Shale gas: opportunities and challenges for independents

or, What’s in it for me??

Bob Cluff (SIPES 1832)
The Discovery Group Inc.
Denver, Colorado
SIPES 2009 Annual Meeting, Hilton Head, S.C.
What’s hot...........

- **Barnett Shale, Ft Worth basin**
  - old reliable, continues to deliver,
    independents do well

- **Woodford Shale, western Arkoma basin**
  - hard, cherty, not for the faint hearted

- **Fayetteville Shale, eastern Arkoma basin**
  - didn’t work with vertical wells, continuous improvement with horizontals
Marcellus Shale
- dark horse in the Appalachian basin
- Upper Devonian shales have produced since early 1800’s
- overpressured, relatively thin Middle Devonian shale was a surprise

Haynesville Shale
- hot, deep, & expensive, but monster IP’s
Major shale gas basins in the United States with total resource potential of 500 to 1,000 tcf.

Schlumberger, 2005, Shale Gas white paper

the Marcellus and Haynesville did not appear on this 2005 slide!
and what’s not?

- **Antrim Shale**
  - play is winding down as the economic limits have been reached

- **New Albany Shale**
  - not working for most players
  - even those sticking with it are less than enthusiastic

- **Floyd Shale**
  - the play that refuses to deliver despite Kent Bowker’s best efforts
- **Western Interior Cretaceous shales**
  - “gas shales” have mostly turned out to be silty zones interbedded in low TOC marine, gray shales (Mancos, Baxter, Lewis)

- **Penn shales, Texas Panhandle**
  - play appears to have fizzled out

- **West Texas Barnett-Woodford**
  - huge apparent GIP
  - but deliverability and cost challenged
Who the players are.....

- Chesapeake
- Devon
- Southwestern Energy
- EOG
- XTO
- Range Resources
- EnCana
- Newfield
- PetroHawk
- & many, many more

- BP
- ExxonMobil
- ConocoPhillips
- Shell
- *Chevron staying out?*
First principles:

- If you are in a hydrocarbon productive basin,
  - there will be a mature hydrocarbon source rock someplace in the section.
- And, if there are significant non-associated gas fields in the area,
  - there must be a source rock in the gas window down there!
- Now, all you have to do is find it! Well, except
  - you’ll have to lease it first,
  - then horizontally drill and frac it,
  - and produce it for years,
  - and dispose of water........................ and on and on.
Geologically, what is important?

- **Thickness** – mo’ is betta
- **TOC** – production is from the organic rich black shales.
- **Kerogen type** - Thus far, all production is from marine shales with mostly Type II kerogens.
- **Maturity** – high maturity shales appear to have much better deliverability
- **Porosity** – high microporosity is good
- **High gas in place** – combination of h, TOC, porosity, and maturity ($\rightarrow Sw$)
- **“Fracability”** – brittle shales that hydraulically fracture work best. Natural fractures are probably there, but not as important.
Thickness

- In every play, deliverability improves with greater target thickness
- Traditional subsurface mapping
  - total unit thickness
  - high GR zone thickness
  - low bulk density thickness
  - high resistivity shale thickness
  - net feet of neutron-density cross-over
- can do it with paper or raster logs. This is old school geology.
Typical log, West TX

DOWNES 1

<table>
<thead>
<tr>
<th>Depth</th>
<th>GR</th>
<th>T2</th>
<th>LLD</th>
<th>RHOB</th>
<th>NPHI</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.2</td>
<td>125</td>
<td>250</td>
<td>GR</td>
<td>0.45</td>
<td>-0.15</td>
</tr>
<tr>
<td>0.4</td>
<td></td>
<td></td>
<td>LLD</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.6</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.8</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.4</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.6</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.8</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Upper

Barnett Shale

Lower

Mississippian Ls

Upper

Woodford Shale

Middle

Lower

Devonian-Silurian Ls undifferentiated
Don’t be afraid of digital logs

- Digital logs ("LAS files") are widely available, but they are not free
- Standard geoscience packages like Petra, Geographix, can compute
  - net interval thicknesses above user cutoffs
  - sum any property, e.g. GR-feet
  - average any log values, e.g. Rdeep or bulk density
- Maps of basic log properties reveal changes in shale lithology, organic content, and even gas saturation!
Total organic carbon

- TOC, by convention in weight %, is the total amount of organic carbon in the rock
- This relates to:
  - How much material there was to generate oil or gas.
  - The adsorptive capacity of a shale to hold gas in the matrix, independent of porosity
- All gas shale plays occur in the black, high TOC shale facies. None are in the interbedded low TOC or “gray” shales.
How do we estimate TOC?

- TOC roughly correlates with high GR, low bulk density, and high $\Delta T$
- Linear regressions against core data provide good first order estimates
- Separating TOC from porosity can be problematic

Hasenmueller & Leininger, 1987
RhoB vs TOC
Huron shale, Ohio

low TOC
gray shales

high TOC
black shale

Devonian Ls

2.45 or 15% LS φ
Net radioactive Huron Shale

Net radioactive M. Devonian shale

Kerogen type

- All shale gas plays are in oil prone, marine “Type II” kerogen facies
- So called “gas prone” or coaly OM are not significant!

<table>
<thead>
<tr>
<th>Maceral</th>
<th>Kerogen Type</th>
<th>Original OM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alginite</td>
<td>I</td>
<td>Fresh-water algae</td>
</tr>
<tr>
<td>Exinite</td>
<td>II</td>
<td>Pollen, spores</td>
</tr>
<tr>
<td>Cutinite</td>
<td>II</td>
<td>Land-plant cuticle</td>
</tr>
<tr>
<td>Resinite</td>
<td>II</td>
<td>Land-plant resins</td>
</tr>
<tr>
<td>Liptinite</td>
<td>II</td>
<td>All land-plant lipids; marine algae</td>
</tr>
<tr>
<td>Vitrinite</td>
<td>III</td>
<td>Woody and cellulosic material from land plants</td>
</tr>
<tr>
<td>Inertinite</td>
<td>IV</td>
<td>Charcoal; highly oxidized or reworked material of any origin</td>
</tr>
</tbody>
</table>
SOM in transmitted light, a.k.a. “strew mounts”

Gas prone, phytoclasts

Oil prone, amorphous OM

www.millenni.demon.co.uk
Thermal maturation

http://www.uky.edu/KGS/coal/coalkinds.htm
Changes to kerogen with maturation

- Kerogen is gradually transformed as liquid and gaseous HC are generated
  - TOC goes down as hydrocarbons are expelled from source rock
  - Kerogen moves from high H content to low H, OI also decreases (down and slightly to the left on VK diagrams)
  - Residual or spent kerogen resembles Type IV with low HI and low OI (ultimately, graphite / pure C)
Two things are thought to happen when a gas shale enters the “gas window”

- more gas has been generated, so it is far more likely the bottle is completely filled with gas
- gas flow through the rock appears to be significantly improved
  - might be changes in the pore structure and pore throats, probably from volume changes of the kerogen itself,
  - or maybe microfractures were created during the maturation process,
  - or something we don’t understand happened.
Porosity

- Shale porosity is not well understood
- Core measurements indicate shales have 1 to 12% effective helium porosity
  - usually called gas filled porosity, this doesn’t count the pore space filled with clay bound water
- SEM studies suggest much of this is associated with organic matter, but there is no correlation between TOC and porosity
- For logs both kerogen and porosity look about the same, so peeling them apart is problematic
Gas in place

- **GIP is a combination of**
  - “free gas” in the porosity
    - just like gas in a sandstone, you need to know saturation, porosity, and gas volume factor
  - “adsorbed gas” on the organics
    - a function of organic matter type, maturity, organic content, and gas composition
    - measured in the laboratory using “isotherm” experiments
  - “absorbed” or dissolved gas
    - this is usually ignored or lumped in with adsorbed gas
  - total sorbed gas = all three
y = 14.217x - 32.974

R² = 0.9733

Total organic carbon (%)

Pressure (psi)

increasing TOC
GIP log calculations

- compute temperature and pressure as function of depth
- compute Langmuir parameter $V_L$ from density log or TOC log as a curve
  - have to decide how to approximate $P_L$ and temperature effect
- compute $G_c$ in SCF/ton from Langmuir equation
- $GIP/ac-ft = 1359.7 \times \text{RhoB} \times G_c$
  - $1 \text{ g/cm}^3 = 1359.7 \text{ tons/ac-ft}$
- cumulate the GIP/ac-ft curve over the well to get GIP/ac, convert to BCF/mi$^2$
Free gas calculation

- most companies presently playing gas shales assume they are mostly a free gas system, like a very tight siltstone

- GIP (mcf/ac-ft) = 43.56 * φ * S_g / B_g
  - φ is porosity available for gas storage, v/v
  - S_g is the gas saturation, v/v
  - B_g is the gas formation volume factor, rcf/scf

- We calculate this as a continuous curve
Total gas

- Convert the adsorbed gas content from SCF/ton (coal units) to MCF/ac-ft
- Free gas is in same units
- Sum the two to get total gas
- Cumulate from bottom up. Cumulative gas is in MCF/ac, usually converted to BCF/mi²
Total Gas Log

Schlumberger Shale Gas Advisor example

All gas in SCF/ton
Solves for cumulative gas (BCF/section)
Identify and quantify resource not visible with conventional logs
Total GIP Barnett + Woodford (BCF/ sq mile)
“Fracability” is everything
- if the shale won’t frac, you won’t produce gas.

The more brittle the rock, the better
- think “peanut butter” vs. “peanut brittle”, you choose

A brittle rock in an isotropic stress field tends to shatter when its fraced
- ideally, you get a broad elliptical fracture field with closely spaced fracs in multiple directions (“complex fracture pattern”)
Barnett shale fracture pattern

- Frac monitored from nearby observation well with microseismic technology
- Large single stage slickwater frac in center (red) well
- Distinct linear “streets and alleys” pattern develops over time
- 5 offset wells killed

Pinnacle Technologies
What determines brittle behavior?

- Poissons ratio and Youngs modulus (E) are the key rock parameters; the *insitu* stress field is the key area parameter
  - Brittleness “index” is a composite of PR and E

- Difficult to get without modern shear sonic (dipole) logs, preferably run in anisotropy mode

- *But*, simple correlations with DTC might get you close enough with evaluation of borehole breakouts and other stress indications
• YME is highly correlated with bulk density and sonic logs
What should you do?

- If you are in a gassy basin, there could well be shale gas potential under you.
- Do your homework first. You can get 70% of the picture without ever drilling a well.
  - basic subsurface geology
  - TOC and porosity from log analysis
  - geochemistry from cuttings or nearby cores
  - rock mechanics from sonic logs and caliper logs
- Develop the play concept, lease the core
- Partner up to drill a science or a proof-of-concept well
  - demonstrate presence of mobile gas
  - magnitude of gas in place resource
  - some minimum level of deliverability after frac
- Development will require horizontal drlg and fracing. Gets $$$$$ quickly. Few of these plays work on a low cost, vertical well basis.
Thank you!

Got questions?

www.discovery-group.com