Geochemical Assessment of Unconventional Shale Resource Plays, North America*

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Daniel M. Jarvie[1], R. Paul Philp[2], Brian M, Jarvie[3], and James D. Jarvie[3]

[1] Worldwide Geochemistry, PO Box 789, Humble, Texas 77347 USA (danjarvie@wwgeochem.com)

Current address: Institut Francais du Petrole, 1 et 4, avenue de Bois-Preau, 92852 Rueil-Malmaison, France (daniel-m.jarvie@ifp.fr)

[2] University of Oklahoma, 100 East Boyd Street, Suite 810, Norman, OK 73019 USA (pphilp@ou.edu)

[3] Geomark Research, 218 Higgins Street, Humble, Texas 77338 USA (bjarvie@geomarkresearch.com;jjarvie@geomarkresearch.com)

Introduction

Unconventional shale resource plays have grown dramatically in the last 10 years in North America. The low porosity (~4-5%), nanodarcy permeability Mississippian Barnett Shale in the Newark East Field, Fort Worth Basin, Texas, is now the largest gas field in the USA. Interestingly it will possibly be exceeded by several other shale-gas plays including the Haynesville/Bossier, Marcellus, and Muskwa shale systems of North America.

There are many factors that affect the producibility of hydrocarbons from shale source/reservoir rocks. Basic geochemical data goes a long way toward characterizing these plays and their likelihood of high-graded commercial success:

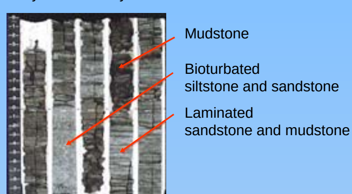
- Gas type
- TOC
- Thermal maturity
- Kerogen type
- Residual oil saturation
- Gas-in-place (GIP)
- Mineralogy including clay speciation
- Rock mechanical properties
- Porosity/permeability

The bulk of gaseous hydrocarbons are generated from secondary decomposition of resins (NSOs) (Behar et al., 2007). Thus, it is important to understand gas generation, but also gas storage and preservation at higher thermal maturities.

While these plays are often characterized as engineering or stimulation plays, they are not until the right areas are identified; otherwise the engineers would be stimulating any and all shales, most of which would not be productive.

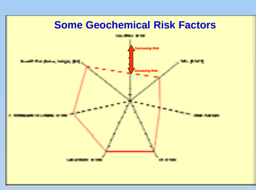
Shale-gas and shale-oil plays are not necessarily strictly "shale" plays as hybrid system – those systems with mixed lithofacies present – appear to be the most productive. Strictly speaking shale is defined by particle size, but in shale-gas plays it is more important to know mineralogy as well as having clay speciation.

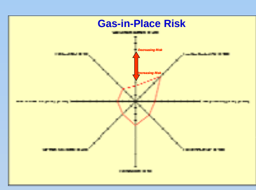
Hybrid Shale System: mixed lithofacies at variable scales

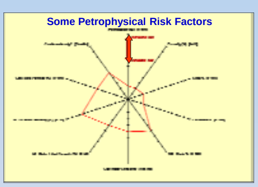


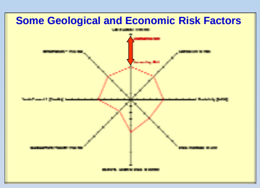
Risking Shale-Gas Systems

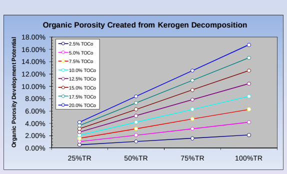
One of the principal issues in evaluating shale-gas systems is making an accurate determination of thermal maturity, or more appropriately, the type of products that will be found. Thus, some calibration to a given system is required. We use a polar plot to assess geochemical risk as well as other variables as shown below.

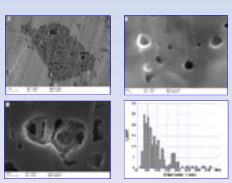






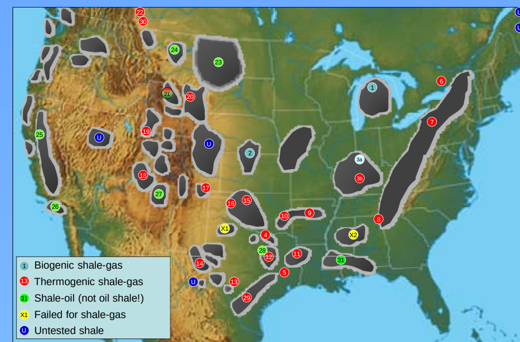






Porosity can be developed by decomposition of organic matter (e.g., Tissot & Welte, 1984). The graphic above shows the total potential porosity that could be derived from organic matter decomposition for shales of varying organic richness and at very levels of conversion of organic matter. After much investigation by the Bureau of Economic Geology, University of Texas, no open fractures or matrix porosity have been revealed. However, Reed et al. (submitted) identified nanopores in the Barnett Shale utilizing an argon ion milling technique derived from the semiconductor industry. They identified "nanopores" that range in size from 1-2 nanometers to 400 nanometers. This appears to be the main means for storage of gas in the Barnett Shale. At PVT conditions 5% porosity can store over 700 mcf/af (16.9 m^3/m^3).

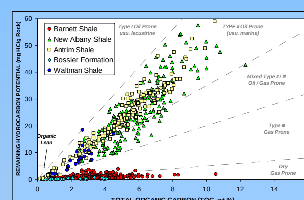
North American Shale Resource Plays

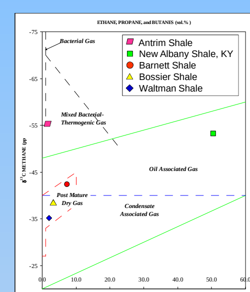


No.	Age, Shale, Basin	Type	No.	Age, Shale, Basin	Type
1	Devonian Antrim Shale, Michigan Basin	bg	16	Penn Shale, Panhandle Area, Anadarko Basin	tgh
2	Cretaceous Niobrara Shale, Central Nebraska area	bg	17	Cretaceous Pierre Shale, Raton Basin	tgh
3a-b	Devonian New Albany Shale, Illinois Basin	bgtg	18	Pennsylvanian Gothic Shale, Paradox Basin	tg
4	Devonian Woodford Shale, Ardomore Basin	tg	19	Cretaceous Baxter Shale, Greater Green River Basin	tg
5	U. Jurassic Bossier Shale/Sand, East Texas Salt Basin	tgh	20	Cretaceous Mowry Shale, Big Horn Basin	tg
6	Ordovician Utica Shale,	tg	21	Paleocene Waltman Shale, Wind River Basin	tm
7	Devonian Marcellus Shale, Appalachian Basin	tg	22	Devonian Muskwa Shale, Big Horn Basin, BC	tg
8	Cambrian Conasauga Shale,	tg	23	Devonian Bakken Formation, Williston Basin	oh
9	Mississippian Fayetteville Shale, Arkoma Basin	tg	24	Pennsylvanian Heath/Tyler Shales, Central Montana Trough	oh
10	Devonian Woodford Shale, Arkoma Basin	tg	25	Miocene Antelope Shale, San Joaquin Basin	of
11	U. Jurassic Haynesville/Bossier Shales, ETNL Salt Basin	tgh	26	Miocene Monterey Shale, Santa Maria Basin	of
12	Mississippian Barnett Shale, Fort Worth Basin	tg	27	Cretaceous Mancos Shale, San Juan Basin	of
13	Cretaceous Pearsall Shale, Maverick Basin	tg	28	Mississippian Barnett Shale, Fort Worth Basin	ot
14	Penn-Miss-Devonian Shales, Delaware Basin	tg	29	Cretaceous Eagle Ford Shale, South Texas Basin	tgh
15	Devonian Woodford Shale, Anadarko Basin	tg	30	Triassic Montney Shale, West Canada Basin	tgh
			31	Cretaceous Tuscaloosa Shale, Mississippi Salt Basin	ot

Type codes:
bg = biogenic shale gas
tg = thermogenic shale gas
tgh = thermogenic shale gas, hyrbid non-shale lithofacies
tgm = thermogenic shale gas, migrated
of = shale oil, fractured
oh = shale oil, hybrid non-shale lithofacies
ot = shale oil, tight shale

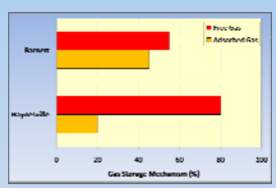
Comparison of Five Different Shale-Gas Systems





Above - These data show yields (S2) versus TOC indicative of high remaining potential for those source rocks having greater than 10 mg/g S2 for five different shale gas systems. Organic-rich rocks with TOC > 2% are prime targets from an organic richness viewpoint. Right – Carbon isotopic values versus gas wetness show differences in type, thermal maturity, or origin among these five systems. The importance of these differences lies in what ultimately will be recovered from these shales in terms of bcf or m3/m3. They may be IP rated as follows:

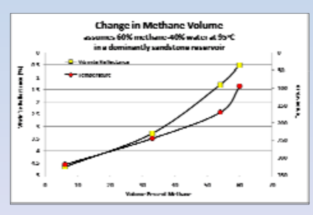
Biogenic and low thermal maturity shales < gas window maturity shales < gas window shale hybrids



Barnett Shale porosity is almost entirely derived from organic matter decomposition.

On the other hand, Haynesville Shale porosity exceeds its organic porosity development by a factor of 2. This means that more gas is stored as free gas rather than adsorbed gas resulted in very high initial production (IP) rates. This is due to Haynesville having additional matrix porosity derived from secondary porosity in carbonate–a hybrid system.

If high thermal maturity is good, then excessively high thermal maturity must be even better? This appears to be incorrect, although not understood. Data is contradictory but there is evidence of possible gas destruction in hot reservoirs. The data on the right is derived from Barker and Takach (1991) showing a 50% volumetric loss of methane at high thermal maturity (>3.5%Ro).



Research Questions

Many questions remain poorly understood in shale-gas and shale-oil systems:

- What are the best indicators of high flow rate wells?
- Is commercial gas producible above 3.0%Ro?
- What are the best landing zones for horizontal wells? highest gas contents; most brittle rock?
- How important is carbonate content in shale or associated lithofacies?
- Why do some wells produce fair amounts of liquid hydrocarbons with gas whereas other wells are choked by the present of liquid hydrocarbons?
- Why are wells next to each other sometimes so variable in performance?
- When and how often are generated products expelled and how much is retained? Can this be used as a proxy for GIP?
- Do organic acids including CO2 play a role in creation of migration conduits or secondary porosity?
- What are the controls on porosity in addition to organic matter decomposition?
- How important is depositional setting on the likelihood of success for shale gas or oil?
- How can oil be produced more effectively from tight shales?