Geological sequestration of carbon dioxide in the Cambrian Mount Simon Sandstone: Regional storage capacity, site characterization, and large-scale injection feasibility, Michigan Basin

David A. Barnes, Diana H. Bacon, and Stephen R. Kelley

ABSTRACT

The Mount Simon Sandstone (Cambrian) is recognized as an important deep saline reservoir with potential to serve as a target for geological sequestration in the Midwest, United States. The Mount Simon Sandstone in Michigan consists primarily of sandy clastics and grades upward into the more argillaceous Eau Claire Formation, which serves as a regional confining zone. The Mount Simon Sandstone lies at depths from about 914 m (3000 ft) to more than 4572 m (15,000 ft) in the Michigan Basin and ranges in thickness from more than 396 m (1300 ft) to near zero adjacent to basement highs. The Mount Simon Sandstone has variable reservoir quality characteristics dependent on sedimentary facies variations and depth-related diagenesis. On the basis of well-log-derived net porosity from wells in the Michigan Basin, estimates of total geological sequestration capacity were determined to be in excess of 29 billion metric tons (Gt). Most of this capacity is located in the southwestern part of the state.

Numerical simulations of carbon dioxide (CO_2) injection were conducted using the subsurface transport over multiple phases-water-CO_2-salt (STOMP-WCS) simulator code to assess the potential for geologic sequestration into the Mount Simon saline reservoir in the area of Holland, Ottawa County, Michigan. At this locality, the reservoir is more than 260 m (850 ft) thick and has a minimum of 30 m (100 ft) of net porosity. The simulation used a CO_2 injection period of 20 yr at a rate of 600,000 metric tons (t)/yr, followed by an equilibration period of 280 yr, for a total of 300 yr. After 20 yr, the

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total amount of CO_2 injected is 12 million metric tons (Mt); after 300 yr, 9.8 Mt is modeled to remain as a free-phase (nonentrapped) supercritical CO_2, 0.7 Mt is capillary-entrapped (residual) supercritical CO_2, and 1.5 Mt dissolved into the brine. The injected CO_2 spread to an area with a radius of 1.8 km (1.12 mi) after 20 yr of injection at a single well and to an area with a radius of 3.8 km (2.36 mi) after 300 yr. The low-permeability Eau Claire retards the upward migration of CO_2. Pressures during injection at the bottom of the cap rock (1540.5-m [5054-ft] depth) are well below the fracture pressure limit of 27.9 MPa (4046.6 psi), assuming a fracture pressure gradient of 0.018 MPa/m (0.8 psi/ft) caused by the high permeability of the Mount Simon Sandstone.

INTRODUCTION

Geological sequestration (GS) of anthropogenic carbon dioxide (CO_2) from stationary emission sources is an important component of the greenhouse gas emission reduction strategy termed carbon capture and geological storage. The feasibility of cost-effective GS in any area is fundamentally dependent on local and suitable GS systems, including effective reservoir zones for injection and storage and stratigraphically related seals for confinement. The GS system must lie at a depth within the subsurface sufficient to retain CO_2 in its supercritical state (Figure 1), possess sufficient injectivity and storage capacity for the scale of the project under consideration, and have injection and confining zone characteristics that preclude buoyant, supercritical CO_2 escape over long periods (generally accepted to exceed at least 1000 yr; see IPCC, 2005, for details).

The Middle (?)–Upper Cambrian Mount Simon Sandstone is recognized as an important deep subsurface reservoir in the Midwest United States: Illinois, Indiana, Kentucky, Michigan, and Ohio. The Mount Simon Sandstone has been the reservoir injection zone for many class I underground injection control (UIC) wells in all of these states for many decades. The Mount Simon Sandstone is also a gas storage reservoir in areas of the Illinois Basin. The geological sequestration capacity (GSC) for the Mount Simon Sandstone in the Midwest (Illinois, Indiana, Michigan, and Ohio) has recently been estimated to be between approximately 50 to nearly 200 billion metric tons (Gt) (DOE/NETL, 2008).

This article presents the results of a refined regional assessment of the Mount Simon Sandstone GSC in Michigan based on conventional core and wireline-log data analysis. We have also conducted a site characterization investigation in Ottawa County, Michigan, one of the more prospective areas in the state, using log and conventional core data from key wells in the area. These subsurface site characterization data were then used as inputs for numerical simulations of CO_2 injection using the STOMP-CO_2 simulator to assess the dynamics of a hypothetical GS project using the Mount Simon Sandstone near Holland, Michigan.

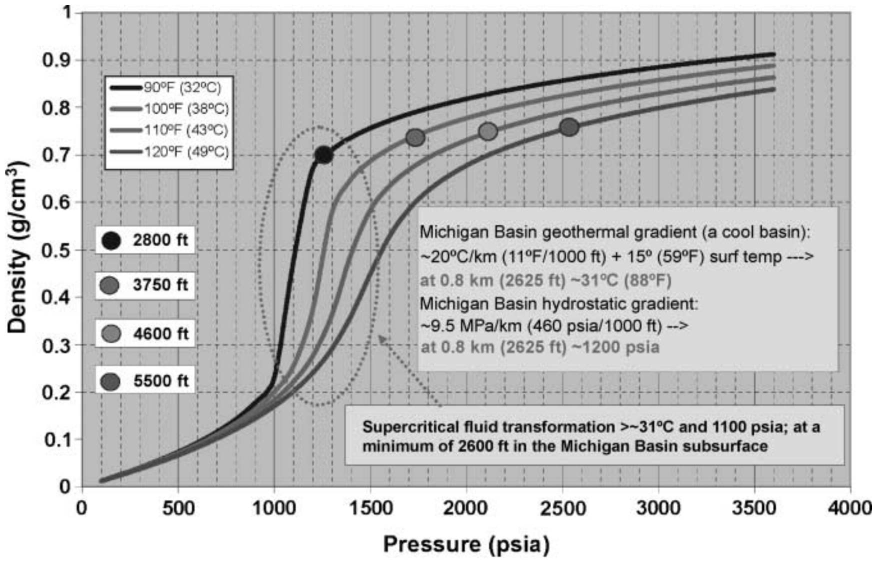


Figure 1. Pressure-temperature-density plot for CO_2 and pressure-temperature-depth relationships in the Michigan Basin. Colored dots represent the pressure-temperature-density relationships at selected depths in the basin.

BACKGROUND: MOUNT SIMON SANDSTONE IN THE MIDWEST

The Mount Simon Sandstone in the Midwest region is characterized by predominantly quartzose sandstone with minor amounts of shale and dolomite, which was first described in outcrop in Wisconsin by Ulrich (Walcott, 1914, p. 354). The unit is predominantly a quartz arenite in most locations, but in places, the lower part of the unit is arkosic. The Mount Simon Sandstone constitutes the basal, transgressive sandstone unit of the Sauk sequence (Sloss, 1963), which unconformably overlies various Precambrian rock types in the Midwest from western Ohio to the proto Michigan-Illinois Basin in Illinois, Indiana, western Kentucky, and Michigan (Wickstrom et al., 2005; Baranoski, 2007). Related Middle to Upper Cambrian sandy clastic rocks elsewhere in North America unconformably onlap the Precambrian craton along the northeast–southwest-trending, transcontinental arch extending from the Lake Superior region southwest to what is now Arizona (Prothero and Dott, 2004).

The Mount Simon Sandstone reaches a maximum thickness of nearly 762 m (2500 ft) in the northeastern Illinois Basin and is overlain by the Eau Claire Formation throughout the Midwest (Willman et al., 1975; Wickstrom et al., 2003). The Eau Claire Formation consists of low-porosity crystalline dolomite, sandy dolomite, dolomitic and feldspathic sandstone, siltstone, and shale and is identified as a regional confining zone in the Midwest (Wickstrom et al., 2005).

The Mount Simon Sandstone in the Michigan Basin subsurface overlies a diverse Precambrian basement complex and grades upward to fine-grained, shaley clastics and interbedded carbonate strata of the Eau Claire Formation (Catacosinos, 1973; Catacosinos and Daniels, 1991) (Figure 2). The Mount Simon Sandstone can be

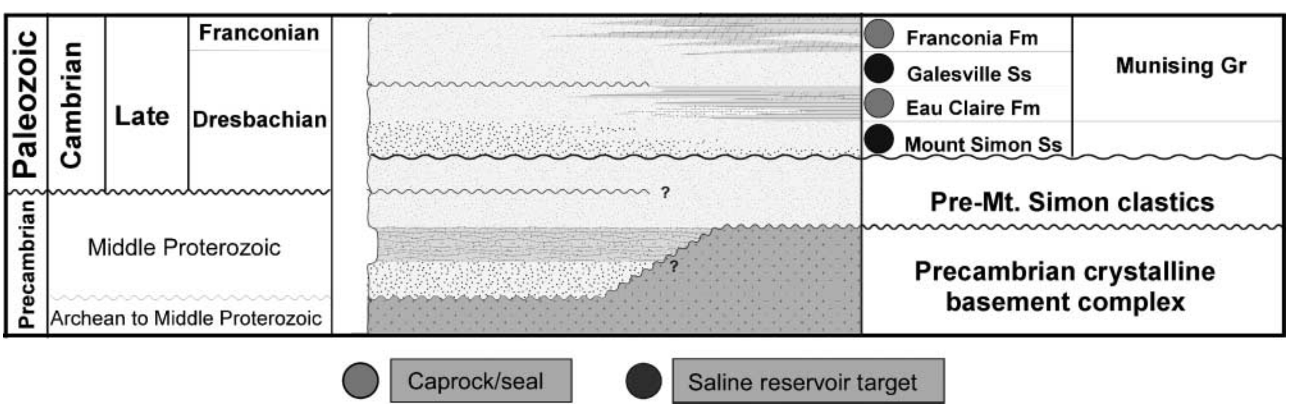


Figure 2. Precambrian through Cambrian stratigraphic column for the Michigan Basin (modified from Catacosinos et al., 2001).

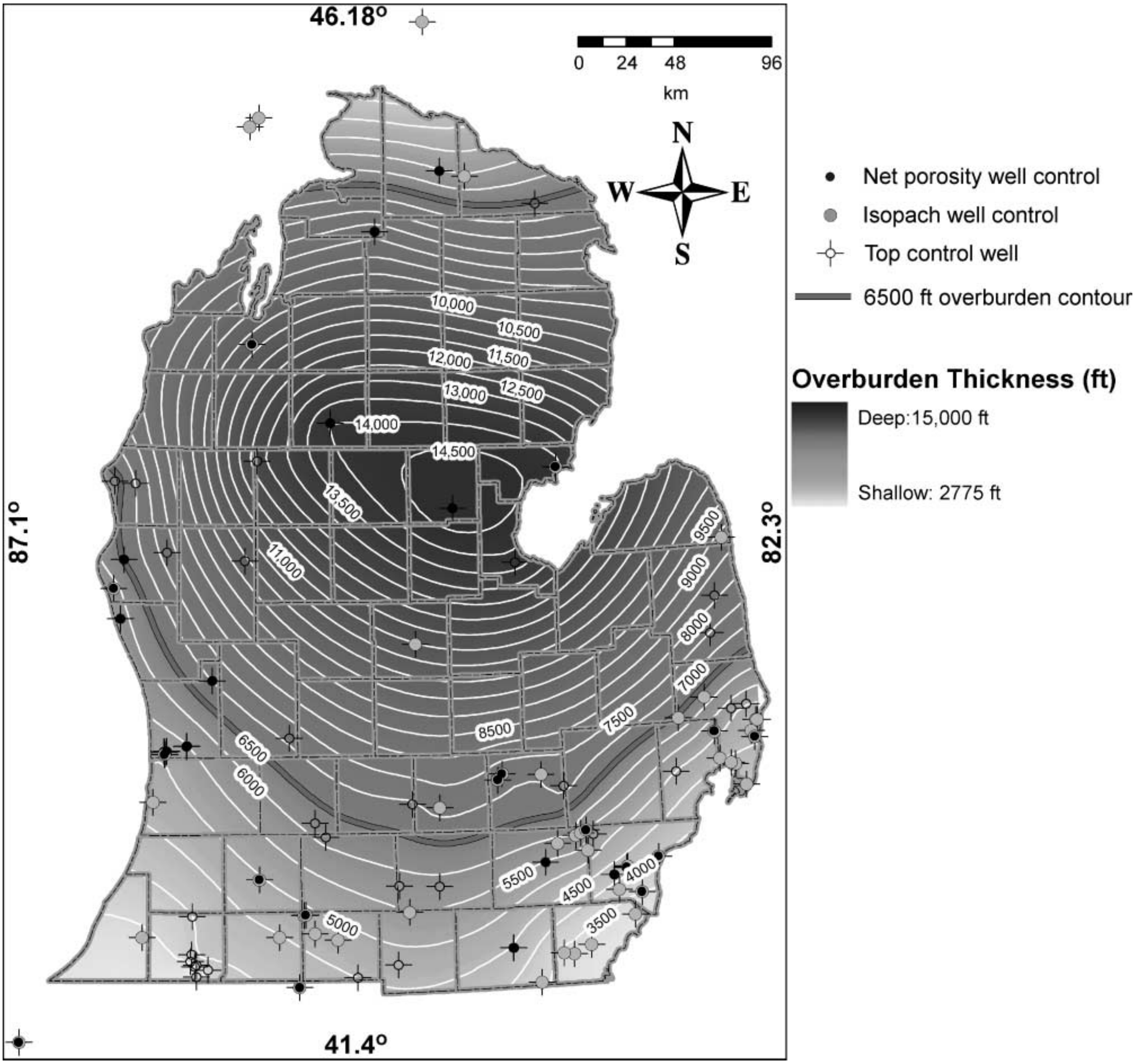


Figure 3. Mount Simon overburden thickness map (driller's depth to the top of Mount Simon) in the Michigan Basin.

grossly subdivided in the Michigan subsurface into three transitional units. A pink-red, hematite-cemented and arkosic sandstone unit occurs at the base of the Mount Simon Sandstone in several wells (Briggs, 1968; Lilienthal, 1978). Above this basal arkosic sandstone unit, the Mount Simon Sandstone consists of medium- to coarse-grained quartz sandstone with minor greenish shale interbeds and variable amounts of glauconite. The upper part of the Mount Simon Sandstone is transitional, through an increase in calcareous, argillaceous, and fine-grained arkosic interbeds, into the overlying Eau Claire Formation.

MOUNT SIMON SANDSTONE IN THE MICHIGAN BASIN SUBSURFACE

Stratigraphic relationships were investigated in this study using subsurface wireline-log data from more than 100 borehole penetrations of the Mount Simon Sandstone in the Michigan Basin, along with limited conventional core data and driller's reports. An overburden thickness map (driller's depth to the top of Mount Simon, Figure 3) indicates that the top of Mount Simon ranges in depth from almost 4572 m (15,000 ft) in the central Michigan Basin (Hunt Martin #1-15 well, P# 35090, Gladwin

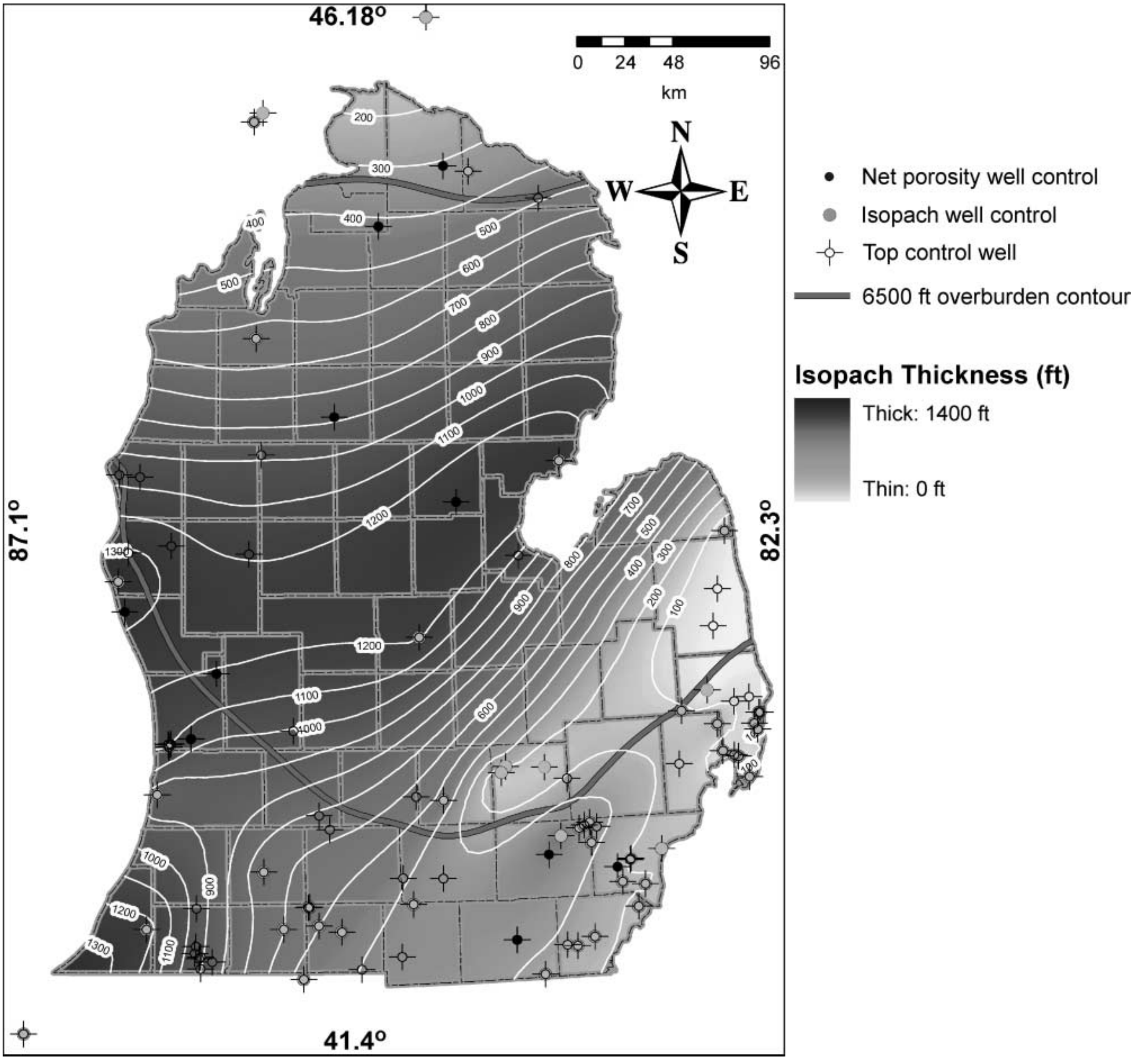


Figure 4. Isopach thickness map of the Mount Simon Sandstone in the Michigan Basin.

County) to just more than 914 m (3000 ft) in the southwest and southeast corners of the state. This structural surface is consistent with the basin-centered subsidence in the Michigan Basin throughout the Paleozoic (Howell and Van Der Pluijm, 1999). The depth of the unit in the subsurface throughout the lower peninsula of the state lies within the CO_2 supercritical pressure realm (i.e., greater than 800 m [2600 ft] in depth).

The entire Mount Simon Sandstone was penetrated in 52 boreholes and, an isopach map (Figure 4) indicates thickness from more than 396 m (1300 ft), along a southwest–northeast trend through the center of the state, to essentially zero in the southeast near a northeast-trending basement high extending from Livingston through St. Clair counties. This basement high is generally aligned with the Mount Simon thickness in the central Michigan Basin as well as the interregional, transcontinental arch. The isopach map of Mount Simon is not consistent with the Michigan Basin subsidence trends in younger strata and indicates a precursor subsidence regime and paleogeography not directly related to subsequent Paleozoic subsidence patterns in the basin (Howell and Van Der Pluijm, 1999).

The base of the Mount Simon Sandstone (Figure 5) is identified by a substantial increase in gamma-ray (GR) log signature above 50 to 100 American Petroleum

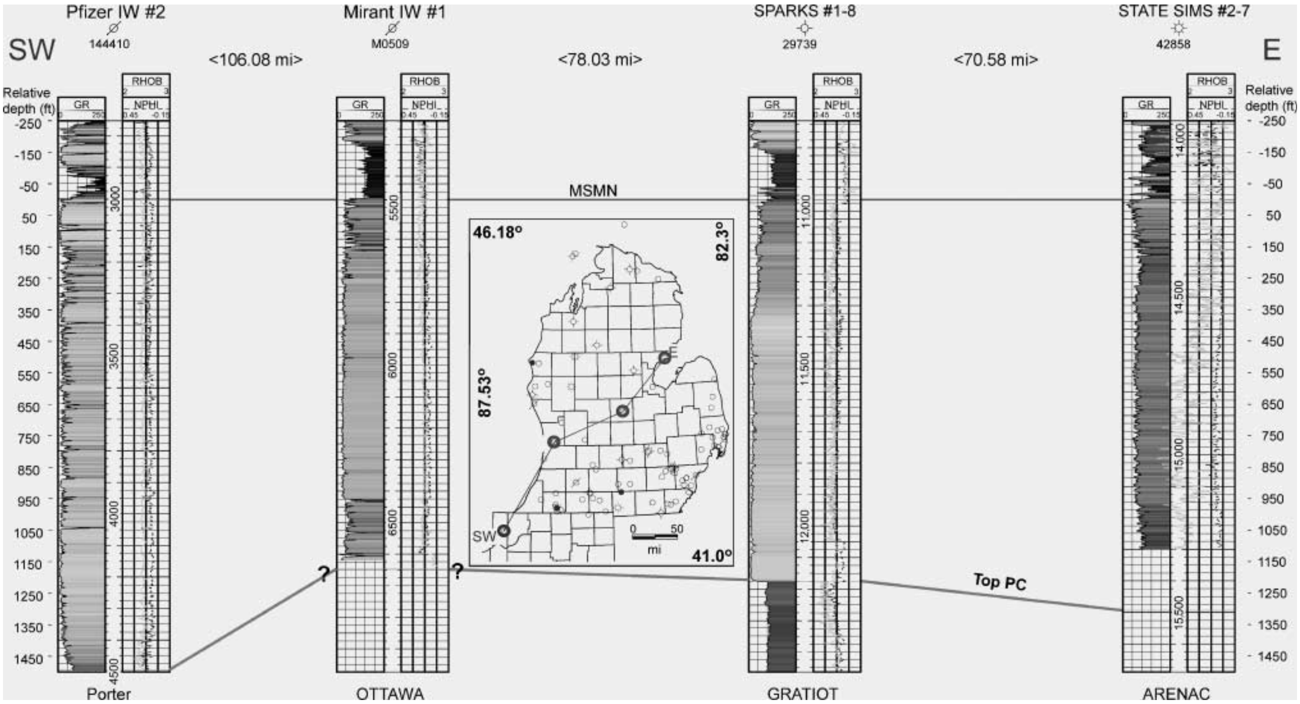


Figure 5. Southwest to northeast stratigraphic cross sections showing logs from complete or near complete penetrations of the Mount Simon Sandstone. MSMN = top Mount Simon Sandstone; Top PC = top Precambrian. Note that bulk density (RHOB) and neutron porosity (NPHI) logs in some wells are of questionable reliability, especially in deeper well penetrations (see Sparks #1-8 and State Simms #2-27 wells). GR = gamma ray.

Institute (API) units downward, although several Mount Simon wells have questionable log data. In most wells, the top Mount Simon Sandstone is identified by a photoelectric effect log response rising above about 2.5 barns/electron or in the absence of this log where the GR log increases persistently above 50 to 100 API units upsection into the Eau Claire Formation. These log criteria are spatially variable because of inferred facies changes to the south and east. Three fairly persistent GR log facies are identified in many boreholes especially in the western basin. A relatively thin (in most basin wells) basal unit, characterized by a GR log response of greater than 25–50 API units, is overlain by a thicker, very low GR log facies, which is in turn overlain by an irregular GR log facies with interbeds exceeding 50 API units. An anomalously thick occurrence of this lower GR log facies occurs in the west-central part of the state, further supporting an irregular depositional surface below the Mount Simon Sandstone as suggested by previous studies (Willman et al., 1975; Wickstrom et al., 2003, 2005). These GR log facies are interpreted to represent the basal arkosic, middle quartzose, and upper argillaceous-arkosic units, respectively, described by previous workers.

Sedimentary Facies, Lithology, and Petrophysics in the Mount Simon Sandstone

Direct observation of sedimentary facies and petrophysical properties from conventional core and cuttings samples in the Mount Simon Sandstone is limited. Two closely spaced (97 m [318 ft] apart) key wells in Holland, Ottawa County, Michigan, the BASF Chemetron D-2 (P# M0071) and the BASF Chemetron D-1 (P# M0070, Figure 6), were available for study. These wells were drilled and used for Environmental Protection Agency (EPA)-UIC class I waste disposal starting as early as 1966 and have a combined total injection volume of more than 1.14 million m^3 (300 million gal of injectate; R. Vugrinovich, MDEQ-OGS, 2008, personal communication). The total UIC well injection volume in the Holland area (as of 2007 in nine injection wells) exceeds 4 billion gal.

The study of sedimentary facies in two cored intervals in the BASF Chemetron D-1 well indicates that the middle and upper GR log facies of the Mount Simon Sandstone consist mostly of fine- to medium-grained moderately sorted quartzose sandstone with abundant current-induced sedimentary structures, including planar

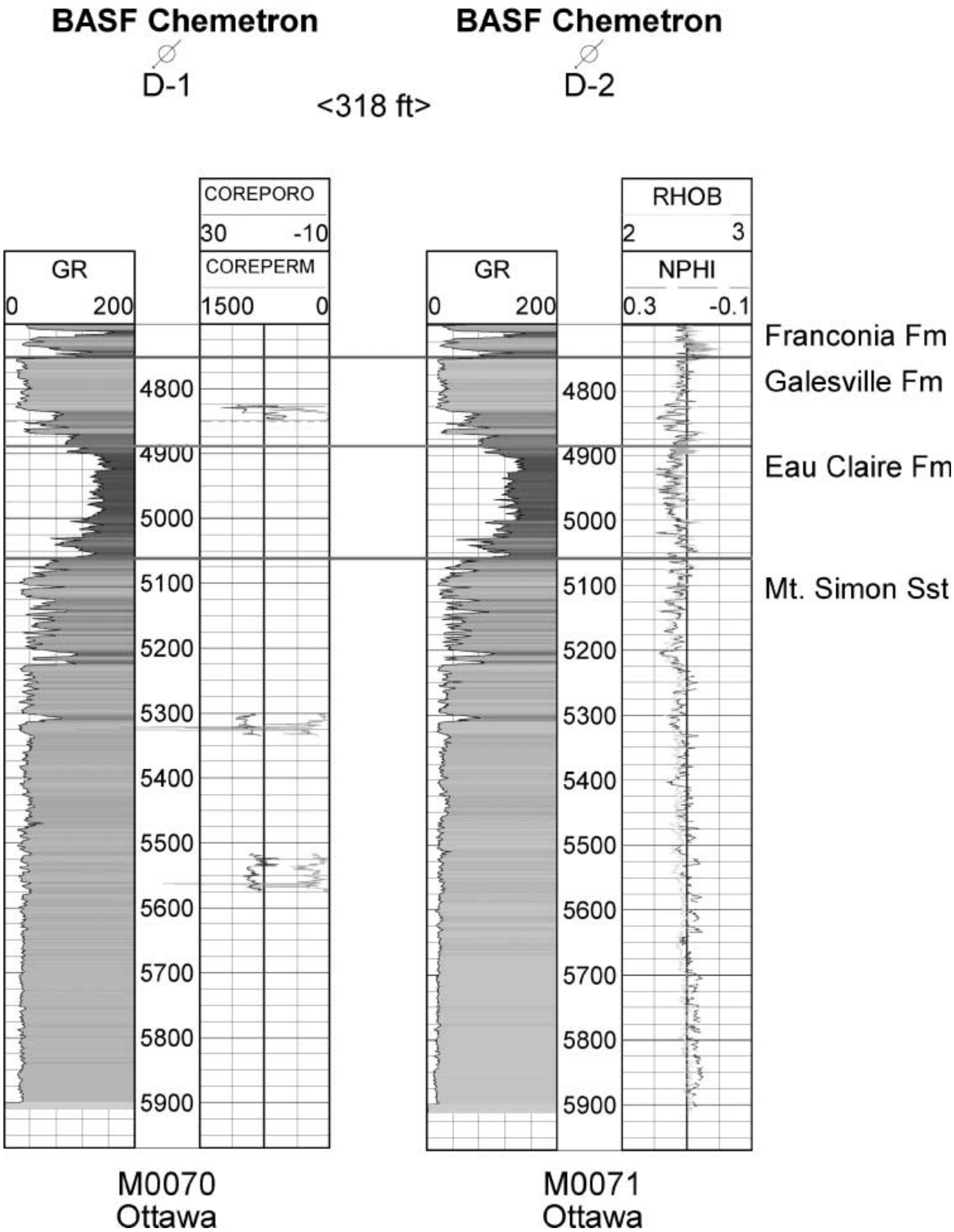
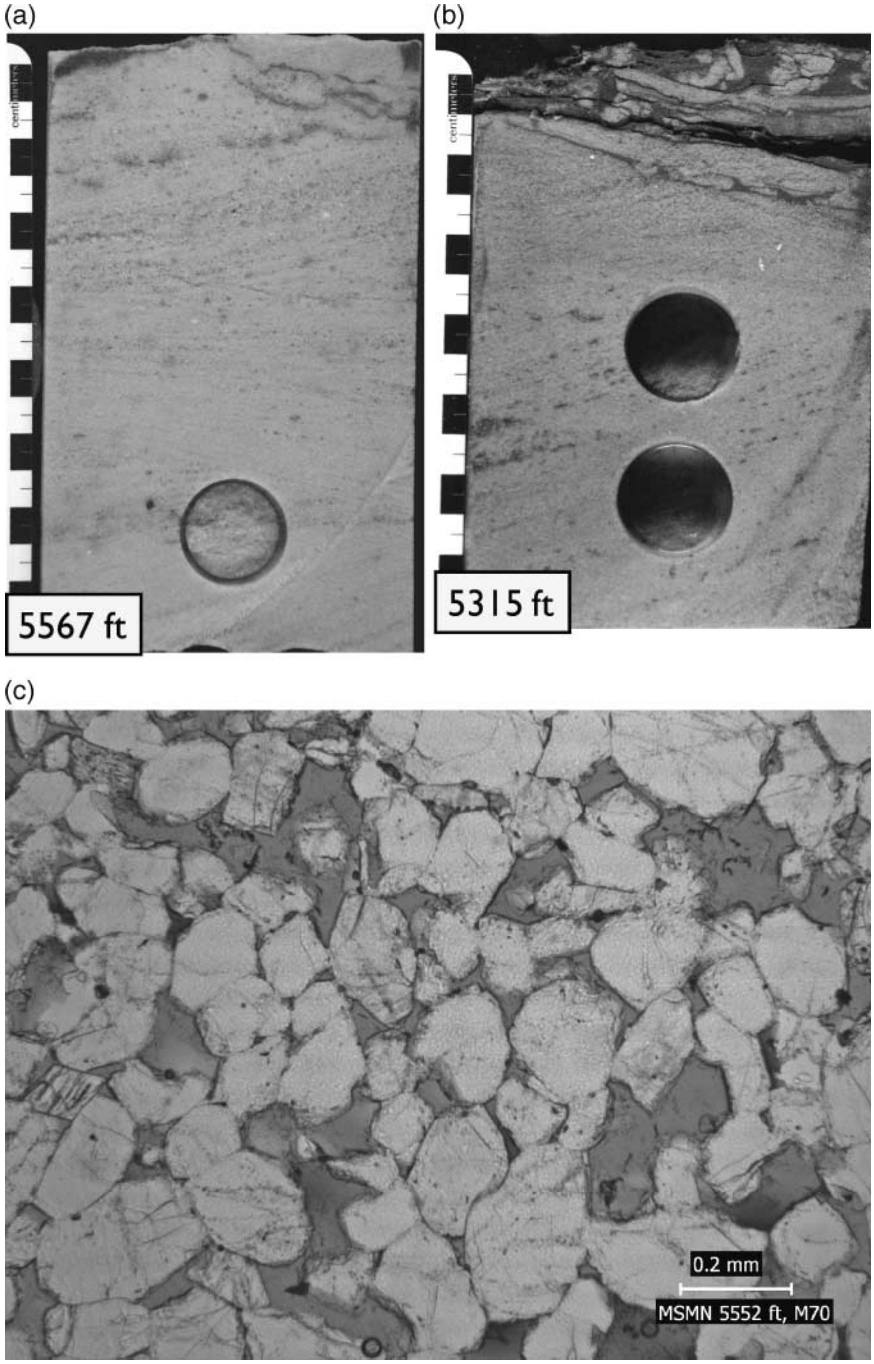


Figure 6. Key Mount Simon wells near Holland, Ottawa County, southwestern Michigan. Well logs show gamma-ray (GR) logs on the left track. The right log track in the D-1 well shows conventional core porosity (%, COREPORO) and permeability (md, COREPERM). The right track in the D-2 well is the bulk density (gray, RHOB) and neutron porosity (black, NPHI).

and cross-bedding and minor, thin shale interbeds (Figure 7a, b). Marine fossils (inarticulate brachiopod and trilobite fragments) are minor constituents of some sandstone beds along with minor, burrowed shaley interbeds (Figure 7b), which increase in abundance upsection. *Cruziana* and *Skolithos* ichnofacies traces in sandstone beds are fairly common in the cores. These textures, structures, and primary grain constituents indicate a shallow subtidal, marine, generally high-energy, shelf depositional environment similar to much of the Mount Simon Sandstone in the upper Mississippi Valley outcrop area of Wisconsin (Driese et al., 1981). The unusual lateral persistence, albeit substantial variation in thickness, of these sheet sandstone facies in lower Paleozoic sandstone formations in the Midwest is noteworthy (Runkel et al., 2007).

An initial study of sandstone petrology from samples in the core from the BASF Chemetron D-1 well suggests a mineralogic composition similar to the Mount Simon Sandstone in Wisconsin and Illinois (Odom, 1975; Hoholick et al., 1984), with a generally mineralogically mature quartzose (>90–95% quartz framework grains) sandstone composition. Increased proportions of K-feldspar and polycrystalline quartz are also present

Figure 7. (a, b) Conventional core photos of representative sedimentary facies from the BASF Chemetron D-1 well. (c) Thin-section photomicrograph from conventional core sample in the BASF Chemetron D-1 well at approximately 5552 ft (1692 m) (measured depth; exact depth is not known). The visual porosity from point count is 20%. MSMN = Mount Simon Sandstone.



especially in thin, fine-grained lamina. Incipient quartz and well-developed K-feldspar overgrowths are common in samples from this core (Figure 7c). Pelletal glauconite, interstitial carbonate cement, and interstitial clay of probable authigenic origin are minor constituents of some samples. Intergranular porosity is noteworthy in all samples (Figure 7c), and some parts of the cored intervals consist of nearly unconsolidated sand. Conventional core porosity and permeability (n = 90) in the Mount Simon Sandstone from the D-1 well average 13.4% and 238 md, respectively.

Core-to-Log Correlation, Reservoir Quality Analysis, and Regional Facies Relationships

Conventional core analysis data were compared to neutron porosity (NPHI) log data in the two BASF Chemetron

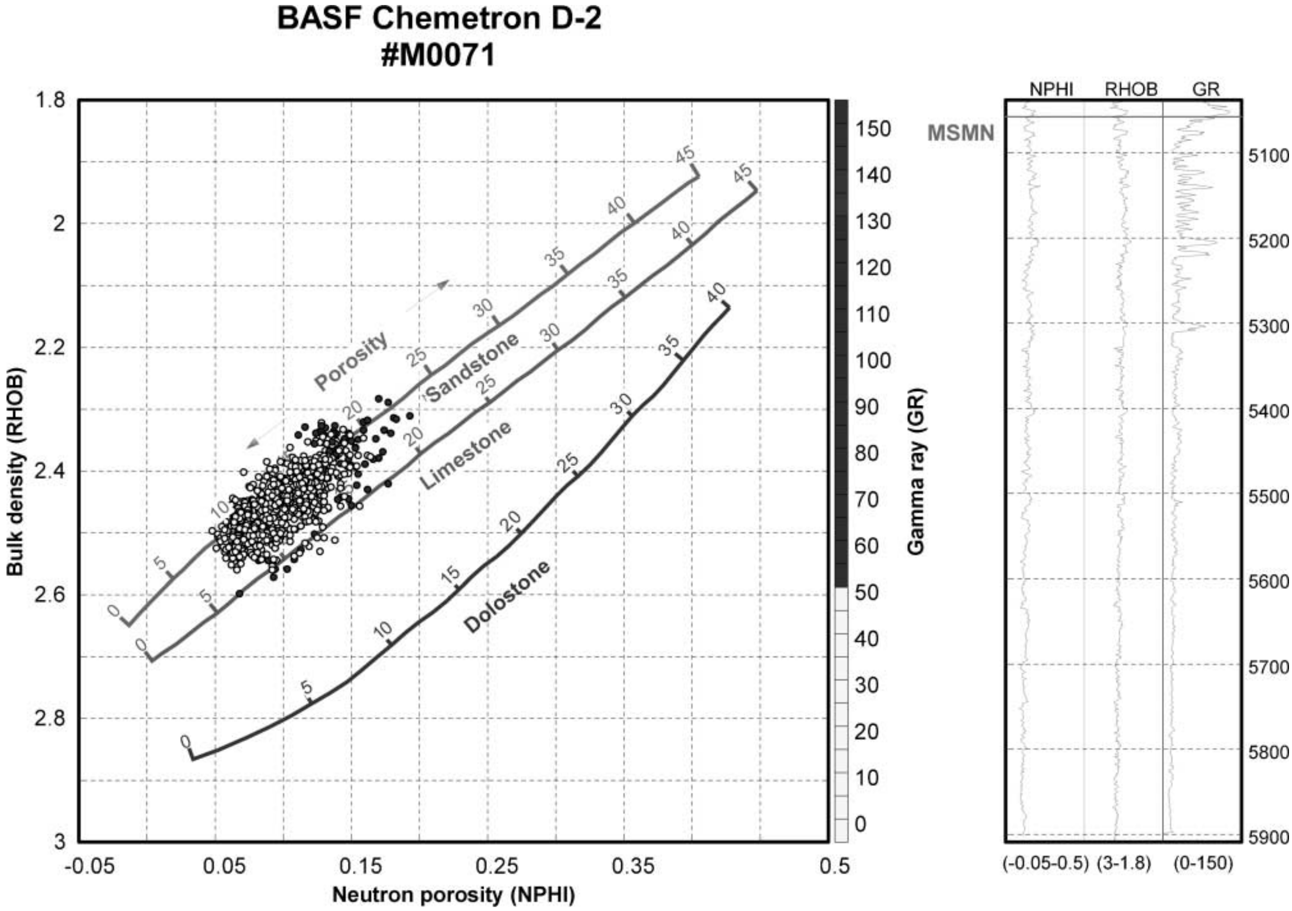


Figure 8. The NPHI-RHOB log crossplot from the BASF Chemetron D-2 well showing the interpreted porous sandstone lithology in the Mount Simon Sandstone.

wells to establish the relationships among core-measured porosity, permeability, and log-based porosity values. A correction factor was established from samples in the D-1 and D-2 wells of

$$\text{NPHI} + 3\% = \text{conventional core porosity} \quad (1)$$

which is consistent with well-established relationships for sandstone porosity in limestone-calibrated NPHI logs (see Asquith and Krygowski, 2004) (Figure 8).

Variations in lithology and porosity in the Mount Simon Sandstone were investigated on the basis of wireline-log data and in the context of fundamental geological influences on reservoir quality, expected because of regional facies changes and burial depth in the Michigan Basin (Figure 3). Lithologic variability relative to sediment source terrains to the (modern) north and west and current depth of burial in the Michigan Basin are shown in a well-log cross section (Figure 9a) from more proximal wells, including the BASF Chemetron D-2 reference well in Ottawa County and the St. Blair #2-24 in Grand Traverse County, compared to a more distal well, the Stofer-Marshall #1, Washtenaw County. The St. Blair well is located to the north of the BASF Chemetron well and roughly along depositional strike. It contains a generally shale-poor, sandstone-dominated succession in the Mount Simon Sandstone (Figure 9b). This well is also in a more deeply buried part of the Michigan Basin (>3048 m [10,000 ft]), and the Mount Simon Sandstone here contains significantly lower values for porosity. The Stofer-Marshall well is located down the inferred proto-Michigan Basin paleoslope to the southeast and contains more admixed shale and calcareous rock types compared to the Mount Simon Sandstone in the Chemetron and Blair wells (Figure 9c). Mount Simon sediment source terrains interpreted to lie to the northwest and up paleoslope by previous workers (Hamblin, 1958; Briggs, 1968; Runkel et al., 2007) would explain the coarser- to finer-grained transition, generally lower reservoir quality, and more argillaceous-arkosic and carbonate-dominated facies along with thinning to the southeast.

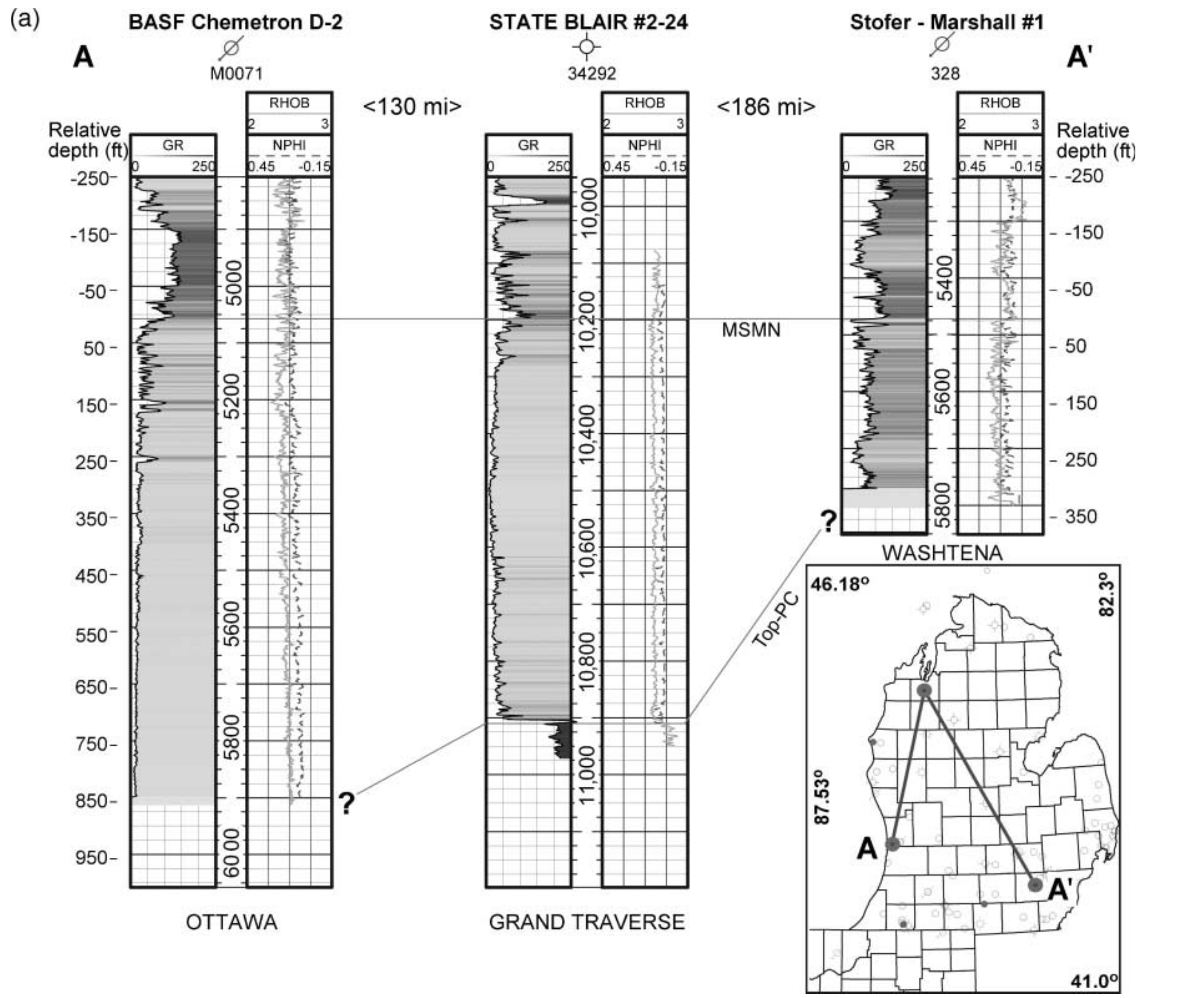


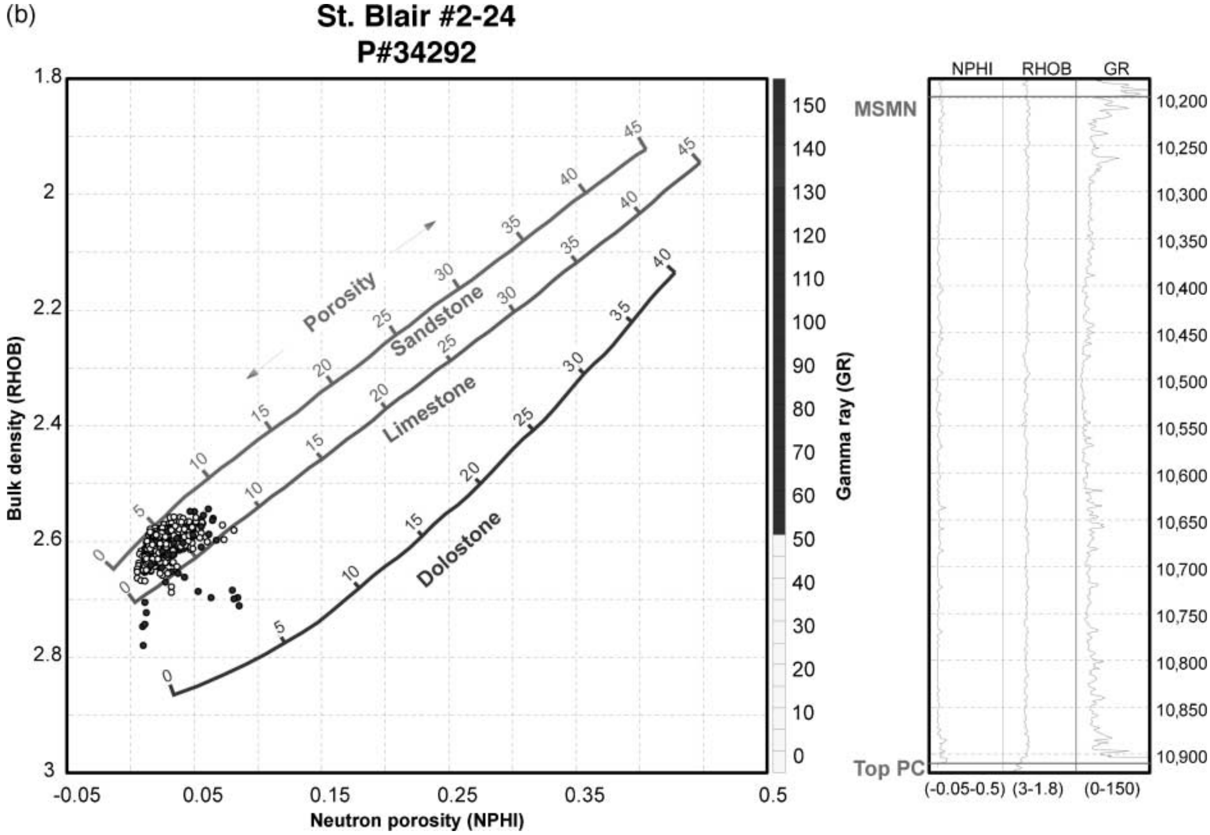
Figure 9. (a) Cross section showing variation in log response in the Mount Simon Sandstone caused by regional facies relationships and burial depth in the Michigan Basin. (b, c) The (NPHI-RHOB) log crossplot from the State Blair #2-24, Grand Traverse County, and Stofer-Marshal #1, Washtenaw County, showing interpreted lithology and porosity variations. MSMN = top Mount Simon Sandstone; Top PC = top Precambrian.

Variation in Mount Simon Sandstone Reservoir Quality with Depth

Other workers have recognized the depth dependence of porosity and reservoir quality in the Mount Simon Sandstone in the Midwest. Hoholick et al. (1984) presented a careful documentation of diagenetic trends relative to burial depth in the Mount Simon Sandstone in the Illinois Basin and interpreted the increase in quartz overgrowth cements and the pressure solution with depth as the main porosity-reducing mechanisms. Similar depth-dependent porosity occlusion by quartz diagenesis was suggested by Cottingham (1990) in the Michigan Basin. Medina et al. (2008) documented the relationship of reduction in porosity and permeability with depth for the area of the Midwest Regional Carbon Sequestration Partnership (MRCSP) from log-data analysis. A global trend of increasing quartz diagenesis and porosity occlusion with depth because of increased burial time and temperature above approximately 75–90° C (167–194°F) (along with other factors) is well established (Giles et al., 2000). The average depth of the Mount Simon Sandstone versus the average NPHI (Figure 10) supports the dramatic decrease in porosity with depth below approximately 1981 to 2438 m (6500 to 8000 ft) in Mount Simon wells in the Michigan Basin.

Regional Trends in CO_2 Storage Capacity

To evaluate the regional CO_2 storage capacity in the Mount Simon Sandstone, establishing a suitable value for minimum effective porosity and determining the



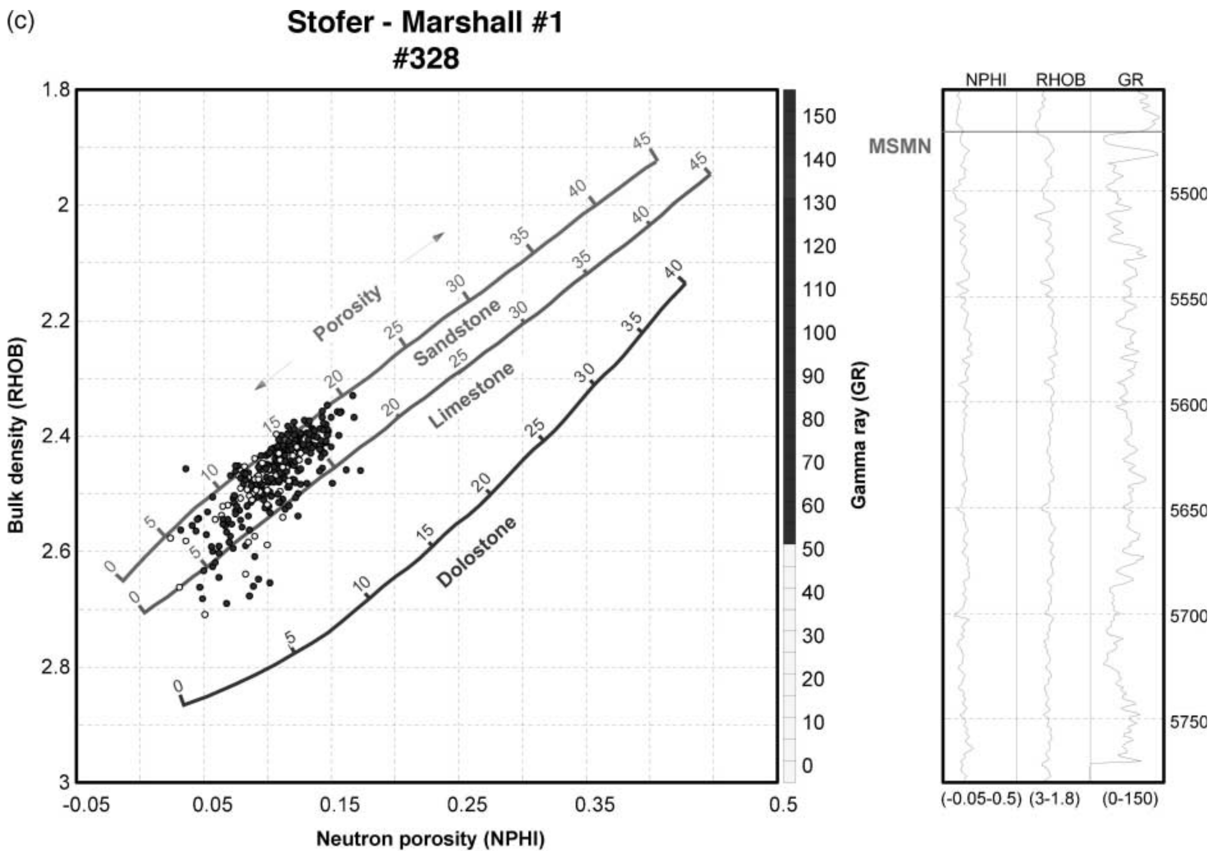


Figure 9. Continued.

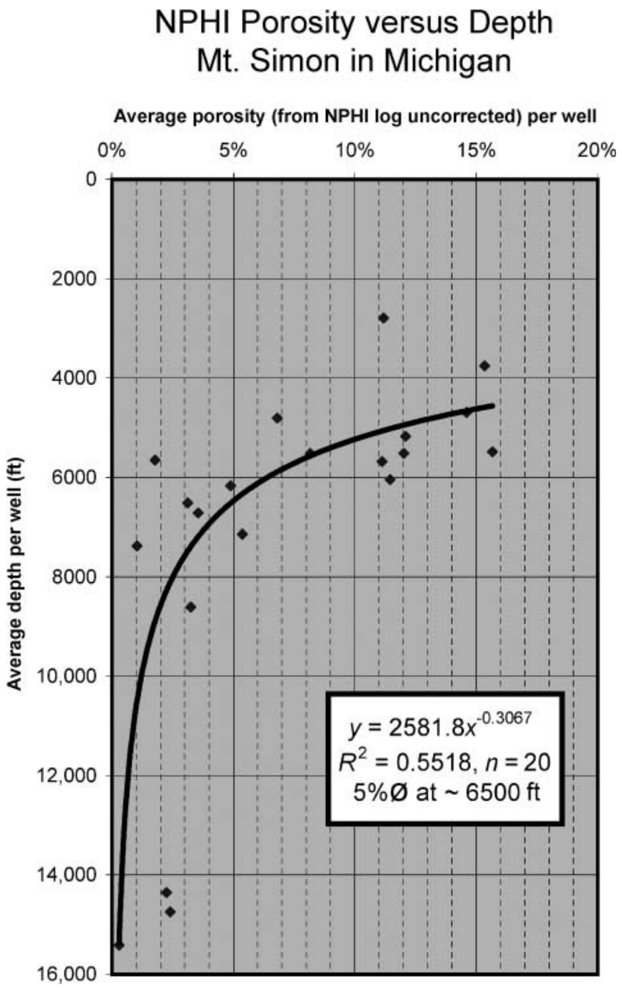


Figure 10. Plot of average measured driller's depth versus average, raw NPHI (uncorrected porosity) log. The trend line suggests that porosity decreases significantly below about 1981 to 2438 m (6500 to 8000 ft) in the Michigan Basin subsurface.

net porosity from well data are necessary. An effective porosity cutoff value was determined by analysis of conventional core porosity and permeability data in the BASF Chemetron D-1 well (Figure 11). A trend line for these data modestly supports ($R^2 = 0.503$) a power function with the relationship of

$$K\ (\text{md}) = (5 \times 10^{-4}) \times Ø^{4.815} \qquad (2)$$

where K (md) is the permeability and Ø (percent) is the porosity. This relatively low correlation coefficient suggests that only about half of the samples conform closely to the trend-line relationship between porosity and permeability and that more than one pore geometry population probably exists in the samples. Porosity and permeability data from the D-1 well are also compared to calculated curves representing the relationship among porosity, permeability, and effective pore-throat geometry (r^{35}, Figure 11); r^{35} refers to the estimated minimum pore-throat radius, or port size, of the pore system thought to dominate fluid flow in any reservoir. Port size was calculated from conventional core-plug porosity and permeability data through an empirical relationship established by H. D. Winlan (see Hartman and Beaumont, 1999, p. 9-31–9-33). Note in Figure 11 that all samples with porosity above the proposed 10% effective porosity cutoff have a calculated port size greater than 5 μm, and therefore these reservoir rocks are interpreted to be dominated by excellent reservoir-quality macropore systems (Coalson et al., 1985). Using the above-cited function (equation 2), 33 md was determined to be the value of permeability associated with the effective porosity cutoff of 10%.

Although porosity cutoff values for effective CO_2 injectivity into saline reservoirs are poorly defined in the literature, relative permeability characteristics of CO_2-brine systems are dependent, in part, on reservoir port size characteristics (Bachu and Bennion, 2008). The larger the pores and especially pore throats in saline reservoirs, the higher the injectivity and effective porosity of the nonwetting-phase CO_2 in a CO_2-brine system. Longstanding industry default (net-reservoir) cutoffs of 0.1 md for natural gas reservoirs and 1.0 md for oil reservoirs are typically used in net-pay calculations (Worthington and Cosentino, 2005). The porosity cutoff (10%) and corresponding minimum permeability value (33 md) used in this analysis should provide an underestimation of the effective porosity and calculated storage capacity because CO_2 has relative permeability

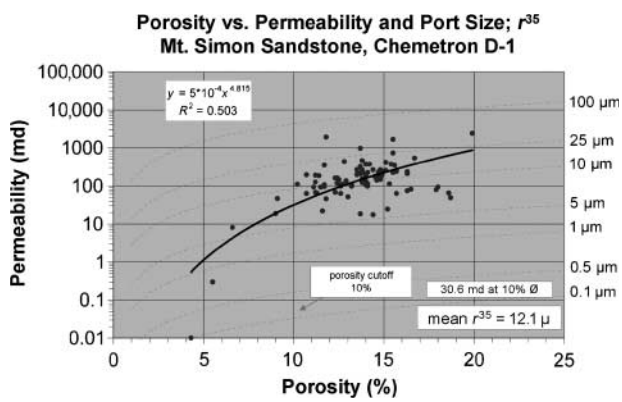


Figure 11. Plot of conventional core porosity versus permeability for Mount Simon Sandstone samples in the BASF Chemetron D-1 well, near Holland, Ottawa County, Michigan. Three probable spurious data points were excluded from the plot because of anomalously high permeability relative to porosity values.

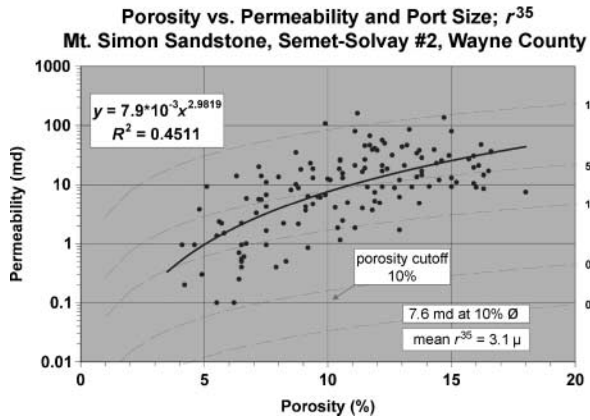


Figure 12. Plot of conventional core porosity versus permeability for Mount Simon Sandstone samples in the Semet-Salvay #2 well, Wayne County, Michigan.

intermediate between high-gravity–low-viscosity liquid hydrocarbon and typical natural gas.

Uncertainty associated with the use of a single cutoff porosity value for regional consideration of net porosity in the Mount Simon Sandstone was investigated using conventional core-porosity data from a UIC class I disposal well, the Semet-Solvay #2 well in Wayne County, southeastern Michigan, an area comprising more distal sedimentary facies in the Mount Simon Sandstone (Figure 12). The mean port size (r^{35}) of about 3 μm (n = 132) and the calculated permeability (from a power trend line of a porosity versus permeability plot) of 7.6 md at the proposed 10% porosity cutoff indicate a dominantly meso- to macropore system in the Mount Simon Sandstone in this well. These lower-reservoir-quality characteristics in the Mount Simon Sandstone in southeast Michigan, compared to southwest Michigan, are consistent with Michigan Basin, regional sedimentary facies, and lithologic trends described above. In light of these spatial variations in Mount Simon lithology and reservoir-quality characteristics in the Michigan Basin, we believe that a 10% porosity cutoff value provides a conservative estimate of effective porosity throughout the study area.

Regional CO_2 Storage Capacity Calculations

Thirty-two wells with suitable wireline-log data were analyzed for net porosity in the Mount Simon Sandstone in Michigan (Figure 13). The net porosity analysis was conducted using corrected digital NPHI, GR, and bulk density (RHOB) well logs. The 10% effective porosity cutoff filter was applied. Additional filters were applied to eliminate inferred, nonsandstone lithology by calculating the net porosity only from log footages with a GR log response below 50 API and an RHOB between 2.3 and 2.8. The net porosity calculations were very sensitive to the value chosen for GR log filtering. Conventional core analysis data (in the Semet-Solvay #2, for example) indicate that the Mount Simon Sandstone has substantial reservoir quality in some areas and in stratigraphic intervals where the GR log response is in excess of 50 API units. Although good reservoir quality is present in parts of the Mount Simon Sandstone with higher GR log than the cutoff value used, this porosity was not included in the net porosity calculation for individual wells. K-feldspar and glauconite may, in part, explain higher GR log responses in wells in these facies areas. These relationships suggest that the results of regional net porosity calculations are conservative estimates of regional storage capacity, especially in more distal facies areas in southeastern Michigan.

Several important geological relationships are supported by the net porosity map shown in Figure 13. Net porosity is, in part, consistent with formation isopach thickness but is profoundly modified by porosity reduction because of deep burial-induced (>1981 m [6500 ft]) diagenesis in the central Michigan Basin. Moderate to poor reservoir quality and thinning of the Mount Simon Sandstone, where buried to only moderate depth, result in modest net porosity values in southeastern Michigan. Maximum net porosity was determined for the Mount Simon Sandstone in a well in northern Indiana (Pfizer IW #2, Porter County, Indiana) of 148 porosity-feet (Øh), whereas several wells in the central and northern Michigan Basin have little or no effective porosity, despite substantial stratigraphic thickness, and are therefore unsuitable for CO_2 injection.

A map of calculated CO_2 storage capacity, by county, is shown in Figure 14. The calculation for storage capacity was done using the following relationship:

$$SC = \text{Ø}h \times \rho_{CO2} \times \xi \times A_g \times C \tag{3}$$

where SC is the CO_2 storage capacity in metric tons (t) per acre, Øh is the net porosity; ρ_{CO2} is the CO_2 density (a constant value of 700 kg/m^3 was used for all depths); ξ is the storage efficiency of 10%, A_g is the grid cell area in acres, and C is a constant for unit conversion to metric tons per acre. The map shows a storage capacity summation, by county, and indicates that the total GSC in Michigan is in excess of 29 Gt. Southwestern Michigan has the most substantial GSC with as much as 11,000 t of CO_2 per acre (27,160 t/ha) and 10 counties with in excess of 1 Gt of GSC.

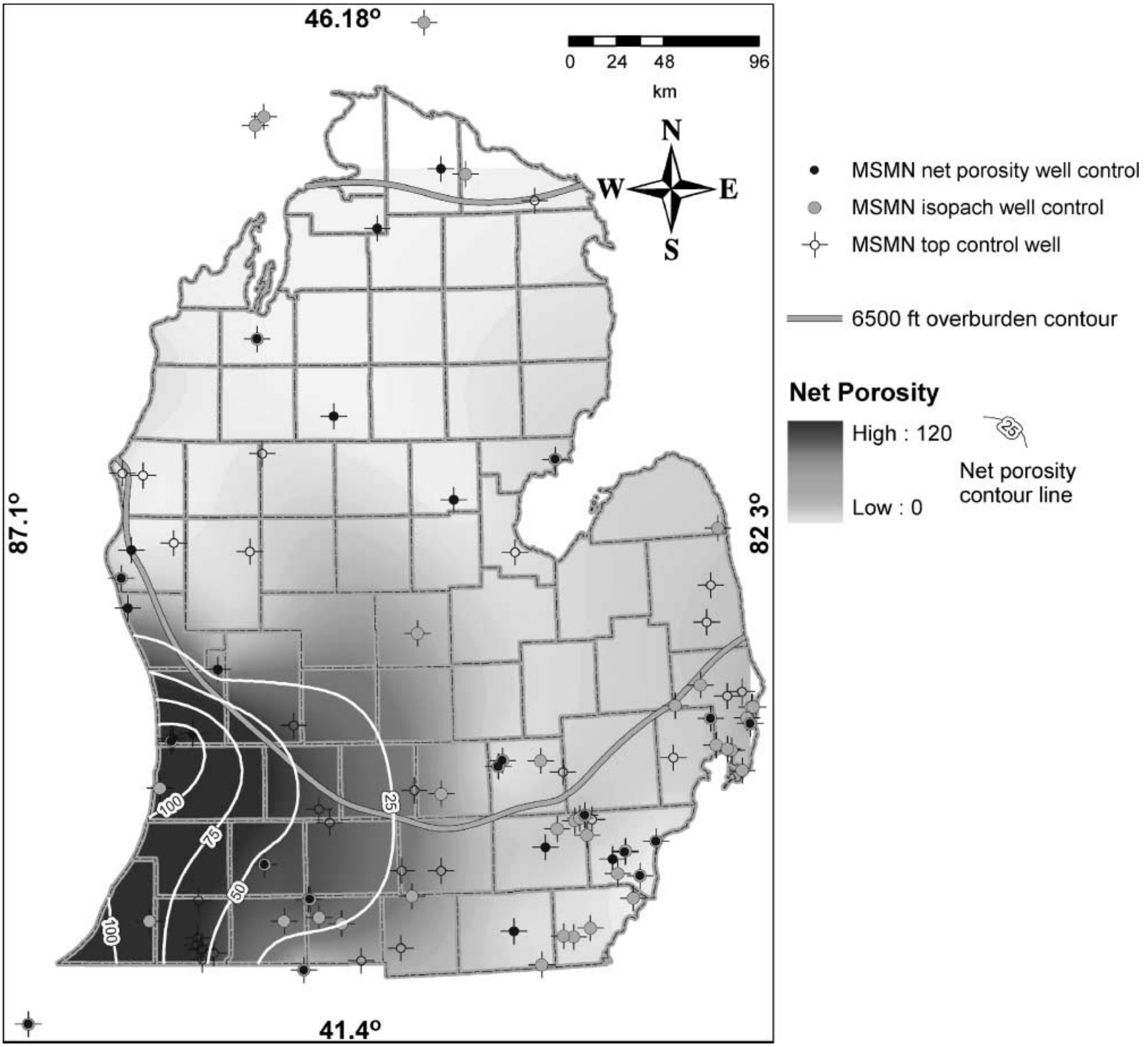


Figure 13. Gridded and contoured net porosity for the Mount Simon Sandstone in Michigan. Geostatistical analysis was done using ordinary kriging and a spherical variogram model with a root-mean-square error for 32 data points of 23. MSMN = Mount Simon Sandstone.

A critical term in the calculation shown in equation 3 is storage efficiency (ξ). The DOE/NETL (2008) presented storage efficiency factors appropriate for regional storage capacity calculations and suggested that a range of values between 1% and 4% are appropriate for calculations when values of gross formation thickness, gross porosity, and large regional area are used instead of net values of porosity from regional wells. The approach used in this analysis is modified from the DOE/NETL (2008) methodology and incorporates a substantial decrease in uncertainty through consideration of net porosity calculated per well as described above. We believe that the use of net porosity values determined from well-log analysis in a regional storage capacity calculation eliminates most, if not all, regional pore volume uncertainty represented in the DOE/NETL (2008) methodology. A range of values for the CO_2 storage efficiency factors between 3% and 35% percent result from the consideration of areal, vertical, and microscopic displacement efficiency and gravity effects in proximity to a single well according to DOE/NETL (2008). The use of a 10% storage efficiency factor for the Mount Simon Sandstone in this analysis may result in some overestimation of regional GCS capacity, but

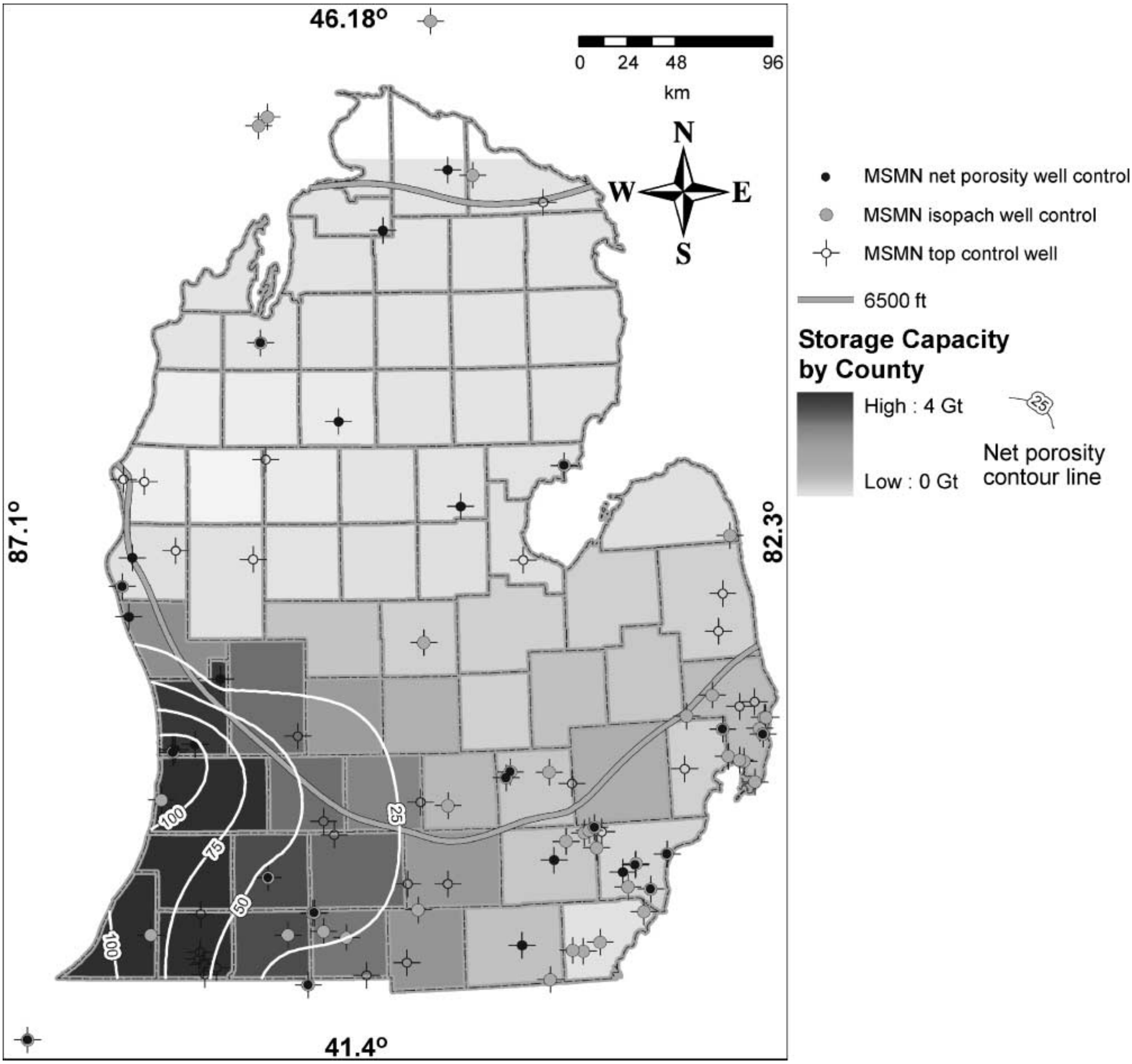


Figure 14. Grid map of calculated CO_2 GSC in Michigan by county. The total GSC is estimated at more than 29 Gt, mostly in the southwestern part of the state.

we believe that this storage efficiency factor is justified for assigning uncertainty to the area immediately surrounding a well-characterized penetration of the reservoir at a given locality and better established uncertainty.

INJECTION SIMULATION MODELING OF CO_2

Numerical simulations of CO_2 injection were conducted using the STOMP-CO_2 simulator (release date February 12, 2008) to assess the potential for geologic sequestration in the deep Mount Simon Sandstone reservoir in a prospective area of southwestern Michigan near Holland in Ottawa County. The ability of the overlying Eau Claire Formation to act as a cap rock was simulated and analyzed. Numerical simulation of CO_2 injection into deep geologic reservoirs requires modeling complex, coupled hydrologic, chemical, and thermal processes, including multifluid flow and transport; partitioning of CO_2 into the aqueous phase; and chemical interactions with aqueous fluids and rock minerals. The simulations conducted for this investigation were executed with the serial version of the STOMP-CO_2 (water,

CO_2, and brine) simulator (White and Oostrom, 2006). The STOMP has been verified against other codes used for simulation of the geologic disposal of CO_2 as part of the GeoSeq code intercomparison study (Pruess et al., 2002) and has been validated against data collected during hydraulic tests and CO_2 injections at other sites (Bacon et al., 2008).

Partial differential conservation equations for fluid mass, energy, and salt mass comprise the fundamental equations for STOMP-CO_2. Coefficients within the fundamental equations are related to the primary variables through a set of constitutive relations. The conservation equations for fluid mass and energy are solved simultaneously, whereas the salt transport equations are solved sequentially after the coupled flow solution. The fundamental coupled flow equations are solved following an integral volume finite-difference approach with the nonlinearities in the discretized equations resolved through Newton-Raphson iteration. The dominant nonlinear functions within the STOMP simulator are the relative permeability-saturation-capillary pressure (k-s-p) relations.

For these simulations, a fixed mass-injection rate well model in STOMP-CO_2 was used. A well model is a type of source term that extends over multiple grid cells. Assuming a given pressure at the bottom of the well and a hydrostatic column of supercritical CO_2 in the wellbore, the injection pressure at each cell in the well is determined as a function of depth. The CO_2 injection rate is proportional to the pressure gradient between the well and surrounding formation. The well model iterates on the injection pressure in the well to match the desired mass-injection rate.

The simulation described herein includes the effect of hysteresis caused by residual supercritical CO_2 entrapment within the Mount Simon Sandstone following injection. A theoretical model for hysteretic saturation functions for aqueous-gas systems was developed by Parker and Lenhard (1987). A simplified version of this model, analogous to Kaluarachchi and Parker (1992), has been implemented in the STOMP simulator with brine as the aqueous phase and supercritical CO_2 taking the function of the gas phase. The model includes effects of residual gas entrapment during aqueous-phase imbibition paths. Gas entrapment during aqueous-phase imbibition will depend on the aqueous saturation and current saturation path. The amount of entrapped gas varies linearly between zero and the gas-effective residual saturation with the apparent saturation, which varies between the reversal point from the main drainage to one. Effective residual gas saturations are computed using an empirical relationship developed by Land (1968) for aqueous and nonaqueous-phase liquid systems. In this simplified hysteretic model for aqueous-gas systems, supercritical CO_2 can be trapped or free, where free-phase supercritical CO_2 refers to continuous volumes, which advect freely, and trapped supercritical CO_2 refers to discontinuous ganglia of supercritical CO_2 occluded within the aqueous phase. Occluded supercritical CO_2 is assumed to be immobile.

Geologic Setting and Hydraulic Parameters

To conduct the simulation, porosity values and their vertical distribution (10-ft [3.048-m] intervals) were used as input data to the simulator from a geophysical log suite from the BASF Chemetron D-2 well (Holland, Ottawa County) that characterized the Mount Simon reservoir very well. The overlying Eau Claire confining unit was similarly characterized using log and core data from the DuPont Montague #1 well, Muskegon County, approximately 76 km (47 mi) to the northwest of Holland. A vertical sequence of permeability values was generated (on 10-ft [3.048-m] intervals) using the porosity-permeability function (equation 2) established for the Mount Simon Sandstone in the Michigan Basin. The Mount Simon Sandstone at the simulation locality occurs at a depth between 1540.5 and 1798.9 m (5054 and 5902 ft). The cap-rock formation at this site is the Eau Claire, located between the depths of 1483.5 and 1540.5 m (4867 and 5054 ft). A maximum residual trapped supercritical CO_2 saturation of 0.2% was assumed for the Mount Simon Sandstone.

Geostatistical Analysis

In the simulation, the geology of the Mount Simon Sandstone and Eau Claire Formation was represented by a spatially correlated random field of porosity and intrinsic permeability that maintained the mean and variance of the data from the wireline logs. The porosity was assumed to be normally distributed, and the intrinsic permeability was assumed to be log-normally distributed. For the Mount Simon Sandstone, the mean porosity calculated was 12.89% with a variance of 0.05%, whereas the mean log permeability calculated was 2.0687 (log md) with a variance of 2.448. For the Eau Claire Formation, the mean porosity calculated was 5.9% with a variance of 0.06% and a mean log permeability of −2.22 (log md) with a variance of 1.16.

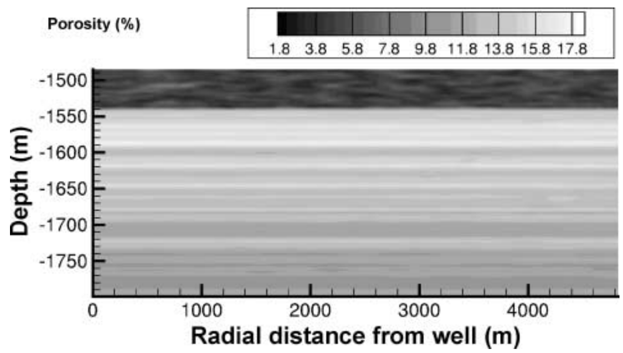


Figure 15. Geostatistical realization of diffusive porosity in the Mount Simon (1540–1799 m [5052–5902 ft]) and Eau Claire (1483–1540 m [4865–5052 ft]) formations.

For the Mount Simon Sandstone, a spherical variogram model was fit to the petrophysical data with a vertical range of 1 m (3.28 ft) for both porosity and log permeability. For the Eau Claire Formation, a spherical variogram model was fit to the well data with a vertical range of 0.305 m (1 ft) for both porosity and log permeability. At the time the model was developed, limited core data were available, so little information about the horizontal variogram range was available. A very long horizontal to vertical ratio of 10,000:1 was assumed for the variogram length in both formations. Based on these variogram models, correlated random fields of petrophysical properties for the Mount Simon Sandstone and Eau Claire Formation were generated using the geostatistical program Sequential Gaussian Simulation (SGSIM) (Deutsch and Journel, 1998). The SGSIM uses a sequential Gaussian simulation algorithm to predict the distribution of porosity (Figure 15) and permeability (Figure 16) within defined vertical grid cells of the reservoir and the confining unit.

Model Parameters

The simulation used a CO_2 injection period of 20 yr. The CO_2 was injected in a 190-ft (57.8-m) interval between 1707.6 and 1765.4 m (5602 and 5793 ft) into the Mount Simon Sandstone reservoir. The injection well was assumed to have an inside-casing diameter of 22 cm (8.7 in.). The assumed fracture pressure gradient of 0.018 MPa/m (0.8 psi/ft) sets an upper limit on the well-bottom pressure of 31.9 MPa (4627 psi).

Simulations were executed on a two-dimensional (2-D) radial grid (Figure 17). The grid covered a vertical depth (in the Z direction) of 315.4 m (1035 ft) between the depths of 1483.5 and 1798.9 m (4867 and 5902 ft). The grid extended 4.8 km (2.98 mi) from the well in the radial R direction. The 2-D grid had a resolution of 158 grid nodes in the radial R direction and a vertical grid resolution of 103 grid nodes. The horizontal grid spacing was 30.48 m (100 ft), and the vertical grid spacing was 3.048 m (10 ft).

A downward pressure gradient of 0.011 MPa/m (0.486 psi/ft) was used to initialize the brine pressure field, which results in initial pressures that range between 20.0 MPa (2901 psi) at the bottom of the Mount Simon Sandstone and 16.5 MPa (2393 psi) at the top of the Eau Claire Formation. A hydrostatic pressure gradient was assigned to vertical boundary surfaces located radially from the vertical injection well. This assumption allows reservoir brine to leave the computational domain (laterally) as CO_2 is injected.

A formation temperature of 50°C (122°F) was assumed at a depth of 1798.9 m (5902 ft), with the temperature in the formation decreasing linearly in the vertical direction at a gradient of 0.0195°C/m (0.011°F/ft). A brine chemistry of 300,000 ppm total dissolved solids (TDS), entirely as NaCl, was assumed. The upper and lower boundaries of the model were assumed impermeable.

The simulation used a CO_2 injection period of 20 yr, followed by an equilibration period of 280 yr, for a total of 300 yr. Numerical dispersion was minimized by constraining the time steps to maintain the Courant condition (Pruess et al., 2002)

$$\Delta t \leq \frac{\Delta x}{v} \tag{4}$$

where Δt is the time step, Δx is the grid spacing, and v is the velocity.

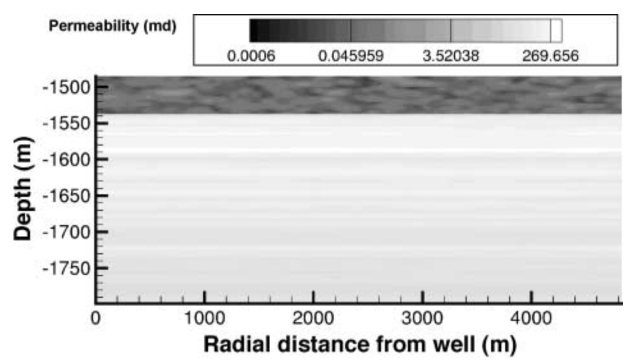
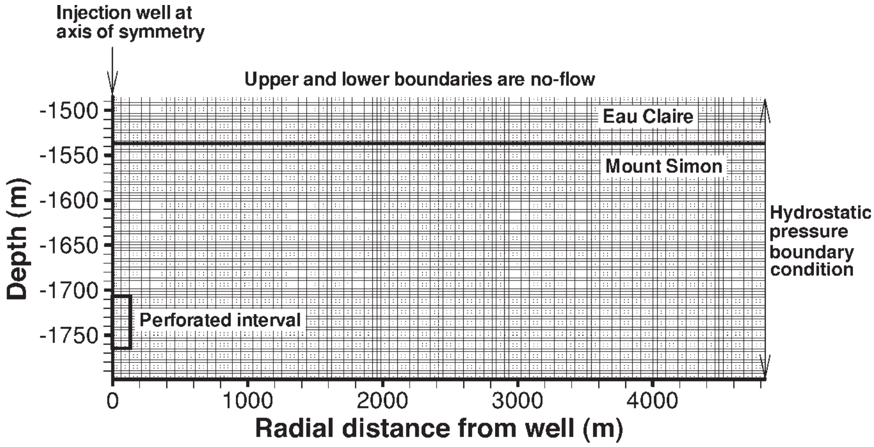


Figure 16. Geostatistical realization of intrinsic permeability in the Mount Simon and Eau Claire formations.

Figure 17. Model grid and boundary conditions for CO_2 injection simulations.



Model Results

Injecting CO_2 into the Mount Simon Sandstone for 20 yr at a rate of 600,000 t/yr results in a 7% increase in the bottomhole pressure from 19.7 to 21.2 MPa (2857 to 3075 psi) initially, as the formation becomes saturated with gas near the well, and then gradually decreases to 20.2 MPa (2929.8 psi) at the end of the injection period at 20 yr (Figure 18). After 20 yr, the total amount of CO_2 injected is 12 Mt; after 300 yr, 9.8 Mt is free-phase (nonentrapped) supercritical CO_2, 0.7 Mt as entrapped in the capillaries of the reservoir pore system, and 1.5 Mt is dissolved into the brine (Figure 19). Once the CO_2 is entrapped or is dissolved in the brine, it is considered permanently sequestered. No accommodations were made in the simulation for CO_2 that may have become fixed as solid mineral phases within the reservoir or seal.

The injected supercritical CO_2 was simulated to have spread into a cylindrical plume with a radius of 1.8 km (1.12 mi) after 20 yr of injection and 3.8 km (2.36 mi) after 300 yr (Figure 20). The supercritical CO_2 rises buoyantly beneath the cap rock because it is less dense than the preexisting brine (Figure 21), leaving small amounts of CO_2 residually trapped in the vicinity of the wellbore (Figure 22). Pressure increase in the formation during injection is slight because of the high permeability of the Mount Simon Sandstone (Figure 23). Pressures during injection at the bottom of the cap rock (1540.5-m [5054-ft] depth) are well below the fracture pressure limit of 27.9 MPa (4046.6 psi), assuming a fracture pressure gradient of 0.018 MPa/m (0.8 psi/ft).

The low-permeability Eau Claire Formation retards the upward migration of CO_2. Three hundred years after the start of injection, only 0.26 Mt of supercritical

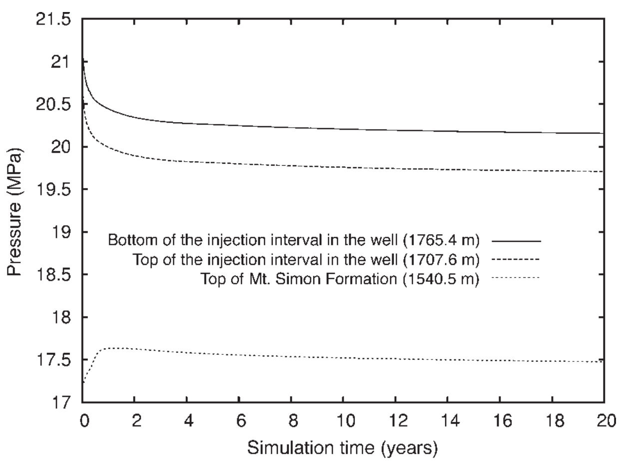


Figure 18. Injection well pressure during CO_2 injection into the Mount Simon Formation at a rate of 600,000 t/yr.

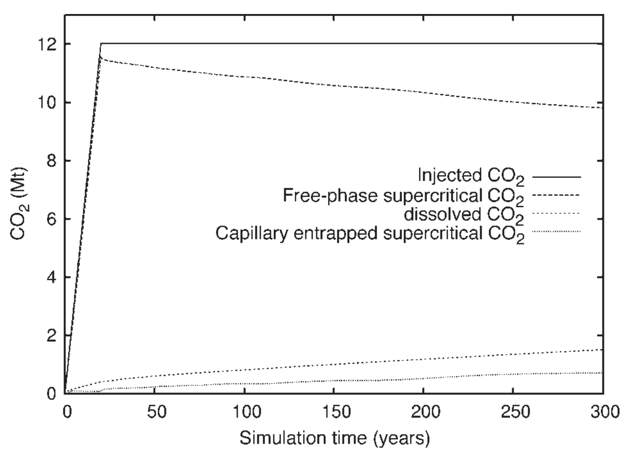


Figure 19. Mass balance of CO_2 injected into the Mount Simon Formation.

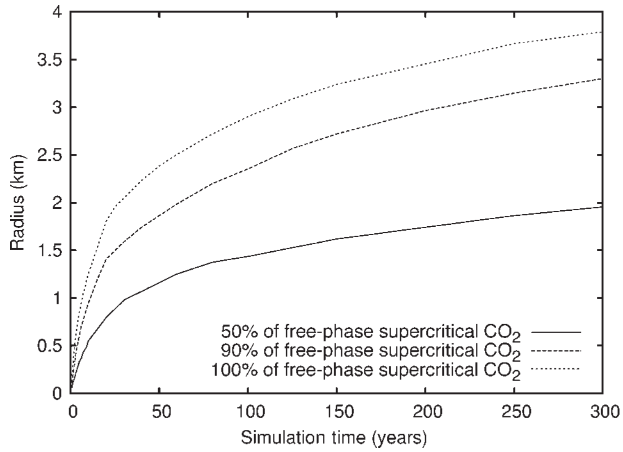


Figure 20. Distance and percentage saturation of the free-phase CO_2 injected into the Mount Simon Formation.

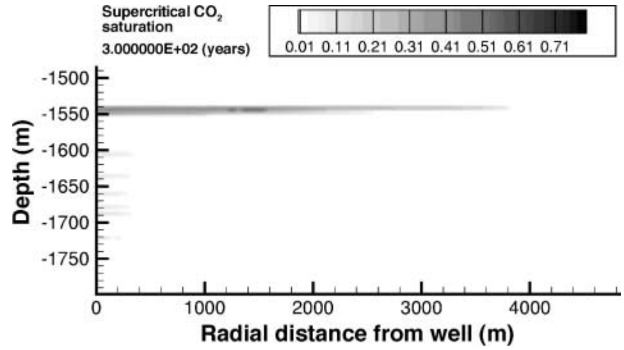


Figure 22. Saturation of supercritical CO_2, 280 yr after the end of the 20-yr injection into the Mount Simon Formation.

CO_2 diffused into the bottom grid cell representing the Eau Claire Formation, which is about 2% of the total amount injected. None of the injected supercritical CO_2 has leaked upward through or out of the Eau Claire Formation.

CONCLUSIONS

The Mount Simon Sandstone in Michigan is an important saline reservoir target for geological sequestration of CO_2 in Michigan. The Mount Simon Sandstone lies at depths between about 914 m (3000 ft), on the periphery of the lower peninsula of Michigan, to almost 4572 m (15,000 ft) in the central basin. Predominantly quartzose sandstone with minor interbedded shale and dolomite occurs in three regional GR log facies. The total isopach thickness ranges from more than 396 m (1300 ft) in a southwest–northeast-trending trough through the center of the state to near zero near basement highs in the southeast lower peninsula. Interpretation of conventional core samples indicates that much of the Mount Simon Sandstone was deposited in shallow subtidal, marine, generally high-energy shelf depositional environments. This depositional system probably extended over large tracks of the Cambrian epicratonic surface and produced a laterally extensive (albeit variable thickness), sandstone-dominated, sheet deposit. Conventional core-to-log correlation indicates both primary sedimentary facies and burial depth control reservoir quality in the Mount Simon Sandstone. Depositional facies-related decrease in reservoir quality caused by the admixture of fine-grained arkosic, carbonate, and argillaceous material to the south and east is associated with a decrease in formation thickness that results in diminished net porosity and geological carbon storage capacity. A dramatic decrease in porosity at burial depths below 1981 m (6500 ft) caused by quartz diagenesis results in little or no storage capacity in the deep Michigan Basin. Estimates, using wireline-log data from 43 regional wells, indicate in excess of 29 Gt of geological carbon storage capacity concentrated in the southwestern lower Michigan. This area corresponds

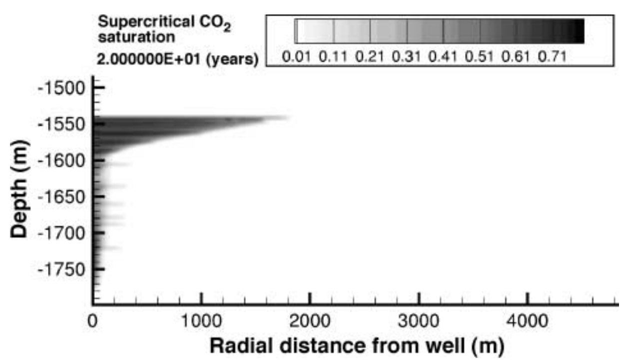


Figure 21. Saturation of supercritical CO_2 after 20 yr of injection into the Mount Simon Formation.

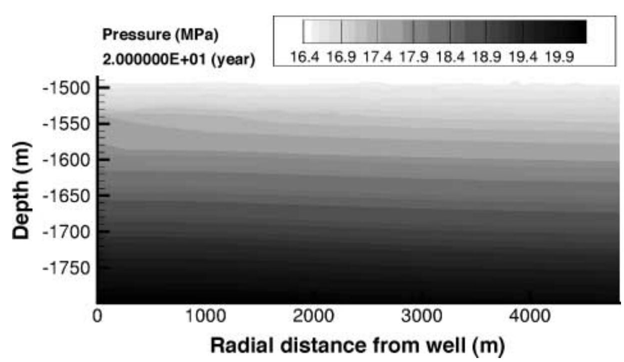


Figure 23. Formation pressure in the Mount Simon Formation after supercritical CO_2 injection.

to thick, sedimentary facies and relatively shallow burial depths where only modest diagenetic modification of reservoir quality has occurred.

Numerical simulations of CO_2 injection were conducted using the STOMP-CO_2 simulator to assess the potential for geologic sequestration in the Mount Simon Sandstone reservoir in a prospective area of southwestern Michigan near Holland in Ottawa County. The simulation used an injection period of 20 yr at a rate of 600,000 t/yr, followed by an equilibration period of 280 yr, for a total of 300 yr. After 20 yr, the total amount of CO_2 injected is 12 Mt; after 300 yr, 9.8 Mt is simulated to remain as a free-phase supercritical CO_2, 0.7 Mt as entrapped in the capillaries of the reservoir pore system, and 1.5 Mt is dissolved into the brine. The supercritical CO_2 was modeled to have spread into a disk-shaped plume with a radius of 1.8 km (1.12 mi) after 20 yr of injection, and to 3.8 km (2.36 mi) after 300 yr. The low-permeability Eau Claire Formation retards almost all the upward migration of CO_2 with 2% of the injected CO_2 invading the lowermost part of this confining unit. Pressures during injection at the bottom of the cap rock (1540.5-m [5054-ft] depth) are well below the fracture pressure limit of 27.9 MPa (4046.6 psi), assuming a fracture pressure gradient of 0.018 MPa/m (0.8 psi/ft) caused by the high permeability of the Mount Simon Sandstone.

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