DEVELOPING AN EXPLORATION MODEL BY INVESTIGATING THE GEOLOGICAL CONTROLS ON RESERVOIR PRODUCTION WITHIN THE FORT SCOTT LIMESTONE, NESS COUNTY, KANSAS

by

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Abstract

Ness County, Kansas is situated along the western flank of the Central Kansas uplift, and has been an active center of oil exploration since the 1920's. It currently ranks fourth among Kansas counties in oil production, largely from Mississippian-age carbonate reservoirs. Some production has been realized from lower Pennsylvanian-age carbonate formations, although the distribution of these reservoirs appears sporadic. The goals of this study were to develop an exploration model that predicts the development of reservoir conditions within the Marmaton-age Fort Scott Limestone.

A two-township area was studied to examine relationships between production rates and subsurface variations. No core was available through the Fort Scott, hence drill cuttings were thin-sectioned and examined under a petrographic microscope to see details of porosity type not easily visible under a binocular microscope. Production appears to be defined by stratigraphic variations in porosity controlled by original depositional environment. The best wells are within an oolitic limestone, with subsequent development of secondary, vuggy porosity. These conditions occur in bands along the Mississippian paleo-topographic highs. I interpret these bands to be ancient ooid shoals, with geometries and scales analogous to those previously reported from Lansing/Kansas City reservoirs in Russell County, Kansas. This study provides insights into production trends within the Fort Scott Limestone, and should be included during exploration in Ness County, Kansas.

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CHAPTER 1 - INTRODUCTION

The exploration for petroleum in Kansas has been underway since the first discovery in 1860, and it has been a major economic contributor to the state ever since. Currently the price of oil is near $50/barrel, having recently achieved its all time high of over $140/barrel. Even though production has continued for almost 150 years, there is a lot more oil left in place, and new exploration paradigms are expected to increase the proven reserves in Kansas. It is estimated only 31% of Kansas petroleum has been discovered, therefore, the remaining 69% of Kansas petroleum needs a better exploration model, and possibly, new targeted formations to be discovered (Kansas Geological Survey, 2008). A high percentage of oil production in Kansas has been from carbonate reservoirs of Mississippian age (Figure 1-1). This has been the primary target in many areas in Kansas, in particular, Ness County.

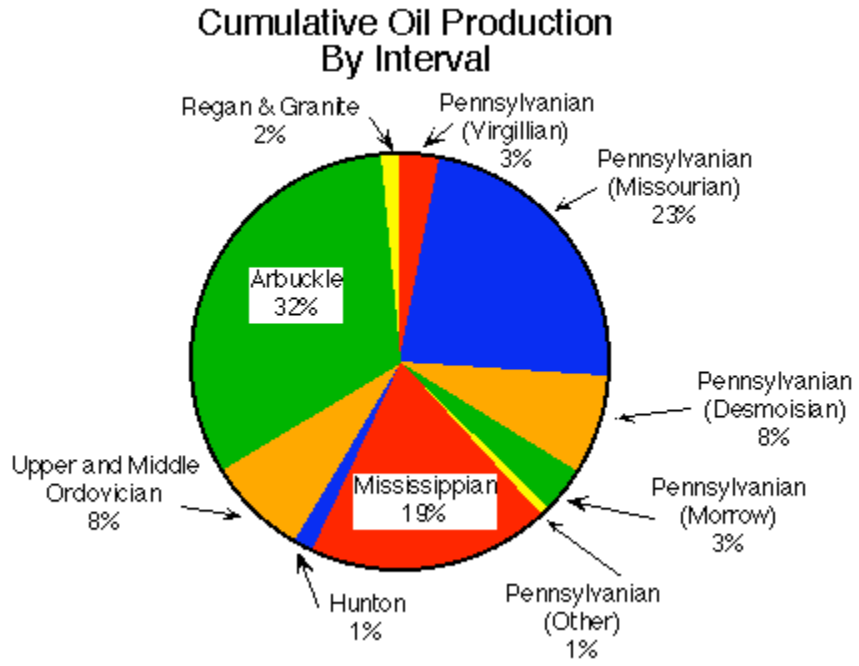


Figure 1-1 Oil Production in Kansas (Franseen et al. 2004)

STUDY AREA

Ness County is located in west-central Kansas in the Hugoton embayment of the Anadarko basin, on the western slope of the Central Kansas uplift (Figure 1-2).

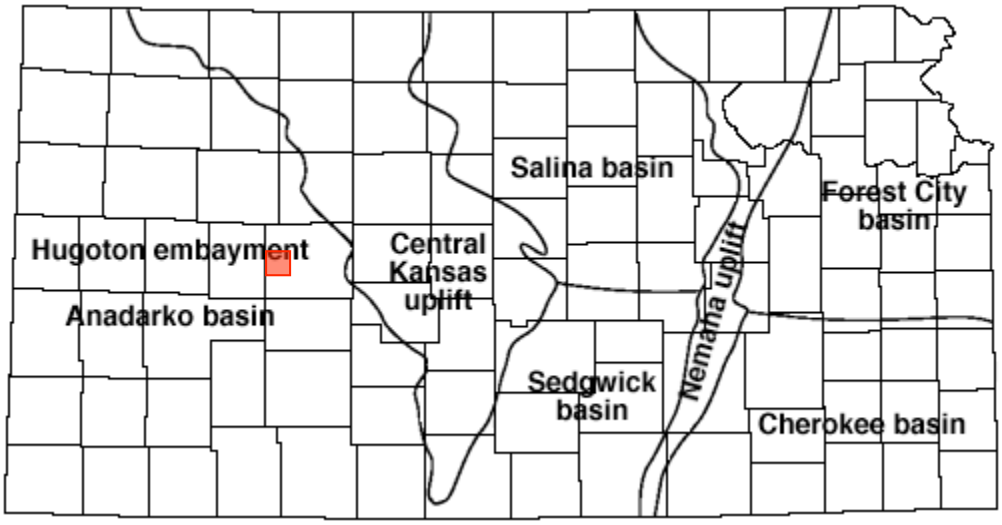


Figure 1-2 Study Area in Red (modified from Baars et al. 2001)

Exploration in Ness County began in 1922 (Carpenter, 1945) and new wells are still being drilled today. As of 2009, there have been approximately 6,280 wells drilled in Ness County, Kansas. In 2006, Ness County was ranked fourth in oil producing counties in Kansas (Kansas Geological Survey, 2008). Not all production has been from Mississippian-age reservoirs; some production has been established from Pennsylvanian-age sandstone and limestone. Production from lower Pennsylvanian limestones in Ness County has been sporadic (Walters, 1979), and so far no one has adequately explained the reasons for its irregularity.

STRATIGRAPHY

Pennsylvanian rocks in Kansas are divided into five series: Virgilian, Missourian, Desmoinesian, Atokan, and Morrowan. The Pennsylvanian units consist mainly of thin-bedded,

alternating marine limestones and shales, alternating with non-marine clastic deposits (Merriam, 1963). The cyclic nature of these beds has been attributed to eustatic sea level changes.

Mississippian rocks, the primary target in the Ness County area, are mostly shallow-water carbonates. The average thickness west of the Central Kansas uplift, in the Hugoton embayment, can be more than 1,700 feet (Zeller et al., 1968). The Upper Mississippian Series in the area consists of mostly limestone and dolomite. The dolomite can be an excellent reservoir, due to its porous nature. Much of this is intercrystalline porosity resulting from dolomitization, with additional vuggy porosity due to dissolution. Mississippian deposition was followed by a period of non-deposition and erosion, which contributes to the development of dissolution porosities (Blatt, 1992).

The first period of deposition following the post-Mississippian unconformity was the Desmoinesian stage. The lowest division of the Desmoinesian series is the Cherokee group, which is composed primarily of shale and sandstone, with occasional limestone. This group varies in thickness from approximately 5 feet to over 200 feet. Because the Mississippian surface was erosional, the contact between Pennsylvanian rocks and Mississippian rocks will differ in the area, thus, resulting in a variable thickness of the lower Pennsylvanian Series. The thickest Cherokee group tends to form in the lows of the Mississippian paleo-topography.

The Marmaton Group conformably overlies the Cherokee Group. Zeller et al. (1968) reports that the Marmaton is more calcareous than the Cherokee, representing a change from clastics to carbonates in the area. There are four limestones with interbedded shales that make up the Marmaton Group; Fort Scott limestone, Pawnee Limestone, Altamont Limestone, and the Lenapah Limestone. The interbedded shales between these units may have some localized sandstone deposits. The focus of this study is on the lowest member of the Marmaton Group, the Fort Scott Limestone (Figure 1-3).

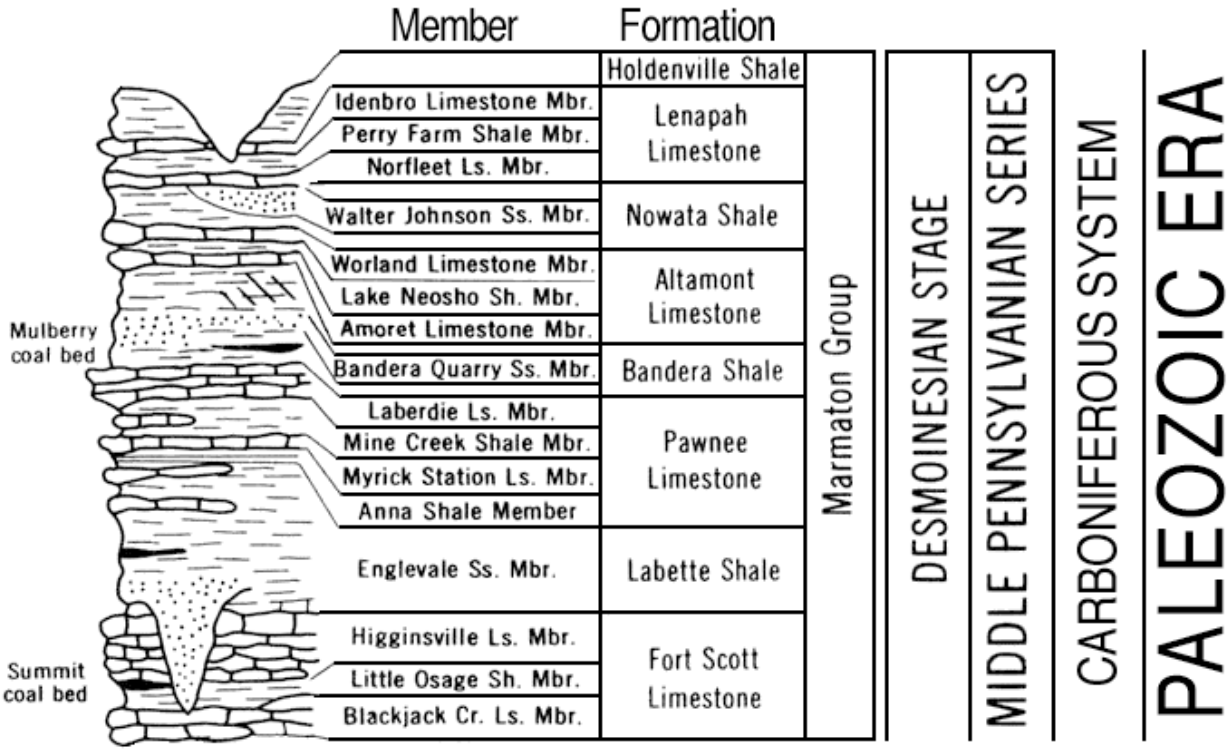


Figure 1-3 Stratigraphy of Marmaton Group (modified from Zeller, 1968)

The Fort Scott Limestone is primarily cream to tan to light-gray microcrystalline limestone that has occurrences of fusulinids, crinoid stems, and some developments of oolitic limestones (Stoneburner, 1976). The formation is composed of three members: the Blackjack Creek Limestone, the Little Osage Shale, and the Higginsville Limestone (Zeller et al., 1968). The formation thickness may vary in the study area, but averages 24 feet on the Ness County type log (Kansas Geological Survey, 2009). In the northeast corner of Ness County it has been reported to range from 8-12 feet thick (Stoneburner, 1976).

IMPORTANCE OF FORT SCOTT RESERVES

Desmoinesian rocks have produced 8% of the oil in Kansas, from both the Cherokee and the Fort Scott Formations. The Fort Scott Formation has typically been a secondary exploration target, incidental to deeper Mississippian production. Though some production has been achieved, it has been relatively small compared to deeper zones (Franseen et al. 2004). Because the Fort Scott limestone has produced in the past, it is a logical target for future exploration. To

date, the conditions necessary for production are unpredictable, and an adequate model to explain economic accumulations of petroleum has not been developed. It is the aim of this research to determine the geological controls on reservoir development within the Fort Scott Limestone in Townships 18 and 19 South, Range 25 West, Ness County, Kansas.

The potential significance of the results of this study is to open a new exploration play within the mature petroleum basin of western Kansas. A valid exploration paradigm for the Fort Scott will allow a reasonable success rate with the Fort Scott as a primary target. This is particularly important for areas with limited Mississippian potential. Furthermore, if wells can be drilled with two targeted formations, the Fort Scott formation and a lower Mississippian formation, an operator can increase the odds of success. If a valid model can be developed in this limited region of Ness County, it may be expanded to similar areas across Kansas.

The two township study area is located in western Ness County, Kansas and covers 72 square miles. These two townships have numerous fields, including: Aldrich, Alicuri, Charlies Teapot Dome, Dex, Hardman, Laird, Chrif, Fritzler, Manteno, Schroyer, Sonador, Spruill, Standish, Sunshine, WCV, and Wesley. It has approximately 400 wells, producing out of Mississippian, Fort Scott, and Lansing/Kansas City rocks. The first well was drilled in 1929 to a depth of 4431 feet, which discovered the Aldrich Field, and new wells are still being drilled today (www.kgs.ku.edu/DPA/dpaHome.html).

CHAPTER 2 - CARBONATE POROSITY TYPES

Porosity plays a key role in identifying the quality of a reservoir. Porosity is simply the volume of the void spaces within the rock. The porosity is important because oil or gas is stored in the pores and moves through the pores into the wellbore during production. Permeability, which is the ease in which fluid moves through the reservoir, is also important in recovering hydrocarbons (Dikkers, 1985). The type of porosity can positively or negatively impact the amount of permeability, which in turn, will affect the hydrocarbon recovery. Therefore, the ability to identify different types of porosity is important in this study.

Based on Choquette and Pray's 1970 classification of carbonate porosity, there are numerous types of porosity. However, in this study I will only refer to intraparticle, intercrystal, moldic, and vuggy porosity.

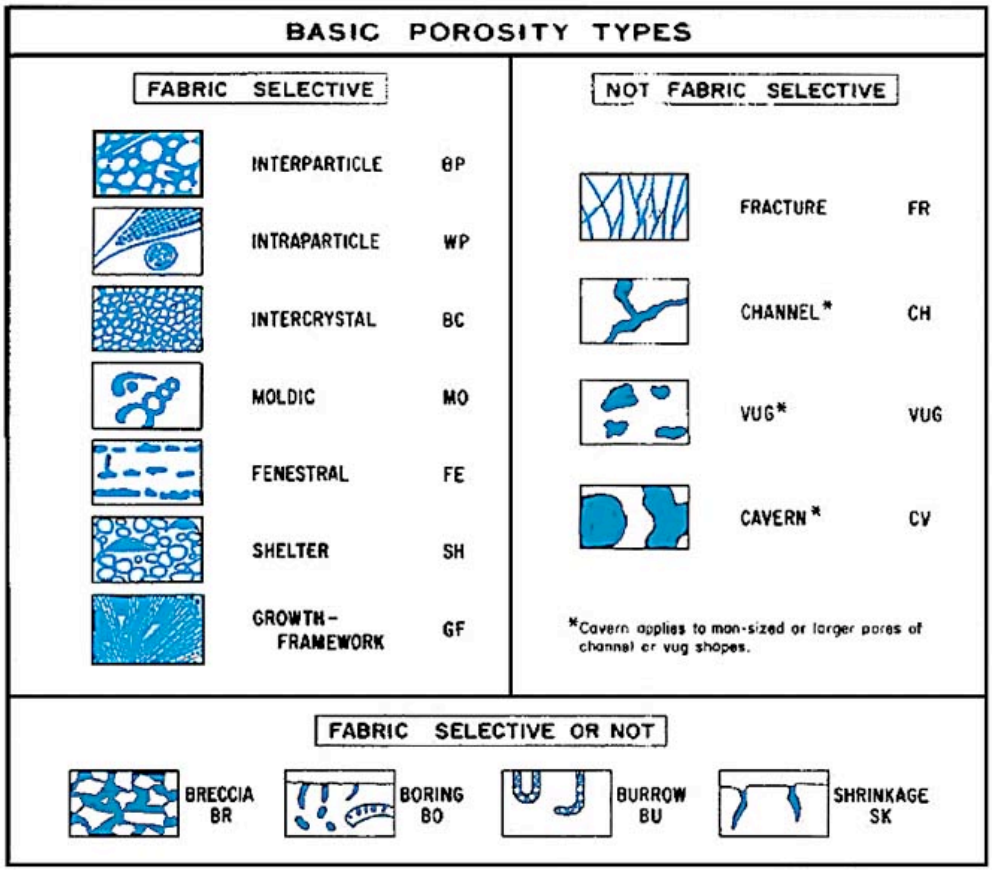


Figure 2-1 Carbonate Porosity Types (Choquette and Pray, 1970)

Intraparticle porosity is the pore space within grains. This type can originate from the living chambers of organisms such as gastropods, Foraminifera, bryozoans, or brachipods. The empty chambers of these organisms can be primary or can occur during early digenesis by the process of maceration (Scoffin, 1987). The spaces between abiotic grains such as ooids can also provide intraparticle porosity. Microbial activity may increase the intraparticle porosity. This can occur before, during, and shortly after deposition (Moore, 1989). This porosity is common in reef environments due to the presence of chambered colonial organisms. However, these chambers my not connect, giving the rock poor permeability (Scoffin, 1987).

Intercrystalline porosity occurs between crystals of similar size that have formed by recrystalization or dolimitization (Scoffin, 1987). This occurs as the fluid chemistry changes within the rock. The chemistry can change late in burial, due to hydrocarbon maturation or anytime during burial, if the limestone has been influence by meteoric water caused by an

unconformity (Moore, 1989). The size of the crystals being formed has an impact on permeability. Permeability will decrease as the size of the crystals decrease, because of excessive surface tension effects (Scoffin, 1987).

Moldic porosity is a secondary process, in which, grains are removed by dissolution. In order for this process to occur there needs to be a distinct difference in solubility between the grains and the framework. One example would be the dissolution of ooids within an oolitic limestone. Moldic porosity can have good permeability if the pores are interconnected (Scoffin, 1987).

Vuggy porosity is described as irregular holes that can cut across grains and cement boundaries within the rock. Vuggy porosity is secondary and occurs because of dissolution. This type of porosity can be indicative of karst weathering in wet climates and the occurrence of a freshwater lens (Scoffin, 1987).

CHAPTER 3 - METHODS

Creating the Database

A data base was compiled comprising approximately four hundred wells in Townships 18S-25W and 19S-25W, Ness County, Kansas. All well header information, including spot location, well symbols, operator, unique well identification number, lease name, and well remarks, was downloaded from public access information available from the Kansas Geological Survey website. This information was imported into Petra software, generously made available on an academic license to KSU from IHS, Inc. The location of each well was entered and referenced using the North American Datum 83. Also obtained from the Geological survey were wire line logs and tops data in the study area. The Kansas Geological survey had sixty wire line logs available, and formation tops for approximately four hundred wells. Each top that was imported into Petra was checked using scout cards and wire line logs from Walter's digital library in Wichita, Kansas. Dozens of tops taken from the KGS were incorrect, and were

corrected to insure quality data for mapping. Two hundred additional well logs were obtained from Walter's digital library. Since the well logs are scanned photocopies of the original paper logs, and not digital, each log had to be calibrated so that Petra could recognize depths. All cartographic data that were imported into the map module of Petra were downloaded from the Kansas Geospatial Community Commons website (http://www.kansasgis.org/). The data downloaded included county lines and public land survey system. All drill stem tests within the Fort Scott formation in the study area were compiled using Walter's digital library. The drill stem tests help establish an estimate of the quality of the reservoir. Drill stem test data were entered manually into Petra software. This was very time consuming because, frequently, the scout cards had incorrect formation top information, therefore, each drill stem test depth interval had to be checked on the well log.

Using Petra

Using the cross-section module in Petra, tops for the Stark Shale, Kansas City Group, Pawnee Limestone, Fort Scott Limestone, and Cherokee group were hand-picked for all 260 wells with available well logs. Tops were picked by interpreting log signatures of the gamma ray curve, neutron curve, density curve, and induction curve. Each formation looks significantly different in their log characteristics (Figure 3-1). The type log for Ness County was used to identify the unique log characteristics for each formation.

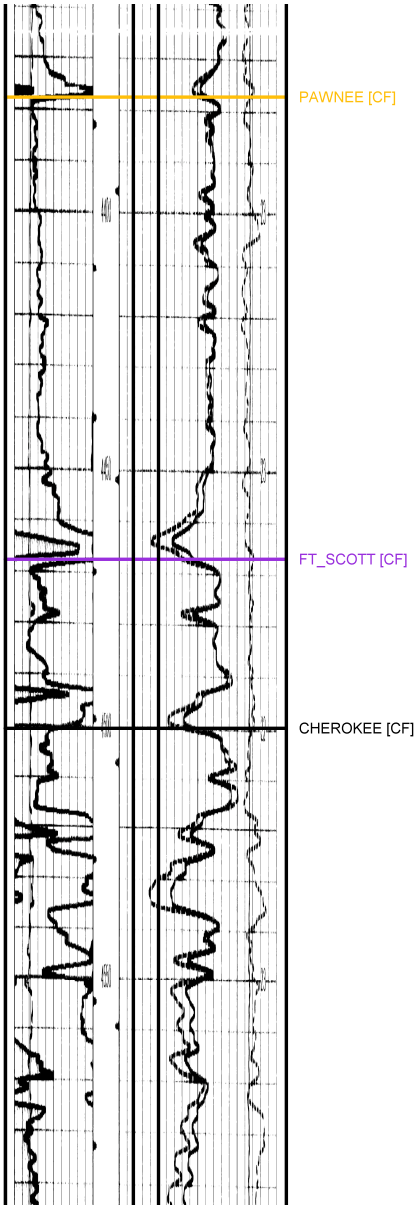


Figure 3-1 Differences in log characteristics for the Pawnee, Fort Scott, and Cherokee.

After all tops were picked, cross-sections were constructed along several different directions in the study area. These cross sections were useful in determining current day structure, paleostructure, and stratigraphy. Structure maps were constructed on the top of the Pawnee Limestone, Fort Scott Limestone, and Cherokee group, using the map module in Petra. The main module in Petra calculated the thickness of the Fort Scott for all wells. Isopach map of the Fort Scott formation was constructed using the calculated formation thickness values. The purpose of creating this variety of maps was to aid in interpreting the data. Structure maps were combined with drill stem test data to determine the control of structure on production. Isopach

maps combined with drill stem tests were created to determine if thickness has influence on the quality of the reservoir. A variety of wells were chosen to examine well cuttings based upon the different maps, drill stem tests, and well logs. The array of wells that were chosen had good, bad, and mediocre drill stem tests and variable production rates. Table 1 displays examples of good, bad, and mediocre drill stem tests.

Table 1 Examples of different quality drill stem tests

Good	1720 feet of clean gassy oil and 120 feet of heavy oil cut mud
Mediocre	10 feet of gas in pipe, 5 feet of frothy oil, 75 feet of heavy oil cut mud
Bad	10 feet of mud

Well Cuttings

Forty-three wells were picked for drill-cutting study and obtained from the Kansas Geological Survey Well Sample library in Wichita, Kansas. Before viewing the cuttings for each well, the lag time was estimated from the log data and drill time data, in order to correctly predict the sample depth that contains the Fort Scott formation. Using the black shales above and below the Fort Scott as markers, the Fort Scott Limestone was easily distinguished from the overlying Pawnee Limestone and the underlying Cherokee group. All cuttings at the depth of the Fort Scott formation were examined using a binocular microscope. The cuttings were carefully viewed to identify and document the lithology and presence of fossils, porosity, oil stains, and ooids. Individual cuttings were hand-picked from each well, and mounted as grain mounts and polished to approximate thin sections. These thin sections were made using epoxy resin and hand polished to a thickness of approximately 30 microns using corundum powder. Each thin section was viewed under a petrographic microscope to examine variations in lithology and porosity types in greater detail than the binocular microscope allows.

CHAPTER 4 - RESULTS

CUTTINGS

Table 4-1 lists the results of the drill cutting examination using a binocular microscope. It includes descriptions of porosity types found at each well.

Table 2 Description of Cuttings

UWI #	LOCATION	DEPTHS FEET	POROSITY TYPE	COMMENTS	IMAGE FIG. #
15-135-71129	12-19S-25W	4290-4295	Vuggy	Slightly oil stained. Good porosity. Presents of crinoids	
		4295-4300	Vuggy and oomoldic	Great porosity, lots of oil stain and an abundance of ooids	
		4300-4305	Vuggy and oomoldic	Good porosity, good oil stain and abundance of ooids.	
15-135-21014	14-19S-25W	4304-4315	Vuggy	Poor porosity and very little staining	
		4315 Cir 90 min	Intercrystalline	Good porosity and a lot of oil stain	A-1
15-135-29861	12-19S-25W	4280-4285	Intercrystalline	Some porosity and little oil stain	
		4300 Cir 30 min	Vuggy and oomoldic	Great porosity and oil stain.	A-2

15-135-29861	12-19S-25W	4300 Cir 60 min	Vuggy	Great porosity and a lot of oil stain	
15-135-23065	1-19S-25W	4310-4320	Intercrystalline	Good porosity with little oil stain	
15-135-00371	36--18S-25W	4305-4310	Vuggy	Great porosity with lots of oil staining	A-3
		4320-24	Vuggy	Good porosity but no oil staining	
		4324 Cir 90 min	Vuggy and oomoldic	Great porosity between ooids and lots of oil staining	
15-135-21453	17-19S-25W	4450-4460	Vuggy	Great porosity but no oil stain	
		4460-4470	Vuggy and Intercrystalline	Great vuggy porosity and moderate crystalline porosity with slight oil stain	
		4470-4480	Vuggy	Great vuggy porosity but very little oil stain	
15-135-23465	10-19S-25W	4340-4350	Vuggy	Great vuggy porosity with lots of oil stain. Crinoids present	
		4350-4360	Vuggy and oomoldic porosity	Great vuggy and oomoldic porosity with heavy oil stain	
		4360 Cir 60 min	Vuggy, intercrystalline, and oomoldic porosity	Oil stain is heavy in the vuggy and oomoldic porosity cuttings but very slight in the intercrystalline	

15-135-23993	4-19S-25W	4420-4430	Oomoldic and Interparticle porosity	Most cuttings are abundant in ooids but highly cemented. Some samples have great porosity with heavy oil staining	
		4430 Cir 90 min	Oomoldic porosity	High abundance of ooids. More ooids present in this well than any other well that was examined. Most cuttings are highly cemented but some cuttings show great porosity and staining	A-4 A-5
15-135-23769	4-19S-25W	4370-4380	Vuggy, oomoldic, and intercrystalline porosity	Great porosity, abundance of ooids, but no oil stains.	A-6
		4380-4390	Oomoldic and vuggy porosity	Great oomoldic (interparticle) porosity with heavy oil stain	A-7 A-8 A-9
		4390 Cir 30 min	Vuggy and intercrystalline	Ooids present and good vuggy porosity. No oil staining	
		4390 Cir 60 min	Oomoldic	Oomoldic (intraparticle) porosity with good oil stain	
15-135-20505	8-19S-25W	4465-4470	Vuggy and intercrystalline porosity	Good vuggy porosity with slight oil stain	

15-135-20505	8-19S-25W	4470-4475	Vuggy porosity	Good vuggy porosity with good oil stain	
		4475 Cir 30 min	Vuggy	Slightly porous with little oil staining	
15-135-20260	20-19S-25W	4530-4540	Vuggy and moldic	Great porosity with no oil stain. Moldic porosity is from a foram	A-10
		4540-4550	Vuggy	Good porosity with good oil stain	
		4550-4560	Vuggy	Good porosity with good oil stain	
15-135-20349	29-19S-25W	4520-4530	Vuggy	Good porosity with good oil stain	
		4530-4540	Vuggy, intercrystalline, oomoldic	Great porosity and oil staining within all porosity types	
		4540-4550	Vuggy and oomoldic	Great porosity with some oil stain	
15-135-20339	29-19S-25W	4500-4510	Vuggy and oomoldic	Good vuggy porosity with slight oil stain. Great oomoldic porosity with no oil stain. Ooids have been dissolved	
		4510-15	Oomoldic	Great oomoldic porosity with slight oil stain. Ooids have been dissolved	
		4515-4520	N/A	Did not see any porosity with the samples collected	

15-135-20339	29-19S-25W	4520-4525	Oomoldic and moldic porosity	Great oomoldic porosity and moldic porosity is present. Slight oil stain. Ooids have been dissolved.	A-11
15-135-23359	36-18S-25W	4350 Cir 15 min	Vuggy	Good vuggy porosity with heavy oil stain	
		4350 Cir 30 min	Vuggy	Great vuggy porosity with heavy oil stain	
		4350 Cir 45 min	Vuggy	Great vuggy porosity with slight oil stain	
15-135-20574	21-19S-25W	4450-4455	Vuggy and oomoldic	Great porosity with moderate oil stain	
		4455-4460	Vuggy, oomoldic, and intercrystalline	Great porosity with good oil stain	
		4460-4465	N/A	No porosity evident in the samples that were collected	
		4465-4470	Vuggy	Great vuggy porosity with very slight oil stain	
15-135-21813	13-19S-25W	4300-4310	Vuggy and Moldic	Great porosity but no staining. Moldic porosity is from a foram.	
		4310-4320	Vuggy	Slightly porous with no oil stain	
15-135-23347	4-19S-25W	4420-4430	Vuggy	Very little porosity and no oil stain	

15-135-23347	4-19S-25W	4430-4440	N/A	Ooids are highly cemented	
		4440-4450	N/A	Ooids are highly cemented	
		4450-4460	Vuggy and oomoldic	Slightly porous with little oil stain	
15-135-23065	1-19S-25W	4300-4310	Vuggy	Slightly porous with very little stain	
		4310-4320	Vuggy, oomoldic, and moldic	Heavy oil stain in the vuggy rock, no staining in the oomoldic or moldic. Ooids have been dissolved	A-12
		4324 Cir 30 min	Vuggy	Great porosity with oil stain	A-13
15-135-24581	36-18S-25W	4300-4310	Vuggy	Good porosity with slight oil stain	
		4310-4320	Vuggy	Slightly porous with little oil stain	
		4318 Cir 45 min	Vuggy	Great porosity with heavy oil stain	
15-135-20133	36-18S-25W	4330-4340	Oomoldic	No staining. Ooids have been dissolved	
		4350-4360	Moldic	Some porosity but no oil stain	A-14
15-135-00603	9-18S-25W	4240	Vuggy	Slightly porous with no oil staining	

15-135-00603	9-18S-25W	4260 Cir 45 min	Vuggy	Good porosity with oil stain	
15-135-21388	30-18S-25W	4310-4320	Vuggy and oomoldic	Great porosity with heavy oil stain	
		4320-4324	Vuggy	Good porosity with oil stain	
		4324 Cir 60 min	Vuggy, oomoldic, and moldic	Good oil stain in the vuggy and oomoldic samples but no staining in the moldic	
15-135-21900	18-18S-25W	4385-4390	Vuggy and oomoldic	Great porosity with heavy oil stain	
		4390-4395	Vuggy and oomoldic	Great porosity with moderate oil stain	
		4395-4400	Vuggy and oomoldic	Great porosity with heavy staining	
15-135-21984	12-18S-25W	4250-4260	Vuggy	Good porosity with no oil stain	
			Vuggy	Good porosity with slight oil stain	
		4270-4280	Vuggy	Good porosity with heavy oil stain	
15-135-21091	4-18S-25W	4200-4210	Vuggy	Good porosity with oil stain	
		4210-4220	Vuggy and oomoldic	Great porosity and oil stain in the vuggy rock. No staining in the oolite	

15-135-21091	4-18S-25W	4224 Cir 60 min	Vuggy	Great vuggy porosity with heavy oil stain	
15-135-21588		4400-4410	Vuggy, intercrystalline, oomoldic	Great porosity and heavy oil stain in the vuggy and oomoldic samples. Lightly oil stained in the intercrystalline sample.	
		4410-4420	Vuggy and intercrystalline	Good porosity and moderate oil stain. Crinoids present	
15-135-22528	12-19S-25W	4290-4300	Vuggy	Very little porosity and light oil stain	
		4300 Cir 30 min	Vuggy and intercrystalline	Slightly porous with very little oil stain	
15-135-23821	25-19S-25W	4335 Cir 20 min	Vuggy and moldic	Good vuggy porosity with oil stain. Moldic porosity has no staining	
		4335 Cir 40 min	Vuggy	Great porosity with no oil stain	
		4335 Cir 60 min	Vuggy and oomoldic	Great porosity. Some ooids have been dissolved. Good oil stain	
15-135-21589	11-19S-25W	4320-4325	Vuggy and intercrystalline	Good porosity with oil stain	
		4325-4330	Vuggy and intercrystalline	Good porosity with oil stain	
		4330-4335	Vuggy	Great porosity with oil stain	

15-135-20353	20-19S-25W	4490-4495	Vuggy	Very little porosity with no oil stain	
		4495-4500	N/A	No porosity in the samples that were collected	
		4500-4505	Vuggy, intercrystalline, and oomoldic	Great porosity and oil stain in vuggy and oomoldic samples. No staining in the highly porous intercrystalline rock	
		4505-4510	Vuggy and oomoldic	Great ommoldic porosity and good vuggy porosity. Oil stain is more abundant in the oomoldic rock	
15-135-21093	28-18S-25W	4350-4355	Vuggy	Good vuggy porosity with heavy oil stain	
		4360 Cir 45 min	Vuggy, moldic, oomoldic	Good porosity and oil stain in all rock samples. Some ooids have been dissolved	
		4360 Cir 90 min	Oomoldic	Good porosity with slight oil stain. Ooids are dissolved	
15-135-23996	36-18S-25W	4311	Vuggy	Slightly porous with little oil stain	
15-135-21278	15-18S-25W	4350 Cir 30 min	Vuggy	Good porosity with little oil stain	

15-135-21278	15-18S-25W	4350 Cir 60 min	Vuggy	Good porosity with good oil stian	
15-135-21042	1-19S-25W	4310-4315	Vuggy	Good porosity with oil stain	
		4320-25	Vuggy and intercrystalline	Good porosity with slight oil stain	
		4325 Cir 30 min	Vuggy and oomoldic	Great oomoldic porosity with no oil stain. Ooids have been dissolved. Vuggy porosity does have good oil stain	

THIN SECTIONS

Table 4-2 describes the porosity type and the carbonate classification of both Folk (1974) and Dunham (1962). Thin sections were viewed using a petrographic microscope to determine whether the porosity was interparticle, intraparticle, intercrystalline, or intracrystalline. Furthermore, the petrographic microscope made it possible to classify the rock in better detail than the binocular microscope.

Table 3 Description of Thin Sections

UWI #	Location	DEPTH	POROSITY TYPE	FOLK	DUNHAM	FIGURE
15-135-21219	35-18S-25W	4390-4400	Intraooid, Interooid	Oosparite	Ooid grainstone	B-1 B-2
		4410-4415	Intercrystalline	Biosparite	Packstone	
15-135-21813	13-19S-25W	4300-4310	N/A	Micrite	Mudstone	B-3

15-135-23465	10-19S-25W	4340-4350	Intercrystalline	Biosparite	Packstone	
15-135-71129	12-19S-25W	4285-4290	Interooid Intraooid Moldic	Oobiosparite	Ooid grainstone	B-4
15-135-29861	12-19S-25W	4285-4290	Interooid Intraooid Moldic	Oobiosparite	Ooid grainstone	B-5 B-6
15-135-20260	20-19S-25W	4520-4530	Intercrystalline	Biosparite	Grainstone	
15-135-23347	4-19S-25W	4410-4420	N/A	Biosparite	Packstone	B-7
15-135-00371	36-18S-25W	4300-4305	Intercrystalline Intraparticle	Biosparite	Packstone	B-8
		4315-4320	Intercrystalline	Sparite	Packstone	
15-135-20349	29-19S-25W	4520-4530	Intraooid Interooid	Oosparite	Ooid grainstone	B-9 B-10 B-11
15-135-20353	20-19S-25W	4490-4495	Intraooid Interooid	Oosparite	Ooid grainstone	B-12
15-135-21042	1-19S-25W	4305-4310	Interooid Intraooid	Oobiosparite	Ooid grainstone	B-13
		4320-4325	Intercrystalline	Sparite	Packstone	
15-135-23065	1-19S-25W	4320-4330	Intercrystalline	Sparite	Packstone	
15-135-21014	14-19S-25W	4304 Cir 60min	Interooid Intercrystalline	Oosparite	Ooid Packstone	

15-135-23359	36-18S-25W	4350 Cir 45min	Intercrystalline	Spartie	Packstone	
15-135-20339	29-19S-25W	4490-4500	Cemented	Oosparite	Ooid grainstone	B-14 B-15
		4500-4510	Intercrystalline	Sparite	Packstone	B-16
15-135-23993	4-19S-25W	4430 Cir 90min	Interooid Intraooid	Oosparite	Ooid grainstone	B-17

SUBSURFACE MAPS

The following maps were created to see how different attributes determine the controls on production. All maps were created using Petra software and data that were collected through log analysis, cutting descriptions, thin-section descriptions, and formation thickness calculations.

Base Map

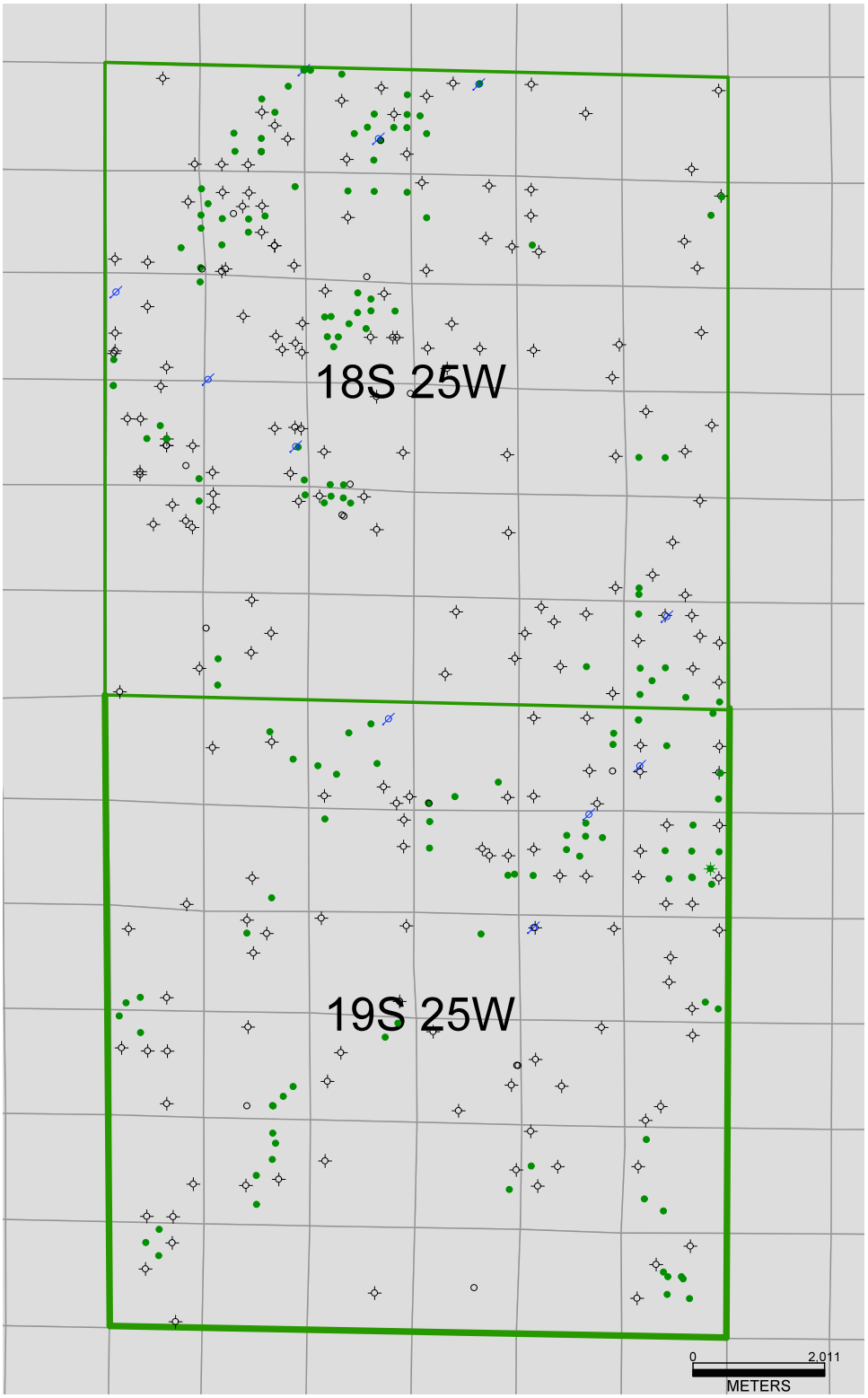


Figure 4-1 Base map of study area, displaying well location and well symbol code

Drill Stem Tests/Production

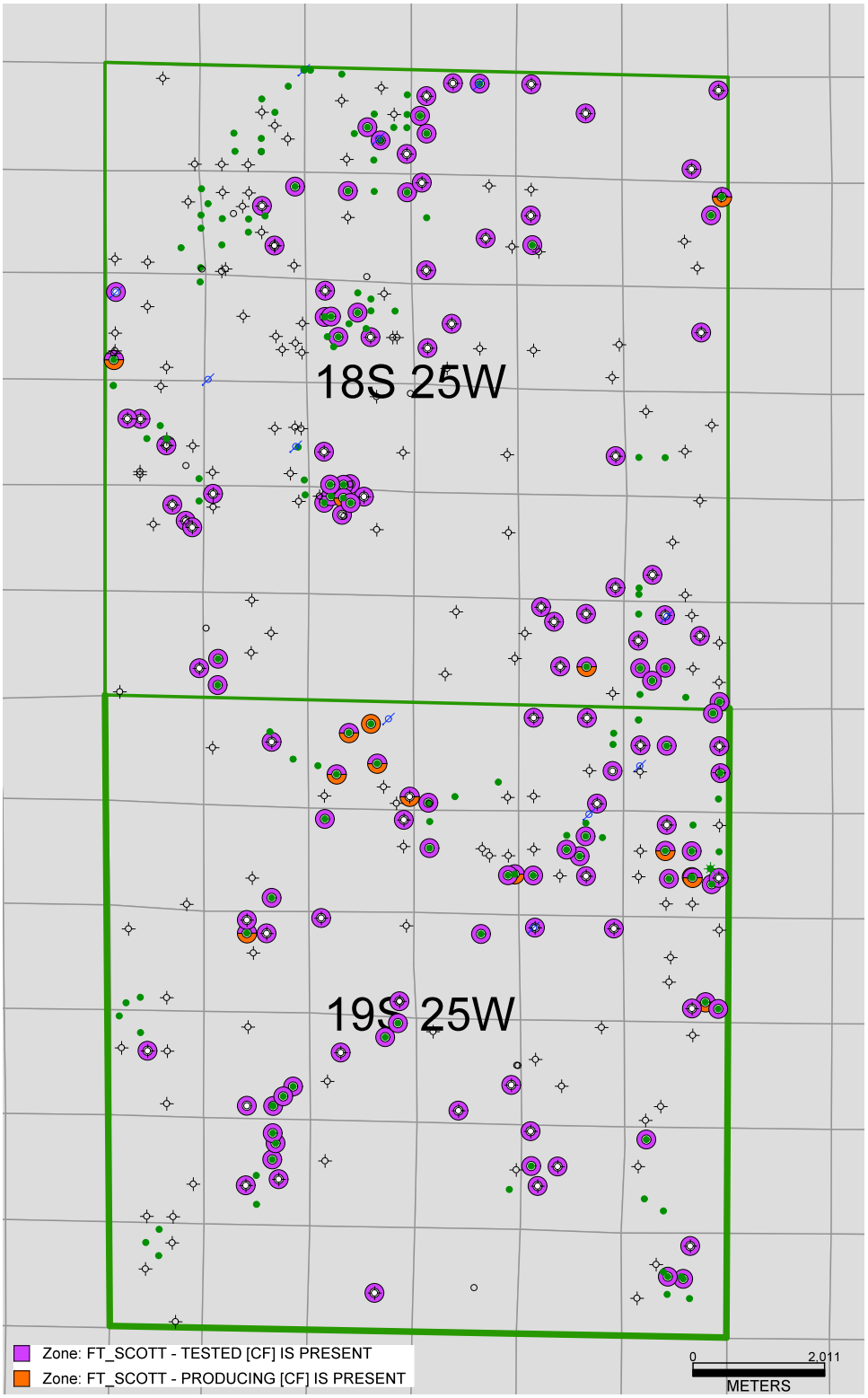


Figure 4-2 Map displays wells with production information and drill-stem test data

Structure Map of the Fort Scott

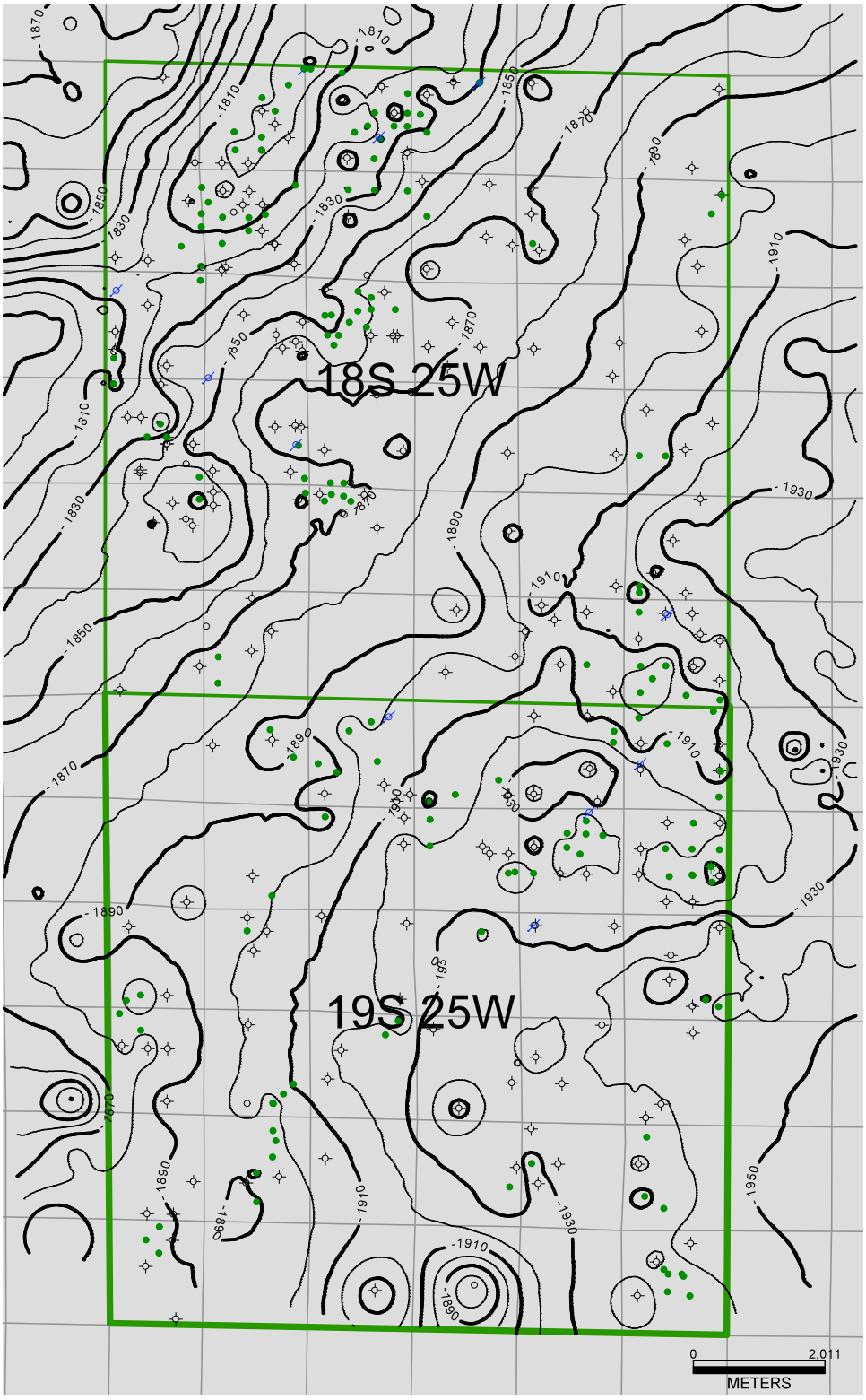


Figure 4-3 Structure on the Fort Scott formation, CI 10 Feet

Isopach of the Fort Scott



Figure 4-4 Isopach map of the Fort Scott formation, CI 0.5 Feet

Isopach of the Cherokee

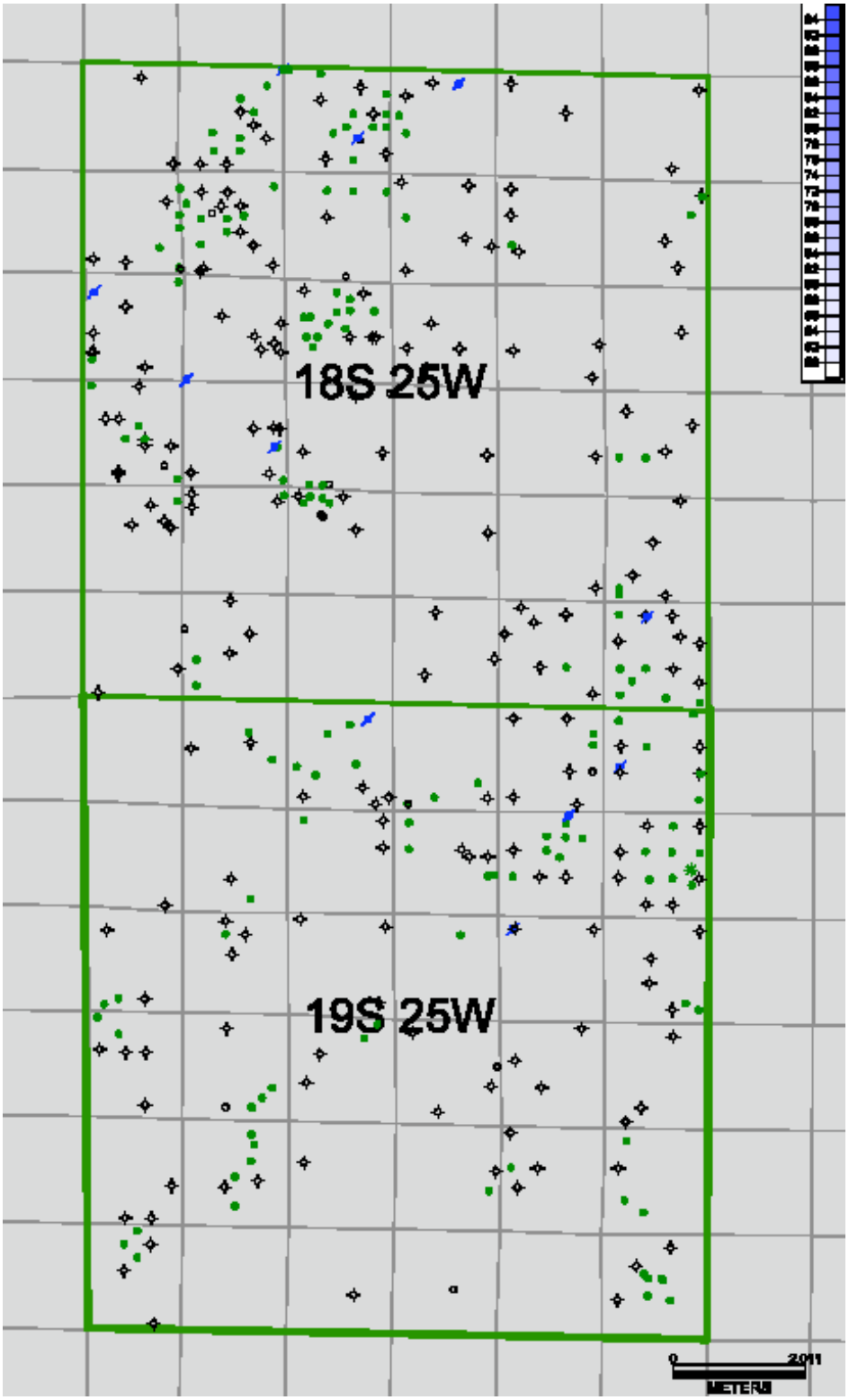


Figure 4-5 Isopach of the Cherokee formation, CI 2 Feet

Cuttings

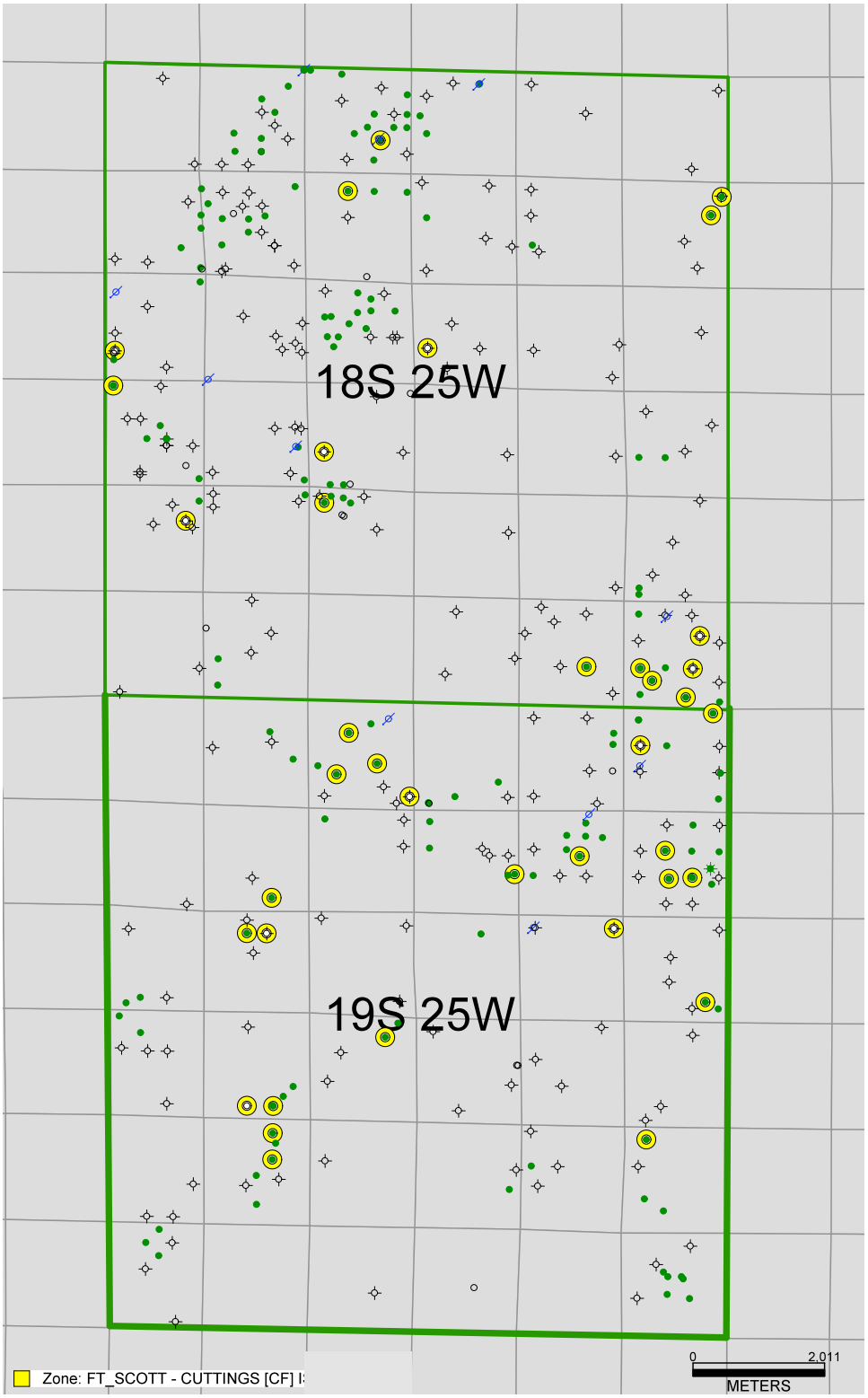


Figure 4-6 Map displays all wells that were used for cutting descriptions

Ooids

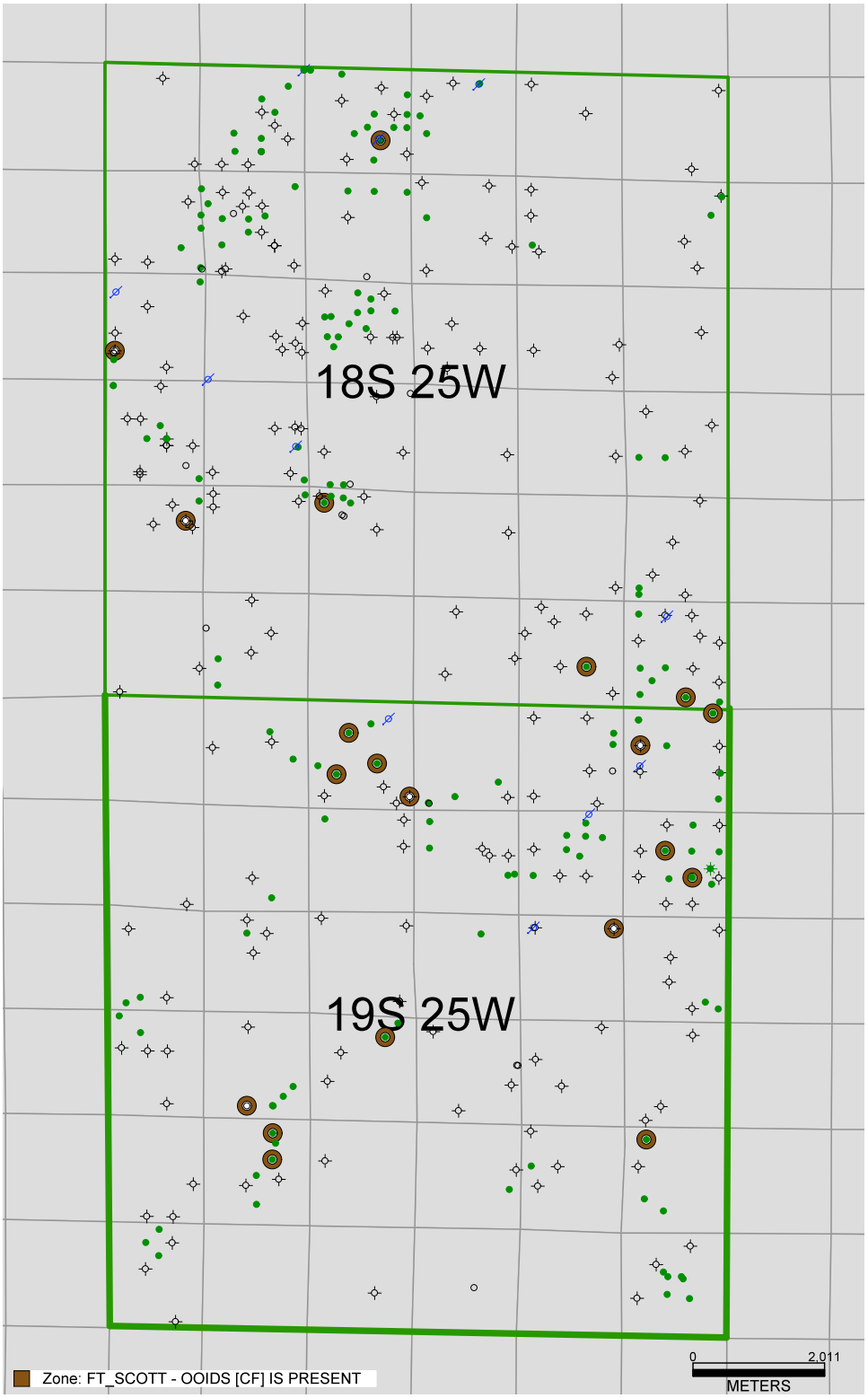


Figure 4-7 Map displays distribution of ooids

CROSS-SECTIONS

Map of Cross-Sections

Figure 4-8 displays the location of the cross-sections described in this section.

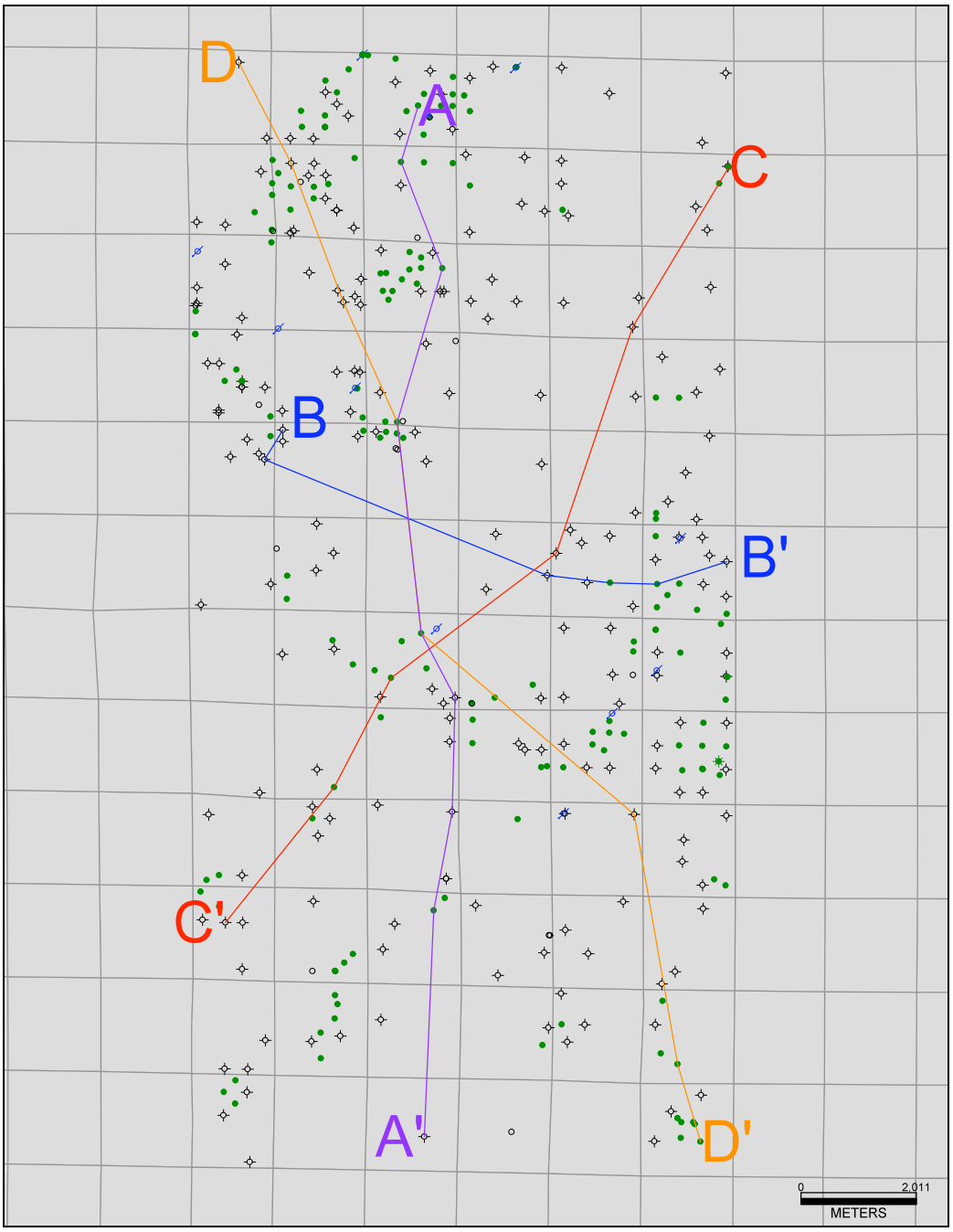


Figure 4-8 Displays location of cross sections

North-South

Figure 4-9 displays the subsurface structure from North to South in the study area. Structure progressively dips to the south with some minor structural changes of highs and lows in the center part of the study area.

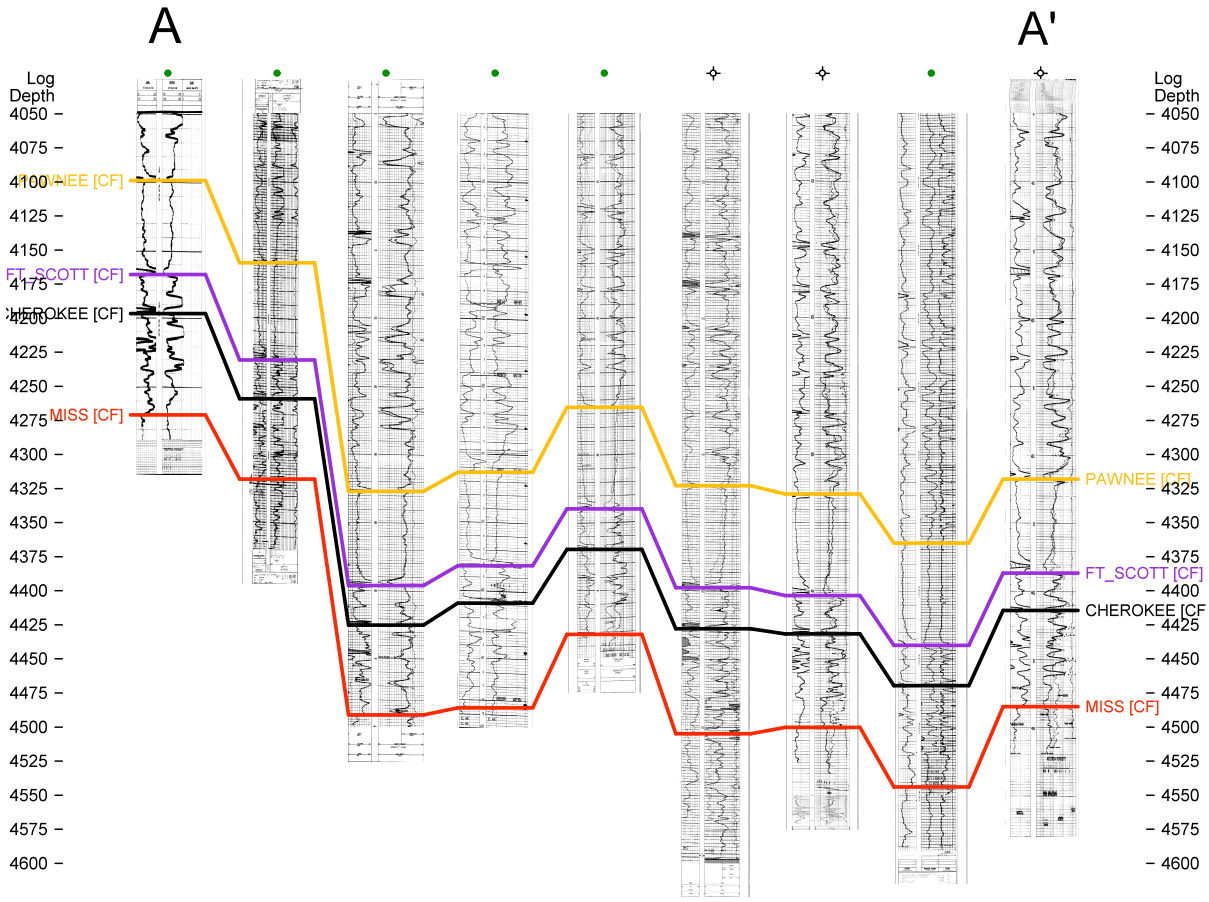


Figure 4-9 North-South cross-section

West-East

Figure 4-10 displays the subsurface structure from east to west across the study area. Structure stays relatively consistent with a high in the east and gradually dipping to the west.

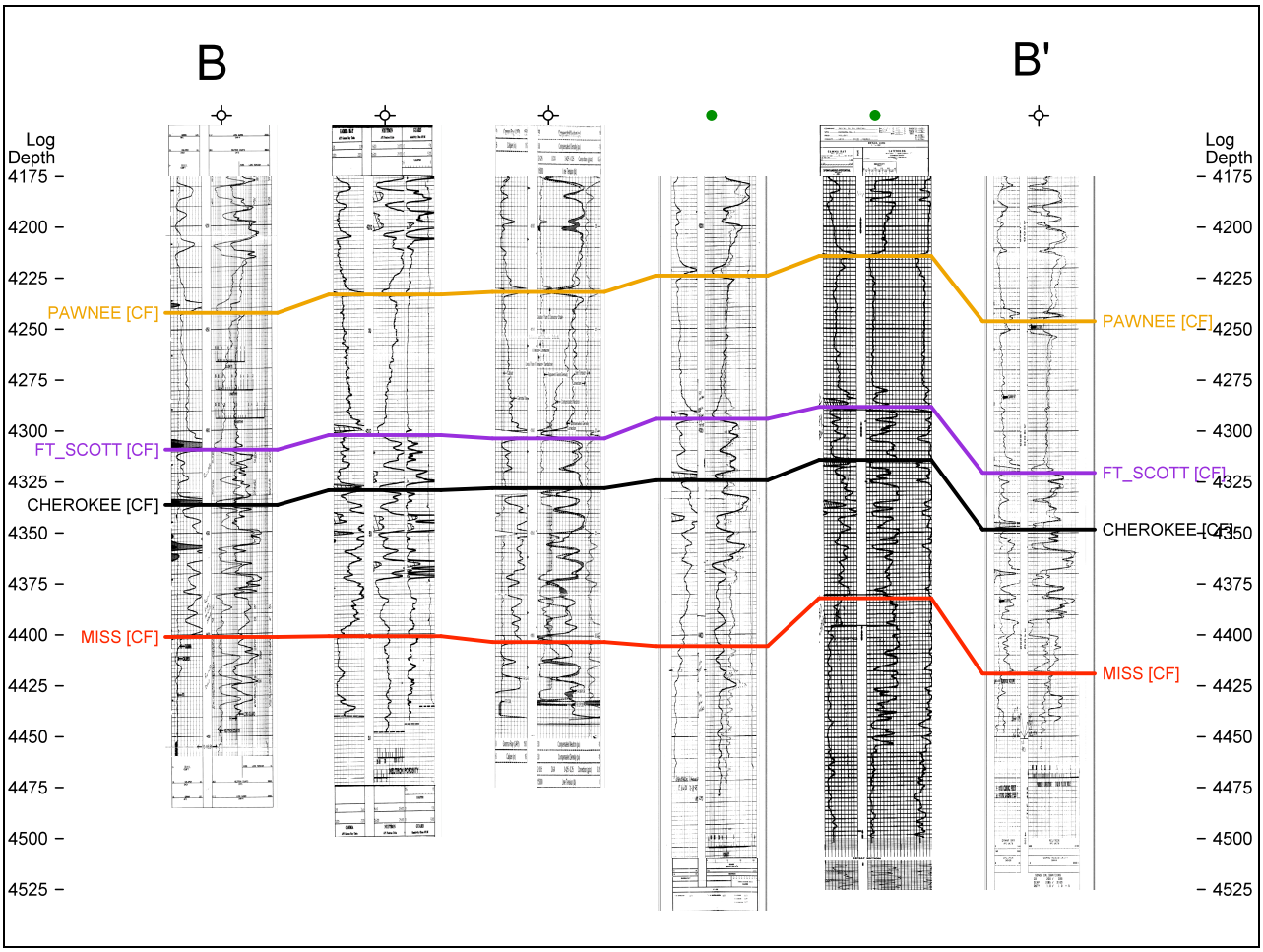


Figure 4-10 West-East cross-section

Northwest-Southeast

Figure 4-11 displays the subsurface structure from the northwest to southeast in the study area. The rock formations gradually dip until they reach the flank of the Aldrich anticline to the northwest.

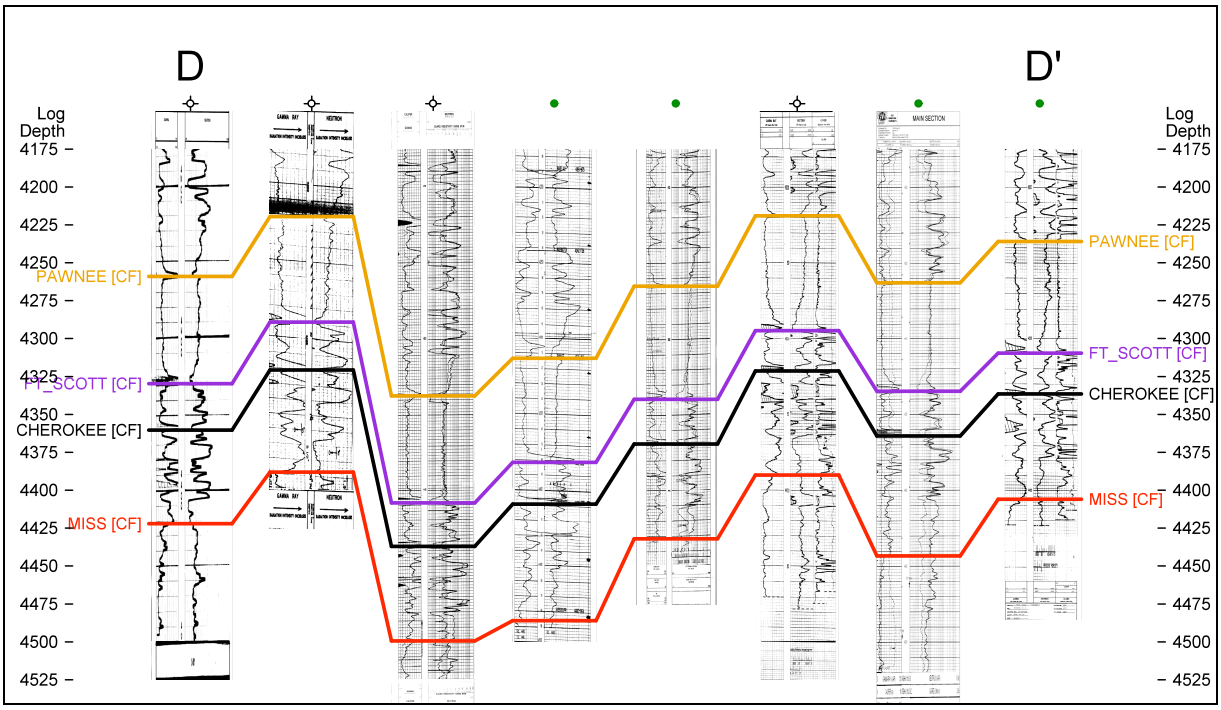


Figure 4-11 Northwest-Southeast cross-section

Northeast-Southwest

Figure 4-12 displays the subsurface structure from the northeast to the southwest in the study area. The rocks gradually dip towards the southwest across the area.

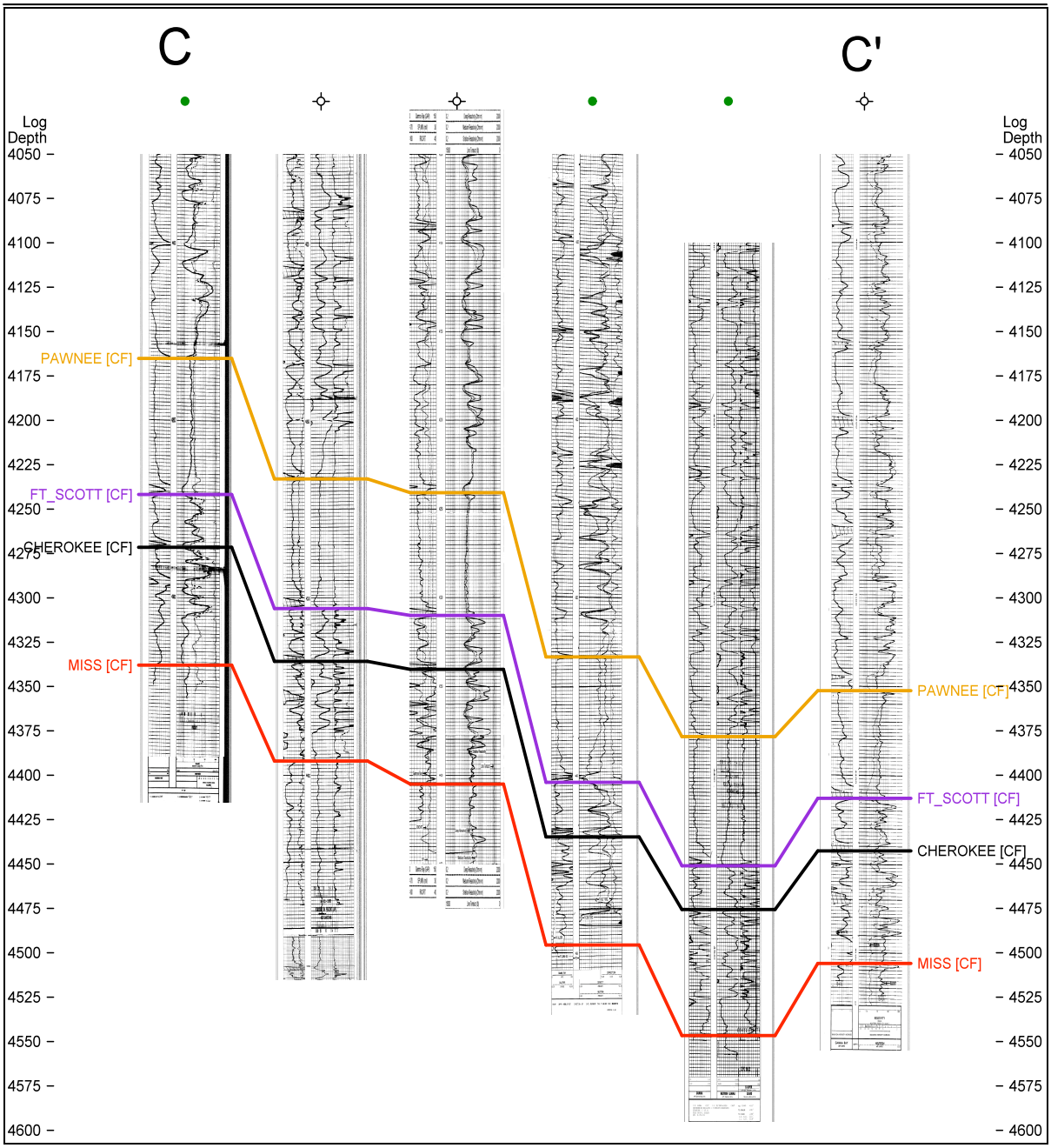


Figure 4-12 Northeast-Southwest cross-section

CHAPTER 5 - DISCUSSION

Structure and Production

Figure 5-1 displays the distribution of drill stem tests with good recovery from the Fort Scott, relative to structure. Good recovery drill stem tests have been recorded in the structural high areas in the northwest sections of the study area, but also down dip in the structural lows to the southeast. The anticline to the northwest has been the primary target for deeper Mississippian reservoirs, however, has not resulted in Fort Scott production. The Mississsippian production play trends northeast-southwest along the crest of the structure, this can be seen by the location of producing wells in the northwest. This structure is known as the Aldrich anticline and influenced the development of the Aldrich field. An array of wells with good Fort Scott drill stem tests do appear to have structural similarities between the -1890 and -1910 subsea interval in the southcentral part of the study area, and a cluster of wells along a structural high in the east. However, there are also numerous wells to the north that show good drill stem tests that have no relationship to Fort Scott structure. An ideal model that displays production based on structure, will have producing wells in the structural highs, with a gradual decrease in oil production and increase in associated formation water in the structural lows. There are wells along the eastern flank of the Aldrich anticline, in the northeast, and in the southeast sections, that had sufficient amounts of water. Therefore, having tests with water and tests with oil in similar areas and at similar structural datums would imply that there must be other influences on production/drill stem tests besides structure. After viewing the structure map related to production and drill stem tests, there appears to be no strong relationship between Fort Scott production/good recovery drill stem tests and Fort Scott structure.

Isopach and Production

The thickness of the Fort Scott formation, varying from 20ft to 30ft, appears to be laterally continuous over the study area (Fig 5-2). The thickest zones are sporadic in the 72 square mile region, being located in all quadrants of the two townships. Good recovery drill stem tests/production are equally distributed in the 10ft variation of thickness. Because the

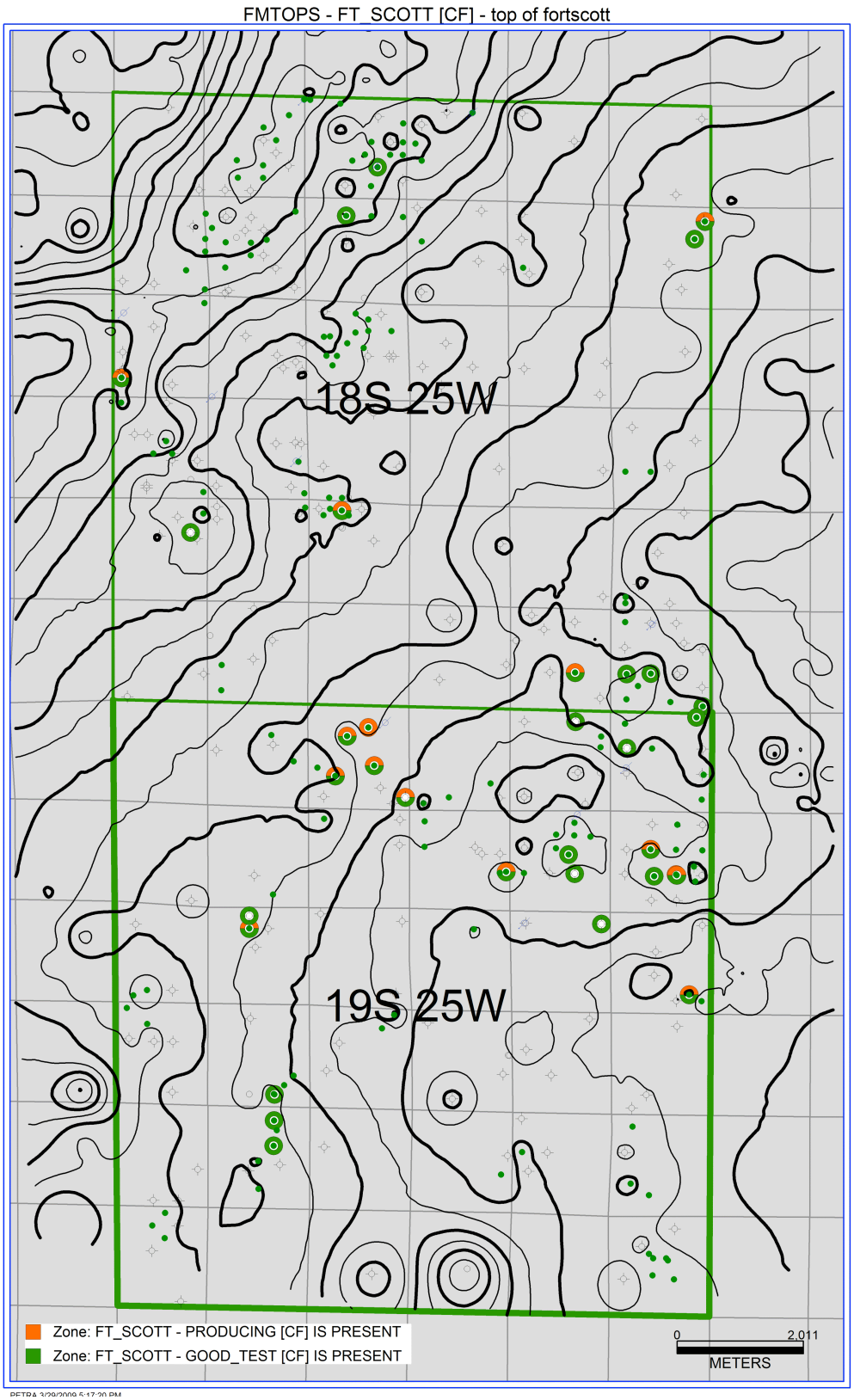


Figure 5-1 Distribution of wells with good drill stem tests or production on structure of the Fort Scott formation

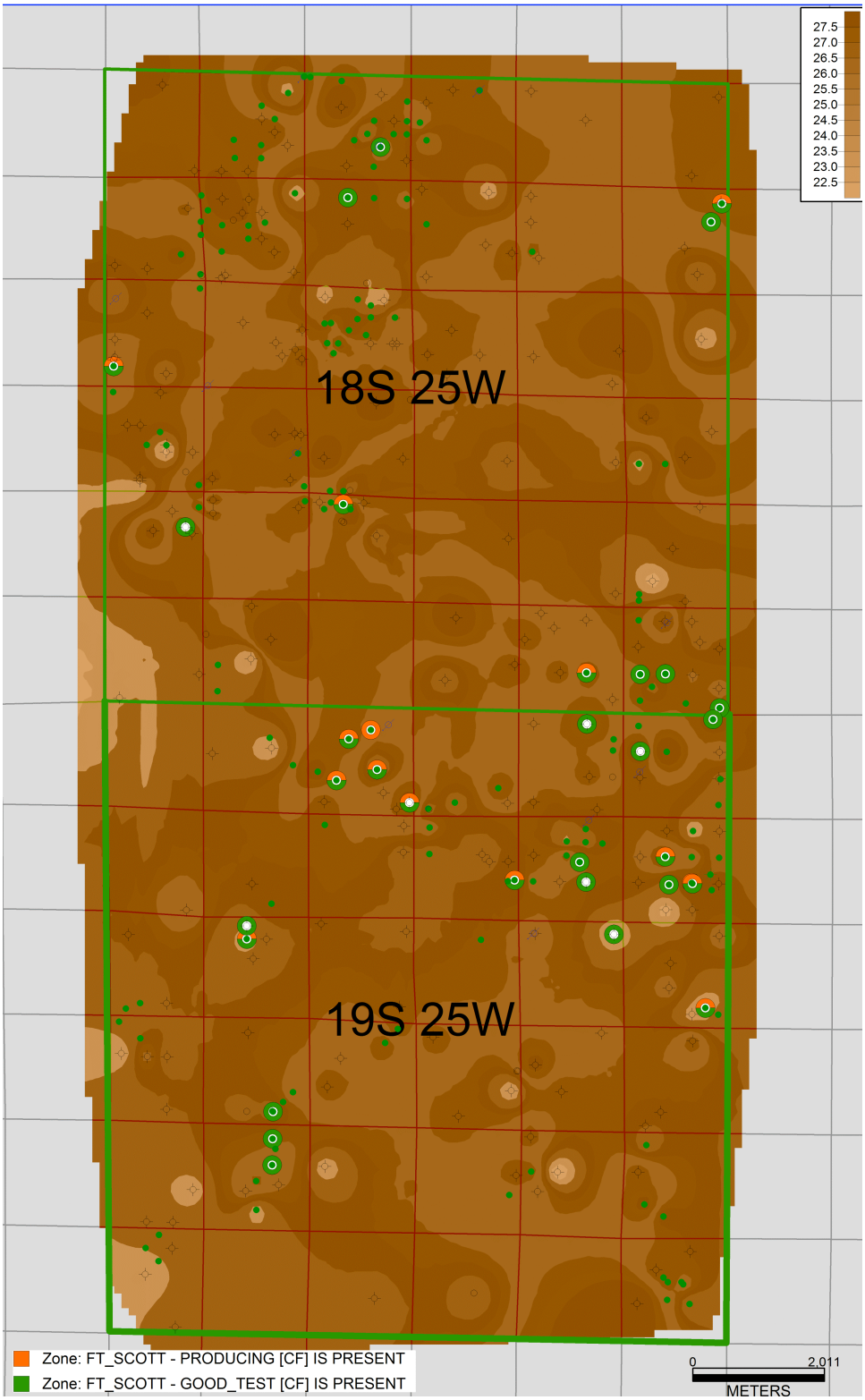


Figure 5-2 Isopach of the Fort Scott formation with location of wells with good drill stem tests or production from the Fort Scott. CI is only 0.5 feet

thickness does not vary significantly in the study area, it also must not be an important control on petroleum accumulation.

Ooids

Ooids are a spherical or ellipsoid grain ranging from 0.25mm to 2.00mm. They have a center nucleus that is covered by one or more precipitated concentric layers. The nucleus is usually detrital terrigenous material or skeletal fragments. Modern calcareous ooids are typically composed of aragonite or Mg-calcite. This has been also true for ooids throughout the Phanerozoic. Ooids require an environment that enables inorganic or microbial precipitation and biological encrustation of grains. Also needed is repeated rotation of grains to form the concentric coating. In order to have the repeated rotation, ooids are best formed in environments such as, tidal deltas and bars, or beaches, where they have daily influence for rotation. Since ooids and reefs are found in similar areas they are often competing for space. Therefore, where there is biological stress, inhibiting organism growth, it will enhance the rates of carbonate precipitation, thus, increasing ooid formation (Scholle and Ulmer-Scholle, 2003). An example of modern ooilte formation is in the Bahamas, as oolitic shoals in relatively high energy, shallow water environments. Figure 5-3 is an example of modern oolitic shoals from the Bahamas.

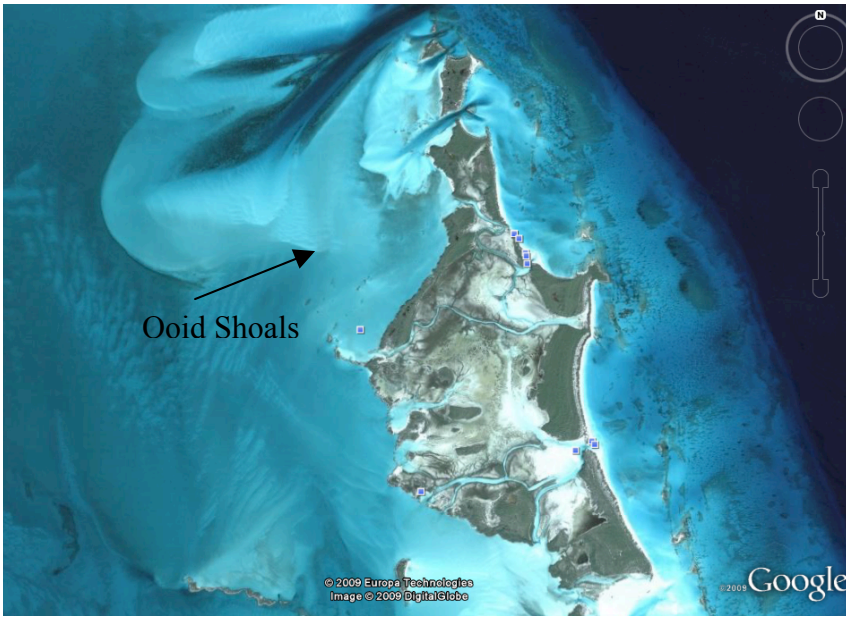


Figure 5-3 Modern analog of ooid shoals, Bahamas (www.googleearth.com)

Ooids and Fort Scott Structure

Ooids are located throughout the study area, excluding the northeast. There were samples collected on the flanks of the anticline, along the down dip slope in the southcentral part of the study area, in the structural high to the east, and in the structural low to the southeast (Fig 5-4). According to the Fort Scott structure map, there is no relationship between the presence of ooids and structure.

Ooids and Production/Drill Stem Tests

Of the 138 drill stem tests, 31 had significant oil recoveries and can be considered good tests. It is clear from Figures 5-2 and 5-3 that Fort Scott structure and thickness do not influence the reservoir quality. The distribution of ooids, however, shows a similar distribution as the distribution of good drill stem tests/production (Fig 5-5). To the northwest along the structural high, there are numerous tests that have been completed, but only a few good tests. The wells with good tests have ooids present within the well or neighboring wells. To the south, between the -1890 and -1910 subsea intervals, there are numerous good drill stem tests/production, trending to north and south. Again, with these good recovery drill stem tests there is an association with the occurrence of ooids (Figure 5-5). The other abundance of good drill stem tests/production in the study area is on the structural high to the east. There have been tests to the north of the structural high, but none were significant, and there were also no ooids seen within the rock samples. However, along the high and to the south where there are good tests/production there were ooids present within the samples. The presence of ooids in areas with good drill stem tests and Fort Scott production suggests that ooids are playing a role in the quality of the reservoir. There is a well to the southeast that has ooids, but did not have a good oil recovery on drill stem test. However, the well recovered a large quantity of fluid, indicating a permeable reservoir, validating the impact of ooids on reservoir quality. This fluid had insufficient amounts of hydrocarbons and thus recorded as a bad drill stem test, but the permeability required for production was developed.

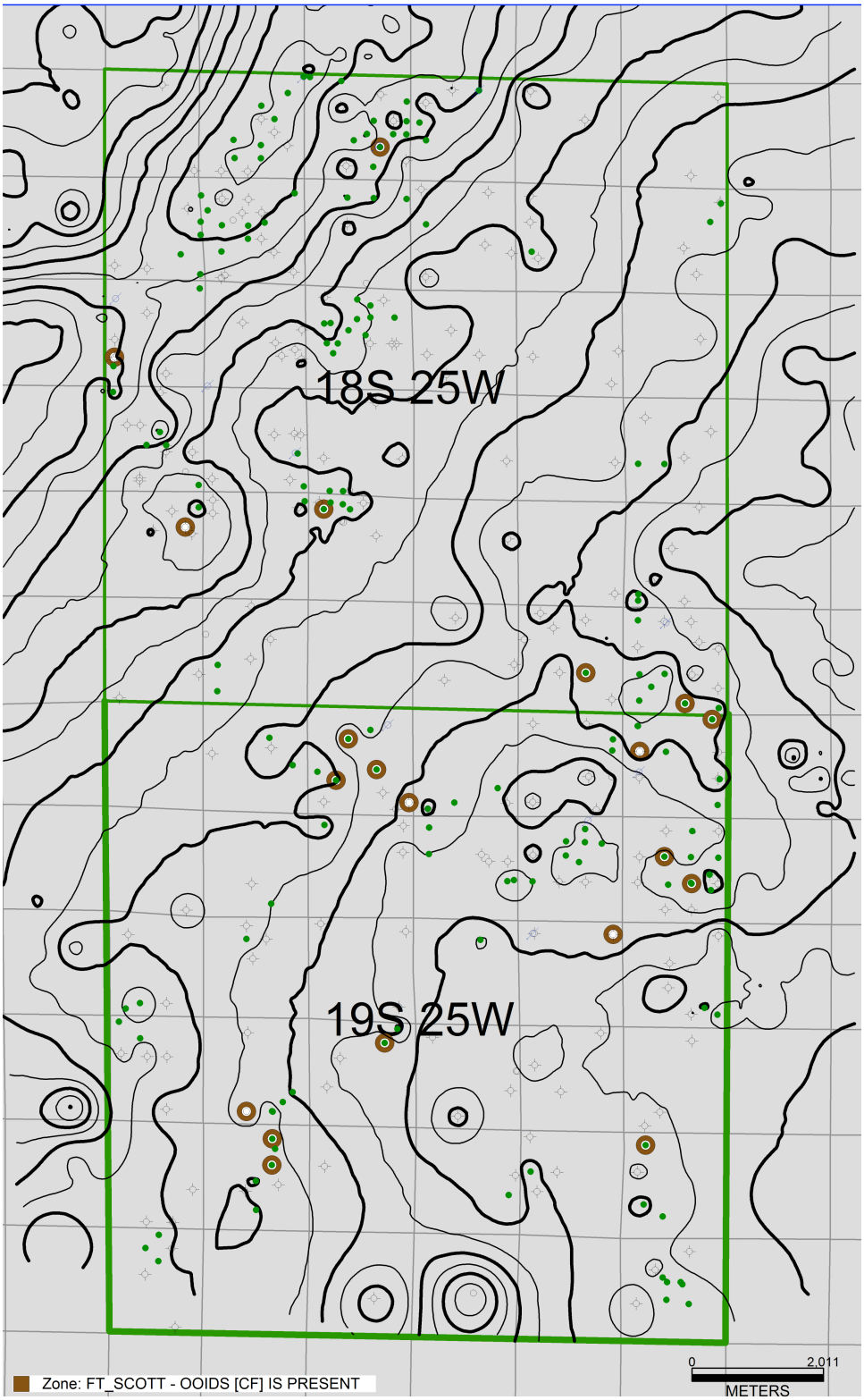


Figure 5-4 Distribution of ooids with Fort Scott Structure

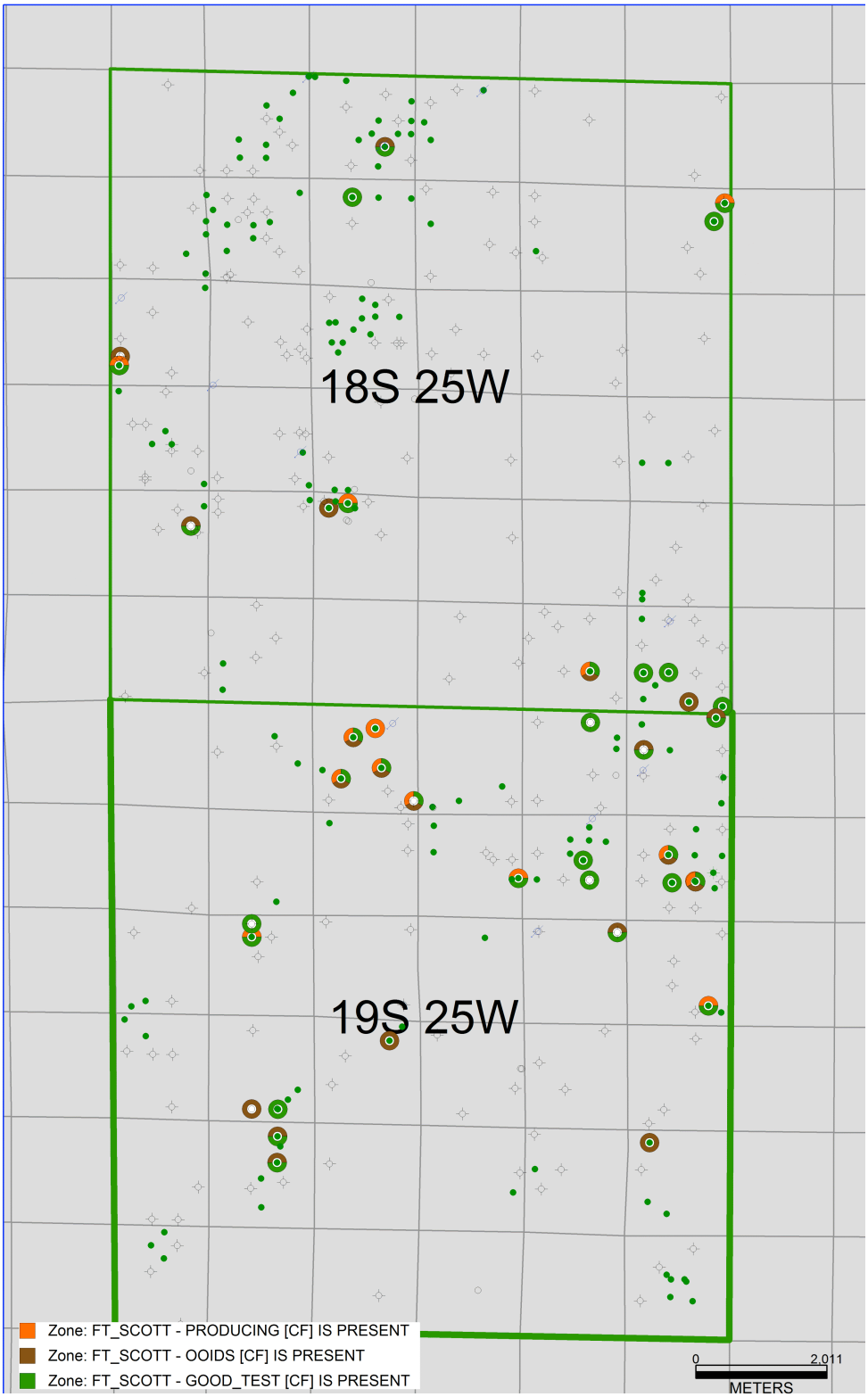


Figure 5-5 Relationship between good drill-stem tests, production, and ooids

Ooids and Cherokee Group Isopach

The isopach map of the Cherokee formation is a reflection of the paleo-topographical relief in the region when the lower Pennsylvanian units were deposited. The Cherokee group isopach is the thickness from the top of the Mississsippian to the base of the Fort Scott. The Mississippian was an erosional surface and therefore, the accommodation space for Cherokee age sediments varied in thickness. The thickest areas, which represent the paleolows of Mississippian time, and the thins on the Cherokee isopach are indicative of the paleohighs. Because ooids are indicative of shallow marine environments with high energy, the ooid distribution should be found off the flank of the paleo-topographical highs. This is seen in modern day environments such as the ooid shoals in the Bahamas (Figure 5-3). It is also seen along the flanks of the paleohighs, as seen from the thins on the Cherokee isopach (Figure 5-6). The Ooids to the north are also distributed along the edge of the topographical highs. As the isopach gets thicker, indicating the paleo-topographical lows, the presences of ooids decreases. Also, the thinnest areas have a lack of ooids. This can be interpreted as the thickest areas being water that is too deep for ooids to form and the thinnest areas being too shallow for the formation of ooids. The locality of ooids along the borders of topographical highs implies the presence of ancient ooid shoals. Furthermore, the distribution of good drill stem tests/production is located along the flanks of the topographical highs, similar to the ooids. The scarcity of good drill stem tests/production has a positive correlation with the distance from the topographical highs. The wells located further away have significantly lower production/good drill stem tests. Therefore, it can be interpreted, that the depositional environment is having an impact on the quality of the reservoir.

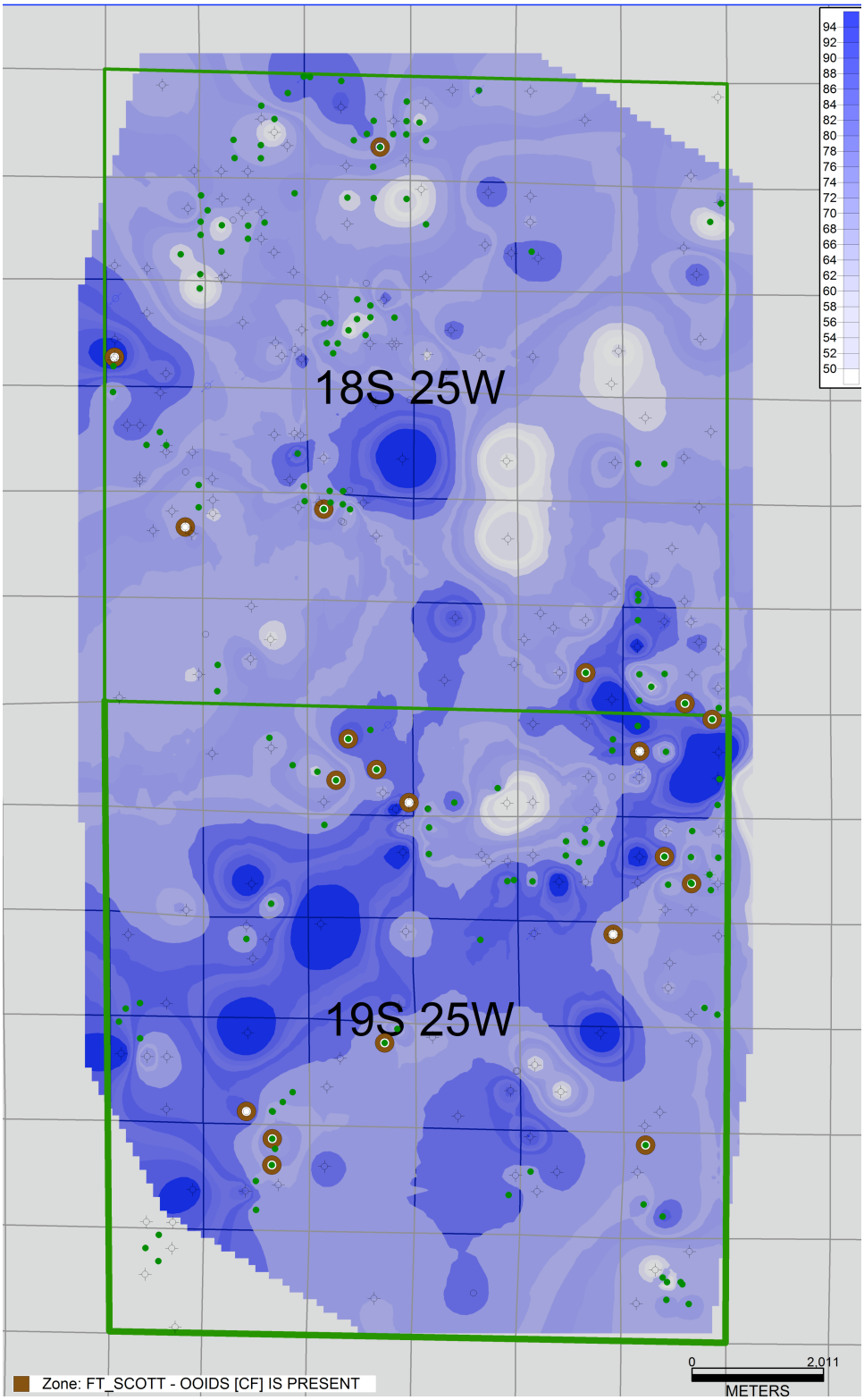


Figure 5-6 Isopach of the Cherokee formation showing distribution of ooids found in the Fort Scott.

Similar work has been done in the Dickman Field, Ness County Kansas. Using seismic data, isotime maps were made from the Fort Scott to the Mississippian to estimate topographical highs and lows. The thinnest areas over structural highs indicate positive relief during Fort Scott deposition. The antecedent topography or structure influenced shoal distribution. The geometries and size of these ooilitic shoals in the Dickman Field are similar to modern day ooid shoals of the Bahamas (Watney et al. 2007). The geometries and size found in the Dickman Field and the Bahamas is also similar to oolitic shoals found within the study area (Figure 5-7).

Drill Stem Tests and Well Logs

The most common well log in the study area is the Radiation Guard log, which uses a neutron tool to estimate porosity. These logs are relied upon to evaluate the well before making the decision to run production casing. It is evident from this study that the porosity of the ooilitic zones of the Fort Scott are underestimated by Neutron logs in the study area. The high recovery drill stem tests from some of the best producing Fort Scott wells in the study area do not show good porosity on the neutron porosity curves of the well logs. An example is seen in well 15-135-23347, where the drill stem tested 450' of clean gassy oil, but and the neutron density averages only 6% porosity (Figure 5-8). Wells with good neutron porosity (up to 25%), but no ooids often recover only drilling mud. The neutron porosity does not appear to be accurate when looking at oolitic limestones. Detailed sample work, combined with drill stem tests, are the best indicator of reservoir development in the Fort Scott within the study area.

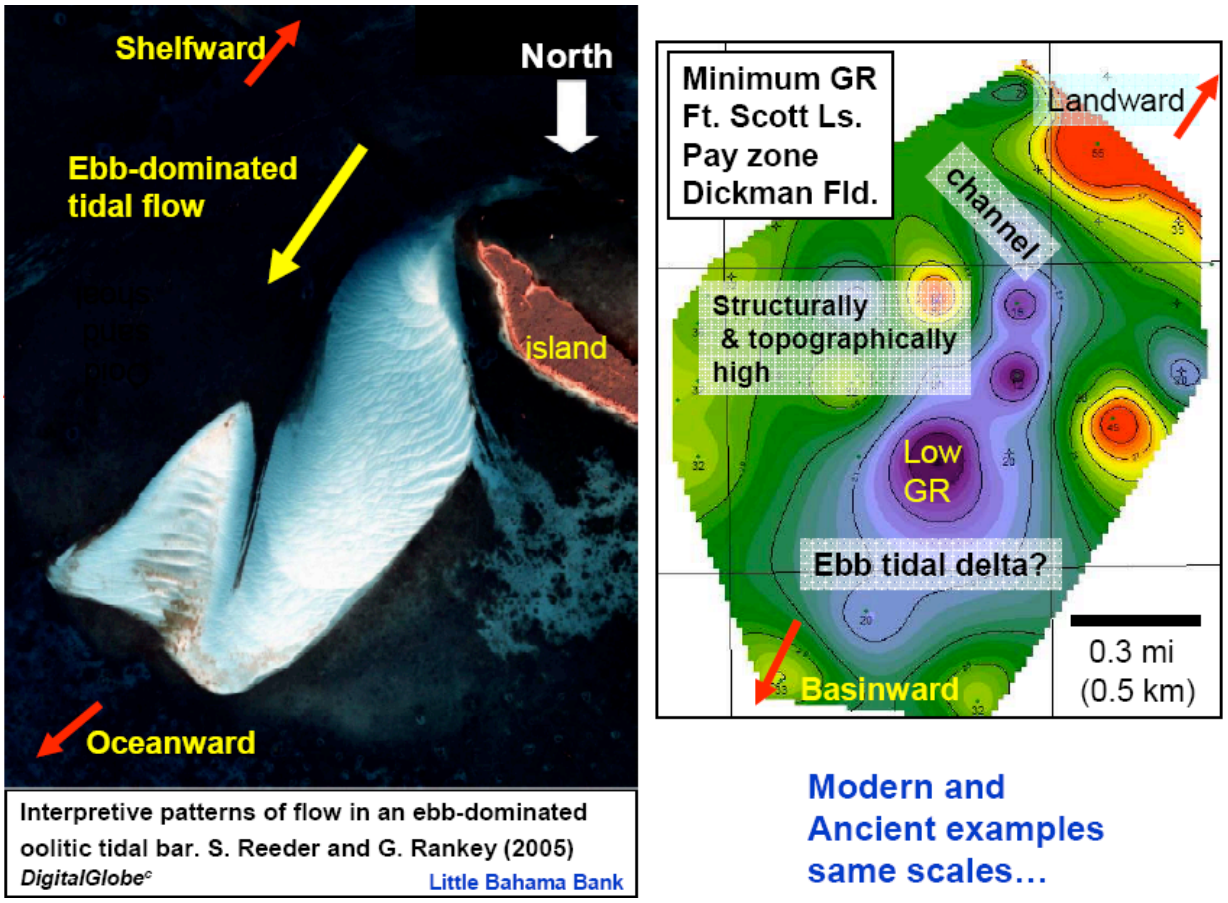


Figure 5-7 Modern analog compared to Dickman field (Watney, et. al).

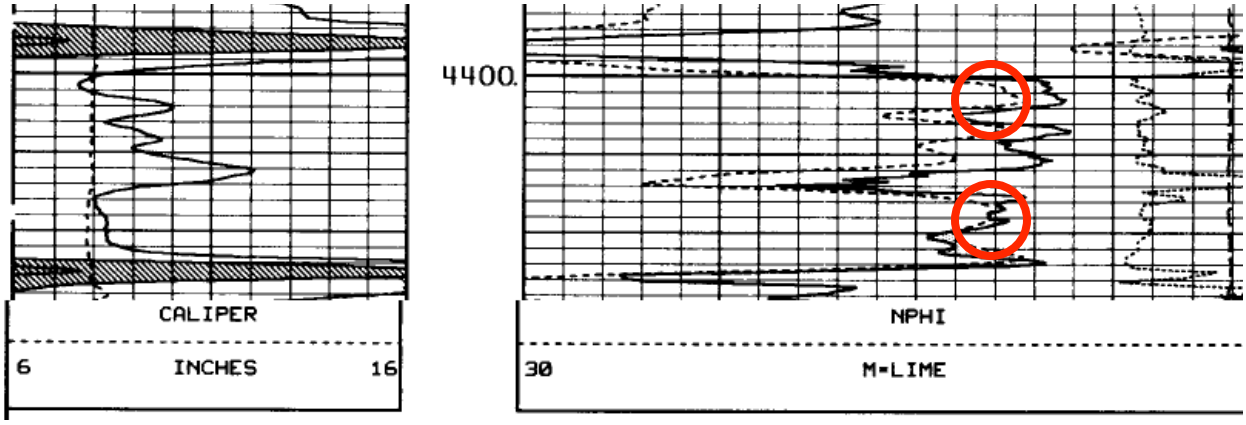


Figure 5-8 Neutron curve indicating neutron porosity values in the Fort Scott formation.

Cuttings and Thin-Sections

The limited cuttings that were available gave insight into what type of porosity is in the formation. Furthermore, it aided in determining if porosity type had any influence on the reservoir quality. Examining thin-sections of the well cuttings is the more precise method to determine the distribution of pores within the rock. In addition, thin-sections were needed to classify the rocks using Dunham and Folk carbonate classification. There were a variety of porosity types (Tables 4-1) recorded for the study area and it is apparent they have great influence on reservoir quality, based upon drill stem test and production data. It also became evident that the logs curves were not correlating with what was being viewed in the cuttings and thin-sections. Figure 5-9 had an average of 7% neutron porosity, yet tested 2440' gas in pipe, 55' of slight oil and gas cut mud, 120' of heavy oil and gas cut mud, and 305' of muddy oil. It is unlikely for a test with this amount of fluid recovery to have only 7% porosity. As seen in Figure 5-9, there is significant porosity within the drill cutting. Obviously, core data would be better in describing the pore distribution of the reservoir. Preparing thin sections of the well cuttings is a good alternative in the absence of core. These thin-sections lead to better understanding of reservoir conditions than standard cutting examination methods, or log analyses.

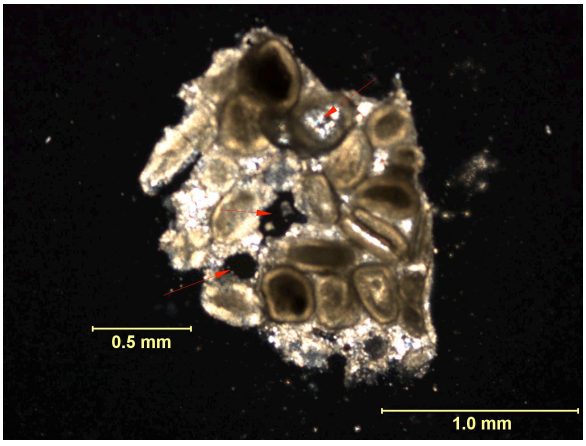


Figure 5-9 Thin section of oolitic limestone in the Fort Scott formation. Arrows show interconnected inter-oolitic porosity not evident under a binocular microscope. Neutron porosity of this well was only 6%. This image is also in Appendix B.

CHAPTER 6 - CONCLUSIONS

Subsurface mapping of over 400 wells within a two township area in western Ness County, Kansas illustrates the sporadic distribution of Fort Scott oil production. Reservoirs are not developed over structural highs, such as on the deeper Mississippian formations. The Fort Scott limestone shows very little variation in thickness, hence exploration by mapping the Fort Scott thickness is not fruitful. The lack of an exploration model has hindered the development of these resources.

To better understand the distribution of petroleum accumulations in the Fort Scott, drill cuttings were examined from 43 wells chosen to represent the variability of reservoir conditions across the study area. Drill stem test data and production data (when available) were used to establish the quality of the potential reservoir. Porosity was best evaluated by examining thin sections prepared from the drill cuttings.

The distribution of petroleum accumulations in the Fort Scott limestone in western Ness County is explained by the stratigraphic variation of depositional environment. Porosity and permeability are best developed within an oolitic shoal facies, which is distributed along the flanks of paleohighs within the area during Marmaton time. These areas had the conditions most favorable for development of these high energy, oolitic-rich rocks.

The best exploration model for Fort Scott production is to identify the paleotopography by mapping the Cherokee isopach. The thinnest isopach represents the paleohighs, along the flanks of these highs are the regions most favorable for finding the oolitic shoal facies. Rocks of these facies are potentially productive, even when not on structure.

Neutron density logs typically underestimate porosity in the oolitic-rich facies. Either a different calibration for these rocks should be used when calculating porosity from these zones, or different porosity tools should be considered. Significant Fort Scott reservoirs might have been overlooked by the combination of concentrating on structural position, and not testing wells because of underestimated log porosity.

Evaluating an actively drilling well for the potential of Fort Scott production should include careful examination of drill cuttings for the presence of oolites. Any well that encounters these facies is a good candidate for drill stem testing, regardless of structural position. Preparation of thin-sections from drill cuttings and examination under a petrographic microscope will confirm the presence of porosity conditions necessary for production. These could be prepared while the well is evaluating the deeper Mississippian zones, and straddle drill stem tests might be used to evaluate zones with good porosity found in this way.

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Appendix A - Images of Well Cuttings at approximately 20x power

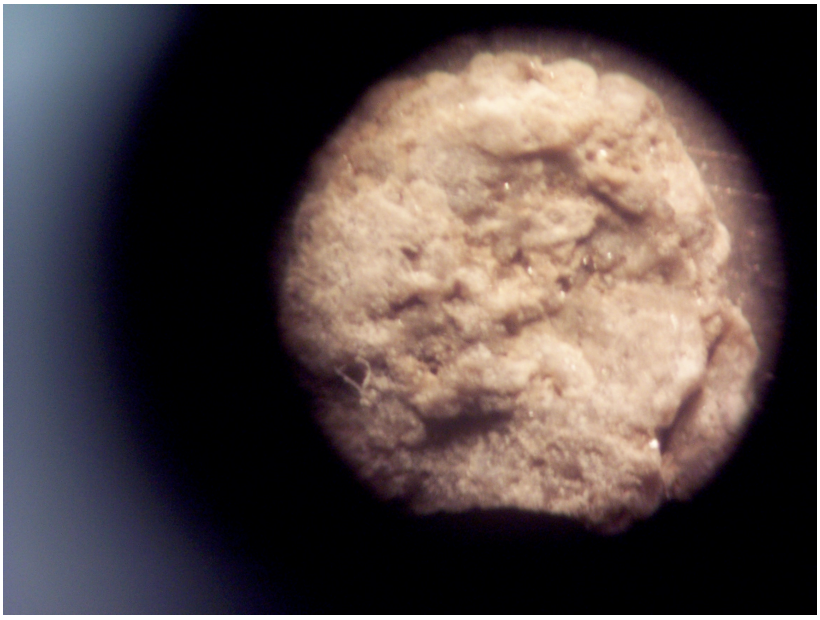


Figure A-1 Cutting sample from well 15-135-21014

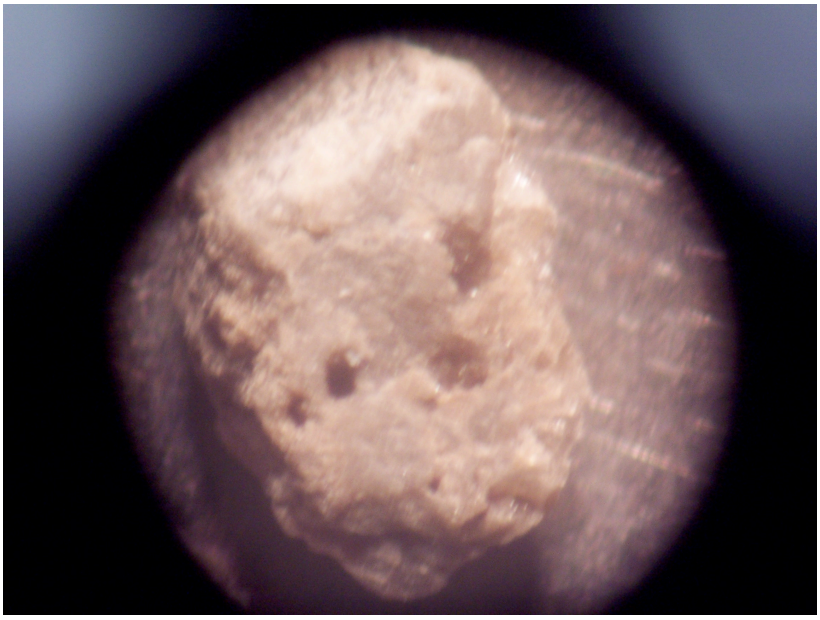


Figure A-2 Cutting sample from well 15-135-29861



Figure A-3 Cutting sample from well 15-135-00371

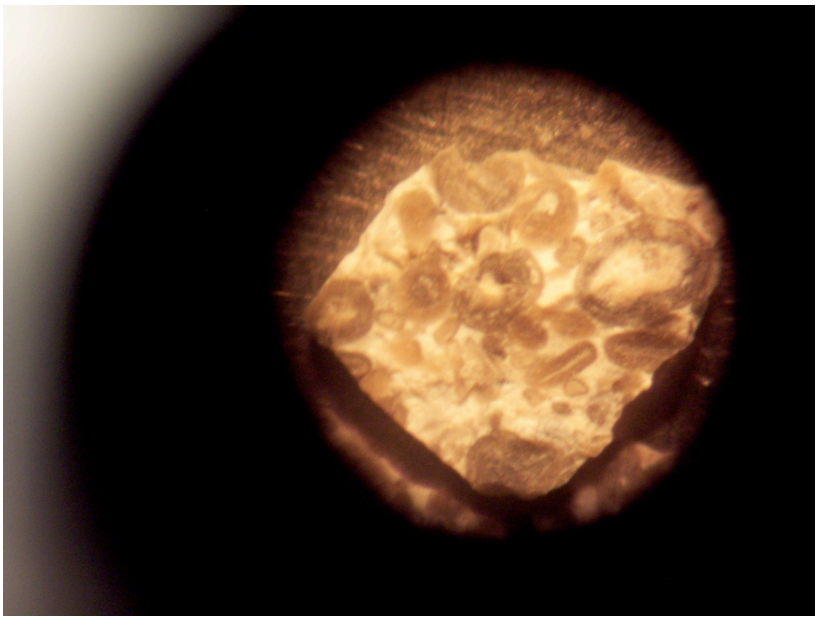


Figure A-4 Cutting sample from well 15-135-23993

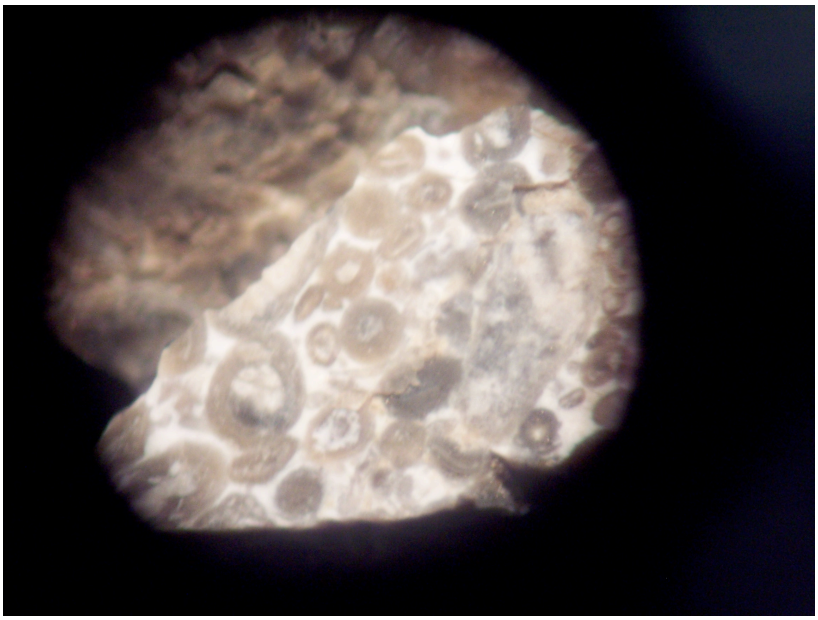


Figure A-5 Cutting sample from well 15-135-23993



Figure A-6 Cutting sample from well 15-135-23769

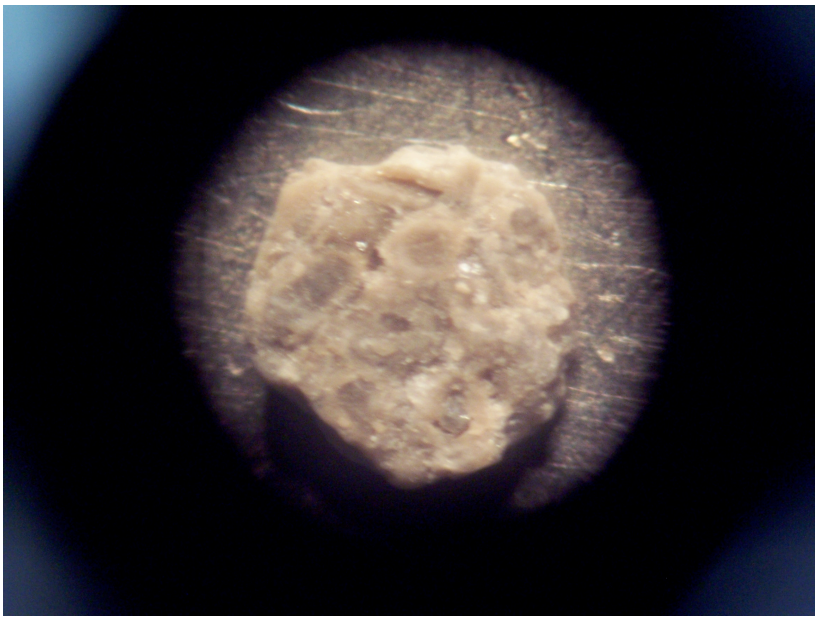


Figure A-7 Cutting sample from well 15-135-23769

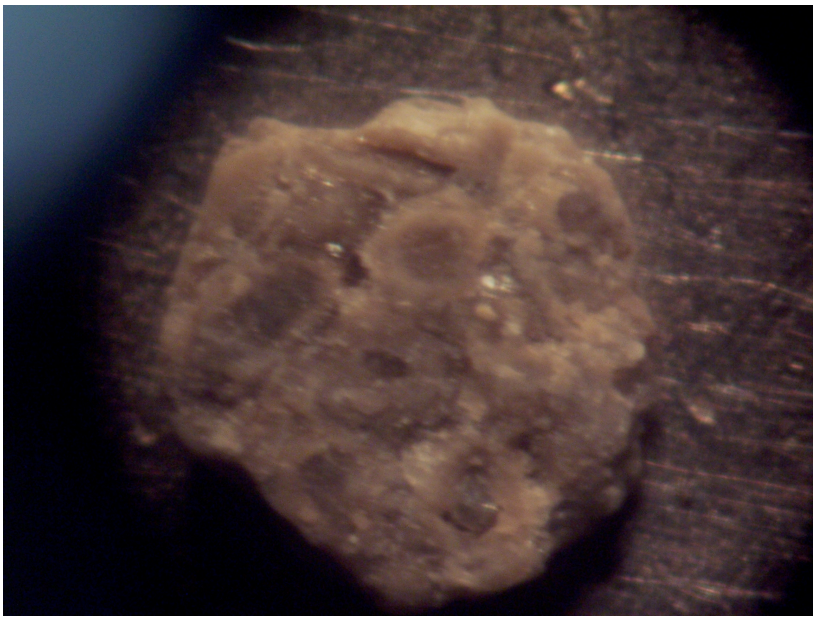


Figure A-8 Cutting sample from well 15-135-23769



Figure A-9 Cutting sample from well 15-135-23769

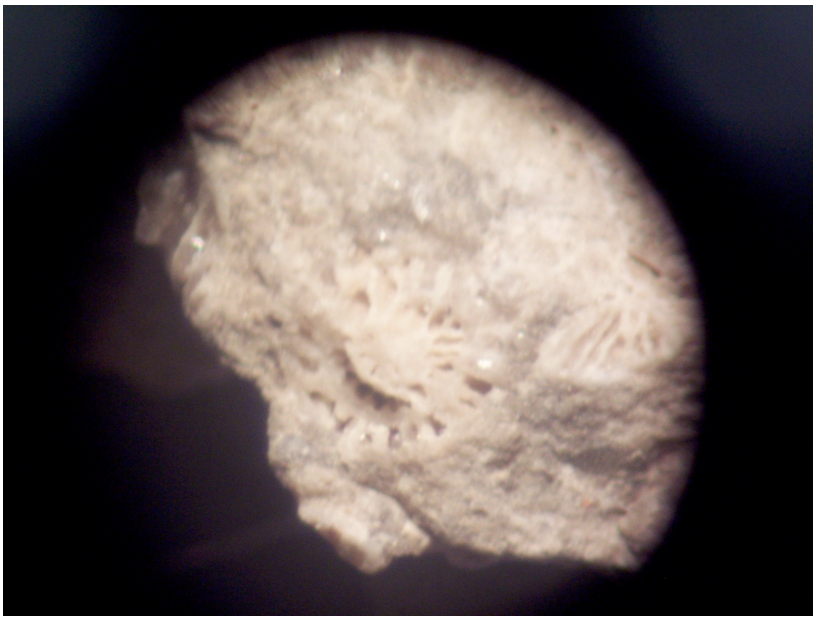


Figure A-10 Cutting sample from well 15-135-20260

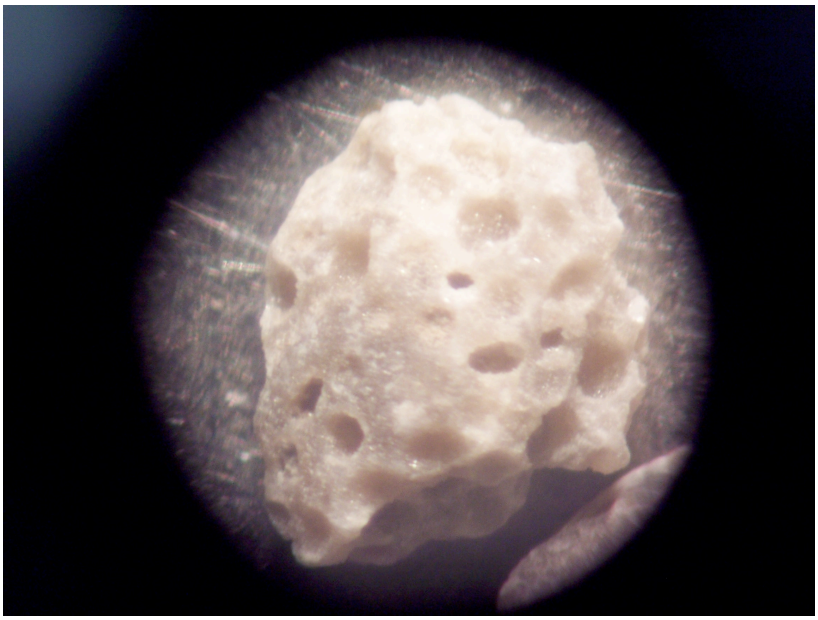


Figure A-11 Cutting sample from well 15-135-20339



Figure A-12 Cutting sample from well 15-135-23065

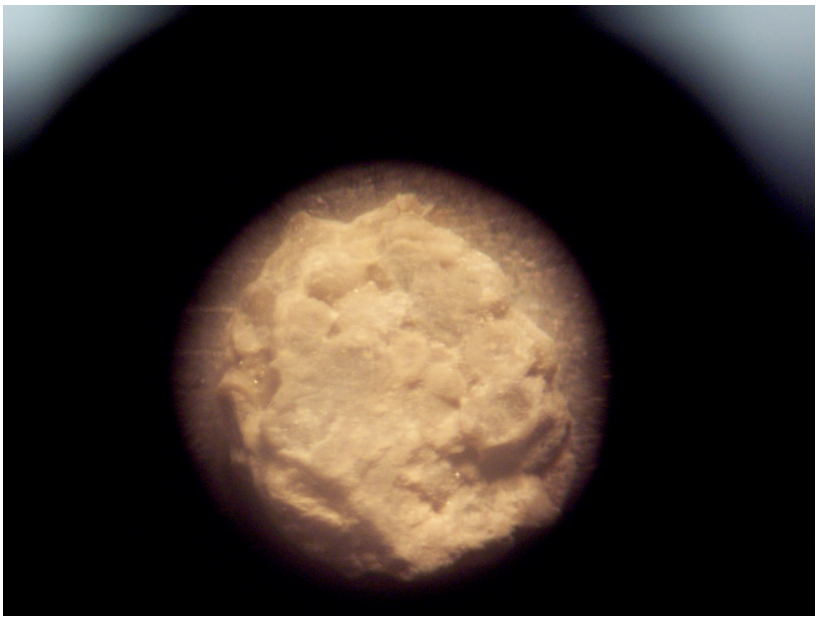


Figure A-13 Cutting sample from well 15-135-23065

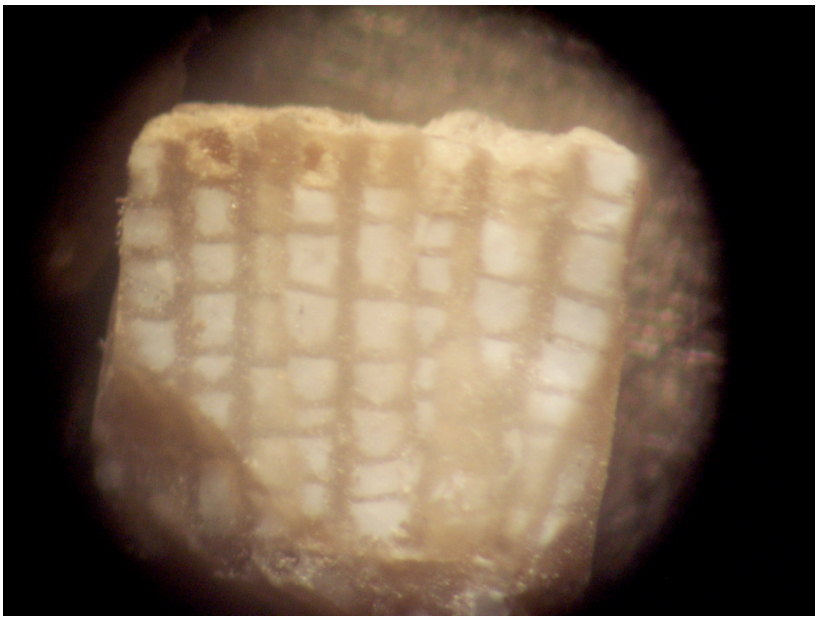


Figure A-14 Cutting sample from well 15-135-20133

Appendix B - Pictures of Thin-Sections

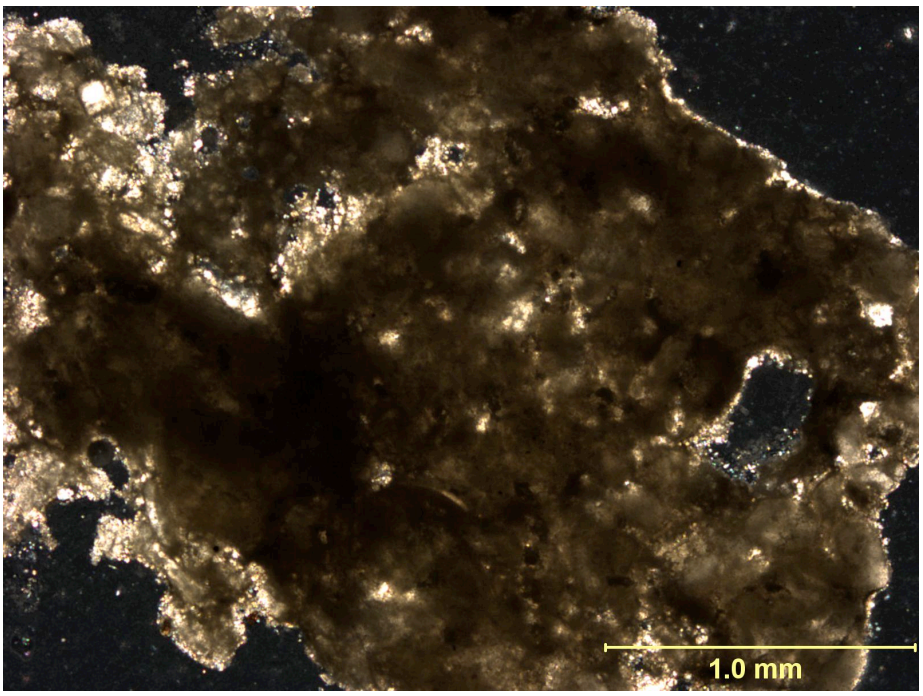


Figure B-1 Thin-section of cutting sample from well 15-135-21219

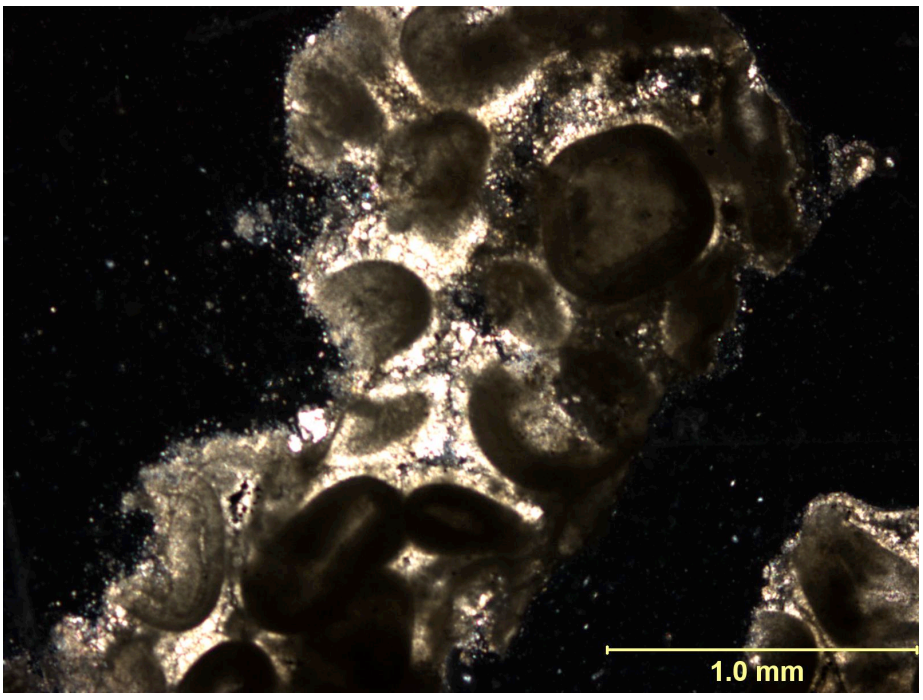


Figure B-2 Thin-section of cutting sample from well 15-135-21219

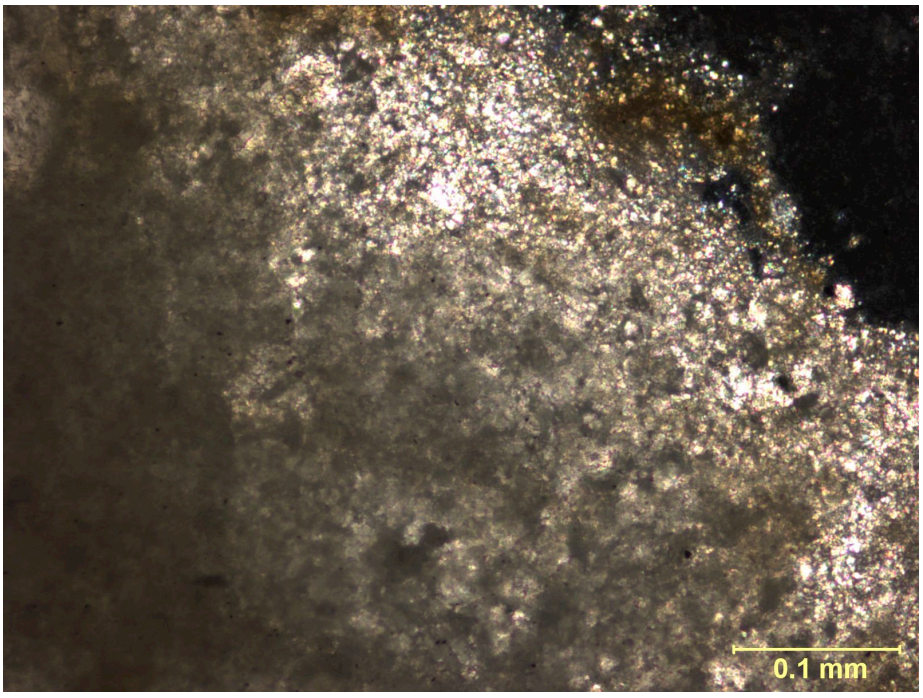


Figure B-3 Thin-section of cutting sample from well 15-135-21813

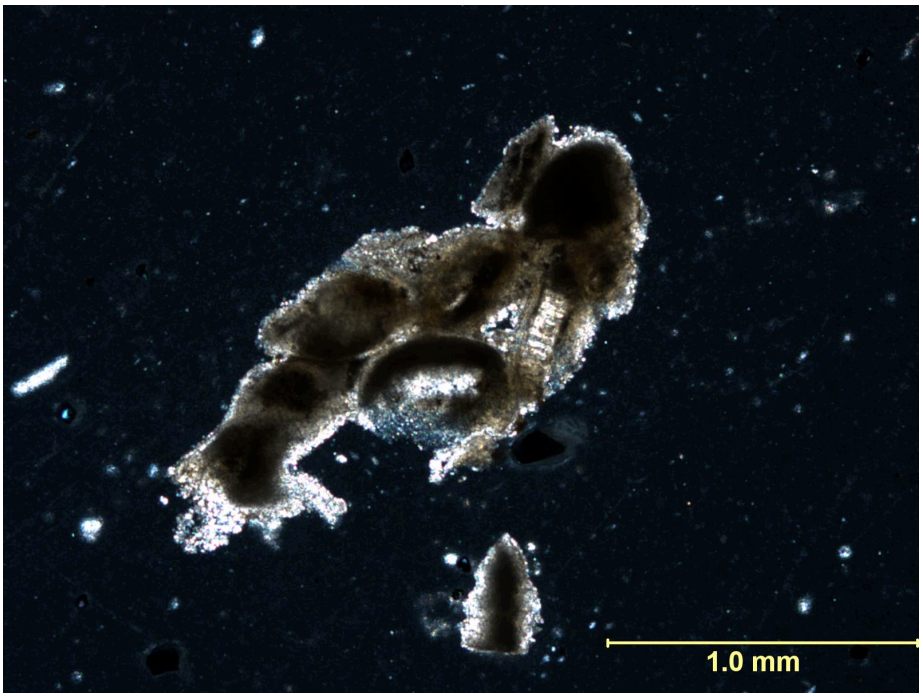


Figure B-4 Thin-section of cutting sample from well 15-135-71129

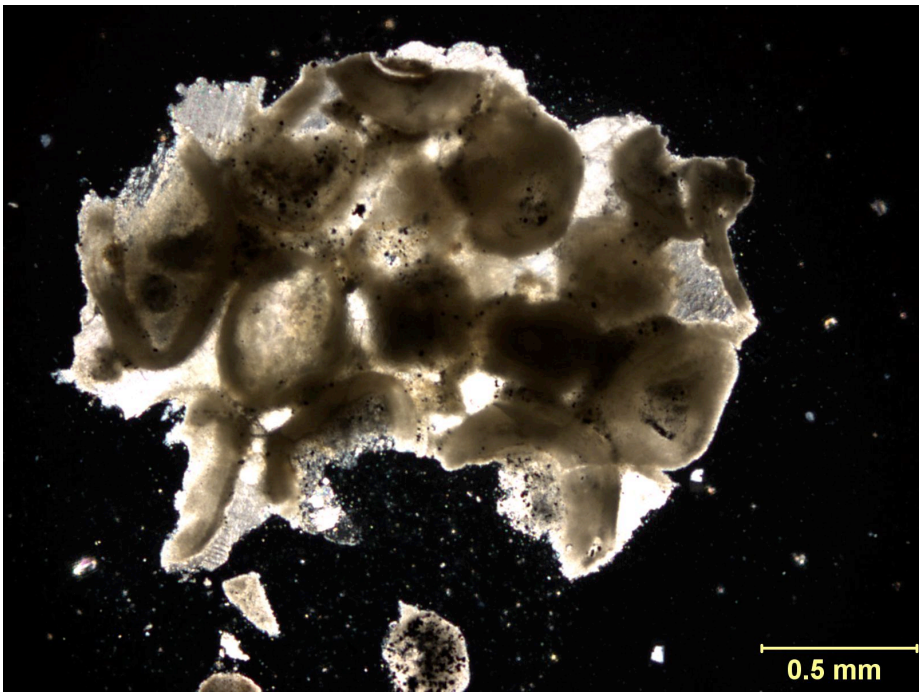


Figure B-5 Thin-section of cutting sample from well 15-135-29861

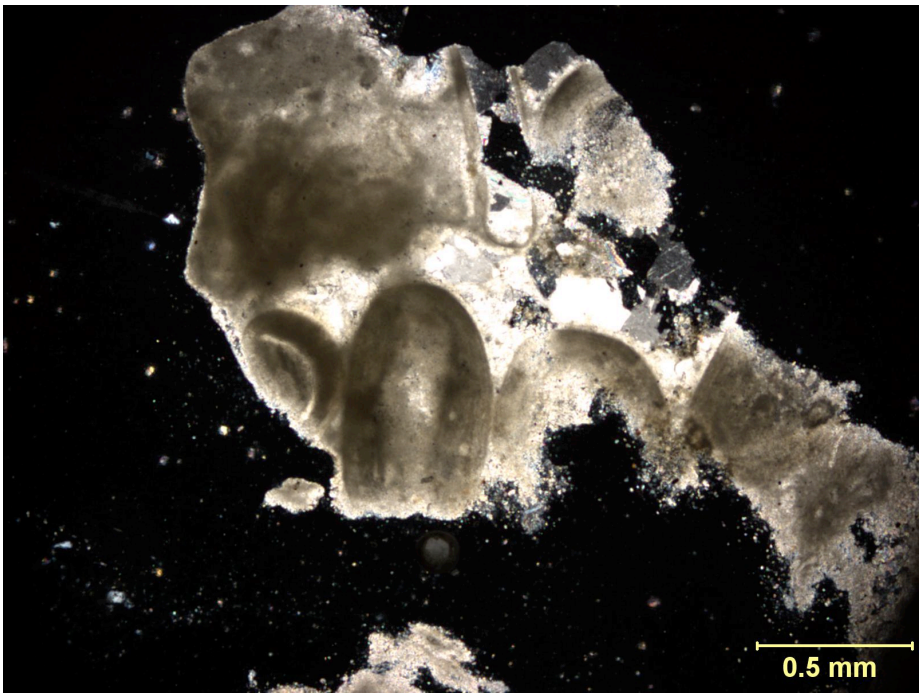


Figure B-6 Thin-section of cutting sample from well 15-135-29861

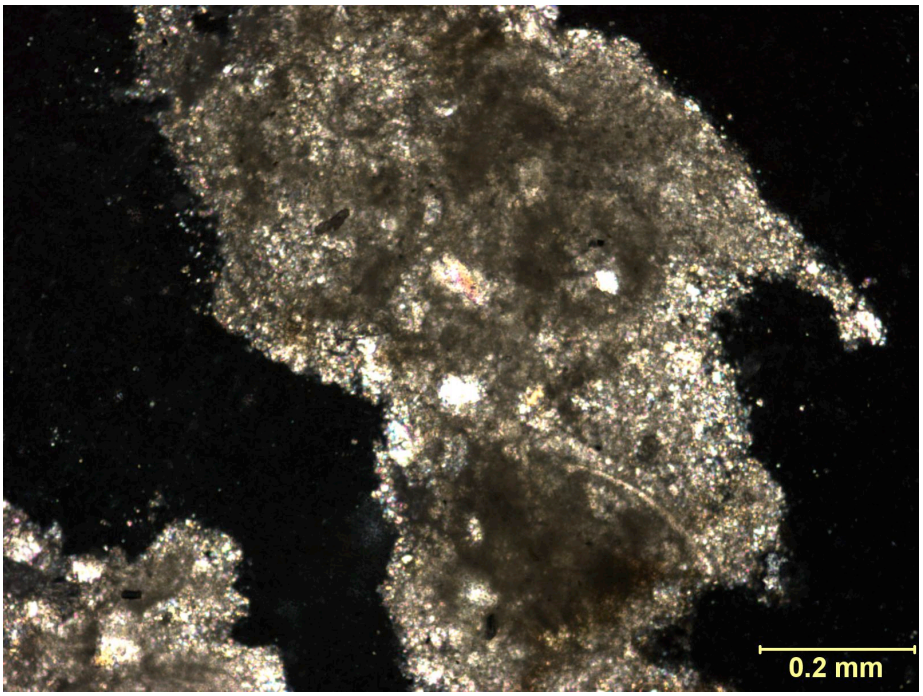


Figure B-7 Thin-section of cutting sample from well 15-135-23347

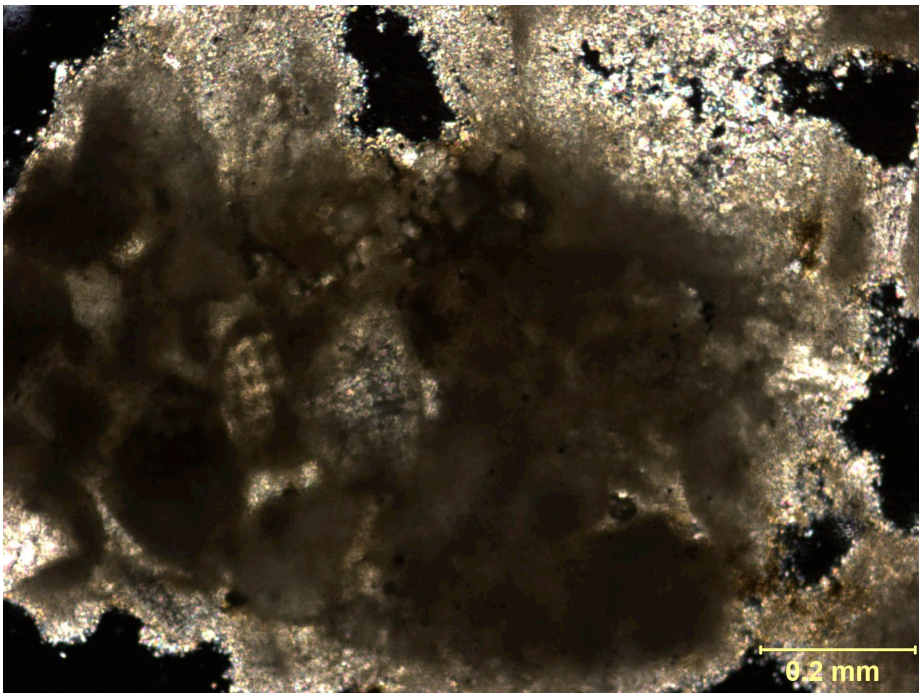


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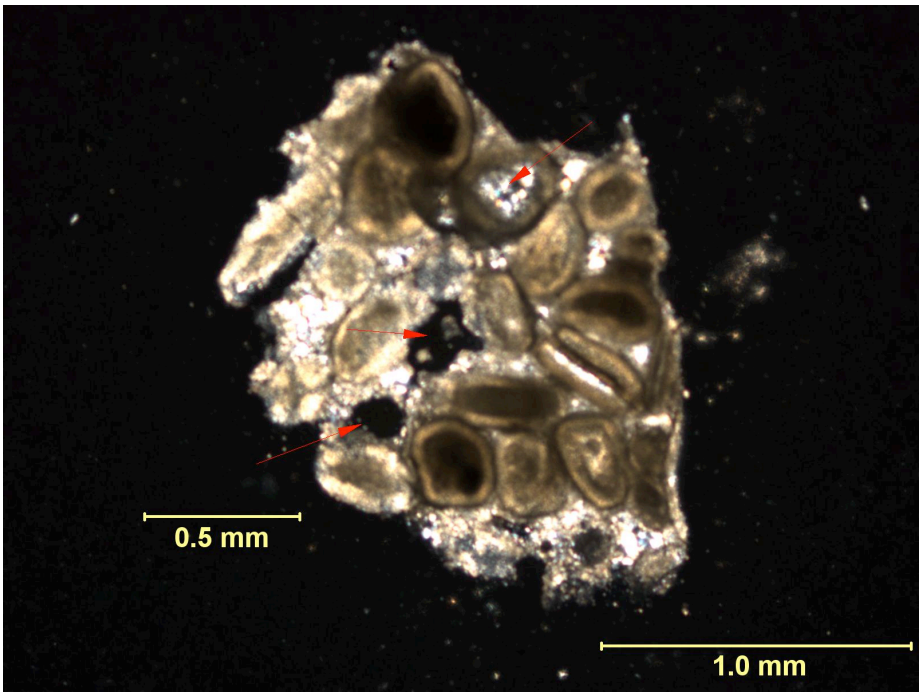


Figure B-9 Thin-section of cutting sample from well 15-135-20349

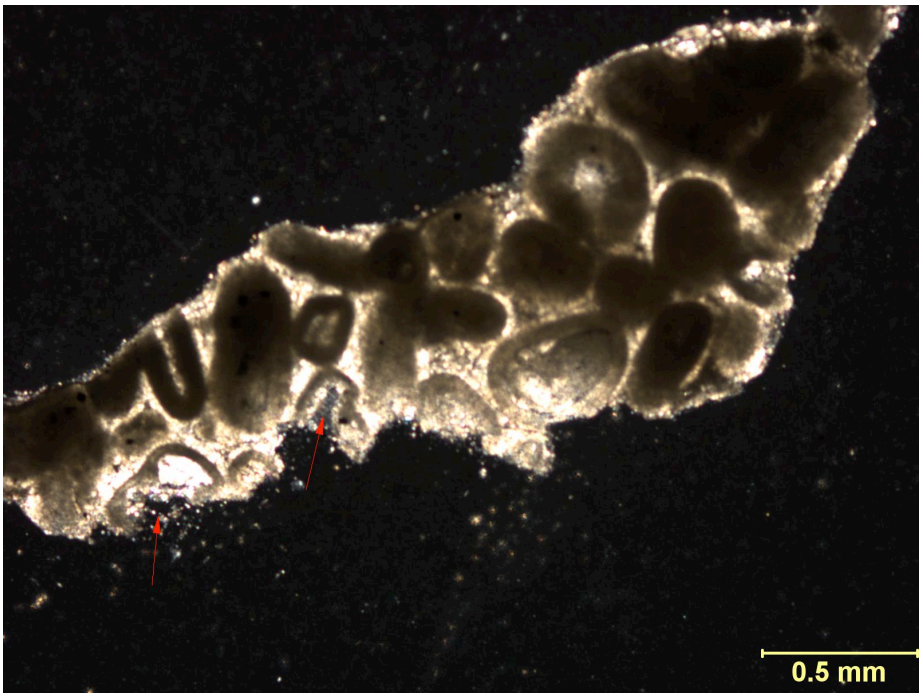


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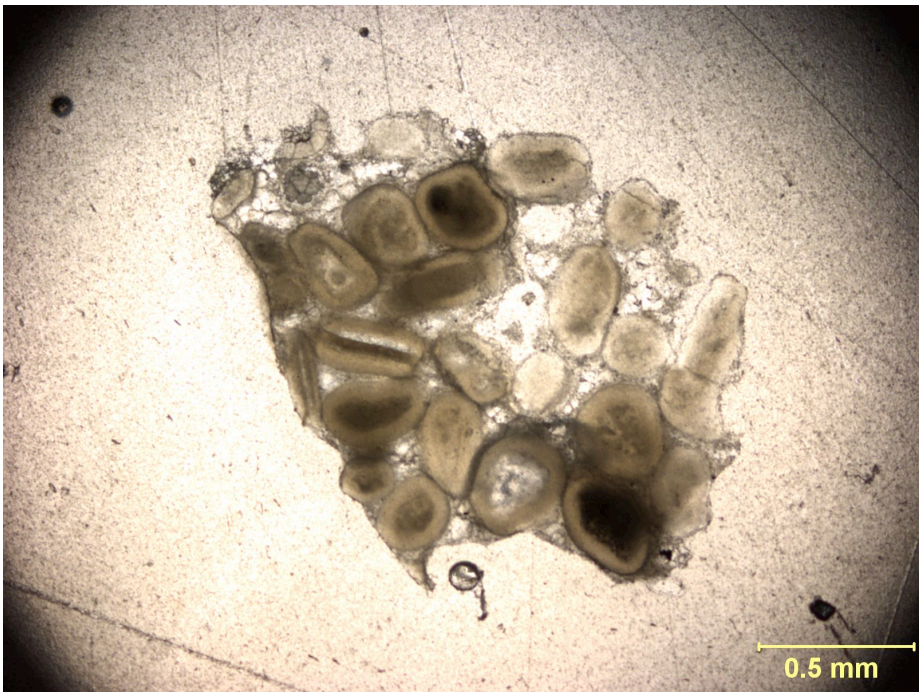


Figure B-11 Thin-section of cutting sample from well 15-135-20349

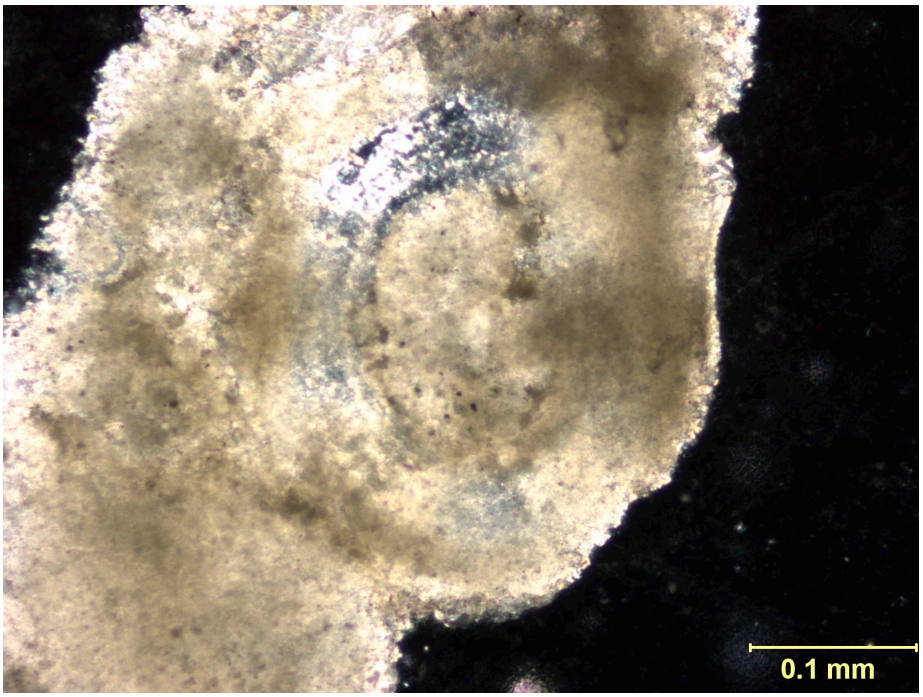


Figure B-12 Thin-section of cutting sample from well 15-135-20353

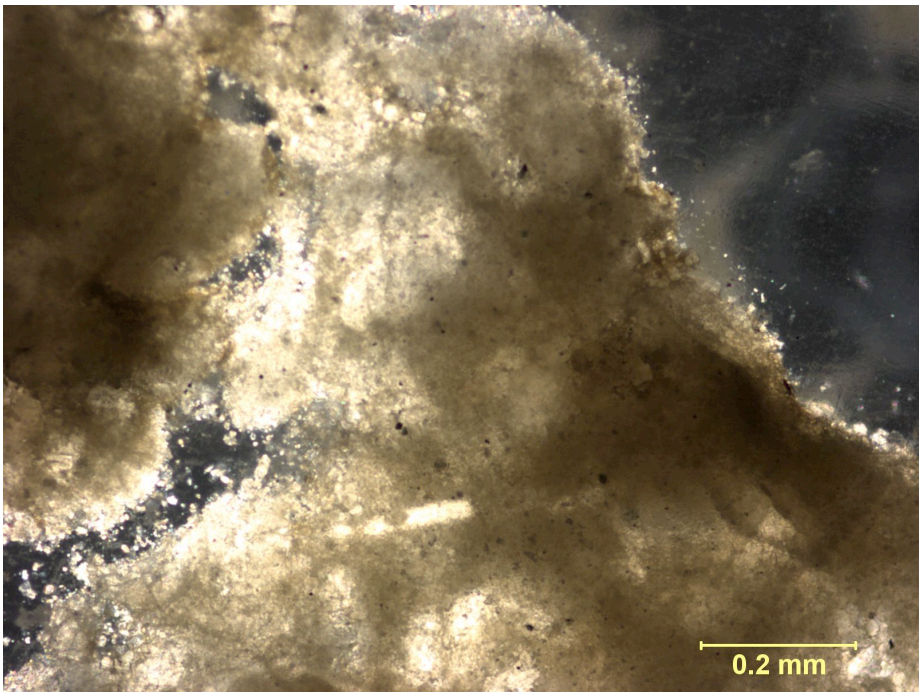


Figure B-13 Thin-section of cutting sample from well 15-135-21042

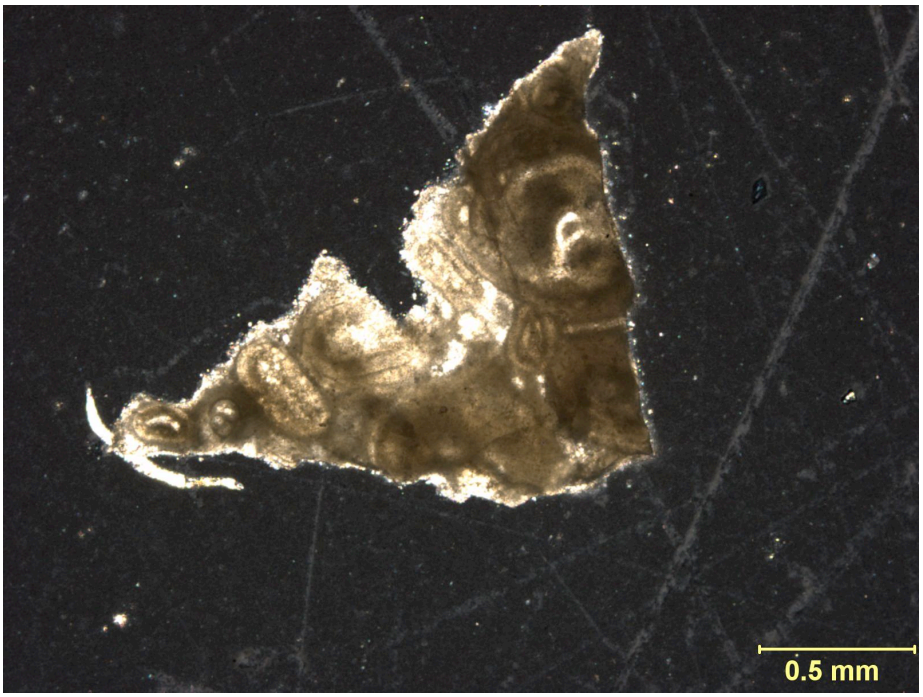


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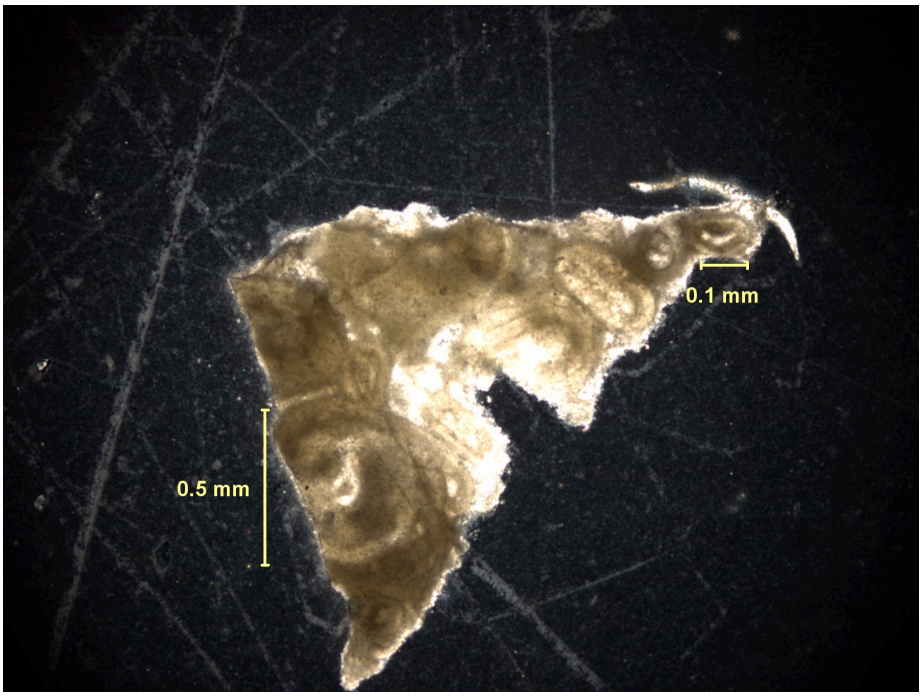


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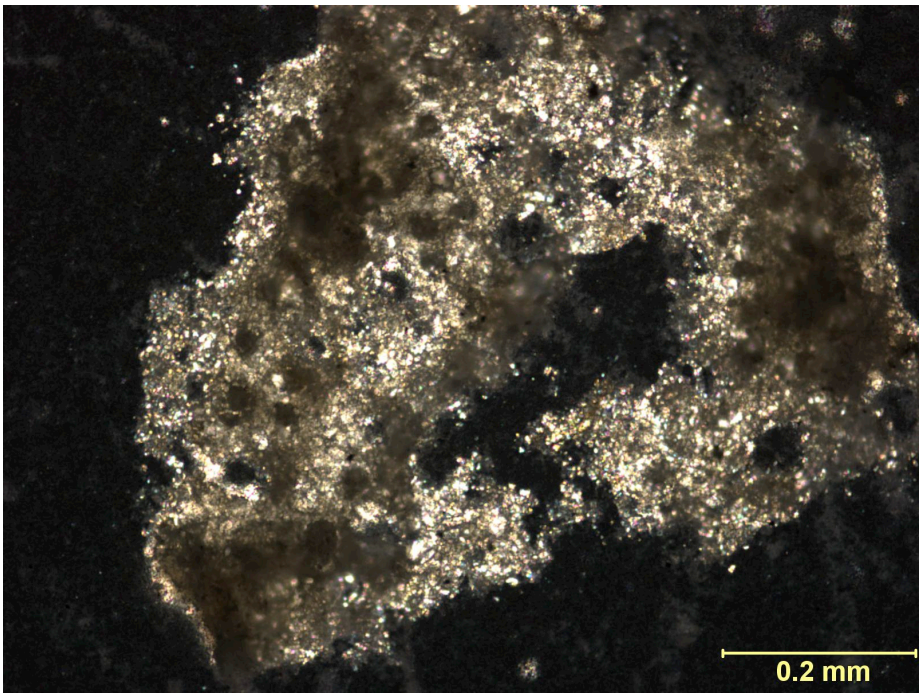


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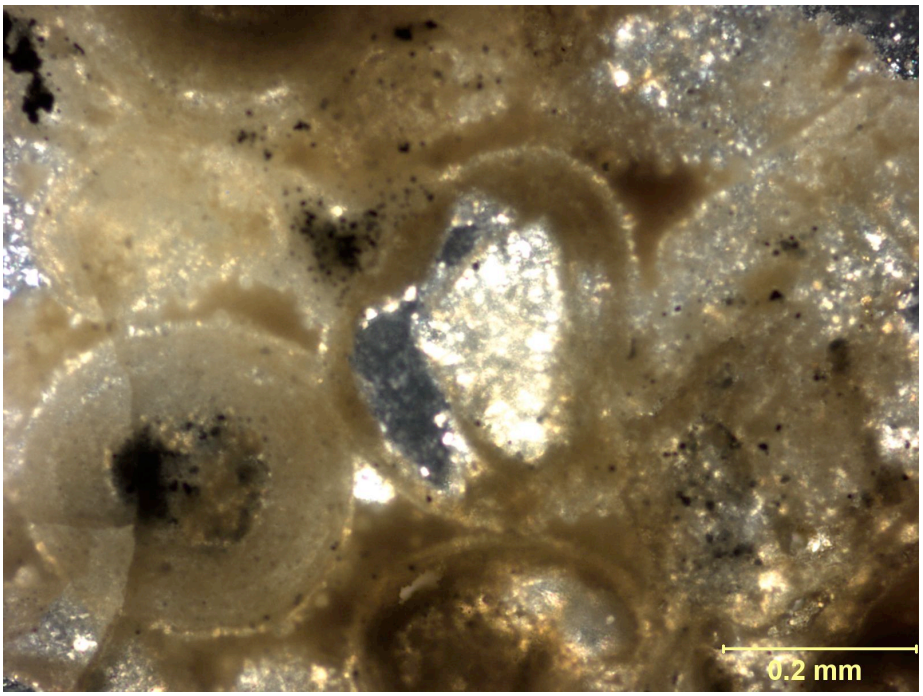


Figure B-17 Thin-section of cutting sample from well 15-135-23993