Corporate Update
December 2014

Hangingstone – Thermal Oil

Duvernay – Light Oil
Forward Looking Statement

This presentation contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words "anticipate," "plan," "continue," "estimate," "expect," "may," "will," "project," "should," "believe," "target," "predict," "pursue" and "potential" and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company's current plans, objectives, goals, strategic plans, assumptions and projections about the Company's industry, business and future financial results. This information involves known and unknown risks, uncertainties, and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this presentation should not be unduly relied upon. This information speaks only as of the date of this presentation. In particular, this presentation may contain forward-looking information pertaining to the following: the Company's strategic focus and related goals; the Company's plans for, and results of, exploration and development activities; Athabasca's plans with respect to its Light Oil assets, in particular in respect of its Duvernay and Montney properties, and the expected benefits to be received by Athabasca from such assets; expectations regarding the Company's Light Oil division including anticipated production levels and timing of receipt of significant revenues and operating results therefrom; the Company's first quarter 2015 production guidance from the Light Oil division; the Company's expected future cash flow from the Duvernay; future production and production potential from the Company's Thermal Oil division; in respect of Hangingstone Project 1, Hangingstone Project 2A, Hangingstone Project 2B and the Dover West Sands, Dover West Carbonates and Birch assets; future funding, financing, cash balances and liquidity; production targets, forecasts and guidance; cash flow growth and cash flow potential; reserve growth potential; the timing of first steam and first production from Hangingstone Project 1; the timing of the completion of the construction of the Enbridge takeaway infrastructure for Hangingstone; the receipt of proceeds from the promissory notes issued by Phoenix Energy Holdings Ltd. ("Phoenix") (the "Promissory Notes"); the timing of the drilling, completion and tie-in of planned Duvernay wells; the Company's capital expenditure program and expectations regarding future capital expenditures and capital allocation; future well costs and the Company's anticipated cost learning curve in respect of drilling and completing such wells; projected Light Oil type curves; drilling and development plans, including the number of Light Oil drilling rigs to be utilized; the expected quality and composition of the hydrocarbons that will be produced from certain of the Company's Light Oil assets; the Company's estimated future commitments; the use of in-situ recovery methods such as Steam Assisted Gravity Drainage ("SAGD") and thermal assisted gravity drainage ("TAGD") for production of recoverable bitumen, including the potential benefits of such methods; economic and financial forecasts and estimates; and the expected receipt of regulatory approvals, including, in respect of the Hangingstone Projects 2A and 2B.

With respect to forward-looking information contained in this presentation, assumptions have been made regarding, among other things: commodity prices for crude oil, natural gas and bitumen blend; geological and engineering estimates in respect of the Company's reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities; the applicability of technologies for the recovery and production of the Company's reserves and resources; future commodity prices; the Company's ability to obtain qualified staff and equipment in a timely and cost efficient manner; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct its business; the adjusted value of the Company's tax pools; the impact that the timing of the Company's receipt of payments made by Phoenix under the Promissory Notes will have on the Company, including the Company's financial condition, capital programs and results of operations; future capital expenditures to be made by the Company; the future sources of funding for the Company's substantial capital requirements; the Company's future debt levels; and the Company's ability to obtain financing on acceptable terms.

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company's most recent annual information form dated March 18, 2014 ("AIF"), which is available on SEDAR at www.sedar.com, including, but not limited to: the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements; failure by counterparties to make payments or perform their obligations to Athabasca in compliance with the terms of contractual arrangements (including under the Promissory Notes) between Athabasca and such counterparties, including in compliance with the time schedules set out in such contractual arrangements, and the possible consequences thereof; risks affecting the ability of HSBC Canada to honour obligations under the irrevocable letters of credit issued to secure the Promissory Notes; aboriginal claims; fluctuations in market prices for crude oil, natural gas and bitumen blend; general economic, market and business conditions in Canada, the United States and globally; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; failure to meet development schedules and potential cost overruns; variations in foreign exchange and interest rates; factors affecting potential profitability; risks related to future acquisition and joint venture activities; reliance on, competition for, loss of, and failure to attract key personnel; the degree to which developments in the environment, regulations inherent in estimates of quantities of reserves and resources; changes to Athabasca's status given the current stage of development; uncertainties inherent in SAGD, TAGD and other bitumen recovery processes; risks related to hydraulic fracturing; expiration of leases and permits; risks inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources; risks related to gathering and processing facilities and pipeline systems; availability of drilling and related equipment and limitations on access to Athabasca's assets; increases in operating costs that could make Athabasca's projects unprofitable; the effect of diluent and natural gas supply constraints and increases in the costs thereof; gas over bitumen issues affecting operational results; environmental risks and hazards and the cost of compliance with environmental regulations, including GHG regulations and potential Canadian and U.S. climate change legislation; extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time; risks related to Athabasca's filings with tax authorities, including the risk of tax related reviews and reassessments; changes to royalty regimes; political risks; failure to accurately estimate abandonment and reclamation costs; exploration and development delays and increased costs in crude oil and natural gas operations, including the production of crude oil and natural gas using multi-stage fracture and other stimulation technologies; the potential for management estimates and assumptions to be inaccurate; long term reliance on third parties; reliance on third party infrastructure, seasonality, hedging risks; risks associated with establishing and maintaining systems of internal controls; insurance risks; claims made in respect of Athabasca's operations, properties or assets; competition for, among other things, capital, the acquisition of reserves and resources, expert pipeline capacity and skilled personnel; the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits; risks related Athabasca's credit facilities; alternatives to and changing demand for petroleum; risks related to Athabasca's common shares; and risks pertaining to Athabasca's senior secured notes.

Information and statements in this presentation relating to "reserves", "resources", "hydrocarbons in-place" and "bitumen in-place" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. The assumptions relating to the Company's reserves and resources are contained in the reports of GLJ Petroleum Consultants Ltd. ("GLJ") and DeGolyer and MacNaughton Canada Limited ("D&M"), each dated effective December 31, 2013. There is no certainty that it will be commercially viable to produce any portion of the resources. With respect to the estimates of undiscovered "bitumen-in-place", there is no certainty that any portion of the resources will be discovered. The estimates of reserves and future revenue for individual properties in this Presentation may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. For important additional information about the Company's reserves and resources, please refer to the AIF. For additional information regarding the specific contingencies which provide the classification of the Company's Contingent Resources and Resource Evaluations – Contingent Resources Estimates" in the AIF. "Contingent Resources", "Best Estimate", "Proved Reserves" and "Probable Reserves" have the meanings given to those terms in the AIF. The forward-looking statements included in this presentation are expressly qualified by this cautionary statement. Athabasca does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

Additional Oil and Gas Information:

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf : 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Test Results and Initial Production Rates:

The well test results and initial production rates provided in this presentation should be considered to be preliminary, except as otherwise indicated. Test results and initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery.
Value Proposition

**World Class Assets**
- 1,000+ well inventory in the Duvernay shale play at Kaybob
- 80,000 bbl/d project potential at the Hangingstone thermal asset
- Significant long-term optionality within a diverse portfolio (9 billion barrels of contingent resource\(^{(1)}\))

**Well Funded**
- Multi-year funding in place
- Core assets self funding in the medium term

**Execution**
- Clear path to deliver material year over year cash flow, production and reserve growth
- Technical rigor; employees have significant North American shale and heavy oil expertise

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\(^{(1)}\) Best estimate adjusted for Dover disposition
Delivering on Commitments

- Set achievable plans
- Deliver on targets

Cash Flow Growth
- Accelerate near-term cash flow
- Focus on returns

Balance Sheet Strength
- Capital and cost discipline
- Focus on core assets

Execution Excellence
- Technical rigor drives investment
- Maintain operational agility

Athabasca Target
- Light Oil: 7,000 – 8,000 boe/d 2015 production exit target based on the initial budget*
- Hangingstone Project 1: First steam by the end of the Q1 2015; 3,000 – 6,000 bbl/d 2015 production exit target
- Maintain balance sheet strength by adapting the capital program to economic cycles and drilling results

* $167 million initial 2015 light oil budget; predominately reflects drilling & completion activity until spring break-up
Financial Highlights and Initial 2015 Budget

Capitalization Highlights

<table>
<thead>
<tr>
<th>Stock exchange listing</th>
<th>TSX</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trading symbol</td>
<td>ATH</td>
</tr>
<tr>
<td>52-week trading range</td>
<td>$2.36 - $8.84 $/sh</td>
</tr>
</tbody>
</table>

Basic shares outstanding

- Fully diluted shares: 426.0 MM
- Insider ownership: 4.1%

Market capitalization (Dec. 5, 2014)

- $964 MM

Cash and working capital (1)

- ($633) MM

Promissory notes (2)

- ($584) MM

Long-term debt (3)

- $802 MM

Total enterprise value

- $550 MM

Tax Pools

- >$2,000 MM

(1) Share count and balance sheet as at September 30, 2014
(2) $584 million promissory notes issued by Phoenix Energy Holdings Ltd. (subsidiary of PetroChina). $300MM due March 2015, $150MM due August 2015 and $134MM due August 2016. Notes are unconditional and secured by irrevocable standby letters of credit issued by HSBC Bank Canada. Additional details on the debt and credit facilities outlined on slide 24.

Capital Expenditures / Funding in Place ($ MM)

- Initial capital program
- Full year

Production (boe/d)

- Exit outlook based on the initial capital program; full year budget to be assessed in Q1 2015
Focused on our Core Assets

Light Oil: Kaybob

- ~$167 million initial budget; predominately reflects operations until spring break-up
- 11 Duvernay wells in the winter program
- Significant flexibility to control the pace of development
- Duvernay production growth to materialize in H2/15
- Duvernay primary target; 200,000 acres with the potential for 1,000+ wells
- Ownership and operatorship in strategic infrastructure
- Montney secondary target; two-well appraisal program

Thermal Oil: Hangingstone

- $93 million 2015 budget
- ~1 billion barrels of resource in place\(^{(1)}\) supports production potential of 80,000 bbl/d
- Hangingstone Project 1, first steam expected end of Q1 2015
- Production expected to commence 4 to 6 months thereafter
- Plateau production of 12,000 bbl/d expected in 2016

\(^{(1)}\) Includes 51.1 MMbbl proved reserves, 174.0 MMbbl probable reserves and 782.0 MMbbl of best estimate contingent resource
Duvernay Overview
## The Duvernay is a World Class Resource

### World Class Resource
- Large in place resource
- High liquid content: 100-1,000 bbl/MMcf free condensate
- Initial results compare favorably to the Eagle Ford

### Duvernay Advantage
- Proactive fiscal and regulatory environment
- Minimal surface land use conflicts
- Well situated to services and infrastructure
- Premium pricing on condensate – strong local market

### AOC Advantage
- 100% WI Kaybob position, industry activity ramping up
- > 200,000 acres across the liquids fairway
- Excellent land tenure – ability to control pace
- Strategic ownership of key infrastructure

### Materiality
- High Duvernay exposure relative to market cap
- Superior economics
- Opportunity to accelerate production & cash flow growth
- 1,000+ wells

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**Duvernay estimated hydrocarbons in place**
- 443 Tcf of natural gas
- 11.3 Bbbl of NGLs
- 61.7 Bbbl of oil

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(1) ERCB/AGS open file report 2012-06 – Summary of Alberta’s shale and siltstone hosted hydrocarbon resource potential – P50 resource estimate
Industry Transitioning to Development

- Apache
- Chevron
- Conoco
- Hitic
- Shell
- Talisman
- Trilogy
- Other
- Athabasca
- Xto
- Encana
- Farm In
- Shell Partial
- Apache Partial
Activity on the Upswing

Industry transitioning to development

- Majors are accelerating activity from the appraisal to development stage
- Increased licensing activity by the majors a precursor for an uptick in spending Y/Y
- 6 - 8 multi-well pads (Apache, Chevron, Encana, Shell); companies remain active ahead of 2014+ land expiries
- Announced $1.5 billion Chevron/KUFPEC deal sets a new high watermark for valuation (~US$15,000/ac)
**Duvernay Activity Update**

### Well Details:

<table>
<thead>
<tr>
<th>Well</th>
<th>Vertical Strat</th>
<th>Core</th>
<th>On Stream</th>
<th>30 Day IP (Restricted)</th>
<th>CTD</th>
<th>Liquids</th>
</tr>
</thead>
<tbody>
<tr>
<td>4-29 S/C/Hz.</td>
<td>16-36</td>
<td>S - vertical strat, C - core</td>
<td>June 16, 2014</td>
<td>615 boe/d (0.7 MMcf/d &amp; 710 bbl/MMcf)</td>
<td>47 mboe, 71% liquids</td>
<td></td>
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<tr>
<td>8-29 Hz.</td>
<td>6-10</td>
<td>On stream: Dec. 28, 2012</td>
<td>CTD – 127 mboe, 52% liquids</td>
<td></td>
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<td></td>
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<tr>
<td>1-25 S/Hz.</td>
<td>1-7</td>
<td>On stream: May 9, 2014</td>
<td>1,461 boe/d (3.0 MMcf/d &amp; 315 bbl/MMcf)</td>
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<tr>
<td>2-34 S/Hz.</td>
<td>24-25</td>
<td>On stream: Dec. 16, 2014</td>
<td>615 boe/d (0.7 MMcf/d &amp; 710 bbl/MMcf)</td>
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<tr>
<td>1-7 S/Hz.</td>
<td>8-18</td>
<td>On stream: March 15, 2014</td>
<td>784 boe/d (0.8 MMcf/d &amp; 763 bbl/MMcf)</td>
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</table>

### Notes:

- Continued lands have been drilled and grouped to gain 5 years of tenure beyond primary term. Ungrouped land is in its primary term (4 year tenure from initial crown acquisition).
- IP rates are producing day rates (raw field gas and condensate volumes).
- Cumulative production is AOC estimate sales volumes including test volumes to October 31, 2014.
Liquids Yield is Driving Economics

*Liquid yield is cum/cum for wells with > 3 months production. Public domain data with the exception of AOC wells.
**Current Duvernay Well Economics are Compelling**

**02/2-34-62-20W5**

```
<table>
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<tr>
<th>Months</th>
<th>Production (boe/d)</th>
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<tr>
<td>0</td>
<td>2,000</td>
</tr>
<tr>
<td>1</td>
<td>1,700</td>
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<td>2</td>
<td>1,400</td>
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<tr>
<td>3</td>
<td>1,100</td>
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<tr>
<td>4</td>
<td>800</td>
</tr>
<tr>
<td>5</td>
<td>500</td>
</tr>
<tr>
<td>6</td>
<td>200</td>
</tr>
<tr>
<td>7</td>
<td>100</td>
</tr>
<tr>
<td>8</td>
<td>0</td>
</tr>
</tbody>
</table>
```

**Cumulative Production (mboe)**

- **02/2-34 type curve liquids**
- **02/2-34 type curve gas**
- **102/02-34-062-20W5/02**
- **102/02-34-062-20W5/02 Cumulative**

**Initial Free Liquids Economic Sensitivity**

```
<table>
<thead>
<tr>
<th>Raw Gas (BCF)</th>
<th>NPV 10% ($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.50</td>
<td>0</td>
</tr>
<tr>
<td>1.00</td>
<td>5</td>
</tr>
<tr>
<td>1.50</td>
<td>10</td>
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<td>2.00</td>
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<td>3.00</td>
<td>25</td>
</tr>
<tr>
<td>3.50</td>
<td>30</td>
</tr>
<tr>
<td>4.00</td>
<td>35</td>
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</table>
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**Expected Range across Duvernay Trend**

- **Well cost:** $10 - $15 MM (D&C)
- **IP30:** 400 - 1,400 boe/d
- **EUR:** 360 - 1,000 mboe
- **Free liquid yields:** 100 – 1,500 bbl/MMcf

**NPV(10%)**

- **$15.1 MM**
- **$19.5 MM**

- **Capital**
  - $15 MM
  - $10 MM

- **ROR (%)**
  - 68%
  - 145%

- **Payout (yrs)**
  - 1.6
  - 1.0

**Economics include Shale Gas Royalty incentive and NGDDP incentive**

*Based on GLJ January 1, 2014 pricing: WTI: $95.59 USD/bbl, Edm. light sweet crude oil: $97.37 CDN/bbl; exchange rate: $ 0.95 USD/CDN; AECO: $4.18 CDN/MMbtu

**Assumes $15MM well cost**
Defining the Duvernay Fairway

*Assumes NPV 10 and GLJ January 1, 2014 pricing. Four wells/section at 90% utilization with $15 MM capital per well (lease edge)

**Saxon/Simonette**
- Acreage: 53,000 ac
- Locations: 300
- NPV/well: $13 – $20 MM

**Kaybob West**
- Acreage: 52,000 ac
- Locations: 295
- NPV/well: $10 – $17 MM

**Kaybob East**
- Acreage: 113,000 ac
- Locations: 640+
- NPV/well: $5 – $15 MM

*As of August 28, 2014*
Duvernay Growth Scenario

Potential for material production growth

- Inventory of >1,000 wells; growth weighted to high value liquids
- Timeline can be accelerated with a more aggressive rig ramp up
- Cumulative free cash flow positive in the midterm
- Project rate of return > 50%\(^1\)

\(^1\) Based on GLJ January 1, 2014 pricing
• Operatorship to control development pace
• Battery and 91 km pipeline working interest 50%
  • Pipeline to SemCAMS 10%
  • Upstream gathering 100%; Saxon battery 100%
• Provide flexibility with takeaway options
  • Scalable for future growth

AOC Controls Strategic Infrastructure

- Total Battery Capacity
  - Oil Capacity: 36,000 bbl/d
  - Gas Capacity: 84 MMcf/d, expandable to >130 MMcf/d

- Gas Pipeline
  - Gas Capacity: Up to 180 MMcf/d

Key locations:
- Kaybob East
- Kaybob West
- Saxon
- Keyera
- Simonette
- Placid
- AOC 91 km Pipeline

Map showing gas pipelines (TCPL/Alliance), oil pipelines (Pembina), and diluent pipelines (Inter Pipeline).
Hangingstone Overview
Hangingstone Development

Resource

- 225 MMbbl reserves\(^{(1)}\)
- 782 MMbbl contingent resources\(^{(2)}\)

Development

- Project HS1 – 12,000 bbl/d
  - First Steam – expected end Q1 2015
- Project HS2A
  - 8,000 bbl/d incremental debottleneck of HS1
- Project HS2B
  - 32,000 bbl/d expansion
- Ultimate development > 80,000 bbl/d
  - Progressive design provides efficient and flexible development options
- Enbridge takeaway infrastructure should be in place during HS1 ramp-up

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Submit EIA for HS Expansion

<table>
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<tr>
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</thead>
<tbody>
<tr>
<td>HS1 Regulatory Approval</td>
<td>Started Construction &amp; Drilling for HS1</td>
<td>HS1 Expected First Steam</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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(1) Proved plus probable
(2) Contingent resource best estimate
Efficient Delivery of First Thermal Project

Cost Performance Hangingstone Project 1(1)

<table>
<thead>
<tr>
<th>Progress</th>
<th>Incurred</th>
<th>Remaining</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$532 MM</td>
<td>$33 MM</td>
</tr>
</tbody>
</table>

(1) Status at the end of September 2014

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Progress

- **Engineering**: 87%
- **Procurement**: 100%
- **Construction**: 94% First Steam
- **D&C**: 100%
- **Overall**: 94% First Steam

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Dilbit tanks – September 2014

Evaporator tower – September 2014

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(1) Hangingstone Project 1

$565 MM
Drilling and Reservoir Results to Date

Application of Industry Best Practices
- One delineation well per SAGD pair
- High resolution 3D seismic
- Integrated workflow providing optimal reservoir planning and drilling execution

Use of Leading Drilling Technologies
- Learning while drilling strategy to optimize well placement
- Maintained consistent wellbore profiles

Drilling Status
- drilled & completed 25 pairs

Effective wellbore length average above design target > 90%

Production & injection wellbores in the HS1 the reservoir
Development Profile

Approved – In Construction

- Hangingstone Project 1
  - First steam end Q1 2015
  - Plateau production 12,000 bbl/d in 2016
  - Capital intensity ~$47,000/bbl

Hangingstone Development Options

- Hangingstone Project 2A – 8,000 bbl/d debottleneck
  - Low capital intensity project with improved rate of return
  - Design maintains capital and execution efficiency
  - Capital intensity $31,000/bbl - $34,000/bbl
- Hangingstone Project 2B – 32,000 bbl/d expansion
  - Capital intensity $35,000/bbl - $40,000/bbl

*Assumes GLJ January 1, 2014 pricing
Other Assets
Development and Exploration Opportunities

**Slave Point**
- > 675,000 acre land position
- Validated oil production with 2013 pilot program

**Montney**
- Two-well appraisal program underway at Placid
- ~100,000 acres of Montney prospective for commercial development

**Grosmont**
- 418 MMbbl\(^{(1)}\) (AOC interest)
- Apply recovery mechanisms being tested by industry

**Birch**
- 2.1 Bbbl\(^{(1)}\)

**Dover West Sands**
- ~2.7 Bbbl\(^{(1)(2)}\)

**Dover West Carbonates**
- 3.0 Bbbl\(^{(1)}\)

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\(^{(1)}\) Contingent resource best estimate
\(^{(2)}\) Based on Dec 31, 2013 GLJ evaluation of ~3 Bbbl, adjusted for non-core divestment of approximately 191 MMbbl completed in Q1 2014
Supplemental Information
## Long-term Debt and Credit Facility Overview

### Undrawn Credit Facilities

<table>
<thead>
<tr>
<th>Description</th>
<th>As at Sept. 30, 2014 ($ MM, Cdn)</th>
<th>Interest Rate</th>
<th>Pre-payment Terms</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cdn $125 MM senior secured revolving credit facility due 2017</td>
<td>$125</td>
<td>~ 5%</td>
<td>Pre-payable without penalty</td>
</tr>
<tr>
<td>US $50 MM senior secured term loan delayed draw facility due 2019</td>
<td>$56</td>
<td>LIBOR + 7.25%</td>
<td>2015 – 102% 2016 – 101% 2017 and beyond – 100%</td>
</tr>
</tbody>
</table>

**Total undrawn facilities** $181

### Outstanding Debt

<table>
<thead>
<tr>
<th>Description</th>
<th>As at Sept. 30, 2014 ($ MM, Cdn)</th>
<th>Interest Rate</th>
<th>Pre-payment Terms</th>
</tr>
</thead>
<tbody>
<tr>
<td>US $225 MM senior secured term loan due 2019</td>
<td>$252</td>
<td>LIBOR + 7.25% 1.00% LIBOR floor</td>
<td>2015 – 102% 2016 – 101% 2017 and beyond – 100%</td>
</tr>
<tr>
<td>Cdn $550 MM senior secured second lien notes due 2017(1)</td>
<td>$550</td>
<td>7.50%</td>
<td>2014 – 107.50% 2015 – 103.75% 2016 and beyond – 100%</td>
</tr>
</tbody>
</table>

**Total outstanding debt** $802

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(1) The senior secured second lien notes have an assigned B credit rating from both DBRS and S&P
Montney Appraisal, Leading to Development

AOC Placid Type Curve
Initial condensate yield 100 bbl/MMcf
Stabilized condensate yield 40 bbl/MMcf

Approximately one township of Montney potential offsetting development in Bigstone

Appraisal Program Objectives

- Demonstrate Placid well performance similar to Bigstone results
- Prove resource extent to justify facility investment
Duvernay 4-32 Pad Initial Production

**8-29-64-20W5**
(On-strike orientation)

- 77 day soak period

**4-29-64-20W5**
(North-south orientation)

- 69 day soak period

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**TEST POST SOAK**

- **Post Soak (77 days)**
- **Gas (mcf/d)**
- **Oil (bbl/d)**
- **Water (bbl/d)**
- **Casing Pressure (psi)**
- **Tubing Pressure (psi)**

- **TEST POST SOAK**
- **Post Soak (69 days)**
- **Gas (mcf/d)**
- **Oil (bbl/d)**
- **Water (bbl/d)**
- **Casing Pressure (psi)**
- **Tubing Pressure (psi)**

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**30 day IP (restricted)** – 784 boe/d
- **CGR** – 763 bbl/MMcf
- **API Gravity** – 48°
- **CTD** – 67 mboe (77% liquids)

**30 day IP (restricted)** – 615 boe/d
- **CGR** – 710 bbl/MMcf
- **API Gravity** – 46°
- **CTD** – 47 mboe (71% liquids)
Duvernay 1-7 and 1-25 Initial Production

**1-7-64-20W5**

- 30 day IP (restricted) – 750 boe/d
- CGR – 475 bbl/MMcf
- API Gravity – 45°
- CTD – 101 mboe (65% liquids)

**1-25-62-25W5**

- 30 day IP (restricted) – 1,461 boe/d
- CGR – 315 bbl/MMcf
- API Gravity – 54°
- CTD – 127 mboe (52% liquids)
Management Team

Thomas Buchanan, FCA
President & Chief Executive Officer
• Over 30 years experience in the oil and natural gas sector, and currently Chairman of Spyglass Resources Corp.
• Formerly CEO of Spyglass Resources Corp. prior thereto, CEO of Provident Energy Trust, previously known as Founders Energy
• Brings extensive experience in the energy sector, a strong financial background, leading growth through internal expansion, mergers and acquisitions and investor relations

Kim Anderson, CA
Chief Financial Officer
• Joined Athabasca Oil Corporation in February 2014, as Chief Financial Officer
• Brings 14 years of diversified financial experience in the energy industry
• Prior to joining Athabasca, Ms. Anderson was CFO of KANATA Energy Group Ltd. and prior thereto, held various roles at Provident Energy Ltd.

Chief Operating Officer
• Joined Athabasca Oil Corporation in November 2012 and is Chief Operating Officer
• Brings over 20 years of exploration and production expertise
• Prior to joining Athabasca, Mr. Broen managed a capital budget of over $1 billion and a 120,000 boe/d North American shale gas portfolio (Montney, Duvernay, Marcellus and Eagle Ford) for Talisman Energy Inc.

Robert Bowie, MBA
Vice-President Corporate Development
Blair Hockley
Vice-President Hangingstone Asset
Rick Koshman, MBA, P.Eng.
Vice-President Operations

Anne Schenkenberger, B.Sc., LLB
Vice-President Legal & Corporate Secretary
Kevin Smith, P. Eng.
Vice-President Light Oil
Matt Taylor, CFA
Vice-President Capital Markets & Communications

Board of Directors

Thomas Buchanan, FCA
Chairman, President & Chief Executive Officer

Sveinung Svarte, MBA, MSc.
Vice Chairman of the Board and member of the Reserves and HSE Committee

Ronald Eckhardt
Lead Director, Chair of the Reserves and HSE Committee, and member of the Compensation and Governance Committee

Gary Dundas, CMA, MBA
Board member, Chair of the Compensation and Governance Committee, and member of the Audit, Reserves and HSE Committees

Marshall McRae, CA
Board member, Chair of the Audit Committee, and member of the Compensation and Governance Committee

Peter Sametz
Board member, member of the Reserves and HSE Committee and member of the Audit Committee