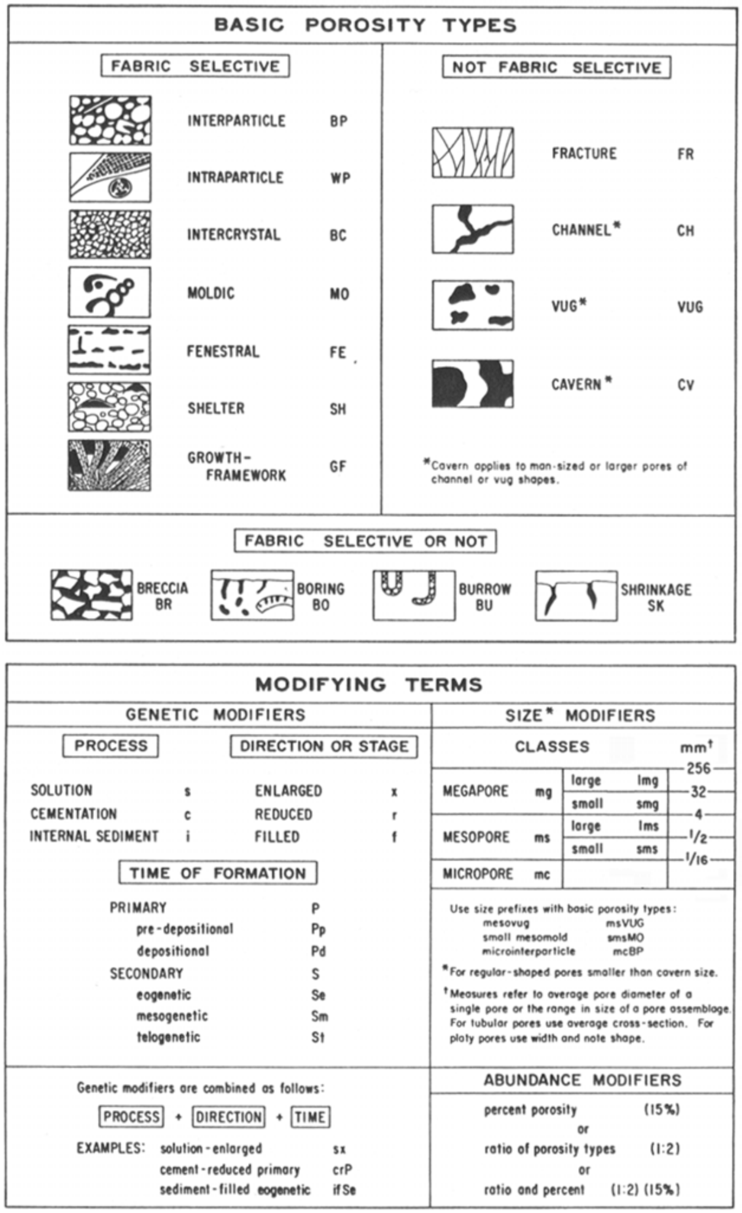

Figure 12. Classification of pores and pore systems in carbonate rocks (Choquette and Pray, 1970).

Porosity Types

All samples exhibit microporosity in the form of intercrytalline (BC) microporosity (figure 13) and micro-boxwork porosity (figure 14). Microporosity represents an important site for untapped hydrocarbons and possible targets for horizontal drilling. Dissolution has contributed to porosity in most samples (figure 13). It has created moldic (MO), vuggy (VUG), and channel (CH) porosity. Dissolution pores are most often in the mesopore size range.

Permeability is related to the size and number of pore throats, and, particularly, to the continuity of pore throats (figures 15 and 16). Pore cast examination reveals the presence of "dead end" pore throats that undoubtedly limit permeability. In general, permeability is limited in these samples by the presence of such pore throats, as well as the presence of cements, pyrobitumen, and tight dissolution remnants.

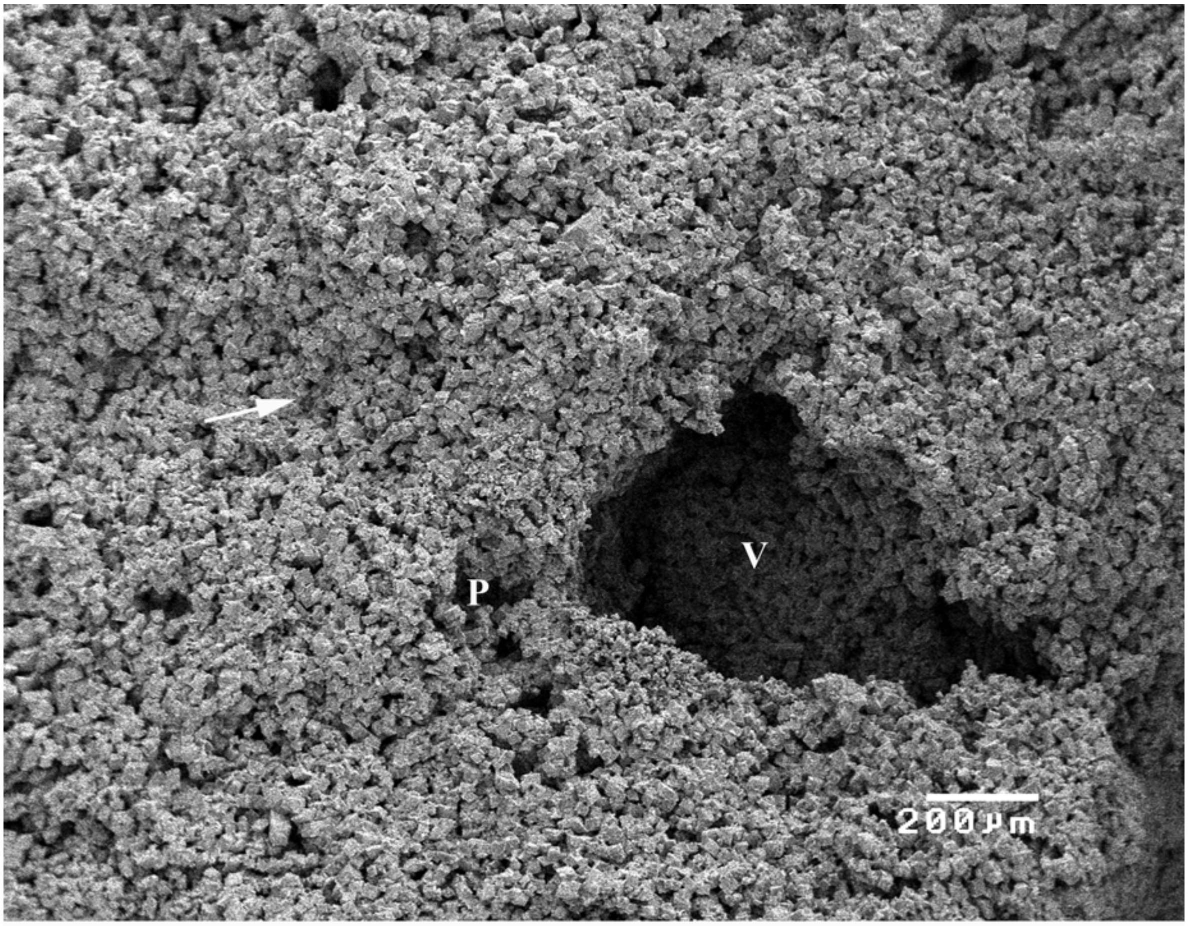

Figure 13. Scanning electron microscope photomicrograph of a core plug from 5,768.7 feet, Cherokee no. 22-14 well. Dolomite exhibits three porosity types: intercrystalline microporosity – BC (arrow); moldic microporosity – MO (P); and a large mesovug – msVUG (V). Oil drainage is mainly from macro- and mesopores, but not from micropores (BC). Scale represents 200 microns (0.2 mm). Porosity = 22.9 percent; permeability = 215 millidarcies based on core-plug analysis.

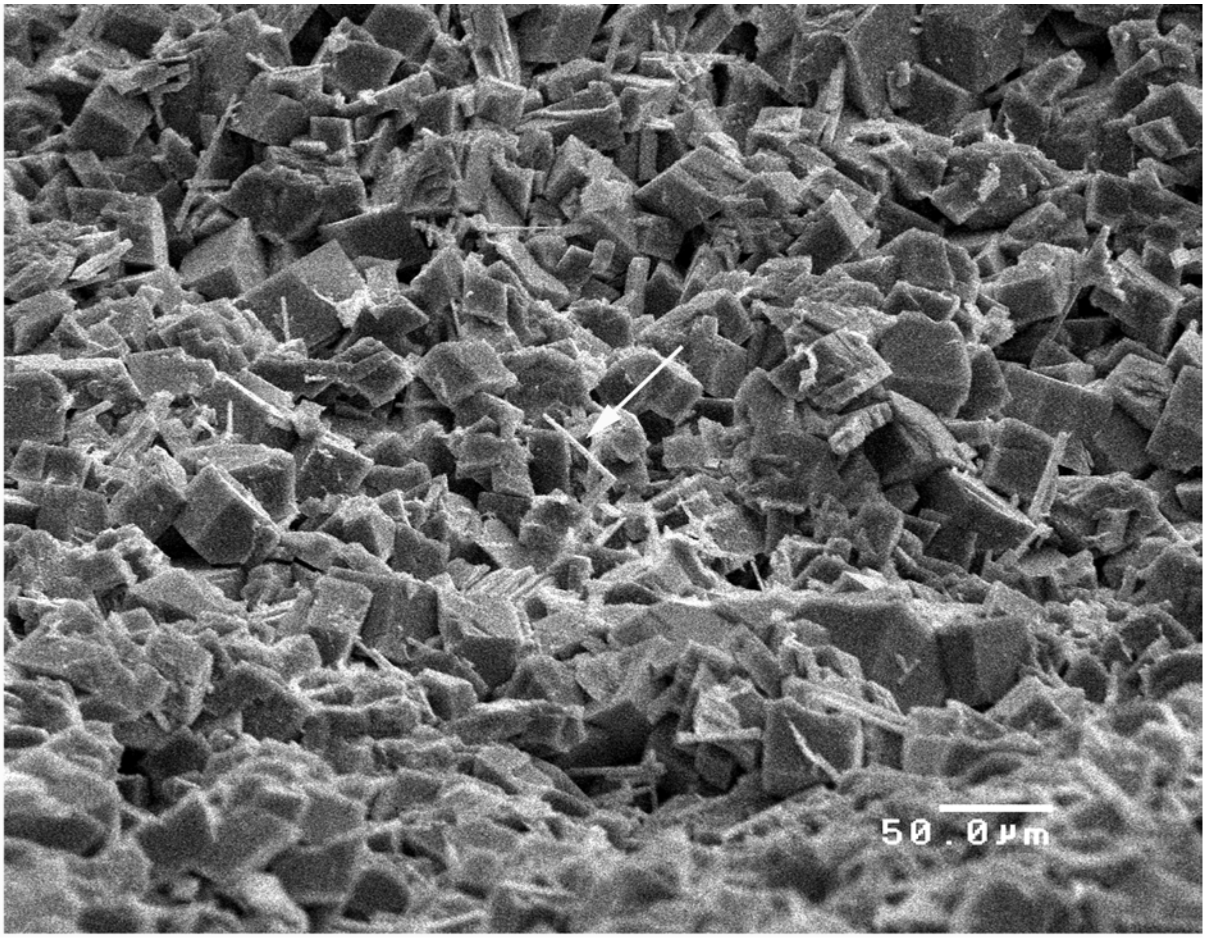

Figure 14. Scanning electron microscope photomicrograph of a core plug from 6,315 feet, May Bug no. 2 well, showing dolomite with intercrystalline microporosity – BC (black). Fragments (lathes) (arrow) of dolomite represent partially dissolved dolomite rhombs present within a yellow portion of the sample. The collapse and/or crushing of dolomite rhombs within the internal hollow dolomite sediment indicate early dolomitization and early meteoric dissolution resulting in micro-boxwork porosity. Scale represents 50 microns (0.05 mm). Porosity = 10.3 percent; permeability = 5.7 millidarcies based on core-plug analysis.

A

B

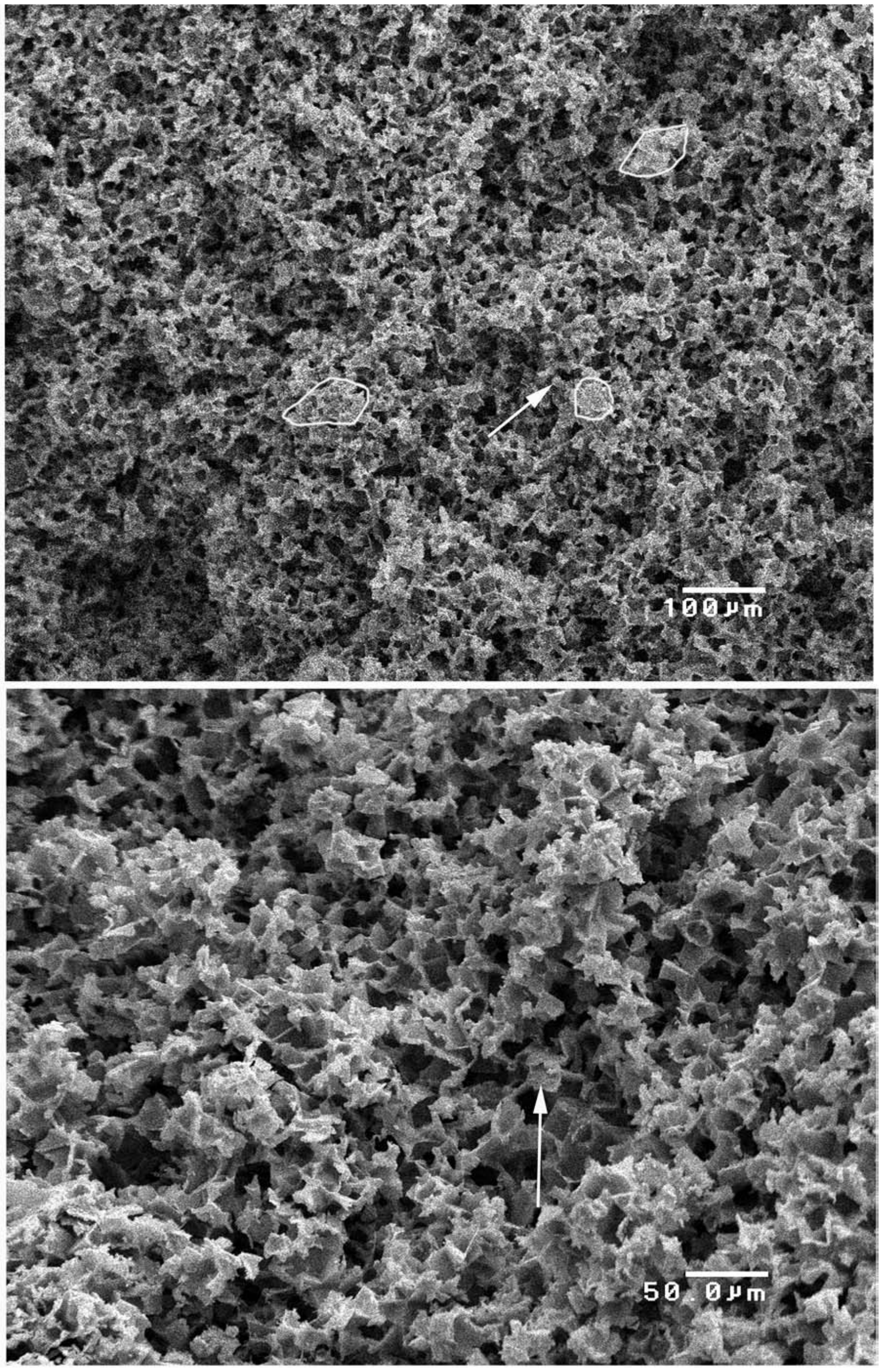

Figure 15. Scanning electron microscope photomicrograph of a pore cast from 5,768.7 feet, Cherokee no. 22-14 well. (A) The overall intercrystalline microporosity – BC (arrow) is relatively uniform. A few larger micropores are visible (outline). Note that the solid areas (light gray) represent porosity and the open areas (dark gray to black) represent matrix. Scale represents 100 microns (0.1 mm). (B) Enlargement of (A) showing microporosity. Impressions of dolomite rhombs are visible (arrow). Scale represents 50 microns (0.05 mm). Porosity = 22.9 percent; permeability = 215 millidarcies based on core-plug analysis.

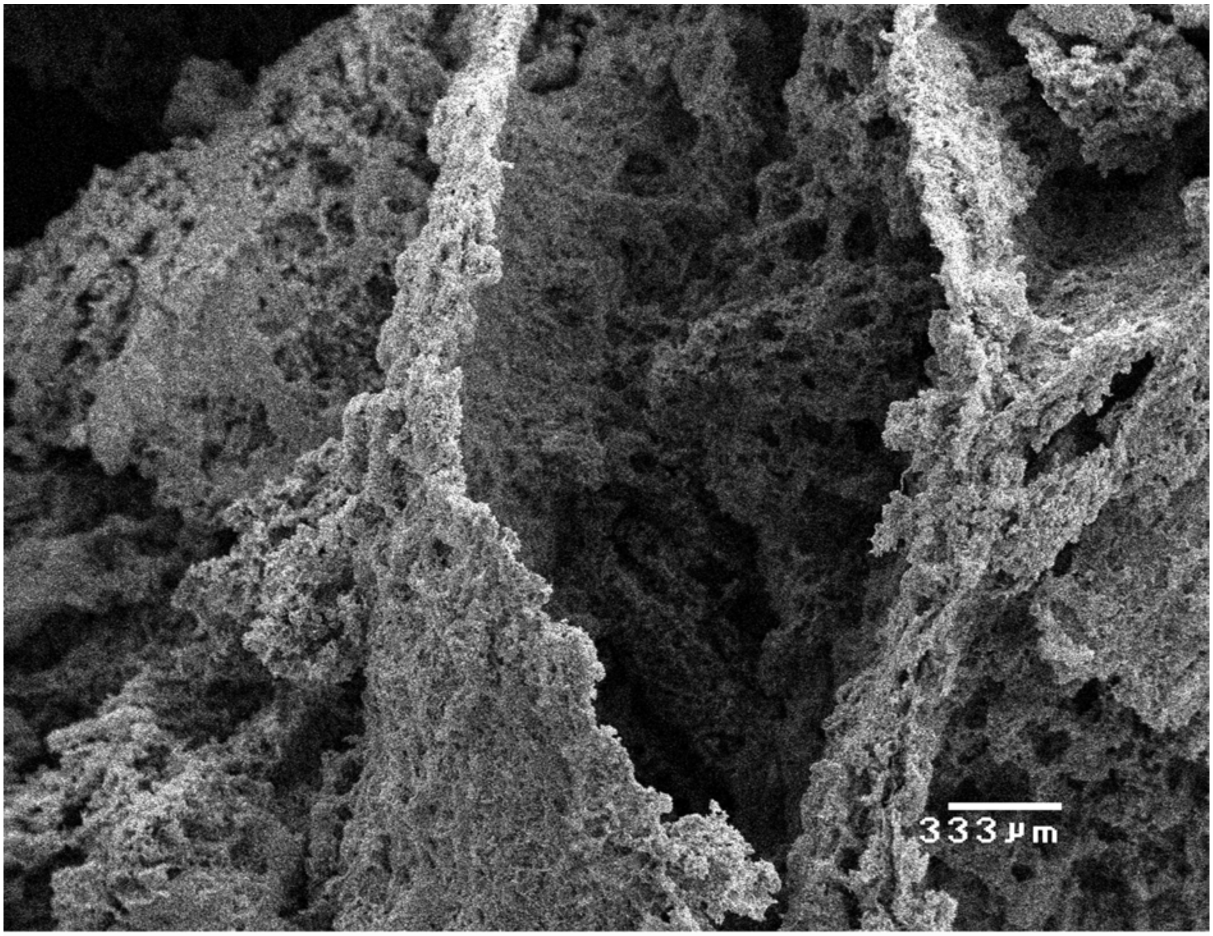

Figure 16. Scanning electron microscope photomicrograph of a pore cast from 6,304 feet, May Bug no. 2 well. Sheet-like linear pores - MO - are associated with phylloid-algal fronds. Note that the solid areas represent porosity. Scale represents 333 microns (0.333 mm). Porosity = 10.9 percent; permeability = 99 millidarcies based on core-plug analysis.

Fractures enhance the permeability in three samples: the 5,768.7-foot (1,758.2-m) sample from the Cherokee no. 22-14 well; the 6,304-foot (1,921-m) sample from the May Bug no. 2 well (figure 17); and the 6,289.7-foot (1,917.0-m) sample from the Bug no. 4 well (figure 18). The permeability of these three samples is among the highest of those examined.

Lithology, Cements, and Diagenesis

All samples contain dolomite (figure 13 and 19). Anhydrite, calcite, smectite clays, and pyrobitumen are present in some samples. The dominant cement occluding porosity and permeability in the Cherokee wells is anhydrite (figure 20). Although we did not observe anhydrite in the 5,781.2-foot (1,762.0-m) sample of the Cherokee no. 33-14 well, thin section analyses suggest that it is present.

Porosity reduction in the Bug wells is the result of tight areas that consist of former calcite cements that have been dolomitized. Anhydrite contributes to porosity and permeability reduction in these wells, too, as anhydrite is present in the 6,312-foot (1,924-m) sample of the May Bug no. 2 well and the 6,289.7-foot (1,917.0-m) sample of the Bug no. 4 well. Pyrobitumen is common in many samples lining pores and plugging pore throats (figure 21).

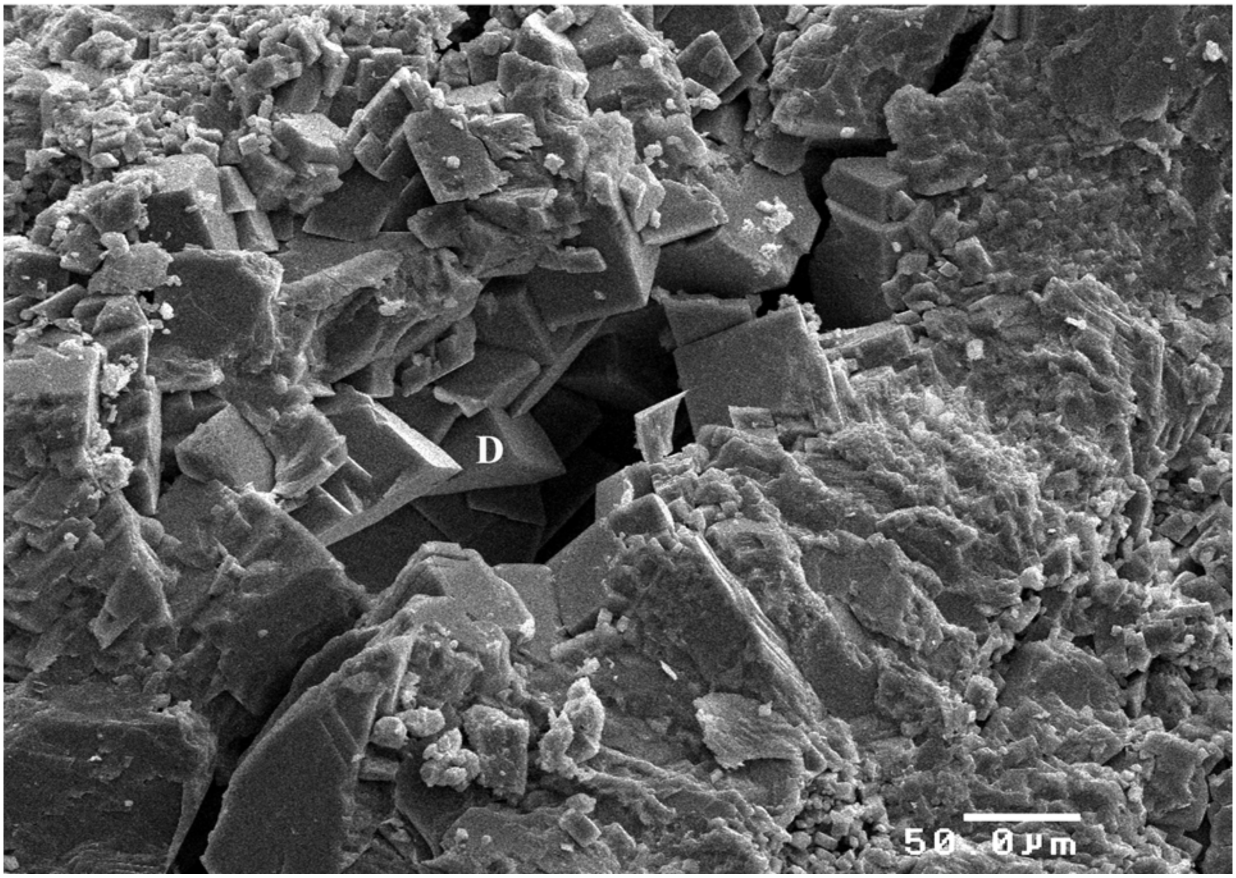

Figure 17. Scanning electron microscope photomicrograph of a core plug from 6,304 feet, May Bug no. 2 well, showing a fracture pore and dolomite (D) within it. This demonstrates that the fracture was open during dolomite deposition. Scale represents 50 microns (0.5 mm). Porosity = 10.9 percent; permeability = 99 millidarcies based on core-plug analysis.

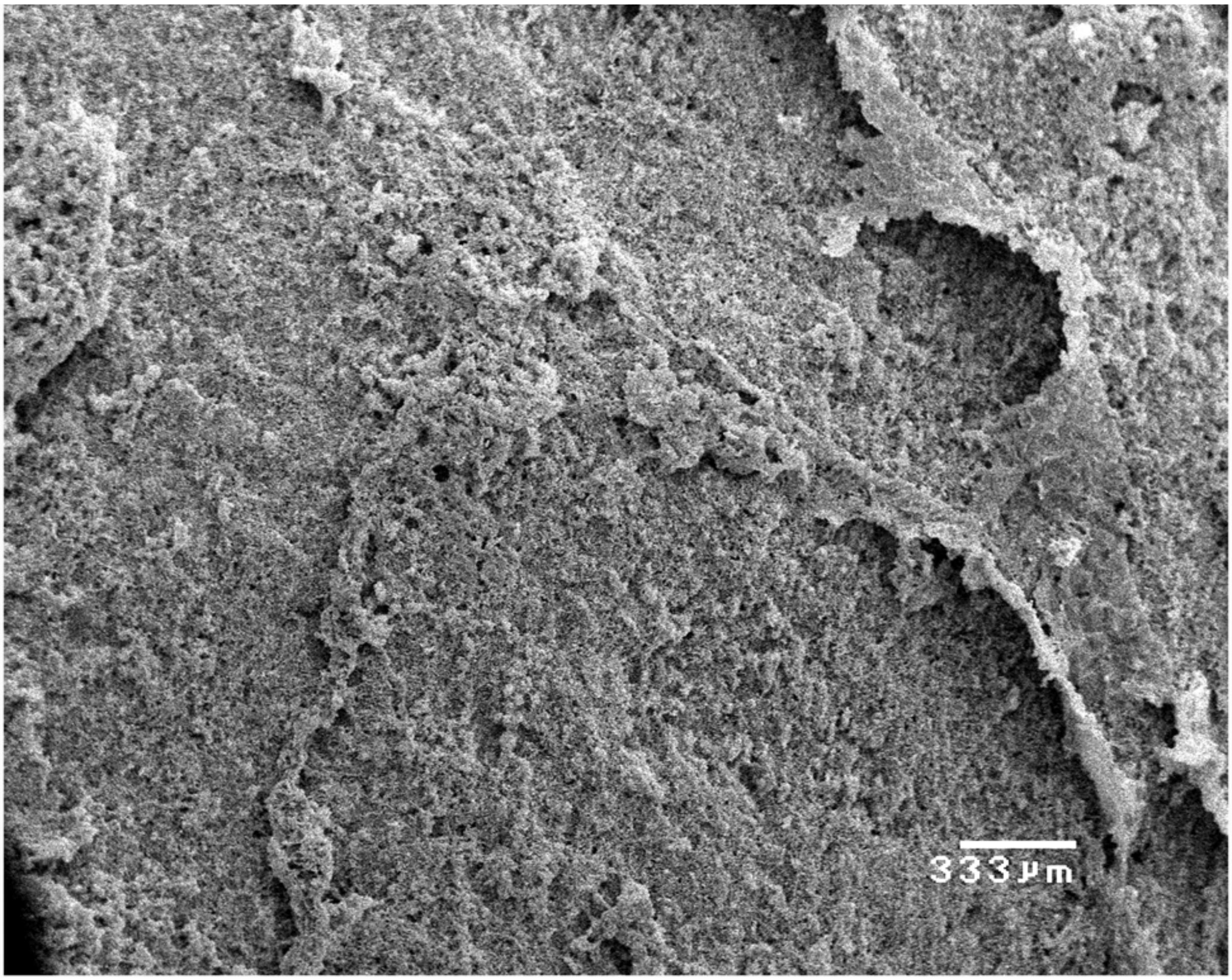

Figure 18. Scanning electron microscope photomicrograph of a pore cast from 6,289.7 feet, Bug no. 4 well, showing pattern of intersecting fractures in a tight portion of the sample. The linear feature in the upper right may represent artificially bent fracture-filling epoxy. The circular feature is a grain. Note that the solid areas represent porosity. Scale represents 333 microns (0.333 mm). Porosity = 14.5 percent; permeability = 92 millidarcies based on core-plug analysis.

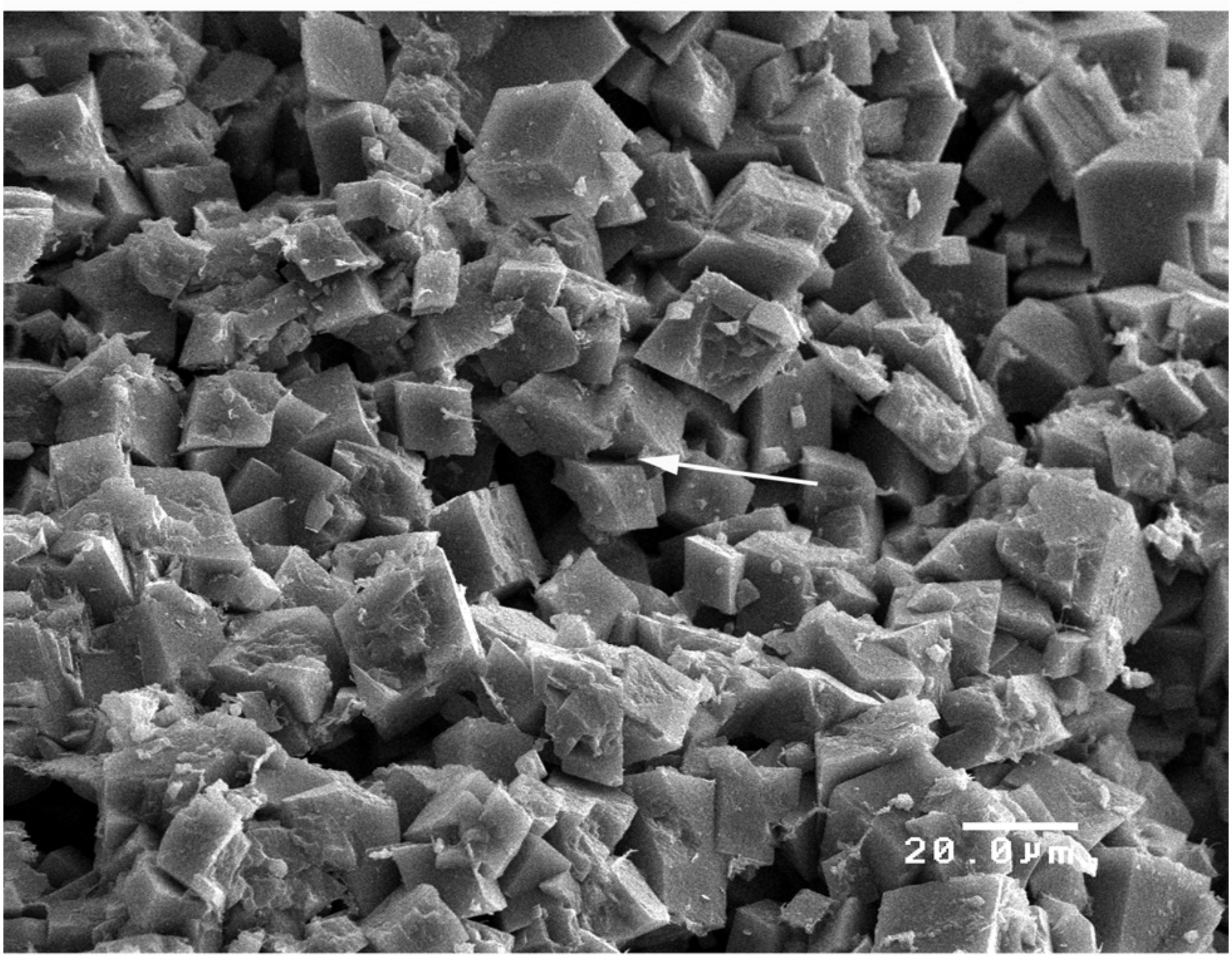

Figure 19. Scanning electron microscope photomicrograph of a core plug from 5,781.2 feet, Cherokee no. 33-14 well, showing well-developed dolomite rhombs exhibiting abundant intercrystalline microporosity – BC (arrow). Scale represents 20 microns (0.02 mm). Porosity = 23.6 percent; permeability = 103 millidarcies based on core-plug analysis.

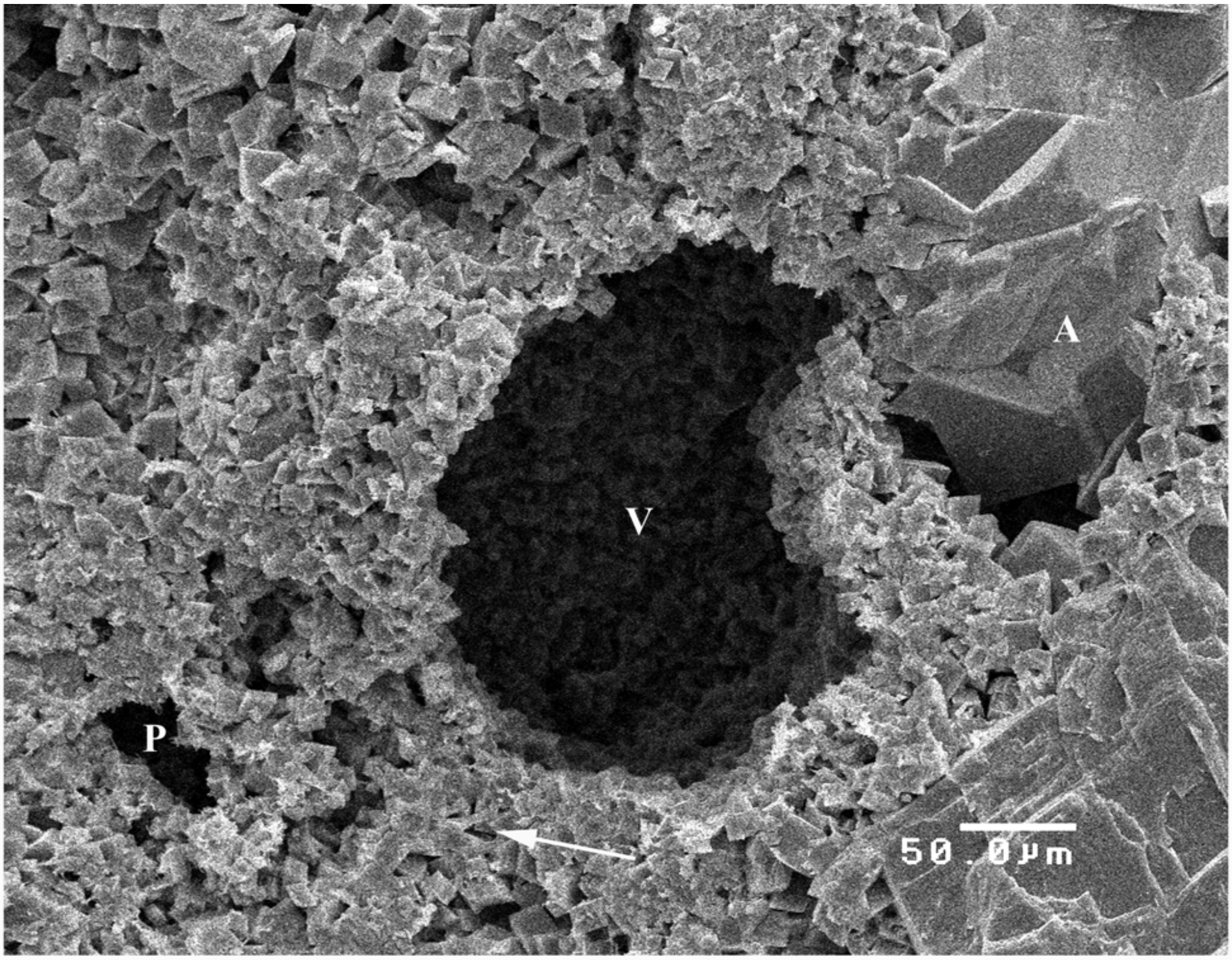

Figure 20. Scanning electron microscope photomicrograph of a core plug from 5,827.7 feet, Cherokee no. 22-14 well, showing dolomite with a mesovug – msVUG (V) and visible anhydrite (A) cement, smaller mesopores (P), and intercrystalline micropores – BC (arrow). Scale represents 50 microns (0.05 mm). Porosity = 17.1 percent; permeability = 4.5 millidarcies based on core-plug analysis.

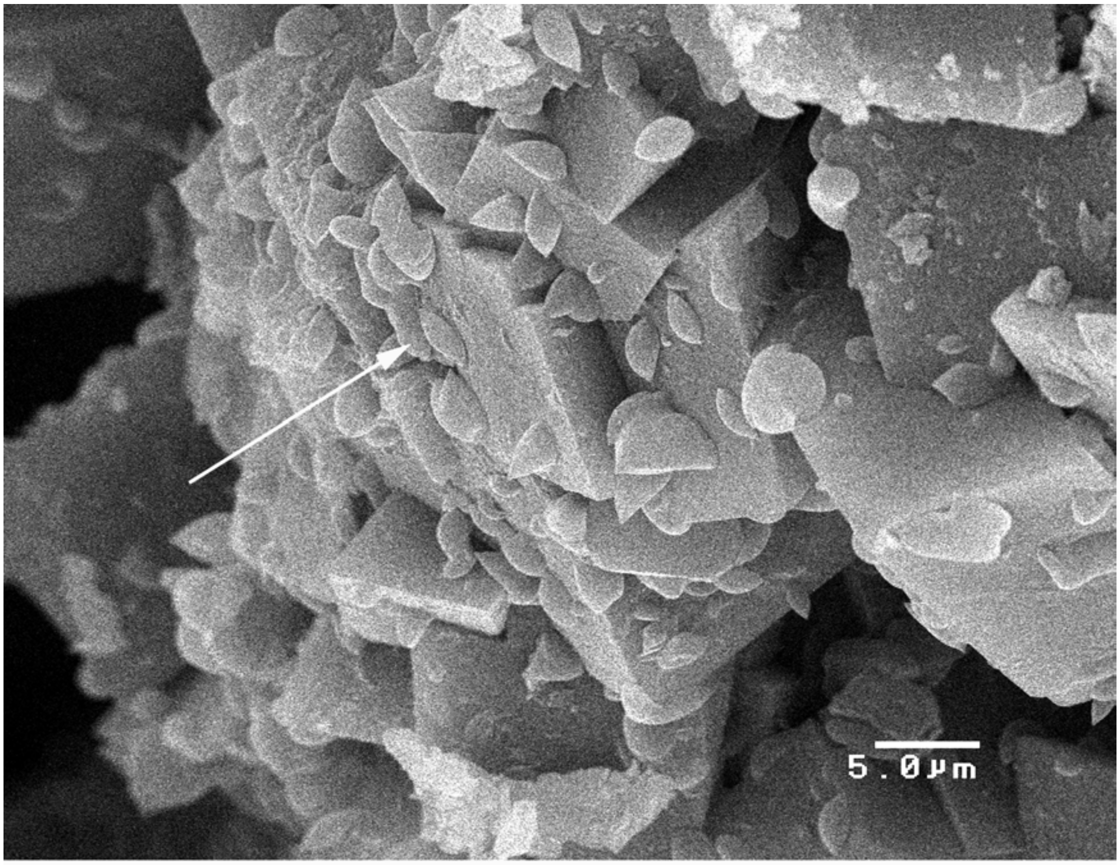

Figure 21. Scanning electron microscope photomicrograph of a core plug from 5,768.7 feet, Cherokee no. 22-14 well, showing pyrobitumen (arrow) on dolomite, within a microfracture. Micropores are black areas. Scale represents 5 microns (0.005 mm). Porosity = 22.9 percent; permeability = 215 millidarcies based on core-plug analysis.

Calcite (figure 22) and quartz (figure 23) are very rare, but are present in the Cherokee wells and in one sample (6,312 feet [1,924 m]) of the May Bug no. 2 well. Smectite clay is present (figure 22), but is also extremely rare. It is visible in the Cherokee wells only. The minor constituents of calcite, quartz, and smectite contribute little to the overall lithology and are relatively insignificant to reservoir quality.

The general diagenetic sequence for these samples, based on SEM and pore casting analyses, is listed below (not all diagenetic events were identified in every sample). The various diagenetic events are included in table 3.

1. Deposition of calcite cement
2. Dissolution
3. Dolomitization
4. Dissolution
5. Fracturing
6. Calcite cementation
7. Quartz cementation
8. Clay deposition
9. Anyhydite cementation
10. Pyrobitumen emplacement

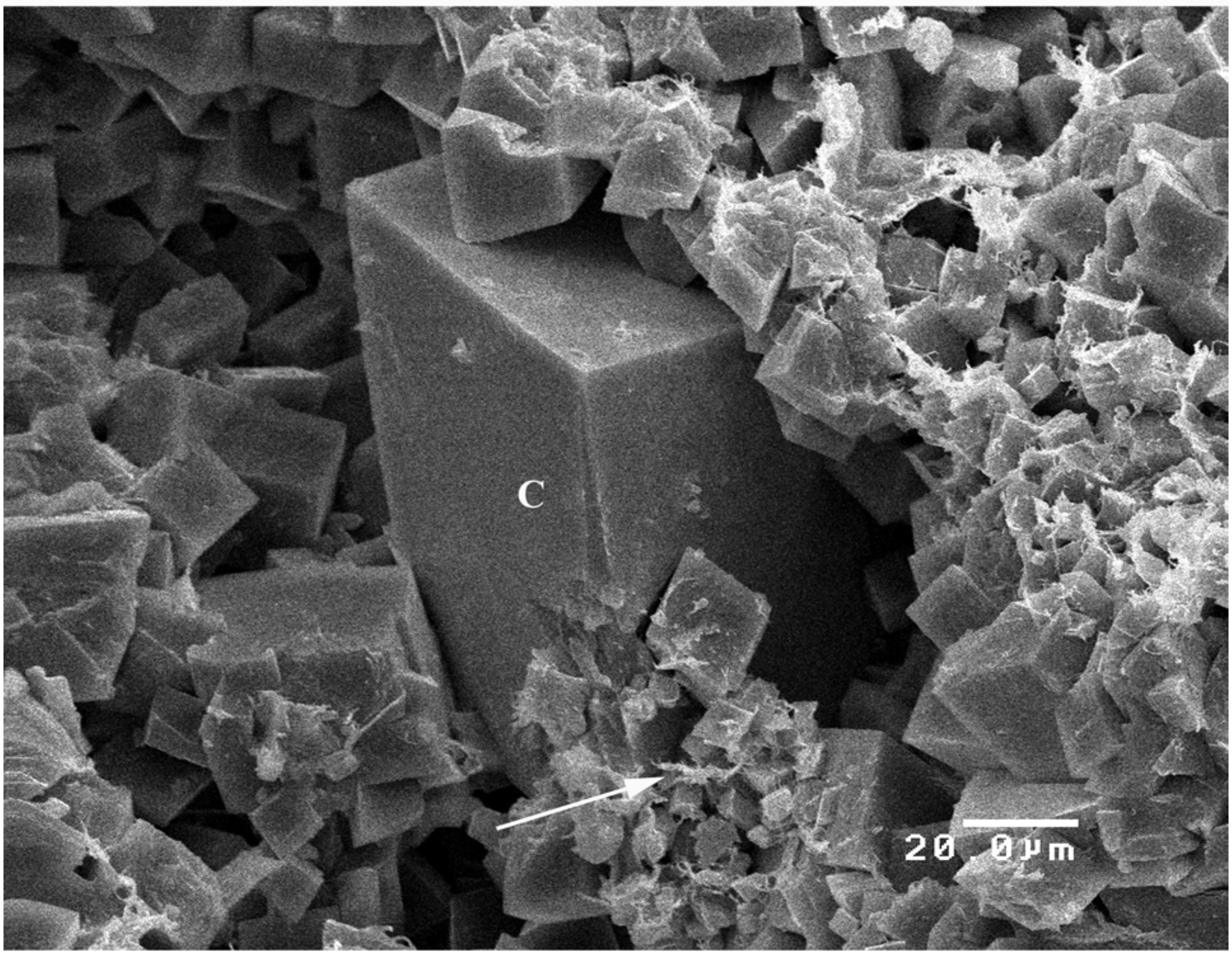

Figure 22. Scanning electron microscope photomicrograph of a core plug from 5,827.7 feet, Cherokee no. 22-14 well, showing equant spar calcite (C), a burial cement, as well as minor smectite clay (arrow) present in a large moldic (MO) pore on the dolomite. Scale represents 20 microns (0.02 mm). Porosity = 17.1 percent; permeability = 4.5 millidarcies based on core-plug analysis.

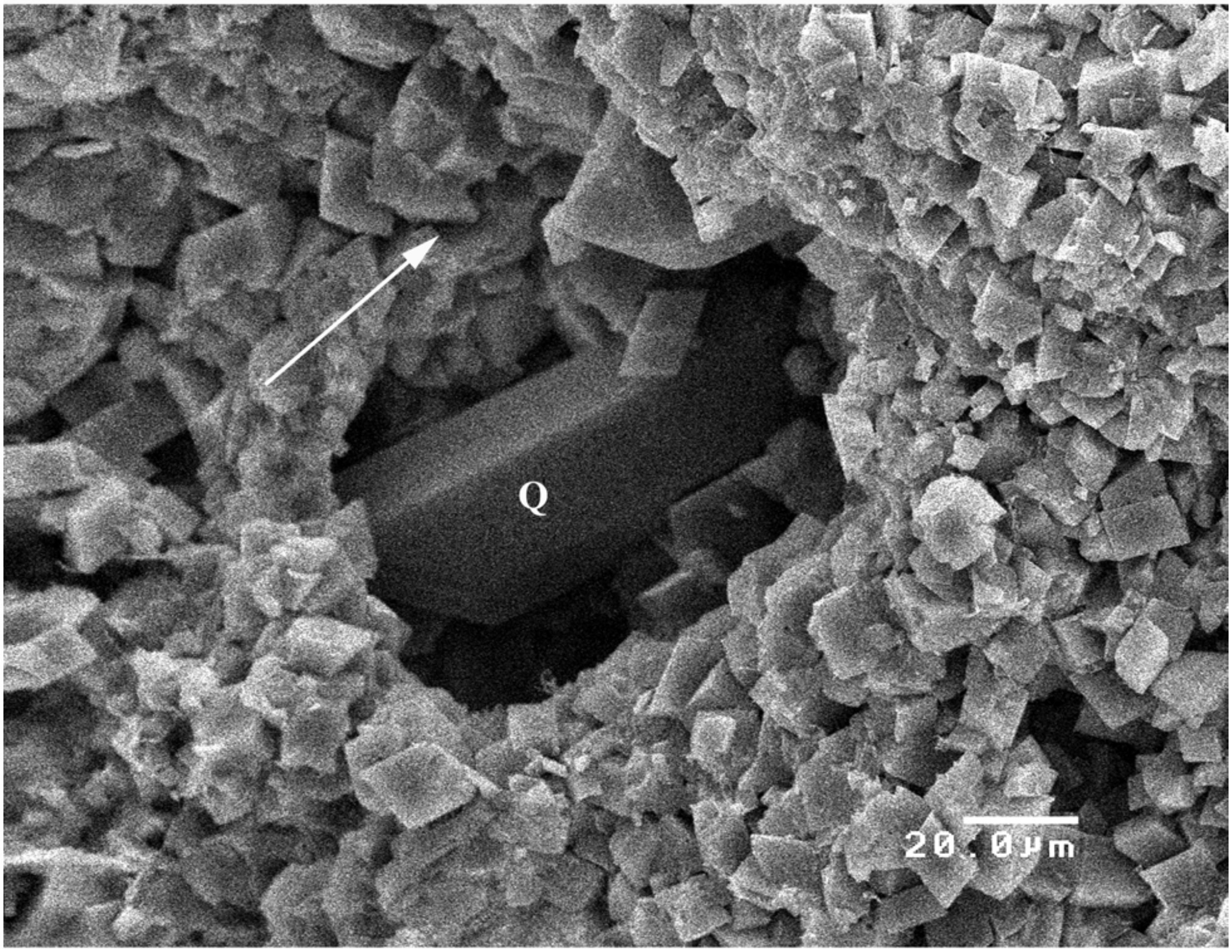

Figure 23. Scanning electron microscope photomicrograph of a core plug from 5,773.9 feet, Cherokee no. 33-14 well, showing authigenic quartz crystal (Q) within a mesovug - msVUG. Note the presence of intercrystalline microporosity – BC (arrow). Scale represents 20 microns (0.02 mm). Porosity = 19.1 percent; permeability = 11 millidarcies based on core-plug analysis.

TECHNOLOGY TRANSFER

The UGS is the Principal Investigator and prime contractor for three government-industry cooperative petroleum-research projects, including two in the Paradox Basin. These projects are designed to improve recovery, development, and exploration of the nation's oil and gas resources through use of better, more efficient technologies. The projects involve detailed geologic and engineering characterization of several complex heterogeneous reservoirs. The two Class II Oil (this report covers the Class II Revisit project) projects include practical oil-field demonstrations of selected technologies in the Paradox Basin. The third project involves establishing a log-based correlation scheme for the Tertiary Green River Formation in the southwestern Uinta Basin to help identify new plays and improve the understanding of producing intervals. The DOE and multidisciplinary teams from petroleum companies, petroleum service companies, universities, private consultants, and state agencies are co-funding the three projects. The UGS is also the Principal Investigator and prime contractor for the DOE Preferred Upstream Management (PUMP II) project titled *Major Oil Plays in Utah and Vicinity* which will describe and delineate oil plays in the Thrust Belt, Uinta Basin, and Paradox Basin.

The UGS will release all products of the Paradox Basin project in a series of formal publications. These publications will include all the data, as well as the results and interpretations. Syntheses and highlights will be submitted to refereed journals, as appropriate, such as the *American Association of Petroleum Geologists (AAPG) Bulletin* and *Journal of Petroleum Technology*, and to trade publications, such as the *Oil and Gas Journal*. This information will also be released through the UGS periodical *Survey Notes* and on UGS and CGS project Internet web pages.

The Technical Advisory Board advises the technical team on the direction of study, reviews technical progress, recommends changes and additions to the study, and provides data. The Technical Advisory Board is composed of field operators from the Paradox Basin. This board ensures direct communication of the study methods and results to the Paradox Basin operators. The Stake Holders Board is composed of groups that have a financial interest in the study area including representatives from the Utah and Colorado state governments (Utah School and Institutional Trust Lands Administration, Utah Division of Oil, Gas and Mining, and Colorado Oil and Gas Conservation Commission), Federal Government (U.S. Bureau of Land Management and U.S. Bureau of Indian Affairs), and the Ute Mountain Ute Indian Tribe. The members of the Technical Advisory and Stake Holders Boards receive all semi-annual technical reports and copies of all publications, and other material resulting from the study.

Project materials, plans, and objectives were displayed at the UGS booth during the AAPG Rocky Mountain Section meeting, September 8-10, 2002, in Laramie, Wyoming. Four UGS scientists staffed the display booth at this event. Project displays will be included as part of the UGS booth at professional meetings throughout the duration of the project.

An abstract was submitted to the AAPG on regional facies and potential drilling targets in the Ismay zone. The paper has been accepted and will be presented during the 2003 AAPG annual national convention in Salt Lake City, Utah. An abstract was also submitted to the DOE for a requested presentation of project results and lessons learned at a Class II Review conference sponsored by the National Energy Technology Laboratory to be held at the Center for Energy and Economic Diversification (CEED) in Odessa, Texas, December 2002.

The UGS is preparing a short course, "Pennsylvanian Heterogeneous Shallow-Shelf Buildups of the Paradox Basin: A Core Workshop," for the 2003 AAPG convention with a planned date of May 10, 2003. The short course will be co-sponsored by the DOE. Core from representative Ismay and Desert Creek fields will be examined. All core displayed will be placed into regional paleogeographic settings. The core workshop will be organized into topical modules with participants performing a series of exercises using core, geophysical well logs, and photomicrographs from thin sections. These modules include: describing reservoir vs. non-reservoir facies, determining diagenesis and porosity from core, recognizing barriers and baffles to fluid flow, correlating core to geophysical well logs, and identifying potential completion zones and candidates for horizontal drilling.

Utah Geological Survey *Survey Notes* and Internet Web Site

The purpose of *Survey Notes* is to provide non-technical information on contemporary geologic topics, issues, events, and ongoing UGS projects to Utah's geologic community, educators, state and local officials and other decision makers, and the public. *Survey Notes* is published three times yearly. Single copies are distributed free of charge and reproduction (with recognition of source) is encouraged. The UGS maintains a database that includes those companies or individuals (more than 300 as of October 2002) specifically interested in the Paradox Basin project or other DOE-sponsored UGS projects.

The UGS maintains a web site on the Internet, http://geology.utah.gov. The UGS site includes a page under the heading *Economic Geology Program*, which describes the UGS/DOE cooperative studies (Paradox Basin, Ferron Sandstone, Bluebell field, Green River Formation, PUMP II), and has a link to the DOE web site. Each UGS/DOE cooperative study also has its own separate page on the UGS web site. The Paradox Basin project pages http://geology.utah.gov/emp/Paradox2/index.htm and http://geosurvey.state.co.us contain: (1) a project location map, (2) a description of the project, (3) a list of project participants and their postal addresses and phone numbers, (4) a reference list of all publications that are a direct result of the project, and (5) semi-annual technical progress reports.

Technical Presentation

The following technical presentation was made during the first six months of the third project year as part of the technology transfer activities.

> "Reservoir Diagenesis and Porosity Development in the Upper Ismay Zone, Pennsylvanian Paradox Formation, Cherokee Field, Utah" by Thomas C. Chidsey, Jr., and David E. Eby, American Association of Petroleum Geologists Rocky Mountain Section Meeting, Laramie, Wyoming, September 9, 2002. Core photographs, SEM, pore casts, photomicrographs, capillary pressure/mercury injection graphs, maps, diagenetic analysis, and horizontal drilling recommendations were part of the presentation.

Project Publications

Chidsey, T.C., Jr., and Eby, D.E., 2002, Reservoir diagenesis and porosity development in the upper Ismay zone, Pennsylvanian Paradox Formation, Cherokee field, Utah [abs.]: American Association of Petroleum Geologists Rocky Mountain Section Meeting, Official Program Book p. 20-21.

Wray, L.L., Eby, D.E., and Chidsey, T.C., Jr., 2002, Heterogeneous shallow-shelf carbonate buildups in the Paradox Basin, Utah and Colorado: targets for increased oil production and reserves using horizontal drilling techniques – semi-annual technical progress report for the period October 6, 2001 to April 5, 2002: U.S. Department of Energy, DOE/BC15128-4, 32 p.

CONCLUSIONS

The Blanding sub-basin within the Pennsylvanian Paradox Basin developed on a shallow-marine shelf that locally contained algal-mound and other carbonate buildups. The two main producing zones of the Paradox Formation are the Ismay and the Desert Creek. The Ismay zone is dominantly limestone comprising equant buildups of phylloid-algal material. The Ismay is productive in fields of the southern Blanding sub-basin. The Desert Creek zone is dominantly dolomite comprising regional nearshore shoreline trends with highly aligned, linear facies tracts. Two Utah fields were selected for evaluation on a local scale: Cherokee in the Ismay trend and Bug in the Desert Creek trend.

Capillary pressure/mercury injection analyses were used to assess reservoir potential and quality by: (1) determining the most effective pore systems for oil storage versus drainage, (2) identifying reservoir heterogeneity, (3) predicting potential untested compartments, (4) inferring porosity and permeability trends, and (5) matching diagenetic processes, pore types, mineralogy, and other attributes to porosity and permeability distribution. The pore-throat-radius histogram for both the Cherokee no. 22-14 and Cherokee no. 33-14 wells, shows that half of the pore size distribution falls under 2.0 microns or in the microporosity realm. The saturation profiles for both wells show that a relatively high injection pressure is required to occupy more than the last 70 percent of the pores. The Cherokee no. 33-14 well has a steeper saturation profile than the Cherokee no. 22-14 indicating a greater amount of microporosity and thus, a high potential for untapped reserves. The pore-throat-radius histograms for Bug field show that some zones likely have significant microporosity (micro-boxwork porosity), while other zones are dominated by moldic porosity. Steeper saturation profiles for Bug field indicate a significant amount of micro-boxwork porosity and excellent targets for horizontal drilling.

Scanning electron microscope and/or pore casting analyses helped disclose the diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of Cherokee and Bug fields. All samples exhibit microporosity in the form of intercrystalline (primarily in Cherokee field) or micro-boxwork porosity (primarily in Bug field). Dissolution has contributed to porosity in most samples. It has created moldic, vuggy, and channel porosity. All samples contain dolomite. Anhydrite, calcite, smectite clays, and pyrobitumen are present in some samples. The dominant cement occluding porosity and permeability in the Cherokee wells is anhydrite. The general diagenetic sequence for these samples, based on SEM and pore casting analyses, are: (1) deposition of calcite cement, (2) dissolution, (3) dolomitization, (4) dissolution, (5) fracturing, (6) calcite cementation, (7) quartz cementation,

(8) clay deposition, (9) anhydrite cementation, and (10) pyrobitumen emplacement.

The diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of Cherokee and Bug fields are indicators of reservoir flow capacity and storage capacity. The microporosity in Cherokee field and the micro-boxwork porosity in Bug field represent important sites for untapped hydrocarbons and possible targets for horizontal drilling using stacked, parallel horizontal laterals from existing vertical wells.

ACKNOWLEDGMENTS

Funding for this ongoing research was provided as part of the Class II Oil Revisit Program of the U.S. Department of Energy, National Petroleum Technology Office, Tulsa, Oklahoma, contract number DE-FC26-00BC15128. The Contracting Officer's Representative is Gary D. Walker. Support was also provided by the Colorado Geological Survey and David E. Eby, Eby Petrography & Consulting, Inc.

Pore casting and SEM analyses were produced and interpreted by Louis H. Taylor, Standard Geological Services, Inc. Littleton, Colorado. Capillary pressure/mercury injection analysis was conducted by TerraTek, Inc, Salt Lake City, Utah. Core and petrophysical data were provided by Burlington Resources, Seeley Oil Company, and Wexpro Company. Jim Parker and Cheryl Gustin of the Utah Geological Survey prepared the figures. The report was reviewed by David Tabet and Mike Hylland of the Utah Geological Survey. Cheryl Gustin, Utah Geological Survey, formatted the manuscript for publication.

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