Silurian “Clinton” Sandstone Reservoir Characterization for Evaluation of CO_2-EOR Potential in the East Canton Oil Field, Ohio

Final Report

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ABSTRACT

The purpose of this study was to evaluate the efficacy of using CO_2-enhanced oil recovery (EOR) in the East Canton oil field (ECOF). Discovered in 1947, the ECOF in northeastern Ohio has produced approximately 95 million barrels (MMbbl) of oil from the Silurian “Clinton” sandstone. The original oil-in-place (OOIP) for this field was approximately 1.5 billion bbl and this study estimates by modeling known reservoir parameters, that between 76 and 279 MMbbl of additional oil could be produced through secondary recovery in this field, depending on the fluid and formation response to CO_2 injection.

A CO_2 cyclic test (“Huff-n-Puff”) was conducted on a well in Stark County to test the injectivity in a “Clinton”-producing oil well in the ECOF and estimate the dispersion or potential breakthrough of the CO_2 to surrounding wells. Eighty-one tons of CO_2 (1.39 MMCF) were injected over a 20-hour period, after which the well was shut in for a 32-day “soak” period before production was resumed. Results demonstrated injection rates of 1.67 MMCF of gas per day, which was much higher than anticipated and no CO_2 was detected in gas samples taken from eight immediately offsetting observation wells. All data collected during this test was analyzed, interpreted, and incorporated into the reservoir characterization study and used to develop the geologic model. The geologic model was used as input into a reservoir simulation performed by Fekete Associates, Inc., to estimate the behavior of reservoir fluids when large quantities of CO_2 are injected into the “Clinton” sandstone.

Results strongly suggest that the majority of the injected CO_2 entered the matrix porosity of the reservoir pay zones, where it diffused into the oil. Evidence includes: (A) the volume of injected CO_2 greatly exceeded the estimated capacity of the hydraulic fracture and natural fractures; (B) there was a gradual injection and pressure rate build-up during the test; (C) there was a subsequent, gradual flashout of the CO_2 within the reservoir during the ensuing monitored production period; and (D) a large amount of CO_2 continually off-gassed from wellhead oil samples collected as late as 3½ months after injection. After the test well was returned to production, it produced 174 bbl of oil during a 60-day period (September 22 to November 21, 2008), which represents an estimated 58 percent increase in incremental oil production over pre-injection estimates of production under normal, conditions.

The geologic model was used in a reservoir simulation model for a 700-acre model area and to design a pilot to test the model. The model was designed to achieve a 1-year response time and a five-year simulation period.
The reservoir simulation modeling indicated that the injection wells could enhance oil production and lead to an additional 20 percent recovery in the pilot area over a five-year period. The base case estimated that by injecting 500 MCF per day of CO_2 into each of the four corner wells, 26,000 STBO would be produced by the central producer over the five-year period. This would compare to 3,000 STBO if a new well were drilled without the benefit of CO_2 injection.

This study has added significant knowledge to the reservoir characterization of the “Clinton” in the ECOF and succeeded in identifying a range on CO_2-EOR potential. However, additional data on fluid properties (PVT and swelling test), fractures (oriented core and microseis), and reservoir characteristics (relative permeability, capillary pressure, and wet ability) are needed to further narrow the uncertainties and refine the reservoir model and simulation. After collection of this data and refinement of the model and simulation, it is recommended that a larger scale cyclic-CO_2 injection test be conducted to better determine the efficacy of CO_2-EOR in the “Clinton” reservoir in the ECOF.

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EXECUTIVE SUMMARY

The purpose of this study was to evaluate the efficacy of using CO_2-enhanced oil recovery (EOR) in the East Canton oil field (ECOF). Discovered in 1947, the ECOF in northeastern Ohio has produced approximately 95 million barrels (MMbbl) of oil from the Silurian "Clinton" sandstone. Production has been solely from primary recovery under 40-acre state spacing requirements. Encompassing 175,000 reservoir acres with more than 3,100 current or past producing wells, this is the most significant, actively producing oil field in Ohio. The original oil-in-place (OOIP) for this field is estimated to be approximately 1.5 billion bbl of oil. Using an average primary recovery factor of 7 percent, the estimated original oil reserves are 105 MMbbl. Thus an estimated 10 MMbbl of remaining oil reserves could be produced through primary recovery alone. In this study it is estimated by modeling known reservoir parameters, that between 76 and 279 MMbbl of additional oil could be produced through secondary recovery in this field, depending on the fluid and formation response to CO_2 injection.

A CO_2 cyclic test ("Huff-n-Puff") was conducted on a well in Stark County as part of this study. All data collected during this test were analyzed, interpreted, and incorporated into the reservoir characterization study and used to develop the geologic model. The geologic model was used as input into a reservoir simulation performed by Fekete Associates, Inc., to estimate the behavior of reservoir fluids when large quantities of CO_2 are injected into the "Clinton" sandstone. A CO_2 injection pilot area was identified using the geologic reservoir model and included the location of the cyclic-CO_2 test well.

The primary goal was to provide Ohio River Clean Fuels, LLC (ORCF) and the U. S. Department of Energy a practical study and demonstration of CO_2 injection at a geological site, which in this case is a nearly depleted but economically promising oil reservoir for potential geologic CO_2 sequestration from a planned biomass and coal to liquids plant at Wellsville, Ohio. Results of the cyclic CO_2 test, the reservoir characterization and geologic model, and the reservoir simulation are summarized in this report.

SICKAFOOSE-MORRIS #1 CYCLIC-CO_2 TEST

A cyclic-CO_2 test was designed to test the injectivity in a "Clinton"-producing oil well in the ECOF and estimate the dispersion or potential breakthrough of the CO_2 to surrounding wells. Eighty-one tons of CO_2 (1.39 MMCF) were injected over a 20-hour period, after which the well was shut in for a 32-day "soak" period before production was resumed. Results demonstrated injection rates of 1.67 MMCF of gas per day, which was much higher than anticipated. It is presumed that the injected CO_2 stayed within an area close to the wellbore as no CO_2 was detected in gas samples taken from eight immediately offsetting observation wells. Furthermore, a large quantity of CO_2 was gradually recovered during the production monitoring period.

Results strongly suggest that the majority of the injected CO_2 entered the matrix porosity of the reservoir pay zones, where it diffused into the oil. Evidence includes: (A) the volume of injected CO_2 greatly exceeded the estimated capacity of the hydraulic fracture and natural fractures; (B) there was a gradual injection and pressure rate build-up during the test; (C) there was a subsequent, gradual flashout of the CO_2 within the reservoir during the ensuing monitored production period; and (D) a large amount of CO_2 continually off-gassed from wellhead oil samples collected as late as 3½ months after injection. After the test well was returned to production, it produced 174 bbl of oil during a 60-day period (September 22 to November 21, 2008), which represents an estimated 58 percent increase in incremental oil production over pre-injection estimates of production under normal, unstimulated conditions. The cyclic-CO_2 test had a CO_2 utilization factor (ratio of CO_2 injected to additional oil recovered) of 8 thousand standard cubic feet/stock tank barrel of oil (MSCF/STBO), assuming all oil production is attributed to CO_2 injection, and 21 MSCF/STBO, if only the estimated additional incremental oil production is attributed to CO_2 injection, over the 2-month monitor period. These results are obscured by extreme water production during the monitor period, uncertainty in the original production rates, limited and non-optimal amount of CO_2 injected, and by failure to reach and maintain higher reservoir pressures during the test.

RESERVOIR CHARACTERIZATION AND GEOLOGIC MODEL

Regionally, the "Clinton" interval has an average gross thickness of 110 ft. The net sandstone map and published core studies suggest a fluvial-deltaic and offshore marine depositional environment. The clastic source is from the east and is dominantly controlled by three deltaic lobes oriented east–west and southeast–northwest. Net sand thickness ranges from less than 10 ft in the offshore marine environment and interchannel areas to over 60 ft in the thicker, deltaic/tidal channel sands. The western boundary of the ECOF is parallel to the north–south trending shoreline.

For this study, the "Clinton" interval was subdivided into five sandstone units with the objective of developing a geologic model to better understand and delineate the porosity and permeability distribution and compartmentalization, as it may affect fluid flow within the reservoir. In this report these units are called "CLNN1" through "CLNN5" in order of deposition. Within the 700-acre model area there are 23 wells with reported production data, and they have produced a combined total of 866,000 bbl of oil and 2.5 billion cubic ft (BCF) of gas. The Sickafoose-Morris #1 well, subject of the cyclic-CO_2 test, has produced 60,654 bbl of oil and 133 MMCF of gas since 1969.

A grid of 32 stratigraphic cross sections using digitized well logs was constructed across the 10,240-acre area of review (AOR). Compartmentalization due to shale baffles between individual sandstone units is evident between wells. The “CLNN3” and “CLNN4,” as interpreted on gamma-ray and density logs, represent the bulk of the “Clinton” reservoir with a combined net sand thickness ranging from 1 to 57 ft. Using an 8-percent porosity cutoff, the net ft of sandstone for the entire “Clinton” interval (“CLNN1” through “CLNN5”) ranges from 1 to 63 ft in the AOR. The average values for Sw (water saturation) range from 13 to 42 percent in the “CLNN3” and from 13 to 34 percent in the “CLNN4.”

Matrix permeability for this study was estimated based on core data from 3 wells in the ECOF. In the AOR average maximum matrix permeability (Kmax) from core is 0.69 millidarcies (md). Where log porosity average is greater than 8 percent (pay), the permeability averages 1.05 md.

For this study, 16 wells in the model area were used to plot oil production versus porosity-ft. The plot shows little to no relationship, which suggests other factors, such as fractures or completion practices, are contributing to the oil production yield. From published reports, the hydraulic fracture[1] direction in the “Clinton” is N63ºE, and a recent microseismic test in the ECOF showed a preferential direction of N55ºE. Anecdotal evidence from other hydraulic fracture treatments in the ECOF confirms the general direction between N55ºE and N 63ºE from limited observed communication between wells.

It remains unclear the extent to which natural fractures affect production within the “Clinton” sandstone reservoir in the ECOF. The best evidence for fluid communication between wells is from artificially induced hydraulic fractures, which trend in the direction parallel to the northeast–southwest contemporary stress field. Core measurements and basin tectonic features suggest a northwest–southeast trend for the natural fractures. However, based upon the above mentioned observations and the opinions of oil and gas operators in the ECOF, a natural fracture network was incorporated in the modeling and simulation in a direction parallel to the hydraulic fractures.

RESERVOIR MODELING AND SIMULATION

Using the previously described geologic model, Fekete Engineering Associates was retained to conduct a reservoir simulation model for the 700-acre model area and to design a pilot to test the model. The model was designed to achieve a 1-year response time and a five-year simulation period.

Within the model area the OOIP is estimated at nearly 13 MMSTBO, 90 percent of which is in the “CLNN 3” and “CLNN4.” Recovery to date has been 866 MSTBO, or 6.7 percent of the OOIP. A dual-porosity (matrix and fracture) model was selected, and the pilot design included four CO_2 injection wells and one central producer drilled on a 12-acre pattern elongated in the assumed direction of fracture orientation. Based on the modeling, Fekete concluded the injection wells could enhance oil production and lead to an additional 20 percent recovery in the pilot area over a five-year period. The base case estimated that by injecting 500 MCF per day of CO_2 into each of the four corner wells, 26,000 STBO would be produced by the central producer over the five-year period. This would compare to 3,000 STBO if a new well were drilled without the benefit of CO_2 injection. During simulation, peak rate of 32 bbl of oil per day (bopd) was attained within the first seven months. As a result of fractures in the simulation model, CO_2 breakthrough to the central producer first occurred within weeks and increased over the five-year simulation period to 1.4 MMCF/d of CO_2 or 70 percent of the injected volumes. During the same period the oil production rate steadily decreased to an estimated 10 bopd baseline. Average pressure in the pilot area increases to 1,000 psi in less than one year, with a very gradual rise to 1,200 psi in year five. This is hundreds of psi less than the measured minimum miscibility pressure of 1,450 psi, the pressure needed to attain the most effective CO_2 sweep and oil production response.

Considerable uncertainty exists in the model due to our limited knowledge of fluid properties and fracture distribution and connectivity. Sensitivity studies were conducted during simulation by varying fluid properties and fracture anisotropy within the pilot area. Results showed CO_2-enhanced peak production rates ranged from 14 bopd to 43 bopd depending on the assumed values for fluid properties, matrix permeability, and fracture anisotropy. By altering the values, cumulative production for the central producer in the pattern would vary from 12,000 to 42,000 bbl of oil over the five-year simulation period.

Core, petrophysical, fracture analyses and detailed mapping are critical to assess the “Clinton” reservoir and provide necessary information for planning proper well spacing and design of future pilot floods in secondary recovery efforts. Additional oriented cores, fracture data, and fluid analyses are needed to high-grade the next stage of modeling and simulation work. Such additional modeling and simulation will enable future efforts to more definitively evaluate CO_2-EOR potential in the ECOF and to finalize pilot design configuration. After collection of this data and refinement of the model and simulation, we recommend that a larger-scale cyclic-CO_2 injection test be conducted to better determine the efficacy of CO_2-EOR in the “Clinton” reservoir in the ECOF.

[1]The term *hydraulic fracture* as used in this report refers to the well completion practice of inducing fractures in the producing formation by injecting materials, such as water, gel, gas, and sand, down the tubing under pressure in order to break down the formation, creating a fracture to expand the “fetch area” of the wellbore.

SILURIAN "CLINTON" SANDSTONE RESERVOIR CHARACTERIZATION FOR EVALUATION OF CO_2-EOR POTENTIAL IN THE EAST CANTON OIL FIELD, OHIO

INTRODUCTION

Discovered in 1947, the ECOF in northeastern Ohio has produced approximately 95 MMbbl of oil from the Silurian "Clinton" sandstone (Figure 1). Production has been solely from primary recovery drilled on 40-acre spacing as required by the State of Ohio. Encompassing 175,000 reservoir acres with more than 3,100 former or presently producing wells, this is the most significant, actively producing oil field in Ohio, in terms of geographic size and produced volume of oil. The Department of Energy (DOE)-funded Tertiary Oil Recovery Information System (TORIS) Project estimated the OOIP for this field to be approximately 1.5 billion bbl of oil (Ohio Division of Geological Survey, 1997). Using an average primary recovery factor of 7 percent, the estimated original oil reserves are 105 MMbbl. Thus, an estimated 10 MMbbl of remaining oil reserves (ROR) could be produced through primary recovery. It is estimated, by modeling known reservoir parameters, that between 76 and 279 MMbbl of oil could be produced through CO_2-EOR in this field, depending on the fluid and formation response to CO_2 injection.

In spite of the maturity of this field and quantity of remaining oil reserves, only limited secondary recovery operations have been attempted in the ECOF. Presumed reservoir characteristics, particularly low permeabilities have discouraged secondary recovery attempts in this and other "Clinton" fields in the region. In the late 1980s and early 1990s Belden and Blake conducted three natural gas cyclic ("Huff-n-Puff") projects in the ECOF (Wozniak and others, 1997). While not economical at that time, these tests were successful in demonstrating that additional incremental oil was produced through "Huff-n-Puff" natural gas injection.

There has never been a large, economical source of CO_2 available in the Appalachian Basin for EOR use; thus CO_2-EOR has not been practiced except as small pilot tests in the region (Figure 2). Thus far, CO_2 -EOR in the Appalachian Basin region has been limited to these small-scale operations: (1) four CO_2 pilot tests in the Devonian-Mississippian Berea and Big Injun sandstone reservoirs, West Virginia (Watts, 1985); (2) a nitrogen/CO_2 flood in the Silurian Keefer Sandstone, Kentucky; and (3) the cyclic-CO_2 test ("Huff-n-Puff") conducted in the "Clinton" sandstone in the ECOF for this project (Figure 2). If large-scale capture of anthropogenic CO_2 comes to fruition in this region, it is anticipated by the authors that a regional pipeline network will be constructed that could distribute CO_2 to candidate oil fields for use as a secondary and tertiary recovery agent. Thus oil fields such as the East Canton could be in optimum locations for future CO_2-EOR opportunities.

The purpose of this study is to develop a geologic model to assist in the assessment of the viability of using CO_2-EOR in the ECOF. As part of this study, a cyclic-CO_2 ("Huff-n-Puff") test was conducted to test the injectivity of CO_2 in the "Clinton" reservoir. Results of this well test were incorporated into the geologic model. The geologic model was used as input into a reservoir simulation to estimate the behavior of reservoir fluids when large quantities of CO_2 are injected into the "Clinton" sandstone matrix. A CO_2 injection pilot area was chosen based on the geologic reservoir model. The ultimate goal of this project is to provide Baard Energy, LLC and the DOE a practical study and demonstration of CO_2 injection at a geological site, which in this case is a nearly depleted but economically promising oil reservoir for potential geologic CO_2 sequestration from a planned biomass and coal to liquids plant at Wellsville, Ohio.

DATABASE AND METHODOLOGY

A regional study of the ECOF and surrounding area was conducted in order to establish a consistent geologic framework and to better understand the depositional systems specific to this field. The study was followed by detailed geologic mapping and reservoir characterization of a 4 × 4-mile (10,240-acre) area of review (AOR) (Figure 3). A 700-acre model area was selected from within the AOR based upon the availability of well log and production data and also due to its impressive production history. A CO_2 pilot area was selected within the model area based on the geologic model. The pilot area also was selected because it includes the cyclic-CO_2 test well, which provided valuable data for the development of the model and simulation.

To accomplish these goals, the following tasks were conducted in the ECOF and surrounding region:

1. Review of published studies.
2. Compilation of data and creation of a digital database of basic well headers, wireline logs, cores, production, fluid properties, and engineering data.
3. Examination of available cores.
4. Examination of the regional stratigraphic framework and depositional setting.
5. Examination of the regional natural and hydraulic fracture trends.
6. Detailed reservoir characterization and geologic mapping study of the 10,240-acre AOR.
7. Coordination with Fekete Associates, Inc., which performed a reservoir modeling and simulation of a proposed pilot CO_2-EOR project using the data and model provided by the geology team (authors of this report).

Five stratigraphic cross sections were constructed using 133 well logs through a five-county area of the ECOF and surrounding vicinity to develop the regional stratigraphic framework (Figure 1). Two of these were oriented north–south along the depositional strike, and three were oriented east–west along the regional dip. Cross sections were located to include wells with cores, which were tied into wireline logs and used to assist in identifying formation/unit boundaries, unconformities, and inferred flood surfaces. A regional net sandstone map also was constructed throughout a five-county area in the ECOF and vicinity using gamma ray log data from 834 wells. A greater-than-75-percent "clean sand" gamma ray cutoff was used based on methodology described by Knight (1969). One hydraulic fracture was modeled by Hal-

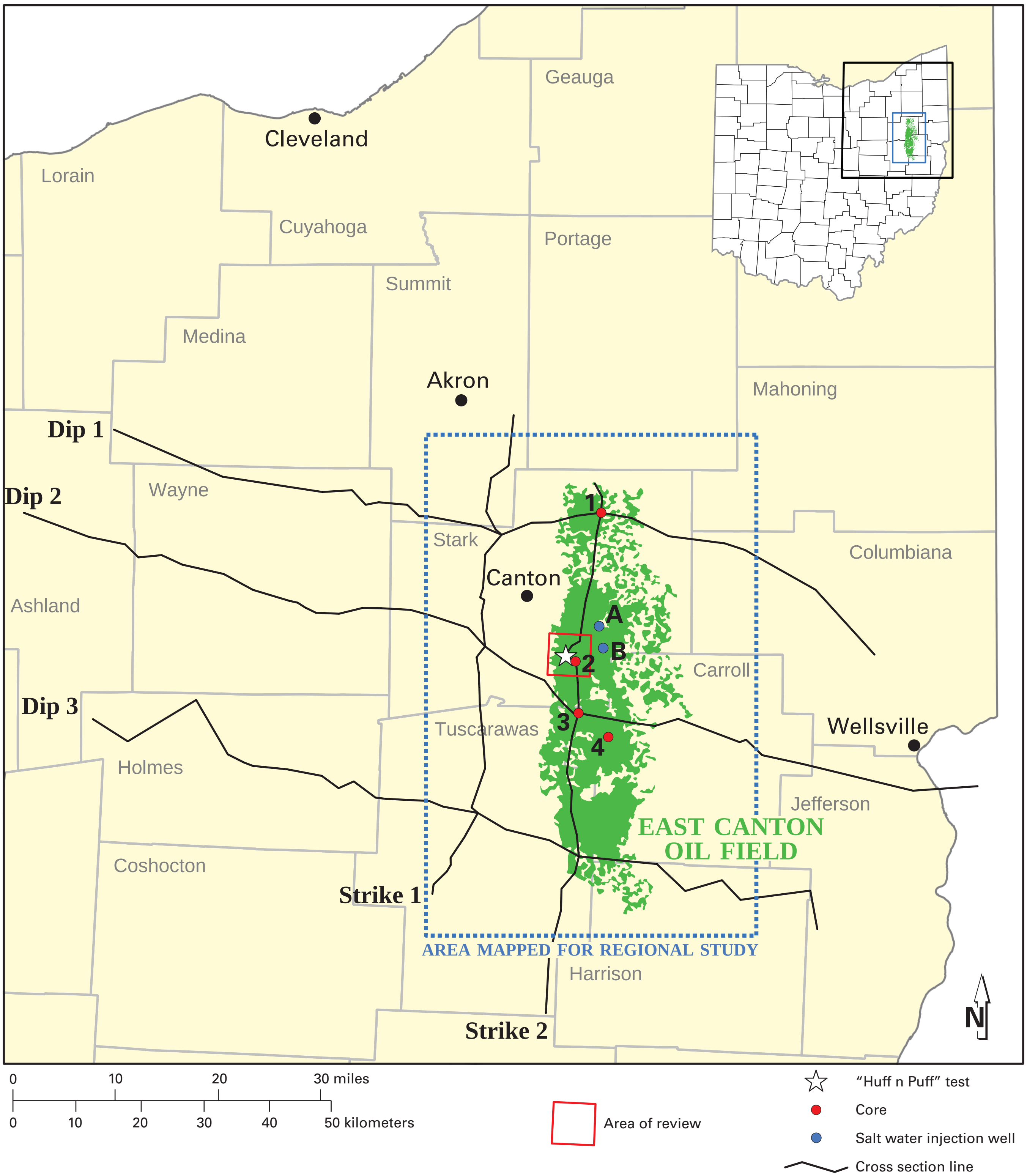

Figure 1.—Location map showing the East Canton oil field, regional mapped area of net sandstone, regional cross section lines, area of review, and “Clinton” cores and injection wells used in this study. Injection wells: **A** = Kolm #1 (3415121295); **B** = Foltz Partnership #2 (3415122088). Cored wells: **1** = McCabe #1 (3415124758); **2** = Creighton #1 (3415122005); **3** = Smith & Evan #4 (340192256); **4** = Kaplan #4 (3401920446).

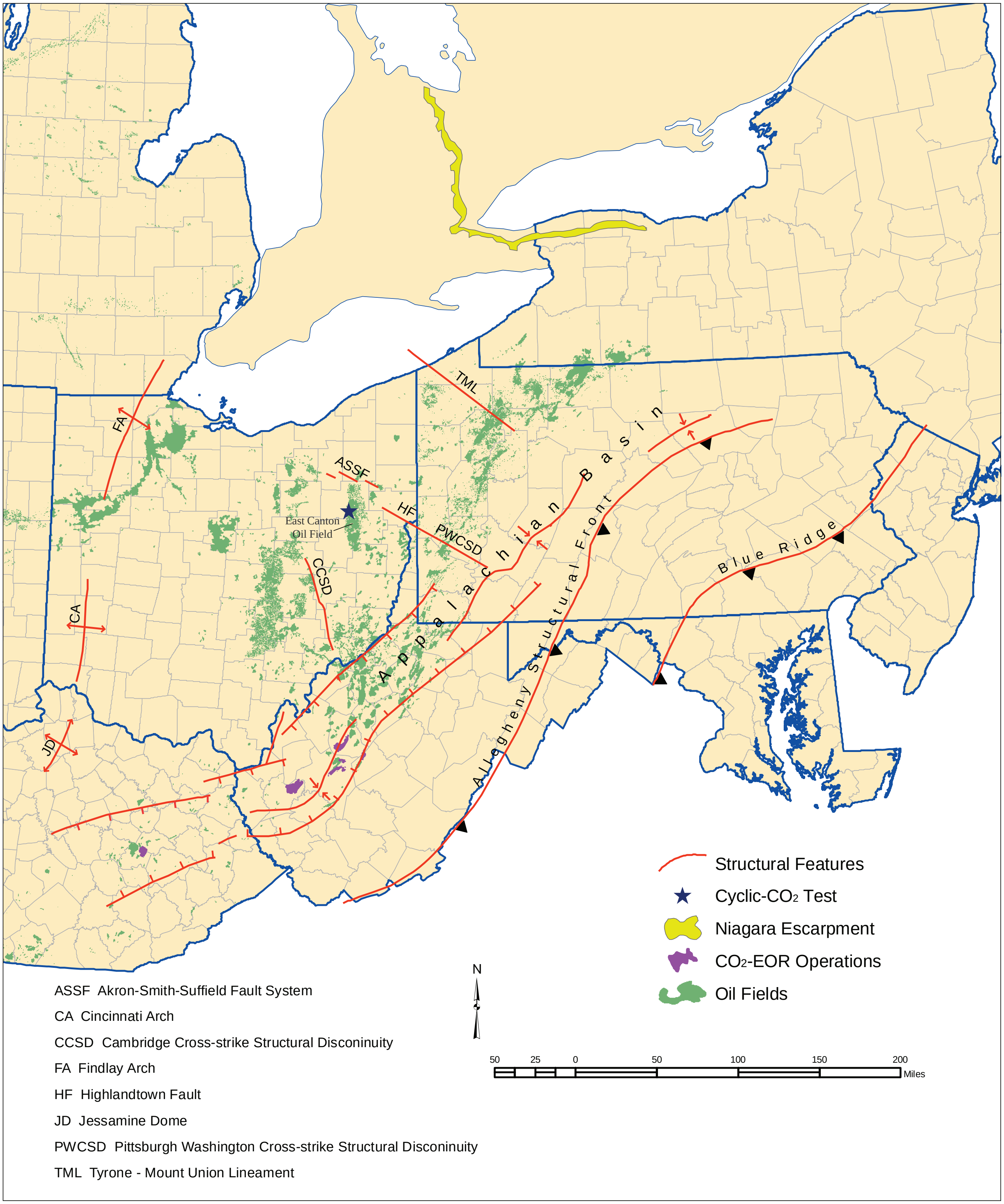

Figure 2.—Regional map of the Appalachian Basin showing the major structural features (modified from Shumaker [1996] and Baranoski [2002]), oil fields, and CO_2-EOR operations. Also shown is the Niagara escarpment.

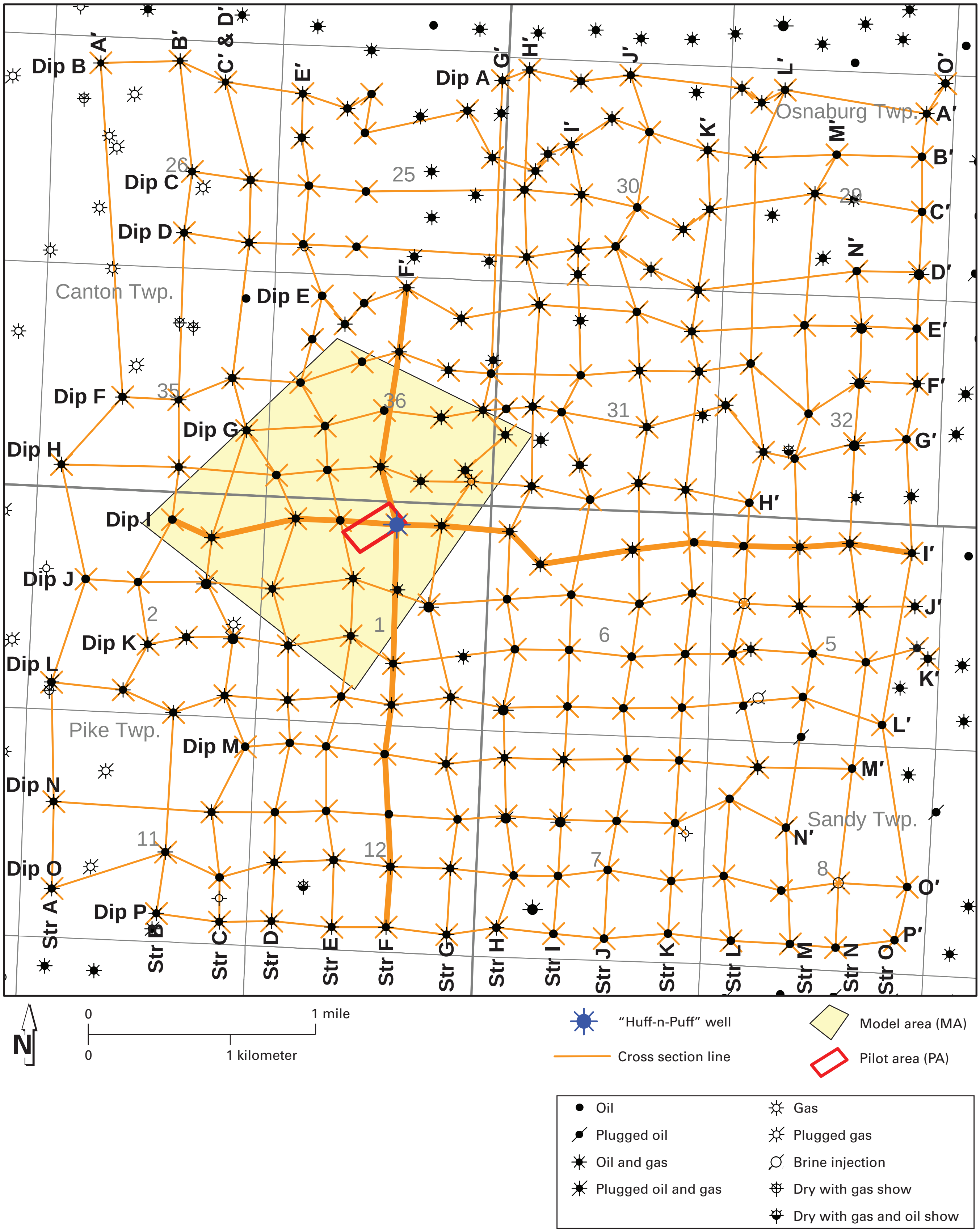

Figure 3.—Map showing the East Canton oil field area of review (AOR), model area, and pilot area. Also shown are the detailed stratigraphic cross section lines in the AOR. See Figure 1 for location of mapped area.

liburton. Directional properties and connectivity were interpreted from anecdotal and injection information, from hydraulic fracture operations, and salt water injection wells. During the course of the project, four cores were examined, largely for formation boundary information, depositional environment, and quantitative reservoir characteristics (Figure 1), and these included one oriented core in Marlboro Township, Stark County (APINO 3415124758) containing a fracture orientation report prepared by Core Laboratories (Riess and Manni, unpub. data, 1991) for Belden and Blake Corporation.

Approximately 350 digital wireline logs were scanned and converted to digital files in LAS (Log ASCII Standard) format for the regional cross sections and detailed characterization work in the AOR. These digital logs were used for constructing cross sections and performing petrophysical analyses. Completion data for 251 wells in the AOR and 133 wells used in regional cross sections were queried and compiled in tabular form (Appendix 1), including basic well header data such as location, API number (APINO), operator, lease name, total depth, ground elevation, and producing formation. Formation/unit tops were interpreted from wireline logs and entered into a digital database. All available production data within the AOR also was collected and compiled into a digital database. Reservoir pressure and oil property data performed in this and previous studies were compiled and provided to Fekete Associates, Inc., for reservoir simulation work and included MMP (Minimum Miscibility Pressure) analyses performed for this study, pressure and injection data on the cyclic-CO_2, and published PVT (Pressure/Volume/Temperature) data.

For the detailed reservoir characterization in the AOR, thirty-two cross sections were constructed using 221 digital gamma ray-neutron/density logs (Figure 3). Correlations were made for formations/units from the top of the Ordovician Rochester Shale to the top of the Queenston Shale based on the stratigraphic framework defined from the regional geologic interpretation, which includes five informal sandstone units within the “Clinton” interval, separated by shale units. A total of fifty-four maps were constructed in the AOR depicting various properties of the “Clinton” sandstone units informally named “CLNN1” through “CLNN5,” including the following:

- Structure.
- Gross thickness.
- Net ft of sandstone, using both 2.55 and 2.60 grams per cubic centimeter (gm/cc) density cutoffs.
- Average wireline log-calculated porosity for zones with greater than 5 percent and 8 percent.
- Average Sw (water saturation) for zones with porosity greater than 5 and 8 percent.
- Estimated permeability maps.

All maps created during this project are listed in Appendix 2.

All reservoir characterization data and geologic maps generated for the AOR were provided to Fekete Associates, Inc. in a Geographix software project. These maps and data provided the basis for the geologic model used by Fekete for reservoir simulation modeling of CO_2-EOR potential in the ECOF. The geology team worked closely with Fekete to assist the reservoir modeling study. A companion report by Fekete on the results of the reservoir modeling study was prepared and submitted to Baard Energy, LLC in December 2009.

REGIONAL STRUCTURAL FEATURES

Structurally, the ECOF is part of a regional east–southeast dipping monocline on the western edge of the Appalachian Basin (Figure 2). The trapping mechanism is primarily from stratigraphic traps produced by the westward updip thinning and pinchout of the “Clinton” sandstone lenses (McCormac and others, 1996). The Appalachian Basin trends north–northeast, dominated by the normal faults of the Rome Trough failed rift system, which generally defines the axis. The eastern flank of the basin is bounded by regional thrusts of the Allegheny Plateau and Allegheny Structural front. Numerous cross-strike structural discontinuities or faults transect the basin, including the Akron-Suffield-Smith faults, the Highlandtown fault, the Pittsburgh-Washington cross-strike structural discontinuity (CSD), the Tyrone-Mt. Union lineament and the Cambridge CSD.

Dominant structures in the vicinity of the ECOF are the N60^{o}W trending Akron-Suffield fault system at the northern margins of the field and the north–northwest trending faults within the field boundaries. These and other inferred faults, largely trending N20^{o}W to N30^{o}W appear as closely spaced contours with a more rapid change of slope on the base of the “Packer Shell” structure contour map (Figure 4). One north–south trending fault appears to bisect the southern portion of the AOR. In addition, numerous faults are inferred from lineaments on Landsat and Light Imaging Detection and Ranging (LiDAR) images of the area in and around the ECOF. Dominant lineaments are present, both parallel to and perpendicular to the Akron-Suffield fault system (Figure 5).

REGIONAL STRATIGRAPHY AND DEPOSITIONAL SETTING

STRATIGRAPHIC NOMENCLATURE

A basin-wide correlation chart illustrates the varied nomenclature used for equivalent units in the “Clinton” interval in Ohio and the surrounding Appalachian Basin states (Figure 6). In Ohio the Lower Silurian “Clinton” sandstone is an informal drillers’ term applied to units within the Cataract Group. These units do not outcrop in Ohio. In the study area the stratigraphic relationships are determined by interpretation of subsurface wireline logs and cores. The “Clinton” interval is stratigraphically equivalent to the Lower Silurian Grimsby Formation, which outcrops in northwestern New York and Ontario at the Niagara escarpment (Figure 2). In eastern Ohio various authors have applied informal drillers’ terminology to subdivide and correlate “Clinton” units into the “Stray,” “Red,” and “White” (Pepper and others, 1953; Knight, 1969). For this study the “Clinton” interval has been subdivided into five sandstone units, informally named the “CLNN1” through

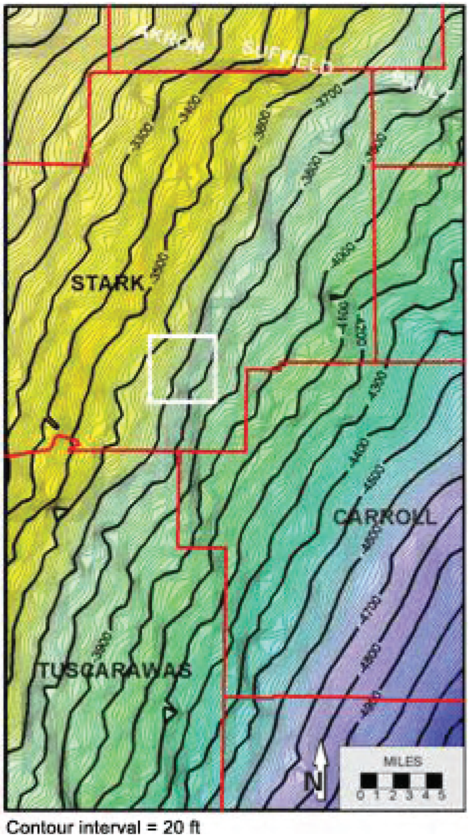

Figure 4.—Structure contour map of the base of the Dayton Formation (“Packer Shell”) in northeastern Ohio. White square shows the East Canton oil field area of review.

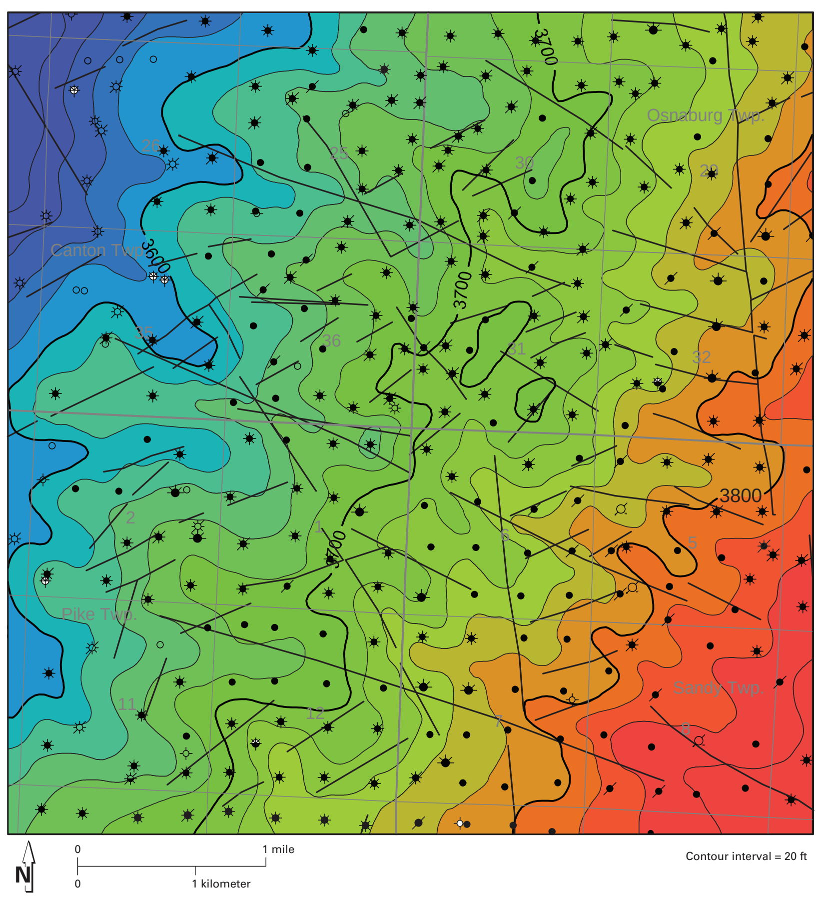

Figure 5.—Structure map on the base of the Dayton Formation (“Packer Shell”) in the East Canton oil field area of review in Stark County, Ohio. Also shown are the interpreted lineaments from Landsat and LiDAR imagery.

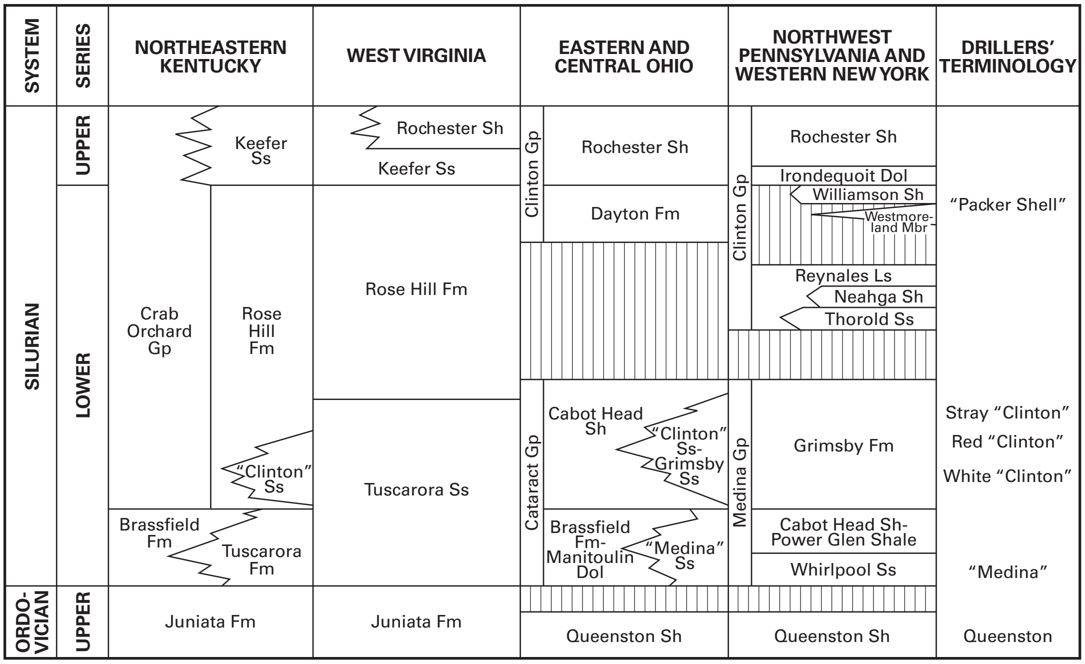

Figure 6.—Stratigraphic correlation chart of the Upper Ordovician through Upper Silurian units in Ohio and adjacent states. Modified from Wickstrom and others (2005).

"CLNN5." The Sickafoose-Morris #1 (APINO 3415122018) well log is used as a type log to illustrate the mapped units used in this project, and also shows the probable relationship to drillers' units of the "Stray," "Red," and "White" (Figure 7).

The Cataract Group is bounded at both the top and base by unconformities. A regionally widespread unconformity is recognized at the top of the Upper Ordovician Queenston Shale and has been named the Cherokee unconformity (Dennison and Head, 1975; Brett and others, 1990), basal unconformity (Castle, 1998), and unconformity 1 (Hettinger, 2001; Ryder, 2000, 2004). The base of the Dayton Formation ("Packer Shell") marks the upper unconformity (Brett and others, 1990).

CONSTRUCTION OF REGIONAL CROSS SECTIONS

Five regional stratigraphic cross sections, using 133 oil and gas well wireline logs, were constructed to establish the stratigraphic framework surrounding the AOR (Figure 1; Appendix 3, pls. 1–4). Two of the cross sections were oriented roughly north–south along depositional strike and three of the cross sections were oriented east–west along regional dip. All cross sections except Strike 1 extend through the ECOF. Four cored wells (APINOs 3415124758, 3415122005, 3402920256, and 3402920446), with associated wireline logs, were used in the cross sections to assist in identifying mappable, correlatable horizons and to identify possible sequence boundaries and inferred flood surfaces. Wells are generally spaced 1 to 2 miles apart, although in some areas, such as extreme eastern Ohio and West Virginia, the maximum distance is approximately 6 miles due to sparse control. All standard log curves (gamma ray, neutron-density) were utilized for correlation purposes; however, for final display only the gamma ray curves are shown for ease of printing and viewing by the reader (Appendix 3). The stratigraphic interval displayed and correlated in regional cross sections is from the top of the Silurian Rochester Shale to the top of the Ordovician Queenston Shale. The datum used for all cross sections is the base of the Dayton Formation ("Packer Shell").

REGIONAL NET SANDSTONE MAP AND DEPOSITIONAL SYSTEMS

To better understand the depositional systems and geometry of sandstone distribution, a net sandstone map was constructed for the entire "Clinton" interval in a five county area that includes the ECOF and surrounding region (Figure 8). This map was created by analyzing 834 gamma ray logs for lithology based on their deflection from the shale base line. Use of the gamma ray curve was chosen for regional mapping because of the abundance of wells with this log curve, and the paucity of wells with density curves. This standard lithologic technique has been used by previous workers including Knight (1969) to construct net sandstone maps. In mapping sandstone quality, the 75-percent deflection is used in this study to identify areas of "clean" sand that have good reservoir quality rock and also assist in identifying the depositional systems (i.e., delta lobes, distributary and tidal channels, and offshore marine deposition).

The regional net sandstone map clearly illustrates the sand depositional trends in the area of the ECOF. A fluvial-deltaic depositional environment has been proposed for the "Clinton" sandstone interval (Pepper and others, 1953; Knight, 1969; Overbey and Henniger, 1971; Castle and Byrnes, 2005). Depositional systems include distributary channels, crevasse-splay, delta plain, prodelta, tidal channel, and offshore marine deposits (Knight, 1969; Overbey and Henniger, 1971; Hettinger, 2001; Ryder, 2000, 2004; Castle and Byrnes, 2005). Silurian siliciclastic rocks reflect the progressive erosion and lowering of the Taconic highlands to the east (Milici and de Witt, 1988). In the ECOF area, mapping shows three delta lobes or distributary systems. The two northernmost lobes are roughly oriented east–west and the southernmost

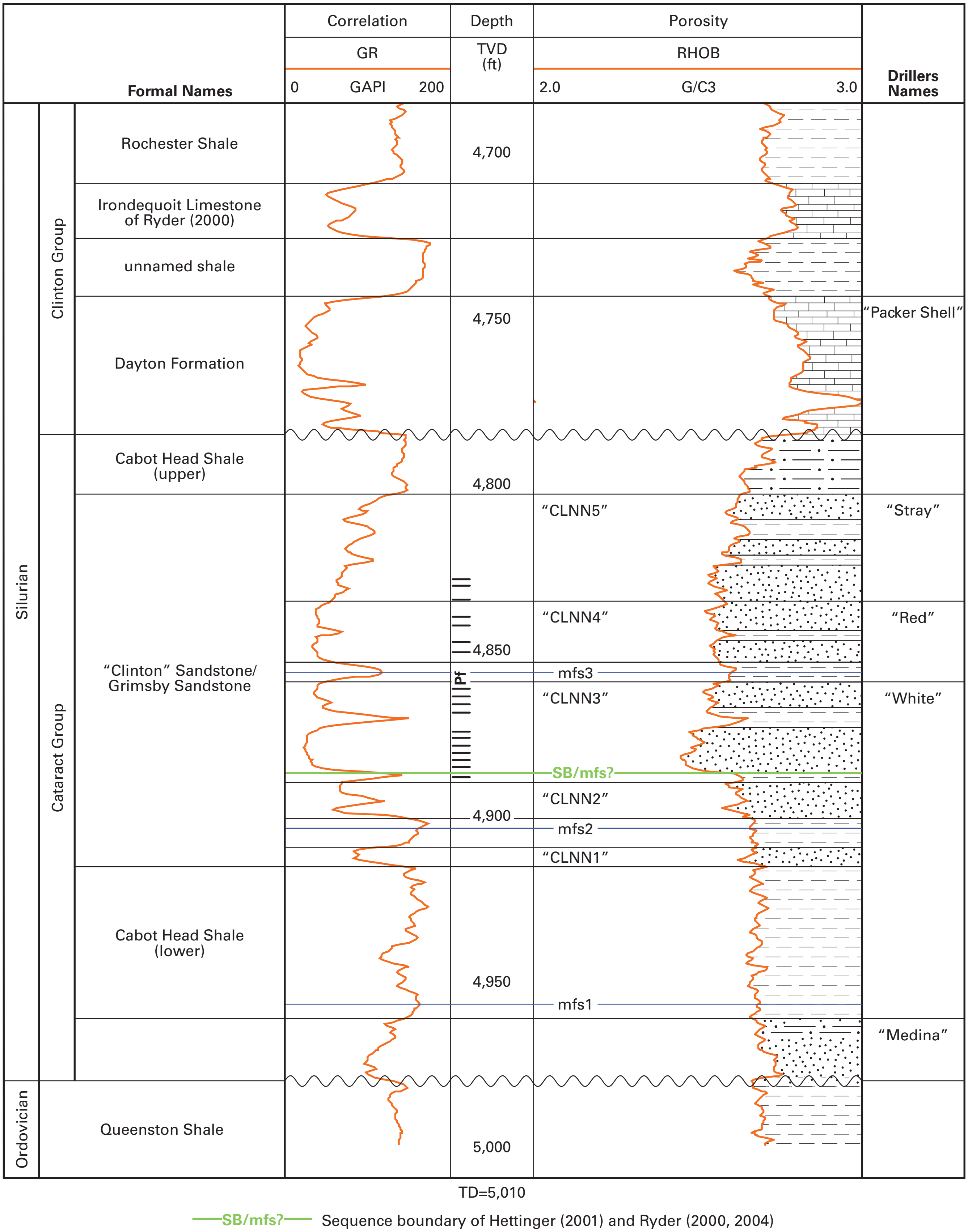

Figure 7.—The Sickafoose-Morris #1 (APINO 3415122018) type log and the mapped units for this study of the East Canton oil field. Also shown are the formal names and corresponding drillers' names.The proposed sequence boundary is uncertain by the authors of this report and may be a maximum flood surface (mfs).

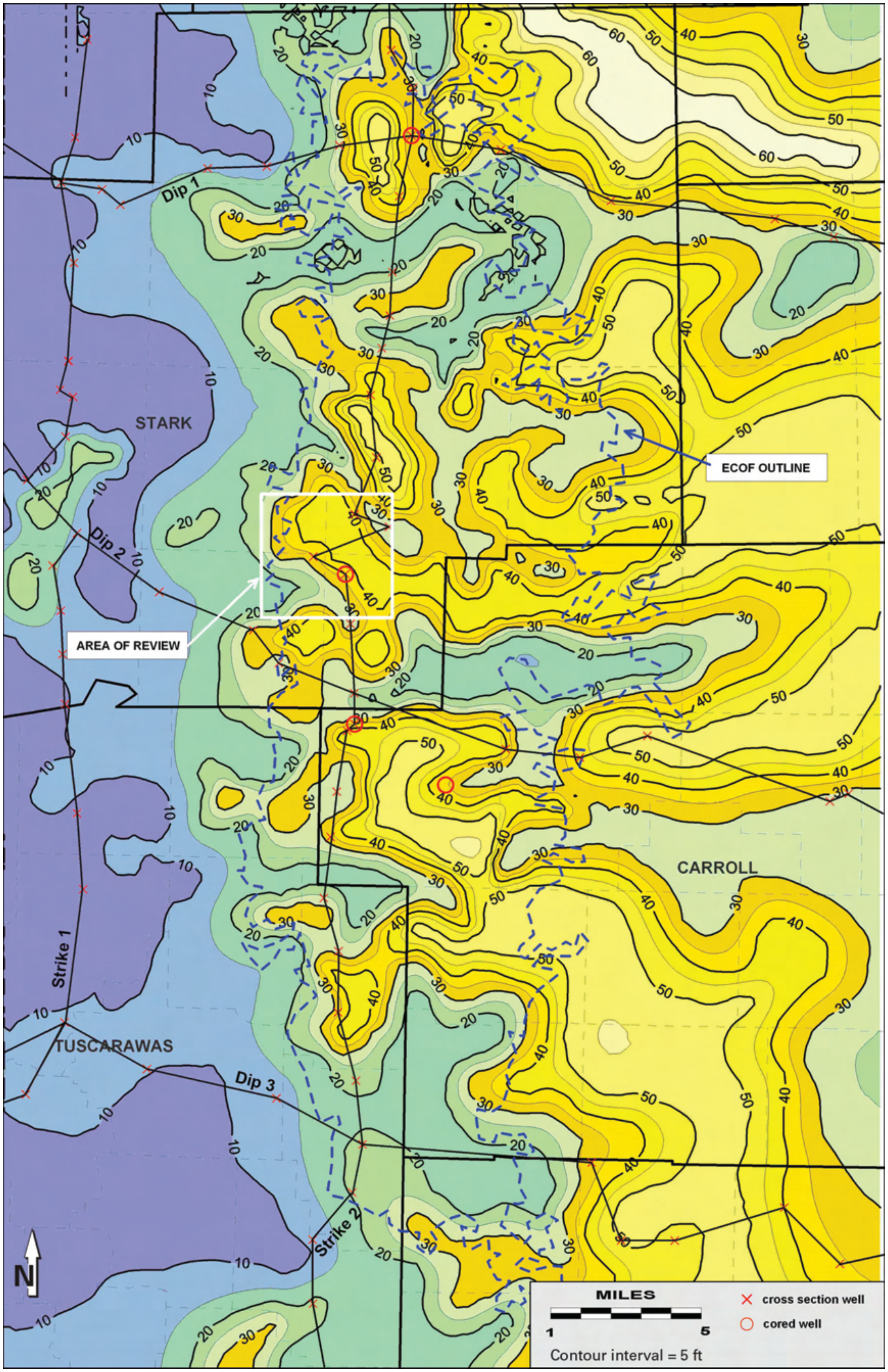

Figure 8.—Net sandstone map for the "Clinton" sandstone interval in the East Canton oil field area of review. Regional cross section lines are shown along with cored wells.

lobe is oriented southeast–northwest. Multiple regressive (coarsening upward) and transgressive (fining upward) cycles occurred during the "Clinton"/Grimsby deposition and are separated by inferred maximum flood surfaces (mfs).

Net sand thickness ranges from less than 10 ft primarily in the offshore marine and interchannel environment to over 50 ft in the thicker deltaic/tidal channel sands. In the mapped area the shore face is oriented approximately north–south. The western boundary of the ECOF approximately trends parallel to the shoreline. Sands are thickest in the ECOF area where stacked distributary and tidal channels occur on the delta plain. The thicker sand bodies are comprised primarily of the "CLNN3" and "CLNN4" sand reservoir channels trending generally east–west.

GENERAL STRATIGRAPHY AND PETROLOGY

For this study, the "Clinton" interval is subdivided into five mappable, correlatable sandstone units that are stratigraphically located between the upper and lower Cabot Head Shale (Figures 7 and 9), informally named the "CLNN1" through "CLNN5" in ascending stratigraphic order. Directly overlying the Queenston Shale is the "Medina," which is an arenaceous carbonate of poor reservoir quality in the AOR of the ECOF region. For that reason the "Medina" has not been included in reservoir modeling for our study. Three or possibly four inferred flood surfaces are identified within the interval between the Queenston Shale and the base of the Dayton Formation. The siliciclastic sequence of sandstone and interbedded shale units are bounded by two major sequence boundaries or unconformities; the lower being located at the top of the Ordovician Queenston Shale and the upper boundary at the base of the Silurian Dayton Formation. Another possible sequence boundary has been proposed at the base of the "CLNN3" sandstone unit by Hettinger (2001) and Ryder (2000, 2004).

The interval thickness from the base of the Dayton Formation to the top of the Queenston ranges from approximately 170 to 200 ft across the regional study area. The "Clinton" interval has an average gross thickness of 110 ft within the ECOF and reaches a maximum gross thickness of approximately 150 ft at the eastern end of the regional study area (Appendix 3, Plates 1–4).

The upper Cabot Head Shale directly overlies and is laterally equivalent to the "Clinton" sandstone interval. In the regional study area the upper Cabot Head Shale averages in thickness from 10 to 20 ft, but it may thicken to as much as 40 ft (Appendix 3, Strike 2, APINO 3415724758) in areas where the uppermost "Clinton" sandstone unit ("CLNN5") has been eroded. In eastern and central Ohio the Dayton Formation is a widespread carbonate interval and has an unconformable contact with the underlying Cabot Head Shale as discussed earlier. The carbonate interval may be subdivided into as many as three individual carbonate units separated by shale in the eastern part of the regional study area (Appendix 3, Plates 1–4). Thickness of the Dayton Formation ranges from 13 ft in the western portion to 67 ft in the eastern portion of the regional study area.

Lithologically, the "Clinton" interval consists of interbedded sandstones, siltstones, and shales, with minor amounts of carbonate (Pepper and others, 1953; Knight, 1969; McCormac and others, 1996). The sandstones of the "Clinton" interval consist of medium- to very fine-grained, monocrystalline quartzose sandstone with subangular to subrounded grains, variable sorting, and thin, discontinuous shale interbeds (Frech, 1983; McCormac and others, 1996; Castle and Byrnes, 2005). Variability in color from white to gray to red has resulted in drillers' names of the "Red Clinton" and "White Clinton" (Figure 7) in eastern Ohio. The "Red Clinton" is an approximate equivalent to the "CLNN4" of this report. The "CLNN5" (approximate equivalent of the drillers' "Stray Clinton") consists of nearly white- to light-gray, coarse- to fine-grained quartz siltstone and very fine-grained sandstone (Pepper and others, 1953; Knight, 1969). Grains are subrounded to subangular and the angularity decreases upwards. Sedimentary structures in the "Clinton" interval include parallel laminations, cross laminations, ripple marks, scour and fill, and burrows (Pepper and others, 1953; Knight, 1969; Castle and Byrnes, 2005).

Most of the sandstone in the "Clinton" interval is well cemented. The primary cementing agent is silica (quartz overgrowths). Other cementing agents include carbonates, hematite, chlorite, and evaporites (Frech, 1983; McCormac and others, 1996; Castle and Byrnes, 2005). Petrographic data indicate that primary porosity has been reduced by growth of quartz, carbonate, and clay minerals during burial (Heald and Larese, 1974; Laughrey, 1984, Castle and Byrnes, 2005). Secondary porosity is predominantly from dissolution of unstable cement minerals (Ryder and Zagorski, 2003). Locally occurring hematite is the cause of the reddish coloration for the "Red Clinton."

MAPPED UNITS

The "Clinton" sandstone interval is a progradational episode that followed the "Medina" flooding of the upper Ordovician unconformity. Three to four marine incursions and one sea level downshift occurred during "Clinton" deposition. The objective for subdividing the interval into five sandstone units was to develop a geologic model to better understand and delineate the porosity and permeability distribution and compartmentalization as it may affect fluid flow within the reservoir. Mapped units were based on identification of four parasequences separated by three to four maximum flood surfaces (mfs1, 2, and 3) and/or one possible sequence boundary (Figure 9). These sequences were interpreted from wireline logs by the coarsening upward (prograding) or fining upward (retrograding) character of the gamma ray curve and the continuity of bounding shales. The prograding/retrograding cycles are called here the "CLNN1" through "CLNN4" and the final fining upward cycle is called the "CLNN5" (Figure 9). Subdivision and identification of the "CLNN5" was based on the lack of continuity and poor reservoir quality of this transgressive sandstone unit.

The lowermost maximum flood surface in the mapped interval is named mfs1 (Figure 9) and is identified on wireline logs as a higher gamma ray API reading relative to the overlying and underlying units (Figure 7). The mfs1 often occurs at the top of a fining upward zone and base of an overlying coarsening upward cycle (Appendix 3, Plates 1–4). This correlation event may be difficult and somewhat arbitrary to identify and is generally 10 to 20 ft above the top of the "Medina" sandstone. The mfs1 is also recognized by Hettinger (2001) and Ryder (2000, 2004) based on regional wireline log cross sections that extend through western Pennsylvania and eastern Ohio.

Overlying the mfs1 is a coarsening upward cycle, which grades into the first sandstone unit, named in this study the "CLNN1" unit (Figure 9). The bottom of this lowermost sandstone unit marks the base of the "Clinton" interval and overlies and grades laterally into the lower Cabot Head Shale. Some workers consider this sandstone part of the Cabot Head because it generally consists of thin, discontinuous sandstone stringers that are often non-reservoir quality. Identifying and correlating the "CLNN1" unit can be problematic since the top is often

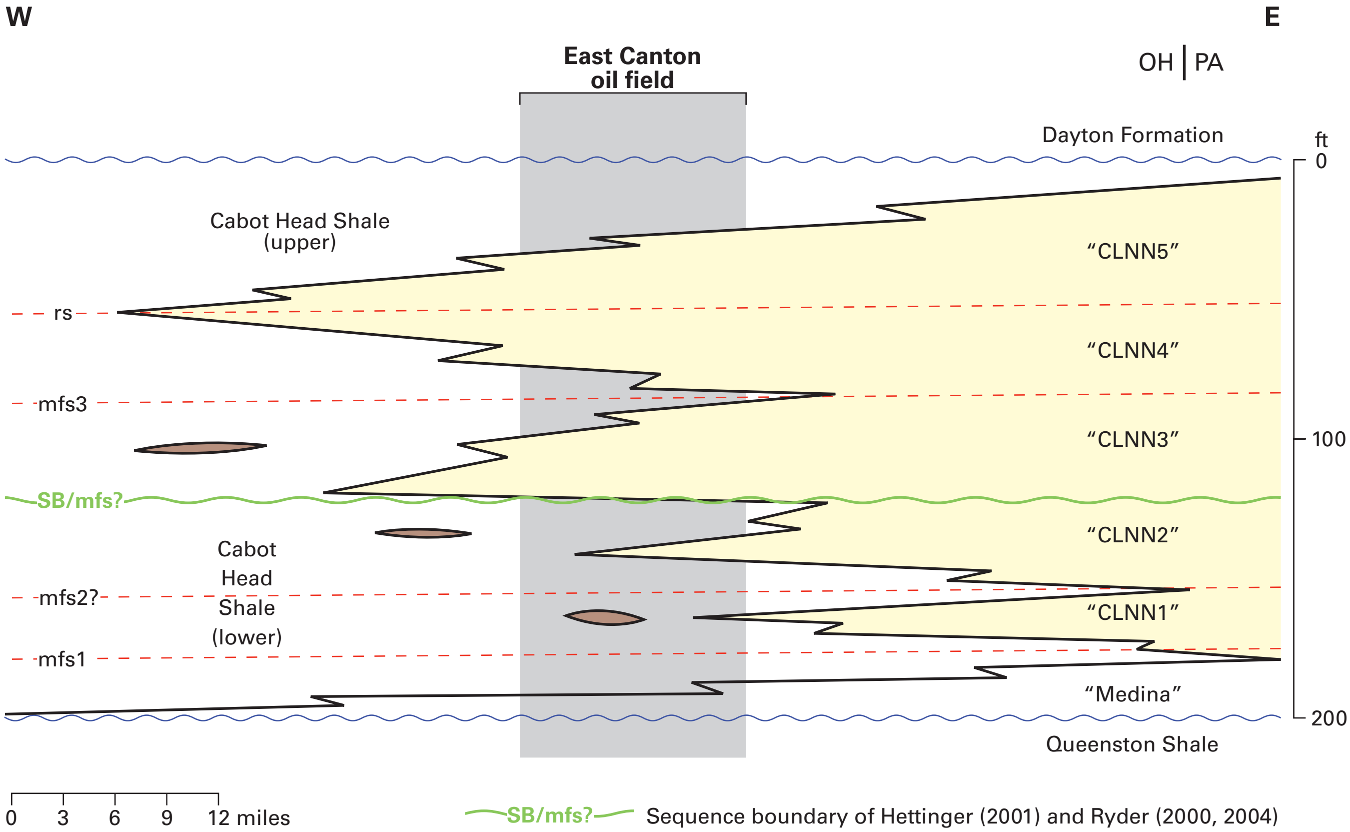

Figure 9.—Diagrammatical illustration through the East Canton oil field and surrounding area of review, illustrating the major depositional units of the "Clinton" interval ("CLNN1" through "CLNN5") and maximum flood surfaces (mfs1 through mfs3) as interpreted for this study.

an erosional surface, and there may be siltstone or sandy units in the underlying Cabot Head Shale that grade upward into the base of this unit. The shale overlying "CLNN1" is interpreted as a transgressive event called mfs2 (Figure 9) and is marked by a higher gamma ray API response. However, regional correlations of the mfs2 are somewhat tenuous because of the complexity and nature of this shale event and the relationship to the discontinuous sands of the "CLNN1" unit. It is possible that the mfs2 shale is due to lobe-switching and not a flood surface.

The mfs2 event was followed by an apparent coarsening-upward regressive cycle in which the "CLNN2" sandstone unit was deposited (Figure 9). As with the "CLNN1" unit, this is generally represented by thin, argillaceous sandstone beds. For ease of correlation and mapping purposes, multiple sandstone lenses within "CLNN2" interval were combined into the same unit. The same consolidation of multiple lenses was also done for mapping the "CLNN1." The thinner argillaceous and discontinuous nature of the "CLNN1" and "CLNN2" units indicates that they were probably deposited in an offshore or shoreface marine environment, which is in agreement with the interpretation by Hettinger (2001) and Ryder (2000, 2004). Cursory core examination also indicates bioturbation in these sandstone intervals, which is indicative of a marine shoreface environment. Thickness of individual sandstone lenses within both the "CLNN1" and "CLNN2" units are generally less than 5 ft (Appendix 3, Plates 1–4). However, these sandstone units may locally be up to 20-ft thick as seen in the no. 5-3858 Knight well (APINO 3415322892) and no.1 Gerbec well (APINO 3416921701; Appendix 3, Plate 1).

Following deposition of the "CLNN2," there is generally a thin shale interval, probably representing a marine transgression followed by an abrupt facies change to sandstone deposition of the "CLNN3" (Figure 9). The contact is often sharp on wireline logs in the AOR, typically represented on gamma ray and density curves by an abrupt base and fining upward signature, which is often characteristic of fluvial-deltaic or tidal channel deposits (Selley, 1978; Cant, 1984). The gamma ray signature is sometimes blocky" rather than fining upward. Thickness of this unit is up to 30 ft and contains significantly higher porosities than the underlying units. Regional correlations between wells display the irregular undulating nature of the basal contact of the "CLNN3" unit (Appendix 3, Plates 1–4), supporting the interpretation of Hettinger (2001) and Ryder (2000, 2004) that this surface is a sequence boundary. In the Smith and Evans #4 (APINO 3401920256) and McCabe #1 (APINO 3415124758) cores, there is a sharp contact between the underlying shale and overlying, well-developed "CLNN3" sandstone unit (Figure 10). Small, angular rip-up clasts of shale are present above the contact in the Smith and Evans #4 core. Further detailed examination of cores and outcrops are necessary to determine the nature of this contact and whether it represents a local unconformity or a more regional downshift in sea level.

The "CLNN 3" sandstone was followed by deposition of marine shale. On wireline logs this interval is represented by a higher gamma ray API reading. The highest gamma ray reading in this interval is inferred to be the maximum flood surface and is designated in this report as mfs3 (Figure 9). Thickness of this shale interval ranges from 0 to over 20 ft (Appendix 3, Plates 1–4). This shale interval separates the "CLNN3" and "CLNN4" and creates an apparent compartmentalization between these individual sandstone units. Locally, where thick,

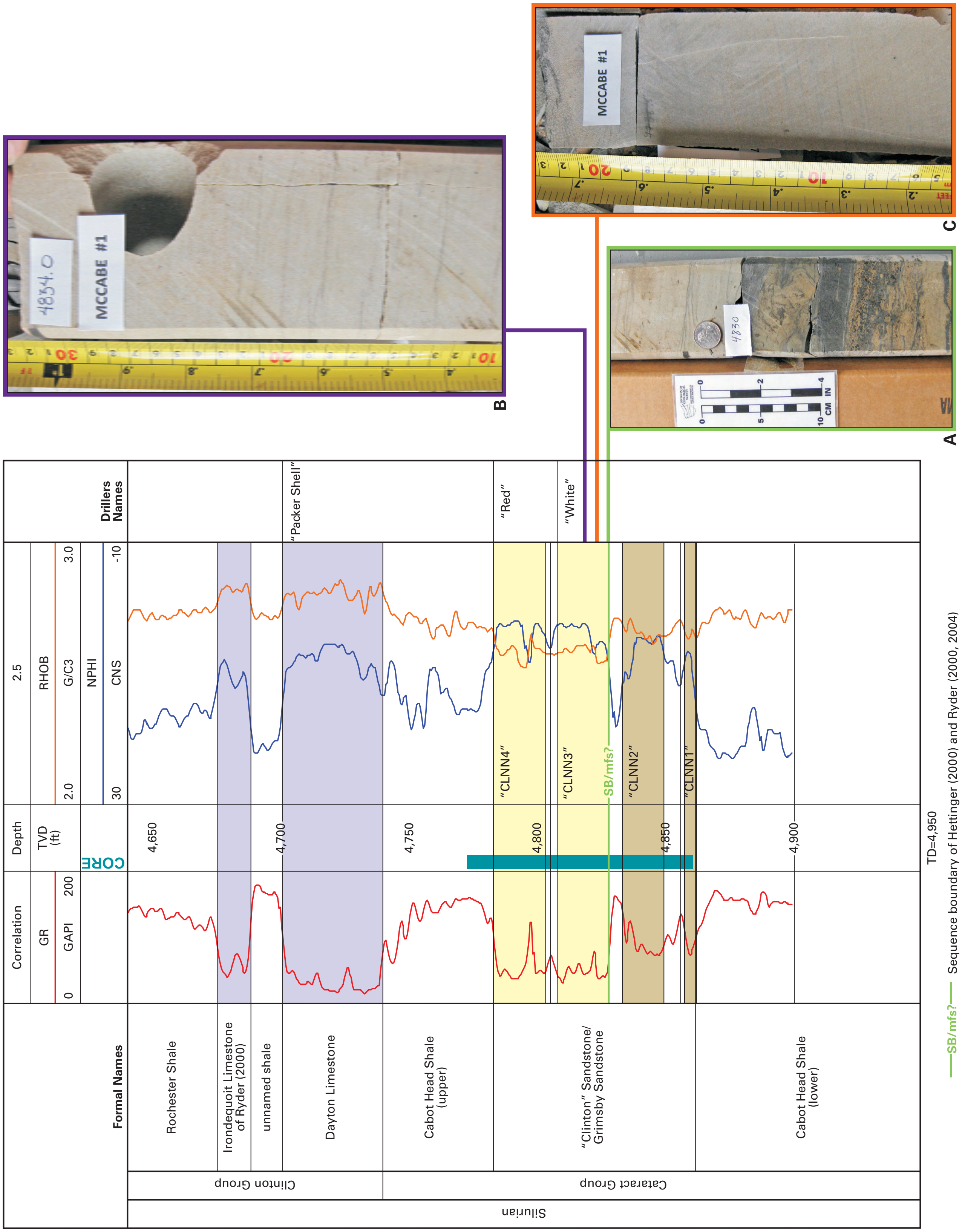

Figure 10.—Gamma ray-neutron/density log for the McCabe #1well (APINO 3415124758) and the cored interval. Photos of the oriented core show (**A**) the contact at the base of the "CLNN3" and the underlying shale, (**B**) an open fracture, and (**C**) a mineralized fracture. Location of cored well is shown in Figure 1.

coalesced sand bodies have eroded the mfs3 shale interval, placement of this boundary is problematic. In these cases correlations were estimated, in an attempt to portray sand continuity of both layers. Reservoir-time fluid communication has not been assumed between the sands. Generally, it is one of the best regional, correlatable shale events on wireline logs within the "Clinton" interval, and provides a useful timeline for correlation and mapping of these sandstone units.

Overlying the mfs3 is the regressive "CLNN4" sandstone unit (Figure 9), which represents the final and most basinward pulse of "Clinton" sandstone deposition in the regional study area. The top of the "CLNN4" is placed at the top of the coarsening upward cycle as indicated by decreasing gamma ray API response. This event, interpreted as the maximum regressive surface, also marks the base of the final transgressive event within the "Clinton" sandstone interval (labeled *rs* in Figure 9).

Based on thickness and reservoir quality, the "CLNN3" and "CLNN4" represent the most important reservoir rock in the "Clinton" interval for oil production and potential CO_2-EOR/sequestration. Petrophysical and core data analyses indicate the reservoir quality (porosity and permeability) for units "CLNN3" and "CLNN4" are the highest for the entire "Clinton" interval. These two units combined attain a maximum gross thickness of 60 ft in the regional study area and contain 90 percent of the OOIP in the AOR (Fekete Associates, Inc., 2009).

The "CLNN5" is the uppermost sandstone unit of the "Clinton" interval. On the gamma ray-density log signatures, the gradual increase in the gamma ray API signature and decrease in density porosity represents a fining upward, transgressive cycle with increased shale content (Figure 9; Appendix 3, Plates 1–4). The top of the "CLNN5" is placed at the top of the fining upward interval where there is a sharp break from sandstone or siltstone to shale. For the entire "Clinton" interval the base of the "CLNN5" unit is one of the best regional, correlatable surfaces that can be identified on subsurface wireline logs. Average thickness of this unit is approximately 25–30 ft, but locally, it may be absent because of erosion. The "CLNN5" unit grades upward and laterally into the upper Cabot Head Shale. Reservoir quality of the"CLNN5" is typically poor because of the more argillaceous nature of this unit. In terms of oil production and CO_2-EOR potential/sequestration, this unit is of secondary importance compared to the "CLNN3" and "CLNN4."

PRODUCTION ANALYSES

Range Resources Corp. provided production data on 78 of the 250 wells in the AOR (Figure 11). The data consisted of yearly oil and gas production from 1969 to 2008. Oil data were believed to be complete; however, there were numerous years for which gas data were not reported. The unreported gas data were estimated using gas-to-oil ratios (GOR) from years where gas data was supplied. Thirty of the wells reported combined production into various shared-tank batteries. In these cases the total tank battery production was split evenly among the producing wells (Figure 11). Since no water production data were provided by Range, the production data was supplemented by records from the ODNR Division of Geological Survey, Production of Oil and Gas in Ohio (POGO) database for years 1984–2008. Water production was estimated for years 1969–1984.

Within the model area there were 21 wells with available production data (Figure 11). Estimates were supplied by the operator for the remaining three wells in the model area. A combined total of 866,000 bbl of oil and 2.5 BCF of gas are estimated to have been produced from the model area. These wells had an average initial production of 25 barrels of oil per day (bopd) and 66 thousand cubic ft of gas per day (mcfgpd) in their first year online and are currently averaging around 0.5 bopd, 2 mcfgpd, and an estimated 0.13 barrels of water per day (bwpd). Five wells in the model area are no longer in production but not reported as plugged. Wells currently not reporting production ceased producing as follows: 21870 in 1998, 21988 in 2004, 22957 in 2005, and 21372 and 22009 in 2006. There is no production data available for well 21894. Wells 22060 and 22077 in the southeastern portion of the model area are considered primarily gas producers indicating a possible gas/oil contact at the western edge of the AOR.

There are three groups of wells within the model area that produce into shared-tank batteries. The production numbers reported for these wells represent a per-well average of the total production into their respective tanks. Figure 12 shows a bubble map of the cumulative oil production for the 24 wells in the model area. Wells producing into the Brenner-Sickafoose tank battery have the highest total production per well at 71,724 bbl of oil and 122 MMCF of gas per well. The Sickafoose-Morris well #1 (22018) was added to the Brenner-Sickafoose tank battery in 1995 and has produced 60,654 bbl of oil and 133 MMCF of gas. Within the pilot area it is not possible to ascertain the best producer since it likely produced into this shared tank battery. The poorest total producer within the pilot area is well 22957, which has produced a total of 7,509 bbl of oil since 1978.

The Brenner-Sickafoose tank battery, with three wells averaging 1 bopd and 2.8 mcfgpd each, remains the best group of wells producing in the model area. The Sickafoose-Morris #1, which produces into this tank, was the subject of the Ohio River Clean Fuels, ODNR Division of Geological Survey, and Range Resources cyclic-CO_2 ("Huff-n-Puff") test. Of the wells still producing in 2008, the Adelman wells, at 0.26 bopd and 1 mcfgpd, are the smallest producers. The Gill wells (22071 and 22075), producing 0.43 bopd and 2.8 mcfgpd, apparently have been comingled into a single tank.

STRATIGRAPHY AND RESERVOIR CHARACTERIZATION IN AREA OF REVIEW

DETAILED STRATIGRAPHIC CORRELATIONS

In the AOR 32 detailed, stratigraphic cross sections were constructed using all available well logs to establish consistent correlations for mapped units (Figure 3; Appendix 4). Of these cross sections, 17 were oriented east–west along dip and 15 were oriented north–south along strike. Wells are generally about 1,320-ft apart based on the 40-acre spacing requirements. All standard log curves (gamma ray, neutron-density) were digitized and displayed for all cross sections. Within the AOR, there are 249 wells, of which 225 wells have wireline logs. Gamma ray logs are available for all 225 logged wells, and 114 wells have both gamma ray and density logs. As with the regional cross sections, the stratigraphic interval displayed is from the base of the Ordovician Queenston Shale to the top of the Silurian Rochester Shale, and the datum is the base of the Dayton Formation ("Packer Shell"). Two representative cross section figures are included in this section (Figures 13 and

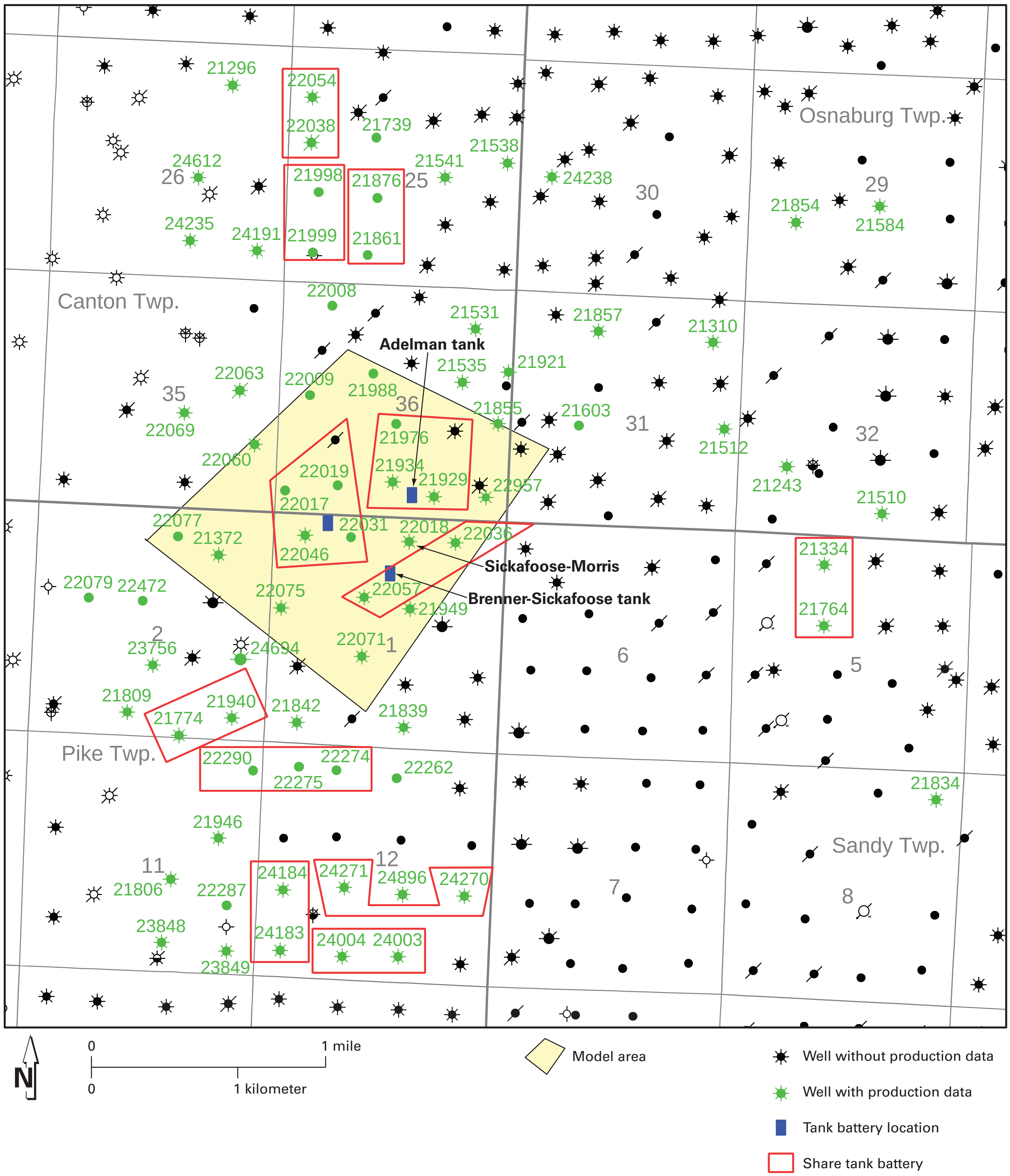

Figure 11.—East Canton oil field area of review showing wells with production data and shared-tank batteries. See Figure 3 for well symbol legend.

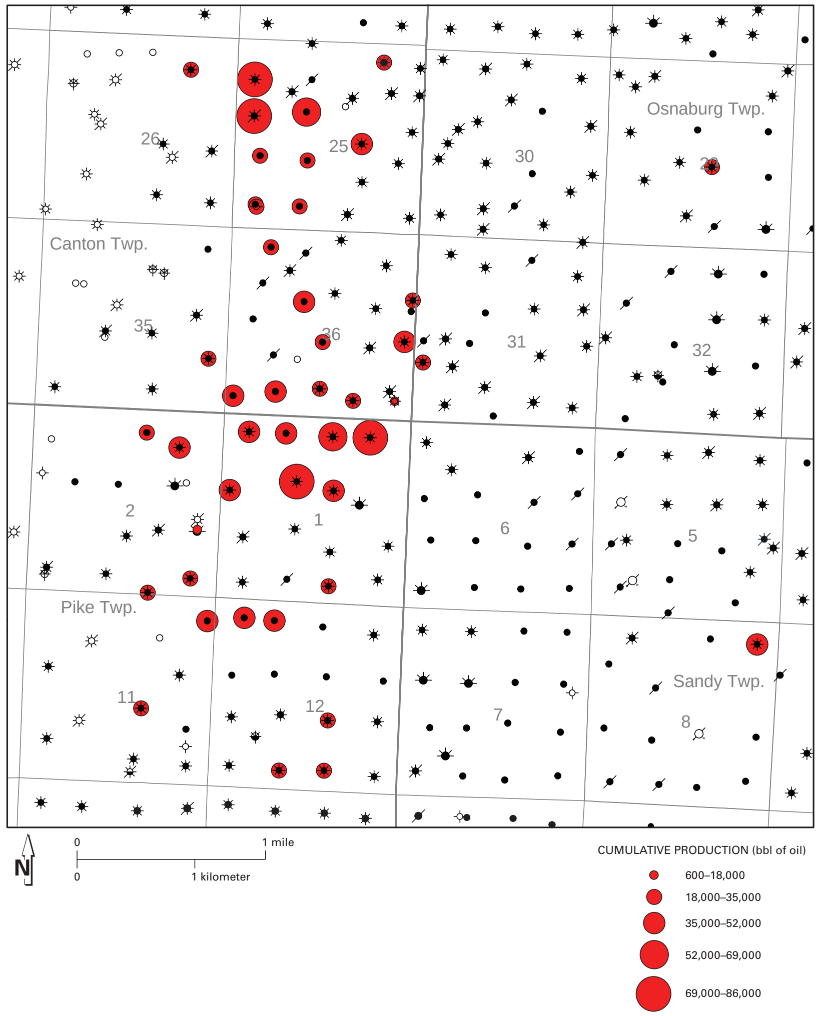

Figure 12.—Bubble map of cumulative oil production in the East Canton oil field area of review.

14), and all 32 cross sections are included as digital figures (Appendix 4). Correlations were based on the stratigraphic framework established in the regional geologic five-county study area. All cross sections display the correlation of the five “Clinton” sandstone units (“CLNN1” through “CLNN5”) and intervening shale units. In the AOR the gross thickness of the entire “Clinton” interval (top of lower Cabot Head to top of “Clinton”) ranges from 92 to 139 ft.

Detailed cross sections exhibit the heterogeneity of the “Clinton” interval across the AOR. Compartmentalization between individual sandstone units is evident between wells (Figures 13 and 14). In the AOR the “CLNN3” and “CLNN4” are generally the thickest and most porous sandstone units on gamma ray-density curves and have a combined thickness ranging from 30 to 60 ft. Compartmentalization is evident between these two sandstone units, which are separated by a thin, transgressive shale interval that ranges in thickness from 0 to 12 ft. These sandstone units are highly channelized and represent multiple periods of shifting sand deposition across a tidal flat/fluvial-deltaic environment.

NET SANDSTONE AND WATER SATURATION ANALYSES

Understanding the geometry and distribution of the individual “Clinton” sandstone units through detailed petrophysical analyses and mapping are necessary for an accurate assessment of reservoir compartmentalization and fluid flow. Net sandstone maps will assist in assessing the reservoir sandstone geometry and provide necessary information for planning proper well spacing and design of future pilot floods in secondary recovery efforts.

Within the AOR the net feet of sandstone were calculated and mapped for the entire “Clinton” interval and also for each sandstone unit (“CLNN1” through “CLNN5”). To determine net feet of sandstone, two petrophysical methods were employed using both gamma ray and bulk density cutoffs. Geographix software was utilized in both methods of petrophysical analyses. The net feet of sandstone were calculated and maps were generated with a gamma ray cutoff of 50 and 75 percent sandstone using the method by Knight (1969). They were also calculated using a bulk density (RhoB) cutoff of both 2.55 and 2.60 grams per cubic centimeter (g/cc). This roughly corresponds to 8 and 5 percent calculated log porosity, respectively. We determined that use of the bulk density curves was a more reliable method of determining net sandstone and, although less common, these curves were the basis for the maps provided to Fekete Associates, Inc., for the simulation

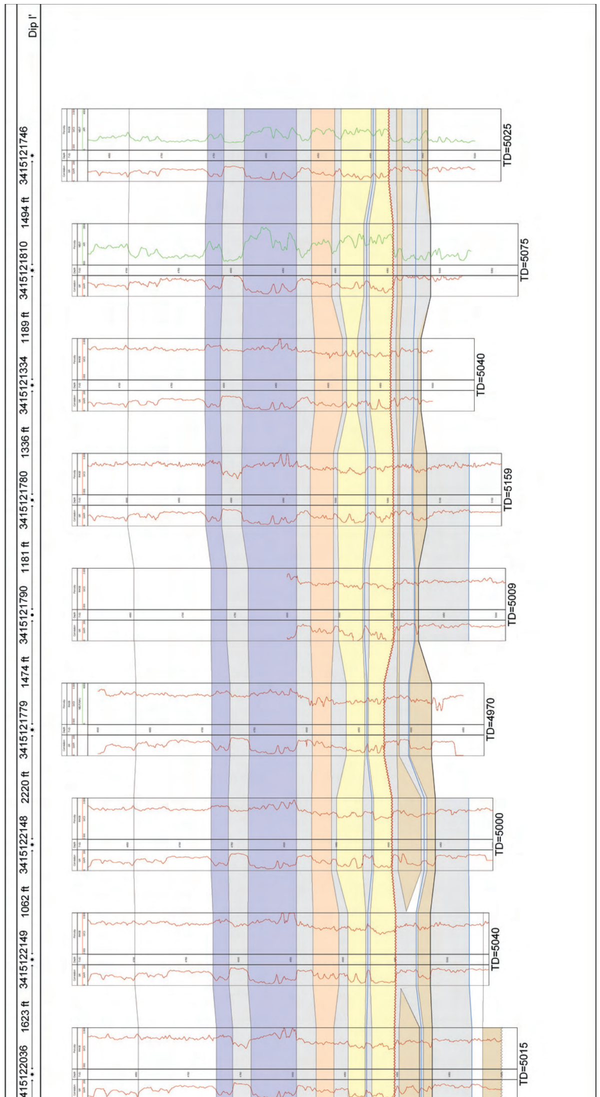

Figure 13.—Stratigraphic cross section Dip I–I′ in the East Canton oil field area of review, illustrating the mapped units. Datum is the base of the Dayton Formation (“Packer Shell”). The location of the line is shown in Figure 3.

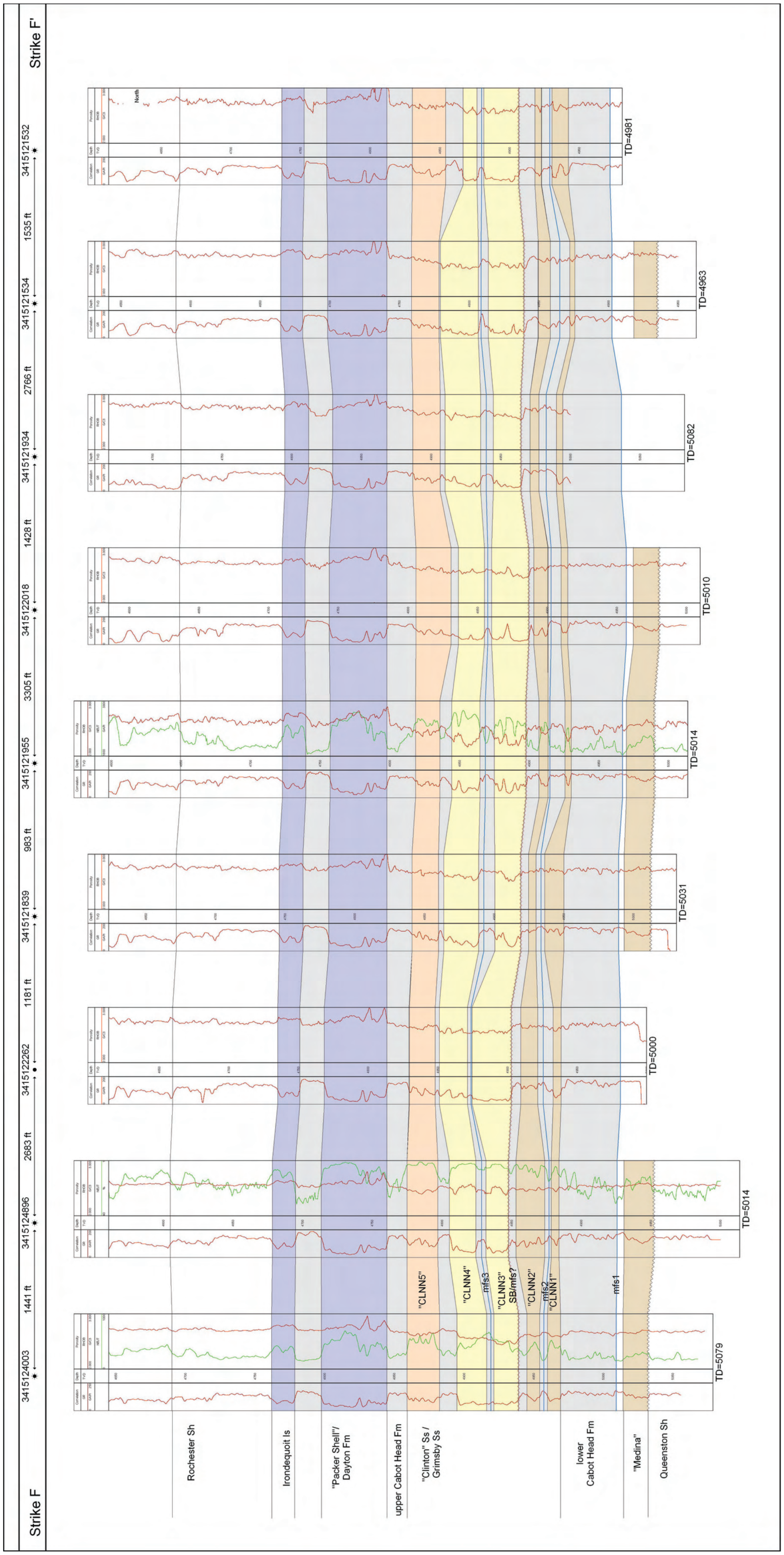

Figure 14.—Stratigraphic cross section Strike F–F′ in the East Canton oil field area of review, illustrating the mapped units. Datum is the base of the Dayton Formation ("Packer Shell"). The location of the line is shown in Figure 3.

work. Although there were more wells with gamma ray curves than RhoB curves available in the AOR, most wells in the modeling and simulation area contain RhoB log curves. It was decided to use sandstone with greater than 8 percent porosity to define net sandstone ("pay") for the Fekete reservoir simulation. Their results (summarized at the end of the geologic report) confirmed the geologists' interpretation that the reservoir zones for primary oil production and CO_2-EOR potential were primarily from the "CLNN3" and "CLNN4" (Figures 15 and 16). The net sandstone maps using a 2.55 g/cc cutoff (8 percent porosity) for the "CLNN3," "CLNN4," and entire "Clinton" interval are presented here and illustrate the sandstone-body geometry and complexity within the ECOF.

The net ft of sandstone for the "CLNN3" unit ranges from 0.5 to 41.5 ft in the AOR (Figure 15). The Sickafoose-Morris #1 well has a net sandstone thickness of 24 ft for the "CLNN3" sandstone unit. Thicker buildups of sand that are greater than 10 ft are evident as thin, sinuous trends that may represent deltaic or tidally influenced channel sand deposits, as proposed by Hettinger (2001) and Ryder (2000, 2004). The "CLNN4" has a net sandstone thickness ranging from 0.5 to 26.7 ft using a RhoB cutoff of 2.55 g/cc (Figure 16). The "CLNN4" net thickness in the Sickafoose-Morris #1 well is 4 ft. The net ft of sandstone for the entire "Clinton" interval ("CLNN1" through "CLNN5") ranges from 0.5 to 63 ft in the AOR (Figure 17) with 28 ft for the Sickafoose-Morris #1 well. Thicker sand buildups greater than 20 ft are evident and are primarily from the "CLNN3" and "CLNN4" units.

There are 64 oil and gas well logs on file at the ODNR Division of Geological Survey that contain resistivity curves in the AOR. Tabulated water saturation (Sw) data were compiled from these wells and entered into a database. These data were analyzed and determined the average Sw for "Clinton" zones with greater than 5 and 8 percent porosity for each well. Maps were then constructed for each "Clinton" interval ("CLNN1" through "CLNN5") that show the average Sw using these porosity cutoffs. The average Sw maps for zones with greater than 8 percent porosity are shown for the "CLNN3" and "CLNN4" units (Figures 18 and 19). Average values for Sw ranged from 13 to 42 percent for the "CLNN3" and from 13 to 34 percent for the "CLNN4."

POROSITY AND PERMEABILITY ANALYSES

The "Clinton" sandstone in eastern Ohio is generally considered to be a low-permeability reservoir. Wozniak and others (1997) presented a model in the northern area of the ECOF using an average matrix permeability of 0.16 md, which is determined from core data (APINO 3415124758) and history matching of production data. Schrider and others (1970) reported average "Clinton" sandstone matrix permeability of less than 0.10 md, derived from the Rose Township, Carroll County core (APINO 3415120256), when evaluating potential sweep efficiency for waterflood operations. Both papers rely on fracture permeability to explain reservoir productivity as high as 575 bopd. Watts and others (1972) estimated average permeability in the "Clinton" sandstone to be 1.07 md based on pressure build-up test data from 15 wells in Rose Township, Carroll County. Castle and Byrnes (2005), using data from 22 cores, mostly in Ohio, reported average air permeability of 0.15 md in "Clinton" sandstone tidal channel environments. All of the aforementioned studies consider average permeabilities without defining conditions or confining measurements to effective net reservoir sandstone (i.e., pay).

For this study, matrix permeability was estimated based solely on porosity vs. permeability plots derived from core data from three ECOF wells—the McCabe #1 (APINO 34151224758) well in Marlboro Township, the Creighton #1 (APINO 3415122005) well in Sandy Township, both in Stark County, and the Smith and Evans #4 (APINO3415120256) well in Carroll County, Rose Township (Figure 1). Effective reservoir was defined as porosity greater than 8 percent as calculated from bulk density logs. The data were culled by estimating or interpreting which permeability measurements represent true matrix permeability. The data were also restricted to the "CLNN3" and "CLNN4" sands, because they consist of the bulk of the producing reservoir. A porosity versus permeability plot (Figure 20) illustrates how the data were interpreted. Data with high permeability (K; >2 md) were culled from matrix K, possibly representing fractures, while low K (<0.10 md) data were culled as non-reservoir (circled in Figure 20). Remaining points were considered matrix permeability.

The Creighton #1 is the only well within the AOR for which core permeabilities were available. In addition, digital wireline log data exists and detailed porosity could be calculated from bulk density curves. We considered it desirable to correct core porosity measurements to approximate log porosity, since limited core data were available whereas abundant density logs exist in the AOR. This was accomplished by plotting core porosity versus log porosity for the same interval within the "Clinton" sandstone in the Creighton core. The cross-plot produced the linear relationship defined by the following equation:

$$y = 0.6273x + 0.0182 \qquad (1)$$

Core porosity was corrected using this equation and re-plotted against core permeability (Figure 21). The best-fit curve yielded the equation:

$$y = 0.1656e^{14.297x} \qquad (2)$$

We believe this to be the best approximation of the calculated log porosity relationship to measured core permeability possible with existing data, and the equation was used to calculate the average permeability in wells with average porosity calculated from RhoB density logs. Matrix permeability maps for each interval were constructed from these estimates for pay defined as RhoB <2.55 (porosity >0.08). Maps of the average porosity for the "CLNN3" and "CLNN4" pay intervals show the porosity distribution (Figures 22 and 23). Average Kmax, including all 33 samples representing matrix, is 0.69 md. Where log porosity average is greater than 8 percent (pay), the permeability averages 1.05 md.

NATURAL AND HYDRAULIC FRACTURE ANALYSES

Not much is understood about the fracture systems in the "Clinton" sandstone in eastern Ohio. The Grimsby ("Clinton" equivalent) sandstone at Niagara Gorge in New York is pervasively fractured (Figure 24). Those rocks display two sets of well-developed, regional orthogonal fractures with dominant systematic trends of east–west and northeast–southwest. While the fracture directional trends of northern New York

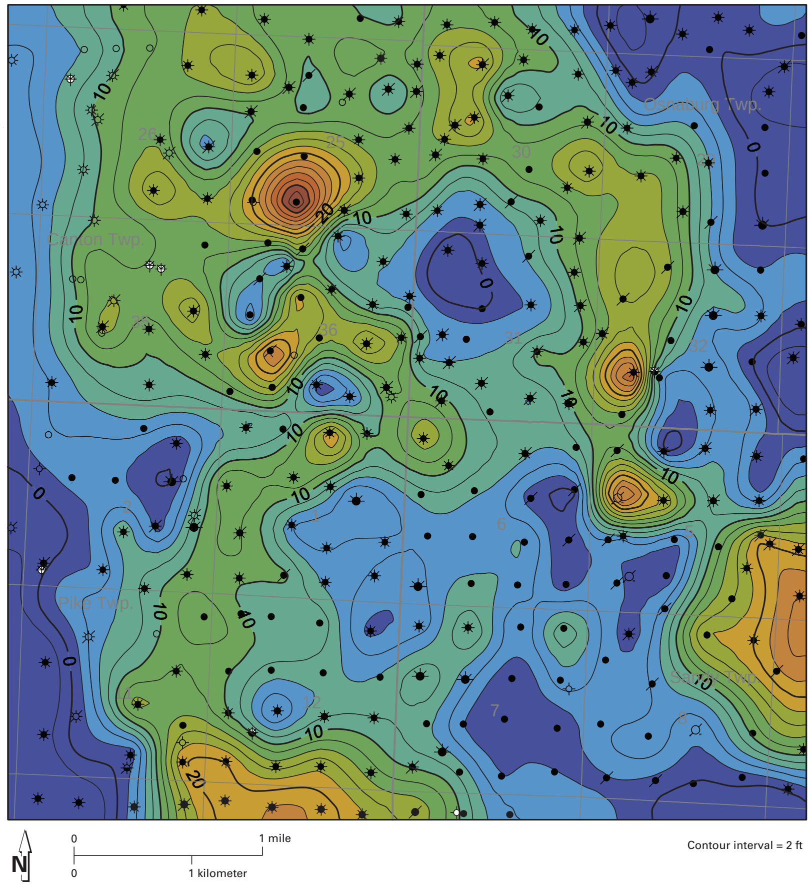

Figure 15.—Net sandstone map using a bulk density (RhoB) cutoff of 2.5 g/cc for the "CLNN3" unit in the East Canton oil field area of review.

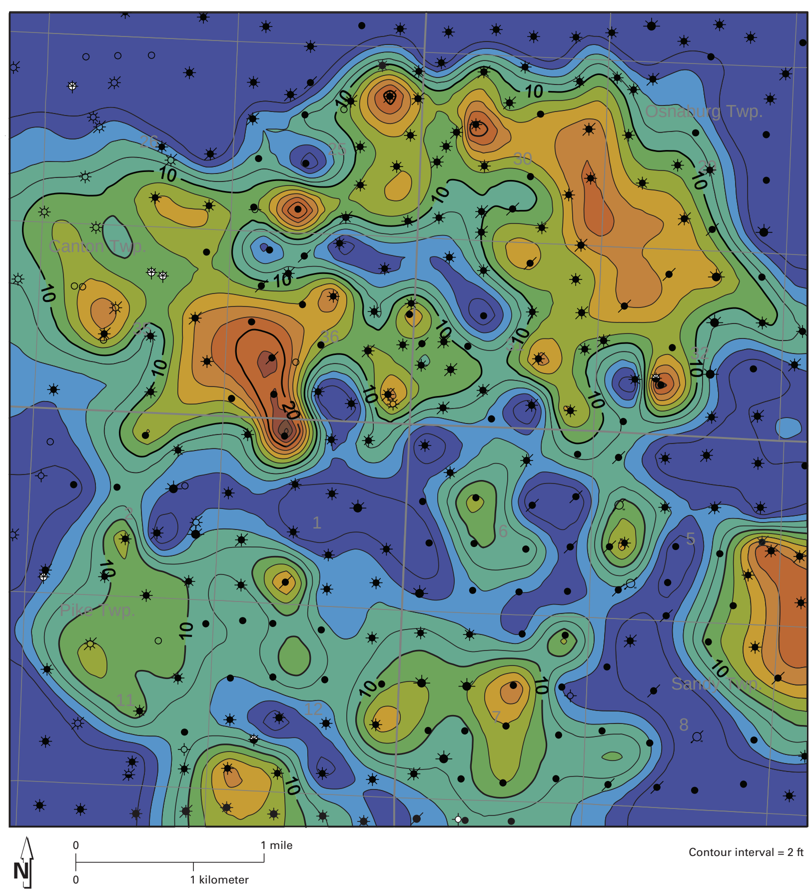

Figure 16.—Net sandstone map using a bulk density (RhoB) cutoff of 2.5 g/cc for the "CLNN4" unit in the East Canton oil field area of review.

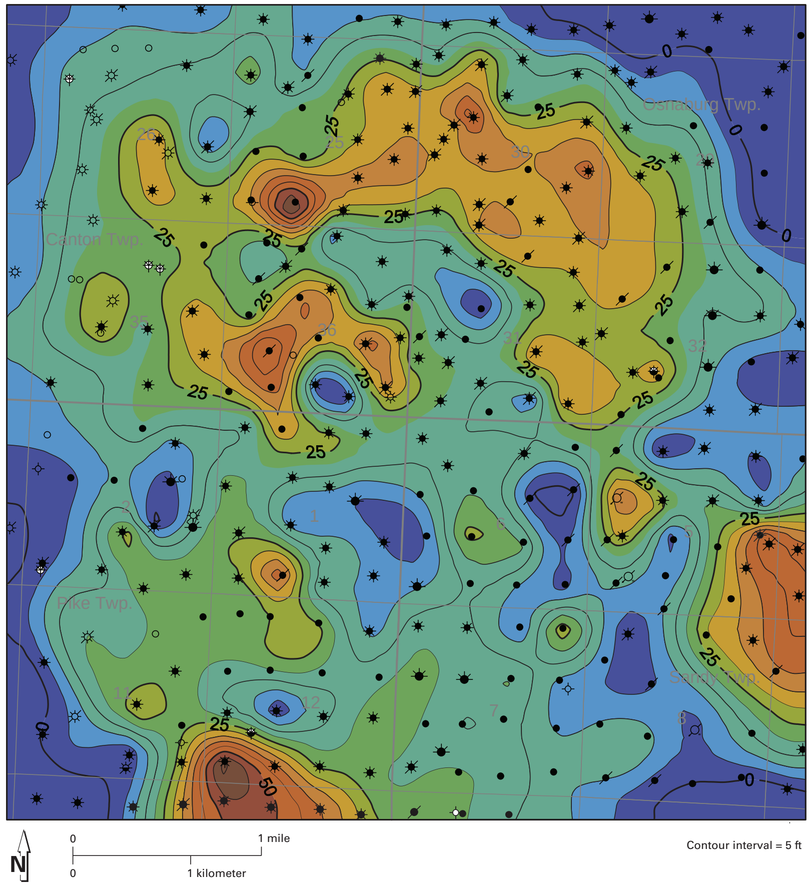

Figure 17.—Net sandstone map using a bulk density (RhoB) cutoff of 2.5 g/cc for the entire "Clinton" interval in the East Canton oil field area of review.

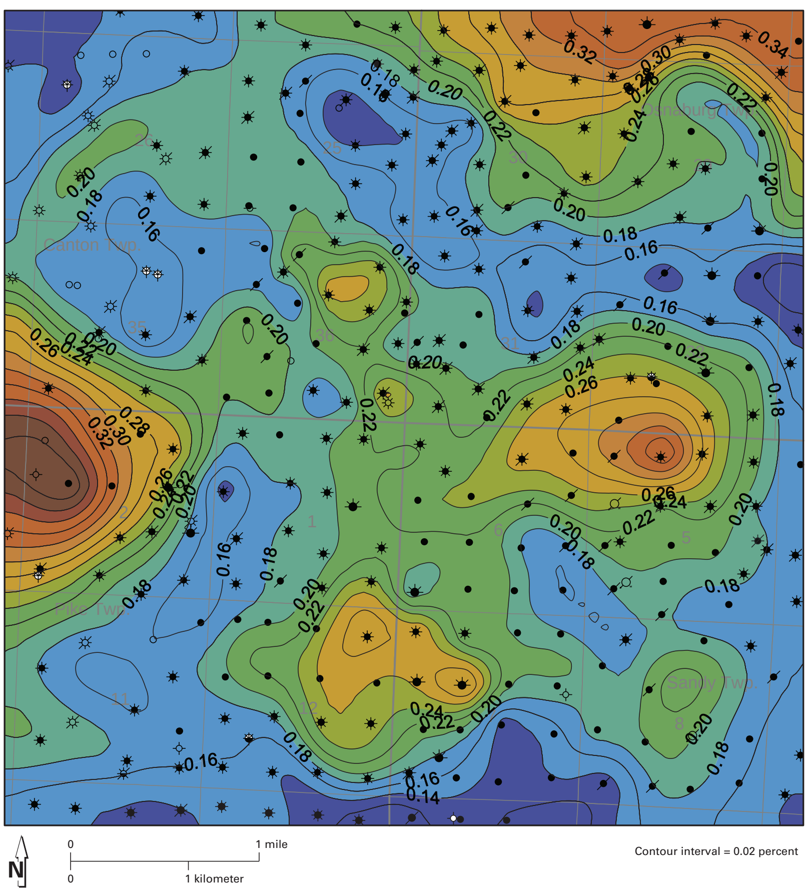

Figure 18.—Map of the average water saturation (Sw) above 8 percent porosity for the "CLNN3" unit in the East Canton oil field area of review.

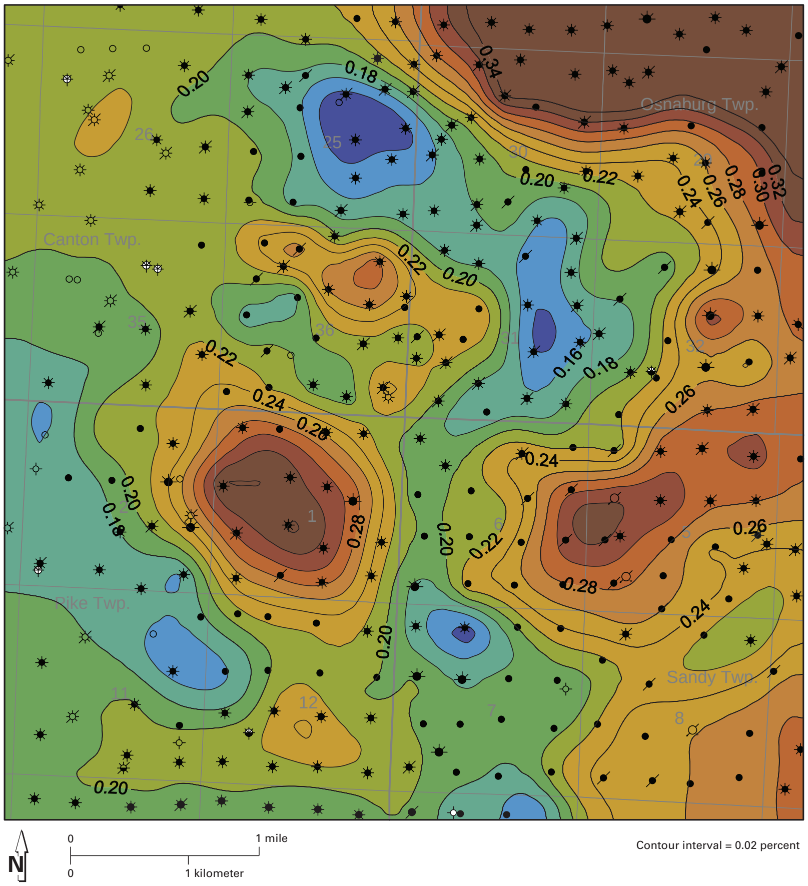

Figure 19.—Map of the average water saturation (Sw) above 8 percent porosity for the "CLNN4" unit in the East Canton oil field area of review.

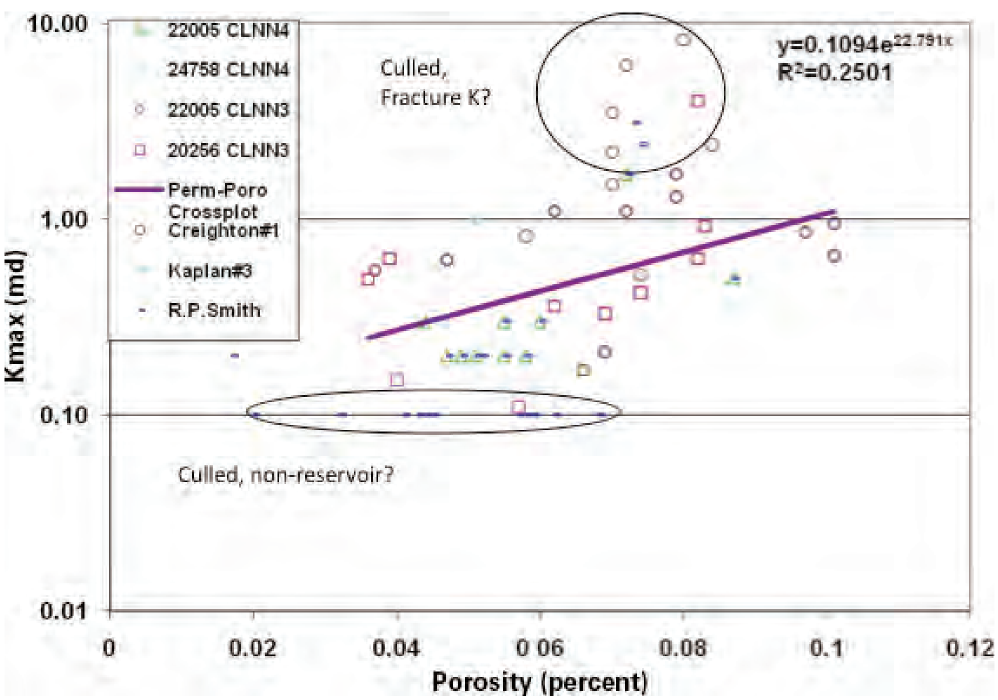

Figure 20.—Porosity versus permeability, containing data for four cored wells within the East Canton oil field area of review: McCabe #1 well (3415124758), Creighton #1 (3415122005), Smith & Evans #1 well (3401920256), and the Kaplan #1 well (3401920446). Circled points are the data points culled from the matrix permeability analysis.

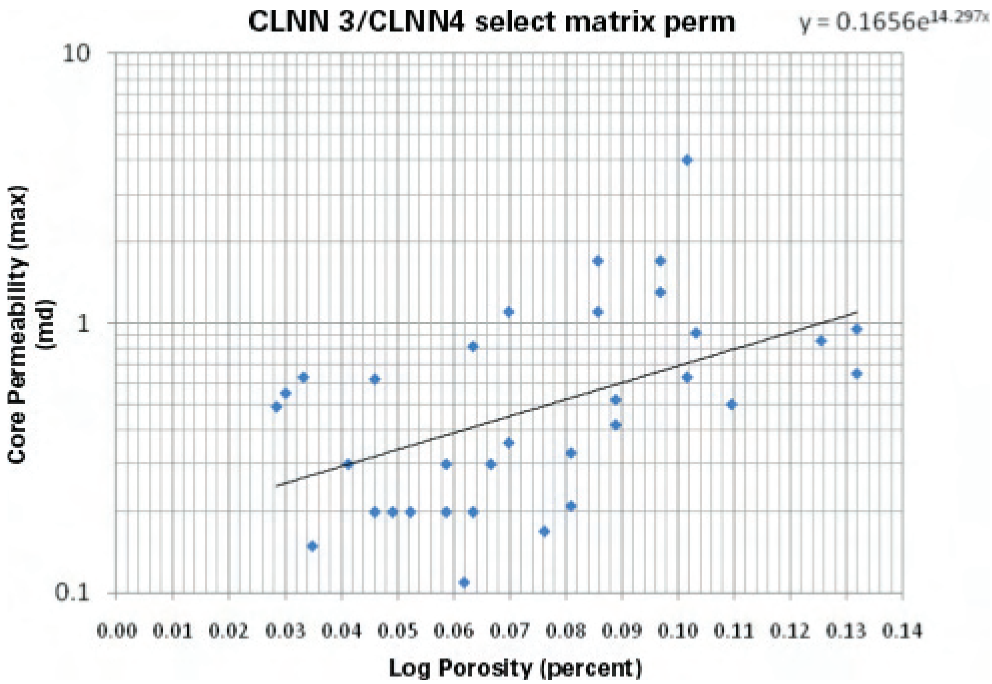

Figure 21.—Log porosity versus core permeability, derived from core analysis of the Creighton #1 well in the East Canton oil field area of review, which reported permeability compared to log porosity.

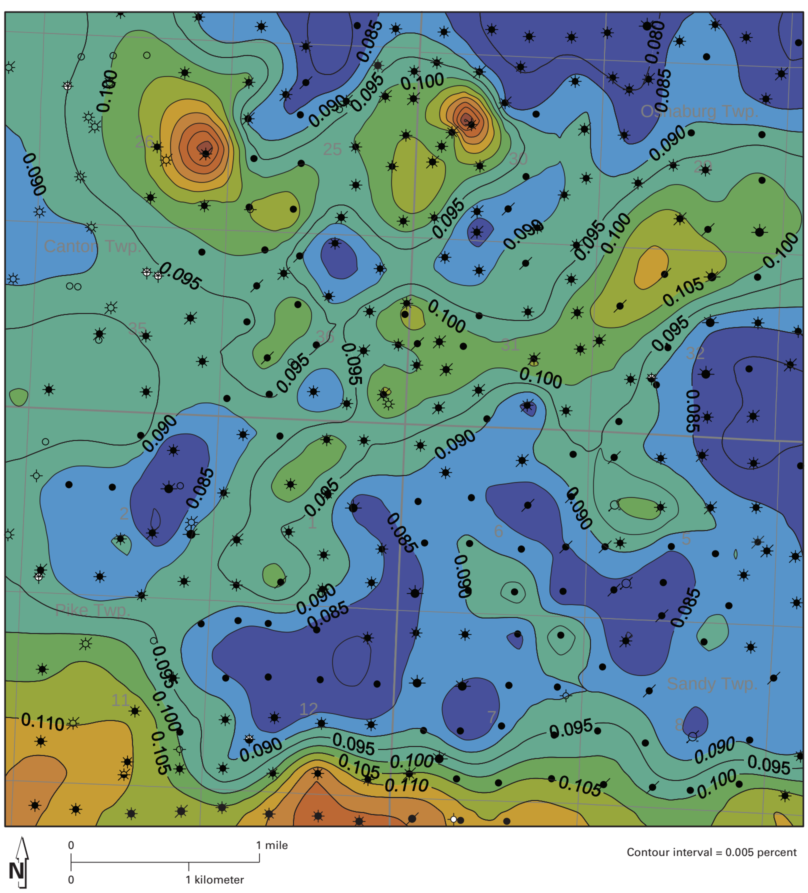

Figure 22.—Map of the average porosity greater than 8 percent for the "CLNN3" unit in the East Canton oil field area of review.

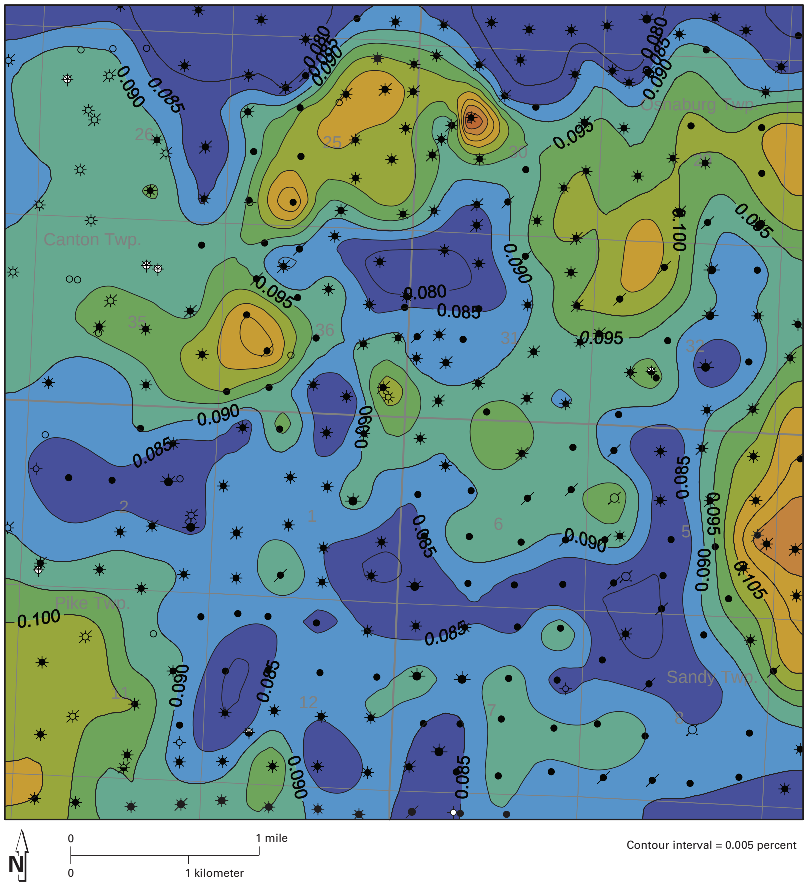

Figure 23.—Map of the average porosity greater than 8 percent for the “CLNN4” unit in the East Canton oil field area of review.

Figure 24.—Grimsby sandstone outcrop in Niagara Gorge at Art Park, Lewiston, New York.

are not applicable to eastern Ohio, it is reasonable to surmise that some systematic regional fracture trend would persist in the vicinity of the ECOF. The “Clinton” in both areas was buried in the subsurface for over 400 million years and was subject to significant regional stress during that period, not the least of which, were the Acadian and Alleghanian orogenic episodes.

Overbey and Henniger (1971) reported natural fractures observed in oriented core with a preferred orientation of N55º to 75ºE in Hocking County, approximately 70 miles southwest of the ECOF. Watts and Whieldon (1969) measured numerous vertical fractures in the Smith & Evans #4 well in Rose Township, Carroll County, ranging from a few inches to several ft in length (not oriented). Core Laboratories (Riess and Manni, unpub. data, 1991) was retained by Belden & Blake Inc. to evaluate fractures in the oriented core of the McCabe #1 well drilled near the northern extent of the ECOF (Figure 1). They measured 25 natural fractures, mostly vertical, within 76 ft of core, with fracture lengths varying from 0.3 inches to 10.3 inches. None of the fractures exhibited signs of oil-stain, although “dead oil” was reported on one fracture plane. Both open and mineralized fractures were observed (Figure 10). Preferred orientations as measured by Core Laboratories were N15ºW and N60º to 100ºW (Figure 25). A secondary trend of N45ºE was also noted. These fracture data may not be representative of the entire ECOF since it is located just south of the northwest–southeast trending Akron-Suffield fault system (Riess and Manni, unpub. data, 1991).

Opinions are quite mixed among “Clinton” workers as to the effectiveness of natural fractures in transmitting fluids within the “Clinton” sandstone reservoir. There is no direct evidence and there has been no serious study designed to specifically address this uncertainty.

Ryder and Zagorski (2003) suggest that “most petroleum-exploration geologists acknowledge natural fractures as the chief cause of high-yield oil and/or gas wells in ‘Clinton’/‘Medina’ sandstone reservoirs” (p. 858). “High-yield” is not defined by the authors. Review of their citations show this to be based on opinions of numerous “Clinton” workers with little or no quantitative evidence. They note that natural fractures may have influenced the high gas production at Cooperstown, Olive and Noble/Buffalo fields in Pennsylvania and Ohio, which are located near cross-strike regional fault systems.

Wozniak and others (1997) in their reservoir model for the “Clinton” sandstone in Marlboro Township, Stark County considered a “six layer dual porosity/single permeability model having both a matrix and fracture component to each layer.” They used fracture permeabilities of 800 md and never explain their reasons for using fractures in their model. The McCabe #1 well, which core data was used as model input, showed no oil-stained fractures and no permeabilities in the range of 800 md.

Watts and others (1972) concluded from pressure build-up testing of fifteen wells in Rose Township, Carroll County, that fractures are not effective conduits for oil in the “Clinton” reservoir. They based this on their 1.07 md average permeability calculation (too low for fractures) and high breakdown pressures experienced during hydraulic fracturing operations. Based on data from the same testing, Schrider and others (1970) noted that there is little connectivity due to natural fractures, since interference testing showed no communication observed between wells over the 2-month duration of the 15-well test. They consider abundant microfractures to be responsible for high-directional permeability observed in some core measurements.

Wicks and others (2009) calculated that CO_2 injected into the Sickafoose-Morris #1 well in Pike Township, Stark County, was an order of magnitude greater than could be stored in fractures alone (summarized below). They argue that this shows the matrix porosity and permeability played an important role in accepting the injected CO_2. In addition, there was no observed slope change on the injection pressure verses time curve that would suggest CO_2 moving from fractures into less permeable matrix porosity. Observation wells showed no CO_2 increase during the 32-day shut-in monitoring period.

Castle and Byrnes (2005) related “Clinton” production data to depositional environment and facies type, which they contend controls porosity-permeability characteristics within the reservoir. For part of this study production from 16 wells, for which complete data were

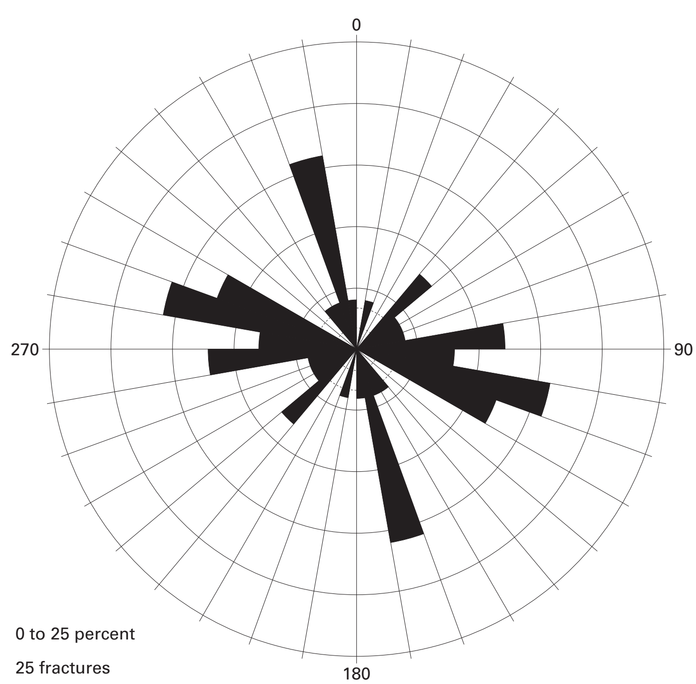

Figure 25.—Rose diagram showing percent distribution of true natural fracture strike from the McCabe #1 well (3415124758) in the East Canton oil field area of review. From Riess and Manni (unpub. data, 1991).

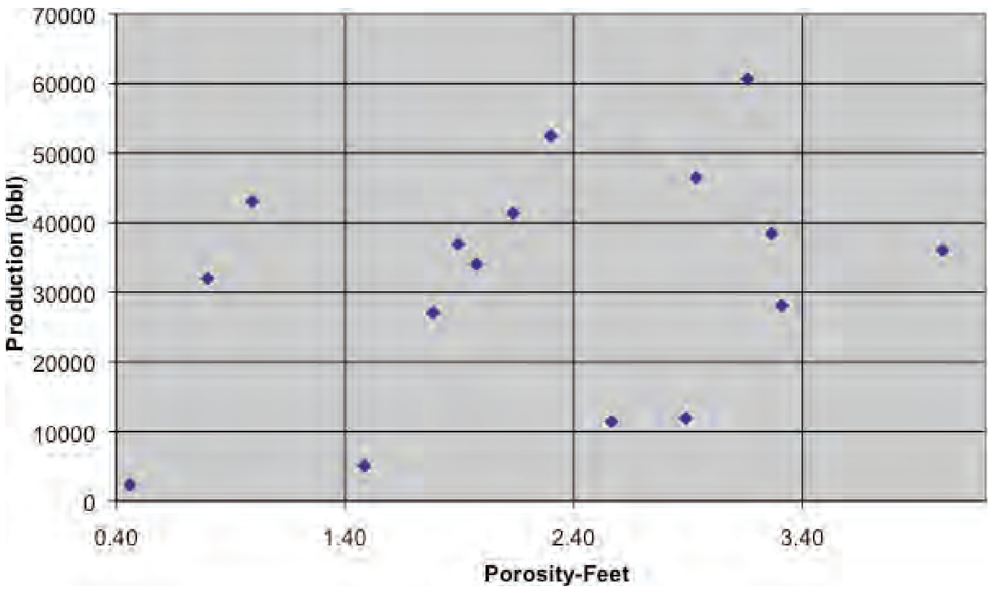

Figure 26.—Oil production versus porosity-feet for reservoir rock greater than 8 percent porosity for sixteen wells within the East Canton oil field model area.

available, were plotted against porosity-ft (Figure 26). The plot shows a poor to fair relationship between porosity and production. Five wells produced between 30 and 40 thousand barrels of oil with porosity-ft varying from 0.6 to 4.0 while the two highest producers calculated fourth and eighth in terms of pore-ft. This suggests other factors, such as fractures or completion practices, are contributing to oil production yields in the area.

"Clinton" sandstone wells in the ECOF generally are hydraulically fractured during completion. A typical fracture job consists of 1,000 to 5,000 bbl of water and between 0.5 lbs and 1 lb of sand per gallon of water. Often acid, gels, or gasses such as nitrogen are used in the process. The formation breaks down at pump pressures ranging from 1,000 psi to 4,000 psi and takes the fluids also in that pressure range with pump rates of 20 to 50 barrels per minute (bpm). Recently, at the request of these authors, Halliburton modeled a fracture produced by a hydraulic fracture operation performed in the Sickafoose-Morris #1 well in the ECOF, completed at 5,000-ft depth. The operation consisted of 5,100 bbl of water and 75,000 lbs of sand with 100 SCF of nitrogen per barrel of water. Formation breakdown was 1,400 psi, with fluids and sand injected at a rate of 37.5 bpm. Average injection pressure was 3,600 psi. Halliburton calculated the fracture half-length to be 513 ft and height to be 358 ft. After treatment, the subsurface fracture volume was estimated to be 500 to 1,000 ft^3 with an average conductivity of 238 md-ft.

Overbey and Henniger (1971) reported the hydraulic fracture direction of N63ºE in Hocking County. A recent microseis test, recorded during a hydraulic fracture operation in the Stark County portion of the ECOF, showed a preferential direction of N55ºE, which is roughly parallel to the contemporary tectonic maximum stress field (Engelder and others, 2009). In addition, abundant anecdotal evidence from operators in the field confirms the general direction of N60ºE from observed communication between wells. This includes several eyewitness accounts of fluid breakthrough during hydraulic fracture operations, to adjacent wells. The Kolm #1 well (Permit 21295) in Osnaburg Township, Stark County, was converted to a water disposal well in 1997. The same year, the Aller #2 well (Permit 23345) located 1,780 ft away in a N52ºE direction began taking on significant water at the expense of oil and gas and had to be shut-in. The Aller #2 well had been producing oil with low water cut steadily since 1985. In contrast the Foltz & Foltz Partnership LLC #2 well has been injecting oil field disposal salt water since 1997 with no apparent response in the offset wells. It should be mentioned that thousands of wells are hydraulically fractured, and there are numerous water disposal wells that do not experience water breakthrough to adjacent wells.

It remains unclear to these authors whether natural fractures affect production within the "Clinton" sandstone reservoir in the ECOF. The best evidence for fluid communication between wells comes from artificially induced hydraulic fractures that trend in the direction parallel to the northeast–southwest contemporary stress field (Engelder, 2009). Core measurements (Figure 26) and basin tectonic features (Figure 2) suggest a northwest–southeast trend for the natural fractures. These fractures, when observed in core, are often healed by mineralization and rarely exhibit oil staining. If natural fractures do facilitate production at ECOF, is it the rule or the exception? Is the extent of connectivity local or regional? The answers to these questions are critical to understanding the reservoir response to large quantities of fluid injection, which in this case is supercritical CO_2.

Based on the previously mentioned observations in the field and the opinions of ECOF field geologists, a northeast–southwest trending natural fracture network was incorporated in the reservoir simulation effort accompanying this study.

SICKAFOOSE-MORRIS #1 CYCLIC CO_2 TEST SUMMARY

The Ohio River Clean Fuels, LLC; Range Resources Corp.; and the ODNR Division of Geological Survey, through funding provided by the U.S. Department of Energy, conducted a cyclic-CO_2 test ("Huff-n-Puff") operation on the Sickafoose-Morris Unit #1 well (APINO 3415122018) in the west-central portion of the ECOF, Ohio (Figure 1). The operation was designed to test CO_2 injection rates into the "Clinton" reservoir at the ECOF and estimate the dispersion or potential breakthrough of CO_2 into adjacent wells. Results of this test were provided to the Ohio River Clean Fuels, LLC in a separate report (Wicks and others, 2009) and are summarized here.

INJECTION RESULTS

1. The cyclic-CO_2 test on the Sickafoose-Morris #1 well clearly demonstrates the capacity of the "Clinton" sandstone in this area of the ECOF to accept significant volumes of injected CO_2. Approximately 81 tons (1.39 MMCFG) of CO_2 at surface conditions were injected during a 20-hour period into the test well (1.67 MMCF/D). This was the maximum capacity of the pumping equipment, and it is estimated that this reservoir could have sustained a higher rate of injection. Considering the low reported permeabilities of the "Clinton" sandstone reservoir, this was much higher than anticipated.
2. The CO_2 was injected at a maximum surface injection pressure of 617 psi (~1,300 psi estimated bottom-hole pressure), which fell-off to 330 psi within 7 hours of completing the injection. This is below the estimated minimum miscibility pressure (MMP) of 1,450 psi. Estimates show that the MMP is well under fracture gradient and ample working space exists for CO_2 injection.
3. Multiple lines of evidence suggest strongly that the majority of the injected CO_2 entered the matrix porosity, where it diffused into the oil. The evidence includes: (A) the volume of injected CO_2 greatly exceeded the estimated capacities of the hydrofrac and natural fractures; (B) there was a gradual injection and pressure rate build-up during the test; (C) the gradual flashout of the CO_2 within the reservoir during the flow-back period: and (D) a large amount of CO_2 off-gassed from wellhead oil samples 3½ months after injection.
4. Several factors also indicate that the injected CO_2 was not pushed far beyond the test well, including (A) a lack of CO_2 increase found in the gas samples from offset wells, (B) the persistent but gradual decrease of CO_2 in fluid samples taken from the injection well after production was restarted, and (C) a standard calculation of radius of influence. Most of the CO_2 was probably pushed into and then diffused within the higher permeability "Clinton" sandstone zones that communicate with the hydrofrac system near the borehole. Holtz (2008) calculated the radius of influence to be approximately 68 ft.

PRODUCTION RESULTS

1. After the test well was returned to production, it produced 174 bbl of oil during a 60-day period (September 22 to November 21, 2008), which represents an estimated 58 percent increase in oil production over pre-injection estimates that the well would have produced under normal, unstimulated conditions. Considerable uncertainty exists concerning the pre-injection production rates of the test well since it shared a tank battery with two other wells.
2. Results demonstrate that even under immiscible conditions CO_2 diffuses into the oil in the pore space, changes its characteristics, and enhances its mobility. Injection of larger volumes of CO_2 at or above MMP is clearly feasible, moving to a pilot flood phase is appropriate and higher-efficiency recoveries are anticipated.
3. The additional incremental oil produced is interpreted to result primarily from a combination of (A) diffusion of CO_2 into the oil within the pore space, changing the oil mobility and relative permeability to water and gas, and (B) solution CO_2 drive during depressuring. Lesser contributing factors include CO_2-bypassed oil and natural pressure build-up during shut-in. It is not possible to quantify the relative contribution of each increment, but high concentrations of CO_2 in the gas stream show that CO_2 continued to breakout (through December 2008) and influence oil production, suggesting it played the dominant role in the enhanced oil production.
4. A considerable increase in water production occurred following the injection test. This began at over 40 times estimated pre-injection water rates and settled in at the end of the monitoring period at five times estimated pre-injection rates. The anomalous water production is interpreted to be a consequence of the breakdown of the salt scale, or "skin" that had previously precipitated in pore channels near the borehole during the production history of the well. Scaling is typical for "Clinton" sandstone brines, known to contain high dissolved solids. The scale buildup likely centered on preferential zones with high water cuts. These zones could also contain significant residual oil and make good targets for CO_2 flooding
5. The cyclic-CO_2 test had a CO_2 utilization factor (ratio of CO_2 injected to additional oil recovered) of 8 MSCF/STBO, assuming all oil production is attributed to CO_2 injection, and 21 MSCF/STBO if only the estimated additional incremental oil production is attributed to CO_2 injection over the 2-month monitoring period. These results are obscured by the extreme water production during the monitoring period, uncertainty in the original production rates, limited amount of CO_2 injected, and failure to reach and maintain higher reservoir pressures.

RESERVOIR MODELING AND SIMULATION SUMMARY

The previously described geologic model was used by Fekete Associates, Inc., engineers to simulate oil production and CO_2-EOR in a portion of the AOR. The primary objectives of the model were to (1) quantify the potential of a CO_2-EOR project for improving oil producibility and recovery and (2) design a pilot to test the model. Results of this reservoir modeling and simulation study were provided to Baard in a separate report (Fekete Associates, Inc., 2009), which is summarized here.

The OOIP in the model area is estimated at nearly 13 MMSTBO, 90 percent of which is in the "CLNN 3" and "CLNN4." Recovery to date has been 866 MSTBO, or 6.7 percent of the OOIP. Using a dual-porosity model, Fekete concluded that CO_2 injection wells drilled on a 12- acre elongated pattern (pilot) could lead to effective oil mobilization resulting in 20 percent additional oil recovery in the pilot area over a five-year period. Sensitivity studies within the pilot area showed the central producer had CO_2 enhanced peak production rates, ranging from 14 bopd to 43 bopd depending on fluid property, matrix permeability, and fracture anisotropy assumptions. While varying the assumptions, cumulative production for the central producer in the pattern varied from 12,000 to 42,000 bbl of oil over the five-year simulation period. Field-wide CO_2 flooding could lead to an additional recovery from 76 to 279 MMbbl of oil. Considerable uncertainty of these simulation results exists due to our limited knowledge and understanding of fluid properties, fracture distribution, and connectivity.

METHODS

The model area was chosen based on the availability of production and geologic data and consisted of a 1 mile × 1.2 mile rectangle (~770 acres) containing 23 wells, most of which have been producing since 1969. The model was discretized using grid blocks of 300 × 60 ft, aligned in the N63°E presumed direction of natural and hydraulic fracture planes (Figure 27). Artificially induced hydraulic fractures were assumed to encompass a single plane extending 300 ft to each side of the wellbore. Natural fractures were spaced 50-ft apart in the X direction and 5-ft apart in the Y direction, where fractures are interconnected and span throughout the domain. The pilot area was designed based on the geology and intended to provide maximum reservoir feedback from CO_2 injection within a one-year response time. A 12-acre, five-spot pattern was chosen and oriented northwest–southeast, which is parallel to the fracture direction and has a length-to-width ratio of 3 to 1. Injectors, located on the corners, were approximately 1,250-ft apart in the long direction and 415 ft in the short direction with a central producer 600 ft from each injector. The Sickafoose-Morris #1 well (3415121018) was utilized as one of the injectors.

The geologic model provided by the ODNR Division of Geological Survey and J. L. Wicks, including maps of structure, net pay, porosity, water saturation, fracture analysis, and permeability, was utilized as presented in the preceding sections of this report. Production data for history matching was provided by Range Resources and supplemented by the ODNR Division of Geological Survey database. To be consistent with the reported oil production, adjustments to portions of the data were made to account for unreported gas and water production.

Both a single-porosity and dual-porosity (matrix and natural fractures) simulation history match were examined. The single-porosity model showed enhanced production rates as high as 82 bopd and an oil yield of 20,000 bbl during the one-year simulation period. Based on previous studies and consultation with Range Resources, and due to limited funding and schedule constraints, the single-porosity method was abandoned and emphasis was placed on the preferred dual-porosity model. The significance of natural fractures on oil and gas production within the “Clinton” sandstone reservoir is not well understood.

PVT data and initial reservoir pressure of 1,600 psia were taken from published reports. In the absence of published information, a bubblepoint pressure of 1,600 psia was assumed. Correlations were used to generate the black-oil properties. The current pressure estimate of 200 to 300 psia was based on analysis of the fall-off test associated with the cyclic-CO_2 (“Huff-n-Puff”) test. Range Resources, the field operator, concurred with a current reservoir pressure in this range. Gas/oil relative permeability was obtained from available experimental data. The absence of water/oil relative permeability data required it to be varied during the history match. This was also true in the case of capillary pressure. The only available data for East Canton oil properties in the presence of CO_2 is the MMP (minimum miscibility pressure) of 1,450 psia. Therefore, light oil fluid characteristics or parameters from the Midale reservoir in Saskatchewan were used as a basis and adjusted for the ECOF. These were chosen because they were familiar to Fekete, the modelers, and thought to be reasonable analogues for the ECOF.

A forecast of oil, CO_2, water, and pressure was simulated over a five-year period. Three simulation cases were modeled:

1. <u>As-Is</u> with no additional infill or injection wells,
2. <u>Four infill producers</u> were added (as required for the above mentioned five-spot pattern) for primary production with no injection wells, and
3. The 12-acre, five-spot pattern was implemented with the four corner wells injecting CO_2 at a rate of 500 MCF/day per well, with a central producer. In addition, three producing wells outside the pilot area were converted to water injectors to create a shielding effect.

Cases 1 and 2 were used for a baseline from which to compare Case 3, defined as the Base Case (or most likely outcome).

After establishing the Base Case described above, sensitivity studies were conducted varying the following parameters:

1. Average matrix permeability was reduced from 0.65 md in the Base Case to 0.13 md.
2. Fracture anisotropy ratio was increased from 10 in the Base Case to 30.
3. Properties of the individual components used in the definition of the fluids were changed (GOR [gas-to-oil ratio], FVF [Formation Volume Factor], and viscosity), while keeping the basic properties of the reservoir fluid relatively unchanged.

RESULTS

The following is a summary of the results for the CO_2-EOR pilot simulation and sensitivity studies performed by Fekete Associates, Inc., (2009).

PILOT SIMULATION

- CO_2-EOR in the pilot area should lead to mobilization of a significant portion of the matrix porosity oil. Predicted cumulative oil production over five years by the pilot area central producer with four injectors is approximately 26,000 STBO, compared to 12,000 STBO produced from four new infill wells with no injectors (Table 1) or 3,000 STBO per well.
- The injected CO_2 not only affects production of the central producer but also the offset wells. A significant increase is anticipated from CO_2 injection in the model area. The forecasted oil production from all wells in the model area over a five-year period is (1) nearly 69,000 STBO in the pilot CO_2; (2) 42,000 STBO for the four infill producers; and (3) 30,000 STBO for the As-Is case (Table 1).

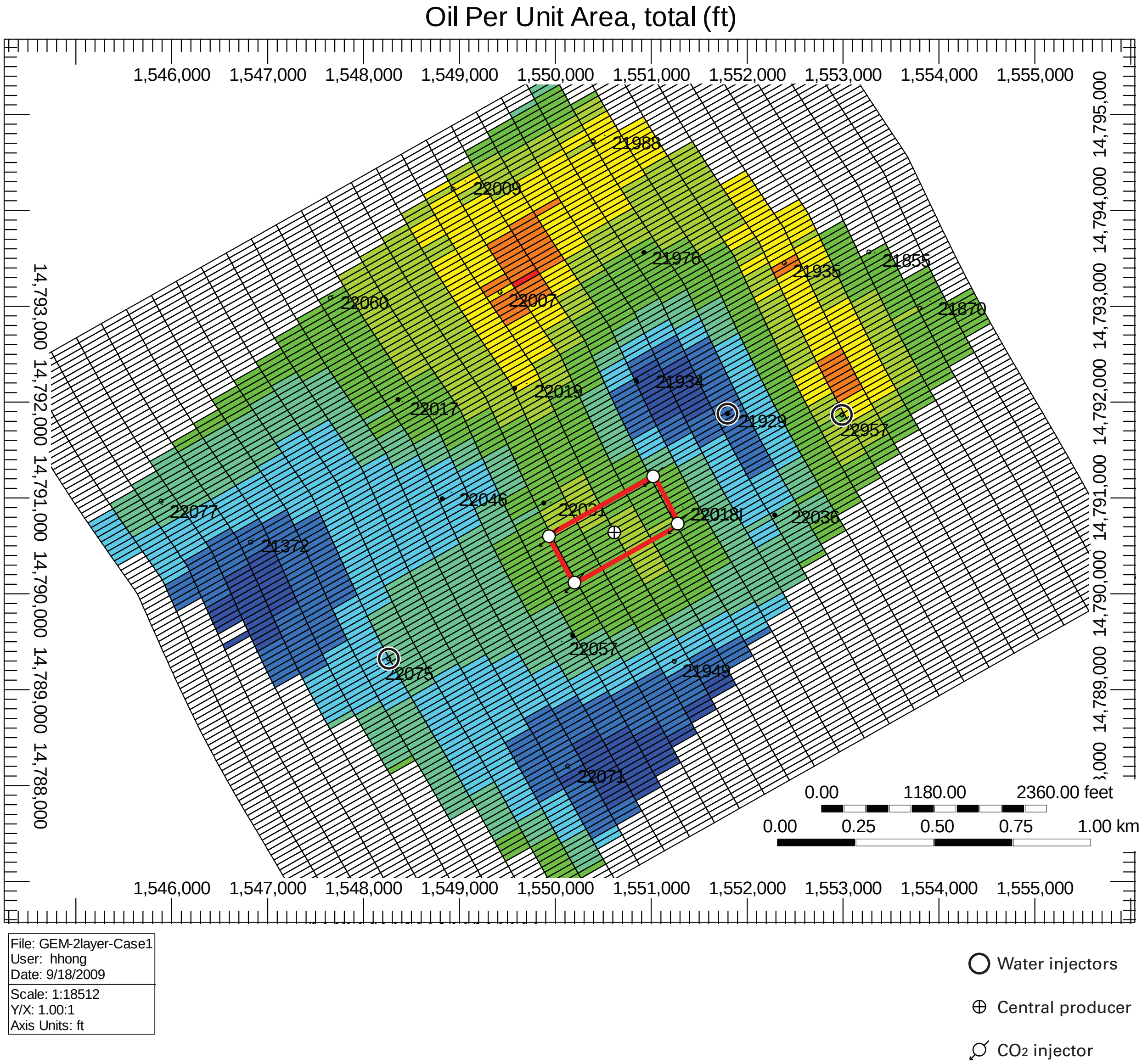

Figure 27.—Distribution of remaining oil-in-place in “CLNN3” and “CLNN4” sands in the East Canton oil field model area. The red rectangle shows the pilot area. Modified from Fekete Associates, Inc. (2009).

Table 1.—Predicted cumulative oil production in the model area over a five-year simulation period

Case	*No. Prod. Wells*	*Cum. Prod. (STBO)*	*Peak Prod (BOPD)*
As-Is (no injectors)	21	30,000	30
Four Infill Producers (no injectors)	25	42,000	70
Central Producer Upside (four injectors)	1	44,000	43
Central Producer Base Case (four injectors)	1	26,000	32
Central Producer Downside (four injectors)	1	12,000	15
Entire model area with Pilot CO_2 (four injectors)	22	69,000	47

- Results indicate that of the 220 MSTB of remaining oil-in-place within the pilot area at the beginning of CO_2 injection, 18 percent of additional oil was displaced over a five-year period compared to the As is case, 59 percent of which was captured by the central production well within the pilot area. This is significant compared to primary recovery to date, which is approximately 7 percent.
- The effect of CO_2 on oil indicates that within the first six months, little of the matrix oil outside of the pilot area will be affected by CO_2. However, after injection periods of one and five years, a significant area of the reservoir outside of the pilot area has been affected by the CO_2. Presence of the CO_2 along with high pressures leads to swelling of the matrix oil and reduction in its viscosity. This oil is displaced into the fractures through which it proceeds to areas of lower pressure around the producing wells.
- Consistent with behavior of fractured reservoirs, fast breakthrough of CO_2 was observed. Within the five-year study period, CO_2 spread to the boundaries of the model area and breakthrough was observed in approximately half of the wells. CO_2 production rate increases rapidly such that a large fraction of the daily injected CO_2 needs to be recycled from the central producer alone (i.e., CO_2 production rate from the central producer as compared with the total CO_2 daily injection rate is 25 percent in eight months, 50 percent in two years, and 70 percent in five years).
- Preliminary simulation studies indicated that at an injection pressure equal to the initial reservoir pressure, an injection rate of 1.67 MMCF/day as used in the cyclic-CO_2 test, cannot be sustained and the injection rate decreases with time. Furthermore, at high injection rates the CO_2 would bypass considerable additional oil in the matrix, leading to excessive CO_2 production rates. The injection rate used in this model is 0.5 MMCF/day.
- Average pressure within the pilot area increases to 1,000 psia in less than a year, with a very gradual subsequent rise. This pressure is hundreds of psia less than the minimum miscibility pressure (1,451 psi). The PVT properties suggest that for the fluid model used in this study, a significant degree of beneficial oil swelling and reduction in oil viscosity would still be realized at the lower (sub-MMP) pressure levels used during the simulation.
- Achieving higher pressures in the pilot area would require one or a combination of (1) controlling the flowing production pressure, (2) injecting at a higher injection rate (which could raise pressure above the initial reservoir pressure), and (3) pressurization of reservoir with water or CO_2 while production is temporarily ceased.

SENSITIVITY STUDIES BY VARYING THE RESERVOIR PARAMETERS AND PILOT DESIGN

- Actual rock and fluid properties are likely to have a significant effect on oil production in the pilot area. In particular, lower matrix permeability or a larger fracture anisotropy ratio could lead to a significant reduction in oil production rate, while a favorable PVT behavior between the oil and CO_2 could enhance oil production (Figure 28).
- Lowest oil production is realized from the pilot area when matrix permeability is reduced by 20 percent from the Base Case (0.13 md compared to 0.65md).
- Significant reduction in forecasted production occurs when the permeability anisotropy ratio in the fracture is changed from the Base Case of 10 to 30. If a value of 30 is used, CO_2 moves preferentially along the fractures and does not displace oil towards the central producer as effectively. If fracture characterization studies in the pilot area suggest such a large anisotropy ratio, the pattern geometry should be redesigned (with a larger aspect ratio) to ensure better displacement towards the producer.
- When reservoir fluid is characterized with different components, oil production could be significantly higher. There is uncertainty in the potential of a CO_2-EOR project in the pilot area, such that the cumulative oil production rate after one year of CO_2 injection could vary by a factor of 4. A reservoir and fluid characterization study will allow narrowing the range of uncertainties in the results.

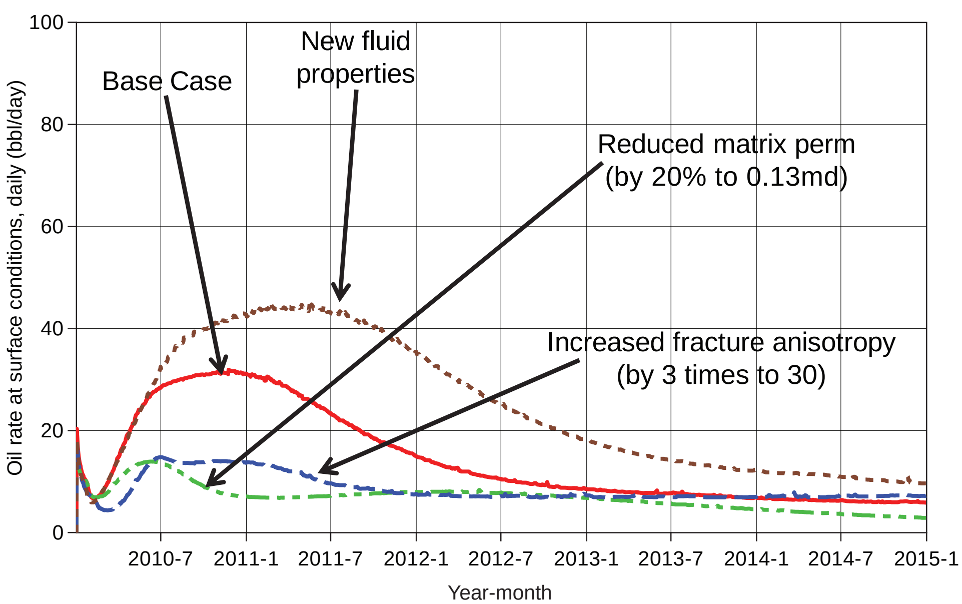

Figure 28.—Forecast of oil production rate for the East Canton oil field pilot area central producer for the five-year simulation period showing the Base Case and three sensitivity study cases. Modified from Fekete Associates, Inc. (2009).

- Shutting in the offset producing wells did not improve capture of the displaced oil by the central producer.
- Shutting in the water injectors did not reduce oil production significantly. The potential for creating a water shield should be further evaluated.

CONCLUSIONS AND RECOMMENDATIONS

After conducting a geological study of the “Clinton” sandstone reservoir in the East Canton oil field and surrounding region, a detailed geologic model was constructed over a 10,240-acre AOR. The model utilized all technical data and published information available for the area and incorporated the results of a cyclic-CO_2 injection test performed in the Sickafoose-Morris #1 well within the AOR. The 110-ft “Clinton” sandstone interval was separated into five units and reservoir property maps were constructed for each unit. The most effective reservoir sandstone was found to be the stacked distributary and/or tidal channels within the “CLNN3” and “CLNN4” units, which contain over 90 percent of the OOIP. Conventional views on the “Clinton” reservoir consider it a very low permeability (0.10 md average) matrix, with interconnected hydraulic and natural fractures needed to move the oil and gas to the wellbore. Based on the cyclic test, which demonstrated the “Clinton” matrix porosity readily accepted 81 tons of CO_2, and a review of the core data from the main reservoir sands, matrix permeability may average as high as 1.0 md in the pay zones, and the role of natural fractures on oil conductivity is unclear.

Fekete Associates, Inc., conducted a reservoir simulation model for a 700-acre model area within the AOR and designed a pilot to test the model. After first simulating a single-porosity model (no natural fractures), a dual-porosity model considering low matrix permeability and a connected fracture network was chosen for the simulation model. Given the limits of the data, sensitivity studies were performed during simulation to estimate a reasonable range of outcomes to CO_2 injection. The reservoir was first simulated without CO_2 injection, as a baseline for comparison. The pilot design included four CO_2 injection wells and one central producer, drilled on a 12-acre pattern elongated in the assumed direction of fracture orientation (N63^{o}E). Fekete concluded that the CO_2 injection wells could enhance oil production and lead to an additional 20 percent recovery in the pilot area over a five-year simulation period.

Considerable uncertainty exists because of our limited knowledge of the fluid properties, fracture distribution, and connectivity. Fekete Associates, Inc. conducted sensitivity studies during simulation by varying fluid properties, matrix permeability, and fracture anisotropy within the pilot area. Results showed CO_2-enhanced peak production rates ranged from 14 bopd to 43 bopd depending on our assumptions. While varying the assumptions, cumulative production for the central producer in the pilot area varied from 12,000 to 42,000 bbl of oil over the five-year simulation period. Extrapolating these findings indicates possible additional recovery ranging from 76 to 279 million bbl of oil through CO_2-EOR in the ECOF.

This study has added significant knowledge to the reservoir characterization of the “Clinton” in the ECOF and succeeded in identifying a range on CO_2-EOR potential. However, additional data on fluid properties (PVT and swelling test), fractures (oriented core and microseis), and reservoir characteristics (relative permeability, capillary pressure, and wetability) are needed to further narrow the uncertainties and refine the reservoir model and simulation. After collection of this data and refinement of the model and simulation, it is recommended that a larger-scale cyclic-CO_2 injection test be conducted to better determine the efficacy of CO_2-EOR in the “Clinton” reservoir in the ECOF.

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