

RESERVOIR ANALYSIS OF THE COMPARTMENTALIZED MISSISSIPPIAN AGES
SPIVEY-GRABS FIELD, SOUTH CENTRAL KANSAS

by

LOGAN STEVENS

B.S., Kansas State University, 2013

A THESIS

submitted in partial fulfillment of the requirements for the degree

MASTER OF SCIENCE

Department of Geology
College of Arts and Sciences

KANSAS STATE UNIVERSITY
Manhattan, Kansas

2016

Approved by:

Major Professor

Matthew Totten

Copyright

LOGAN STEVENS

2016

Abstract

Mississippian chert reservoirs, also known as chat reservoirs among the mid-continent in Kansas and northern Oklahoma, produce an abundant amount of hydrocarbons. Since the 1920s, chat reservoirs in Kansas have yielded over 380 million bbl of oil and 2.3 tcf of natural gas. The largest Mississippian field in south-central Kansas is the Spivey-Grabs, which spans Kingman and Harper Counties. Development of the Spivey-Grabs Mississippian reservoir, and continued production within the field, has been compromised by compartmentalization within the field, resulting in unpredictable producing rates. Previous research has investigated the differences of the fluids within the separate compartments (Evans, 2011; Kwasny, 2015), and identified the existence of at least two oil types of differing viscosity (Kwasny, 2015). The objective of this research was to determine whether the compartmentalization of the reservoir is controlled by the different lithologic characteristics between the various compartments. This was accomplished by examining drill cuttings under binocular microscope, under a petrographic microscope using digital imaging software, and under the high magnification of a scanning electron microscope.

Calculated rock porosity from ImageJ software showed variation among the wells selected for this study; but the porosity variation does not correlate with differences in fluid viscosity that was previously observed, i.e. heavy and light viscosity oils (Kwasny, 2015). Heavy oils were seen in wells that had both higher and lower porosity values, and the same is true for the distribution of light oils. This suggested that fluid viscosity is the major controlling factor in compartmentalization in the Spivey-Grabs and not rock properties.

Table of Contents

List of Figures	vi
List of Tables	ix
Dedication	x
Chapter 1 - Introduction.....	1
1.1 Introduction to the Spivey-Grab Field	1
1.2 Compartmentalization.....	3
1.3 Significance	3
1.4 Previous and Concurrent Research	4
1.5 Objectives	5
1.6 Study Area	5
Chapter 2 - Background	8
2.1 Stratigraphy.....	8
2.2 Regional Deposition	12
2.3 Spivey-Grabs Field	14
2.3.1 Field History and Production Data	14
2.3.2 Compartmentalization of the Spivey-Grabs field	15
Chapter 3 - Methods.....	20
3.1 Selecting Samples	21
3.2 Creating Thin Sections.....	23
3.3 Porosity Calculations using ImageJ	23
3.4 Scanning Electron Microscope	24
3.5 Energy Dispersive Spectroscopy	25
Chapter 4 - Results.....	26
4.1 Krehbeil A1.....	26
4.2 Maple F2	27
4.3 Bruch 1	28
4.4 Maple E2.....	30
4.5 Maple F1	31
4.6 Bruch 2.....	32

4.7 Maple G1	33
Chapter 5 - Discussion	38
5.1 Variation of Reservoir Properties - Porosity.....	38
5.2 Approaches to Compartmentalization Compared to Porosity	38
5.2.1 Oil Maturity and Oil Type Compared to Porosity	39
Chapter 6 - Conclusion	45
References.....	47
Appendix A - Petropoxy 154 and Steps for Final Thin Sections.....	49
Appendix B - Adobe Photoshop and Using jPOR to Calculate Porosity in ImageJ.....	53
Appendix C - Additional Images	55

List of Figures

Figure 1. Chert reservoirs in the United States and Canada (Rogers and Longman, 2001).	2
Figure 2. Chert, or "chat," reservoirs with relation to the Central Kansas Uplift (Montgomery et al., 1998).	2
Figure 3. Current map of the SPivey-Grabs field with relation to specific townships and ranges used in this study.....	7
Figure 4. Map of Canadian Shield extension relative to North America and with respect to Kansas (Gore, 2005).	8
Figure 5. Simplified Osagean stratigraphic column showing Pineville Tripolite above the Reeds Spring Limestone (Mazzullo et al., 2010).	11
Figure 6. Mississippian paleogeographic map showing the equator position relative to Kansas' location (Mazzullo et al., 2009).	13
Figure 7. Mississippian paleogeographic map showing shelf location in Kansas (Watney et al., 2001).	13
Figure 8. Reeds Spring Formation and Pineville depositional model proposed by Mazzullo et al. (2011).	14
Figure 9. Initial potential (IP) for 13 wells within the study area. The top number in the symbol represents barrels of oil (BO) and the bottom number represents a thousand cubic feet of gas (MCF). Variations in IP can be seen throughout the field, this suggests possible compartments.	17
Figure 10. Biomarker maturation index from Evans (2011) showing two separate oils and the possibility of compartments.	18
Figure 11. Basic porosity types (Choquette and Pray, 1970).	19
Figure 12. Map of Spivey-Grabs field with study area circle in red (Evans, 2011), with wells from this study represented by red dots.	20
Figure 13. (A) Drill cuttings from Krehbiel A1 under binocular microscope; (B) Photomicrograph of 4113-4118 1/2 cir. using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4113-4118 1/2 cir.; (E) SEM image at 1000X mag, showing porosity.	27

Figure 14. (A) Drill cuttings from Maple F2 under binocular microscope; (B) Photomicrographs of 4157 -40 min using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4157 -40 min; (E) SEM image at 1000x mag, showing porosity.	28
Figure 15. (A) Drill cuttings from Bruch 1 under binocular microscope; (B) Photomicrograph of 4215-15 1 cir. using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4215-15 1 cir.; (E) SEM image at 1000x mag, showing porosity.	29
Figure 16. (A) Drill cuttings from Maple E2 under binocular microscope; (B) Photomicrographs of 4175-4180 using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4175-4180; (E) SEM image at 1000x mag, showing porosity.	31
Figure 17. (A) Drill cuttings from Maple F1 under binocular microscope; (B) Photomicrograph of 4145-45 1/2 cir. using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4145-45 1/2 cir.; (E) SEM image at 1000x mag, showing porosity.	32
Figure 18. (A) Drill cuttings from Bruch 2 under binocular microscope; (B) Photomicrograph of 4160 -60 min using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4160 -60 min; (E) SEM image at 1000x mag, showing porosity.	33
Figure 19. (A) Drill cuttings from Maple G1 under binocular microscope; (B) Photomicrograph of 4137-37 1/2 cir. using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4137-37 1/2 cir.; (E) SEM image at 1000x mag, showing porosity.	34
Figure 20. SEM images of producing intervals. (A) Krehbiel A1 - 4113-4118 1/2 cir.; (B) Maple F2 - 4157 -40 min; (C) Bruch 1 - 4215-15 1 cir.; (D) Maple E2 - 4175-4180; (E) Maple F1 - 4145-45 1/2 cir.; (F) Bruch 2 - 4160 -60 min; (G) Maple G1 - 4137-37 1/2 cir..	36
Figure 21. Oil samples from Kwasny (2015) showing two distinct types of oil, a light and a heavy oil.	41
Figure 22. Pineville Tripolite Isopach map from Evans (2011). Wells indicated by a four quadrant pie graph with the top left representing oil type from Kwasny (2015), the top right representing maturity from Evans (2011), the bottom left representing observed permeability, and the bottom right representing calculated ImageJ porosity. There are no real groupings to indicate correlation. Therefore, the map shows porosity doesn't correlate with maturity or to one specific oil type. See Figure 22 for legend as to what the different colors represent.	43

Figure 23. Different colors in each quadrant represent different characteristics of a well. The top left represents oil type, top right represents maturity, bottom left represents observed permeability, and the bottom right represents ImageJ porosity.	44
Figure 24. (A) Plain white paper on hot plate; (B) Adding blue resin dye; (C) Epoxy mixture covering samples; (D) Image showing double sided tape in bell jar; (E) Sample under vaccum.	51
Figure 25. Showing lab setup.....	52

List of Tables

Table 1. Table indicating well name, location, depth of producing intervals, porosity type as seen under binocular microscope, geologic reports, and comments.	22
Table 2. SEM porosity type compared to calculated ImageJ porosity.	35
Table 3. Table showing the well names, the sampled and studied interval, the calculated porosities for each interval using ImageJ, and the average log porosities.	38
Table 4. Porosity doesn't correlate to maturity type.	40
Table 5. Modified oil type table from Kwasny (2015), showing well name, oil type, and ImageJ calculated porosity. Wells highlighted in blue produce light oil and wells highlighted in pink produce both light and heavy oil. However, the porosities vary between these wells.	42

Dedication

To the people who believed in me.

Chapter 1 - Introduction

1.1 Introduction to the Spivey-Grab Field

Paleozoic chert reservoirs throughout the United States (Figure 1) have complex pore systems yet have yielded over 1 billion bbl of oil and 3 tcf of natural gas. Mississippian chert reservoirs, also known as chat reservoirs in the Mid-Continent in Kansas and northern Oklahoma, are major hydrocarbon producers in the region (Montgomery et al., 1998; Watney et al., 2001). Chat reservoirs are difficult to characterize due to the diversity of reservoir properties, such as porosity, permeability, texture, and facies variations. An additional characteristic of many chat reservoirs is low resistivity in well logs. This is caused by the combination of high porosities and large amounts of water within the matrix. These features can be seen throughout the Mid Continent (Montgomery et al., 1998; Watney et al., 2001), and result in variations in production rates, which can be a problem for the petroleum industry as expectations might not be attained.

In Kansas alone, chat reservoirs have yielded 380 million bbl of oil and 2.3 tcf of natural gas (Montgomery et al., 1998). These chat reservoirs are located within an arcuate fairway that is more than 160 km long (Figure 2) that is constrained by the Central Kansas uplift and the Nemaha uplift (Montgomery et al., 1998; Watney et al, 2001). Productive chat is not continuous throughout the fairway, but is rather a sequence of overlapping bioherms that can range in size from 2.5 – 7.8 km² (Montgomery et al., 1998).

Within the producing fairway of central Kansas are a number of oil fields, the largest of which is the Spivey-Grabs. The Spivey-Grabs is recognized as a chat reservoir that is also thought to be compartmentalized (Evans, 2011).

Figure 1. Chert reservoirs in the United States and Canada (Rogers and Longman, 2001).

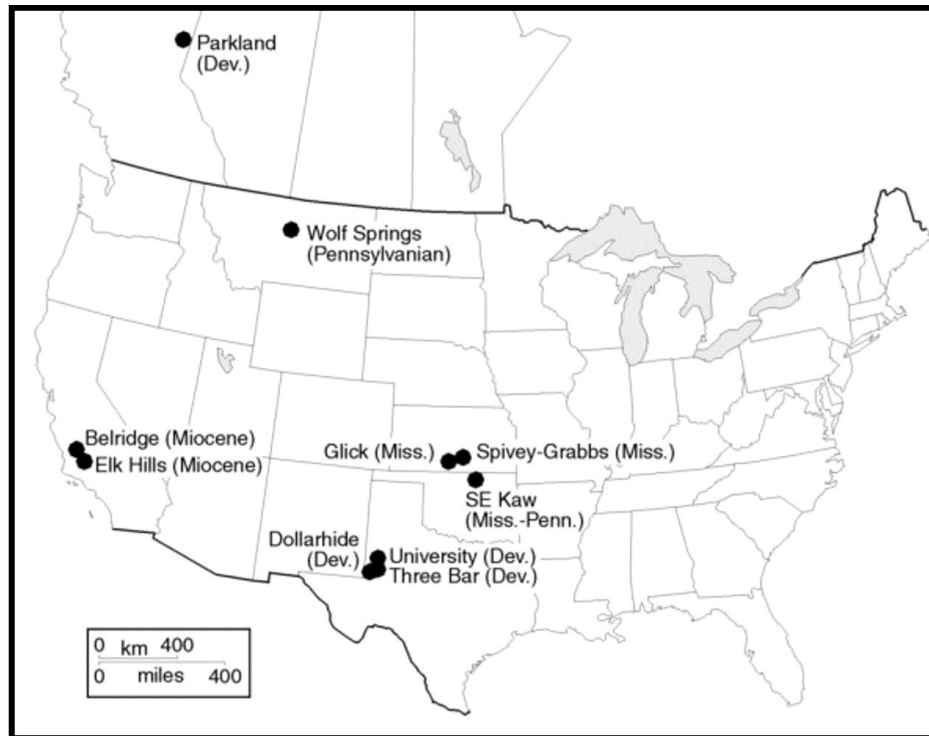
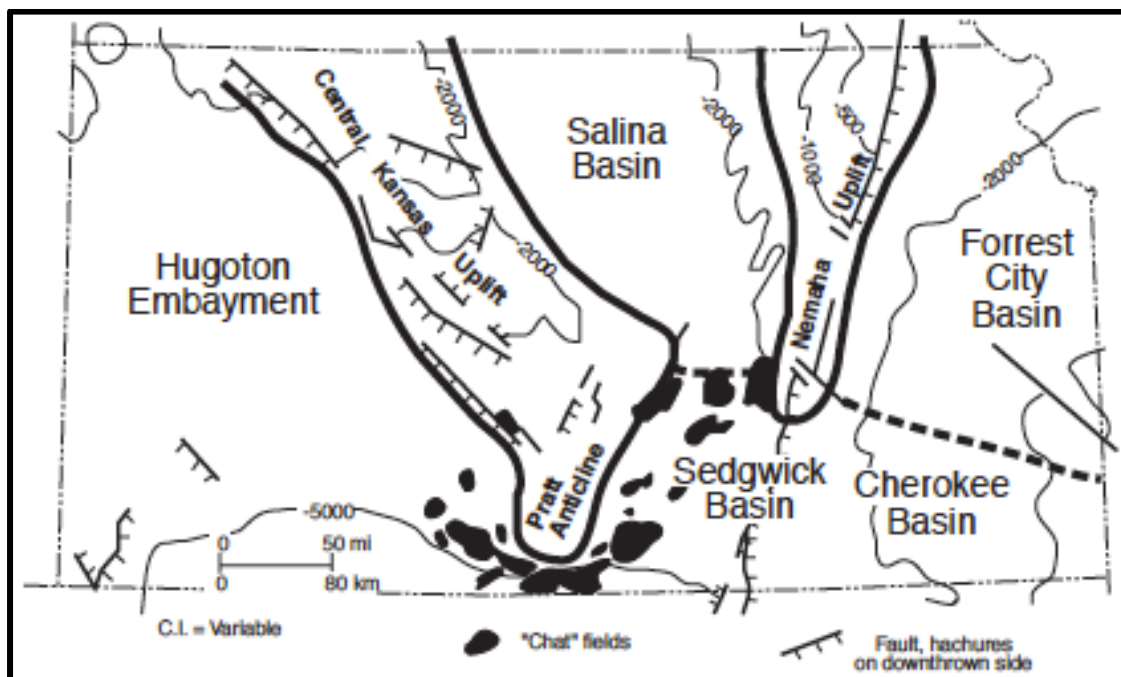


Figure 2. Chert, or "chat," reservoirs with relation to the Central Kansas Uplift (Montgomery et al., 1998).



1.2 Compartmentalization

Most hydrocarbon reservoirs are somewhat heterogeneous due to normal geologic processes, but some reservoirs can be highly compartmentalized (Rahman, 1998). Identification of the compartments is a must in further developing an oil field. When a reservoir is compartmentalized, there is some form of separation between the hydrocarbon accumulations, and each compartment is filled with individual fluid and pressure. There are two basic types of separations or boundaries, static seals and dynamic seals. Static seals completely contain fluids and are capable of doing so over geologic time without any cross flow. Dynamic seals have very low permeability; they act as baffles that limit the amount of cross flow to rates that are too slow to measure reliably at the present time. The volume of producible oil or gas is therefore impacted by reservoir compartmentalization and is also a key measure used in valuing an oil company. Therefore, to avoid unexpected compartmentalization during the production stage, an accurate evaluation of a reservoir should be undertaken during the appraisal stage (Jolley et al., 2010).

1.3 Significance

Often the compartmentalization is not easily predicted, complicating well placement, well stimulation, and reservoir maintenance. The Spivey-Grabs field is one of the largest Mississippian oil and gas producing fields in the Mid-Continent, and has documented reservoir compartments (Evans, 2011), but the cause of this compartmentalization is not known. Better understanding of what causes compartmentalization could lead to better prospecting methods and maximize production in this field.

Not only will the Spivey-Grabs field profit from this study, the analysis and development of similarly characterized fields could be enhanced by the methods used in this study. Additional,

augmentation of this study could lead to better production in geographically distant fields with similar attributes.

1.4 Previous and Concurrent Research

The complexity of compartmentalization of an oil field makes investigation a daunting task; previous studies have focused on examination of depositional, stratigraphic, and structural qualities. The Spivey-Grabs field is one of the largest Mississippian oil and gas producing fields in the Mid-Continent; hence several studies have attempted to decipher the compartments within the field (Evans, 2011; Kwasny, 2015).

Evans (2011) investigated the organic geochemical properties of the oils from the Spivey-Grabs field and described it as a compartmentalized reservoir. His results showed two different biomarkers present within a portion of the field; this suggests a difference in maturation throughout the field and potentially the existence of two types of oils within the field. It was not determined whether the compartments were separated before the two oils migrated in or whether the compartmentalization took place post-migration.

Kwasny (2015) studied the inorganic constituents with the oil in the Spivey-Grabs field, expanding on the results of Evans (2011). She showed that there are two physically different types of oil within the Spivey-Grabs field, a heavy and a light viscosity oil (Kwasny, 2015). Some of the wells only had one oil type, which corresponded to the two biomarkers of Evans, while others had a mixture of the two. This was only observed by separating the oils over a long period of time (30 days), something the operator of the field did not notice. She postulated that the compartmental behavior might be a result of the different fluid properties, and not necessarily different reservoir rock properties.

Wall (2015) also conducted research attempting to establish a source rock correlation for the Spivey-Grabs oils. Using inorganic tracers and established biomarkers, she investigated potential correlations between the underlying Chattanooga Shale and the Mississippian reservoirs of the Spivey-Grabs oil field (Wall, 2015). She determined that the Chattanooga was consistent with a source that could have provided these oils.

1.5 Objectives

Operators and geologists in Kansas speculate over the reasons for compartmentalization in the Spivey-Grabs field. The objectives of this project are to characterize the lithologic differences of the reservoir rocks from different compartments of the Spivey-Grabs and to determine whether these lithologic differences are the main cause of the observed compartmentalization. If the rocks themselves are different, then these differences must have controlled the migration of the different hydrocarbon fluids into the reservoir. On the other hand, if the compartmentalization is not predicted by rock properties, then the fluids themselves may be the controlling factor. An understanding of these controls could further a strategy to develop and maximize the overall production of the field.

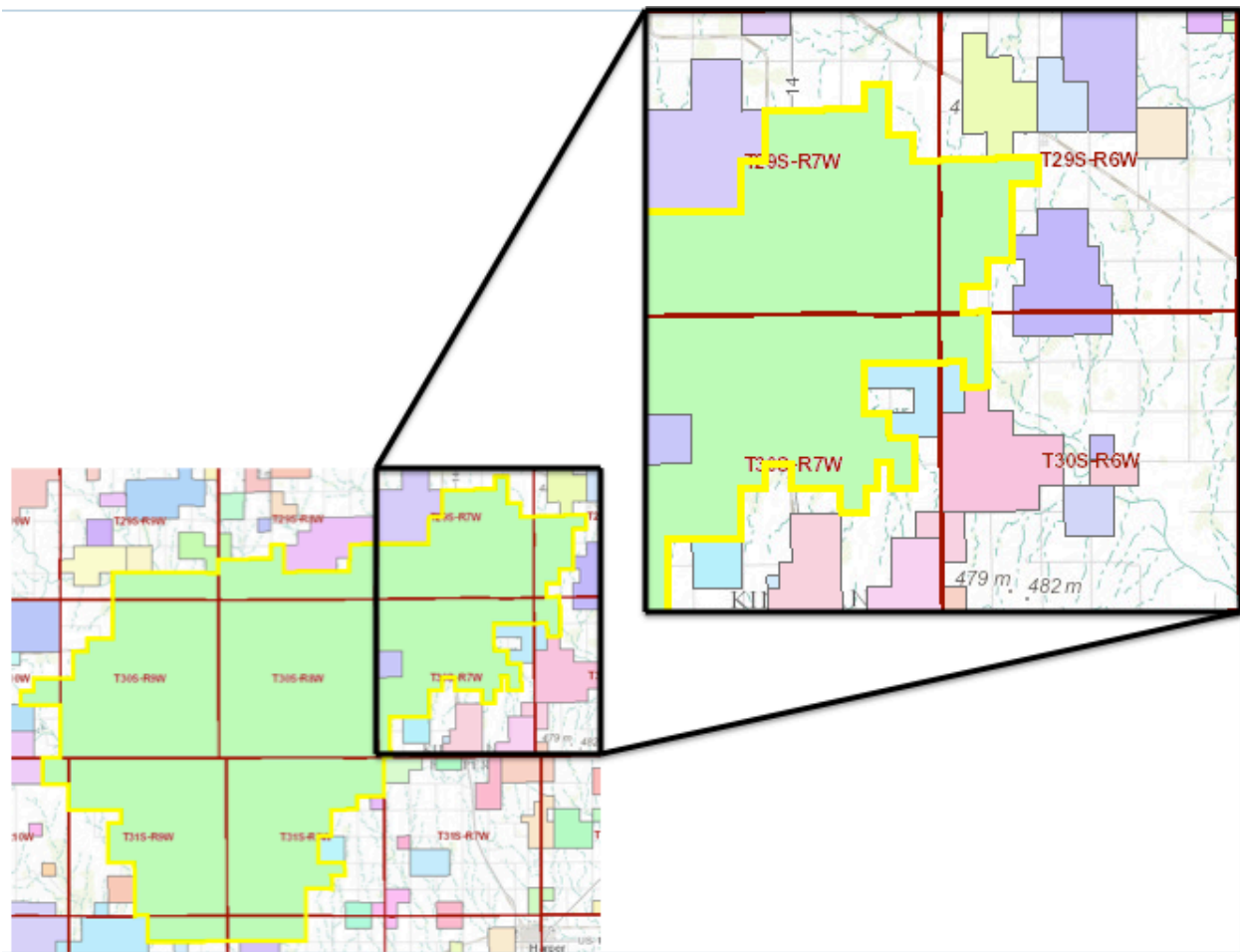
1.6 Study Area

The Spivey-Grabs field in south-central Kansas is one of the largest chat fields discovered to date and covers 380 km² across Harper County and Kingman County (Watney et al., 2001), making it one of the largest pools and having the greatest number of reservoirs in the fairway (Montgomery et al., 1998). The reservoir of the Spivey-Grabs Field varies in thickness from 0 – 49ft (Evans, 2011) and produces out of Mississippian age rocks.

Due to the large size of the Spivey-Grabs field, this study focused on a smaller sub-area including T29S-R7W, T29S-R6W, and T30S-R7W (Figure 3). This focused area overlapped the previous studies of Evans (2011) and Kwasny (2015). Understanding the narrowed study area should indicate the general occurrences throughout the rest of the field.

As stated by Evans (2011), “The [focused area of the] Spivey-Grabs-Basil field was chosen as the study area for several reasons: 1) that bulk production comes from the Mississippian Tripolite [which is referring to a producing formation of the Spivey-Grabs oil field, and is characterized by Mazzullo et al. (2010) as highly altered by meteoric water, light gray to white chert. This is also the formation that will be analyzed in this project.]; 2) known heterogeneity in its production; 3) large volumes of petroleum produced; 4) for being highly developed; 5) newly drilled well and 6) for ease of access.”

Figure 3. Current map of the SPivey-Grabs field with relation to specific townships and ranges used in this study



Chapter 2 - Background

2.1 Stratigraphy

The Spivey-Grabs field is located in Kingman and Harper Counties of south-central Kansas. The Mesozoic stratigraphy of Kansas consists chiefly of thin units that are almost parallel to each other; this is likely due to the fact that Kansas is located on the southern extension of the Canadian Shield, a platform-like extension of a large and stable craton (Figure 4) (Merriam, 1963; Gore, 2005; Kwasny, 2015;).

Figure 4. Map of Canadian Shield extension relative to North America and with respect to Kansas (Gore, 2005).



The Spivey-Grabs field produces from the upper portion of the chert-rich Reeds Spring formation, in what is known as the Pineville Tripolite facies, which has been described as a highly altered, light gray and white chert (Mazzullo et al., 2010). Both the Reeds Spring formation and the Pineville Tripolite facies occur in the Osagean series of the Mississippian (Figure 5). Mississippian rocks can be found throughout the Kansas subsurface. They only outcrop in the southeastern corner of the state (Zeller et al., 1968; Watney et al., 2001; Kwasny, 2015) and reach a thickness of more than 1,700 ft in the southwestern region near the Hugoton Embayment (Zeller et al., 1968). The Mississippian period can be divided into two stages, the Lower Mississippian and the Upper Mississippian. The Lower Mississippian includes the Kinderhookian and Osagean stages, and the Upper Mississippian includes the Meramecian and Chesterian stages.

In the Kinderhookian, the oldest period within the Lower Mississippian, is comprised of the Hannibal Shale, the Compton Limestone, the Sedalia Dolomite, the Northview Formation, and the Gilmore City Limestone. Overlying the Kinderhookian is the Osagean, which are separated by an angular unconformity.

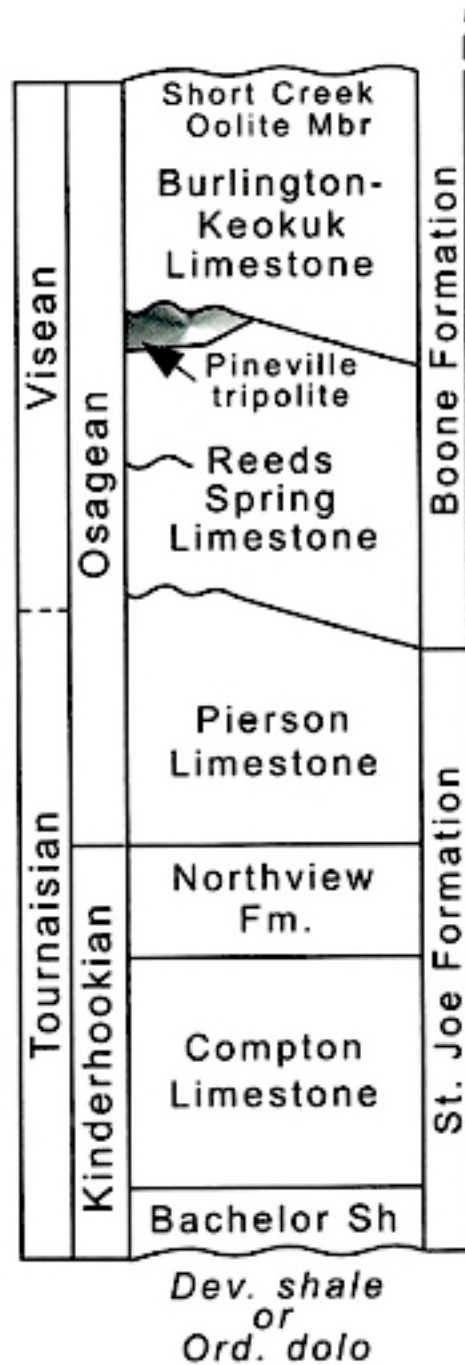
The Osagean consists of dolomite, limestone, chert, and cherty dolomite and limestone beds. The formations include the Pierson Limestone, the Reeds Spring Limestone, the Elsey formation, the Burlington-Keokuk Formation, and the Short Creek Oolite Member. The Peirson Limestone unconformably underlies the Reeds Spring formation/Pineville Tripolite. It has a thickness that ranges from 10 ft to 100 ft, and its dolomitic limestone lithology has several cross-bedded limestones and crinoid fossils. Mazzullo et al. (2010) observed several Peirson Limestone outcrops in Missouri that have been interpreted as evidence of transgressive-regressive cycles. The evidence comes from crinoid sands that gradually coarsen upwards and an

unconformable contact with the Burlington-Keokuk formation. On petrophysical logs the Peirson Formation has a tight appearance in terms of its porosity and resistivity; it also has a clean appearance on the gamma ray track (Evans, 2011), indicating relatively good reservoir quality.

The Reeds Springs Formation has a thickness of 200 ft and is dominated by interbedded nodular chert (Evans 2011). The chert content is high in the south-central region of Kansas and is also pale blue-gray to semi-translucent or translucent in color (Goebel, 1971). At the top of the Reeds Spring Formation is highly altered tripolitic chert that is heavily fractured and burrowed and is known as the Pineville Tripolite facies (Parham and Northcutt, 1993; Watney et al., 2001; Rogers, 2001; Mazzullo, 2010; Evans, 2011). This highly altered chert facies flanks the southern edge of the Central Kansas Uplift and the southeastern edge of the Nemaha Uplift (Montgomery et al., 1998).

The Pineville Tripolite lays unconformably below the Cherokee Group of the Des Moinesian from the Pennsylvanian, where the missing strata includes the Burlington-Keokuk formation, the Meramecian and Chesterian series of the Mississippian, and the Morrowan and Atokan series of the Pennsylvanian. The Cherokee Group includes shale, sand, and coal lithologies. Shales formed from lowland inundation and deep seas, sand members were produced from regressive seas, and coal members were associated with very shallow seas (Evans, 2011). The Cherokee Group, as stated by Howe (1956), reached 450 ft to 500 ft thick in the southeastern region of Kansas.

Figure 5. Simplified Osagean stratigraphic column showing Pineville Tripolite above the Reeds Spring Limestone (Mazzullo et al., 2010).



2.2 Regional Deposition

Kansas was located about 20° south of the equator during the Mississippian (Figure 6). During this time period a shallow epi-continental transgressive-regressive sea was common and produced shelf carbonates across much of the region, including southern Kansas. The carbonate shelf environment deepened southward from the shelf margin into a basinal environment (Figure 7). This rise and fall of sea level subaerially exposed the carbonate shelf (Witzke, 1990; Bunker and Witzke, 1996). This brought about the formation of diverse environments for which distinctive types of sediments were deposited: “shale, carbonates and cherts; each unique to their own time” (Evans, 2011). According to Mazzullo et al. (2009), this area experienced low to moderate energy depositional conditions, which was a result of isolation due to the Nemaha Uplift and Pratt Anticline.

The fluctuating sea level, with the addition of tectonics, is what likely created the Pineville Tripolite facies. Exposure during a major eustatic low-stand combined with some tectonic uplifting (Mazzullo et al., 2010) resulted in alteration of the Reeds Spring Formation through interaction with meteoric water. This combination created a highly porous, low permeability reservoir rock in the Spivey-Grabs field (Figure 8). Mazzullo et al. (2009) suggests low permeability is due the very limited core data available in this region. This combination of major exposure and tectonics also played a part in the generation of the unconformity that separates the Pennsylvanian Cherokee Formation and the Pineville Tripolite facies (Evans, 2011).

Figure 6. Mississippian paleogeographic map showing the equator position relative to Kansas' location (Mazzullo et al., 2009).

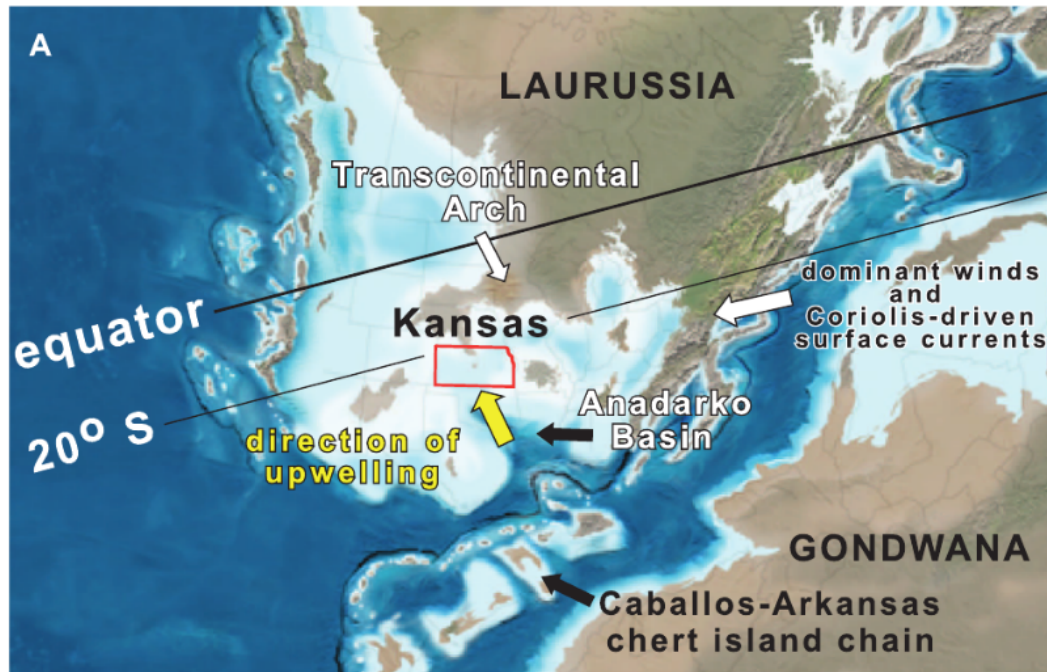


Figure 7. Mississippian paleogeographic map showing shelf location in Kansas (Watney et al., 2001).

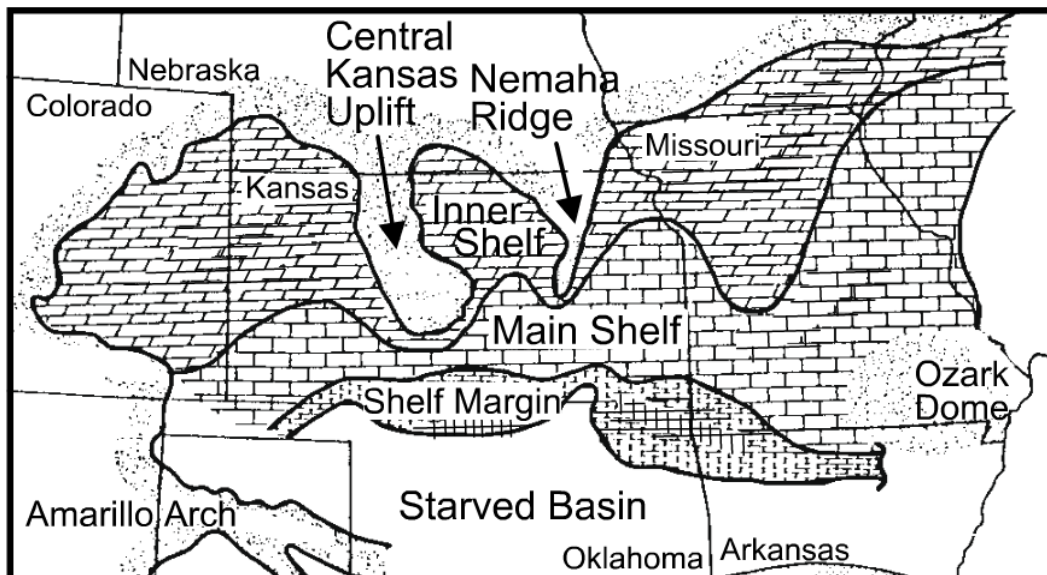
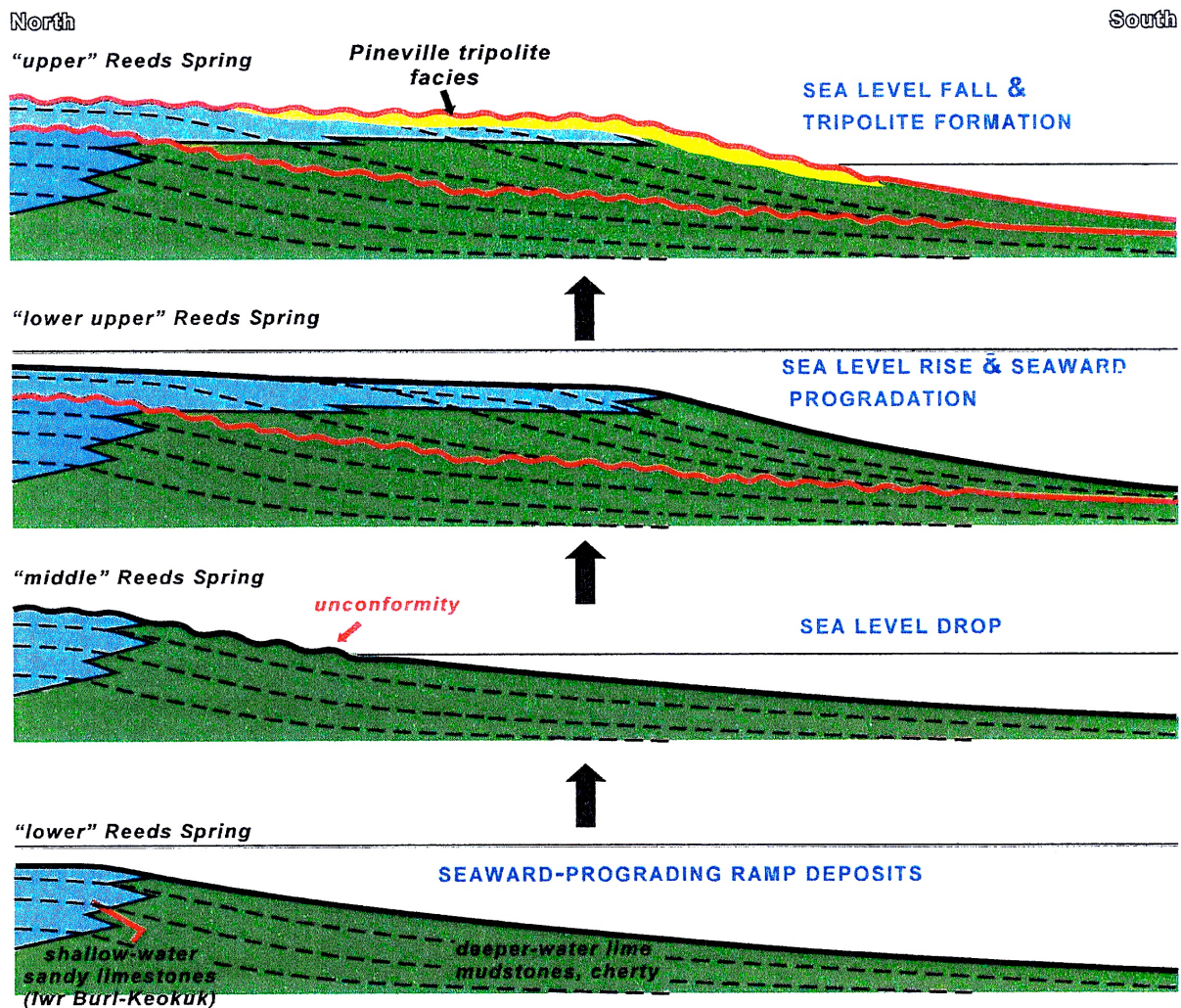


Figure 8. Reeds Spring Formation and Pineville depositional model proposed by Mazzullo et al. (2011).



2.3 Spivey-Grabs Field

2.3.1 Field History and Production Data

Over the last half century, Mississippian chat has been produced in the Spivey-Grabs field, with other chat fields in south central Kansas being producing since the 1920's (Watney et al., 2001). According to Evans (2011), large volumes of oil and gas were being produced early on in that area, which lead to expanding exploration and production in south-central Kansas. The growth in production accounted for many promising discovers in the Lansing-Kansas City,

Viola, Cherokee, Permian, and Simpson formations. This also accounted for the Spivey-Grabs field, which was discovered in 1949 and produced in T31S R9W Sect. 13 at a depth of 4,398 feet. Since 1949, the Spivey-Grabs field has produced oil (cumulative oil: 62 million bbl) and gas (cumulative gas: 793 mcf) from Mississippian aged chat (Watney et al., 2001), or more specifically, the Pineville tripolitic chert.

2.3.2 Compartmentalization of the Spivey-Grabs field

The varying initial potential values of oil (BO) and gas (MCF) indicate that production in the study area is unpredictable, which validates the idea that the Spivey-Grabs field is compartmentalized (Figure 9). Previous studies have also mentioned such behavior; Evans (2011) suggested possible compartments within the field due to differing maturation throughout the field (Figure 10), and Kwasny (2015) observed two physically different types of oil within the Spivey-Grabs field, and suggest the field's behavior is due to the fluid differences. However, both Evans (2011) and Kwasny (2015) found no evidence suggesting the observed compartmentalization was a result of physical reservoir properties.

The producing formation of the Spivey-Grabs field is Mississippian aged chat, which is known to be a difficult to characterize because of its diverse properties such as facies variation, texture, permeability, and porosity (Montgomery et al., 1998; Watney et al., 2001). Of the various reservoir properties, porosity and permeability are considered important, and without porosity or permeability there wouldn't be any oil that is economically producible. Porosity is essential in determining the quality of a reservoir. The reason porosity is important to the petroleum industry is because it controls the available storage space for hydrocarbons. Simply put, porosity is the volume of void spaces within the rock and therefore reflects the potential volume of hydrocarbons. The porosity, according to Mazzullo et al. (2011), of the Spivey-Grabs

field is mostly micro-intercrystalline pores, micro-vugs, as well as fracture porosity. The basics of these porosity types are illustrated in Figure 11.

While this study focused on the porosity or the storage of hydrocarbons, the rocks capacity for transmitting fluid is also important. This is called permeability. Higher permeability means that fluid moves throughout the reservoir with relative ease; but as stated before, fluctuating sea level with the addition of tectonics, likely created a highly porous and low permeable Pineville Tripolite facies reservoir (Mazzullo et al., 2010). The depositional environment of the Pineville Tripolite facies, suggests the controlling factors of the “compartmentalization” could be due to porosity or permeability.

Figure 10. Biomarker maturation index from Evans (2011) showing two separate oils and the possibility of compartments.

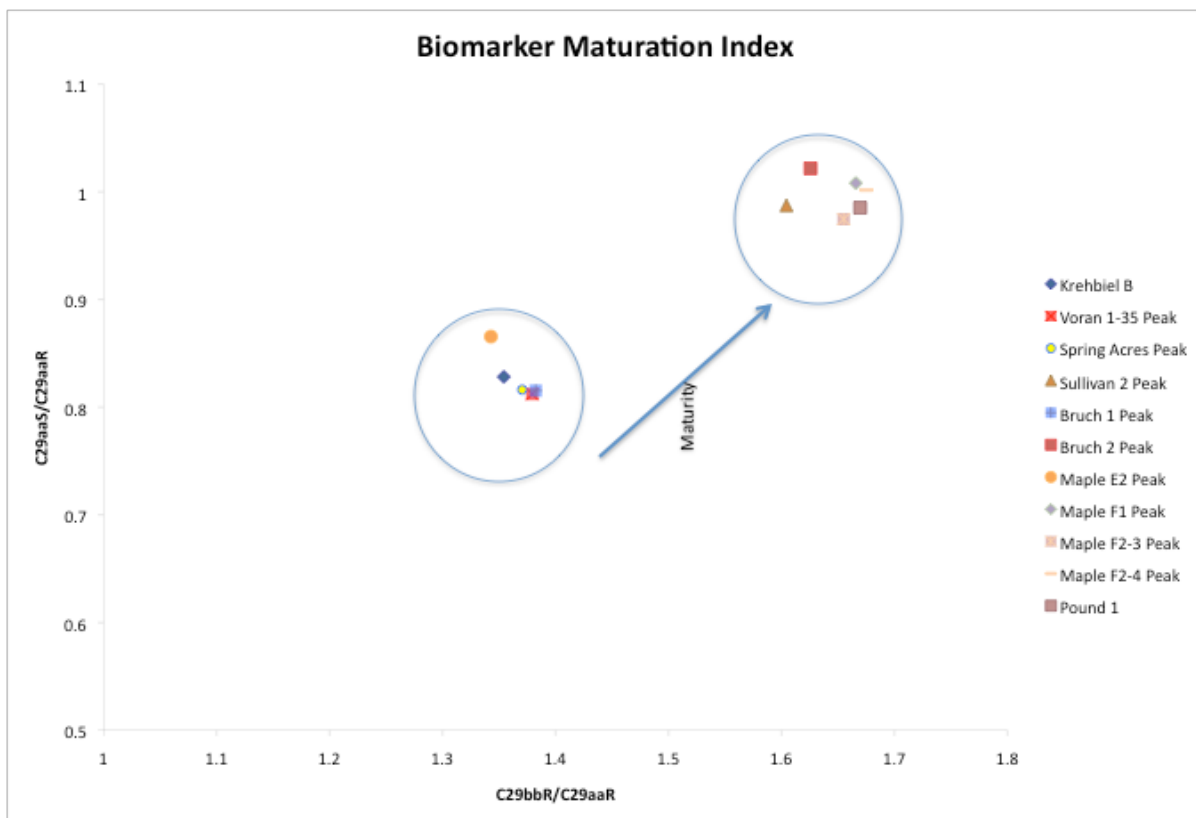
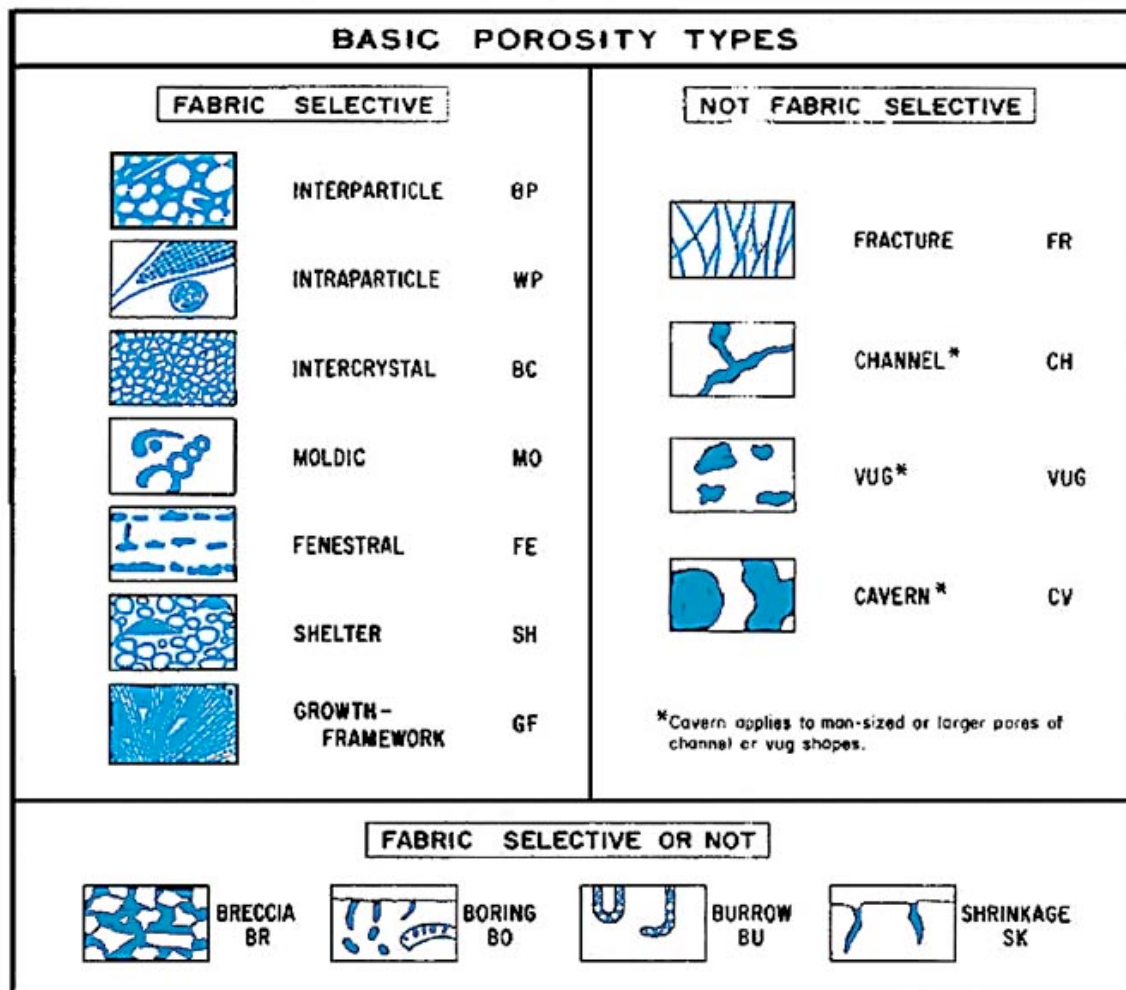


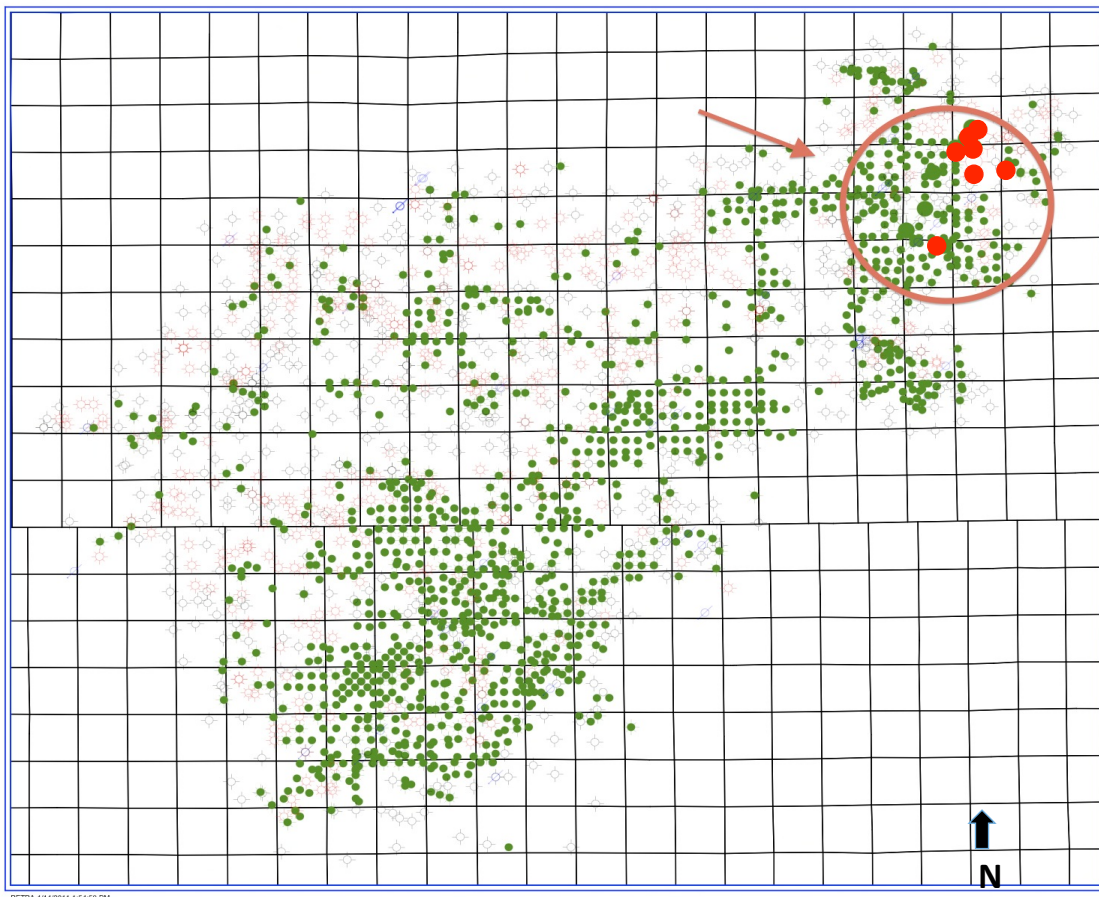
Figure 11. Basic porosity types (Choquette and Pray, 1970).



Chapter 3 - Methods

Seven wells, from a 12 mi² location in the northeastern region of the Spivey-Grabs field were selected for this study (Figure 12). These wells were chosen to coincide with the wells studied by Evans (2011) and Kwasny (2015). The producing intervals for the seven wells were found from Evans (2011) and from wireline logs obtained through the Kansas Geological Survey (KGS).

Figure 12. Map of Spivey-Grabs field with study area circle in red (Evans, 2011), with wells from this study represented by red dots.



3.1 Selecting Samples

From the seven boxes of drill cuttings, one for each well, samples were selected by using a binocular microscope. This allowed me to determine which samples matched the descriptions listed in the Geologic Reports that were posted by the KGS (Table 1). The selected samples were then placed in small paper cups that were labeled with the well name and interval depth. This helped insure that drill cutting from one well didn't get mixed with drill cuttings from another well.

Drill cuttings with "oil shows," meaning grains with a brownish color stain on the surface under a binocular microscope, at the appropriate depth, and the correct lithology were selected and handpicked from the cuttings for further study. These cuttings were handpicked to match the sample description listed on the Geologic Reports from the KGS, and were used to document the lithology, porosity, and oil staining present.

Table 1. Table indicating well name, location, depth of producing intervals, porosity type as seen under binocular microscope, geologic reports, and comments.

Well Name	API	Location	Producing Formation (Per Evans)	Producing Interval (Per Evans)	Depth (ft)	Porosity Type	Geo Report	Comments
Kehbel A 1	15-095-00753	02-305-07W	N/A	N/A	4133-4138 1/2 cfr.	Intercrystalline	Chert- Unledgeable	weathered chert, minimal oil stain-light brown
					4113-4118 1 cfr.	Intercrystalline		weathered chert, minimal oil stain-light brown
					4118-4123	Intercrystalline		weathered chert, minimal oil stain-light brown/ black
					4123-4123 1 cfr.	Intercrystalline		weathered chert- Slight oil stain-light brown, some black
Maple F 2	15-095-22204	25-295-07W	Pineville	4127-4137	4123-4130	Intercrystalline	Chert- Unledgeable	weathered chert, minimal oil stain-light brown
					4130-4140	Intercrystalline		weathered chert, minimal oil stain-light brown
					4140-4150	Intercrystalline		weathered chert, minimal oil stain-light brown/ black
					4157 20 min cfr.	Intercrystalline		weathered chert- more weathered than others, minimal oil stain-light brown
Bruch 1	15-095-01780	24-295-07W	Pineville	4202-4210	4157 40 min cfr.	Intercrystalline	Diverfied chert and silicified dolomite, pin-point, honey-comb and vugular porosity, far to good; 50% stain and saturation, Good order, Good show of free oil	weathered chert, minimal oil stain-light brown
					4205-4210	Intercrystalline		weathered chert, minimal oil stain-light brown
					4215-4215 1/2 cfr.	Intercrystalline with few vugs		weathered chert, minimal oil stain-light brown, some vugs
					4215-4215 1 cfr.	Intercrystalline		weathered chert- oil stain-light brown specs
Maple E 2	15-095-20210	25-295-07W	Pineville	4140-4200	4215-4215 1 1/2 cfr.	Intercrystalline	Granular, weather chert with leached porosity and trace of free oil. Abundant residual stain. Faint odor. White drab, chalky chert. Traces of white, siliceous, glauconitic lime. Some white, tripolitic chert with slight show of free oil	weathered chert- oil stain-light brown
					4160-4170	Intercrystalline		weathered chert- oil stain-light brown
					4170-4175	Intercrystalline		weathered chert- oil stain-light brown
					4175-4175 1/2 cfr.	Intercrystalline		weathered chert- oil stain-light brown
Maple F 1	15-095-00720	25-295-07W	Pineville	4140-4150	4175-4175 1 cfr.	Intercrystalline	Chert, white and brown, tripolitic with good pinpoint and vuggy porosity. Light show of free oil.	weathered chert- oil stain-light brown
					4145-4145 1/2 cfr.	Intercrystalline		weathered chert, minimal oil stain-light brown
					4145- 4155	Intercrystalline with few vugs		weathered chert, minimal oil stain-light brown
					4160 40 min cfr.	Intercrystalline		weathered chert, minimal oil stain-light brown
Bruch 2	15-095-22118	24-295-07W	Pineville	4132-4142	4160 60 min cfr.	Intercrystalline	Chert- Unledgeable - NOTE- Not lagged, perf zone 4132-4142	weathered chert, minimal oil stain-light brown specs
					4165 20 min cfr.	Intercrystalline		weathered chert, minimal oil stain-light brown specs
Maple G 1	15-095-00106	30-295-06W	N/A	N/A	4127-4137	Intercrystalline	White tripolitic chert; good pinpoint porosity, rich stain and good show of free oil. Excellent stain and saturation in tripolitic chert. Good pinpoint and vuggy porosity. Strong odor. Some white, cherry lime; otherwise chert same as above.	weathered chert- oil stain-light brown-carnel like
					4137-4137 1/2 cfr.	Intercrystalline with very few vugs		weathered chert- oil stain-light brown-carnel like
					4137-4137 1 cfr.	Intercrystalline		weathered chert- oil stain-light brown-carnel like
					4137-4143	Intercrystalline with few vugs		weathered chert- oil stain-light brown-carnel like

3.2 Creating Thin Sections

The cuttings were impregnated on a glass slide with blue-dyed epoxy by the use of a vacuum pump and a bell jar. The glass slides, along with the impregnated samples were then placed on a hot plate that allowed the epoxy resin to harden. Then the grain mounts were hand polished using corundum powder and increasing grits of silicon carbide sandpaper to produce a thin-section that was viewable under a petrographic microscope. See Appendix A for the final steps to creating the thin-sections.

A total of 29 thin sections were produced for all seven wells. Each thin section from each producing interval was then analyzed under a petrographic microscope to identify the best drill cuttings for this study. These were identified using two criteria: (i) clarity (i.e how well I could focus the grain using 10x magnification) and (ii) the grain with the best visible porosity (i.e. the grain that had the most visible blue color from the blue dyed epoxy under a petrographic microscope). The grains that met these two criteria were then photographed and used for porosity calculations using ImageJ.

Thin sections were created using drill cuttings rather than core for this study, and because of this, several thin sections had to be remade due to completely polishing the drill cuttings away. With this in mind, thin sections likely have thickness variations throughout each sample due to pressure changes when hand polishing.

3.3 Porosity Calculations using ImageJ

After the thin sections were completed for all seven wells, photomicrographs were taken using a petrographic microscope. These images were then processed using Adobe Photoshop, which prepared the digital images for image analyses through ImageJ. ImageJ is a quick and

efficient system to quantify porosity of blue resin-impregnated thin sections (Grove & Jerram, 2011) and is free to download.

Adobe Photoshop was used as a preprocessing tool to convert the digital image into an 8-bit paletted .bmp file for the use of the jPOR macro in ImageJ. After the images were processed into an 8-bit paletted .bmp file, they were used to calculate porosity in ImageJ. The steps to get a digital image into an 8-bit paletted .bmp file can be found in Appendix B.

The default maximum threshold level of ImageJ is set low, low enough to need to be adjusted. ImageJ uses a 256 color palette where you have the ability to set the maximum threshold level (Grove and Jerram, 2011). So when the maximum threshold level was set to 72, porosity would change drastically. This was the standard threshold level that was used throughout this study.

3.4 Scanning Electron Microscope

A Scanning Electron Microscope (SEM) was used to view drill cuttings under high magnification. Ravindra Thakkar at the Nanotechnology Innovation Center of Kansas State (NICKS) assisted in running seven samples. The machine used was a Hitachi S-3500N scanning electron microscope. The samples for SEM examination were determined by selecting the sample from each well with the highest porosity measurement from ImageJ. These samples were coated in Au-Pd and viewed at 1000X magnification and 6000X magnification, and the reasoning behind this was to get an overall and close up image of the porosity.

The operator of the SEM at VetMed was unable to process the thin-sections. Extra drill cuttings from the highest calculated porosity intervals were selected from each well and mounted for SEM. It should be noted that cuttings examined under SEM were not polished flat.

3.5 Energy Dispersive Spectroscopy

An Oxford Energy Dispersive Spectrometer (EDS) was used for elemental mapping and to acquire qualitative compositional information from the samples. The elements that can be detected are from atomic number 4 through 92. This range includes atomic number 14 and 8, which are silicon and oxygen, and the elemental composition of chert is SiO_2 . EDS analysis was done to qualitatively ensure the samples being tested were in fact tripolitic chert and not another composition.

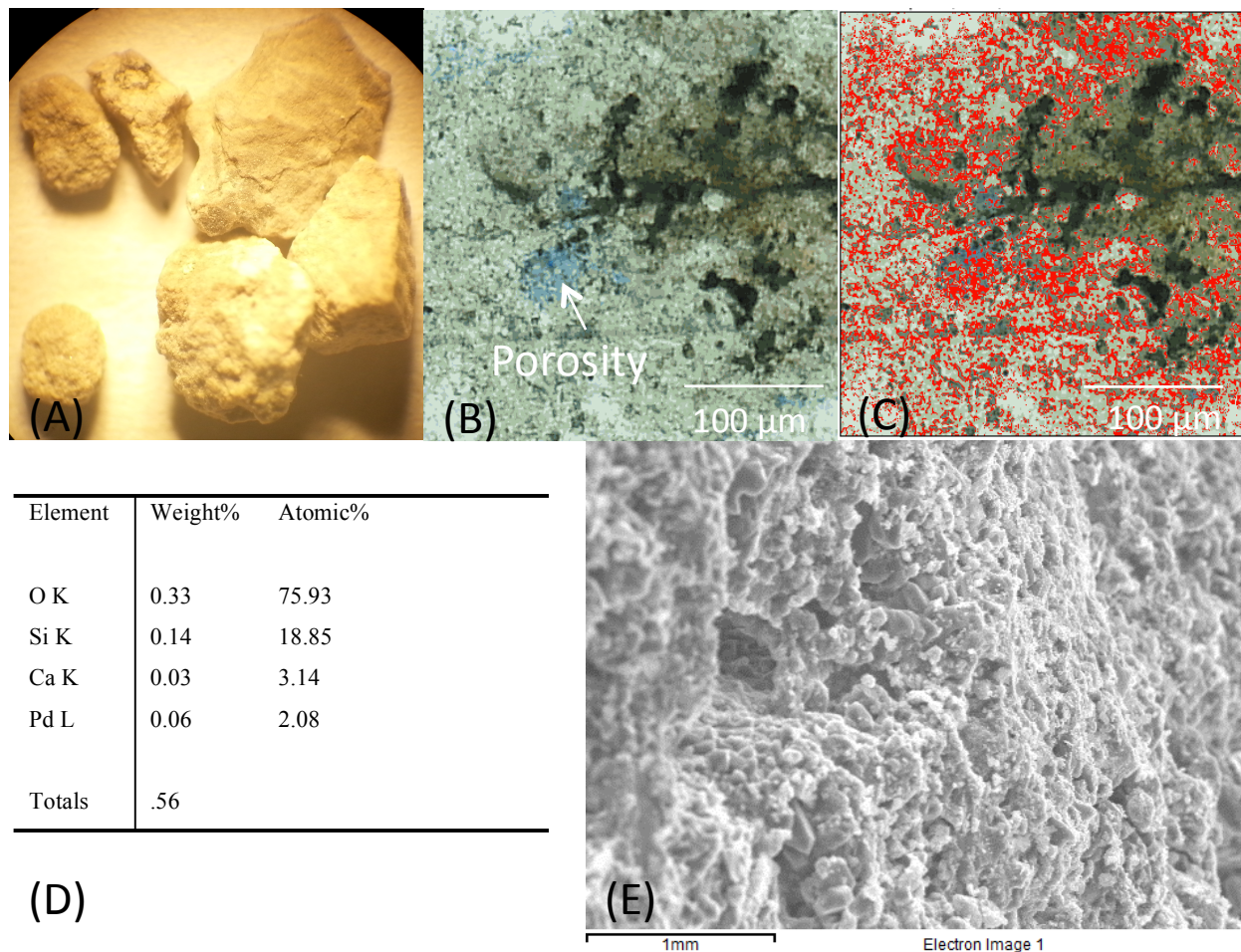
Normal sample preparation for EDS analysis requires the sample to be flat, polished, and nonporous (Australian Microscopy and Microanalysis Research Facility, 2014). Uneven drill cuttings likely scattered the X-rays used for EDS, which resulted in a decrease in accuracy. Additionally, the samples were coated in Au-Pd, which will absorb many of the X-rays, further hindering the accuracy of the EDS data. Ideally, the samples would have been coated in a light, conductive element, such as carbon. However, EDS data does qualitatively show that silicon and oxygen were the most abundant elements in the sample, confirming the samples tested were chert.

Chapter 4 - Results

4.1 Krehbeil A1

The drill cuttings analyzed from the producing interval (4113-4118 ½ cir.) of Krehbeil A1 (Figure 13A) were identified under binocular microscope as weathered chert with intercrystalline porosity and minimal oil staining that is light brown (Table 1). Under thin-section, the sample shows micro-intercrystalline pores with a few micro vugs (Figure 13B). The calculated porosity of the producing interval (4113-4118 ½ cir.) from ImageJ shows 21.8% (Figure 13C). SEM-EDS analysis indicates that the sample is mainly silicon and oxygen, consistent with chert, and the 1000x magnification image shows micro vugs and micro-intercrystalline pores (Figure 13D and 13E).

Figure 13. (A) Drill cuttings from Krehbiel A1 under binocular microscope; (B) Photomicrograph of 4113-4118 1/2 cir. using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4113-4118 1/2 cir.; (E) SEM image at 1000X mag, showing porosity.

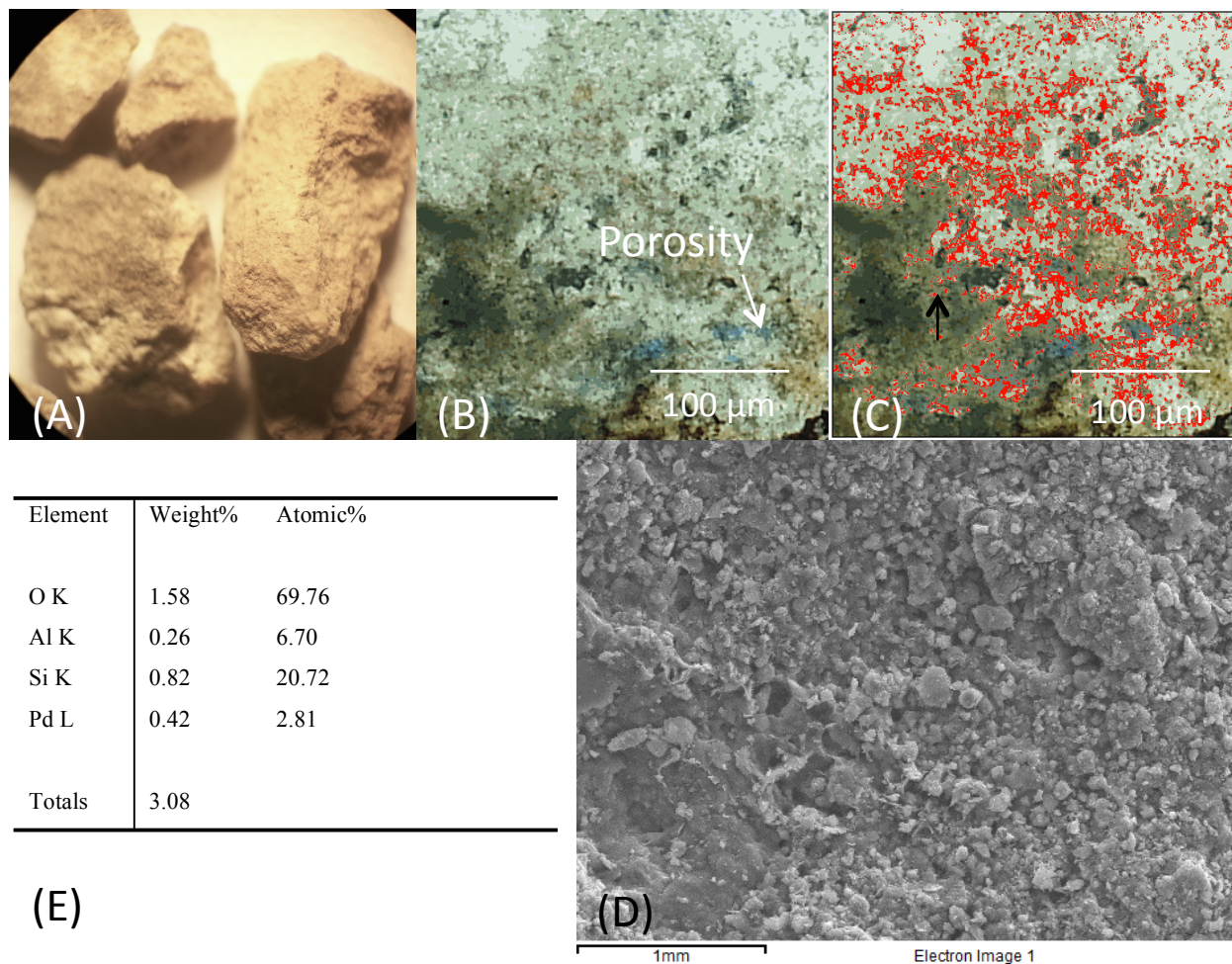


4.2 Maple F2

The drill cuttings analyzed from the producing interval (4157 – 40 min) of Maple F2 (Figure 14A) were identified under binocular microscope as weathered chert with intercrystalline porosity and minimal oil staining that is light brown (Table 1). Under thin-section, the sample shows micro-intercrystalline pores with two micro vugs (Figure 14B). The calculated porosity of sample 4157 40 min cir. from ImageJ is 14.9% (Figure 14C). SEM-EDS analysis indicates that

the sample is mainly silicon and oxygen, and the 1000x magnification image shows micro-intercrystalline pores (Figure 14D and 14E).

Figure 14. (A) Drill cuttings from Maple F2 under binocular microscope; (B) Photomicrographs of 4157 -40 min using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4157 -40 min; (E) SEM image at 1000x mag, showing porosity.



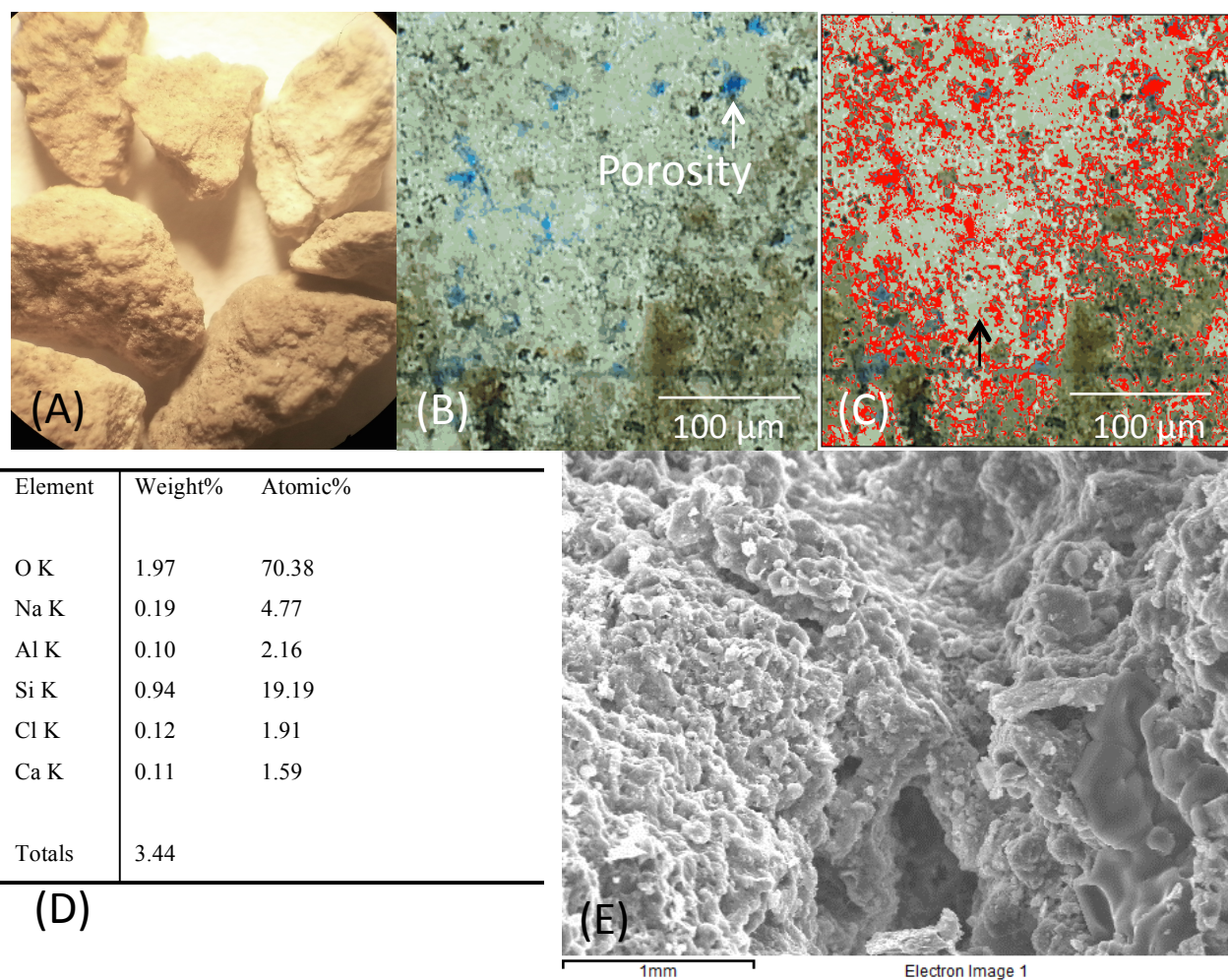
4.3 Bruch 1

The drill cuttings analyzed from the producing interval (4215-15 1 cir.) of Bruch 1 (Figure 15A) were identified under binocular microscope as weathered and devitrified chert with pin-point intercrystalline porosity and minimal oil staining that is light brown (Table 1). Under thin-section, the sample shows micro-intercrystalline pores with several micro vugs (Figure

15B). The calculated porosity of sample 4215-15 1 cir. from ImageJ is 22.6% (Figure 15C).

SEM-EDS analysis indicates that the sample is mainly silicon and oxygen with the addition of sodium, aluminum, calcium, and chlorine. The 1000x magnification image shows sizable vugs and micro-intercrystalline pores (Figure 15D and 15E).

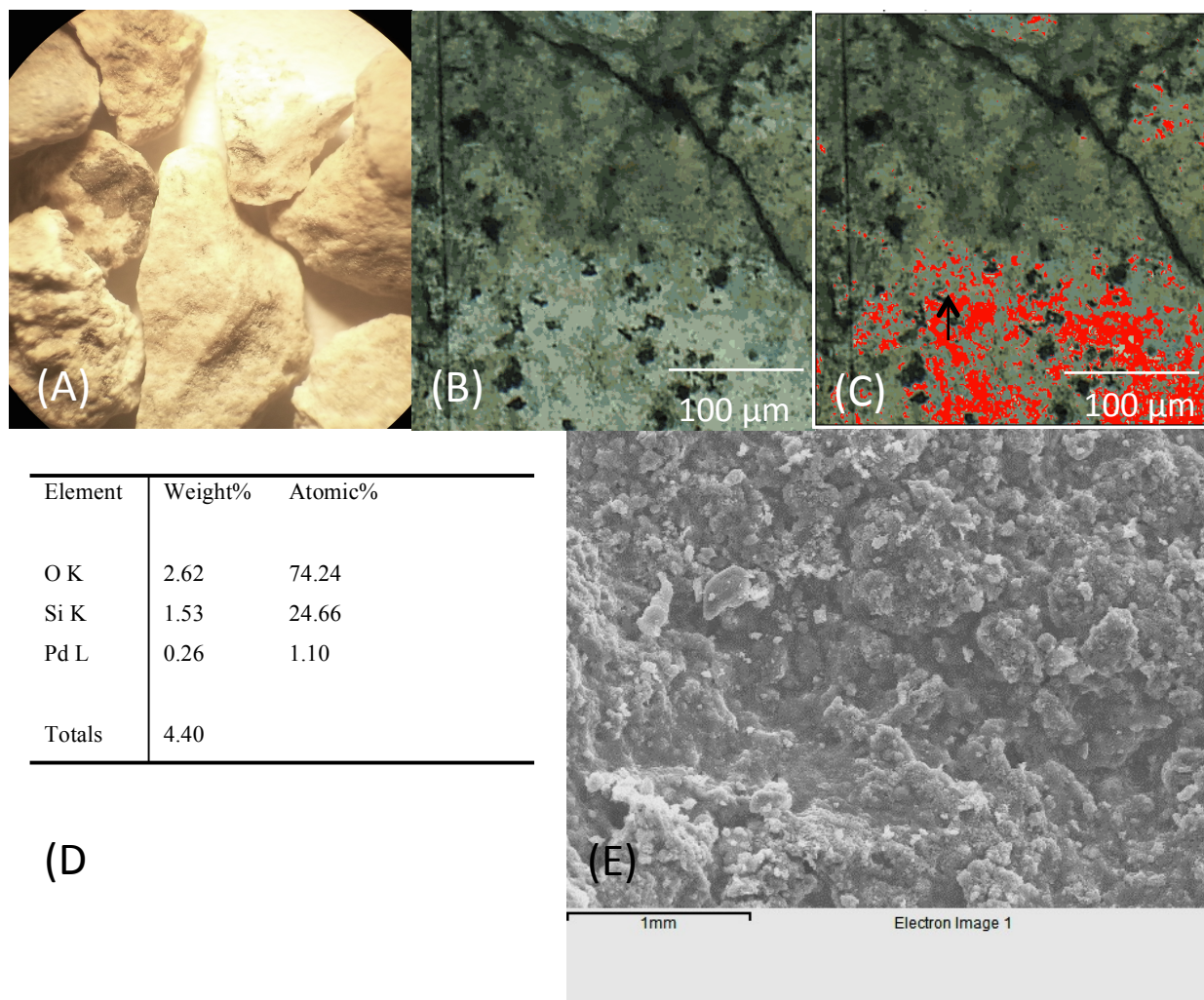
Figure 15. (A) Drill cuttings from Bruch 1 under binocular microscope; (B) Photomicrograph of 4215-15 1 cir. using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4215-15 1 cir.; (E) SEM image at 1000x mag, showing porosity.



4.4 Maple E2

The drill cuttings analyzed from the producing interval (4175-4180) of Maple E2 (Figure 16A) were identified under binocular microscope as granular weathered chert with intercrystalline porosity and minimal oil staining that is light brown (Table 1). Under thin-section, the sample shows micro-intercrystalline pores (Figure 16B). The calculated porosity of sample 4175-4180 from ImageJ is 11.1% (Figure 16C). SEM-EDS analysis indicates that the sample is mainly silicon and oxygen, and the 1000x magnification image shows micro-intercrystalline pores and a few micro vugs (Figure 16D and 16E).

Figure 16. (A) Drill cuttings from Maple E2 under binocular microscope; (B) Photomicrographs of 4175-4180 using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4175-4180; (E) SEM image at 1000x mag, showing porosity.

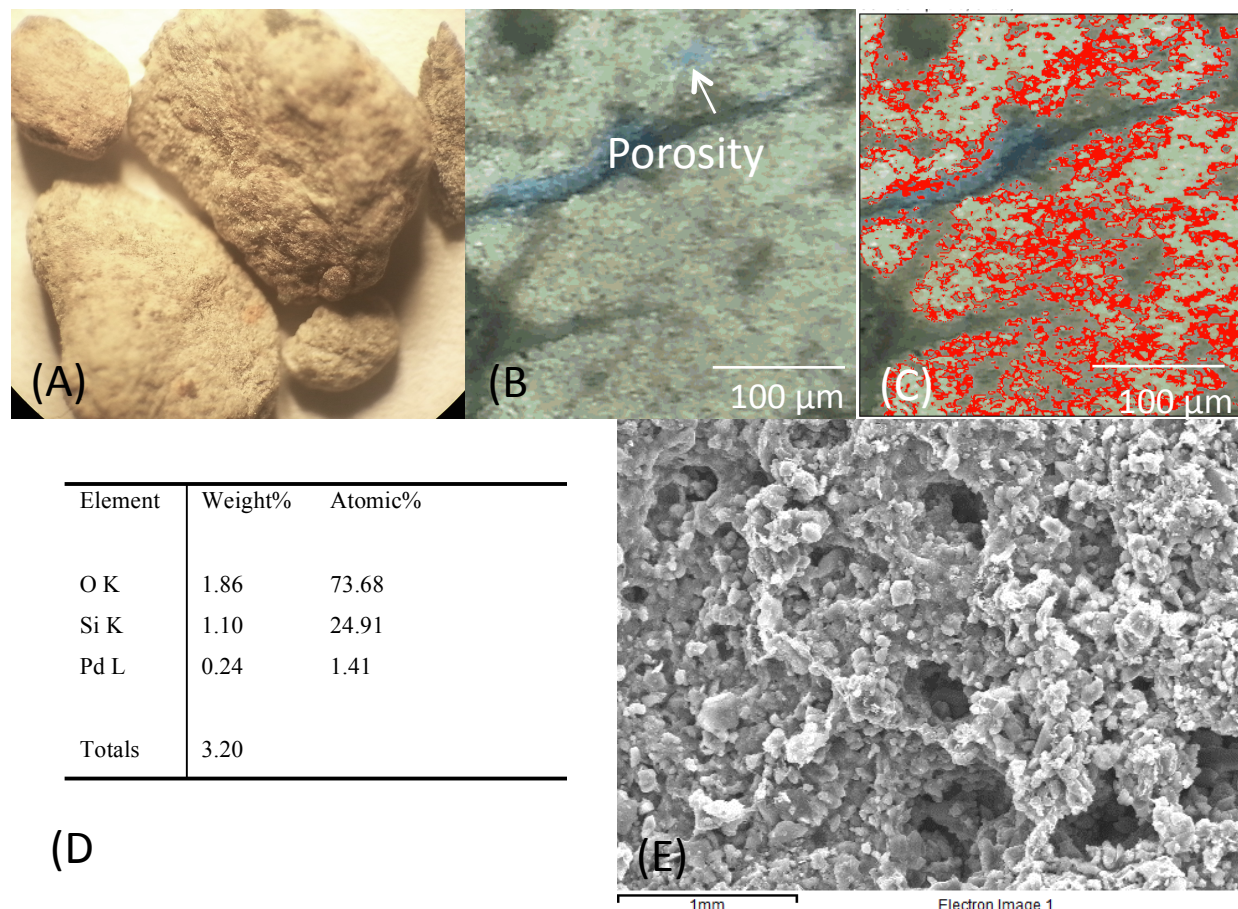


4.5 Maple F1

The drill cuttings analyzed from the producing interval (4145-45 ½ cir.) of Maple F1 (Figure 17A) were identified under binocular microscope as weathered chert with pin-point intercrystalline porosity and minimal oil staining that is light brown (Table 1). Under thin-section, the sample shows fracture porosity and micro-intercrystalline pores (Figure 17B). The calculated porosity of sample 4145-45 ½ cir. from ImageJ is 24.6% (Figure 17C). SEM-EDS analysis indicates that the sample is mainly silicon and oxygen, and the 1000x magnification

image shows micro vugs to vuggy porosity and micro-intercrystalline pores (Figure 17D and 17E).

Figure 17. (A) Drill cuttings from Maple F1 under binocular microscope; (B) Photomicrograph of 4145-45 1/2 cir. using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4145-45 1/2 cir.; (E) SEM image at 1000x mag, showing porosity.

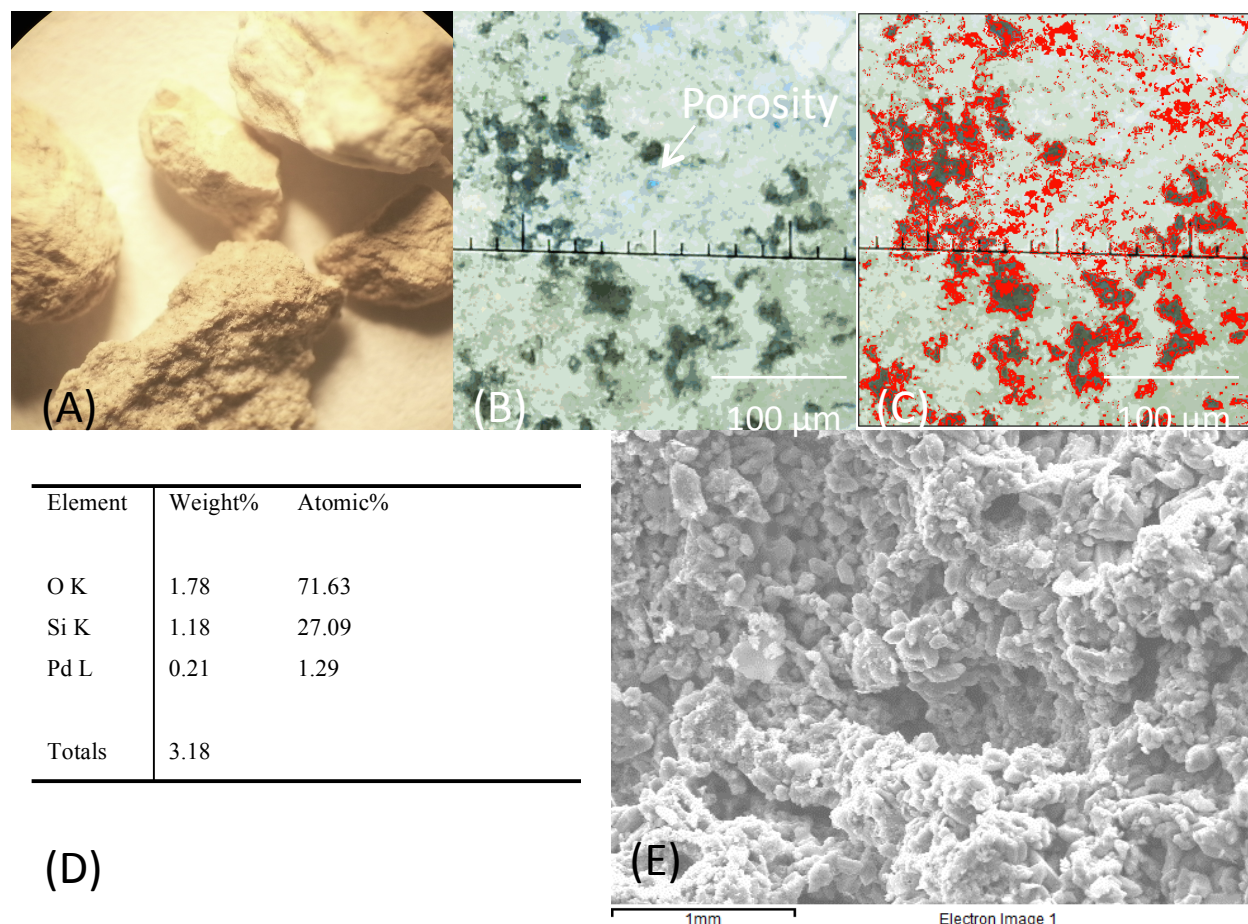


4.6 Bruch 2

The drill cutting analyzed from the producing interval (4160- 60 min) of Bruch 2 (Figure 18A) were identified under binocular microscope as weathered chert with intercrystalline porosity and minimal oil staining with light brown specs (Table 1). Under thin-section, the sample shows micro-intercrystalline pores with a few micro vugs (Figure 18B). The calculated porosity of sample 4160 60 min cir. from ImageJ is 19.1% (Figure 18C). SEM-EDS analysis

indicates that the sample is mainly silicon and oxygen, and the 1000x magnification image shows micro vugs and micro-intercrystalline pores (Figure 18D and 18E).

Figure 18. (A) Drill cuttings from Bruch 2 under binocular microscope; (B) Photomicrograph of 4160 -60 min using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4160 -60 min; (E) SEM image at 1000x mag, showing porosity.

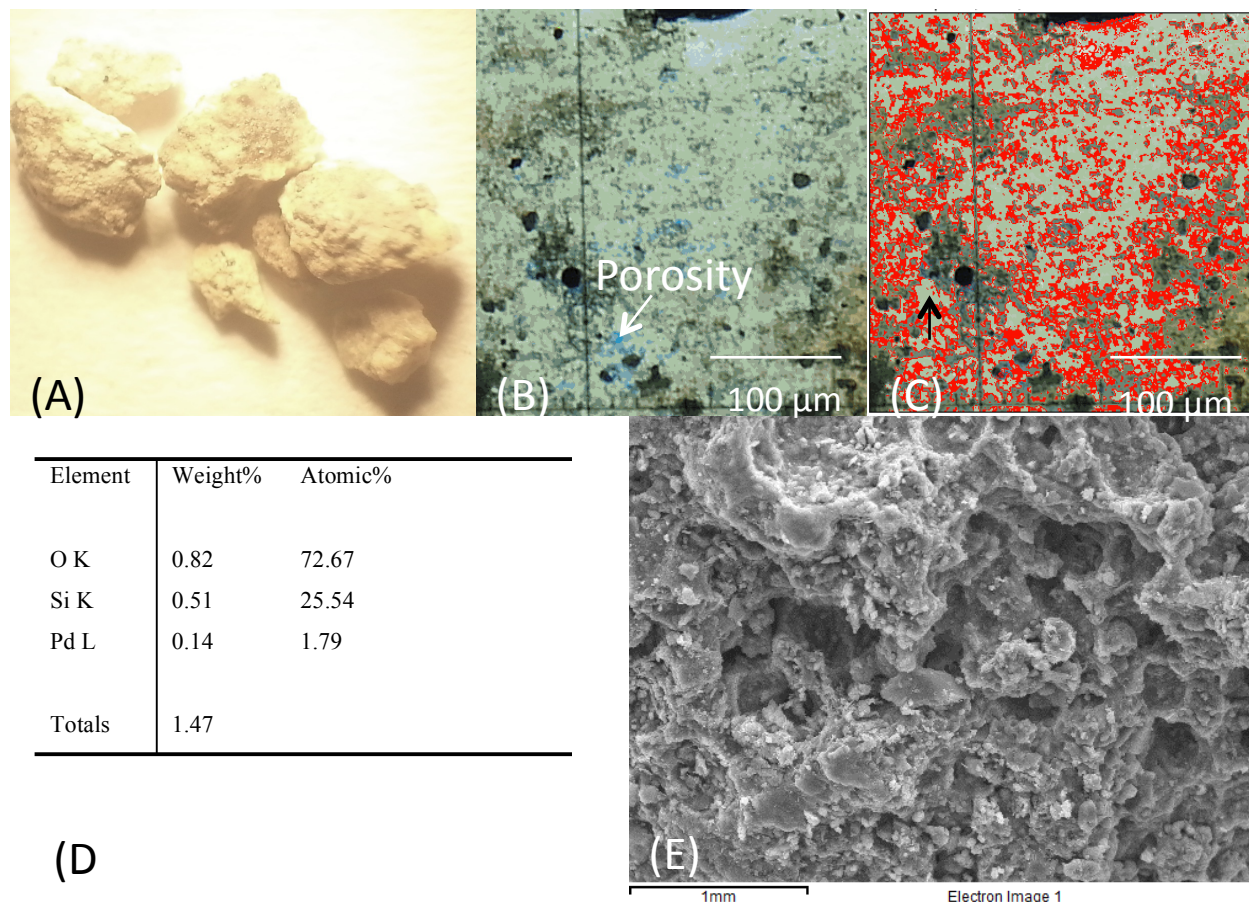


4.7 Maple G1

The drill cuttings analyzed from the producing interval (4137-37 ½ cir) of Maple G1 (Figure 19A) were identified under binocular microscope as weathered chert with vuggy intercrystalline porosity and minimal oil staining that is light brown-caramel like (Table 1). Under thin-section, the sample shows micro-intercrystalline pores with a few micro vugs (Figure 19B). The calculated porosity of sample 4137-37 ½ cir. from ImageJ is 28.3% (Figure 19C).

SEM-EDS analysis indicates that the sample is mainly silicon and oxygen, and the 1000x magnification image shows micro vugs to vuggy porosity and micro-intercrystalline pores (Figure 19D and 19E).

Figure 19. (A) Drill cuttings from Maple G1 under binocular microscope; (B) Photomicrograph of 4137-37 1/2 cir. using 10x mag; (C) ImageJ indicating porosity in red; (D) Elemental analysis of 4137-37 1/2 cir.; (E) SEM image at 1000x mag, showing porosity.



In summary, the binocular microscope analysis show that in all seven wells the lithology is weathered chert, and porosity varies from intercrystalline to intercrystalline-vuggy porosity. Oil staining in the form of light brown coloring was visible on each grain selected, and a few pieces had what looked like a thin layer of caramel covering a portion of the grain.

The thin-section analysis supports the existence of fracture porosity, identified by abundant thresholded pixels that formed in a line. Also visible were micro-vugs, which were indicated by small areas of bright blue dyed resin, as well as micro-intercrystalline pores, which were only indicated by running the thin section image through ImageJ where it colored the thresholded pixels red.

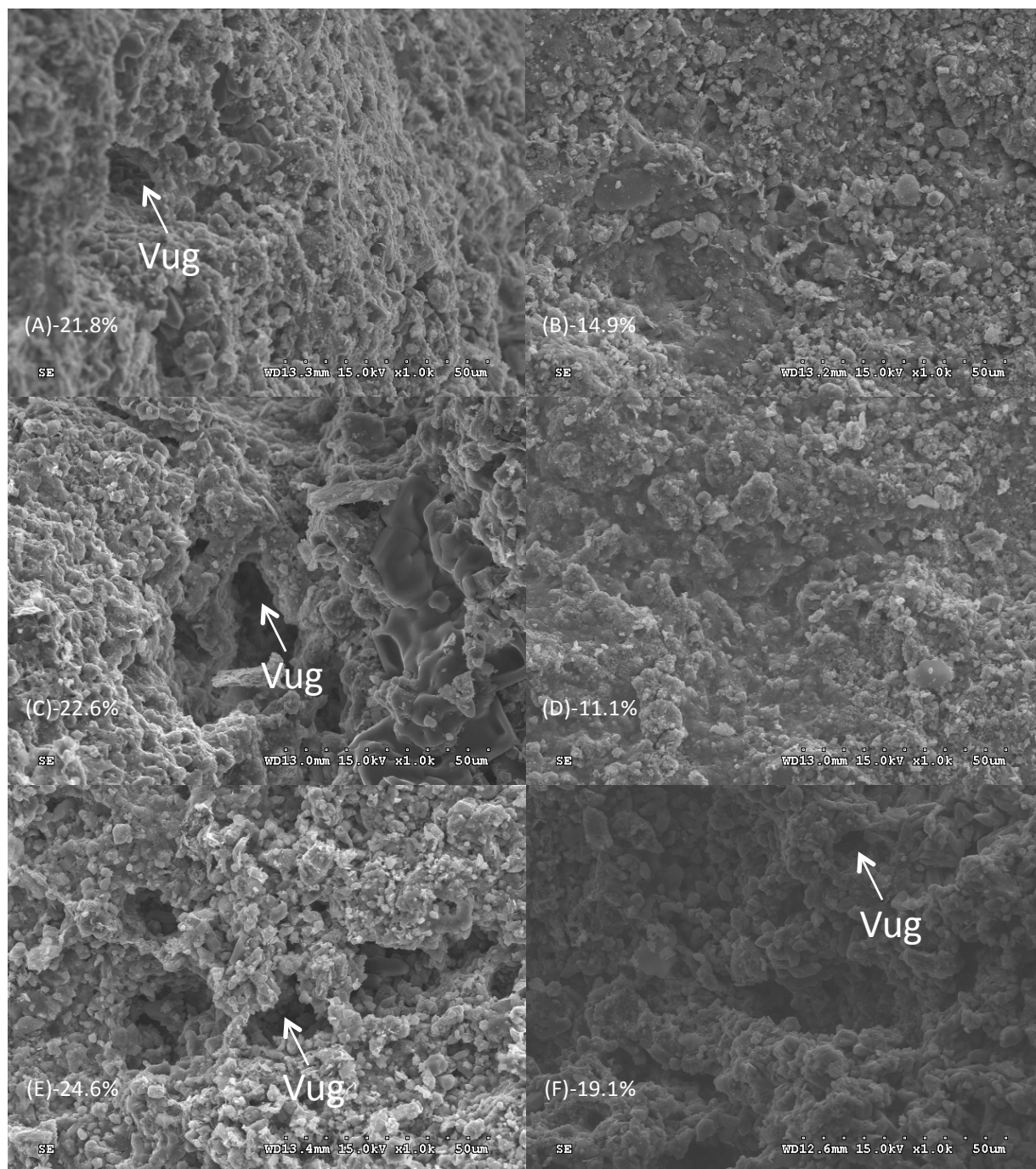
Visually the 1000X magnification SEM images are consistent with the ImageJ calculated porosity values (Figure 20). For example, Maple F2 and Maple E2 have the lowest calculated porosities (Table 2), and they clearly lack the obvious micro vugs in the SEM images shown by samples with higher calculated porosities, such as, Maple G1 or Maple F1.

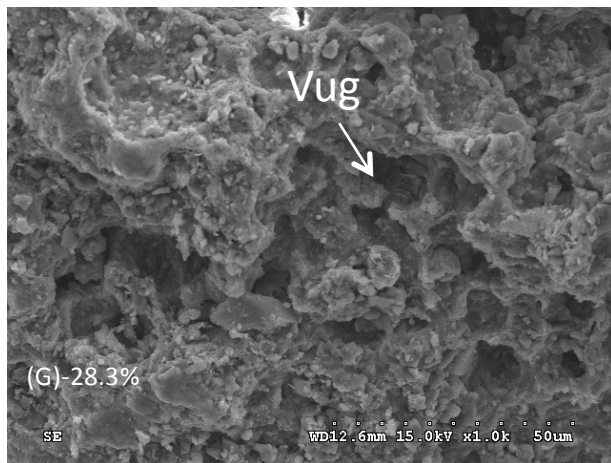
Qualitative permeability observations of the SEM images show Maple G1 has several micro-vugs that seem to be relatively the same size and well connected. Krehbiel A1, Bruch 1, Bruch 2, and Maple F1 all have micro-vugs of the relatively same size but don't seem to be connected like Maple G1. Maple F2 and Maple E2 have little to no micro-vugs and don't look to be connected at all. These observations suggest that Maple G1 has "Good" qualitative permeability; Krehbiel A1, Bruch 1, Bruch 2, and Maple F1 has "Intermediate" qualitative permeability; Maple F2 and Maple E2 have the "worst" qualitative permeability.

Table 2. SEM porosity type compared to calculated ImageJ porosity.

Well Name	1000X SEM Porosity Type	ImageJ Porosity
Krehbiel	micro vugs and micro-intercrystalline pores	21.8331%
Maple F2	micro-intercrystalline pores	14.9484%
Bruch 1	sizable vugs and micro-intercrystalline pores	22.6021%
Maple E2	micro-intercrystalline pores and a few micro vugs	11.1527%
Maple F1	micro vugs to vuggy porosity and micro-	24.6353%
Bruch 2	micro vugs and micro-intercrystalline pores	19.1051%
Maple G1	micro vugs to vuggy porosity and micro-	28.3837%

Figure 20. SEM images of producing intervals. (A) Krehbiel A1 - 4113-4118 1/2 cir.; (B) Maple F2 - 4157 -40 min; (C) Bruch 1 - 4215-15 1 cir.; (D) Maple E2 - 4175-4180; (E) Maple F1 - 4145-45 1/2 cir.; (F) Bruch 2 - 4160 -60 min; (G) Maple G1 - 4137-37 1/2 cir..





Chapter 5 - Discussion

5.1 Variation of Reservoir Properties - Porosity

Porosity values calculated from thin section are compared to log porosities in Table 3. Six of the seven wells had porosity logs available on the Walters Digital Geological Library (Kansas Geological Society & Library, 2015). The logs used differing scales, and averaged between 3-8.5% porosity, which is less than half of what ImageJ calculated. Logs are a sliding average over several vertical feet, and aren't sensitive to thin bed porosity. Furthermore, the well logs used in this field used carbonate scales for porosity, which would give pessimistic log porosity for cherts.

Table 3. Table showing the well names, the sampled and studied interval, the calculated porosities for each interval using ImageJ, and the average log porosities.

Well Name	Studied Interval	ImageJ Porosity%	Ave. Log Porosity%
Krebeil A1	4113-4118 ½ cir.	21.8%	7.25%
Maple F2	4157 – 40 min	14.9%	7.25%
Bruch 1	4215-4215 1 cir.	22.6%	5%
Maple E2	4175-4180	11.1%	N/A
Maple F1	4145-4145 ½ cir.	24.6%	3%
Bruch 2	4160 – 40 min	19.1%	5%
Maple G1	4137-4137 ½ cir.	28.3%	3%

5.2 Approaches to Compartmentalization Compared to Porosity

The Spivey-Grabs oil field is one of the biggest chat fields in south central Kansas and is reported to be compartmentalized. The identification of the compartments is critical to further

develop the oil field. Evans (2011) reported a maturation difference in the hydrocarbons across the field, and suggests this was a result of the compartmentalized reservoir. Similarly, Kwasny (2015) concluded that there are two separate types of oil within the Spivey-Grabs field, a light and heavy density oil.

Are these separate oils the result of separate reservoir rocks within the field, or is the compartmentalized behavior the result of different fluid properties? Comparing the occurrence of the different oils with the results of this study will start to paint a picture of what is happening with the Spivey-Grabs field with respect to compartmentalization.

5.2.1 Oil Maturity and Oil Type Compared to Porosity

According to the isopach maps produced by Evans (2011), some wells, such as the Sullivan 2 and the Krehbiel 1, have hydrocarbons of different maturities and are separated by a region where the isopach map thins. Additionally, other areas of the field aren't separated by isopach thins, but hydrocarbons still have different maturities. For example, the hydrocarbons in Bruch 2, Maple F1 and F2 wells exhibit similar degrees of maturity; in contrast, hydrocarbons from the Bruch 1 and Maple E2 are significantly less mature (Figure 22 & 23). Evans (2011) did not describe the maturity of the Maple G1 or Krehbiel A1.

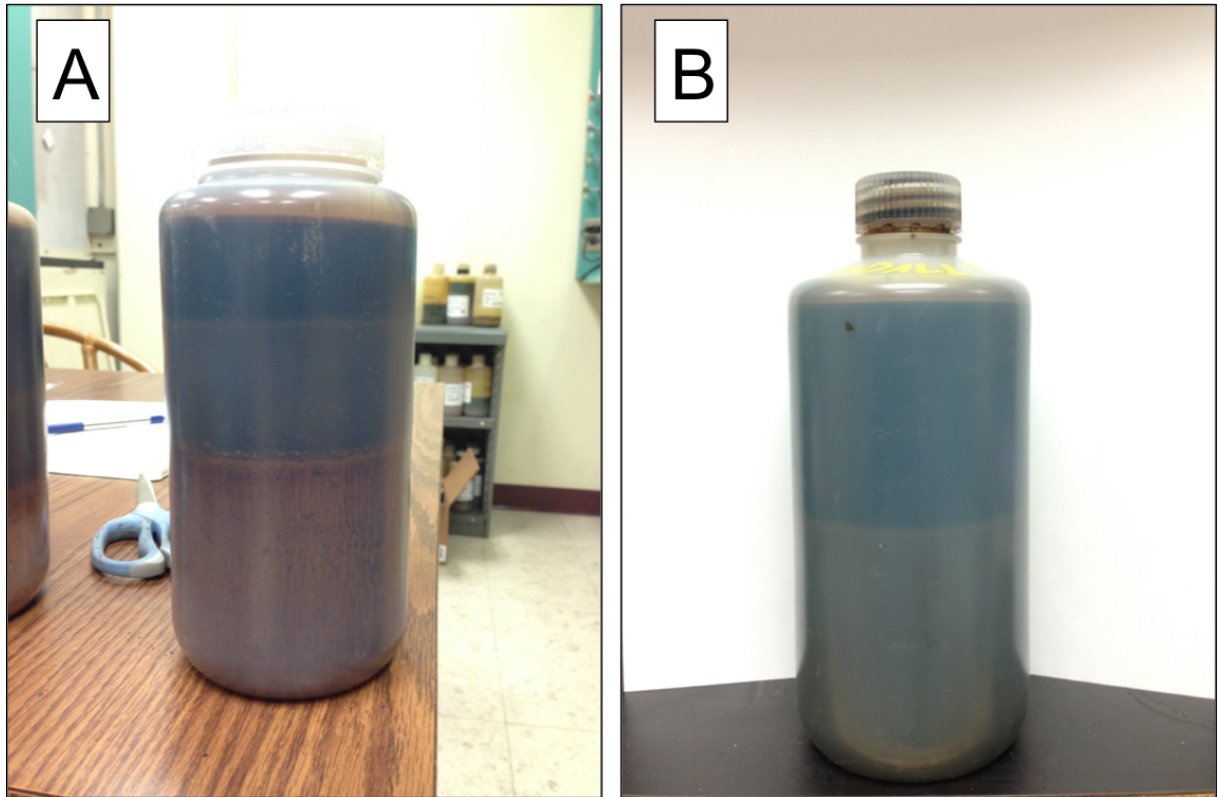
Comparing the calculated porosities in the area that isn't divided by an isopach thin, it became evident that porosity didn't correlate to a specific maturity. This was because the porosities varied with maturity type (Table 4); such as highly mature oils seen only in areas with a lower percentage of porosity or less mature oils seen in an area with a higher percentage porosity, or vice versa.

Table 4. Porosity doesn't correlate to maturity type.

More Mature	Less Mature
Bruch 2 – 19.1% porosity	Bruch 1 – 22.6% porosity
Maple F1 – 24.6% porosity	Maple E2 – 11.1% porosity
Maple F2 – 14.9% porosity	

Kwasny (2015) collected the oil from the wellhead, and allowed them to sit for several weeks (30 days) to let the oil and brine separate. She found, however, that most of her oil samples separated into two distinct oils, a light oil and heavy oil (Figure 21). Even though the bulk of the wells were the same in both studies, Evans (2011) did not report this behavior. His samples were sent quickly for analyses, and it is assumed that not enough time had passed for the oils to separate. It should also be noted that the operator of the wells sampled did not report this behavior.

Figure 21. Oil samples from Kwasny (2015) showing two distinct types of oil, a light and a heavy oil.



Comparing the results of Kwasny (2015), with calculated porosity values (Figure 22 & 23) of this study shows that, the oil type doesn't correlate with porosity values throughout the Spivey-Grabs field (Table 5). While the Maple E2 and Maple F1, highlighted pink in Table 5, are less than one mile apart, both wells indicate that they have light and heavy oil production, but their porosity values vary by more than 10%. Again, porosity variations occur in Bruch 1 and Maple F2, highlighted blue in Table 5, yet both produce light oil. This shows two sets of wells that have varying porosity while producing the same oil type.

Table 5. Modified oil type table from Kwasny (2015), showing well name, oil type, and ImageJ calculated porosity. Wells highlighted in blue produce light oil and wells highlighted in pink produce both light and heavy oil. However, the porosities vary between these wells.

Well Name	Oil Type	Porosity %
Bruch No. 1	Light	22.6%
Bruch No. 2	Light	19.1%
Pound No.1	Both	N/A
Maple E2	Both	11.1%
Maple G1	Light	28.3%
Maple F1	Both	24.6%
Maple F2	Light	14.9%
Krehbiel B1	Both	N/A
Coykendall 10	Both	N/A
Krehbiel A1	Heavy	21.8%

The oil collected by Evans (2011) and Kwasny (2015) from the Spivey-Grabs field showed varying characteristics, for which porosity didn't correlate with a specific type of maturity or one specific oil type (Figure 22 & 23). If the rock property, porosity, is not controlling the compartmentalization of the Spivey-Grabs field, the compartmentalization is likely due to the different physical characteristics of the oil. The thicker and heavier oil could be acting as a barrier so the lighter oil cannot migrate throughout the field. This could give the illusion of compartments by isolating both light and heavy oils within the field.

Figure 22. Pineville Tripolite Isopach map from Evans (2011). Wells indicated by a four quadrant pie graph with the top left representing oil type from Kwasny (2015), the top right representing maturity from Evans (2011), the bottom left representing observed permeability, and the bottom right representing calculated ImageJ porosity. There are no real groupings to indicate correlation. Therefore, the map shows porosity doesn't correlate with maturity or to one specific oil type. See Figure 22 for legend as to what the different colors represent.

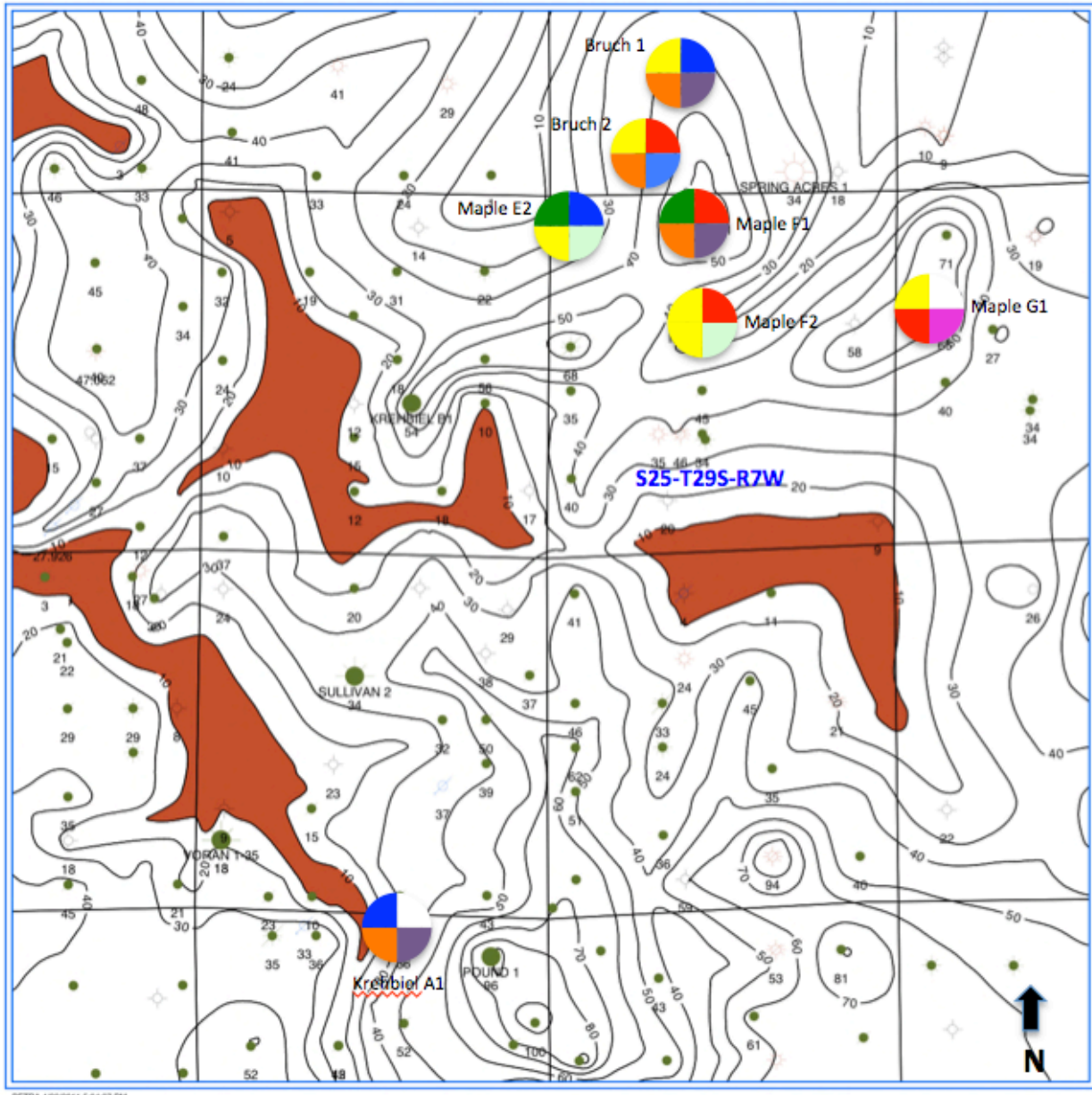
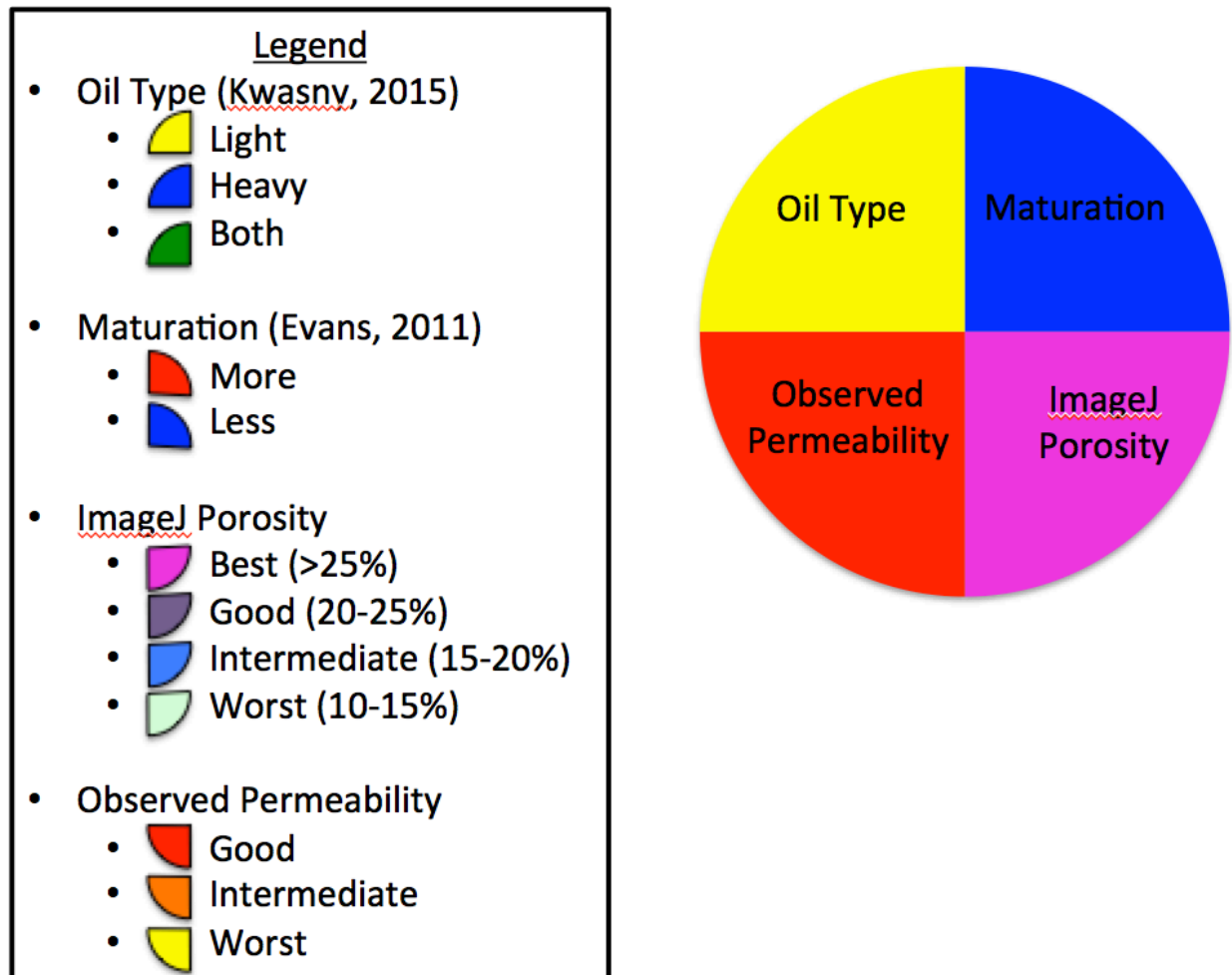


Figure 23. Different colors in each quadrant represent different characteristics of a well. The top left represents oil type, top right represents maturity, bottom left represents observed permeability, and the bottom right represents ImageJ porosity.



Chapter 6 - Conclusion

Understanding the compartmentalization of an oil field can lead to better development methods and maximize production. While the Spivey-Grabs field is the largest Mississippian chert, or chat reservoir it has been subject to unpredictable performance. This study investigated whether differences in the reservoir rock, in particular variations in porosity, were the cause of the observed compartmentalization. The conclusion of the current study, in combination with the past research of Evans (2011) and Kwasny (2015), suggest that rock properties are not the cause.

This conclusion is supported by the variance in calculated porosities of the wells, the oil type, and the maturity of the oil. The following provides evidence for conflicting porosity values compared to oil type and maturities.

1. Neighboring wells, where porosity values vary significantly, have similar oil type. An example of this is from wells Maple E2 and Maple F1.
2. Hydrocarbon maturity, based on Evans (2011), doesn't correlate with porosity. Wells can be considered highly mature, but the porosity of those wells can vary greatly. An example of this can be seen in Maple F1 and Maple F2, both being considered more mature and having a 10% variance in porosity.

Mazzullo et al. (2010) states that the Pineville Tripolite facies reservoir is highly porous and has low permeability. The heavier and thicker oil that was identified by Kwasny (2105) could be blocking the connectivity between the pores, causing a dynamic seal, thus resulting in compartments that produce different types of oils throughout the Spivey-Grabs field.

Due to the differing physical characteristics of the oil, other possible explanations for the compartmentalization of the Spivey-Grabs field are: (i) that the oils in the reservoir were supplied during multiple events from the same source, or (ii) the oils matured at different rates

while in the reservoir and after migration.

References

- Australian Microscopy and Microanalysis Research Facility., 2014, May 12. Quantitative EDS X-ray microanalysis using SEM | MyScope. Retrieved from <http://www.ammrf.org.au/myscope/analysis/eds/quantitative/>
- Bunker, B.J., and Witzke, B.J., 1996, Relative sea-level changes during Middle Ordovician through Mississippian deposition in the Iowa area, North American craton, in Witzke, B.J., Ludvigson, G.A., and Day, J., eds., Paleozoic sequence stratigraphy: views from the North America craton: Geological Society of America Special Paper 306, p. 307-330.
- Evans, D., 2011, The compartmentalization and biomarker analysis of the Spivey-Grabs-Basil Field, south-central Kansas. Thesis: Kansas State University. 101 p.
- Goebel, Edwin D., 1971, Southeast Kansas – northeast Oklahoma – southwest Missouri, in Adler, Frank J. et al. Future petroleum provinces of the Mid-Continent. Pp. 1088-1097.
- Gore, P. J., 2005, October 29. *The Earth Through Time*. Retrieved from http://onlinelibrary.wiley.com/higheredbcs/legacy/college/levin/0471697435/chap_tut/chaps/chapter08-07.html
- Grove, C., & Jerram, D. A., 2011, jPOR: An ImageJ macro to quantify total optical porosity from blue-stained thin sections. *Computers & Geosciences*, 37(11), 1850-1859.
- Howe, Wallace B., 1956, Stratigraphy of Marmaton Desmoinesian (Cherokee) rocks in southeastern Kansas. Bulletin – Kansas Geological Survey, V. 132 p.
- Jolley, S. J., Fisher, Q. J., Ainsworth, R. B., 2010, Reservoir compartmentalization: an introduction: Geological Society, v. 347, p. 1-8.
- Kansas Geological Society & Library., 2015, Kansas Geological Society & Library (KGS, KGS&L) - Wichita, KS. Retrieved from <http://www.kgslibrary.com>
- Kwasny, B., 2015, An investigation of the crude oil in the Spivey-Grabs field of south-central Kansas: an insight into oil type and origin. Thesis: Kansas State University. 85 p.
- Mazzullo, S.J., Wilhite, B.W., Woolsey, I.W., 2009, Petroleum Reservoirs with a Spiculite-dominated depositional sequence: Cowley formation (Mississippian: Lower Carboniferous), south-central Kansas: AAPG Bulletin, v. 93, p. 1649-1689.
- Mazzullo, S. J., Wilhite, B. W., & Boardman II, D. R., 2011, Lithostratigraphic Architecture of the Mississippian Reeds Spring Formation (Middle Osagean) in Southwest Missouri, Northwest Arkansas, and Northeast Oklahoma: Outcrop Analog of Subsurface Petroleum Reservoirs. *Oklahoma City Geological Society*, 61(5), 254-269.

- Mazzullo, S.J., Wilhite, B.W., Boardman, D.R., Morris, B., Turner, R., and Godwin, C., 2010, Lithostratigraphy and conodont biostratigraphy of the Kinderhookian to Osagean Series in southwest Missouri, northwest Arkansas, and northeast Oklahoma: Field Trip Guide, Kansas Geological Society, 2010.
- Merriam, Daniel F., 1963, The geologic history of Kansas. Kansas Geological Survey Bulletin 162. 317 p.
- Montgomery, Scott L., Mullarkey, James C., Longman, Colleary, William M., and Rogers, James P., 1998, Mississippian “Chat” reservoirs, south Kansas: low resistivity pay in a complex chert reservoir. AAPG Bulletin, Vol. 82, No. 2, pp.187-205.
- Parham, K.D., Northcutt, R.A., 1993, MS-3, Mississippian chert and carbonate and basal Pennsylvanian sandstone- central Kansas uplift and northern Oklahoma, in Bebout, D.C., White, W.A., Hentz, T.F., and Grasmich, M.K., eds., Atlas of major mid-continent gas reservoirs: Gas Research Institute and Texas Bureau of Economic Geology, p. 57-60.
- Rahman, N. M., 1998, Transient pressure analysis in compartmentalized reservoirs. Dissertation: University of Alberta, 277 p.
- Rogers, S.M., 2001, Deposition and diagenesis of Mississippian chat reservoirs, north-central Oklahoma: AAPG Bulletin, v. 85, p. 115-129.
- Rogers, James P. and Longman, Mark W., 2001, An introduction to chert reservoirs of North America. AAPG Bulletin, Vol. 85, No. 1, pp.1-5.
- Wall, M., 2015, An oil-source rock correlation examining the potential of the Chattanooga shale as a source rock for oil within the Spivey-Grabs-Basil Field, Kingman and Harper Counties, Kansas. Thesis: Kansas State University. 79 p.
- Watney, W. Lynn, Guy, Willard J., and Byrnes, Alan P., 2001, Characterization of the Mississippian chat in south-central Kansas. AAPG Bulletin, Vol. 85, No. 1, pp. 85-113.
- Witzke, B.J., 1990, Paleoclimatic constraints for Paleozoic paleolatitudes of Laurentia and Euramerica, in W.S. McKerrow and C. R. Scotese, eds., Paleozoic paleogeography and biogeography: London, Geological Society Memoir 12, pp. 57-73.
- Zeller, Doris E., Jewett, John Mark, Bayne, Charles K, Goebel, Edwin D., O’Conner, Howard G., and Swineford, Ada., 1968, The stratigraphic succession in Kansas. Kansas Geological Survey Bulletin 189. 81 p.

Appendix A - Petropoxy 154 and Steps for Final Thin Sections

Many different trial and error methods were used to produce the best possible, and the most efficient, hand polished thin section; and each trial improved the epoxy resin puck that contained drill cuttings. Though, after producing a few trial pucks with extra drill cuttings, I concluded that the epoxy resin used was not suitable and resulted in bad petrographic images, and therefore the epoxy resin was switched to Petropoxy 154.

Petropoxy 154 is an epoxy that is manufactured for the preparation of thin sections. This is an ideal epoxy for making thin sections because it has a high bond strength that permits for a rougher grind, meaning it can withstand a courser sanding grit, to a thinner section. It also removes the need to rush, as the pot life is 5 days at 21°C (70°F). Additionally, it has a short cure time with an optimal cure temperature of 135°C (275°F). Finally, Petropoxy 154 has a low viscosity allowing for excellent impregnation.

To create thin sections with Petropoxy 154, new steps were added with the guidance of the Petropoxy 154 User's Manual. The following steps were taken to create the thin sections used for this study (Figure 24).

Step 1. Place selected cuttings (4-5 grains) on a clean and dry glass slide.

Step 2. Warm hot plate to 270-275°F with a plain white piece of paper resting on the top of the hot plate (Figure 24A).

Step 3. Mix Petropoxy 154 with a 10:1 ratio (10 parts resin to 1 part curing agent).

Step 4. Add 1 drop of blue resin dye. This dye will be used help determine porosity (Figure 24B).

Step 5. Cover drill cuttings on glass slide with Petropoxy 154 mixture (Figure 24C).

Step 6. Place glass slide on double-sided tape, this will help keep the sample intact when under vacuum (Figure 24D).

Step 7. Place bell jar over sample and glass slide.

Step 8. Vacuum air out of sample 3 times (vacuum air out, then release vacuum to allow epoxy to impregnate the drill cuttings) (Figure 24E).

Step 9. Once impregnated, place glass slide on plain white paper and then place on hot plate for 10 minutes at 270-275°F (plain white paper is used to catch any epoxy spills while on the hot plate).

Step 10. Take the glass slide off of the hot plate at exactly 10 minutes and allow to cool for 1-2 minutes.

Step 11. Immediately after cooling, start to grind down and polish the sample using corundum powder, water, and a glass plate. It works best when using a figure 8 motion. This is due to the shrinking of Petropoxy 154, also known as curing, and if not done with a few minutes after being off of the hotplate then the Petropoxy 154 could crack the glass slide.

Step 12. Hand grind sample until close to desired thickness, in this case 30 microns.

Step 13. Stop periodically to check sample.

Step 14. After hand grinding the sample close to the desired thickness the next step is to polish with higher grit sand paper.

Step 15. Next, use water and 800-grit silica carbide sandpaper that is placed on an upside down palm sander. The fast vibrations from the palm sander help to achieve the desired thickness in less time (Figure 25).

Step 16. Use a vacuum pump and attach a $\frac{3}{4}$ " rubber hose and suction the back of the glass slide. This allows you to easily hold the sample and apply pressure to the silica carbide sandpaper on the palm sander (Figure 25).

Step 17. Follow this by hand polishing the thin section on 1000, 1500, 2000, 2500 grit wet sandpaper.

Step 18. Check thin sections under petrographic microscope.

Figure 24. (A) Plain white paper on hot plate; (B) Adding blue resin dye; (C) Epoxy mixture covering samples; (D) Image showing double sided tape in bell jar; (E) Sample under vacuum.

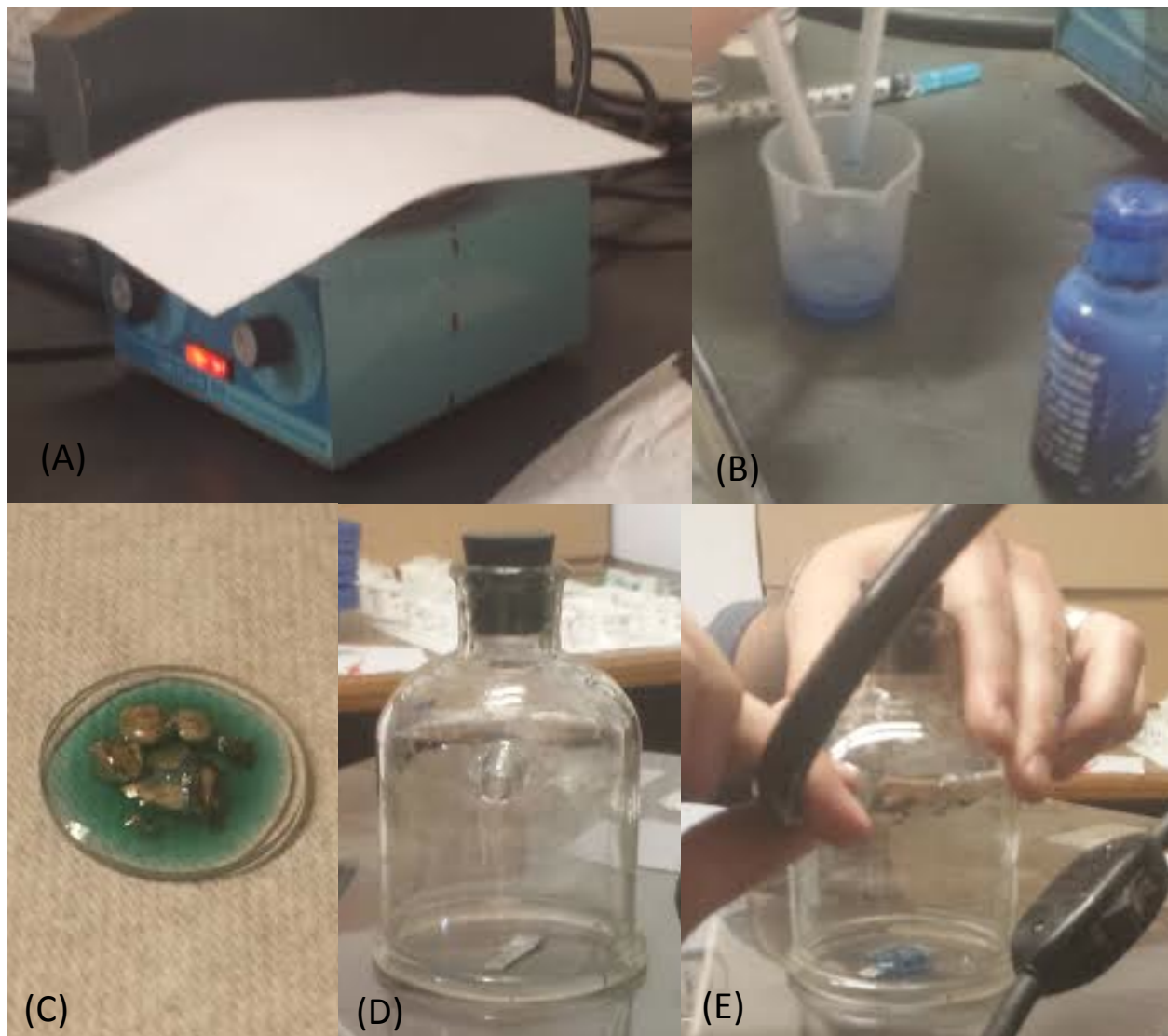


Figure 25. Showing lab setup.



(F)

Appendix B - Adobe Photoshop and Using jPOR to Calculate Porosity in ImageJ

The steps to get a digital image into an 8-bit paletted .bmp file are as follows (Grove & Jerram, 2011).

1. Open image in Adobe Photoshop.
2. Crop image only comprising the sample. Making sure to use the same image size throughout the samples.
3. Convert cropped image to an 8-bit palette file by using jPOR_60 palette.
 - a. “Image > Mode > Indexed Colour. Set “Palette” to “Custom” and you will be presented with a new window—click load and navigate to the custom JPOR palette (JPOR_60) and click load—OK this operation. Set dither to none under Indexed Colour options and click OK. The image will now be an 8-bit palette file. This can be automated by recording the action then playing it via the Automate > Batch tool,” (Grove & Jerram, 2011).
4. Save the image as a .bmp file.

The steps to calculate porosity using the jPOR Palette in ImageJ are as follows (Grove & Jerram, 2011).

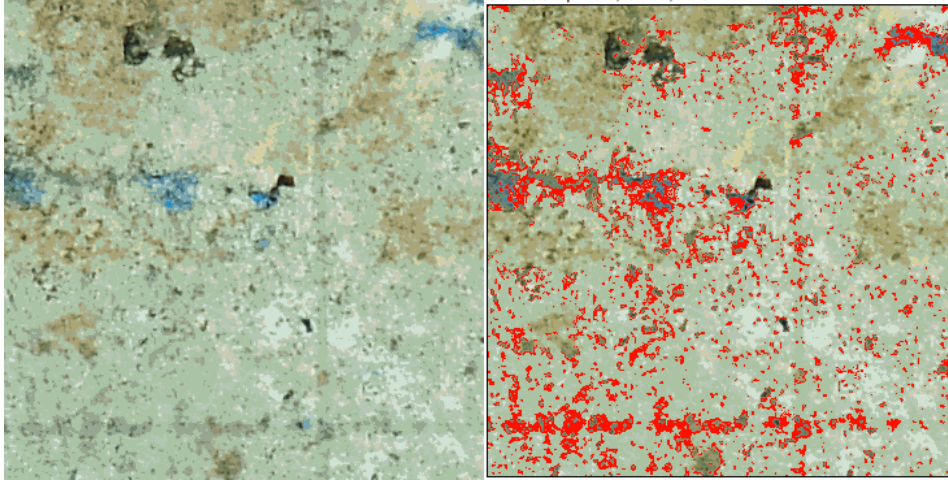
1. Right click saved .bmp file and open it using ImageJ.
2. This will open up the image into a new window within ImageJ and it will also prompt you to start porosity measurements by pressing F1.
3. “Pressing F1 automatically thresholds the image using the default values, and displays the threshold command box where the threshold level can be manually adjusted to refine the porosity selection,” (Grove & Jerram, 2011).

4. Once the porosity is selected press F2.
5. This calculates the area of thresholded pixels within the images, meaning it calculates the area of color pixels that are within the selected threshold range (ex. 50,000 pixels indicate porosity of a total 130,000 pixels. Which totals a porosity value of 38.4615%).
6. To avoid recalculating the porosity and to end the batch, press F5

Appendix C - Additional Images

Bruch 1

4205-10



Total pixels=

130682

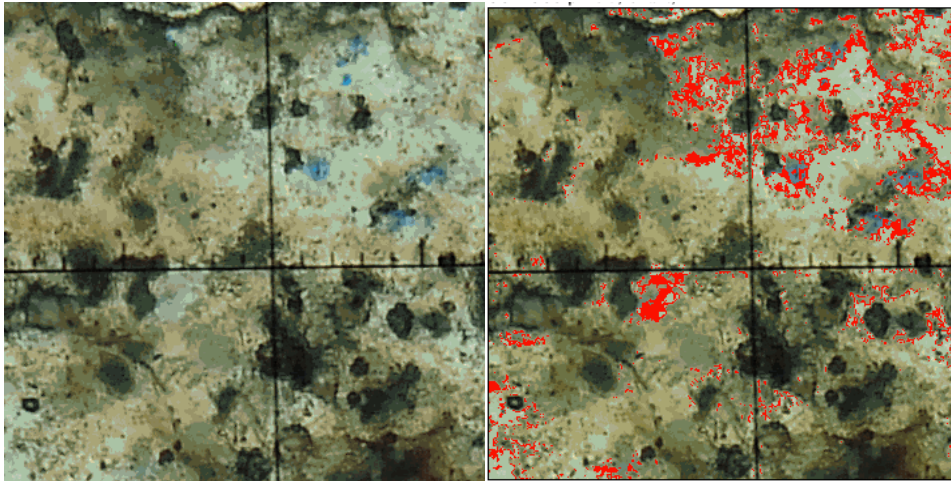
Pixels forming porosity=

14570

Porosity=

11.1492

4215-15 ½ cir



Total pixels=

129960

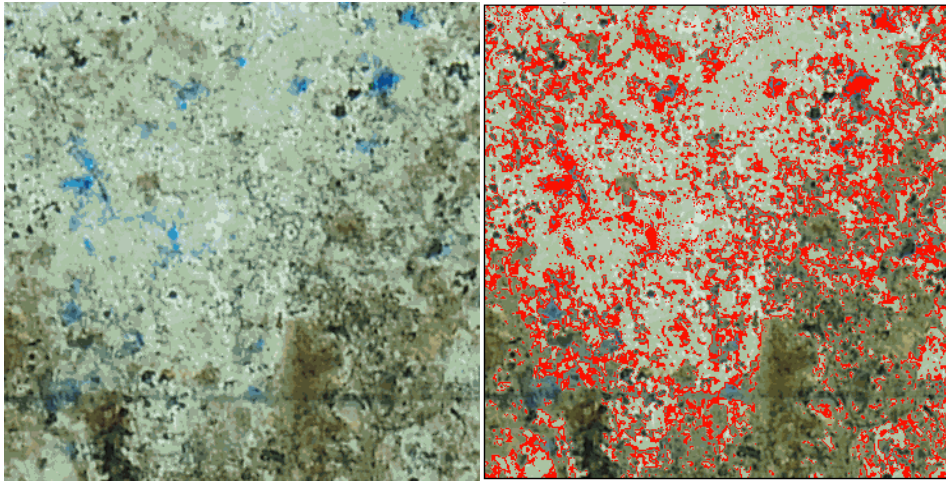
Pixels forming porosity=

8902

Porosity=

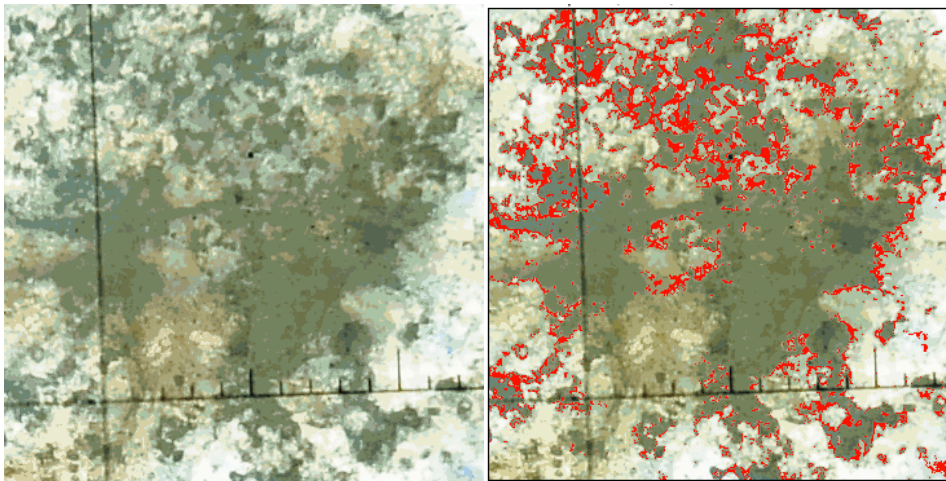
6.8498

4215-15 1 cir



Total pixels=
135054
Pixels forming porosity=
30525
Porosity=
22.6021

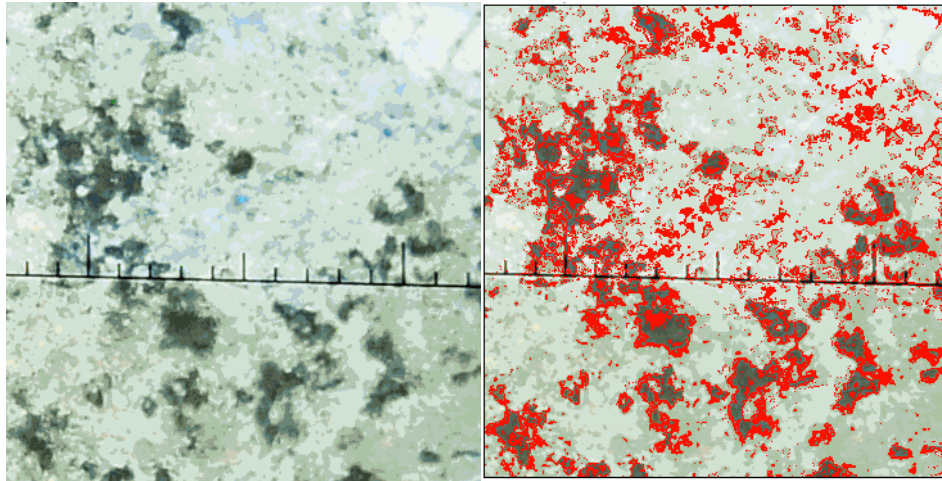
4215-15 1 and 1 half cir



Total pixels=
132132
Pixels forming porosity=
12660
Porosity=
9.5813

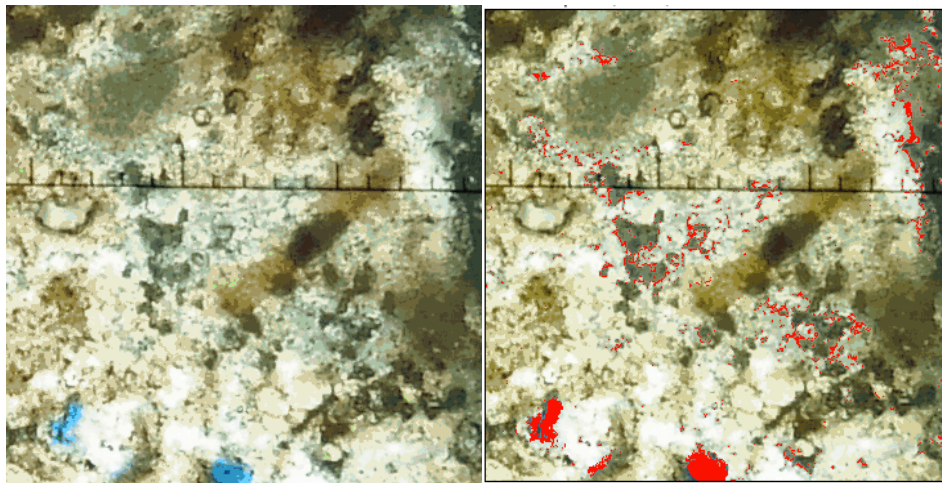
Bruch 2

4160 40 min



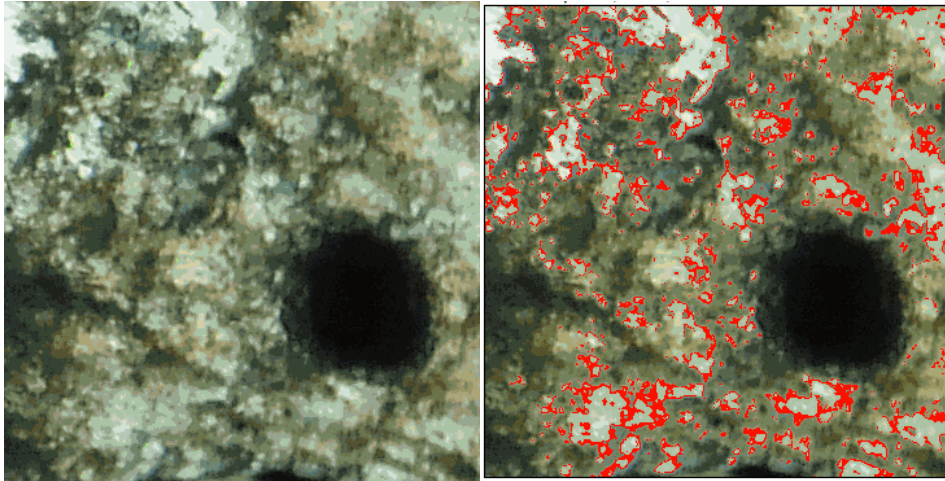
Total pixels=
133221
Pixels forming porosity=
25452
Porosity=
19.1051

4160 60 min



Total pixels=
132130
Pixels forming porosity=
3649
Porosity=
2.7617

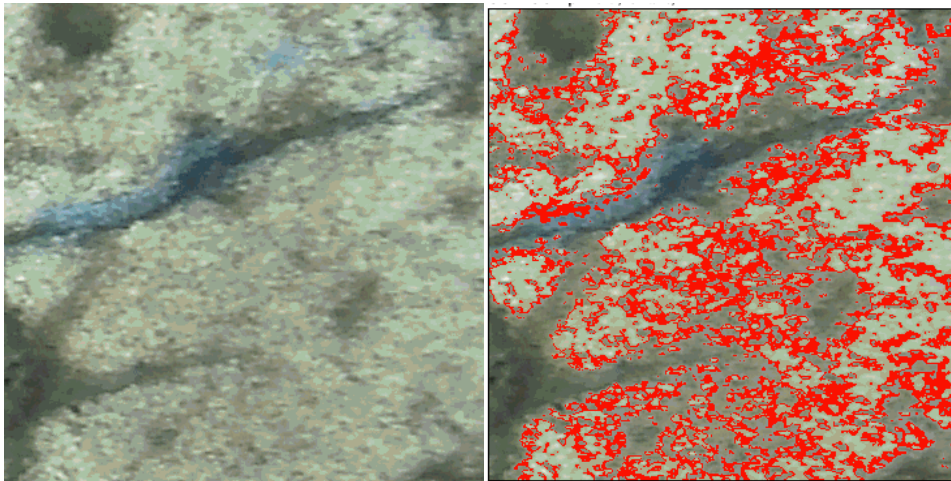
4165 20 min



Total pixels=
130680
Pixels forming porosity=
12110
Porosity=
9.2669

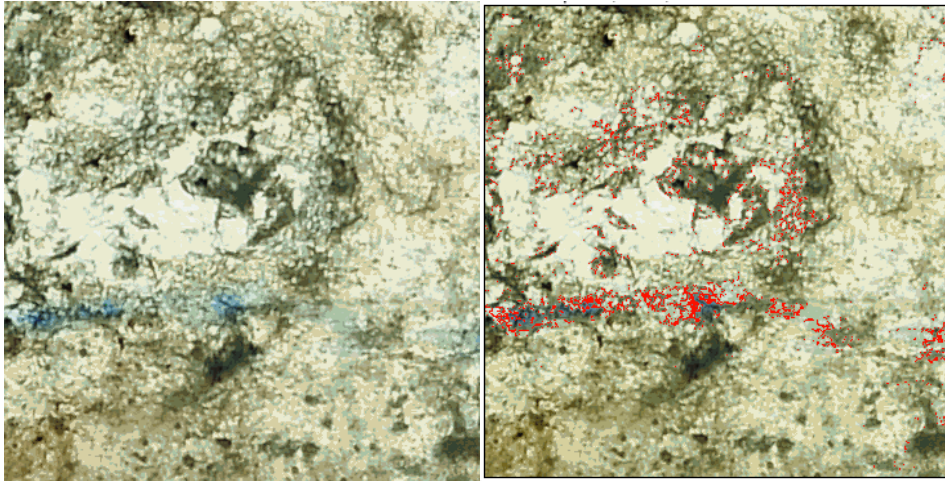
Maple F1

4145-45 1 half cir



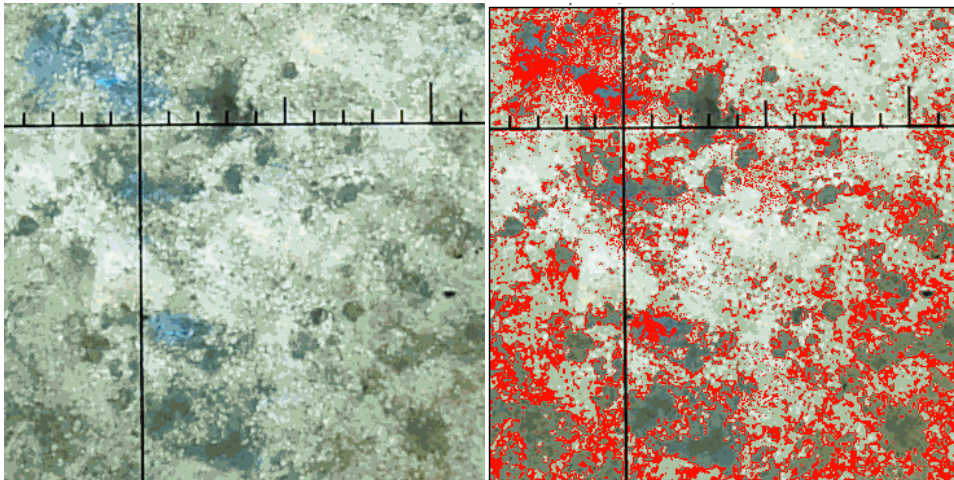
Total pixels=
130321
Pixels forming porosity=
32105
Porosity=
24.6353

4145-45 1 cir



Total pixels=
132130
Pixels forming porosity=
3157
Porosity=
2.3893

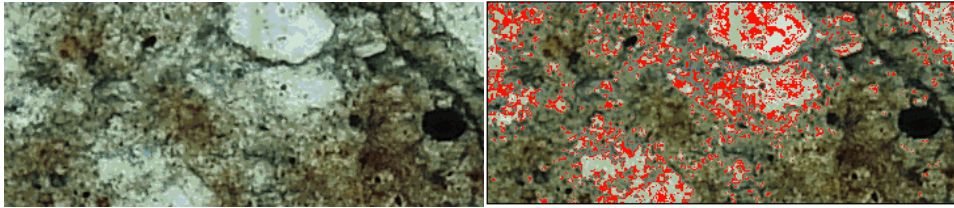
4145-55



Total pixels=
132860
Pixels forming porosity=
32348
Porosity=
24.3474

Maple F2

4130-4140



Total pixels=

55080

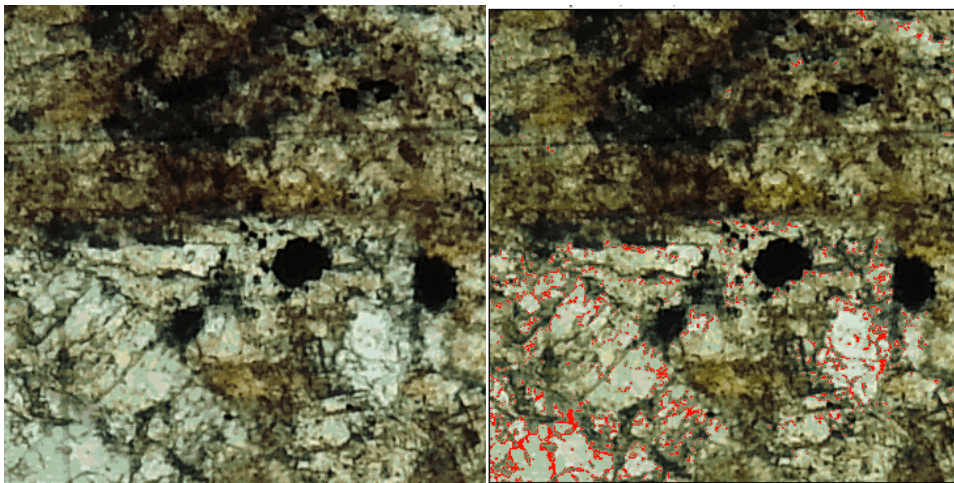
Pixels forming porosity=

6747

Porosity=

12.2495

4140-4150



Total pixels=

131043

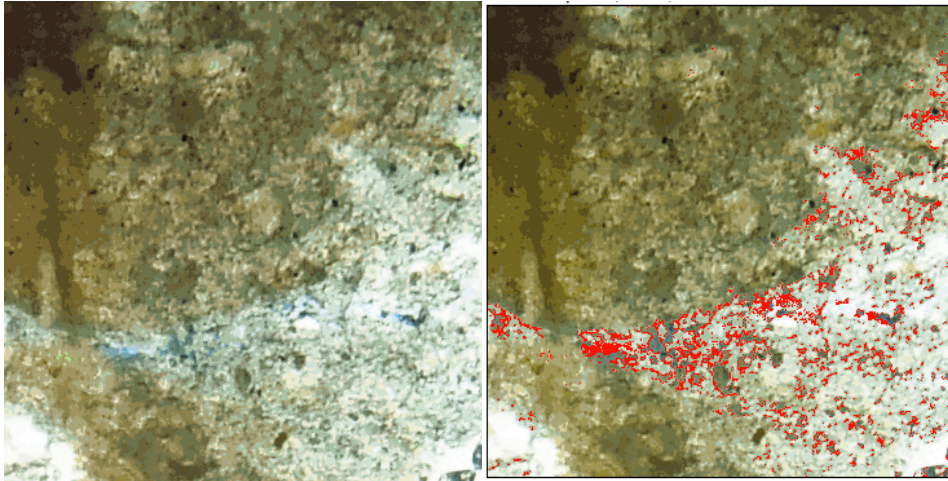
Pixels forming porosity=

3475

Porosity=

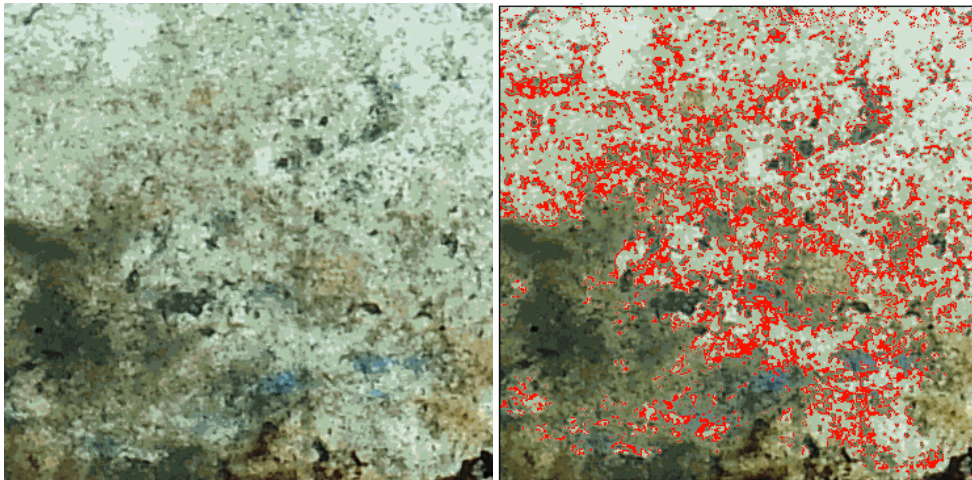
2.6518

4157 - 20 min



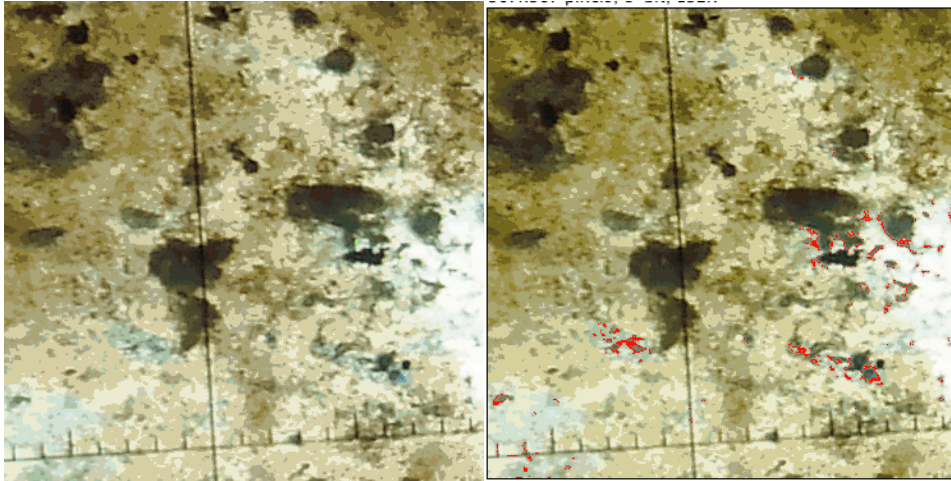
Total pixels=
131768
Pixels forming porosity=
5751
Porosity=
4.3645

4157 - 40 min



Total pixels=
131760
Pixels forming porosity=
19696
Porosity=
14.9484

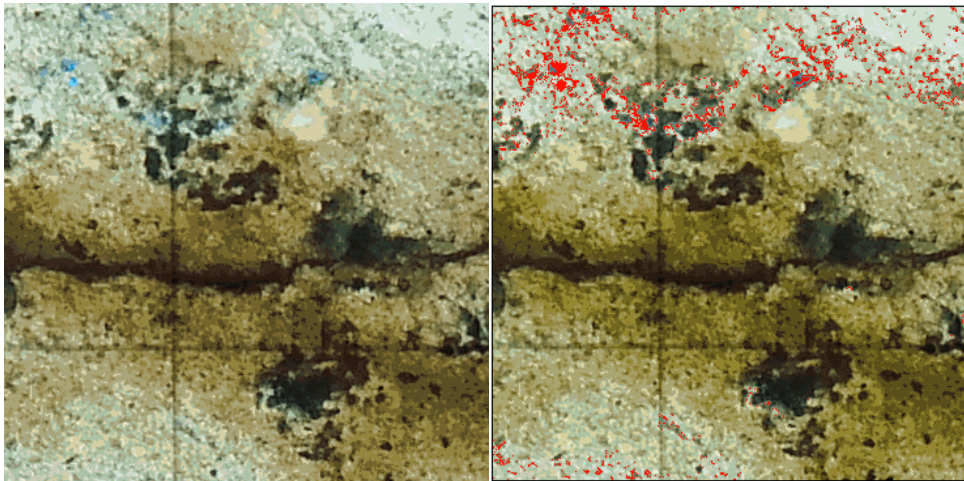
4157 - 60 min



Total pixels=
134689
Pixels forming porosity=
913
Porosity=
0.6779

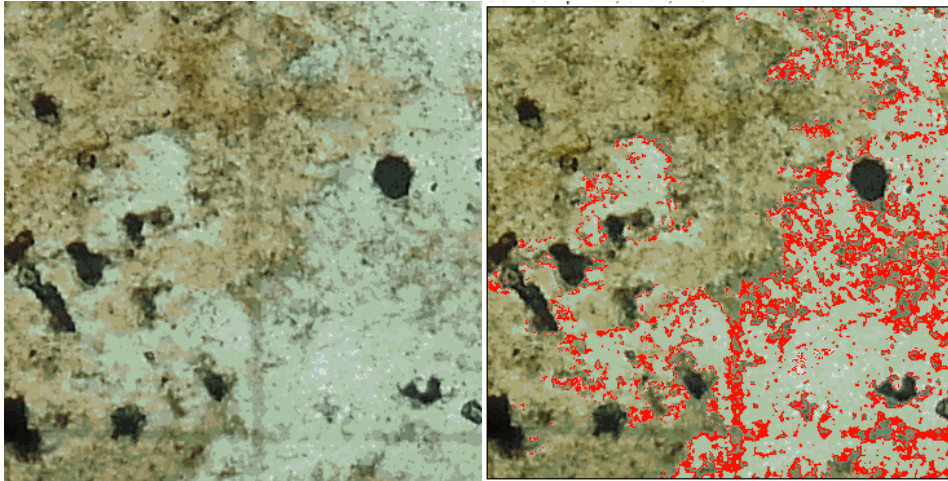
Maple E2

4160-4170



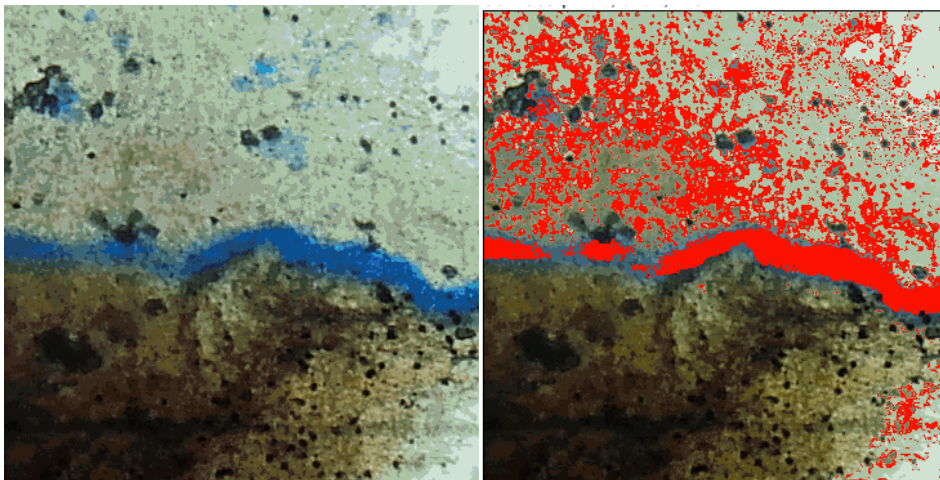
Total pixels=
132492
Pixels forming porosity=
3465
Porosity=
2.6153

4170-4175



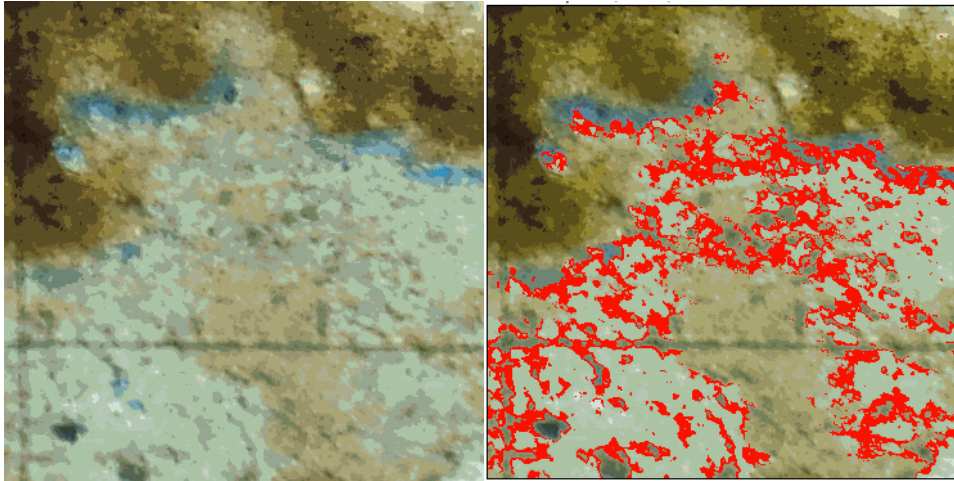
Total pixels=
131768
Pixels forming porosity=
15475
Porosity=
11.7441

4175-75 1 half cir



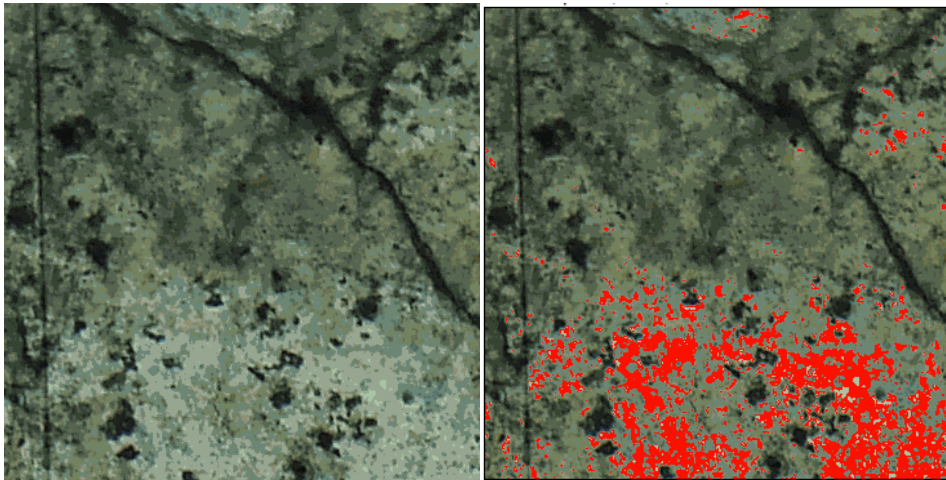
Total pixels=
131765
Pixels forming porosity=
28805
Porosity=
21.8609

4175-75 1 cir



Total pixels=
134322
Pixels forming porosity=
21336
Porosity=
15.8842

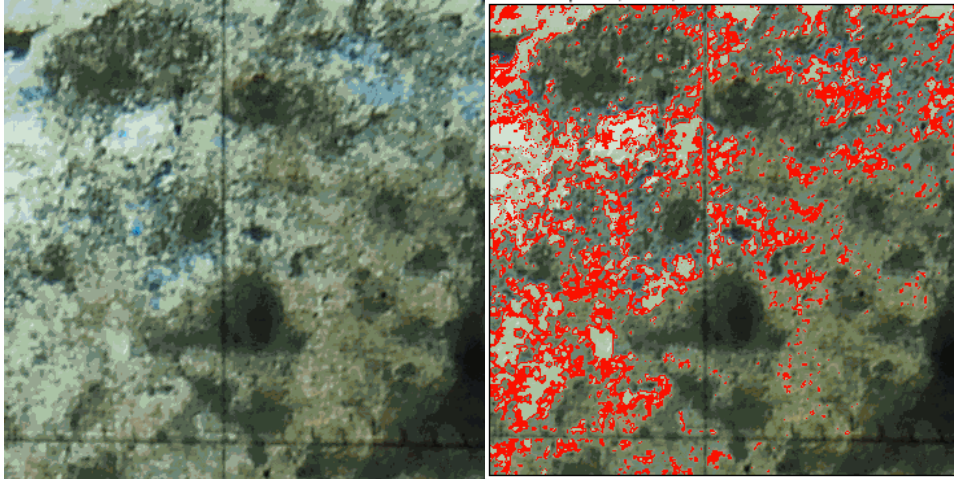
4175-4180



Total pixels=
132130
Pixels forming porosity=
14736
Porosity=
11.1527

Maple G1

4127-4137



Total pixels=

131406

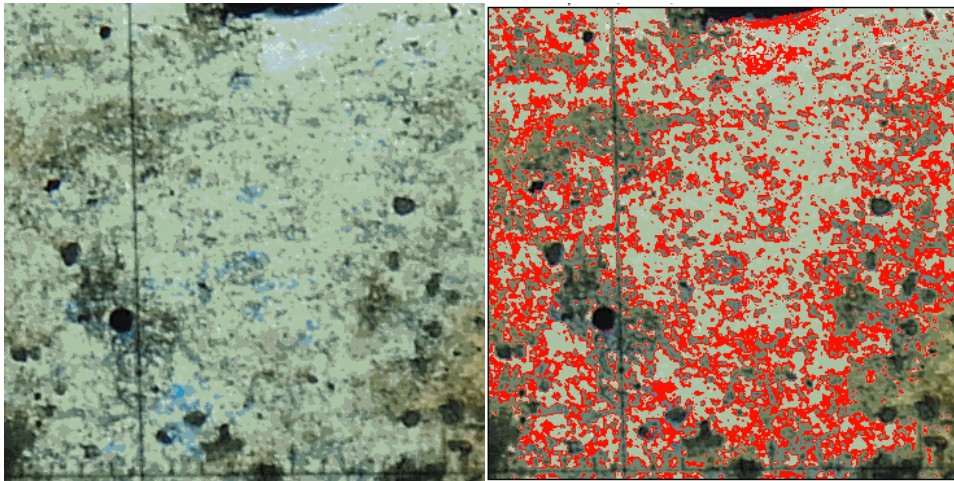
Pixels forming porosity=

21539

Porosity=

16.3912

4137-37 1 half cir



Total pixels=

132132

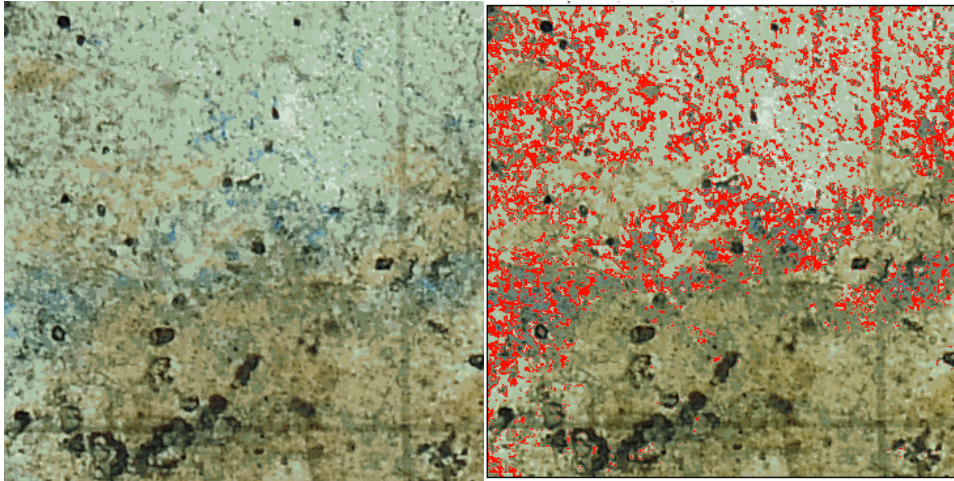
Pixels forming porosity=

37504

Porosity=

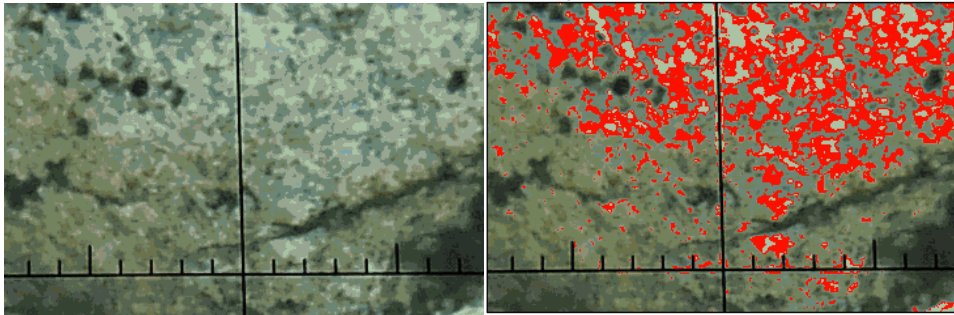
28.3837

4137-37 1 cir



Total pixels=
129600
Pixels forming porosity=
19112
Porosity=
14.7469

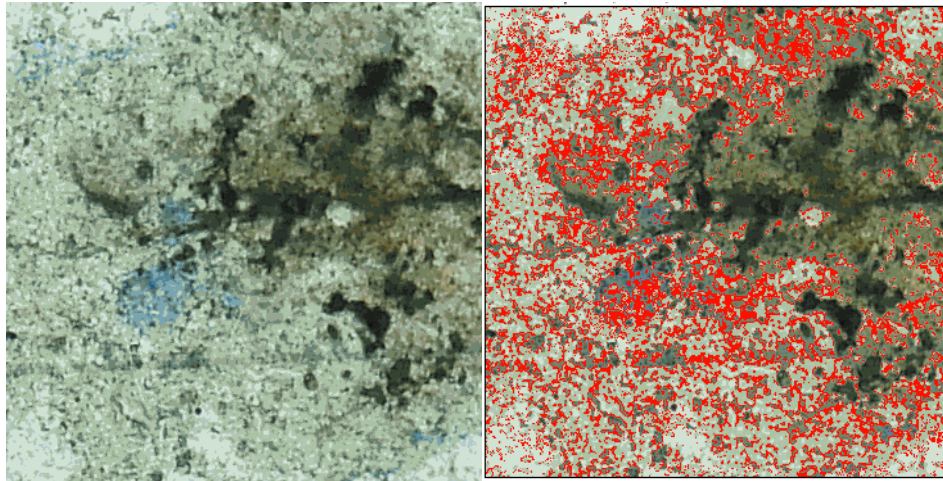
4137-4143



Total pixels=
85432
Pixels forming porosity=
17519
Porosity=
20.5064

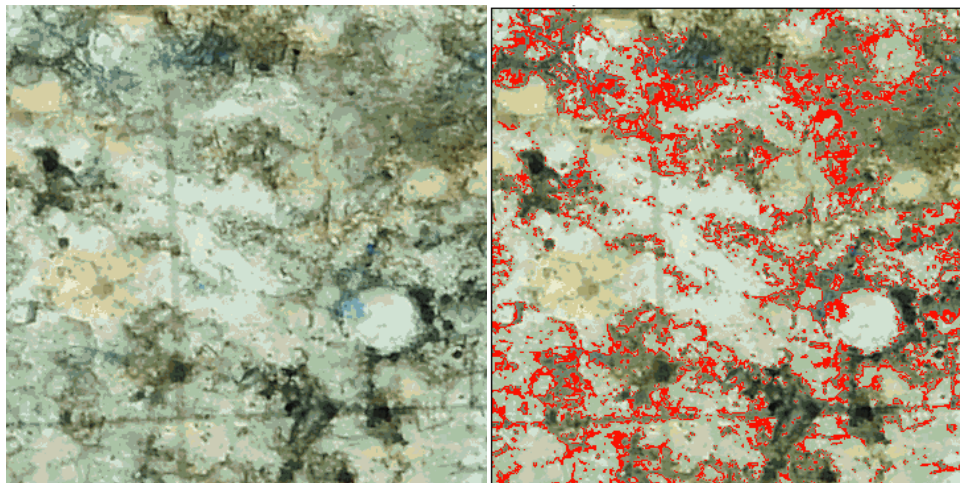
Krehbiel A1

4113-4118 1 half cir.



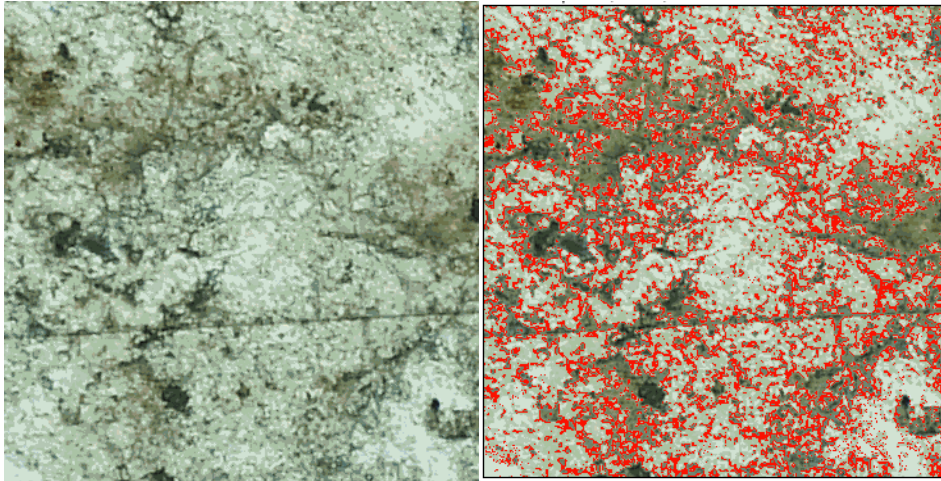
Total pixels=
132858
Pixels forming porosity=
29007
Porosity=
21.8331

4113-4118 1 cir



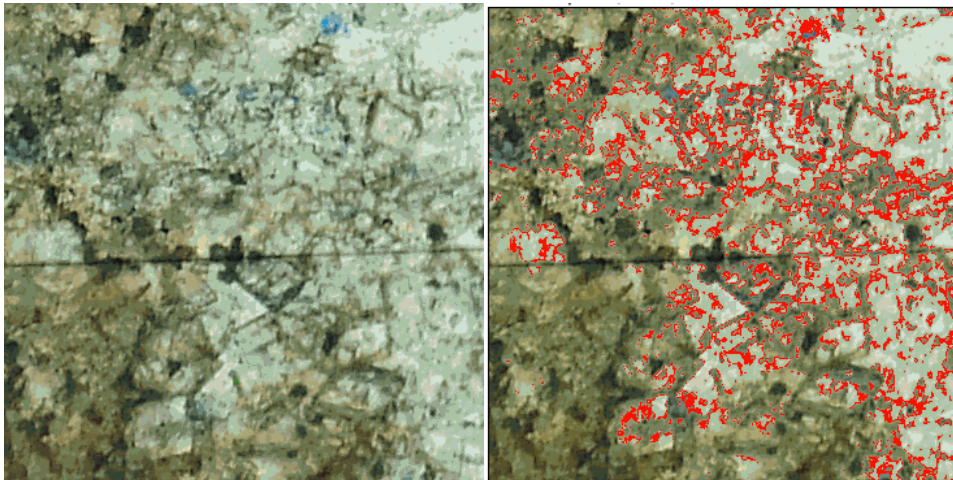
Total pixels=
130682
Pixels forming porosity=
18171
Porosity=
13.9047

4118-4123



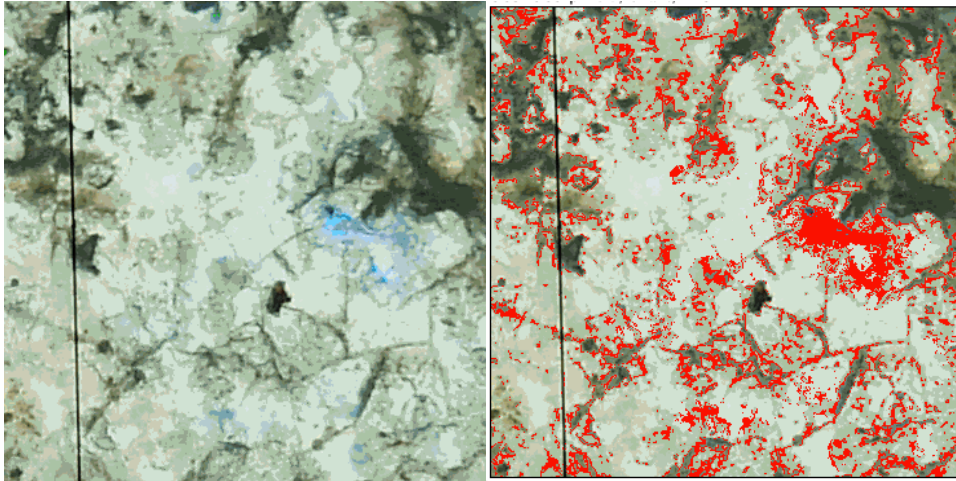
Total pixels=
133221
Pixels forming porosity=
27023
Porosity=
20.2843

4123-23 1 cir.



Total pixels=
131769
Pixels forming porosity=
15914
Porosity=
12.0772

4123-4130



Total pixels=
132495
Pixels forming porosity=
18914
Porosity=
14.2753