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Structural, Depositional, and Diagenetic Controls on Reservoir Development: St. Peter Sandstone, Newaygo County, Michigan

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STRUCTURAL, DEPOSITIONAL, AND DIAGENETIC CONTROLS ON RESERVOIR DEVELOPMENT: ST. PETER SANDSTONE, NEWAYGO COUNTY, MICHIGAN

by

Mark S. Caldwell

A Thesis
Submitted to the
Faculty of The Graduate College
in partial fulfillment of the
requirements for the
Degree of Master of Science
Department of Geology

Western Michigan University
Kalamazoo, Michigan
December 1991
Enhanced reservoir quality in the Middle Ordovician St. Peter Sandstone is observed in gas bearing zones in wells located on domal structures. Geometry and degree of this enhanced porosity development is the result of the interplay of structural, depositional, and diagenetic controls. An integrated subsurface study of the Woodville/Goodwell field area was performed in order to document controls on hydrocarbon accumulation.

Recurrent structural growth of domal features throughout the Paleozoic is well documented by isopach mapping. Burial and thermal history studies indicate that hydrocarbons were generated in Ordovician aged source rocks during late Devonian to early Mississippian time, and accumulated in Ordovician to Silurian aged paleo-structural traps. These paleostructural hydrocarbon accumulations were then modified by a post late Pennsylvanian period of structural growth.
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My understanding of the petroleum geology of the Woodville area benefitted from many discussions with geologists working the Michigan basin including: Charlie Stewart, Paul Basinski, Jim Hughes, Kevin Sullivan, John Esch, and John Vrona.

Mark S. Caldwell
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Structural, depositional, and diagenetic controls on reservoir development: St. Peter Sandstone, Newaygo County, Michigan

Caldwell, Mark Sutton, M.S.
Western Michigan University, 1991
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INTRODUCTION AND STUDY OBJECTIVES

Deep drilling in the Michigan basin has led to the discovery of significant reserves of natural gas from Middle Ordovician-aged sandstone reservoirs. Through the end of 1990, 59 fields had been discovered within the Michigan Basin from sandstones of the Glenwood, St. Peter Sandstone, and Prairie du Chien Formations. Although several recent publications (Barnes, 1988; Brady and DeHaas, 1988; Bricker, Milstein, and Reszka, 1983; Catacosinos, Daniels, and Harrison, 1991; Fisher and Barratt, 1985; Harrison, 1987; Nadon, Simo, Byers, and Dott, 1991; and Syrjamaki, 1977) have addressed the stratigraphy, depositional history, and diagenesis of the Middle Ordovician sequence in the Michigan Basin, no detailed studies describing the petroleum geology of St. Peter Sandstone fields have been published. The relative timing of structural growth, porosity development, and hydrocarbon accumulation in St. Peter Sandstone reservoirs is poorly documented in the literature. By integrating structural and isopach mapping, petrophysical analysis, petrography, burial history, and production history, the controls on St. Peter Sandstone reservoir development and hydrocarbon accumulation may begin to be understood.
The study area (Figure 1) covers portions of Goodwell and Norwich Townships (T14N-T15N;R11W) in eastern Newaygo County, Michigan. The study area encompasses five producing St. Peter fields (Figure 2). Goodwell and Woodville fields have proven reserves of 22 and 60 Bcfg (billion cubic feet of gas), respectively, in the upper St. Peter Sandstone. Other St. Peter fields within the study area include Betts Creek, Bissel Lake, and Hungerford fields. The study area was selected because preliminary work indicated that: (a) dramatic porosity variation is present in the uppermost St. Peter Sandstone; (b) porosity variation appeared related to structural position and hydrocarbon accumulation; and (c) a variety of structures that had undergone differing structural histories were represented.

The objectives of this study are as follows: (a) to establish the timing of structural growth relative to hydrocarbon generation and migration; (b) to determine the depositional environment of the St. Peter Sandstone study interval and the depositional control on reservoir quality; (c) to examine the role of diagenesis in reservoir development; and (d) to determine reservoir geometry, fluid saturation, and reservoir characteristics of the St. Peter Sandstone.
Figure 1. St. Peter Producing Gas Fields and Regional Structure of the West Central Michigan Basin.
Figure 2. St. Peter Gas Fields of the Study Area. Field name, year of discovery, and cumulative production to 1-1-91 are indicated.
METHODS

Documenting the structural history of the study area was accomplished by basic subsurface geologic methods. Twenty-five correlated tops were picked from petrophysical logs for each of the 34 Ordovician wells drilled in the study area. Up to ten tops were picked where logs were available from approximately 85 Devonian and Mississippian wells drilled. All wells were located on 1:24,000 scale base maps. From the data base of well tops, a series of eight isopach maps and four structure maps were created and contoured honoring regional trends as defined by previous proprietary work done by the writer.

Conventional four inch cores from the Wolverine Patrick and St. Norwich #2-28 (SWSE, Sec. 28-T15N-R11W) and the Wolverine Jansma #1-29 (NENE, Sec. 29-T15N-R11W) were examined and described for this study. Lithology, sedimentary structures, trace fossils, porosity, grain size, sorting, rounding, diagenetic fabrics, and oil stain were recorded on a standard core analysis form. Horizontal air permeability and Boyle's Law porosity measurements were performed by Core Laboratories (Mt. Pleasant) in one foot increments on the entire cored intervals for the above two wells. Vertical air permeability was also measured for the Jansma #1-29.
Thirty-eight thin sections, six from the Patrick and St. Norwich #2-28 and 32 from the Jansma #1-29 were examined with a petrographic microscope in order to characterize the petrography, diagenesis, and microscopic reservoir quality of the St. Peter Sandstone within the study area. All thin sections were impregnated with blue stained epoxy to aid in defining porosity, and stained with alizarin red to distinguish calcite from dolomite cement.

Wireline log curves for 30 St. Peter Sandstone tests in the study area were digitized in one foot increments and analyzed using the TERRASCIENCES workstation at Western Michigan University, Kalamazoo. Curves digitized included gamma-ray (GR), bulk density (RHOB), neutron porosity (NPHI), deep laterolog (LLD), shallow laterolog (LLS), and micro laterolog (MLL). These log curves were analyzed over a study interval spanning roughly 110 feet (Figure 3, type log) of the lower Glenwood Formation and upper St. Peter Sandstone. Neutron-density crossplot porosity, true resistivity, and water saturation were then calculated and plotted using the workstation.
Figure 3. Type St. Peter Sandstone Log for Study Area.
HISTORY AND GENERAL GEOLOGIC SETTING

The study area is located on the southwest flank of the Michigan intracratonic basin (Figures 1 and 4). Regional northeast dip increases from about 25 feet/mile for Mississippian-aged rocks to about 75 feet/mile for Ordovician-aged rocks. This regional pattern of gentle basinward slope is punctuated by subtle anticlinal closures, terraces, and basinward plunging noses of structure contours. Over 10,000 feet of Cambrian through Jurassic rocks are present in the study area (Figure 5). Studies pertinent to the stratigraphy and geologic history of the Michigan basin include: Dorr and Eschman (1971), Ells (1967), Gardner (1974), Hinze, Kellogg, and O'Hara (1975), Lillienthal (1978), Mesolella, Robinson, McCormick, and Ormiston (1974), and Newcombe (1933).

In 1983, Jennings Petroleum discovered Michigan's second St. Peter Sandstone gas field beneath Goodwell Devonian field. The Anderson #1-8A (BHL:NENESE, sec. 8, T14n-R11W) discovery well produced ten million cubic feet gas per day (Mmcfgd), and 36 barrels of condensate per day (Bcpd) through perforations in the upper St. Peter Sandstone on production test. This was followed by deep gas discoveries at Woodville (1985), Betts Creek (1987) and Hungerford (1988) fields.
Figure 4. Precambrian Structure of the Michigan Basin. Keeweenawan-aged rift zone is shaded. Modified from Catacosinos and Daniels (1991).
Figure 5. Generalized Stratigraphy of the Michigan Basin. Modified from Fisher et al. (1988).
Prior to the St. Peter Sandstone discovery, the petroleum history of the area was dominated by development of oil and gas in Devonian and Mississippian reservoirs. In 1943, discoveries were made on structural closures at Goodwell and Woodville fields, and through 1986 cumulative production of 1,145,293 barrels of oil from the Traverse Limestone (Devonian) was reported for Goodwell field from 31 wells. Goodwell and Woodville Stray Sandstone (Mississippian) reservoirs have been converted to gas storage fields with working storage capacity of 19 Bcfg and 5 Bcfg, respectively.
STRATIGRAPHY

Considerable disagreement exists among geologists as to the proper stratigraphic nomenclature for the Middle Ordovician sequence found in the Michigan basin. The massive sandstone underlying the Glenwood Formation has been referred to as Prairie du Chien (Bricker et al., 1983; Lillienthal, 1978; Wheeler, 1987), Bruggers (Fisher and Barratt, 1985), and New Richmond (Ells, 1967). A growing number of geologists (Barnes, 1988; Catacosinos et al., 1991; Harrison, 1987; Lundgren, 1991; Nadon et al., 1991) have argued that the massive sandstone is stratigraphically equivalent to the St. Peter Sandstone of widespread occurrence in the mid-continent (Dapples, 1955; Ostrom, 1978). The confusion over stratigraphic nomenclature resulted from miscorrelation of the thin St. Peter Sandstone outcrop in Wisconsin and Illinois to the thick massive sandstone of the Michigan basin subsurface. The Michigan basin was undergoing rapid subsidence during St. Peter time (Catacosinos et al., 1991; Fisher and Barratt, 1985) that accounts for the variation in thickness from tens of feet thick on the Wisconsin arch, to over 1000 ft. thick in the central Michigan basin.

Harrison (1987) has suggested that the Glenwood should properly be assigned formation status as opposed to
being the lowermost member of the Black River Formation (Bricker et al., 1983; Lillienthal, 1978). Direct application of existing stratigraphic nomenclature outside the Michigan basin, primarily in Wisconsin and Illinois, dictates that the interbedded dolomite, siltstone, anhydrite, and sandstones occurring beneath the St. Peter Sandstone (variously called Foster, Brazos, or Trempealeau) are properly referred to as the Prairie du Chien Formation. For the purposes of this paper, the terms Glenwood, St. Peter Sandstone, and Prairie du Chien (Figure 3) will be applied as shown in a reference section for the Patrick and St. Norwich #2-28 well.
STRUCTURAL DEVELOPMENT

Structure

Woodville Anticline

Structural mapping on the top of the St. Peter Sandstone (Figures 6-8) shows that the most prominent feature present in the study area is a northwest-southeast trending anticline roughly six miles long by one mile wide. This anticline is doubly plunging from a culmination located in the N1/2 section 33 and the S1/2 section 28, T15N-R11W. Woodville, Bissel Lake, and Betts Creek St. Peter fields are located along this anticline (Figure 6). Woodville field actually consists of two domal features separated by a saddle (Figure 6). Maximum St. Peter Sandstone structural closure at Woodville field is 90 feet. The Bissel Lake and Betts Creek domes are separate features with maximum closure of 40 feet. Structural mapping on the top of the Traverse Limestone (Figure 9) and Mississippian Stray Sandstone (Figure 10) shows a well defined closure of about 40 feet shifted slightly north of the Woodville St. Peter dome. The deeper Bissel Lake and Betts Creek structures have little shallow expression other than a slight nosing of structure contours to the southeast (Figures 9 and 10).
Figure 6. Structure Contours on the Top of the St. Peter Sandstone.
Figure 7. North-South St. Peter Structural Cross Section.
WOODVILLE
28 PATRICK & ST. NORWICH 2-28 WENSTROM 1-33

GOODWELL
ANDERSON 1-8 ANDERSON 1-8A PRIMARK 1-17

ST. PETER STRUCTURAL CROSS SECTION
PRODUCTION TOTALS TO 1-1-91 HORIZONTAL NOT TO SCALE

- PERFORATED INTERVAL
- DST INTERVAL

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Figure 8. East-West St. Peter Structural Cross Section.
Bisel Lake

MYERS 1-34

Hudson 1-35

Coxon 1-2

DANELS 1-1A

DANELS 1-1

Betts Creek

Bulk Density < 2.5 g/cc
Porosity > 10%

St. Peter SS

DST. 3.5 MMCFD
P: 3 MMCFD
18 BC
Cum. Prod. 0.33 BCFG

No Tests

DST 7.8 MMCFD
P: 3.3 MMCFD
9 BC
120 BBL H2O
Cum. Prod. 0.07 BCFG
Zone Abnd.

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Figure 9. Structure Contours on the Top of the Traverse Limestone (Devonian).
Figure 10. Structure Contours on the Top of the Michigan Stray Sandstone (Mississippian).
Goodwell Dome

Well control indicates a minimum of 60 feet of closure on the top of the St. Peter Sandstone at Goodwell (Figure 6). However, based on proprietary seismic data reviewed by the writer (C.J. Stewart III, personal communication), closure of 160 feet is likely with a down-to-the-southwest fault indicated south of Goodwell Dome. Further evidence for this fault interpretation is observed on the Michigan Stray Sandstone structure map (Figure 10). Based on relatively abrupt south structure contour dip (150 ft./mi.), a northwest-southeast trending, down-to-the-southwest fault is inferred at depth to the south of Goodwell Dome (Figure 10). It is inferred that this fault dies out up section above the St. Peter Sandstone, as wellbore evidence of a fault (i.e. missing section) is not observed. The Goodwell dome has a structural closure on the Michigan Stray Sandstone in excess of 100 feet (Figure 10), in comparison to closure of 40 feet at Woodville. The Goodwell dome has a structural closure on the Michigan Stray Sandstone in excess of 100 feet (Figure 10), in comparison to closure of 40 feet at Woodville.

Hungerford Dome

In December of 1988, Petrostar Energy, Traverse City, Michigan, completed the St. Norwich #1-22 (T15N-R11W) for
10 Mmcfd and 144 Bcpd from a lower St. Peter Sandstone reservoir after drill-stem testing five Mmcfd from the uppermost St. Peter Sandstone. This discovery is located nearly two miles north, and over 150 feet lower, at the St. Peter Sandstone level to the Woodville crestal dome (Figure 6). It is evident that this well is located on an entirely separate structure from Woodville Anticline. The size of this feature remains undefined by drilling, however, seismic data presented by Petrostar to the State of Michigan for a field spacing hearing indicates that it is a dome shaped feature which covers about 500 acres.

**Goodwell East Nose**

Goodwell East field (section 23 and 26; T14N-R11W) produces oil and gas from the Traverse Limestone and Michigan Stray Sandstone. Structure mapping (Figures 9 and 10) shows that production occurs from closure of 30 feet or less, located on a north-south trending basinward plunging nose of structure contours, which extends to the south well beyond the study area. Two wells drilled on this feature were completed as dry holes at the Ordovician level. Both wells were completed as moderate gas producers in the Silurian Burnt Bluff dolomite.
Thinning of Isopachs

Domal structures mapped at the St. Peter Sandstone level are associated with thinning of overlying formations (Figures 11-18). Mappable isopachous thinning over deep structures are well defined in most intervals between the Salina A2 Carbonate and the top of the St. Peter Sandstone (Figures 11-14).

The oldest mappable thinning of isopachs over domal structures is present in the Glenwood isopach (Figure 11). This isopach thins from 140 feet off structure to 110 feet on structure at Woodville dome. No obvious gross lithologic facies changes associated with the isopach thinning are observed by wireline log correlation, rather a gradual and systematic thinning of the entire interval. Similarly, the Trenton to Glenwood (Figure 12) and Niagaran to Trenton (Figure 13) isopachs indicate subtle yet mappable thinning over the deep structures with no obvious disconformities present.

The most dramatic thinning of isopachs is in the Salina A1 and A2 Salts, represented by the A2 Carbonate to Niagaran isopach (Figure 14). This pattern of isopach thinning very closely corresponds to deeper structure. The A2 and A1 Carbonates respectively overlie the A2 and A1 Salts, and show no appreciable thickness variation across the study area. However, the A1 Salt, regionally 370 feet
Figure 11. Top of Glenwood to Top of St. Peter Isopach.
Figure 12. Top of Trenton to Top of Glenwood Isopach.
Figure 13. Top of Niagaran to Top of Trenton Isopach.
Figure 14. Top of Salina A2 Carbonate to Top of Niagaran Isopach.
Figure 15. Top of Salina F Unit to Top of A2 Carbonate Isopach.
Figure 16. Top of Dundee to Top of Salina F Unit Isopach.
Figure 17. Top of Sunbury shale to Top of Dundee Isopach.
Figure 18. Base of Jurassic Red Beds to the Top of the Parma Sandstone Isopach.
thick, thins to a minimum of 288 feet at Betts Creek field. Similar thinning is mappable over the other St. Peter fields, yet no thinning whatsoever is present at Goodwell East field.

Upper Silurian through upper Mississippian isopachs exhibit gradual basinward thickening and indicate no systematic thinning of isopachs associated with known deeper structures (Figures 15-17). A widespread post-Bass Islands (Late Silurian) unconformity is documented across the Michigan Basin (Fisher et al., 1988); however, no discernible thickness variations indicative of structural growth and subsequent planation by an erosion surface are evident. Another widespread unconformity of regional extent, between the Mississippian Marshall Formation and the overlying Michigan Formation is well documented in the Michigan Basin (Lillienthal, 1978; Newcombe 1933). Evidence of structural growth and subsequent erosional planation at this unconformity surface is not present in the study area. Rather, the lithologic sequence below the top of the Michigan Formation is remarkably uniform and laterally consistent across the study area.

Dramatic thinning is again mappable in an interval between the upper Pennsylvanian and the base of the Jurassic (Figures 18 and 19). The basal Pennsylvanian Parma Sandstone (Saginaw Formation) lies unconformably on the
Upper Mississippian Bayport Limestone (Michigan Formation) (Lilienthal, 1978). The interbedded sandstones and shales of the Saginaw Formation are in turn overlain unconformably by Jurassic (Kimmeridgian) Red Beds. The Parma Sandstone varies in thickness from 40 to 130 feet across the study area with no apparent relation between thickness and structural position. However, an isopach map of the interval between the base of the Jurassic Red Beds and the top of the Parma Sandstone (Figures 18-19) defines a systematic and mappable thinning of isopachs in close correspondence to Parma Sandstone structural closures. This isopach (Figure 18) defines mappable thinning over Woodville, Goodwell, and Goodwell East fields while no thinning is present at Bissel Lake or Betts Creek fields.

Cause of Thinning

The close correspondence in map view of isopachous thinning and positive structure is highly indicative of structural uplift as the cause of thinning. The present sites of St. Peter structural highs were intermittently positive areas for a long span of geologic time. Landes (1959) recognized this recurrent structural style as very common across U.S. mid-continent oilfields:

Whatever the cause for folding, it must be, in most instances, an activity subject to repeat performances, for recurrent folding is the rule rather than
Figure 19. Jurassic to Mississippian Gamma-Ray Log Stratigraphic Cross Section. Datum is base of Jurassic. This demonstrates dramatic thinning indicative of post-Late Pennsylvanian structural growth.
the exception in the mid-continent and similar areas. Subsurface isopach mapping has shown that most structures are the result of several periods of folding. "Once an anticline, always an anticline is a maxim with wide applicability." (Landes, 1959, p. 289)

The amount of thinning undergone is the result of the interplay of structural uplift, sedimentation rate, erosion, compaction, and plastic flow. Gay (1989) has suggested that "syndepositional compaction structures" are a much more common feature of sedimentary basins than is presently recognized. Syndepositional compaction structures form as a result of gravitational compaction over positive topographic features (Gay, 1989).

The remarkably close correspondence of deeper structure and thinning in the A1 and A2 salt, coupled with the fact that the salts are stratigraphically the lowest relatively incompetent structural units, suggests that the salt isopach thins are the result of plastic flow of salt in response to "late" (i.e., Pennsylvanian or later) structural growth. However, isopach mapping (Figure 18) indicates that Goodwell East field experienced Pennsylvanian (or later) structural growth yet exhibits no thinning of the A1 or A2 Salts (Figure 14). If the thinning of the A1 and A2 Salts were solely due to plastic flow in response to structural uplift, the greatest thinning of salt would correspond in map view with the most pronounced folding (i.e. Woodville Dome). This is not the case. Theoretical studies of the mechanical behavior of salt masses
(Jackson and Talbot, 1986) indicate that salt should experience plastic behavior at relatively shallow burial depths (less than 1000ft).

Fault Control of Structural Growth

Although unequivocal evidence for faulting is lacking, the presence of a deeply buried fault system controlling the patterns of structural uplift is by far the simplest and most workable hypothesis. The most compelling evidence for fault control is the repeated occurrence throughout the Paleozoic of localized thinning over positive structures. It is well documented that the Paleozoic Michigan basin is underlain by a buried segment of the Mid-continent rift system (Dickas, 1986; Fowler and Kuenzi, 1978; Hinze et al., 1975;) of Proterozoic (1.1 Ga) age (Figure 4). Rift related structures are superimposed on older structural grains in the igneous and metamorphic rock complex inherited from the Penokean and other Archean or Proterozoic orogenic events (Hinze et al., 1975). Observed structures in the Minnesota-Wisconsin segment of the mid-continent rift are dominated by normal faulting, which parallels the main trend of the gravity and magnetic anomaly (Dickas, 1986). The dominant northwest trend of structures in the Michigan basin largely parallels the trend of the mid-Michigan gravity anomaly.
The simplest and most obvious conclusion is that the structures observed in Paleozoic rocks in the central Michigan basin were largely controlled by a buried fault system in Precambrian rocks that was initially formed during the Keeweenawan rifting event, and were, subsequently, reactivated intermittently during the Paleozoic. Structures of similar proposed origin overlying the Mid-continent Rift System have been recognized in Kansas (Beriendsen, Blair, Watney, Newell, and Steeples, 1989), Nebraska (Carlson, 1989), and the Illinois basin (Kolata, 1990). Versical (1990) has suggested that many of the anticlines in Michigan formed as "tulip structures" in response to strike-slip movement on basement faults. These "deep-seated" faults do not appear to propagate upward and through the Paleozoic cover rocks.
LITHOFACIES AND DEPOSITIONAL ENVIRONMENT

Lithofacies

Of the 30 wells drilled that penetrated the St. Peter Sandstone within the study area, only two cores of the uppermost St. Peter Sandstone were taken. Conventional four inch cores from the Wolverine Patrick and St. Norwich #2-28 (SWSE, Sec. 28-T15N-R11W) and the Wolverine Jansma #1-29 (NENE, Sec. 29-T15N-R11W) were examined and described for this study. As observed in core, the upper St. Peter Sandstone and lower Glenwood Formation study interval (Figures 20-21) may be divided into three general lithofacies. In ascending order these are: (1) burrowed, rippled sandstone lithofacies, (2) planar-laminated sandstone lithofacies, and (3) argillaceous, sandy-dolomite lithofacies.

Burrowed, Rippled Sandstone Lithofacies

This lithofacies consists of fine to medium grained, sorted to well-sorted, rounded to well-rounded, buff to dark grey or white sandstone. Represented in the interval of 7959-8003 feet in the Patrick and St. Norwich #2-28 well (Figure 20), this lithofacies is generally bioturb-
Figure 20. Core Description, Patrick and St. Norwich #2-28.
Figure 21. Core Description, Jansma #1-29.
ated, with horizontal grazing traces observed toward the base and vertical skolithos burrows prevalent toward the top. Current induced sedimentary structures include ripple cross stratification, possible hummocky cross stratification (Harms, Southard, Spearing, and Walker, 1979) and some remnant horizontal planar lamination. Bedding geometry is defined by erosional bases, clay laminations and abundant mud chip rip-up clasts that define cross laminae slip faces. Stylolites and scour surfaces are common. Many of the primary sedimentary structures are obscured by bioturbation and/or diagenetic fabrics such as pervasive quartz overgrowth cementation, pressure solution, or stylolitization. The burrowed, rippled sandstone lithofacies is gradational upward into the overlying planar-laminated sandstone lithofacies.

In thin section, this lithofacies consists of quartz-arenites with minor (5% or less) amounts of K-feldspar grains. The principle intergranular materials are clays, quartz overgrowths, and dolomite cement.

**Planar-laminated Sandstone Lithofacies**

This lithofacies, present in both cored wells, (Figures 20 and 21) consists of a fine to medium-grained, well-sorted, well-rounded, red to brown sandstone. This lithofacies generally is not bioturbated and exhibits sub-
horizontal to horizontal-planar lamination (Harms et al., 1975). This lithofacies has a noticeably lower percentage of clay-sized material (either true mineralogical clay or micritic carbonate) than the underlying burrowed, rippled sandstone lithofacies. Stylolites, mud chip rip-up clasts, and clay laminations are rare or absent. This lithofacies is somewhat striking in core because of its sometimes bright red color and its massive homogenous appearance. This lithofacies is oil-stained to varying degree in both cored wells. The planar-laminated sandstone lithofacies is the main gas producing zone in the study area and exhibits marked changes in porosity on and off structure.

In thin section, this lithofacies consists of quartz-arenite with minor amounts of K-feldspar grains. This lithofacies has a noticeably lower interstitial clay content than the underlying burrowed, rippled sandstone lithofacies. In addition to clay, which in places lines pores, quartz overgrowths, dolomite, and bitumen (dead oil), are the primary intergranular materials. Minor interstitial material includes feldspar overgrowths and anhydrite cement.

Argillaceous, Sandy-Dolomite Lithofacies

Ten feet of this lithofacies, typical of the Glenwood Formation, is present in the Jansma #1-29 from 7950-
7964 feet (Figure 21). This lithofacies consists of interbedded dark to light grey argillaceous dolomite, and bioturbated buff to white dolomitic argillaceous sandstones. The gradational Glenwood-St. Peter Sandstone contact is picked at 7964 feet in the Jansma #1-29 well. Any evidence of current-formed sedimentary structures in the sandstones has been completely obliterated by extensive bioturbation.

Depositional Environment

The burrowed, rippled sandstone lithofacies represents deposition in middle to lower shoreface environments (Dickinson, Berryhill, and Holmes, 1972; Harms et al., 1975; Moslow, 1984; Scholle and Spearing, 1982). Seaward, and in deeper water than the foreshore and upper shoreface zone, normal, relatively quiet water deposition alternates with turbulent conditions experienced during periodic storms. Storm events produce abundant scour surfaces and "hummocky cross stratification" (Harms et al., 1975, p. 23). Under fair weather conditions, clays and mud will settle from suspension on the lower shoreface. These fine grained sediments are then mixed into underlying sands by burrowing organisms. Burrowing intensity generally increases with water depth in the shoreface zone (Moslow, 1984).
The planar-laminated sandstone lithofacies was deposited in high energy foreshore to upper shoreface environments (Dickinson et al., 1972; Harms et al., 1975; Moslow, 1984; Scholle and Spearing, 1982). As defined by Harms et al. (1975) the foreshore includes the swash, surf, and breaker zones. Typical foreshore to upper shoreface deposits are described as mineralogically and texturally mature sandstones, with low angle to planar "swash cross stratification" (Harms et al., 1975). These high energy deposits have little clay sized material due to winnowing and the lack of burrowing (Dickinson et al., 1972; Harms et al., 1975; Moslow, 1984; Scholle and Spearing, 1982).

The inferred depositional environment for the argillaceous, sandy-dolomite lithofacies is restricted marine shelf, seaward and in deeper water than the shore zone. Beginning in Glenwood time, sand transport into the basin was cut off as a result of regional transgression. Carbonate deposition commenced in response to higher sea level, as evidenced by the 15 to 20 foot thick bed of shaly-dolomite in the lower Glenwood Formation. Sands observed in the lower Glenwood Formation probably represent reworking of upper St. Peter Sandstone deposits. The extensive bioturbation and high clay content of these sediments indicate sediment starved conditions that reflect deeper
water depths than interpreted for the underlying St. Peter Sandstone.

Discussion

Based on the vertical succession of lithologies and sedimentary structures described above, the St. Peter Sandstone study interval represents a shoaling upward sequence deposited by lateral progradation of a sandy shoreline (Dickinson et al., 1972; Harms et al., 1975; Moslow, 1984; Scholle and Spearing, 1982). This sandstone sequence was subsequently "drowned" by a relatively rapid rise in sea level and overlain by restricted marine argillaceous carbonates and reworked sandstones of the lower Glenwood Formation. From the top of the St. Peter Sandstone to the base of the study interval (Figure 20) an overall upward decrease in clay-sized material is observed. Mud chip rip-up clasts, clay laminations, and stylolites generally decrease upward. This trend is well represented by gamma-ray log profiles (Figure 20), which display a general "cleaning" upward trend. The average and maximum grain size of the framework grains exhibits an overall coarsening upward profile, however grain size variations are subtle. If the volume of clay-sized matrix material were quantified, and averaged with framework grain size, a more pronounced up-
ward coarsening sequence, typical of a prograding shore-
line, would be apparent.

In general, the degree of bioturbation increases with
depth in the study interval. The planar-laminated, sand-
stone lithofacies is completely devoid of trace fossils.
Burrowing organisms are not observed in modern beach en-
vvironments (Blatt, Middleton, and Murray, 1980; Moslow,
1984) but are more abundant further offshore in middle to
lower shoreface environments.

Core is unavailable outside of Woodville field, how-
ever, based on log cross sections (Figures 7 and 8), it is
likely that the overall vertical succession described ab-
ove is present in all wells in the study interval. Based
on log correlation the foreshore to upper shoreface dep-
osits have consistently lower gamma-ray log response in
the vicinity of Woodville field (Figures 7 and 8). Given
the generally shallow water setting of St. Peter Sandstone
deposition and the evidence for "early" structural growth
(see following section on structural development and Nadon
et al., 1991), it is likely that subtle facies changes due
to shoaling over sea-floor highs occurred.

Barnes (1988), Harrison (1987), and Lundgren (1991)
have documented that in many other areas of the Michigan
basin, a generally deepening upward sequence is observed
in the upper St. Peter Sandstone, that is gradational into
the overlying Glenwood Formation. Perhaps the "anomalous" shallowing upward sequence described above is the result of shoreline progradation during rising relative sea level. The prograding shoreline built upward and kept pace with rising sea level, and was subsequently "drowned" as sand supply was cut off by inundation of the source area.
RESERVOIR CHARACTERISTICS

Core Porosity and Permeability

Air permeability and Boyle's Law porosity measurements were performed by CORE LABORATORIES INC., Mt. Pleasant, Michigan, in one foot increments on the entire intervals described above for the two wells. Vertical air permeability was also measured for the Jansma #1-29. The results of core analysis indicate (Figure 22) that the highest porosity and permeability is found in the fore-shore to upper shoreface, planar-laminated sandstone lithofacies. The underlying middle to lower shoreface burrowed, rippled sandstone lithofacies has lower porosity and permeability (Figure 22). The argillaceous, sandy-dolomite lithofacies has the lowest porosity and permeability of all lithofacies. Based on the porosity vs. permeability crossplot (Figure 22), three reservoir facies and a reservoir seal are recognized that generally correspond to the lithofacies described above. It should be noted that the close correspondence of reservoir facies to lithofacies is observed only in structurally high wells, such as the two cored. Reservoir Facies A (see below) is not present in off structure wells.
Figure 22. Core Porosity vs. Permeability Crossplot.
Reservoir Facies A

Reservoir Facies A has average porosity of 16% (range 11 to 21.1%) and average permeability of 160 millidarcies (md) (range 20 to 427 md) (Figure 22). In thin section, Reservoir Facies A rocks are generally very low in clay content and have well developed secondary porosity. Porosity can be described as intergranular macroporosity (ie. pores >.015 mm [Coalson, Hartman, and Thomas, 1985]) with a large open pore geometry, and well connected open pore throats. In 25% of the samples of Reservoir Facies A in the Jansma #1-29, vertical permeability was higher than horizontal permeability. This may be caused in part by leached vertical burrows that appear in core as vertical vuggy porosity. All producing gas wells in the study area are perforated in Reservoir Facies A.

Reservoir Facies B

Reservoir Facies B has average porosity of 10% (range 5 to 15%) and average permeability of 6 md (range 2 to 30 md) (Figure 22). Reservoir Facies B rocks contain a higher percentage of interstitial clay which lines pores and bridges pore throats. This pore system is classified as intergranular macroporosity with considerable intercrystalline microporosity (Coalson et al., 1985). Although mea-
sured porosity is not much lower than Reservoir Facies A, permeability is an order of magnitude lower.

**Nonreservoir Rock**

A third grouping of samples of the lowest porosity and permeability includes rocks with average porosity of less than 12% (range 1 to 11.8%) and permeabilities of less than 2 md (range less than .02 to 2 md)(Figure 22). Pervasively clay-cemented sandstones and tightly quartz overgrowth-cemented sandstones comprise the common nonreservoir rock in the St. Peter Sandstone. Bitumen-plugged sandstone and extremely tightly dolomite-cemented sandstone are found interbedded with Reservoir Facies A rocks. All of the above rock types have low effective porosity and permeability, and do not contribute significantly to the storage capacity or the deliverability of the reservoir. Thus, they are characterized as nonreservoir rocks.

**Sealing Facies**

The reservoir seal consists of an impermeable dolomite cap rock of the Glenwood Formation. Measured permeabilities over a ten foot section of this interval in the Jansma #1-29 (7950-7960 ft.) average less than .02 md. Based on wireline log interpretation and correlation the dolomite beds maintain a thickness of about sixteen feet
across the study area, and form the seal to structural hydrocarbon accumulations.

**Petrophysical Log Analysis**

The results of core description and analysis indicates significant vertical variation in reservoir quality. Defining the horizontal porosity distribution and quantifying the relationship between porosity, structural position, and hydrocarbon saturation requires correlation and analysis of petrophysical logs. By integrating core data with log analysis and structural history the controls on reservoir development may be established.

**Neutron-Density Crossplot Porosity**

A common method (Asquith, 1982) of determining the porosity of rocks in the subsurface is by crossplotting neutron porosity and density porosity. This method gives reliable true porosity values regardless of lithology. Neutron-density crossplot porosities were calculated in one foot increments for 30 St. Peter Sandstone wells in the study area. The very close fit between measured core porosity and neutron-density crossplot porosity (Figure 23) attests to the accuracy and utility of this method.

Average neutron-density crossplot porosities were calculated for all wells in the uppermost St. Peter Sand-
stone correlative to the interval of 7924 to 7958 ft. in the Patrick and St. Norwich #2-28. This interval, which comprises the main pay zone (Reservoir Facies A) in all study area fields, varies from 32 to 37 feet thick across the study area and is readily correlated. The results of this analysis (Figure 24) documents dramatic variation in porosity in map view. A "background" or regional porosity average of 10-11% is fairly constant in off structure wells across the study area while porosity systematically increases with increasing structural position above closure to nearly 17% at Woodville and 18% at Goodwell. Enhanced porosity is also observed to a lesser extent at Hungerford, Bissel Lake, and Betts Creek fields. In general, porosity increases linearly at a rate of 5-6% porosity per 100 feet of structural height above closure (Figure 25).

**Water and Hydrocarbon Saturation**

A close relationship between porosity enhancement and structure is evident. Much of the pore space in areas of enhanced porosity is occupied by hydrocarbons in these structurally controlled accumulations. One of the objectives of this study is to determine the role of hydrocarbons in the evolution of porosity. As such, relating the distribution of hydrocarbons to structure and reservoir...
Figure 23. Core Porosity and Neutron-Density Log Crossplot Porosity for both Cored Wells. GR=gamma ray, CORG=core gamma ray, CORP=core porosity, PHIX and XPP=ND crossplot porosity.
Figure 24. Average Neutron-Density Crossplot Porosity for Foreshore/Upper Shoreface Facies. See text for discussion.
Figure 25. Average Neutron-Density Crossplot Porosity vs. Structural Position.
geometry, by means of log analysis, is required.

Water saturation (Sw) is the percentage of pore volume in a rock which is occupied by formation water (Asquith, 1982). Water saturations are calculated based on empirical knowledge of the inherent resistivity of the formation, resistivity readings obtained from the laterolog tool, and neutron-density crossplot porosity (Asquith, 1982). Deep laterolog values were corrected for the effects of invasion of drilling mud filtrate to obtain true formation resistivity (Rt), using tornado chart algorithms programmed into the workstation. Water saturations (Sw) were then calculated using the formula and parameters defined in Figure 26.

Calculating water saturations in the St. Peter Sandstone is a complicated and often frustrating experience. In addition to inherent resistivity of the rocks and their contained fluids (water or hydrocarbons), resistivity log response is affected by variable depth of invasion of drilling mud filtrate into the formation, high resistivity "shoulder" bed effects, and the "Groningen" effect (Lorenzen, 1989). Cementation exponent (m) is probably quite variable as well because of the variable pore geometry described above in this diagenetically complex reservoir. In spite of the difficulties in calculating water saturations, the results of log analysis are streng-
\[
S_w^{-n} = \frac{R_t}{R_w} \Phi_{XP}^m
\]

where:

- \(S_w\) = Water Saturation
- \(R_w\) = Formation Water Resistivity
  
  \[0.027 \text{ ohm-m} \times \text{BHT (147 deg. F)}\]
- \(R_t\) = Formation Resistivity
- \(\Phi_{XP}\) = Crossplot porosity
- \(m\) = Cementation Exponent = 1.58
- \(n\) = Saturation Exponent = 1.71

**Figure 26. Water Saturation Equation.** See text for discussion.
thened by drill stem test results integrated with structure mapping. For example, the Patrick #1-28 (SW/4, NE/4; Sec. 28, T15N-R11W) and the Anderson #1-8 (NE/4, NE/4; Sec. 8, T14N-R11W) have calculated water saturations in excess of 50% in the foreshore to upper shoreface facies. These structurally low wells (Figures 6-8) recovered 3522 and 6235 feet of formation salt water during drill-stem testing, indicative that these wells penetrated the reservoir below the gas water contact. Productive gas wells all exhibit calculated water saturations of 10 to 40% in the foreshore to upper shoreface facies.

The results of log analysis, integrated with subsurface mapping, indicates that a water saturation cutoff of greater than 50% closely approximates the gas-water contact (Figure 27). Reservoir Facies A rocks exhibit irreducible water saturations as low as 10% and average 15% where productive across the study area. Irreducible water saturation is defined as "the water saturation at which all the water is adsorbed on the grains in a rock, or is held in the capillaries by capillary pressure" (Asquith, 1982, p. 2). A hydrocarbon zone at irreducible water saturation will produce hydrocarbons water free. Reservoir Facies B rocks exhibit irreducible water saturations of 20-50%, as a result of clay-sized intergranular matrix with more capacity to hold water than the cleaner Reser-
Figure 27, Computer Processed Log: Patrick 2-28. See text for discussion.
voir Facies A.
ORIGIN AND MODIFICATION OF POROSITY

Porosity varies dramatically within relatively short distances (i.e., less than 2500 ft.) within foreshore to upper shoreface facies of the uppermost St. Peter Sandstone (Figure 24). It has also been observed that porosity varies from about 10% in lower energy depositional facies to as much as 20% in higher energy facies in the same wellbore. The observed porosity distribution in the St. Peter Sandstone is the result of a sequence of geologic processes that acted upon the original sediments. These processes can be classified as either depositional or postdepositional (diagenetic).

Depositional Control of Porosity

The primary depositional controls on reservoir quality are sandstone composition, grain size, and sorting (Blatt et al., 1980; Bloch, 1991). Within the St. Peter Sandstone analyzed for this study, porosity development is closely related to depositional facies. Rock of the highest porosity occurs in sandstones deposited in high energy foreshore to upper shoreface environments. Lower energy middle to lower shoreface facies have consistently lower porosity (and permeability), largely due to interstitial
clay-sized material of depositional origin. These rocks remain of comparably low reservoir quality.

Although a subtle coarsening-upward pattern is observed in the study interval, grain size and sorting of framework grains are similar in both high and low energy facies. More than anything, this is probably a function of provenance from multicycle Early Paleozoic sandstones of the source area (Harrison, 1987; Lundgren, 1991). There simply was not a wide spectrum of grain sizes (or grain composition) supplied to the depositional basin. Depositionally, the difference in porosity and permeability observed between high and low energy facies is due to the relative abundance of fine grained (clay sized) sediment present in lower energy facies.

Diagenetic Modification of Porosity

The St. Peter Sandstone has undergone complex diagenesis that has resulted in sandstone porosities ranging from 0 to 22% in the study interval. Diagenetic processes can either reduce or enhance primary porosity by physical and chemical processes that "are functions of temperature, effective pressure, and time." (Bloch, 1991; p. 1147). The principle intergranular materials that occlude pore space are quartz overgrowths, clays, and dolomite cement. Minor interstitial material includes bitumen (dead oil), feld-
spar overgrowths, and anhydrite cement. Perhaps the finest reservoir rock present in the St. Peter Sandstone of the Michigan basin is located in the study area (Reservoir Facies A), with porosities ranging up to 22% and permeabilities of over 600 millidarcies. The high reservoir quality observed is likely the result of the pervasive development of secondary porosity (Barnes, 1989; Lundgren, 1991). Within the study interval, evidence for secondary porosity (Figures 28-31) includes cement dissolution fronts, elongate and oversize pores, partial dissolution of grains, and inhomogeneity of packing (Schmidt and McDonald, 1979).

A two to three foot thick, tightly dolomite cemented zone is observed in core ten feet below the top of the St. Peter Sandstone (7936-38 ft. in the Patrick and St. Norwich #2-28) (Figures 20 and 30). This tightly dolomite cemented sandstone is separated from excellent reservoir quality rock by a dissolution front (Figure 31) with no changes of framework grain size or sorting evident across the front. The dolomite cement is recognized as being a very early carbonate cement by the presence of "floating" sandstone grains (Erdman and Surdam, 1984). This tight zone is persistent throughout the study area in both on and off structure wells (Figures 7 and 8), which also suggests depositional or early burial origin. This example
Figure 28. Photomicrograph of Secondary Porosity Developed in Foreshore/Upper Shoreface Facies. (Jansma #1-29, 7985 ft.). Evidence for secondary porosity includes elongate, oversize pores, partial dissolution of grains, and general inhomogeneity of packing. Note pressure solution, quartz overgrowths, and sericitized K-feldspar grain. Magnification 70X, plain light.
Figure 29. Photomicrograph of Well Developed Secondary Porosity in Foreshore Facies. (Jansma #1-29, 7994 ft.). This sample had measured plug permeability of 609 md. and 18.2% porosity. This sample exhibits very open framework that does not appear to have undergone significant compaction, and only minor pressure solution. Open framework and notable absence of quartz overgrowth cement may result from early carbonate cement that was subsequently dissolved. Note residual oil and the absence of interstitial clay. Magnification 70X, plain light.
Figure 30. Photomicrograph of Tightly Dolomite Cemented Sandstone. (Patrick and St. Norwich #2-28; 7937 feet). Porosity=1.7%, permeability=.02 md. Sand grains "floating" in dolomite matrix and the lack of significant compaction or quartz overgrowth cementation are suggestive that this cement represents early marine carbonate cement, that was subsequently dolomitized. The degree of grain support increases toward the dissolution front (Fig. 31). Magnification 70X, plain light.
Figure 31. Photomicrograph of Dissolution Front. This illustrates the abrupt change in reservoir quality that occurs due to dissolution. Pervasive dolomite cement reduces porosity and permeability to nearly zero while excellent reservoir quality is present across the dissolution front. This sample is from high energy foreshore/upper shoreface facies. Magnification 70X, plain light.
presents conclusive evidence for secondary porosity formation across a diagenetic front. It is also evident (Figures 30 and 31) that this zone of early carbonate cement did not experience subsequent diagenetic modification other than dolomitization. This interval "survived" the secondary porosity forming processes, and very nearly maintained its original depositional fabric.

Barnes (1988), Barnes, Turmelle, and Adam (1989), Budros and Daly (1986), and Lundgren (1991) have shown that pervasive quartz overgrowth cementation commonly occludes porosity in shallow water, high energy lithofacies in the St. Peter Sandstone. The relationship of porosity to depositional facies is anomalous within the study area, in that quartz overgrowth cementation does not completely destroy porosity in foreshore to upper shoreface facies. Perhaps, pervasive quartz overgrowth development did not occur because primary porosity was partially filled with early carbonate cement. This carbonate cement was subsequently dissolved upon further burial, nearly restoring porosity to that of shallow burial conditions.

In summary, porosity distribution in the St. Peter Sandstone has been modified by diagenetic processes including compaction, pressure solution, dissolution and cementation by calcite (now dolomite), quartz, chlorite,
illite, and other minerals (Figures 28-33). A generalized paragenetic sequence of diagenetic events (Figure 34) based on observations in this study is in general agreement with previous work by Barnes (1988); Barnes et al. (1989); Budros and Daly (1986); and Lundgren (1991).

Discussion

The existence of comparatively "tight" rock (10% porosity) immediately adjacent laterally to enhanced porosity (Reservoir Facies A) within upper shoreface to foreshore facies is problematic. Based on close correlation of gamma-ray logs (Figures 7 and 8) and given the known lateral continuity of shoreface environments, a depositional origin for this pattern of porosity development is unlikely. The linear relationship (Figure 25) of porosity to structural position, and the correspondence of hydrocarbon accumulation to areas of enhanced porosity, are also suggestive of post depositional modification of porosity.

The existence of secondary porosity in rocks of moderate to deep burial depth has become widely recognized in recent literature (McDonald and Surdam, 1984; Schmidt and McDonald, 1984). Theoretical and experimental studies show that thermal maturation of kerogen produces organic and inorganic acids with the potential to dissolve rock matrix and framework grains (Surdam, Boese, and Crossey, 1984).
Figure 32. Photomicrograph of Clay Filled Sandstone. This sample from lower energy middle to lower shoreface facies (Jansma #1-29, 8003 ft.). Measured porosity of this sample is 15.3% but permeability was only 2.2 md. Much of the porosity is microporosity associated with clay minerals, which line pores and bridge pore throats. Pervasive quartz overgrowth cementation is lacking, possibly as a result of clay coats inhibiting nucleation sites. This sample has undergone significant compaction. Note partially sericitized K-feldspar grain. Magnification 70X, plain light.
Figure 33. Photomicrograph of Supermature Quartzarenite of Foreshore/Upper Shoreface Facies. Measured permeability is 17 md. and porosity 11.4%. Reservoir quality is reduced by pore filling bitumen which blocks pore throats and locally completely fills pore space. Note pressure solution and relative lack of interstitial clay or quartz overgrowth cementation. Magnification 70X, plain light.
### Relative Timing of Diagenetic Events

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<tr>
<th>EARLY</th>
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<tr>
<td>Early Marine Carbonate Cement</td>
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<tr>
<td>Quartz Overgrowth Cementation</td>
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<td>Mechanical Compaction</td>
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<td>Pressure Solution</td>
<td>Dolomitization of Precursor Carbonate</td>
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<td>Formation of Secondary Porosity</td>
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<td>Hydrocarbon Emplacement</td>
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<td>Burial Dolomite</td>
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*Figure 34. Generalized Sequence of Diagenetic Events.*
Bjorlykke (1984) has suggested that much secondary porosity identified in the literature may in fact be dissolution enhanced primary porosity. In well-cemented sandstones, limited pathways for dissolution fluids exist, while "maximum leaching by pore water will occur in sandstones having the highest primary porosity" Bjorlykke (1984, pg. 282). Fabric and texture of dissolution enhanced primary porosity would be indistinguishable from secondary porosity as defined by Schmidt and McDonald (1984). Possibly the tightly dolomite cemented zone described above survived dissolution because it retained no porosity and permeability pathways for leaching fluids, while sandstone retaining some amount of primary porosity experienced dissolution enhancement.

Although much of the porosity observed is likely the result of leaching by acidic pore waters, it is also recognized that the present porosity and permeability distribution is largely controlled by depositional facies. Rock of the highest reservoir quality was deposited in high energy foreshore to upper shoreface facies that initially had the highest primary porosity. Lower energy middle to lower shoreface deposits had lower primary porosity due to a higher mud to sand ratio. These basic depositional differences exerted control over later diagenetic
processes by controlling the extent to which water moved through or within a given sediment package. Original porosities and permeabilities of homogenously burrowed, fine grained, clay-rich deposits of the lower shoreface were likely low because of the abundance of detrital clay, and were further reduced at an early stage by compaction. Because of the very low permeability, these deposits probably acted as systems which were closed or semiclosed (experiencing expulsion but not input) to migrating pore waters. The dominant diagenetic reactions in these sediments reflected rearrangement of materials in situ and included processes such as clay neomorphosis and minor development of quartz overgrowths. (Stonecipher and May, 1990, p. 41).

Higher energy, foreshore/upper shoreface facies sediments can be characterized as relatively open pore systems with the potential for throughflow of migrating pore waters.
TIMING OF HYDROCARBON ACCUMULATION

Timing of Trap Formation

The results of isopach mapping are summarized (Figure 35) by a series of histograms for the five St. Peter fields and Goodwell East nose. The percentage of thinning for each structural feature was determined by dividing the minimum thickness of a stratigraphic interval by its regional thickness. Based on the above arguments (see Structural Development section), it is concluded that patterns of isopach thinning are a direct indicator of syn-depositional structural growth. Thus, Figure 35, in effect, is a graph of structural growth rate versus time. In summary, all St. Peter fields show substantial early (pre-A2 Carbonate) domal development, while Goodwell East field does not. Upper Silurian through upper Mississippian isopachs exhibit gradual basinward thickening and reveal no evidence of structural growth associated with known deeper structures. Marked thinning is again mappable in an interval between the upper Pennsylvanian and the base of the Jurassic, at Goodwell, Woodville, and Goodwell East field. The timing of this period of structural growth is inferred to be post-Late Pennsylvanian pre-Jurassic.
Figure 35. Percentage Isopachous Thinning Histograms.
The observation that hydrocarbons occupy secondary porosity attests to the relative timing of porosity development with respect to hydrocarbon accumulation. Theoretical and experimental studies show that thermal maturation of kerogen produces organic and inorganic acids with the potential to dissolve rock matrix and framework grains (Surdam et al., 1990). Dissolved CO₂, forming carbonic acid, "lowers the pH of pore fluids, thus providing an acidic solvent for carbonate and other materials, and CO₂ gas creates a gas-drive mechanism for the migration of hydrocarbons into reservoir rock (Porter and Weimer, 1982, p. 2556)". Much of the CO₂ gas generated during degradation of organic matter occurs early, before peak oil generation (Schmidt and McDonald, 1979). Thus, the development of secondary dissolution porosity occurs just prior to migration and accumulation of hydrocarbons in available traps.

Timing of Hydrocarbon Generation and Migration

Establishing the burial and thermal history of a sedimentary basin is critical to developing an understanding of the timing of hydrocarbon generation and accumulation. The burial and thermal history of the Michigan basin has been a source of recent controversy among researchers, although most agree that "almost all Paleozoic
strata in the Michigan basin display elevated levels of organic maturity that cannot be explained by present-day burial depths, geothermal gradients and heat flow" (Pollack and Cercone, 1989). Nunn, Sleep, and Moore (1984) theorized that a deep-seated thermal event was responsible for the observed elevated levels of thermal maturity. Cercone (1984), and Pollack and Cercone (1989), postulated that a "thermal blanket" of over 3000 feet of Pennsylvanian rocks raised the geothermal gradient, but were subsequently unroofed due to widespread epeirogenic uplift and erosion during Late Paleozoic and Early Mesozoic time.

Detailed oil-source rock correlations for St. Peter Sandstone accumulations are unavailable in the literature. Organic-rich shales and mudstones of the uppermost Prairie du Chien group ("Foster" or "Brazos") are likely source rocks (Harrison, 1987). Based on the Lopatin (1971) method, Cercone (1984) concluded that during the Paleozoic, rocks entered the top of the oil window at burial depths ranging from 6200 to 7500 feet (Figure 36) in the central Michigan basin. If true, Lower and Middle Ordovician source rocks would have commenced generating hydrocarbons in Early Devonian to Early Mississippian time. Thus, hydrocarbons generated in Early Devonian to Early Mississippian time accumulated in paleostructural traps that have been
documented to have formed during the Siluro-Ordovician.

Discussion

All St. Peter Sandstone fields, within the study area and beyond, exhibit evidence of pre-Devonian paleostructural growth. Fundamentals of carbonate sedimentology (Wilson, 1975) dictate that, within the confines of the study area, the Devonian Traverse Limestone depositional surface was flat and at or very near sea-level. As such, a Traverse Limestone to St. Peter Sandstone isopach should closely represent St. Peter Sandstone paleostructure (Figure 37) in Late Devonian time. Thus, hydrocarbons generated in Early Devonian to Early Mississippian time accumulated in paleostructural traps that have been documented to have formed during the Siluro-Ordovician. During the post-Late Pennsylvanian stage of structural growth, paleostructural closures at Goodwell and Woodville domes were accentuated by further folding. Paleostructural closures at Bissel Lake and Betts Creek domes did not experience such late domal growth, but were tilted down to the east as a result of uplift in the vicinity of Woodville dome.
Figure 37. Top of St. Peter Paleostructure in Late Devonian (Traverse Limestone) Time. See text for discussion.
Reservoir quality in the beach/upper shoreface facies is considerably lower in off structure wells. A close relationship between structural position, hydrocarbon saturation, and porosity development is observed within this facies. Several features of interest concerning this reservoir heterogeneity are apparent: (a) increased porosity/reservoir quality is observed in gas bearing intervals; (b) the greater the amount of structural closure the higher the average porosity; (c) at Woodville, wells below the GWC show regional porosity (10-11%) while at Goodwell "wet" wells still show enhanced porosity; and (d) at Bisset Lake and Betts Creek areas of enhanced porosity do not coincide closely with present structural position.

Given the evidence for secondary porosity, the porosity pattern observed resulted from: (a) secondary porosity forming processes (dissolution by acidic migrating pore waters) that were concentrated and more complete on the crests of domal structures (Figure 38, Bjorlykke, 1984) and/or; (b) secondary porosity forming processes affected the study area uniformly and hydrocarbons subsequently migrated into paleostructural traps. During progressive burial, continued cementation occluded porosity
Figure 38. Model for Leaching and Precipitation in a Folded Sandstone. From Bjorlykke (1984).
below the hydrocarbon-water contact, while porosity was preserved by hydrocarbons that had accumulated in the paleostructural trap. Proving which of these two processes was responsible for the observed porosity distribution is impossible given the available data. However, Lundgren (1991) has demonstrated that "late" burial dolomite is common in the St. Peter and, based on neutron-density crossplots (Figure 39), it is likely that the off structure cement is also dolomite, as well.

By comparing variations in structural development and reservoir geometry of several of the fields present in the study area an integrated model for reservoir development emerges which serves to explain the observed geology. For example, the Wolverine Daniels #1-1A (NE/4 SW/4; sec. 1-T14N,R11W) exhibited an interval of enhanced porosity that corresponds exactly to the gas filled portion of the reservoir (Figure 40). This well was directly offset to the west by the Nomeco Coxon #1-2. This offset was structurally level and on the same feature as the Daniels #1-1A yet was completed as a dry hole, with no porosity enhancement present in the upper St. Peter Sandstone whatsoever. The zone of hydrocarbon accumulation (and porosity enhancement) coincides better with paleostructural closure than present structure (Figure 40). It is likely that sec-
Figure 39. Neutron-Density Crossplot of Average Values for Foreshore/Upper Shoreface Facies.
Figure 40. Betts Creek Field Model for Reservoir Development.
ondary porosity was preserved by hydrocarbons which accumulated in a paleostructural trap. This paleostructure was later tilted up to the northwest in Pennsylvania, or later time as Woodville Dome was further uplifted. The hydrocarbon column of 20 feet or less remained "diagenetically trapped" but was not of sufficient height to generate high enough buoyancy pressure (Arps, 1950; Schowalter, 1979) to force hydrocarbons into the low reservoir quality rock in the vicinity of the Coxon #1-2 well.

Areas of enhanced porosity at Woodville Field (Figure 24) closely correspond to the area of Late Devonian paleostructural closure (Figure 37). Woodville Field exhibits a gas column of 68 feet that corresponds very closely with the Traverse Limestone paleostructural relief (Figure 18). The gas column at Goodwell is only 36 feet although Late Devonian paleostructural closure is at least as great as at Woodville Field. At Goodwell wells in off structure positions exhibit enhanced porosity (Figure 24) in spite of the fact that they are water filled. If the proposed model for reservoir development described above is correct then it is likely that these "wet" wells with enhanced porosity were located above the hydrocarbon water contact during the late phase of cementation. The Goodwell dome has a structural closure on the Michigan Stray Sandstone in excess of 100 feet (Figure 10), in
comparison to closure of 40 feet at Woodville. A late period of structural growth of greater magnitude than observed in any of the other fields in the study area is well documented at Goodwell. As Goodwell Dome was accentuated during this period of growth, the flanks of the hydrocarbon bearing paleostructure were rotated below the gas water contact. Since that time little or no further cementation has occurred.
PRODUCTION HISTORY AND RECOVERY EFFICIENCY

The problem of low recovery efficiency from St. Peter Sandstone gas fields is one of grave concern to the oil and gas industry. Many wells throughout the Michigan basin are initially very impressive with high gas flow rates recorded on DST's and IP tests only to yield extremely disappointing cumulative recoveries. For example the Daniels #1-1A (Betts Creek Field) was DST'd for 7.8 Mmcf/d from the upper St. Peter Sandstone, yet only produced 64 Mmcfg from this interval prior to abandonment. This well suffered from early water production that severely lowered the permeability to gas and filled the wellbore effectively "killing" the well. Bisel Lake field and three flank producers at Woodville Field suffered similar problems and are now plugged and abandoned. The Anderson #1-8A (Goodwell Field) produced gas at a steady rate of about 100,000 Mcf/month for nearly five years, with cumulative production of over 7 Bcfg through October, 1989. Subsequent to shutting in of the well for a three day bottom hole pressure test, water production increased substantially, and gas production rate precipitously decreased (C.J. Stewart III, personal communication). Similar well histories to these are common across the Michigan basin, and have contributed to the decrease in exploration activity.
CONCLUSIONS

Significantly enhanced reservoir quality in the St. Peter Sandstone is observed in gas bearing zones in wells located on domal structures. Geometry and degree of this enhanced porosity development is the result of the interplay of structural, depositional, and diagenetic controls.

Within the study interval, the St. Peter Sandstone represents a shoaling upward sequence deposited by lateral progradation of a sandy shoreline. Depositional facies exert fundamental control on reservoir quality. Sandstone of the highest reservoir quality was deposited in high energy foreshore to upper shoreface environments and initially had high primary porosity. Lower energy middle and lower shoreface deposits initially had lower porosity and permeability, largely due to interstitial clay of depositional origin. These rocks remain of comparably low reservoir quality.

Recurrent structural growth of domal features throughout the Paleozoic is well documented by isopach mapping. Burial and thermal history studies indicate that hydrocarbons were generated in Ordovician aged source rocks during late Devonian-early Mississippian time, and accumulated in Ordovician to Silurian aged paleostructural traps. These paleostructural hydrocarbon accumulations
were then modified by a post late Pennsylvanian period of structural growth.

Enhanced reservoir quality is the result of pervasive carbonate dissolution secondary porosity development that occurred just prior to hydrocarbon emplacement. The degree of secondary porosity development is a function of depositional facies and structural position. Hydrocarbons may play a role in preserving secondary porosity above the hydrocarbon water contact. Alternatively, leaching may have been greater on the crests of domal structures.

Proved reserves range from 3 to 60 Bcfg for the five St. Peter fields located within the study area. Recovery efficiencies of only 20-50% are demonstrated for these fields, largely because of production problems associated with water encroachment.
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