UNCONVENTIONAL OIL AND GAS OPPORTUNITIES IN SOUTH AUSTRALIA

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Unconventional Gas and Oil

Prospective plays in the mix:

1. Shale gas in the Cooper (> 3 JVs)
2. Shale gas in the Otway (> 2 JVs)
3. Shale gas in the Officer (2 JVs)
4. Gas in low permeability reservoirs (tight gas) – Cooper Basin (> 3 JVs)
5. Fracture stimulation of coals, Cooper Basin (> 3 JVs)
6. Coal Seam Gas in the Eromanga (> 3 JVs)
7. Underground coal gasification – Walloway, Arckaringa, Pedirka and other basins (2 JV)
8. Coals mining - Arckaringa & Tertiary basins for power generation, syngas and synfuel (> 4 JVs)
9. Other Coal -Sourced Gas in Jurassic and Tertiary Basins (>2 JVs)
Objective: Inform industry strategies and government policies to underpin optimum life-cycle upstream-downstream planning for the deployment of technologies and infrastructure for exporting unconventional petroleum gas and liquids

Strategy: Convene a Roundtable (government and Industry) focused on unconventional petroleum gas and liquids to rank opportunities and threats in a roadmap for the development of unconventional gas

Outcomes (via roadmap to be released in May 2012):
- Informed industry investment and infrastructure strategies
- Informed government legislation, policies and programs
Cooper Basin and US shale gas basins

Shale Gas Plays, Lower 48 States

Cooper Basin inset from Beach Energy Presentation, "Cooper Basin Shale Gas", April 2010
### Comparison with US Shale Gas Plays

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Barnett</th>
<th>Fayetteville</th>
<th>Marcellus</th>
<th>Haynesville</th>
<th>Cooper Basin</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (ft)</td>
<td>5400 - 9600’</td>
<td>1200 - 7500’</td>
<td>1500 - 8000’</td>
<td>10000 - 13000’</td>
<td>9500 - 11500’</td>
</tr>
<tr>
<td>Thickness (ft)</td>
<td>250 - 500’</td>
<td>50 - 200’</td>
<td>75 - 300’</td>
<td>200 - 300’</td>
<td>400 - 500’</td>
</tr>
<tr>
<td>Petrology</td>
<td>Siliceous Mudstone</td>
<td>Siliceous Mudstone</td>
<td>Argillaceous Mudstone</td>
<td>Argillaceous/ Calcareous Mudstone</td>
<td>Siltstone/ Siliceous Mudstone</td>
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<tr>
<td>Age</td>
<td>Carboniferous</td>
<td>Carboniferous</td>
<td>Devonian</td>
<td>Jurassic</td>
<td>Permian</td>
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<tr>
<td>Porosity %</td>
<td>7</td>
<td>6.5</td>
<td>6</td>
<td>10</td>
<td>To be measured</td>
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<tr>
<td>TOC Av%</td>
<td>5</td>
<td>4</td>
<td>6</td>
<td>4</td>
<td>5</td>
</tr>
<tr>
<td>Ro %</td>
<td>1-1.3 (type II)</td>
<td>&gt;1</td>
<td>&gt;1</td>
<td>2.2 - 3 (type III)</td>
<td>0.9 - 3.4 (type II to III)</td>
</tr>
<tr>
<td>Temp F</td>
<td>200</td>
<td></td>
<td>240 - 322</td>
<td>300 - 390</td>
<td></td>
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<tr>
<td>GIP (Av)</td>
<td>100</td>
<td>48</td>
<td>100</td>
<td>200</td>
<td>~25 (prelim)</td>
</tr>
</tbody>
</table>

Modified from Beach Energy Presentation, “Cooper Basin Shale Gas”, April 2010
Unconventional gas Cooper Basin

**Beach Energy: PEL 218**
Holdfast 1 flowed gas at up to 2 MMscf/d after seven stage fracture stimulation of gas saturated Early Permian succession. Beach estimate potential 300 TCF gas in place in PEL 218 (Nappamerri Trough, SA) – almost 100 TCF in shales and >200 TCF in sands (BCGA)

**Santos:**
Booked 2C (contingent, probable, recoverable, Santos share) unconventional gas resources (shale gas, tight gas, deep coal) of ~2.22 TCF (2,345 PJ)

**Senex Energy, PEL 516:** Estimate 75-110 TCF gas in place in shales and coals

**Strike, Beach, PELs 94, 95, 96:** Mean prospective resource estimate 12.39 TCF gas and 113 MMbbls liquids in coals and shales
Cooper Basin Structural Elements

3 Main Troughs
- Patchawarra
- Nappamerri (current shale gas focus)
- Tenapperra
Cooper Basin shale gas targets

Roseneath Shale (Lacustrine)
Comprises light and dark brown siltstone, mudstone and minor sandstones. Siltstones are micaceous with minor fine grained pyrite.

Murteree Shale (Lacustrine)
Comprises black to dark grey - brown argillaceous siltstone and minor sandstones, becoming sandier to the southern Cooper Basin.
Comparison of Barnett (USA) and Cooper REM Shale Gas Plays ....and unlike CSG – Shale Gas can be rich in ethane, LPG & condensate

**Barnett Shale**
- Siliceous mudstone
- Type II source rock
- Thickness: 250-500’
- TOC Ave: 5%

**Moomba 77 – Cooper Basin**
- Roseneath Shale (191’, 58m)
- Epsilon Formation (224’, 68m)
- Murteree Shale (163’, 50m)

**REM**
- Roseneath-Epsilon-Murteree
- Siliceous mudstone
- Type II source rock
- Thickness: 400-500’
- TOC Ave: 5%

*From Beach Energy presentation “Cooper Basin Shale Gas”, Gordon Moseby, 30 March 2010

Wireline log through Barnett Shale from Kinley et al, 2008 “Hydrocarbon Potential of the Barnett Shale (Mississippian), Delaware Basin, west Texas and southeastern New Mexico” AAPG v92, No 8
Evidence for Basin Centred Gas Accumulation

Log evaluation suggests thick gas columns and tests have recovered only gas and no water. Resistivity of the entire rock section exceeds 20 Ωm over large intervals (Hillis et al, 2001)
GeoFrac (Dennis Cooke, ASP):

- Fracture stimulation and geomechanics research for unconventional reservoirs
- Natural fracture density, critically stressed natural fractures, local stress, geomechanical causes of frac complexity, proppant embedment, proppant placement

ASP

- Elizabeth Baruch – PhD student (has worked with Conoco-Phillips Eagleford Shale research team in US) will be researching geological and geomechanical characteristics of REM in Cooper Basin (project not finalised – Mark Tingay supervisor)
- Engineering students researching proppant emplacement in coals (Proffesor Pavel Bedrikovetsky supervisor)

Adelaide University:

- Dr Martin Kennedy recently appointed to staff professorial position. Research focuses on new source rock model that considers preservative effects, depositional controls, and influence on cracking T of the mineral surfaces hosting organic matter
Moomba-Big Lake: Attribute analysis - Most positive curvature

From “Geomechanical Characterization of Unconventional Play on the Cooper Basin of Australia” Presentation by Guillaume Backé and Ros King, 2010
Research by the GEOFRAC consortia at the University of Adelaide
Targeting production and ~5,000 PJ resource by 2015

2004–2010

**Acquired the resource understanding**
- Australia’s first shale fracture and coring program in 2006
- Australia’s first independently certified shale and unconventional resource bookings achieved in 2008

**2011–2012**

**Vertical well technology trials and optimisation**
- Acquiring further data to enable appraisal optimisation
- Dedicated shale well including dedicated shale fracturing

**2012–2013**

**Horizontal well technology trials and optimisation**
- Dedicated shale horizontal drilling trial
- Extensive fracturing trials beyond levels currently tested in the Cooper

**2013+**

**Evaluation across broader Santos Cooper acreage**
- Multiple horizontal and vertical appraisal wells
- Targeting initial shale reserve bookings in 2013, and production in 2015

\[2C^* \text{ Outlook} \]

* Santos share – total shale and other unconventional resources

Source: Santos Investor Seminar, 10 November 2011
Beach Energy Nappamerri Trough Project (PEL 218)

Fracture stimulate Encounter-1 ~ 7 zones
Q4 2011

Independent certification of reserves and resources bookings
Q1 2012

Three horizontal and five vertical wells
2012

Extended flow testing of new wells
Q1/Q2 2013

Expansion of production pilot wells
2013

Development and production program
2013/2014

$200 million estimated capex

Source: Beach Energy Limited, AGM Presentation, November 2011
Deep coal seam gas play – Cooper Basin

• 375 billion cubic metres of Patchawarra coal
• 525 billion tonnes (assuming density 1.4 g/cc)
• Seams up to 22m thick; combined thickness >60m in Patchawarra Fm
• 12,440 TCF energy equivalent (assuming 0.000025 PJ/tonne specific energy)
• Current Australian gas market 1 TCF/annum

Patchawarra Formation
High rank bituminous to anthracitic coal

Toolachee Formation
COOPER BASIN COALS
fracking coals a potential play

Wimma 1 – Patchawarra Formation

45 ft coal seam at 
~11,155 ft
2800 units
Total Gas

Moomba 77 – Patchawarra Formation

30 ft coal seam at 
~9514 ft
~900 units
Total Gas

New release planned for mid 2012: PEL 111 relinquished acreage (likely to be oil play)

- Avg area PELs 386,370 acres (1563 sqkm)
- Formerly 1 PEL, 3 major releases 1998-2000

**Expiry year**
- 2010 – 2011
- 2012 – 2013
- 2014 – 2015
- 2016 – 2017

**Relinquishment upon renewal**
- Half
- Third
- All
Otway Basin

- Conventional gas, oil, CO₂
- Competitive tender region, no current onshore acreage release
- Vacant acreage + licences with relinquishments in 2012
- Some unconventional gas and shale oil potential
- Infrastructure – pipelines and plant
- Offshore acreage release in May 2012

Asphaltite collected from a beach (oil source)

Current licence
2011 relinquishment
Retention licence (PRL)
Production licence (PPL)
Gas pipeline
Otway Basin – Structural elements
Otway Basin – Potential shale gas and shale oil targets
Penola Trough, Otway Basin
Penola Trough, Otway Basin
Otway Basin – HI vs Tmax plot, Casterton Fm

Total Organic Carbon (TOC)

Range: 0.6 to 9%
Average: 1.9% (39 samples; 6 wells).

Type II (algal rich oil prone kerogen) to Type III (Gas prone) source rocks

Casterton Fm possibly up to 500m thick in onshore Robe Trough

Courtesy: Hector Gordon, Somerton Energy
Otway Basin – Shale gas play

Bed maturity map for top Casterton Formation as a proxy for the base Lower Sawpit Shale.

The main shale gas play for the Casterton Formation and Upper and Lower Sawpit Shales is highlighted in pink and corresponds to a VR range of 1.3 to 2.6% (depth >3800m);
Arckaringa Basin – Early Permian sediments infill erosional land surface shaped by the Gondwana glaciation

Seismic dip line across West Trough and Phillipson Trough (3 x vertical exaggeration)

Composite seismic line along Boorthanna Trough (10 x vertical exaggeration)
Stratigraphic Column – Southern Arckaringa Basin (modified from Menpes 2010)

### Table: ARKETTA 1

<table>
<thead>
<tr>
<th>Age</th>
<th>Biostrat Unit</th>
<th>Depositional Environment</th>
<th>Formation and Seismic Horizon</th>
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<tbody>
<tr>
<td><strong>PERMIAN</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sakmarian</td>
<td>PP2</td>
<td>Brackish-Restricted Marine*</td>
<td>Upper Mount Toondina Formation</td>
</tr>
<tr>
<td>Asselian</td>
<td>PP1</td>
<td>Brackish-Lacustrine*</td>
<td>Lower Mount Toondina Formation</td>
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<tr>
<td><strong>EARLY</strong></td>
<td></td>
<td></td>
<td>Cage Range Formation</td>
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</table>

**Notes:**
- Depositional environment interpreted from Arkeeta 1 palynological study (McBain, 1987)
- Palynological zones from Arkeeta 1 palynological study (McBain, 1987) converted to biostratigraphic units defined by Price et al, 1985
- Lithology modified from Lake Phillipson Bore (after Hibburt, 1984, Figure 12)

### Graphical Information:
- Organic rich marine shales
- 70m thick black shale in Arck-1, depth 854m - prelim. analysis indicates potential oil yields of between 25 to 45 litres per tonne.
## Arkeeta 1 Rock Eval Data

<table>
<thead>
<tr>
<th>DEPTH</th>
<th>T MAX</th>
<th>S1</th>
<th>S2</th>
<th>S3</th>
<th>S1*S2</th>
<th>PI</th>
<th>S2/S3</th>
<th>PC</th>
<th>TOC</th>
<th>HI</th>
<th>DI</th>
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<td>84-87</td>
<td>421</td>
<td>2.00</td>
<td>160.80</td>
<td>7.90</td>
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<td>13.56</td>
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<td>123-126</td>
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<td>190.55</td>
<td>6.01</td>
<td>193.60</td>
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<td>31.70</td>
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<td>134-137</td>
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<td>3.88</td>
<td>10.66</td>
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<td>3.11</td>
<td>0.88</td>
<td>4.05</td>
<td>205.81</td>
<td></td>
</tr>
</tbody>
</table>

50mg/g of rock = ~57 litres/tonne of rock = ~0.36 bbls/tonne of rock

### Lower Mount Toondina Formation (Early Permian)

- TOC > 2%, HI > 400

### Stuart Range Formation (Early Permian)

### Upper Boorthanna Formation (Late Carb – Early Perm)

### Lower Boorthanna Formation (Late Carb – Early Perm)
Arckaringa Basin – organic rich shales

Hydrogen Index versus Tmax (°C)

Tmax vs HI – Arck 1, Boorthanna Trough

Tmax vs HI – Arkeeta 1, Phillipson Trough
Boorthanna Trough

Flattened on Blue Horizon (8X Vertical)

Organic rich shales?
Big fish bite if you’ve got good bait
For more information, visit APPEX booth 134