The Barnett Shale as a Model for Unconventional Shale Gas Exploration

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(Houston is our largest suburb)
Petroleum Geochemistry

- **Exploration**
  - High-grading plays/prospects for likelihood of hydrocarbon charge
    - Source rocks
    - Oil typing
    - Correlations
    - Inversions

- **Production**
  - Assessing reservoirs and well plumbing
    - Reservoir continuity
    - Commingled allocation
    - EOR assessment
    - Well plumbing

**Exploration / Production**

Finding bypassed pay and predicting pre-test, pre-completion oil quality
Fractured Shale Petroleum Systems

• An organic rich, black shale is the source of hydrocarbons:
  1. from bacterial decomposition of organic matter
  2. from primary thermogenic decomposition of OM
  3. from secondary thermogenic cracking of oil

• May be the reservoir or other horizons may be primary or secondary reservoirs

• Have generation induced microfractures and perhaps tectonic fractures

• Undergo episodic generation, expulsion, and venting with maturation
Fractured shales yield oil and gas in various basins: there exist numerous similarities and differences among these systems.
USGS Data on Gas Bearing Shales

<table>
<thead>
<tr>
<th>Basin</th>
<th>Formation</th>
<th>T.O.C. (wt.%)</th>
<th>Range of Maturities (%Ro)</th>
<th>Estimated Recoverable Shale Gas (Tcf)</th>
<th>Shale Gas in place (Tcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appalachian</td>
<td>Ohio Shale</td>
<td>1-4.5*</td>
<td>0.4 - 1.3%</td>
<td>14.5 - 27.5</td>
<td>225 - 248</td>
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<tr>
<td></td>
<td>Barnet Shale</td>
<td>1-20</td>
<td>0.4 - 0.6</td>
<td>11 - 19</td>
<td>35 - 76</td>
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<tr>
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<td>Antrim Shale</td>
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<td>0.4 - 1.0</td>
<td>1.9 - 19.2</td>
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<td>New Albany Shale</td>
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<td>0.4 - 1.0</td>
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<td>86 - 160</td>
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<tr>
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<td>Barnett Shale</td>
<td>1-12*</td>
<td>0.6 - 1.6*</td>
<td>3.4 - 10</td>
<td>20**(min.)</td>
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<tr>
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<td>Lewis Shale</td>
<td>1-2.5*</td>
<td>1.6 - 1.9</td>
<td>na</td>
<td>na</td>
</tr>
</tbody>
</table>

* modified from USGS  ** author’s estimate
Gas Production from Fractured Shales

Barnett Shale est. 2002 based on 97 BCF in first half of 2002

Ref: Hill, 2000; Bowker, 2002
Petroleum System Definition:
Components and Processes

- Source Rock
- Migration Route
- Reservoir Rock
- Seal Rock
- Trap

- Generation
- Migration
- Accumulation
- Preservation

For high flow rate gas in fractured shales, must have oil destruction!

Ref: Modified from Armentrout, 2001
Distribution of Organic Matter in Rock Sample (low maturity)

Dispersed Organic Matter: the “source” of oil + assoc. gas

Total Organic Carbon (T.O.C.)

<table>
<thead>
<tr>
<th>Live Carbon</th>
<th>Dead Carbon</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td></td>
</tr>
<tr>
<td>Organic Matter (Kerogen)</td>
<td>Dead Carbon</td>
</tr>
<tr>
<td>Oil Prone</td>
<td>Gas Prone</td>
</tr>
<tr>
<td>S1</td>
<td>S2 (and Tmax)</td>
</tr>
</tbody>
</table>

Ref: Jarvie, 1991
Compositional Yields from Primary Cracking of Barnett Shale

CORRECTED MACT10 PY/GC YIELDS*

- C1: 13%
- C2-C4: 22%
- C5-C14: 55%
- C15+: 10%
Maturation of Organic Maturity

1. OM is converted to oil and gas; slight increased in dead carbon
2. 1 continues, but oil cracks to gas also
Episodic expulsion also changes the mix

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Total Organic Carbon (TOC)

Dead Carbon

Gas  Oil  OM  Dead Carbon

Genereation fracture

Residual oil, OM, and DC in rock

Expulsion

TOC

Oil  OM  Dead Carbon

Gas  Oil
Residual Oil and Residual OM are cracked to gas (if sufficient depth of burial)

Gas wetness is controlled by thermal maturity and perhaps physico chemical interaction of oil with clays in Barnett
Ft. Worth Basin

Location and principal geological features delimiting the basin
Barnett Shale Rock Characteristics

- Organic-rich, black shales
- **Thickness up to 1000 ft., average 300 ft.**
- Variable lithologic features
  - calcareous shale predominates
  - clay-rich shale intervals
  - cherty intervals
  - dolomitic intervals
- **Microfractures present, but limited visible fractures evident at surface**
Has expulsion of Barnett generated hydrocarbons into younger or older formations occurred?

- Low maturity oils in the western basin are all Barnett (8 horizons fingerprinted including the deeper Ellenburger) and are very high quality for low maturity \((ca. \ 40^\circ\text{API})\).

  n.b. This also explains natural ground water contamination in the basin.

- Higher maturity oils in Wise County are also Barnett sourced oils with similar properties although color is slightly different.

Thus, expulsion is episodic (different times and maturities)
In the Western Ft. Worth Basin, oils from the:
- Barnett
- Caddo
- Canyon
- Chester
- Chappel
- Conglomerate
- Ellenburger
- Flippen
- Gardner
- Harry Key Ls
- Hodge Eagle
- Hope
- Moran

Are all Barnett-sourced oils (43) based on oil fingerprinting results
(Ref: Jarvie et al, 2001)
Barnett Shale: Petroleum Potential and Maturity Trend

THERMAL MATURITY (Tmax in °C)

BO / AF (based on S2)

Lampasas outcrops!

Kerogen transformation trend line

Gas Window

If high TOC these are also gas window despite low (unreliable) Tmax values
General Observations

• High TOC marine shales are more efficient expellers of hydrocarbons
  – 1% poor  3% fair  10% excellent
• High TOC and clay content aid retention of hydrocarbons by adsorption
• Episodic expellers, a.k.a. pressure cookers: Generate HCs, form vapor lock – critical pressure exceeded, vent, and reseal; repeated depending on burial history
Generation of Oil and Gas

Source of Gas in Barnett Shale

- Gas from OM Cracking
- Gas from Oil Cracking
CACULATED TRANSFORMATION RATES for BARNET OM CRACKING and OIL CRACKING to GAS

Primary Kerogen Cracking

Secondary Oil-to-Gas Cracking
### Experimental Conversion of Barnett Shale

<table>
<thead>
<tr>
<th>Tmax</th>
<th>TOC</th>
<th>S2</th>
<th>HI</th>
</tr>
</thead>
<tbody>
<tr>
<td>432</td>
<td>5.21</td>
<td>19.80</td>
<td>380</td>
</tr>
<tr>
<td>435</td>
<td>4.53</td>
<td>13.45</td>
<td>297</td>
</tr>
<tr>
<td>437</td>
<td>4.11</td>
<td>10.27</td>
<td>250</td>
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<tr>
<td>443</td>
<td>3.77</td>
<td>5.88</td>
<td>156</td>
</tr>
<tr>
<td>455</td>
<td>3.41</td>
<td>1.81</td>
<td>53</td>
</tr>
<tr>
<td>470</td>
<td>3.32</td>
<td>1.36</td>
<td>41</td>
</tr>
</tbody>
</table>

**CONVERSION TO OIL and GAS**

- 36% ↓ TOC
- 89% ↓ HI

**Remaininng potential decreases**

**Tmax increases**

**Increasing Thermal Maturity**

**Original TOCs can be back calculated on high maturity samples:**

\[ \text{TOC}_p / 0.64 = \text{TOC}_o \]
Barnett Shale - Ave. Values

- T. P. Sims #2
  Newark East Field
  (n=46)
  - 4.45 TOC \( \text{TOC}_{\text{orig}} \) 6.95%
  - 0.60 S2 \( \text{S2}_{\text{orig}} \) 30.9
  - 555 Tmax
  - 44 HI
  - 6 NOC
  - 13 BO/AF

- or -

- 676 BO/AF
- 0.9 BBO
- 20 TCF

If across Newark E. Field
Transformation Ratio

A measure of the extent of kerogen conversion

- to determine this with reasonable accuracy, the original potential of the source rock must be determined

- multiple formulas
  - \( S_2_{\text{original}} - S_2_{\text{present}} / S_2_{\text{original}} \)
  - \( H_{I_{\text{original}}} - H_{I_{\text{present}}} / H_{I_{\text{original}}} \)
Newark East Field

T.P. Sims #2: Transformation Ratio

Original HI = 445  Present day HI = 44

TR = (445-44) / 445 x 100 = 89%

i.e., the Barnett Shale in the Sims well has lost 89% of its original hydrocarbon potential

Note: HI = mg HC/g TOC
Producibility and Gas Content

• Worst production comes from highly fractured (naturally) Barnett (Bowker, 2002)

• Gas content is directly proportional to TOC and maturity

• BTU content is inversely proportional to thermal maturity (Bowker, 2002)
Gas Yields Proportional to TOC values

Ref: Chattanooga Shale
Volumetric Calculation Chart

Requires:

TOC
HI original
HI present
Source thickness
Source areal extent
Source density

Schmoker’s chart for conversion of hydrocarbon mass to volumes of oil or gas equivalent

Schmoker, 1994
Volumes Calculated for Newark East Field only using the assumptions shown above

1E+15 CF gas ~ 1000 TCF gas

50% conversion loss ~ 500 TCF

1% recoverable ~ 5 TCF
Gas Composition
based on Production Results by County (ave.)

Ft. Worth Basin
2000 PRODUCTION
GORs by county

Source: TRRC

GOR=1000

GOR=3000

GOR=5000+

no production

Scale in Miles
Generalized Maturity Map based on TRCC production data (YTD 2000)

- **Oil**
- **Gas w/Oil**
- **Dry Gas**

Map showing varying maturity levels across different counties.
Why is there gas in Wise and Johnson Counties?
Primary and secondary gas generation

DUAL PHASE SYSTEM DUE TO GAS GENERATION FOLLOWED by PRESSURE and TEMPERATURE DROP IN LAST 50 ma
Johnson County:
Calculated vs. Measured %Ro

Good match between measured and calculated Ro
Why is there oil in Montague County?
Burial History and Hydrocarbon Generation History

Maximum burial temperatures yield only oil
Why wasn’t the ORYX GRANT #1 HORIZONTAL WELL COMMERCIAL FOR OIL?

Only 1 zone shows oil saturated Barnett

Productive Oil or Gas Intervals

Oil stains - shows

Lean - no production potential
Other wells have commercial oil that is evident from simple tests.

Zones yielding about 100 BO/day.

NORMALIZED OIL CONTENT (mg oil/g TOC)
Eastland County: Also in gas zone, different burial history
The presence or absence of top and bottom seals has impact on fracturing.
Risking Geochemical Data

• TOC – Quantity of Organic Matter
  – proportional to the amount of oil and gas generated
  – impacts expulsion efficiency

  ▪ 0.0 to 1.0% : Poor risk for oil or gas
  ▪ > 1.0 % : Good risk for oil or gas

Remember in the gas window, TOC may be reduced 30-50%
Risking Geochemical Data (cont.)

• Ro: 0.2%Ro to 4.0%Ro post mature

  • 0.55%Ro = onset of oil generation
  • 0.90%Ro = peak oil generation
  • 1.10%Ro = wet gas generation window
  • 1.40%Ro = dry gas generation window
  • 2.10%Ro = dry gas only zone
  • > 2.10 %Ro = reservoir destruction, CO₂ risk

Poor Risk for Gas

Good risk for gas
Risking Geochemical Data (cont.)

- TR: 0-100 % conversion of organic matter
  - 0.0 to 50.0 % TR – primarily oil
  - 50.0 to 75.0% TR – mixed oil and gas
  - 75.0 to 90.0% TR – primarily gas
  - > 90.0% TR – primarily dry gas

Poor Risk for Gas
Good risk for gas
Risking Geochemical Data (cont.)

- Gas yields: gas wetness ratios (0-100%)
  - gas flow gas yield
  - desorbed gas yield
  - macerated cuttings gas yield
  
  - 0.00 to 50.0: oil
  - 50.0 to 75.0: mixed oil and gas
  - 75.0 to 90.0: primarily gas
  - > 90.0: dry gas

    Poor Risk for Gas

    Good risk for gas
Finding High BTU Gas:
Ft. Worth Basin

BTU content is inversely proportional to maturity

BTU content is controlled by wet gas content (and nonhydrocarbon gases, if present)
Risking Geochemical Data (cont.)

- Seals
  - Top seal (Marble Falls)
  - Middle seal (Forestburg)
  - Lower seal (Viola)
  \[
  \text{Poor Risk for Gas}
  \]
  \[
  \text{Good risk for gas}
  \]
Risking Geochemical Data (cont.)

- Timing of expulsion / Uplift
  - No charge build-up
  - Charge build-up and venting
  - Charge build-up and no venting

\[ \text{Poor Risk for Gas} \]
\[ \text{Good risk for gas} \]
Risking Geochemical Data (cont.)

- Thickness of shale
  (must be considered jointly with TOC)
- Assume 4.5% TOC

  - 10 ft. \{ Poor Risk for Gas \}
  - 50 ft.
  - 100 ft. \{ Good risk for gas \}
  - 250 ft
  - 400 ft
  - 500+ ft
Shale Gas Evaluation Criteria:
Geochemical Risk Factors

- TOC < 1.00%
- %Ro < 1.1
- Tmax < 450
- TR < 0.70
- < 100,000 ppm headspace gas

Minimum values for gas prospects
Shale Gas Evaluation Criteria: Wise County Example

Min. values for gas prospects

High maturity shale: All risk factors favorable for high BTU gas
Shale Gas Evaluation Criteria:
Barnett Analog – Gas but Oil Window Maturity

Min. values for gas prospects
Antrim Shale: Biogenic Petroleum System

Measured Antrim data

Min. values for gas prospects
Know Petroleum System Character

1. Biogenic gas shale petroleum systems
2. Mixed biogenic/thermogenic gas shale systems
3. Thermogenic gas shale petroleum systems
   A. source and reservoir not the same
      i. timing of expulsion, migration, trap, and seal formation
      ii. dependent upon source rock OM type, maturity
      iii. could be primary or secondary gas expelled from source
   B. source and reservoir the same
      i. secondary gas generation (maturity/temperature)
      ii. timing of oil decomposition, episode of expulsion
4. Tight gas sands
5. Coal bed methane (primary gas generation)
What does it take for a commercial gas discovery in the Barnett Shale?

• Thermal maturity at some point in the past to reach 150°C+ for conversion of kerogen to oil/gas and oil to gas
  – %Ro > 1.1% but less than 2.1% to avoid reservoir destruction and high CO₂ yields
  – TR > 0.80
  – Tmax > 450°C
  – TOC values > 4%

• Uplift prior to expulsion / venting
Evaluation of Gas Potential while drilling – sweet spot identification

- Gas samples from gas flow line – new technique – an indication of “lost” gas (gas desorbed from the reservoir into the mud)
- Canned cuttings samples (desorbed gas) – the amount of gas (SCF/ton) that will be liberated from cuttings
- Cuttings gas analysis (gas liberated upon crushing cuttings – an indication of “frac” yields)
- TOC, Rock-Eval, TEGC, and vitrinite reflectance analyses (is it rich enough, converted enough (TR and Ro) to have generated commercial amounts of hydrocarbons)
Using Gas Composition and Isotopes for sweet spot and maturity assessments
CONCLUSIONS

• Barnett Shale has world-class petroleum potential; limiting factors are
  – thermal maturity
  – episodic expulsion
  – seals (leaky through time due to venting)

• Other unconventional resources have similar characteristics, but also some unique twists

• Risks can be reduced by careful evaluation of thermal maturity (kerogen conversion) and timing of events (generation, expulsion)
References


Jarvie, Daniel M.,


Appendix

- Terms
- Other graphics and maturity/TR/temp correlation table
- Barnett Shale: TOC and Rock-Eval values
- Solution to Schmoker’s oil and gas volume calculation
- SPI calculations
- Identifying sweet spots
- Oil and water saturation curves for SS and Sh
- Using geochemistry in unconventional gas plays
Terms

- **TOC** = total organic carbon (organic richness)
- **%Ro** = vitrinite reflectance (thermal maturity indicator)
- **TR** = transformation ratio (extent of conversion of kerogen where e.g., \( \frac{(\text{HIo}-\text{Hip})}{\text{HIo}} \))
- **Rock-Eval S1** = free oil content in rock
- **Rock-Eval S2** = remaining kerogen content in rock
- **Rock-Eval Tmax** = temperature at maximum S2 yield; an indication of thermal maturity
- **Primary cracking kinetics** = rate at which kerogen decomposes into hydrocarbons (oil and gas)
- **Secondary cracking kinetics** = rate at which oil decomposes into gas
Back-calculations of TOC

• At high maturity (85%+ Transformation Ratio (TR))
  
  - TOC present day  TOC original
    • 4.50% 7.00%
    • 2.00% 3.13%
    • 8.00% 12.50%

• Different TOCs at high maturity, reflect organofacies differences and impact expulsion and gas yields
Expulsion Efficiency is Related to TOC (but is dependent upon heating rate)

Ref: Burnham and Braun, 1991
Derivation of $HI_{\text{original}}$

- From a database of samples of the same organofacies of low thermal maturity
  - average HI value
- From back calculation or estimation of original
  - estimate the original potential from $HI_{\text{present}}$, visual kerogen, $T_{\text{max}}$, and $R_o$ data

{Organofacies is a single, mappable unit of organic matter of the same type without regard to the inorganic matrix}
Bakken Maturity Increases with depth of burial

Tmax shows a logarithmic increase with increasing depth of burial

Price et al., 1984
Extent of Organic Matter Conversion

Ave. HI_{Brown Cty} = 396

Ave. HI_{Eastland Cty} = 68

TR(\%) = \frac{(396-68)}{396} \times 100

= 83\%

and

328 \text{ mg HC/g TOC}

generated

Ref: Jarvie and Lundell, 1991
Eastern Ft. Worth Basin:

No Relationship between depth of burial and measured vitrinite reflectance value
Importance of Quality of Organic Matter – Kerogen Type: Differences in Organic Matter Types by product distribution

**Type I: Lacustrine Oil Prone Source Rocks**
- Labile: 60%
- Refractory: 10%
- Inert: 20%
- EOM: 10%

**Type II: Marine Oil Prone Source Rocks**
- Labile: 40%
- Refractory: 10%
- Inert: 40%
- EOM: 10%

**Type III: Gas Prone Source Rocks**
- Refractory: 25%
- Inert: 60%
- Labile: 10%
- EOM: 5%
Schematic Cross Section from Brown to Eastland County

Mitcham #1

TOC=4.67%
HI = 396
Ro = 0.60%
Tmax = 434

Brown City

Barnett Shale

TOC=3.40%
HI = 68
Ro = 1.10%
Tmax = 454

A.E.A. Heirs #1

Eastland Cty

Ref: Jarvie and Lundell, 1991
Relative Correlation of Vitrinite Reflectance to Rock-Eval Tmax
General Relationship between Transformation Ratio and %Ro
Secondary Cracking of Oil to Gas

Gulf of Mexico Case Study

Claypool and Mancini, 1989

Measured Oil Cracking in GOM at 3.0°C/My

\[ y = 0.1196e^{0.0141x} \]

\[ R^2 = 0.9997 \]
Relative Flow Rates vs. Thermal Maturity in selected fields

For illustration purposes only: too many variables to be a universal equation
Hypothesized Key Correlations
Type II (marine shale) low sulfur organic matter:

1. Thermal Maturity
2. Kerogen Transformation
3. Oil-to-Gas Transformation
4. Temperature

<table>
<thead>
<tr>
<th>Rock-Eval Tmax (°C)</th>
<th>Est. TR</th>
<th>Est. PI</th>
<th>Est. %Ro</th>
<th>Est. Oil-to-Gas Cracking</th>
<th>Est. Temperature (°C)</th>
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<tr>
<td>435</td>
<td>0.08</td>
<td>0.10</td>
<td>0.7</td>
<td>0.00</td>
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<td>0.15</td>
<td>0.8</td>
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<td>0.19</td>
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<td>450</td>
<td>0.52</td>
<td>0.24</td>
<td>0.9</td>
<td>0.00</td>
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<td>455</td>
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<td>1.0</td>
<td>0.05</td>
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<td>460</td>
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<td>1.1</td>
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<td>465</td>
<td>0.96</td>
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<td>1.2</td>
<td>0.28</td>
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<td>470</td>
<td>0.97</td>
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<td>1.3</td>
<td>0.45</td>
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<td>475</td>
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<td>1.4</td>
<td>0.58</td>
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<td>0.72</td>
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<td>487</td>
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<td>0.81</td>
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<td>492</td>
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<td>1.7</td>
<td>0.87</td>
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<td>498</td>
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<td>0.90</td>
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<td>503</td>
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<td>0.95</td>
<td>195</td>
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<td>507</td>
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<td>na</td>
<td>2.0</td>
<td>0.99</td>
<td>200</td>
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</table>
Calculate Transformation Ratio

\[ TR (\text{mg HC/g TOC}) = \frac{H_{\text{original}} - H_{\text{present}}}{H_{\text{original}}} \]

\[ H_{\text{present}} = \text{measured Hydrogen Index (HI) from sample at depth (mature)} = 150 \]

\[ H_{\text{original}} = \text{measured Hydrogen Index (HI) from immature sample} = 380 \]

\[ TR = \frac{(380-150)}{380} = 0.61 \text{ or } 61\% \text{ conversion} \]
Barnett Shale - Ave. Values

- All Barnett (n=540)
  - 3.16 TOC
  - 2.52 S2
  - 449 Tmax
  - 23 HI
  - 21 NOC
  - 55 BO/AF

- Low maturity Barnett (n=36)
  - 3.26 TOC
  - 7.87 S2
  - 432 Tmax
  - 165 HI
  - 33 NOC
  - 172 BO/AF

(in both cases primarily cuttings analysis)
Barnett Shale - Ave. Values

- Sims Core (n=46)
  - 4.45 TOC
  - 0.60 S2
  - 555 Tmax
  - 44 HI
  - 6 NOC
  - 13 BO/AF

- Lampasas Outcrops (n=3)
  - 11.82 TOC
  - 47.26 S2
  - 426 Tmax
  - 395 HI
  - 31 NOC
  - 1035 BO/AF
Barnett Shale: Petroleum Yields

Oil (BO/AF)
Newark East Field
Volumetric Calculation

• Calculate mass of organic carbon
• Assumptions
  – 25 x 37 mi areal extent (2.395739e+13 cm^2)
  – 450 ft. thick (U. and L. Barnett) (13,716 cm)
  – V = 3.2859956e+17 cm^3
  – density at 2.4 g/cm^3
  – TOC_{present} = 4.50; TOC_{original} = 6.95
  – Mass (g TOC) = 3.6540271e+16 g TOC
Calculation of Mass of HCs per gram of TOC

\[ M = H_{Io} - H_{Ip} \]
\[ = 380 - 44 \]
\[ = 336 \text{ mg hydrocarbons} / \text{g TOC} \]
Calculate Hydrocarbons Generated (HCG)

- HCG (kg HC) = R x M x 10^{-6} kg/mg
  - R in mg HC/g TOC
  - M in g TOC
  - 10^{-6} kg/mg is a conversion from mg to kg

HCG = 336 mg HC/g TOC x 3.6540271e+16 g TOC x 10^{-6} kg/mg

= 1.2277531e+13 kg HC
Schmoker’s Volumetric Calculation Chart

Humble Geochemical Services

Schmoker, 1994
Source Potential Index (SPI)

- A measure of the potential of a source rock to generate hydrocarbons over a given areal extent

- SPI = \( h \times (S1+S2) \times \frac{p}{1000} \)
  - where \( h \) = thickness of source rock
  - \( S1+S2 \) data from Rock-Eval (mg HC/g rock)
  - \( p \) = density, assume 2.5 t/m\(^3\)

- Must also account for migration and entrapment styles

Ref: Demaison and Huizinga, 1994
SPI – Barnett Shale, Wise County

- **Assumptions:**
  - $h = 250$ ft. or 76.2 m
  - $S_1 + S_2 = 20.00$ t/kg rock
  - $p = 2.50$ t/m³
- **SPI** = $76.2 \times 20 \times 2.5 / 1000$
  - = 3.81 t / m²
- **Add U. Barnett (150 ft.)**
  - = 6.10 t / m²
- **Increase S1+S2 (27.79 ave. per unit TOC) based on Lampasas outcrop yields**
  - = 8.34 t / m²
- **Maximum S1+S2 at Lampasas = 47.75**
  - = 14.38 t / m²
# EXAMPLES OF AVERAGE SOURCE POTENTIAL INDICES

(tons HC/m²)

<table>
<thead>
<tr>
<th>Rank</th>
<th>Location</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Junggar (China)</td>
<td>65</td>
</tr>
<tr>
<td>2</td>
<td>L. Congo (Cabinda)</td>
<td>46</td>
</tr>
<tr>
<td>3</td>
<td>Santa Barbara Channel (U.S.A.)</td>
<td>39</td>
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<tr>
<td>4</td>
<td>San Joaquin (U.S.A.)</td>
<td>38</td>
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<td>5</td>
<td>Central Sumatra (Indonesia)</td>
<td>34</td>
</tr>
<tr>
<td>6</td>
<td>E. Venezuela fold and thrust belt</td>
<td>27</td>
</tr>
<tr>
<td>7</td>
<td>Offshore Santa Maria (U.S.A.)</td>
<td>21</td>
</tr>
</tbody>
</table>

Ref: Demaison and Huizinga, 1994
EXAMPLES OF SPI (cont.)

(tons HC/m²)

8. Middle Magdalena (Colombia): 16
10. Central Arabia (S. Arabia): 14
12. Gulf of Suez (Egypt): 14

★ Reserves estimated at 10 TCF or ~ 1.67B BOE
Finding High BTU Gas

BTU content is controlled by wet gas content

V. High Maturity
High Maturity
Mod. Maturity

BTU content is controlled by wet gas content

GAS CALORIFIC VALUE (BTU)

DRY-to-WET GAS RATIO
Identification of oil, wet or dry gas by fingerprinting directly from cuttings or core chips: TEGC
Also useful for GOR prediction

Oil Prone

Gas Prone
C$_7$-determined Generation Temperatures for Barnett Oils

Barnett Oils on trend line with Bakken oils

Increasing GOR
GORs can be predicted with some degree of accuracy from both vitrinite reflectance and oil/condensate light hydrocarbons

\[ R^2 = 0.9233 \]
TYPICAL SANDSTONE RESERVOIR ROCK

![Graph showing relative permeability vs. water saturation]
TYPICAL SHALE RESERVOIR ROCK is quite different from a conventional reservoir

Ref: Okui and Waples, 2000
Using Geochemistry in Unconventional Plays

- Construct maps
  - Organic facies (maceral) maps
  - Maturity and TR maps
  - Composition (GOR) maps
  - BTU maps
- Needs to construct maps
  - Geological/geophysical information
  - Geochemical data (TOC, RE, Ro, Compo.)
Using Geochemistry in Unconventional Plays

• Construct well and basin models
  – Burial history curves
  – Timing of generation and expulsion
• Evaluate amounts expelled (reduces amount of oil to crack to gas)
• Timing of uplift impacts expulsion
• Optimize models using geochemical data such as TOC, Ro, TR