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Bekki White, Director and State Geologist

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HYDROCARBON POTENTIAL AND RESERVOIR CHARACTERISTICS OF THE ARBUCKLE-KNOX AND ELVINS GROUPS IN NORTHEASTERN ARKANSAS

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Hydrocarbon Potential and Reservoir Characteristics of the Arbuckle-Knox and Elvins Groups in Northeast Arkansas

Peng Li, Christopher Marlow, Marc Charette, and Ciara Mills

INTRODUCTION

Unconventional hydrocarbons have become significant energy resources in the United States since the beginning of the 21st century. Led by new applications of hydraulic fracturing technology and horizontal drilling, development of shale resource systems has had a dramatic impact on the supply of hydrocarbons, especially gas, in North America. In Arkansas, the Fayetteville Shale gas play in the Arkoma Basin has been successfully developed since 2004, with a cumulative gas production of 7.96 Tcf by 2017 (Li, 2018). The annual gas production of the Fayetteville Shale has accounted for more than 90% of total gas production of the state. Another potential unconventional resource in Arkansas is the Lower Smackover Brown Dense (LSBD) Mudstone. Since the first exploration well was drilled in 2009, only nine LSBD wells have been drilled in southern Arkansas. With unfavorably limited amounts of oil extracted and relatively low crude oil prices, oil companies halted their investment in the LSBD and moved to more profitable areas. The Arkansas Geological Survey conducted a comprehensive and integrated geological study on the cores and crude oil of a LSBD well (Session No. 1 well in Union County) to evaluate the reservoir characteristics of the LSBD (Li et al., 2016).

After natural gas was discovered in the Cambrian Conasauga Shale in Alabama in 2005, the time-equivalent Elvins Group and overlying Arbuckle-Knox Group in northeastern Arkansas have attracted increasing attention as a potential unconventional shale gas target. Northeastern Arkansas is situated in the upper Mississippi Embayment area, where geological and geophysical studies of the New Madrid Seismic Zone have revealed the ancient Reelfoot Rift beneath it (Figure 1) (Ervin and McGinnis, 1975; Braile et al., 1986; Van Arsdale, 2014). Failed rift basins have proven to be prime targets for exploration as significant hydrocarbon production occurs in these basins throughout the world (e.g. North Sea rift basin) (Nehring, 1978; Klemme, 1980; Selley, 1998). The purpose of this study is to provide data and information regarding the hydrocarbon potential and unconventional reservoir characteristics of the Elvins and Arbuckle-Knox groups in this area.

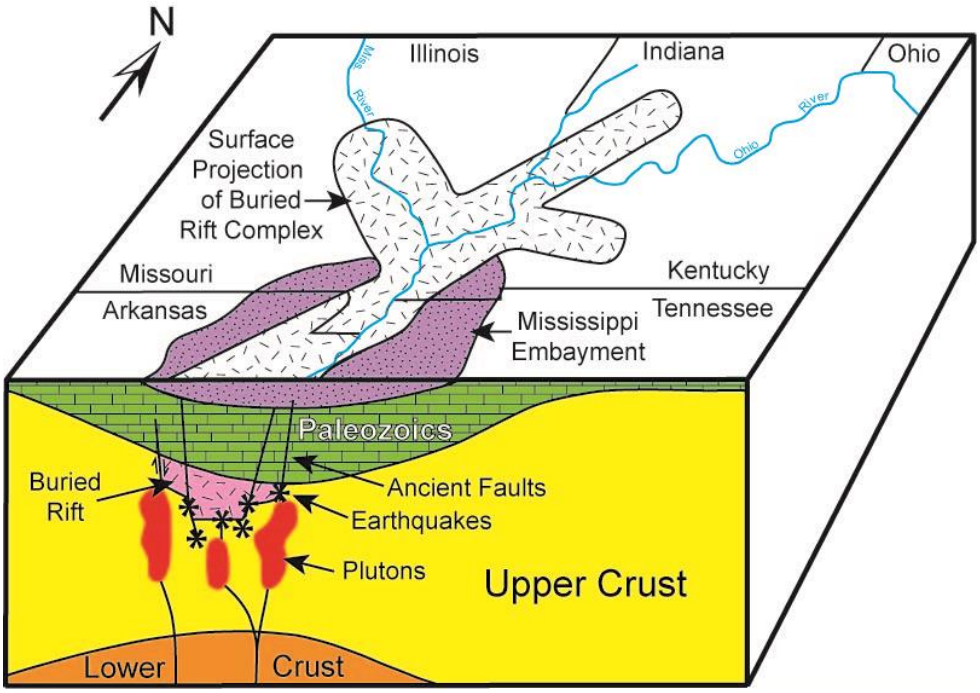

Figure 1. Block Diagram of the Reelfoot Rift. Modified from Braile et al. (1986)

GEOLOGICAL SETTING

The Reelfoot Rift is generally thought to be a late Precambrian to Middle Cambrian failed continental rift which was reactivated during the Cretaceous (Ervin and McGinnis, 1975). It extends from east-central Arkansas to western Kentucky and lies beneath the upper Mississippi Embayment, a trough filled with 1 km of Late Cretaceous and Cenozoic clastic sediments (Figure 1) (Ervin and McGinnis, 1975; Hildenbrand, 1985; Nelson and Zhang, 1991; Dart and Swolfs, 1998; Thomas, 2006; Csontos et al., 2008; Van Arsdale, 2014). The Reelfoot Rift represents one of three failed triple arms that attempted to separate Laurentia during the breakup of Rodinia (Figure 2) (Thomas, 1991; Van Arsdale, 2014).

Active rifting in the Reelfoot area commenced in the latest Precambrian and continued through the Middle Cambrian. During this time, the rift area underwent crustal stretching, extensional faulting, regional subsidence, and subsequent marine transgression (Howe, 1985). Subsidence of the rift along steeply dipping bounding faults resulted in the accumulation of syn-rift sediments of the Lamotte Sandstone (Nelson and Zhang, 1991). Post-rifting Cambrian and Ordovician sedimentary rocks were deposited in a marine environment and include the Bonneterre Formation, Elvins Group, and Arbuckle-Knox Group. Little is known about the original thickness of post-Arbuckle-Knox sediments due to extensive erosion during Late Pennsylvanian-Permian uplift of the northern Reelfoot Rift. Formation of the modern Mississippi Embayment began with subsidence of the Gulf Coastal Plain during breakup of Pangea in the Late Cretaceous (Caplan, 1954).

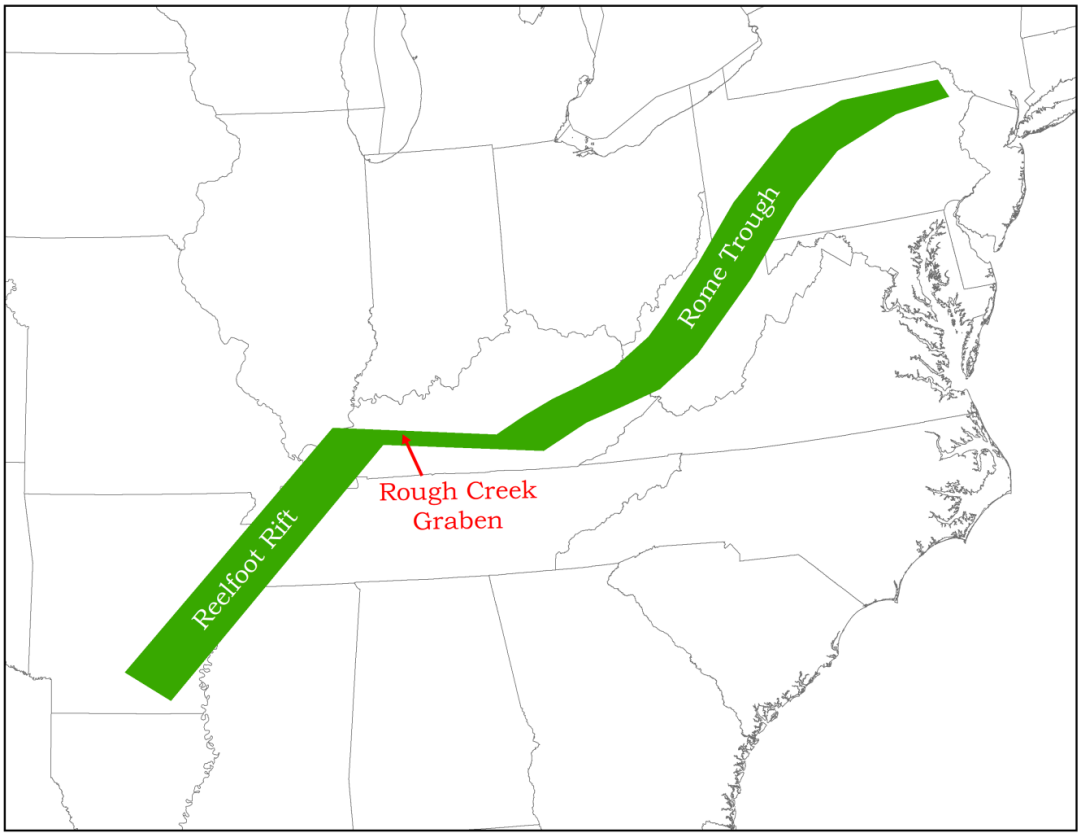

Figure 2. Intracratonic rift systems formed during the breakup of Rodinia

STRATIGRAPHY

A stratigraphic column of the northeastern Arkansas is summarized in Figure 3. The detailed lithologic description of key units is as follows.

Precambrian Crystalline Rocks

The Precambrian crystalline rock consists of granitic gneiss with interspersed dioritic gneiss originally as dikes or sills in the granitic host (Denison, 1984). Potassium/Argon dating gives a radiometric age of 845 ± 42 ma for the latest metamorphic event to affect these Pre-Cambrian gneisses (Howe, 1985).

Erathem	System	Series	Group	Formation
Cenozoic	Quaternary	Holocene		Alluvium
		Pleistocene		Terrace Deposits
				Dune Sand
				Silt and Sand
				Loess
				Sand and Gravel
	Tertiary	Eocene	Jackson	Redfield
				White Bluff
			Clairborne	Cockfield
				Cook Mountain
				Sparta
				Cane River
				Carrizo
			Wilcox	Detonti
				Saline
				Berger
		Paleocence	Midway	Porters Creek
				Clayton
Mesozoic	Cretaceous	Gulf	Navarro	Arkadelphia
				Nacatoch
			Taylor	Saratoga
				Marlbrook
				Annona
				Ozan
			Austin	Brownstown
				Tokio
Paleozoic	Carboniferous	Pennsylvanian		Atoka
				Bloyd
				Hale
		Mississippian		Pitkin
				Fayetteville
				Batesville
				Moorefield
				Boone
	Devonian			Chattanooga
				Clifty
				Penters
	Silurian			Lafferty
				St. Clair
				Brassfield
				Carson
	Ordovician	Upper		Fernvale
		Middle		Kimmswick
				Plattin
				Joachim
				St. Peter
				Everton
		Lower	Arbuckle-Knox	Powell
				Cotter
				Jefferson City
				Roubidoux
				Van Buren
				Gascondade
				Eminence
				Potosi
	Cambrian	Upper	Elvins	Derby-Doerun
				Davis
				Bonneterre
				Lamotte

Figure 3. Stratigraphic Column of Northeastern Arkansas Modified from Caplan (1954) and Howe (1985)

Lamotte Sandstone

A thick interval of the Upper Cambrian sediments overlies the crystalline basement. Howe (1985) referred to it as the Lamotte Sandstone and divided it into two parts. The lower part of the Lamotte is a red, well-sorted, medium to fine-grained arkosic sandstone. The upper part of the formation is remarkably similar to the lower part except for a gray to off-white color, more abundant carbonate and a more quartzose composition (Denison, 1984). The marked upward gradation from red to gray arkoses may reflect the initial marine transgression and the accompanying change from oxidizing to reducing conditions (Houseknecht, 1989). Weaverling (1987) and Houseknecht (1989) reported the presence of strata (Reelfoot Arkose and St. Francis Formation) older than the Lamotte Sandstone in the Reelfoot Rift basin. They designated this arkosic interval as the Reelfoot Arkose. McKeown et al. (1990) and Leach et al. (1997) used a more descriptive term, basal clastic rocks, for this interval.

Bonneterre Formation

The Bonneterre Formation signifies widespread marine conditions throughout the southern midcontinent region resulting from Cambrian sea level rise (Houseknecht, 1989). In northeastern Arkansas, the lower half of the formation consists of oolitic, dolomitized, carbonate sands, and the upper half contains shales and micritic limestones (Howe, 1985).

Elvins Group

The Elvins Group in the Reelfoot Rift basin is primarily composed of limestone and dolomite (Kurtz, 1989). It is divided into the Davis Formation and Derby-Doerun Dolomite. On the eastern Missouri platform, the Davis Formation consists of dark-green to dark-gray and locally black shale (Palmer, 1989). The Derby-Doerun is generally finely crystalline, argillaceous dolomite which in part is also cherty, sandy, silty, and fossiliferous (Caplan, 1960). Elvins Group shales suggest low-energy, basinal marine environments of deposition (Howe, 1985).

Arbuckle-Knox Group

The Upper Cambrian-Lower Ordovician Arbuckle-Knox Group of the Reelfoot area is a thick carbonate sequence composed predominately of limestone, marl, and dolomite with subordinate amounts of sandstone, shale, and chert, suggesting a long period of widespread shallow marine deposition (Howe, 1985). It consists of the Potosi, Eminence, Gascondade, Van Buren, Roubidoux, Jefferson City, Cotter, and Powell formations. The thickness of this group within the Reelfoot Rift basin ranges from 5,000 to 8,000 feet. In the Dow Chemical #1 Wilson well it reaches about 7,600 feet thick.

Middle Ordovician–Late Paleozoic Strata

Little is known about the original thickness of post-Arbuckle-Knox sediments in much of the Reelfoot area due to extensive erosion during Late Pennsylvanian-Permian uplift. Schwalb (1982) estimated that at least 1.7 miles of post-Arbuckle-Knox through Pennsylvanian sediments accumulated in the northern Reelfoot Rift. West of the Reelfoot Rift boundary in northeastern Arkansas, these eroded strata are present.

Upper Cretaceous–Quaternary Strata

Formation of the modern Mississippi Embayment began with subsidence of the Gulf Coastal Plain in the Late Cretaceous (Caplan, 1954). In the upper Mississippi Embayment in northeastern Arkansas, the relatively unconsolidated Coastal Plain sediments of Late Cretaceous through

Quaternary age unconformably overlie the Arbuckle-Knox Group. In the Dow Chemical #1 Wilson well, these undifferentiated intervals are approximately 2,900 feet thick.

No Permian, Triassic, Jurassic or Lower Cretaceous (Comanchean) sediments have been found in the area covered by this report.

SAMPLES AND METHODS

Core and cutting samples were collected from five wells located in the Reelfoot Rift of northeastern Arkansas (Figure 4). A structural cross section of these wells was made to show the stratigraphic tops of basal crystalline rocks and overlying sedimentary strata (Figure 5). The well location information is listed in Table 1. The Dow Chemical #1 Garrigan well contains both core and cutting samples and the other four wells only have cuttings.

Organic geochemical analysis was conducted on 786 samples (81 cores and 705 cuttings) from five wells to evaluate the source rock characteristics. Leco total organic carbon (TOC) was measured to assess the organic matter richness. Rock-Eval pyrolysis was then conducted on 26 samples (2 cores and 24 cuttings) which had a TOC value greater than a minimum of 1.0%. Visual kerogen analysis was performed on 11 samples (4 cores and 7 cuttings) to determine the organic matter type and thermal maturity.

Integrated digital rock analysis with Ingrain Services provides a quantitative understanding of the rock properties and intricate pore networks of fine-grained strata. A series of parameters are measured and calculated on 35 core plugs from the Dow Chemical #1 Garrigan well for the analysis. Bulk density is measured by the density logging tool and aids in identification of lithology, hydrocarbon density, gas-bearing zones, and evaporate minerals (Asquith and Krygowski, 2004). It can also indicate organic matter content and porosity. Photoelectric effect factor (PEF) is a measure of rock matrix properties, which is only very slightly dependent on porosity. X-ray fluorescence (XRF) analysis determines the bulk elemental weight percent of samples. The elemental data was normalized to the content of three minerals: silica, clay, and carbonate. Pseudo gamma ray values were also calculated from XRF. As uranium is primarily associated with organic material, the pseudo gamma ray values without uranium (only thorium and potassium) were used to estimate the clay content. Fourier transform infrared spectroscopy (FTIR) provides quantitative interpretation of broad mineral groups, such as silica, clay, and carbonate in this study. It also generates TOC measurements that complement and support the Leco TOC studies. Brittleness index (BI) is a term used to describe the relative tendency of a rock formation to fracture as opposed to deforming gradually in response to tensile or shear stress (Rickman et al., 2008). In this study, the definition proposed by Rickman et al. (2018) was used, in which BI depends upon static Young's modulus and Poisson's ratio with an additional assumption that the relevant moduli and Poisson's ratio can be taken from normalized solid mineral properties. In practical terms, greater BI means the rock is easier to hydraulically fracture.

ZoneID^{TM} analysis with Ingrain Services was performed on 5 core plugs in the Dow Chemical #1 Garrigan well to understand the pore system. Locations of 2D scanning electron microscope

(SEM) were selected on the basis of the results of XRF. After precise ion polishing, approximately 5-10 locations per sample were analyzed with a Carl Zeiss SEM system that employs simultaneous energy selective backscatter electron and secondary electron detectors at resolution of approximately 10nm/pixel. Resulting images were then processed to determine the abundance of total porosity, organic matter, porosity in organic matter, and high density minerals.

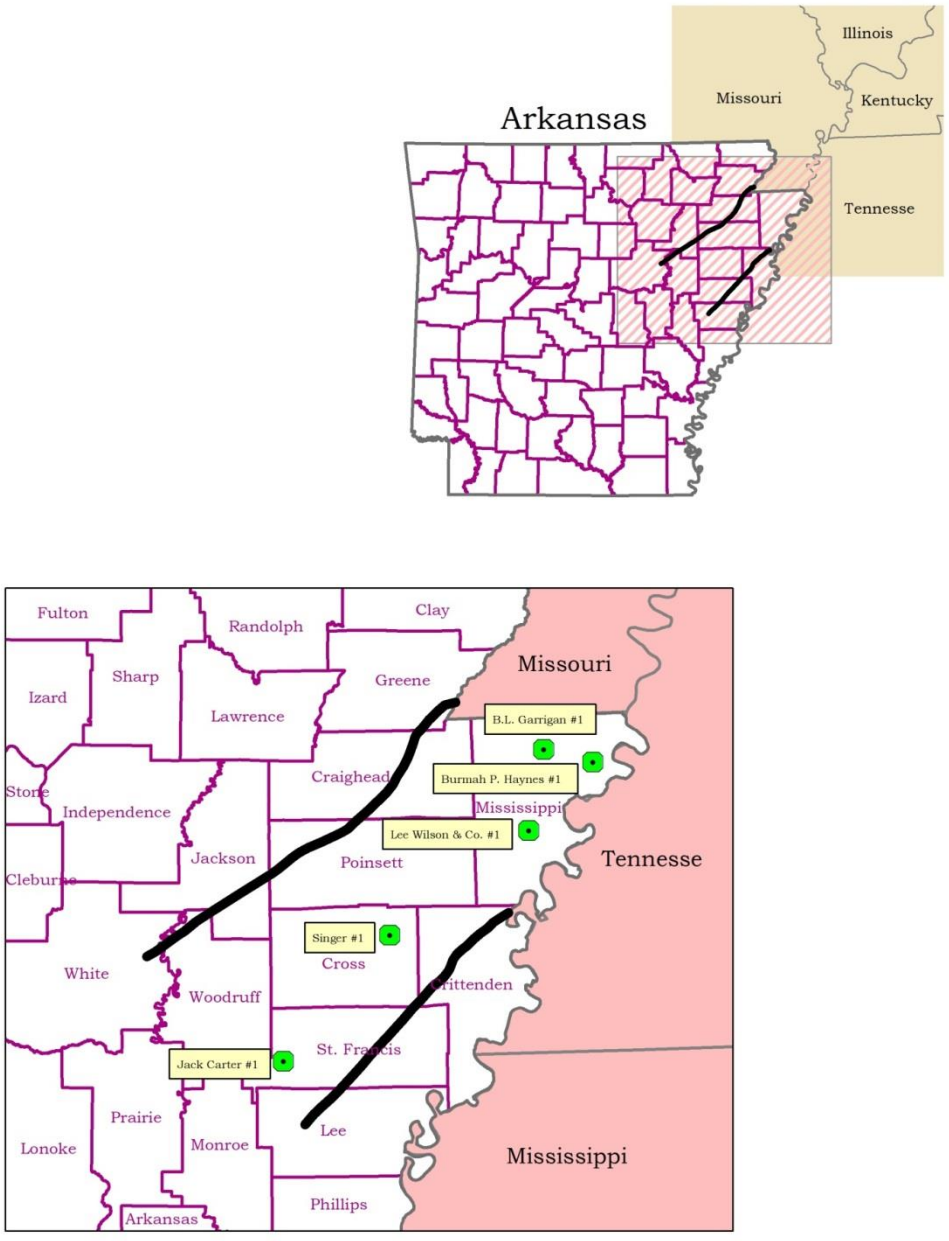

Figure 4. Location Map of Sampling Wells. Reelfoot Rift Boundaries are NE–SW Trending Black Lines

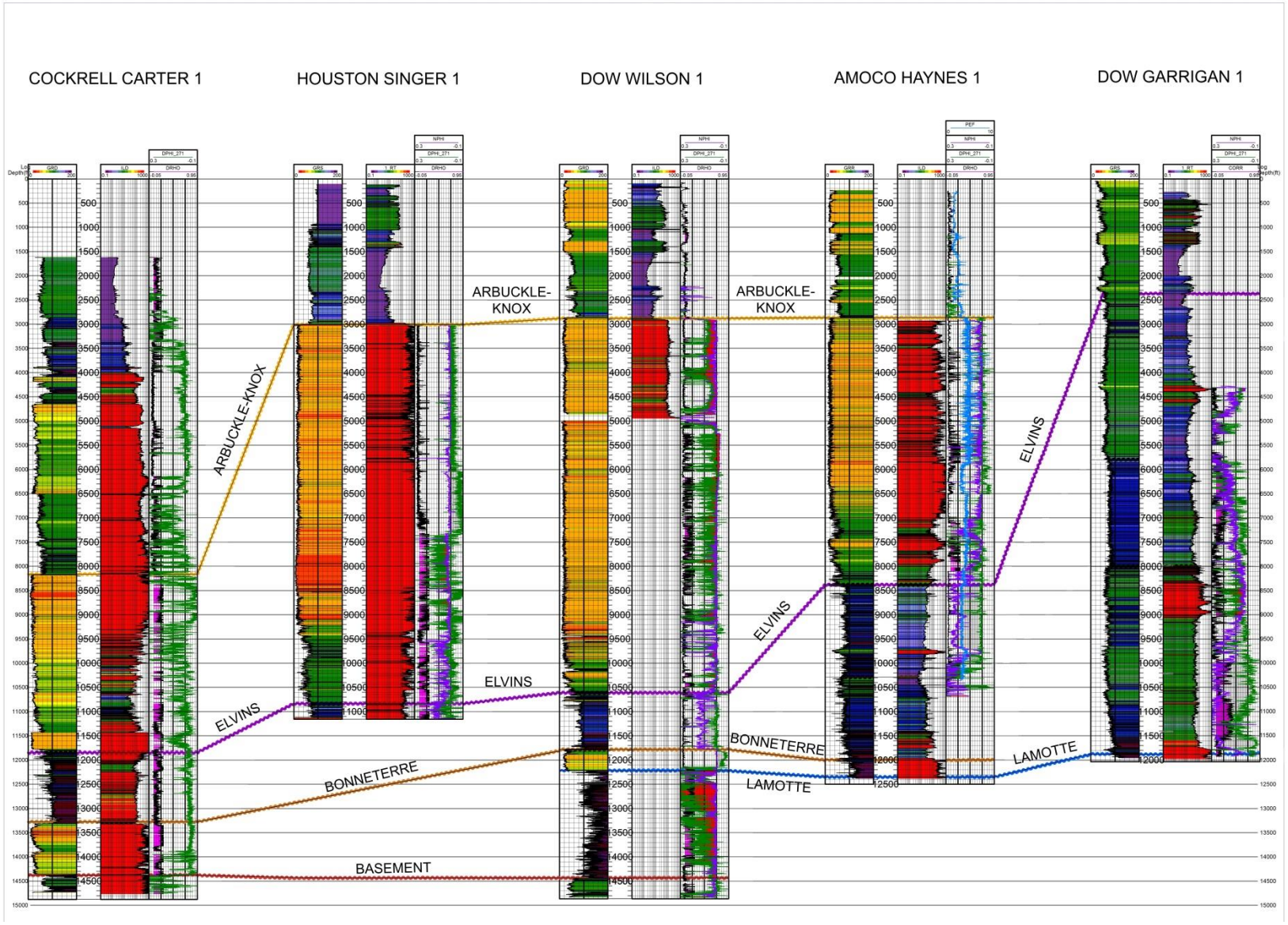

Figure 5. Cross Section of the Sampling Wells

Table 1. Well Location Information

Well Name	Operator	API	Location Sec.-Twp.-Rge.	County	TD (ft)
Jack Carter #1	Cockrell Corp.	03-123-10001-0000	4-4N-1E	St. Francis	14,881
Singer #1	Houston Oil & Minerals Corp.	03-037-10002-0000	36-9N-4E	Cross	11,158
Lee Wilson & Co. #1	Dow Chemical Co.	03-093-10001-0000	14-12N-9E	Mississippi	14,868
Burmah P. Haynes #1	Amoco Production Co.	03-093-10004-0000	6-14N-12E	Mississippi	12,500
B.L. Garrigan # 1	Dow Chemical Co.	03-093-10002-0000	28-15N-10E	Mississippi	12,038

RESULTS AND DISCUSSION

Source Rock Characteristics

TOC

The Dow Chemical #1 Garrigan well penetrated approximately 9,500 feet of the Elvins Group. It includes shaly intervals at the base totaling about 2,500 feet that average TOC values of 0.85 % in cuttings and 0.58% in core chips, with some shale as high as 3.95% TOC (Figure 6). The cutting samples of the Elvins Group in the Dow Chemical #1 Wilson well have TOC values of 0.08-0.26%, with an average measured TOC of 0.16% indicating that no beds in the group contain sufficient organic matter (Figure 7). The Houston #1 Singer well encountered approximately 8,000 feet of the Arbuckle-Knox Group. Arbuckle-Knox carbonate beds in this well apparently have very poor source rock potential as was indicated by an extremely low average TOC value of 0.06% (Figure 8). TOC values were measured for both Arbuckle-Knox and Elvins beds in the Amoco #1 Haynes well (Figure 9). The samples from the Arbuckle-Knox average 0.10% of TOC. TOC values of the Elvins have a range of 0.02-0.78% with an average of 0.33%. The Cockrell #1 Carter well came into approximately 1,500 feet of the Elvins Group. TOC values of the Elvins range between 0.02% and 0.24% with an average TOC of 0.09% (Figure 10). Overall, Elvins shale and siltstone beds are more organic-rich than the Arbuckle-Knox limestone and dolomite beds and prone to be a probable source rock in northeastern Arkansas.

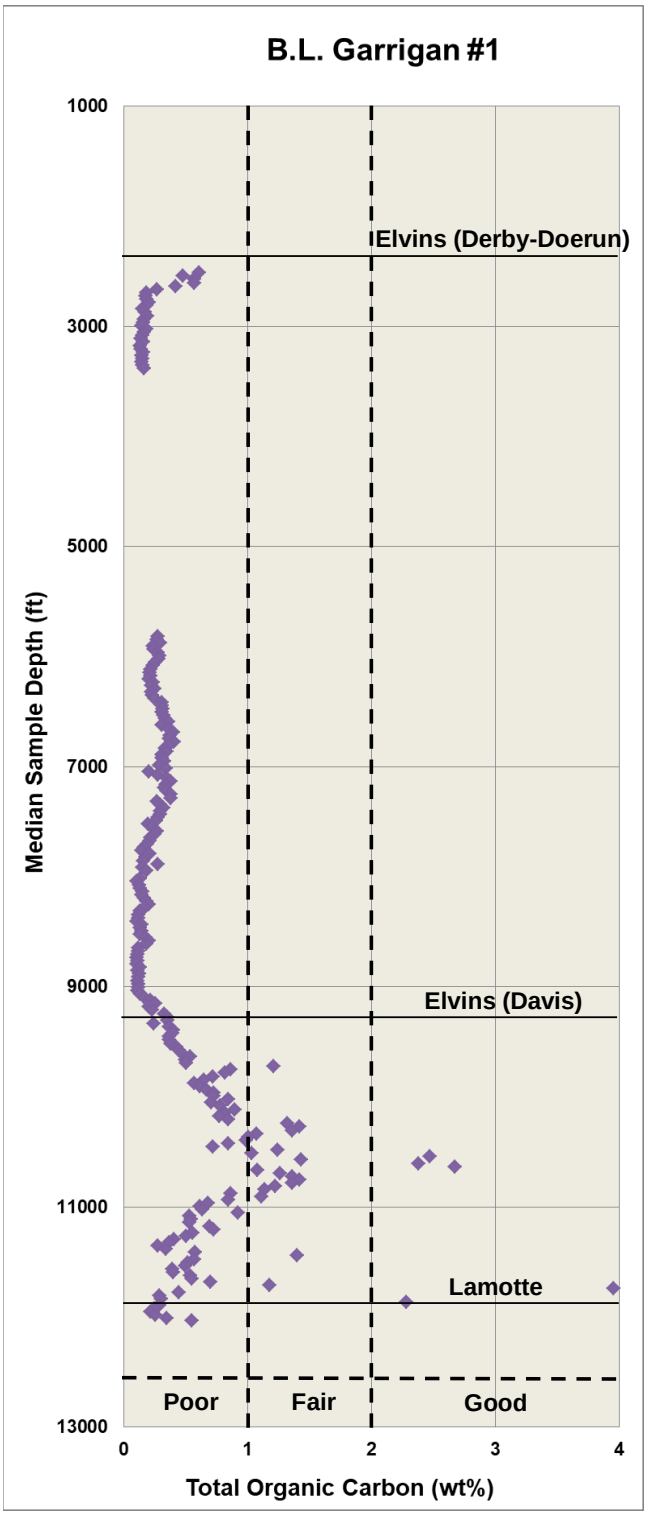

Figure 6. TOC Values of the Dow Chemical #1 Garrigan Well

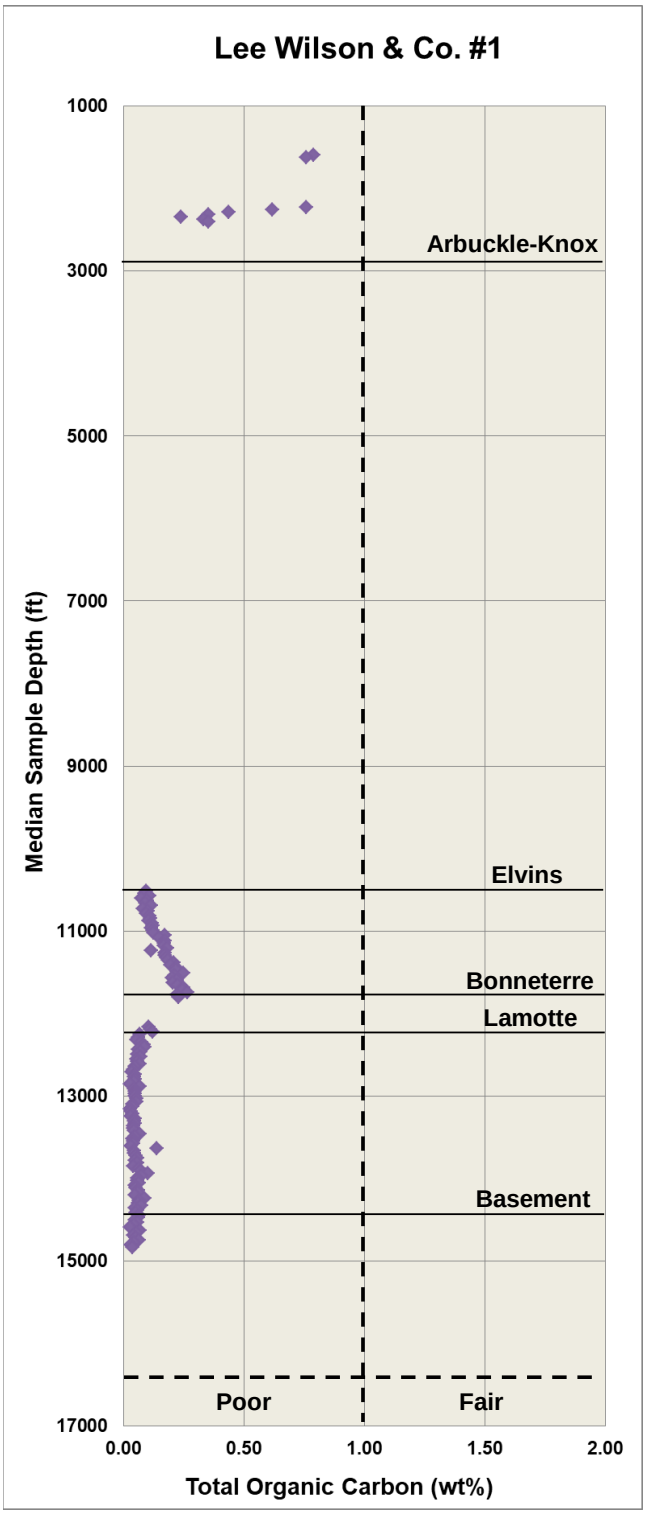

Figure 7. TOC Values of the Dow Chemical #1 Wilson Well

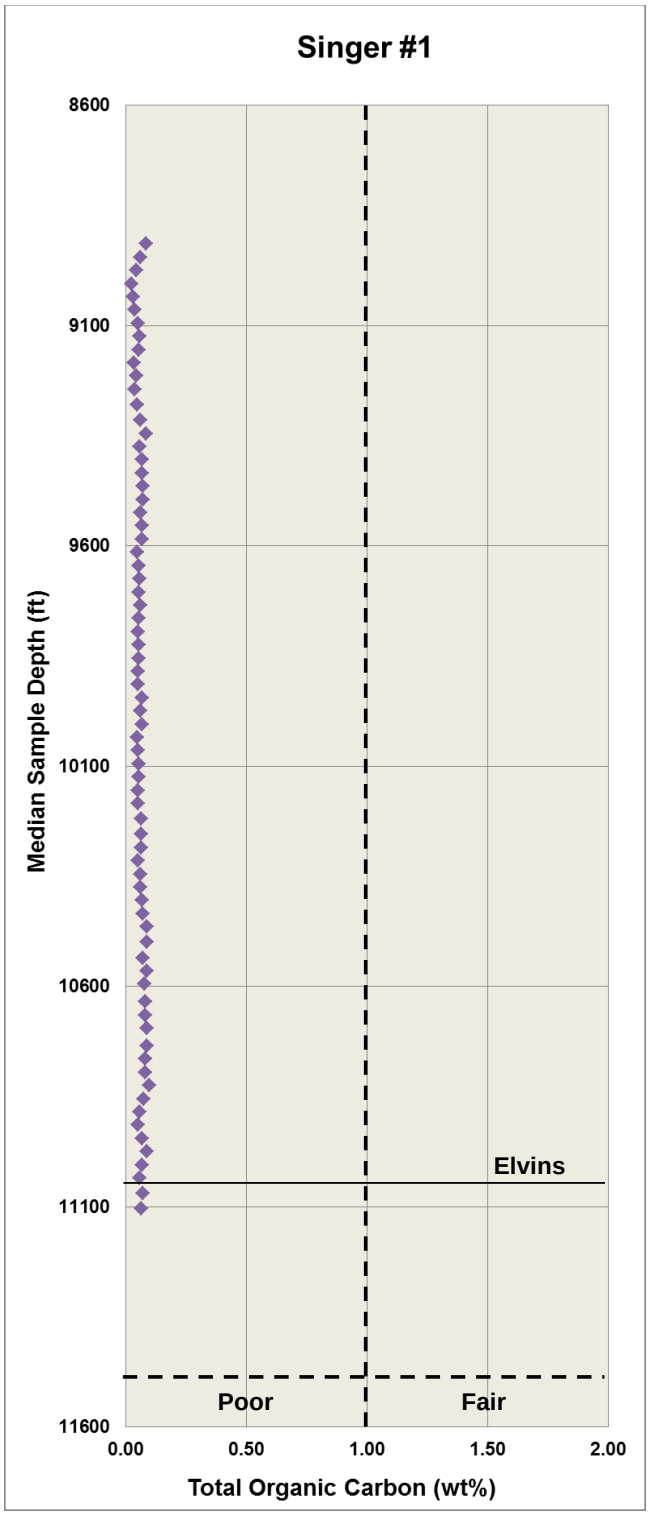

Figure 8. TOC Values of the Houston #1 Singer Well

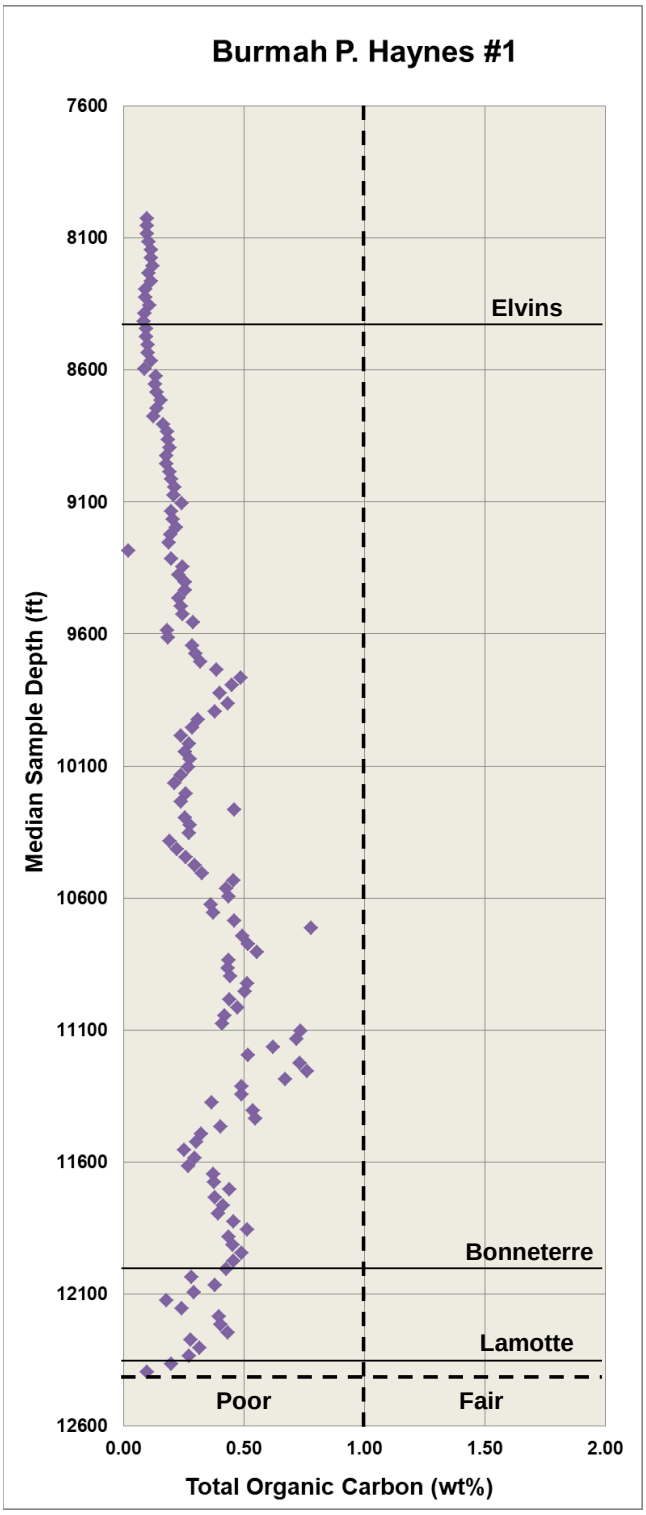

Figure 9. TOC values of the Amoco #1 Haynes Well

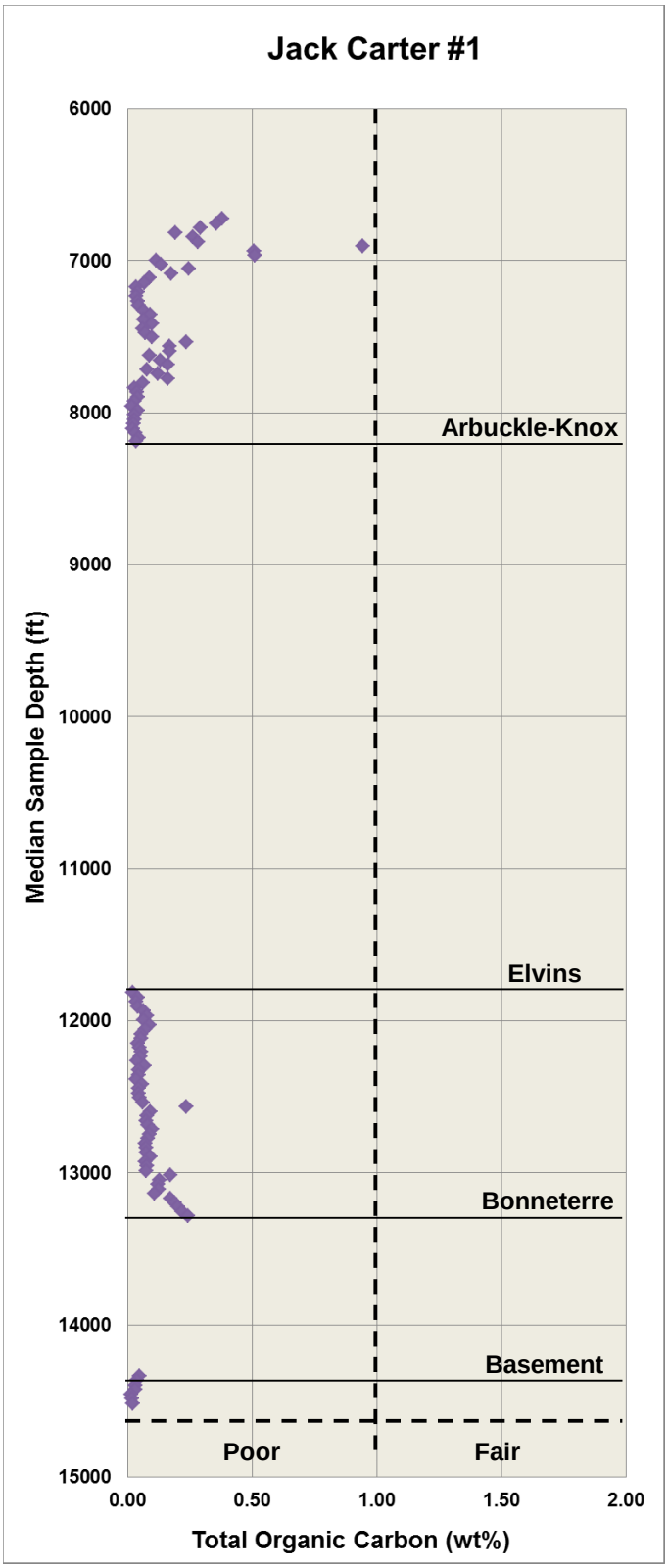

Figure 10. TOC Values of the Cockrell #1 Carter Well

Visual Kerogen Analysis

Visual kerogen analysis was conducted on 11 organic-rich, calcareous shale samples from the Elvins Group of the Dow Chemical #1 Garrigan well (Table 2). The kerogen composition consists mostly of amorphous organic matter (AOM) with minor solid hydrocarbon and detrital inertinite, which characterizes Type II kerogen. Ro values were measured from 7 samples with occurrence of representative vitrinite. Measured Ro ranges from 3.95% at the depth of 7986.3 feet to 4.10% at 10,226.4 feet. While Ro has become a common practice in determining the thermal maturity of post-Silurian rocks, the absence of terrestrial plants in pre-Silurian formations requires reflectance measurements of solid hydrocarbons, such as bitumen. Many correlations have been made in an attempt to equate bitumen reflectance values (BRo) to Ro values. The correlation by Landis and Castaño (1994) was used in this report. BRo values from 9 samples range from 3.95% at 9,080 feet to 4.54% at 11,407.4 feet, which is equivalent to a Ro range of 4.00–4.54%. Maturity values suggest that samples in the Elvins Group have reached post-mature stage.

Rock-Eval Pyrolysis

Rock-Eval pyrolysis was performed on the samples with TOC values in excess of 1.0%, which are considered to have adequate source potential (Table 3). All these samples came from the Elvins Group of the Dow Chemical #1 Garrigan well. The organic-rich intervals account for approximately 10% thickness of the Elvins in the well.

S_2 represents the present-day petroleum generation potential of the samples. Values of 2.00-5.00 mg/g indicate fair source potential and values greater than 5.00 mg/g are indicative of good source potential (Espitalié, 1982), although these values are diminished with increasing thermal maturity. S_2 shows high variability within the samples, ranging from a low value of 0.34 mg/g to a high of 26.05 mg/g. The average S_2 value is 4.25 mg/g. Overall, the organic-rich samples are interpreted as having good to excellent petroleum generation potential.

The hydrogen index (HI) is the normalized hydrogen content of a sample. Therefore, kerogen type can be derived from this value. HI values of the samples vary widely from 31 to 659 mg/g TOC, with an average of 208 mg/g TOC. All organic-rich values (350–700 mg/g) indicate Type II, oil prone kerogen (usually marine) (Jones, 1984). The lower HI values (<350 mg/g TOC) are indicative of mixed (Type II/III) or Type III kerogen. Like S_2, HI decreases as the sample matures. Thus, the low average HI value is interpreted to be the outcome of post-mature level of thermal maturity.

S_2/S_3 ratio reflects the ratio of hydrogen to oxygen, which is similar to HI divided by oxygen index. It is utilized as an indication of kerogen type (Clementz, 1979). The sampled intervals have an average S_2/S_3 of 10.42, which points to Type I or II oil prone kerogen types.

Table 2. Visual Kerogen Analysis Data of the Elvins Group in the Dow Chemical #1 Garrigan Well

Depth (ft)	Sample Type	% Kerogen Facies Assemblage							Measured Vitrinite Ro (%)	Solid Hydrocarbons	
		Recycled & Oxidized Kerogen	Graptolite	Inertinite	Detrital Inertinite	Amorphous Organic Matter (AOM)	Primary Liptinites (Marine)	Solid HC/Bitumen		Measured Solid HC Ro (%)	Equivalent Vitrinite Ro (%)
7986.3	core	nd	tr	nd	5	87	5	3	3.95	-	-
8975	cuttings	nd	tr	nd	5	95	tr	tr	4.06	-	-
9035	cuttings	nd	tr	nd	3	95	tr	2	-	3.96	4.01
9095	cuttings	nd	tr	nd	5	90	tr	5	4.06	3.95	4.00
10226.4	core	nd	tr	nd	5	90	tr	5	4.10	4.17	4.20
10229.0	core	nd	tr	nd	5	87	5	3	4.09	4.18	4.21
10545	cuttings	nd	tr	nd	10	80	tr	10	-	4.16	4.20
10575	cuttings	nd	tr	nd	5	90	tr	5	3.99	4.30	4.32
10605	cuttings	nd	tr	nd	5	80	5	10	-	4.19	4.22
10635	cuttings	nd	tr	nd	5	85	5	5	4.06	4.34	4.35
11407.4	core	nd	tr	nd	5	87	5	3	-	4.54	4.54

nd: not detected; tr: trace; HC: hydrocarbon.

T_{max} is the temperature of maximum rate of evolution of S_2 hydrocarbons, which is a chemical indicator of thermal maturity (Espitalié et al., 1977, 1985). T_{max} also varies depending upon the kerogen type. Using the average S_2/S_3 and HI values, the T_{max} interpretation can be narrowed into the Type II kerogen category. T_{max} values in the samples range from 428 to 437°C with an average of 432 °C. Calculated vitrinite reflectance (R_o) is derived from the measured T_{max} using the conversion formula of Jarvie et al. (2001). The samples have a calculated R_o value range of 0.54–0.71% with an average of 0.61%. Both T_{max} and calculated R_o ranges are indicative of the oil generation phase for Type II kerogens, which is inconsistent with the result of the visual kerogen analysis. T_{max} may be affected by the presence of heavy, free hydrocarbons in the S_2 peak which may cause the T_{max} value to be anomalously low. The S_1 values in the samples average 0.28 mg/g (Table 2). These low values imply that some of the free hydrocarbons are too heavy to be thermally extractable in S_1 peak and therefore carried over into the S_2 peak.

Table 3. Rock-Eval Pyrolysis Data of the Elvins Group in the Dow Chemical #1 Garrigan Well

Depth (ft)	Sample Type	Leco TOC (wt.%)	Rock-Eval S_1 (mg/g)	Rock-Eval S_2 (mg/g)	Rock-Eval S_3 (mg/g)	T_{max} (°C)	Calculated Ro (%)	HI	OI	S_2/S_3	S_1/TOC x 100	PI
9,725	Cuttings	1.21	0.12	3.72	0.21	437	0.71	307	17	18	10	0.03
10,245	Cuttings	1.32	0.18	2.27	0.3	432	0.62	172	23	8	14	0.07
10,275	Cuttings	1.42	0.17	1.6	0.26	432	0.62	113	18	6	12	0.1
10,305	Cuttings	1.36	0.14	0.85	0.26	431	0.6	63	19	3	10	0.14
10,335	Cuttings	1.07	0.13	0.43	0.27	432	0.62	40	25	2	12	0.23
10,365	Cuttings	1.01	0.1	0.43	0.27	431	0.6	43	27	2	10	0.19
10,485	Cuttings	1.24	0.15	2.15	0.31	431	0.6	173	25	7	12	0.07
10,515	Cuttings	1.03	0.08	0.34	0.31	433	0.63	33	30	1	8	0.19
10,545	Cuttings	2.47	0.24	11.46	0.5	428	0.54	464	20	23	10	0.02
10,575	Cuttings	1.43	0.14	3.47	0.33	432	0.62	243	23	11	10	0.04
10,605	Cuttings	2.38	0.2	7.43	0.48	431	0.6	312	20	15	8	0.03
10,635	Cuttings	2.67	0.15	10.67	0.54	430	0.58	400	20	20	6	0.01
10,665	Cuttings	1.08	0.14	0.34	0.18	429	0.56	31	17	2	13	0.29
10,695	Cuttings	1.26	0.1	1.14	0.36	435	0.67	90	29	3	8	0.08
10,725	Cuttings	1.36	0.14	1.2	0.37	433	0.63	88	27	3	10	0.1
10,755	Cuttings	1.42	0.13	1.29	0.35	433	0.63	91	25	4	9	0.09
10,785	Cuttings	1.36	0.14	1.41	0.4	432	0.62	104	29	4	10	0.09
10,815	Cuttings	1.22	0.09	1.1	0.33	433	0.63	90	27	3	7	0.08
10,845	Cuttings	1.14	0.14	1.69	0.38	431	0.6	148	33	4	12	0.08
10,905	Cuttings	1.11	0.14	1.55	0.4	433	0.63	140	36	4	13	0.08
11,445	Cuttings	1.4	0.88	4.78	0.48	430	0.58	341	34	10	63	0.16
11,715	Cuttings	1.18	0.2	3.17	0.4	431	0.6	269	34	8	17	0.06
11,745	Cuttings	3.95	1.4	26.05	0.56	429	0.56	659	14	47	35	0.05
11,865	Cuttings	2.28	1.35	13.36	0.32	430	0.58	586	14	42	59	0.09

S_1 - volatile hydrocarbon (HC) content
S_2 - remaining HC generative potential
S_3 - carbon dioxide content
HI - hydrogen index = S_2 x 100 / TOC, mg HC/g TOC
OI - oxygen index = S_3 x 100 / TOC, mg HC/g TOC
PI - production index = S_1 / (S_1 + S_2), mg HC/g TOC

Digital Rock Analysis

Bulk Density and PEF

The mean bulk density and PEF values of the samples in the Elvins Group of the Dow Chemical #1 Garrigan well are 2.725 g/cm3 and 3.277 b/elec, respectively (Figure 11). Compared with the reference values for average shale (2.650 g/cm3 and 3.420 b/elec) and calcite (2.710 g/cm3 and 5.084 b/elec), the measured values suggest that samples are composed principally of shale and limestone. Dolomite and heavy minerals contribute to higher mean bulk density of the samples than that of calcite.

XRF

The normalized average concentrations of 10 major elements were measured from XRF analysis for samples in the Elvins Group of the Dow Chemical #1 Garrigan well (Figure 12). The primary elements in the samples are Si, Ca, and Al. The bulk mineralogy of the samples was deduced from these major element abundances, indicating 50% clay, 26% silica, and 24% carbonate contents on average (Figure 13). Pseudo gamma ray without uranium value, an indicator of clay content, varies from 28 to 106 API. The correlation between the pseudo gamma ray and clay content through the samples appears to be poor (Figure 14).

FTIR

The FTIR results indicated that the normalized mineralogical composition of the Elvins Group in the Dow Chemical #1 Garrigan well consists of 37% silica, 37% clay, and 27% carbonate on average (Figure 15). TOC values calculated from FTIR are up to 1.36% with an average of 0.78%, which are fairly consistent with the measured TOC values.

Brittleness Index

The average brittleness index for the Elvins Group samples in the Dow Chemical #1 Garrigan well is very high with a range from 66 to 84 (Figure 16). This indicates that the samples have a strong tendency to fracture.

ZoneID™ Analysis

2D SEM images taken for the Elvins Group samples in the Dow Chemical #1 Garrigan well were analyzed to calculate the total porosity, organic matter volume, and porosity in organic matter (Table 4). The total porosity has a range between 0.17% and 0.47%. Organic matter volume varies from 0.73% to 2.46%. Porosity in organic matter is not a predominant type of total porosity development in the potential source rock samples.

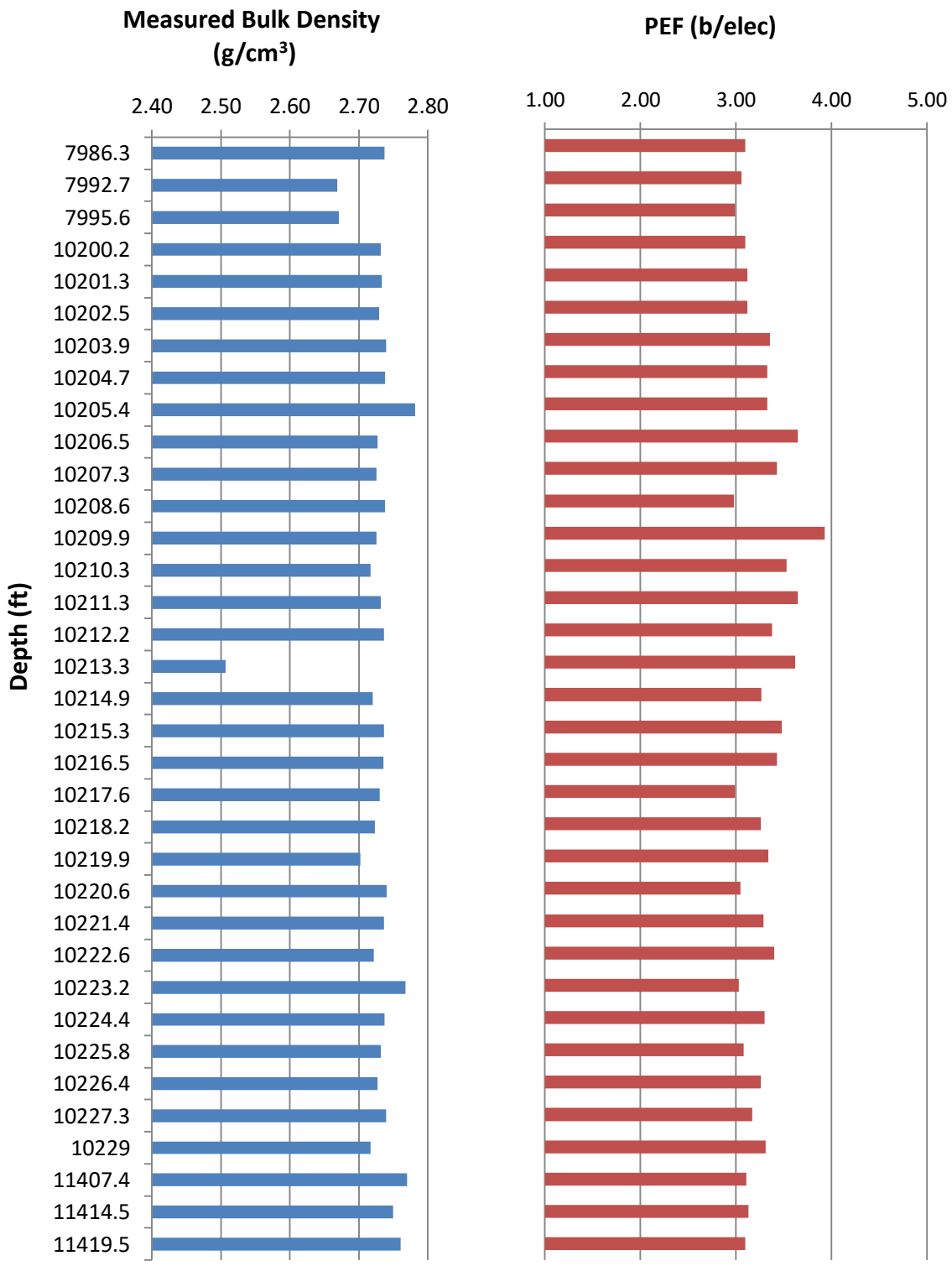

Figure 11. Measured Bulk Density and PEF Values of the Elvins Group in the Dow Chemical #1 Garrigan Well

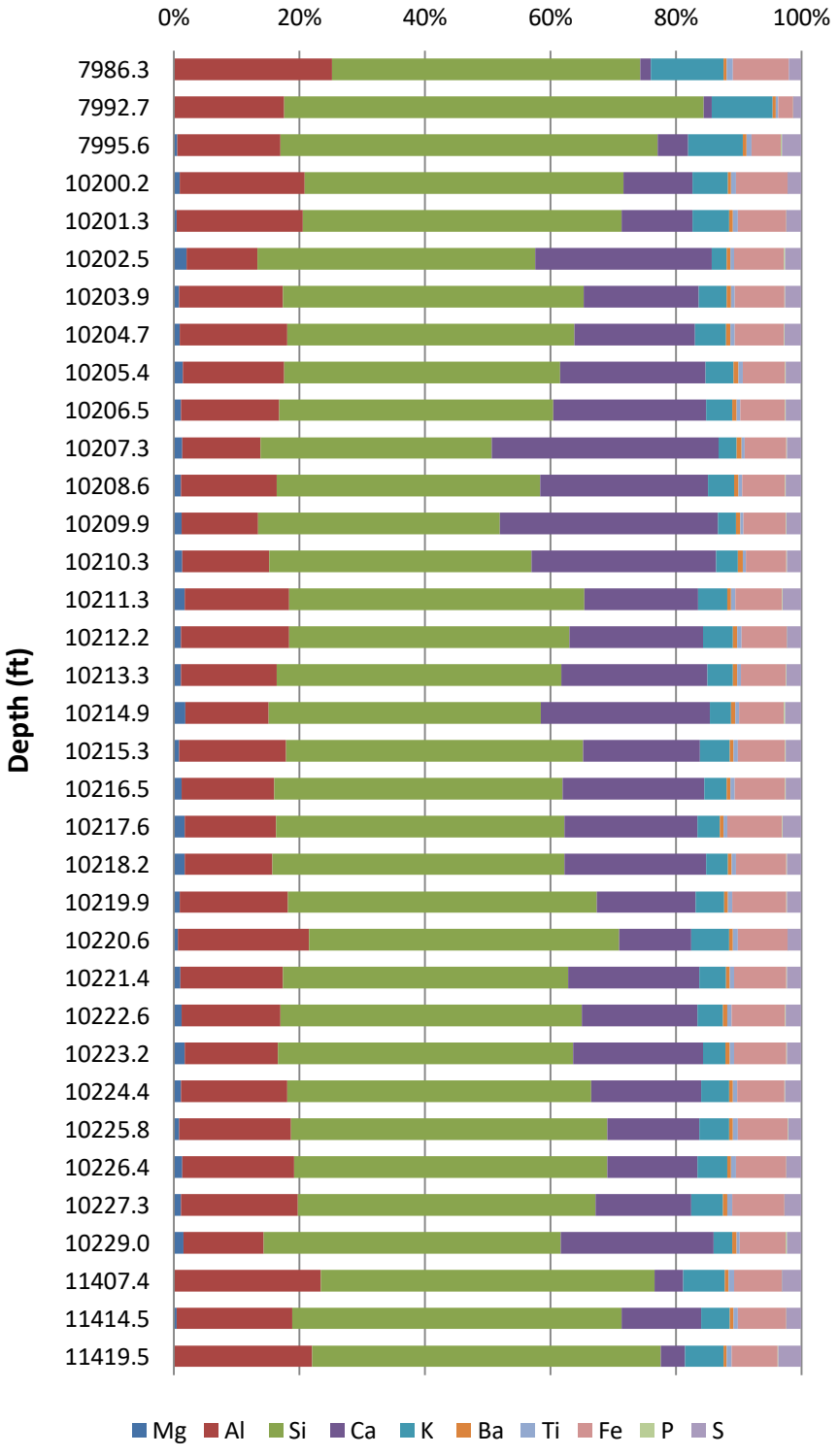

Figure 12. Elemental Data of the Elvins Group in the Dow Chemical #1 Garrigan Well from XRF

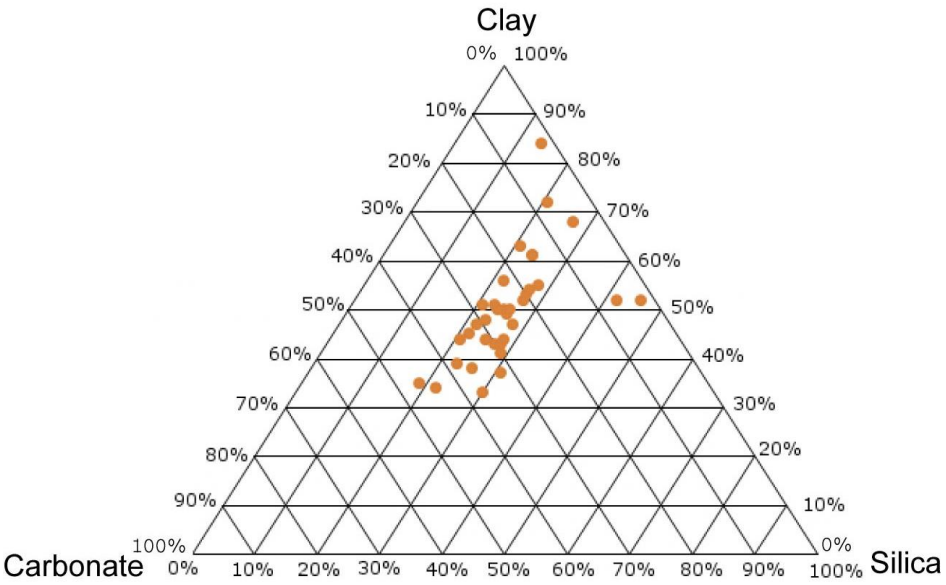

Figure 13. Mineralogical Composition of the Elvins Group in the Dow Chemical #1 Garrigan Well from XRF

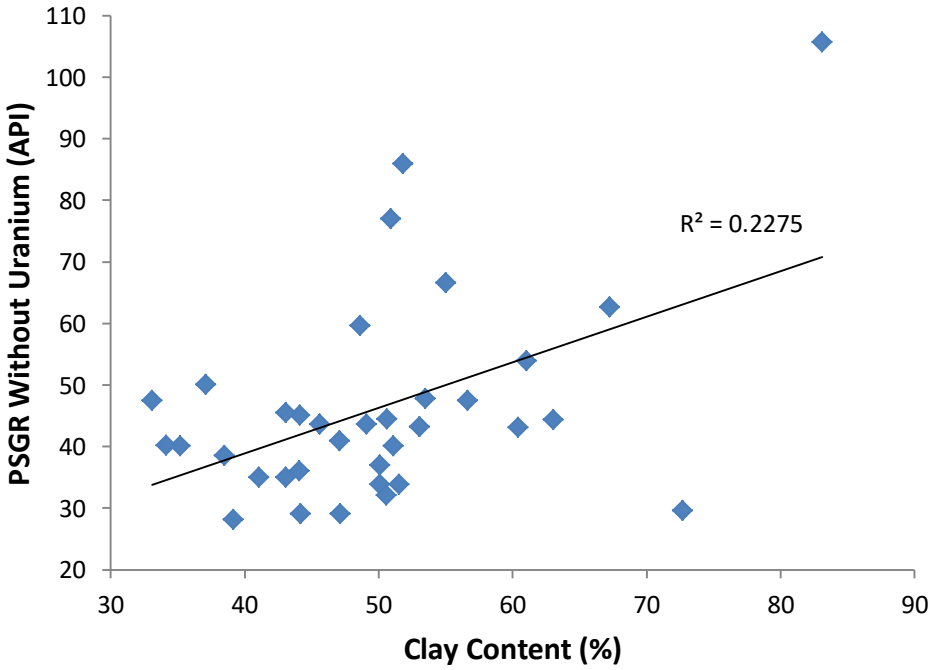

Figure 14. Correlation between Pseudo Gamma Ray without Uranium and Clay Content from XRF

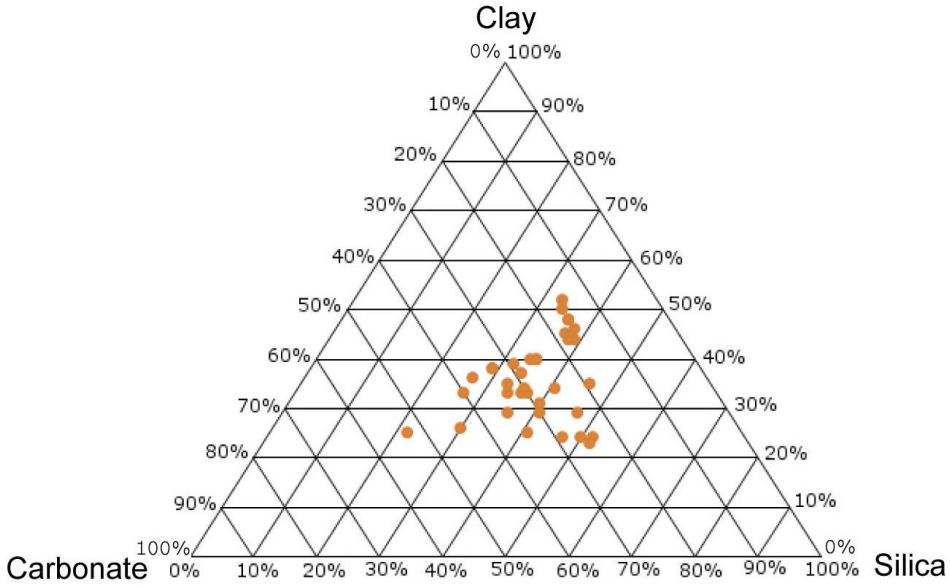

Figure 15. Mineralogical Composition of the Elvins Group in the Dow Chemical #1 Garrigan Well from FTIR

Table 4. Total Porosity and Organic Porosity Calculated from 2D SEM Images

Depth (ft)	Sample Type	Porosity (%)	Organic Matter (%)	Porosity in Organic (%)	High Density Material (%)
7986.3	Core	0.47	0.75	0	1.16
10204.7	Core	0.21	2.01	0.03	1.68
10215.3	Core	0.17	2.46	0.05	0.71
10226.4	Core	0.22	1.60	0.02	1.82
11407.4	Core	0.25	0.73	0	2.79

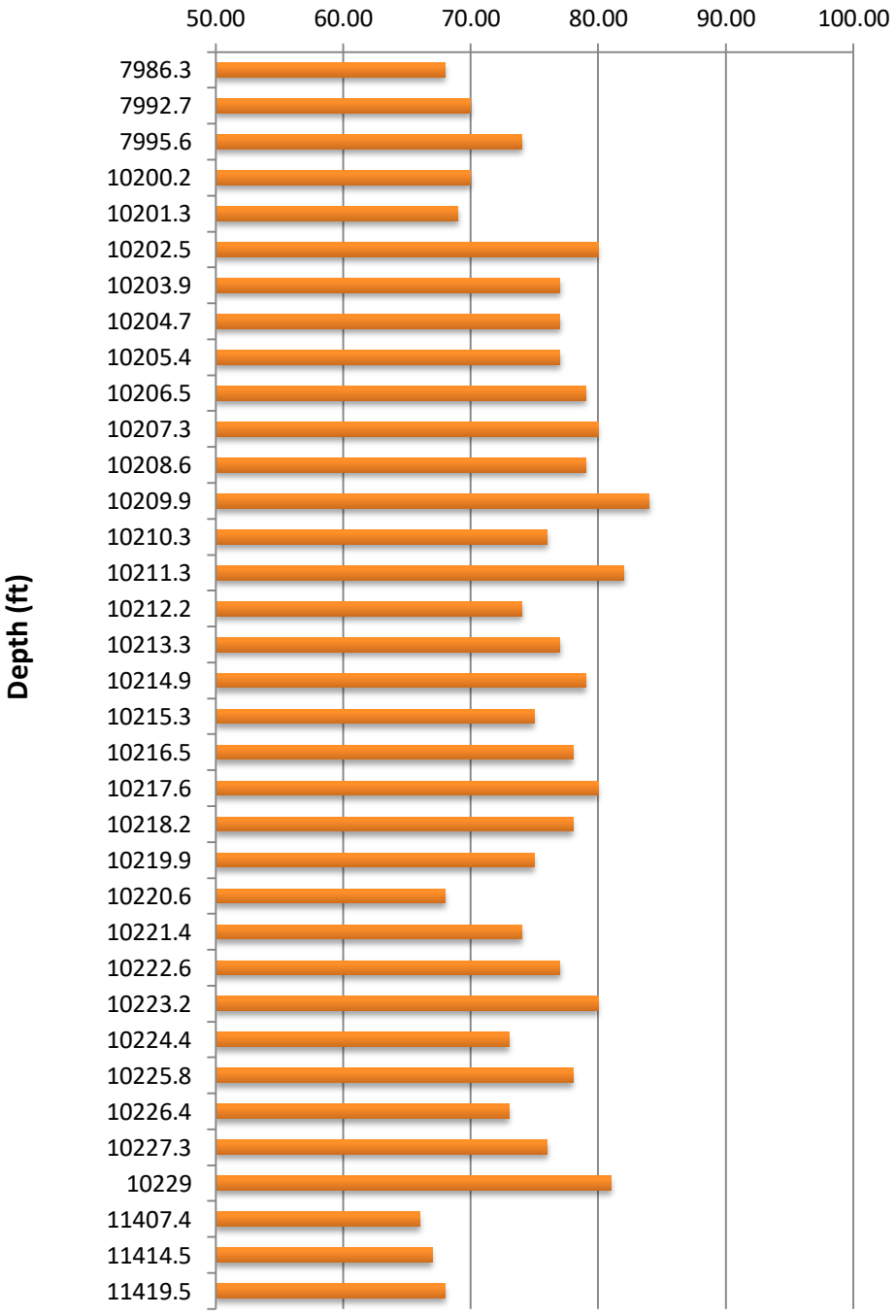

Figure 16. Brittleness Index Values of the Elvins Group in the Dow Chemical #1 Garrigan Well

CONCLUSIONS

The results of source rock characteristics yield insights into the richness, type, and thermal maturity of organic matter in the potential source rocks. The samples from the Arbuckle-Knox Group in northeast Arkansas have very low TOC values, indicating that it has little potential to be an effective source rock. TOC values of the Elvins shale and siltstone beds are generally low while some fairly good organic intervals with TOC values up to 3.95% are present. Both the visual kerogen analysis and pyrolysis products from organic matter in the Elvins Group reflect the characteristics of Type II kerogen. Thermal maturity parameters suggest that the Elvins Group has reached post-mature stage in the study area. Based on the aforementioned organic geochemical observations, the Elvins Group in northeast Arkansas, where fair to good TOC occurs, is capable of generating gas at present. The Arbuckle-Knox Group does not contain sufficient organic matter and therefore cannot be considered as a potential source rock. The results of the digital rock analysis show that the Elvins samples are dense as indicated by high bulk density. Brittleness index of the Elvins suggests that it is good for hydraulic stimulation. 2D SEM images indicate that porosity in organic matter is not a predominant type of total porosity development in the Elvins Group.

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