PS Synthetic Nano-Petrophysics Investigation of the Haynesville Shale in Eastern Texas*

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Abstract

As one of the most productive shale gas plays, the Haynesville Shale has the properties of high geopressured gradient and temperature. To analyze pore geometry and wettability related connectivity of this formation, multiple methods such as TOC, XRD, vacuum saturation, mercury intrusion capillary pressure (MICP), contact angle, and fluid imbibition have been used on 10 Haynesville Shale core samples from a well over a vertical distance of 123 ft. The results from those tests show that the Haynesville Shale is calcareous in nature with 2~5% of TOC. The porosities range from 2 to 8% and the pore-throat sizes are concentrated on the nanoscale. Most of the samples show strong oil-wet behavior and three samples exhibit mixed wettability. In general oil-wet samples show a higher pore connectivity when they imbibe hydrophobic (n-decane:toluene=2:1) than hydrophilic (deionized water) fluids

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Hammes, U., H.S. Hamlin, and T.E. Ewing, 2011, Geologic analysis of the Upper Jurassic Haynesville Shale in east Texas and west Louisiana: AAPG bulletin, v. 95/10, p. 1643-1666.

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Abstract

As one of the most productive shale gas plays, the Haynesville Shale has the properties of high geopressured gradient and temperature. To analyze pore geometry and wettability related connectivity of this formation, multiple methods such as TOC, XRD, vacuum saturation, mercury intrusion capillary pressure (MICP), contact angle, and fluid imbibition have been used on 10 Haynesville Shale core samples from a well over a vertical distance of 123 ft. The results from those tests show that the Haynesville Shale is calcareous in nature with 2~5% of TOC. The porosities range from 2 to 8% and the pore-throat sizes are concentrated on the nanoscale. Most of the samples show strong oil-wet behavior and three samples exhibit mixed wettability. In general oil-wet samples show a higher pore connectivity when they imbibe hydrophobic (n-decane:toluene=2:1) than hydrophilic (deionized water) fluids

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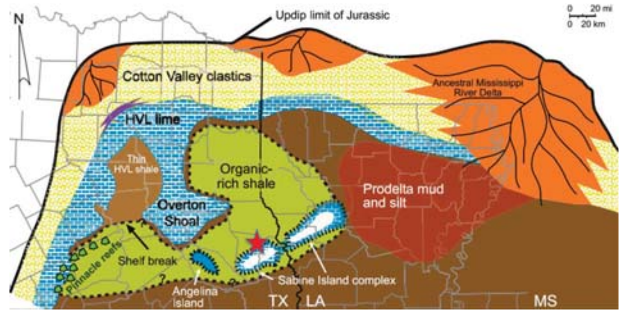
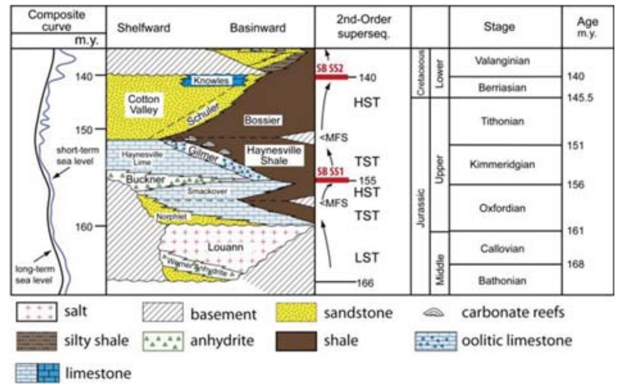
Introduction

(1) A package within the upper part of the upper Jurassic Haynesville Formation.
(2) Deposited in an area in northeast Texas and northwest Louisiana in the northern Gulf of Mexico basin.
(3) Partially time equivalent to the carbonate-rich Gilmer and Haynesville Lime members of the Haynesville Formation.
(4) More calcareous and more organic rich in this study area.
(5) High geopressure gradient (>0.9 psi/ft), while the normal pressure gradient is around 0.433 psi/ft.

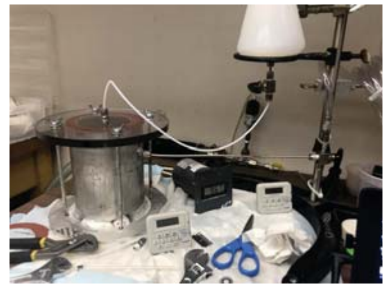




Methods


TOC


XRD


Vacuum saturation


MICP


Contact Angle

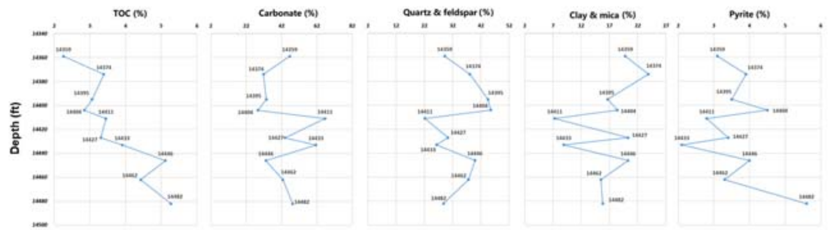

Fluid Imbibition

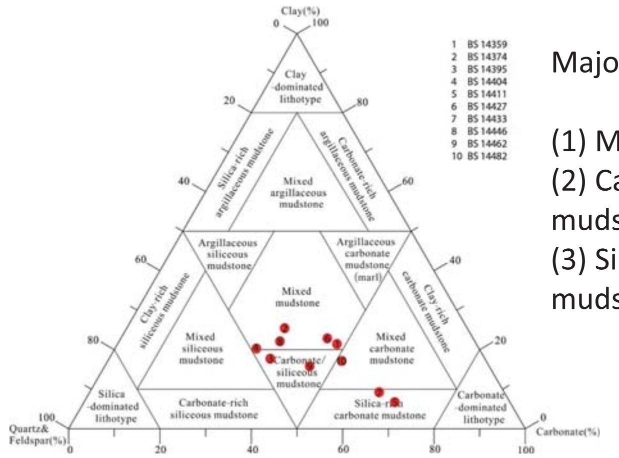
Why Nano-petrophysics?

(1) Investigating pore structure of shale
(2) Characterizing fluid migration behavior in ultra-low porosity and permeability media.
(3) Providing more detail information for petroleum geologists and petroleum engineers.

Results

(1) Organic richness and Mineralogy (TOC&XRD)





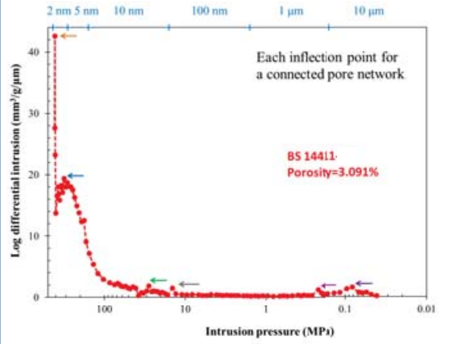
Major lithofacies

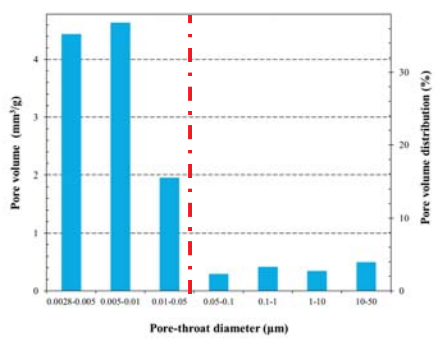
(1) Mixed mudstone
(2) Carbonate/ siliceous mudstone
(3) Silica-rich carbonate mudstone

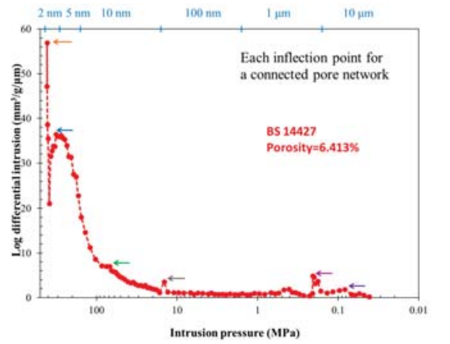
(2) Porosity (MICP & Vacuum saturation)

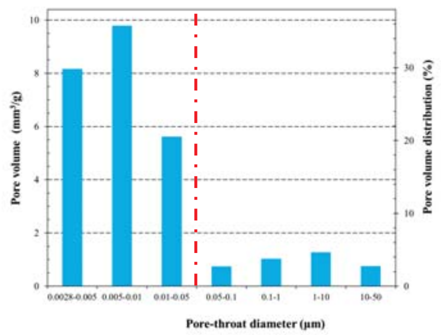
Porosity (%) / Sample ID	MICP	Vacuum saturation		
	Mercury	DI Water	DT2	THF
BS 14359	7.313	6.026±1.238	7.774	7.678
BS 14374	6.034	5.841±0.855	7.490	7.910
BS 14395	2.837	2.929±0.367	N/A	3.319
BS 14404	4.712	5.946±1.495	5.527	8.625
BS 14411	3.091	2.626±0.525	3.140	3.548
BS 14427	6.413	6.631±0.890	5.543	1.175
BS 14433	4.406	4.751±0.581	3.778	6.254
BS 14446	5.540	6.173±0.768	5.309	10.422
BS 14462	5.217	5.289±0.380	4.140	6.073
BS 14482	4.245	5.156±0.624	6.918	6.624

(4) Pore-throat distribution (MICP)







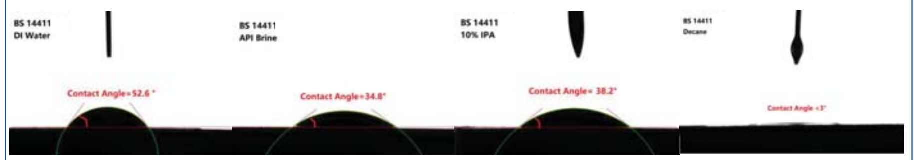


Most of pore-throat sizes are concentrated in 2.8 nm to 50 nm. The composition of those pores are clay interlayer pores, organic pores, intraparticle pores.

(5) Permeability and tortuosity of nano-pore space (MICP)

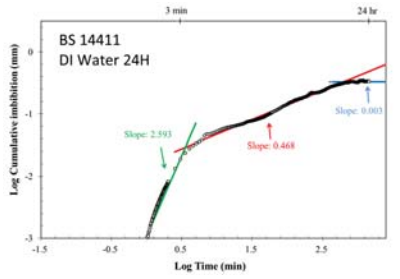
Sample ID	Permeability (nD)	Effective tortuosity	Geometrical tortuosity
BS 14359	23.4	1580	10.748
BS 14374	13.1	1914	10.746
BS 14395	7.9	3433	9.87
BS 14404	4.8	3296	12.461
BS 14411	3.7	2011	7.884
BS 14427	6.5	1879	10.977
BS 14433	4.0	1753	8.788
BS 14446	6.4	2570	11.932
BS 14462	4.7	2751	11.979
BS 14482	5.9	1413	8.586

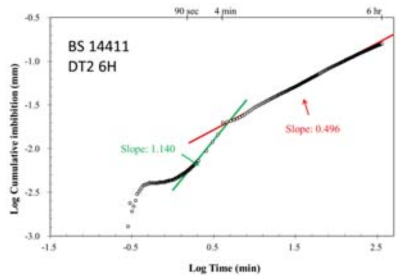
(6) Wettability related connectivity



Hydrophilic API Brine Amphiphilic Hydrophobic

Sample ID	DI water	API brine	10% IPA	n-decane	Wettability Classification
BS 14359	58.3	13.2	49.4	<3	Oil-Wet
BS 14374	28.0	22.3	25.0	<3	Oil-Wet
BS 14395	15.4	15.5	33.4	<3	Intermediate-Wet
BS 14404	41.0	30.0	24.3	<3	Oil-Wet
BS 14411	52.6	34.8	38.2	<3	Oil-Wet
BS 14427	33.3	32.5	28.0	<3	Oil-Wet
BS 14433	24.0	38.0	61.3	<3	Intermediate-Wet
BS 14446	7.4	33.3	24.1	<3	Intermediate-Wet
BS 14462	52.8	38.4	50.6	<3	Oil-Wet
BS 14482	46.1	26.9	6.1	<3	Oil-Wet





Sample ID	Fluid type	Wall & edge slope	Interior stage slope	Connectivity	Fluid type	Wall & edge slope	Interior stage slope	Connectivity
BS 14359	DI Water	0.516	0.430	Intermidate	DT2	1.801	0.660	High
BS 14374	DI Water	2.062	0.288	Low	DT2	0.784	1.108	High
BS 14395	DI Water	0.424	0.381	Intermidate	DT2	0.989	0.678	High
BS 14404	DI Water	1.313	0.519	High	DT2	1.175	0.417	Intermidate
BS 14411	DI Water	2.593	0.468	Intermidate	DT2	1.140	0.496	High
BS 14427	DI Water	2.531	0.428	Intermidate	DT2	1.261	0.573	High
BS 14433	DI Water	0.071	0.455	Intermidate	DT2	3.527	0.750	High
BS 14446	DI Water	-0.194	0.932	High	DT2	3.800	0.638	High
BS 14462	DI Water	0.818	0.234	Low	DT2	0.437	0.314	Intermidate
BS 14482	DI Water	5.697	0.545	High	DT2	5.973	0.450	Intermidate

Conclusions

(1) The Haynesville Shale is an organic-rich reservoir with more than 70% of brittle minerals (carbonate, quartz, mica).
(2) Pore-throat size is concentrated in 2.8~50 nm.
(3) The Haynesville shale show mixture wettability but have the preference of hydrophobic fluid.
(4) 7 samples show high hydrophobic fluid connectivity.

Acknowledgement

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(1) Gao, Z., & Hu, Q. (2013). Estimating permeability using median pore-throat radius obtained from mercury intrusion porosimetry. Journal of Geophysics and Engineering, 10(2), 025014.
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(3) Hammes, U., Hamlin, H. S., & Ewing, T. E. (2011). Geologic analysis of the Upper Jurassic Haynesville Shale in east Texas and west Louisiana. AAPG bulletin, 95(10), 1643-1666
(4) Hu, Q., Ewing, R. P., & Dultz, S. (2012). Low pore connectivity in natural rock. Journal of contaminant hydrology, 133, 76-83.