Final Technical Summary Report for FY 2010–2014
NCRDS State Cooperative Program

SUBSURFACE GAS- AND OIL-SHALE SAMPLES OF TEXAS SHALES FROM THE PERMIAN, FORT WORTH, AND MAVERICK BASINS AND SAN MARCOS ARCH: CORE SAMPLING FOR MEASURED VITRINITE-REFLECTANCE (R_o) DETERMINATION: FINAL TECHNICAL SUMMARY REPORT (FY 2010–2014)

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Subsurface Gas- and Oil-Shale Samples of Texas Shales from the Permian, Fort Worth, and Maverick Basins and San Marcos Arch: Core Sampling for Measured Vitrintite-Reflectance (R_o) Determination: Final Technical Summary Report (FY 2010–2014)

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Executive Summary

Shale samples analyzed for measured vitrinite reflectance during FY 2010–2014 were collected from varying depositional basins in Texas and strata of different ages. They include the Upper Devonian and Lower Mississippian Woodford Shale (Permian Basin), the Lower Pennsylvanian Smithwick Shale (Fort Worth Basin), the Lower Permian shales and Spraberry Formation (Midland Basin), the Lower Cretaceous Pearsall Formation, and the Upper Cretaceous Eagle Ford Shale (Maverick Basin and adjacent area). Although an approximate trend of increasing vitrinite-reflectance values with depth (i.e., increasing thermal maturity, or rank) occurs in the Eagle Ford Shale of the San Marcos Arch, this pattern is not exhibited with the other units sampled. Moreover, when measured vitrinite-reflectance values are compared to calculated-R_o values of Lower Permian shales and the Spraberry Formation, consistently lower values occur with the measured-R_o data set. Sample values from the remaining three successions studied (with the possible exception of the Smithwick Shale) are characterized by similarly lower-than-expected vitrinite-reflectance values. These low values are probably a result of markedly lean successions and not of the presence of low-rank strata. (Lean = either no vitrinite was present in a sample or it was too small to be measured.) Oil- and gas-shale core samples do not appear to be ideal for measuring vitrinite reflectance primarily because of the fine-grained character of the rock, as opposed to coal, in which vitrinite is sufficiently coarse, visible, and abundant to consistently derive R_o values.

Introduction

Fundamental geologic and geochemical attributes of many existing, and especially emerging, shale-gas plays in the U.S. are generally not fully known. Within Texas, the Barnett Shale play is the best studied, and great strides have been made in explaining its petroleum system. However, other regionally extensive gas-shale units in Texas the production potentials of which are promising but lesser known are currently being actively explored. These emerging plays include the Eagle Ford (Clanton, 2009), Pearsall (Clarke, 2007), Smithwick (Hill and others, 2007), Wolfcamp/Spraberry ("Wolfberry") (Prose, 2007; Hamlin and Baumgardner, 2012), and Woodford (Cardott and Lambert, 1985; Comer, 2001, 2008) shales. Basic geologic and geochemical data from them have been gathered and studied in detail by both the Bureau of Economic Geology and private industry. Part of that data set includes thermal maturity data from measured vitrinite-reflectance (R_o) analyses of these units that have been collected for the ongoing NCRDS project; geologic context, sample data, and analysis are presented in Hentz and others (2010–2012, 2014, 2015). These data provide basic guidance in natural gas and oil assessment and exploration within their depositional basins (fig. 1).

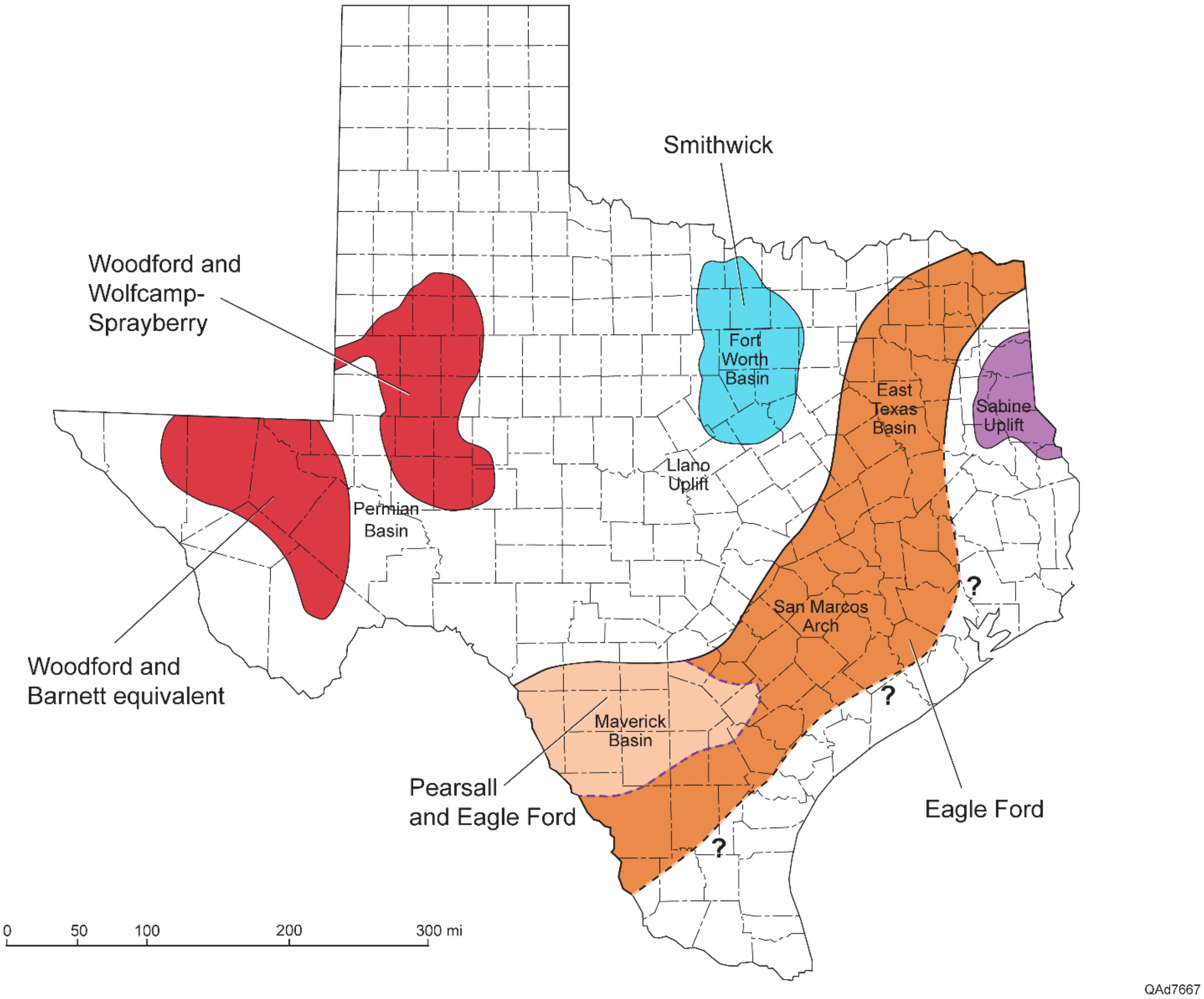

Figure 1. Areal distribution of Texas gas and oil shales sampled during the report period.

Relevance and Impact

Over the past decade, shale gas has dramatically become an increasingly important source of natural gas, in both Texas and the U.S. (Cardott, 2008). Energy forecasters predicted that shale gas would compose a significantly greater proportion of total natural gas production in North America in the near future (Krauss, 2009). As a result, the petroleum industry and Federal agencies focused their attention on the gas- and oil-shale resources of Texas, largely because of the success of the Barnett Shale play of the Fort Worth Basin, but also because of the potential of several emerging shale-gas plays in the state.

Some Texas gas shales, such as the Eagle Ford and Haynesville/Bossier shales of the Texas Gulf Coast Basin and East Texas/adjacent Louisiana, respectively, are currently proven economic producers, although only from parts of their known subsurface extent. The Eagle Ford Shale in particular currently produces natural gas only from the Maverick Basin and adjacent west flank of the San Marcos Arch of South Texas (Clanton, 2009), although the unit extends to depths potentially conducive to oil and perhaps natural gas generation at least another 350 mi northeastward to the East Texas Basin (the so-called “Eaglebine play” [Hentz and others, 2014]). The full play areas of these two producing units, and those of the other Texas gas shales that are yet to be proven producers, have also yet to be fully defined.

Thermal maturity data gathered from cores of these and other Texas gas-shale units across their subsurface extent will be useful in delineating potential producing areas, particularly where gas-shale fields have not yet been developed. Vitrinite reflectance is sensitive to temperature ranges that correspond to those of natural gas and oil generation. With suitable calibration, vitrinite reflectance can be used readily as an indicator of maturity in hydrocarbon source rocks, which in the case of gas shales are also the reservoir rocks.

Because the Bureau houses the largest public core repository in the United States, it has been in a good position to materially contribute fundamental, rock-based, local (field-scale) and regional (play-scale) geochemical data about Texas’s gas and oil shales. These data could potentially aid ongoing USGS resource assessment projects involving gas-shale formations.

Sampled Stratigraphic Units and Results

Eagle Ford Shale

In FY 2010, we provided oil- and gas-shale samples from the productive Upper Cretaceous (Cenomanian–Turonian) Eagle Ford Shale in Texas. The Eagle Ford play extends from the Maverick Basin in the south part of the play area to the San Marcos Arch to the north in south-central Texas (fig. 2). During this project period, we analyzed samples primarily along the San Marcos Arch but also from the south in Frio County and to the north in Robertson County.

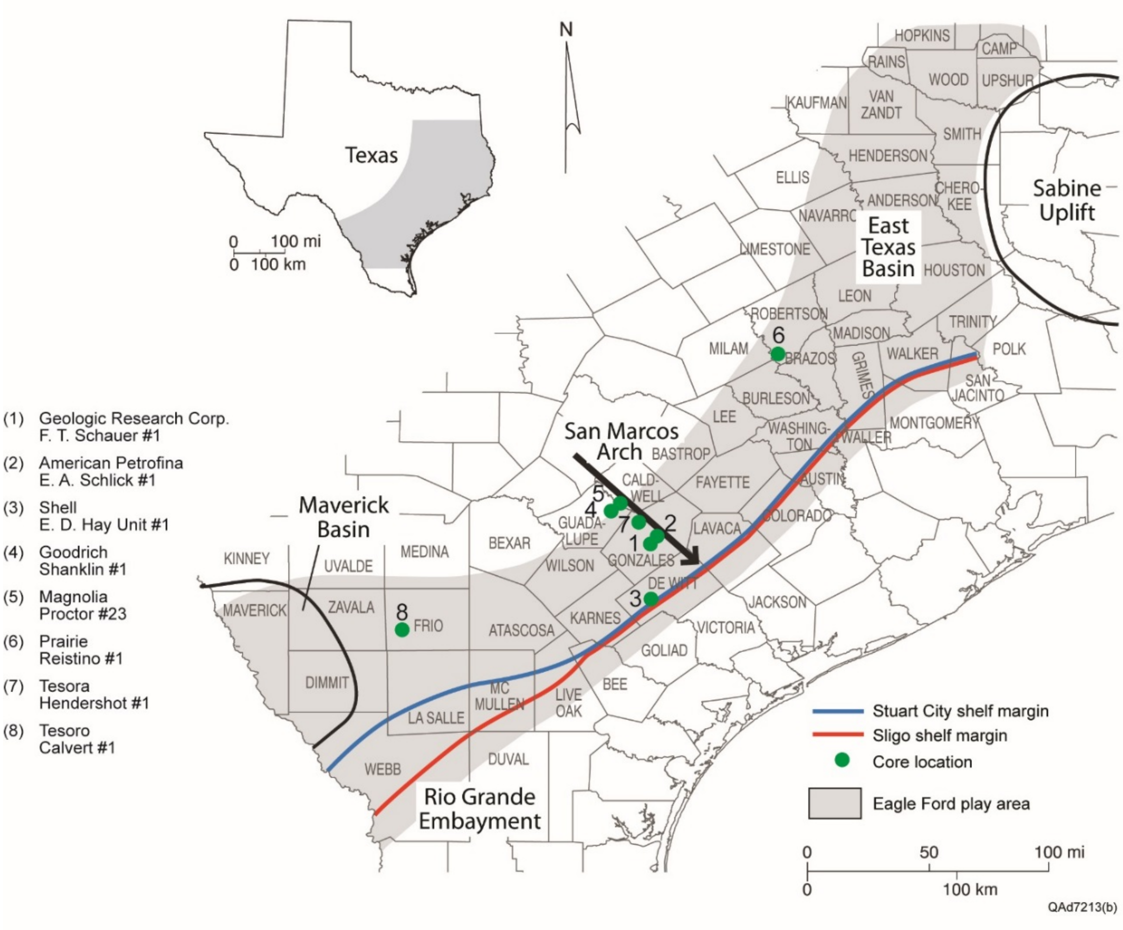

Figure 2. Sample locations and structural domains within the Eagle Ford Shale play area.

Twenty-nine Eagle Ford Shale samples were taken from whole cores of eight wells in south and central Texas: Magnolia Proctor #23 in southwest Caldwell County, Goodrich Shanklin #1 in northeast Guadalupe County, Tesoro Hendershot #1 in north Gonzales County, Tesoro Calvert #1 in southwest Frio County, Prairie Reistino #1 in south Robertson County, American Petrofina E. A. Schlick #1 in central Gonzales County, Geologic Research Corp. F. T. Schauer #1 in central Gonzales County, and Shell E. D. Hay Unit #1 in southwest DeWitt County (fig. 2, Table 1).

Table 1. Measured vitrinite-reflectance results for oil-shale samples from cores of the Eagle Ford Shale in central Texas. Sigma (σ) = standard deviation. "Lean" indicates no visible vitrinite.

Magnolia Proctor #23 (Caldwell County, TX)

Sample depth (ft)	R_o	σ
1,955.5	0.24	0.02
1,957	0.18	0.03
1,960	0.24	0.04
1,964	0.28	none given
1,965	0.33	0.07
1,967	lean	n/a

Goodrich Shanklin #1 (Guadalupe County, TX)

Sample depth (ft)	R_o	σ
2,139	0.41	0.07
2,141	lean	n/a

Tesoro Hendershot #1 (Gonzales County, TX)

Sample depth (ft)	R_o	σ
4,748	0.25	0.01
4,757.5	0.26	none given
4,762.5	0.43	0.07

4,771	0.48	0.01
4,773.5	lean	n/a

Tesoro Calvert #1 (Frio County, TX)

Sample depth (ft)	R_o	σ
6,117.5	lean	n/a
6,129	0.36	0.11
6,146	0.47	0.04
6,159	0.44	0.05

Prairie Reistino #1 (Robertson County, TX)

Sample depth (ft)	R_o	σ
6,428.5	0.70	0.13
6,433.5	0.31	0.11
6,435	0.36	0.07

American Petrofina E. A. Schlick #1 (Gonzales County, TX)

Sample depth (ft)	R_o	σ
7,187	0.26	0.02
7,202	lean	n/a

Geologic Research Corp. F. T. Schauer #1 (Gonzales County, TX)

Sample depth (ft)	R_o	σ
8,095	0.41	0.05
8,109.5	0.39	none given
8,130	0.36	0.07
8,142	0.44	0.07
8,154	lean	n/a

Shell E. D. Hay Unit #1 (DeWitt County, TX)

Sample depth (ft)	R_o	σ
13,701	1.10	0.06
13,824.5	0.94	0.16

Eagle Ford Shale and Pearsall Formation

In FY 2011, we continued to provide analyses of Eagle Ford samples—this time from the Maverick Basin and surrounding area (fig. 3). Lower Cretaceous Pearsall Formation samples were also taken from the same area. All Pearsall Formation samples were taken from the calcareous shale facies of the lower Bexar Member. This facies is the only one in the Pearsall Formation that has so far proven to produce economic quantities of natural gas.

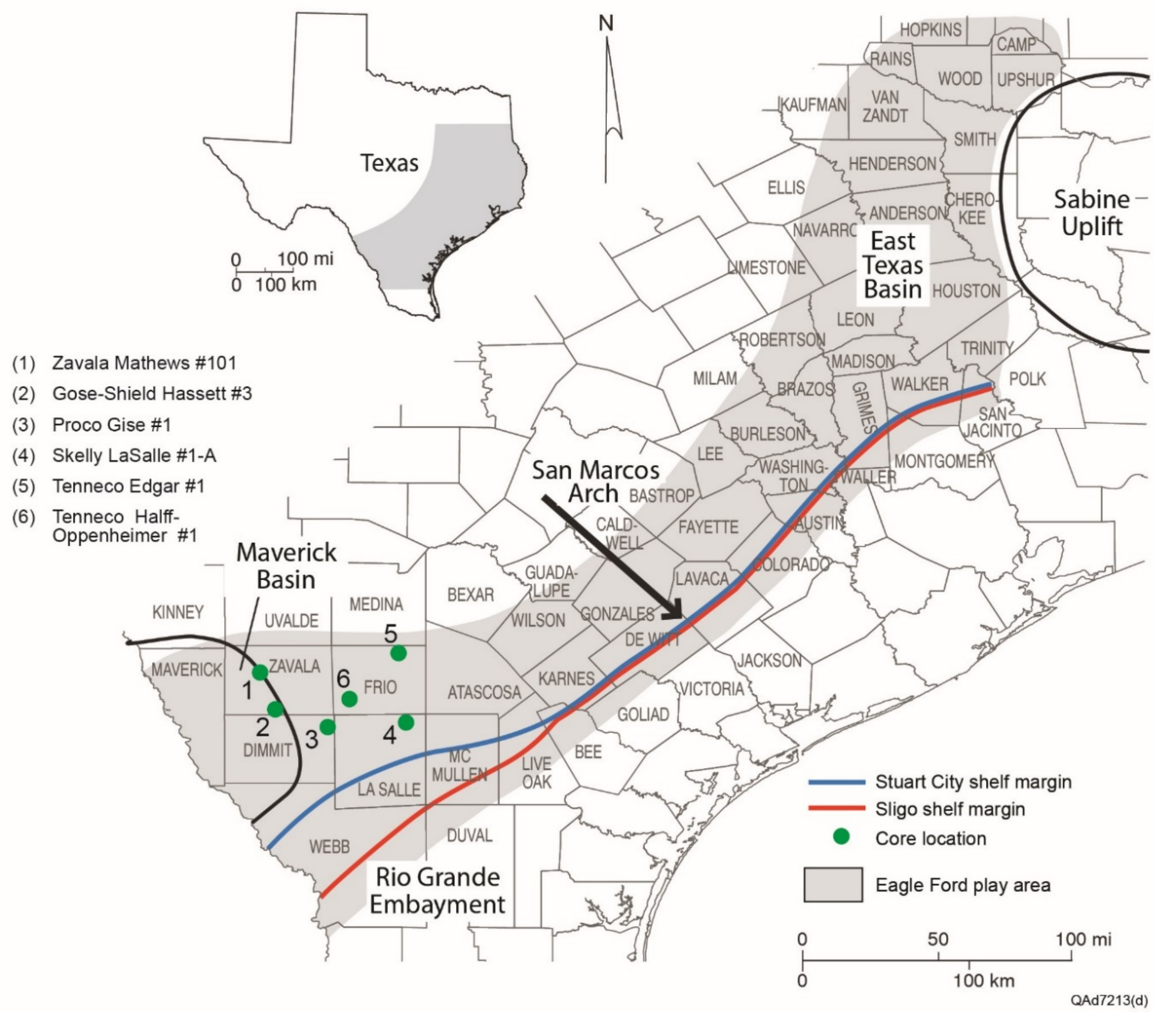

Figure 3. Sample locations and structural domains within the Eagle Ford Shale and Pearsall Formation play area.

Thirty-seven Eagle Ford Shale and Pearsall Formation samples were taken from whole cores of six wells in south Texas: Zavala Mathews #101 (Eagle Ford Shale) in northwest Zavala County, Gose, S.—Shield Co. Hassett #3 (Eagle Ford Shale) in south-central Zavala County, Proco Gise #1 (Eagle Ford Shale) in northeast Dimmit County, Tenneco Edgar #1 (Pearsall Formation) in northeast Frio County, Tenneco Halff-Oppenheimer #1 (Pearsall Formation) in southwest Frio County, and Skelly LaSalle #1-A (Pearsall Formation) in northeast LaSalle County (fig. 3, Table 2).

Table 2. Measured vitrinite-reflectance results for oil-shale samples from cores of the Eagle Ford Shale and Pearsall Formation in south Texas. Twelve of the Eagle Ford Shale samples were analyzed for total organic carbon (TOC) content by GeoMark Research, Ltd. (2010). Sigma (σ) = standard deviation. "Lean" indicates no visible vitrinite.

Eagle Ford Shale Cores

<u>Zavala Mathews #101</u> (Zavala County, TX)

Sample depth (ft)	R_o	*σ*	*TOC (wt%)*
(4,619.0)	0.47	0.07	4.68
4,628.0	lean	n/a	
4,634.0	lean	n/a	
4,641.0	lean	n/a	
(4,647.0)	0.35	none given	1.02
4,651.7	0.35	none given	
4,655.4	0.41	none given	
(4,662.0)	0.44	none given	4.28
(4,681.4)	lean	none given	8.06
4,686.0	0.41	none given	

(…..) Sampled for TOC content.

Gose, S.—Shield Co. Hassett #3 (Zavala County, TX)

Sample depth (ft)	*R_o*	*σ*	*TOC (wt%)*
(6,212.8)	0.54	none given	4.60
(6,214.0)	too fine		6.45
(6,220.4)	too fine		5.41
(6,225.4)	too fine		6.00
(6,230.2)	0.54	none given	5.53
6,235.0	too fine	none given	
(6,239.0)	too fine		4.12

(…..) Sampled for TOC content.

Proco Gise #1 (Dimmit County, TX)

Sample depth (ft)	*R_o*	*σ*	*TOC (wt%)*
7,105.7	lean	n/a	
7,113.8	0.35	none given	
7,117.9	lean	n/a	
7,132.0	lean	n/a	
7,142.6	lean	n/a	
7,153.2	lean	n/a	
7,164.1	0.36	none given	
7,175.3	wrong organics		
(7,181.4)	0.33	none given	1.63
(7,191.6)	0.42	none given	1.50
7,214.0	0.41	none given	

(…..) Sampled for TOC content.

Pearsall Formation Cores

Tenneco Edgar #1 (Frio County, TX)

Sample depth (ft)	*R_o*	*σ*
5,896.0	lean	n/a
5,907.0	0.24	none given

5,916.0	lean	n/a

<u>Tenneco Halff-Oppenheimer #1</u> (Frio County, TX)

Sample depth (ft)	R_o	σ
9,787.0	0.17	none given
9,804.0	0.17	none given
9,815.0	0.20	none given

<u>Skelly LaSalle #1-A</u> (LaSalle County, TX)

Sample depth (ft)	R_o	σ
11,706.0	0.18	none given
11,736.0	0.18	none given
11,795.0	0.18	none given

Smithwick Shale

In FY 2012, we provided oil- and gas-shale samples from shallow cores (2,070 ft) of the Lower Pennsylvanian Smithwick Shale in Texas. The Smithwick Shale extends across most of the southern half of the Fort Worth Basin (fig. 1), where it was deposited in the slowly subsiding Fort Worth Basin during Morrowan–Atokan time. During this project period, we analyzed samples from the southern, shallower part of the basin north of the Llano Uplift in Brown, McCulloch, and San Saba counties (fig. 4).

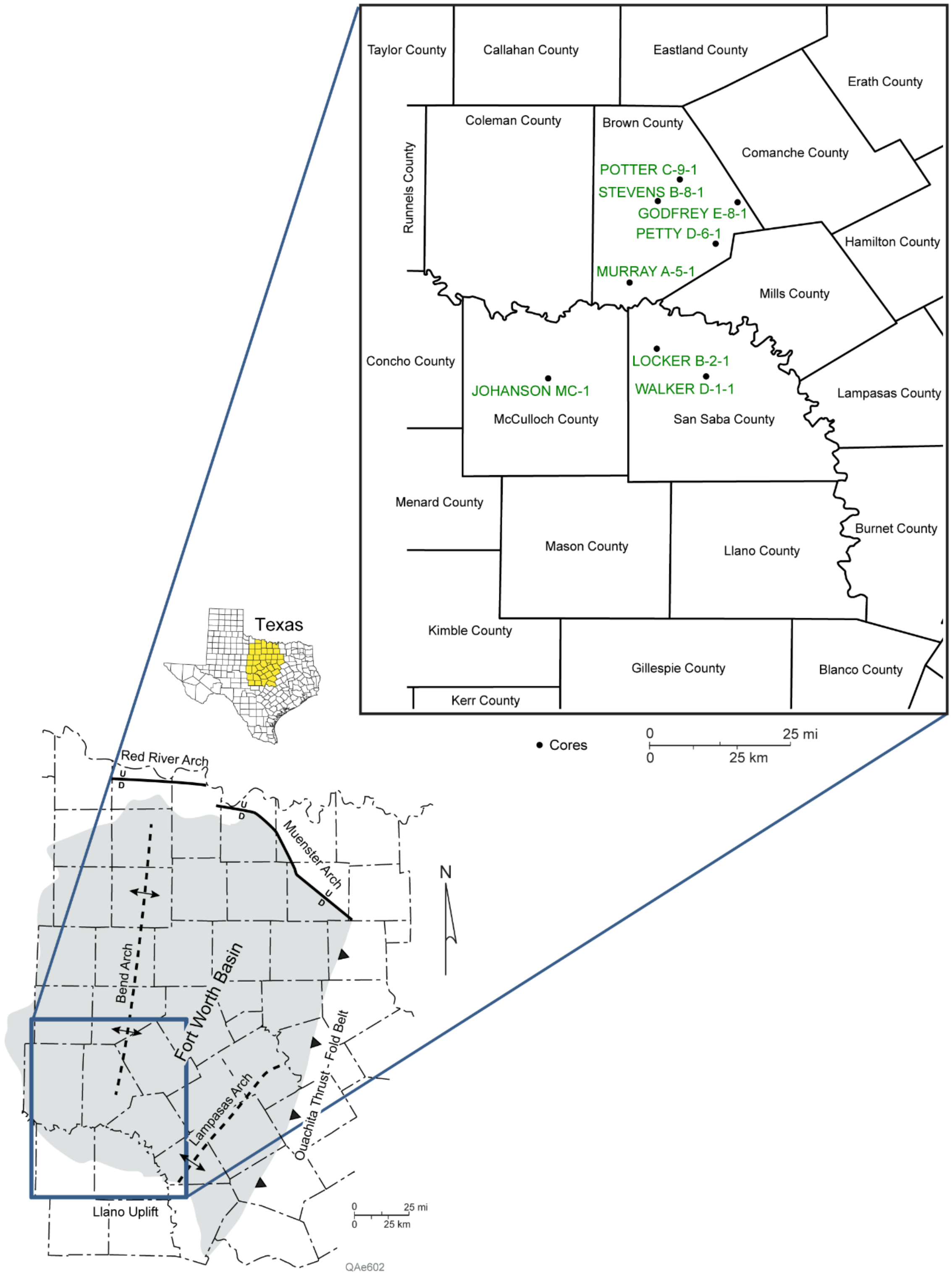

Figure 4. Location of eight cored wells from which Smithwick Shale samples were extracted.

Fifty Smithwick Shale samples were taken from whole cores of eight wells in north Texas. All the cores were taken as part of a mineral-prospecting venture by Houston Oil & Minerals Co.: Godfrey E-8-1 in east-central Brown County, Stevens B-8-1 in central Brown County, Potter C-9-1 in north-central Brown County, Petty D-6-1 in southeastern Brown County, Murray A-5-1 in south-central Brown County, Locker B-2-1 in northwestern San Saba County, Walker D-1-1 in central San Saba County, and Johanson MC-1 in central McCulloch County (fig. 4, Table 3).

Table 3. Distribution of gas-shale samples from cores of the Smithwick Shale in north Texas. Sigma (σ) = standard deviation. "Lean" indicates no visible vitrinite.

Godfrey E-8-1 (API # 4204931815)

Sample depth (ft)	R_o	*σ*
2,050.0	0.55	0.03
2,100.0	0.48	none given
2,135.0	0.55	0.05

Stevens B-8-1 (API # 4204931646)

Sample depth (ft)	R_o	*σ*
1,561.0	0.59	0.09
1,631.0	lean	n/a
1,646.0	lean	n/a
1,710.0	lean	n/a
1,725.0	lean	n/a
1,769.0	lean	n/a
1,784.0	lean	n/a

Potter C-9-1 (API # 4204931769)

Sample depth (ft)	R_o	*σ*
1,730.0	0.42	none given
1,818.0	0.53	0.04
1,875.0	0.43	0.01
1,895.0	lean	n/a
1,911.0	lean	n/a

1,930.0	lean	n/a
1,948.0	0.56	none given
1,995.0	lean	n/a
2,049.0	0.52	none given
2,069.0	lean	n/a

<u>Petty D-6-1 (API # 4204931785)</u>

Sample depth (ft)	R_o	σ
1,590.0	0.59	0.09
1,610.0	0.61	0.05
1,630.0	0.70	none given

<u>Murray A-5-1 (API # 4204931745)</u>

Sample depth (ft)	R_o	σ
1,029.0	0.55	0.03
1,050.0	0.51	0.08
1,092.0	0.50	none given
1,122.0	lean	n/a
1,139.0	lean	n/a
1,180.0	lean	n/a

<u>Locker B-2-1 (API # 4241130101)</u>

Sample depth (ft)	R_o	σ
280.0	lean	n/a
341.0	lean	n/a
394.0	lean	n/a
425.0	no vitrinite	

<u>Walker D-1-1 (API # 4241130100)</u>

Sample depth (ft)	R_o	σ
350.0	lean	n/a
410.0	0.59	0.09
486.0	lean	n/a
531.0	lean	n/a

545.0	lean	n/a
635.0	lean	n/a
665.0	lean	n/a
755.0	lean	n/a
815.0	lean	n/a
906.0	0.48	none given
1,010.0	lean	n/a

<u>Johanson MC-1 (API # 4230730487)</u>

Sample depth (ft)	R_o	σ
882.0	no vitrinite	
908.5	0.58	none given
927.5	0.50	none given
937.5	lean	n/a
945.0	lean	n/a
956.0	0.54	none given

Woodford Shale

In FY 2013, we provided oil- and gas-shale samples from shallow cores of the Lower Pennsylvanian Smithwick Shale in Texas (fig. 5). The Woodford Shale was deposited within the Permian Basin throughout West Texas and southeastern New Mexico mostly during Late Devonian (Frasnian–Famennian) time, with the uppermost part deposited during Early Mississippian (Tournaisian) time (Puckette and others, 2013). The unit is an organic-rich petroleum source rock and an oil- and gas-producing reservoir and consists of two primary lithofacies: mostly black shale and minor siltstone.

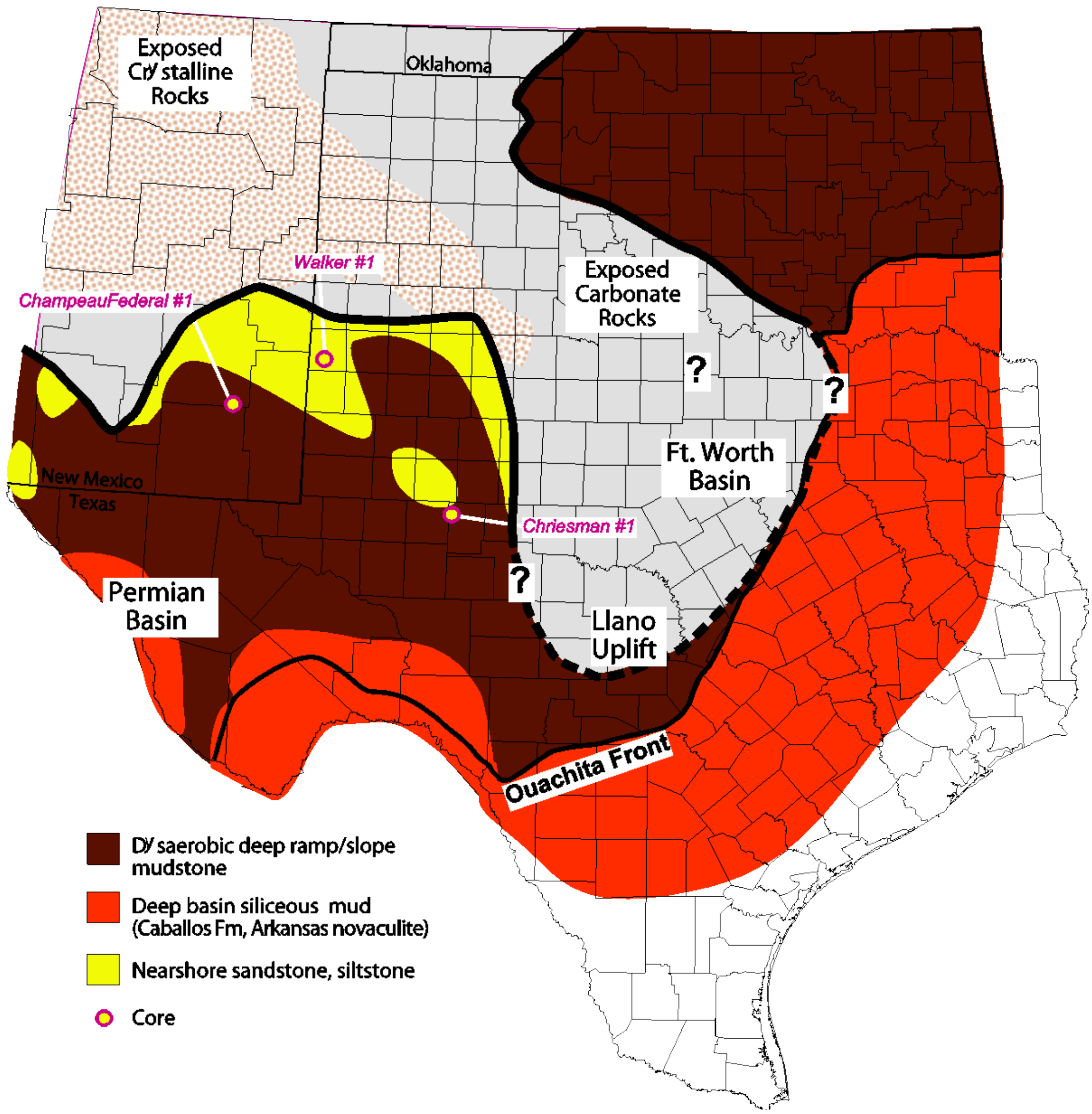

Figure 5. Map of Late Devonian paleogeography of Texas and eastern New Mexico showing the location of three cored wells from which Woodford Shale samples were extracted: Pan American Walker #1, Shell Chriesman #1, and Shell Champeau Federal #1.

Thirty-four Woodford Shale samples were taken from whole cores of three wells in West Texas and northeast New Mexico: Shell Champeau Federal #1 in Chaves Co., New Mexico; Shell Chriesman #1 in Glasscock County, Texas; and Pan American Walker #1 in Cochran County, Texas (fig. 5, Table 4). The Woodford Shale is 50 ft thick in the Pan American Walker #1 well, 46 ft thick in the Shell Chriesman #1 well, and 33 ft thick in the Shell Champeau Federal #1 well.

Table 4. Distribution of gas-shale samples from cores of the Woodford Shale in West Texas and southeast New Mexico. Sigma (σ) = standard deviation. "Lean" indicates no visible vitrinite.

<u>Shell Champeau Federal #1 (API # 30005005180000)</u>

Sample depth (ft)	R_o	*σ*
10,901	lean	n/a
10,903	0.41	0.06
10,904	0.33	0.08
10,909	0.41	0.06
10,915	0.37	0.06
10,919	too soft	
10,923	lean	n/a
10,926	0.33	0.03
10,933	0.39	0.06
10,936	0.35	0.03

<u>Shell Chriesman #1 (API # 42173007160002)</u>

Sample depth (ft)	R_o	*σ*
10,920	0.55	0.04
10,923	0.60	none given
10,925	0.58	0.08
10,927	0.62	0.16
10,930	0.66	0.11
10,933	lean	n/a
10,935	0.46	0.14
10,939	0.46	0.09
10,941	0.54	0.14

Pan American Walker #1 (API # 42079200220000)

Sample depth (ft)	R_o	σ
11,642	0.26	0.06
11,645	0.22	0.02
11,648	0.24	0.00
11,651	0.18	0.03
11,654	0.27	0.04
11,657	lean	n/a
11,660	lean	n/a
11,663	lean	n/a
11,666	no analysis (sandy)	
11,669	no analysis (sandy)	
11,672	0.26	0.05
11,675	0.26	0.03
11,678	lean	n/a
11,681	lean	n/a
11,684	lean	n/a

Wolfcampian and Lower Leonardian Shales and Upper Leonardian Spraberry Formation

In FY 2014, we provided oil- and gas-shale samples from cores of the Lower Permian shales of the Wolfcampian and lower Leonardian succession and the upper Leonardian Spraberry Formation in the Midland Basin of West Texas. In the Midland Basin (the eastern subbasin of the Permian Basin of West Texas and southeastern New Mexico [fig. 1]), the Wolfcampian Series and the Leonardian Series (Lower Permian) include 2,000 to 4,500 ft of siliciclastic and carbonate rocks that were deposited in marine deep-water environments (fig. 6). The interval is characterized by turbidite sandstones that are interbedded with hemipelagic shales and finely laminated siltstones (Hamlin and Baumgardner, 2012).

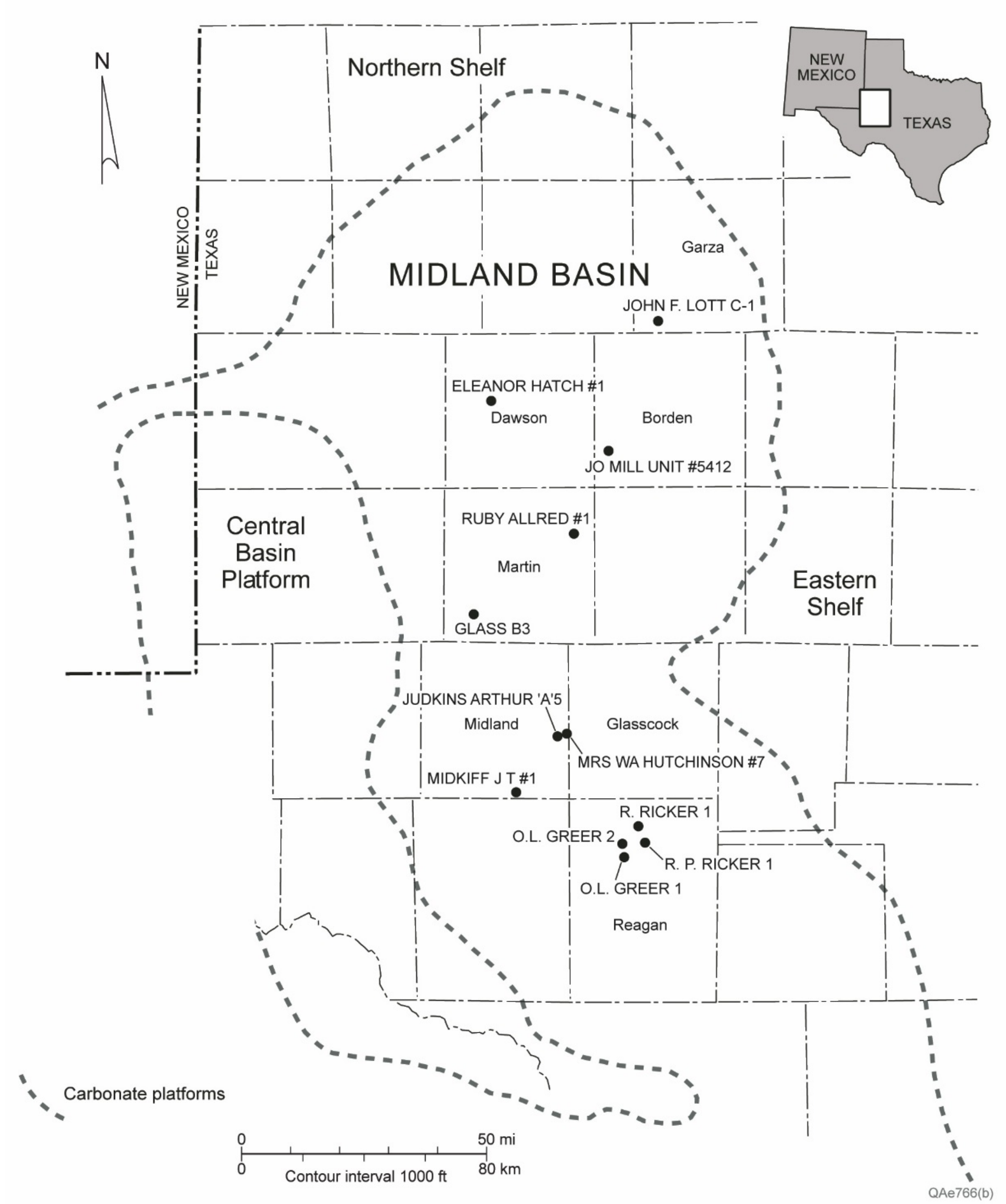

Figure 6. Map of the Midland Basin and adjacent paleogeographic features showing the location of eleven cored wells from which samples of Wolfcampian and Leonardian shales and Spraberry Formation were extracted. Samples from the O. L. Greer #1 well were analyzed for measured vitrinite reflectance for a previous study.

Thirty-five samples of the Wolfcampian and lower Leonardian shales and upper Leonardian Spraberry Formation were taken from whole cores of eleven wells in the Midland Basin (fig. 6, Table 5). Measured vitrinite-reflectance data from an additional well (Pan American O. L. Greer #1), which were analyzed by Weatherford Laboratories, are also provided.

Table 5. Measured vitrinite-reflectance results for oil-shale samples from cores of Wolfcampian and lower Leonardian shales and Spraberry Formation in the Midland Basin, West Texas. TOC analyses by Weatherford Laboratories. Sigma (σ) = standard deviation. "Lean" indicates no visible vitrinite.

Wolfcampian and lower Leonardian shales

Shell R. Ricker #1 (API # 42383106110000)

Sample number	*Sample depth (ft)*	*TOC (%)*	*R_o*	*σ*
R1-7871.08	7,871.08	5.73	lean	none given
R1-7907.58	7,907.58	6.55	0.58	0.09
R1-7939.83	7,939.83	6.61	0.61	0.06
R1-7961.93	7,961.93	6.35	0.81	0.01
R1-7990.93	7,990.93	6.80	0.45	0.06
R1-8015.08	8,015.08	6.32	0.75	0.02

Clinton Rupert P. Ricker #1 (API # 42383105190000)

Sample number	*Sample depth (ft)*	*TOC (%)*	*R_o*	*σ*
RPR1-8315	8,315.0	4.42	0.53	none given
RPR1-8343	8,343.0	3.26	lean	n/a
RPR1-8356	8,356.0	3.79	lean	n/a
RPR1-8397	8,397.0	3.57	lean	n/a

Clinton O. L. Greer #2 (API # 42383105750000)

Sample number	*Sample depth (ft)*	*TOC (%)*	*R_o*	*σ*
G2-8665.8	8,665.8	2.69	0.65	0.01
G2-8679.5	8,679.5	3.62	0.50	none given
G2-8690.9	8,690.9	2.51	lean	n/a

G2-9122.3	9,122.3	2.26	0.41	none given
G2-9141	9,141.0	2.23	0.39	0.01
G2-9177.2	9,177.2	2.95	lean	n/a
G2-9505.1	9,505.1	2.24	lean	n/a

Pan American O. L. Greer #1 (API # 42383101890000) (R_o analysis by Weatherford Laboratories)

Sample depth (ft)	*R_o*
7,665.1	0.81
7,691.2	0.79
7,727.1	0.67
7,769.1	0.67
7,809.1	0.67
7,840.1	0.79
7,852.1	0.78
7,937.1	0.86
7,948.1	0.78
8,009.1	0.82
8,055.5	0.78
8,092.9	0.91
8,115.4	0.87
8,236.3	0.91
8,240.1	0.82
8,280.1	0.83
8,348.9	0.86
8,378.1	1.06
8,390.1	0.84
8,497.1	0.92
8,548.3	0.89

Spraberry Formation

Amoco John F. Lott #C-1 (API # 42169302380000)

Sample number	*Sample depth (ft)*	*R_o*	*σ*
John F. Lott #C-1, 5968	5,968	0.43	0.05

Mobil Arthur Judkins #A-5 (API # 42329318180000)

Sample number	*Sample depth (ft)*	*R_o*	*σ*
Arthur Judkins #A-5, 6969	6,969	lean	n/a

Texaco Jo Mill #5412 (API # 42033304050000)

Sample number	*Sample depth (ft)*	*R_o*	*σ*
Jo Mill #5412, 7140	7,140	0.40	none given
Jo Mill #5412, 7145	7,145	lean	n/a

Sun Mrs. W. A. Hutchinson #7 (API # 42329016490000)

Sample number	*Sample depth (ft)*	*R_o*	*σ*
Mrs. W. A. Hutchinson #7, 7430	7,430	lean	n/a
Mrs. W. A. Hutchinson #7, 7558	7,558	0.44	none given
Mrs. W. A. Hutchinson #7, 7606	7,606	lean	n/a

Amoco Ruby Allred #1 (API # 42317311650000)

Sample number	*Sample depth (ft)*	*R_o*	*σ*
Ruby Allred #1, 7826	7,826	lean	n/a
Ruby Allred #1, 7855	7,855	lean	n/a

Forest & Champlin Hatch #1 (API # 42115004400000)

Sample number	*Sample depth (ft)*	*R_o*	*σ*
Hatch #1, 7911	7,911	0.47	0.06

Sun J. T. Midkiff #1 (API # 42329303110000)

Sample number	*Sample depth (ft)*	*R_o*	*σ*
J. T. Midkiff #1, 8036	8,036	lean	n/a
J. T. Midkiff #1, 8039	8,039	lean	n/a
J. T. Midkiff #1, 8310	8,310	lean	n/a
J. T. Midkiff #1, 8314	8,314	0.53	0.04

Gulf Glass #B-3 (API # 42317001300000)

Sample number	*Sample depth (ft)*	*R_o*	*σ*
Gulf Glass #B-3, 8401	8,401	0.50	0.04
Gulf Glass #B-3, 8612	8,612	lean	n/a
Gulf Glass #B-3, 8743	8,743	0.54	0.01
Gulf Glass #B-3, 9098	9,098	lean	n/a

Summary Analysis

Shale samples analyzed for measured vitrinite reflectance during FY 2010–2014 were collected from varying depositional basins in Texas, strata of different ages, and a variety of thermal-maturity environments. From oldest to youngest, they include the Upper Devonian and Lower Mississippian Woodford Shale (Permian Basin), Lower Pennsylvanian Smithwick Shale (Fort Worth Basin), Lower Permian shales and Spraberry Formation (Midland Basin), Lower Cretaceous Pearsall Formation, and Upper Cretaceous Eagle Ford Shale (Maverick Basin and adjacent area).

Among the Woodford Shale samples (Table 4), those from the Shell Champeau Federal #1 and Shell Chriesman #1 cores were taken within the same general depth range (~10,900–10,940 ft). However, the average measured vitrinite reflectance values of the two cores are 0.37 and 0.56, respectively. Not enough data exist to identify a specific reason for the difference. The variance in average R_o values is likely a result of differences in the burial, and thus thermal, histories of the core locations (northeast New Mexico and West Texas) (fig. 5). Vitrinite-reflectance values from the deeper samples of the Pan American Walker #1 core (11,642–11,684 ft) are consistently lower than those in the other Woodford cores, averaging 0.24. The analyst, Dr. James Hower, noted that several of the samples submitted (for which no values could be determined) were “lean, not right type of shale,” “sandstone with few shale intervals,” and “too soft.” Therefore, the lower values of the Walker #1 core samples are possibly caused by an unusually lean succession of the Woodford Shale. “Lean” is a term meaning either no vitrinite was present in a sample or it was too small to be measured.

Samples of the Lower Pennsylvanian Smithwick Shale of the Fort Worth Basin were collected from shallow cores north of the exposed Llano Uplift (fig. 4). Sample depths range from only 280 to 2,135 ft (Table 3). Vitrinite-reflectance values for all eight Smithwick cores accordingly vary within a small range of 0.42 and 0.70, with an average value of 0.54. Moreover, 30 of the 50 Smithwick Shale samples are designated lean, likely reflecting their generally thermally low-rank nature.

Samples of Lower Permian shales and the Spraberry Formation of the Midland Basin (fig. 6) were taken from whole cores of eleven wells in the Midland Basin (fig. 6, Table 5). Measured vitrinite-reflectance data from an additional well (Pan American O. L. Greer #1) were independently analyzed by Weatherford Laboratories. This data set is the only one of the five fiscal-year studies that enables comparison between *measured* and *calculated* vitrinite reflectance from nearby cores. The two data sets display considerable variation in vitrinite-reflectance results despite the fact that all Wolfcampian and Leonardian basinal intervals contain organic-rich lithofacies based on TOC analyses (Hamlin and Baumgardner, 2012). Measured vitrinite-reflectance of 21 Wolfcampian and lower Leonardian mudrock samples for the Pan American O. L. Greer #1 (fig. 6, Table 5) that were analyzed by Weatherford Laboratories for Hamlin and Baumgardner (2012) have a maximum value of 1.06, a minimum value of 0.67, and an average value of 0.82. In contrast, the 17 sample values provided by Dr. James Hower that represent the same sample-depth range (Shell R. Ricker #1, Clinton Rupert P. Ricker #1, and Clinton O. L. Greer #2) differ considerably: maximum value of 0.81, minimum value of 0.39, and average value of 0.53. All of Hower’s numbers are significantly lower than those provided by Weatherford. The reason for the discrepancy is not immediately apparent. Dr. James Hower (personal communication, 2015) noted that almost one-half of the samples he analyzed were too lean. The mudrock samples obviously had organic matter; many are just too fine grained. Among those samples he analyzed, all had relatively few vitrinite fragments of sufficient size to derive a measurement, thus reducing the range of values determined from each sample. Perhaps the

Weatherford samples had a larger number of vitrinite fragments per sample, thus resulting in larger average vitrinite-reflectance values for each sample.

The nine core samples of the Lower Cretaceous Pearsall Formation collected from three wells just northeast of the Maverick Basin consistently show low vitrinite-reflectance values ranging from 0.17 to 0.24, with two samples designated as lean (fig. 3, Table 2). However, the depth range of the low-value samples is considerable (5,896.0–11,795.0 ft), indicating that the Pearsall interval likely occurs within the oil and gas thermogenic windows. As with the Lower Permian shales and the Spraberry Formation of the Midland Basin, the low vitrinite-reflectance values of the Pearsall core samples are possibly a result of an unusually lean Pearsall succession and not of the presence of low-rank strata.

Vitrinite-reflectance samples from the Eagle Ford Shale were collected from the axis of the San Marcos Arch and in the Maverick Basin (figs. 2, 3; Tables 1, 2). In the FY 2010 report (Hentz and others, 2010), we discussed two primary objectives related to analysis of these sample sets: (1) compare R_o data between the Maverick Basin and those of the San Marcos Arch, two distinct structural provinces of the greater Eagle Ford play area, and (2) compare R_o data from samples collected from cores taken along the southeast-plunging axis of the San Marcos Arch. In the context of the second objective, how do R_o results vary along the structure?

Within the Maverick Basin, we collected 28 core samples at depths ranging from 4,619.0 to 7,214.0 ft, with R_o values ranging minimally from 0.33 to 0.54 (average: 0.41) from 13 of the 28 samples (Table 2). All other samples were designated lean or too fine grained to derive values. Twenty-two core samples were collected on or near the axis of the San Marcos Arch at depths ranging from 1,955.5 to 13,824.5 ft. (Samples are from all but two wells—Tesoro Calvert #1 [Frio County] and Prairie Reistino #1 [Robertson County]—that occur southwest and northeast, respectively, of the structure.) Sample values range from 0.18 to 1.10, with the lowest values (<0.35) generally occurring at depths less than about 2,100 ft. Higher values (0.35–0.48) generally occur at depths between about 2,100 and 8,100 ft, with highest values at about 13,800 ft (0.94, 1.10). With the exception of these highest values, all others appear to be low when considering the fact that most of these wells are oil producers. Moreover, TOC content of the Maverick Basin wells indicates organic levels that support production (Table 2).

The vitrinite-reflectance results for the Eagle Ford Shale in both the San Marcos Arch and Maverick Basin areas are likely similar to those of the Pearsall Formation and the Lower Permian shales and the Spraberry Formation described above. That is, the lower-than-expected vitrinite-reflectance values of the Eagle Ford core samples are a result of an unusually lean succession and not of the presence of low-rank strata. Oil- and gas-shale core samples do not appear to be ideal for measuring vitrinite reflectance, primarily because of the fine-grained character of the rock (therefore, commonly lean), as opposed to coal, in which vitrinite is sufficiently coarse and abundant to consistently derive R_o values.

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