Lower 48 Onshore

June 2016

MidCon - Multi Lateral Development Pad
Our Mission, Strategy and Commitment

• Build a **premier, market visible, competitive** onshore operating company

• Create a **high performance culture** based on empowerment, accountability and collegiality

• Deliver **high rates of return** and **create value** on our massive, largely **untested** acreage

• Drive **capital efficiency** through **innovative** drilling and completion techniques

• Maintaining BP’s Core Values and **strong commitment** to **Safety** and the **Environment**
Our Assets Today

- Five business units
- 6.0m net acres
- Produced 293 mboed in 1Q 2016
- 24,000 wells, 10,000 operated
- Resource base of 7.5 bn boe at YE 2015
  - 37 tcf gas and 1.2 bn boe liquids
- 15,000 horizontal laterals identified

**L48 Relative to Other Independents**

<table>
<thead>
<tr>
<th>Enterprise value ($ in bn)</th>
<th>$13</th>
<th>$15</th>
<th>&lt;= --&gt;</th>
<th>$10</th>
</tr>
</thead>
<tbody>
<tr>
<td>% Gas</td>
<td>93%</td>
<td>77%</td>
<td>83%</td>
<td>67%</td>
</tr>
</tbody>
</table>

**1Q 2016 Daily Production (mmcfe/d)**

Source: BP Internal and Credit Suisse public company data
Note: L48 conversion rate: 5.8 mcfe = 1 boe. Estimated enterprise value as of 6/2016 pro forma for transactions as necessary.
Increasing Capital Efficiency Through Innovative Well Designs
Evolution of Development Programs Leading to Multi-Lateral Horizontal Wells
North - Greater Green River Basin
Material Horizontal Development Potential

- 500,000 net acres
- Six distinct petroleum systems
- 1.4 bn boe of resource potential
- Multiple stacked liquid rich targets
- ~2,000 horizontal locations identified
## North - Greater Green River Basin

Liquid Saturated Stacked Reservoirs

<table>
<thead>
<tr>
<th>Horizon</th>
<th>Hydrocarbon</th>
<th>Horizontals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fort Union</td>
<td>Wet Gas</td>
<td>~120</td>
</tr>
<tr>
<td>Fox Hills</td>
<td>Wet to Dry Gas</td>
<td>~60</td>
</tr>
<tr>
<td>Lewis</td>
<td>Oil to Condensate</td>
<td>~180</td>
</tr>
<tr>
<td>Almond</td>
<td>Wet to Dry Gas</td>
<td>~1,600</td>
</tr>
</tbody>
</table>

~7,000’ TVD

~5,000’

~14,000’ TVD
North - Greater Green River Basin
Early Horizontal Wells Creating Significant Value

- 2015 – 1st horizontal in eight years
- Eight horizontal wells since September 2015
- Horizontal wells delivering up to 45% IRR*
- Aggressively building drilling inventory
- First multilateral to spud June 2016
- Multilateral development economics projecting >80% IRR and $9.7/boe development cost at $14m well cost in Tier 1 locations

* At $10m well cost
Economics are post tax, include capitalized overhead and were run at $3HH and $55WTI
West - San Juan Basin
World Class Gas Resource

- Applying innovative techniques to achieve premier returns
- 570,000 net acres
- Four prolific and discrete reservoirs with multiple intervals/seams in each
- 2.1 bn boe of resource potential
- 2,000 horizontal locations identified
- Additional untested intervals within and below producing stratigraphic column
West - San Juan Basin
Discrete and Prolific Reservoirs with Horizontal/Multilateral Potential

<table>
<thead>
<tr>
<th>Horizon</th>
<th>Reservoir</th>
<th>Locations</th>
<th>Hydrocarbon</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fruitland</td>
<td>Coal bed methane</td>
<td>200</td>
<td>Dry Gas</td>
</tr>
<tr>
<td>Mesaverde</td>
<td>Marine &amp; non-marine sands</td>
<td>50</td>
<td>Wet Gas</td>
</tr>
<tr>
<td>Mancos</td>
<td>Marine source rock</td>
<td>~1,600</td>
<td>Gas &amp; Oil</td>
</tr>
<tr>
<td>Dakota</td>
<td>Marine sands</td>
<td>120</td>
<td>Wet Gas</td>
</tr>
</tbody>
</table>
West - San Juan Basin Coal Bed Methane
Innovative well designs driving premier returns

• Highest multilateral production in the basin
• Average multi-lateral development cost of $1.9/boe
• Successful tri-lateral accessing 14,600 ft of coal
• Continuing to innovate with more and longer laterals

Dual-Lateral

Tri-Lateral

Economics are post tax, include capitalized overhead and were run at $3HH and $55WTI

<table>
<thead>
<tr>
<th></th>
<th>Parry E2</th>
<th>Seibel A2</th>
<th>Seibel B2</th>
<th>Horther</th>
</tr>
</thead>
<tbody>
<tr>
<td>D&amp;C, m$</td>
<td>2.0</td>
<td>1.7</td>
<td>1.8</td>
<td>2.6</td>
</tr>
<tr>
<td>IRR, %</td>
<td>47%</td>
<td>100%+</td>
<td>100%+</td>
<td>100%+</td>
</tr>
<tr>
<td>Max 30, mmscfd</td>
<td>2.2</td>
<td>5.7</td>
<td>5.5</td>
<td>5.5*</td>
</tr>
<tr>
<td>EUR, bcf</td>
<td>5</td>
<td>6</td>
<td>6</td>
<td>11</td>
</tr>
</tbody>
</table>

* Peak rate since well still ramping up
West - San Juan Basin Mancos
Early Mover in Emerging Play with Tremendous Potential

- Devon acquisition added material position
- 1,600+ horizontal locations identified*
- Projecting >25% IRR and $3.0/boe development cost, at $6.8m well cost in Tier 1 area through improved targeting, execution and enhanced completions
- Evaluating potential of oil window

* Based on 5,000 ft wells
Economics are post tax, include capitalized overhead and were run at $3HH and $55WTI
MidCon - Anadarko and Arkoma Basins

Hydrocarbon Rich Regions with Stacked Oil and Gas Pay

**Anadarko Basin**
- 900,000 net acres
- 1,200 producing wells; 100 horizontals
- Production from 10+ different horizons
- 400 mmboe of resource potential; 30% oil
- 2,400+ laterals identified

**Arkoma Basin**
- 650,000 net acres
- 1,600 producing wells; 200 horizontals
- Production from 10+ different horizons
- 700 mmboe of resource potential; 95% gas
- 4,000+ laterals identified

[Map showing hydrocarbon rich regions with stacked oil and gas pay]
# MidCon - Anadarko and Arkoma Basins

Prolific Reservoirs Sourced by Woodford and Carboniferous Shales

<table>
<thead>
<tr>
<th>Formation</th>
<th>Basin</th>
<th>Reservoir Type</th>
<th>Horizontals</th>
<th>Petroleum System</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cleveland</td>
<td>Anadarko</td>
<td>Tight Sand</td>
<td>385</td>
<td>Oil to Wet Gas</td>
</tr>
<tr>
<td>Marmaton</td>
<td>Anadarko</td>
<td>Tight Sand</td>
<td>180</td>
<td>Oil to Condensate</td>
</tr>
<tr>
<td>Granite Wash</td>
<td>Anadarko</td>
<td>Tight Sand</td>
<td>410</td>
<td>Condensate to Wet Gas</td>
</tr>
<tr>
<td>Cromwell</td>
<td>Arkoma</td>
<td>Tight Sand</td>
<td>180</td>
<td>Oil</td>
</tr>
<tr>
<td>Woodford</td>
<td>Arkoma</td>
<td>Shale</td>
<td>890</td>
<td>Condensate to Dry Gas</td>
</tr>
</tbody>
</table>

- **Oil to Condensate**
- **Condensate to Wet Gas**
- **Wet to Dry Gas**
MidCon - Anadarko Basin Industry First Innovations
Cleveland Dual-Lateral, Cleveland Tri-Lateral and Onshore Junction Isolation

- > 8,000’ of stimulated reservoir
- Projecting ~25% IRR and $5.8/boe development cost at $3.8m well cost
- Additional laterals decrease cost per lateral foot
- IP30 1,360 boepd (37% oil)
- Oil yield increases with multi-laterals

- > 12,000’ of stimulated reservoir
- Projecting 30% IRR and $5.8/boe development cost at $5.1m well cost (42% oil)
- 48% capital cost reduction over single laterals
- Industry first onshore junction isolation system
- Expect first production in August 2016

Economics are post tax, include capitalized overhead and were run at $3HH and $55WTI
MidCon - Arkoma Basin Development Performance
Premier Execution in Woodford Shale

- 176,000 acres in the core area
- Projecting 25% IRR and $2.8/boe development cost at $4.0m well cost
- Evaluating multi-lateral potential

Economics are post tax, include capitalized overhead and were run at $3HH and $55WTI
East - East Texas Basin
Large Lease and Mineral Position in a Prolific Basin

- 1,400,000 net acres, including 1,000,000 mineral acres
- Five discrete petroleum systems
- 950 mmboe of resource potential
- ~1,000 horizontal locations over three stacked pays
- Evaluating seven additional stacked pays
East - East Texas Basin
Robust Opportunities in Stacked Plays

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<tr>
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<th>Horizontals</th>
<th>Reservoir Type</th>
<th>Petroleum System</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cotton Valley</td>
<td>100</td>
<td>Tight Sands</td>
<td>Wet to Dry Gas</td>
</tr>
<tr>
<td>Bossier</td>
<td>400</td>
<td>Shale</td>
<td>Dry Gas</td>
</tr>
<tr>
<td>Haynesville</td>
<td>500</td>
<td>Shale</td>
<td>Wet to Dry Gas</td>
</tr>
</tbody>
</table>

Additional horizontal plays under evaluation:

- Travis Peak
- Austin Chalk
- Wilcox
- Pettit
- Woodbine
- Yegua
- James Lime
East - East Texas Basin

Haynesville Results Delivering Premier Returns

- Integrating advanced technology to optimize completions design
- Projecting ~35% IRR and $5.9/boe development cost at $9.1m well cost
- Potential 50% IRR uplift on mineral acreage

Micro-seismic Imaging Integrated with 3D Seismic

Economics are post tax, include capitalized overhead and were run at $3HH and $55WTI
South - Eagle Ford Development
World Class Shale Gas Development Program

- 190,000 net acres
- Non-operated, average 41% WI
- Drilled > 400 horizontal wells in five years
- Proven value creating relationship with Lewis Energy Group, a vertically integrated operator in South Texas
- 1.6 bn boe of resource potential
- 4,800 horizontal locations
- Additional stacked reservoirs: Escondido, Olmos, and Austin Chalk
South - Eagle Ford Development
Premier Stacked Pay Opportunities

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<th>Petroleum System</th>
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<tr>
<td>Escondido</td>
<td>600</td>
<td>Tight Sand</td>
<td>Wet Gas</td>
</tr>
<tr>
<td>Olmos</td>
<td>350</td>
<td>Tight Sand</td>
<td>Wet to Dry Gas</td>
</tr>
<tr>
<td>Austin Chalk</td>
<td>Evaluating</td>
<td>Limestone</td>
<td>Oil to Dry Gas</td>
</tr>
<tr>
<td>Upper Eagle Ford</td>
<td>1,250</td>
<td>Shale</td>
<td>Oil to Dry Gas</td>
</tr>
<tr>
<td>Lower Eagle Ford</td>
<td>3,600</td>
<td>Shale</td>
<td>Oil to Dry Gas</td>
</tr>
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</table>
South - Eagle Ford Development
Enhanced Frac Design Yields Step Change In Performance

- New enhanced fracture stimulations initiated
  - Increased number of frac stages
  - Increased proppant loading
  - First three wells producing a combined 36mmcf/d

- IRR ~50% and $2.1/boe development cost at $5.1m well cost

- Offset operators include Noble Energy and SM Energy

Economics are post tax, include capitalized overhead and were run at $3HH and $55WTI
Improving Cost Structure

- Utilizing data analytics to increase efficiency and decrease deferment
- Hiring in-house data scientist and matching with engineering teams
- Staff reduction of 54% from 2012 to 1Q 2016

Production cost includes LOE (Lease operating expense), G&A (General and administrative expense) and midstream fees. It does not include depreciation, depletion and amortization, ad valorem and severance taxes and certain other costs.
Profitable and Flexible Growth Vehicle

- 7.5 bn boe, short-cycle incumbent resource position
- 15,000 horizontal lateral locations identified
- Innovative approaches dramatically improving cost and capital efficiency
  - Data analytics
  - Advanced artificial lift
  - Multi-lateral wells
  - Custom completion designs
- 42% of yet to drill resources are economic at $3 HH or below*

* Break-even was calculated using after tax PV10, WTI prices: 2016 $46.99, 2017 $51.13, 2018 $59.93, 2019 $81.40, inflated 2% thereafter