Characterization of Geologic Sequestration Opportunities in the MRCSP Region

Phase I Task Report

By

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MRCSP
MIDWEST REGIONAL
CARBON SEQUESTRATION
PARTNERSHIP

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NOTICE

ABOUT THE MRCSP

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is a public/private consortium that is assessing the technical potential, economic viability, and public acceptability of carbon sequestration within its region. The MRCSP region consists of seven contiguous states: Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, and West Virginia. A group of leading universities, state geological surveys, non-governmental organizations and private companies listed below and led by Battelle, makes up the MRCSP. It is one of seven such partnerships across the U.S. that make up the U.S. DOE Regional Carbon Sequestration Partnership Program. The U.S. DOE through NETL contributes the majority of funds for the MRCSP's research accounting for 68.62% of the total funding or $2.41 million for the current phase of work all under Agreement No. DE-PS26-05NT42255. The next largest contributor is the Ohio Coal Development Office within The Ohio Air Quality Development Authority under Agreement No. CDO/DE-02-17. The MRCSP also receives funding from all of the other members listed below.

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ABSTRACT

From October 2003 to Sepember 2005, the Midwest Regional Carbon-Sequestration Partnership (MRCSP) Phase-1 geologic team conducted a preliminary assessment of the region's geologic CO_2 sequestration potential for the Paleozoic geologic sequence in Indiana, eastern Kentucky, Maryland, Michigan, Ohio, Pennsylvania, and West Virginia and for Cenozoic-age strata in the Maryland coastal plain. Nine potential reservoir, and five potential confining cap-rock, intervals (this includes organic shales) were identified, their structure, depth, and thickness mapped, and other physical and chemical data pertinent to CO_2 sequestration compiled. A comprehensive series of digital maps and tabular databases were constructed to facilitate regional sequestration planning and modeling. The Phase-1 assessment indicates the MRCSP region has the potential to sequester in excess of 450 gigatonnes of CO_2 in deep, subsurface geologic formations. This estimate of the CO_2-storage capacity is very large when compared to the present level of CO_2 emissions for the region. Furthermore, geologic mapping and calculations of the storage capacity conducted during Phase-I reveals that the geologic storage capacity for CO_2 is disproportionately distributed, both between and within the partnership states; some areas have high storage potential, while others have little or no known capacity. Hence, for CO_2 sequestration technology to be practical, it is essential that any future CO_2 point-source is located in an area where the subsurface geology is amenable to large-scale CO_2 injection, or, at the least, that the economics of transporting the CO_2 from the point-source to the geologic CO_2 reservoir is included in the site planning. Future research, to be conducted during Phase-2 of the partnership, will include additional geologic mapping and modeling of additional stratigraphic intervals determined to be viable sequestration targets as well as the refinement of those maps and models developed during Phase-1. Future MRCSP CO_2 sequestration research will also contain components investigating the economic variables associated with transporting CO_2 from existing point-sources to any potential CO_2-storage site. These additional analyses will provide the region with the geologic and economic foundation necessary to advance with CO_2 sequestration technology.

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EXECUTIVE SUMMARY

The Midwest Regional Carbon-Sequestration Partnership Phase-1 geologic team consists of members from the states of Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, and West Virginia. This team examined the regional geology in those portions of each state that lie in the Appalachian and Michigan basins, the Cincinnati and Findlay arches region, and the Atlantic coastal plain. This research resulted in the creation of a regional correlation chart showing those units in the Paleozoic with the physical qualities deemed critical to their use in the geologic sequestration of carbon dioxide. This initial synoptic analysis resulted in the identification of nine potential geologic reservoirs and five potential confining units (this includes organic shale intervals, a rock type that can also be considered a potential reservoir). In total, the MRCSP geologic assessment team used over 85,000 data points that resulted in 30 original structure (depth) and thickness maps, 9 regional thematic maps, and 14 derivative capacity maps. One of the more significant thematic map layers created was a new oil-and-gas-fields map for the MRSCP region—the first ever compiled for the seven-state area. All data and maps, collected and generated for this project, are stored in a modern geographic information system (GIS), and are available for interactive use on the MRCSP website.

Using these data, estimates of the CO_2-storage capacity for each state in the MRCSP partnership were calculated for each geologic unit and reservoir type considered viable for use in CO_2 sequestration (for example, deep saline formations, oil and gas reservoirs, unmineable coals, and organic shales). This Phase-1 assessment determined that the MRCSP region contains the following approximations:

- 450 to 500 gigatonnes of storage potential in deep saline formations; of these, the Mt. Simon, St. Peter, and Rose Run sandstones have the highest potential in the region.
- Between 2-3 gigatonnes of CO_2 potential storage may be possible in existing and depleted oil and gas fields. Using CO_2 for enhanced oil recovery could result in the additional production of hundreds of millions of barrels of oil that otherwise would be left in the ground.
- Unmineable coals in the northern Appalachian basin are estimated to have the potential to sequester between 0.2 to 0.3 gigatonnes of CO_2. Using CO_2 to enhance the gas recovery from these coal beds (coalbed methane) could contribute trillions of cubic feet of additional natural gas resources in the nation.
- A potential may exist to sequester over 45 gigatonnes of CO_2 within the organic shales of the region, and at the same time, generate (or enhance existing) natural gas production.

This assessment clearly illustrates that the MRCSP region, based on current levels of CO_2 production, has the capacity to store hundreds of years worth of anthropogenic CO_2 emissions. Moreover, it also indicates the region has many opportunities—at least in the near term—for value-added production of oil and natural gas generated concurrent with many types of CO_2 sequestration; thus, not having the geology for adequate CO_2 total storage capacity in the MRCSP region is not an issue. However, this CO_2-storage capacity is unevenly distributed, both across the region and within the individual partnership states. Indeed, some areas have an abundance of storage capacity while others have little or no known potential for CO_2 sequestration. What the team asserts through this analysis is that locating future CO_2 point-sources where the subsurface geology is amenable to large-scale CO_2 injection is critical if this technology is to be used. Further, a comprehensive analysis of the economics of transporting CO_2 from existing point-sources to CO_2-storage sites is essential for the fruition of CO_2 sequestration technology.

CHARACTERIZATION OF GEOLOGIC SEQUESTRATION OPPORTUNITIES IN THE MRCSP REGION

GEOLOGIC TEAM MEMBERS

The geologic team for the MRCSP project consists of a multifaceted collaboration of geologic, geographic information system, and computer scientists from the geological surveys of Indiana, Kentucky, Ohio, Maryland, Pennsylvania and West Virginia, and the Michigan Basin Core Research Laboratory of Western Michigan University. These agencies are the major repositories for most publicly available geologic data in the seven state MRCSP region.

Larry Wickstrom, of the Ohio Geological Survey, served as the geologic team leader. Other team members included John Rupp and Premkrishnan Radhakrishnan (Indiana); Dr. James Drahovzal, Dr. Stephen Greb, Brandon Nuttall, Marty Parris, and Mike Solis (Kentucky); Dr. Gerald Baum, Christine Conn, Catherine Garcia, and Sacha Lanham (Maryland); Dr. William Harrison III and Dr. David Barnes (Michigan); Larry Wickstrom, James McDonald, Donovan Powers, Ernie Slucher, Dr. Erik Venteris, and Joseph Wells (Ohio); Dr. John Harper, Kristin Carter, and Karen McCoy (Pennsylvania); Katharine Lee Avary, Dr. Michael Hohn, Patrick Kish, and Susan Pool (West Virginia); Dr. Neeraj Gupta (Battelle Institute). Members of this team brought to the project extensive experience, from both the public and private sectors, in analyzing and evaluating the diverse geology of the MRCSP region.

ACKNOWLEDGMENTS

Recognizing the contributions of all individuals and organizations, without inadvertent omissions, that contributed to a project of this magnitude is always difficult. However, the contributions of several individuals deserve special recognition, and are herein thanked for their contributions. Charles Byrer of the U.S. DOE/NETL served as the DOE project manager for the MRCSP. Ron Cudnik served as the Battelle project manager during the formative stages of Phase I and David Ball is the current project leader for the partnership. Strategic guidance was also provided by Jim Dooley of Battelle's Joint Global Change Research Institute and outreach support was led by Judith Bradbury, also of Battelle.

We thank Lisa Van Doren and Edward V. Kuehnle in the Cartography and Editing Group of the Ohio Division of Geological Survey for their patience and great skills in helping compile this report and their assistance to team members giving presentations related to this study.

TASK STATEMENT

Under Subtask 2.1 of the MRCSP Phase I project, the geologic team examined the regional geology of the project area, created a regional correlation chart showing the various geologic units in the study area, and delineated the most promising prospective geologic reservoirs and sinks for CO_2 sequestration via data collation, interpretation, and mapping. These data and maps were then used to calculate a first approximation of the region's geologic CO_2 sequestration capacities of four main reservoir classes: deep saline formations, oil and gas fields, unmineable coal beds, and organic-rich shales. All information was captured in a Geographic Information System (GIS) using ESRI's suite of ARC-GIS products.

BACKGROUND INFORMATION

The MRCSP region generates almost 21 percent of our country's electricity, 78 percent of which is from coal, and can be appropriately considered America's "engine" room. The region also contains a wide array of facilities classified as CO_2 point-sources that produce 26 percent of the nation's CO_2 emissions from power plants and 12 percent of the nation's total CO_2 emissions (Ball, 2005). Task 1 of the MRCSP study identified over 600 stationary facilities that are considered CO_2 point-sources, of which at about 300 are classified as large sources (> 100,000 tons of CO_2/year), that emit over 800 million tons of CO_2 per year. These facilities include plants that produce ammonia, cement, ethanol, ethylene, ethylene oxide, hydrogen, and power, as well as petroleum refineries, gas processing facilities, and iron and steel mills. Because of this large number of, and the high volumes of emissions from, these point-sources the future prospects of environmental liability from these CO_2 emissions necessitate research in the potential of using geologic units for carbon dioxide sequestration in all seven states (Figure 1). The main objective of Subtask 2.1 for the MRCSP Phase I project was to evaluate the potential capacity for geologic sequestration of CO_2 in the MRCSP region.

Until recently, the major options under consideration for mitigation of greenhouse gas emissions included switching to noncarbon-based fuels, increasing energy efficiency thereby reducing greenhouse gas emissions, and terrestrial or biotic sequestration of CO_2. However, during the last several years, the idea of storing CO_2 in geologic reservoirs has gained increased prominence as a result of research funded by the U.S. DOE, similar agencies in other countries of the world, and a growing interest of CO_2-producing industries.

The primary attraction of the geologic sequestration option is due to the potential for direct and long-term storage of captured CO_2 emissions in close proximity to the CO_2 source. However, to achieve this objective, the potential capacity of any geologic reservoir needs to be verified by a detailed regional assessment as well as by a site-specific investigation to insure that decision-makers fully understand the characteristics of the geologic sequestration system. Thus, a major task of the Phase I work of the DOE-funded regional partnerships was a first-round regional assessment of this capacity.

In principal, geologic storage of CO_2 emissions involves purification of the gas (capture) from its sources (e.g., power plants and refineries), compression of the CO_2 in order to transform it to a supercritical phase, followed by its injection in deep geologic formations

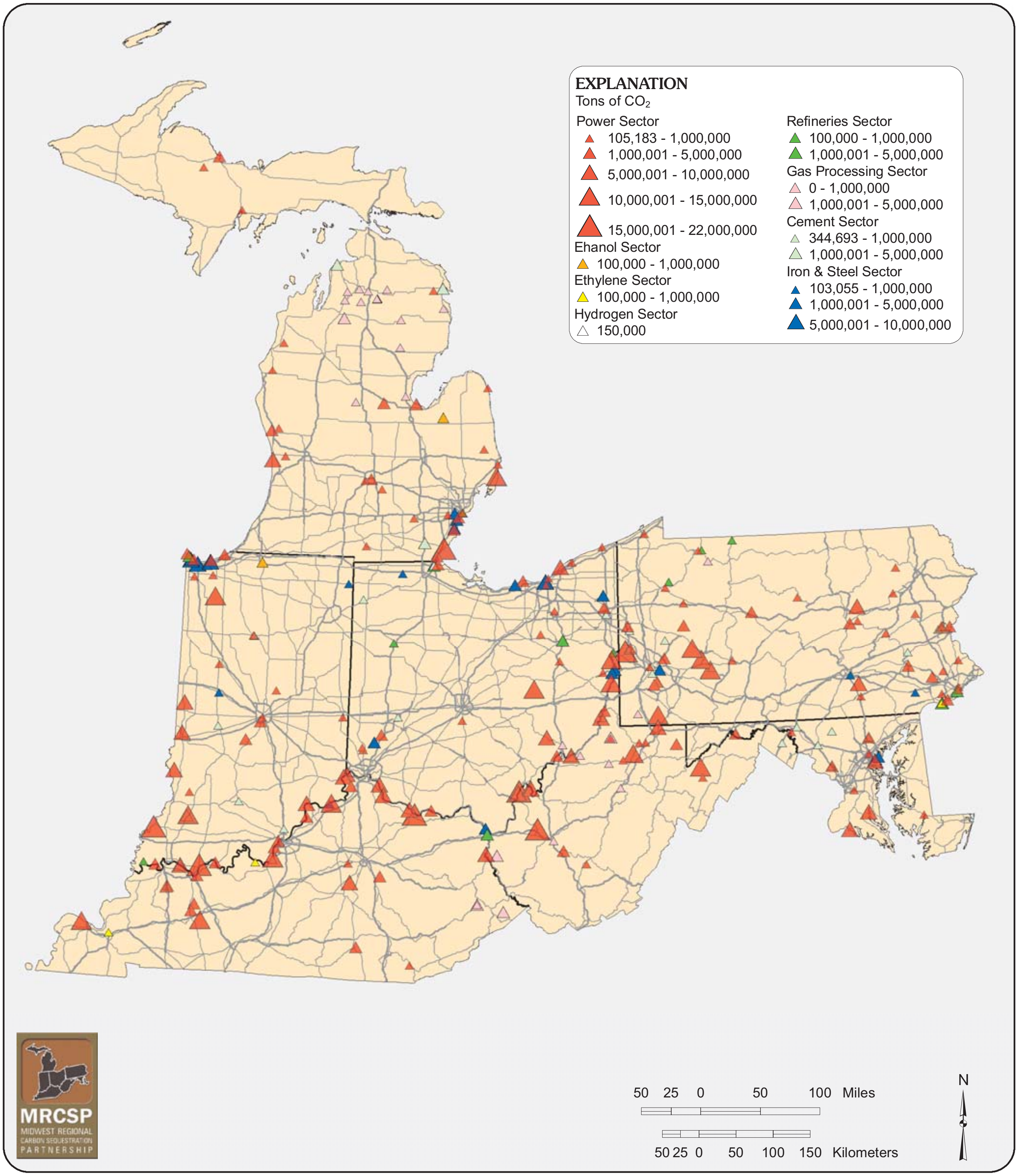

Figure 1.—Large (>100,000 tons per year) point-sources of CO_2 within the MRCSP region (data from MRCSP task-1 report).

(a minimum depth of approximately 2,500 feet below the surface is required to maintain the CO_2 in the supercritical phase). Natural geologic reservoirs have held oil, natural gas, water, and even CO_2, for millions of years without leaking (or at least with minimal leakage). Therefore, these same systems are thought to offer both near-term opportunities and longer-term possibilities for future management of anthropogenic CO_2 (Reichle and others, 1999; Beecy and others, 2002). Societal industries currently use these natural reservoirs for storage of industrial wastes (Class I injection wells) and the disposal of oil field brines (Class II injection wells). The injection of CO_2 into oil fields in order to stimulate additional oil production [Class II enhanced oil recovery (EOR) injection wells] is a growing methodology in the petroleum industry. Thus, a substantial quantity of experience currently exists on CO_2 injection operations. Furthermore, several large-scale CO_2 geologic sequestration projects have been in operation for several years; these include the North Sea Sleipner project (injecting into a saline formation) (Gale and others, 2001) and the North American Weyburn project (sequestering CO_2 while performing enhanced oil recovery) (Whittaker, 2005; Brown and others, 2001). These projects have been closely monitored and studied, yielding much information to this emerging technology.

Additionally, the injection of anthropogenic CO_2 may be in conjunction with the production of methane from unmineable coal beds or oil and/or natural gas from active or depleted petroleum reservoirs. In both cases the produced fuels may defray some of the cost of CO_2 capture and injection. While these enhanced recovery options are considered to be near-term opportunities, due to potentially favorable economic conditions, the overall storage capacity in coal beds or oil-and-gas reservoirs is relatively small compared to the potential of deep saline formations.

POTENTIAL GEOLOGIC RESERVOIRS

The U.S. Department of Energy has identified several categories of geologic reservoirs for potential CO_2 sequestration (U.S. Department of Energy, 1999, 2004, 2005). Of these categories, four are considered important for the MRCSP region: (1) deep saline formations, (2) oil and gas fields, (3) unmineable coal beds and (4) organic-rich (carbonaceous) shales.

Deep Saline Formations

Saline formations are natural salt-water bearing intervals of porous and permeable rocks that occur beneath the level of potable groundwater. Currently, a number of the saline formations in the MRCSP region are used for waste-fluid disposal (especially in Indiana, Michigan, and Ohio); thus, a long history of technological and regulatory factors exist that could be applied to CO_2 injection/disposal. Saline formations are widespread, close to many large CO_2 sources, and are thought to have large pore volumes available for injection (Reichle and others 1999, U.S. DOE, 2004, 2005). In order to maintain the injected CO_2 in a supercritical phase (i.e. liquid) the geologic unit must be approximately 2,500-feet or greater in depth. Maintaining the CO_2 in a liquid phase is desirable because, as a liquid, it occupies less volume than when in the gaseous phase. One tonne of CO_2 at surface temperature and pressure (in gaseous phase) occupies approximately 18,000-cubic feet. The same amount of CO_2, when injected to approximately 2,600 feet in depth, will occupy only 50-cubic feet. Deep sequestration depths also help insure there is an adequate interval of rocks (confining layers) above the potential injection zones to act as a geologic seal. For the purposes of the MRCSP Phase I project, no consideration was given to the potential use of shallow saline formations for CO_2 sequestration.

In this type of reservoir, CO_2 is injected, under pressure, down a specially constructed well where it displaces (hydrodynamic trapping) and mixes (solubility trapping) with saline water and fills the pore spaces between the mineral grains of the rocks in the reservoir and is trapped within minerals (mineral trapping) in the rock matrix. Depth, permeability, injectivity, reservoir pressure, reservoir integrity, and water chemistry are some of the variables that control the sequestration potential in deep saline formations (Reichle and others, 1999; Bach and Adams, 2003). In addition to favorable properties of the injection zone in the reservoir, an overlying seal unit (confining layers) is necessary. The injected CO_2 has a lower specific gravity, and thus, is more buoyant than the natural formation fluids and will rise to the top of the porous zones. Hence, all cap-rock units must be relatively impermeable and sufficiently thick to arrest any appreciable vertical movement of the CO_2 within the sequestration interval, thereby trapping it in the deep subsurface. The MRCSP geologic team collected data and mapped several intervals that would act as satisfactory cap rock as part of the Phase I study.

Storage of CO_2 can be in either subsurface traps or in unconfined strata. In subsurface traps, the more buoyant CO_2 will occupy the highest portion of any structural (e.g. anticline) or stratigraphic (e.g. pinch-out) feature. This same mechanism of trapping is found in many of the natural gas and oil reservoirs (i.e., traps) that occur in the MRCSP study area. Within such traps, only the pore volume available in the rock and the size of the trap limits the volume of CO_2 that can be injected. In unconfined storage units, the CO_2 is injected in regional aquifers located in rocks without specific structural closures or stratigraphic traps. Once injected, the CO_2 will migrate to the highest portion of the saline formation where it accumulates against the cap rock, which prevents further vertical movement (Bentham and Kirby, 2005). At that point the injected CO_2 then will migrate laterally, following the normal hydrodynamic flow regime of the region (usually towards shallower areas). However, it must be emphasized that flow velocities in deep geologic systems occur at rates measured in feet per hundreds or thousands of years.

Commercial sequestration in saline formations has been successful in the Sleipner field of Norway, and the U.S. Department of Energy is involved in a small-scale demonstration project in the Frio Formation of Texas (Hovorka and others, 2001). Further testing and pilot studies will occur in the United States during Phase II of the Regional Carbon Sequestration Partnerships (U.S. DOE, 2004, 2005).

Oil and Gas Fields

Oil and gas fields represent known geologic traps (structural or stratigraphic) containing hydrocarbons within a confined reservoir with a known cap or seal. In depleted or abandoned petroleum fields, CO_2 would be injected into the reservoir to fill the pore volume left by the extraction of the oil or natural gas resource (Westrich and others, 2002). The injected CO_2 would be trapped by the natural limits of the reservoir (whether structural or stratigraphic) for secure storage. Volume, permeability, injectivity, pressure, reservoir integrity, water chemistry, the nature of the cap rock or reservoir seal, and the history of production are some of the variables that control the sequestration potential in depleted oil and gas fields (Reichle and others, 1999). This option may be attractive in many parts of the MRCSP region because vast areas of the region have a long history of oil and gas recovery (exploration for oil began in the 1800s). In addition, the MRCSP region includes four of the top seven, natural-gas storage states in the nation (Natural Gas Monthly, 2002). Such large volumes of gas storage capacity strongly suggest that CO_2 gas can be successfully managed in subsurface reservoirs within the region.

In active oil fields, it has been demonstrated that CO_2 can be used for enhanced oil recovery (EOR). In this process, some of the oil that remains in reservoirs after primary production is recovered by injecting CO_2 that either (1) repressurizes the reservoir and displaces and drives the remaining oil to a recovery well (immiscible flooding) or (2) directly mixes and chemically interacts with the remaining oil as it pushes it to the producing well (miscible flooding). Approximately 70 oil fields worldwide currently inject CO_2 for EOR (U.S. DOE, 2004) demonstrating the effectiveness of this value-added sequestration option. Moreover, enhanced oil recover, while sequestering CO_2, could provide an economic incentive to storage in several parts of the MRCSP region where CO_2 sources are near oil fields.

Unmineable Coal Beds

The MRCSP region includes the Appalachian basin, which contains the second- (West Virginia), third- (Kentucky), fourth- (Pennsylvania) and fourteenth- (Ohio) leading coal-producing states in the nation (EIA, 2005). Unmineable coal beds offer an alternative option for geologic sequestration in the region because, unlike the previously described reservoir types, CO_2 injected into a coal bed would not only occupy pore space, but would bond, or adsorb, onto the carbon in the coal itself. The adsorption ratio for CO_2 in coals is approximately twice that of methane; thus, in theory, the injected CO_2 would displace methane, allowing for the potential of enhanced gas recovery (Reznik and others, 1982; Gale and Freund, 2001; Schroeder and others, 2002). Because of the adsorption mechanism, concerns of miscibility that occur in oil and gas reservoirs are not an issue. Thus, the injection of CO_2 and resulting enhanced recovery of coalbed methane could occur at shallower depths than for depleted oil reservoirs. Hydrogeologic flow, water chemistry, coal thickness and quality, and subsurface temperature-pressure conditions are some of the variables that control the potential use of coal beds for CO_2 sequestration and enhanced coalbed-methane recovery (Pashin and others, 2003). Although there is currently only limited coalbed methane production in the MRCSP region, rising gas prices have led to growing interest in this energy resource in the last decade, and secondary recovery of methane may provide an economic incentive for sequestration of CO_2 from sources in the coal fields.

Carbonaceous Shales

The MRCSP region also contains widespread, thick deposits of carbonaceous shales. These shales are interesting in that they are often multifunctional—acting as seals for underlying reservoirs, as source rocks for oil and gas reservoirs, and as unconventional gas reservoirs themselves. Analogous to sequestration in coal beds, CO_2 injection into unconventional carbonaceous shale reservoirs could be used to enhance existing gas production. As an added bonus, it is believed the carbonaceous shales would adsorb the CO_2 into the shale matrix, permitting long-term CO_2-storage, even at relatively shallow depths (Nuttall and others, 2005a).

INTRODUCTION TO THE MRCSP REGION'S GEOGRAPHY AND GEOLOGY

GEOGRAPHY

The seven-state MRCSP partnership is an enormous and economically diverse area of the United States that excess of 255,000 square miles in size (>662,000 square kilometers). The area considered for geologic sequestration (excluding the upper peninsula of Michigan and the Illinois basin portion of Indiana and Kentucky) contains over 201,000 square miles (501,000 square kilometers). The diverse topography, hydrology, and bedrock geology of the region present a variety of geologic sequestration options. Additionally, numerous environmental considerations will be needed in different parts of the seven-state region. The MRSCP region encompasses three major physiographic regions: 1) Atlantic Plain, including the Continental Shelf and Coastal Plain (Maryland); 2) the Appalachian Highlands, including the Piedmont Province (Maryland), Blue Ridge Province (Maryland, West Virginia), Valley and Ridge Province (Maryland, Pennsylvania, West Virginia), and Appalachian Plateaus Province (Kentucky, Ohio, Pennsylvania, West Virginia); and the 3) Interior Plains, including the Interior Low Plateaus (Kentucky, Ohio) and Central Lowland (Indiana, Michigan, Ohio) (Figure 2).

Bedrock is at or near the surface in much of the Appalachian Highlands and is covered by Quaternary-age sediments in the Atlantic Plain and in parts of the Interior Plains north of the Ohio River. Variable surface topography, climate, and sediment and bedrock types covering the area result in varied land uses, surface water, and ground water conditions across the seven states.

GENERAL GEOLOGY, MAJOR STRUCTURAL FEATURES AND TARGET AREAS

Because the four reservoir classes being considered under this task all occur in sedimentary rocks, only those areas within the seven states with thickness of sedimentary rocks considered adequate for CO_2 sequestration were evaluated for their geologic sequestration potential. This differs from the terrestrial sequestration portion of the MRCSP project, which examined the entire land-surface area of the seven-state region. Also, although sedimentary rocks of appropriate thickness occur in a large part of the MRCSP region, the types and depths of potential CO_2 reservoir strata vary. Figure 3 is a generalized map of the geologic units at or near the surface that also shows the major geologic structures of the region. Figure 4 is a cross section across the map illustrating the sedimentary rocks thicken into geologic basins and thin above structural arches.

Much of the Appalachian highlands, from the Piedmont on the east to the Allegheny front on the west, were not included in this investigation because they are dominated by folded and faulted metamorphic and igneous rocks. Additionally, it was not possible, within the scale of this project, to map most of the local sedimentary deposits within this folded section of the Appalachian Mountains because of a lack of data on the depth and thickness of individual units. Likewise, the Upper Peninsula of Michigan was not included in the geologic assessment of CO_2 sequestration potential because it consists mostly of metamorphic and igneous rocks. Although a small area of sedimentary rocks, considered to be a part of the Michigan basin, does exist in the Upper Peninsula, these rocks do not obtain depths great enough for consideration as a geologic sequestration target and were not included in this study.

The eastern limit of MRCSP geologic investigations is the Maryland shoreline. Although many offshore sedimentary rocks may have a potential for sequestration, they were not investigated in this project. The western boundary for geologic mapping within the MRCSP region is a multi-county boundary that represents the ap-

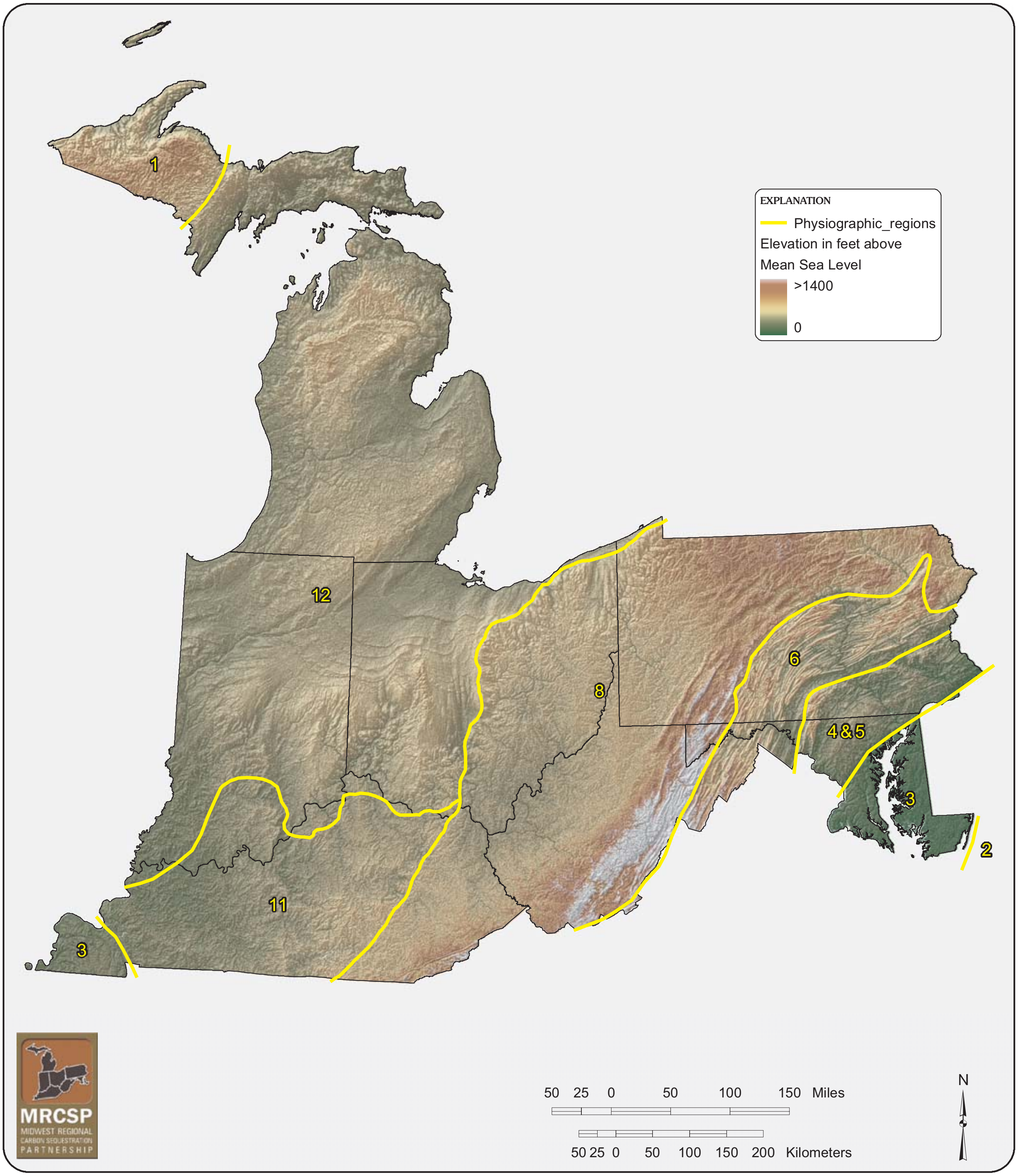

Figure 2.—Shaded topographic relief map of the MRCSP study area showing the boundaries of the general physiographic provinces. 1 = Superior Upland; 12 = Central Lowland; 3 = Coastal Plain; 11 = Interior Low Plateaus; 8 = Appalachian Plateaus; 6 = Valley and Ridge; 4 & 5 = Piedmont and Blue Ridge; 2 = Continental Shelf. Physiographic regions from Barton and others (2003); topographic data from NASA (2002).

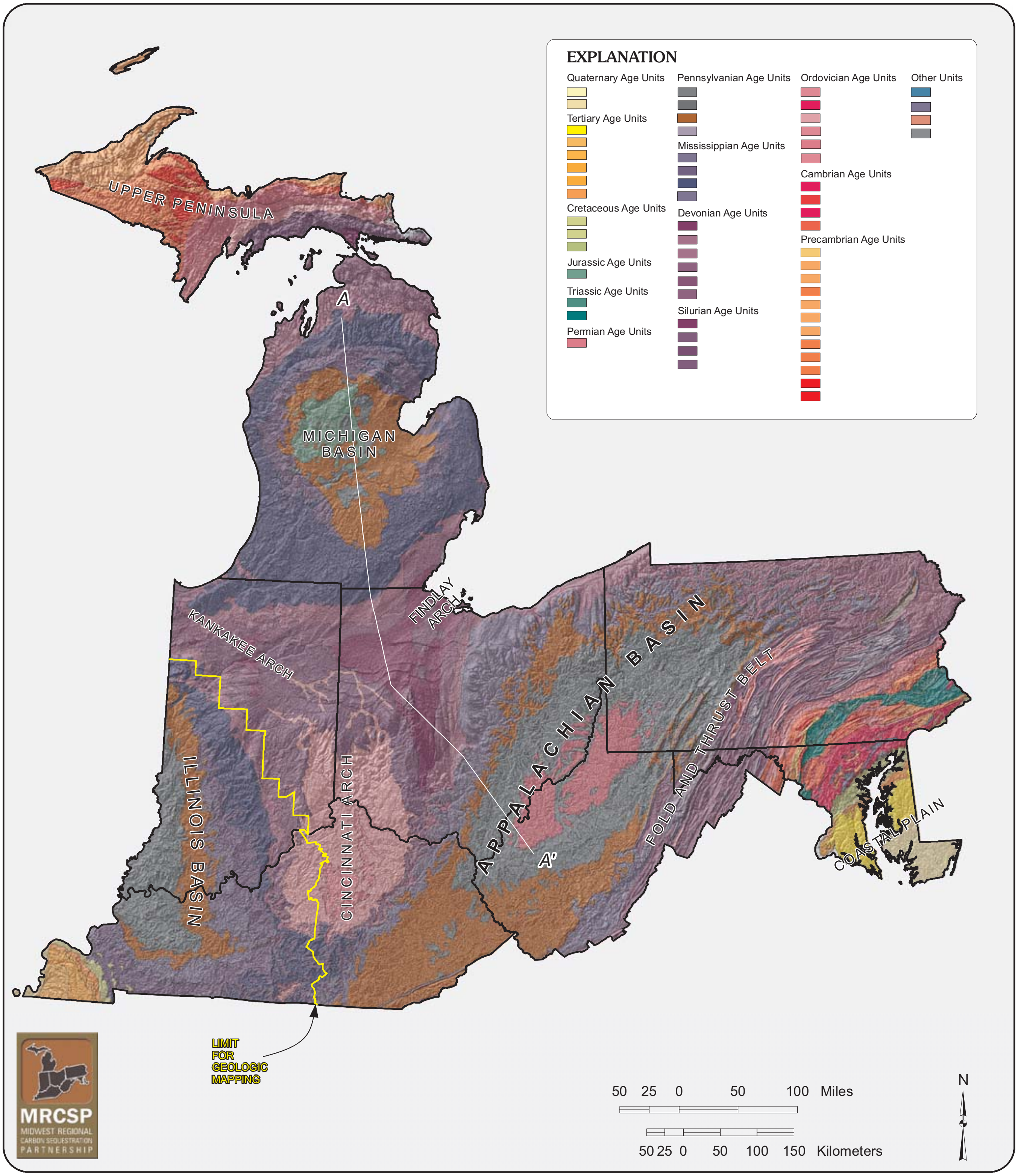

Figure 3.—Shaded topographic-relief map showing generalized bedrock-geology units (by system) found at or near the surface and bedrock contacts. Major geologic features (folds, arches and basins) of the MRCSP study area are also labeled (from Schruben and others, 1997). A-A' line is location of cross section shown in Figure 4.

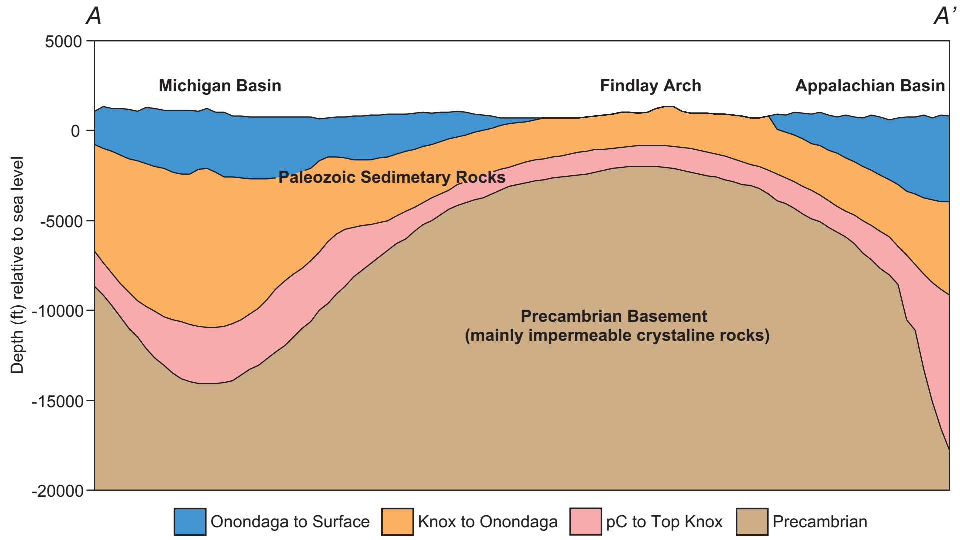

Figure 4.—Generalized cross section across the Michigan and Appalachian basins. Profile line is shown on Figure 3. Elevations for geologic layers in this cross section obtained from maps produced for this report.

proximate boundary between the Kankakee arch and Illinois basin in Indiana and the western flank of the Cincinnati arch in Kentucky (Figure 3). The Illinois basin, the focus of another DOE-Carbon Sequestration Partnership, was not included in this MRCSP study.

Michigan Basin

The Michigan basin is a nearly circular cratonic basin, occurring mostly within the state of Michigan, but locally extending into northern Indiana and northwestern Ohio. The basin is bordered on the north and east by the Canadian shield, on the west by the Wisconsin highland, on the southeast by the Findlay arch, and on the southwest by the Kankakee arch (Figure 3). Interestingly, the basin is situated above a gravity high, a feature that may represent complex basement faulting or a failed rift zone at depth (Hinze and others, 1975). At the center of the Michigan basin, Precambrian basement rocks are overlain by nearly 16,000 feet of sedimentary strata that was deposited from Cambrian through Carboniferous time (Figure 5). Although there have been slight shifts in the depositional center of the basin with time, the basin has remained essentially circular throughout most of the Paleozoic.

Appalachian Basin

The northern Appalachian basin is an elongate, asymmetric foreland basin with a preserved northeast-southwest trending central axis that extends through Pennsylvania, western Maryland, and West Virginia (Figure 3). The eastern margin of the basin is concealed beneath thrust sheets in the Blue Ridge Province of the Appalachian Mountains. The western margin of the basin occurs in east-central Kentucky and central Ohio. The Cincinnati and Findlay arches separate the Appalachian basin from the Illinois and Michigan basins, respectively (Figure 3).

The Appalachian basin initially developed during the Cambrian Period and above the Rome trough, a basement aulocogen formed during Iapetan rifting (McGuire and Howell, 1963; Ammerman and Keller, 1979; Shumaker, 1996). The Rome trough extends eastward from Kentucky into West Virginia, thence northeastward, possibly continuing beneath Ordovician and younger-age sediments of the northern Appalachian basin. Following Iapetan rifting, the basin was enlarged by periodically reactivation of geologic structures that developed in response to collisional tectonics along the eastern margin of North America during the Taconic (Upper Ordovician), Acadian (Middle to Upper Devonian), and Alleghany (Upper Carboniferous) orogenies of the Paleozoic Era (Tankard, 1986; Quinlan and Beaumont, 1984; Thomas, 1995; Shumaker, 1996).

The Precambrian basement is overlain by more than 45,000 feet of sedimentary rocks in the central Pennsylvania portion of the northern part of the basin. Sedimentary rocks in the Appalachian basin range Neoproterzoic to Carboniferous-Permian in age.

Structural Arches

Although the thickest sedimentary cover (and therefore greatest potential for sequestration) are in the basins, portions of several of the broad, structural arches in the MRCSP region also have potential for sequestration of CO_2. The Findlay arch may have started as a positive feature in the late Ordovician during the last phases of the Taconic orogeny (Wickstrom and others, 1992). In northwestern Ohio, the arch forms a broad, shallow platform where there has been significant oil and gas production from the Ordovician Trenton Limestone.

The Kankakee arch, a post early Ordovician feature, separates the Michigan basin from the Illinois basin in northern Indiana. The Indiana-Ohio platform is a broad relatively flat-lying area formed where the Kankakee and Cincinnati arches merge. Several waste-fluid disposal wells have been drilled to the Mount Simon Sandstone (a deep saline formation) along this trend in northeastern Indiana. The Cincinnati arch is a late Ordovician positive feature that separates the Illinois from the Appalachian basins in Kentucky, Indiana and Ohio. The western boundary of the MRCSP region, in Kentucky and Indiana, represents the approximate boundary between the Cincinnati arch and Illinois basin. Unlike the previously discussed arches, where Precambrian igneous and metamorphic rocks close to the surface, the Cincinnati arch is underlain by the East Continent rift basin, an elongate north-south trending basin filled with a thick sequence of Proterozoic arenaceous rock (Shrake and others, 1991; Drahovzal and others, 1992).

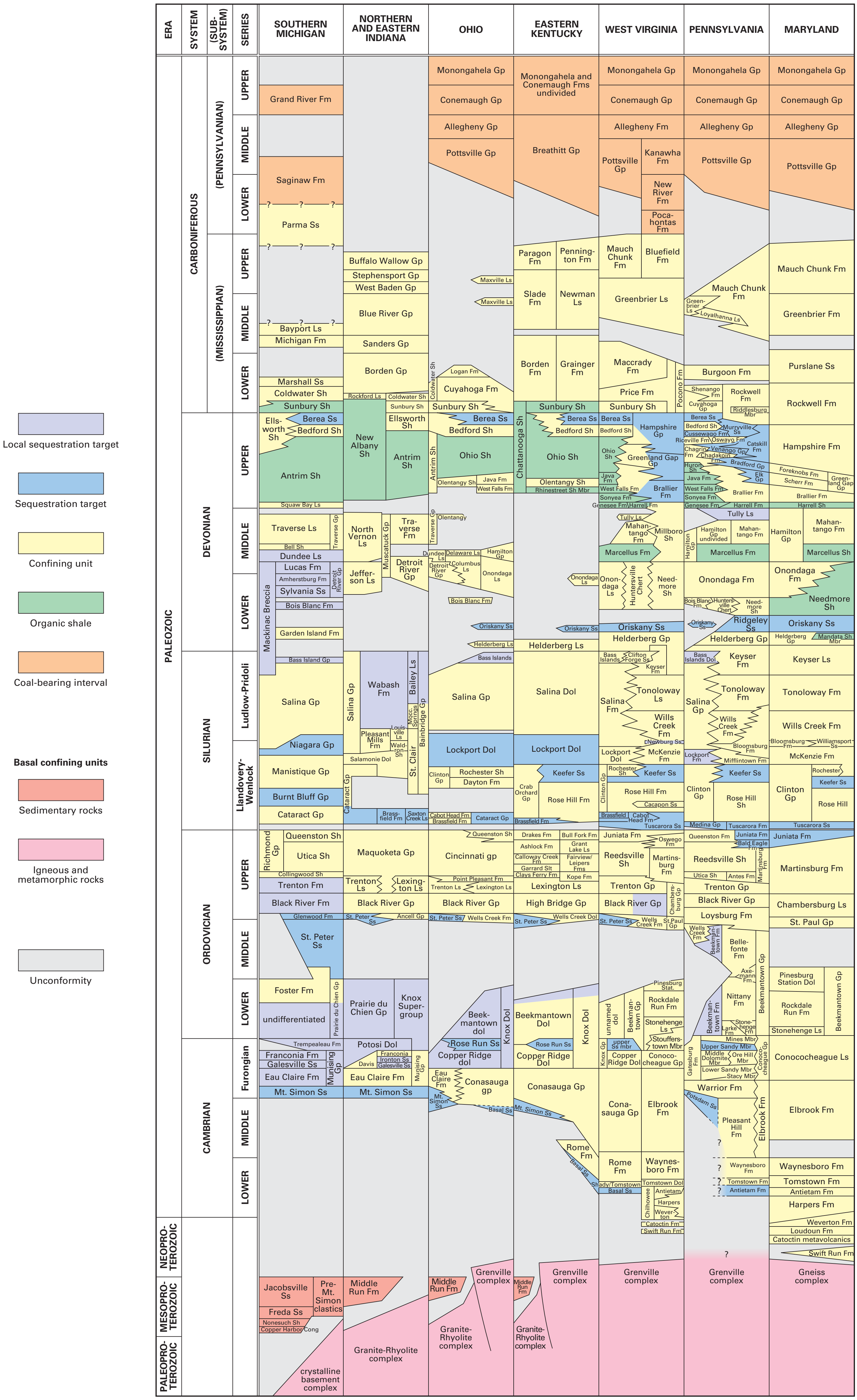

Figure 5.—Stratigraphic correlation and CO_2 sequestration characterization chart of geologic units in the MRCSP region.

GEOLOGIC UNCERTAINTIES

Our knowledge about the sequestration potential in deep geologic units is limited by the availability of data on the various subsurface attributes of the region. For example, in making broad regional assessments, such as this Phase I task, our assessment is constrained, and thus limited, by the availability of oil-and-gas-well data, accessibility to seismic data, and our previous experience and working knowledge in and of the region.

In general, the amount of data available for mapping and analysis of any particular unit is directly proportional to its depth below the surface. Thus, the deeper the unit, the less certain is our understanding of the various parameters related to, and needed for, assessing geologic CO_2 sequestration targets in the subsurface of the MRCSP region. Unfortunately, since our primary data set is based mainly on oil and gas wells, the control points used to map the various units discussed herein is limited by where and how deep companies in this industry drill. The deeper the well, the more costly it is to drill; hence, overall, there are fewer deep wells. This is especially true once the well depth exceeds about 6,000 to 7,000 feet. Consequently, our knowledge on the deepest portions of the region is limited—to date, no wells are known to have been drilled to the deepest extreme of the Appalachian basin, a depth thought to exceed 45,000 feet. These depths are not practical, in any event, for current sequestration consideration.

Another deep feature of the region that may represent a significant potential sequestration target is the region containing the Rome trough, a inadequately known structural feature in the subsurface of the Appalachian basin (Figure 6). The Rome trough is a large, deep feature that occurs in Kentucky, West Virginia, and Pennsylvania and is approximately parallel to the Ohio River (it is thought the current location of sections of the Ohio River are controlled by structural irregularities related to this feature). Seismic data and a limited number of deep wells drilled in this area indicate the Lower Paleozoic geologic section rapidly expands within this feature. For example, it is known that several thousand feet of sedimentary rock occur in the Rome trough proper, that are not known to exist outside the boundaries of the feature. These same data indicate sandstones, some of which may have good storage reservoir potential, occupy many portions of this expanded section. However, what is not known is how extensive these potential reservoirs are. Nonetheless, some of these potential sandstone sequestration targets are within the economic limit of feasibility making them a possible target for consideration as a large injection target (perhaps in the 9,000 to 12,000-foot range).

It is beyond the scope or economic abilities of this project to test these deep regions. However, their presences should be mentioned because, should the Rome trough contains the sandstone intervals that some believe to be there, this deep feature could easily double the sequestration potential within the MRCSP region.

STRATIGRAPHIC CORRELATION

Assessing the regional potential for CO_2 sequestration requires an understanding of the many stratigraphic units (groups and formations) in the MRCSP region and their geologic and stratigraphic relationships between various areas of the partnership (Figure 5). Therefore, a regional correlation chart was one of the first, and most significant, undertakings accomplished by the geologic team.

Each state has, over the past 150 years or so, developed its own stratigraphic nomenclature in order to explain the geologic history and stratigraphic succession of rocks within each state—some of these terms are unique to rocks that occur only in the subsurface. The changing geologic character of many of these rock units, or at least their position within a geologic basin, has created some differences in the nomenclatures used in each state (see Figure 5). Other variations between states are related to different methods used for establishing the placement of unit boundaries or how a unit is classified (ranked, i.e., group, formation, member) within a specific rock interval or in a different area of the region. Prior to the development of this correlation chart, no detailed chart showing the correlations between the individual MRCSP states existed. We continue to refine this chart as work progresses. More detailed correlation charts, where needed, are presented in the discussion of the individual units/intervals in Appendix A.

SELECTION OF MAPPED UNITS AND LIMITATIONS

Using the regional correlation chart and our knowledge of these units as a basis, an initial list of potential CO_2 sequestration reservoirs and seal (cap rock) intervals was chosen for further consideration. Known stratigraphic intervals of saline formations, petroleum-producing units, gas-generating (source rock) carbonaceous shales, and coal-bearing units were identified in each state. Many of these intervals can be readily correlated between states or basins; however, others are restricted to a single basin or regions with a basin, and determining their relationship to other more established units is problematic.

Phase I of all DOE regional partnership projects called for a regional assessment of the CO_2 sequestration potential in each partnership area within a defined time frame. To expedite our evaluations, a list was developed that consists of wide-ranging stratigraphic intervals (often composed of multiple groups and formations) and was the basis for an initial assessment of potential reservoirs and cap rock units that could be regionally mapped using existing data sources. Maryland and Michigan were later added to the partnership and the process and list had to be repeated and slightly modified. Where possible, we adapted previously chosen mapping units to for use within the new states. However, the addition of the coastal plain and inclusion of the entire Michigan basin required adding additional units to the selection list.

After the list of geologic intervals and/or individual units to be mapped was finalized and a database schema devised, individual states of the team started collecting the data available to them. This included, amoung other things, oil-and-gas-well data files (both electronic and paper), previously completed geologic mapping databases, published and unpublished studies within individual states, and miscellaneous data (i.e., core and sample records, geochemical analyses, miscellaneous geologic data files). As time permitted and as data sources were discovered, some individual units were added to the mapping list—an example of this addition is the inclusion of the Niagaran reefs and Sylvania Sandstone. Table 1 is a final list of all mapped units in the MRCSP project.

Nine potential reservoir horizons and five potential cap-rock intervals (including organic shales that can also be considered potential reservoirs) were chosen for regional mapping and further analyses after our initial screening. Our selection of which reservoir and seal intervals to map is by no means all-inclusive for the region. On the contrary, throughout our Phase I analysis, several other prospective reservoirs were noted. Additionally, the selected intervals do not necessarily represent laterally continuous zones of homogenous reservoirs or seals. Many assumptions are necessary when mapping at such a regional scale. Considering the magnitude of this project, the calculated volumes of potential CO_2 that can sequestered may vary

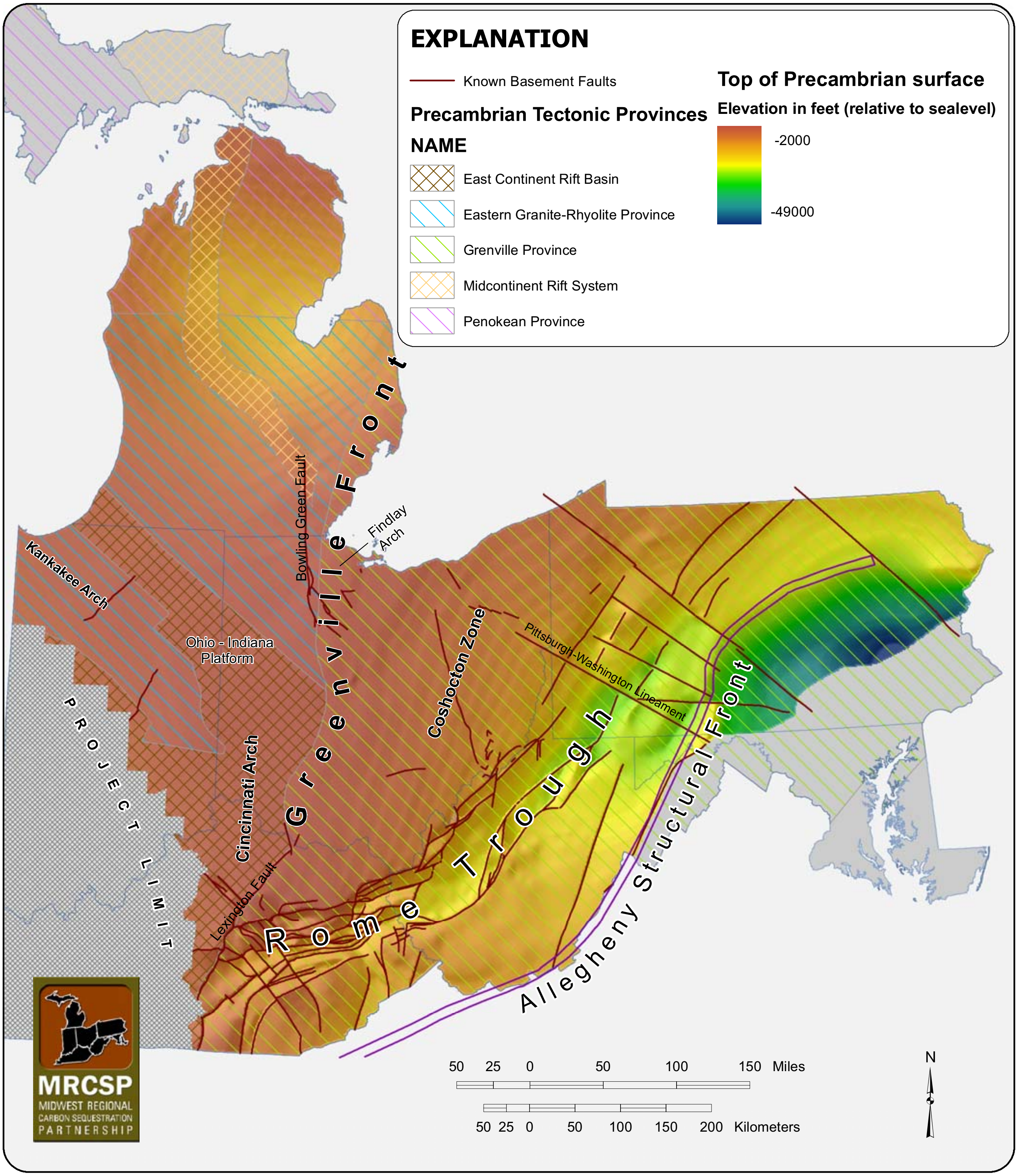

Figure 6.—Map of major basement faults (known), Precambrian tectonic provinces, elevation on top of the Precambrian unconformity, and other structural features of the MRCSP features.

Table 1.—Summary of geologic layers mapped and map type, responsible state for each layer, interpolation methods and software used to create the maps

Geologic Layer(s) Mapped	*Type of Map(s)*	*State Responsible*	*Methodology*	*Software*
Precambrian Structure	Structure	Ohio	Kriging with extensive hand interpolation	ArcGIS
Cambrian basal sandstones	Structure & thickness	Ohio	Kriging, hand interpolation in Ky	Geostatistical Analyst (ArcGIS)
Top of basal sands to Copper Ridge interval	Structure & thickness	Indiana	Local polynomial interpolation	Geostatistical Analyst (ArcGIS)
Rose Run Sandstone	Structure & thickness	Ohio	Kriging, with extensive hand interpolation in Ky and Pa portions	Geostatistical Analyst (ArcGIS)
Knox to Lower Silurian interval	Structure (2) & thickness	Ohio	Kriging	Geostatistical Analyst (ArcGIS)
St. Peter Sandstone	Structure & thickness	Indiana	Local polynomial interpolation	Geostatistical Analyst (ArcGIS)
Medina Sandstone	Structure & thickness	Pennsylvania	Proprietary method, "Highly Connected Features" setting in "Create Contour Grid" procedure, and manual editing	Petra (geoPLUS, 2005)
Lockport to Onondaga interval	Structure & thickness	Indiana	Local polynomial interpolation	Geostatisical Analyst (ArcGIS)
Niagaran Reefs	Structure	Michigan	Kriging	Surfer
Oriskany Sandstone	Structure & thickness	Pennsylvania	Proprietary method, "Highly Connected Features" setting in "Create Contour Grid" procedure, and manual editing	Petra
Sylvania Sandstone	Structure & thickness	Michigan	Kriging	Surfer
Needmore Shale	Structure & thickness	Maryland	Kriging	Geostatistical Analyst
Devonian Shales	Structure & thickness	Kentucky	Kriging	Geostatistical Analyst
Appalachian Basin coal thickness	Aggregate thickness	Ohio/ Kentucky	Kriging and hand editing	Geostatistical Analyst
Saginaw Coal	Structure & thickness	Michigan	Kriging	Surfer
Waste Gate	Structure & thickness	Maryland	Kriging	Geostatistical Analyst

depending on the detail, and scale, of an individual analysis. Rather, this Phase I analysis delineates stratigraphic intervals that have the potential to be used as reservoirs and seals for CO_2 sequestration across the region and provides a basis for approximating the carbon storage potential of the region in much the same way as the availability of future energy resources are assessed throughout the world. Over time, with the application of new technology and a refinement of those that now exist, coupled with an increase in available data, the reserve/sequestration potential numbers will inevitably change for many years to come following an area's initial assessment.

CHALLENGES AND OPPORTUNITIES

This project was the first time Michigan, Ohio, Indiana, Kentucky, Pennsylvania, West Virginia, and Maryland have worked collectively on a project. In itself, this represents a significant milestone for each state that will have many benefits in future years. Most previous regional geologic consortia focused on research topics within an individual basin. However, the MRCSP project is the first consortium in this section of the U.S. to embark upon mapping multiple geologic units across multiple basins. Such an approach allowed the various geologists from the multiple states a unique opportunity to map and analyze many regionally complex geologic intervals, all the while maintaining a common goal of developing an understanding of the total geologic system across multiple geologic provinces (a challenge most geologists relish, yet rarely have!).

Compiling data into a usable format from a seven-member state working group proved challenging because each state (and members within states) collects and stores data differently. Much of the data used for mapping deeper, subsurface-geology units came from oil and gas wells; hence, the variability in data from state to state reflects differences in regulatory requirements as enacted in each state. The age of the available records also varied across the region. Drilling began in some MRCSP member states over 150 years ago, yet others, like Michigan, did not experience petroleum production until 1925 (1951 in Maryland). Records are missing or inadequate on some older wells mostly because there were no regulations in place or agencies charged with gathering these data at these early dates. Thus, inconsistencies in the types and amounts of data varied from state to state. The form of the data was another challenge. All member states are in the process of converting their paper records to digital format—some just beginning, others are nearing completion.

Consequently, some states were able to compile basic mapping data quickly, which allowed them extra time to researching additional data types and sources. Others had to spend much of the project gathering basic data from paper records and entering it into a computer compatible format.

One of the benefits of this project was that conducting a regional compilation allowed for the sharing and mapping of data seamlessly across political boundaries. An added benefit was this process permitted, perhaps a first for the region, the analyses of trends (many being previously undetected) that occur through areas of variable data for the benefit of the entire region. These results will be critical for future carbon management in the region and will also be useful to a wide range of nonsequestration applications.

The thickness and depth of nine potential sequestration target units and five cap-rock intervals were mapped by the MRCSP working group. In total, the MRCSP geologic assessment resulted in 30 original depth and thickness maps, nine regional thematic maps, and 14 derivative capacity maps in a state-of-the-art GIS database. Moreover, the regional digital oil-and-gas-fields map and database was a very significant accomplishment for the seven state region. It is the first compilation at this scale in the region and represents the first digital compilation of petroleum fields data for Maryland, Michigan, Pennsylvania, and West Virginia. The completion of this basic field-level data, along with the detailed field polygons, within this regional GIS compilation will prove very useful not only for CO_2 sequestration research and planning, but also to the oil and gas industry, academia, and others in the public and private sectors.

This project represents the first time these geologic units or intervals have been mapped across this entire region. Also a first for this project was the collection of the geothermal gradient and salinity information in a centralized digital database. A number of the maps produced represent the first time any type of map for that specific interval have been constructed—such as the basal Cambrian sands. Although several of the member states were part of MIDCARB (DOE's initial CO_2 sequestration partnership), the MRCSP project represents the first time that the geologic CO_2 sequestration potential has been evaluated for Maryland, Michigan, Pennsylvania, and West Virginia. The cooperation of the member organizations in this geologic investigation provides an excellent opportunity for understanding and implementing future carbon management options based on the best-available geologic knowledge of the region.

GEOLOGIC MAPPING PROCEDURES, DATA SOURCES AND METHODOLOGY

The central products of the MRCSP Phase I geologic tasks were a series of regional-scale, digital spatial models and maps, with the overall goal to create a GIS to support regional planning for carbon sequestration. The GIS provides spatial data that can be used to evaluate the potential for geologic sequestration of CO_2 at any particular site within the MRCSP study area by digitally analyzing which underlying geologic units might be suitable for further analyses as a CO_2 reservoir and/or seal, their depths and overall thickness, and to provide an estimate of sequestration capacities. Selected sites that appear suitable must still be subjected to further, more detailed studies and site-specific testing and analyses. Digital maps were compiled for the depth and thickness of target and confining geologic layers, the extent of major oil and gas fields, the locations of industrial injection wells, as well as for other geochemical and petrophysical data needed to calculate CO_2 sequestration capacity.

Most of the mapping effort focused on generating structure and isopach maps for nine regional geologic sequestration targets and five confining layers. The mapping also represents one of the first attempts to create regional-scale geologic maps using quantitative methods with rigorous error assessments. Geologic structure and isopach maps were created by interpolating formation tops from oil-and-gas-well records that were compiled by the individual partnership states. The MRCSP geologic database contains a total of 85,650 individual wells (Figure 7) and approximately 162,000 formation tops. Control points (wells) available for mapping individual layers ranged from less than 500 points for very deep layers (Lower Cambrian rocks), to in excess of 23,000 points for shallower layers such as the Lockport-Onondaga interval. Point data were converted to isoline maps using a couple of different, commercially-available software packages that utilize a range of interpolation methods/algorithms. Unfortunately, these computer interpolations occasionally resulted in the generation of surface trends that contradicted known geologic surfaces. In these cases, isolines were manually edited. Grids (rasters) were created for every layer to facilitate spatial analyses, modeling, and cartographic display. The accuracy of the maps was evaluated rigorously. Root Mean Square Errors (RMSE) ranged from 20 to 500 feet for the structure grids and from 20 to 600 feet for isopach grids. Such error ranges reinforce the previous statements that the maps of this project are of sufficient quality for regional planning, but cannot be used in place of detailed site studies.

METHODOLOGY FOR STRUCTURE AND ISOPACH MAPPING

Maps in this project were created to identify major regional sequestration targets and confining layers. Our definition of mapping units reflects these goals rather than traditional stratigraphic-use customs. Hence, in many cases the mapped layers do not follow formal lithologic units or sequence-stratigraphy definitions as currently used by many workers. For some map layers, several lithologic units that are considered diachronous were merged together. For example, the Cambrian basal sandstones layer includes the Mt. Simon Sandstone, the basal sandstones of the Rome Trough, the Potsdam Sandstone, and unnamed sandstones of the Conasauga Group (Figure 8). These units range from the Furongian (Upper) to the Lower Cambrian in their occurrence, yet have little genetic relationship to one another. However, the grouping of these units together is useful in and of itself since all sandstones directly overlying the Precambrian unconformity can now be found on one map, thus reducing the complexity of using multiple maps for a like stratigraphic unit.

The mapping workflow for this project included six steps: (1) data gathering, (2) data filtering to remove erroneous wells, (3) interpolation and contouring of gridded data, (4) manual editing of digital contour maps, (5) peer review and adjustments, and (6) creation of grids from final contour maps. The various MRCSP geologic teams divided the mapping responsibilities amongst themselves based on individual areas of expertise. Each organization was responsible for the aforementioned steps 1 thru 5 for each selected interval and each team was allowed the freedom to use the mapping software of their choosing. After review, the final contour map files were sent to the Ohio Division of Geological Survey, where final gridding was applied for use in the CO_2 capacity calculations.

Original Data

The primary dataset consisted of well data provided by each

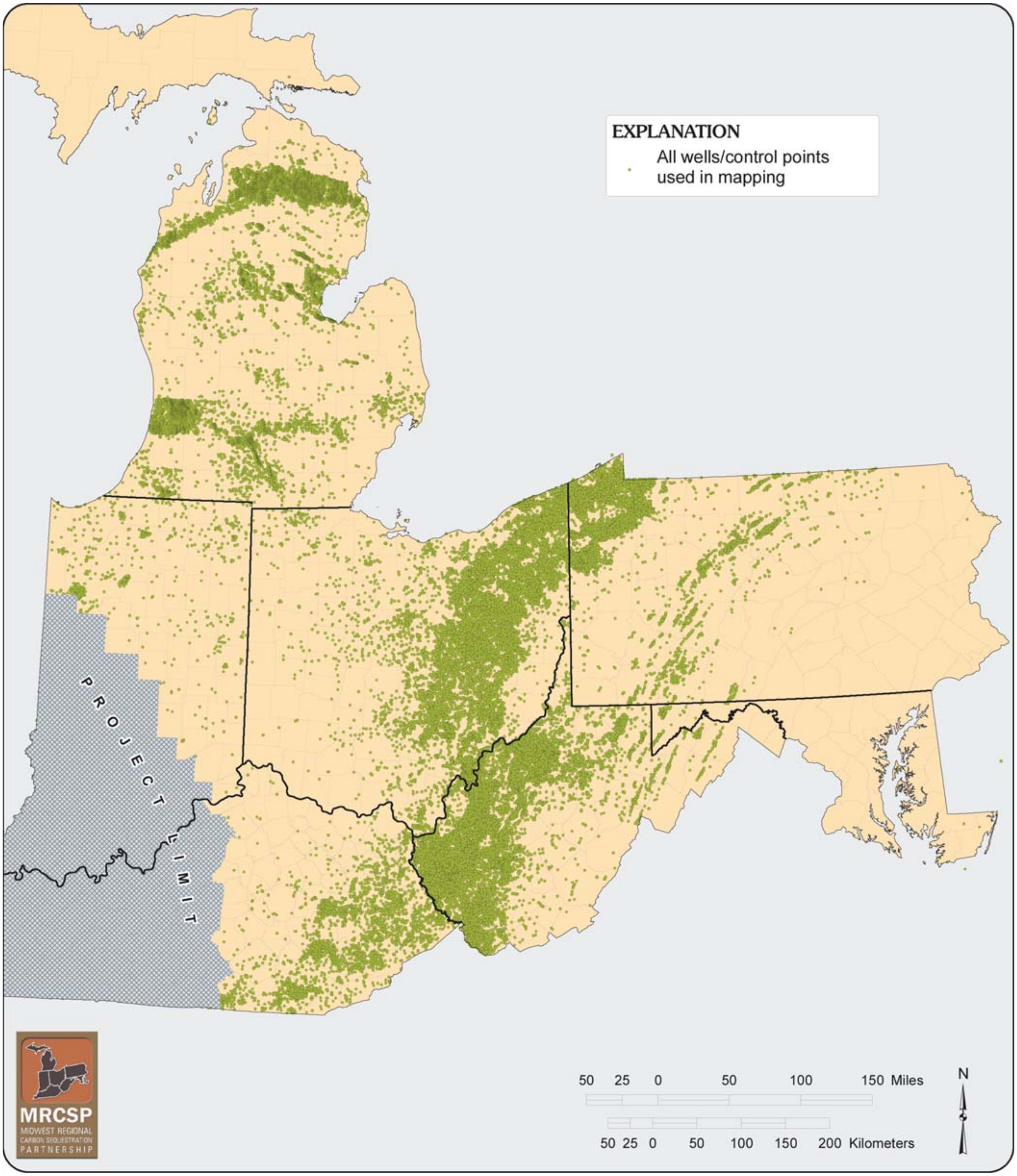

Figure 7.—Map showing the distribution of all wells (85,650 unique wells) used to make the geologic structure and isopach maps in the MRCSP phase I study area.

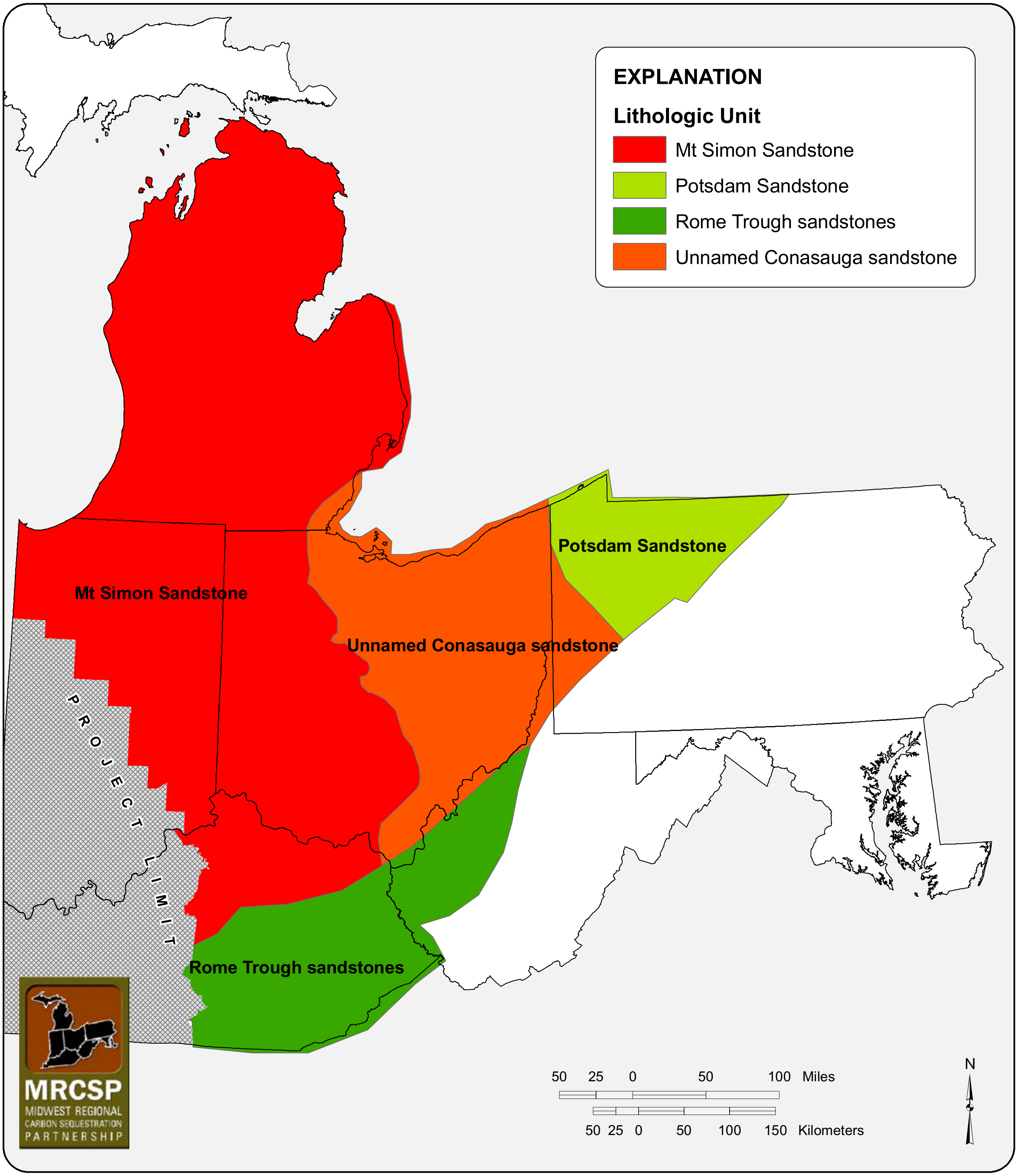

Figure 8.—Map showing the rock units that comprise the Cambrian basal sandstones and their distribution in the MRCSP region.

MRCSP member state. The bulk of the data originated from oil-and-gas-well completion records. Also, each organization supplemented the datasets, when possible, with data created from previous work containing detailed geophysical-log-based interpretations. The resultant data files for this project used, for each structure map creation, the geographic position of the well, its elevation, and the depth of the top of each mapped interval. Due to the range of data sources, the quality of depth data varied across the region. For example, some formation tops were determined by experienced drillers, others or by industry or government geologists, while others had an unknown origin. Because of this, filtering procedures were needed to remove errors and irregularities from the dataset.

Data filtering was accomplished by a variety of methods. For example, for layers created by the Ohio Division of Geological Survey (see Table 1), a geostatistical approach was adopted using Geostastistical Analyst (ArcGIS). A preliminary variogram was modeled and an initial surface created. Cross validation was conducted and points with residuals, two standard deviations or more from the mean residual value, were flagged as potential outliers. Then, flagged points were inspected; those deemed valid, yet flagged because of the influence of bad neighboring points were left in the system; erroneous data were removed. The data sets were also corrected by searching for output that did not conform to projected geologic trends across a region. If the error could not be resolved using just the data and map, geophysical-log based cross sections were constructed to reconcile the areas of conflict. The filtering and inspection process was repeated until all erroneous wells were removed or resolved. The accuracy of the resultant interpolated surfaces is directly proportional to the amount and distribution of well control use to construct any particular map surface.

As briefly mentioned above, the amount of data available for mapping and analysis of any particular unit is directly proportional to depth below the surface. Thus, the amount of data available the units varied with depth. Layers in the Devonian and Silurian can have over 10,000 control points (for example, the Onondaga, Figure 9). The amount of control drops precipitously as the depth to the formations increases. For the deepest target layer, the Cambrian basal sandstones, there were only 510 wells deep enough to be used as control points (Figure 10). The amount and distribution of well control has a marked effect on the accuracy of the resultant interpolated surfaces (Table 2).

Other datasets were also used to supplement the point data and to improve the geologic quality of the maps. In Kentucky, hand-drawn structure contour and isopach maps were provided for units below the Knox unconformity. This was mainly because of the complex normal faulting (Figure 11) associated with the Rome trough (Gao and others, 2000) and the limitations of computer mapping software used to portray these areas in a geologically acceptable manner. In addition, geologic maps from the literature were digitized and used to constrain interpretations in data-poor portions of the study area (Figure 12 illustrates one example).

Interpolation Methods

Computer-based and manual interpolation methods were needed to convert the point data into isoline maps and grids. Each state chose an interpolation algorithm that gave the best representation of the geologic layer to be mapped and fit within the individual software capabilities of each state mapping team (Table 1). For all methods, the end result was a set of digital isolines that required considerable manual editing in GIS software to remove edge effects, to repair errors caused by data scarcity, and to rectify match-up errors with pre-existing digital surface and near-surface geologic maps of specific mapped intervals.

Manual Isoline Editing

Considerable manual manipulation of contour lines was needed to create geologic maps that conformed to both the data and geologic knowledge. Line editing was generally accomplished digitally using ArcEdit (a module of ArcGIS). The bulk of the editing was done to fill in data gaps and to rectify contour line variations as the lines approached crop lines of those units eroded by surface processes (Figure 12). More extensive editing and interpretations were conducted in the faulted areas of Kentucky, especially on the deeper units (Precambrian thru Rose Run). This mapping, to account for the structurally complex Rome trough (Figure 6) followed a separate procedure. Initial isolines were created using Inverse Distance Weighting in Spatial Analyst (ArcGIS). Next, the contour lines were manually adjusted to account for known offsets along the faults. These lines were blended and joined to contours from the rest of the study area. Final contour intervals were based mainly on cartographic and ArcIMS display considerations rather than on data accuracy.

Geologic Map Review

Each map was subjected to peer review by various members of the geologic team. Maps were made available digitally for all members to review through a web-based comment system. In addition, two group meetings were held to review large format prints of each of the maps and to also evaluate each map for geologic correctness and cartographic quality; noted corrections were applied as needed.

Gridding Method

A consistent method of converting both computer-generated and hand-edited contour lines back into a grid format is essential for sequestration capacity modeling, GIS analysis, and cartography. Capacity calculations and many analyses within the GIS environment must have the data in grid format, and in some cases, use grid-to-grid operations. Gridding algorithms for this project must be able to handle both unfaulted and faulted regions. Two methods were compared as part of this project. Contours were converted to a TIN, which, in turn, was converted to a grid using 3-D Analyst (ESRI, 2005). In the TIN model, contours were modeled as mass points and faults as hard break-lines. Contours were also converted to grids using a software package named ANUDEM (version 5.1; Hutchinson and Gallant, 2000), which combines localized splining with an ability to introduce vertical discontinuities (cliffs) into the final grids. Hence, ANUDEM can be used for geological modeling where faulting can be assumed to be vertical. A comparative study (Venteris and others, 2005) found that the ANUDEM-based method was superior to the TIN-conversion method, as long as high grid-resolutions (<15,000 feet grid squares) were used. The study also found that the optimal grid resolution for these data sets was best between 2,000 and 10,000 feet. Based on these results, a grid cell resolution of 5,000 feet was adopted for all the layers in this study, which also provided a consistent grid size for grid-to-grid operations.

Map Accuracy

The uncertainties in the structure and isopach maps were calcu-

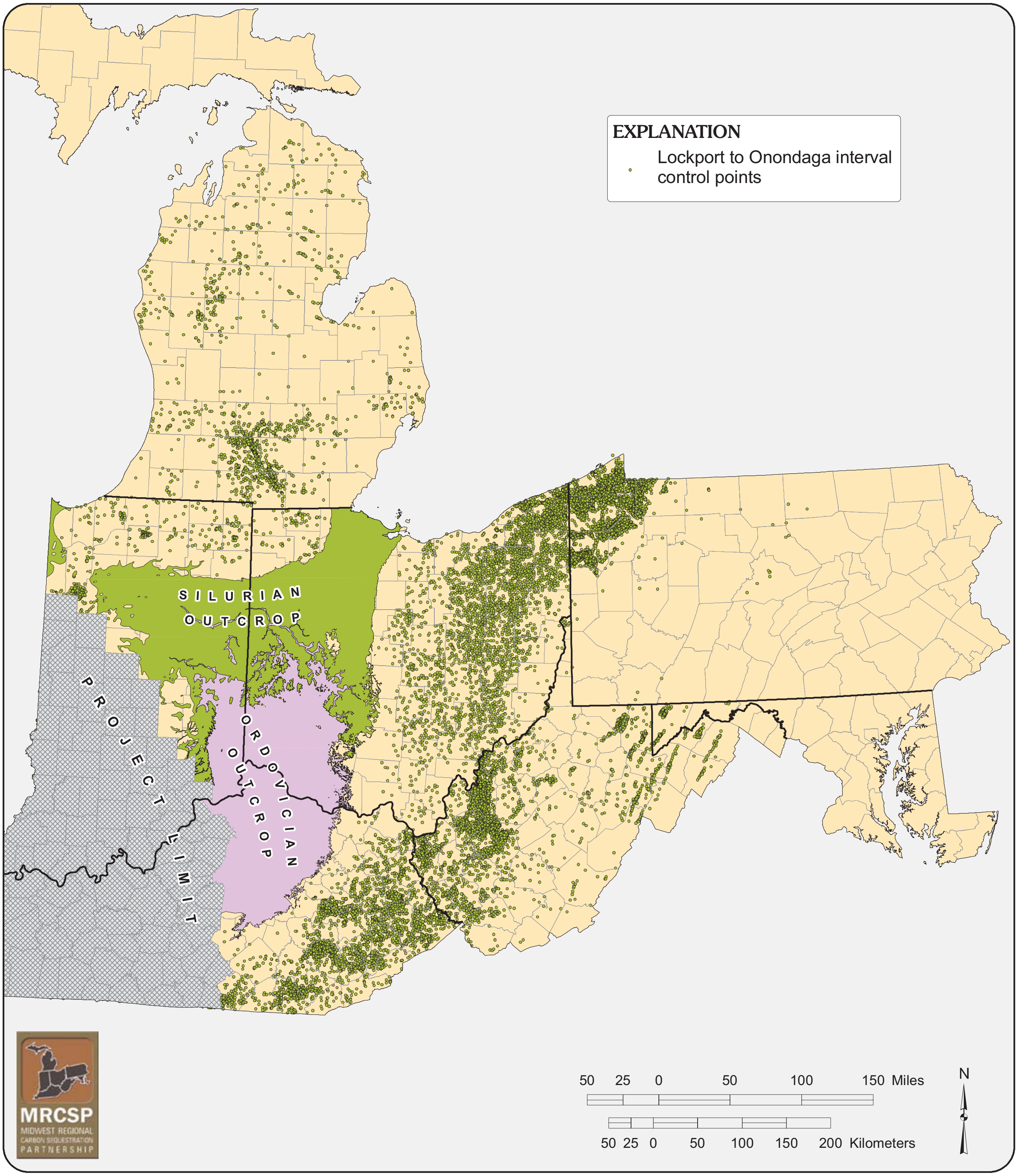

Figure 9.—Map showing the distribution of control points (wells) used for the Lockport to Onondaga interval. This layer has 23,485 wells.

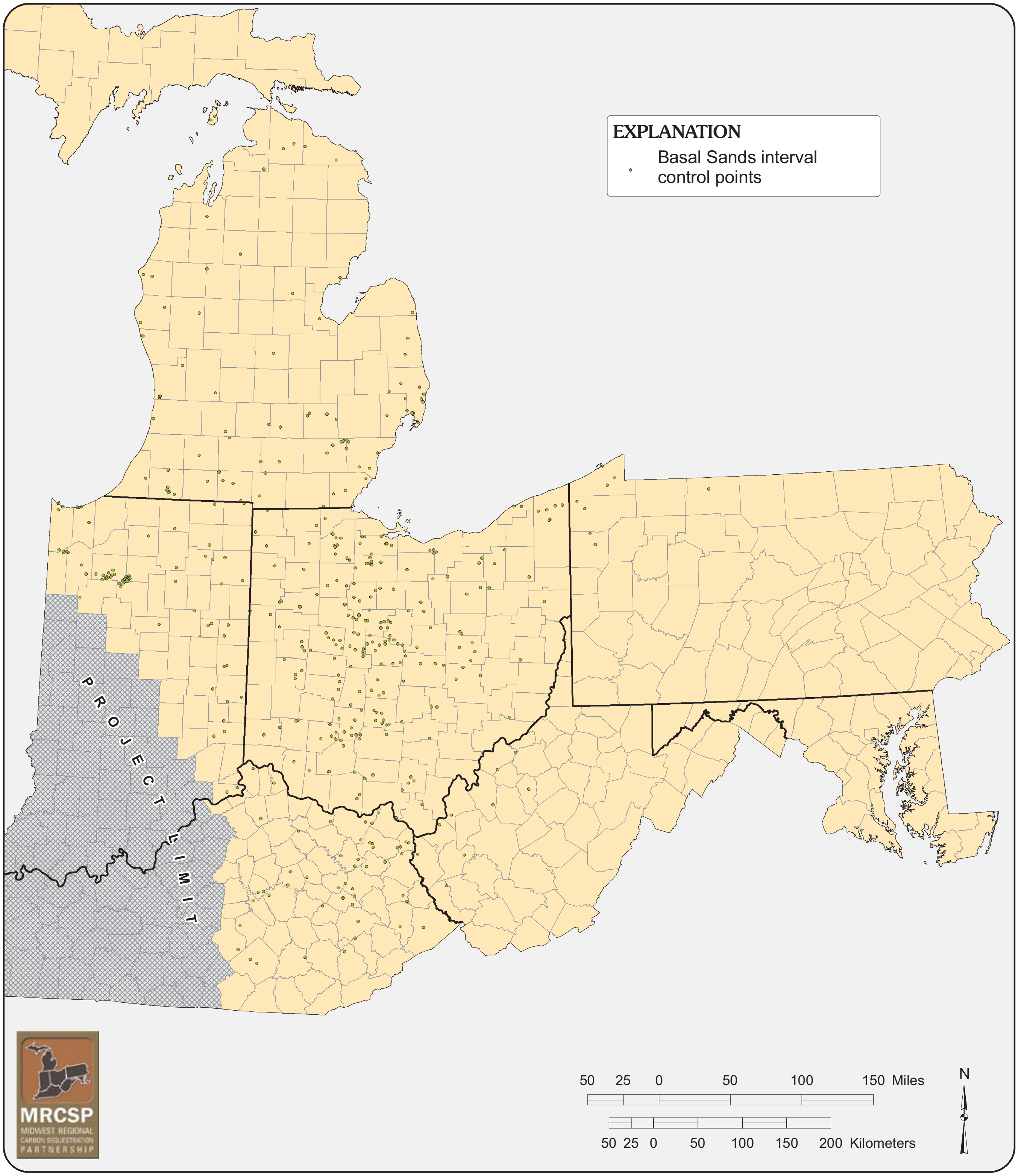

Figure 10.—Map showing the distribution of control points (wells) for the Cambrian basal sandstones. This layer has 510 wells.

Table 2.—Summary of data and error statistics (5,000-foot grid resolution) for the major regional maps of this project

Mapping Unit	*Number of Wells*	*Square Miles/ Well*	*Cross Validation Error (RMSE ft)*	*Grid Error (RMSE ft)*	*Range of Values (ft)*
Basal Cambrian Injection Targets Structure	510	323	595	361	17,210
Basal Cambrian Injection Targets Isopach	373	441	123	100	2,022
Copper Ridge Structure	641	321	385	390	15,691
Copper Ridge Isopach	337	610	658	567	9,751
Rose Run Structure	1,786	40	236	259	17,933
Rose Run Isopach	1,756	41	32	27	611
St Peter Structure	502	162	362	474	10,709
St Peter Isopach	254	321	60	84	1,156
Knox Structure	2,424	77	161	183	13,806
Knox-Silurian Isopach	2,051	90	86	47	5,202
Queenston Structure	11,327	15	74	55	10,431
Medina Structure	6519	13	58	78	9,299
Medina Isopach	6976	12	23	25	627
Oriskany Structure	11724	5	216	154	7,907
Oriskany Isopach	11024	6	21	10	386

lated and are provided as a useful guide when using the maps of this project. Rigorous measures of map accuracies have been obtained for most of the major regional-scale maps in this study. Uncertainty was estimated using the two approaches described below.

How good are the interpolations at unsampled locations?

This question was evaluated using geostatistical cross-validation based on ordinary kriging. Grids that obey well points exactly may provide a poor prediction at unsampled locations (which is the majority of the area being considered). Consequently, the surfaces were estimated by kriging at each point location, but without using the value at that point. Summary statistics (RMSE) were generated using the differences between the actual data value at a known point versus the interpolated (kriged) value at that same point (Table 2). The resultant RMSE value provide a general estimate of the systematic and random error of interpolation at unsampled locations. The value is an average error for the map; actual error at any specific location on the map can be smaller or larger than the RMSE value. Not all final maps were created using geostatistics (Table 1); however, cross validation was calculated for all layers as a method to compare the strength of geostatistical interpolation between mapped layers. The results of this analysis are provided in the column labeled "Cross-validation error" in Table 2.

How accurately do the final grids obey the well values?

This question was evaluated by calculating the difference between the value at the control point (well) and the value of the nearest calculated grid cell. The result was summarized using the RMSE method. Faithfulness of the grid (Table 2) was partly a function of grid cell size, as finer grids were more able to accurately model complex trends. Analysis found that a cell resolution of 5,000 feet provided a reasonable compromise between grid accuracy and computational efficiency (Venteris and others, 2005). However, increasing the cell resolution to 2,000 feet further reduced grid errors for many of the map layers; yet there was little to be gained from using resolutions greater than 2,000 feet. The results of this analysis are provided in the column labeled "Grid error" in table 2.

Accuracy Discussion

There were considerable differences between the accuracy of the various structure and isopach surfaces. RMSE values ranged from 10 to 658 feet. Several factors contributed to the uncertainty of the maps.

1. Accuracy is expected to increase with the number of wells per unit area. Ultimately, the value and geometry of the point data have the biggest influence on the final surface produced by computer interpolation, regardless of the method used. Increased numbers of data points lead to more robust statistical prediction.
2. Increased range of data values can have negative and positive influences on spatial modeling. Large trends in areas of sparse data result in errors for non-exact interpolators, such as kriging, that relies heavily on neighboring values. Large trends can also increase the strength of the prediction model (variogram) by decreasing the signal to noise ratio.
3. The shape of the surface and the amount of faulting affect accuracy. Surfaces that are smooth and predictable are easier to model than those with abrupt discontinuities (faults, breaks in slope). These discontinuities violate the basic assumptions of geostatistical interpolation. Also, spatial data often have a component of spatial variability below the scale of sampling. The greater this variability (the micro variance component of the nugget effect), the less the interpolated values will agree with the proximal data values.
4. The well data set is also a source of error. Individual data points should be very accurate (within 10^1 feet). However, misidentified horizons are common and can result in errors greater than 100 feet. Such cases are usually detected by the screening method and removed.
5. Gridding (ANUDEM) in areas of intense faulting may introduce additional errors. In areas of a very steep slope (as found in the Rome trough) small errors in gridding can result in a large difference between well and grid values.

For this data set, error sources one and two had the most influ-

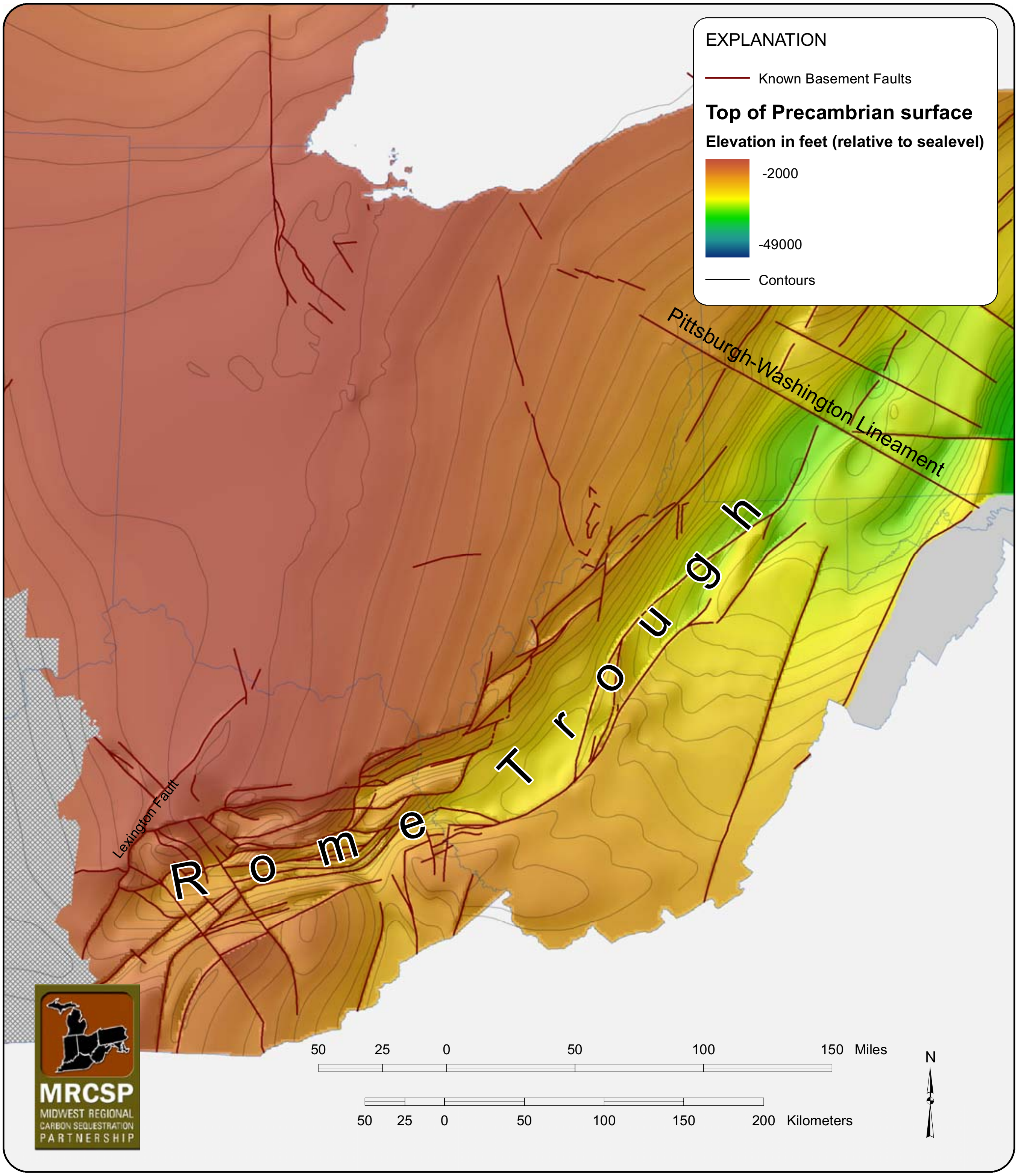

Figure 11.—Structure map on the top of the Precambrian unconformity illustrating the complexity within the Rome trough area. Hand-contouring was used within the heavily faulted portions of the Rome trough and computer-based contouring was employed in less faulted areas.

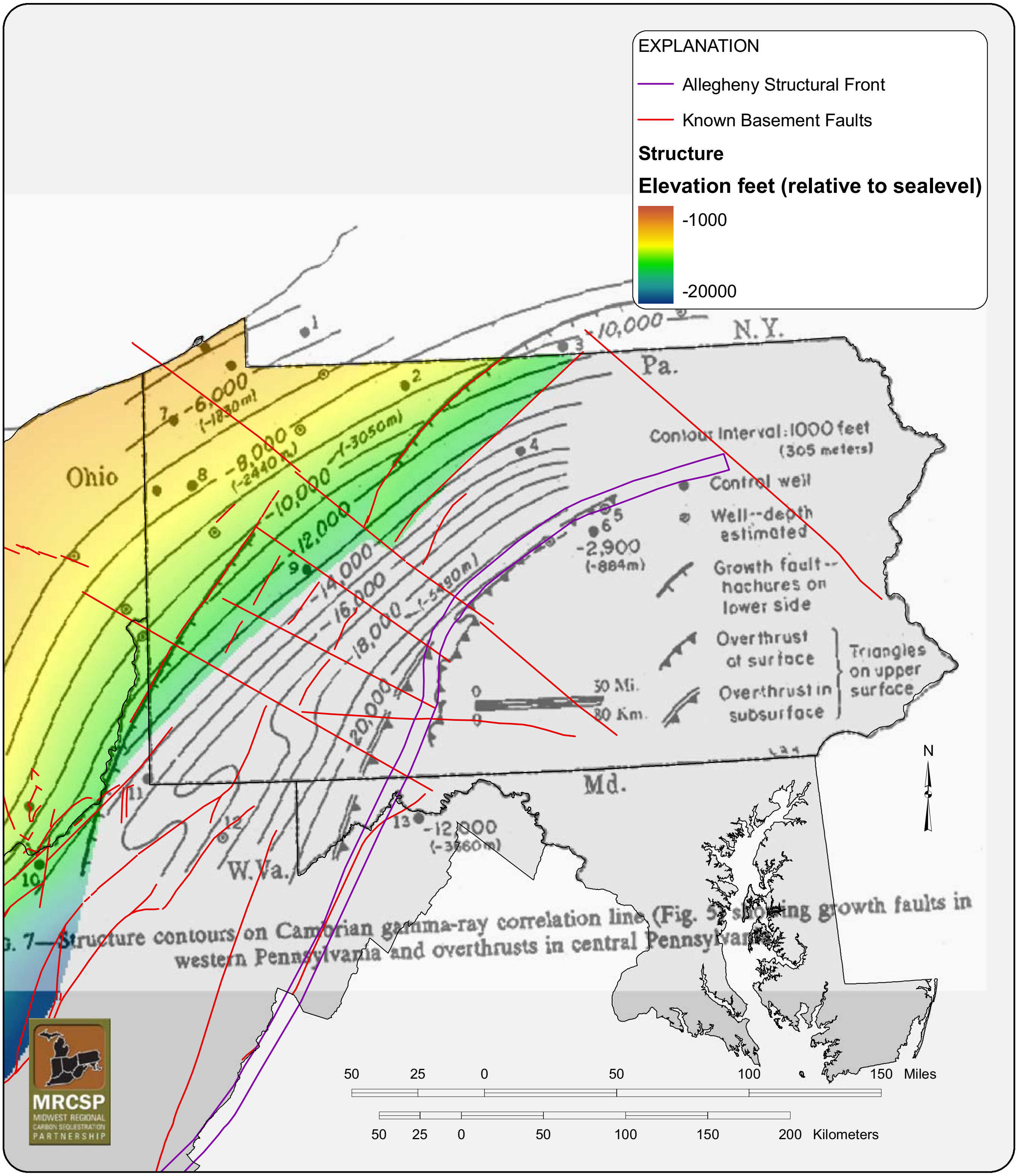

Figure 12.—An example of using a previously published map to aid interpretation in areas with sparse well control. A copy of Figure 7 from Wagner (1975), showing the elevation of a gamma-ray pick within the Cambrian, was overlain and georeferenced to the MRCSP base map with faults for the same interval. This map was used to aid interpolation and interpretation in data-deficient areas.

ence on the accuracy of the final grids. The correlation coefficient between cross-validation error and data density was 0.51 and the coefficient between cross-validation error and the range was 0.39 (for these data, increased range was associated with increased error). Data density and range were combined in a multi-variate linear regression model that explained 81 percent of the variance in cross-validation error and predicted the amount of error within 100 feet (RMSE). The maps could be improved by more well control, especially in deep and faulted areas of the Rome trough and Appalachian basin.

Comparisons between cross-validation error and gridding error provided additional discernment on uncertainty issues. In general, if the two error measurements showed good agreement, it confirmed the gridding method was creating surfaces with error levels compatible with those expected from direct gridding from kriging (block kriging). However, the gridding error was much smaller for the Cambrian basal sandstones structure map and showed the improved fit of the hand-contoured map in the Rome trough area. Yet, such improvement was not observed on other Lower Paleozoic maps. The gridding error was much larger than the cross-validation error for both the Oriskany and Medina structure maps, which were interpolated using Petra. One possible interpretation was that the gridding method (ANUDEM) found it difficult to fit the small closed-contour features present on these maps.

Both the computer interpolation and final gridding routines were expected to have difficulty in the faulted regions of the study area. Faults violate the basic assumptions of kriging and are difficult to represent in a grid. RMSE grid errors were compared between the faulted areas and the rest of the basin. The faulted areas had much larger errors in the Cambrian basal sandstones structure and the Copper Ridge Dolomite isopach maps (Table 3). These layers contained many wells that occurred directly on faults (the Cambrian basal sandstones isopach was very thin in the faulted area and had a small RMSE value). Otherwise, the magnitude of error was similar for the two regions and the faulted areas did not consistently contain increased error over the rest of the region (Table 3). However, the user should be particularly cautious when using the maps in the faulted regions of the Lower Paleozoic.

Table 3.—Comparison between uncertainty in faulted and non-faulted areas

Mapping Unit	*Faulted Area (RMSE ft)*	*Rest of Basin (RMSE ft)*
Basal Cambrian Injection Targets Structure	754	297
Basal Cambrian Injection Targets Isopach	33	402
Copper Ridge Structure	359	401
Copper Ridge Isopach	1,141	332
Rose Run Structure	211	263
Rose Run Isopach	26	27
Knox Structure	130	185

METHODOLOGIES FOR OTHER MAPS

Oil and Gas Fields Map

The mapping and compilation of state oil and gas fields maps into one regional GIS layer for this project has greatly advanced our ability to assess energy and sequestration resources at regional and state scales. The map represents the first digital petroleum field data for the states of Maryland, Michigan, Pennsylvania, and West Virginia. Moreover, Michigan and Maryland were able to significantly update their petroleum fields maps, and in Pennsylvania and West Virginia, their current oil and gas field digitization projects were completed as a result of the MRCSP project. Digital layers from these states were combined with updated digital maps from Indiana, Kentucky, and Ohio to make the first seamless regional map and database of oil and gas fields. The resulting map/GIS layers will have many uses for CO_2 sequestration, oil and gas exploration and development, regional planning, general public education, and uses by other sectors.

Methodologies used in creating and storing oil-and-gas-field tabular data and field boundary maps differed widely from state to state. The biggest challenge to making an integrated, regional map was to conform the tabular field data from each state into a common format. Ohio Division of Geological Survey personnel designed a data structure that allowed tabular attributes to be populated with data from each state (data tables can be found on the accompanying GIS CD). The oil and gas fields database contains the basic attributes necessary for the calculation of CO_2 sequestration potential (average depth, porosity, thickness). The main challenge in creating the system was assembling data from geologically similar units into common regional plays. Common plays were developed by combining geologic units of similar age and lithology using the stratigraphic correlation chart created by the MRCSP team as guidance (Figure 5). For instance, the "Clinton"/Medina play map locally contains fields that produce from the Silurian "Clinton" sandstone of Ohio (Cataract Group on Figure 5), the Medina Group sands of Pennsylvania and the Tuscarora Sandstone of West Virginia (see Figure A7-2).

The methods used to draw the oil-and-gas-field boundaries (polygons) varied from state to state. The most common method was to sort the well data by play or individual producing formation, and draw the field boundaries by hand. Usually a buffer of less than one-quarter to no more than one-half mile was used to define the boundary near the outmost wells of a pool or field. Within larger fields, holes will be found within the interior of the field polygon; this is where dry holes are encountered, or where producing wells have been drilled farther apart than the established minimum buffer. Such hand-drawn maps existed as legacy data for most of the states and were used as a starting point in Pennsylvania, Indiana, West Virginia, Kentucky and Ohio—in these instances the field boundaries were simply digitized and attributed. These new digital maps can, and are, digitally updated as needed by automatic or semi-automatic buffering methods (using a GIS package) when new wells are drilled in Indiana, West Virginia, and Ohio. Field maps for Michigan were made solely using GIS buffering of the well locations for Phase I, but will be augmented by hand-digitizing in the future. Field boundaries were merged into a common GIS layer, but blending of oil-and-gas-field boundaries between the states was not done. The individual state maps were compiled from a variety of base maps that were at different scales (see metadata in the oil-and-gas-fields layer on the accompanying GIS CD); users should be cognizant of the accuracy differences from state to state because of this.

Injection Wells

The different injection-well types gathered for the MRCSP region are categorized as follows: 1) Class I—hazardous and industrial-waste injection well, 2) Class II—brine injection well, and 3) Class III—solution mining well. Locating all of these wells had never been accomplished before by all of the MRCSP project members; this information is usually kept by state or federal regulatory agencies. However, information about these wells, especially the Class I and II wells (Figure 13) will be crucial in understanding the injection characteristics of many of the target formations under consideration. Therefore, under Phase II of the MRCSP Partnership, the geologic team will obtain as much information as possible from these injection operations.

Salinity Grid

A salinity grid can be generated from mapping, either by direct interpolation (Kriging etc.) or by exploiting the general relationship of salinity increasing with depth. Mapping salinity accurately in this region is difficult because the data needed are not routinely gathered and submitted to state agencies; therefore the coverage is sparse. For example, the Mount Simon Sandstone has only 18 measurements of salinity scattered across the MRCSP area. In addition, formation waters are continuously modified by filtration through clay membranes, ion exchange reactions, precipitation of minerals, and by the solutioning of the surrounding rocks (Blatt and others, 1980), causing further uncertainty. For these reasons, a statistical salinity verses depth model was used to create the salinity grids used in capacity calculations for this investigation. The model was constructed from existing sample data using least-squares regression. Individual models were created for each formation and used with the overburden (depth) maps to make a continuous salinity grid for each formation.

Geothermal Gradient and Temperature

Models of the surface temperature and geothermal gradient were created to calculate the temperature at depth for use in the capacity calculations. For the surface temperature, the thirty-year average for over 275 cities was obtained for the conterminous United States (NOAA, 2000). The temperatures were interpolated into a grid using a minimum curvature algorithm.

For the geothermal gradient, a number of datasets were investigated. These datasets included the American Association of Petroleum Geologists (AAPG) bottom-hole temperature dataset (AAPG, 1994), the Southern Methodist University (SMU) dataset (Blackwell and Richards, 2004a), and the 2004 AAPG heat flow dataset (Blackwell and Richards, 2004b). Each dataset was evaluated for data quality and spatial distribution. The AAPG heat flow dataset (Blackwell and Richards, 2004b) was not used because the data distribution was considered too sparse in the project area—only three heat flow measurements were for Ohio. The 1994 AAPG geothermal dataset was unsatisfactory because it was uncorrected for thermal equilibrium and, when analyzed using spatial statistics, the spatial variance was quite large. Of those evaluated, the SMU dataset (Blackwell and Richards, 2004a) was the best for this project because it combined a good combination of data coverage and quality. A regional correction was applied, which significantly reduced the spatial variance. In areas where the SMU dataset was missing data, such as Pennsylvania, data from the AAPG bottom hole temperature dataset (AAPG, 1994) was used to augment the SMU dataset. The augmented SMU dataset was used to create the geothermal gradient grid for the region using kriging in Geostatistical Analyst.

Screening Maps

The large number of maps, data grids, and calculations generated in this regional assessment make it difficult for the public, or any other user, to interpret the various attributes related to CO_2 sequestration in geologic units in the MRCSP study area.. Therefore, the geologic team has devising several methods to condense the various types of information contained herein into a smaller number of summary maps for quick reference, by both technical and non-technical audiences.

Several techniques for creating summary maps were investigated. Approaches ranging from complex expert systems models, which codify qualitative geological knowledge numerical algorithms, to simple screening maps. Because the expert systems models rely on so much soft information (knowledge rather than data), it was decided, at this stage in the project, that simple Boolean screening maps were the best approach to presenting meaningful summaries. Quantifying geologic knowledge through expert systems approaches must be done with care and can be time consuming if realistic algorithms are to be developed. Research into more advanced techniques will continue in Phase II.

A screening/planning map was produced using grids for all deep saline formations. Structure and isopach grids were reclassified into binary grids showing where the geology was appropriate and inappropriate for CO_2 injection, then reclassified to show areas where overburden thickness was greater than 3,000 feet (using the 2,500-foot rule of thumb for miscible injection, with 500 feet added to account for potential map error). Isopach grids were reclassified to show thicknesses greater than 50 feet. The reclassified grids were recombined into a single grid showing the number of appropriate targets and the name of the targets (Figure 14). This map can also be viewed as a 3-dimensional scene (Figure 15). The map is presented herein and will be discussed further with various stakeholder groups, including the partnership sponsors, to elicit input on its usefulness, clarity, and how it can be improved and added-to for development in Phase II.

DATA STORAGE AND DISTRIBUTION

Geologic data for this project is provided in both digital and as hard copy (paper) map formats. This was done to ensure that the needs of a wide range of stakeholders were met. The approach allows information to be distributed to individuals ranging from sophisticated GIS modelers to non-technical users who just need a map for a planning meeting.

Data Storage

All GIS data is being stored in a centralized ArcSDE database maintained by the Ohio Division of Geological Survey. For geologic target and confining layers, there are contour and grid data, geologic unit crop lines, and fault locations stored. Point data used in mapping are stored as a database containing all formation tops with a listing of basic well-header data (i.e., well operator, location, producing formation, well status, etc.). The database also contains all GIS layers created in this project, including layers from the terrestrial studies, CO_2 sources, surface digital-elevation model, oil and gas fields, and the various data and grids needed for capacity calculations. The database may be queried to obtain data for an individual geologic layer, by formation, depth, location, or any combination the user requires.

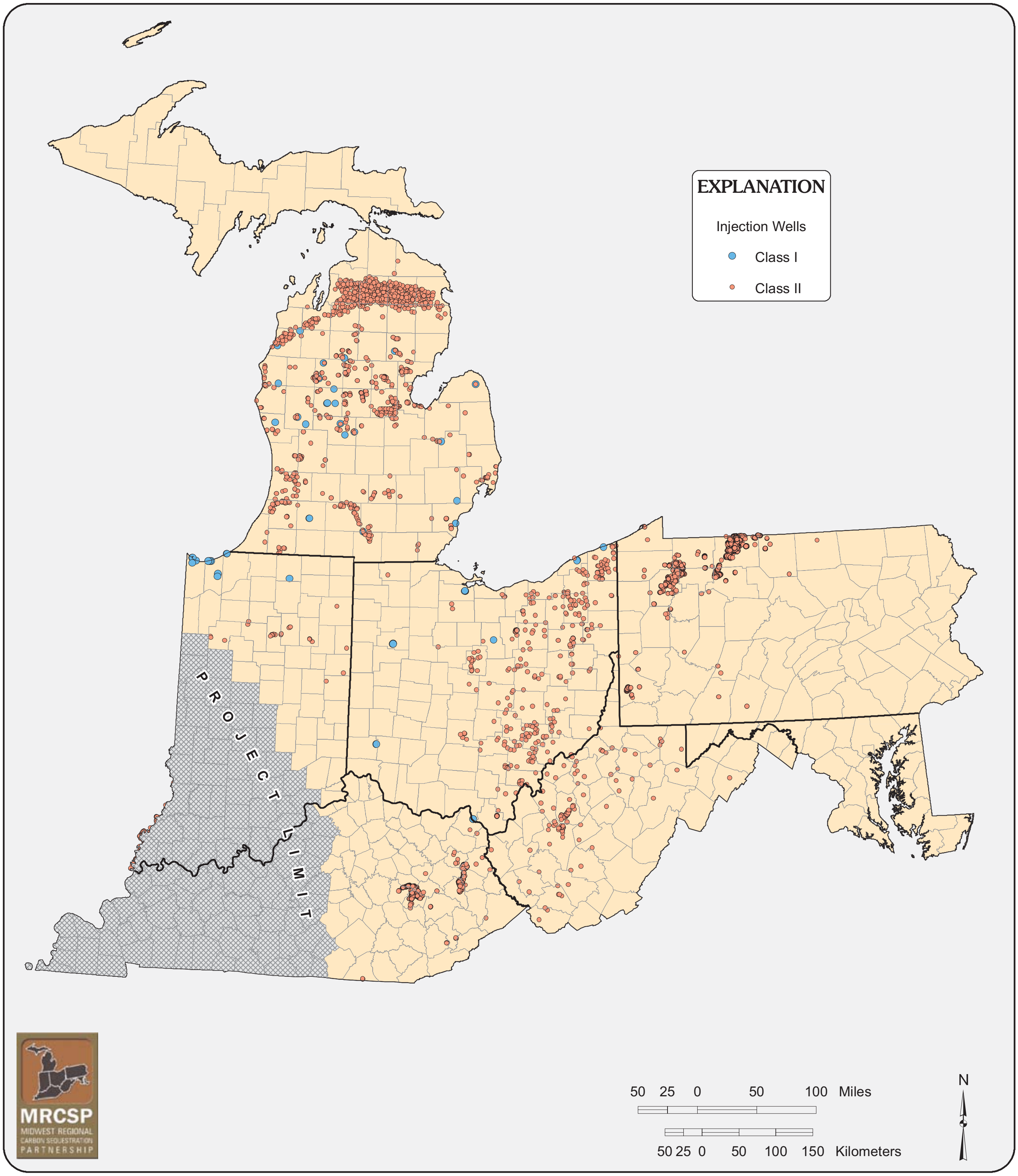

Figure 13.—Locations of Class I (hazardous and industrial waste) and Class II (oil field brine) injection wells.

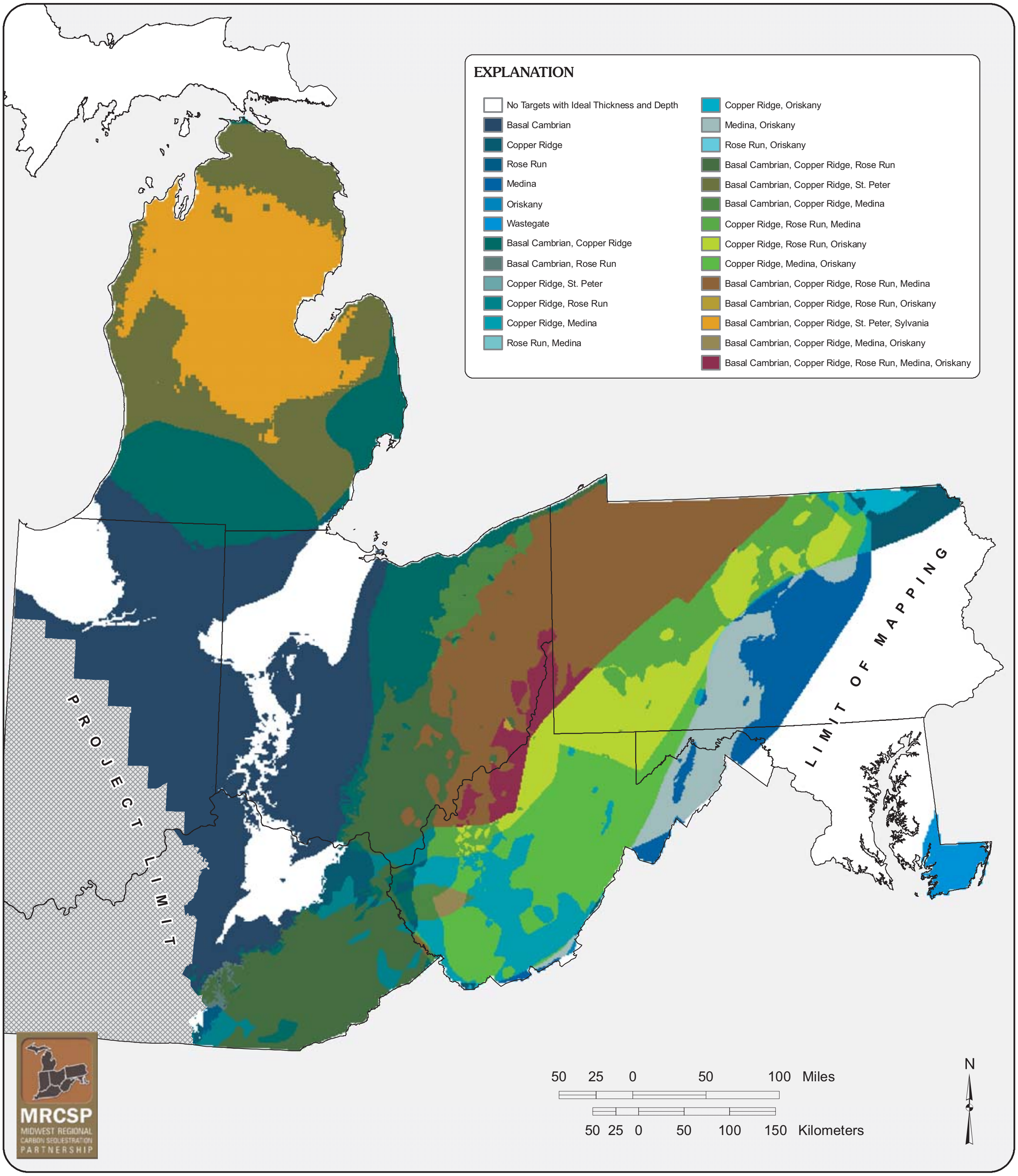

Figure 14.—Screening map summarizing the saline formations. The map shows which saline formation or combination of formations meet the criteria of 3,000 feet or greater overburden thickness and a CO_2 sequestration target-layer thickness greater than 50 feet. Although 2,500 feet of depth is generally used as the cut-off to keep CO_2 in supercritical state, 3,000 feet is used on this screening map to be conservative and because of the potential large error inherent in mapping the relatively sparse data associated with some of these geologic units.

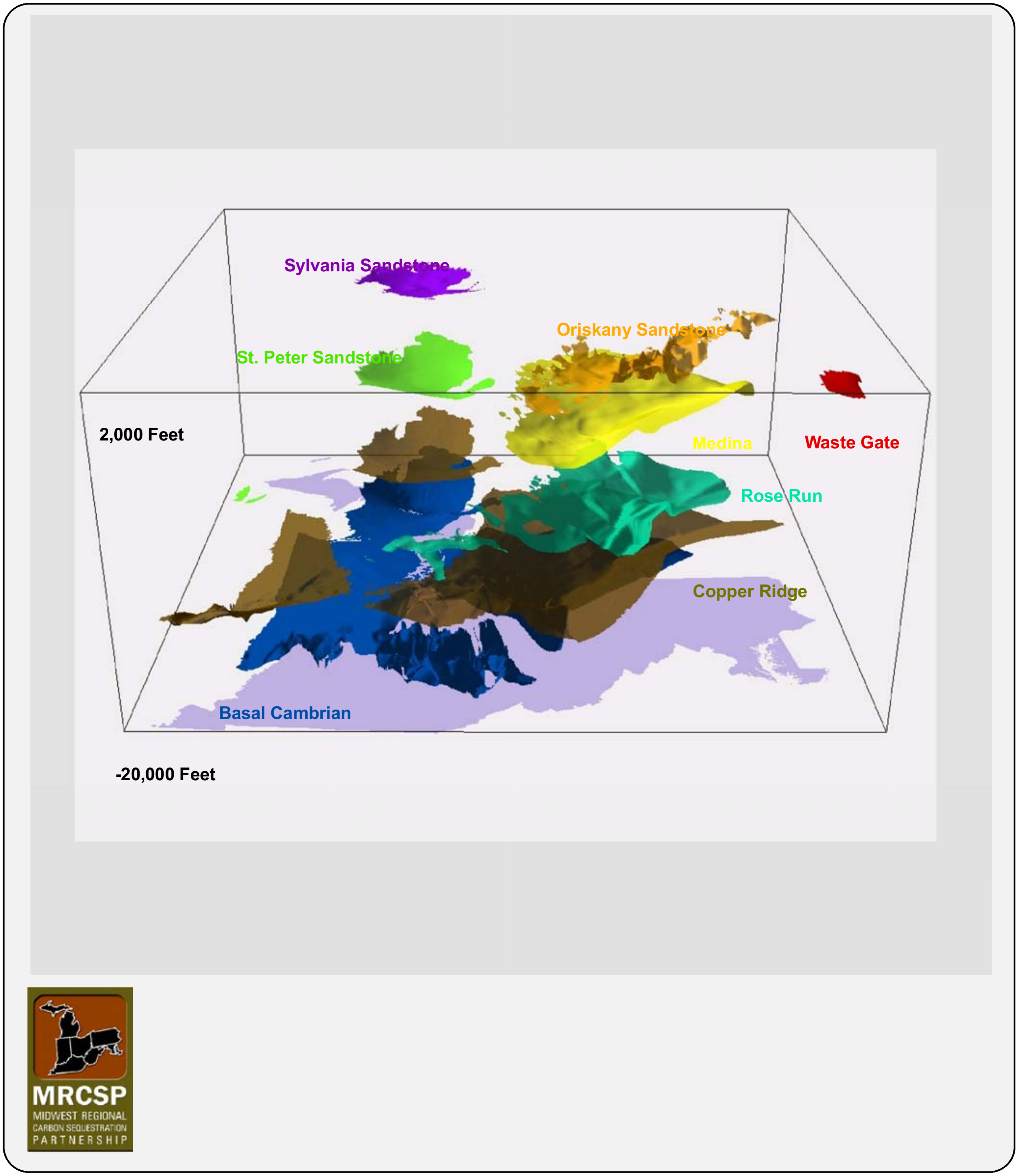

Figure 15.—Three-dimensional view (looking from the south) of the screening map presented in Figure 14.

Data can be provided to the public as ESRI shape files (vector) and ESRI grids (Raster). A myriad of other GIS formats exist and can generally be accommodated. Requests of non-ESRI GIS data formats will be handled on a case-by-case basis.

Metadata

Metadata was an essential part of this GIS data compilation and was created for all layers using the Federal Geographic Data Committee (FGDC) format for guidance. Metadata is provided in html format and can be read in any standard web browser. The metadata provides information on the data sources, compilation procedures, accuracy, projection parameters, and who to contact to ask questions about or obtain copies of the data.

Web-based Map Browser

An ArcIMS (Internet Mapping System) web-based GIS application was created to allow the contents of the ArcSDE database to be browsed using a simple web browser such as Microsoft Internet Explorer or Netscape. The site allows users to make custom map views that are flexible as to content and scale. The ArcIMS site provides a convenient way to inspect the data created and used in this study and to print the custom maps. The website does not allow the direct downloading of GIS data; rather, it is envisioned as a tool for stakeholders to inspect our data holdings. A data request can then be generated by e-mail or telephone. The universal resource locator (URL) to visit the site is: http://www.mrcsp.org/.

Other Formats

Hard copy maps of geologic targets and other GIS data are available as page-sized copies as found elsewhere in this report. Maps are also available as large format (36" x 36") prints for more detailed inspection. Maps can be provided as paper copies or as Adobe portable document format (PDF) files for electronic distribution.

OIL, GAS, AND GAS STORAGE FIELDS

Oil and gas reservoirs can be utilized in two main ways for CO_2 sequestration: 1) the CO_2 can be injected as part of a designed program to enhance additional oil and/or natural gas production from the reservoir or 2) the CO_2 can simply be injected into the known space formerly occupied by oil and/or natural gas in a depleted reservoir. In the first instance, the oil or gas produced via the program provides a value-added commodity to the sequestration project. In the second instance, the injection project is similar to that of injecting into a saline formation.

The MRCSP region contains some of the largest historic oil-and-gas-producing areas in the conterminous United States. The first commercial oil well was drilled in Pennsylvania in 1859 and the industry quickly grew and spread to eastern Ohio and northern West Virginia. These early oil fields were of great significance both to the birth and development of the oil and gas industry, and to the history and industrial development of the nation.

The MRCSP region, being the site of the beginning of the oil and gas industry, contains large numbers of wells drilled (many problematic to locate 100+ years later) prior to regulatory mandates on the industry. Fortunately, these early, unlocated wells were mostly rather shallow in depth and should not pose a significant risk for deeper drilling and injection. However, care must be taken when evaluating an area for potential older wells mainly because their existance can provide one of the easiest means for leakage from an injection reservoir.

With the advent of modern rotary drilling rigs, soon followed by the development of geophysical logging technology, hydraulic fracturing methods, and reflection seismic surveys, drilling, starting in the late 1940s, became progressively deeper in the region as new targets were explored. Many of the best fields developed during that era have now been partially or wholly plugged, or are near the end of their primary productive life.

The MRCSP region has produced over 5 billion barrels of oil and more than 50 trillion cubic feet of natural gas (Table 4). Additionally, over 1 million wells have been drilled in search of these resources over the last 150 years (Table 4; Figure 16). The region has seen a number of “boom and bust” cycles as new plays were discovered, feverishly drilled, and followed by a period of maximum production before declining. Overall, the region is considered mature and production has been in a state of overall decline for decades. However, most of the production has been from relatively shallow reservoirs; the potential remains that large reserves may be discovered in deep untested portions of the region. Additionally, it should be noted that the majority of the oil and gas fields in the region have not undergone any type of enhanced recovery operations.

Within the Michigan basin, oil and natural gas are produced from rocks that range from the Cambrian through Mississippian; most major production is currently from the Silurian pinnacle-reef trend around the margin of the basin. The Devonian Antrim Shale is another major gas producer in the shallow subsurface on the northwestern margin of the basin. The deepest production in the Michigan basin is from the Glenwood and Prarie Du Chein Formations in central Michigan at a depth of 11,500 feet (Michigan Oil and Gas Association, 1999).

Oil and natural gas have been produced from large regions of the Appalachian basin from reservoirs ranging in age from the Cambrian through Carboniferous. The majority of the production has come from Ordovician through Mississippian carbonate rocks on the western margin of the basin, and from Silurian through Pennsylvanian carbonates and clastics in areas of the basin axis. To date, the deepest natural-gas production occurs from a depth of 14,358 feet and is from the Conasauga Formation in Jackson County, West Virginia. Recent exploration has focused on deeper Cambrian and Ordovician carbonate rocks (such as the Beekmantown Dolomite and Trenton-Black River) and sandy carbonate systems (like the Rose Run Sandstone) at depths up to 12,000 feet.

The earliest noted production of coalbed methane (CBM) in the northern Appalachian basin occurred in 1924 in Carroll County, Ohio. However, CBM production was not sought as an individual play within the basin until the late 1980s. Since then, hundreds of wells have been drilled in southwestern Pennsylvania and northern West Virginia. These wells produce CBM from abandoned coal mines (GOB or coal mine methane wells), mine ventilation wells (many drilled years in advance of mining to degas the coal), as well as from conventional vertical and horizontal wells. CBM is just in its infancy in the Appalachian region and applying CO_2-enhanced gas recovery methods, as explained in Chapter 15 of the Appendix, could significantly increase the amount of natural gas produced from the reservoirs while sequestering considerable volumes of anthropogenic carbon dioxide.

Adams (1984) estimated approximately 61 TCF as the original gas-in-place in coalbeds of the northern Appalachian basin. Rice

Table 4.—Summary of oil and gas production, by state, within the MRCSP region

State	*Year First Commercial Production*	*Total Number of Wells*	*Total Number Productive*	*Total Oil Production*	*Yearly (2004) Oil Production*	*Total Gas Production (mcf)*	*Yearly (2004) Gas Production (mcf)*
Indiana (northern)*	1886	15,000	400	107,000,000	3,000	*	750,000
Kentucky	1860	250,000	63,190	772,532,160	2,548,105	5,388,675,103	94,258,790
Maryland	1951	220	7	0	0	48,752,678	36,276
Michigan	1925	53284	28720	1,243,000,000	6,393,353	6,643,000,000	193,141,644
Ohio	1860	258,897	216,640	~1,105,000,000	5,785,338	>8,009,749,438	90,301,118
Pennsylvania	1859	~350,000	Unknown	>1,380,944,000	>1,708,435	>11,026,657,000	>171,042,843
West Virginia	1859	~150,000	~135,000	584,024,000	1,474,000	18,650,000,000	201,770,000

*Figures reported for northern Indiana only which is dominated by the historic Trenton oil and gas fields.
Because of the age of this drilling, these numbers are estimates and a total gas production figure is unknown.

(1995) concluded of this amount, only about 11.5 TCF is technically recoverable. Recently, Milici (2004) estimated a limited portion of northern West Virginia and southwestern Pennsylvania contained reserves of almost 5 TCF of technically recoverable CBM; however, his assessment did not provide an estimate for the entire northern Appalachian coalfields. Regardless, based on these numbers, many regions of the northern and central Appalachian basin contain significant potential for CBM by enhanced gas recovery methods that use, and more importantly would sequester, anthropogenic CO_2.

In a typical oil reservoir, primary production techniques (allowing natural pressures to produce the oil or pumping the well) obtain only about 10 percent of the total amount of oil trapped. Many secondary-recovery technologies used to recover additional oil and gas from reservoirs include waterflooding, reinjection of produced natural gas, and steam and CO_2 flooding. Different formations respond differently to various enhanced oil recovery (EOR) methods; thus, the optimal EOR technology for each reservoir must be decided after careful study of the reservoir rock and fluid properties. A model is then developed and a pilot injection project is initiated to test the model.

The reservoir of a successful EOR project can usually be expected to produce at least another 10 percent of the original oil-in-place. Therefore, by widely applying EOR practices in the region, it may be possible to produce hundreds of millions of barrels of additional oil that otherwise would stay in the ground unused. Such practices could also add hundreds of jobs to the region.

Secondary recovery accounts for less than one-half of one percent of the oil production in Ohio compared to as much as 25 to 50 percent in surrounding states in the Appalachian basin (Blomberg, 1994). Pennsylvania was an early pioneer in secondary recovery techniques, especially waterfloods. Indeed, by the 1950s as much as 80 percent of the crude oil produced in Pennsylvania was from waterflood operations (Harper and Laughrey, 1987). Currently, Ohio has about 64,000-producing oil and gas wells; approximately half of these are oil stripper wells (producing less than 10 barrels per day). It has been estimated that 10,000 of these oil wells would benefit from enhanced oil recovery techniques (Schrider, 1993). Premature oil-well abandonment results in the loss recovery of many millions of barrels of oil reserves as well as jobs, and a continued reliance on foreign oil imports. While water flooding and other methods have been applied in the region, many with great success, some reservoirs have not responded favorably to these efforts. Carbon dioxide flooding technology may work in some of these reservoirs to enhance recovery, or at least be better than some of the earlier attempted methods used in the infancy of enhanced recovery technology. Cooperative efforts between governmental and industrial partnerships to test and apply CO_2-enhanced recovery technology in the region may help to impede the declining trend in domestic oil production and enable the nation to become less dependent on foreign imports.

Carbon dioxide is one of the best mediums used for EOR because of its unique properties—low temperature and pressure to stay in supercritical phase, low viscosity, and it is soluble with oil and native formation fluids. In a typical application, CO_2 is initially injected into a geologic unit to form a bank that goes into solution with the naturally occurring oil and brine. Water is then injected behind the CO_2 bank to help increase formation pressure and push the CO_2/oil bank away from the injection wells and towards the producing wells (Figure 17). Alternating cycles of CO_2 and water are repeatedly injected into the well throughout the life of the EOR project. The CO_2, in solution with the oil, lessens the viscosity of the oil and aids its movement through the reservoir porosity system.

Carbon dioxide produced from natural reservoirs has been used for decades in the southwestern U.S. (Colorado, New Mexico, and Texas) to enhance local oil field production. Hundreds of miles of pipelines have been built to transport the CO_2 from these reservoirs to the producing oil fields. Furthermore, since the early 1980s, over 400 million tons of CO_2 have been purchased from this network and used to produce approximately 650 million barrels of incremental oil (Martin, 2002). Yet, there has never been a large, economical source of CO_2 available in the Appalachian and Michigan basins for EOR use; thus, this method of enhanced recovery is atypical in the MRCSP region. If large-scale capture of anthropogenic CO_2 comes to fruition in the MRCSP region, it is anticipated a regional network of pipelines will develop to distribute the CO_2 to candidate oil fields as well as to appropriate saline storage reservoirs.

Figure 18 illustrates the 10 largest oil and gas fields greater than 2,500-feet deep within the MRCSP region. These fields would most likely be among those first considered for enhanced production assisted by CO_2 or use as CO_2 storage reservoirs. Table 5 lists the storage properties and conservative estimates for the amount of CO_2 that may be sequestered within these fields. Although oil and gas reservoirs in the MRCSP region contain less volume capacity compared to the region's saline formations, their trapping abilities and value-added prospects should make them some of the first geologic units to be utilized for CO_2 sequestration.

In Phase II, the MRCSP team plans to expand its study of oil and gas systems in the region by defining those reservoirs best suited for CO_2 EOR operations, and perhaps implementing at least one EOR

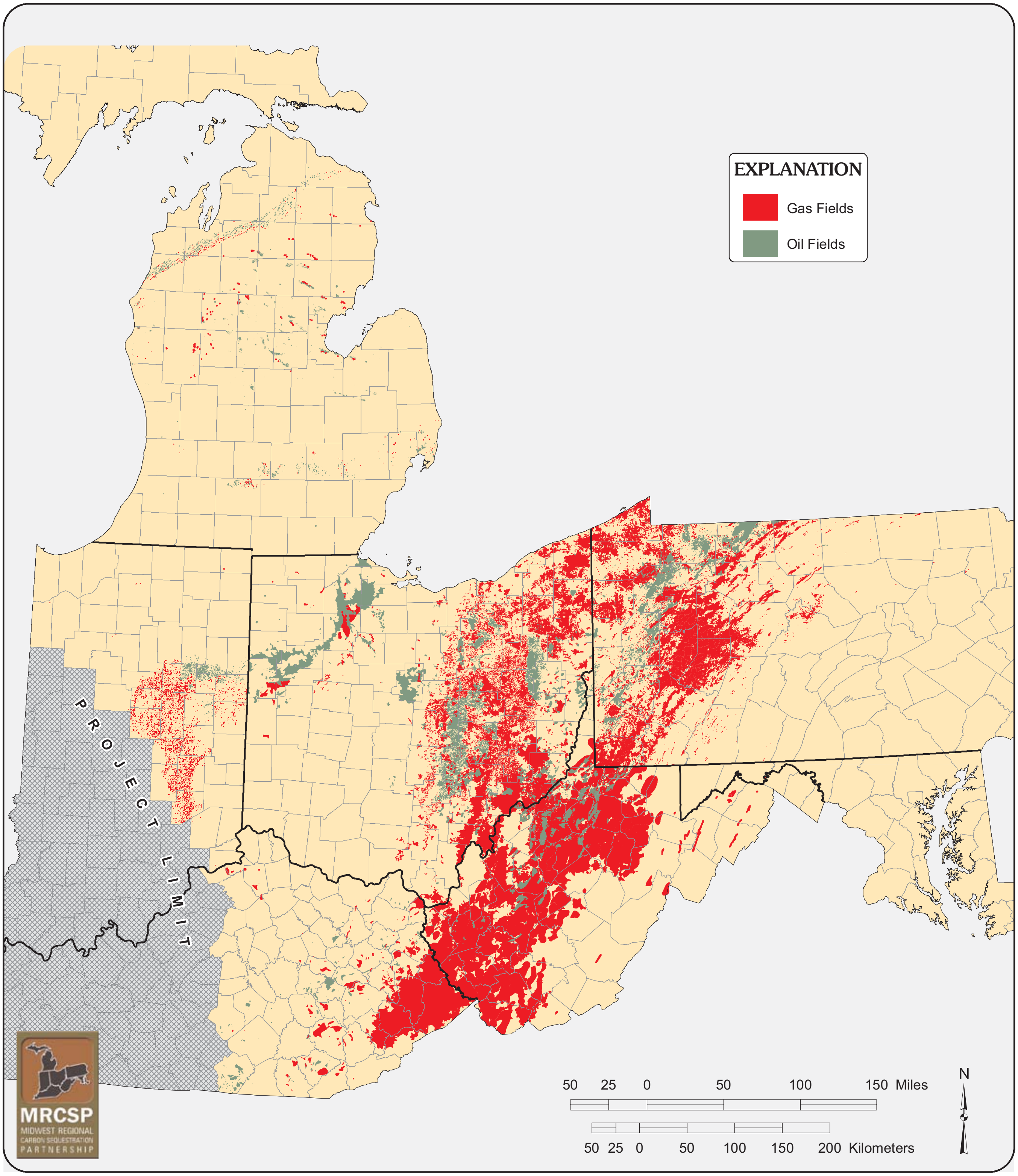

Figure 16.—Oil and gas fields of the MRCSP region.

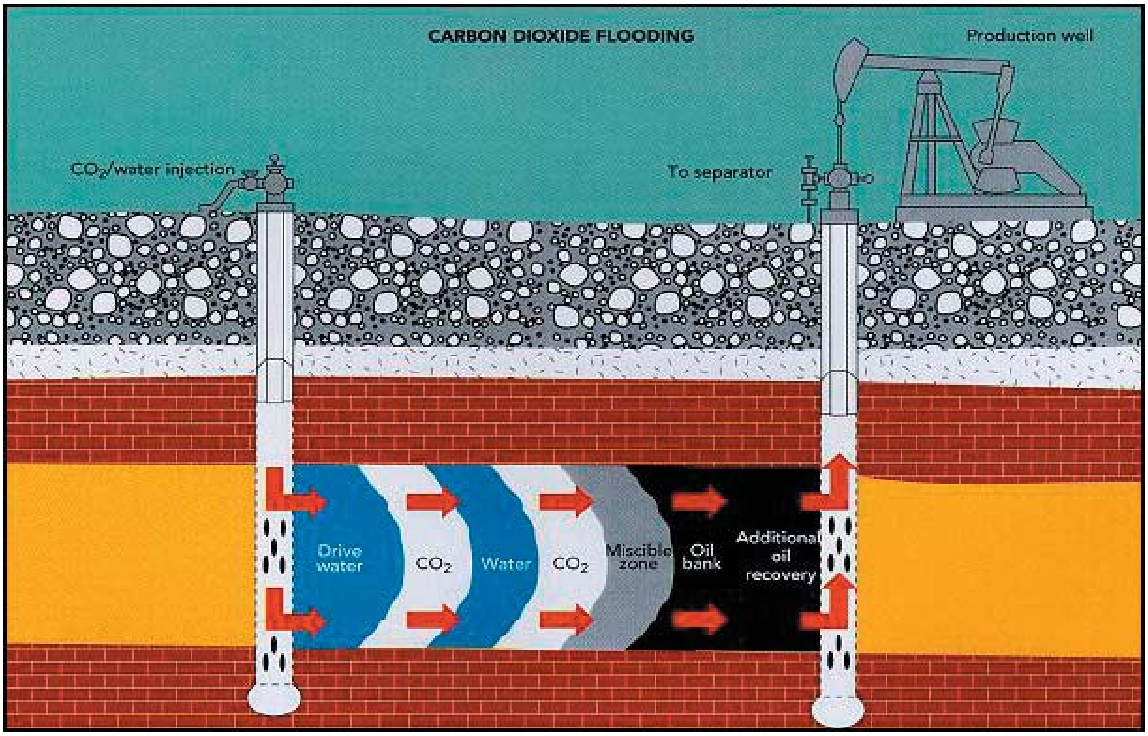

Figure 17.—Schematic diagram of a CO_2-enhanced oil recovery operation. A CO_2 pank is introduced to the producing reservoir from injection wells. The CO_2 pank forms a zone wherein CO_2 is in solution in the oil. Alternating pank of CO_2 and water maintain reservoir pressure and push the oil bank towards the production well. Any CO_2 that is produced with the oil is separated and typically recycled into the injection stream (figure from Martin, 2002).

Table 5.—Top ten gas and oil fields (greater than 2,5000 average depth) in the MRCSP region based on calculated CO_2-storage capacities

Field Name	*State*	*Producing Formation(s)*	*Avg. Depth*	*Number Wells*	*Acres*	*Porosity*	*Thickness (ft)*	*CO_2 Potential (Tonnes)*
			Natural Gas					
St. Marys	WV	Devonian Shale	3484	321	33,336	0.07	334	364,273,174
South Burns Chapel	WV	Oriskany & Helderberg	7634	130	64,046	0.08	110	341,464,601
Elk-Poca (Sissonville)	WV	Oriskany	5032	1121	244,733	0.14	18	329,504,518
Volant	PA	Medina	6050	353	31,451	0.18	85	310,040,473
North Ellsworth Consolidated	OH	Clinton	5100	662	108,919	0.078	50	244,852,087
Baltic	OH	Rose Run	6390	113	84,083	0.098	40	232,384,208
Weston-Jane Lew	WV	Devonian Sands	3757	845	59,925	0.08	71	227,015,516
Roaring Run	PA	Devonian Shale	2600	355	21,400	0.11	116	175,907,173
Belington	WV	Devonian Sands	4169	552	53,877	0.08	74	172,273,607
Conneaut	PA	Clinton	2800	44	7,151	0.08	1958	157,521,943
			Oil					
East Canton Consolidated	OH	Clinton	5300	1290	135,100	0.076	43	501,100,680
Morrow Consolidated	OH	Copper Ridge	3600	332	138,647	0.08	14	26,452,262
Gore Consolidated	OH	Clinton	3130	1421	37,057	0.098	15	31,108,749
Sheakleyville	PA	Medina	4950	62	6,123	0.18	133	95,167,666
Salem-Wallace	WV	Gordon	2800	2399	39,598	0.12	8	22,652,621
Bear Lake 22 - 23N - 15W	MI	Niagaran Reef	4542	10	5,317	0.04	154	31,971,830
Blue Lake 18 - 28N - 05W	MI	Niagaran Reef	6600	7	2,770	0.083	185	47,231,076
Chester 18 - 30N - 02W	MI	Niagaran Reef	5930	14	7,234	0.08	110	50,019,838
Claybanks 02 - 13N - 18W	MI	Niagaran Reef	3458	3	2,089	0.052	309	28,773,624
Onondaga 21 A - 01N - 02W	MI	Niagaran Reef	3700	9	7,256	0.065	128	58,826,167

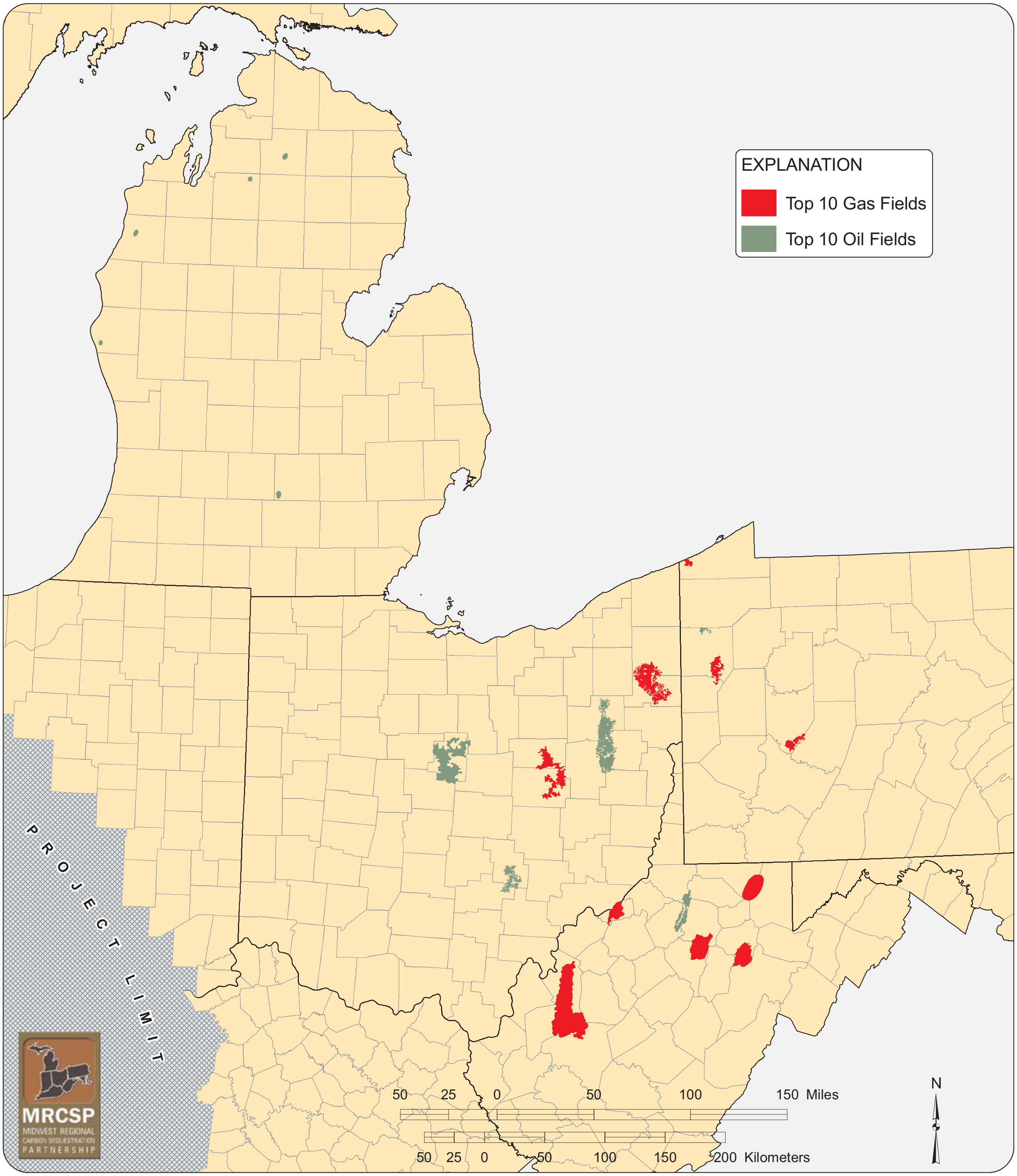

Figure 18.—Top-10 oil fields and top-10 gas fields in the MRCSP region based on calculated CO_2 sequestration capacity. See Table 4 for field attributes.

injection pilot project. Should economical sources of CO_2 become available to the region, it is imperative that we are prepared to use this methodology to recover these additional natural resources.

GAS STORAGE

Consumer demand for natural gas is seasonal; higher demand during extreme cold periods for home heating purposes and lower demand during the warmer summer months. In general, natural gas supplies are fairly constant because natural gas distributors utilize underground gas-storage fields to maintain a reserve of gas for peak demand periods.

The MRCSP region has more natural gas storage potential than any other region of the country. In fact, four of the top seven states in gas storage capacity are in the region (Figure 19)—Michigan is the national leader. These statistics unequivocally indicate the region contains exceptional geological formations for the underground storage of both natural gas and CO_2, for that matter.

Most of the region's storage fields (Figure 20) were once producing gas fields. Later, many of these fields were converted to storage reservoirs by drilling wells designed specifically for injection operations and also by building pipeline and compressor station infrastructures to support the conversion. Gas storage fields are designed to allow the entire amount of working gas to be cycled in and out of the field once each year. Typically, the storage fields are filled from pipelines in the summer months for withdrawal when demand peaks in the winter months.

The gas storage fields provide an excellent analogue for study when examining CO_2 storage. By analyzing these fields, we can better model the amount of CO_2 that can be stored in similar strata or reservoirs, and learn more about the injectivity rates that different reservoirs can be expected to handle. Such investigations will allow us to better forecast how many wells, and over what size of an area, will be needed for a specific CO_2 project. Furthermore, gas storage fields may be a viable means for future use as CO_2 storage fields—either permanent storage from a large CO_2 source, or as a CO_2 buffer operation for a larger CO_2 EOR operation. Occasionally a gas storage field will be offered for sale. Any future CO_2 producer or EOR operator might find purchasing such a field cost efficient for storage of CO_2, especially if the preexisting infrastructure could be used. The MRCSP Phase II project will examine storage fields in greater detail for these reasons.

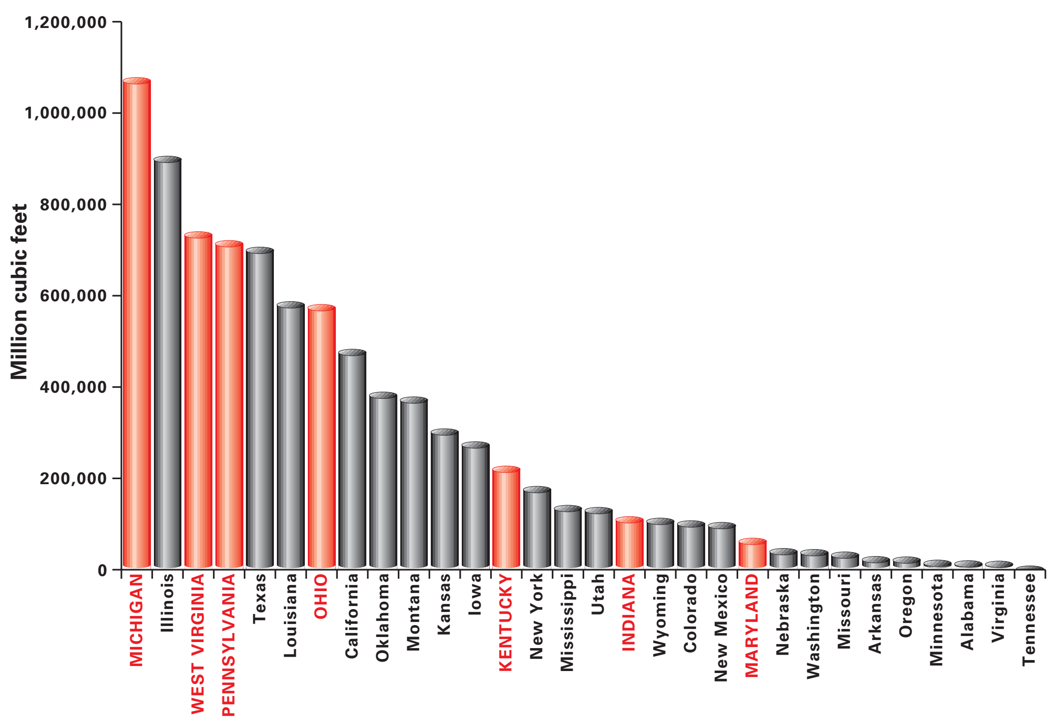

Figure 19.—Gas storage capacity and ranking by state with MRCSP-member states highlighted. Data source: Natural Gas Monthly, 2002.

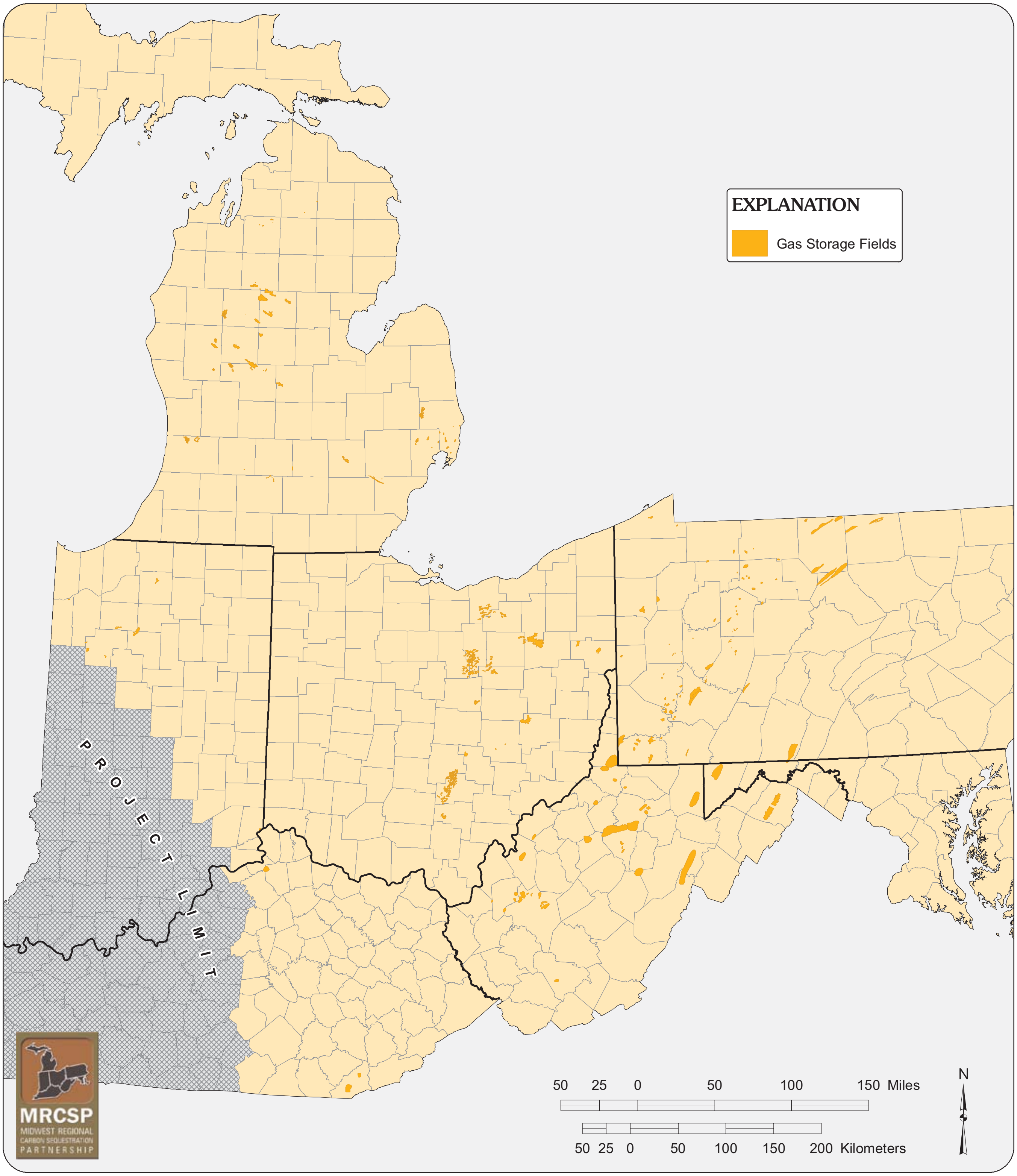

Figure 20.—Location of gas storage fields in the MRCSP region.

CO_2-SEQUESTRATION STORAGE CAPACITY FOR THE MRCSP PROJECT

CO_2-STORAGE MECHANISMS IN GEOLOGIC FORMATIONS

Carbon dioxide sequestration in geologic strata relies upon a number of different storage mechanisms that are based on site-specific geologic conditions. Based on the geologic sequestration research conducted over the last decade by a number of researchers, these mechanisms are now fairly well described in published papers and proceedings of conferences such as the Greenhouse Gas Control Technology (GHGT) series organized by the International Energy Agency Greenhouse Gas R&D Programme (see www.ieagreen.org.uk for conference proceedings information) or in the Special Report on Carbon Dioxide Capture and Storage prepared by the Intergovernmental Panel on Climate Change (IPCC) (e.g. Houghton and others, 1996; 2001). The commonly discussed storage mechanisms are volumetric storage, solubility storage, adsorption storage, and mineral storage. Volumetric storage refers to the amount of CO_2 that is retained in the pore space of a geologic unit, generally as a supercritical phase retained by structural or stratigraphic traps or by the overlying cap-rock layers. Solubility storage involves dissolution of a part or all of the CO_2 into the formation waters of the geologic unit. Adsorption storage involves the holding of CO_2 molecules onto the fracture faces and into the matrix of organic-rich rock units, such as coal or black shale. Mineral storage involves the chemical reaction of CO_2 with the minerals and brine in the geologic unit. Under appropriate conditions, some chemical reactions may form a solid precipitate, permanently binding the carbon to the geologic unit. Mineral storage is not investigated as part of this report because the complex nature of the reactions and the uncertainty in reaction rates makes it difficult to determine the storage volumes on a regional scale. In addition to the types of formations and storage mechanisms evaluated in this report, basalt layers and salt caverns are also potential repositories for CO_2-storage; however, due to the early state of research for these options, they were not evaluated at this time for MRCSP region.

CO_2 PROPERTIES

Before the description of the calculation methods used for CO_2-storage capacity determinations can begin, it is important to briefly review the physical properties of CO_2, since these physical properties affect how much CO_2 can be placed into storage. The phase behavior of CO_2 is well understood and can be found in general chemical references such as Lemmon and others (2003) or in literature on enhanced oil recovery (e.g., Jarrell and others, 2002). Carbon dioxide can exist as four different phases (Figure 21), as a solid, liquid, gas, or as a super-critical gas. The triple point for solid, liquid, and gas is at -69.826º F (-56.57º C) and 75.2020672 psia (0.5185 MPa). At temperatures greater than 87.8º F (31.1º C) and pressures greater than 1,071 psia (7.38 MPa), CO_2 is in a super-critical state, behaving similar to a gas by filling all available space, while having the density of a liquid. Using typical parameters for the MRCSP area, such as a geothermal gradient of 0.01º F/ft (0.0182º C/m), a surface temperature of 56º F (13.33º C), and a pressure gradient of 0.433 psia/ft (9,792.112 Pa/m), a line representing the typical pressures and temperatures with depth can be superimposed on the phase diagram (Figure 21). This line shows that at shallow depths (less than ~2,500 ft), CO_2 would be stored in a gaseous phase, while at deeper depths (greater than ~2,500 ft), most of the CO_2 will be in the super-critical gas phase, with some storage as a liquid. The recognition of the super-critical gas phase is important since, under most geologic storage scenarios being evaluated, CO_2-storage will occur as a super-critical gas.

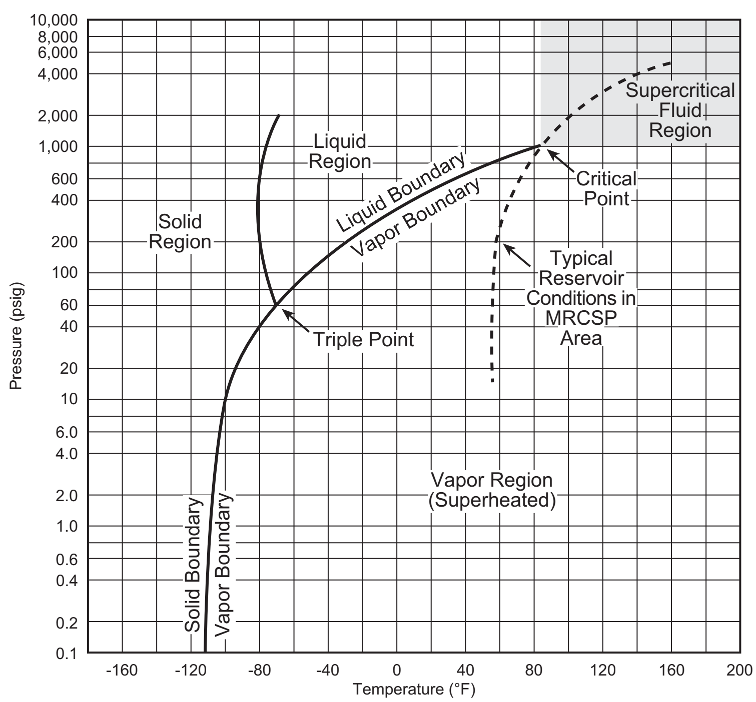

Figure 21.—CO_2 phase diagram. The triple point for CO_2 occurs at -69.826°F (-56.57°C) and 75.202 psia (0.518 MPa) (Lemmon and others, 2003). The super-critical gas phase occurs at 87.8°F (31.1°C) and 1,071 psia (7.38 MPa). The dashed line represents typical reservoir conditions in the MRCSP area.

One of the most important properties for the sequestration of CO_2 is density. In Figure 22, temperature is plotted against pressure and density. At low pressures, similar to conditions in shallow reservoirs, CO_2 density is low, so the relative volume of a given amount of CO_2 will be large. Hence, at low pressure, low temperature, and low density, the amount of CO_2 that could be stored in a given space will be relatively low. At increasing depths, density rapidly increases as CO_2 changes phase to first a liquid and then a super-critical gas. In fact, the density of CO_2 at standard temperature and pressure is only 0.1124 lbs/ft^3 (1.8 kg/m^3) while the density at the critical point is 29.09 lbs/ft^3 (466 kg/m^3)—an increase of about 260 times! At very high pressure and temperature conditions found in very deep geologic layers the density of CO_2 may be as high as 62.43 lbs/ft^3 (1000 kg/m^3). Thus, the amount of CO_2 that can be stored in the liquid or super-critical gas phases, in a given space, will be several hundred times larger than storing it in the gaseous phase. Figure 23 illustrates how the density of CO_2 increases with increasing depth (temperature and pressure increase with depth), using typical temperature and pressure parameters for the MRCSP area—geothermal gradient (0.01º F/ft (0.0182º C/m)), surface temperature (56º F (13.33º C)), and pressure gradient (0.433 psia/ft (9,792.112 Pa/m))—which corresponds to an assumption of a freshwater gradient. At shallow depths, CO_2 is in a gaseous phase, so its density is low. As the depth increases to approximately 2,500 ft (762 m) below surface, the density rapidly increases because the CO_2 changes phase to a liquid and then a super-critical gas. This high density at depth provides a much larger storage capacity than the gas-phase storage and is the primary reason that 2,500 ft (762 m) is considered to be the approximate minimum depth for CO_2-storage.

The primary reason why the petroleum industry is interested in injecting CO_2 is because its physical properties make it a good media for enhancing the recovery of oil. Where CO_2 injection has already been used for secondary recovery, for example in Texas, it has been used as either a liquid or super-critical gas, and its density and viscosity make it ideal for enhanced oil recovery (Jarrell and others, 2002). The density of CO_2 is similar to that of oil, but its viscosity is lower.

For the storage of CO_2 in brine solution, it is important to examine the physical properties of CO_2 in solution. Figure 24 shows that the solubility of CO_2 in fresh water increases with decreasing temperature and increasing pressure (Jarrell and others, 2002). Conversely, CO_2 solubility decreases with increasing salinity as shown in Figure 25 (Jarrell and others, 2002). NaCl is used here as a proxy for overall brine compositions. For example, Figure 25 shows a more than a 50 percent reduction in solubility as salinity increases to 200,000 parts per million. Because high salinity brine is likely to be present in most deep geologic storage reservoirs, especially in the MRCSP region, solubility related storage will not provide a large fraction of the total storage capacity in the short-term. Slowly, over time, the CO_2 will dissolve into the brine-bearing formation fluids. However, the rate of this dissolution and concurrent mineralization-based storage will be controlled by the total salinity, reaction rates, and the slow hydrodynamic flow in these layers that will inhibit mixing.

In order to correctly model the density of CO_2 in the MRCSP area, it was necessary to understand the distribution of the fluid pressure gradient, surface temperature, and geothermal gradient. For the fluid pressure gradient, a value of 0.433 psia/ft (9,792.112 Pa/m) was used for the entire region. This value was calculated from a fresh water pressure gradient, because adequate data is not regionally available to determine brine density with depth in the MRCSP project area. Limited numbers of available data indicate a pressure gradient range of 0.38 to 0.48 psi/ft (8,595 Pa/m to 10,858 Pa/m) is representative of the region (Gupta and others 2004a; Gupta and Bair 1997; Russell, 1972). Using these relationships and the temperature and pressure grids described earlier in this report, the CO_2 density at any particular depth is calculated.

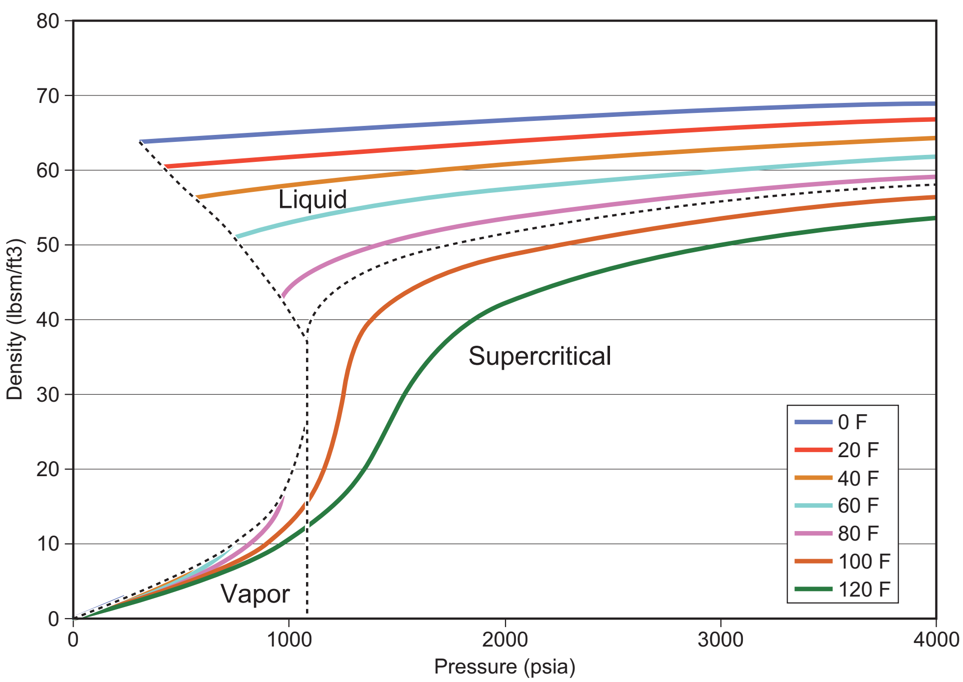

Figure 22.—Diagram for CO_2 of different temperature curves plotted against pressure and density. CO_2 density data from Lemmon and others (2003).

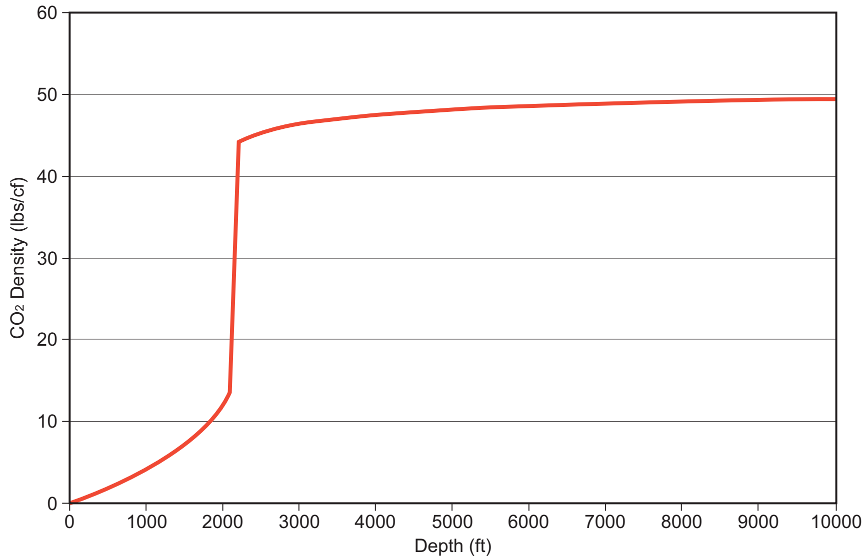

Figure 23.—Diagram showing CO_2 density with depth for a typical pressure gradient, surface temperature, and geothermal gradient in the MRCSP area. CO_2 density data from Lemmon and others (2003).

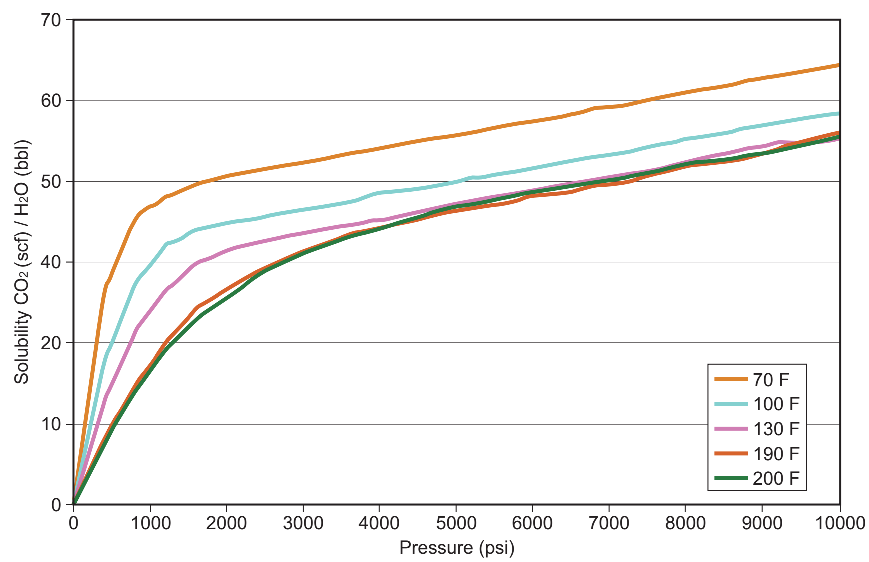

Figure 24.—Solubility of CO_2 in fresh water. Data from Jarrell and others (2002).

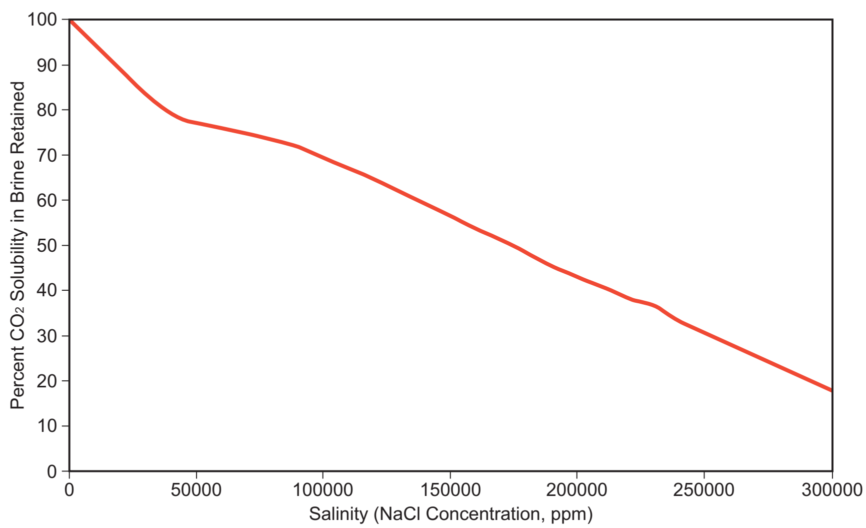

Figure 25.—Diagram showing the decrease in CO_2 solubility with increasing salinity. Data from Jarrell and others (2002).

ESTIMATING STORAGE CAPACITIES

Calculation of the storage capacities in various geologic formations has been attempted by a number of research projects during the last ten years. However, despite these efforts, there is no single accepted methodology for determining capacities at local, regional, basin, or global scales. The estimates in existing studies vary over a large range. This uncertainty is a result of the lack of detailed geologic data on formation thickness, lithology, pressure, fluid density, salinity, etc., for most of the sedimentary basins, except in areas where extensive oil and gas exploration has occurred. Almost of all of the methods involve estimating the total pore volume for the subject formation and using an assumption for the storage efficiency and mechanism to evaluate the fraction of the total capacity that may be available for actual storage. An early estimate of the global storage capacity developed by Hendricks and Blok (1993) ranges from 400 to 10,000 gigatonnes of CO_2. Similarly, Bergman and Winter (1995) estimated U.S. saline-reservoir storage capacity ranges from 5 to 500 gigatonnes of CO_2. Several other approaches are cited in the following sections. In addition to the regional rock volume-based approaches, detailed reservoir simulations (e.g. Gupta and others 2004a) have also been used to more accurately determine site-specific storage and injection rates. Such detailed studies based on site characterization (e.g., Gupta and others, 2004b) will certainly be a requirement for actual project implementation. The following sections discuss the methods used in this study for estimating total pore volumes and possible storage capacity for volumetric, solubility, and adsorption-based storage in the MRCSP region.

Volumetric Storage

Storage of CO_2 in pore spaces as a free phase is herein referred to as volumetric storage. The CO_2 is injected into the geologic unit and occupies some portion of the pore space. For the saline formations in the MRCSP project, it is initially assumed that CO_2 will completely displace the brine pore waters. While not realistic, it does give the maximum amount of CO_2 that can be placed into storage. A wide range of factors, including reservoir chemistry, heterogeneity, cementation, and structure, will further constrain the actual amount of CO_2 that can be stored at any site. For depleted oil-and-gas fields, it is assumed that there is residual-water saturation occupying pore space, which decreases the amount of pore space available for CO_2 to occupy. The volumetric capacity calculation is modified to reflect the residual-water saturation.

Injection into the geologic unit's pore space will initially displace the pore fluids. These pore fluids include brine waters, oil, and gas. The injection will initially be as a separate phase of CO_2 liquid or super-critical gas. Only over a long period of time will CO_2 dissolve into the formation fluids and possibly react with the matrix and formation fluids to precipitate carbonate minerals. In addition, the amount of CO_2 that dissolves into the pore fluids will be limited by the temperature and salinity of the fluid. Due to the long time intervals for the CO_2 to react with the geologic unit and its formation fluids, volumetric storage will be the primary storage mechanism considered for the CO_2-sequestration capacity calculations.

The general equation for volumetric storage CO_2-sequestration capacity essentially provides an estimate of the total pore volume in the formation:

$$Q_{CO_2} = \rho_{CO_2} * \theta * Vb \quad (1)$$

where:

Q_{CO_2} = CO_2-sequestration capacity for total pore volume
ρ_{CO_2} = Density of CO_2 under reservoir conditions
θ = Porosity
Vb = Bulk reservoir volume

For the MRCSP project, the equation is slightly modified, due to the use of English units of measurement, to:

$$Q_{CO_2} = \rho_{CO_2} * \theta * A * H / 2200 \quad (2)$$

where:

Q_{CO_2} = CO_2 sequestration capacity (metric tonnes)
ρ_{CO_2} = Density of CO_2 under reservoir conditions (lbs/ft^3)
θ = Porosity (%)
A = Area (ft^2)
H = Thickness of the geologic sequestration unit (ft)
2200 = Conversion from lbs to metric tonnes

Other variations of this volumetric approach have been used by Van der Straten (1996) to estimate saline-reservoir capacity in Europe and by Gupta and others (1999; 2001) to estimate storage capacities for the Mt. Simon Sandstone and the Rose Run sandstone in the U.S. Both of these use factors such as storage efficiency (6 percent) and net-to-gross-ratios to adjust the calculated pore volumes.

The calculations for the saline formations were conducted using GIS software, using the raster-based Spatial Analyst extension of the ArcGIS software system. The general procedure for performing the calculations is to first create a structure contour grid and an isopach grid for the saline formation sequestration unit (Venteris and others, 2005). The structure elevation grid is then subtracted from a surface DEM grid to obtain a depth grid. This depth grid is used to obtain the pressure and temperature of the saline formation at depth. The reservoir pressure is obtained by multiplying the fresh water pressure gradient of 0.433 psia/ft (9,792.112 Pa/m) with the depth grid, which results in the formation fluid pressure at depth. To obtain the reservoir temperature, the geothermal gradient grid is multiplied with the depth and the surface temperature grid is added to this result. Using a custom-created macro (modified from Radhakrishnan and others, 2004) to determine the CO_2 density from a database table, these new reservoir pressure and temperature grids are then used, along with the isopach grid and the average porosity for the sequestration unit, to calculate the CO_2-sequestration capacity. For the saline formations, the resultant CO_2 capacity grid can be displayed (for example, see Figure 26) to illustrate where any particular unit has higher and lower capacity potential.

Volumetric sequestration capacity in depleted oil-and-gas fields has an equation similar to the saline formation capacity calculation, except that the volumetric capacity calculation is modified to reflect the residual-water saturation. The residual-water saturation is expected to reduce the amount of pore space initially available for CO_2 to occupy.

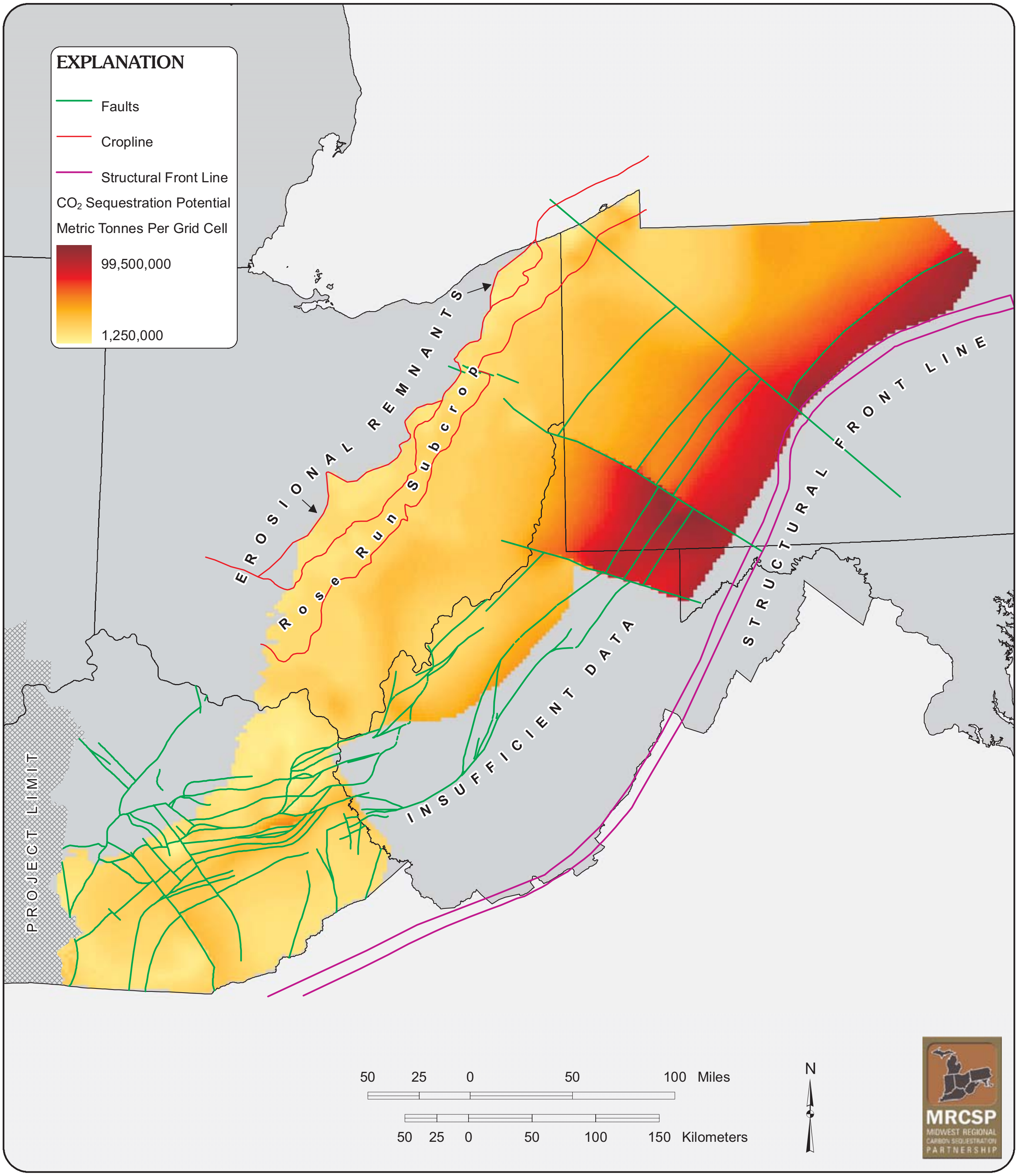

Figure 26.—Rose Run sandstone CO_2-sequestration capacity results from grid-to-grid and table look-up operations. Grid cells are 10,000-feet^2 (3.587 sq. mi.).

$Q_{CO_2} = \rho_{CO_2} * \theta * A * H\ (1 - S_W) / 2200$ (3)

where:

Q_{CO_2} = CO_2 sequestration capacity (metric tonnes)
ρ_{CO_2} = CO_2 density (lbs/acre-ft)
θ = Porosity (%)
A = Area (acres)
H = Net thickness (ft)
S_W = Water saturation (%)
2200 = Conversion from lbs to metric tonnes

The calculation methodology used for oil-and-gas fields is different than the method used for saline formations. The calculations are conducted using database techniques, as opposed to the calculations being conducted in a GIS using raster-modeling techniques. The reservoir temperature, pressure, thickness, porosity, and irreducible-water saturation for the oil and gas field are calculated from available data for the wells that are associated with the oil-and-gas pool or field. The assumptions for missing temperature and pressure data, which are incorporated in equations (4) and (5), is a surface temperature of 61° F (16.11° C), geothermal gradient of 0.007° F/ft (0.01276° C/m), and hydrostatic pressure gradient of 0.433 psi/ft (9,792.112 Pa/m). The assumptions for missing thickness, porosity, and irreducible-water saturation data are located in Table 6.

T (F) = 61 + 0.007 (F/ft) x depth (ft) (4)
P (psia) = 0.433 (psi/ft) x depth (ft) (5)

The area for the pool or field is taken from the polygon area from the oil-and-gas fields GIS, with the unit of measurement converted from ft^2 to acres. Once all the information on the oil and gas field has been populated in a database table, the calculations are performed. The reservoir pressure and temperature are used, as part of an SQL look-up, to find the density of CO_2 in the reservoir. Density along with the other reservoir parameters of thickness, porosity, irreducible-water saturation, and area of the oil and gas pool or field, are then used to calculate the CO_2-sequestration capacity of the oil and gas field.

The equations used in this section provide an estimate of the total pore volume available for storage. The actual volume of storage will depend on factors such as storage efficiency, porosity, and net-to-gross-ratio. Each of these factors will reduce the amount of CO_2 that can be sequestered at any specific site, so the total pore volume needs to be further adjusted for these factors. Tables 7 through 22 show the total CO_2-sequestration capacity at the 10 percent level.

Table 6.—Assumptions for missing data in oil-and-gas field CO_2-sequestration calculations

Formation	*Net Thickness (ft)*	*Porosity (%)*	*Sw (%)*
Clinton sandstone	18	8	5
Trenton Limestone	12	10	5
Beakmantown dolomite	10	15	5
Rose Run sandstone	35	8	5
Copper Ridge sandstones	13	9	5
Copper Ridge dolomite	13	8	5
Krysik Sandstone	14	14	5
Knox “B” zone	14	6	5

This is an estimate of the amount of CO_2 that will ultimately occupy the pore space. Modeling studies by van der Meer (1995) and Holt and others (1995) have predicted storage efficiencies ranging from 1to 6 percent (van der Meer, 1995) to 30 percent (Holt and others, 1995). Thus, the 10-percent total sequestration-capacity represents an estimate that the MRCSP project anticipates is more realistic for the actual amount of CO_2 that could actually be sequestered in the region’s reservoirs. Given the spatial variability in parameters and the lack of detailed data on the deep formations, for the purpose of the current study, it is assumed that 10 percent of the pore volume in these will be available for actual storage within any individual reservoir.

Solution Storage

Carbon dioxide can dissolve into formation fluids, but it is expected that large amounts of solubility storage will only occur over long time periods due to high salinity, extremely slow mixing rates in the deep formations, limited interaction face between the CO_2 plume and surrounding brine, and slow solution rates. For example, Gupta and others (2004a) used compositional reservoir simulations for CO_2 injection in the Mt. Simon Sandstone to show that over a period of 500 years, only 8 percent of the total CO_2 injected has moved into dissolved phase. As stated above, most salinity measurements of potential storage reservoirs within the MRCSP are very high (CO_2 solubility is inversely proportional to salinity). Because of the low solution rates, high salinities, and generally increasing salinities with depth in the MRCSP area, solubility calculations were not performed systematically for the Phase I project. Nonetheless, one representative solution calculation was performed for comparison purposes, and that is described in the *Discussion of Results* section. For completeness, however, the calculation methodology for solution storage is covered here.

One method of calculating the capacity of CO_2 that can dissolve into formation fluids is derived from Carr and others (2003).

$Q_{CO_2} = 1.1023* ((7758* (\theta * A * H) * S_{CO_2} * B_{CO_2})/(1000 * 17.25)$ (6)

where:

Q_{CO_2} = CO_2-sequestration capacity (metric tonnes)
7758 = Conversion from acre * ft to bbl.
θ = porosity (%)
A = area (acres)
H = thickness (ft)
S_{CO_2} = CO_2 solubility in fresh water (SCF/bbl water)
B_{CO_2} = CO_2 solubility in brine (%)
1000 = Conversion from ft^3 to MCF
17.25 = Conversion from MCF to short tons
1.1023 = Conversion from short tons to metric tonnes

The values for CO_2 solubility in fresh water and CO_2 solubility in brine are derived from Jarrell and others (2002). To determine the CO_2 solubility in fresh water and CO_2 solubility in brine, the reservoir temperature, pressure, and salinity (NaCl in ppm) are needed. Reservoir temperature and pressure are used to determine CO_2 solubility in fresh water using a database look-up table. The salinity data is used in a database look-up table to determine the CO_2 solubility in brine. The CO_2 solubility in brine is multiplied by the CO_2 solubility in fresh water to determine the CO_2 solubility in the formation fluids (Jarrell and others, 2002).

Table 7.—Summary of estimated effective CO_2-storage capacity by geologic interval or reservoir type (in gigatonnes)

Sequestration Target	*Porosity (%)*	*Density (g/cc)*	*Gas Content (scf/ton)*	*Area (mi²)*	*Total*
Oil and Gas Fields					2.51
Waste Gate Formation	10			1,342	4.38
Coal beds (net thickness)		1.32	100	25,578	0.25
Antrim and Ohio shales		2.62	42.9	109,043	45.3
Needmore Shale		2.62	42.9	850	0.05
Sylvania Sandstone	10			25,324	15.11
Oriskany Sandstone	10			57,313	19.43
Medina/Tuscarora SS	8			72,328	70.53
St. Peter Sandstone	10			41,796	88.13
Rose Run sandstone	8			57,493	49.27
Potsdam Sandstone	2			9,298	1.71
Conasauga Formation	2			24,973	4.25
Rome trough sandstones	1			18,452	1.23
Mt. Simon Formation	8			85,916	217.18
Total					519.35

Table 8.—Estimated effective CO_2-storage capacity by reservoir type and state (in gigatonnes)

State	*Saline*	*Coal*	*Shales*	*Oil & Gas*	*Total*
Eastern Indiana	80.7	0	0	0.01	80.7
Eastern Kentucky	10.9	0.02	1.7	0.65	13.2
Maryland	9.5	0	0.009	0	9.5
Michigan	216.1	0	4.2	0.05	220.3
Ohio	37.3	0.04	8.5	0.4	46.3
Pennsylvania	75.6	0.08	12.0	0.8	88.5
West Virginia	41.1	0.11	19.0	0.6	60.8
Total	471.2	0.25	45.4	2.5	519.3

Table 9.—Oil and gas fields. Estimated CO_2-storage capacity by state (in gigatonnes)

State	*<2499 Feet*	*>2500 Feet*
Eastern Indiana	0.006	0.008
Eastern Kentucky	0.009	0.644
Michigan	0.046	0.003
Ohio	0.366	0.053
Pennsylvania	0.455	0.310
West Virginia	0.533	0.082
Total	1.415	1.100

The calculations for the saline formations were conducted using GIS software, in a very similar methodology as with the volumetric calculations. The general procedure for performing the calculations is to first create a structure contour grid and an isopach grid for the saline formation sequestration unit (Venteris and others, 2005). The structure elevation grid is then subtracted from a surface DEM grid to obtain a depth grid. This depth grid is used to obtain the pressure and temperature of the saline formation at depth as discussed earlier. A custom created macro (modified from Radhakrishnan and others, 2004) is used to determine the CO_2 solubility in fresh water from a database table using the temperature and pressure, and the salinity is used to determine the CO_2 solubility in brine from a database table. These solubility values are then used, along with the isopach grid and the average porosity for the sequestration unit, to calculate the CO_2-sequestration capacity.

The salinity grid construction was discussed previously in the methods sections. For the representative calculation performed as part of the MRCSP project, a least-squares relationship was calculated for the salinity value taken from the geologic unit being modeled, which in this case, was the Mount Simon Sandstone. The resulting equation was then used to calculate the CO_2 solubility in brine.

Other solubility-based approaches for capacity estimates include those by Bachu and Adams (2003) for the Alberta basin; Brennan and Burruss (2003) developed a solubility- and saturation-based approach, which, as an example, was used to estimate the storage capacity in the U.S. and Canada by Dooley and others (2004).

Adsorption Storage

CO_2 sequestration in organic-rich rock units, such as coal beds and black shales, could, potentially, provide both long-term CO_2-storage and a method to increase production of a highly usable fossil fuel, natural gas, in a manner analogous to CO_2-enhanced oil recovery. Carbon dioxide, when introduced to a coal bed or black shale, preferentially displaces methane, which is adsorbed on the coal surface within the cleat system and is adsorbed in pore spaces of organic matter and clay mineral surfaces that occur in the matrix of the coal or shale. Previous studies on CO_2 sequestration and methane recovery indicate that, for coals of the type found in the Appalachian and Michigan basins, at least two molecules of CO_2 can be injected for every one molecule of CH_4 released from the coal bed (Gale and Freund, 2001). On average, more than twice as much CO_2 can be stored on a volumetric basis than the amount of CH_4 extracted (Gluskoter and others, 2002; Mastalerz and others, 2004). CO_2 and CH_4 adsorption isotherm data indicate also the ratio may be much higher. The use of coal beds and black shales could provide a larger area in which CO_2 can be sequestered or offer multiple options for sequestration at some locations. The production of methane from these organic-rich rock units will also help to offset costs of sequestering CO_2.

Sequestration in coal beds is the basis of a proposed efficient null-greenhouse-gas emission power-plant fueled either by mined coal or coalbed methane from deep unmineable coal (Wong and Gunter, 1999). The produced CO_2 from the power plant would be injected into coal beds to produce more methane. In addition, the CO_2 would be geologically sequestered in the coal beds (Wong and Gunter, 1999).

Burlington Resources has demonstrated the success of enhanced gas recovery (EGR) to recover methane by injecting CO_2 into the relatively high permeability coal beds in the San Juan basin for several years (Schoeling, 1999). Coalbed methane production has been stimulated while injected CO_2 has not broken through to production wells. The injected CO_2 appears to be adsorbed into the coal matrix displacing methane, and remains in the ground. An additional project is underway to further test the EGR process in the relatively low permeability coal beds in Alberta, Canada. These projects and others show also that there are limitations to sustained injection, such as swelling. For the purposes of this project, these limitations are not considered.

The MRCSP project uses GIS technology for computing CO_2-sequestration potential in organic-rich rock units. In this report, a proposed methodology for estimating CO_2 sequestration volumes in coal beds and black shales is presented. Due to the nature of the gas-trapping mechanism in these type of reservoirs, we are using the standard methodology for *gas in place* calculation in non-conventional reservoirs developed by the Gas Research Institute (Mavor and Nelson, 1997); a different approach than used for volumetric calculations in conventional reservoirs. The CO_2-sequestration potential calculations are basically a series of simple mathematical operations on defined GIS-raster grids. The calculations for determining coal bed and black shale CO_2-sequestration potential are well suited to using GIS techniques.

In order to calculate the CO_2-storage potential of a coal bed, a number of steps are required. The calculation is basically a series of simple mathematical operations on defined grids. Raster grids were created for the themes listed below:

H_{coal} = Coal thickness or isopach map (ft)
G_{coal} = Gas content of the coal, (SCF/short Ton)

The calculation of CO_2-sequestration potential in coal beds is based upon the observation that CO_2 preferentially displaces and replaces CH_4 adsorbed on the coal-bed cleats. To calculate the CO_2-sequestration potential, the coalbed methane (CBM) resources must first be calculated. This calculation involves using the coal bed gas-content values for a given volume of coal at a given density:

$$R_{cbm} = \rho_{coal} * V * G_{coal} / 1000 \quad (7)$$

where:
R_{cbm} = Coalbed methane resources (MCF)
ρ_{coal} = Coal density (short tons/ft^3)
V = Volume of coal (ft^3)
G_{coal} = Coal bed gas-desorption value (SCF/short Ton)
1000 = Conversion from SCF to MCF

The CBM resources can be expressed as:

$$R_{cbm} = (\rho_{coal} * A * H_{coal} * G_{coal}) / 1000 \quad (8)$$

where:
A = Area (ft^2)

Initial studies have shown that CO_2 displaces CH_4 at a ratio of 2:1. Further studies (Gluskoter and others, 2002; Mastalerz and others, 2004) show that CO_2: CH_4 adsorption ratios will vary from 2:1 to 16:1, depending on the coal rank. The preliminary estimate for CO_2-sequestration potential in all coal beds will be at least double that of the CBM resources for the same area:

$$Q_{CO2} = C_{CO2CH4} * R_{cbm} \quad (9)$$

where:
Q_{CO2} = CO_2-sequestration potential in all coal beds (MCF)
C_{CO2CH4} = CO_2:CH_4 ratio, which for the MRCSP project is 2

The final step in the calculation of the CO_2-sequestration potential involves the conversion of the volume of gaseous CO_2 to short tons. At surface conditions of 60º F (15.55º C) and 1 atm (101,325.01 Pa), the conversion factor is 17.25 MCF/short ton (8.625 ft^3/lbs).

The full version of the equation to calculate CO_2-sequestration potential:

$$Q_{CO2} = 1.1023 * C_{CO2CH4} * (\rho_{coal} * H_{coal} * A * G_{coal}) / (1000 * 17.25) \quad (10)$$

where:
1.1023 = Conversion from short tons to metric tonnes

The calculation for organic-rich shales is very similar to the calculation for coal beds. Carbonaceous gas-shales of Devonian age underlie the Appalachian and Michigan basins within the study area of the MRCSP. These continuous, low-permeability shales serve as both a sealing interval for deeper reservoirs and a potential sequestration target. In addition, CO_2 injection into fractured gas-shales represents a potential method to enhanced natural-gas production. The Kentucky Geological Survey, an MRCSP geologic team member, has been investigating the potential use of carbonaceous shales for CO_2 sequestration under a separate U.S.

DOE contract (*Analysis of the Devonian Black Shale in Kentucky for Potential Carbon Dioxide Sequestration and Enhanced Natural Gas Production*, DOE/NETL contract DE-FC26-02NT41442) and much of the following discussion results from that work (Nuttall and others, 2005b).

For estimating sequestration volumes in organic-rich shales, two storage strategies must be considered. Injected CO_2 will occupy the natural fracture system as either a free gas or a supercritical fluid depending on reservoir pressure and temperature conditions. Standard volumetric methods can be used to estimate this capacity, but should only be applied within the extent of known gas-producing areas of the shale.

A much larger volume of CO_2 is likely to be permanently stored as gas adsorbed onto organic matter and clay minerals in the shale matrix (similar to coal). The method used to estimate this CO_2-storage capacity is to convert a volume of shale to a weight of shale using its density and then calculate the volume of CO_2 using gas content data.

The shale volume is estimated from gridded isopach data imposing the limitations that the top of the shale must be a minimum drilling depth of 1,000 feet (304.8 m) and the shale is a minimum of 100 feet (30.48 m) thick. The strict application of these conditions eliminated areas in Ohio and Pennsylvania where the shale is shallower than 1,000 feet (304.8 m), but exceededs several thousand feet in thickness. With this consideration, additional areas in those two states were added for evaluation. These limits were arbitrarily selected to ensure sufficient reservoir and seal capacity for CO_2 sequestration.

Shale density varies inversely with organic matter content (Schmoker, 1993). Figure 27 is a gamma-ray density cross-plot derived from digital logs from wells in the Big Sandy field in eastern Kentucky. The plot demonstrates the variation of shale density (top of Ohio Shale to the base of its Lower Huron Member). Clastic-rich gray shales (gray dots) with minimal organic matter generally exhibit a bulk density greater than 2.55 grams per cubic centimeter (g/cc) and gamma-ray reading of less than 250 API units. Maximum shale density (minimal organic matter) is approximately 2.82 g/cc. Minimum shale density (maximum organic matter) is approximately 2.35 g/cc. For initial regional assessments, a shale density of 2.62 g/cc is used (Nuttall and others, 2005b).

To determine gas content of the shale, CO_2 adsorption isotherm data were collected as part of the current Kentucky U.S. DOE-funded project. These data indicate the adsorption capacity of the shale averages 42.9 standard cubic feet of CO_2 per ton (scf/ton) of shale (1.134 m^3/tonne) and ranges from 13.9 to 135.7 scf/ton (0.43 to 4.24 m^3/tonne) (Nuttall and others, 2005b). Observed adsorption data are log-normally distributed. For comparisons with the other reservoir types, a gas content value of 42.9 scf/ton was used to calculate CO_2-storage capacity herein. This value is a reasonable average for regional calculations based on available CO_2 isotherms (Nuttall and others, 2005b), but actual values would obviously vary with organic content.

Although the methodology used to calculate storage capacity in organic shales of the region is reasonable for a first cut at a regional assessment, it can be improved. Original calculations assumed storage capacity to be proportional to density and suggested increasing

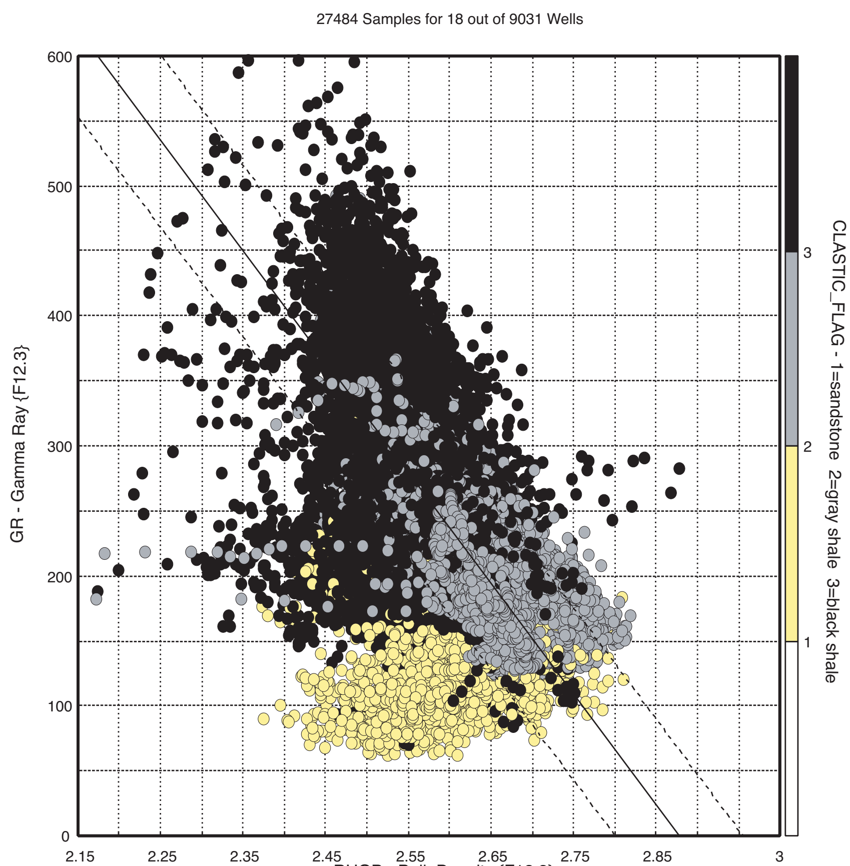

Figure 27.—Gamma-ray density cross-plot derived from digital logs from wells in the Big Sandy field in eastern Kentucky showing the variation of shale density with gamma-ray intensity.

density yielded higher sequestration capacities. In actuality, the adsorbed gas capacity (and thus sequestration potential) is inversely proportional to density which, itself, is a function of total organic content (TOC). Schmoker (1993) described the relationship between density and TOC in his method to determine total organic matter content from density logs. The relation between measured TOC and adsorption capacity is being investigated in current shale research at the Kentucky Geological Survey (Nuttall and others, 2005b).

There are a number of factors that will reduce the amount of CO_2 that can be adsorbed into coal beds. These include the amount of moisture, the heating value (BTU) and vitrinite reflectance, maceral composition, surface area and pore throat size, and cleat and fracture permeability (Drobmiak and others, 2005). Presumably, these factors will also affect organic-rich shales. Each of these factors will affect the amount of CO_2 that can be sequestered at any specific site, so the total pore volume needs to be further adjusted for these factors. Tables 7, 8, 11-13 show the total CO_2-sequestration capacity at the 10 percent level. This is an estimate of the amount of CO_2 that will ultimately be adsorbed by coal beds and organic-rich shales.

DISCUSSION OF RESULTS

The primary results of the volumetric storage capacity calculations shows that the MRCSP project area has a large amount of potential capacity for CO_2 sequestration. However, actual capacity will be limited by a large number of factors that are discussed in the following pages, but is likely less (and more variable) than what is calculated herein. Nonetheless, the results calculated do provide a basis for a comparison between units, states, and other regions using similar methods to determine future storage capacity. The total amount of potential CO_2 sequestration capacity for the MRCSP region is estimated at about 520 gigatonnes (Table 7). The majority of the CO_2-sequestration capacity in the MRCSP area, about 470 gigatonnes, or approximately 90 percent of the total estimated CO_2-storage capacity, represents the potential of the deep saline formations. The black shales have the next largest storage potential, with a sequestration capacity of 45.4 gigatonnes, which is approximately 9 percent of the total estimated CO_2-storage capacity. Oil-and-gas fields have a potential sequestration capacity of about 2.5 gigatonnes, which is approximately 0.5 percent of the total estimated CO_2-storage capacity. The smallest sequestration capacity occurs in coal, with a total of 0.25 gigatonnes, which is approximately 0.5 percent of the total estimated CO_2-storage capacity (Table 7). The reader is referred to the MRCSP web-based interactive maps or the GIS on CD accompanying this report to view the capacity maps per geologic-interval mapped to see variations across the area.

Comparisons by State

Each state has their own set of geologic conditions and reservoirs that can sequester CO_2. Tables 7 through 22 show the breakdown of CO_2 sequestration potential by reservoir and by state. Also included in tables 7 and 10 through 22 is the area occupied by each reservoir in the MRCSP region. These area values can be used to make comparisons between different reservoirs and between different states in the MSRCSP region.

The largest potential sequestration capacity occurs in the state of Michigan with a capacity of about 220 gigatonnes (Table 8), which corresponds to 42 percent of the total capacity in the MRCSP project area. Almost all of this capacity is in deep saline formations. The Sylvania Sandstone, St. Peter Sandstone, and Mount Simon Formation, provide the majority of the capacity.

The state with the next largest sequestration capacity is Pennsylvania with a potential capacity of nearly 90 gigatonnes, which corresponds to 17 percent of the MRCSP regional sequestration capacity. Unlike the state of Michigan, the sequestration capacity in Pennsylvania is unequally distributed between five different deep saline formations, the Devonian black shales, the Needmore Shale, the oil-and-gas fields, and the coal beds. Pennsylvania also has the largest potential oil-and-gas field sequestration capacity.

The eastern part of the state of Indiana has the third largest sequestration capacity in the MRCSP region with a potential sequestration capacity of about 80 gigatonnes. Almost all of Indiana's sequestration capacity is in the Mt. Simon Sandstone. Minor amounts of sequestration capacity are found in the St. Peter Sandstone and the oil-and-gas fields in the state. Indiana's coal fields are outside of the MRCSP boundary and were not considered in the calculations.

West Virginia has the fourth largest potential sequestration capacity with a total of about 60 gigatonnes. The deep saline formations have a potential sequestration capacity of over 40 gigatonnes, while the organic-rich shales have a potential capacity of about 20 gigatonnes. Both the shale and coal bed sequestration capacities are the largest among the states in the MRCSP project. Also, the area in which coal sequestration was considered possible in West Virginia was limited to non-mining areas, so the total potential coal CO_2-sequestration capacity may be greater than estimated.

Ohio has the fifth-largest potential sequestration capacity of over 45 gigatonnes, of which, over 35 gigatonnes are in deep saline formations. The saline formations with the largest potential capacity are the Mt. Simon Sandstone (20 gigatonnes) in western Ohio, and the Rose Run (8 gigatonnes) and Medina (5.6 gigatonnes) sandstones in eastern Ohio. These three reservoirs contain 71 percent of the state's total potential sequestration capacity, and 89 percent of the saline formation capacity. The Devonian shales have a potential capacity of 8.5 gigatonnes.

Eastern Kentucky has the sixth largest potential capacity, with over 13 gigatonnes. The potential capacity is only calculated for that part of the state in the MRCSP region. The majority of the capacity is in the deep saline formations, with a total of nearly 11 gigatonnes (82 percent). The three largest deep saline formations are the Rose Run sandstone, at 5 gigatonnes (41 percent of the total capacity), Mt. Simon Sandstone, at 4 gigatonnes (33 percent of the total capacity), and basal sandstones in the Rome trough sandstone, at 1 gigatonnes (8 percent of total capacity). The next largest type of reservoir is the Devonian shale, with a potential capacity of nearly 2 gigatonnes (13 percent).

The estimated total potential storage capacity in Maryland is nearly 10 gigatonnes. Almost all of this capacity occurs in deep saline formations (Waste Gate Formation, Oriskany Sandstone, and Medina/Tuscarora Sandstones). The Waste Gate Formation has the largest capacity, over 4 gigatonnes (46 percent of the total capacity). The next largest is the Medina Sandstone, at 3 gigatonnes (36 percent of the total capacity). There is also a minor amount of sequestration potential in the organic-rich Needmore Shale. Additional storage capacity may be present in the offshore reservoirs along the Maryland coast; however, these reservoirs were not evaluated due to the lack of data.

Comparisons by Reservoir Type and Unit

The storage capacity in each reservoir is largely a function of its spatial extent, thickness, and the porosity. Given its presence in much of the MRCSP region, the saline formation with the largest capacity in the region is the Mt. Simon Sandstone, followed

Table 10.—Waste Gate Formation estimated effective CO_2-storage capacity (in gigatonnes)

State	*Area (mi²)*	*Total*
Maryland	1,342	4.4
Total	1,342	4.4

Table 11.—Net coal greater than 500 feet deep. Estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Eastern Kentucky	3,751	0.02
Ohio	5,053	0.04
Pennsylvania	4,724	0.08
West Virginia	12,042	0.11
Total	25,571	0.25

Table 12.—Devonian Shales estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Eastern Kentucky	14,066	1.68
Michigan	38,428	4.18
Ohio	24,693	8.50
Pennsylvania	7,720	12.04
West Virginia	18,323	18.91
Total	109,043	45.3

Table 13.—Needmore Shale estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Maryland	165	0.010
Pennsylvania	54	0.003
West Virginia	631	0.041
Total	850	0.054

Table 14.—Sylvania Sandstone estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*10%*
Michigan	25,324	15.1
Total	25,324	15.1

Table 15.—Oriskany Sandstone estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Kentucky	7	0.002
Maryland	1,123	0.981
Ohio	4,896	0.728
Pennsylvania	29,022	7.669
West Virginia	22,265	10.049
Total	57,313	19.429

Table 16.—Medina Sandstone estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Kentucky	420	0.089
Maryland	1,288	3.382
Ohio	15,647	5.579
Pennsylvania	31,333	36.024
West Virginia	23,642	25.459
Total	72,328	70.534

Table 17.—St. Peter Sandstone estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Indiana	1,212	0.103
Michigan	39,396	87.967
Ohio	1,187	0.064
Total	41,796	88.134

Table 18.—Rose Run sandstone estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Eastern Kentucky	13,146	5.443
Michigan	334	0.762
Ohio	16,353	8.100
Pennsylvania	22,222	29.748
West Virginia	5,438	5.215
Total	57,493	49.268

Table 19.—Potsdam Sandstone estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Ohio	18	0.002
Pennsylvania	9,280	1.704
Total	9,298	1.706

Table 20.—Unnamed Conasauga sandstones estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Eastern Kentucky	25	0.001
Michigan	409	0.164
Ohio	21,185	3.469
Pennsylvania	2,410	0.459
West Virginia	943	0.0161
Total	24,973	4.255

Table 21.—Rome trough sandstones estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Eastern Kentucky	13,157	1.001
Ohio	201	0.006
West Virginia	5,094	0.221
Total	18,452	1.228

Table 22.—Mt. Simon Formation estimated effective CO_2-storage capacity by state (in gigatonnes)

State	*Area (mi²)*	*Total*
Eastern Kentucky	6,661	4.336
Indiana	18,957	80.612
Michigan	40,530	112.839
Ohio	19,768	19.390
Total	85,916	217.177

by the St. Peter Sandstone and the "Clinton"/Medina/Tuscarora Sandstones. The deep saline formations with the smallest potential are the Potsdam Sandstone and basal sandstone in the Rome trough in eastern Kentucky. The low potentials stem from assigning these two aquifers very low porosities, since porosity generally decreases with depth, and both units are deeply buried. In addition, because of the lack of exploratory wells in many areas, such as in the deepest portion of the Appalachian basin in Pennsylvania, some areas contained no data and could not be mapped (see the structure and isopach maps of Appendix A). This also accounts for much of the small potential of the basal sandstones. The unnamed sandstones in the Conasuaga were also assigned a low porosity, since initial studies indicated the primary lithology of the Conasauga in eastern Ohio and western Pennsylvanian is a sandy or silty dolomite.

It is perhaps useful to compare the estimated capacities in this study with some other assessments. An assessment of the Mt. Simon Sandstone (including areas outside MRCSP) by Gupta and others (2001) showed a capacity range of 160 to 800 gigatonnes based on a porosity range of 5 to 25 percent, net-to-gross-ratio of 50 to 95 percent, and storage efficiency of 6 percent. In the same study, the capacity range for 8.5 percent porosity was 195 to 371 gigatonnes. This compares well with the estimated 10 percent capacity number of 217 gigatonnes for Mt. Simon in the MRCSP region in this study. Similarly, the Rose Run sandstone capacity range of 9 to 43 gigatonnes of Gupta and others (2001) is comparable to the 49 gigatonnes estimated in the current study.

Estimated CO_2 sequestration capacity in the Devonian Ohio Shale (Cleveland to Lower Huron Members) and equivalents in the Appalachian basin and the Antrim Shale in the Michigan basin ranges between 23.2 and 88.3 gigatonnes, varying between CO_2 adsorption rates of 22 and 84 standard cubic feet of gas per ton (U.S.) of shale. Capacity estimates for the black shales in eastern Kentucky represent only that part of the shale in the MRCSP region. The 90^{th} percentile figures calculated for Ohio, Pennsylvania, and West Virginia seems overly optimistic. The gray shales and intertonguing siltstones characteristic of the Devonian shale in these states may not have a sufficient organic matter content to adsorb such large volumes of CO_2. More realistically, the sequestration capacity is likely in the calculated range between the 10^{th} and 50^{th} percentiles. All of these estimates are, of course, contingent on the injectivity of CO_2 into the shale, which is untested.

For the oil-and-gas fields, the fields are separated into those that are less than 2,499 feet in depth and those that are greater than 2,500 feet in depth (762 m). The 2500-foot depth cutoff roughly corresponds to the predicted transition from the gaseous phase to the super-critical phase of CO_2, which is approximately 260 times denser than the gaseous phase and, therefore, more desirable.

Solubility Storage

While solubility storage is described in this document, it is not applied in this study, since most of the initial sequestration will occur as volumetric storage. Instead, one representative calculation was conducted for the project. The solubility capacity was calculated for Mt. Simon Sandstone of Indiana, Michigan, and Ohio. The potential CO_2-storage capacity using the solubility calculation is in excess of 83 gigatonnes, while the potential storage capacity using the volumetric calculations is over 217 gigatonnes, an increase by a factor of 2.6. However, an interesting phenomenon occurs in the solubility calculation. In the center of the Michigan basin, there is no solubility capacity. This is because the modeled salinity is too high to allow CO_2 to dissolve into the formation fluids. The high salinity, generally increasing salinities with depth, and the low solution rates indicate that solubility storage will not be a near-term factor in sequestering CO_2 in the MRCSP area. As a comparison, Dooley and others (2004) used the solubility approach to estimate that the total storage capacity in the Mt. Simon Sandstone, including all of the Illinois basin and the Appalachian basin is approximately 225 gigatonnes.

CONCLUSIONS AND REGIONAL ASSESSMENT FOR GEOLOGIC SEQUESTRATION

Under Subtask 2.1 of the MRCSP Phase I project, the geologic team examined the region's overall geology, created a regional correlation chart, and delineated the most promising prospective geologic CO_2 reservoirs and sinks via data collation, interpretation, and mapping. We then used the collected data and maps to calculate a first approximation of the region's geologic CO_2 sequestration capacities of four main reservoir classes: deep saline formations, oil and gas fields, unmineable coalbeds, and organic shales. The deep saline formations, especially the Mt. Simon, St. Peter, and Rose Run sandstones, are, by far, the region's largest assets for long-term geologic CO_2 sequestration. All of this information has been captured in a Geographic Information System using ESRI's suite of ARC-GIS products.

Through these efforts we have also defined a number of promising additional sequestration target formations including the Bass Islands Dolomite, Lockport Dolomite, and Copper Ridge Dolomite. These will be mapped and analyzed as separate units within the Phase II project to complete the region's assessment. During Phase II the geologic team will also develop more comprehensive data on the region's EOR potential, Class I and II injection wells, and gas storage fields. All of these data are necessary to provide a sound knowledge basis for moving forward with widespread implementation of geologic CO_2 sequestration.

This Phase I assessment has shown that the MRCSP region has approximately 450 to 500 gigatonnes of storage potential in deep saline formations for future deployment of geologic CO_2 sequestration technology. In fact, our region can easily accommodate many hundreds of year's worth of CO_2 emissions at current or expanded levels within this one type of reservoir. This region also has the potential to store at least 2.5 giggatones of CO_2 in existing and depleted oil and gas fields. By using anthropogenic CO_2 in enhanced oil recovery operations in current and recently abandoned oil fields, the region could realize hundreds of million of barrels of additional oil production. The northern Appalachian basin unmineable coalbeds have the potential to contain approximately 0.25 gigatonnes of CO_2. Only recently have operators started to develop the vast amount of coalbed methane found beneath the northern Appalachian basin. Application of enhanced gas recovery using CO_2 early in this endeavor could add significantly to the amount of gas produced from the deep unmineable portions of this resource while sequestering millions of tons of CO_2 in its place. The use of organic shales as a CO_2-storage medium is still an untested research topic. Should this technology prove practical, the MRCSP region has one of the richest holdings of these deposits in the world.

Although we are herein reporting capacities of reservoirs at 10 percent of total assumed volumes, we do not believe these estimates to be sufficiently conservative. It should also be kept in mind that many other restrictions will be emplaced on the use of any subsurface storage space that have not been accounted for in studies of this type to date. Such restrictions, or access issues, might include: inability to inject below large metropolitan areas or large bodies of water; inability to inject below or within specific offsets (both vertically and horizontally) of producing oil and gas fields or active mines; and the inability to inject within specific offsets (both vertically and horizontally) of other injection operations—Class I, II, or III. In addition to these listed possible restrictions, the consideration that large-scale CO_2 injection operations should not be permitted too close to one another to avoid any possibility of interaction of their related pressure fronts should be stressed. Many of these restrictions will fall under the purview of regulatory agencies to enact. As with the entire carbon capture and storage technology arena, regulations for CO_2 injection and storage are still in an early formative stage. Once regulations are known, restrictions can be applied to these capacity maps to calculate potentials including such considerations.

The above-cited storage potential is not distributed evenly over the region. Some areas have very significant storage potential while others have very little known storage potential. Mapping the distribution of this potential is just as significant to the region as calculating the potential for storage. The existing large stationary CO_2 sources of the region are not all situated over sufficient known storage potential. Therefore, it is hoped that this study, and subsequent investigations, will be used by utility and industrial decision-makers to plan future plant locations with necessary subsurface conditions in mind. Further, the maps/results of this investigation can be used to start planning for future pipelines to match existing CO_2 sources with appropriate geologic sinks.

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APPENDIX A

Geologic Summaries of Mapped Units

When contemplating the potential widespread use of deep injection into geologic reservoirs within such a large and varied area such as the MRCSP study area, decision-makers will be faced with many options. The characteristics of any single, potential carbon dioxide (CO_2) reservoir unit or seal interval can change considerably over its area of occurrence. The scope of this project did not allow the extensive undertaking required to interpret, collate, and map a large number of important geologic variables, such as porosity, lithology, and permeability, for each unit or interval across such a vast area. Nonetheless, in order to provide as much information about each mapped interval to users of this report, we have prepared a short compendium on each interval of this investigation. The following sections provide a variety of information about important aspects for each of the mapped intervals that are relevant to their use for carbon dioxide sequestration in geologic units. Additionally, a large reference list is included so users can research additional details on the geology of the intervals. The sections are arranged, geologically, from oldest to youngest.

1. PRECAMBRIAN UNCONFORMITY SURFACE

The Precambrian unconformity map represents the configuration of the surface separating Paleozoic Cambrian rocks (above) from Precambrian (Proterozoic) rocks (beneath). Despite differences in composition and age of the Precambrian below this unconformity, these rocks are generally referred to as "basement rocks," and this is the definition used herein. The term basement is used because these rocks, and the structures contained within them, form the foundation upon which younger sedimentary rocks were deposited.

The composition of Precambrian rocks below the unconformity surface is quite varied across the MRCSP study area. Rocks of the Grenville province (east of a line extending from south-central Kentucky, through western Ohio, and into the easternmost part of Michigan) are composed of Middle to Upper Proterozoic metamorphic rocks that have been intruded by igneous rocks. The age of metamorphism and faulting for the Grenville province rocks in the study area ranges from 1.1 to 0.880 billion years (Ga) (Lidiak and others, 1966; Hoppe and others, 1983; Keller and others, 1983; Van Schmus and Hinze, 1985; Lucius and Von Frese, 1988; Drahovzal and others, 1992). Protolith ages of the Grenville rocks are, at least in part, much older—1.457 Ga (Hoppe and others, 1983).

Grenville province strata were thrust (in a present-day west-northwestward direction) over other Precambrian terrains during the Grenville orogeny (Green and others, 1988; Pratt and others, 1989; Culotta and others, 1990; Drahovzal and others, 1992; Stark, 1997; Dean and Baranoski, 2002a,b). This orogenic event is thought to have created a large mountain chain that was mostly eroded during a subsequent period of prolonged Precambrian exposure. It is this erosional surface, creating the vast regional unconformity, that is mapped. The western limit of Grenville province rocks is called the Grenville front (Figure A1-1).

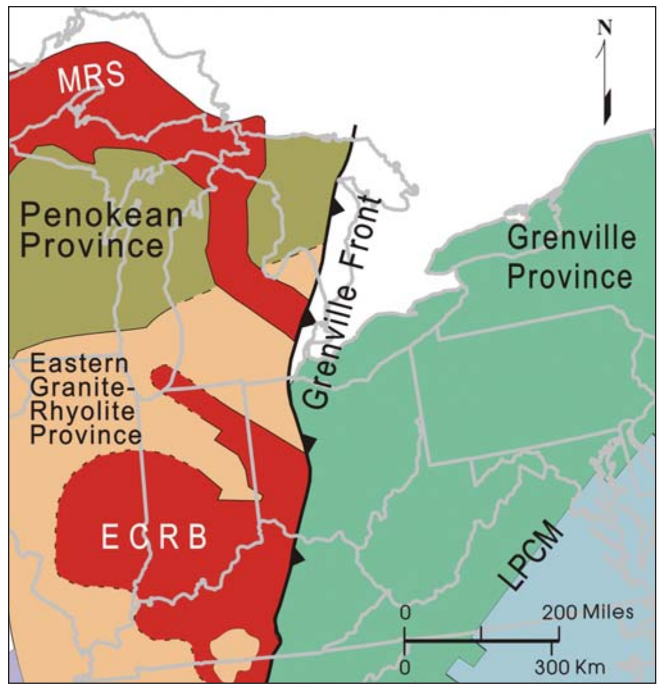

Figure A1-1.—Index map showing relationships of Precambrian tectonic provinces in and surrounding the MRCSP region. ECRB = East Continent Rift Basin, MRS = Midcontinent Rift System, and LPCM = Late Proterozoic continental margin. Map is modified from Drahovzal and others, 1992; Drahovzal, 1997; and includes elements from Van Schmus and others, 1993 and VanSchmus and Hinze, 1993.

West of the Grenville front, rocks of the East Continent rift basin (ECRB), the Granite-Rhyolite province, the Penokean province, and the Midcontinent rift system occur. Figure A1-1 illustrates the general extent of these Precambrian provinces (the relationships are also schematically shown on Figure 5 where rocks of the ECRB are represented by the Middle Run Formation and those of the Midcontinent rift system by the Cooper Harbor Conglomerate through the Jacobsville Sandstone).

The Eastern Granite-Rhyolite province is an extensive Precambrian terrain that consists of various types of unmetamorphosed Mesoproterozoic igneous and dominantly felsic volcanic rocks. Age-dating of rocks from this province indicate they are of a similar age to the Grenville protoliths, ranging in age from 1.48-1.45 Ga (Lidak and Zietz, 1976; Hoppe and others, 1983; Denison and others, 1984; Bickford and others, 1986).

The ECRB, a recently defined Middle and Late(?) Proterozoic province of rocks, lies west of, and partially buried beneath, the Grenville front. Rocks in the ECRB consist mainly of sedimentary clastics interbedded with felsic and mafic volcanic rocks (Shrake and others, 1990; Wickstrom and others, 1992a; Drahovzal and others, 1992). Sedimentary and volcanic rocks of this interval encountered in drill holes consist primarily of lithic arenites and basalts that are thought to range in age from ≥1.5 to 0.6(?) Ga (Drahovzal and others, 1992; Drahovzal, 1997; Santos and others, 2002; Stark, 1997; Drahovzal and Harris, 2004). Limited evidence suggests that some intervals of rocks within the ECRB may contain enough porosity and permeability to serve as saline formations, and thus, potential CO_2 reservoirs, (Drahovzal and Harris, 2004). However, very few wells have penetrated rocks of the ECRB; thus, the extent of such occurrences is presently unknown.

Another Middle Proterozoic rift system is found abutting the Grenville front in southern Michigan. This feature extends, in a circular fashion, northward through the upper peninsula of Michigan then southward, out of the MRCSP study area, through Minnesota, Iowa, and into Kansas. Termed the Midcontinent rift system, this feature exhibits similar lithologies and ages (1.2-1.1 Ga) to that of the ECRB (Daniels, 1982; Green, 1982; Van Schmus and Hinze, 1985; Dickas, 1986). However, insufficient data exist to ascertain if these two rift systems are related (Drahovzal and others, 1992).

The Penokean province is an early Proterozoic magmatic belt that consists of felsic and mafic volcanics (1.88-1.83 Ga) that contain younger granitic intrusions (1.83-1.7 Ga) (Smith, 1978; Sims and others, 1989; Van Schmus and Hinze, 1993). Penokean rocks are found only in portions of northern Michigan within the MRCSP study area.

Basement rocks occur at the surface in the upper peninsula of Michigan and consist of a variety of igneous, metamorphic, and sedimentary rocks that range from Archean to Proterozoic in age. East of the MRCSP study area, basement rocks are exposed in the Blue Ridge province where Grenville and Piedmont province metamorphic rocks occur in westward-thrusted blocks of the Appalachian mountains. Between these two areas, the basement rocks are in the subsurface. The top of basement ranges from surface exposures in Michigan and the Appalachians to depths that are speculated to be greater than 45,000-feet below sea level in southeastern Pennsylvania (Shumaker, 1996); however, no wells have penetrated nearly that deep, thus the actually depth remains unknown.

Overall, the configuration of the basement can be seen as a bifurcating high-area in the west that has deeper areas to the southwest, north, and east (Figure A1-2). The shallowest areas on the map occur in west-central Ohio and north-central Kentucky, along the Cincinnati arch; here, basement rocks occur less than 2,000-feet below sea level. The Cincinnati arch extends from south-central Kentucky to west-central Ohio where it dissipates into the Ohio-Indiana platform, a broad expanse of relatively flat-lying terrain. To the northwest, the Kankakee arch extends across northern Indiana. Northeast of the Ohio-Indiana platform, and on the east side of the Grenville front, the Findlay arch, another positive structural element, occurs and extends northeastward into Canada.

These positive features—the Cincinnati, Kankakee, and Findlay arches and the Ohio-Indiana platform (Figures 6 and A1-2)—separate the three major structural and sedimentary basins of this region: the Michigan basin to the north (centered in the lower peninsula of Michigan), the Illinois basin to the southwest (centered in southwest Indiana, south-central Illinois, and western Kentucky), and the Appalachian basin to the east (occurring in eastern Kentucky, eastern Ohio, West Virginia, western Maryland, and Pennsylvania). While subsidence was occurring in the three surrounding basins, the Cincinnati-Findlay-Kankakee arch complex remained relatively stable (at least compared to the rate of subsidence in the basins). However, during the major tectonic orogenies of the Paleozoic, some structural arching did occur and is reflected locally by the occurrence and distribution of various lithologic facies within specific intervals of rocks preserved in the MRCSP study area. Yet, despite this influence of the orogenic events of the rocks, most structural relief of the arches is thought to be the result of differential subsidence within the basins rather than tectonic arching of these structurally positive features (Wickstrom and others, 1992b). However, it should be pointed out that the majority of the subsidence of the surrounding basins occurred in the Silurian and later.

The map of the structural surface of the Precambrian (Figure A1-2) represents its present-day configuration. The major sedimentary basins, as known today, did not exist during the Precambrian, nor during much of the Paleozoic. The reader will find many references, in later sections of this report, to proto-basins (e.g., proto-Michigan basin, etc.) meaning the early-formed portions of these basins. Throughout the early Paleozoic, these basins developed different configurations as the centers of deposition shifted with time (illustrated by the thickness (isopach) maps of units with different ages) in response to the multiple tectonic events that occurred during the Paleozoic. Mapping the structural elements (faults, highs, and lows as can be seen on various geologic surfaces) and the thickness of individual units as well as combined intervals of the area, reveals the geologic complexities of the region. Understanding these complexities are fundamental and necessary prerequisites in order to delineate where potential adequate, safe storage of CO_2 may be found.

A few faults cut the Cincinnati arch, Ohio-Indiana platform, Kankakee arch and Findlay arch complex (Figure 6). One of these faults, the Grenville front fault, extends from south-central Kentucky, northward into eastern Michigan. In northern Ohio and southern Michigan, this fault system is expressed as the north-south trending Bowling Green fault system, which is locally exposed at the surface. To the south, in west-central Ohio, however, the fault is not exposed and a paucity of data limits our understanding of the feature. As a result, the extent and displacement on the fault during the Paleozoic is unknown and its position is imprecise, being based largely on potential field data (Lidiak and Zietz, 1976; Mayhew and others, 1982; Denison and others, 1984; Lidiak and others, 1985). Further south, the Grenville front is once again expressed at the surface by a major fault system, the Lexington fault system, in central Kentucky.

Several minor, northeast-oriented, down-to-southeast faults cut the axis and southwest flank of the Kankakee arch in northern Indiana and several northwest-trending faults cut the southeast flank of the Findlay arch in northwestern Ohio. On regional reflection seismic profiles in central Ohio, deep basement reflectors can be seen dipping to the southeast. To the east, in east-central Ohio, a zone of indistinct reflectors is present, while west-dipping reflectors occur in the basement of eastern Ohio. The transition zone between the southeast- to west-dipping reflectors is called the Coshocton zone (Figure 6) and is thought to represent an ancient continent to continent suture zone (Culotta and others, 1990).

North of the Kankakee arch and west of the Findlay arch, the Michigan basin forms a nearly circular depression that reaches a depth of more than 15,000-feet below sea level (Warner, 1989). The configuration of the basin is largely based on oil and gas test wells because little publicly available seismic data exist for the region. Because of this, little is known of deep basement faulting in the basin. The Mid-Michigan rift part of the Midcontinent rift system (Figure 6) has been mapped largely on potential field data and is interpreted to form a Precambrian graben that extends northwestward across the basin (Hinze and others, 1971, 1975, 1997; Brown and others, 1982).

South and southwest of the Kankakee arch, basement of the MRCSP study area dips southwest onto the northeast edge of the Illinois Basin, a feature that covers most of Illinois, southwestern Indiana and western Kentucky. The southwest dip is fairly regular at a rate of about a half of a degree (Buschbach, 1984; Rupp, 1991).

To the east of the Cincinnati-Findlay arch is the Appalachian basin. The basement dips at an average rate of about one degree to the southeast in the Ohio part of the basin (Baranoski, 2002). Much of the basement configuration for Ohio is based on oil and gas well data, backed up by about 600 miles of publicly available reflection seismic data.

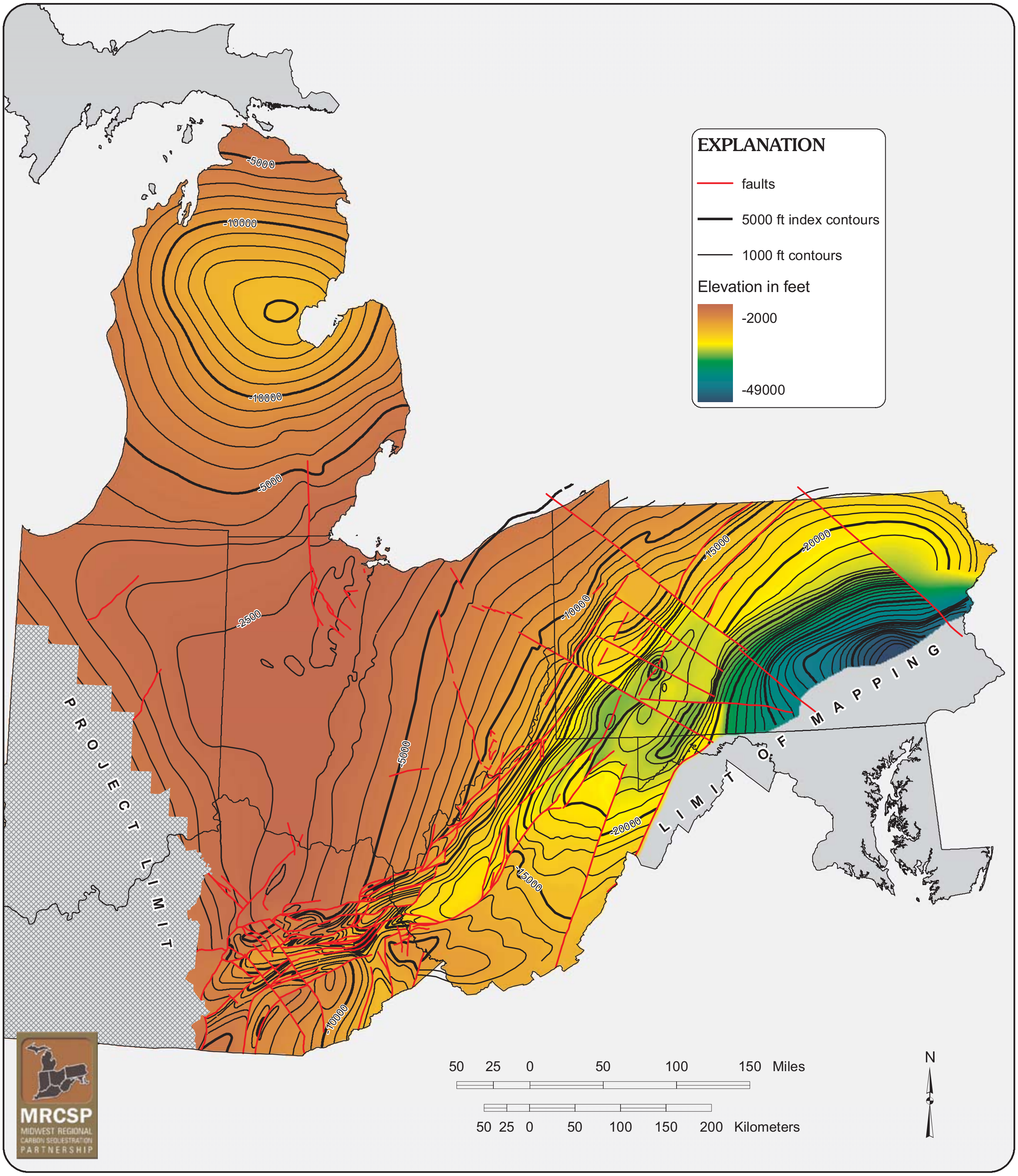

Figure A1-2.—Structure map drawn on the top of the Precambrian unconformity.

One of the most striking features in the Appalachian basin east and south of Ohio is the Rome trough (Figures and A1-2). The Rome trough is a graben that extends from the Lexington fault system in central Kentucky to at least as far northward as southwestern Pennsylvania (Woodward, 1961; McGuire and Howell, 1963; Harris 1975; Wagner, 1976; Cardwell, 1977; Beardsley and Cable, 1983; Shumaker, 1986, 1996; Harper, 1989; Drahovzal and Noger, 1995; Gao and others, 2000; Wilson, 2000; Harris and others, 2004). The trough is the result of a Cambrian rifting event that down-dropped basement rocks thousands of feet. The apparent highly faulted nature of the Rome trough in eastern Kentucky is interpreted from the mapped surface geology and a relatively large number of basement tests that have been integrated with available seismic data (Drahovzal and Noger, 1995). Farther northeastward, in West Virginia and Pennsylvania, where the basin is deeper, there are fewer basement wells and less publicly available seismic data, making these areas *appear* to be less faulted. In eastern Kentucky, the structural relief on the top of the Precambrian is greater than 13,000 feet from the northern boundary of the Rome trough along the Kentucky River fault system to the trough's deepest part near the center of the graben on the West Virginia state line. The trough in Kentucky steps down from a high northern boundary fault across a series of down-to-south normal faults into the center of the graben and then up again across a lower southern shoulder bounded by a smaller displacement fault, the Rockcastle River fault. The Rockcastle River fault changes from a low-displacement normal fault to a high-displacement thrust fault in southern Kentucky where it was reactivated during the Alleghany orogeny (Drahovzal and Noger, 1995; Drahovzal and White, 2002). Many of the faults of the Rome trough were reactivated during subsequent Paleozoic orogenic movements and are expressed in Quaternary-age surface materials.

The relatively symmetrical graben structure of the Rome trough, as mapped in Kentucky, changes near the West Virginia line to an asymmetric half graben, dipping southeast and bounded on the southeast by the major East-Margin fault (Gao and others, 2000; Wilson, 2000). Offsets along the East-Margin fault are up to 7,000 feet. The half-graben structural character continues north into southwestern Pennsylvania to the cross-strike structural discontinuity referred to as the Pittsburgh-Washington lineament (Lavin and others, 1982; Parrish and Lavin, 1982; Alexander and others, in press).

North of the lineament, the structural character of the basement changes to a southeast dipping monocline cut by down-to-southeast dipping normal faults. Offsets across the lineament range from 0 to 2,500 feet. Offsets along the down-to-southeast normal faults are generally less than 500 feet. Several other northwest-oriented lineaments cross the basement monocline farther to the northeast but exhibit relatively small offsets. The presence of the Rome trough north of this lineament is equivocal, but it has been postulated by a number of workers (Harris, 1975; Wagner, 1976; Shumaker, 1986, 1996; Harper, 1989; Jacobi and others, 2004) to extend into New York in the north-central part of the state.

The basement rocks of the MRCSP study area are extremely important because of their influence on the overlying Paleozoic rocks. Basement structure, in particular, has influenced the subsequent structural history of the Paleozoic rocks. In many cases, major basement faults were reactivated by later orogenic movement to fault the younger overlying rocks. Other basement faults show little or no reactivation and exhibit no shallow expression in Paleozoic rocks. Still other faults in Paleozoic rocks apparently have no basement roots, being solely the result of shallow tectonics. Careful study is required when assessing the faulting in a region to distinguish these three types of faults. The distinction between the types of faults and related structures is critical in the siting of sequestration targets in order to assure the integrity of seals associated with potential CO_2 reservoirs. However, it is known that not all faults are permeable, or represent points of leakage, because mineralization may seal the faults, making them impermeable barriers rather than fluid pathways. Thus, site-specific investigations and testing are required to ascertain the integrity of any proposed CO_2-storage site.

During Phase II of the Regional Carbon Sequestration Partnership studies, additional data on the basement structures will be required for those areas that are being considered for CO_2 injection. Reflection seismic profiles will be required to provide information on structure, especially faults that could compromise the reservoir seals. The data may also provide an indication of subsurface lithology, facies/permeability changes, and may even reveal some permeable basement zones, which may themselves be candidates for sequestration. Such initial seismic data will be critical in determining whether further examination of the area is warranted based on basement faulting and structure, as well as the structure of shallower Paleozoic sequestration target zones. Seismic reflection data will also act as a guide to the location of any subsequent drill holes, indicating best placement for injection, or where to drill to provide the most useful analytical information. Subsequent drill-hole and core data will not only provide critical information on reservoir and seal properties in the target sequestration zones, but will provide important basement lithologic and structural data that may have bearing and influence on overlying reservoirs.

2. CAMBRIAN BASAL SANDSTONES

The basal sandstone interval includes some of the most promising targets for CO_2 sequestration within the MRCSP study area. The Mt. Simon Sandstone, which is part of this mapped interval, has the largest sequestration potential of any individual geologic unit within the MRCSP study area (see volume calculations section). However, the Mt. Simon has also been one of the most misunderstood geologic units within the region. Many previous workers have assumed the Mt. Simon was present across much of the region (Janssens, 1973; Havorka and others, 2000; Gupta, 1993) when, in fact, recent research has shown that the true Mt. Simon pinches out in central Ohio (Baranoski, in preparation). East of this pinch-out, thinner, less continuous sandstones are found in this "basal sand" position. Thus, for the Phase I MRCSP assessment, these sandstone intervals have been mapped as one group across the entire region.

Cambrian stratigraphic nomenclature for the MRCSP study area is problematic. A cursory examination of the geologic correlation chart (Figure 5) demonstrates a lack of regional consistency in currently accepted geologic terms as well as a number of states simply using the term "basal sandstone." In general, this problem grew from the practice of taking geologic contacts and formalized terms from outcrops studied in the upper Mississippi Valley and Appalachian fold and thrust belt and carrying them many miles into the deep subsurface of the region by analyzing drilling cuttings from sparse well control and interpreting correlative surfaces. The advent of modern geophysical logs allowed more detailed regional correlations; however, geologic terms remain entrenched provincially, and numerous correlation difficulties are not resolved. While the same can be said for many younger geologic units, the problem is especially acute within the deep Cambrian strata because of the low number of wells, and great distances between wells, that have been drilled into, or through, this interval (Figure 10). The correlation difficulties and inconsistencies illustrate that an adequate treatment of nomenclature is beyond the scope of this project. Thus, the MRCSP geology team has simply mapped the interval within which "basal" sandstones occur across the region. In general, this "basal" interval includes all units deposited on the Precambrian unconformity. The basal interval consists of a complex assemblage of Early, Middle and Furongian (previously Late) Cambrian clastic and carbonate rocks. Both the top and base of this interval are diachronous, which further complicates correlation and mapping of consistent, repeatable, and reliable surfaces throughout the region.

The complexity of this basal interval is reflected by, and largely controlled by, structure and basin architecture of the Rome trough, and proto-Illinois/Michigan and Appalachian basins. The underpinning Precambrian basement complex and poorly understood regional Cambrian tectonics controlled subsidence, sediment input, and facies variations within and around the depositional centers of this interval. These geologic factors as well as multiple episodes of diagenesis ultimately control porosity and permeability of these highly heterogeneous saline reservoirs.

STRATIGRAPHY

The stratigraphically complex basal Cambrian sandstones lie unconformably on the Precambrian basement. For the region, we have mapped four basic units within this interval (Figures 8 and A2-1), each with distinctive stratigraphic and injection reservoir characteristics: 1) the Mt. Simon Sandstone of the proto Illinois/Michigan basin area (Michigan, Indiana, western Kentucky, and western Ohio), 2) the unnamed dolomitic sandstones of the Conasauga Group (eastern Ohio, northern Kentucky, western Pennsylvania, and West Virginia), 3) Potsdam Sandstone (northern and north-central Pennsylvania), and 4) stratigraphically older unnamed basal Cambrian (Rome trough) sandstones in the fault-bounded Rome trough and eastern proto-Appalachian basin (eastern Kentucky, West Virginia, and western Pennsylvania). This unnamed basal sandstone of the Rome trough may be equivalent to the Antietam Formation as named in eastern Pennsylvania and Maryland. The nature of the transition from the Potsdam Sandstone of northwestern Pennsylvania to the Antietam Sandstone and Rome trough unnamed sandstones is unclear because of a lack of deep wells in southwestern Pennsylvania and West Virginia. The transition from the Mt. Simon Sandstone of the Illinois and Michigan basins to the less continuous sands in the east can be clearly seen on the thickness map (Figure A2-2)—east of western Ohio there are no large accumulations of the basal sands as there are in Michigan and Indiana.

The Mt. Simon consists of a lower subunit of shaley, arkosic sandstone and an upper subunit of relatively shale-free, massive sandstone in the eastern proto-Illinois/Michigan basin and western Ohio area. The Mt. Simon pinches out eastward, in central Ohio, into the western proto-Appalachian basin where unnamed Conasauga sandstones and the Potsdam Sandstone lie unconformably on the Precambrian. The unnamed Conasauga sandstones and the Potsdam Sandstone are feldspathic and dolomitic and stratigraphically distinctive from the Mt. Simon. Unnamed Conasauga sandstones, possible lateral equivalents to the Mt. Simon, may exist deeper in the proto-Appalachian basin/Rome trough based on regional thickness relationships. However, this hypothesis cannot be tested in the absence of additional well data and reliable geochronological markers. In Kentucky, the basal sandstones north of the northern boundary fault of the Rome trough are considered Mt. Simon, while deeper sandstones, occurring south of this fault, are simply called unnamed Rome trough sandstones. The unnamed basal Cambrian (Rome trough) sandstones are considered older than the Mt. Simon, Potsdam, and unnamed Conasauga sandstones based on their stratigraphic relationships observed in sparse deep-well control and limited seismic reflection data. The poorly understood, unnamed basal Cambrian sandstones were included within this mapping interval because of the proximity to the Precambrian unconformity and the potential for containing thick, extensive saline reservoirs. Seismic data suggests further study is warranted to locate potential unnamed basal Cambrian sandstone reservoirs.

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

The following list provides significant references for each of the correlative units of the basal sandstones interval in the MRCSP

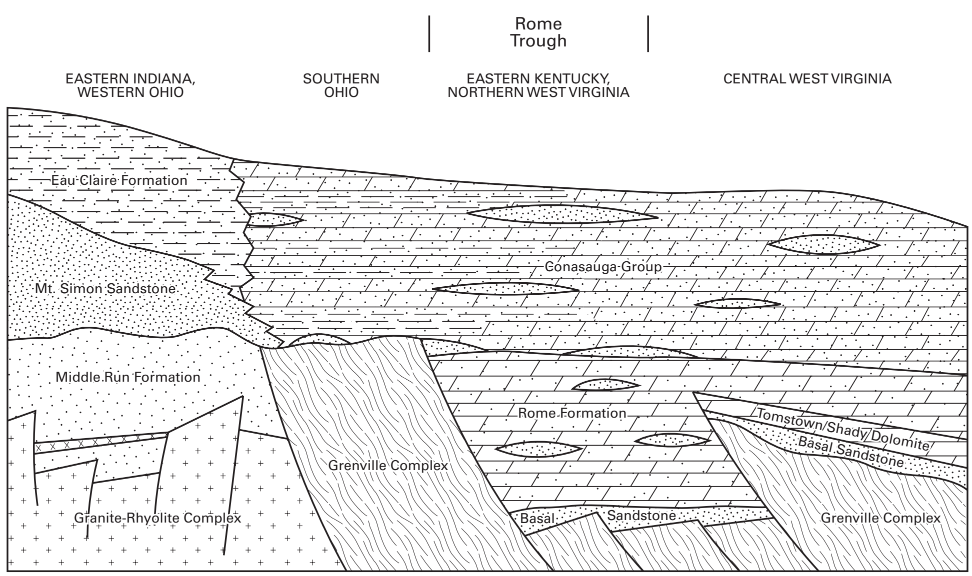

Figure A2-1.—Generalized schematic cross section illustrating the relationships of the mapped basal sandstones to other geologic units and structure.

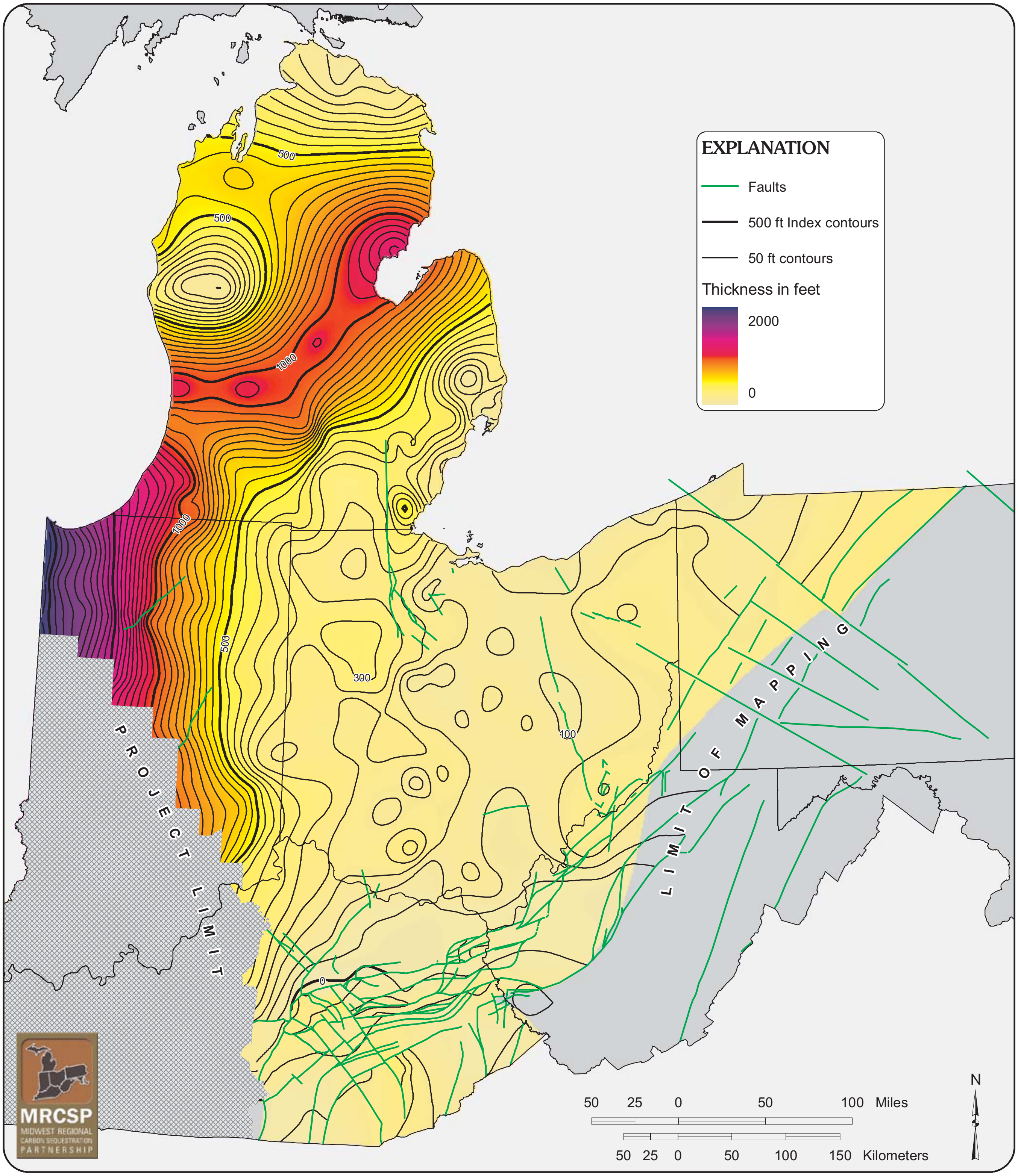

Figure A2-2.—Map showing the thickness of the Cambrian basal sandstones interval.

study area (Figure 5). The name Mt. Simon Sandstone was first used by Walcott (1914) to designate a sandstone exposed near Eau Claire, Wisconsin (the type section). The Potsdam, described by Emmons (1838), was named for sandstone cropping out at Potsdam, New York. Haynes (1891) named the Conasauga Group for exposures of shale and limestone in the Conasauga Valley of northwest Georgia. The reader is referred to the following papers which include discussions on formal and informal nomenclature relative to the lower Sauk interval in statewide to semi-regional context (Cohee, 1948; Fettke, 1948; Sloss and others, 1949; Freeman, 1953; McGuire and Howell, 1963; Catacosinos, 1973; Janssens, 1973; Rickard, 1973; Calvert, 1974; Wagner, 1976; Bricker and others, 1983; Patchen and others, 1985a,b; Shaver and others, 1986; Rupp, 1991; Ryder, 1991, 1992a,b; Riley and others, 1993; Ryder and others, 1995, 1996; Harris and others, 2004).

NATURE OF LOWER AND UPPER CONTACTS

The basal sandstone interval directly overlies the Precambrian unconformity surface, which locally may have significant topographic and/or structural relief (most apparent in western Ohio where well control is greatest). In some local areas, the entire interval is missing or is thicker due to incised channel development. The thickness of the interval can vary dramatically over such features, thus affecting reservoir quality in these areas. The lower contact is generally sharp due to a regolith found at the base of these rocks, but may appear gradational on geophysical logs depending on the underlying Precambrian lithology. A decrease in grain size and an increase in lithic and feldspathic components at the top of the Mt. Simon make the upper contact, where it underlies the Eau Claire Formation, appear gradational in the western part of the MRCSP study area. The upper contact is moderately gradational in the eastern region where thin discontinuous dolomitic sandstone layers of the Conasauga Group and Potsdam mark the top of the interval. The upper contact of the unnamed basal sandstones in the Rome trough and the adjacent eastern region is considered disconformable with the overlying Tomstown and Rome Formations (Harris and others, 2004).

Gamma-ray log response of the Mt. Simon in western Ohio and the proto-Illinois/Michigan basin is relatively lower than that of the overlying Eau Claire Formation, indicating sandstone with lower feldspar, shale, and glauconite content. Gamma-ray curve shapes range from blocky-, to funnel-, and bell-shaped. Density and photoelectric (PE) logs are indicative of relatively higher quartz content of the Mt. Simon. The log response of the lower portion of the Mt. Simon locally appears cyclic, and may representing alternating beds of quartz arenite, shale, arkose, and sublitharenite. Conversely, the gamma-ray log response of the unnamed Conasauga sandstones and Potsdam Formation is higher than that of the Mt. Simon, an indicator of higher feldspar, shale, and glauconite content. Gamma-ray curve shapes for the unnamed Conasauga sandstones and Potsdam Formation are typically more ”spikey” than those of the Mt. Simon, indicating the greater cyclicity of lithologic components. PE logs of the Conasauga and Potsdam also indicate a higher dolostone content than the Mt. Simon. In eastern Kentucky, core from one well indicates that basal sandstones in the Rome trough are commonly arkosic, an attribute that affects the gamma ray log, giving a more shaley appearance.

LITHOLOGY

The Mt. Simon Sandstone is a white, pink, or purple, fine- to coarse-grained, moderately to well-sorted, quartz arenite that can be arkosic. The Mt. Simon also contains thin interbeds of red, green, gray, or black, sandy to silty shale. Locally, thin beds of tight, silica-cemented quartz arenite occur. Bedding thickness ranges from thin to medium with many beds containing lamina and wisps of finer grained materials. Graded beds and cross bedding are common. Bioturbation is present but generally, poorly developed. However, in Michigan, preservation of burrowing has been observed to increase upward towards the contact with the overlying Eau Claire. Grains are sub-rounded to rounded, commonly etched and generally poorly cemented and friable. The lower portion is commonly conglomeratic and shaley, and stained by hematite, some of which is mottled. In the Michigan subsurface, dolomite cement is common in some intervals around the basin margin. Deeper in the proto-Michigan basin, below 7,000 feet, there is pervasive quartz overgrowth cement. Secondary porosity is common where carbonate cement and feldspar has been dissolved.

The unnamed Conasauga sandstone and Potsdam Sandstone consist of interbedded, cyclical-appearing sandstone and dolostone. The sandstone components are typically white to light-gray and pinkish gray, and fine- to medium-grained, with moderate- to well-sorted, sub-rounded to angular grains, although arkosic sandstones occur in the basal portions of the Potsdam in northwestern Pennsylvania and south-central New York. Authigenic and primary feldspar, glauconite, and bioturbated zones are common. Normal and reverse graded bedding and trough cross-bedding are common thoughout the unit. Coarse to pebbly, normal graded bedding, and thin zones of rip-up clasts mark thin intercyclic intervals. Bedding ranges from thin to medium and massive, to interbedded with laminated and wispy dark gray shale. Bioturbation, including filled vertical burrows (*Skolithos*), graded bedding, and cross-bedding are common. The dolostone is light to medium gray and pinkish gray, cryptocrystalline, microcrystalline, medium crystalline, and arenaceous. Minor beds and laminae of gray to black shale, frosted quartz grains, vugs filled with selenite and dolomite crystals, ooids, pelloids, disseminated pyrite, laminae and thin beds of glauconite, apatite, flat pebble conglomerate, rip-up clasts, mudcracks, and clay-rich zones are also present (Harris and others, 2004; Baranoski, in preparation).

The basal sandstones of the Rome trough are arkosic and, based upon a core from a well in Wolfe County, Kentucky, are interbedded with red and green shale, siltstone, sandy shale, and nodular evaporites. The unit is locally conglomeratic and may contain poorly developed cross beds (Harris and others, 2004).

DISCUSSION OF DEPTH AND THICKNESS RANGES

Depth to the top of the basal sandstones interval ranges from approximately 2,000-feet below sea level (bsl) in northern Ohio and northwestern Indiana on the Ohio-Indiana platform to 14,000 feet bsl in the center of the Michigan basin, and 20,000 to 25,000 feet bsl in the Rome trough of southwestern Pennsylvania (Figure A2-3). Thickness ranges from zero, where local Precambrian topography (Janssens, 1973; Baranoski, 2002) exists, to more than 2,500 feet in northwestern Indiana and east-central portion of Illinois, just west of the MRCSP study area (Figure A2-2). This thick accumulation of sediments, or depocenter, is unique in its location, not being coincident with depocenters for any younger stratigraphic units. The Mt. Simon reaches a thickness in excess of 1,300 feet in east-central Michigan (Figure A2-2), where again this depositional pattern is not seen in other geologic units. Eastward, away from the Illinois and Michigan basins, the Mt. Simon is 50 to 300 feet thick in Ohio and adjacent central Kentucky. In eastern Kentucky, the Mt. Simon gradually thins eastward toward the Rome trough. The unnamed

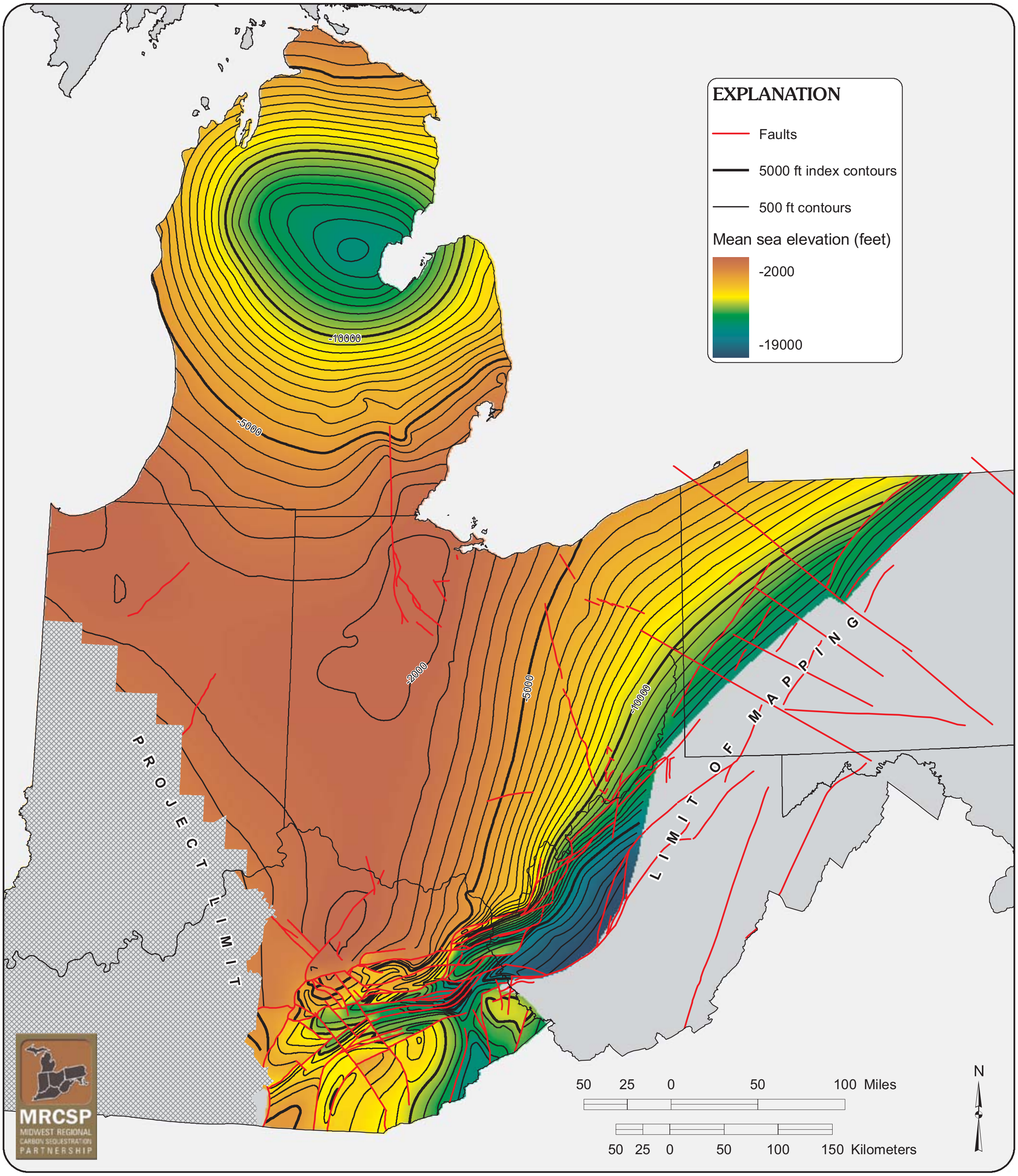

Figure A2-3.—Structure map drawn on the top of the Cambrian basal sandstones interval.

basal sandstones, Conasauga sandstones, and Potsdam Sandstone of eastern Ohio, West Virginia, and Pennsylvania range from 50 to 150 feet. However, this is a total thickness of the interval; the amount of porous/permeable sandstone within the interval is uncertain and is highly variable and discontinuous. A recent deep well in Mason County, West Virginia encountered less than 10 feet of porous/permeable sandstone within this interval.

Within the Rome Trough, the basal sandstones appear to thicken southward independent of major faults, indicating that the sandstones may be pre-rift deposits unaffected by movement on the major bounding faults of the Trough. Post-depositional structural movement, however, influenced depth and local thickness preservation (Harris and others, 2004). Some of the variability in thickness may also indicate structural influences from localized faulting, especially where there are substantial thickness changes in the basal sandstone across relatively short distances.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

During late Precambrian and early Paleozoic time, the MRCSP states were part of a large crustal plate, named Laurentia, which occupied a position straddling the equator (Dott and Batten, 1976). Laurentia included the present-day Canadian Shield and possibly the Transcontinental arch. In late Precambrian time, the Laurentian plate rifted away from an adjacent plate, creating the Iapetus Ocean between them (Dietz, 1972). At this time, the southern margin of Laurentia became a passive continental margin. During early and middle Cambrian time, the Grenville rocks in what is now the Appalachian basin states remained exposed to erosion. Deposition of sand on the Precambrian unconformity began late in the Middle Cambrian as sea level rose and the southern margin of Laurentia began to subside in response to the sediment loading. During the Lower or Middle Cambrian, the Rome trough formed along the southern margin of Laurentia. Harris (1978) described the Rome trough as the failed arm of a triple junction (an aulogen), extending from the Mississippi embayment through Kentucky to Pennsylvania. The aulacogen is thought to have originated on incipient Precambrian crustal-block faults derived from stresses during the opening of the Iapetus Ocean. Thus, the basal sandstones interval of the MRCSP study area is a transgressive sequence of sandstone, shales and carbonates deposited on the regional Precambrian uncomformity surface. Both lower and upper boundaries are highly diachronous, making regional correlations difficult and tenuous at best. The basal sandstones in the Rome trough are not correlative to the Mt. Simon and unnamed Conasauga sandstones. The Mt. Simon and unnamed Conasauga sandstones are considered younger than the unnamed basal sandstones of the Rome Trough.

Depositional environments for the basal sandstones range widely, from marginal marine, to marine, littoral, fluvial, and estuarine (Jannssens, 1973; Driese, 1981; Haddox and Dott, 1990). The marine influence is evident where sandstone intertongues with dolostone in the Appalachian basin area. In the Rome trough, red and green shales and siltstones with nodular evaporates interlayer with the sandstones, suggesting very shallow, subtidal to intertidal deposition, with restricted marine circulation (Harris and others, 2004). The regional shoreline generally migrated northward from the proto-Illinois/Michigan basin, Rome trough and eastern proto-Appalachian basin to the Canadian shield during transgression (Milici and de Witt, 1988).

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

The lithology of the intervals mapped varies, from the typical Mt. Simon Sandstone in western Ohio, Indiana, and Michigan to the basal shaley and arkosic sandstones of the Rome trough and sandy dolostones of the unnamed Conasauga sandstones. The Mt. Simon has overall higher porosity and permeability based on core analyses and a 35-year history of relative higher injectivity rates and volumes than the unnamed Conasauga sandstones. Data for the basal sandstones of the Rome trough is scant.

The Mt. Simon of the Indiana-Ohio platform has good to excellent reservoir quality - gross thickness (200 to 350 feet), porosity (average 14 percent), and permeability (range 10 to 200+ millidarcies [md]) (Janssens, 1973; Clifford, 1975). Salinity ranges from 111,000 to 316,000 milligrams per liter (mg/L) with an average specific gravity of about 1.075 grams per cubic centimeter (g/cc). Original reservoir pressure at 3,100 feet ranges from 1,000 to 1,100 pounds per square inch (psi).

Table A2-1 lists information from Ohio Class-1 injection wells, from which a number of observations can be made. Those sites that list the Mt. Simon as the injection interval (all in western Ohio) have higher porosities and permeabilities, thicker injection zones, higher injection rates, and larger cumulative volumes injected. In general, the Mt. Simon Class-1 sites have also been in operation longer and, with the exception of the Aristech site, are still in operation. The Class-1 facilities in northeastern Ohio that utilized the thinner sandstones and carbonates of the Conasauga Group (Reserve Environmental Services and Tomen Agro) could not attain very high injection rates. In fact, the Reserve Environmental Services site could not inject enough material to sustain its operation. This information should prove useful when examining prospective sites/reservoirs for potential CO_2 injection.

In Kentucky, there has been only one attempt to inject waste into the Mt. Simon, near Louisville, west of the MRCSP study area. Upon drilling, the sandstones were found to be tight, and a porous zone within the shallower Copper Ridge Dolomite was ultimately chosen as the injection horizon.

The overall reservoir character of the basal sandstones (Rome trough) is not known, but suspected to be relatively poor because the sandstones are shaley. However, proprietary seismic data in the region indicates areas where thick, well-developed, sandstones might be present. Future drilling would be required to confirm the presence and injection properties of the sandstones. Further characterization of injection properties of all the basal sandstones and other prospective reservoir units will be a goal of Phase II efforts within the MRCSP study area.

The overlying shales, siltstones, and carbonates of the Eau Claire through Copper Ridge interval provide an excellent vertical seal system for the Mt. Simon Sandstone in the western part of the MRCSP study area. Measured vertical permeabilities of the shale and siltstone intervals typically range from unmeasurable ($< .001$ md) to 0.01 md. Some sandy intervals within the seal sequence may have significantly more permeability and porosity, providing good zones to absorb and trap any CO_2 that might make it through the lower permeability layers. As depth to the Mt. Simon increases in the Michigan basin, additional seal units are stacked above this interval. Should injection intervals be found within the unnamed Conasauga sandstones, Potsdam Sandstone, or Rome trough sandstones, a very thick succession of overlying carbonates of the Knox

Table A2-1.—Class 1 well data from Ohio

Company	*County*	*Allowable surface injection pressure*	*Depth to Injection interval (feet)*	*Thickness Injection interval (feet)*	*Injection Unit*	*Total confining interval (feet)*	*Porosity (percent)*	*Permeability (millidarcies)*	*Salinity (mg/L)*	*Injectate Specific gravity*	*Avg/Max Flow Rate (gal/min)*	*Cumulative volume injected* (gals)*	*Date of 1st well*	*No. of active wells*	*No. of plugged wells*
Cargill Incorporated (Akzo Salt)	Cuyahoga	150 psi	1,294	87	Oriskany	1,000	11	650	184,000 to 277,000	1.2	20-40	43,268,128	1971	INACTIVE Plugged 1999	1
Aristech	Scioto	1,650 psi	5,550	40	Conasauga/ Mt. Simon	5,000	12	27	258,000 to 316,000	1.02	60-75	1,454,889,519 through 4/96	1968	INACTIVE Plugged 1996	2
AK Steel (Armco Steel)	Butler	634 psi	2,975	260	Mt. Simon	2,500	13	55	unknown	1.21	30-40	519,800,000	1969	2	
BP Chemicals	Allen	825 psi	2,800	340	Mt. Simon	2,350	14	10 to 100	122,500	1.025	120-256	6,334,547,975	1968	4	
Waste Management of Ohio (Chemical Waste Management)	Sandusky	790 psi	2,800	140	Conasauga/ Mt. Simon	1,900	14	42	111,000	1.15	40 - 90	1,245,000,000	1976	4	3
Empire Reeves Steel Div.	Richland	1,500 psi	4,990	500	Conasauga	4,490	10	9	unknown	1.195	35	10,314,933 through 10/70	1967	INACTIVE Plugged 1970	1
Tomen Agro (Zeneca Ag; ICI Americas)	Lake	1,689 psi	5,643	450	Conasauga	5,130	8	4 to 6	195,000 to 283,000	1.025	unknown	630,634,412	1971	INACTIVE Plugged 1996	
Reserve Enviromental Services	Ashtabula	1,450 psi	5,469	500	Conasauga	4,899	7	3 to 10	182,000	1.09	15 - 20	89,344,171 through 12/94 TOTAL = 10,327,799,138	1985	INACTIVE Plugged 1994	1

*Most volume data from Ohio EPA, Division of Drinking and Ground Waters. Cumulative volumes through December, 2003.

Group, Beekmantown Group, Black River and Trenton limestones, and the Upper Ordovician clastics of the Cincinnati Group, Reedsville Shale, and Martinsburg Formation (Figure 5) directly overlie the injection interval. Additional layers of Middle and Upper Paleozoic clastics, carbonates, and evaporates would be added on top of this with increasing depth.

3. BASAL SANDSTONES TO TOP OF COPPER RIDGE INTERVAL

The stratigraphic interval from the top of the basal sandstones to the top of the Copper Ridge Dolomite (Figure 5) serves largely as a confining interval for possible injection in the underlying basal sandstones of the MRCSP study area. In some locations, however, units within the interval may be possible injection targets, although even for these units, the remainder of the interval would be considered a seal.

The Basal Sandstones to the top of the Copper Ridge Interval can be divided into three informal sub-intervals across the region for descriptive purposes: 1) a thick clastic and carbonate interval above the basal sandstones within the Rome trough, including the Tomstown Dolomite, Rome Formation, Waynesboro Formation, and the lower part of the Conasauga Group; 2) an interval dominated by clastics in the west and carbonates in the east above the basal sandstones outside of the Rome trough, and continuous above the trough-filling interval, which includes the Eau Claire Formation, Conasauga Group, Elbrook Formation, and Warrior Formations; and 3) an upper, carbonate-dominated interval, that is extensive across the region, including the upper Munising Group, Trempealeau Formation, Davis Formation, Potosi Dolomite, Copper Ridge Dolomite, Gatesburg Formation, and Conococheague Group (Figure 5). Stratigraphic relationships and thicknesses for these units in the eastern half of the MRCSP study area are based on a series of published regional cross sections (Ryder, 1991, 1992a; Ryder and others, 1992, 1996, 1997).

Tomstown/Rome/Waynesboro/Lower Conasauga Formations—Units in this sub-interval are mostly confined to the Rome trough of eastern Kentucky, West Virginia, and Pennsylvania, and the eastern proto-Appalachian basin as far east as Maryland (Figures 5 and 6). The Shady or Tomstown Dolomite (250 to 500 feet thick) overlies the basal sandstone in the Rome trough and areas south and east of the Rome trough. The Shady/Tomstown is overlain by mixed clastics and carbonates of the Rome Formation in the Rome trough. Across the northern bounding faults of the Rome trough in eastern Kentucky, the Rome Formation may thicken from less than 300 feet to more than 6,000 feet, depending on usage (definitions of the top of the Rome have varied). In West Virginia, dramatic increases in thickness also occur across the southern or eastern fault boundary, although this is based on a limited number of wells deep enough to confirm the exact offset across the southern bounding faults into southern West Virginia. Eastward into northern West Virginia, Maryland, and Pennsylvania, the Shady/Tomstown Dolomite is overlain by shale and siltstone of the Waynesboro Formation (Figure 5). The Waynesboro (400 to 500 feet thick) is equivalent to that part of the Rome Formation that extends south and east of the Rome trough. The Rome is overlain by the Conasauga Group (Figure 5). Like the underlying Rome Formation, the lower part of the Conasauga shows dramatic thickening into the Rome trough (from less than 200 feet north of the Rome trough, to more than 5,000 feet within the trough). In eastern Kentucky and West Virginia, six formations are defined within the Conasauga, from oldest to youngest: 1) the Pumpkin Valley Shale (0 to 300 feet thick); 2) the Rutledge Limestone (0 to 1,200 feet thick); 3) the Rogersville Shale (0 to 700 feet thick); 4) the Maryville Limestone (0 to 2,400 feet thick); 5) the Nolichucky Shale (0 to 500 feet thick); and 6) the Maynardsville Limestone (0 to 200 feet thick). The three lower formations are confined to the Rome trough, as is the lower part of the Maryville. The three upper units extend beyond the trough, but become thinner, and pinch out or merge with lateral units.

Eau Claire/Conasauga/Elbrook/Warrior Formations—In the proto-Illinois/Michigan basin of Indiana and Michigan (Figure 6), the basal sandstone is overlain by the Munising Group (Figure 5). The lower part of the Munising is called the Eau Claire Formation (100 to 1,000 feet thick), which extends from Indiana and Michigan into western and central Ohio and northern Kentucky (Shaver and others, 1986; Rupp, 1991; Catacosinos and others, 2001). Eastward from central Ohio, the Eau Claire Formation thins and merges laterally into the Conasauga Group. That part of the Conasauga Group above the basal sand in southeastern Ohio and northeastern Kentucky represents only the upper part of the Conasauga preserved to the southeast in the Rome trough (Figure 5). In the trough, the upper third of the Maryville Limestone, the Nolichucky Shale, and the Maynardsville Limestone are equivalent to the Eau Claire. Farther east, the upper two thirds of the Maryville Limestone interfingers with the Elbrook Formation/Dolomite, and the Nolichucky and Maynardsville pinch out or are truncated beneath the lower sandy interval of the overlying Copper Ridge Dolomite. The lower third of the Elbrook (also called the Honaker Dolomite) is equivalent to the lower part of the Conasauga Group in the Rome trough, as well as an unnamed limestone in the upper Rome Formation. North and east into Pennsylvania, the Elbrook is estimated to be more than 3,000 feet thick (Kauffman, 1999). In central and western Pennsylvania, the lower part of the Elbrook is equivalent to the Pleasant Hill Limestone/Formation (400 to 500 feet thick), and the upper part of the Elbrook is equivalent to the Warrior Formation (400 to 1,200 feet thick). In some parts of western Pennsylvania, the Warrior Formation rests directly on the Potsdam Sandstone, which is the basal sandstone in this area, but younger than the basal sandstone in the Rome trough (Figure 5).

Upper Munising/Trempealeau/Potosi/Davis/Copper Ridge/Gatesburg/Conococheague Formations—In Michigan, this sub-interval includes the upper part of the Munising Group and the overlying Trempealeau Formation (Milstein, 1983) (Figure 5). The Munising consists of the Galesville Sandstone (less than 100 to 600 feet thick) and Franconia Formation (100 to 500 feet thick). The Galesville and Franconia thicken toward the Chicago area in northern Illinois (Becker and others, 1978). In Indiana, the Ironton Sandstone occurs between the Galesville and Franconia within the upper Munising Group, and these units are restricted to the northwestern part of the state (Becker and others, 1978). Where the Munising Group thins southward and eastward in Indiana, the upper Munising is equivalent to the Davis Formation (Figure 5). The Davis thins gradationally into the Potosi Dolomite in southern Indiana (Shaver and others, 1986). The overlying Trempealeau Formation in Michigan (less than 100 to 900 feet thick) is also equivalent to the Potosi Dolomite (20 to 2,000 feet thick). Eastward, the Potosi is equivalent to the Copper Ridge Dolomite (700 to 1,200 feet thick) in Ohio, Kentucky, and western West Virginia, and the Conococheague Group/Limestone (2,500 feet thick) in eastern West Virginia, Pennsylvania, and Maryland. The Gatesburg Formation (1,000 to 1,350 feet thick) of western and central Pennsylvania is partly equivalent to the Copper Ridge part of the Knox Group to the west (Figure 5).

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

Many of the stratigraphic names applied to this interval in the MRCSP study area were originally defined for units exposed at the surface outside of the region or in the Appalachian fold and thrust belts where these units come to the surface. For ease of presentation, the units are arranged alphabetically, followed by the reference for the original description, and the type locality.

Conococheague Group (Limestone)—Stose (1908) for outcrops in Scotland, Pennsylvania.

Conasauga Group (Shale, Dolomite, Limestone, or Formation)—Hayes and others (1891) for outcrops in a valley in northwestern Georgia.

Copper Ridge Dolomite (Member)—Butts (1940) for outcrops near Thorn Hill, Tennessee

Davis Formation—Bueler (1907) for outcrops on Davis Creek in St. Francois County, Missouri

Eau Claire Formation—Wolcott (1914) for outcrops near Eau Claire, Wisconsin

Elbrook Formation (Limestone or Dolomite)—Stose (1906) for a quarry in Franklin County, Pennsylvania

Franconia Formation—Berkey (1897) for outcrops in Franconia, Chicago County, Minnesota

Galesville Sandstone—Trowbridge and Atwater (1934) for outcrops in Trempealeau County, Wisconsin

Gatesburg Formation—Butts (1918) for outcrops in Centre County, Pennsylvania

Ironton Sandstone (Member)—Thwaites (1923) for outcrops near Ironton, Sauk County, Wisconsin

Knox Group (Supergroup, Formation, or Dolomite)—Safford (1869) for outcrops in Knox County, Tennessee

Maryville Limestone—Keith (1895) for outcrops in Blount County, Tennessee

Maynardsville Limestone—Oder (1934) for outcrops in Union County, Tennessee

Munising Group—Lane and Seaman (1907) for bluffs exposed in Munising, Michigan

Nolichucky Shale—Keith (1896) for outcrops in Greene County, Tennessee

Pleasant Hill Formation (Limestone)—Butts (1918) for outcrops in Blount County, Pennsylvania

Potosi Dolomite—Winslow (1894) for outcrops near Potosi, Missouri

Pumpkin Valley Shale—Rodgers and Kent (1948) for outcrops in Hawkins County, Tennessee

Rogersville Shale—Campbell (1894) for outcrops in Hawkins County, Tennessee

Rome Formation—Smith (1890) for outcrops in Rome, Georgia

Rutledge Limestone (Dolomite)—Keith (1896) for outcrops in Grainger County, Tennessee

Shady Dolomite—Keith (1903) for outcrops in Johnson County, Tennessee

Tomstown Dolomite—Stose (1906) for outcrops in Franklin County, Pennsylvania

Trempealeau Formation—proposed by E.O. Ulrich in Thwaites (1923) for outcrops in bluffs of the Mississippi River in Trempealeau County, Wisconsin

Warrior Formation (Limestone)—Butts (1918) for exposures along Warrior Run in Blair County, and Warrior Creek in Huntingdon County, Pennsylvania

Waynesboro Formation—Stose (1906) for outcrops in Franklin County, Pennsylvania

For more information concerning the history of stratigraphic nomenclature in this interval, and the correlation of rock units in statewide to semi-regional contexts, see Cohee, 1948; Fettke, 1948; Sloss and others, 1949, 1986; Freeman, 1953; McGuire and Howell, 1963; Catacosinos, 1973; Janssens, 1973; Rickard, 1973; Calvert, 1974; Wagner, 1976; Webb, 1980; Berg and others, 1986; Bricker and others, 1983; Patchen and others, 1985a; Rupp, 1991; Ryder, 1991, 1992a; Riley and others, 1993; Ryder and others, 1995, 1996; Harris and Baranoski, 1996; Catacosinos and others, 2001; and Harris and others, 2004.

NATURE OF LOWER AND UPPER CONTACTS

In the western portion of the MRCSP study area, where the Eau Claire Formation is present (western Ohio, central Kentucky, Indiana, and Michigan), the lower contact of the Basal Sandstones to top of Copper Ridge Interval is gradational and conformable. In the eastern portion of the MRCSP study area, above the Rome trough, and in areas south of the Rome trough, the Shady/Tomstown Dolomite overlies an older basal sandstone, and the contact is also mostly conformable (e.g., Ryder and others, 1996). In some areas, there may be a more abrupt change from the underlying basal sandstones to carbonates, rather than sandstone to shale to carbonate. In the central-eastern portion of the MRCSP study area (eastern Ohio and southwestern Pennsylvania), the lower contact of this interval is variable, based on the available data. In many wells, the basal sandstone is absent, leaving the sandy dolomites of the Conasauga Group in direct contact with Precambrian basement. In other wells, there is a minimal thickness of the basal sand, which gradually becomes more dolomitic upwards towards the Conasauga Group. The stratigraphic relationships of these basal units is currently the focus of a separate study by the Ohio Geological Survey. In parts of Pennsylvania, northern West Virginia, and western Maryland, the basal sandstone is the Antietam, which is overlain by the Shady-Tomstown Dolomite. In these areas, the Antietam is gradational with a calcareous shale in the Shady-Tomstown, which is overlain by thin-bedded carbonates (Brezinski, 1991). In northern Pennsylvania, the younger Potsdam Sandstone is the basal sandstone (Figure 5). In areas where the Potsdam Sandstone is the basal sand, it is conformably overlain by sandy limestones of the Warrior Formation. In at least one graben in northern Pennsylvania the Potsdam is overlain by argillaceous carbonates and/or sandstones at the base of the Warrior Formation (Ryder, 1992b).

The upper contact of this interval (top of the Copper Ridge equivalents) is also variable across the MRCSP study area. In central and western Ohio, erosion on the regional Middle Ordovician Knox unconformity extends down into the Copper Ridge (Figure 5). Where this occurs, the Copper Ridge Dolomite is overlain unconformably by the Wells Creek Formation or, in some instances, the Black River Limestone. In the western Appalachian basin (eastern Ohio, northern Kentucky, western Pennsylvania, and western West Virginia), the upper contact of the Copper Ridge equivalents is defined at the base of the Rose Run Sandstone or the Upper Sandy member of the Gatesburg Formation (Figure 5). In southern Indiana, central Kentucky, and southwestern Ohio, the Rose Run is absent (see next interval for Rose Run distribution), and the Copper

Ridge is directly overlain by dolomites of the Knox Group (Beekmantown Dolomite), making the contact very difficult to discern. The contact is also nearly indistinguishable in western Maryland, central Pennsylvania, and eastern West Virginia where limestones of the Conococheague (a Copper Ridge equivalent) are directly overlain by limestones of the Beekmantown Group (Figure 5). In the Michigan basin (also northwesternmost Ohio, northern Indiana, and Michigan), the contact between the Potosi Dolomite/Trempealeau Formation (a Copper Ridge equivalent) and sandy dolomites in the overlying Prairie du Chien Group is gradational and difficult to differentiate.

LITHOLOGY

Tomstown/Rome/Waynesboro/lower Conasauga Formations—The Shady or Tomstown Dolomite is a relatively consistent unit of limestone, shale, and dolomite (Ryder and others, 1996; 1997). In Maryland and Pennsylvania, the Shady-Tomstown consists of a calcareous shale grading upward into thin-bedded limestone, overlain by thick- to medium-bedded, dark gray, coarse-grained dolostone, and overlain by massive dolostone, and interbedded limestone and dolostone (Brezinski, 1991). The Rome and Warrior Formations unconformably overlie the Shady-Tomstown across much of the eastern MRCSP study area (Ryder and others, 1996, 1997). Both the Rome and Warrior are laterally and vertically heterogeneous in this area. The Rome Formation contains a complex sequence of shales, siltstones, sandstones, and carbonates that is divided into three units, in ascending order (Ryder, 1992b; Harris and others, 2004): 1) alternating thin shales and arkosic, very fine-grained to conglomeratic sandstones. Sandstones are most common toward the northern, fault-bounded margin of the trough as part of a thick, clastic wedge; 2) a more consistent, shale-dominated sequence; and 3) a 300-footthick carbonate-ramp sequence, which interdigitates and grows thinner above the clastic wedge along the northern margin of the trough (Ryder and others, 1997; Harris and others, 2004). East of the Rome trough, units above the Shady-Tomstown Dolomite are mapped as the Rome or Waynesboro Formation. The Waynesboro is differentiated from overlying and underlying units by the presence of red, dolomitic to anhydritic shales and can be divided in some areas into a lower red clastic interval (red to purple shale and sandstone), middle dolostone to impure limestone, and upper red shale (Ryder, 1991, 1992b; Kauffman, 1999). The Rome outside of the trough may also contains redbeds (Read, 1989a; Ryder, 1992b). In central and western Pennsylvania, the Waynesboro also contains coarse- to medium-grained sandstones (Kauffman, 1999). Above the Rome Formation, within the Rome trough, the Pumpkin Valley Shale is a gray shale and siltstone (Ryder, 1992b). The overlying Rutledge Limestone is dominated by micritic limestone with lesser amounts of sandy limestone and sandstone (Ryder, 1992b). The Rogersville Shale consists of silty red and green shales and micritic limestones, which grades north and westward into sandy shales of the Rome Formation (Ryder, 1992b; Ryder and others, 1996, 1997). The Maryville Limestone is a thick sequence of limestone and argillaceous limestone that interfingers to the south and east with the Elbrook/Honaker Dolomite. The Maryville may contain a 50- to 300-foot thick sandy interval in its lower half within the trough (Ryder and others, 1997).

Eau Claire/Conosauga/Elbrook/Warrior Formations—In the western portion of the MRCSP study area (eastern Indiana and Michigan), the Eau Claire Formation (lower part of the Munising Group) conformably overlies the basal sandstone. The Eau Claire consists of dark gray, red, and green shales; dolomitic, feldspathic, and partly glauconitic siltstone; very fine-grained to fine-grained, well-sorted sandstone (often feldspathic and lithic); silty to sandy dolostone; and oolitic limestone (Shaver and others, 1986; Catacosinos and Daniels, 1991). Shales dominate the lower part of the unit above the underlying Mt. Simon Sandstone, and siltstones and silty dolostones and limestones dominate in the upper, coarsening-upward part of the unit beneath the Galesville Sandstone or Davis Formation (Becker and others, 1978). Pore systems in the Eau Claire are poorly developed and often filled with diagenetic feldspar, clay minerals, dolomite and/or quartz cement . The Eau Claire Formation intertongues eastward in central Ohio with dolostone and dolomitic and feldspathic sandstones of the Conasauga Group**.** Bedding within the Conasauga sandstones ranges from thin to medium to massive, to interbedded with laminated and wispy, dark-gray shale. Bioturbation (including filled vertical burrows), graded bedding, and crossbedding are common. Dolostone are arenaceous and ranges from light- to medium-gray and pinkish gray in color, and from cryptocrystalline to microcrystalline to medium crystalline in texture. Minor beds and laminae of gray to black shale, frosted quartz grains, vugs filled with selenite and dolomite crystals, ooids, pelloids, disseminated pyrite, laminae and thin beds of glauconite, apatite, flat pebble conglomerate, rip-up clasts, mudcracks, and clay-rich paleosols(?) are also present. Eastward toward the Rome trough, the Conasauga Group is composed of multiple formations. The lower part of the Conasauga in this area is restricted to the Rome trough. The upper formations extend beyond the trough, either pinching out laterally away from the trough or merging with unnamed units in the Conasauga Formation. The Nolichucky Shale is a calcareous, olive-green to gray, silty shale and siltstone (Elton and Haney, 1974). The overlying Maynardsville Limestone is a micritic to coarse-grained limestone, transitional between the Nolichucky and the overlying carbonates of the Copper Ridge (Webb, 1980). The upper two thirds of the Maryville Limestone is equivalent to the Elbrook Formation or Dolomite farther east, beyond the southern and eastern limits of the Rome trough. The Elbrook consists of a lower limestone, a middle, oolitic dolostone, and in some areas, an upper sandy dolomitic limestone (Ryder, 1991; Ryder and others, 1992b, 1996, 1997). In Pennsylvania, the Pleasant Hill Limestone is a sandy limestone and calcareous shale grading upward into dark-gray limestone (Berg, 1981). The overlying Warrior Formation consists of oolitic limestone and silty to sandy dolostone (Ryder and others, 1992b; Kauffman, 1999). Where it is thick in the Rome trough of southwestern Pennsylvania, the Warrior may also include a thick sequence of dolomitic sandstone overlain by dark-gray to black shale (Ryder, 1992a). In the subsurface of western Pennsylvania, the Pleasant Hill and Warrior limestones have been thoroughly dolomitized. This makes regional correlation difficult on the basis of drill cuttings or cores. However, the gamma-ray and density log signatures typically remain fairly constant despite the change in lithology, making correlation by geophysical logs the most preferred method.

Upper Munising/Trempealeau/Potosi/Davis/Copper Ridge/Gatesburg/Conococheague Formations—In Michigan, the upper Munising Group consists of the Galesville Sandstone and Franconia Formation. The Galesville (previously Dresbach) consists of light-colored, fine- to coarse-grained, dolomitic sandstones. The upper part of the unit is glauconitic (Catacosinos, 1973; Lilienthal, 1978) and the lower part of the unit contains well-sorted quartz arenites with thin interbeds of dolostone and green shale (Milstein, 1983). The Galesville grades upward into the Ironton Sandstone in northwestern Indiana with a similar distribution to the Galesville. The Ironton consists of sandy dolostone, white, medium- to coarse-grained sandstone, dolomitic sandstone, and dolostone (Becker and others, 1978). Where both sandstones occur, they cannot easily be distinguished from one another (Becker and others, 1978; Shaver and others, 1986). Both sandstones become increasingly dolomitic and thin to the south and east (Becker and others, 1978). The Franconia consists of glauconitic, pink to gray, fine- to medium-grained dolomitic sandstone, quartz arenites, dolostone, shaly dolostone, dolomitic siltstone, and interbedded shales (Milstein, 1983; Shaver and others, 1986). Like the Eau Claire, the Franconia is feldspathic (Galarowicz, 1997). The Franconia has a similar thickness distribution to the underlying Galesville and Ironton Sandstones. Also, like those units, it becomes more dolomitic and thinner eastward and southward, where it grades into the upper part of the Davis Formation, or into the lower part of the Potosi Dolomite (Becker and others, 1978; Shaver and others, 1986). The Davis Formation is composed of siltstone, shale, limestone, and dolostone that conformably overlie the Eau Claire Formation in eastern and southern Indiana (Becker and others, 1978; Shaver and others, 1986). The Upper Munising/Davis units are overlain by the Trempealeau Formation and the laterally equivalent Potosi Dolomite in the western MRCSP study area. In Michigan, the Trempealeau is a buff to light brown dolostone, locally sandy and containing chert, with minor amounts of dolomitic shale and shaly dolostone. The Trempealeau contains a large amount of glauconite and minor amounts of anhydrite (Lilienthal, 1978; Milstein, 1983). Similarly, the equivalent Potosi Dolomite in Indiana is a pale gray to tan, dense, micritic to medium-grained dolostone with interbeds of shale and siltstone. The lower and upper parts of the Potosi may be glauconitic (Shaver and others, 1986). Eastward, the Potosi/Trempealeau interval is equivalent to the Copper Ridge Dolomite (Knox Group). The Copper Ridge is a thick interval of sandy dolostone with interbeds of sandstone and dark gray, argillaceous limestone in the eastern part of the MRCSP study area (Ryder and others, 1996, 1997). Dolostones of the Copper Ridge in parts of northern Kentucky, eastern Indiana, and Ohio range from dense to vuggy. Vuggy dolostones may occur throughout an interval of at least 400 feet in this area (Shrake and others, 1990). Farther eastward, in eastern West Virginia, Pennsylvania, and Maryland, the upper carbonate interval is equivalent to the Conococheague Group/Limestone and part of the Gatesburg Formation. The Conococheague is a thick carbonate-dominated sequence that is divided into several formations in Pennsylvania (Kauffman, 1999). The Conococheague contains sandy dolostone, which may be argillaceous and contain local layers of dolomitic, quartzose sandstones near the base of the unit; limestones with chert; and thin interbeds of limestone and dolostone (Kauffman, 1999). Cycles of intra-formational conglomerates, cross bedded grainstones, alternating thin-bedded limestone and dolostone (called "ribbon rock"), and planar laminated to mud-cracked dolostone are documented in Virginia, where this unit is exposed (Demicco, 1983, 1985). The part of the Gatesburg Formation beneath the Rose Run-equivalent in Pennsylvania is a dolostone similar to the Copper Ridge, which tends to be sandy toward the base (Ryder, 1991, 1992b)

DISCUSSION OF DEPTH AND THICKNESS RANGES

The Basal Sandstone to top of Copper Ridge Interval ranges in thickness from slightly more than 1,100 feet in the western portion of the MRCSP study area to more than 9,000 feet in the Rome trough in West Virginia (Figure A3-1). Isopachs are not projected beyond the trough into southern West Virginia because there are no wells deep enough in this area to penetrate the interval. However, those wells in southeastern Kentucky, southwest Virginia (just outside of the MRCSP study area), and northern West Virginia that reach basement indicate that there is substantial thinning of the interval south and east of the trough-bounding faults so that thinning is expected in southern West Virginia. Most of the thickness variation within the trough occurs within the Rome Formation and lower part of the Conasauga Group (Ryder and others, 1996, 1997; Harris and others, 2004).

The Basal Sandstone to top of Copper Ridge Interval also thickens into the Michigan basin (Figure A3-1). Thickening of the Franconia and Trempealeau formations into central Michigan indicates that the proto-Michigan basin continued to develop at this time (Catacosinos and Daniels, 1991). Subsidence occurred at a much slower rate than during the deposition of the basal sandstone. The proto-Appalachian basin also developed during this time, as indicated by southeastward thickening of units east of the Rome trough.

The shallowest depth at which the top of the Basal Sandstone to top of Copper Ridge Interval occurs is across the Cincinnati arch (in some cases less than 500 feet) (Figure A3-2). In the center of the Michigan basin, the top of this interval may be deeper than 10,000 feet, and in the Appalachian basin, the depth exceeds 20,000 feet.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

During deposition of the Basal Sandstone to top of Copper Ridge Interval, a shallow epicontinental sea covered the MRCSP study area. Subsidence above the Rome trough and lesser subsidence in the proto-Michigan and Appalachian basins influenced depositional facies, as did sea-level fluctuations. The pervasive dolomitization of the upper part of this interval (Copper Ridge equivalents) throughout the North American continent continues to be enigmatic, although it may be related to the expulsion and migration of fluids from the Ordovician Sevier or late Paleozoic Alleghanian orogenies (Glumac and Walker, 2002; Montanez, 1994).

Tomstown/Rome/Waynesboro/lower Conasauga Formations—The Shady-Tomstown Dolomite was deposited as a carbonate ramp along the Cambro-Ordovician passive margin of the craton (Read, 1989a, 1989b). Because the thickness of the dolostone does not change substantially across the southern bounding faults of the Rome trough, it is presumed to represent pre-rift deposition (Harris and others, 2004). The great thickness of the Rome Formation within the trough document growth during rifting (Harris and others, 2004). Evidence suggests that sediments were transported into the trough from the north. The deeper parts of the trough were occupied by a distal clastic shelf or ramp. Along the northwest margin of the trough, delta front and shallow marine shelf deposits dominated a shallower structural platform , with sand supplied by fluvial systems to the north. Presumably, the areas north and west of the trough at this time were dominated by nondeposition or erosion on the Precambrian surface. Age correlations for this interval are hampered by a lack of cores with usable biostratigraphic data. During the time of deposition of the upper Rome Formation, the deeper Rome trough was occupied by a carbonate ramp. A deeper water, intra-shelf basin is interpreted in south-central Kentucky, based on the few wells drilled there (Harris and others, 2004). Lateral facies of the lower Conasauga Formation may represent downslope facies equivalents of Rome clastic wedges building off the northern trough margin into deeper water (Ryder, 1992b; Ryder and others, 1996, 1997). Thickening of these units into the trough indicates continued (but lessened) growth faulting. Outside of the Rome trough, in southern West Virginia, anhydrites and redbeds in the Rome and Waynesboro Formations may indicate upper tidal

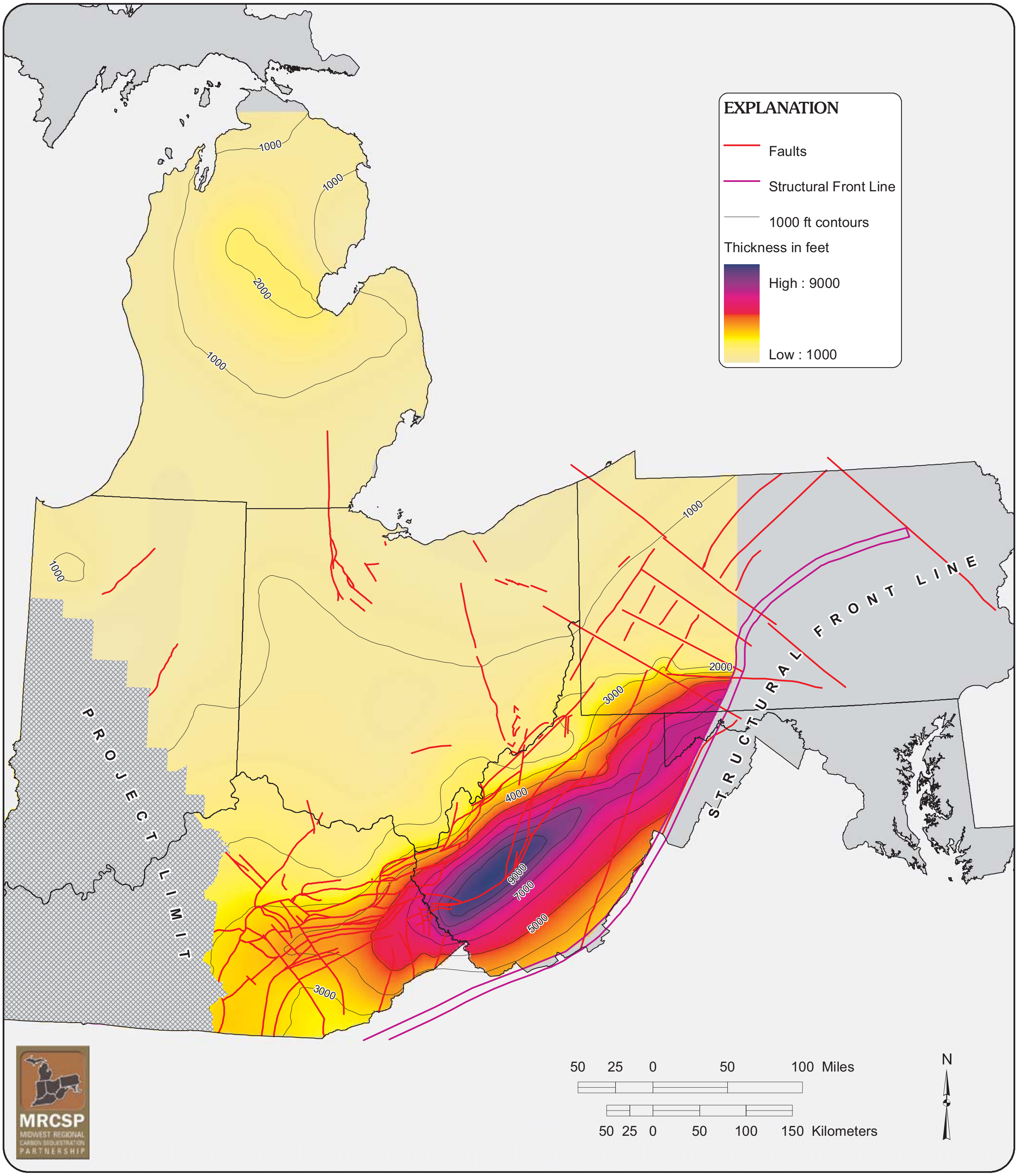

Figure A3-1.—Map showing the thickness of the interval from the top of the Cambrian basal sandstones to the top of the Copper Ridge Dolomite.

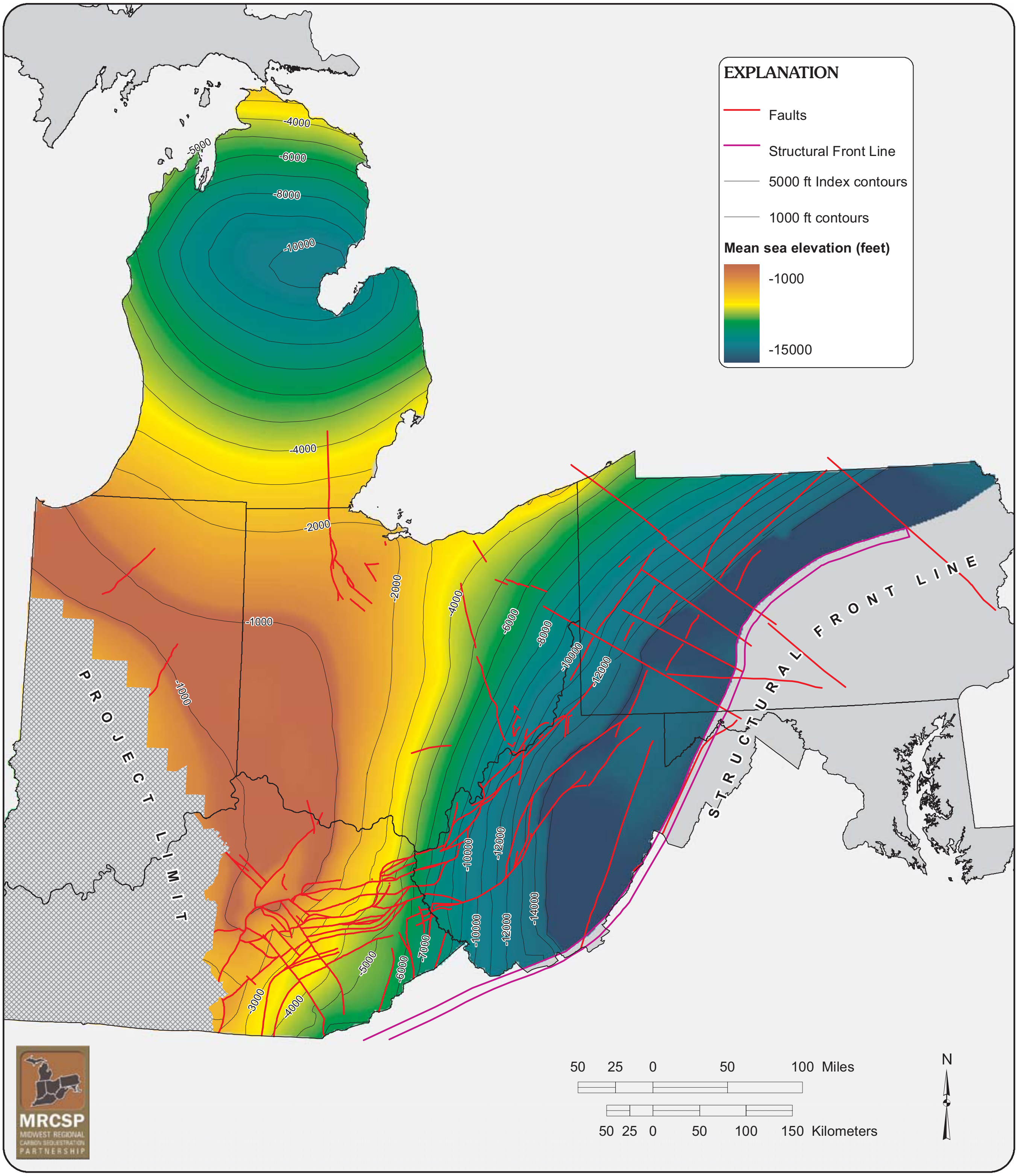

Figure A3-2.—Structure map drawn on the top of the Copper Ridge Dolomite.

flat to sabkha conditions. The carbonate bank represented by these formations dipped seaward toward southeastern Virginia (southeast of the MRCSP study area) where these units are dominated by peritidal carbonates (Haynes, 1991).

Eau Claire/Conosauga/Elbrook/Warrior Formations—Marine conditions continued in the units capping the trough fill. The marine shales of the Eau Claire Formation in the western part of the MRCSP study area represent the continuation of the Mt. Simon transgression (Driese and others, 1981). It bears repeating that this transgressive sequence is different from the transgressive sequence that includes the basal sands in the Rome trough and the basal sands east of the Rome trough. The Eau Claire and lateral units represent deposition following filling of the Rome trough. Across the MRCSP study area, there is a west to east transition in this sub-interval from shallow marine siliciclastics of the Eau Claire Formation; to mixed carbonates and clastics deposited in intra-shelf settings in the Conasauga; to peritidal carbonates of the Elbrook and Pleasant Hill Formations (Read, 1989a, 1989b). The latter carbonates are part of the persistent carbonate bank that existed on the eastern, passive margin of the craton during Cambrian and Early Ordovician time.

Upper Munising/Trempealeau/Potosi/Davis/Copper Ridge/Gatesburg/Conococheague Formations—During this sub-interval, a regression caused progradation of peritidal carbonates across the entire MRCSP study area (Read, 1989a and 1989b). This regression may have been related to the cessation of extensional tectonics on the passive margin, and marks the Sauk II/Sauk III boundary (Glumac and Walker, 2000). The Copper Ridge and its equivalents were deposited in a variety of peritidal environments. To the east, the Conococheague was deposited as platform carbonates transitional to deeper basinal facies to the south and east (Demicco, 1985). Shallowing-upward cycles within the Conococheague record repeated facies successions from storm to subtidal algal reef to subtidal shoal to intertidal flat and, ultimately, to sabkha (Demicco, 1983). Sandstones in the lower part of the Concocococheague and lateral equivalents may be related to detrital influx following the Sauk II/Sauk III sea-level fall (Marchefka and Glumac, 2002). More widespread sandstones in Michigan and parts of Indiana (Galesville and Ironton) were deposited as shallow marine shelf sands, which preceded the accumulation of peritidal carbonates in the Trempealeau Formation (Catacosinos and Daniels, 1991).

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

Given the variability in the geology across the region, it is not surprising that the mineralogy of lithologies within the Basal Sandstone to top of Copper Ridge Interval in the MRCSP study area is quite variable. Much of the sandstone in the interval is composed of reworked, multicycle quartz similar to the underlying mineralogy of the basal sandstone. There are also significant amounts of detrital and diagenetic feldspars, as well as a variety of detrital and authigenic clay minerals present in some units. Additionally, there are numerous portions of the section that contain significant amounts of glauconite. The varied mineralogy complicates analyses of the interval because geophysical log responses are, in many cases, not representative of the actual porosity of the rocks. Microporosity in shales, and the complex mixing of carbonate and siliciclastic lithologies, complicate geophysical log responses in some areas and in some parts of the interval. These minerals make the assessment of porosity and, especially, permeability problematic. Core analyses from this interval on the Ohio platform indicate low permeability in the interbedded clastics and carbonates -, suggesting good to excellent reservoir seal/confining characteristics.

Although the overall interval is mapped as a seal, there are units within the interval (especially in the east) that are possibilities for sequestration. These units themselves are confined by thick sections of shales or carbonates that would act as a seal. In northeastern Ohio, where limited porosity and permeability have been encountered, injection wells have been completed in the sandstones of the Conasauga Group. However, total cumulative injection volumes for these units are low when compared to Mt. Simon injection sites. In addition, multiple stratigraphic units had to be utilized at these sites to obtain the necessary injectivity.

Geophysical log responses of a few well-developed dolomitic sandstone units within the Conasauga Group of eastern Ohio suggest potentially good to excellent injection reservoirs. Site-specific evaluation, coring, and core analysis would be necessary before using these sandstones as an injection target. These are possible targets for Phase II studies.

Another potential sequestration target would be sandstones in the Rome Formation. These arkosic, marine sandstones may be as much as 500 feet thick (averaging approximately 250 feet). Limited oil and gas well drilling has encountered permeabilities as high as 177 md, with an average of 62 md, and with mean porosities of 12 percent (Harris and others, 2004). Because these are not regionally extensive units, they were not a focus of Phase I research, but they could be examined as part of the continuing geologic characterization in Phase II. Opportunities for structural closure exist within the fault-bound Rome trough, although reservoir heterogeneity may be common (Harris and Baranoski, 1996). The overlying shales of the Conasauga Group would form the seal on these potential reservoirs.

Thick zones of vugular porosity have also been encountered in a number of scattered wells within the Copper Ridge Dolomite. Vuggy dolostones were used at the DuPont WAD Fee well in Louisville, Kentucky (just west of the MRCSP study area) for the disposal of industrial waste fluids, after a well in the Mt. Simon Sandstone encountered "tight" sandstones at that horizon. The interval of vuggy dolostone is sealed above by dense dolostones of the Copper Ridge. Coring of the potential reservoir and seal units within the Copper Ridge would be required to further evaluate their sequestration potential in this and other parts of the MRCSP study area. Where this unit is deep enough to keep the CO_2 in miscible form, analysis appears warranted for use as an injection target, especially as a backup or secondary target for deeper Mt. Simon wells. These are also potential targets for Phase II studies.

4. UPPER CAMBRIAN ROSE RUN SANDSTONE

In Ohio and eastern Kentucky, the Cambrian-Ordovician Knox interval is subdivided, in ascending stratigraphic order, into the Copper Ridge Dolomite, Rose Run sandstone, and Beekmantown Dolomite. The Cambrian Rose Run sandstone is the only laterally persistent sandstone within the Knox Dolomite. This sandstone interval can be correlated in the subsurface from eastern Ohio, where it subcrops beneath the Knox unconformity (Figure A4-1), to eastern Kentucky, into western West Virginia (upper sandstone member of the Knox), Pennsylvania (Upper Sandy member of the Gatesburg Formation) (Figure 5), and extends into New York (partial equivalent of the Theresa Formation).

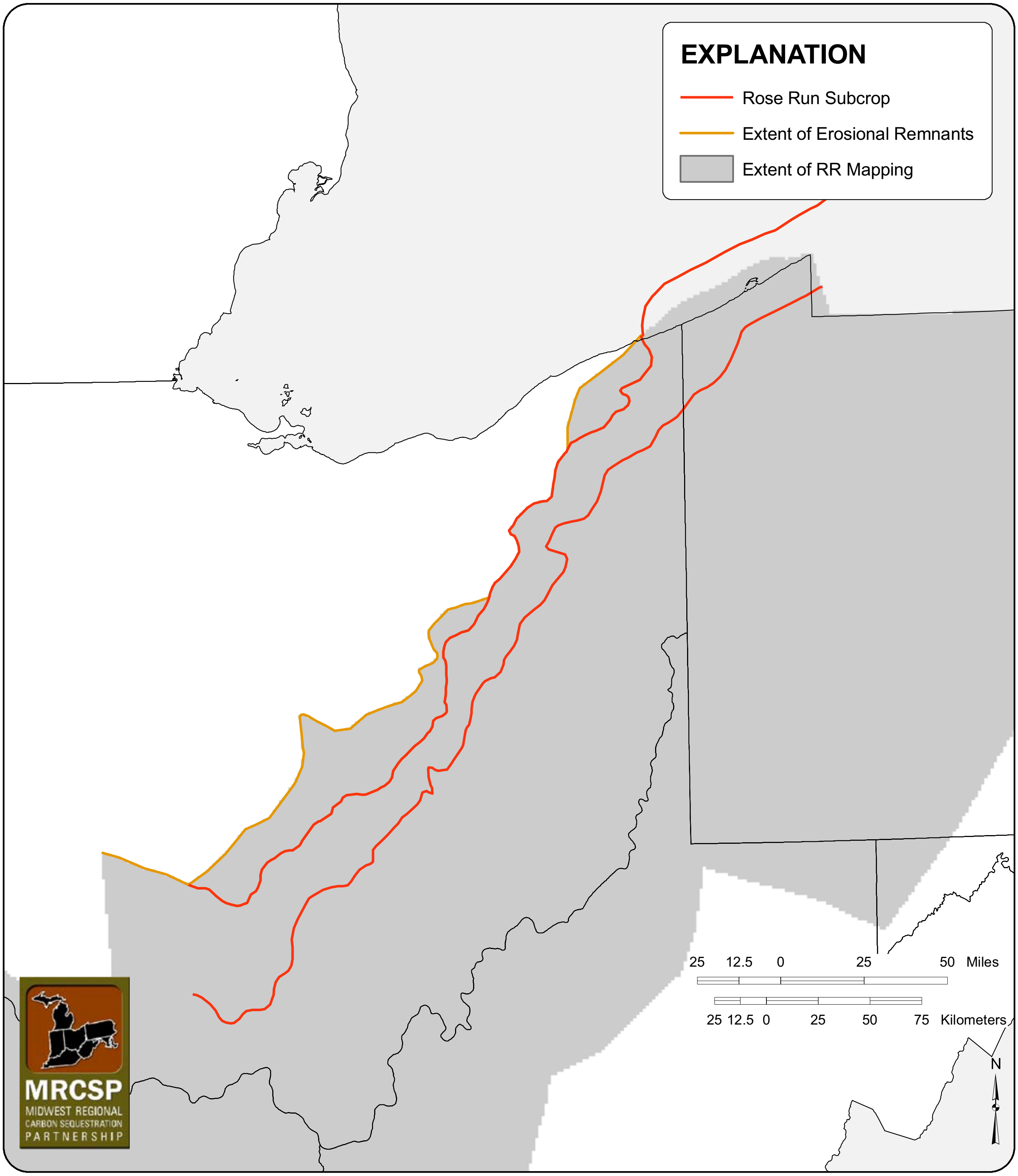

Figure A4-1.—Subcrop and extent map of the Rose Run sandstone.

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

The Rose Run sandstone was first described and named by Freeman (1949) from the Judy and Young #1 Rose Run Iron Co. well in Bath County, Kentucky where about 70 feet of poorly sorted sandstone was encountered approximately 300 feet below the Knox unconformity. Butts (1918) initially named the Upper Sandy member of the Gatesburg Formation (Rose Run equivalent) from outcrop studies in central Pennsylvania. Wagner (1961, 1966a,b,c, 1976) conducted subsurface studies of Cambrian-Ordovician stratigraphy of western Pennsylvania and bordering states and attempted to establish a workable nomenclature for this interval. He adopted the central Pennsylvania nomenclature of Kay (1944), Wilson (1952), and others for the majority of rocks in western Pennsylvania. In this classification scheme, the Gatesburg Formation in western Pennsylvania is subdivided, in ascending stratigraphic order, into the Lower Sandy member, the Ore Hill member, and the Upper Sandy member (see Figure 5).

Janssens (1973), in a detailed stratigraphic study of the Cambrian-Ordovician rocks in Ohio, extended the use of the term Rose Run from the subsurface of Kentucky into Ohio, but did not attempt to name it as a formal unit. He recognized the Copper Ridge, Rose Run, and Beekmantown as informal units of the Knox Dolomite. More recently, Riley and others (1993) performed a detailed investigation of the Rose Run in Ohio and Pennsylvania. They recognized the Copper Ridge, Rose Run, and Beekmantown as mappable, correlable units in the subsurface based on cores, cuttings, and geophysical logs, and suggested that these units be recognized as formal units in Ohio.

Regional subsurface correlations of the Cambrian-Ordovician interval across the Appalachian basin have been published that illustrate the lateral extent of the Rose Run and equivalent units (Ryder, 1991; 1992a,b; Ryder and others, 1992, 1996). A more detailed review of nomenclature, and previous work on the Rose Run and equivalent units, can be found in Riley and others (1993) and Baranoski and others (1996).

NATURE OF LOWER AND UPPER CONTACTS

The Rose Run sandstone directly overlies the Copper Ridge Dolomite or equivalent throughout the mapped area (Figure 5). The base of the unit is typically a gradational contact with the underlying Copper Ridge Dolomite and is difficult to correlate consistently across the basin using geophysical logs. In Ohio, the Rose Run interval, as recognized in core and geophysical logs, consists of a stacked sequence of as many as five sandstone units interbedded with thin, low-permeability dolostone and carbonaceous shale (Baranoski and others, 1996; Riley and others, 2002). The basal sandstone unit of the Rose Run interval is typically separated from the main sandstone body by a dolostone lens approximately 30 feet thick (Figure A4-2). The contact with the underlying Copper Ridge is placed at the base of this lowermost sandstone unit. This lowermost sandstone is less developed in southern Ohio and Kentucky. In Kentucky, the lowermost sandstone unit of the Rose Run in Ohio is either poorly developed or absent. Thus, the Rose Run-Copper Ridge contact is identified at the base of the main (i.e., well-developed) sandstone interval there, which is stratigraphically higher in the section than in central Ohio. Therefore, the thickness of the Rose Run, as mapped in Kentucky, is less than that mapped in Ohio (Figure A4-3). The base of the Rose Run or equivalent in West Virginia and Pennsylvania is also difficult to identify consistently on geophysical logs because of the heterogeneity of the interval, but is typically placed at the base of the lowermost sandstone unit as in Ohio.

The Rose Run sandstone conformably underlies a dolostone interval called the Beekmantown Formation in Ohio and eastern Kentucky (equivalent to the Mines Member of the Gatesburg Formation in central Pennsylvania), except within the Rose Run subcrop trend, where the Beekmantown is absent because of erosion on the Knox unconformity. Where the Beekmantown is eroded, either the Wells Creek Formation or Black River Group directly overlies the Rose Run. In areas with Beekmantown dolostone, the contact is gradational and the top of the Rose Run is placed at the top of the first well-developed, porous, sandstone unit underlying a low-permeability, nonporous dolostone (Riley and others, 1993; Baranoski and others, 1996; Riley and others, 2002). Within the Rose Run subcrop trend, the top of the Rose Run sandstone is a sharp, unconformable contact, and is placed at the top of porous, permeable sandstone that is overlain by impermeable interbedded shale and dolostone of the Wells Creek, or by impermeable, nonporous, dolostone of the Black River.

LITHOLOGY

The Rose Run interval, as described in subsurface core in Ohio, consists of white to light gray, fine-to medium-grained, sub- to well-rounded, moderately sorted, quartz arenites to subarkoses interbedded with thin lenses of nonporous dolostone (Riley and others, 1993; Baranoski and others, 1996). Glauconite and green shale laminae occur locally. Low-angle cross bedding is the most common sedimentary structure observed in both core and formation micro-imager (FMI) logs. Ripple marks have also been noted in both core and FMI logs. Polygonal mud cracks are present in several of the cores, indicating subaerial exposure of the sandstones during low stands in sea level.

In core and outcrop in Pennsylvania, the Rose Run equivalent, the Upper Sandy member of the Gatesburg Formation, contains three principal facies: 1) sandstone; 2) mixed sandstone and dolostone; and 3) dolostone (Riley and others, 1993). The sandstone facies consist of light-gray, fine-grained, well-sorted quartz arenites. The principal cement is silica. Cross bedding is present, including herringbone cross-stratification. The mixed sandstone and dolostone facies is dominated by sandstone that consists of fine- to medium-grained, moderately well sorted quartz arenites. The principal cement is dolomite. The dolostone facies are light-gray to olive-gray and display nodular bedding and bioturbation. Outcrops in central Pennsylvania contain "ribbon rocks" (thin-bedded, wave-rippled and burrowed dolostone), wavy dololaminite, flat pebble conglomerates, and thrombolitic algal mounds in the dolostone facies (Riley and others, 1993). Ooid grainstones are common within the dolostone facies.

From a regional study of cores and outcrops in Ohio and Pennsylvania (Riley and others, 1993), monocrystalline quartz and potassium feldspar are the dominant framework constituents in the Rose Run. Polycrystalline quartz and chert generally comprise less than one percent of the sandstone and appear in the more feldspathic samples. Minor amounts (less than one percent) of muscovite and accessory minerals—zircon, tourmaline, garnet, and pyrite—occur locally. Allochems are locally abundant in the Rose Run and include dolostone clasts, glauconite, peloid and dolomitized ooids. Four major cementing agents occurring in the Rose Run include: 1) dolomite; 2) clays; 3) quartz overgrowths; and 4) feldspar overgrowths (Riley and others, 1993). Dolomite is the dominant cementing agent as observed in cores throughout Ohio and Pennsylvania. Five pore textures were observed in the Rose Run, including: 1) intergranular

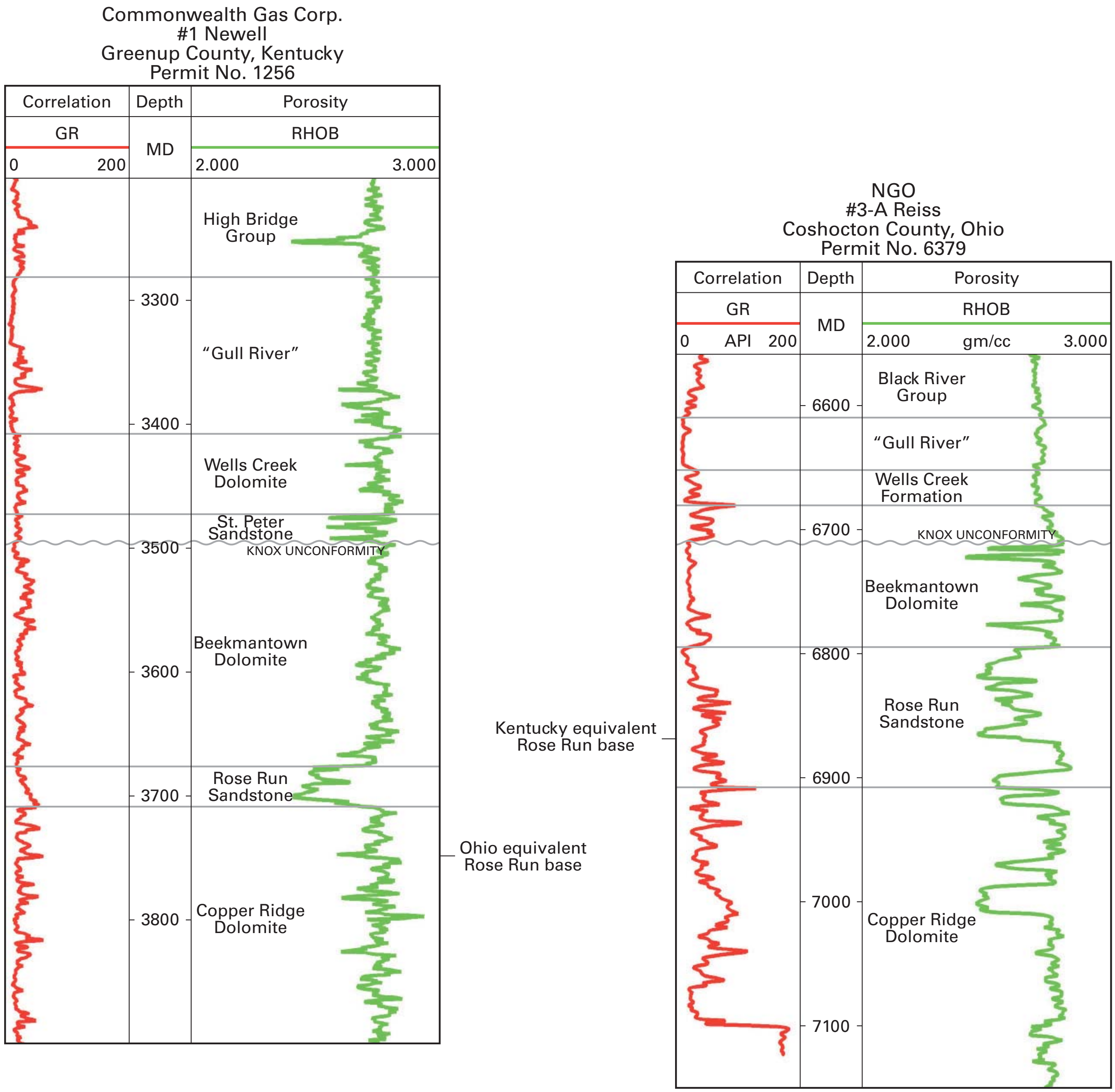

Figure A4-2.—Figure showing difference in interpretation of the Rose Run sandstone between Ohio and Kentucky based on geophysical log picks. The basal sand unit of the Rose Run sequence as mapped in Ohio and Pennsylvania, is not present, or poorly developed, in Kentucky. Therefore, the Kentucky thickness map cannot be merged with the Ohio thickness map as can be seen on Figure A4-3.

pores; 2) oversized pores; 3) moldic pores; 4) intraconstituent pores; and 5) fractures (Riley and others, 1993). Intergranular porosity is the most abundant porosity type in the Rose Run and appears to be mostly secondary based on corroded grain boundaries. Oversized pores are caused primarily by dissolution of dolomite and feldspar. Moldic pores occur in the more feldspathic samples and have the highest porosities and permeabilities. Intraconstituent pores occur most commonly in feldspar grains and appear to be more common toward the lower portion of the Rose Run. Fracture porosity is the least common porosity type observed in cores, but it may be locally significant in areas adjacent to major fault systems.

DISCUSSION OF DEPTH AND THICKNESS RANGES

Regional structure on the top of the Rose Run sandstone exhibits dip to the east and southeast with strike trending northeast-southwest (Figure A4-4). Subsea elevations range from 390 feet in north-central Kentucky to 18,900 feet in south-central Pennsylvania. Dips

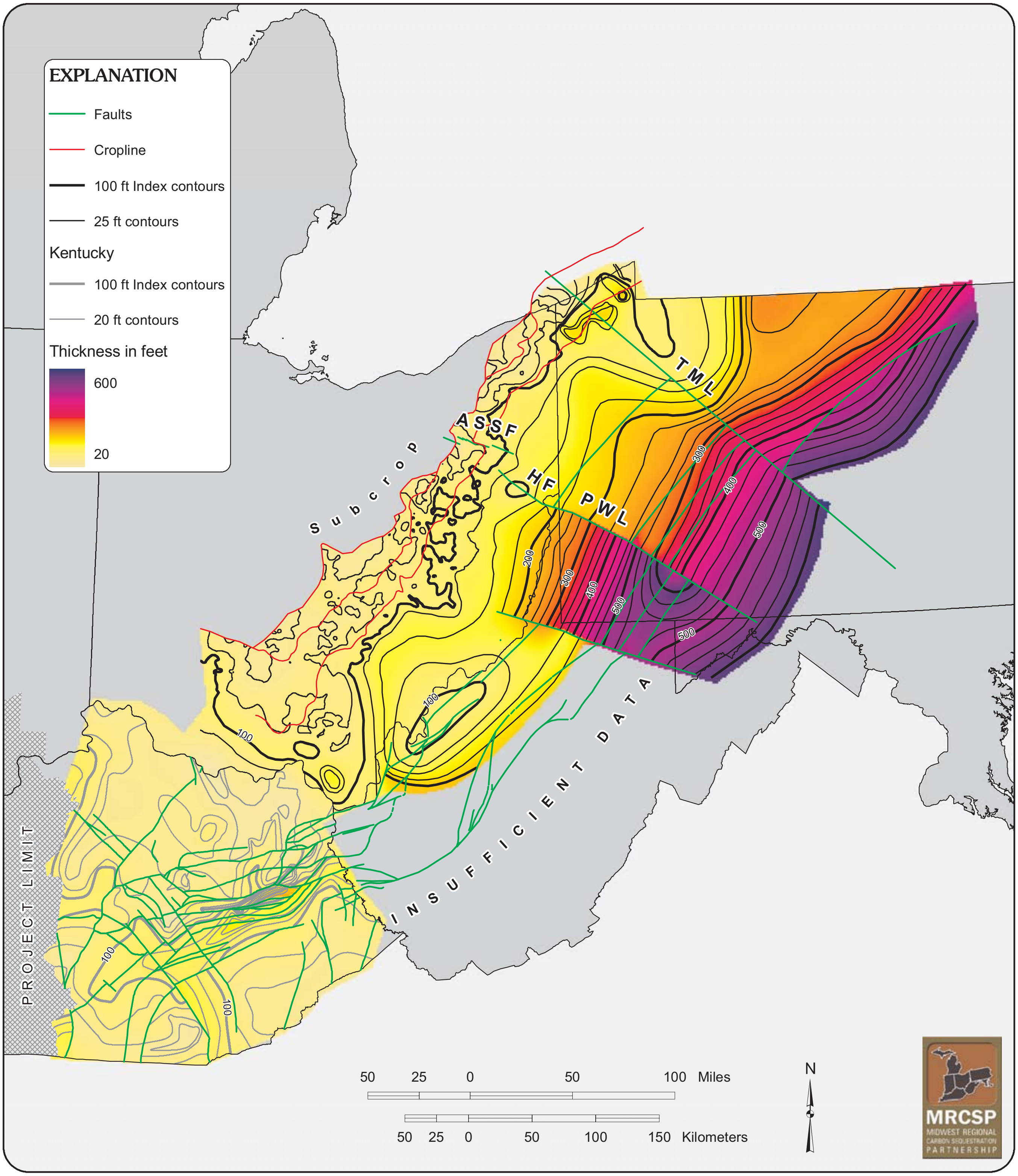

Figure A4-3.—Map showing the thickness of the Rose Run sandstone. See Figure A4-2 for explanation of thickness differences between Ohio and Kentucky. The letters refer to the followig features: ASSF = Akron-Suffield-Smith Fault systems; HF = Highlandtown Fault system; PWL = Pittsburgh-Washington Lineament; TML = Tyrone-Mount Union Lineament.

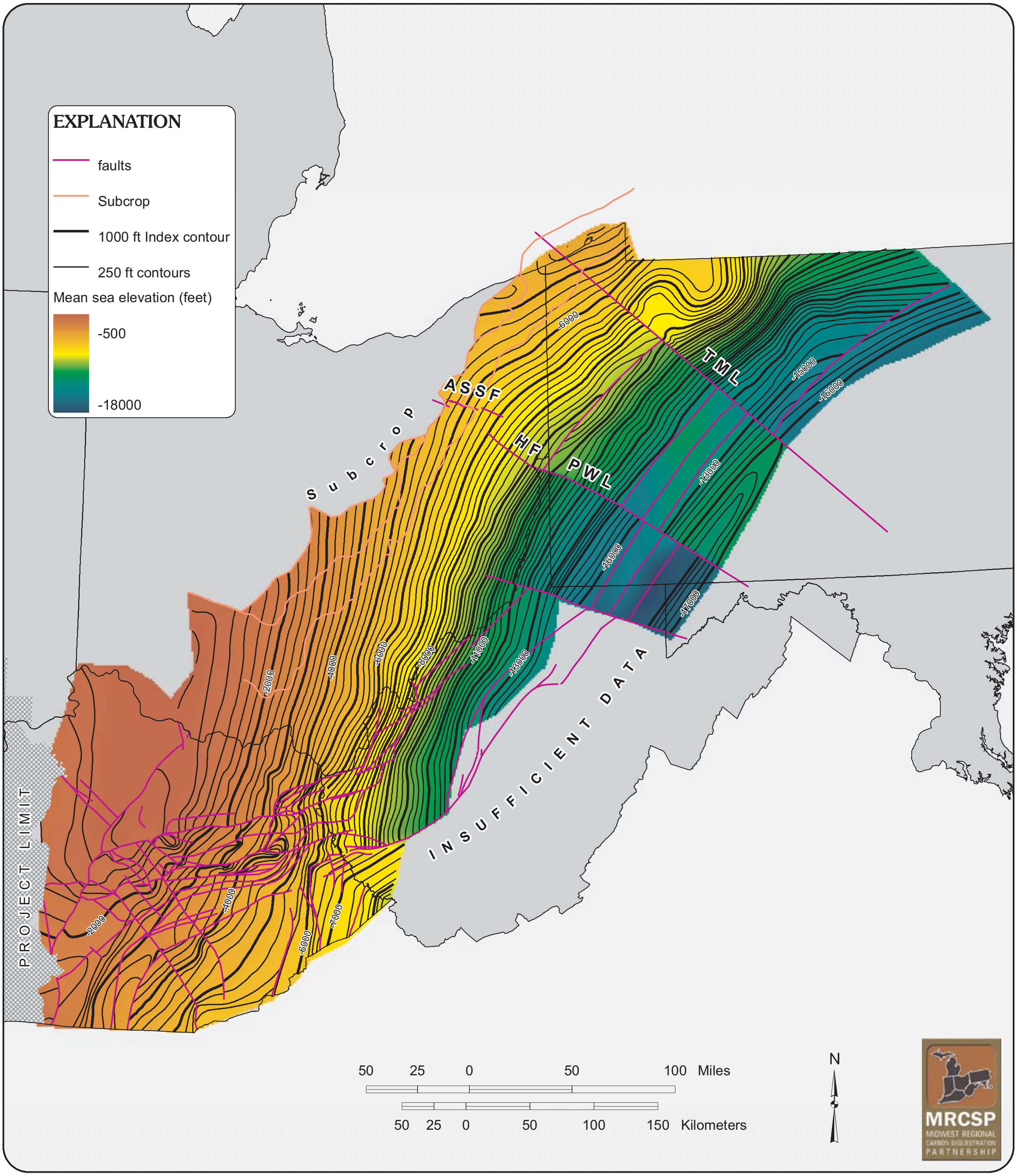

Figure A4-4.—Structure contour map drawn on the top of the Rose Run sandstone. The letters refer to the followig features: ASSF = Akron-Suffield-Smith Fault systems; HF = Highlandtown Fault system; PWL = Pittsburgh-Washington Lineament; TML = Tyrone-Mount Union Lineament.

range from approximately 50 feet per mile in northeastern Ohio and northwestern Pennsylvania to approximately 100 feet per mile in southeastern Ohio, and western West Virginia.

The major tectonic features affecting Rose Run structure occur in northeastern Ohio, western Pennsylvania, eastern Kentucky, and western West Virginia. In western Pennsylvania, these include the Tyrone-Mt. Union and Pittsburgh-Washington lineaments, which have been interpreted as northwest-southeast trending wrench faults (Riley and others, 1993). In addition, numerous growth faults above basement rifts have been proposed that have been offset by movement along these major wrench faults (Laughrey and Harper, 1986; Harper, 1989; Riley and others, 1993). In northeastern Ohio, the major tectonic features indicated by regional mapping are the northwest-southeast trending Akron-Suffield-Smith and the Highlandtown fault systems, which also have been suggested to be wrench faults (Riley and others, 1993). These are extensions of the Pittsburgh-Washington lineament in Pennsylvania. In eastern Kentucky and western West Virginia, the Rose Run structure is broken by the east- to northeast-trending Rome trough. Locally, small-scale features are present that are not evident on the regional-scale maps. A relationship between basement faults and paleotopographic highs on the Knox or Rose Run has been proposed as a controlling factor in reservoir development and hydrocarbon production (Coogan and Lesser, 1991; Riley and others, 1993).

The Rose Run sandstone interval thickens gradually from zero feet at the western limit of the subcrop to about 200 feet throughout the area of eastern Ohio and northwestern Pennsylvania (Figure A4-3). The irregular nature of the Rose Run isopach map in Ohio near the subcrop is a result of erosion on the Knox unconformity. Various paleotopographic features, including numerous erosional remnants, are present along the subcrop trend as a result of paleodrainage.

East of this broad zone of gradual thickening, the contours become narrower in western Pennsylvania as a result of the rapid thickening that is present in the Rome trough. Various authors have indicated that the Rome trough was actively subsiding during Rose Run deposition (Wagner, 1976; Harper, 1991). Approximately 470 feet of Rose Run was encountered in the Amoco #1 Svetz well in Somerset County, Pennsylvania before drilling was stopped at 21,640 feet; most of that thickness occurred in the uppermost sandstone body.

The depositional pattern of the Rose Run in south-central Ohio and north-central Kentucky suggests control by the Waverly arch, a north-south trending feature that was first identified by Woodward (1961). Isopach maps of the Knox by Janssens (1973), and the Prairie du Chien by Shearrow (1987), indicate thinning over the feature. This thinning is also coincident with a facies change in the Rose Run in which it is sandstone-dominant on the east side and carbonate-dominant on the west side of the Waverly arch (Riley and others, 1993). A rather abrupt thinning occurs on the isopach map across the state line boundary of Ohio and Kentucky. This is, in part, an artifact of how the base of the Rose Run is interpreted differently in Ohio and Kentucky as discussed previously. In eastern Kentucky, changes in the contours along the Rome trough indicate that this fault influenced Rose Run deposition.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

Following the Rome trough aulacogen and deposition of the basal sandstones described in an earlier section, Late Cambrian recycled sands, including those of the Rose Run, continued to be deposited across the present-day Appalachian basin area. These sands were mixed with shelf carbonates that eventually dominated this passive margin (Riley and others, 1993). Provenance studies of the Rose Run sandstone suggest that they are compositionally mature and were derived from the crystalline Precambrian shield complexes and overlying platform rocks (Miall, 1984; Riley and others, 1993). The widespread Knox unconformity developed during the initial collision of the passive margin and the lowering of eustatic sea level in the Middle Ordovician (Mussman and others, 1988; Read, 1989). The progressive westward truncation of Knox units along this regional unconformity created and exposed the Rose Run subcrop trend (Figures A4-1, A4-3 and A4-4).

Deposition of the Rose Run and adjacent Knox units has been attributed by various authors to represent a peritidal to shallow subtidal marine environment (Mussman and Read, 1986; Anderson, 1991; Gooding, 1992; Ryder, 1992a; Ryder and others, 1992; Riley and others, 1993). The Rose Run is part of a heterogeneous assemblage of interbedded siliciclastic and carbonate facies in the Knox that were deposited on a carbonate shelf, which Ginsburg (1982) referred to as the "Great American Bank." The Rose Run represents lowstand deposits of siliciclastic sediments that were transported onto the peritidal platform and reworked during subsequent sea-level rises (Read, 1989).

Many authors have interpreted tidal flat deposition for the Rose Run and equivalent strata (Mussman and Read, 1986; Anderson, 1991; Enterline, 1991; Riley and others, 1993) based upon core and outcrop description. Sedimentary features supporting this include herringbone cross bedding and basal lags of dolostone and shaly dolostone indicating scour along tidal channel thalwegs. In outcrop in central Pennsylvania, a shallowing-upward tidal flat sequence is recognized and include the following subfacies: 1) storm sheet deposition with flat pebble conglomerates; 2) algal patch reefs with thrombolitic bioherms; 3) subtidal ooid-peloid sand shoals with cross stratified ooid grainstones; 4) lower intertidal mixed sand-mud flats with ribbon rock; 5) upper intertidal algal flats with prism-cracked wavy laminites; and 6) supratidal flats with mudcracked flat laminites (Riley and others, 1993). Subsurface cores in Ohio also indicate a supratidal facies from the presence of digitate algal stromatolites, mudcracks, and nodular anhydrite and chert replacing evaporites. Extensive mottling from bioturbation indicative of intertidal and subtidal environments is pervasive throughout the Rose Run and adjacent Knox units.

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

Suitability of CO_2 injection for the Rose Run can be subdivided into three geographic areas for discussion: 1) within the Rose Run subcrop trend; 2) downdip of the eastern edge of the subcrop; and 3) within the Rome Trough. In most of these areas, the Rose Run occurs at depths greater than 2,500 feet, which should be within the preferred condition to obtain adequate minimum miscibility pressures for CO_2 sequestration. Availability of subsurface well data is greatest within the subcrop trend, where most of the petroleum exploration and production from this formation has occurred. Thus, knowledge of reservoir characteristics is best within the subcrop trend, where thousands of oil and gas wells have targeted the Rose Run, and decreases basinward away from the subcrop.

Within and adjacent to the Rose Run subcrop, reservoir quality is controlled by erosional truncation and paleotopography on the Knox unconformity. Erosional remnants are found along the subcrop trend, typically 80 acres or less in area. Large-scale injection of CO_2 in Rose Run remnants would be difficult because of their limited size. However, reservoir quality within these remnants is often very good because of enhanced secondary porosity, and would provide good areas for enhanced oil recovery. Within the subcrop trend, average porosities measured from core and geophysical logs range from 6 to 12 percent with values as high as 14 percent (Riley and others, 1993; Baranoski and others, 1996). Permeabilities vary widely from .01 to 198 md, averaging 4 md (Baranoski and others, 1996). Thickness of the Rose Run varies depending on the size of the remnant. Wells with a complete section of Rose Run in the subcrop trend have a gross thickness of approximately 110 feet and a net thickness of about 50 feet of highly porous, permeable sandstone. The subcrop trend of the Rose Run (Figure A4-1) is an attractive prospect for CO_2 injection.

High porosities and permeabilities are not restricted to wells within the subcrop trend. Cores in Jackson and Scioto counties, Ohio, approximately 40 to 50 miles down dip from the subcrop, indicate average porosities ranging from six to 12 percent, and permeabilities often greater than 1.0 md, with some values exceeding 100 md. These porosities and permeabilities indicate good reservoir quality away from the highly drilled and explored subcrop trend. Although the gross interval of the Rose Run thickens to the east, the sandstone-to-carbonate ratio decreases to the east and southeast, suggesting a clastic source to the north and northwest (Riley and others, 1993). Thus, net sandstone generally decreases to the east and southeast. The American Electric Power #1 AEP well drilled in New Haven, West Virginia, encountered only 18 net feet of sandstone greater than six percent porosity within the Rose Run. This well was drilled as part of a DOE-funded project to assess the potential injection for CO_2 sequestration.

There has been no oil or gas production from the Rose Run in Kentucky, and there are fewer data to determine the composition, reservoir quality, and suitability of the Rose Run as an injection target. While the Rome trough was actively subsiding during Rose Run deposition, large amounts of clastic sediment were probably built up in localized areas of Kentucky, West Virginia, and Pennsylvania. Wells such as the Amoco #1 Svetz well in Somerset County, Pennsylvania, with approximately 470 feet of Rose Run, indicate the potential for large sequestration capacity at the greater depths in the Rome trough. Well logs in Kentucky indicate porosity up to 18 percent at depths greater than 5,000 feet in the Rose Run.

In most areas the Rose Run sandstone contains an adequate seal and confining units for CO_2 sequestration, as indicated by the trapping efficiency of significant volumes of oil and gas. The nonporous Beekmantown Formation dolostone and Wells Creek Formation that directly overlie the Rose Run provide an excellent seal for containment of CO_2. In some areas (e.g., south-central Kentucky), the Beekmantown is porous and is a hydrocarbon reservoir. The risk of an inadequate seal is higher in these areas, especially where the Beekmantown is fractured. In Ohio, a thick sequence of Ordovician shales and Black River and Trenton carbonates overlie the Rose Run and serves as a confining unit. Below the Rose Run, a thick sequence of Cambrian dolostone and shale act as the confining unit between the Rose Run and earlier Cambrian sandstones.

To date there has been no injection activity in the Rose Run, thus data regarding CO_2 injectivity is not available. A DOE-funded pilot study is currently under consideration at the AEP New Haven site to inject CO_2 into the Rose Run and other potential units. This will provide critical data necessary for evaluating the injectivity in potential areas for Rose Run sequestration.

5. KNOX TO LOWER SILURIAN UNCONFORMITY INTERVAL

The stratigraphic sequence herein referred to as the Knox to Lower Silurian Unconformity Interval has been mapped because of its potential function as a major confining interval. This interval is dominated by thick, relatively impermeable carbonates at the bottom and thick shale sequences at the top. There is, however, some potential for carbon sequestration in several of the units, including the St. Peter Sandstone (which is mapped and discussed separately for this project), some of the fractured or dolomitized portions of the carbonate sequence, and the coarser clastics of the Bald Eagle and Juniata Formations at the top of the sequence in the eastern part of the MRCSP study area. The interval is bounded by two major unconformities, the Knox unconformity at the base and the Cherokee unconformity at the top (i.e., at the Ordovician-Silurian boundary).

The stratigraphic nomenclature associated with the Knox to Lower Silurian Unconformity Interval can be intimidating (Figure 5). Most of the laterally equivalent units shown in Figure 5 are lithologically similar, at least in the lower half of the correlation diagram, despite name changes across state boundaries. The stratigraphic nomenclature toward the top of the Ordovician sequence, however, becomes much more complex due to the multitude of westward prograding Upper Ordovician flysch facies resulting from the Taconic orogeny.

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

The St. Peter Sandstone is the lowest (Middle Ordovician) strata in the Knox to Lower Silurian Unconformity Interval in the Michigan basin. However, because it is discussed in detail elsewhere in this report, it will not be mentioned further here except in reference to adjacent formations. In the following discussion, italicized state names in parentheses, for example (*Michigan*), indicate the use of the particular stratigraphic name in that state, whether or not it is a direct lithologic correlative of the type section.

Calvin (1906) named the Middle Ordovician Glenwood Formation (*Michigan*) for a thin (3 to 15 feet) shale in Glenwood Township, Winneshiek County, Iowa, lying between the St. Peter Sandstone and the Platteville Limestone. The Ancell Group (*Indiana*), named by Templeton and Willman (1952) for rocks exposed in the Dixon-Oregon area of northern Illinois, comprises in ascending order, the Kingdom, Daysville, Loughridge, and Harmony Hill Formations. Lusk (1927) first used the name Wells Creek Formation (*Kentucky, Ohio, West Virginia, and northwestern Pennsylvania*) without explanation in a stratigraphic column of rocks in central Tennessee, apparently to replace Ulrich's (1911) Wells Chert (the name Wells was already in use for a younger formation in Idaho and Utah). Bentall and Collins (1945) later described the Wells Creek Formation as 432 feet of tan to grayish green, silty to sandy, argillaceous, fine-grained dolostone interbedded with dark-brown to tan, dense limestone lying between the Knox unconformity and the Murfreesboro Limestone in the Ada Belle Oil #2-A well in Trigg County, Kentucky. Ulrich (1911) named the Bellefonte Formation of the Beekmantown Group (*central Pennsylvania and Maryland*) for 2,145 feet of light-gray, argillaceous, highly magnesian limestone and yellowish-gray or drab, generally fine-grained and occasionally laminated dolostone alternating with dark, finely crystalline dolostone at Bellefonte, Centre County, Pennsylvania. All of these formations are more or less equivalent in age and grade laterally with each other.

Field (1919) recognized a zone of interbedded limestone and dolostone above the dolostones of the Beekmantown that he called the Loysburg Formation (*Pennsylvania*) from outcrops at Loysburg, Bedford County, Pennsylvania. This formation is considered Middle Ordovician in age at the type locality, but grows progressively younger westward across the state (Berg and others, 1986). Westward, drillers refer to a clean micritic limestone interval in this part of the section as the "Gull River limestone" (*Ohio*), an erroneous name originally applied to a younger stratigraphic unit in Ontario (Wickstrom, 1996).

Above these strata are the Upper Ordovician Black River Group (or Limestone) (*Michigan, Indiana, Ohio, Pennsylvania, West Virginia, and Maryland*), named by Vanuxem (1842) for the Ordovician limestones lying below the Trenton Limestone in cliffs along the Black River in New York. Its equivalent is the High Bridge Group (*Kentucky*), which was described by Campbell (1898), for 200 feet of white limestone grading downward into gray limestone and calcareous shales. The High Bridge includes in ascending order, the Camp Nelson, Oregon, and Tyrone Limestones (Cressman and Peterson, 2001). Above these strata are the Trenton Group (or Limestone) (*Michigan, Indiana, Ohio, Pennsylvania, West Virginia, and Maryland*), first described by Vanuxem (1938) from Trenton Falls, Oneida County, New York, where 100 feet of light-gray, sparry limestone underlain by dark-gray to black compact limestone are exposed in the waterfall and adjacent cliffs. The equivalent Lexington Limestone (*Kentucky*) was described by Campbell (1898) for 140 to 180 feet of thin-bedded, gray limestone that contains chert nodules at the base and a persistent band of chert at the top. It has since been divided into numerous members (Cressman, 1973).

Above the Trenton/Lexington interval, the section becomes increasingly complicated. Dark mudrocks gradually to sharply replace the carbonates, and in turn are replaced by coarser clastics. The Richmond Group (*southwestern Michigan*) consists of three formations described by Hussey (1926) from Delta County, Michigan, including (in ascending order): 1) the Bill's Creek Shale, composed of thin-bedded shales with thin layers of interbedded argillaceous, fossiliferous limestone exposed on Bill's Creek; 2) the Stonington Formation, consisting of a lower 20 feet of cherty limestones and upper 38 feet of argillaceous limestone in alternating hard and soft layers exposed north of the Stonington Post Office; and 3) the Big Hill Formation, a 27 feet thick sequence of light-gray, moderately hard, noncrystalline limestone grading to dark-gray, hard, coarsely crystalline, argillaceous limestone exposed along Maywood Road. White (1870) described the equivalent Maquoketa Group (*Indiana*) as 80 feet of bluish and brownish shales exposed on the Little Maquoketa River in Dubuque County, Iowa. The U. S. Geological Survey later adopted the name for the middle formation of the Richmond Group in the lower Mississippi Valley.

The Clays Ferry Limestone (*central and eastern Kentucky and southern Ohio*) is equivalent with the lower part of the Maquoketa. It consists of interbedded thin shales, limestones, and siltstones (as summarized by Weir and others, 1965) and grades upward and laterally into interbedded carbonate and clastic lithologies comprising the Fairview, Leipers, Ashlock, Drakes, Grant Lake, and Bull Fork formations (*Kentucky and southern Ohio*), as summarized by Weir and others (1984) and Cressman and Peterson (2001). The Clays Ferry grades northward and eastward into the Point Pleasant Formation (*Ohio and Pennsylvania*), a relatively thick sequence of interlayered gray to green, calcareous shale, limestone, siltstone, and sandstone named by Newberry (1873) for strata exposed at Point Pleasant, Clermont County, Ohio. The Point Pleasant grades eastward and southeastward with the Utica Shale (*southeastern Michigan*, *eastern Ohio, West Virginia, Maryland, and Pennsylvania*), a series of gray to black and brown shales with few, if any, interbedded limestones. This unit was named by Emmons (1842) for black shales exposed in Utica, Oneida County, New York.

Above the Utica is a thick sequence of shales that Ulrich (1911) named the Reedsville Formation (*western Pennsylvania and western West Virginia*) for exposures at Reedsville, Mifflin County, Pennsylvania. The Utica and Reedsville together grade laterally into the Martinsburg Formation (*central Pennsylvania, Maryland, West Virginia, and southeastern Ohio*), named by Geiger and Keith (1891) for exposures at Martinsburg, West Virginia. The Martinsburg consists primarily of dark colored calcareous and argillaceous shales with some siltstone and limestone. This sequence (Utica and Reedsville/Martinsburg) gradually coarsens upward. Where the dominant lithology is sandstone the names Oswego Sandstone (*southeastern Ohio, West Virginia, and Maryland*) and Bald Eagle Formation (*Pennsylvania*) are applied. Prosser (p. 946 in Ashburner, 1888) first used the name Oswego Sandstone to replace "grey sandstone of Oswego," a term used by Emmons (1842) for exposures in Oswego County, New York. The Oswego consists of gray, fine- to coarse-grained sandstones interbedded with siltstones and shales. Grabau (1909) named the Bald Eagle for gray to white conglomerates and quartz sandstones exposed on Bald Eagle Mountain in Blair County, Pennsylvania. The Oswego and Bald Eagle grade upward into the red sandstones and shales of the Juniata Formation (*central Pennsylvania, Maryland, West Virginia, and southeastern Ohio*). Darlton (1896; also Darlton and Taff, 1896) first referred to the Juniata while describing brownish-red sandstones alternating with red shales. The name refers to exposures along the Juniata River in central Pennsylvania. To the north and west, the Juniata loses most of the coarser clastics, and the name changes to Queenston Formation (*southeastern Michigan, northeastern Ohio, and western Pennsylvania*), although the red coloration remains. Grabau (1908) first used the name Queenston for red shales underlying the Medina Sandstone at Queenston, Ontario. Thompson (1999) summarized the stratigraphic and lithologic character of the post-Trenton clastics sequence in Pennsylvania and adjacent areas, and Laughrey and Harper (1996) studied the potential for gas production from the Bald Eagle and Oswego formations. Because the Bald Eagle/Oswego and Juniata sequences have carbon sequestration potential, more details are provided below.

NATURE OF LOWER AND UPPER CONTACTS

The Knox to Lower Silurian Unconformity Interval is bounded on the bottom by the Knox unconformity and at the top by the Cherokee unconformity. Based on lithostratigraphy, both unconformities seemingly grade to conformable contacts eastward in central Pennsylvania and Maryland. However, with the advent of sequence stratigraphy in the 1980s and 1990s, it has been shown that at least the Cherokee unconformity is probably basin wide in nature.

The Knox unconformity (= Owl Creek unconformity in North America) is a much larger magnitude erosional event than the Cherokee unconformity. It developed as a result of a change in the southern margin of the Laurentian plate from passive to convergent by arc-continent or microplate-continent collision during Middle Ordovician time (Jacobi, 1981; Shanmugam and Lash, 1982; Scotese and McKerrow, 1991). This caused major changes in sea level, tectonism, and depositional environments across the continent (Mussman and Read, 1986; Read, 1989). By the early Middle Ordovician, much of the southern continental shelf of Laurentia was emergent, resulting in exposure of the Middle Ordovician through Upper Cambrian strata to severe erosion, from the Transcontinental arch in the midcontinent region almost to the center of the depositional basin in central Pennsylvania and Maryland. Throughout the MRCSP study area, the Knox unconformity is easily recognized by the juxtaposition of upper Middle Ordovician strata (St. Peter Sandstone, Wells Creek Formation, Glenwood Formation) on the often karstified surface of Cambrian or Lower Ordovician strata (Baranoski and others, 1996). In places, it amounted to 30 million years worth of erosion (Brett and Caudill, 2004). In central Pennsylvania, however, there is no specific evidence of an unconformity. A zone of chert occurs near the base of the Bellefonte Formation of the Beekmantown Group (Figure 5) throughout central Pennsylvania from Bedford County to Centre County (Knowles, 1966). Ryder and others (1992; also Riley and others; 1993) speculated that this chert zone might be a remnant of the Knox unconformity surface that is unidentifiable by other means in this area. This hypothesis has never been tested. It is probable that a sequence stratigraphic approach, rather than a classical lithostratigraphic one, will be required to resolve this problem.

The Cherokee unconformity is one of the most important regional unconformities in North America. It resulted from a combination of tectonism—the end of the Taconic orogeny—and eustacy. The Cherokee unconformity, which coincides with the Ordovician-Silurian boundary, has been correlated across most of North America. In classical stratigraphy, the unconformity does not exist in the eastern part of the Appalachian basin (central Pennsylvania, Maryland, and northeastern West Virginia). Instead, the Upper Ordovician Juniata Formation grades conformably upward into the Lower Silurian Tuscarora Formation. There is even a sequence of rocks containing features of both the Juniata and Tuscarora that has been called the "Juniata-Tuscarora transition zone" in Pennsylvania (Avary, 1996; McCormac and others, 1996) and the "lower Tuscarora Sandstone" in Virginia (Dorsch and others, 1994). However, a growing body of evidence from sequence stratigraphic studies in these and adjacent areas suggests that the Cherokee unconformity occurs basin-wide, even within this transition zone (Castle, 1998; Dorsch and others, 1994; Hettinger, 2001; Ryder, 2004).

LITHOLOGY AND DEPOSITIONAL ENVIRONMENTS

Much of the Cambrian and Ordovician stratigraphic section comprises a thick sequence of predominantly shallow-water carbonates formed on what Ginsburg (1982) called the "Great American Bank." This bank extended more than 1,875 miles along the length of the southern seaboard of the Laurentian plate from Early Cambrian through early Late Ordovician time (Hardie, 1986), and contained a complex mosaic of interdependent subenvironments in which depositional processes imprinted distinctive physical, diagenetic, and biogenic features on the sediments. Although sedimentation was primarily carbonate precipitation and skeletal grain reworking, the bank received periodic influxes of shales, siltstones, and sandstones from the Laurentian highlands north and west of the basin (for example, the Glenwood and Wells Creek Formations). The clastics periodically interrupted carbonate deposition and resulted in argillaceous carbonates, alternating carbonates and shales, and the occasional siltstone or sandstone overprint over much of the extent of the platform.

Both the Upper Ordovician carbonates and mixed carbonate/shale sequences typically consist of well-cemented, bioclastic grainstones and carbonate mudstones separated by relatively thin calcareous shales or argillaceous limestones that developed in shallow-platform and peritidal settings (Nuttall, 1996). A generalized depositional model (Figure A5-1) shows a variety of carbonate shelf facies that characterize parts of the Middle and Upper Ordovician sequence in the study area.

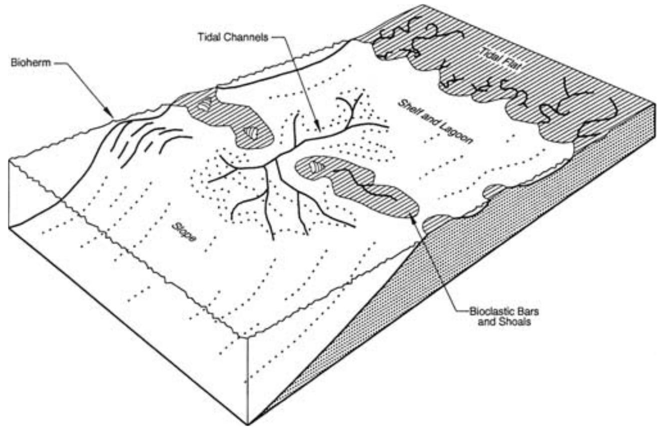

Figure A5-1.—Generalized model of Middle and Upper Ordovician carbonate depositional environments (based on Walker and James, 1992; from Nuttall, 1996).

In summary, the Glenwood and Wells Creek formations represent a brief interval of mixed clastic and carbonate sedimentation in a shallow sea that spread back across the area following the Knox unconformity event. Black River and High Bridge strata were deposited in shallow epeiric seas in environments ranging from shallow subtidal to tidal flat, while Trenton and Lexington carbonates were deposited in somewhat more clastic-rich shelf environments to the east and southwest, and cleaner carbonate platform environments to the northwest (Figure A5-2) (Wickstrom, 1996).

The Utica Shale and Point Pleasant Formation represent a major transgression across the eastern United States, resulting in a deeper interplatform, anoxic depositional environment (Figure A5-2) that probably started penecontemporaneously with the later Trenton carbonate buildups in response to compression from the Taconic orogeny (Wickstrom and others, 1992). The dark colored shales indicate a large influx of organic material, restricted circulation, and low-energy conditions within the depositional basin (Bergström and Mitchell, 1992). In fact, there has been some debate over whether or not an unconformity exists at the top of the Trenton (Keith and Wickstrom, 1993). Wickstrom and others (1992) concluded that the contact between the Trenton/Lexington and the Utica/Point Pleasant represents a disconformity. Based on conodont biostratigraphy, Bergström and Mitchell (1992) determined that this contact represents a period of very slow, or interrupted, deposition in a submarine environment.

The succession of clastics above the Utica/Point Pleasant interval includes, in ascending order: 1) gray shales and minor siltstones of the Reedsville and Martinsburg Formations; 2) gray, sandstones of the Oswego Sandstone and correlative fine- to coarse-grained sandstones and conglomerates of the Bald Eagle Formation; and 3) the reddish sandstones and shales of the Juniata Formation and reddish shales of the correlative Queenston Formation. These units comprise a distinctive clastic sequence in the Appalachian basin during Ordovician time that contains well-developed marine units formed on the continental margin, as well as shallow marine to nonmarine units deposited on the foreland of the Taconic orogenic belt (Laughrey and Harper, 1996). Thompson (1970, 1999) defined six lithofacies that reflect the sedimentary processes active within these diverse depositional systems (Figure A5-3). Grabau (1909) originally defined the Bald Eagle Formation as the gray-colored sandstones lying between the gray shales of the Reedsville Formation and the red beds of the Juniata Formation. However, Horowitz (1965) demonstrated that the Bald Eagle sandstones initially were red like those

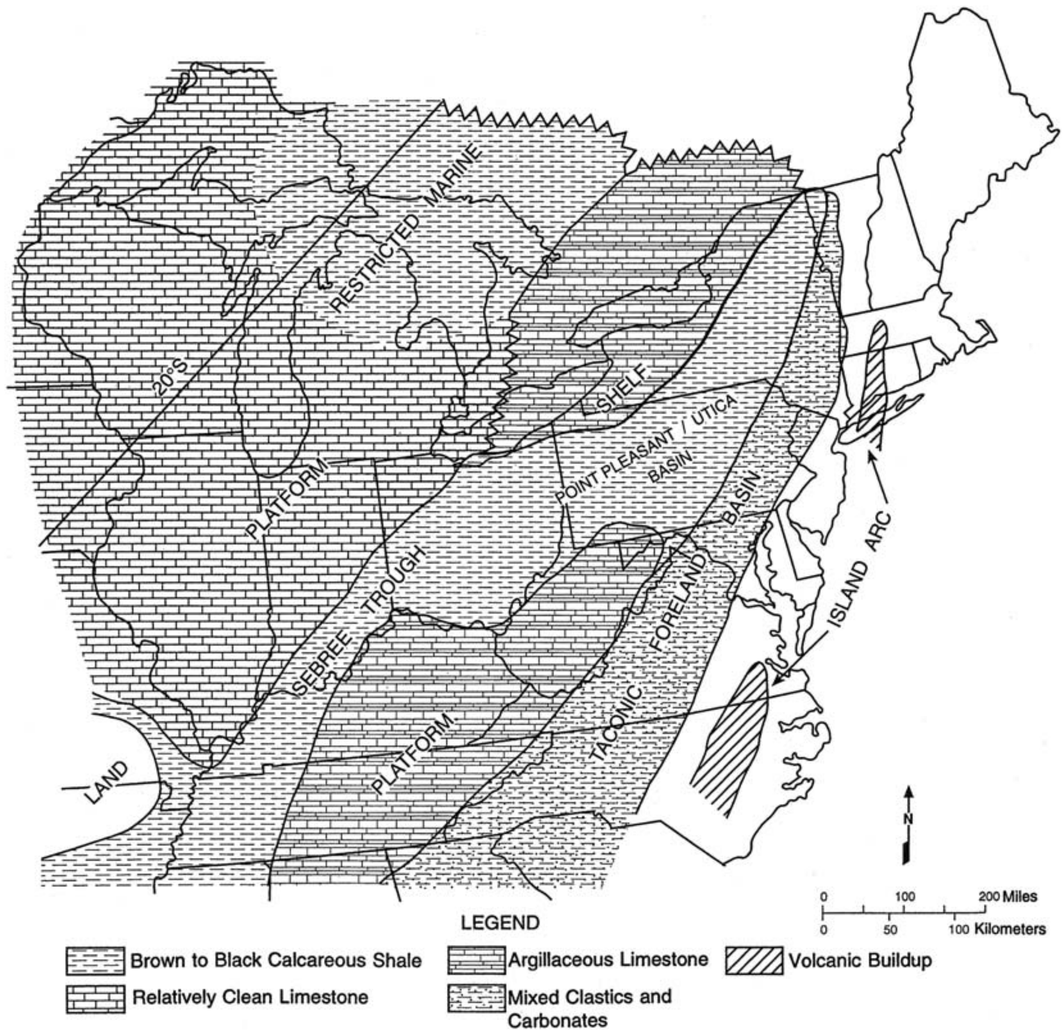

Figure A5-2.—Regional reconstruction of major depositional and tectonic elements present near the end of Trenton-age deposition (from Wickstrom, 1996).

of the Juniata, and that the color was later leached out by diagenetic processes. As such, color in the Bald Eagle is only of diagenetic significance and has no stratigraphic importance. The gray-to-red color boundary actually occurs at different levels at different localities, varies by as much as 656 feet, and crosscuts distinctive lithostratigraphic units (Laughrey and Harper, 1996) (Figure A5-3).

DEPTH AND THICKNESS RANGES

The Knox unconformity surface lies approximately 11,000 feet below sea level at its deepest point in the Michigan basin, but it is only 500 to 1,000 feet below sea level on the Cincinnati, Kankakee, and Findlay arches. It actually is exposed at the surface in central Kentucky (Figure A5-4). The surface deepens again into the Rome trough, and at the point where it seems to disappear from the sequence of dolostones in the Beekmantown Group in south-central Pennsylvania and northeastern West Virginia it is about 15,000 feet below sea level. In the Amoco #1 Svetz well in Somerset County, Pennsylvania, the estimated equivalent position of the unconformity is at about 19,300 feet. In this well, the Beekmantown Group appears to be a completely uninterrupted sequence just under 3,000 feet thick.

The Cherokee unconformity lies at a maximum depth of about 8,500 feet in the Michigan basin (Figure A5-5). It is exposed on the central arches of eastern Indiana, western Ohio, and central Kentucky, but becomes deeper once again down into the Appalachian basin where it reaches a maximum depth of about 9,000 feet in southwestern Pennsylvania and northwestern West Virginia. The pattern of structure contours in the Appalachian basin shown in Figure A5-5 closely follows the present geometry of the basin. This is in contrast to the structure contours on the Knox unconformity (Figure A5-4) that seem to indicate a fairly sharp bend in the basin center in south-central Pennsylvania. The contour differences may represent a progression from Rome trough-dominated structures on the Middle Ordovician carbonate bank to the relatively more modern basin structure that originated with the Taconic orogeny. However, the paucity of wells in the area penetrating the Ordovician section requires cautious interpretation.

The thickness of the Knox to Lower Silurian Unconformity Interval in the western part of the MRCSP study area ranges from 600 feet in the extreme northwestern corner of Indiana to more than 2,800 feet in the Michigan basin (Figure A5-6). Thickness along the central arches ranges from 0 to 2,000 feet thick. In the Appalachian basin, thickness increases from 2,000 along the western edge of the basin in Ohio to more than 6,000 feet in central Pennsylvania.

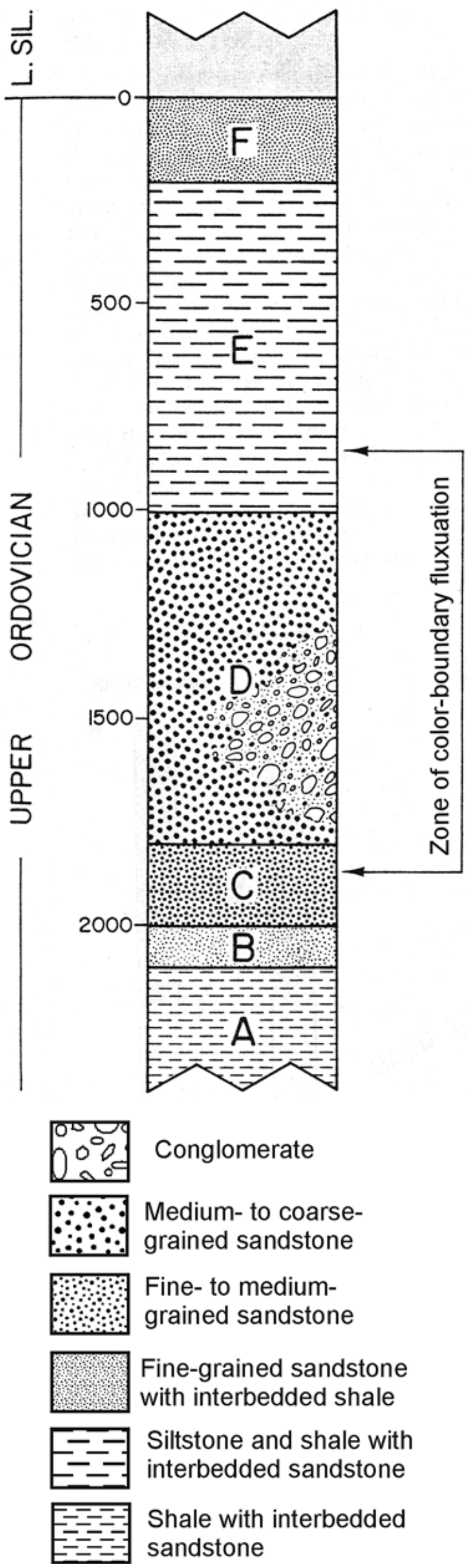

Figure A5-3.—Representation of Upper Ordovician clastic lithofacies (based on Thompson, 1970). The bracketed interval indicates the range of color-boundary fluctuation within the Bald Eagle interval.

TRAPS/STRUCTURE

Figures A5-4 and A5-5 show only the grossest structures in the MRCSP study area—the Michigan and Appalachian basins, and the central arches area of eastern Indiana, western Ohio, and central Kentucky. Other, somewhat more subtle geologic structures occur throughout the region that have affected the siting of wells targeting deeper Ordovician and Cambrian production. Many good hydrocarbon producing areas within the region are associated with flexures and structural noses mapped on higher formations that are not apparent on regional maps (Potter, 1978).

Figure 6 illustrates some of the major structural features affecting the MRCSP study area that are not readily apparent in Figures A5-4 and A5-5. Those of prime importance include the Grenville front, East Continental rift basin, Rome trough, Bowling Green fault zone, Findlay arch, Cincinnati arch, Lexington fault system, and the Pine Mountain thrust fault. Some production is associated with fractures stemming from these structures, and some occur as a result of subtle diagenetic affects related to equally subtle highs. Ordovician carbonate reservoirs, for example, are coincident with subsurface features associated with these structures. Some structural traps occur in narrow, linear, dolomitized zones along normal and strike-slip faults associated with basement faults. For example, the Albion-Scipio trend in Michigan is a model for fault-related fractured and dolomitized reservoir rocks in the Ordovician carbonates. Wickstrom and others (1992) speculated that much of the fracturing associated with Ordovician carbonate reservoirs probably resulted from reactivation of deeper structures. Oil and gas fields associated with fractured Ordovician carbonates in eastern Kentucky and central West Virginia lie along mapped faults associated with the Rome trough, a large Cambrian extensional feature extending from central Kentucky through West Virginia and Pennsylvania (McGuire and Howell, 1963; Harris, 1978), possibly into New York (Harper, 1989; Jacobi and others, 2004).

Similarly, Lacazette (1991) indicated that the Bald Eagle Formation was highly fractured in the limited area of north-central Pennsylvania where the formation produces natural gas. Henderson and Timm (1985) identified deep-seated (basement-involved), down-to-the-north, normal faulting on seismic data extending upward through Upper Ordovician carbonates and shales (Trenton and Utica). Fracture porosity in the Bald Eagle sandstones occurs in zones containing vertical to subvertical fracture sets associated to the deep-seated faulting (Laughrey and Harper, 1996).

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

Sealing Units

The Knox to Lower Silurian Unconformity Interval has many properties favorable for a confining unit. The carbonate rocks above the Knox unconformity typically serve as a fluid barrier (Baranoski and others, 1996), and the shales above provide an extra seal in areas where fracture porosity and permeability exist in the carbonates.

Faults, fractures, and the Knox paleokarst system provide the major migration avenues for fluids within the Ordovician carbonate sequence (Nuttall, 1996), so these rocks would have the most effective sealing properties in areas where fracturing has not occurred, or where the fractures have been sealed by mineralization. Figure 6 shows the major basement structures in the MRCSP study area, structures that are known to have affected fracturing in the carbonates. The best potential areas for seals should occur where these

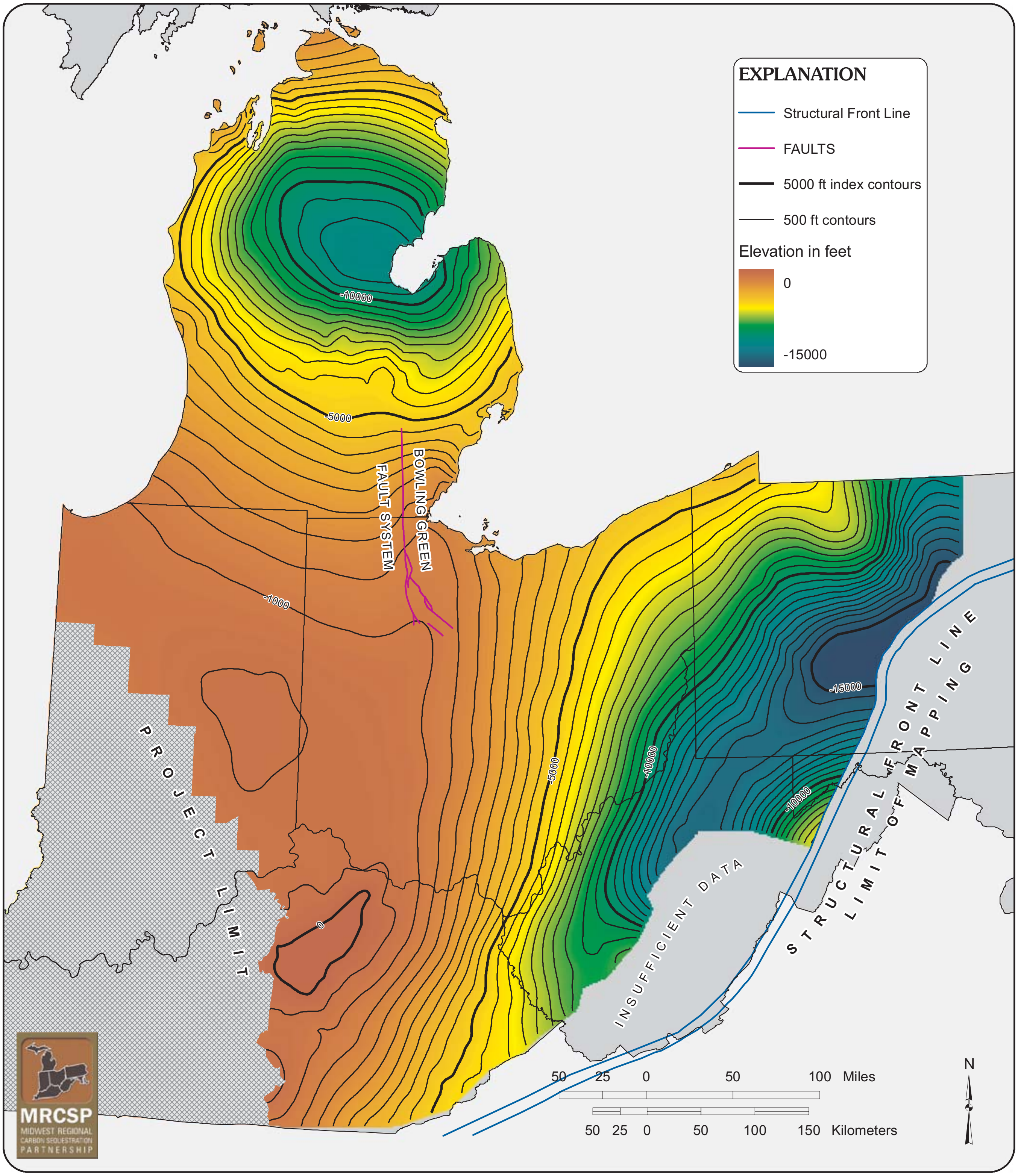

Figure A5-4.—Structure contour map drawn on the top of the Knox surface (mainly Knox unconformity).

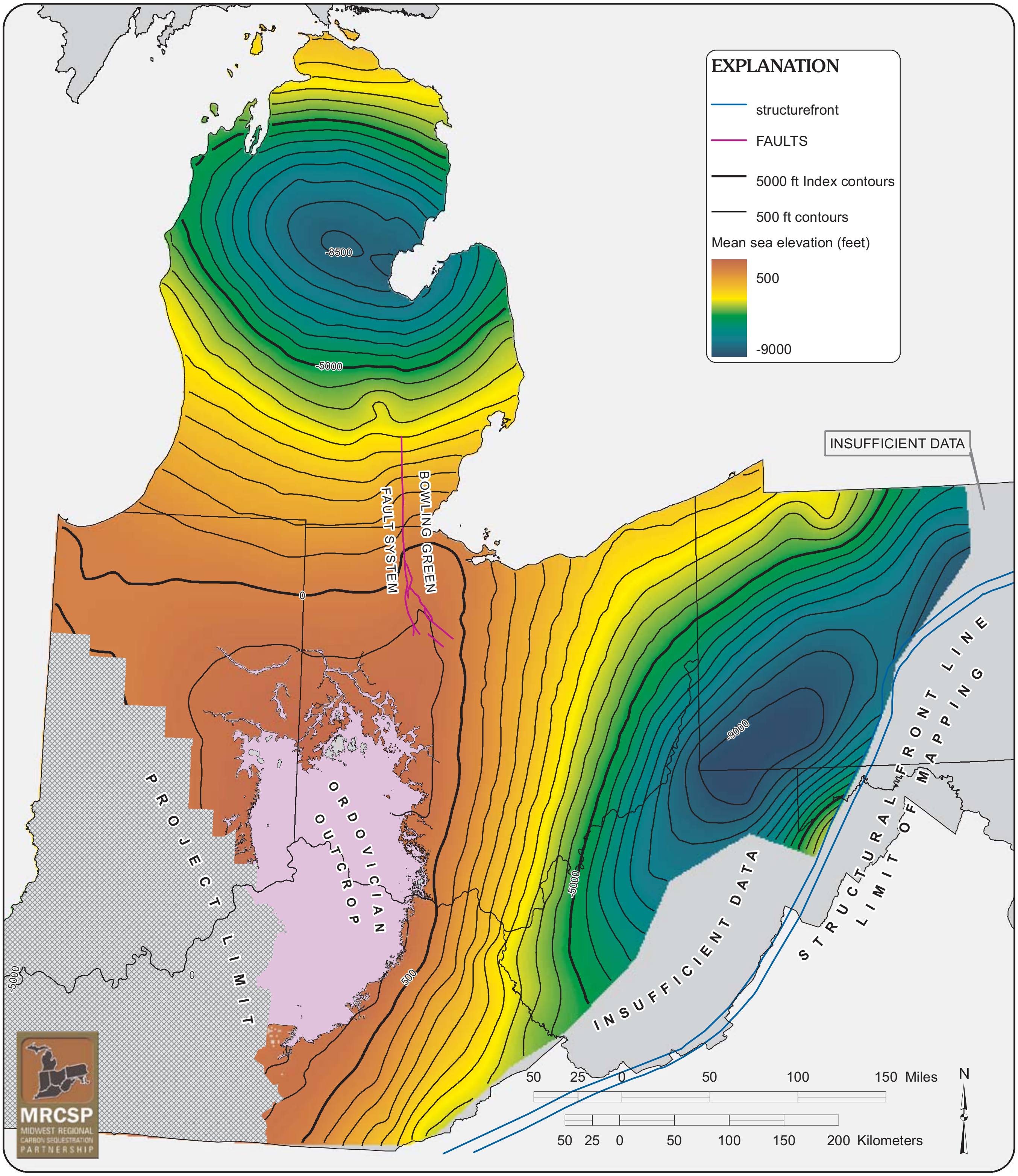

Figure A5-5.—Structure contour map drawn on the Lower Silurian (Cherokee) unconformity.

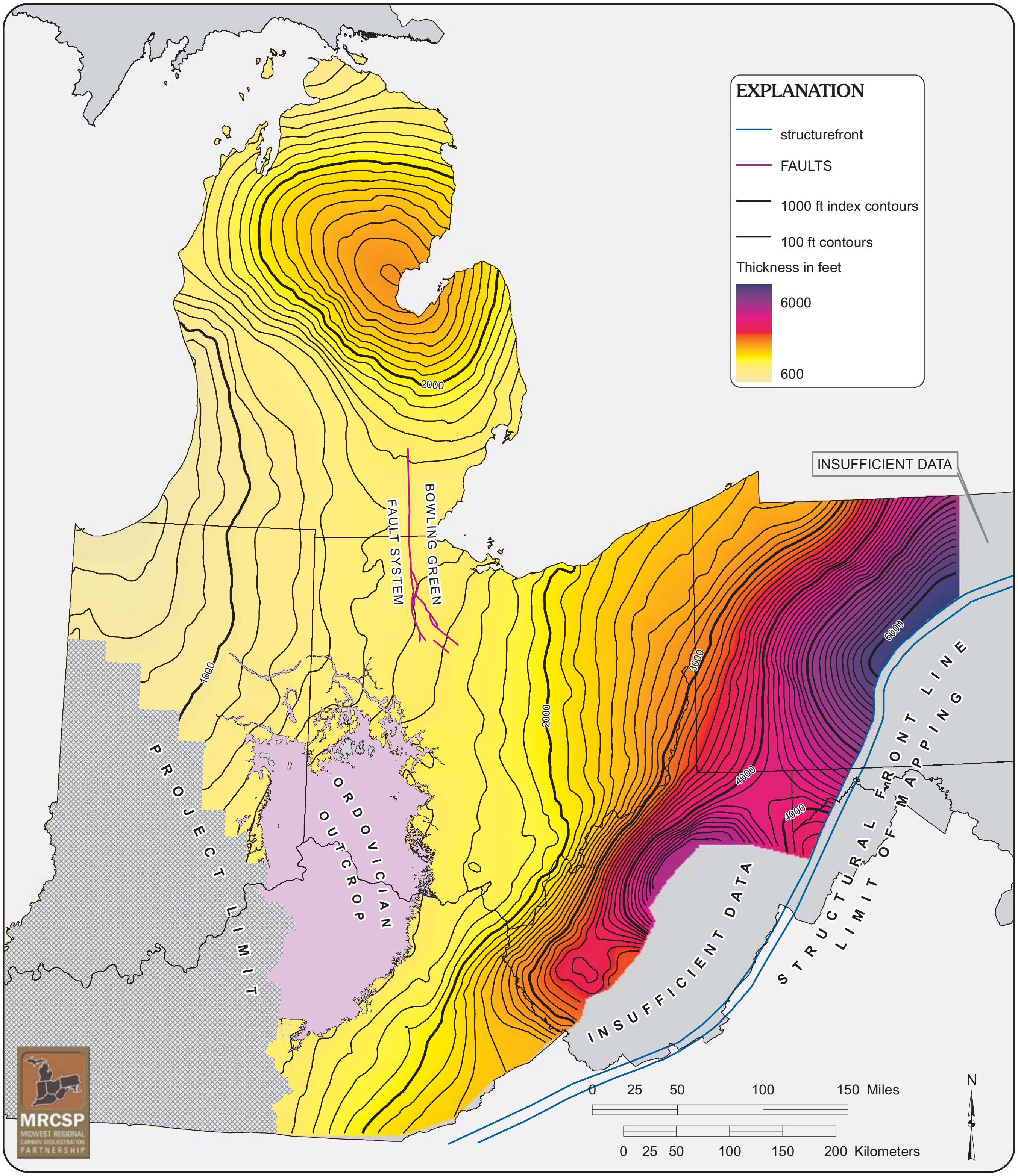

Figure A5-6.—Map showing the thickness of the Knox to Lower Silurian unconformity interval.

structures are absent or have had little or no effect on the interval.

The shales, particularly the very argillaceous and organic-rich shales of the Maquoketa, Clays Ferry, Utica, and Point Pleasant formations, should provide excellent sealing capability. Like the Upper Devonian organic-rich shales, they probably have low matrix porosities and permeabilities, even in fractured zones that would provide effective seals for sequestration targets in lower strata. Although the formation is characterized as fractured, joints within the Maquoketa have collapsed due to the fissile nature of the shale, and where present, the low hydraulic conductivity of the rock inhibits fluid flow. In fact, it has been referred to as the Maquoketa Confining Unit in regional aquifer studies (McGarry, 1996). It is highly likely the same attributes will be found within the other Upper Ordovician shales as well.

Lack of measured physical parameters for these strata in areas not known to produce oil or gas will be a problem in evaluating the rocks for sealing potential. A considerable amount of research will be necessary to determine these parameters prior to initiating any injection projects.

Potential Injection Targets

There are at least four targets for sequestration potential in the Knox to Lower Silurian Unconformity Interval: 1) fractured or coarse-grained bioclastic carbonates; 2) enhanced gas recovery in thick organic-rich black shales of the Utica/Point Pleasant; 3) fractured Bald Eagle and Oswego sandstones and conglomerates; and 4) possible fractured or diagenetically altered Juniata sandstones.

Ordovician Carbonates—According to Sullivan (1983) and Nuttall (1996), stratigraphic traps occur in the upper part of the Lexington Limestone in Kentucky, sealed by fine-grained, impermeable strata and tightly cemented grainstones. Net pay thickness averages 10 feet, and average matrix porosity is 11.8 percent with a maximum porosity of 15 percent. Moldic, interparticular, intraparticular, and intercrystalline porosity types dominate. Nuttall (1996) reported that a core from Clinton County, Kentucky had an average reservoir permeability of 57.1 millidarcies (md) and a maximum permeability of 293 md. In this particular area of Kentucky, the Ordovician carbonates are too shallow for effective sequestration (less than 2,500 feet), but similar reservoir zones in the Trenton Limestone in deeper parts of the Michigan and Appalachian basins could ultimately be useful for sequestration. This is especially true in areas where porosity and permeability occur as a result of fracturing. Production from fractured Black River/High Bridge and Trenton/Lexington reservoirs in central Kentucky and West Virginia appears to be from open, unmineralized fractures, probably related to reactivation of deep-seated faults, although Hamilton-Smith and others (1990) acknowledge that minor secondary mineralization might help keep the fractures open. Dolomitized fracture zones and grainstone facies account for much of the upper Black River/High Bridge and Trenton/Lexington production in southeastern Michigan, Kentucky, central Ohio, south-central Ontario, north-central Pennsylvania, and south-central New York. In areas affected by large fault systems with sizeable gouge zones, fluids interacted with the gouge to create thick zones of mineralization and vugular porosity within the zones, whereas smaller fault systems are more likely to have good intercrystalline porosity development (Wickstrom, 1996).

Utica Shale and Point Pleasant Formation—Both the Utica and Point Pleasant consist of dark gray to black, organic-rich shales, with the Point Pleasant also containing interbedded Trenton-type limestones. Many authors (for example, see Cole and others, 1987; Wallace and Roen, 1989; Ryder and others, 1991; Wickstrom, 1996) consider the Utica/Point Pleasant interval to be the source rocks for the hydrocarbons found in the underlying Trenton and Black River carbonates, as well as many of the overlying units (Bald Eagle, Medina, Tuscarora, Lockport, etc.). The Utica /Point Pleasant interval is more than 700 feet thick in parts of central Pennsylvania, but thins to the northwest until it is only about 100 feet thick in northwestern Ohio (Wickstrom, 1996). Because of their thickness and depth below 2,500 feet in much of the Michigan and Appalachian basins, the Utica/Point Pleasant shales could have potential for sequestration through enhanced shale gas recovery. Gas content probably varies regionally with changes in thickness, pressure, organic carbon content, and thermal maturity, as in the Upper Devonian black shales of Appalachian and Michigan basins (Boswell, 1996). The interval does not have a history of gas production (although strong shows through the interval are regularly noted), so it would require substantial research to determine how effective the shales would be to both sequestration and gas production.

Bald Eagle and Oswego Formations—The Bald Eagle Formation, where it produces natural gas in north-central Pennsylvania at depths of 12,900 to 13,272 feet, is a naturally fractured reservoir in which the fractures are vertical to subvertical and run parallel to structural axes (Laughrey and Harper, 1996). There is no known production from the Oswego Sandstone in the MRCSP study area, but owing to lithologic similarities with the Bald Eagle, it probably would also serve as a producing reservoir and potential sequestration target in zones of intense fracturing. The sandstones from the pay interval consist of moderately sorted to well sorted, fine- to medium-grained, lithic arenites. Monocrystalline quartz and chert dominate composition, but detrital and authigenic feldspars, some altered to chlorites and mixed-layer illite-smectite, mica, low-grade metamorphic rock fragments, and trace amounts of homblende and pyrite also occur. Dolomite, with some minor calcite, comprise the principal cement in the matrix, but they also contain minor authigenic quartz cement (Laughrey and Harper, 1996). The sandstone matrix has relatively low porosity and permeability, which contributes to the seal. In addition, syntectonically precipitated minerals, such as quartz, hematite, and calcite, often partially fill the fractures. Upward-decreasing grain size, increasing clay content, and shale beds in the overlying Juniata Formation might assist in sealing the reservoir (Laughrey and Harper, 1996). Porosity and permeability are extremely variable—fracture zones have porosities as high as 30 percent, whereas matrix porosities tend to be only two to eight percent and matrix permeability was calculated at 0.07 md in the reservoir, with all of the production coming from fracture permeability (Laughrey and Harper, 1996)

Juniata Formation—Although Laughrey and Harper (1996) consider the shales and fine-grained sandstones of the Juniata Formation to contribute to the seal for Bald Eagle/Oswego reservoirs, there is some potential for Juniata sandstones to act as sequestration targets. This apparent discrepancy in interpretation is the result of confusion of terminology. As Thompson (1970, 1999) has shown, the Bald Eagle/Oswego and Juniata are artificial lithologic constructs based on color differences—the Bald Eagle/Oswego is gray, and the Juniata is red. Inasmuch as the color boundary between the two formations varies by up to 656 feet within the Upper Ordovician clastic lithofacies, Thompson (1970) recommended that the lithofacies were far more consistent and meaningful than the formation names. Thompson (1970, p. 1256, 1257) described lithofacies D (Figure A5-3) as "unfossiliferous, cross-bedded medium- to coarse-grained sandstone and conglomerate, with essentially no siltstone or shale, 700 to 800 ft thick . . .” This lithofacies occurs primarily in the Bald Eagle/Oswego, but because of the variability of the color boundary, it also occurs to some extent in the Juniata. Lithofacies E, composed of siltstone and shale with minor sandstone interbeds, overlies lithofacies D, providing the latter with an effective seal. The uppermost lithofacies in the sequence (F) consists of medium-grained sandstone with rare shale interbeds. As such, it could also be a potential sequestration target, given the proper porosity and permeability parameters. These data are lacking, however, because no one has attempted to produce hydrocarbons from the Juniata. Therefore, any consideration of the Juniata as a sequestration target would require a great deal of research to determine its physical and chemical characteristics.

CONCLUSIONS

It is very likely that the Knox to Lower Silurian Unconformity Interval will provide a suitable confining unit for CO_2 sequestration in strata below the Knox unconformity, but only following complete evaluation of the interval at potential target sites. Ideal conditions within the interval at target sites must include, at a minimum, established low matrix porosity and permeability in both the carbonate and shale portions of the interval, as well as a lack of fracturing, or complete mineralization of fractures, in the carbonate section.

Conversely, four of the units have some potential for sequestration within their matrices, including the potential for CO_2 enhanced recovery of hydrocarbons. Matrix porosity typically is restricted to very narrow zones, if it exists at all, within the carbonates and clastics of the interval. However, fracture porosity and permeability, particularly in the carbonates and the Bald Eagle/Oswego sandstones and conglomerates, has been established in numerous areas of the Applachian and Michigan basins. These areas have potential for both sequestering carbon and for producing additional resources to meet the nation’s demand for oil and natural gas.

6. MIDDLE ORDOVICIAN ST. PETER SANDSTONE

The St. Peter Sandstone is a widespread quartz arenite unit in the Michigan and Illinois basin areas of the MRCSP study area (Figures 5, A6-1, and A6-2) (Michigan, Indiana, western Kentucky, and northwestern Ohio). This Middle to Upper Ordovician unit is widely recognized throughout the mid-continent as an unconformity-related sandstone. It lies above dolomitized rocks of the Knox Group in Ohio, eastern and southern Indiana and Kentucky, and above the Prairie du Chien Group in Michigan and northern Indiana. The St. Peter Sandstone is overlain by the Glenwood Formation in Michigan and Indiana and by the Wells Creek Formation in Kentucky, Ohio, and West Virginia. The St. Peter Sandstone appears to be better developed on the western side of the MRCSP study area; however, wells drilled in Ohio, West Virginia, and eastern Kentucky occasionally report a thin St. Peter Sandstone on the Knox unconformity. In local areas of eastern Kentucky along the Rome Trough, the St. Peter is much thicker. The exact stratigraphic relationship of the St. Peter Sandstone in West Virginia and eastern Kentucky is not known due to the sparse deep wells in the area.

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

Owen (1847) first used the name St. Peter Sandstone for sandstone outcrops along the St. Peter River (now Minnesota River) near Minneapolis/St. Paul, Minnesota. The type section is along a bluff where the Minnesota River joins the Mississippi River at Fort Snelling, Minnesota. Many detailed studies describe stratigraphic, sedimentologic, and petrologic relationships in the St. Peter Sandstone in the region of the outcrop in Minnesota, Wisconsin and northern Illinois (for examples, see Dott and Byers, 1981; Mai and Dott, 1985; Mazullo and Ehrlich, 1987; Collinson and others, 1988). Recent studies emphasize correlation to well known outcrop occurrences, stratigraphic and sedimentologic similarities and difference, and petrology of the St. Peter sandstone in the Michigan basin subsurface (Barnes and others, 1992; Barnes and others, 1996). Subsurface studies in other parts of the MRCSP study area include Price (1981) in eastern Kentucky, and Humphreys and Watson (1996). This latter reference provides an overview of the St. Peter gas play in the Appalachian basin.

NATURE OF LOWER AND UPPER CONTACTS

The St. Peter Sandstone overlies an extensive erosional unconformity on top of dolostones of the Knox and Prairie du Chien Groups. This erosional surface can have significant topographic relief, especially across the major structural arches and reactivated faults in the region. The thickness of the St. Peter can vary significantly around such features. This pre-St. Peter topographic relief was caused by erosion, resulting in stream channels, and, more commonly, sinkhole formation upon a karsted surface. The St. Peter underlies the Glenwood or Wells Creek Formations with a gradational contact. In Indiana and Ohio, the upper part of the St. Peter Sandstone is thought to be the facies equivalent of the Wells Creek, which is locally arenaceous near the base. In general, the St. Peter Sandstone is a clean, relatively pure, quartz arenite and yields a very low gamma ray value on geophysical logs. In the Michigan basin, where the St. Peter is very thick, intervals of higher gamma ray values are found near the base and at various intervals throughout the section, indicating interbeds of shale and other argillaceous rocks within the total St. Peter section. Except in the center of the Michigan basin, the base of the St. Peter shows a sharp contact with the underlying dolostone on wireline logs. The upper contact is generally gradational with increasing gamma ray intensity toward the shaley or mixed siliciclastic Glenwood/Wells Creek Formation.

LITHOLOGY

The St. Peter Sandstone is usually a clean, nearly pure, quartz arenite throughout the region. However, in Michigan, the St. Peter Sandstone also exhibits interbedded shale and shaley dolostone. Biostratigraphic data suggests little or no hiatus at the base of the St. Peter in the center of the Michigan basin (Barnes and others, 1996). Portions of central Michigan may have a gradational contact relationship with shaley carbonates of the underlying Foster Formation. Throughout the section in Michigan, the St. Peter has beds with higher potassium feldspar concentrations. Near the top of the formation, the St. Peter becomes arkosic, with more than 25 percent feldspar in some layers. Known cements include considerable amounts of quartz overgrowths and dolomite in some areas. Authigenic clays are also present as matrix. In most areas, the St. Peter Sandstone is medium-grained, although small amounts of coarse- and fine-

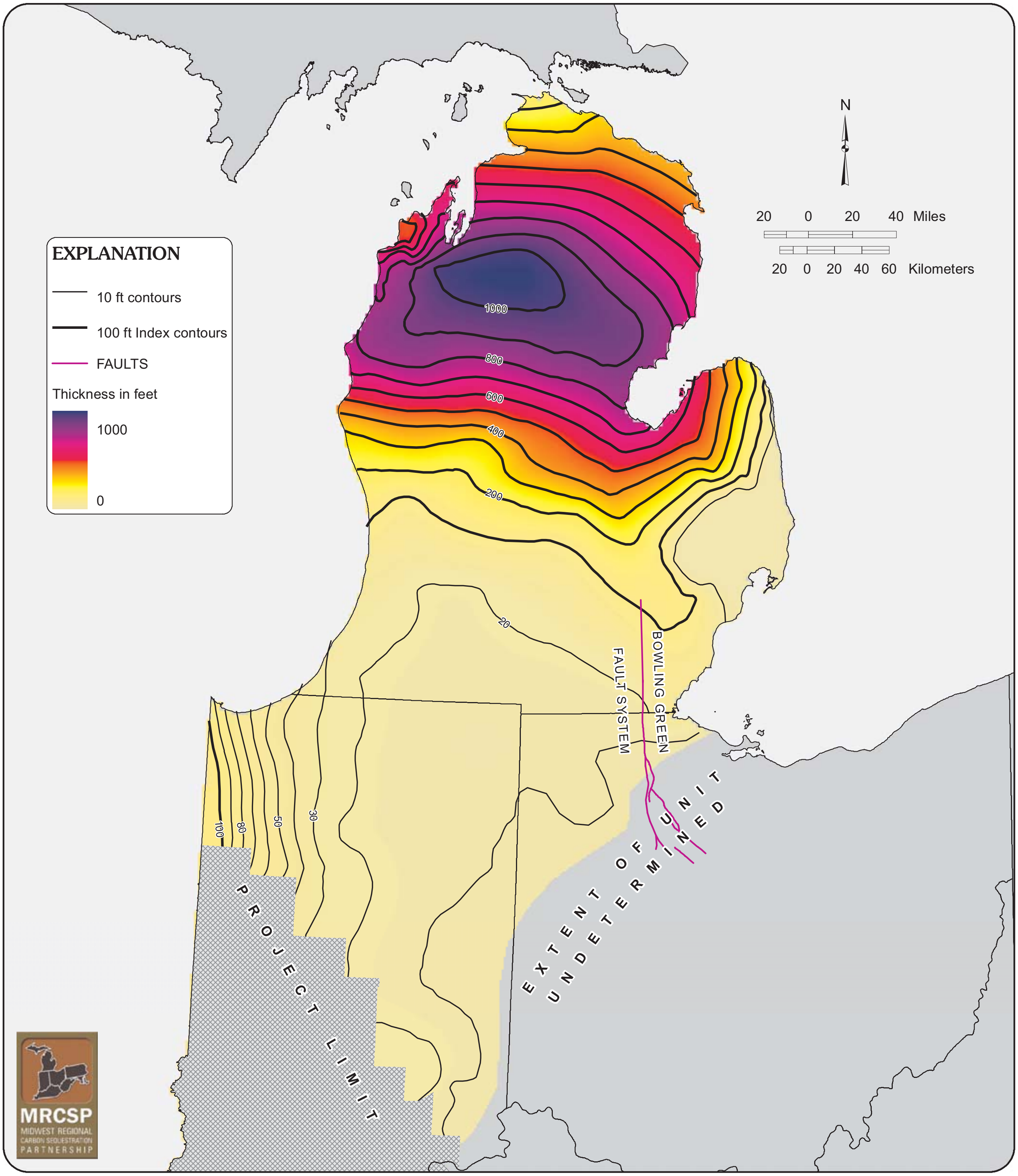

Figure A6-1.—Map showing the thickness of the St. Peter Sandstone.

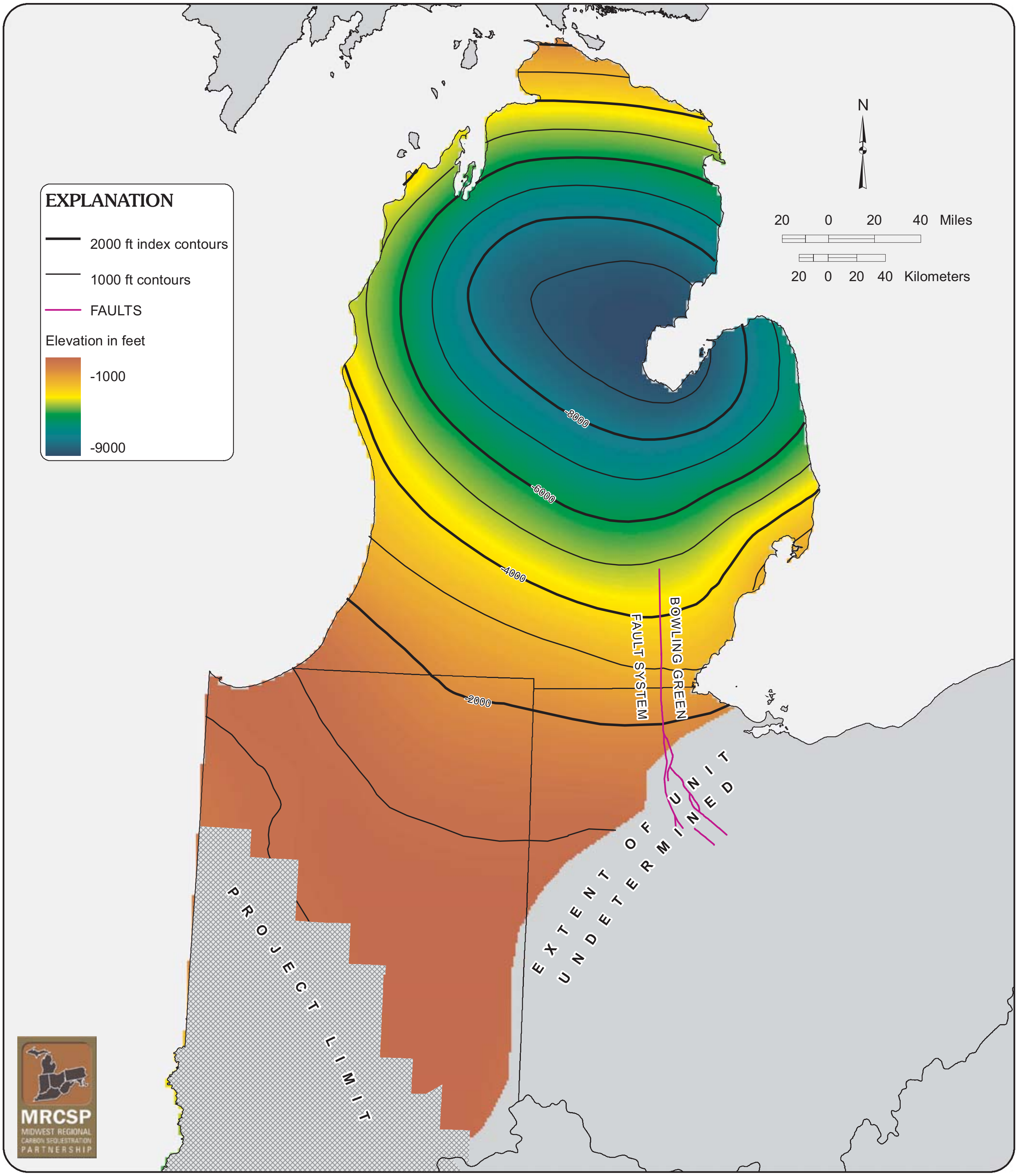

Figure A6-2.—Structure contour map drawn on the top of the St Peter Sandstone.

grained textures are present throughout the section. Cross bedding, bioturbation, and rare shell fossils have been observed in outcrop and core material. Porosity is usually good in outcrop and the shallow subsurface; however, burial compaction and cementation significantly reduce porosity in the deeper subsurface. In some facies in the Michigan basin, early carbonate cement and feldspar grains have been dissolved, producing extensive secondary porosity. Porosity as high as 14 percent has been measured from core at depths greater than 11,000 feet in central Michigan. Throughout Ohio, the St. Peter, where present, is a relatively clean, well-rounded, fine- to medium- to coarse-grained, friable, quartz arenite. Drillers in Ohio encounter flows of brine from this thin, yet highly porous and permeable unit that typically washes out during drilling.

DISCUSSION OF DEPTH AND THICKNESS RANGES

The St. Peter Sandstone is thinnest (10 to 100 feet) and shallowest (depths of less than 2,500 feet) across the arches of Indiana and Ohio (Figures A6-1 and A6-2). The unit is thickest and deepest in the Illinois and Michigan basins. The thickness of the St. Peter Sandstone exceeds 1,100 feet in the center of the Michigan basin, which is ten times greater than the maximum thickness across the arches in Indiana and Ohio. No significant thickening is noted in the southwestern portion of the region at the margin of the Illinois basin. In Michigan, the St. Peter ranges from approximately 3,000 feet deep at the southern state line to more than 11,000 feet deep in the basin center.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

Large areas of the North American craton were exposed during Knox unconformity time, thus providing ample sediments to be reworked and deposited as part of the St. Peter Sandstone. Penecontemporaneous subsidence in the Michigan and Illinois basins resulted in thick accumulations being preserved in those areas. Subsequent erosion may have removed much of the sand deposited across Ohio and adjacent areas. Subsidence along the Rome trough in northern Kentucky also resulted in locally thick St. Peter Sandstone (Price, 1981; Humphreys and Watson, 1996). Studies from the outcrop of the St. Peter Sandstone in Wisconsin (west of the MRCSP study area) suggest that it was deposited in a terrestrial to shallow marine shelf facies belt that transgressed across the upper Midwest (Dott and Byers, 1981). Aeolian facies are known from central Wisconsin and marine facies have been documented from other areas of the outcrop belt. In the Michigan basin, the facies range from shoreface to inner and outer marine shelf (Barnes and others, 1992).

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

Because of its widespread occurrence, depth, and porosity in the Michigan basin, the St. Peter Sandstone should make an important sequestration target there. Northern and eastern Kentucky has good potential, where the St. Peter is locally thick, although more data are needed. Ohio and Indiana have marginal to spotty potential, due mainly to the shallower depths and thin nature of the unit in these areas.

Injectivity rates are not well known for the St. Peter Sandstone in Michigan; however, it is an important oil- and gas-producing unit. High flow rates of natural gas (5 to 30 million cubic feet per day [MMcfpd]) and gas condensate have been recorded from Michigan wells. Porosity above 10 percent is present at various intervals throughout the formation. Permeability ranges from less than 10 to over 300 md. Porosity and permeability have been shown to be related to primary depositional facies and formation of secondary porosity (Barnes and others, 1992).

In the Michigan basin, porosity decreases proportionally with burial depth due to compaction and quartz cementation, so that, below 4,000 to 5,000 feet, there is usually very little porosity in this unit. In some facies that have a high feldspar grain content that had been cemented early with carbonate minerals, however, significant secondary porosity has formed at depth by dissolution of carbonate cement and grains. At depths below 7,000 feet, the only apparent porosity is from this secondary dissolution processes (Barnes and others, 1992). Although permeability generally increases with porosity, the precipitation of authigenic clay minerals in the secondary porosity may severely reduce permeability and create microporosity that may not be very effective. The porosity and permeability at depth will require further analysis.

7. LOWER SILURIAN MEDINA GROUP/“CLINTON” SANDSTONE

The Medina Group (Figure 5) consists of interbedded sandstones, siltstones, and shales with some carbonates of Early Silurian age (McCormac and others, 1996). The stratigraphic nomenclature of this unit is somewhat complex, due to the influence of both facies changes across the Appalachian basin and drillers’ terminology. Specifically, this sequence is known as the Medina Group in northwestern Pennsylvania and western New York; the Cataract Group in southern Ontario and eastern Ohio; and erroneously as the “Clinton” sandstone by basin drillers, particularly in eastern Ohio and northern Kentucky (see discussion below). The Medina Group of Pennsylvania and New York is comprised of three major stratigraphic units, in descending order: 1) the Grimsby Formation; 2) the Cabot Head Shale (sometimes called the Power Glen Shale); and 3) the Whirlpool Sandstone (Figure A7-1). In eastern Ohio, drillers’ terminology predominates, so the Grimsby is called the “Clinton” sandstone, and the Whirlpool is known as the “Medina” sandstone. The “Clinton” undergoes a facies change in central Ohio (Figure A7-2), where the porous (petroleum-producing) sandstones associated with this unit pinch out and are replaced by the Cabot Head Shale and limestone of the Brassfield Formation. The MRCSP discussion of this interval revolves around its potential as a CO_2 sink, thus this interval is not mapped or discussed separately west of this facies change. A fourth unit, known as the Manitoulin Dolomite, is equivalent to the basal Whirlpool Sandstone and is present in southern Ontario, eastern Ohio, and near the shores of Lake Erie in Pennsylvania (Laughrey, 1984; McCormac and others, 1996; Castle, 1998). In the southern and eastern portions of the basin, the Medina Group nomenclature is lost. In northern Kentucky, the “Clinton” and Tuscarora Sandstones are equivalent to the Grimsby and Whirlpool sandstones of northwestern Pennsylvania, respectively (McCormac and others, 1996). In West Virginia and southcentral and central Pennsylvania, the stratigraphic equivalent of the Medina Group is the Tuscarora Sandstone, and in eastern Pennsylvania, the Shawangunk Formation is equivalent to this sequence (Piotrowski, 1981; Avary, 1996).

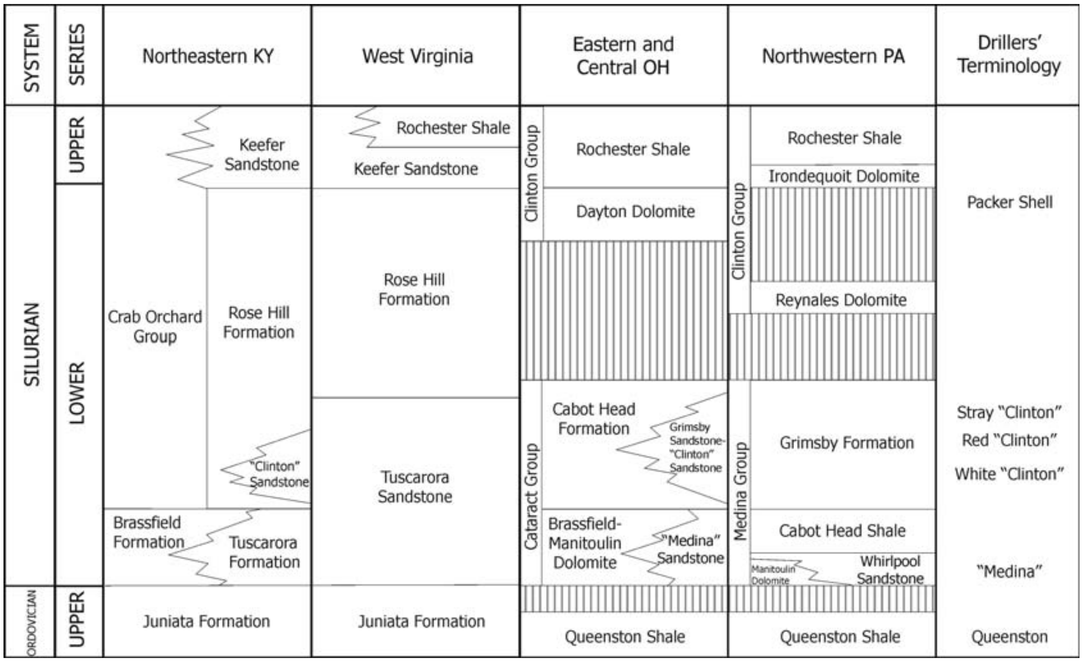

Figure A7-1.—Stratigraphic correlation chart of the Medina Group/“Clinton” Sandstone and equivalent units in the MRCSP study area (modified from Avary, 1996, and McCormac and others, 1996).

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

The Medina Group was named by Vanuxem (1840) for its type locality in Medina, Orleans County, New York. The basal unit of this sequence, the Whirlpool Sandstone, was first named by Grabau (1909) for its type locality along the Canadian side of the whirlpool in the Niagara River Gorge, and the uppermost unit of this sequence, the Grimsby Sandstone, was first named by Williams (1914). Reference to the productive zones in this sequence as “Clinton” originated in Fairfield County, Ohio, where drillers erroneously thought that limestone in the overlying Clinton Group was the source of gas in the Medina discovery well (McCormac and others, 1996). By the time it was established that the Medina Group sandstones were actually the producing units in these early wells, the “Clinton” misnomer had become engrained in basin operator terminology, and still is today.

Early studies of the Medina and equivalent units were performed in the 1960s through early 1980s (Yeakel, 1962; Knight, 1969; Martini, 1971; Piotrowski, 1981; Cotter, 1982, 1983). A summary of these and related works was provided in McCormac and others (1996). By the 1990s, sequence stratigraphy was emerging as an important tool for the interpretation of reservoir rocks. Perhaps the most prominent, recently published studies relative to the Medina Group and equivalent units are those of Castle (1998), Hettinger (2001), and Ryder (2004). Each of these researchers used sequence stratigraphy, rather than lithostratigraphy, to correlate early Silurian-age units in the northern Appalachian basin.

NATURE OF LOWER AND UPPER CONTACTS

The nature of the contacts of the Medina Group with overlying and underlying units varies depending upon which stratigraphic approach is applied. The traditional, lithostratigraphic view of early Silurian-age rocks in the Appalachian basin is consistent with a conformable upper contact between the Medina and Clinton Groups, and a combination of conformable and unconformable lower contacts between this sequence and Upper Ordovician clastics. In the northern portion of the basin, the Medina Group is interpreted as unconformably underlain by the Queenston Shale (Piotrowski, 1981; Laughrey, 1984; Laughrey and Harper, 1986; Brett and others, 1995; McCormac and others, 1996). The origin of this unconformity is associated with a drop in sea level (i.e., regression) during late Ordovician time. As the Medina grades into the Tuscarora Sandstone in south-central and central Pennsylvania, however, traditional lithostratigraphy interprets a gradational contact with the Queenston Shale’s equivalent, the Juniata Formation (Heyman, 1977; Piotrowski, 1981; Avary, 1996; McCormac and others, 1996). This conformable contact between the Tuscarora and Juniata extends southward through West Virginia and into eastern Kentucky (Avary, 1996). In eastern Pennsylvania, the Tuscarora Sandstone’s equivalent facies, the Shawangunk Formation, is unconformably underlain by the Upper Ordovician Martinsburg Formation (Avary, 1996).

In recent years, the oil and gas industry has begun to use sequence stratigraphy to interpret reservoir rock relationships. Using this framework as a guide, the Medina and equivalent units are seen as unconformably underlain by the Queenston Shale and Juniata Formation basin-wide (Castle, 1998; Hettinger, 2001). Hettinger (2001) identifies the Cherokee discontinuity as the sequence boundary between the Medina Group and underlying Queenston Shale, with this boundary interpreted as inferred between the Tuscarora and Juniata Formations in the eastern portion of the basin. At the top of the Medina Group, a marine flooding surface separates the Grimsby Sandstone from the overlying Clinton Group (Castle, 1998).

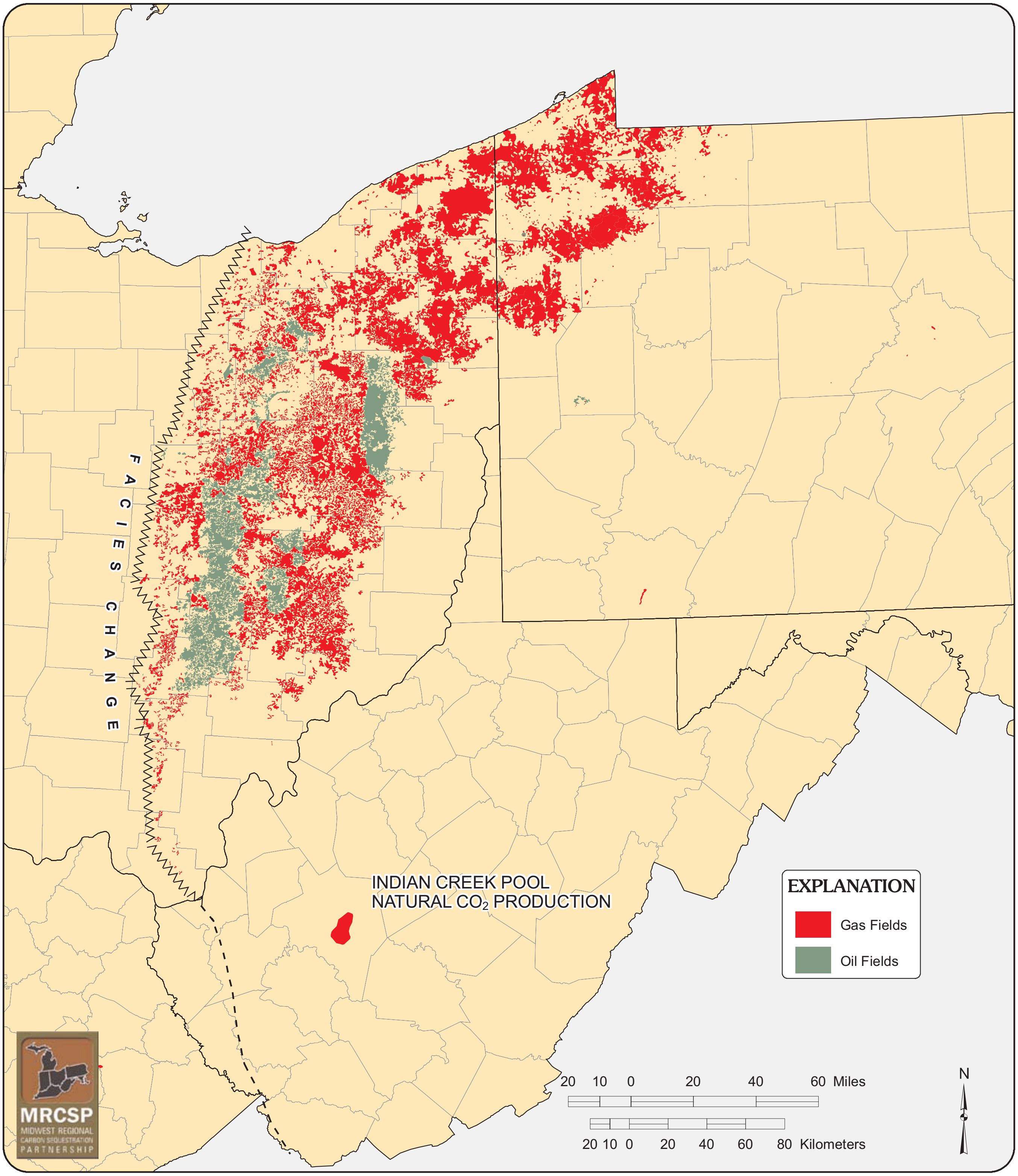

Figure A7-2.—Oil and gas fields producing from the Medina Group/"Clinton" Sandstone and Tuscarora Sandstone. The limit of production in Ohio delineates a facies change whereby these sands pinch-out and are replaced by the Cabot Head Shale and limestone of the Brassfield Formation.

LITHOLOGY

The Medina Group is composed of interbedded sandstones, siltstones, and shales, with some carbonates (Laughrey, 1984; Laughrey and Harper, 1986; McCormac and others, 1996). The sandstones of the Grimsby Formation are very fine- to medium-grained, monocrystalline, quartzose rocks, with subangular to subrounded grains, variable sorting, and thin, discontinuous, silty shale interbeds. These sandstones vary in color, from white to gray to red; hence, the reference to these units by drillers as “Red Clinton” and “White Clinton”, particularly in eastern Ohio (Figure A7-1). Cementing materials include secondary silica, evaporites, hematite, and carbonates (Piotrowski, 1981; McCormac and others, 1996). The Cabot Head Shale is a dark green to black, marine shale with thin, quartzose, siltstone and sandstone laminations that increase in number toward the top of the unit (Piotrowski, 1981; Laughrey, 1984). The Whirlpool Sandstone forms the basal unit of this sequence, and, in the greater part of the Appalachian basin, is composed of a white to light gray to red, fine- to very fine-grained quartzose sandstone that is moderately well sorted and has subangular to subrounded grains (Piotrowski, 1981; Brett and others 1995; McCormac and others, 1996). This basal unit becomes dolomitic in localized areas within the northwestern part of the basin (i.e., the Manitoulin Dolomite) (Laughrey, 1984; McCormac and others, 1996; Castle, 1998).

DEPTH AND THICKNESS RANGES

The Medina Group crops out at its type locality in New York; in central Pennsylvania, outcrops of the equivalent Tuscarora Sandstone are present. In the remainder of the Appalachian basin, however, the Medina and equivalent units remain in the subsurface. The depth to this reservoir ranges from less than 1,000 feet to 6,700 feet, with wells located offshore in central Lake Erie reporting depths of over 2,200 feet (McCormac and others, 1996).

Figure A7-3 illustrates the structure of the Medina Group throughout the basin. Structure contours are given in subsea elevations using an interval of 500 feet. The structure on top of the Medina Group strikes northeast-southwest and dips toward the southeast at a rate of approximately 40 to 70 feet per mile, with more shallowly dipping strata toward the north and west. A low point (subsea elevation of -9,000 feet) exists in southwestern Pennsylvania and northern West Virginia. East of this point, toward the Appalachian structural front, the Medina Group dips steeply to the northwest at rates of 70 to about 180 feet per mile.

Figure A7-4 illustrates the thickness of this sequence across the basin using a contour interval of 50 feet. Gross thicknesses range from 0 feet in the northwestern portion of the basin to more than 700 feet in eastern West Virginia. These thicknesses are generally consistent with those previously published by McCormac and others (1996) and Laughrey and Harper (1986). The actual pay zones of the Medina Group (i.e., where reservoir porosity and permeability are favorable) comprise only a portion of these thicknesses, however. Pay zones range from 3 to 50 feet and average 23 feet in thickness (McCormac and others, 1996).

The structure and thickness of the Medina Group and equivalent units, as presented in Figures A7-3 and A7-4, are consistent with the interpretation that during early Silurian time, an influx of siliciclastic material came from eroding Taconic highlands and an island arc located at the eastern edge of the Appalachian basin (i.e., central Pennsylvania and eastern West Virginia). These sediments were shed across the basin to create a clastic wedge that is thickest in the southeast and thins toward the northwest. The low area on the structure contour map (Figure A7-3) is indicative of the foreland basin that existed adjacent to the eroding highlands.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

The depositional history of the Medina Group dates back to the latter part of the Taconic orogeny in early Silurian time. During this period, clastic material eroded from both foreland fold-belt highlands adjacent to the eastern edge of the Appalachian basin and the plutonic igneous rocks of the island arc orogen (Laughrey, 1984; Laughrey and Harper, 1986; McCormac and others, 1996). The directions of sediment transport from these highlands were both parallel (i.e., northeast-southwest) and perpendicular (i.e., to the northwest) to the shoreline (Laughrey and Harper, 1986), which ran from northern Beaver County to central Warren County in Pennsylvania (Piotrowski, 1981). The Medina depositional system is that of a shelf/longshore-bar/tidal-flat/delta complex. The Whirlpool Sandstone is the basal transgressive unit of this system and is overlain by shelf muds and transitional silty sands of the Cabot Head Shale. These sediments were overlain by shoreface and nearshore sands of the lower Grimsby Sandstone, which grade into argillaceous sands at the top of this unit (Laughrey, 1984; Laughrey and Harper, 1986; McCormac and others, 1996). Laughrey (1984) divided the Medina Group’s depositional system into five facies: 1) tidal flat, tidal creek, and lagoonal sediments; 2) braided fluvial-channel sediments; 3) littoral deposits; 4) offshore bars; and 5) sublittoral sheet sands. Facies 1, 2, and 3 sediments comprise the Grimsby Sandstone, which was deposited in a complex deltaic to shallow marine environment. The deeper, offshore mud and sand bar deposits of Facies 4 were reworked by both storm and tidal currents to become transitional sandstones of the Cabot Head Shale. The Whirlpool Sandstone is included in Facies 5, which was formed in nearshore marine and fluvial, braided river environments in existence during the beginning of a marine transgression (Piotrowski, 1981; Laughrey, 1984; McCormac and others, 1996).

STRUCTURE/TRAP TYPES

Throughout the Appalachian basin, stratigraphic traps have been shown to control the occurrence of gas in the Medina Group, although in localized areas (e.g., Portage County, Ohio, and Mercer County, Pennsylvania), gas production may be enhanced by geologic structure (Piotrowski, 1981; Laughrey and Harper, 1986; McCormac and others, 1996). The overall heterogeneity of this reservoir is evidenced by the variety of mechanisms forming the stratigraphic traps, which include sandstone pinchouts, porosity changes, gas-water contacts, and diagenesis (Laughrey and Harper, 1986).

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

The MRCSP considers the Medina Group/ “Clinton” sandstone as a sequestration target (Figure 5), particularly for its prevalence throughout the Appalachian basin as a reliable oil-and-gas-producing reservoir (Figure A7-2), its sandstone lithologies, and the presence of less permeable confining rocks above and below the sequence. However, several factors, including the variability in lithology, the “tight” nature of this reservoir (with respect to both porosity and permeability), and discontinuity of sandstone lenses in the northwestern portion of the basin, may limit the overall success of the Medina Group as a CO_2 sequestration target.

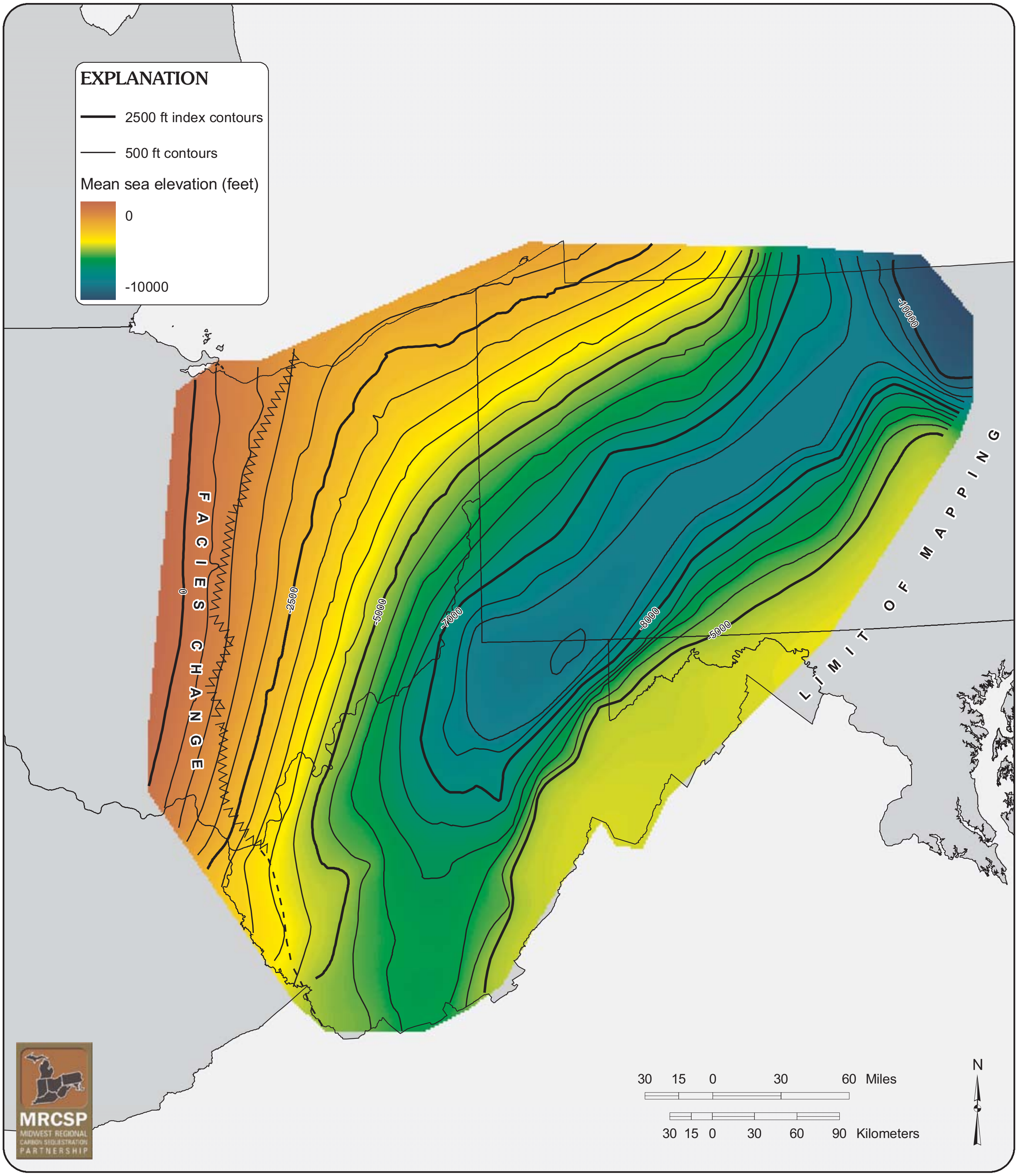

Figure A7-3.—Structure contour map on the top of the Medina Group/“Clinton” sandstone sequence.

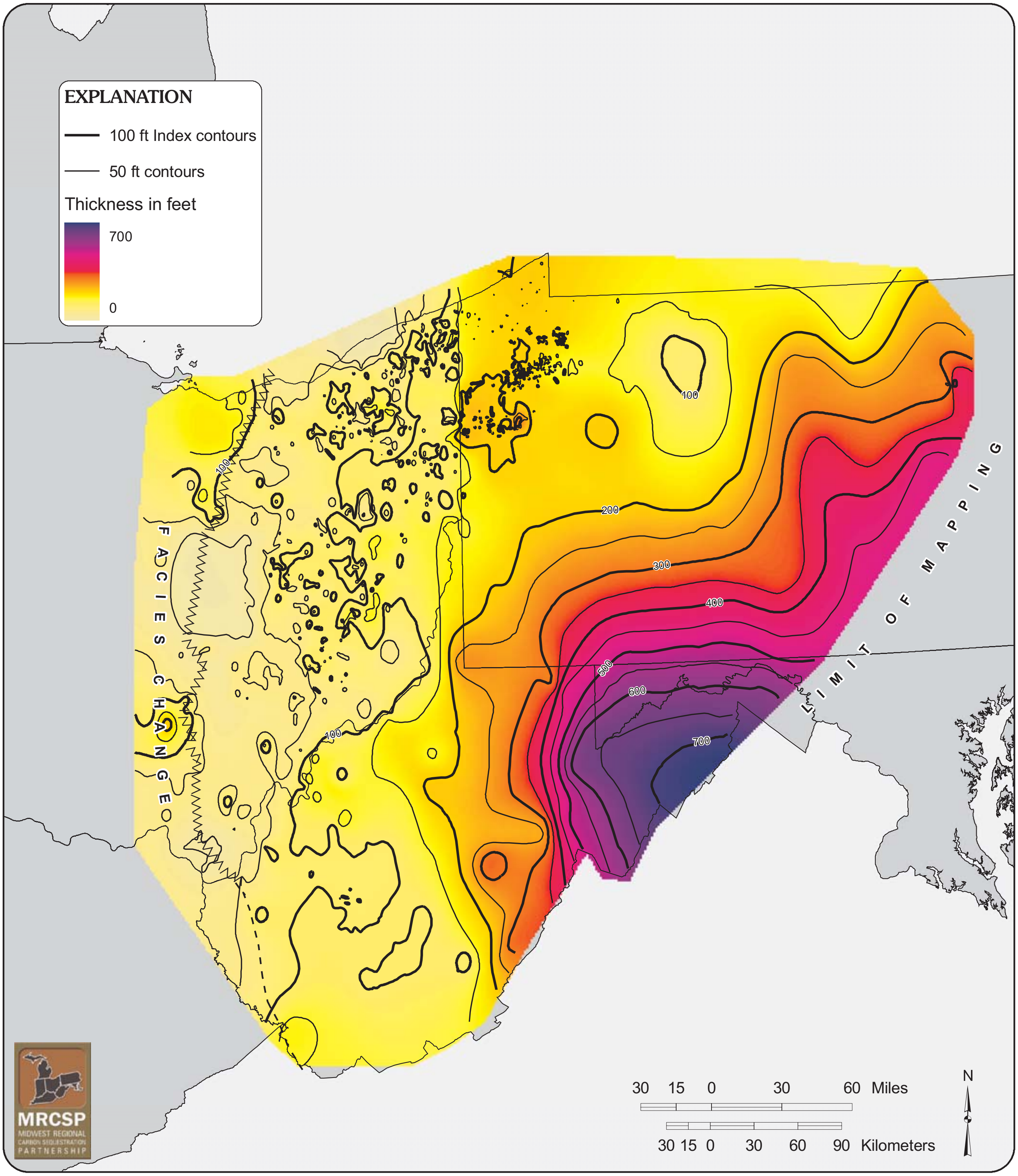

Figure A7-4.—Map showing the thickness of the Medina Group/“Clinton” sandstone.

The Medina Group is comprised of interbedded sandstones, mudrocks, and some carbonates that were deposited under variable conditions (Laughrey, 1984; Laughrey and Harper, 1986; McCormac and others, 1996). As a result, this reservoir is heterogeneous because of variations in several rock characteristics, including grain size, type and degree of cementation, clay content, and pore geometry (McCormac and others, 1996). This is evidenced in the three major facies of this sequence, the Grimsby Formation, Cabot Head Shale, and Whirlpool Sandstone as described above. Due to these lithologic variations within the Medina Group, detailed characterization of this unit for injection potential needs to be performed at each prospective site.

Figure A7-5 illustrates typical geophysical log curves for the Medina Group in the northern Appalachian basin. The gamma-ray signature demonstrates the relatively thick, sandy nature of the Grimsby, the increasing-upward siltstone/sandstone laminations within the Cabot Head Shale, and the abrupt, sandy signature of the Whirlpool Sandstone as it overlies the Queenston Formation. This gamma-ray response has been collectively referred to as a "broken sandstone" signature by Laughrey (1984).

The porosity and permeability of the Medina Group varies due to both depositional and diagenetic processes. The deposition of mudrocks isolated sandy and silty layers of the Grimsby Sandstone and the upper Cabot Head Shale, creating permeability barriers between these reservoir rocks. Diagenesis has altered the relatively tight, primary porosity in the northern portion of the basin, creating two major types of secondary porosity, intergranular and moldic. The secondary intergranular porosity is the result of dissolution of primary calcite cement and grain edges, and moldic porosity is due to the corrosion of silica cement and dissolution of feldspar minerals (McCormac and others, 1996). However, diagenesis does not always enhance porosity in this reservoir. Secondary cementation by authigenic silica has been observed to reduce porosity, in some cases surrounding entire grains to destroy the primary porosity (Laughrey, 1984).

Work performed by Laughrey (1984) in the Athens Field of Crawford County, Pennsylvania, identified several porosity types in the Medina Group, from relict, primary porosity to microporosity, intraconstituent porosity, and fracture porosity. The occurrence of fracture porosity in the Medina and equivalent units has been documented to a limited extent in other parts of the basin as well (McCormac and others, 1996). In northwestern Pennsylvania, Laughrey (1984) associated the highest porosity zones with those areas influenced by both depositional environment and diagenetic phenomena.

Figure A7-5 illustrates typical porosity curves for the Medina Group in the northern part of the basin. The crossover between density porosity and neutron porosity curves is shown with light gray shading and indicates a gas effect in the porous zones in the Grimsby Sandstone, the transitional, silty sandstones of the Cabot Head Shale, and the Whirlpool Sandstone. Medina Group porosities range from 2 to 23 percent across the basin, and average 7.8 percent (McCormac and others, 1996).

Medina Group permeabilities are widely variable, ranging from less than 0.1 md to 40 md (McCormac and others, 1996). In northwestern Pennsylvania, Medina permeabilities fall on the lower end of this range (Laughrey, 1984). Even so, the Perrysville Consolidated Field (Ashland County, Ohio) recorded average permeabilities of over 100 md, and isolated permeabilities of individual layers in this sequence can have permeabilities in excess of 200 md (McCormac and others, 1996).

Brines in the Medina Group of Pennsylvania have salinity values ranging from approximately 95,000 to 280,000 parts per million (ppm). The primary components of these brines are calcium, sodium, and chloride, with lesser amounts of magnesium, strontium, po-

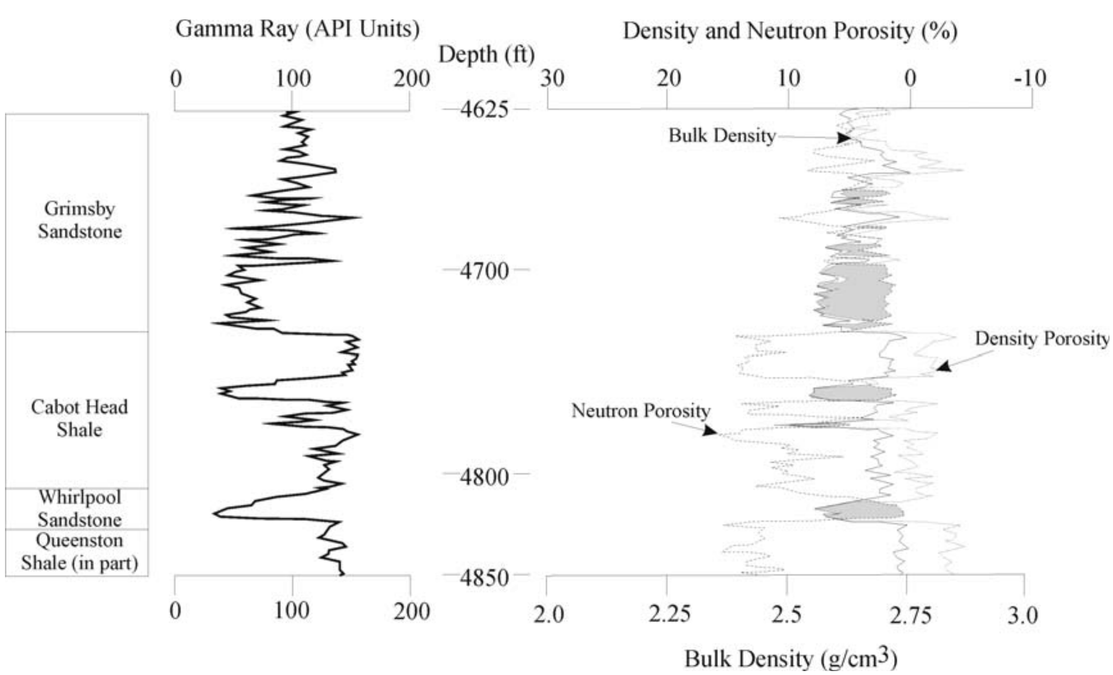

Figure A7-5.—Gamma-ray and porosity geophysical log curves for the Madura #1 (API# 3708520801), a typical Medina gas-producing well in Mercer County, Pennsylvania. The gamma-ray response has been described as a "broken sandstone" signature, and the crossover of neutron porosity and density porosity curves illustrates a gas effect in the porous, gas-bearing zones of this sequence.

Table A7-1.—Summary of data for "Clinton"-Medina gas storage fields in the Appalachian basin. Modified from American Gas Association (2001)

Storage Field /Reservoir Name	*County*	*Max. Depth*	*Min. Depth*	*Avg. Thickness (ft)*	*Number of Wells*	*Total Gas (Base + Working) (MMcf)*	*Max. Pressure (psi)*	*Year Discovered*	*Year Activated*	*State/ Province*
Benton	Hocking, Vinton	2699	1711	10	214	24800	780	1910	1936	Ohio
Chippewa	Wayne	3646	3584	8	99	10557	1500	1918	1941	Ohio
Crawford	Hocking, Fairfield	2699	2048	10	150	30700	800	1895	1977	Ohio
Gabor	Wayne	3842	0	43	35	2805	1500	1956	1961	Ohio
Holmes	Holmes, Wayne	3502	2805	10	135	15700	1150	1918	1954	Ohio
Laurel	Hocking	2542	2031	10	177	23300	780	1901	1950	Ohio
Lorain	Lorain	2653	2296	10	57	10700	1150	1939	1948	Ohio
Lucas	Ashland, Richland	3080	2387	10	427	60400	1150	1910	1936	Ohio
McArthur	Vinton	2402	1924	8	97	10900	900	1916	1957	Ohio
Medina	Medina	3272	2930	10	68	8500	1150	1915	1958	Ohio
Muskie	Muskingum	3551	3431	44	8	924	1100	1966	1973	Ohio
Pavonia	Ashland, Richland	2956	2351	10	299	47500	1150	1910	1951	Ohio
Perry	Perry	2864	2759	26	22	2800	1025	1934	1956	Ohio
Stark-Summit	Stark-Summit	4559	3960	23	630	126220	1550	1927	1941	Ohio
Wayne	Ashland, Holmes, Wayne	4306	2828	10	94	16400	1150	1917	1953	Ohio
Weaver	Ashland, Knox, Richland	3049	2423	10	275	50500	1150	1911	1937	Ohio
Wellington	Lorain, Medina	3454	2172	10	181	22364	1150	1939	1947	Ohio
Zane	Muskingum	4150	4150	nr	1	60	1100	1941	1955	Ohio
Zane	Muskingum	3865	3795	53	17	2149	1100	1947	1954	Ohio
Corry	Erie	4539	4386	12	13	1250	1200	1947	1955	Pennsylvania
						TOTAL = 468529				

tassium, and bromide (Dressel, 1985). In eastern Ohio, correlative “Clinton” brines range from 113,000 to 370,000 ppm, and average 250,000 ppm. Like those in Pennsylvania, the primary components of these brines are sodium, calcium and chloride (Sanders, 1991).

As a sequestration target, the Medina Group/ “Clinton” sandstone and the Tuscarora Sandstone are overlain by limestones, dolostones, and shales of the Clinton Group, and underlain by the Queenston Formation (Medina/”Clinton”) and Juniata Formation (Tuscarora). These units should serve as effective seals above and below the Medina target based on their lithologic and low permeability characteristics, just as they currently serve as components of the stratigraphic trapping mechanism of this reservoir. Further, the presence of extensive, mostly tight, carbonate and evaporite rocks immediately above the Clinton Group contributes to the ability of this rock sequence to prevent any vertical migration of gas out of the Medina Group.

The demonstrated widespread use of this interval for gas storage and brine disposal would seem to validate, to some degree, the potential of this group for use as a CO_2 sequestration reservoir. Gas storage in depleted “Clinton” fields in Ohio was first initiated in 1936 in the Benton storage field in Hocking and Vinton counties and the Lucas storage field in Ashland and Richland counties. Currently there are 19 former, “Clinton” gas fields in Ohio that are operating as gas storage fields, and 32 wells completed in the “Clinton” sandstone are being used as injection wells in that same state to dispose of brine associated with petroleum production. Minimum depths to “Clinton” gas storage fields range from 1,711 feet in Hocking County to 4,150 feet in Muskingum County. Average thickness for all “Clinton” storage fields ranges from 10 to 53 feet. Maximum storage pressures range from 780 to 1,550 psi. Table A7-1 summarizes the information for the “Clinton” gas storage fields in Ohio and Pennsylvania.

In Pennsylvania, only one Medina Group field has been converted to natural gas storage. The Corry storage field, situated in Wayne Township, Erie County, Pennsylvania, was discovered in 1947 and first underwent gas injection in 1955 (Lytle, 1963). The average producing depth and thickness of Medina sandstones in this field were 4,520 and 13 feet, respectively. Maximum storage pressure was reported at 1,200 psi. The total capacity of the Corry storage field is 600 million cubic feet of gas (Lytle, 1963).

It should also be mentioned that the Tuscarora Sandstone contains the only commercial production of CO_2 from a natural reservoir in the Appalachian basin. The Indian Creek pool in Kanawha County, West Virginia produced natural gas with a very high CO_2 content. The CO_2 was used to attempt some small-scale EOR projects in neighboring oil pools in the 1970s and 1980s. Currently it is being used as a commercial CO_2 source for non-EOR uses. Additional data on this field and the associated EOR projects will be analyzed within the MRCSP phase II project.

The Medina Group oil fields typically do not respond well to normal waterflooding for enhanced oil recovery (only seven enhanced recovery wells are in operation in Ohio). This is thought to be due to the relatively low permeability and heterogeneity of the reservoirs. However, CO_2 enhanced recovery may prove to be much more effective in these reservoirs because of the ability of CO_2 to solubilize in the native oil and brine, thereby lessening their viscosity and allowing better flow through this low-permeability, heterogeneous system. If this potential can be proven via a pilot project, a vast area of the Appalachian basin becomes available for CO_2 sequestration with the potential to produce hundreds of millions of barrels of additional oil from reservoirs of this group.

In summary, the Medina Group/ “Clinton” sandstone is a potential CO_2 sequestration target that would require a certain amount of follow-up study were it chosen for a sequestration pilot project. The site-specific lithology and cementation characteristics, particularly as they relate to reservoir porosity and permeability, would need to be evaluated to determine the injectibility of this target. In addition, the relative areal extent and volume of the producing zone(s) targeted for injection would need to be determined, namely because of the discontinuity of Grimsby and Cabot Head sandy/silty lenses in the northwestern portion of the basin.

8. NIAGARAN/LOCKPORT THROUGH ONONDAGA INTERVAL

The Niagaran/Lockport through Onondaga Interval is a multifaceted sequence of Silurian and Devonian carbonates, clastics, and evaporites (Figure 5) that is, overall, viewed as a confining unit. However, both saline formations and oil and gas reservoirs occur as local sequestration candidates in this interval throughout the MRCSP study area.

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

The Lockport Dolomite and its equivalents (Figure 5) are widespread throughout the region as the basal units of the Niagaran/ Lockport through Onondaga interval. Hall (1839) named the Lockport for exposures of carbonate rocks at Lockport, Niagara County, New York. In the subsurface of Ohio, Kentucky, Pennsylvania, and West Virginia, the Lockport consists mostly of Middle Silurian marine dolomites, although limestones do exist in large areas; the carbonates grade eastward into the shales and sandstones of the Mifflintown and McKenzie Formations of central Pennsylvania, West Virginia, and Maryland. Lesley (1878) named the Mifflintown Formation for outcrops of calcareous sandstone on the west bank of the Juniata River near Mifflintown, Juniata County, Pennsylvania. Ulrich (1911) named the McKenzie Formation for sandy shales overlying the shale beds of the Clinton Group at McKenzie Station in Allegany County, Maryland. In central and eastern Ohio, portions of the Lockport are often referred to informally as the “Newburg,” which represents any significant porosity zone, probably associated with patch reef development, within the Lockport interval (Floto, 1955; Janssens, 1977; Noger and others, 1996). Janssens (1977) treated the Lockport as a group in northwest Ohio, and subdivided it into three units, in ascending stratigraphic order: 1) Gasport Dolomite; 2) Goat Island Dolomite; and 3) Guelph Dolomite. Significant production from Lockport carbonates occurs in the Appalachian basin portion of the MRCSP study area (Conrad, 1987; Smosna and others, 1989; Noger and others, 1996). The Lockport equivalent in the Michigan basin is the Niagara Group, which was originally named by Hall (1839) for essentially the same rock as the Lockport where it occurs in outcrop in the gorge of the Niagara River some miles away. Locally, the Niagara Group contains substantial reef buildups, especially in Ohio, Indiana, and Michigan. In Michigan, these reefs (called “Brown Niagaran” pinnacle reefs by the petroleum industry) represent a vast area of oil and gas reservoirs. They are described separately in this report.

Overlying the Lockport Dolomite and its equivalents is the Upper Silurian Salina Group, a a lithologically mixed interval of evaporates, including halite, dolomitic carbonates, and shales that grade eastward into sandstones, shales, and thin-bedded limestones of the Bloomsburg, Wills Creek, and Tonoloway formations in Pennsylvania, Maryland, and West Virginia (Figure 5). The Salina equivalent formation in Indiana is called the Wabash Formation. Also, a gas-productive sandstone called the "Newburg" (not related to the porous Lockport called "Newburg") occurs between the Salina and the Lockport locally in western West Virginia and southeastern Ohio (Patchen, 1996). The Salina Group, named by Dana (1863) for occurrences of salt near Syracuse, New York, is a very important seal and confining unit within the Niagaran/Lockport through Onondaga Interval; however, there are local hydrocarbon reservoirs in the dolostones that could be used for sequestration. Salina salt has been mined in Michigan, Ohio, and northwestern West Virginia, both by relatively shallow (less than 2,000 feet) room-and-pillar mining and much deeper solution mining (Figure A8-1). White (1883) named the Bloomsburg Formation for a series of red shales in the vicinity of Bloomsburg, Columbia County, Pennsylvania. The Wills Creek Formation was named by Uhler (1905) for exposures of yellowish calcareous shales and thin sandstones along Will Creek near Cumberland, Maryland. Ulrich (1911) named the Tonoloway Formation for 400 feet of thin-bedded limestone and shale exposed on the lower slopes of Tonoloway Ridge, Washington County, Maryland. The Wabash Formation was named by Pinsak and Shaver (1964) for the "Niagaran" rocks in northern Indiana equivalent to the Salina Group (Figure 5).

The Salina typically is overlain by laminated dolostones of the Bass Islands Dolomite in Michigan, Ohio, and northwestern Pennsylvania (Figure 5). The Bass Islands Dolomite was named for rocks cropping out on a group of islands in western Lake Erie by Lane and others (1909). Ulteig (1964) defined the Bass Islands as the rocks overlying the stratigraphically highest anhydrite in the Salina Group and underlying the cherty and sandy carbonates of the Middle and Lower Devonian. Janssens (1977), in a subsurface study of Silurian rocks in northwest Ohio, recognized the Bass Islands Dolomite as those rocks that overly the Salina G unit. It is a local oil and gas reservoir in Erie County, Pennsylvania, and outside the MRCSP study area in western New York where it occurs as a narrow, 84-mile-long structurally-controlled trend (Van Tyne, 1996b). The Bass Islands grades southeastward into the dolomitic limestones of the Keyser Formation, which was named by Ulrich (1911) for exposures at Keyser, West Virginia.

Above the Bass Islands and its equivalents is the Helderberg Formation or Group (Figure 5), named by Conrad (1837) for the Helderberg Mountains in Albany County, New York. This formation consists of five or six units, in ascending order: 1) New Creek Limestone; 2) Corriganville Limestone; 3) Mandata Shale; 4) Licking Creek Limestone; and 5) Shriver Chert, which is a facies equivalent to the Licking Creek (Head, 1969), The individual units typically are very low porosity and permeability carbonates; the Mandata Shale may be a sequestration target in western Maryland, south-central Pennsylvania, and northeastern West Virginia. It is discussed separately in this report. In Michigan and Indiana, most, if not all of the Helderberg inverval is missing; however, a carbonaceous shale in Michigan called the Garden Island Formation (Ehlers,1945), apparently is equivalent to the Shriver/Licking Creek interval of the Appalachian basin.

A major interregional unconformity, the Wallbridge unconformity, occurs on top of this part of the interval, truncating formations as low in the section as the upper Salina Group. Overlying this unconformity is the Oriskany Sandstone, a widespread gas reservoir and, often, saline formation in the Appalachian basin part of the MRCSP study area (Pennsylvania, West Virginia, eastern Ohio, and eastern Kentucky) (Harper and Patchen, 1996; Opritza, 1996; Patchen and Harper, 1996). Vanuxem (1839) named the Oriskany Sandstone for exposures on the hillsides above Oriskany Falls, New York. This unit is discussed in more detail elsewhere in this report.

The Oriskany Sandstone is overlain by various carbonates and clastics (Figure 5). The Bois Blanc Formation, named by Ehlers (1945), consists mostly of limestones, with some basal sandstones and siltstones, that occurs above the unconformity in Michigan, Ohio, and northwestern Pennsylvania. The basal sandstone of the Bois Blanc is called the Springvale Sandstone; it is often confused with the Oriskany Sandstone. The Bois Blanc is partly equivalent with the Huntersville Chert in western Pennsylvania and West Virginia. This formation, which was named by Price (1929) for exposures of highly silicified black shale in the vicinity of Huntersville, Pocahonta County, West Virginia, is a very important gas-producing unit in West Virginia and Pennsylvania (Flaherty, 1996). The Huntersville grades laterally to the east with the Needmore Shale in central Pennsylvania, Maryland, and eastern West Virginia. The Needmore also is discussed in more detail in this report.

The Sylvania Sandstone of Michigan, northeastern Indiana, and northwestern Ohio also overlies the Bois Blanc Formation. It forms the lower portion of the Detroit River Group in this part of the MRCSP study area. The Sylvania is detailed further elsewhere in this report.

The uppermost portion of the Niagaran/Lockport thru Onondaga Interval is a carbonate unit called Onondaga Limestone in Kentucky, Maryland, Pennsylvania, West Virginia, and portions of Ohio (Figure 5). Conrad (1837) named the Onondaga for gray crinoidal limestones exposed in Onondaga County, New York that at one time were called the Upper Helderberg limestone by earlier workers. Reef development in the Onondaga in New York and Pennsylvania consists of both patch reefs and pinnacle reefs. Many have been productive of both gas and condensate (Van Tyne, 1996a; Bruner and Smosna, 2002). As a result, these could provide some sequestration capability for nearby CO_2 sources. To the west, the name changes to Columbus Limestone in Ohio (named by Mather, 1859), and to Jeffersonville Limestone in Indiana (named by Kindle, 1899). This interval also correlates with the lower part of the Muscatatuck Group of Indiana, which was named by Shaver (1974) for rocks exposed in the south-central part of that state. In northwestern Ohio, northern Indiana, and Michigan, the Onondaga equivalent includes both the Amherstburg and Lucas formations (Figure 5), which consists of thick dolomitic carbonates interbedded with thick evaporites. Sherzer and Grabau (1909) named the Amherstburg Formation for the rock forming the bottom of the eastern channel of the Detroit River opposite Amherstburg, Ontario. The Lucas Formation was named by Prosser (1903) for exposures in Lucas County, Ohio. Unlike the Salina Group evaporites, the Lucas evaporites have not been extensively mined.

Dennison and Head (1975), Mesolella (1978), and Smosna and Patchen (1978) provided important overviews of the Silurian and Devonian rocks of the Appalachian basin. Significant studies of the Lockport Dolomite were published by Floto (1955), Ulteig (1964), and Janssens (1977) in Ohio, by Laughery (1987) in Pennsylvania, and by Patchen and Smosna (1975) in West Virginia. Fergusson and Prather (1968), Dellwig and Evans (1969), Clifford (1973), Smosna and others (1977), and Tomastik (1997) provided a variety of information on the Salina Group in the Michigan and Appalachian basins. Details of post-Salina Group carbonates and their equivalents can be found in the following reports:

Bass Islands Dolomite—Van Tyne (1996b); Janssens (1997)
Helderberg Formation—Head (1969); Rickard (1984); Dorobek and Read (1986); Janssens (1997)

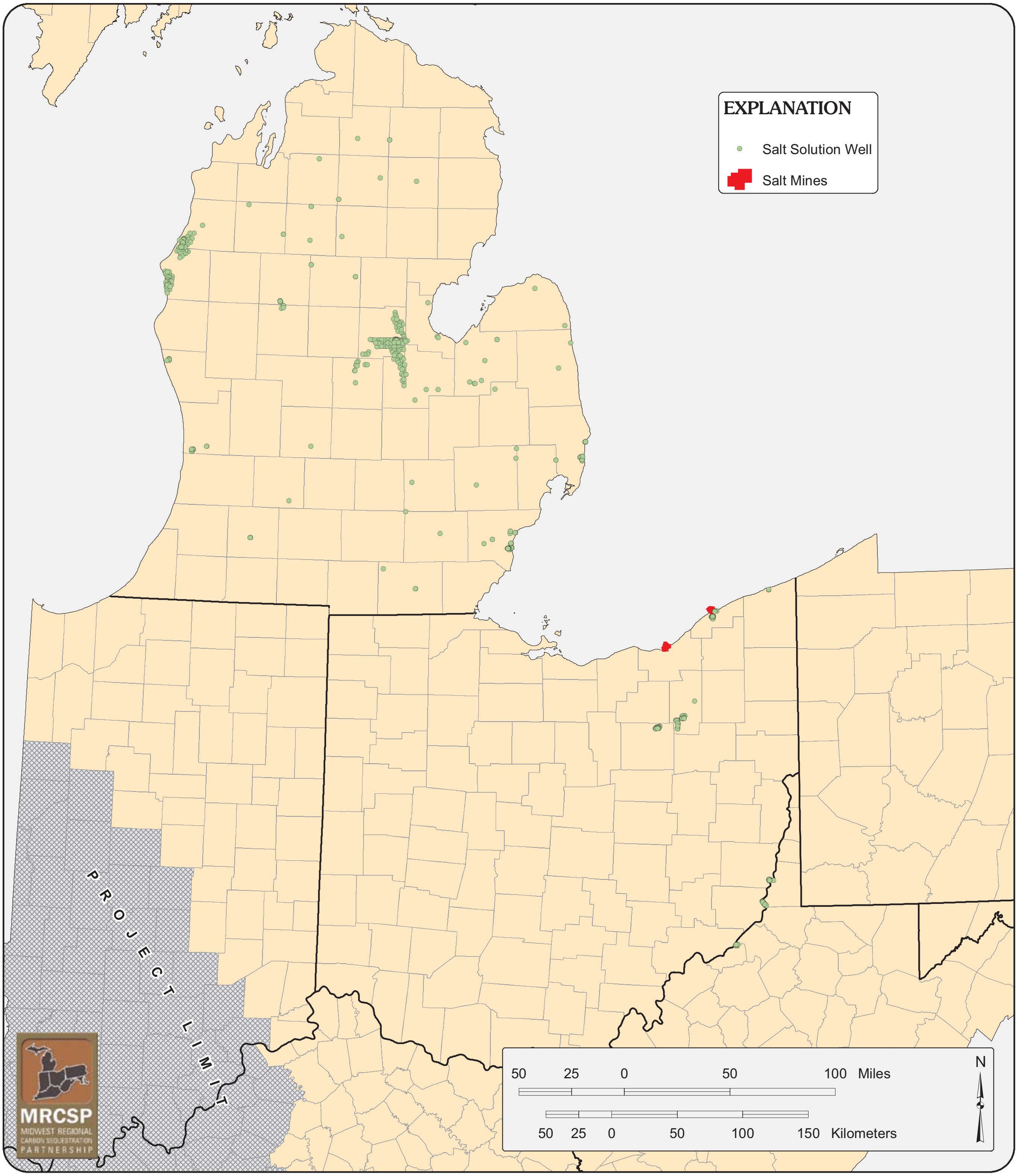

Figure A8-1.—Map showing the location of salt solution wells (Class 3 injection wells) and the extent of major salt mines in the MRCSP region.

Oriskany Sandstone—Harper and Patchen (1996); Opritza (1996); Patchen and Harper (1996); Janssens (1997)
Bois Blanc Formation—Summerson and Swann (1970); Janssens (1997)
Sylvania Sandstone—Gardner (1974)
Huntersville Chert—Weed (1982); Sherrard and Heald (1984); Flaherty (1996)
Needmore Shale—Inners (1975)
Onondaga Limestone—Van Tyne (1996a); Janssens (1997); Bruner and Smosna (2002)
Columbus Limestone—Janssens (1997)
Lucas Formation—Janssens (1997)

NATURE OF LOWER AND UPPER CONTACTS

Because this interval is a complex series of groups and formations, the contacts are quite variable locally. The lower contact of the entire interval is generally gradational with underlying strata, which typically are clastics (shales and some sandstones). In Ohio, where it has been examined in outcrop, the contact between the Lockport Dolomite and underlying Rochester Shale is sharp and conformable (Janssens, 1977). In other areas, such as northwestern Pennsylvania, the contact is transitional between the underlying shale and the dolostone.

In most localities in the MRCSP study area, the uppermost portion of the Niagaran/Lockport through Onondaga Interval is overlain by impermeable dark-gray to black shales or carbonates of the Middle or Upper Devonian. The Middle Devonian Marcellus Formation caps the interval in the east. A regional unconformity at the boundary between the Middle and Upper Devonian (the Taghanic unconformity) separates Upper Devonian shales of the "upper" Olentangy Formation from similar lithology of the "lower" Olentangy Formation in Ohio. This contact is variably sharp, particularly where the unconformity cuts out Middle Devonian strata between the Onondaga equivalent rocks and the "upper" Olentangy, but in some cases the contact appears to be gradational. Along the flanks of the Cincinnati arch, subaerial exposure and erosion at the Taghanic unconformity progressively truncated rocks from Middle Devonian (Onondaga) to Ordovician. Subaerial exposure resulted in porosity development in some areas, and unconformity traps formed where Upper Devonian black shales were buried the unconformity surface (Meglen and Noger, 1996).

LITHOLOGY

Most of the strata in the Niagaran/Lockport through Onondaga Interval are carbonates, variably dolostone and limestone, with smaller amounts evaporates, and relatively minor amounts of sandstones and shales. Great thicknesses of evaporates, mostly anhydrite and halite, occur in the central Michigan basin and the northern Appalachian basin. Shale is a minor component in this interval, except in the east, in central Pennsylvania and Maryland, and northward into New York. Sandstone is important locally (i.e., the Newburg sandstone of West Virginia and Ohio, and the Keefer Sandstone of central Pennsylvania, Maryland, and eastern West Virginia), although it typically is not very thick. The carbonate rocks vary extremely in composition, with petrophysical textures ranging from dense, laminated dolomicrites, to very porous and recrystallized grainstones. In some cases, these grainstones are dolostones or dolomitic limestones, whereas in others, they are limestones.

The Lockport is a fine- to medium-crystalline, slightly argillaceous and fossiliferous dolostone that originated as a carbonate shelf deposit that contained numerous scattered patch reefs. Ooid bars, skeletal sand shoals, patch reef bioherms, lagoons, mud banks, and sabkhas were also associated with this depositional setting (Noger and others, 1996). Patch reefs consisted of corals, stromatoporoids, bryozoans, and crinoids as the primary skeletal grains. The facies change from reef to sand shoal is east to west (Smosna and others, 1989). In Ohio, the Lockport consists of a lower white to light-gray, coarsely crystalline, fossiliferous, vuggy dolostone, whereas the upper part of the formation consists of very light- to medium-brown, microcrystalline dolostone containing chert locally (Janssens, 1977).

In Ohio and Michigan, the Salina Group consists of interbedded dolostone, evaporite, and shale, and is subdivided into seven units designated A through G in ascending order (Ulteig, 1964; Clifford, 1973; Janssens, 1977; Mesolella, 1978; Tomastik, 1997) (Figure A8-2). Recognition of evaporite beds on geophysical logs allows for regional subsurface correlation of these units. In Ohio, the Salina Group is present throughout most of the state, but the salt beds are restricted to the eastern third (Clifford, 1973). Unit A, the lowermost unit, is typically composed of dolostone with interbedded anhydrite and thin shale beds. Halite is present within units B, D, and F, whereas Unit C typically consists of shale. Unit G, the uppermost unit, is mainly composed of shale, but is capped with a thick anhydrite deposit that is called the Bertie Dolomite in New York. In Pennsylvania, the thickest salt beds occur in northwestern and north-central parts of the state, with bedded salt exceeding 200 feet in units B and D and 400 feet in Unit F. The entire Salina Group exceeds 1,900 feet in southwestern Pennsylvania, where the rocks consist mostly of clastics and anhydrite, and greater than 2,000 feet in northeastern Pennsylvania (Fergusson and Prather, 1968). In West Virginia, the Salina and its eastern facies equivalent become thinner to the south and east from a maximum thickness of 800 feet in the northern panhandle to 300 feet in the southeastern outcrops (Smosna and Patchen, 1978). Lithologically, halite and anhydrite deposition were restricted to northwestern West Virginia; the salt basin is ringed by dolomite and limestone to the south and east. Four principal lithologies intergrade within the Wabash Formation: 1) calcareous gray, dense to fine grained, and massive, silty dolostone and dolomitic silty limestone in the lower part of the formation; 2) light colored, mostly finely granular, cherty but otherwise fairly pure, and slabby bedded limestone, dolomitic limestone, and dolostone in the upper part of the formation; 3) light tan to dark brown to greenish and grayish, micritic to fine-grained, generally nonfossiliferous, color banded, and thinly laminated dolostone and dolomitic limestone in the upper part of the formation; and 4) light-colored, granular, massive, vuggy, nearly pure dolostone and limestone with bluish-gray, carbonate mudstone distributed in bank, reef, reef-detrital, and biohermal facies throughout much of the formation (Indiana Geological Survey, 1997).

In northwestern Pennsylvania and northern Ohio, the Bass Islands Dolomite consists of between 70 and 150 feet of laminated, dull, brown to buff to gray, argillaceous, micritic, dolomitic limestone and calcareous dolostone that commonly contains a pelletal, oolitic, brecciated texture (Ulteig, 1964; Fergusson and Prather, 1968). In the Michigan basin, the formation consists of 150 to 600 feet of dolostone with minor amounts of anhydrite and halite (Catacosinos and others, 2001).

The Helderberg Formation (or Group) in the Appalachian basin is a mixed siliciclastic-carbonate sedimentary sequence (Dorobek and Read, 1986). It consists of four principal lithofacies: 1) light to medium gray, fine- to coarse-grained, medium to thick bedded, fossiliferous calcarenites that typically are free of chert; 2) cherty,

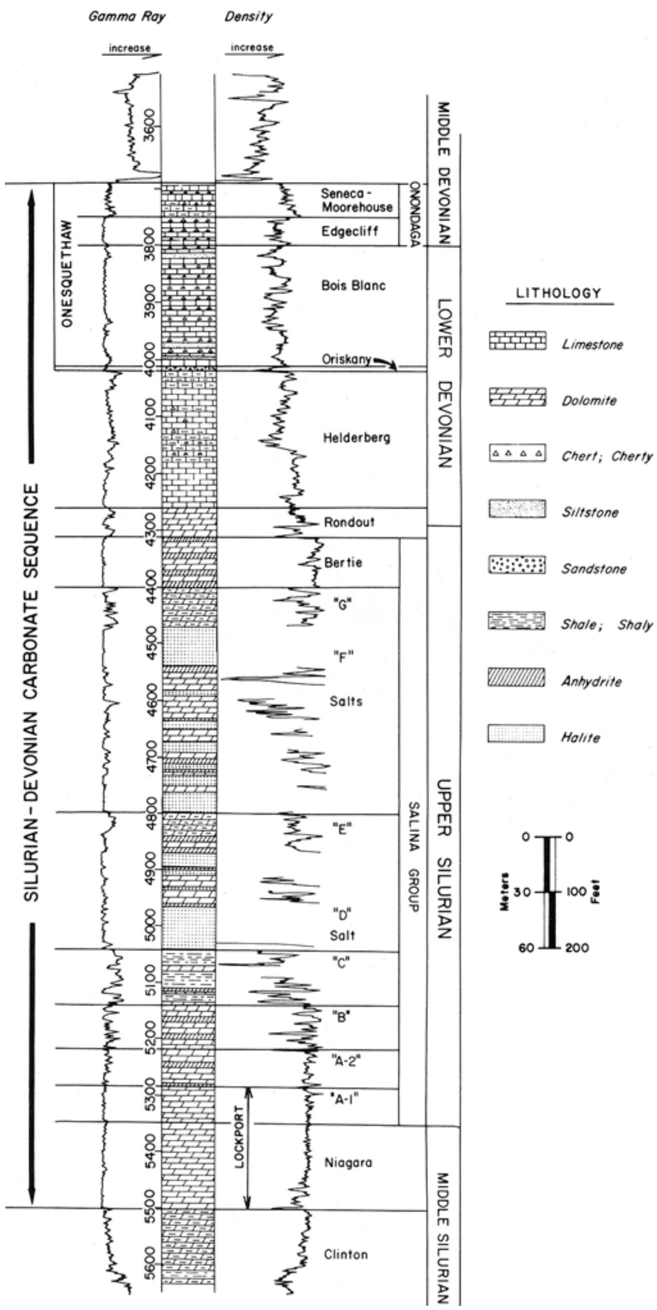

Figure A8-2.—Detailed stratigraphic column and geophysical log curves of the Niagaran thru Onondaga interval from a well in Columbiana County, eastern Ohio (from Mesolella, 1978).

fossiliferous, silt- and sand-sized grainstones, calcareous shales, and silty argillites; dark gray to black, medium bedded, cherty, silt-size grainstones with silty argillites and platy shales; and 4) terrigenous black shales interbedded with thin-bedded mudstones and calcarenites (Head, 1969). In south-central Pennsylvania, western Maryland, and northeastern West Virginia, the upper calcareous facies of the Helderberg (Licking Creek Limestone grades upward into the Oriskany Sandstone. Many drillers have difficulty separating the two, and the formational contact typically is placed at the base of the lowest arenaceous sequence.

The Huntersville Chert is characterized as "variously . . . dark, noncacareous shale, carcareous silty shale, calcareous siltstone, argillaceous and silty or sandy limestone, and a subordinate amount of glauconitic or conglomeratic quartz sandstone" (Basan and others, 1980, p. 42). The sandy facies contains well-rounded quartz grains where the Huntersville lies directly on the Oriskany Sandstone. Thin argillaceous sandstone beds, phosphatic nodules, and glauconite occur in the basal Huntersville as well, indicating the presence of an erosional surface on the top of the Oriskany.

The Onondaga Limestone in northern Ohio consists of light-colored, micritic to coarse-grained, sparry, fossiliferous limestone with fairly abundant chert (Janssens, 1997). The color changes to medium-gray to black to the east. The Onondaga tends to be very argillaceous in the upper portion in places where the limestone grades upward into the organic-rich shales of the Marcellus or "lower" Olentangy formations (Van Tyne, 1996a). In central and western Ohio, the Columbus Limestone is about 215 feet thick and composed of gray to bluish-gray, partly crystalline, and cherty limestone. In the Michigan basin, the Lucas Formation is a siliceous (cherty) dolostone about 35 feet thick, which makes this formation especially distinguishable from the Onondaga and Columbus limestones (Janssens, 1997). The Jeffersonville Limestone of Indiana is brown to gray, dense to crystalline, thick-bedded, dolomitic limestone typically less than 50 feet thick (Patton and Dawson, *in* Murray, 1955).

DISCUSSION OF DEPTH AND THICKNESS RANGES

The Niagaran/Lockport thru Onondaga Interval is relatively shallow over the arches of the region, but attains greater depths in the basins (Figure A8-3). The top of the interval is mostly below 2,000 feet in the Michigan basin, whereas the base is below 8,000 feet in the deepest parts of that basin. In Indiana and western Ohio, the interval is quite shallow, straddling the Cincinnati arch and cropping out along either side of the arch. In the Appalachian basin, the top of the interval ranges from -1,000 feet along the Lake Erie shoreline, to -7,500 feet in south central Pennsylvania. The base ranges from -2,000 feet along Lake Erie to more than -10,000 feet in Somerset County, Pennsylvania (Figure A8-3). In eastern Kentucky several fields produce from this interval at depths of -2,000 to -2,500 feet, but most reservoirs, including the Big Sinking field, are shallower, with depths from -500 to -1,500 feet (Nuttall and others, 2003).

The interval thickness ranges from 250 feet in eastern Kentucky and northern Indiana to more than 6,000 feet in the central part of the Michigan basin (Figure A8-4). Within the Appalachian basin, thickness increases northeastward from about 250 feet in eastern Kentucky to approximately 3,000 feet in central Pennsylvania and western Maryland. These dramatic increases in thickness result mainly from the large accumulations of carbonates and evaporites in the Salina Group.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

Most of the environments represented in this heterolithic interval are normal or restricted marine facies. Intervals of evaporite deposition represent even greater restriction in local areas. The sandstones represent shallow marine or coastal settings (Smosna and Patchen, 1978). The carbonate rocks, in many cases, are influenced by the basin-fringing reef belts, with shallow tidal to supratidal deposits forming behind the reef systems, and deeper subtidal accumulations forming in the basinward settings. In some settings within the deeper portions of the basins, the rocks are very fine grained and rich in shale and clay.

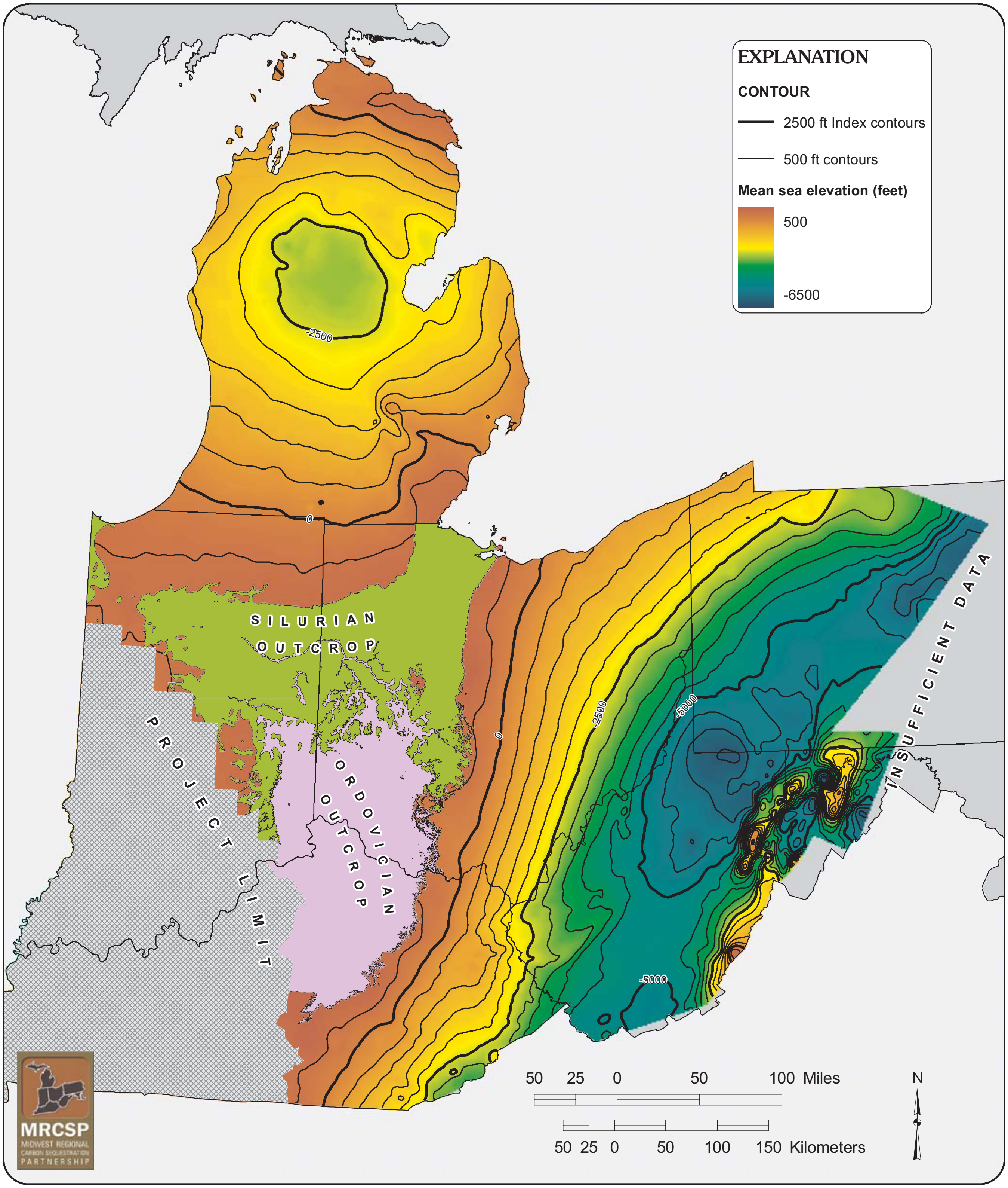

Figure A8-3.—Structure contour map drawn on top of the Onondaga Limestone.

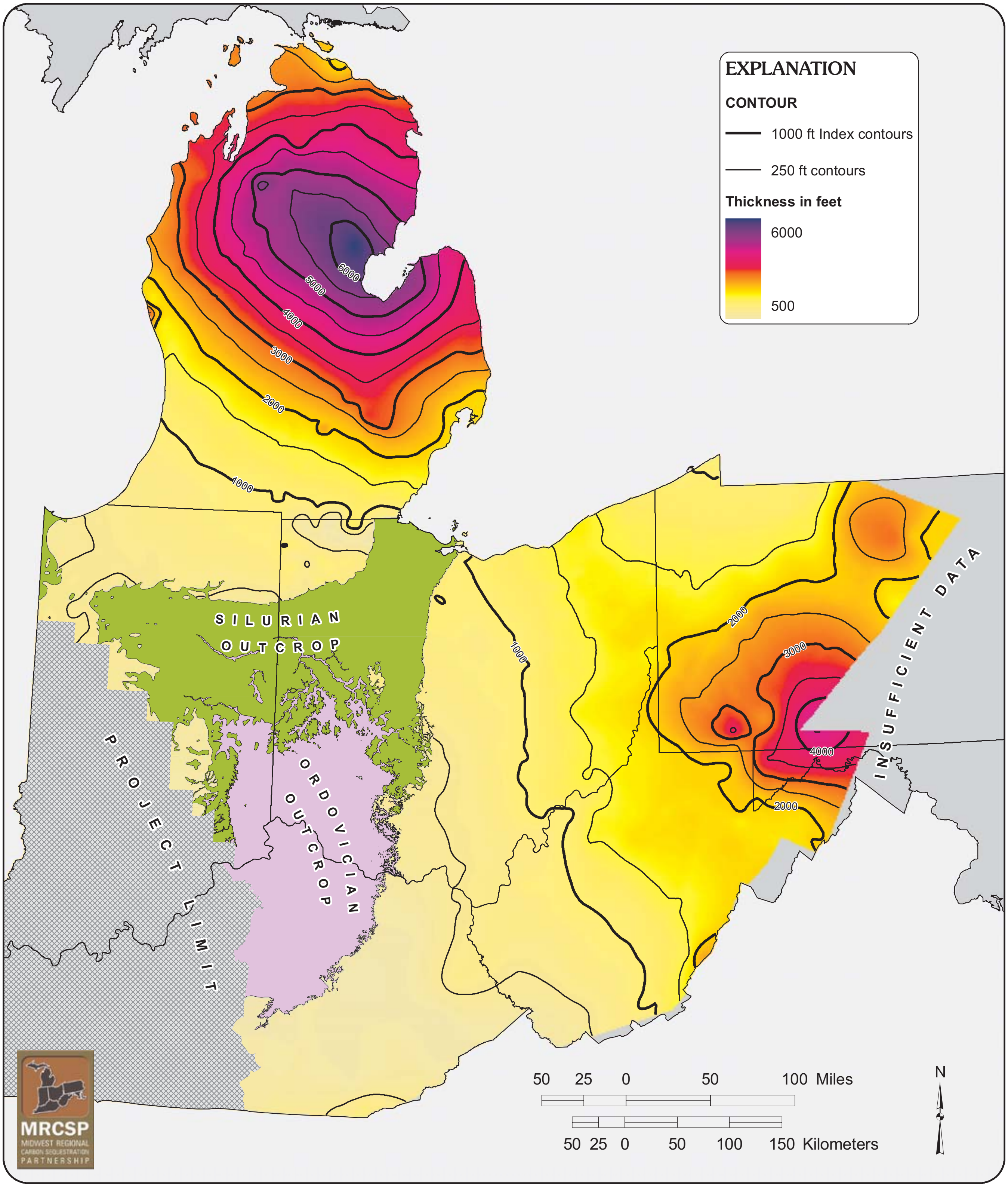

Figure A8-4.—Map showing the thickness of the Niagaran to Onondaga Limestone interval.

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

The Niagaran/Lockport through Onondaga Interval is a major confining unit for CO_2 sequestration in the MRCSP study area. Because of the thickness and combination of lithologies, it should prove to be a very effective seal. The carbonates, in general, have very low porosity and permeability, except in certain units. Similarly, the great thicknesses of evaporites within this interval have low permeabilities that should provide an effective seal against migration of fluids away from lower intervals (such as the Lower Silurian Medina Group/"Clinton" Sandstone). However, Silurian and Middle Devonian dolomitized carbonates represent noteworthy potential sequestration targets in this interval because of significant porosity development within these units. Some oil and gas fields have produced from these dolostones, and some Class II injection wells utilize them. Sandstones in the Lower and Middle Devonian (Oriskany and Sylvania) could also be important sequestration targets. The organic-rich Mandata and Needmore shales might also have potential for sequestration, but this has yet to be determined. During the MRCSP Phase I study, five potential sequestration units from this overall interval, the Niagaran Reefs, Mandata Shale, Oriskany Sandstone, Needmore Shale, and Sylvania Sandstone, were mapped separately, and each is discussed in more detail in other sections of this report. During the MRCSP Phase II investigation, we plan to devote additional study to the Lockport Dolomite and Bass Islands Dolomite, as both appear to have significant, if local, sequestration potential.

The Lockport Dolomite has numerous stratigraphic and combination structural-stratigraphic traps developed in porous patch reef bioherms or skeletal sand shoals encased in impermeable argillaceous dolostone (Noger and others, 1996). Local traps also occur where porosity and permeability pinch out along the flanks of structures. Porosity development in the Lockport is controlled primarily by depositional facies and diagenetic history. Patch reef bioherms and sand shoals have average log-calculated porosities of 8 to 10 percent in producing oil and gas fields, with maximum porosities as high as 14 percent (Noger and others, 1996). In addition to moldic, vuggy, interparticle, and intercrystalline porosities, fracture porosity and permeability enhance production from producing fields, and should allow for maximum sequestration of miscible CO_2 fluids. Seals for trapping fluids within the formation are provided by internal impermeable mudstones and the overlying evaporites and carbonates of the Salina Group.

Caverns within the Salina Group salt units in Michigan and Ohio may have potential for sequestration of CO_2. Such caverns are currently used for underground storage of natural gas liquids. In Ohio, underground storage of hydrocarbons in Salina salt deposits began in 1960. Thirty wells have been permitted for hydrocarbon storage since 1960, but only 11 wells have been used (Tomastik, 2001). Of these 11 wells, only two wells are currently operating. The main products stored in these wells are butane and propane. There are currently two active Salina Group salt mines in Cuyahoga and Lake Counties, Ohio (Figure A8-1) at depths of approximately 2,000 feet. Salt mines in Michigan and Ohio may also represent some sequestration potential, although most are not deep enough to achieve supercritical phase. Approximately 224 salt solution-mining wells have been drilled and completed in the Salina since the late 1890s in Ohio. Two facilities with 44 active wells remain open. Depths to the Salina Group salt beds in these wells range from 1,800 to 3,150 feet (Tomastik, 1997). In West Virginia, there are three solution mining areas: 1) on the Pleasants/Tyler County line; in southwestern Marshall County; and 3) in west-central Marshall County (Figure A8-1). Two of these are currently active (the northern most one in Marshall County is abandoned). Depths to the Salina range from 6,200 to 6,900 feet in these wells. One salt-solution well has been drilled in north-central Pennsylvania with the purpose of using it to store natural gas. However, solution mining of the salt cavity has not been accomplished to date because the project is currently tied up in litigation. However, the great thickness of bedded salt in north-central Pennsylvania, at depths greater than 7,500 feet, indicates the Salina Group could be a valuable injection target in this part of the MRCSP study area.

The Upper Silurian Bass Islands Dolomite could also be useful for sequestering CO_2. Reservoir quality typically occurs where the dolostone is highly fractured, as in the "Bass Islands trend" of New York and Pennsylvania (Van Tyne, 1996b). Little is known about the specifics of porosity and permeability, other than gross generalizations about fracture porosity. One pool in Erie County, Pennsylvania provides most of the details on the "Bass Islands trend." Porosity, as measured on geophysical logs, ranged from 2 to 15 percent, averaging 10 percent. Occasionally, however, the Bass Islands has potential reservoir quality outside of such fractured areas, as provided by anecdotal information. In the early 1980s, a disposal well in northwestern Pennsylvania was investigated for problems of leakage in the annulus. The disposal formation was Upper Cambrian sandstone (Rose Run), but the fluids were migrating uphole into the Bass Islands Dolomite where they spread out into the surrounding region through cavernous porosity within the dolostone. Disposal fluid was found five miles away, leaking through an old, unplugged well in Lake Erie. It is unfortunate that the Bass Islands in this area is very shallow (only 1,700 feet in the disposal well). However, investigation of the Bass Islands Dolomite at depths below 2,500 feet would prove valuable in looking for potential sequestration targets within the dolostone.

9. LOWER SILURIAN NIAGARA GROUP REEFS

The Niagara Group (includes Lockport Dolomite) is early Silurian (Niagaran) in age and characterized by the development of individual "pinnacle" reefs and reef complexes along two linear trends, one in the northern part of the Michigan basin, the other along the southern part of the basin. Overall, the reef belt both contain pinnacle and barrier reef complexes, is mostly in the lower peninsula of Michigan but does extend into northeastern-most Illinois and northernmost Indiana and Ohio. Individual pinnacle reefs and reef complexes (averaging 50 to 400 acres in areal extent) are numerous, extending along linear belts approximately 6 to 15-miles wide in the northern reef belt and up to 20-miles wide in the southern part of the Michigan basin. Currently, there are approximately 800 pinnacle reefs and reef complexes (fields) identified in the northern trend with an additional 400 in the southern trend. Productive reef intervals range from approximately 50 to 700 feet in thickness.

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

Hall (1840) named the Niagara for exposures in the Niagara Falls, New York region. There have been numerous studies discussing the various stratigraphic aspects of the Silurian reefs in the region (for examples, see Droste and Shaver, 1985; Shaver and Sunderman, 1989; Shaver, 1991, 1996). Likewise, there have been numerous studies on the reservoir aspects of the reefs (for examples, see Gill and others, 1974; Gill, 1977; Sears and Lucia, 1979, 1980).

NATURE OF LOWER AND UPPER CONTACTS

The lower contact of the Niagara Group is gradational with the underlying Manistique Group (Figure 5). The Salina Group, a mixed interval of intercalated carbonates and evaporites overlies the Niagara Group and provides a regional seal that is highly competent (Figure A8-2). In the lower portion of the Salina Group, the A-1 evaporite formation overlies the inter-reef Niagara but not the pinnacle reefs. The A-1 carbonate, A-2 evaporite and the A-2 carbonate and B salt all overlie both the inter-reef and the pinnacle reefs (Sears and Lucia, 1979).

LITHOLOGY

The reservoir facies consist primarily of porous and permeable dolostone, although locally primary limestone has reservoir grade porosity and permeability. Porosity is best developed in the pinnacle reef core as well as the immediate off-reef facies (fore-reef, flanking beds) and is characterized primarily by intercrystalline and vuggy pores.

DISCUSSION OF DEPTH AND THICKNESS RANGES

The pinnacle reefs range from 2,000 feet to more than 6,000 feet deep in the Michigan basin (Figure A9-1), with the majority of reefs at depths that average approximately 3,500 to 4,500 feet. Reservoir thickness may be highly variable and ranges from a few feet to several hundred feet. An isopach map was not created for the MRCSP Phase I project due to the small, high-relief reef features that would not have been adequately illustrated by contours generated by conventional gridding algorithims at the regional scale of MRCSP mapping.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

The pinnacle reefs are located along a carbonate ramp generally basinward of a shelf edge barrier reef complex. The reefs are characterized by a complex interaction of biogenic growth and physicochemical precipitation of carbonate cements. Common reef-builders include various forms of stromatoporoids and corals indicative of normal marine conditions during time of deposition. The reefs and associated facies are generally subdivided into six readily recognizable sub-facies (Gill, 1977): 1) biohermal mudmound consisting of carbonate muds and skeletal components including crinoids and bryozoans; 2) reef core consisting of a massive framework formed by stromatoporoids, corals, algae, and a variety of subordinate biotic elements combined with early submarine cements; 3) reef detritus made up of detrital fragments of the reef core and deposited along the flanks of the reef; 4) an inter-reef facies comprised of platform carbonates; 5) restricted (lagoonal) facies consisting of laminated and bioturbated, peloidal mudstones, and wackestones; and 6) supratidal/island facies consisting of algal laminated sediments and other features of high intertidal to supratidal deposition.

The pinnacle reefs were deposited in a tropical to subtropical latitudinal belt. Subsequent diagenetic dolomitization has been attributed to a number of mechanisms, including mixing zone processes, Kohout convection, hypersaline reflux of brines, evaporative drawdown, and hydrothermal circulation, although most workers agree that reflux and hydrothermal processes were probably the main mechanisms (Sears and Lucia, 1980). The relationship between basin subsidence and eustatic changes at the time of pinnacle reef deposition is presently unclear; there are a number of studies investigating the relative timing of reef growth in response to relative sea level changes.

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

Niagaran reefs have been prolific oil-and-gas-producers After their productive life, many are converted to gas storage units due to their high porosity and permeability characteristics and effective overlying seals. Despite the fact that reservoir-grade rock is not regionally continuous, but is found in more localized reefs and reef complexes, the Niagaran reefs should be considered high-quality targets where CO_2 can be economically transported to the reef trends. Porosity values can exceed 35 percent locally but typically average 8 to 12 percent with the best porosity associated with dolomitized reef cores and flank facies. The best reservoir rocks are characterized by well-developed intercrystalline and vuggy porosity with average permeability values of 3 to 10 md. Permeability can be significantly higher where fractures intersect matrix porosity. A high-quality sealing unit is provided by the overlying Salina Group, characterized by abundant salt and anhydrite intercalated with relatively thin carbonates. Cumulative oil production through 2004 was 336 million barrels of oil (MMbo) and 2.5 trillion cubic feet (Tcf) of gas, indicating the high-quality porosity and permeability available in many reefs. While individual reefs and reef complexes are localized (averaging 50 to 400 acres), they can reach up to 2,000 acres in size and have from 150 to 700 feet of vertical relief . Also, the individual reefs are clustered close together within trends. Thus, once a pipeline is brought to the trend, CO_2 injection (and enhanced oil recovery) can proceed from reef-to-reef fairly inexpensively.

A number of the Niagaran reefs are used for natural gas storage operations in Michigan (Table A9-1). Such operations illustrate the integrity of the reservoirs for storage operations. The relatively small surface footprint of the reef-sand thick reservoir with large capability for storage allow relatively large volumes of gas to be cycled with few injection and withdrawal wells.

There is currently a project underway to utilize CO_2 from a gas-processing plant for enhanced oil recovery from three pinnacle reefs along the northern Michigan trend. This work is being performed with the sole purpose of oil recovery in mind, not optimal sequestration of CO_2. The existence of the pipeline infrastructure makes this area a highly attractive prospect for pilot sequestration studies. Such a study would be favorable from logistical, geotechnical, and economic standpoints, as much is known or can be established using available data on reservoir heterogeneity and compartmentalization.

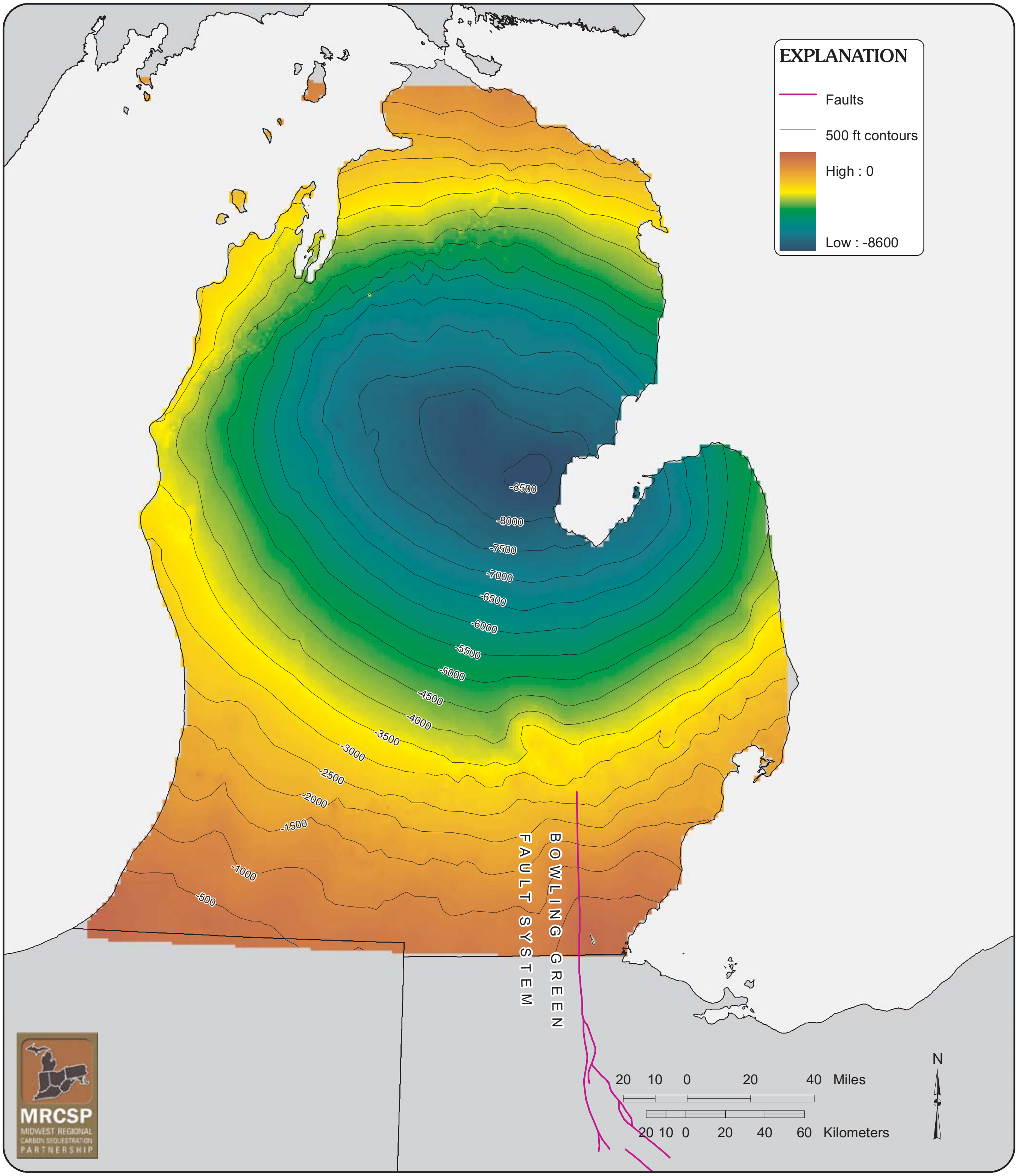

Figure A9-1.—Generalized structure contour map drawn on the top of the Niagaran Group reefs.

Table A9-1.—Summary of data for Niagaran gas storage fields in the Michigan basin. Modified from American Gas Association (2001)

Storage Field/ Reservoir Name	*County*	*Max. Depth*	*Min. Depth (ft)*	*Avgerage Thickness*	*# Wells*	*Total Gas (Base + Working) (MMcf)*	*Maximum Pressure (psi)*	*Year Discovered*	*Year Activated*	*State/Province*
Central Charlton	Otsego, Montmorency	5995	5472	282	9	19000	3445	1975	1982	Michigan
Columbus	St. Clair	3105	2669	190	17	19600	1737	1964	1972	Michigan
Cortright	Calhoun	3300	3160	140	2	985	1350	1972	1976	Michigan
Eaton Rapids 36	Ingham, Eaton	3815	3659	125	14	16234	1928	1972	1990	Michigan
Four Corners	St. Clair	2421	2157	200	3	3780	1080	1966	1972	Michigan
Hessen	St. Clair	2757	2475	200	14	16977	1405	1965	1976	Michigan
Ira	St. Clair	2416	2120	220	11	6750	1220	1953	1961	Michigan
Lee 11 Field	Calhoun	3266	3123	143	1	780	1250	1976	1988	Michigan
Lee 3	Calhoun	3380	3220	75	5	2464	1440	1972	1992	Michigan
Lee 8	Calhoun	3400	3280	120	4	2200	1350	nr	1995	Michigan
Lenox	Macomb	2747	2556	200	6	3500	1263	1960	1965	Michigan
Lyon 34	Oakland	3430	3232	200	4	1358	1635	1987	1992	Michigan
Muttonville	Macomb	2865	2562	194	17	13414	1575	1966	1975	Michigan
Northville Reef	Washtenaw	3158	2922	200	3	1420	1735	1965	1968	Michigan
Partello/ Anderson	Calhoun	3250	3140	75	7	4760	800	1959	1971	Michigan
Puttygut	St. Clair	2715	2377	200	22	14600	1140	1960	1971	Michigan
Ray	Macomb	3219	2905	250	44	64500	1735	1961	1966	Michigan
South Chester 15	Otsego	6579	5914	287	7	19455	3675	1970	1980	Michigan
Swan Creek	St. Clair	2442	2241	200	1	650	1067	1967	1972	Michigan
W. Columbus	St. Clair	3234	2872	206	18	25900	1784	1967	1973	Michigan
Washington 28	Macomb	3502	3138	198	7	11632	1419	1974	1990	Michigan
Lee 2 Field	Calhoun	3374	3374	200	1	806	1440	1974	1981	Michigan
Collins Field	St. Clair	2340	2090	107	2	2263	1100	1968	1981	Michigan
Capac	St. Clair, Lapeer	4821	4297	10	93	38192	2480	1961	1978	Michigan
Belle River Mills	St. Clair	2511	2162	205	24	76120	1475	1961	1965	Michigan
Washington 10	Macomb	3460	3319	305	14	51100	1448	1969	1999	Michigan
Blue Lake 18A	Kalkaska	6930	6600	330	14	54119	3994	1977	1993	Michigan
Coldsprings 12	Kalkaska	6790	6584	172	11	28884	3990	1973	1980	Michigan
Coldsprings 31	Kalkaska	6930	6648	158	4	5302	3965	1974	1981	Michigan
Excelsior 6	Kalkaska	6839	6494	250	8	12310	3956	1973	1981	Michigan
Rapid River 35	Kalkaska	6736	6412	233	9	17327	4000	1973	1980	Michigan
						TOTAL = 536382				

10. LOWER DEVONIAN MANDATA SHALE

The early Devonian Mandata Shale is a thin but extensive black shale interval within the carbonate rocks that are generally termed the Helderberg Group or Old Port Formation in central Pennsylvania, Maryland, and eastern West Virginia (Head, 1974) (Figure 5). In central and south-central Pennsylvania, Maryland and West Virginia, the Mandata Shale overlies the Corriganville Limestone. The Mandata Shale has a conformable contact with the overlying Shriver Chert or Licking Creek Limestone (facies equivalents) in Pennsylvania, Maryland, and West Virginia (Head, 1969, 1974), although Dorobek and Read (1986) suggested that the Mandata is laterally equivalent to the Licking Creek in western Maryland.

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

Swartz (1939) named the Mandata Shale for exposures 0.25 miles south of Mandata, Perry County, Pennsylvania, on the highway to Berrysburg.

NATURE OF LOWER AND UPPER CONTACTS

The Mandata Shale has a sharp, conformable contact with the underlying Corriganville Limestone and grades upsection into the overlying cherty shales of the Shriver Chert or the Licking Creek Limestone (Glaser, 2004) (Figure 5).

LITHOLOGY

The Mandata Shale is a dark gray to black, platy to thin-bedded, organic-rich shale. The shale is sparingly fossiliferous and in western Maryland intertongues with the Licking Creek Limestone Member of the Helderberg Group (Glaser, 2004).

DISCUSSION OF DEPTH AND THICKNESS RANGES

The thickness of the Mandata Shale ranges from 15 to 30 feet based on outcrops and three wells in Maryland (Edwards, 1970; Nutter and others, 1980).

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

The Mandata Shale represents an early Devonian deepening episode that drowned the Helderberg carbonate ramp. The ramp became sufficiently deep to preclude carbonate deposition. This deepening continued into and during the deposition of the Shriver Chert and did not again shallow until the late Gedinnian Stage with the deposition of the Oriskany Sandstone.

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

In Maryland, there are limited analytical data to address the Mandata's suitability as a CO_2 sequestration target. In cooperation with the Pennsylvania and West Virginia Geological Surveys, this issue will be addressed in the Phase II of the MRCSP.

11. LOWER DEVONIAN ORISKANY SANDSTONE

The Oriskany Sandstone of drillers' terminology (Figures 5 and All-1) actually encompasses several discrete formal stratigraphic units in the Appalachian basin (Heyman, 1977; Harper and Patchen, 1996), including: 1) the type Oriskany Sandstone of New York, which also occurs in northwestern Pennsylvania and eastern Ohio; 2) the Ridgeley Sandstone of Pennsylvania, Maryland, Virginia and West Virginia (where it is called Oriskany), which may or may not be identical to the type Oriskany; 3) the Springvale Sandstone, a basal sandstone member or sandy facies of the Bois Blanc Formation in Ontario, northeastern Ohio, and northwestern Pennsylvania (Oliver, 1967; Heyman, 1977); and 4) the Palmerton Formation, a sandstone in eastern Pennsylvania that is equivalent to a portion of the basal Onondaga Limestone (Sevon, 1968). The Palmerton will not be discussed further herein.

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

The Oriskany Sandstone was named by Vanuxem (1839) for its type locality in Oriskany Falls, Oneida County, New York. At this location, the Oriskany is a white, fossiliferous quartz arenite (Opritza, 1996; Patchen and Harper, 1996). Most of the studies done on the formation before 1930 were for purposes of clarifying the stratigraphic and paleontological relationships of Lower Devonian and Upper Silurian rocks (for example, see Swartz, 1913). However, since 1930, the Oriskany has become one of the more important formations for gas exploration in the Appalachian basin. As a result, the Oriskany has been the subject of numerous studies related to structure, stratigraphy, petrology, petrophysics, and other topics. The earliest studies were performed by petroleum geologists documenting the significant discoveries in south-central New York and north-central Pennsylvania in the early 1930s and 1940s (for examples, see Fettke, 1931; Torrey, 1931; Newland and Hartnagel, 1932; Bradley and Pepper, 1938; Stow, 1938; Van Petten, 1939). Subsequent studies by Finn (1949), Ebright and Ingham (1951), Young and Harnberger (1955), Wood (1960), Seilacher (1968), Heyman (1969), Patchen (1968), Jacobeen and Kanes (1974a,b), and many others added to the general knowledge of the formation and provided additional data on the various reservoir properties. A resurgence of interest in this prolific reservoir in the late 1970s and the 1980s resulted in what arguably is the most comprehensive report produced to date on the Oriskany, the exhaustive study done by Basan and others (1980). The most recent reports, in the Atlas of Major Appalachian Gas Plays (Roen and Walker, 1996), provide a summary and a single source of information garnered from earlier studies.

NATURE OF LOWER AND UPPER CONTACTS

The Oriskany Sandstone represents a major change during Early Devonian deposition in the Appalachian basin. The predominant carbonate sedimentation that originated in the late Silurian ceased or slowed, to be replaced temporarily by predominant clastic deposition. The Early Devonian ended with a worldwide regression that resulted in erosion throughout much of North America (the Wallbridge discontinuity of Wheeler, 1963). This discontinuity occurs at the Appalachian basin margins as an unconformity between the carbonate rocks of the Upper Silurian/lower Devonian and the Middle Devonian (Figure A11-1). Some authors, such as Wheeler (1963), described the Oriskany as a basal sandstone deposited on a basin-wide unconformity. Erosion following Oriskany deposition near the basin margins might have been more extensive than pre-Oriskany erosion—there are large areas of the basin where the Oriskany is thin or absent, for example the "Oriskany no-sand area" in northwestern Pennsylvania (Figure A11-2 and A11-3). It is also possible that such areas occur because of lack of deposition on positive paleotopographic highs. The rocks above the upper unconformity in eastern Ohio, northwestern Pennsylvania, and western New York consist of limestones and cherty limestones, often containing a basal sandstone or siltstone with "glauconite" (actually, a group of greenish clay minerals of varying composition) that typically indicate deposition on an erosional surface. This is the Springvale Sandstone member of the Bois Blanc Formation, the "Oriskany" of drillers in areas where the true Oriskany is absent.

The concept that the Oriskany is everywhere bounded by unconformities is very popular, resulting in many studies showing the upper and lower surfaces of the formation to be disconformable with adjacent strata across the basin (for example, see Opritza, 1996, fig. Dop-3). However, based on core data from north-central Pennsylvania and Greenbrier County, West Virginia, the Oriskany actually lies conformably on the underlying rocks of the Helderberg throughout the main portion of the basin south and east of the cratonic margins (Heyman, 1977; Bruner, 1988). Also, in this area, the Oriskany conformably underlies black shales and cherts of the Needmore and Huntersville formations. This supports the concept by Dennison and Head (1975) of uninterrupted deposition within the central Appalachian basin throughout Early Devonian time.

LITHOLOGY AND DEPOSITIONAL ENVIRONMENTS

The Oriskany Sandstone typically is a pure, white, medium- to coarse-grained, monocrystalline quartz sandstone containing well-sorted, well-rounded, and tightly cemented grains (Fettke, 1931; Gaddess, 1931; Finn, 1949; Basan and others, 1980; Diecchio, 1985; Foreman and Anderhalt, 1986; Harper and Patchen, 1996). Quartz and calcite comprise the most common cementing materials in the formation. In many areas of the basin, the formation contains such an abundance of calcite, both as framework grains and as cement, that the rock is classified as an arenaceous limestone.

The sandstone originated in a shallow marine setting fairly early in Devonian time when one or more emergent landmasses to the north and southeast were uplifted and eroded (Harper and Patchen, 1996). Although the character of the sand grains in the Oriskany indicate a mature, multicycled sediment, the specific origin of the Oriskany sand deposits remains unsettled. Dennison (1961) among others, suggested the sand originated to the southeast and spread northwestward across the basin. Stow (1938) determined that, although the sandstone in the central Appalachians (northeastern

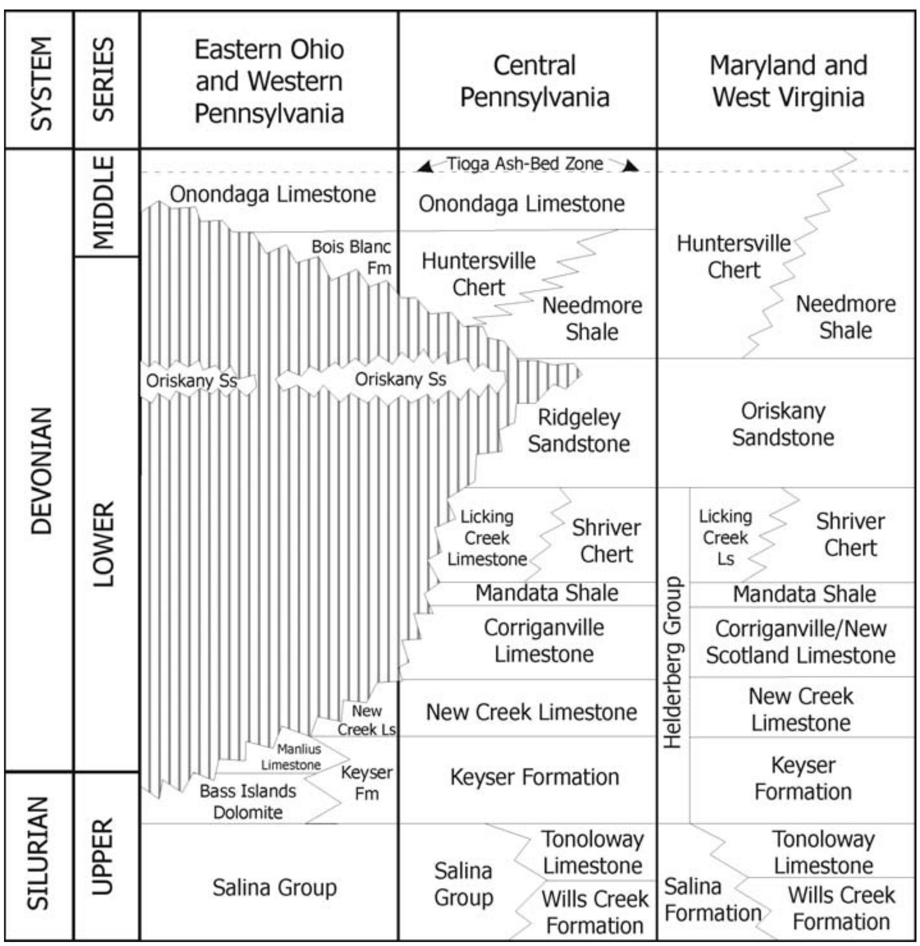

Figure A11-1.—Stratigraphic correlation chart of the Oriskany Sandstone and adjacent strata in the Appalachian basin (from Flaherty, 1996).

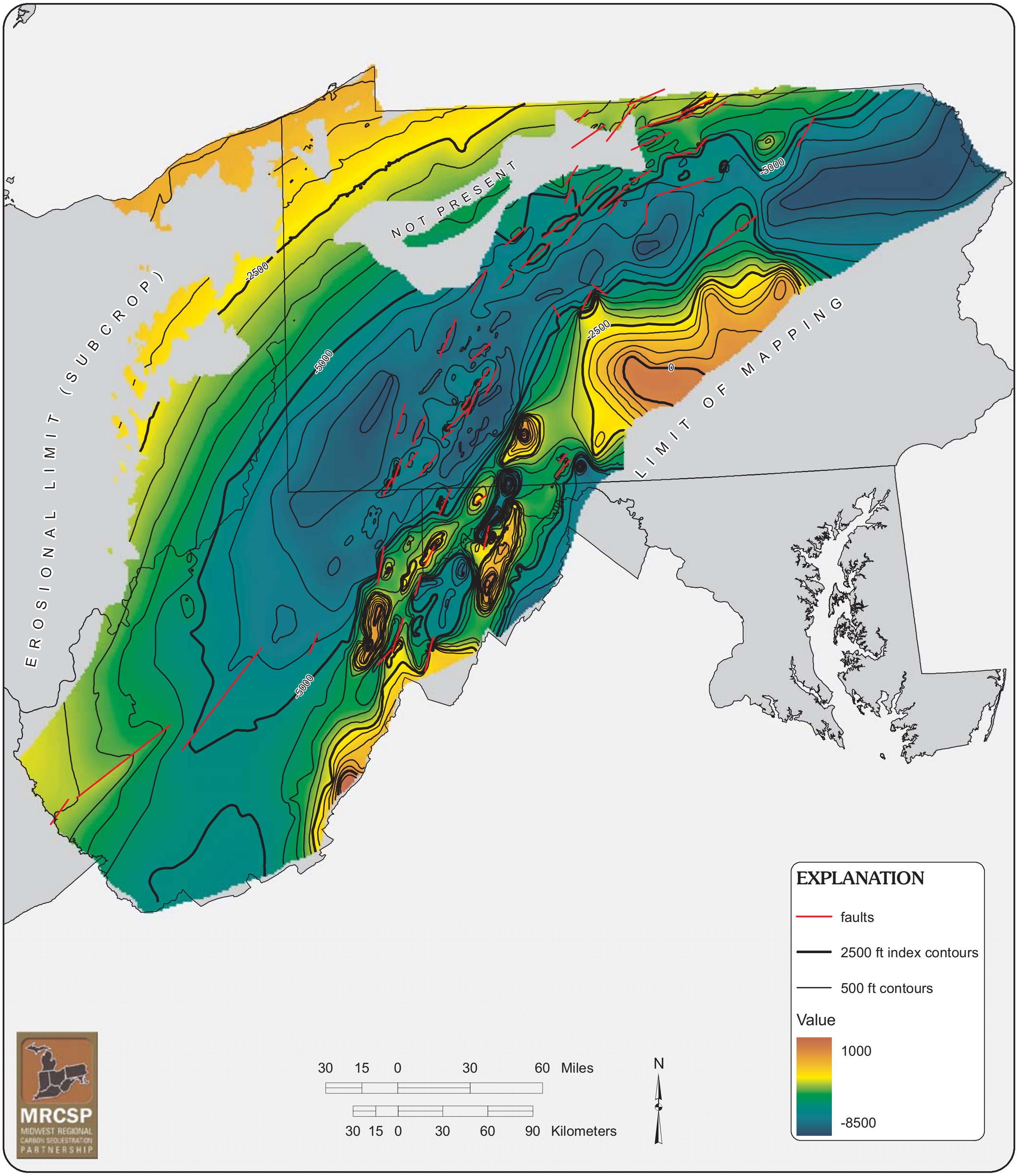

Figure A11-2.—Structure contour map drawn on the top of the Oriskany Sandstrone.

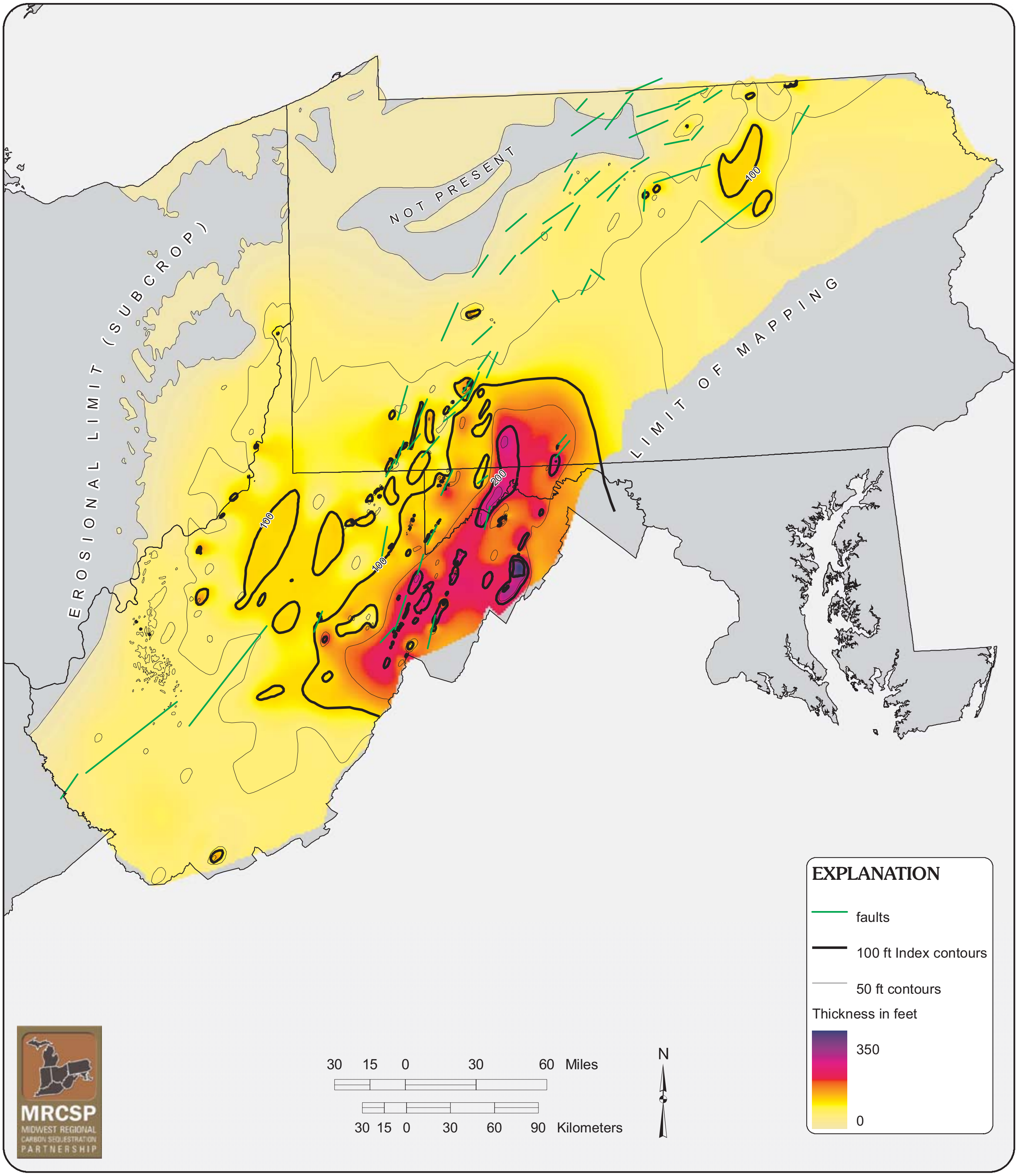

Figure A11-3.—Map showing the thickness of the Oriskany Sandstone.

Pennsylvania to southeastern West Virginia) was derived from older sedimentary deposits to the southeast, in New York it was derived directly from crystalline rocks in the Adirondacks. Basan and others (1980) eventually showed that the Oriskany is very different in different areas. As a result, they suggested three possible source areas for the Oriskany: 1) the Adirondacks (as per Stow, 1938); 2) an emergent landmass on the southeastern margin of the basin; and 3) an emergent landmass in east-central Pennsylvania or New Jersey. The relative abundance of polycrystalline quartz in eastern Pennsylvania exposures, derived from a metamorphic source, provides evidence for this latter possible provenance.

The depositional environments of the Oriskany are varied, but always fall within the broad category of shallow marine. Swartz (1913) proposed a high-energy beachface environment for the Oriskany in the Valley and Ridge province. Other authors have suggested nearshore, shallow water (Stow, 1938), tidal ridges and submarine dunes (Basan and others, 1980), shallow to deeper subtidal (Barrett and Isaacson, 1977), and marine shelf bar (Welsh, 1984; Bruner, 1988) environments (Figure A11-4). But, as Basan and others (1980) pointed out, even within a single outcrop or well location the Oriskany can represent one or more depositional environments.

DEPTH AND THICKNESS RANGES

The Oriskany crops out in central New York near its type locality, as well as within the complex fold belt of central Pennsylvania, western Maryland, northeastern West Virginia, and western Virginia. Based on drillers' records, it ranges from approximately 1,200 feet deep along the shore of Lake Erie in northeastern Ohio and northwestern Pennsylvania to more than 10,000 feet deep in Somerset County, Pennsylvania (Figure A11-2). Depths within the Appalachian Plateau vary greatly as a result of both a general regional southeastward dip and the occurrence of numerous anticlines paralleling the regional strike of the Valley and Ridge Province to the east.

Figure A11-3 illustrates the thickness of the Oriskany Sandstone throughout the basin. Oriskany thicknesses vary within the Appalachian Plateau of eastern Ohio, western Pennsylvania, and West Virginia from 0 to over 300 feet. Adjacent to pinchout areas such as the "Oriskany no-sand area" in northwestern Pennsylvanian and along the eastern pinchout in Ohio, the reservoir sandstone typically averages between 10 and 30 feet thick (Finn, 1949; Abel and Heyman, 1981, Opritza, 1996). At the pinchout, the sandstone forms a thin wedge between relatively impermeable Lower and Middle Devonian carbonates and shales. Thicker zones of Oriskany typically occur in the more structurally complex areas where thrusting and vertical repetition of beds causes apparent thicknesses much greater than 60 feet—even as much as 350 feet in western Maryland (Harper and Patchen, 1996; Patchen and Harper, 1996). The thicknesses shown in Figure A11-3 are comparable to those previously published by Diecchio and others (1983) for this unit in the northern portion of the Appalachian basin.

TRAPS/STRUCTURE

As a natural gas reservoir, the Oriskany is affected by three types of traps—stratigraphic (i.e., updip permeability pinchout) (Opritza, 1996), structural (Harper and Patchen, 1996), and combination stratigraphic and structural (Patchen and Harper, 1996). In the areas of pinchout (Figures A11-2 and A11-3), fluids migrated updip (i.e., westward and northward) to where the sandstone pinches out against overlying and underlying impermeable rocks (typically tight carbonates or shales), creating a stratigraphic trap (Opritza, 1996). Brine often is trapped between the actual sandstone pinchout and the zones or belts of gas production. Where the trapping mechanism is structural, from central-western Pennsylvania and West Virginia eastward, structural complexity increases from west to east. To the west and north, anticlinal structures with rifted cores originated through detachment in incompetent Silurian salt beds. Salt water typically occurs in the cores of these anticlines. To the east, multiple, east-dipping thrust sheets (duplexes), resulted from Alleghanian tectonic thrusting (Flaherty, 1996; Harper and Patchen, 1996). Combination traps occur in a narrow band across easternmost Ohio into western Pennsylvania and western West Virginia where moderate structures enhance trapping in updip porosity pinchout situations (Patchen and Harper, 1996). Figure A11-2 (see also Figure 6) shows the areas of structural complexity within the MRCSP study area. The few faults shown imply far more simplicity and generalization than actually occurs owing to the scale of the map. Studies of individual structures and gas fields indicate much more complexity than can be shown on a map at this scale.

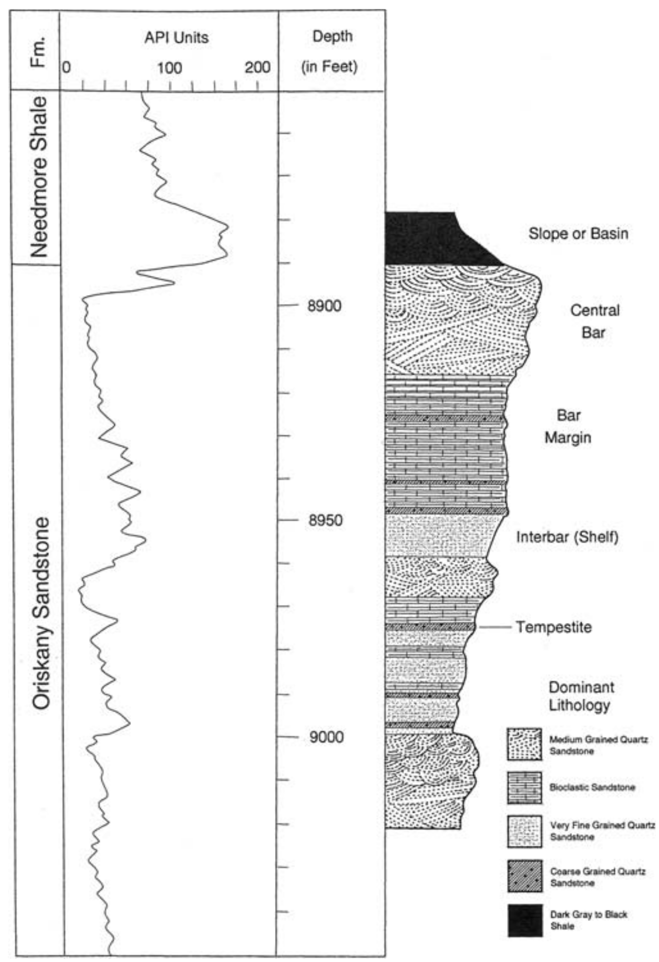

Figure A11-4.—Interpreted environments of deposition in the Oriskany Sandstone from a well in Somerset County, Pennsylvania. Diagram based on gamma-ray log signature and core descriptions (modified from Welsh, 1984).

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

The lithology of the Oriskany Sandstone, were that the only consideration for CO_2 sequestration, could be daunting. Besides the primary composition of quartz and calcite grains, minor proportions of pyrite, dolomite, and other minerals have also been observed (Harper and Patchen, 1996). Authigenic minerals include illite, chlorite, vermicular kaolinite, "glauconite," sphalerite, and pyrite (Martens, 1939; Basan and others, 1980; Foreman and Anderhalt, 1986). Cements vary—the most common are silica and calcite, but minor pyrite, dolomite, ankerite, "glauconite", and chalcedony also occur (Basan and others, 1980). Minor authigenic clays occur as pore-filling materials, grain coats, and feldspar-alteration products. Such clays and matrix can occlude porosity and thus make the sandstone an undesireable target for sequestration. In south-central Pennsylvania, and into Maryland, Virginia, and West Virginia, the rock varies greatly in texture and composition, ranging from extremely fine-grained arenaceous limestone to coarsely conglomeratic quartz arenite (Swartz, 1913; Cleaves, 1939; Woodward, 1943). Such variations inhibit easy characterization of the Oriskany for injection potential. In general, the Oriskany exhibits a coarsening-upward sequence (Patchen and Harper, 1996), but each potential injection point would have to be individually studied for sequestration potential.

The Oriskany Sandstone typically is a tight rock unit except in certain areas affected by fracturing (areas of folding and faulting) or dissolution of cement (generally near pinchout areas). Porosities and permeabilities vary widely across the basin, depending on mineralogy, diagenesis, and amount of fracturing (Harper and Patchen, 1996). Intergranular porosity consists of both reduced primary porosity and secondary porosity due to dissolution of carbonate cements and some grains. While the arenaceous limestones have porosities less than five percent, zones within the arenites can have porosities greater than 20 percent where secondary porosity has been favorable (Basan and others, 1980). Opritza (1996) documented intergranular porosities of 2 to 19 percent, with averages of 7 percent, in producing gas fields along the updip permeability pinchout. In most cases, porosity in the Oriskany averages less than 10 percent. Basan and others (1980) indicated that porosities determined by petrographic examination tend to be higher than those derived by evaluation of geophysical logs. Figure A11-5 shows typical gamma ray and porosity curves for the Oriskany Sandstone in the basin. The neutron-density crossover observed on the porosity logs shows a gas effect indicating that this sandstone unit is generally porous along its entire length.

Fracture porosity, where it is developed, aids greatly in fluid storage within the Oriskany. Because of their greater ductility, the quartz arenites tend to have greater fracture densities than the arenaceous limestones. However, the timing of fracturing is at least as important as its occurrence. Early fractures generally healed during diagenesis, whereas late-stage fractures commonly remain open.

Permeabilities in the Oriskany Sandstone range from less than 0.1 to almost 30 md (Harper and Patchen, 1996). Highly fractured rocks tend to have higher permeabilities, as do rocks in which carbonate dissolution has occurred. Permeabilities are low where fractures have been healed by secondary mineralization, or where secondary dissolution of cements has been minimal. Injection of fluids, therefore, would be more favorable in areas close to an updip pinchout or along structures where fractures have not healed.

The Oriskany commonly is considered to be overpressured because of initial open flow pressures in some areas of the basin as high as 4,500 psi. However, pressure/depth ratios range from 0.228 to 0.742, averaging 0.441, which is essentially the normal hydrostatic pressure gradient. Russell (1972) suggested that, on average, the Oriskany is not an overpressured reservoir, and that overpressuring is more common in areas of intense deformation. Harper and Patchen (1996), however, indicate that the more highly deformed areas, such as south-central Pennsylvania, western Maryland, and eastern West Virginia, tend to have abnormally underpressured reservoirs. Pressure-depth ratios in this area range from 0.257 to 0.500 with an average of 0.393. In contrast, pressure-depth ratios in the "less deformed" areas of western Pennsylvania and south-central New York range from 0.228 to 0.742, averaging 0.459. The relationship of degree of deformation to pressure gradient is not readily apparent but might be due, at least in part, to the ability of the reservoir to maintain fluids following intense fracturing.

Brines in the Oriskany Sandstone typically have very high salinity values, often in the 200,000 to 350,000 ppm range, averaging about 250,000 ppm, and consist of a wealth of element concentrations (Kelley and others, 1973). The highest values are for chlorine, followed by sodium and calcium. Smaller but significant concentrations of magnesium and bromine also commonly occur.

The Oriskany Sandstone has been used for the injection of industrial wastes in several wells in the basin, and for injection of natural gas for gas storage purposes in numerous depleted gas fields. One injection project, a waste disposal well in Pennsylvania, had an injection rate of about 20 gallons per minute at an intake pressure of 1,400 psi during the initial investigation stage (Pennsylvania Geological Survey files). The Oriskany in this well ranged from 5,250 to 5,426 feet. Average porosity and permeability were 5.2 percent and 2.2 md, respectively. One sample reported both the highest porosity at 4.59 percent and the highest permeability at 4.2 md. These numbers are lower than the averages reported by Opritza (1996), Harper and Patchen (1996), and Patchen and Harper (1996), but those porosities and permeabilities were for producing gas fields. The numbers would naturally be lower for areas of non-production (i.e. areas where the sandstone is tight). In order to increase the injectivity in the well, the formation was hydraulically fractured using 14,000 gallons of fluid loaded with 8,500 pounds of sand at 24 barrels per minute and an injection pressure of 3,600 psi. Following fracturing, the injectivity of the formation increased to 55 gallons per minute at 1,700 psi. Initial estimates put the amount of liquid disposible in that one well at 2,555,000 gallons over the course of 50 years. These data indicate that, even in areas of low porosity and permeability, the Oriskany can be used for sequestration of fluids as long as hydraulic fracturing or acidizing is applied prior to injection.

Because areas suitable for CO_2 sequestration are resticted to depths greater than 2,500 feet, the sequestration potential of the Oriskany in northeastern Ohio and northwestern Pennsylvania is limited by shallow depth. In general, the Oriskany lies at sequesterable depths starting about 15 or 20 miles southeast of the lake shore (Piotrowski and Krejewski, 1979) (Figure A11-2). East of the Allegheny front, the intense structural deformation of the Valley and Ridge Province results in numerous fault-bounded anticlines where the Oriskany crops out. Yet within the synclines and synclinoria, multi-tiered duplexes of Oriskany can lie at depths exceeding 8,000 feet, making these areas suitable for sequestration.

In terms of stratigraphic trapping, Harper (1990) found that updip porosity and permeability loss adjacent to the "Oriskany no-sand area" in north-central Pennsylvania occurs within one mile of the sandstone pinchout, but that favorable high porosity and permeability zones extend much farther into the basin. Opritza (1996) indicated that the zones of best porosity and permeability (best potential for

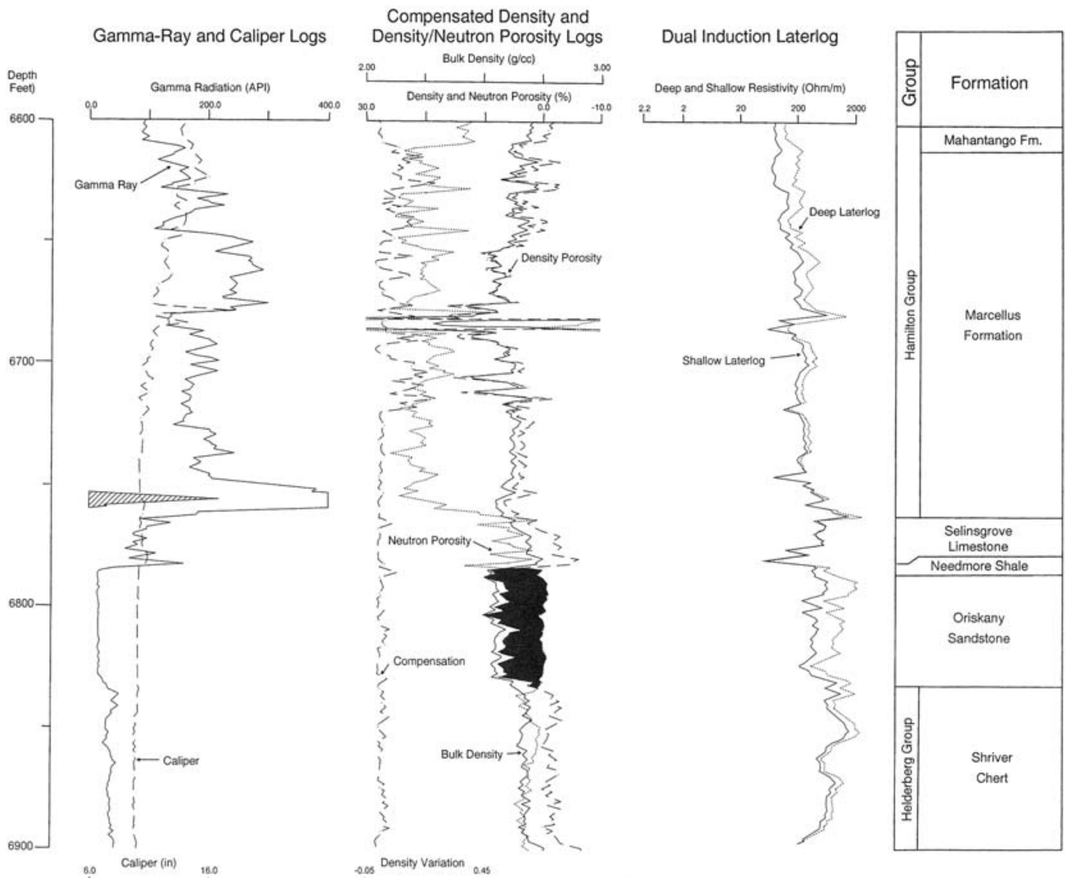

Figure A11-5.—Geophysical log suite of the Oriskany Sandstone and associated rocks from a typical well in Leidy gas field, north-central Pennsylvania (from Harper, 1990).

producing hydrocarbons) within the Oriskany lie generally within 50 miles of the actual pinchout (Figures A11-2 and A11-3).

The Oriskany structure map (Figure A11-2) shows the general locations of the faulted anticlines and other structural complexities known to occur within the region. In general, there are two major types of structures.

In the first type, found on the Appalachian plateau, the structures resulted from thrust faults generated by the flow of incompetent rocks within the Upper Silurian Salina Group and its correlatives. At the stratigraphic level of the Oriskany Sandstone, these structures typically consist of imbricate sheets thrust over seemingly depressed cores at or near the structural axes (Figure A11-6). The anticlines commonly exhibit asymmetry resulting from one limb being steeper than the other. In most of the plateau structures, the southeastern limbs are shorter and steeper; however, the northwestern limbs are steeper and commonly overturned in structures nearer the Allegheny front (Gwinn, 1964). Flexure (subsidiary anticlines and homoclines) may be present on the thrust sheets as a result of drag. In some portions of the anticlines, the southeastern splay faults may be absent, but these are atypical of the structures as a whole. Domes that are mappable at the surface typically indicate intensification of subsurface thrusting, whereas saddles represent the boundaries between adjacent thrust sheets, possibly offset along tear faults within the zone of deformation.

The second type of structure is typical of the Valley and Ridge province (the "eastern overthrust belt" of earlier studies), but has also been encountered on the Appalachian plateau close to the Allegheny Front. In the subsurface, this type of structure consists of a series of imbricate thrust sheets branching from a decollement surface typically based in the incompetent shales of the Upper Ordovician Martinsburg Formation or its equivalent (Gwinn, 1964; Jacobeen and Kanes, 1974a,b; Mitra, 1986, 1988) (Figure A11-7). In contrast, at the surface the structures consist of numerous doubly-plunging, possibly *en echelon*, folds commonly less than 10 miles long. The few producing gas fields found on these structures are situated on thrust-faulted anticlines that generally parallel the regional structural grain (striking approximately 35 degrees northeast). At the depth of the Oriskany Sandstone (about 4,500 feet in Bedford County, Pennsylvania; deepening to about 6,500 feet in Hardy County, West Virginia), the splay faults are considerably steeper than they are at the surface, about 60 degrees or more (Wagner, *in* Lytle and others, 1966). Wells commonly intersect at least one thrust fault, and sometimes as many as six. Strata dip at moderate to steep angles, and early drilling in this play was difficult due to updip drift of the drill holes. According to Wagner (Lytle and others, 1966, p. 46), gas well drillers followed the lead of water well drillers who purposely moved their well locations an average of 500 to 700 feet downdip of the anticipated location at total depth in order to compensate for this drift of the bore hole.

Seals within Oriskany target areas generally consist of reduced porosity and permeability within the overlying and underlying rock sequences, and within the rock sequences adjacent to the reservoir across faults and fractures. Throughout most of the extent of the Oriskany Sandstone, the lower trapping mechanism results from

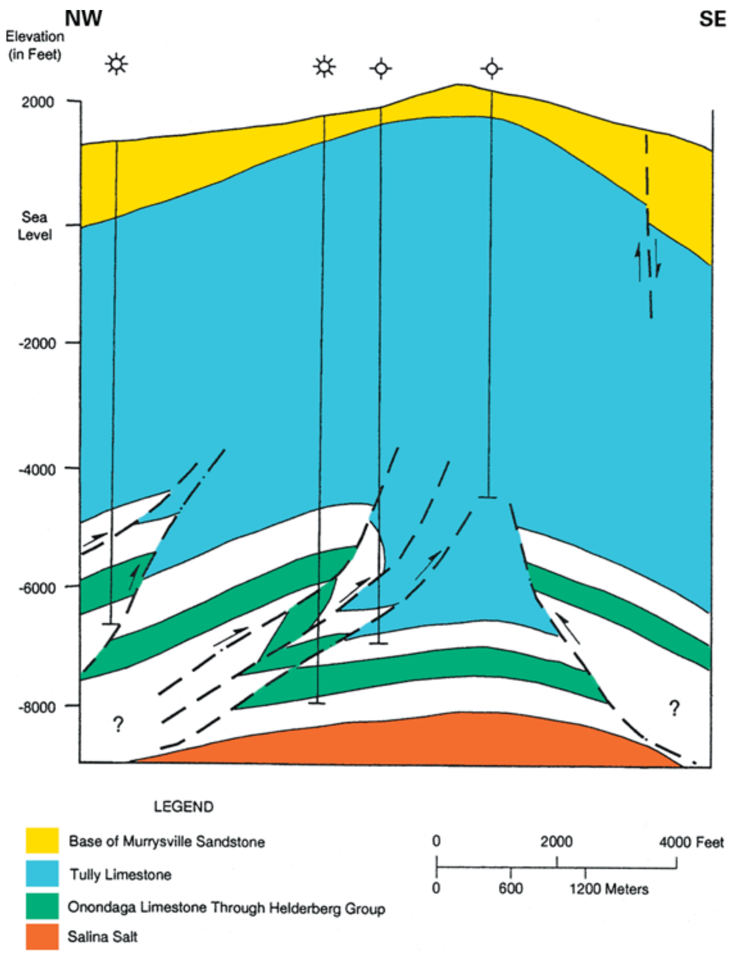

Figure A11-6.—Northwest-southeast cross section of Giffin dome on Chestnut Ridge anticline in Westmoreland County, Pennsylvania (modified from Gwinn, 1964). Imbricate sheets were thrust over the depressed core as result of detachment in the Upper Silurian Salina salt beds.

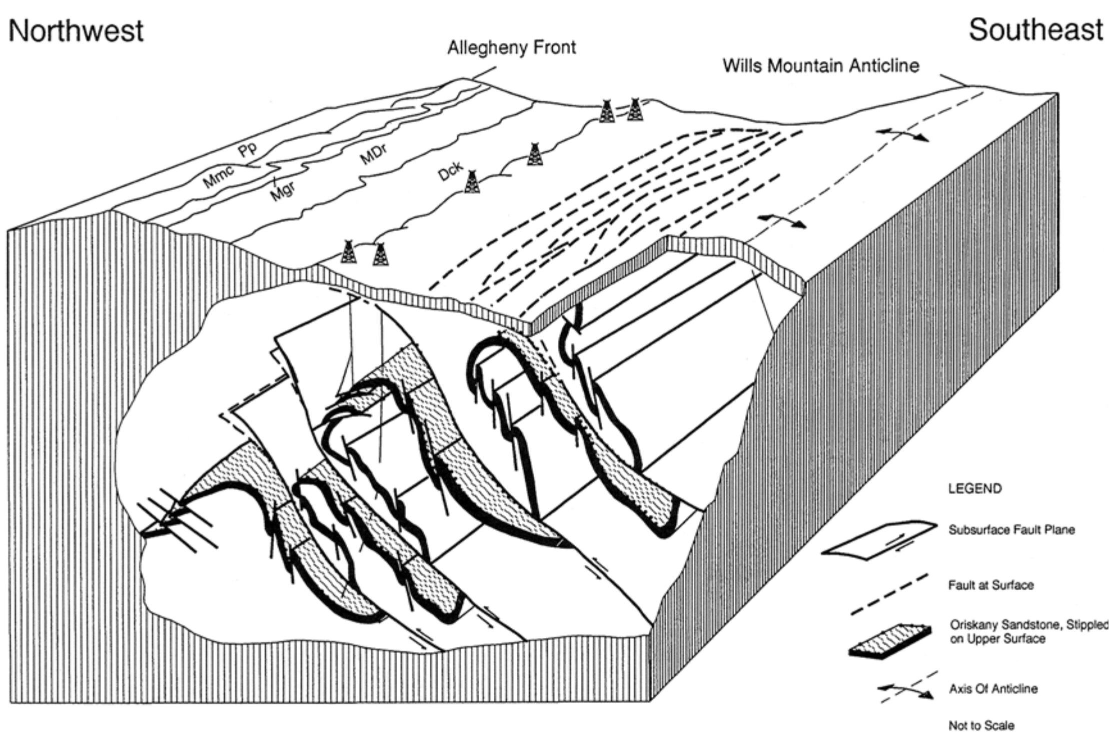

Figure A11-7.—Block diagram showing interpreted three-dimensional structure of the Oriskany Sandstone in the Valley and Ridge of northeastern West Virginia (from Harper and Patchen, 1996). The cutaway section aids in visually identifying separate thrust sheets and large-scale recumbent folds.

low permeability carbonate rocks of the Helderberg Group, Keyser Formation, Bass Islands Dolomite, or even the upper carbonates of the Salina Group (Figure 5 and A11-1).

The upper trapping mechanism varies. In eastern Ohio, northern Pennsylvania, and New York, the overlying rocks consist of low-permeability carbonates of the Onondaga or Bois Blanc Formations. In the central plateau area of Pennsylvania and West Virginia, it consists of the Huntersville Chert. The Needmore Shale forms the cap in central Pennsylvania, Maryland, eastern West Virginia, and western Virgina (Figure A11-8). The Bois Blanc Formation commonly contains a basal sandstone, the Springvale Sandstone, that substitutes for Oriskany where the actual Oriskany Sandstone is absent, and often is called "Oriskany" by drillers. In those areas, the Springvale can be as porous and permeable as the Oriskany itself. The upper seal in these cases consists of the low-permeability carbonates above the Springvale. The Huntersville Chert grades eastward from a cherty limestone to a hard, massive, microcrystalline chert (Flaherty, 1996). The Needmore Shale consists of dark gray to black calcareous siltstone and shale, noncalcareous shale, and argillaceous limestone.

Lateral trapping mechanisms consist of sealed faults and fractures, juxtaposed with impermeable rocks (described above) across fault planes, and permeability barriers within the sandstone as a result of non-dissolution of cement or secondary precipitation of authigenic quartz and other minerals.

The largest single storage problem for sequestration of CO_2 in the Oriskany is the possibility of seal failure that would allow fluids to escape from the sequestration reservoir. In fact, Johnson and others (2004) consider cap rock integrity problems as the single most important constraint on long-term sequestration in all target storage sites. The integrity of Oriskany reservoir cap rocks and fracture seals needs to be evaluated thoroughly for mechanical and, possibly, chemical alteration potential before any pilot injection begins.

Mechanical seal problems would probably be more likely to occur in areas where the structural complexity places a porous or highly fractured rock in juxtaposition (vertical or lateral) with open fractures or high porosity zones in the sandstone. For example, the overlying Huntersville Chert is highly brittle and contains many open fractures along anticlines where it has been bent and flexed. It is these fractures that make the Huntersville a seductive target for gas well drilling in the basin (Flaherty, 1996). But these fractures often extend into the Oriskany, making the Huntersville and Oriskany a single reservoir in many areas of Pennsylvania and West Virginia. In such areas, utilization of the Oriskany for CO_2-storage almost guarantees the fluids will also be injected into the Huntersville. In such cases, the Huntersville must also be evaluated for seal integrity. In addition, one or more seals could be ruptured under high injection pressures (Friedmann and Nummedal, 2003; Johnson and others, 2004).

Despite the potential setbacks one can envision within this structurally complex setting, Oriskany gas storage fields have the capability to store/deliver more natural gas than storage fields in

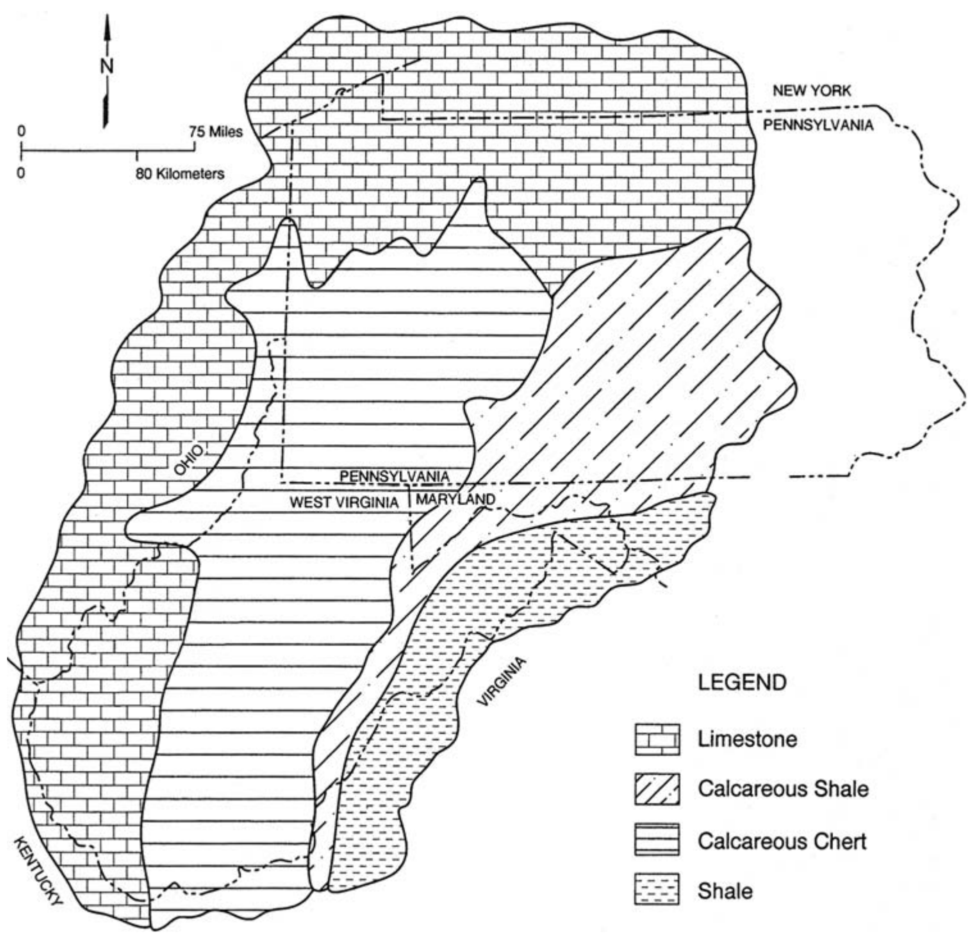

Figure A11-8.—Map showing the variations in lithology of the rocks overlying the Oriskany Sandstone (modified from Oliver and others, 1971).

Table A11-1.—Summary of data for Oriskany Sandstone gas storage fields in the Appalachian basin. Modified from American Gas Association (2001)

Storage Field/ Reservoir Name	*County*	*Max. Depth*	*Min. Depth (ft)*	*Avgerage Thickness*	*# Wells*	*Total Gas (Base + Working) (MMcf)*	*Maximum Pressure (psi)*	*Year Discovered*	*Year Activated*	*State/Province*
Accident	Garrett	7900	7300	100	75	61978	3050	1953	1966	Maryland
Columbiana	Columbiana	3558	nr	6	16	3111	1450	1944	1950	Ohio
Guernsey	Guernsey, Coshocton	3580	3114	8	48	7100	1150	1942	1954	Ohio
Artemas “A”	Bedford	6095	5643	50	16	14457	2100	1962	1972	Pennsylvania
Artemas “B”	Bedford, Allegany	4931	4774	50	4	2147	1900	1963	1972	Pennsylvania
Ellisburg	Potter	5382	4889	27	84	98430	2200	1933	1963	Pennsylvania
Greenlick	Potter, Clinton	6860	6443	39	46	53220	4240	1955	1961	Pennsylvania
Harrison	Potter, Steuben	5243	4702	24	44	34100	2140	1934	1953	Pennsylvania
Hebron	Potter	5403	4842	18	48	29280	2200	1931	1953	Pennsylvania
Leidy	Clinton, Potter	6609	5605	22	64	102003	4200	1950	1959	Pennsylvania
Meeker	Tioga	4307	4135	5	3	5200	1680	1931	1943	Pennsylvania
Palmer	Tioga	4320	3987	5	13	16000	1680	1930	1938	Pennsylvania
Sabinsville	Tioga	4951	4171	23	41	35618	2130	1935	1951	Pennsylvania
Sharon	Potter	4979	4642	17	12	4500	860	1938	1948	Pennsylvania
Summit	Erie	2450	2279	20	45	4200	800	1946	1959	Pennsylvania
Tamarack	Clinton	7159	6740	40	11	11220	4200	1952	1971	Pennsylvania
Tioga	Tioga	4128	3679	24	31	36000	1680	1930	1951	Pennsylvania
Wharton	Potter, Cameron	6552	5371	19	71	31668	3600	1933	1963	Pennsylvania
Augusta	Hampshire	5749	4806	147	6	6961	2797	1953	1971	West Virginia
Coco “A”	Kanawha	6761	4955	20	74	44500	1800	1944	1950	West Virginia
Coco “B”	Kanawha	5446	5041	20	20	9700	1800	1944	1951	West Virginia
Coco “C”	Kanawha	5556	5094	20	27	17270	1800	1944	1957	West Virginia
Hunt	Kanawha	5386	5027	20	19	5839	1200	1947	1951	West Virginia
Little Capon	Hampshire	5761	5243	150	6	7451	2804	1965	1971	West Virginia
Ripley	Jackson	5184	4777	20	49	25050	1675	1945	1954	West Virginia
Rockport	Wirt; Wood	5401	4855	20	25	8160	1800	1948	1953	West Virginia
Blackhawk	Beaver	4673	4660	10	7	2655	2000	1936	1969	Pennsylvania
North Summit	Fayette	7145	6394	168	22	21851	3000	1937	1991	Pennsylvania
Glady	Randolph, Pocahontas	6930	4914	150	49	31200	2050	1954	1964	West Virginia
Terra Alta	Preston	6227	4676	150	32	41663	2350	1946	1960	West Virginia
Terra Alta South	Preston	6582	4954	150	30	16600	2350	1953	1970	West Virginia
Rager Mtn.	Cambria	8045	7680	42	7	20493	3200	1965	1971	Pennsylvania
						TOTAL = 809625				

any other formations within the northern Appalachian basin (AGA, 2001). At least 32 gas storage fields are found within the Oriskany, with a combined storage capacity of nearly 1 TCF, and located in pinchout, stratigraphic, and structural traps (Table A11-1). Many of these storage fields have been in operation since the 1950s, attesting to the integrity of the fields and seals.

In all likelihood the Oriskany Sandstone would make a suitable target for storage of CO_2-miscible fluids, but only after thorough evaluation of the formation at potential target sites. Such target sites include: 1) zones of high porosity and high permeability associated with updip sandstone pinchout, typical of eastern Ohio, and along the southern and eastern boundaries of the "Oriskany no-sand area" in northwestern Pennsylvania; 2) areas of highly fractured Oriskany Sandstone associated with salt solution and migration within the central depositional area of western Pennsylvania and central West Virginia; and 3) areas of intensely faulted and multi-tiered (duplexed) Oriskany Sandstone in the Valley and Ridge of central Pennsylvania, western Maryland, and eastern West Virginia.

12. LOWER DEVONIAN SYLVANIA SANDSTONE

The Sylvania Sandstone, late Early Devonian in age, is a quartzose sandstone that grades laterally into sandy limestone and dolostone in parts of the Michigan basin. The Sylvania is the basal formation of the Detroit River Group and, along with the Bois Blanc and Garden Island Formations, overlie the Kaskaskia unconformity (Figure 5). Gardner (1974) suggests the lower part of the Sylvania may be in facies relationship with the underlying Bois Blanc, especially in northern and western regions of the Michigan basin. However, the relationship of this lower contact is poorly documented, and the recent revision of the Michigan stratigraphic column by the Michigan Geological Survey shows an unconformity between the Sylvania and Bois Blanc Formations. The upper part of the Sylvania intertongues with carbonates of the overlying Amherstburg Formation, another unit in the Detroit River Group. Although arenaceous units are present at various stratigraphic positions above the Kaskaskia unconformity in Michigan, as well as in the Appalachian basin portion of the MRCSP study area—for example the Oriskany Sandstone in Ohio, Pennsylvania, and West Virginia—use of the name Sylvania Sandstone should be restricted to the sandstone that occurs at the base of the Detroit River Group in the Michigan basin (Fisher and others, 1988). In general, details on the vertical and lateral stratigraphic relationships of the Sylvania, its internal lithologic variations, and those attributes making it suitable as a geologic reservoir for CO_2 sequestration, are uncertain for most of the Michigan basin.

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES

Orton (1888) applied the name Sylvania Sandstone to exposures, incorrectly identified as Oriskany by Newberry (1871), in Sylvania Township, Lucas County, Ohio. Other significant investigations on the Sylvania include Grabau and Sherzer (1910), Alty (1933), Carman (1936), and Hatfield and others (1968). Also, Gardner (1974), as part of a detailed subsurface study, presented regional isopach and lithofacies maps of the Sylvania Sandstone in Michigan.

NATURE OF LOWER AND UPPER CONTACTS

The Sylvania Sandstone overlies the Kaskaskia unconformity in southeastern Michigan above the truncated Silurian-age Bass Islands Group. The Sylvania is thin, discontinuous, or completely absent in some areas, especially on the southern and western margins of the Michigan basin. Typically the Bois Blanc underlies the Sylvania although the exact stratigraphic relationship between these two units is unclear. The lateral extent and isopach pattern of the Sylvania Sandstone (Figure A12-1) and Bois Blanc Formation suggests a northwest- to southeast-trending shallow marine basin existed in the area at the time of deposition of the Sylvania (Gardner, 1974). This basin may be related to the trend of the Mid-Michigan rift (Figure 6). The Sylvania Sandstone is the basal unit of the Detroit River Group; its upper contact with the overlying Amherstburg Formation is gradational and intertonguing.

LITHOLOGY

Regional lithologic variations within the Sylvania Sandstone are known mainly from the analysis of geophysical logs (Gardner, 1974). These analyses suggest the Sylvania Sandstone typically consists of dolomitic to cherty, fine- to medium-grained, well-sorted and rounded, quartzose sandstone in central and southeastern lower Michigan but grades into cherty, sandy carbonate in other regions of the Michigan basin. Carbonate interbeds, sometimes containing chert, are common throughout the unit. The Sylvania, in general, is very porous in outcrops and in materials recovered from shallow subsurface cores and exploratory drill holes, particularly in southeastern lower Michigan. Locally, quartz overgrowths and carbonate cement are present in the unit. Most quartz sand grains of the Sylvania are frosted and pitted. Marine fossils, mainly brachiopods, are common in many of the calcareous interbeds. Cross beds and other current-induced sedimentary structures are common in outcrops but rarely observed in cores.

DISCUSSION OF DEPTH AND THICKNESS RANGES

The Sylvania Sandstone ranges from just a few feet thick in northeastern and southwestern areas of the Michigan basin to a maximum thickness of about 350 feet; the area of maximum thickness occurs mostly along a northwest- to southeast-trending belt across the central portion of the basin (Figure A12-1). These thickness estimates are based on geophysical log picks but are problematic due to the complex lithologic variations above, below, and within the geologic interval containing the Sylvania. As previously noted, the northwest- to southeast-oriented isopach pattern is similar to the underlying Bois Blanc Formation, suggesting a similar depositional and structural setting for both units. Moreover, the area of maximum thickness of the Sylvania closely mimics the eastern margin of the Mid-Michigan rift, a feature interpreted as a pre-Paleozoic age failed continental rift. Structural movement resulting from reactivation of parts of the rift may have influenced depositional trends within the Sylvania. These structures may have created basin topography/bathymetry that existed during the transgressive phase of Lower and Middle Devonian sediments that were deposited on top of the Kaskaskia unconformity. The Sylvania Sandstone ranges in depth from in excess of 400 feet above sea level in the southeastern corner of the state to over 4,400 feet below sea level in the central portion of the basin (Figure A12-2).

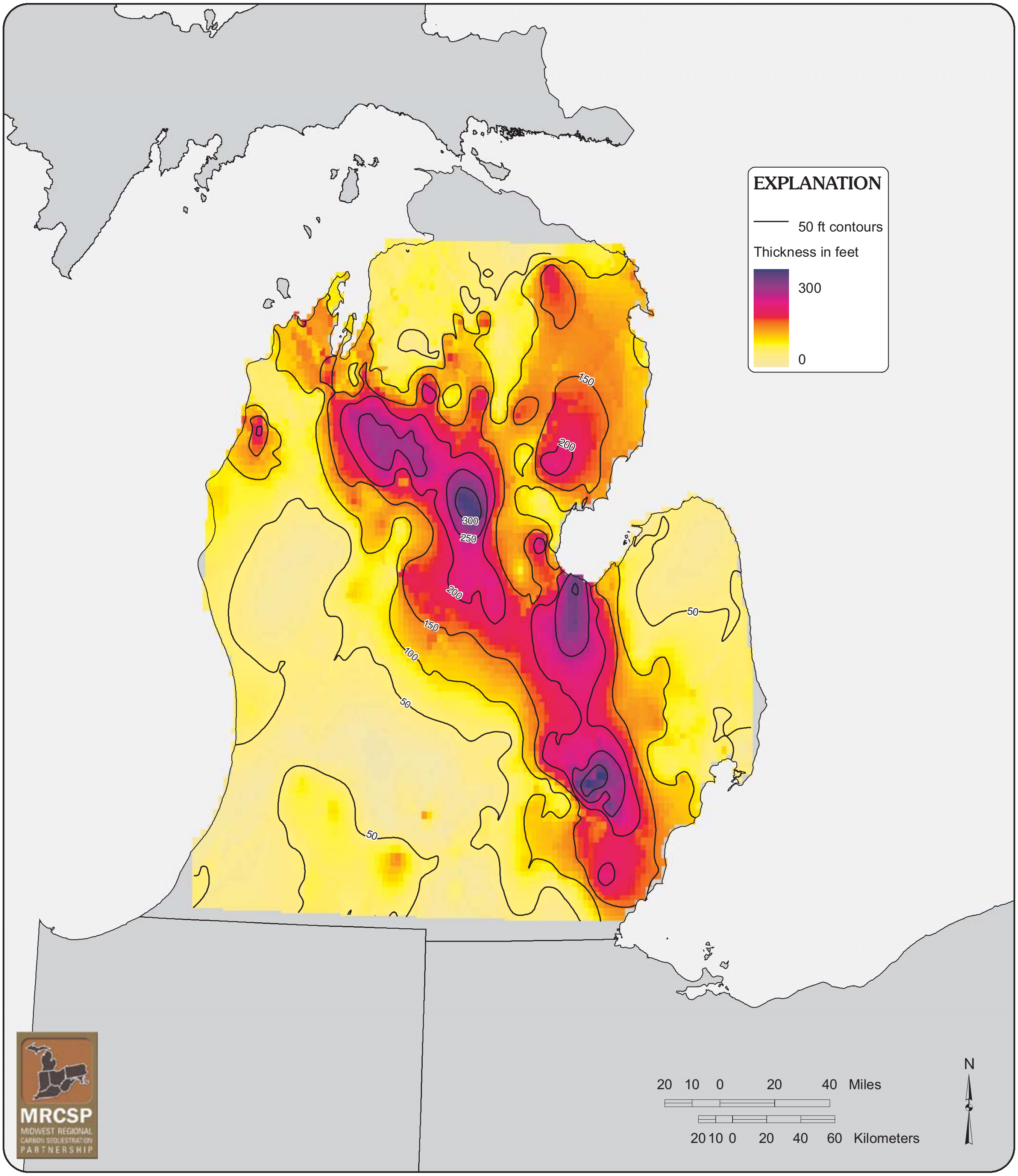

Figure A12-1.—Map showing the thickness of the Sylvania Sandstone.

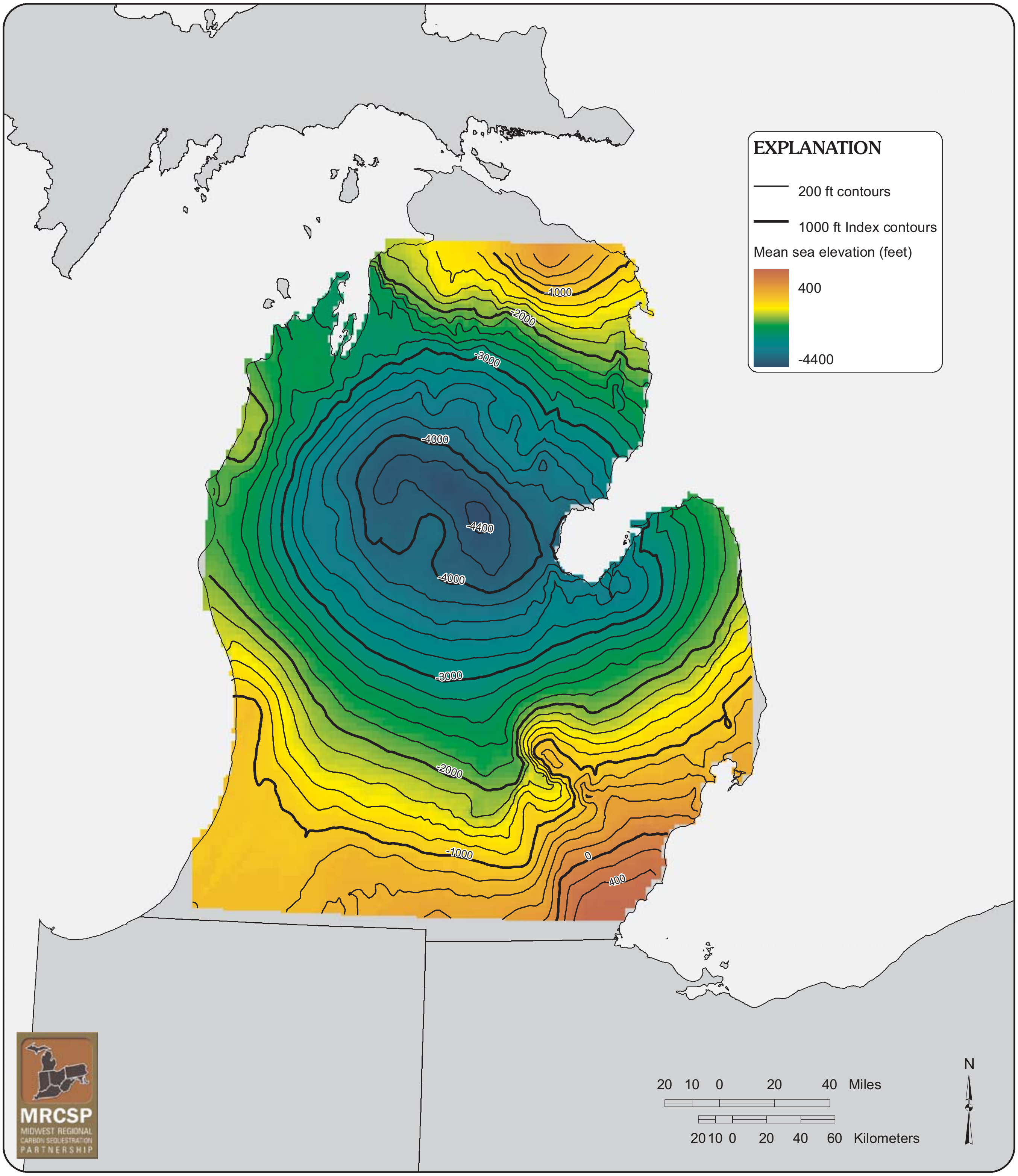

Figure A12-2.—Structure contour map drawn on the top of the Sylvania Sandstone.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

The Sylvania Sandstone represents the initial transgressive phase of an extensive Devonian-age carbonate sequence—the Detroit River Group—that was deposited over the regionally extensive Kaskaskia unconformity. The rounded and frosted quartz grains, common in many parts of the Sylvania, are characteristic of sand deposited in eolian environments or at least sand reworked from older eolian rocks. However, the presence of marine fossils and interbeds of sandstone within adjacent carbonates suggest a predominantly, if not entirely, shallow marine environment. Hatfield and others (1968) concluded the Sylvania was most likely a beach deposit that formed during a eustatic transgression.

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

The sandstone-dominated facies of the Sylvania Sandstone, best developed in central and southeastern lower Michigan, have been used for Class 2 waste-disposal wells and is also a major source for brine in industrial-mineral wells for the chemical industry in Midland County (Fisher and others, 1988). Porosity and horizontal permeability measurements from 24 sidewall-core samples from the Sylvania, collected in a well in southeastern lower Michigan, ranged from 1 to 28 percent porosity with an average of 16.6 percent. Permeability measurements ranged from 0 to 388 md with an average of nearly 100 md. These measurements are consistent with porosity and permeability characteristics presented herein. The primary doubts concerning the suitability of the Sylvania for CO_2 injection centers mostly on the unknown variability of the lithofacies and their distribution throughout the Michigan basin. Subsurface analysis of general lithofacies patterns indicates the sandstone-dominated facies in southeastern and central areas of the Michigan basin are replaced by mainly cherty carbonate facies in other regions. The chert-dominated lithofacies is likely to be porous, and also tripolitic, thereby significantly affecting the injectivity potential of the unit. Thus, a more detailed analysis of variations of the internal facies and rock properties of the Sylvania warrant additional investigation in order to further understand the CO_2 sequestration potential of the unit. In the central portion of the Michigan basin, the geologically older and potential sequestration reservoirs of the Mt. Simon and St. Peter Sandstones are very deep (thus expensive to drill). This great depth may not be advantageous for the occurrence of zones of high porosity and permeability for injection of CO_2 within these older units. In contrast, the Sylvania in much of this same central basin area is fairly thick and occurs at a moderate depth that may be more favorable for development of porosity and permeability ample for CO_2 sequestration.

The Amherstburg Formation, a complex succession of evaporites and carbonates in the Detroit River Group, everywhere overlies the Sylvania Sandstone. Gardner (1974) suggests the continuity and integrity of Amherstburg Formation is variable; thus, its ability to function as a seal for the Sylvania in the Michigan basin is undetermined. However, overlying the Amherstburg are evaporates of the Lucas Formation, the Dundee Limestone, the Traverse Group (shale and limestone), and the Antrim Shale. This combined package should provide an adequate seal to insure integrity to Sylvania Sandstone injection reservoirs.

13. LOWER/MIDDLE DEVONIAN NEEDMORE SHALE

The Needmore Shale is present throughout western Maryland, south-central Pennsylvania, and eastern West Virginia; the upper part of the Needmore is laterally equivalent to the Onondaga Limestone in northern Pennsylvania and New York, and to the Huntersville Chert in western Pennsylvania and West Virginia (Figure 5). The Needmore Shale is underlain by the Early Devonian Oriskany Sandstone and overlain by the Middle Devonian Onondaga Limestone, Huntersville Chert, or Tioga Bentonite, depending upon the location within the Appalachian basin.

Conodont biostratigraphy indicates that the Needmore Shale is of Early and earliest Middle Devonian age. Conodonts from the overlying Tioga Ash Bed suggest that the top of the Needmore is within the *Polygnathus costatus costatus* Zone of Middle Devonian age. (Harris and others, 1994)

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

The Needmore Shale is named for exposures in southern Fulton County, Pennsylvania (Willard and Cleaves, 1939). The name was extended into Maryland, Virginia, and West Virginia by Woodward (1943). This unit was later assigned as a member of the Romney Shale (Lesure, 1957) and the Onondaga Formation, but currently is formational in status.

NATURE OF LOWER AND UPPER CONTACTS

The contact between the Needmore Shale and the underlying Oriskany Sandstone is sharp and unconformable, representing either a transgressive surface or a transgressive surface/unconformity converged (G.R. Baum, personal communication, 2005). The Needmore Shale grades laterally into the Huntersville Chert and, upsection, into dark gray, argillaceous limestones of the Onondaga Limestone. In the absence of the Huntersville Chert and the Onondaga Limestone facies, there is a 10- to 15-foot interval of coarse, brown shale mixed with considerable volcanic ash termed the Tioga Bentonite at the top of the Needmore Shale.

LITHOLOGY

The Needmore Shale is a dense, fissile, dark olive-gray to black, calcareous shale with dark gray interbeds of thin-bedded and nodular, fossiliferous, argillaceous limestone. Dark gray volcanic tuffs and ash beds occur at the top of the formation (Glaser, 2004).

Over most of western Maryland, the upper half of the unit is thickly laminated shale containing nodules and thin beds of limestone. Similar shale without limestone makes up the lower portion of the Needmore Shale, grading at the base to dark fissile non-calcareous shale. In outcrop, the coarser shale and mudrock disintegrate rapidly to pale-olive or tan chips or irregular clasts, whereas the black shale weathers to thin grayish-white plates and papery flakes much like the Marcellus Shale (Glaser, 2004).

DISCUSSION OF DEPTH AND THICKNESS RANGES

Based on well log picks and published reports for Maryland, the thickness of the Needmore Shale ranges from 3 to 190 feet (Edwards, 1970; Nutter and others, 1980). The unit thickens from northwest to the southeast (Figure A13-1). Depth to the top of the Needmore varies from a minimum of about 1,000 feet below

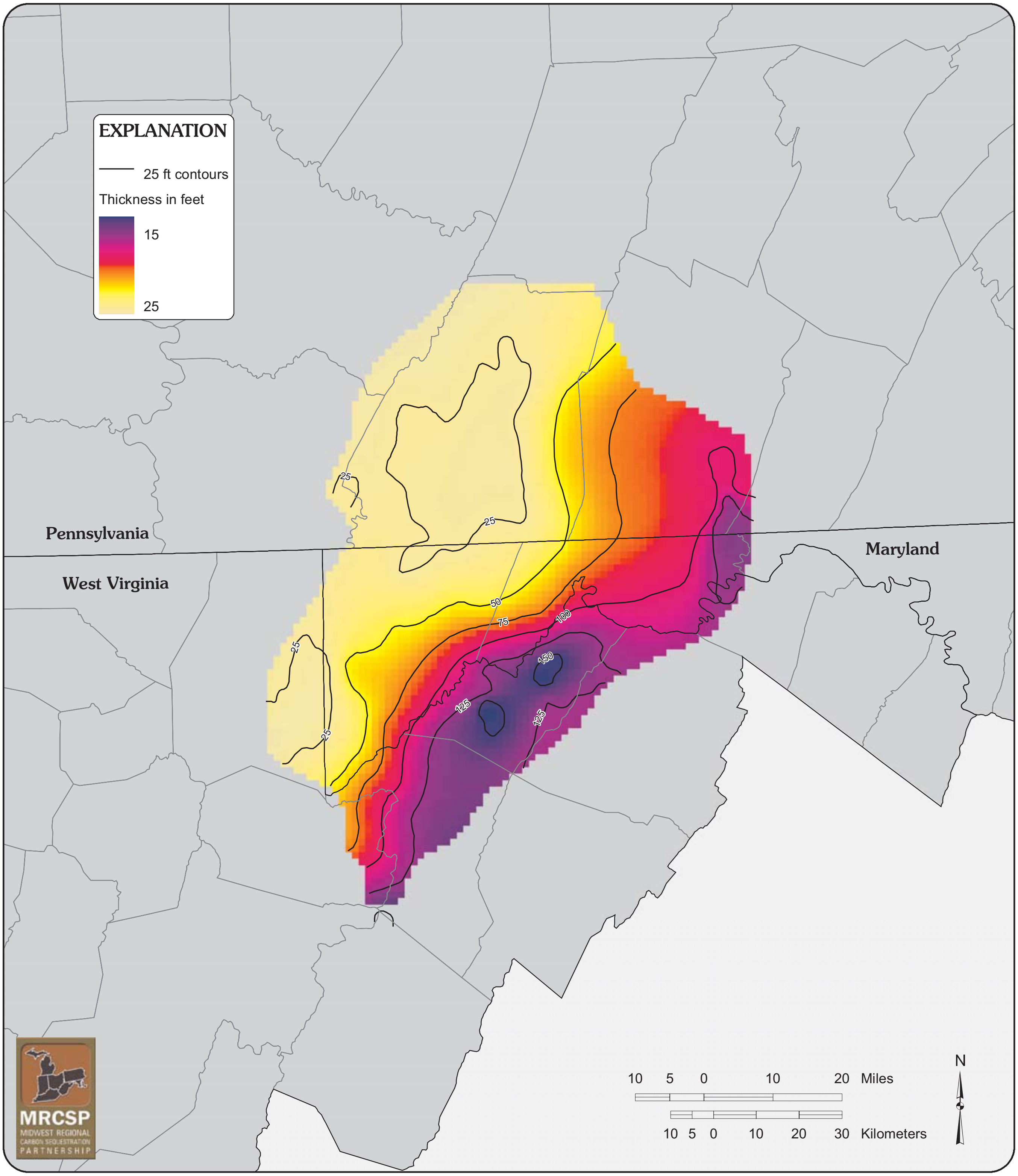

Figure A13-1.—Map showing the thickness of the Needmore shale.

sea level in the southeasternmost tip of Maryland panhandle to -7,500 feet in the central portion of the panhandle (Figure A13-2). The depth varies in a series of deep troughs and shallow highs in northeast-southwest trending bands following the folding of the Appalachian mountains.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

The Needmore Shale is a marine foreland basin shale formed at a near-equatorial latitude in the center of the Appalachian basin during the downwarping associated with the first tectonophase of the Acadian orogenic episode (VanTyne, 1996).

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

Within the state of Maryland, there are limited analytical data to address the suitability as a CO_2 sequestration target. In cooperation with the Pennsylvania and West Virginia Geological Surveys, this issue will be addressed in Phase II of the MRCSP.

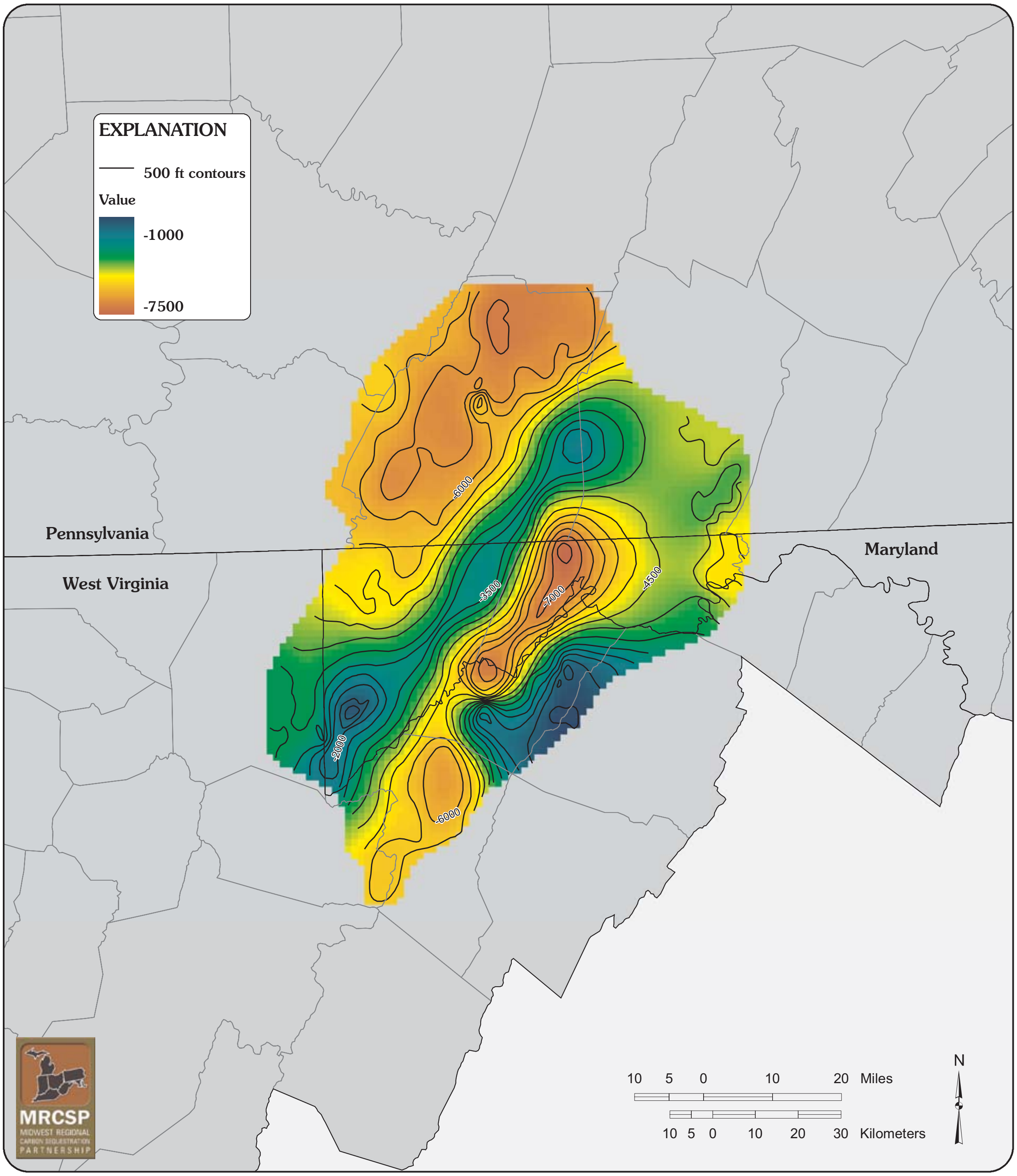

Figure A13-2.—Structure contour map drawn on the top of the Needmore shale.

14. DEVONIAN ORGANIC-RICH SHALES

A very complex sequence of mudstones of Middle and Late Devonian age occurs in both the Appalachian and Michigan basins. In the western two-thirds of the MRCSP study area, these shales are primarily known as the Ohio, Chagrin, or Antrim Shales. In the eastern third of the area—the Appalachian basin of Maryland, Pennsylvania, and West Virginia—the shales have an array of names such as Millboro, Marcellus, Harrell, Brallier, Genesee, Sonyea, and Rhinestreet, to name the most important (Figure 5).

The Ohio Shale members with the highest organic content and the most widespread occurrence in the Appalachian basin are the Cleveland and Huron Members shales (Figure A14-1). In general the lower-most portion of the overall Ohio Shale is black organic-rich shale, which grades upward and eastward into dominantly gray, silty shale in areas of thicker accumulation in the Appalachian basin. In other areas, broad regional structural arches controlled stratigraphy resulting in thinner, but overall dominant, black organic-rich shale. Correlative shales include the New Albany Shale of the Illinois basin and the Chattanooga Shale of the southern part of the Appalachian basin.

In the Michigan basin, there are three formal members and one informal member of the Antrim Shale, the Lachine, Paxton, and Norwood Members, and an unnamed upper member (Gutschick and Sandberg, 1991). The Paxton Member is a gray calcareous shale. All the other units are black shale with varying organic content.

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

Nomenclature of the shale interval varies widely within the MRCSP study area from north to south and west to east, based primarily on the recognition of black, carbonaceous units with generally high gamma-ray response. Stratigraphic studies of Devonian shales are often based on the occurrence of volcanic ash beds, siltstones, and *Foerstia* and *Tasmanites* (algal megaspores) zones. Figure A14-1 is a correlation chart of the major Devonian shale units in the Appalachian basin. Table A14-1 lists the major units, the original reference, and type section. The reader is also referred to de Witt, 1993 as a good overview of Devonian shale stratigraphy for the Appalachian basin. Extensively studies on Devonian shales have occurred by many workers since in the 1800s; thus, no attempt was made to trace the various stratigraphic revisions or changes in unit correlations for this interval in the MRCSP region.

Much of the research on the Devonian-age shales of the eastern United States was performed by the state geological surveys and directed by the U.S. Department of Energy as part of the Eastern Gas Shales Project from 1976 to 1981. Also, studies by the U.S. Geological Survey and investigations sponsored by the Gas Research Institute (now Gas Technology Institute) of Chicago, Illinois, have greatly contributed to the understanding of these Devonian organic-rich, gas-bearing rocks. A few of the more recent studies of significances include work by Decker and others (1992), Roen and Kepferle (1993), Boswell (1996), Milici (1996), and Ryder (1996).

NATURE OF LOWER AND UPPER CONTACTS

Within the Appalachian basin portion of the MRCSP study area, Devonian shales unconformably and conformably overlie carbonates or shales of Upper Silurian or Lower or Middle Devonian age.

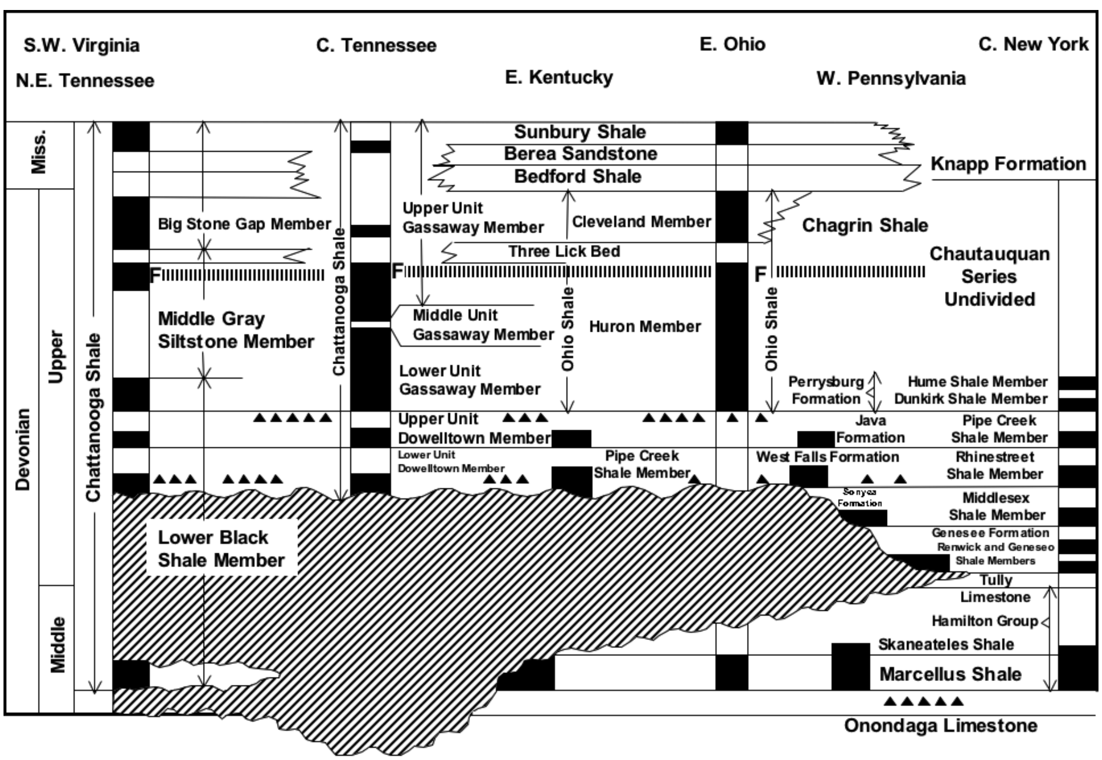

Figure A14-1.—General stratigraphic nomenclature for the Middle and Upper Devonian black shales in the Appalachian basin. Organic shales are shaded black. F = *Foerstia Zone*. Black triangles indicate major ash beds. Redrawn from de Witt and others (1993). See also Roen and Kepferle, 1993, Plate 2, cross section A-A'.

Table A14-1.—Nomenclature of primary shale units

Unit	*Reference*
Antrim Shale	A.C. Lane, 1901, Michigan Mineralogy, vol 3., no. 1, p. 9. Named for exposures in Antrim County, northwestern Lower Peninsula, Michigan.
Chagrin Shale	C.S. Prosser, 1903, Journal of Geology, vol. 11, p. 521 (replaced the Erie Shale, underlying the Cleveland Shale and overlying the Huron Shale. Named for the Chagrin River, Cuyahoga County, Ohio.
Chattanooga Shale	C.S. Hayes, 1891, Geological Society of America Bulletin, vol. 2, p. 143. Named for Chattanooga, Tennessee.
Cleveland Shale Member of the Ohio Shale	J.S. Newberry, 1870, Ohio Geological Survey Report of Progress, 1869, p. 19,21. Named for exposures near Cleveland, Ohio.
Huron Shale Member of the Ohio Shale	J.S. Newberry, 1870, Ohio Geological Survey Report of Progress, 1869, p. 18. Named for exposures on the Huron River, Huron and Erie Counties, northern Ohio.
Ohio Shale	E.B. Andrews, 1870, Ohio Geological Survey Report of Progress 1869, p. 62. Named for the Ohio River hills in north-central Kentucky and Ohio.
Dunkirk Shale Member of the Ohio Shale	J.M. Clarke, 1903, New York State Museum Handbook 19, p. 24. Named for exposures on Lake Erie at Dunkirk, Chautauqua County, New York.
Rhinestreet Shale Member of the West Falls Formation	J.M. Clarke, 1903, New York State Museum Handbook 19, p. 23. Named for exposures along Rhinestreet, north from Naples, Ontario County, New York.
Middlesex Shale Member of the Sonyea Formation	J.M. Clarke, 1903, New York State Museum Handbook 19, p. 23. Named for abundant exposures in the town of Middlesex, Yates County, New York.
Geneseo Shale Member of the Genesee Formation	G. H. Chadwick, 1920, Geological Society of America Bulletin, v. 31, p. 118. Named for exposures in Geneseo, Livingston County, New York.
Burket Shale Member of the Harrell Shale	C. Butts, 1918, American Journal of Science, 4th ser., v. 46, p. 523, 526. Named for black fissile shale exposed at Burket, Blair County, Pennsylvania.
Marcellus Formation	J. Hall, 1839, New York Geological Survey, 3rd Report, p. 295-296. Named for exposures at Marcellus, Onondaga County, New York.

The lower contact is typically sharp above carbonates to gradational above shales, and straightforward on geophysical logs. Minor to moderate topographic relief was developed on this surface in the western part of the basin prior to deposition of the shales. The uppermost Devonian Berea Sandstone and equivalent Bedford Shale generally conformably overlie the Upper Devonian shales in the western part of the Appalachian basin. In the eastern portion of the basin, the shales are overlain by thick sequences of Upper Devonian sandstones and interbedded shale (Figure 5).

In the Michigan basin, the Antrim Shale gradationally overlies carbonates of the Middle Devonian-age Traverse Group and is overlain by the Upper Devonian-age Bedford Shale, Berea Sandstone or the Ellsworth Shale. The upper contact is highly variable across the region and typically indistinguishable and arbitrary in the absence of well-developed black shale. A lateral facies relationship exists between the upper unnamed member of the Antrim and the Ellsworth Shale on the western margin of the Michigan basin.

LITHOLOGY

Many of the Devonian shales, such as the Ohio and Antrim, are black to gray, thinly laminated, fissile, shales and siltstones. The western and northwestern areas are dominantly black shale, which grade eastward into gray shale and siltstone, and coarse-grained clastics of the Catskill delta complex farther east. Hosterman and Whitlow (1983) report that the shales consist of clay (30 to 75 percent) and quartz (20 to 50 percent) with varying amounts of pyrite and calcite being the primary accessory minerals. Clay minerals are primarily mixed layer clays (illite-smectite and illite-chlorite), chlorite, and kaolinite. The shale color (and density) varies based on the organic matter content (bitumen), which ranges from less than one percent to 27 percent (Zielinski and McIver, 1982). Pyrite occurs throughout the unit, but tends to be better preserved in the more organic-rich intervals. Total organic carbon analyses from nine Ohio Shale cores range from less than one percent to greater than 15 percent for the Appalachian basin in Ohio (Knapp and Stith, 1982). The lower portion of the Ohio is well known for large-diameter, iron-rich concretions and for fossilized wood fragments along the outcrop in Ohio. Calcite often occurs as cementation at or near boundaries between the more and less organic units. Large carbonate concretions are also common in the Antrim throughout the Michigan basin.

Matrix porosity estimated from geophysical logs ranges from 1.5 percent to 11 percent with an average of 4.3 percent, which is typical for Appalachian basin wells (Boswell, 1996). Recently acquired sidewall cores from an Ohio Shale well in eastern Kentucky were analyzed using mercury injection and indicate an average matrix porosity of 0.9 percent. The highest porosity, 2.4 percent, occurred in the Lower Huron Member. Permeability from the sidewall cores averaged 0.5 microdarcys (μd). Total porosity (matrix and fracture) for the Antrim in Michigan has been reported as nine percent (Hill and Nelson, 2000).

DISCUSSION OF DEPTH AND THICKNESS RANGES

The maximum drilling depths for Devonian shales in the Appalachian basin occur in West Virginia, Maryland, and Pennsylvania close to the Allegheny Front. In south-central Pennsylvania, western Maryland, and northeastern West Virginia, the base of the shale sequence often exceeds 8,000 or 9,000 feet (Matthews, 1983). However, in eastern Kentucky, southern and southwestern Ohio, and western West Virginia where most Devonian shale drilling and production has taken place, depths are in the 2,000 to 3,000 feet range (Figure A14-2). In general, the Devonian shales increase in thickness eastward from the outcrop in Kentucky and Ohio and southeastward from Lake Erie to the Allegheny Front. Thicknesses range from zero feet in some areas of central Kentucky (southwestern-most extent of the MRCSP study area) to more than 8,000 feet in south-central Pennsylvania (Matthews, 1983) (Figure A14-3). In the Ohio and northern Kentucky region, the unit maintains a relative consistent eastward increase in thickness from about 200 feet at the outcrop to more than 3,000 feet.

In the Michigan basin, the Antrim crops out around the margin of the basin, but is often concealed by overlying glacial deposits. Drilling depths exceed 3,000 feet in Osceola County, central Michigan. The Antrim thickness exceeds 650 feet in central and northwestern lower Michigan (Matthews, 1993).

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

The depositional environments of the Devonian shales in the Appalachian and Michigan basins are considered transgressive basin-fill sequences related to active subsidence and tectonism. The Ohio Shale depositional sequence was summarized by Potter and others (1981), Hamilton-Smith (1993), and Boswell (1996), . The shales were deposited in a shallow to deep foreland basin setting west of the active Acadian orogenic belt. Rapid transgression following the Middle Devonian unconformity resulted in sediment covering the Cincinnati and Findlay arches. The Bellefontaine outlier in western Ohio is the only remaining evidence for deposition on these structural highs (Swinford and Slucher, 1995). Controls on the preservation and distribution of organic matter continue to be debated, but the organics most likely accumulated under dysoxic to anoxic marine conditions. During initial basin subsidence, black shales accumulated under low energy conditions in a euxinic basin across the region, far from the Acadian orogeny and associated Catskill delta deposits. As active tectonism diminished, the black shales were replaced with prograding, gray clastic-rich sediments of the Chagrin/Brallier facies, distal deposits associated with the Catskill deltaic sequence. Gray shales and siltstones of the Chagrin and Brallier thin westward and southwestward, and were deposited by far reaching turbidity currents from the Catskill delta. Sediment supply from the Chagrin and Brallier exceeded subsidence of the Appalachian basin, thus effectively eliminating the anoxic environments required for black shale deposition.

The Michigan basin formed in multiple stages throughout the Paleozoic Era, but originated in an extensional regime during Late Precambrian rifting. Faulting, fracture development, growth of anticlinal structures, and regional basin subsidence occurred periodically throughout the Paleozoic, especially during major orogenic events on the eastern margin of the continent (Howell and van der Pluijm, 1999). In late Devonian through early Mississippian time, the fault-bounded Precambrian rift basin was reactivated during the Alleghanian orogeny causing a period of thermal subsidence yielding a classic sag basin (Catacosinos and others, 1990).

Gamma-ray log response is key to stratigraphic analysis of the Devonian shales. Figure A14-4 illustrates the variation of gamma-ray tool response within the Devonian shale of the Big Sandy gas field, eastern Kentucky. Gray shales exhibit a gamma-ray response of 200 or more API units. In the more organic-rich black shales, the gamma-ray response exceeds 280 API units and may exceed 600 API units. Organic carbon content of the shale has been correlated to the uranium content (Potter and others, 1981). Schmoker (1993) demonstrated the relationship between log response and organic content.

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

The suitability of the Devonian shales for CO_2 injection and sequestration has not been demonstrated, but should be considered in areas where the geologic controls are well known and predictable. The following examples support this hypothesis. It is most commonly assumed that the very low permeability (in the microdarcy range) makes shales more generally appropriate as a sealing unit. However, in the San Juan basin, CO_2 injection has been successfully demonstrated in coals, another organic-rich, low permeability, continuous, fractured reservoir. The similar behavior of gas production from the Devonian shales as compared to CBM indicates they may also serve as sequestration targets. Natural fracturing plays an important role in development of the shales as both a gas producing reservoir and a possible sequestration target. Methane adsorbed on organic matter and clay mineral surfaces (Hamilton-Smith, 1993) desorbs as reservoir pressure declines, thus theoretically creating potential new adsorption sites. Matrix porosity and organic matter content ultimately control the total volume of gas trapped in the shale. Permeability controls the diffusion rate of desorbed methane through that matrix. It is in the fracture system that flow measured in darcies dominates, facilitating the production of natural gas. In general, production in more highly fractured areas exhibits a relatively rapid decline as free gas in the fracture system is depleted, followed by an often decades-long period of steady production controlled by the rate of methane desorption and diffusion through the fracture system. In areas with a less extensive fracture network, production often increases to reach a plateau of steady production analogous to CBM production history. Current research by Nuttall and others (2005) demonstrates a CO_2 adsorption capacity averaging 42.9 standard cubic feet per ton (scf/t) of shale (at expected reservoir pressures of 400 psi). Results from experiments to test the diffusion rate of CO_2 through the shale and any associated displacement of methane are currently being interpreted. Research to model shale gas production histories and investigate CO_2 injection is also needed.

Available reservoir pressure and temperature data indicates that CO_2 can be injected as a gas in these organic-rich reservoirs. It is expected that the fractured black shale intervals will trap CO_2 adsorbed onto the surfaces of organic matter and clay minerals. The gray shale intervals, relatively lacking in organic matter and less fractured, are more likely to serve as permeability barriers or reservoir seals. To evaluate the opportunity for an effective reservoir seal, those areas where the shale is either very thick or at drilling depths of at least 1,000 feet need to be assessed. In those areas, where the shale is often gas productive, overlying Mississippian and Pennsylvanian shales and other impermeable units are anticipated to provide secondary sealing capacity.

The Devonian shales are expected to be most suitable as a sequestration target where they are sufficiently deep, thick, organic-rich, and fractured; that is, in the best shale gas producing areas.

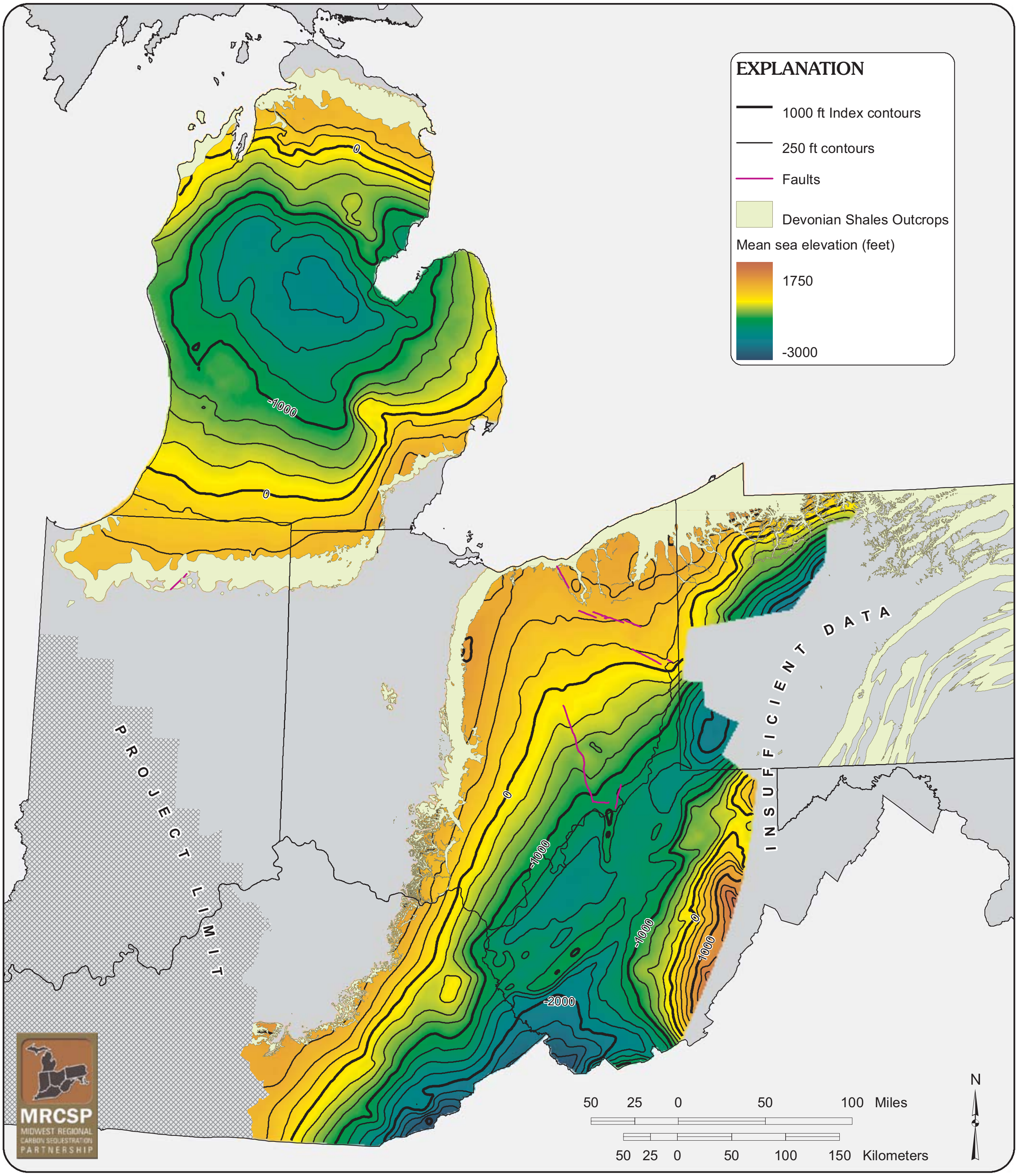

Figure A14-2.—Structure contour map drawn on the top of the Devonian shales.

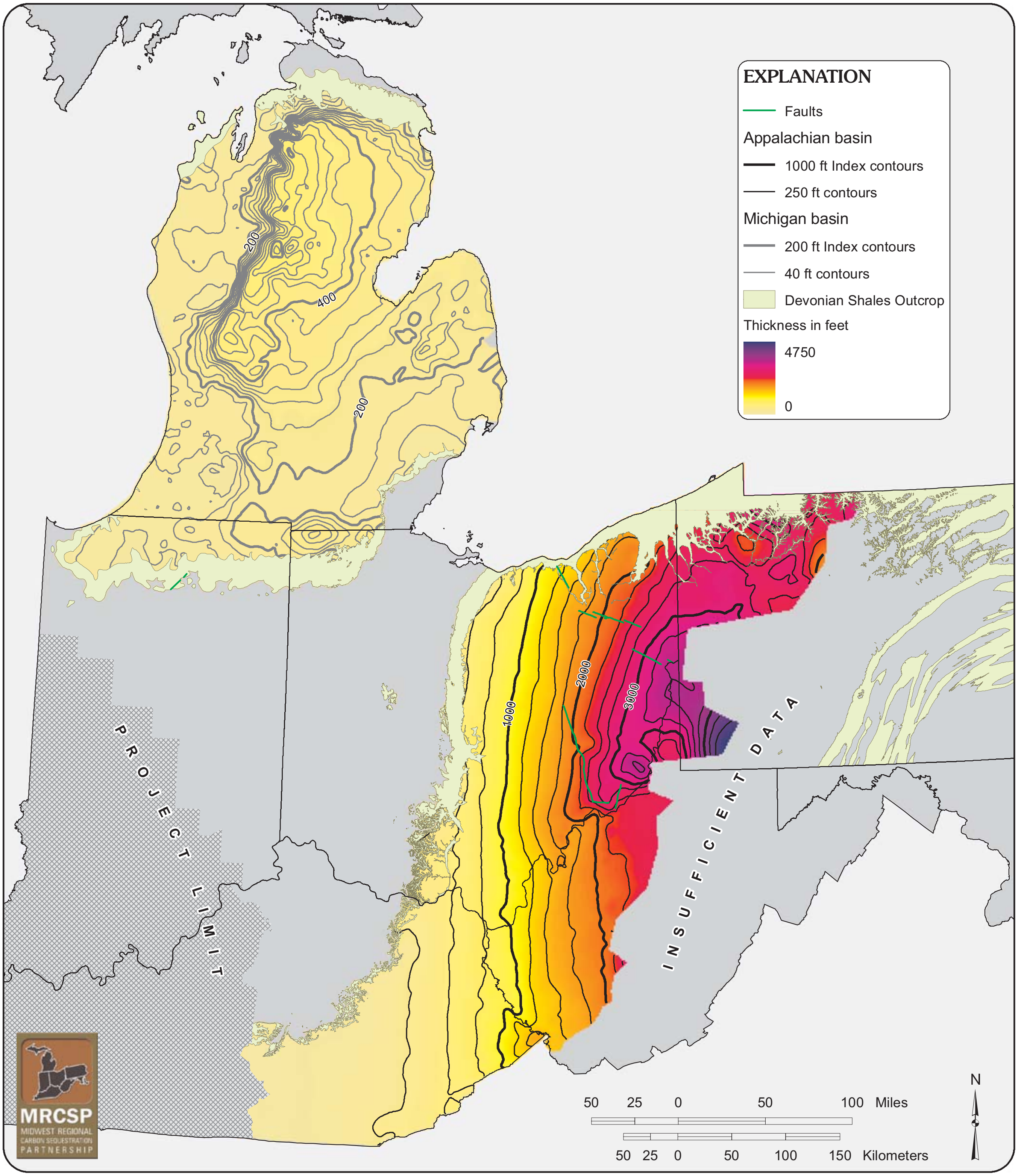

Figure A14-3.—Map showing the thickness of the Devonian shales.

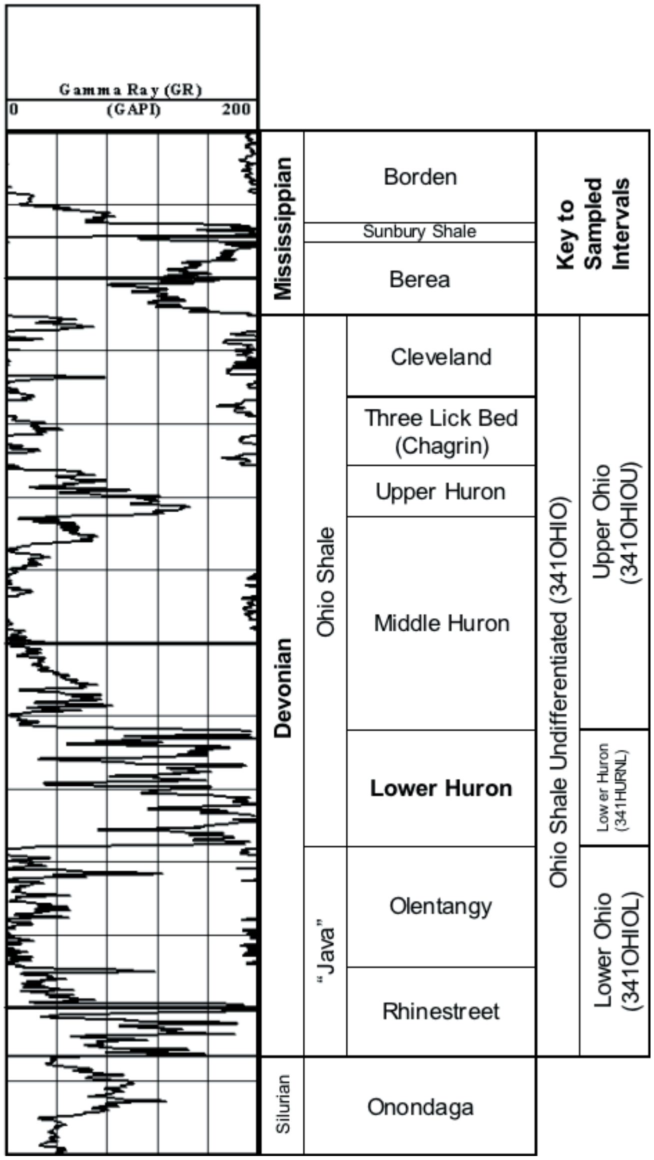

Figure A14-4.—Type log from the Big Sandy gas field in eastern Kentucky illustrating the alternating black (high gamma-ray, greater than 280 API units) and gray (low gamma-ray) shales.

In the Appalachian basin, the primary gas producing area extends from eastern Kentucky, across central West Virginia, into eastern Ohio and through northwestern Pennsylvania (Figure A14-5). In the Michigan basin, Antrim Shale production is most prolific in an eight-county area across northern lower Michigan (Figure A14-5).

The Devonian shale interval should also prove to be a most effective seal for sequestering CO_2 in stratigraphically lower reservoirs. Their great thickness and low permeability will inhibit movement upwards through the shale, especially in non-fractured areas. In addition, the ability of organic-rich shales to adsorb CO_2, as discussed above, may be a seal benefit by "soaking up" any CO_2 that may migrate from other reservoirs.

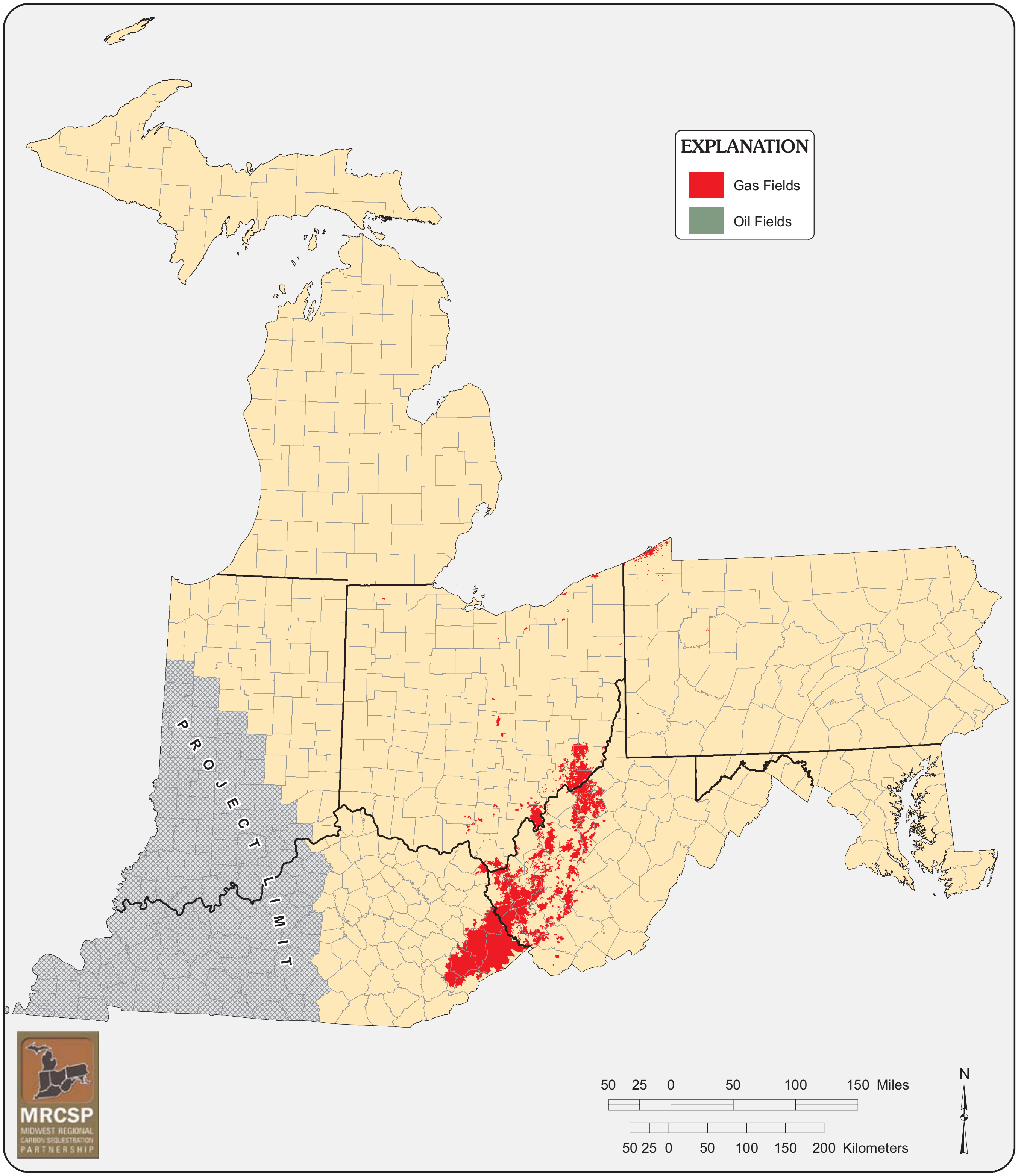

Figure A14-5.—Map showing gas fields in the Devonian shale interval.

15. PENNSYLVANIAN COAL BEDS IN THE APPALACHIAN BASIN

Coal beds of late Carboniferous-age occur in the Appalachian basin portion of the MRCSP study area. The Appalachian basin, one of the largest Pennsylvanian-age coal-producing regions in the world, currently contains the second, third, and fourth leading coal-producing states in the United States—West Virginia, Kentucky, and Pennsylvania, respectively (EIA, 2005). The greater northern Appalachian basin contains a series of smaller, anthracite-bearing synclinal basins in eastern Pennsylvania, but these areas are not included in this report.

STRATIGRAPHY

Coal beds considered potential targets for geologic CO_2 sequestration occur in the Pennsylvanian Subsystem of the Appalachian basin and range from early to late Pennsylvanian in age (Figure 5). Within the MRCSP study area, portions of two sub-basins or depocenters of Pennsylvanian-age occur, the northern Appalachian and central Appalachian basins (Figure A15-1). The boundary between these two sub-basins is approximately the southern limit of the outcrop belt of the Conemaugh Group (Figure 5; see also Figure A15-1) preserved in the Appalachian basin; this boundary also delineates the division between the northern and southern coal fields of West Virginia. Regional lithologic variations between the northern and central Appalachian basins result in a variety of stratigraphic terms applied within individual states of the partnership in order to divide and define this large stratigraphic interval.

Pennsylvanian-age rocks in Ohio, Pennsylvania, Maryland, and the northern coal fields of West Virginia are divided, in ascending stratigraphic order, into the Pottsville, Allegheny, Conemaugh, and Monongahela Groups (Figure 5). In the southern coal field of West Virginia, changes in lithologic attributes and preservation of thicker Lower and Middle Pennsylvanian strata result in the introduction of the terms Pocahontas, New River, and Kanawha Formations. The Kanawha and the upper part of the New River Formations are considered lateral equivalents to the Pottsville Group. The lower part of the New River and all of the Pocahontas are restricted to the southern coal fields of West Virginia; also, the Pocahontas Formation is older than, and does not correlate to, any known Pennsylvanian-age rocks in other MRCSP states in the Appalachian basin.

In Kentucky, the stratigraphic interval equivalent to the Pottsville and Allegheny Groups and the New River and Kanawha Formations is known as the Breathitt Group. Chesnut (1992) proposed a regional stratigraphic nomenclature for the central Appalachian basin that divides the Breathitt Group into eight coal-bearing and four quartzose-sandstone dominated formations; however, to date, this nomenclature has been formalized only in Kentucky.

The Pennsylvanian- and Permian-age Dunkard Group, a unit containing a few mostly thin coals of limited extent, overlies the Monongahela Group in portions of Pennsylvania, Ohio, and West Virginia. However, this unit lacks coal beds of adequate thickness and/or depths for CO_2 sequestration consideration.

ORIGIN OF NAMES, TYPE SECTIONS, SIGNIFICANT STUDIES

Rice and others (1994) summarize much of the stratigraphic nomenclature used for coal-bearing rocks in the study area. Type or reference sections are located where each unit was named.

Pottsville Group—Named for exposures at Pottsville Gap, Pennsylvania.

Allegheny Group—Named for exposures in the Allegheny River valley of Pennsylvania.

Conemaugh Group—Named for exposures along the Conemaugh River, Pennsylvania.

Monongahela Group—Named for exposures along the Monongahela River, Pennsylvania.

Breathitt Group—Named for exposures in Breathitt County, Kentucky.

Kanawha Formation—Named for exposures along the Kanawha River, West Virginia.

New River Formation—Named for exposures in New River Gorge, West Virginia.

Pocahontas Formation—Named for exposures at Pocahontas, Virginia.

Geologic investigations of Pennsylvanian-age rocks have occurred in the Appalachian basin since the 1830s. By the late 19th century, the economic significance of the coals in this interval stimulated a wide array of regional and local studies on the economics, stratigraphy, depositional history, and various other geologic disciplines that continues today. Hence, a multitude of investigations on specific attributes of Pennsylvanian-age rocks, as well as regional summaries within each MRCSP state, have been presented in federal and state geological survey publications. Moreover, numerous special papers, field trip guidebooks, trade journal articles, and miscellaneous reports by various geological societies, organizations, and academia have, over the past 50 years or so, been published on the region. A few notable examples of these types of publications include U.S. Geological Survey Professional Papers 853 (McKee and Crosby, 1975) and 1110-A-L (for example, see Collins, 1979), West Virginia Geological Survey Volume 22 (Cross and Schemel, 1956), Kentucky Geological Survey Series XI Bulletin 3 (Chesnut, 1992), a collection of papers by the Carolina Coal Group (Ferm and Horne, 1979), and numerous regional guidebooks prepared for the meetings of the 9th International Congress of Carboniferous Stratigraphy and Geology, the 28th International Geological Congress, and the 1961, 1981, and 1992 Geological Society of America national meetings. Additional references on the specific geologic framework within each MRCSP state can be obtained from the geological surveys of individual partnership states.

Thickness and chemical data on specific coal beds are available through the National Coal Resource Database system (NCRDS) of the U.S. Geological Survey or from each state geological survey. The U.S. Geological Survey also has published a series of regional coal maps and databases for several of the economically significant coal beds in the region (Appalachian Basin Resource Assessment Team, 2002). In addition, maps of most known, abandoned, underground coal-mines are available from either federal or state agencies for several of the partnership states.

NATURE OF LOWER AND UPPER CONTACTS

A significant geologic disconformity occurs in the Appalachian basin between the top of the Mississippian Subsystem and the base of the Pennsylvanian Subsystem in all but southern West Virginia; there, continuous deposition occurred and Mississippian rocks

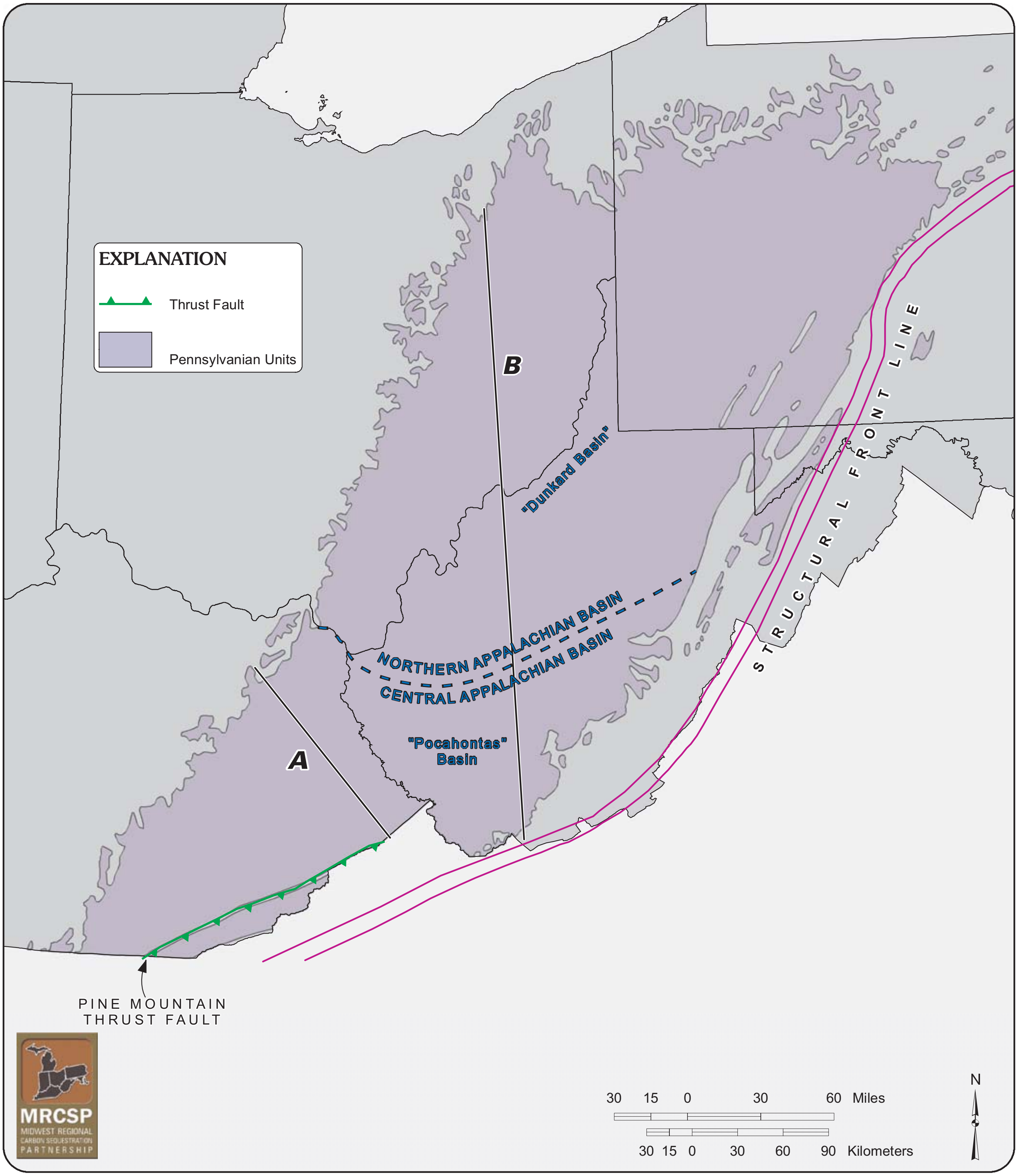

Figure A15-1.—Map showing extent of coal-bearing formations in MRCSP region of Appalachian basin and the division and location of the northern and central Appalachian sub-basins. Locations of cross sections shown in Figure A15-2 denoted by lines A and B.

grade upward into Pennsylvanian-age strata (Arkle and others, 1979; Collins, 1979; Edmunds and others, 1979; Rice and others, 1979; Chesnut, 1992; Greb and others, 2004). No coals of economic importance are found below this disconformity. The amount of erosion on the Mississippian surface prior to deposition of Pennsylvanian-age strata increases to the west and northwestward; also, the age of basal Pennsylvanian strata becomes progressively younger in this direction. In general, the difference in age between uppermost Mississippian and lowermost Pennsylvanian strata preserved in the Appalachian basin increases northwestward in the MRCSP study area. The top of the coal-bearing interval is the present-day land surface throughout the Appalachian basin.

LITHOLOGY

The distribution of coal beds is not uniform throughout Pennsylvanian-age rocks in the MRCSP study area. In the central Appalachian basin, a considerable number of thick and areally extensive coals occur in Lower and Middle Pennsylvanian rocks of the Pocahontas, New River, and Kanawha Formations and their updip equivalents in the Breathitt Group (Middle Pennsylvanian coals tend to be the most widespread). In the northern Appalachian basin, the most widespread coal beds occur in the Middle and Upper Pennsylvanian Allegheny and Monongahela Groups, respectively. One of these coals, the Pittsburgh, which occurs at the base of the Monongahela Group, is one of the most widespread coal beds in the world and is also the most frequently mined coal in the Appalachian basin.

Lower and Middle Pennsylvanian units consist mainly of sandstones, siltstones, and gray and black shales, and contain regionally significant economic beds of coal, and locally economic beds of clay and limestone. Upper Pennsylvanian rocks of the Conemaugh and Monongehela Groups consist mainly of sandstones, siltstones, shales, mudstones, and limestones. Compared to Middle Pennsylvanian strata, the Upper Pennsylvanian contains greater percentages of limestone and mudstones and an abundance of green- and red-colored rocks. Also, regionally significant economic coal beds occur only in the Monongahela Group.

In general, Pennsylvanian-age lithologies grade vertically and laterally into each other across short distances, although some coal beds, carbonates, and marine shales are useful marker horizons that can be correlated within each of the sub-basins (Chesnut, 1992). Increases in the overall thickness of the geologic section and splitting of coal beds into coal zones toward the basin axis, plus the lateral truncation of coal-bearing strata by thick, quartzose sandstones complicate Lower Pennsylvanian stratigraphy in the central Appalachian basin of Kentucky and southern West Virginia (Figure 5) (Arkle and others, 1979; Donaldson and others, 1985; Chesnut, 1992; Greb and others, 2002a, 2004). Noting the occurrence of these thick quartzose sandstones is a critical factor when determining the lowest depth that coal can be found, or the base of the Pennsylvanian section, from geophysical logs.

DEPTH, THICKNESS, AND STRUCTURE OF PENNSYLVANIAN ROCKS

Pennsylvanian strata exhibit two depocenters in the MRCSP study area: 1) the axis of the northern Appalachian (Dunkard) basin in southwestern Pennsylvania, Ohio, and northern West Virginia; and 2) the axis of the central Appalachian (Pocahontas) basin in southern West Virginia and southeastern Kentucky (and adjacent southwest Virginia outside of the MRCSP study area) (Arkle, 1974) (see also Figure A15-1). In the northern Appalachian basin, coal-bearing rocks may extend to depths that are around 1,800 feet below the present-day surface.. In the southern part of the central Appalachian basin, coal-bearing strata may reach depths of 3,000 feet beneath the surface; however, thick quartzose sandstones replace much of the coal-bearing strata in the lower third of the interval. Thus, only 1,600 feet of coal-bearing strata may be below drainage (the level of the lowest stream in an area).

Pennsylvanian-age rocks containing coal beds reach their greatest depth (relative to sea level) in the axis of the northern Appalachian (Dunkard) basin—a northeast-southwest trending synclinorium formed mainly by Alleghanian orogenic tectonism, whose central part extends from about Jackson County, West Virginia, northeastward into Green County, Pennsylvania (Figure A15-1). In general, the base of the Pennsylvanian slowly rises away from this structural axis (in all directions) until basal Pennsylvanian strata occur at the surface. Although the Pennsylvanian section is thickest in the Pocahontas basin region, the structural configuration of the basin causes these older units to rise in structural altitude and crop out along the southern basin margin (Figure A15-2).

These thickness trends are the result of three main factors: 1) erosional relief on the top of the Mississippian, 2) location of the source area for most Pennsylvanian-age sediments, and 3) location of depocenters of the Appalachian basin during Late Paleozoic time.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

During the early Carboniferous, the Appalachian basin was located about 20 degrees south latitude and was part of the paleocontinent Laurentia. By the late Carboniferous, this region had migrated northward and was mostly in the equatorial region (Blakey, 2005). This northward migration of Laurentia through the paleolatitudes, the continental collision of Gondwana (Africa and South America portion) into the southern part of Laurentia, forming the Appalachian mountains, and eustatic responses to continental glaciation events in the southern hemisphere, controlled the types and preservation of sediments deposited in the Appalachian basin during the Pennsylvanian (Cecil and others, 1985; Donaldson and other, 1985; Cecil and Edgar, 1994). Most Lower and Middle Pennsylvanian coal beds formed as extensive peat accumulations in waterlogged, coastal-deltaic environments that were centered mostly in the southern and central portions of the central Appalachian basin (Martino, 1996a; Greb and others, 2002a,b, 2004). Coals in the southern portion of the central Appalachian basin are mainly low- to medium-volatile bituminous with low-sulfur contents, whereas those in the central portion are typically high-volatile bituminous containing low- to moderate-sulfur values (Arkle, 1974). In contrast, most of the preserved Upper Pennsylvanian coal beds formed in continental fluvial, paludal, and limnic environments on an extensive alluvial plain above a depocenter in the northern Appalachian basin (Donaldson, 1974; Ferm, 1974; Arkle and others, 1979; Collins, 1979; Edmunds and others, 1979; Donaldson and others, 1985; Martino, 1996b). Typically, Upper Pennsylvanian coals of the northern Appalachian basin are high-volatile bituminous in rank with high-sulfur contents (Arkle, 1974).

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

In general, subsurface coal beds typically contain natural gas, called coalbed methane (CBM)). A high percentage of this gas is adsorbed naturally on to the surface of the coal. Current methods for

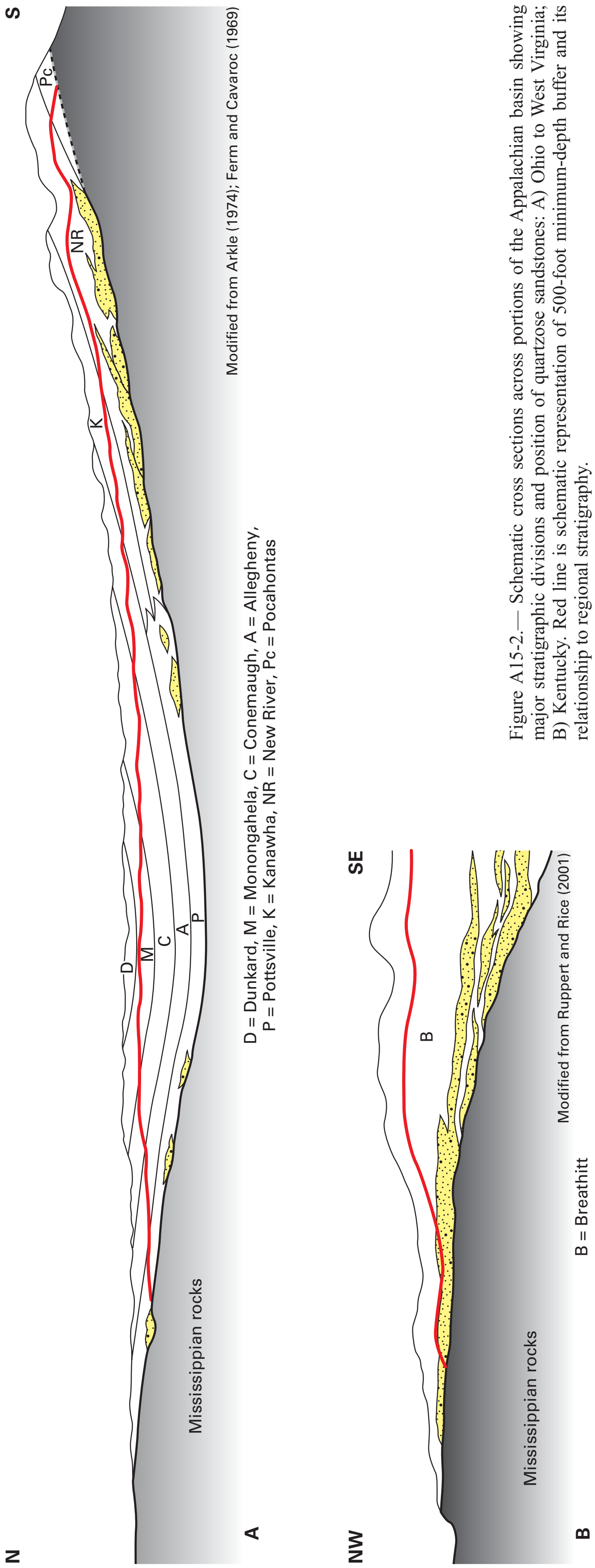

Figure A15-2.— Schematic cross sections across portions of the Appalachian basin showing major stratigraphic divisions and position of quartzose sandstones: A) Ohio to West Virginia; B) Kentucky. Red line is schematic representation of 500-foot minimum-depth buffer and its relationship to regional stratigraphy.

recovering CBM involve depressurizing the reservoir by removal of natural interstitial water from the coal. Methane molecules on the surface of the coal are then freed as gas. An alternative approach for methane recovery is to inject CO_2 into the coal bed in order to enhance methane removal after dewatering has occurred. Experiments indicate that coal beds have an affinity to adsorb approximately twice as many CO_2 molecules compared to the number of methane molecules currently contained in the reservoir. Thus, considering the differences in molecular weights, the potential exists to displace and recover about one ton of CBM for every five tons of CO_2 stored within a coal bed. CO_2 recovery of CBM has been demonstrated in limited field tests (see White and others, 2005). Because of this adsorption ability of coals, geologic sequestration of CO_2 into coal beds is the only circumstance where CO_2 might be considered for injection at shallow depths, above or within proximity to an underground source of drinking water.

Numerous coal beds in the Appalachian basin historically are recognized as having gas contents high enough to create a hazard during underground mining operations. In the last decade, significant CBM production has occurred in some of these historic ‘gassy’ coals, particularly from the Pocahontas Formation in southern West Virginia and western Virginia (which is just south of the MRCSP boundary) (Adams, 1984; Lyons, 1998; Nolde and Spears, 1998). CBM is locally produced from at least 24 pools in Pennsylvania (Markowski, 1998), and historic and modern CBM fields occur also in the northern portion of West Virginia (Avary, 2004). Furthermore, Lyons (1998) reports CBM production in eastern Kentucky, and in Ohio, historic CBM production occurred as early as 1924 (Riley and others, 2004). Although interest in CBM production and exploration is growing in the basin, vast areas remain untested—as well as their CO_2 sequestration potential—and much of the existing data vital in understanding CBM systems are not publicly available.

Identification of “unminable” coal beds that may serve as geologic sinks for CO_2 sequestration in the Appalachian region is a goal of DOE’s sequestration research and is a major component of the MRCSP project. There are, however, many technical and political issues that need to be evaluated to determine at what depth and thickness any of these coal beds would be considered truly unminable, and thereby available for CO_2 sequestration. Although these considerations have yet to be resolved and may vary between states, as an initial evaluation, MRCSP states compiled data on the total net coal thickness that might be available for CO_2 sequestration. Technical and political criteria would have to be subtracted from this data set for enhanced site-specific evaluations.

For this study, data were compiled for coals inferred to be more than one foot thick and greater than 500 feet below the surface, and then used to construct a regional net-coal isopach map (Figure A15-3). Currently, the U.S. Mine Safety and Health Administration considers 400 feet to be the depth that fracturing can generally influence underground mining; thus, a 500 foot depth restriction for defining coals beneath the level of surface fracturing for potential sequestration is deemed appropriate. Likewise, a depth of 500 feet is well beneath the minimum 299 feet depth suggested for optimal methane potential in parts of the northern Appalachian basin (Rice and Finn, 1996), and near the optimal minimal depth of 600 feet suggested by Markowski (1998).

The issue of depth of coal beneath the surface is complicated across the MRCSP study area by the deeply incised topography in the mountainous parts of the coal fields. In these regions, mostly southern West Virginia and southeastern Kentucky, several thousand feet of topographic surface relief can exist. Most coal mining in these areas is done near the surface or by drift mines extending hori-

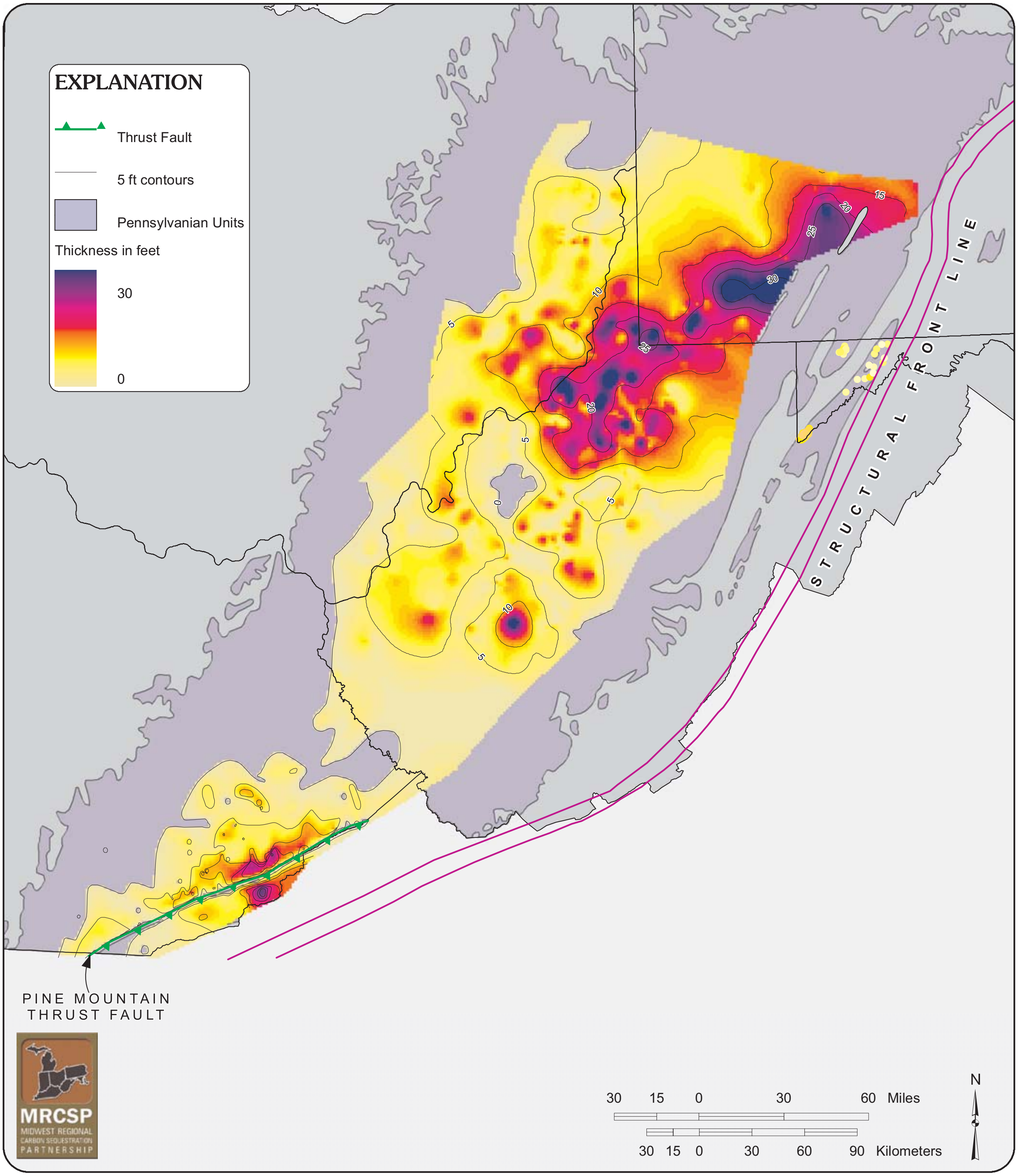

Figure A15-3.—Map showing the net thickness of Pennsylvanian coals that are at least 500-feet deep and one-foot or greater in thickness.

zontally into the sides of hills. Although portions of these mines can reach depths of more than 2,000 feet beneath the surface, most are still above drainage, or above the level of the lowest streams in the area. For sequestration purposes, it may be important to delineate those coal beds that are below the lowest level of streams (called "below drainage") to ensure the sequestered CO_2 gas will not leak to the surface through fractures or updip along bedding partings.

Coal thickness data in each state were obtained mainly from deep diamond-drill core holes and density logs from oil and gas exploration wells on file at each state survey. Oil and gas data are particularly useful for the deeper parts of the basin, although only a fraction of the wells drilled have density logs through the Pennsylvanian strata because, in general, coal-bearing strata are cased-off prior to logging. The manner in which thickness data was compiled in each state varied also because the topography, geology, mining history, and available data were wide-ranging across the region. Data from Maryland, Ohio, Pennsylvania, and West Virginia represent coal beds more than 500 feet beneath the present-day land surface. In eastern Ohio, this may also be close to the below-drainage depth because of minimal- to moderate-topographic relief in this area. In northern West Virginia, many of the oil and gas wells used were cased off to depths of more than 500 feet; so much of the thickness represented may also be below drainage. In Kentucky, data were only compiled for coal beds more than one-foot thick and more than 500 feet below drainage. Coal beds in Maryland occur only in two synclinal basins preserved (one isolated; see Figure A15-3) near the eastern edge of the Appalachian basin proper. Thus, coal thickness data are shown as individual data point values not connected to the main contoured net-coal map for the Appalachian basin.

No data were compiled for southern West Virginia because that is an area of active mining, and it was felt the area should be restricted from consideration for sequestration in that state at this time. If these criteria were used also in Kentucky, no sequestration potential would exist in that state because areas of thickest coal at depth are also areas of mining at or near the surface. Likewise, parts of the thick, cumulative coal thickness in Ohio and Pennsylvania are areas of current near-surface mining**.** Hence, considering these multifaceted elements related to CO_2 sequestration into coal beds, further analysis, public discussion, and additional data collection and mapping will be required in Phase II of the MRCSP project.

16. PENNSYLVANIAN COAL BEDS IN THE MICHIGAN BASIN

The Pennsylvanian Saginaw Formation is a coal-bearing interval that is restricted to the central part of the Michigan basin due to erosional truncation. Along with other Pennsylvanian strata in Michigan, the Saginaw is isolated from correlative coal-bearing strata in the Appalachian basin portion of the MRCSP study area. In general, the Saginaw Formation is equivalent to Lower and Middle Pennsylvanian (e.g., Pottsville and Allegheny formations) strata in adjacent basins.

Although commercial coal production occurred in the Pennsylvanian "Coal Measures" of the central Michigan basin in the late 1800s and early 1900s (maximum production of over two million short tons in 1907), all coal beds in the basin are now considered noneconomic (Ells, 1979). Total current reserves are estimated at 126.5 short tons (Kalliokowski and Welch, 1976) in individual coal beds typically less than three feet thick and laterally discontinuous on a scale of hundreds to thousands of lateral feet (Kelly, 1936).

Complete sections of Pennsylvanian rocks in Michigan do not exist as outcrops or in known diamond drill-hole cores. Stratigraphic relationships are mostly inferred from subsurface geophysical logs, well cuttings, drillers' reports, and rare cores collected during drilling of oil, gas, and water wells (Vugrinovich, 1984). Small-scale, spatial,lateral and vertical lithologic variability characterizes Pennsylvanian strata in Michigan. Various stratigraphic nomenclature has been proposed for these strata; however, no scheme is universally accepted due to the paucity of data, lack of lateral continuity of most units, and complex facies relationships.

Biostratigraphic data are limited for the Saginaw Formation. Age ranges for the unit indicate a late Morrowan (Early Pennsylvanian) through late Desmoinesian (Middle Pennsylvanian) age, with the majority of the Saginaw being Morrowan age (Arnold, 1949; Wanless and Shideler, 1975; Vugrinovich, 1984). However, recent palynological analysis indicates an Early Pennsylvanian, Atokan age for upper portions of the Saginaw (R.M. Ravn, pers. comm., 2005).

The predominantly arenaceous facies of the Parma Sandstone is considered the basal formation of the Pennsylvanian Subsystem in the Michigan basin, although some workers included the Parma as the basal portion of the Saginaw Formation (Ells, 1979). Strata of the Saginaw Formation proper consist of heterolithic sandstones, shales, coals, and limestones with a regionally prominent limestone unit, the Verne Limestone Member, separating pre- and post-Verne cycles (Kelly, 1936). The overlying Grand River Formation is a laterally discontinuous, predominantly fine- to coarse-grained sandstone unit (Kelly, 1936).

Wanless and Shideler (1975) subdivided the Pennsylvanian strata of the Michigan basin, in ascending order, into a sand-dominated basal "A" unit, a predominantly fine-grained shale, siltstone, sandstone, limestone, and coal-bearing "B" unit, and a predominantly sandy "C" unit, even though substantial lithologic variability occurs laterally in each of these units. Vugrinovich (1984) conducted an extensive subsurface investigation in a ten-county area of the central Michigan basin, and proposed an informal revision of Wanless and Shideler's nomenclature. Recently, a regional hydrogeologic study by Westjohn and Weaver (1998) concluded that the "assignment of sandstones or other Pennsylvanian rocks to either the Saginaw Formation or the Grand River Formation is difficult, if not impossible, because there are no lithologic differences or stratigraphic horizons that mark a change from one formation to the other."

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

Lane (1902) named the Saginaw Formation for a series of Pennsylvanian-age sandstones, shales, coals, and limestones observed in drill holes for coal exploration in the central Michigan basin. Kelly (1936) provided more detailed descriptions of the Saginaw from very limited outcrop exposures along the Grand River in Eaton County, from coal mine shafts and pits in the Saginaw Valley, and from other areas of the central Michigan basin as well as. Kelly interpreted the complex lateral and vertical facies changes as indicators of small-scale spatial variations in local depositional environments that ranged from fresh water to brackish and marine, and concluded also that portions of the Saginaw were deposited as cyclothems. Ells and others (1964) and Ells (1979) presented the most accepted stratigraphic terminology and stratigraphic relationships for Pennsylvanian units. Shideler (1969) and Wanless and Shideler (1975) studied the stratigraphy, sedimentology, and paleogeography of Pennsylvanian strata in Michigan, and established a southwestward paleo-sediment transport direction of predominantly fluvial to deltaic sediments. In a detailed study of subsurface data, Vugrinovich (1984) established lithostratigraphy, structure, and isopach thickness relationships, and interpreted depositional environments for Pennsylvanian strata in the central basin area. Recently, Westjohn and Weaver (1998) characterized the areal distribution and lithology of the Saginaw aquifer and confining units (composite Saginaw and Grand River Formations) on the basis of an extensive subsurface study of well logs.

NATURE OF LOWER AND UPPER CONTACTS

General stratigraphic relationships in the Michigan basin, based on subsurface studies, indicate a major unconformity (the base Absaroka unconformity) underlies Pennsylvanian-age rocks in most areas of the basin, and that another unconformity of probable composite origin occurs at the top of the Pennsylvanian section (Ells, 1979). However, Westjohn and Weaver (1998) and Vugrinovich (1984) suggested that the sandstone-dominated lithofacies at the base of the Pennsylvanian section (the Parma Sandstone of some workers) may interfinger and constitute facies equivalents of the Mississippian-age Bayport Limestone in the central Michigan basin, thus obscuring this regional unconformity contact in places. Jurassic rocks overlie portions of the Pennsylvanian section (mostly in the western basin area); however, lithofacies in the Jurassic "red beds" section appear similar to the highly variable lithofacies of the underlying Pennsylvanian, making the pick between these formations problematic in places.

LITHOLOGY AND COAL THICKNESS RELATIONSHIPS

The description of the lithologic variability in the Saginaw Formation is based on current stratigraphic schemes used in Michigan (see above discussion). The lithology of the entire Pennsylvanian section is best considered here because this is the interval mapped for this project. Wanless and Shideler (1975) described a gross lithologic subdivision for the Pennsylvanian section in Michigan.

"Unit A" (Parma Sandstone and lower portions of the Saginaw Formation of other workers) consists of up to 550 feet of mainly clastics with minor amounts of coals, limestones, and evaporites. The coal occurs in beds generally less than three feet thick, but locally, beds as thick as eight feet thick are reported (Vugrinovich, 1984). Total net coal thickness is typically less than seven feet in this interval.

"Unit A" is overlain by "Unit B" (Wanless and Shideler, 1975), an interval of fine-grained clastics with predominantly dark carbonaceous mudstone, minor coal, and limestone (Upper Saginaw Formation and Verne Limestone Member of other workers). Coal is present mainly in the eastern part of the basin in this interval (Wanless and Shideler, 1975). This unit is interpreted as the updip portion of a prograding fluvial deltaic succession with paleosediment transport to the southwest. "Unit B" ranges from zero to185 feet in thickness and has an antithetic thickness relationship to the underlying "Unit A" and the overlying "Unit C." Coal beds are generally less than three feet in thickness with a composite thickness of less than seven feet.

"Unit C" (Wanless and Shideler, 1975; Grand River Formation of others) is a predominantly coarse-grained clastics unit with lesser amounts of mudstones, limestones, gypsums, and minor coals. The coal is irregularly distributed and is generally less than three feet in composite thickness in this unit.

DISCUSSION OF DEPTH AND THICKNESS RANGES

Extensive truncation and deformation of the Pennsylvanian bedrock surface (subcrop) occurred prior to and during Pleistocene glaciation in many areas of the Michigan basin. Thus, the Saginaw rocks lie at relatively shallow depths directly below the Pleistocene deposits (maximum depth of 310 feet above sea level to a high of 880 feet above sea level—Figure A16-1). Although thickness relationships of the Saginaw/Pennsylvanian section are strongly controlled by the basin-centered subcrop surface, it is also influenced by primary depositional controls resulting from the facies relationships and intra-formational unconformities, with resultant complex isopach relationships formed in probable stacked fluvial-deltaic depocenters (Ells, 1979). The Saginaw, in general, ranges in thickness from zero at the subcrop to more than 650 feet thick in the central Michigan basin (Figures A16-1 and A16-2). Considering the lithologic complexity of the rocks, a lack of consistency in stratigraphic nomenclature, and the lack of core and outcrop data, the formation tops and isopach thicknesses used for the Saginaw Formation in this study (Figure A16-2) most likely represent a composite thickness of the Pennsylvanian strata in the basin.

Maximum composite coal bed thickness for the entire Pennsylvanian section is probably less than 12 to15 feet. This thickness may be present only in places in the southern and eastern portions of the study area. A maximum of five percent coal in the entire Pennsylvanian section is a conservative estimate.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

The Pennsylvanian strata of Michigan were deposited during a period of generally southwestward sediment transport in non-marine, marginal-marine, and open-marine environments. Progradational fluvial and deltaic depositional systems produced variable lithofacies and thicknesses of sediments that periodically contained marine incursions represented by laterally persistent marine limestone and shale units. Pre-Pennsylvanian paleotopography was rather irregular due to moderate pre-Pennsylvanian tectonic warping, which is best illustrated by the relief on the Howell anticline, a major structural feature in the area. This structure is represented by a reentrant in the structure and isopach maps in the southeast corner of the subcrop area (Figures A16-1 and A16-2). The thickness of the Saginaw ranges from approximately 44 feet to more than 380 feet over a distance of approximately ten miles in this area (Wanless and Shideler, 1975). With time, these topographic undulations become obscured by infilling sediments, thus indicating a general tectonic quiescence that persisted during the remainder of Pennsylvanian time. Facies and isopach thickness relationships were apparently influenced by eustatic fluctuations that resulted in transgressive and regressive stratigraphic relationships.

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

The Saginaw Formation and other Pennsylvanian strata in the Michigan basin are of interest to the MRCSP because the unminable coal beds and, possibly, the organic-rich shales may be sequestration targets, even though most are at shallow depths (less than 1000 feet) in the Michigan basin. The maximum thickness of the Pennsylvanian section mapped is between 600 and 700 feet but less than five percent of this thickness consists of coal. Maximum coal thickness reported in any one section is probably less than 12 to15 feet (Vugrinovich, 1984).

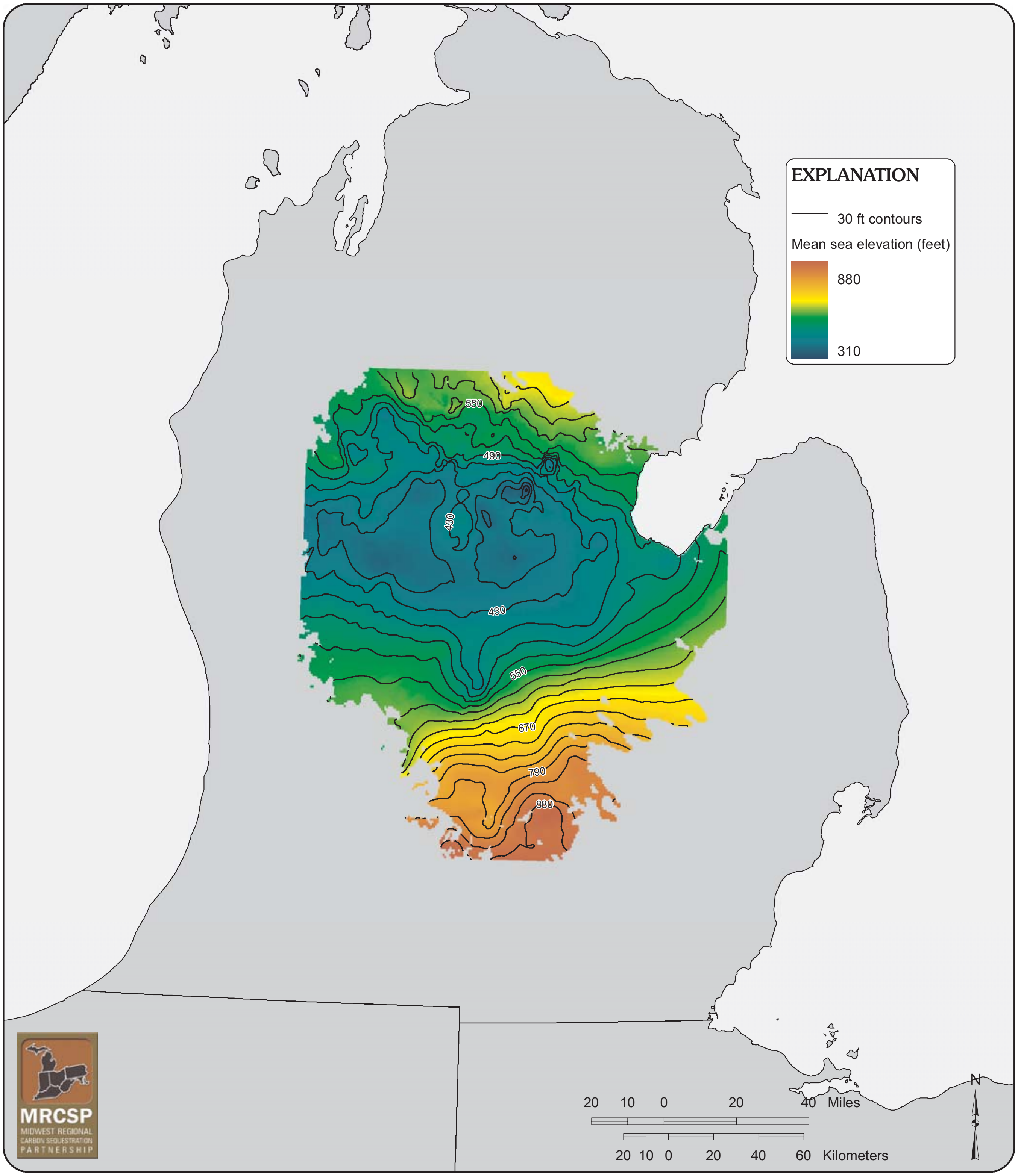

Figure A16-1.—Structure contour map drawn on the top of the Saginaw Formation.

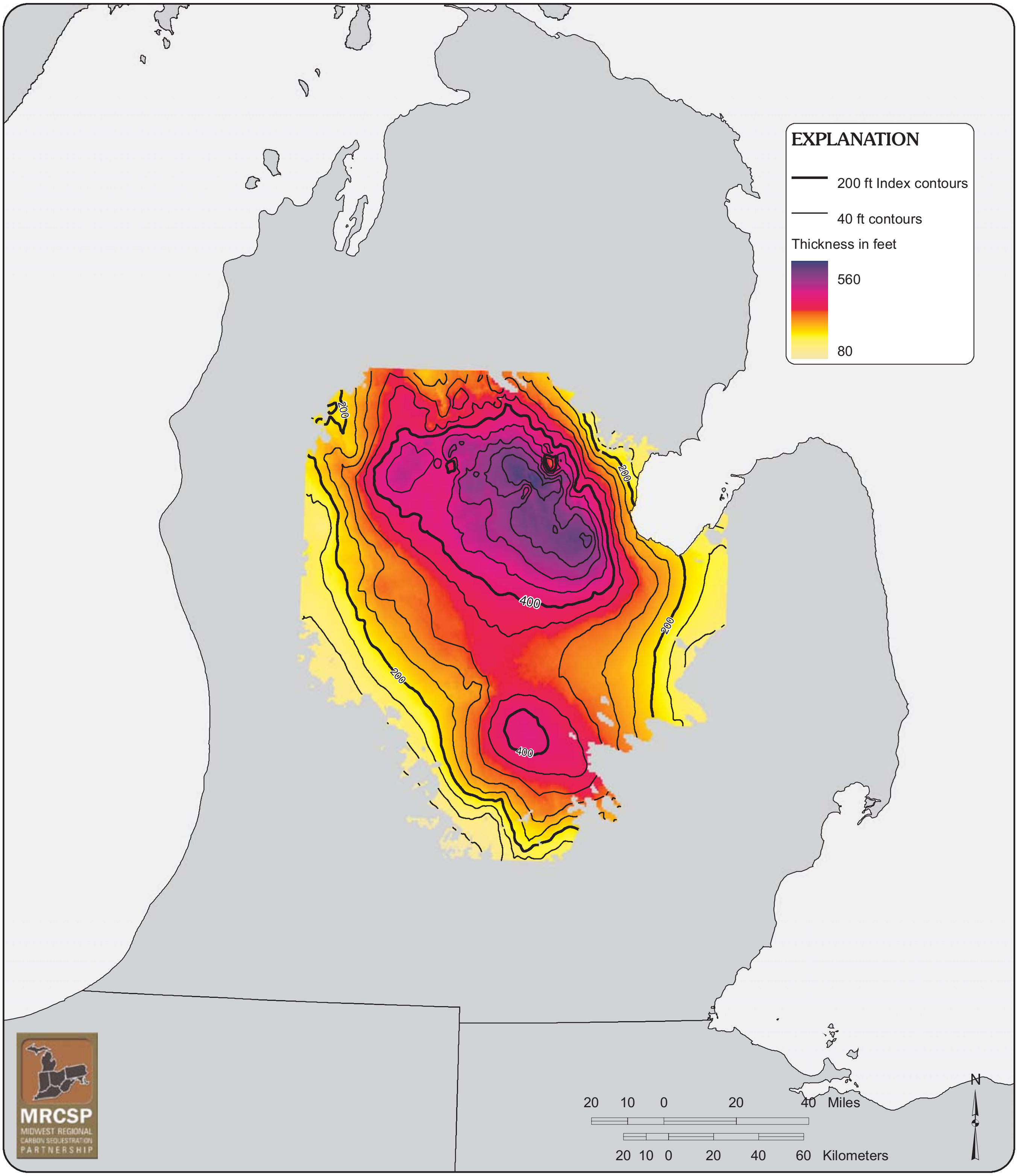

Figure A16-2.—Map showing the thickness of the Saginaw Coal.

Much of the stratigraphy and lateral extent of the Saginaw Formation and other Pennsylvanian-age rocks in Michigan is poorly known because the majority of the data available on this interval consists of limited drill-hole logs and records. However, down-hole, log-based studies of thickness and distribution trends of coals in the Pennsylvanian may be feasible using available log data, gamma-ray, resistivity, neutron-porosity, and density logs (Vugrinovich, 1984). However, these studies are restricted mostly to the deeper portions of the central Michigan basin (Figure A16-1). Other feasible sequestration targets within Pennsylvanian rocks could include organic-rich, carbonaceous shale, a significant but, as yet, unquantified reservoir for CO_2 sequestration.

17. LOWER CRETACEOUS WASTE GATE FORMATION

The Waste Gate Formation of the Potomac Group (Delaware, Maryland, New Jersey, and Virginia) is a stratigraphic unit that includes a correlative sequence of subsurface strata underlying the eastern Delaware-Maryland-Virginia ("Delmarva") Peninsula that are significantly different in age, lithology, and petrophysics from the Patuxent Formation. In the type area, the Potomac Group is divided into formations but, in many places, the formations are less distinct lithologically, and one or more formations, or even the entire group, is treated as an undivided unit. The Waste Gate beds were previously considered part of the Lower Cretaceous Potomac Group (undivided) or the lower part of the Patuxent Formation. A diagram showing the stratigraphy as proposed by Hansen (1984) is provided as Figure A17-1.

The Potomac Group is a largely non-marine fluvial-deltaic complex of interbedded sandstones and mudrocks that generally dips and thickens eastward toward the Atlantic Ocean. While the Waste Gate Formation is limited to the subsurface primarily under the Delmarva Peninsula, the younger units of the Potomac Group crop out updip, west of the Chesapeake Bay and in the northernmost part of the Delmarva Peninsula (Figure A17-2). The Potomac Group pinches out altogether at the Fall Line or Fall Zone, which is the boundary between the Piedmont Province and the Coastal Plain Province, and across which rivers from the upland (Piedmont) region drop as rapids or falls to the Coastal Plain (Figure A17-3).

Hansen (1982, 1984) reported that basal beds (i.e., Waste Gate Formation) decrease in thickness in an up-dip direction, northwestward toward the Baltimore-Washington corridor, and that the upper part of this sequence is marked by an unconformity. This places the Late Cretaceous Magothy Formation on top of the Potomac Group (Figure A17-1).

The Waste Gate Formation is fairly limited in extent. Hansen (1984) indicateed that the Waste Gate occurs beneath the southeastern part of the Delmarva Peninsula, including the southeastern portion of Maryland's eastern shore and the northern part of Virginia's eastern shore. The unit probably underlies part of southeastern Delaware, and possibly may extend at least as far north as the southern tip of New Jersey.

Hansen has also indicated that, offshore of New Jersey, there are partially coeval units, including some non-marine, feldspathic sandstones and shales as well as limestones, calcareous shales, and limy sandstones. The relationship between these units in offshore wells and the Waste Gate (as identified in onshore wells) is not fully

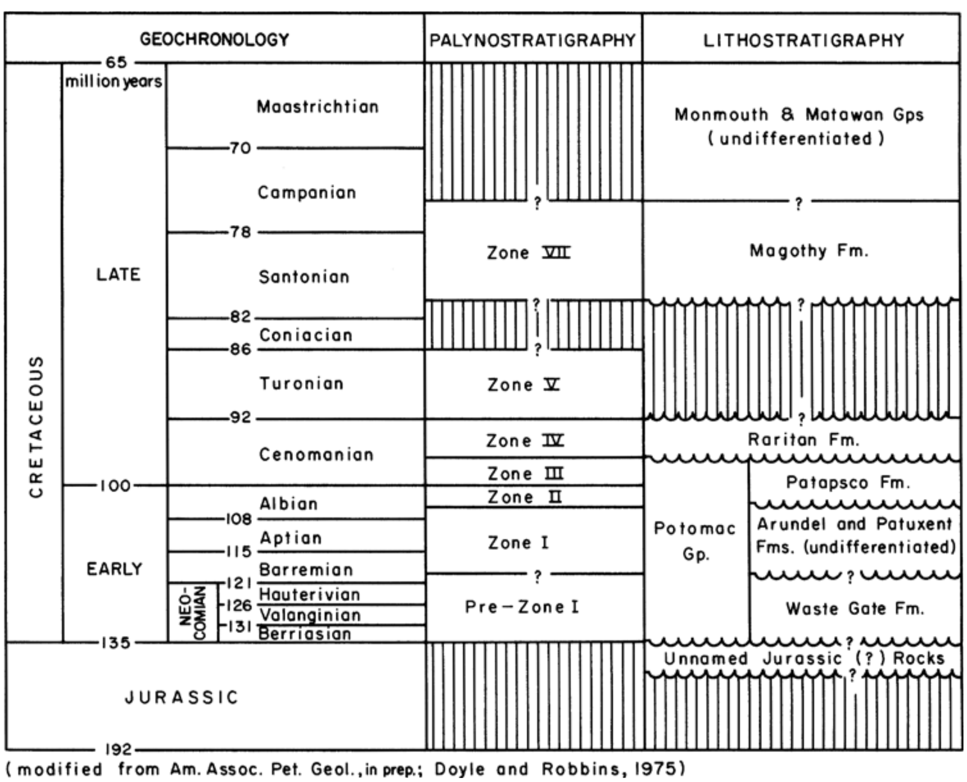

Figure A17-1.—Stratigraphy of the Potomac Group beneath the eastern Delmarva Peninsula (from Hansen, 1984).

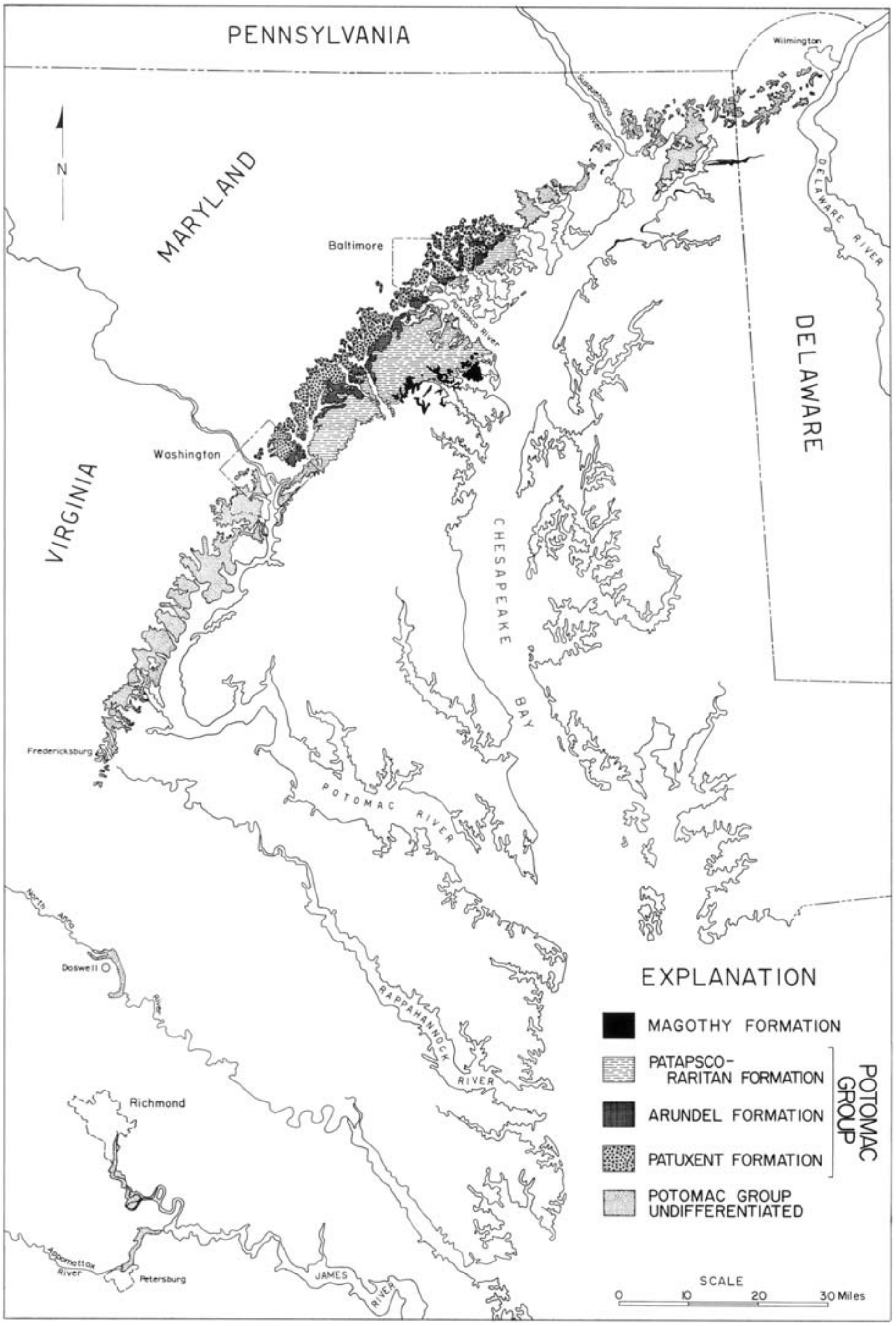

Figure A17-2.—Outcrop belt of the Potomac Group and the Magothy Formation (from Glaser, 1969).

known, but Hansen (1984) suggests that these offshore units may represent lower deltaic distributory facies and marine shelf or delta-front facies, whereas the Waste Gate beds underlying the Delmarva Peninsula may represent upper deltaic fluvial facies.

The Waste Gate Formation is dated Berriasian to Hauterivian(?) because it contains pre-Zone I palynomorphs apparently older than the mid-Barremian to early Albian assemblages characteristic of the overlying Patuxent Formation (Doyle, 1982; Hansen, 1982, 1984).

ORIGIN OF NAMES, TYPE SECTION, SIGNIFICANT EARLIER STUDIES ON THIS INTERVAL

The Waste Gate Formation was originally proposed and defined in an open-file report by Hansen (1982) and subsequently formally named in an information circular by Hansen (1984). The type section was actually designated from the Ohio Oil Company L. G. Hammond No. 1 well (Maryland Geological Survey well number

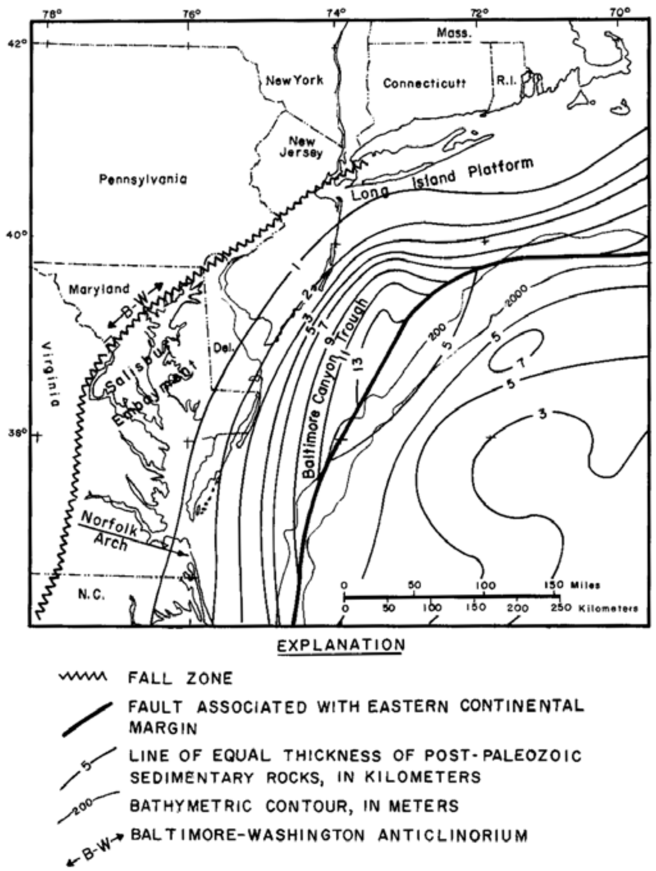

Figure A17-3.—Diagram showing the Fall Zone, the Salisbury Embayment and other tectonic features of the middle Atlantic area (from Hansen, 1978).

Wi-Cg 37) at a depth interval of 4,745 to 5,360 feet. The well was drilled in Maryland about 22 miles west of the Atlantic coast, about 8.5 miles south of the Delaware state line, and slightly west of a place referred to as "Waste Gate". Waste Gate appears to be an informal name for an area around the intersection of Waste Gate Road and Route 350 that is in the vicinity of Waste Gate Creek. The well was drilled in 1944; core descriptions and electric logs were published by Anderson and others (1948).

NATURE OF LOWER AND UPPER CONTACTS

Hansen (1982) defined the Waste Gate Formation on the basis of significant differences in age, lithology and petrophysics from the overlying Patuxent Formation and Arundel Formations. In the type well, the top of the Waste Gate occurs at a depth of 4,745 feet. At this depth, the electric log shows a general increase in resistance associated with sandier intervals (Anderson, 1948, figs. 10 and 20), and an increase in garnet content (Anderson, 1948, fig. 3). Anderson (1948, p. 71) noted "the sands below the 4,750 foot level are all soft, partially consolidated, and poorly sorted and doubtless possess a relatively high permeability." However, Anderson (1948) did not recognize the Waste Gate as a separate unit, instead including these sediments in the Patuxent Formation.

The Waste Gate is characterized as an overlapped subsurface sequence of interbedded sandstones and shales; however, the nature of the upper contact of the Waste Gate Formation is not clearly defined. Various diagrams in Hansen (1984) seem to emphasize the undetermined nature of the contact by showing it as a questionable unconformity or possibly a conformable contact. Due largely to the paucity of data, it is not clear if significant time is missing at the contact or how the nature of the contact may vary at different locations.

Hansen (1982, 1984) reported that palynology data indicate the sediments from the Waste Gate Formation are "pre-palynozone I of Brenner (1963)," largely, if not wholly, Berriasian to Hauterivian(?) in age, and thus older than the overlying Patuxent Formation (Berrimanian and younger). However, Hansen did note that, in one well, an angiosperm type common in the Palynozone I, associated with the younger (overlying) Patuxent-Arundel Formations (undivided), was reported in the upper part of an interval assigned to the Waste Gate, thus leaving open the possibility of upper beds of the Waste Gate possibly being as young as early Barremian. Therefore, it is possible that little or no time separates the Waste Gate from the overlying Patuxent Formation.

In Maryland, the Waste Gate has been penetrated in only four wells (referred to as Hammond No. 1, Bethards No. 1, DOE Crisfield, and Esso No. 1), and even fewer penetrate into the underlying basement rocks. In general, in the vicinity of the Hammond No. 1 well, and to the east of this well, Cretaceous units are underlain by rocks of Jurassic(?) or Triassic(?) age (Anderson and others, 1948; Hansen, 1982). To the west, the Waste Gate Formation is presumably underlain by older, pre-Mesozoic basement metamorphic rocks. In the Hammond No. 1 well, there are approximately 135 feet of what are referred to as Triassic(?) rocks by Anderson and others (1948) and Jurassic(?) by Hansen (1982). The top of the sequence is a hard, indurated quartz conglomerate containing some white feldspars and lime cement. Below the conglomerate are hard, reddish-brown and apple-green shales, sandy shales, and sandstones. In the Bethards No. 1 well, there are approximately 585 feet of Triassic(?)/Jurassic(?) rocks (assigned to the Newark series) characterized by sandstones, sandy shales, and shales with a basal conglomerate (Anderson and others, 1948).

Anderson and others (1948) indicate that, at the Hammond No. 1 well, the top of the pre-Mesozoic basement contact is characterized by "rotten schistose rock containing mica, chlorite, and feldspar and cut by small veins of pegmatite in which the feldspars are almost entirely decomposed." This weathered zone was estimated to be approximately 31 feet thick and underlain by either a biotite-rich quartzite or a mica gneiss and cut by veins of pegmatite. At the Bethards No. 1 well, pre-Mesozoic basement rock appears to be characterized by dark greenish-black gabbros containing joints occasionally filled with carbonate).

LITHOLOGY

Hansen (1984) described the Waste Gate lithology as follows:

The Waste Gate Formation consists largely of an unconsolidated to moderately lithified sequence of interbedded light gray to white arkosic to feldspathic sandstones and drab to occasionally mottled, silty shales (or clays), often finely laminated with carbonaceous material. Anderson (1948, p. 14) reports that the sandstones (sands) are relatively poorly sorted, ranging from fine to very coarse-grained with an occasional pebbly bed. The feldspars are often strongly kaolinized, resulting in a pervasive, clayey matrix sufficiently binding to form friable sandstones in place. The more indurated sandstones are associated with occasional occurrences of calcareous cement. Core descriptions provided by Anderson and others (1948, p. 408-412) indicate that about 27 percent of the arenaceous footage is sufficiently lithified to be called "sandstone," *a figure perhaps representative of the Waste Gate Formation elsewhere in Maryland.*

Hansen (1984) noted in the Hammond No. 1 well, the formation is "about 70 percent sandstone (sand); however each unit is relatively thin and rarely exceeds 100 feet in thickness. In Maryland, carbonaceous laminae and calcareous sandstones are present in the Waste Gate, but no coaly seams or limestones have been found."

Hansen (1982) noted rare occurrences of acritarch cysts found within the Waste Gate Formation in the Bethards No. 1 well. A more detailed discussion of the palynology can be found in Doyle (1982) and Hansen (1982).

Sandstone porosities estimated from geophysical logs generally range from 19 to 27 percent (Hansen 1982). Based on aquifer tests of a well in Crisfield, Maryland, transmissivities of 340 to 430 gallons/day/foot and hydraulic conductivities of 4 to 5 gallons/day/square foot were recorded (Hansen, 1984). Based on limited test data, Hansen (1984) suggested that the Waste Gate sandstones are likely to have relatively low permeabilities in comparison to other Coastal Plain aquifers, perhaps on the order of 15 to 150 md.

It should be noted that younger units in the Potomac Group include aquifers that are an important source of fresh water supply, particularly in areas west of the Chesapeake Bay in Maryland and in some communities on the Delmarva Peninsula. However, under much of the Delmarva Peninsula, the deep Potomac units, including the Waste Gate Formation, are saturated with salty water ranging from slightly brackish to brines with salinities greater than seawater.

DISCUSSION OF DEPTH AND THICKNESS RANGES

The top of the Waste Gate Formation ranges from a depth of about 3,500 feet at its up-dip limit to 5,670 feet near the coast (Hansen, 1984) (Figure A17-4). The Waste Gate Formation is estimated to range in thickness from zero feet thick at its up-dip pinchout to about 1,515 feet thick near the Delmarva coast (Hansen, 1984) (Figure A17-5). Hansen (1984) indicate that the Waste Gate Formation thins relatively rapidly by onlap under the Delamarva Peninsula. The location of the up-dip edge of the unit is poorly defined because of a lack of data, but the pinchout line is estimated to trend roughly northeast-southwest through the middle of the Delmarva Peninsula, based the unit's absence in the few wells in the western part of the Peninsula that penetrate to pre-Mesozoic basement.

DEPOSITIONAL ENVIRONMENTS/ PALEOGEOGRAPHY/TECTONISM

In early Cretaceous time, Potomac Group sedimentation began to occur as the Piedmont and Blue Ridge provinces were uplifted. These sediments were deposited eastward in a broad, open basin (Glaser, 1969). This basin is referred to as the Salisbury Embayment (formerly referred to as the Chesapeake-Delaware Embayment) (Figure A17-3). Glaser (1969, p. 74) also indicated that deposition probably " began near or somewhat beyond the present coast line" and then "…apparently migrated slowly westward toward the present day outcrop belt" (Figure A17-2). According to Glaser (1969) by the time Patuxent Formation sediments were being deposited, the Early Cretaceous fall line or basin margin was located, perhaps, only a few miles inland from the present outcrop margin.

It should also be noted that the gradient of the surface of the pre-Mesozoic basement appears to vary, apparently increasing from west/northwest to east on the Delmarva Peninsula. The apparent dip of the basement surface between a well on the western side of the Delmarva Peninsula (at Cambridge, Maryland) and the Hammond well (central Delmarva Peninsula) is on the order of 64 feet per mile, whereas the apparent dip between the Hammond well and Bethards well on the eastern edge of the Delmarva Peninsula is roughly 150 feet per mile. Given the paucity of wells that penetrate into pre-Mesozoic basement rocks in the Delmarva Peninsula, the nature of the basement surface is not fully characterized (e.g., the extent to which there is local relief) and it is not clear if this apparent change in surface gradient between the two wells may be the result of pre-Mesozoic erosion (e.g., a canyon), warping, a structural feature, or some combination of the three. Hansen (1978) noted that the change in gradient that occurs within about 10 to 15 miles of the coast, that is, between the Hammond No. 1 and Bethards No. 1 wells, suggests the presence of a tectonic hinge zone that might define the shoreward edge of the Baltimore Canyon Trough (Figure A17-3).

Rare occurrences of marine or brackish-water fossils have been noted within the Waste Gate Formation (Hansen, 1984) but, overall, the majority of evidence suggests the formations originated in a high-energy, alluvial setting dominated by fluvial channel facies proximal to the early Cretaceous Fall Line. Hansen (1984) noted that self-potential (SP) log signatures of the sandstones have a blocky aspect, suggestive of braided or stacked sand-channel deposition, rather than the well-defined, fining-upward cycles generally ascribed to deposition by meandering streams. This suggests deposition in a high-energy alluvial complex. In addition, Doyle (1982) reported that samples from the Waste Gate Formation suggest deposition in a humid tropical climatesuch as would be found in the southern Laurasian continent during the Early Cretaceous.

SUITABILITY AS A CO_2 INJECTION TARGET OR SEAL UNIT

Porosities of the Waste Gate sandstone, as estimated from compensated formation density logs and s electric logs, range from 19 to 27 percent (Hansen, 1982, tab. 4). In general, porosity decreases with increasing depth (Table A17-1). In the shallowest (3,900 to 4,225 feet) of five wells penetrating the Waste Gate in Maryland, direct pumping tests yielded sandstone permeabilities in the range of 75 to 120 md; the Schlumberger method yielded similar results of 63 to 122 md. In general, permeability decreases with increasing depth, falling in the range of 16 to 122 md (Table A17-1).

Chemical analyses of the formation waters from two Waste Gate aquifers revealed brines with chloride concentrations of 42,000 mg/l, and salinity (equivalent NaCl concentration) estimates from electric log data ranged from roughly 25,000 to 94,000 ppm (Hansen, 1982, ttabs.. 5 and 6). Salinity increases with depth and are a calcium/sodium chloride type. These waters are at normal hydrostatic pressure and exhibit very lethargic to stagnant flow systems (Hansen, 1984) (Table A17-1).

Hansen (1982, 1984) evaluated the Waste Gate Formation for potential for extraction of chemical commodities such as commercial brines, extraction of geothermal heat, and disposal of hazardous/liquid waste. Perhaps most pertinent to considerations for CO_2 injection is the hazardous/liquid waste evaluation.

Hansen (1984, p. 18) notes:

The fluvial-deltaic Waste Gate Formation is not ideal for well injection because of its complex sand stratigraphy. Individual aquifers and confining beds are only locally correlative. The geometry of each sand body is complex. With sparse well control, it is impossible to predict unequivocally whether a potential reservoir is laterally connected with an adjacent sand or whether it wedges out within a

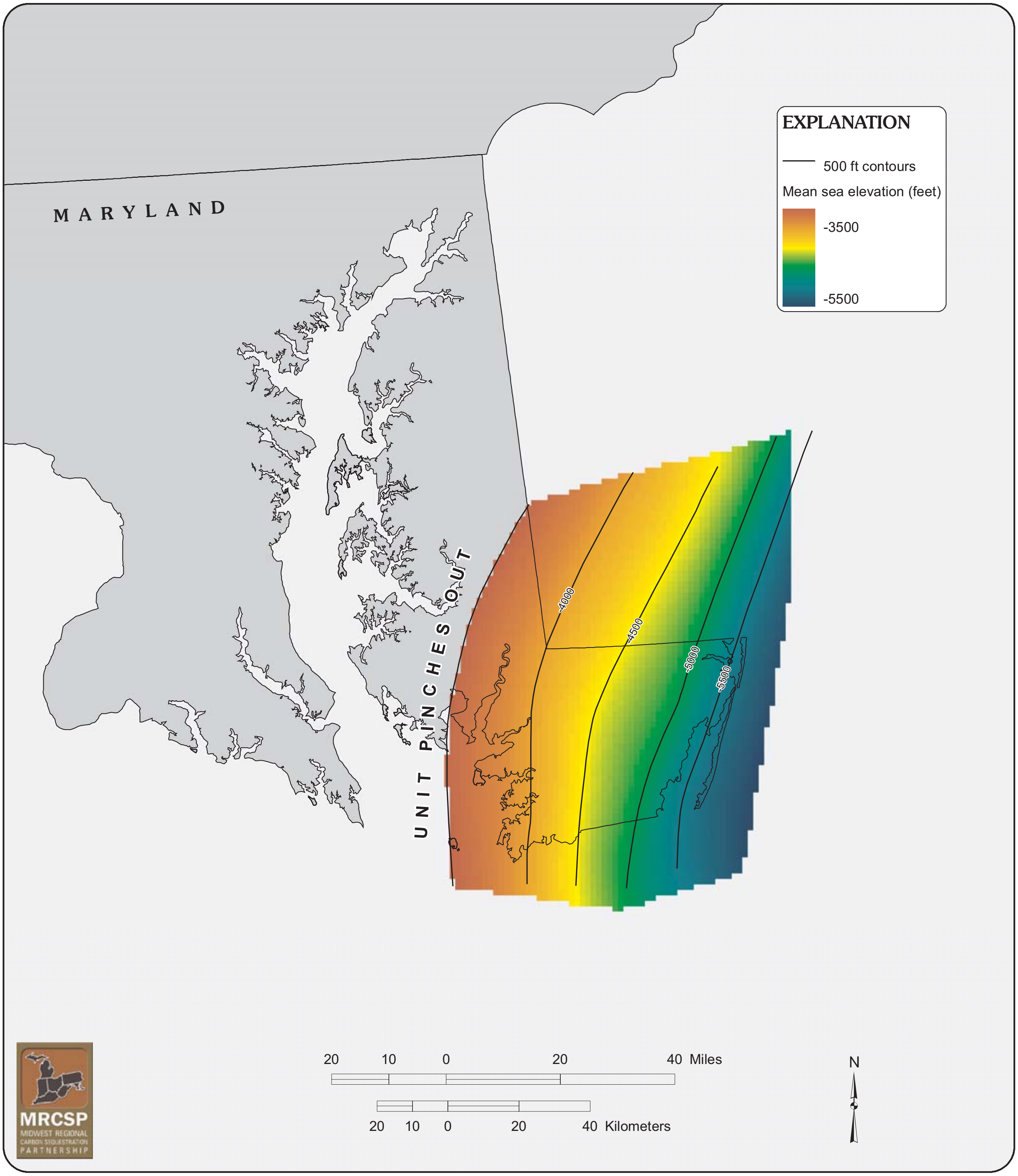

Figure A17-4.—Structure contour map drawn on the top of the Waste Gate Sandstone.

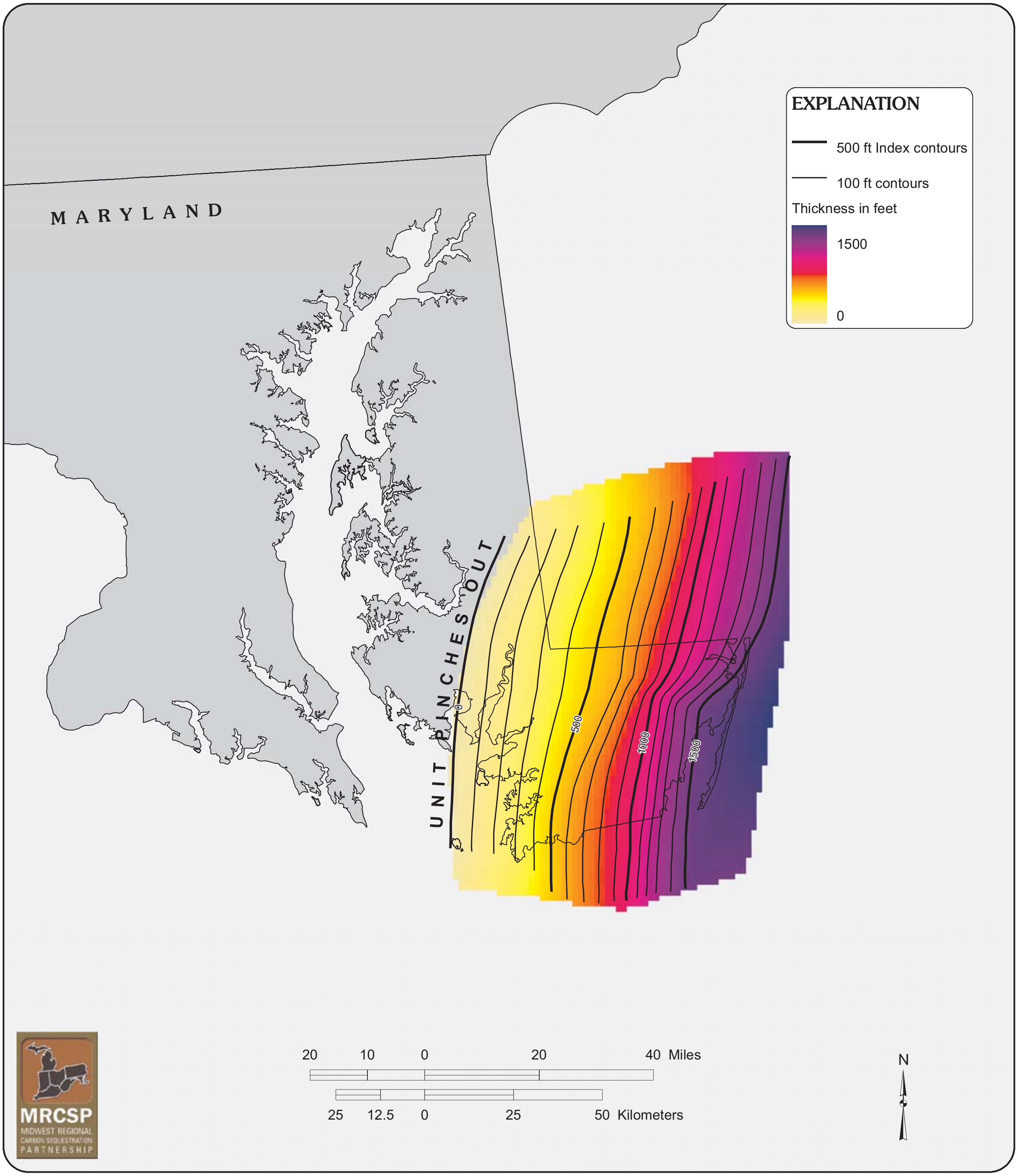

Figure A17-5.—Map showing the thickness of the Waste Gate Sandstone.

Table A17-1.—Summary of depth, thickness, porosity, permeability and salinity of the Waste Gate Formation (adapted from Hansen, 1982)

Well Name	*Depth (ft.)*	*Thickness (ft.)*	*Estimated Sandstone Porosity (%)*	*Estimated Permeability (millidarcies)*	*Salinity (equivalent NaCl) (parts per million)*
DOE Crisfield Airport	3,900-4,225	325	24-27[1]	75-120[3] 63-122[4]	33,700[5] 72,000-80,000[6]
J & J Taylor	4,975-5,915	940	21-24[1]	29-63[4]	24,700[5] 91,300[6]
Ohio Hammond	4,745-5,360	615	23-27[2]	49-122[4]	50,400[5] 53,700[6]
Socony-Mobil Bethards	5,020-6,565	1,545	19-24[2]	16-63[4]	70,200[5] 97,400[6]
Esso Ocean City	5,670-7,180	510	19-24[2]	16-63[4]	73,800[5] 94,300[6]

[1]Compensated formation density log method
[2]Short normal electric log method
[3]Pumping test
[4]Schlumberger formula
[5]Self-Potential method
[6]Resistivity method

clayey confining bed. As a consequence, the isolation of an individual sand can never be assured. In practical terms the waste disposal reservoir should be viewed as including not only the injection zone, but one or two adjacent sands as well. Because the Waste Gate Formation is hydrologically isolated from the shallow fresh-water flow system, this contingency should not preclude waste injection unless local conjunctive use of the Waste Gate is anticipated.

By restricting injecting pressures to 0.64 psi/ft, the minimum pressure gradient at which hydraulic fracturing theoretically occurs, Hansen (1982) has estimated that a 75-foot thick Waste Gate sand could be expected to accept a waste stream of 30 to 115 gpm for fluids ranging in viscosity between 1 to 2.2 centipoises. Pretreatment of the waste prior to injection may be required to prevent deterioration of formation permeability due to precipitate reactions between waste water and the formation water and matrix. For example, certain types of acidic wastes may react with the feldspathic aquifer material . . . producing clays that might reduce aquifer permeability near the disposal well. At the very least entrained gasses and suspended solids must be removed from the wastewater prior to injection.

Hansen (1984, p. 20) concluded that the hydrogeologic setting of the Waste Gate Formation is suitable for liquid waste disposal. Transmissivity and storage properties should be sufficient to accept wastewater in economic volumes within prescribed injection pressures. Thirty to 115 gallons per minute of liquid waste could be injected into typical Waste Gate sandstone without fracturing the rock or its confining beds. By increasing the number of sandstone beds within the injection target, larger volumes of liquid waste should be able to be injected with no adverse affects.

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