ATHABASCA – PREMIER RESOURCE EXPOSURE

INTERMEDIATE OIL WEIGHTED PRODUCER

- ~40,000 boe/d (~90% liquids)
- ~10% corporate decline
- Liquids rich shale at Greater Kaybob
  - 80,000 Montney acres
  - 200,000 Duvernay acres
- Oil sands in northeastern Alberta
  - 80,000 bbl/d of top quality projects

ASSETS IN CANADA’S TOP RESOURCE PLAYS

CORPORATE HIGHLIGHTS (ATH-TSX)

<table>
<thead>
<tr>
<th>Category</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market Capitalization</td>
<td>$525 MM</td>
</tr>
<tr>
<td>Net Debt*</td>
<td>$325 MM</td>
</tr>
<tr>
<td>Enterprise Value</td>
<td>$850 MM</td>
</tr>
<tr>
<td>Proved / P+P Reserves</td>
<td>450 / 1,250 MMBOE</td>
</tr>
<tr>
<td>Tax Pools (total / NCL &amp; CEE)</td>
<td>$3.1 / $1.9 Billion</td>
</tr>
</tbody>
</table>

ATHABASCA OIL (TSX:ATH) Footnotes and additional information included in the back as endnotes
*Q4/18e net debt pro forma infrastructure sale
LEISMER INFRASTRUCTURE TRANSACTION

STRATEGIC TRANSACTION WITH ENBRIDGE

- $265MM cash consideration
- 30 year term with an annual toll of ~$26MM
- Priority service on pipelines & dilbit/diluent tanks (2x 150mbbl)
- Excess volumes above firm commitments receive a discounted toll
- Enhanced credit terms with Enbridge across our Thermal Oil business

Unlocking Value
Proceeds ~50% of market cap

Bolstered Liquidity
~$550MM funding capacity

Competitive Break-evens
US$43 WTI
@ US$18 WCS diff

Recouped Leismer acquisition cash consideration ($435MM) within two years through free cash flow, contingent bitumen royalty and infrastructure proceeds (combined ~$500MM)
ATHABASCA – STRATEGIC OUTLOOK

A BALANCED PORTFOLIO

- Thermal Oil: long life low decline assets
  - 80 year 2P reserve life
- Light Oil: high margin growth
  - Top netbacks in peer group ($32/boe Q3/18)
- Low maintenance capital
  - $95 – $110MM to maintain base production
- Low risk and high quality expansion projects
  - 200 Montney & 1,000 Duvernay well inventory\(^1\)
  - 80,000 bbl/d regulatory approved Thermal projects

RESILIENT BUSINESS MODEL

- Flexible and disciplined capital allocation
  - No land expiries; Duvernay JV capital carry
- Strong balance sheet
  - ~$550MM funding capacity
- Unparalleled exposure to oil price
  - US$5 WTI = C$80MM funds flow

PRODUCTION

- 2018: 37,500 – 40,000 mboe/d
- 2019: 40,000 mboe/d
- 2020: 42,500 mboe/d
- 2021: 45,000 mboe/d

Note: 2019 production does not reflect Government of Alberta mandated short-term production curtailments estimated at 1,500 – 2,000 bbl/d in Q1 2019

FUNDS FLOW & CAPITAL

- 2018: Prelim Budget
- 2019: + $265MM Infrastructure Sale
- 2020: $95 - $110MM Prelim Budget
- 2021: ~$550MM funds flow

Footnotes and additional information included in the back as endnotes.
2019 PRELIMINARY OUTLOOK

CORPORATE
- Minimal capital: $95 – $110MM
- Maintain production: 37,500 – 40,000 boe/d (88% liquids)
- Nimbleness to accelerate high return projects

LIGHT OIL
- Capital: $15 – $30MM net
- Production: 10,000 – 11,000 boe/d (55% liquids)
- Montney: activity deferred until H2/19
- Duvernay: self funded through joint venture capital carry
  - ATH pays 7.5% to earn a 30%WI ($200 - $375MM gross)

THERMAL OIL
- Capital: $80MM
- Production: 27,500 – 29,000 bbl/d
- Major projects: Leismer sustaining pad ($40MM)

2019 OUTLOOK (US$65 WTI & US$20 WCS DIFF)

2019 FUNDS FLOW SENSITIVITY ($MM)

Note: Production guidance does not reflect Government of Alberta mandated short term production curtailments estimated at 1,500 – 2,000 bbl/d through Q1 2019
MARKET ACCESS AND RISK MANAGEMENT

DIVERSIFIED PORTFOLIO MITIGATES RISK
- Both business divisions contribute to the bottom line
  - ~$315MM 2019e operating income (40% LO & 60% TO)

HEAVY OIL DIFFERENTIAL ENVIRONMENT
- Short-term (H1/19): strip US$13/bbl
  - Gov’t mandated industry curtailments (325mbbl/d)
  - Crude-by-rail ramp-up (~400mbbl/d*)
- Mid-term (H2/19 – 2021): <US$20/bbl
  - Inventories rebalance to normal operating levels
  - ENB Line 3 Replacement (~375mbbl/d)
- Long term (2022+): <US$15
  - AOC has secured capacity on pipeline expansions
  - 25mbbl/d Keystone XL & 20mbbl/d TMX

RISK MITIGATION
- Financial hedges + direct refinery sales = synthetic rail contract
  - 40% dilbit hedged at ~US$20.75 WCS diff in 2019
  - 40% direct sales to refineries in 2019
- Storage: 130mbbl secured at Edmonton

Source:
- NBF Commodities, AER (2mo lagged), Genscape (current)
- National Energy Board (2mo lagged) & Genscape (current)
LIGHT OIL
MONTNEY & DUVERNAY
PLACID MONTNEY

HIGHLIGHTS – AOC OPERATED 70%WI

- 80,000 gross prospective acres
  - 48,000 high graded acres
  - 200 well development inventory\(^1\)
- Operated strategic regional infrastructure
  - Secured egress through Pembina, Alliance and TCPL
  - 10,000 bbl/d & 50 mmcf/d capacity
- $23/boe 2019 operating netback (US$65 WTI)

ACTIVITY OVERVIEW

- 2016/17 Winter: 20 wells (5 pads)
- 2017/18 Winter: 12 wells (2 pads)
- H2/18 Fall
  - Tie-in of multi-well pad (6 wells)
  - Rig release multi-well pad (7 wells)
- H2/19: readiness to resume activity
PLACID MONTNEY – STRONG ECONOMICS

PRODUCTION PLOT

INTERNAL TYPE WELL PARAMETERS

<table>
<thead>
<tr>
<th>Rate</th>
<th>Sales Gas</th>
<th>C5+</th>
<th>liquids</th>
</tr>
</thead>
<tbody>
<tr>
<td>boe/d</td>
<td>mmcf/d</td>
<td>bbl/d</td>
<td>%</td>
</tr>
<tr>
<td>IP30</td>
<td>1,000</td>
<td>2.6</td>
<td>501</td>
</tr>
<tr>
<td>IP90</td>
<td>875</td>
<td>2.4</td>
<td>421</td>
</tr>
<tr>
<td>IP365</td>
<td>600</td>
<td>1.8</td>
<td>262</td>
</tr>
</tbody>
</table>

EUR: 675 mmcf, 2.2 bcf, 246 mbbl, 45%

*C25 bbl/mmcf plant recovered NGLs included in IPs & EURs

CUMULATIVE CONDENSATE PRODUCTION

INTERNAL TYPE WELL ECONOMICS

US$WTI | $55 | $60 | $65

Well Cost: ~$8MM drill & completed (2,750m hz)

Payback: 26 months

IRR BT: 35%

NPV10 BT: $2.6

Netback: $25.25

PDP F&D: $11.75

Recycle Ratio: 2.1

Cap Effcy (IP365): $12,985

ATHABASCA OIL (TSX: ATH)

Flat pricing assumed in internal type well economics

US$7.50 MSW diff, C$1.50 AECO, 0.75 FX
JOINT VENTURE HIGHLIGHTS (30% WI)

- Partnered with Murphy Oil in May 2016
- Cash/carry structure minimizes financial exposure
  - $1B gross 4 yr program; $75MM net to retain 30% WI
- Significant resource exposure
  - 200,000 acres and 1,000+ well inventory

DUVERNAY RESULTS

<table>
<thead>
<tr>
<th>Pad</th>
<th>Wells</th>
<th>IP30s (boe/d)</th>
<th>Liquids (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>5-29</td>
<td>1,040</td>
<td>73%</td>
</tr>
<tr>
<td>B</td>
<td>11-18</td>
<td>815</td>
<td>72%</td>
</tr>
<tr>
<td>C</td>
<td>4-32</td>
<td>1,310</td>
<td>75%</td>
</tr>
<tr>
<td>D</td>
<td>16-18</td>
<td>468**</td>
<td>100%</td>
</tr>
<tr>
<td>E</td>
<td>15-16</td>
<td>829**</td>
<td>71%</td>
</tr>
<tr>
<td>F</td>
<td>12-29</td>
<td>1,078</td>
<td>81%</td>
</tr>
<tr>
<td>G</td>
<td>16-03</td>
<td>1,320**</td>
<td>57%</td>
</tr>
<tr>
<td>H</td>
<td>11-14</td>
<td>1,178</td>
<td>57%</td>
</tr>
<tr>
<td>I</td>
<td>3-33</td>
<td>624**</td>
<td>83%</td>
</tr>
<tr>
<td>J</td>
<td>16-14</td>
<td>December On-Stream</td>
<td></td>
</tr>
<tr>
<td>K</td>
<td>16-25</td>
<td>Rig Released</td>
<td></td>
</tr>
<tr>
<td>L</td>
<td>4-21</td>
<td>December On-Stream</td>
<td></td>
</tr>
<tr>
<td>M</td>
<td>16-18 Exp</td>
<td>937</td>
<td>91%</td>
</tr>
<tr>
<td>N</td>
<td>11-12</td>
<td>711</td>
<td>85%</td>
</tr>
<tr>
<td>O</td>
<td>16-06</td>
<td>711</td>
<td>85%</td>
</tr>
<tr>
<td>P</td>
<td>08-03</td>
<td>Awaiting tie-in</td>
<td></td>
</tr>
<tr>
<td>Q</td>
<td>5-19</td>
<td>Drilling Underway</td>
<td></td>
</tr>
<tr>
<td>R</td>
<td>16-29</td>
<td>Drilling Underway</td>
<td></td>
</tr>
<tr>
<td>S</td>
<td>15-28</td>
<td>783</td>
<td>58%</td>
</tr>
</tbody>
</table>

Footnotes and additional information included in the back as endnotes

*Facility constrained & gas flared
** Restricted rates

2019 preliminary activity
- $200 – $375MM gross ($15 – $30MM net)
- Continued volatile oil delineation with an initial emphasis on Two Creeks
**DUVERNAY – COMPETITIVE SHALE PLAY**

**WHAT MAKES THE DUVERNAY COMPETITIVE**

- High liquids yields
  - 200 – 1,000 bbl/mmcf initial yields (C5+)
  - 40 – 55⁰ API condensate
- Royalty advantage (5% for 3yr vs. ~25% US Shale Plays)
- $38/boe 2019 operating netback (US$65 WTI)
- C$8 – 10MM current development pad costs (D&C)

**KAYBOB WEST INTERNAL TYPE WELL ECONOMICS**

<table>
<thead>
<tr>
<th>US$WTI</th>
<th>boe/d</th>
<th>mboe</th>
<th>$MM</th>
</tr>
</thead>
<tbody>
<tr>
<td>$55</td>
<td>950</td>
<td>~650</td>
<td>~$8.5MM</td>
</tr>
<tr>
<td>$60</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$65</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- IP30/365
  - 950 (77% liquids) / 450 (69% liquids)
- EUR
  - ~650 (66% liquids)
- Well Cost
  - ~$8.5MM drill & completed (2,800m hz)
- Payback
  - 26 months / 22 months / 19 months
- IRR BT
  - 42% / 53% / 65%
- NPV10 BT
  - $6.2 / $7.7 / $9.1
- Netback
  - $37.25 / $41.50 / $45.75
- PDP F&D
  - $13.50 / $13.50 / $13.50
- Recycle Ratio
  - 2.8 / 3.1 / 3.4

**SAXON (3 WELLS)**

**KAYBOB EAST (4 WELLS)**

**KAYBOB WEST OIL (3 WELLS)**

**KAYBOB WEST (17 WELLS)**

---

*Flat pricing assumed in internal type well economics
US$5.00 C5+ diff, C$1.50 AECO, 0.75 FX*
HIGHLIGHTS

- Athabasca Light Oil boasts the top netback relative to its Montney/Duvernay peers (last 4 quarters)
  - Strong liquids weighting (>50%)
  - High quality product (condensate and light oil)
  - Low lifting costs (<$10/boe)

OPERATING NETBACK BENCHMARKING* (Q3 2018)

- Liquids Weighted Netback (>40% liquids)
- Gas Weighted Netback (>60% gas)
- Costs (Operating, Transportation, Royalties)

Peer Median ~$15/boe

* Excludes hedging gains/losses and third party processing income
THERMAL OIL
LEISMER & HANGINGSTONE
**LEISMER – TOP TIER OIL SANDS PROJECT**
- 20,000 – 22,000 bbl/d; ~3.5x SOR
- 40,000 bbl/d AER approval
- 660 mmbbl 2P reserves; 85 year 2P RLI
- US$43 WTI breakeven*

**HANGINGSTONE**
- 9,000 – 10,000 bbl/d; ~4.5x SOR
- 180 mmbbl 2P reserves; 45 year 2P RLI
- US$53 breakeven*
- Low near-term sustaining capital

**CORNER – LONG TERM DEVELOPMENT**
- Top tier lease with high quality reservoir
- Delineation drilling completed by Equinor
- 40,000 bbl/d AER approval in place

---

* Break-evens reflect mid-term US$18 WCS differential assumption
Footnotes and additional information included in the back as endnotes
THERMAL OIL – ACTIVITY OVERVIEW

OPTIMIZATION INITIATIVES

- Record low non-energy op. costs in Q3/18
  - 25% reduction Y/Y
  - Leismer $6.69/bbl & Hangingstone $12.20/bbl
- Norlite diluent tie-in (~$20MM annual savings)
- Maintained production with minimal capital
  - Tie-in of predrilled infills
  - Flow control devices & gas co-injection

2019 BUDGET ($80MM)

- Leismer L7 sustaining pad (~$40MM capital)
  - Drilling underway; H2/19 on-stream
  - 1,250m laterals (50% longer) & FCD equipped
  - 4,000 – 4,500 bbb/d peak pad production

LONG TERM DEVELOPMENT

- Minimal sustaining capital for Thermal assets
  - C$5 – 10/bbl annually (5 year range)
CORPORATE SNAPSHOT

CAPITALIZATION OVERVIEW (ATH-TSX)

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic Shares Outstanding</td>
<td>517 MM</td>
</tr>
<tr>
<td>Market Capitalization</td>
<td>~$525 MM</td>
</tr>
<tr>
<td>Pro Forma Net Debt*</td>
<td>~$325 MM</td>
</tr>
<tr>
<td>Total Enterprise Value</td>
<td>$850 MM</td>
</tr>
<tr>
<td>Term Debt (9.875% due Feb 2022)</td>
<td>US$450 MM</td>
</tr>
<tr>
<td>Undrawn Reserve Based Facility</td>
<td>$120 MM</td>
</tr>
<tr>
<td>Pro Forma Funding Capacity*</td>
<td>~$550 MM</td>
</tr>
<tr>
<td>Tax Pools (total / NCL &amp; CEE)</td>
<td>$3.1 / $1.9 Billion</td>
</tr>
</tbody>
</table>

* Q4/18e pro form infrastructure sale

2018/19 GUIDANCE

<table>
<thead>
<tr>
<th>Description</th>
<th>2017a</th>
<th>2018e</th>
<th>2019e</th>
<th>Liquids</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production boe/d</td>
<td>35,421</td>
<td>39,000 – 41,000</td>
<td>37,500 – 40,000</td>
<td>88%</td>
</tr>
<tr>
<td>Light Oil boe/d</td>
<td>7,535</td>
<td>10,500 – 11,500</td>
<td>10,000 – 11,000</td>
<td>55%</td>
</tr>
<tr>
<td>Thermal Oil bbl/d</td>
<td>27,886</td>
<td>28,500 – 29,500</td>
<td>27,500 – 29,000</td>
<td>100%</td>
</tr>
<tr>
<td>Capital $MM</td>
<td>$213</td>
<td>$190</td>
<td>$95 – $110</td>
<td></td>
</tr>
<tr>
<td>Light Oil $MM</td>
<td>$154</td>
<td>$105</td>
<td>$15 – $30</td>
<td></td>
</tr>
<tr>
<td>Thermal Oil $MM</td>
<td>$57</td>
<td>$85</td>
<td>$80</td>
<td></td>
</tr>
<tr>
<td>Adj. Funds Flow $MM</td>
<td>$102</td>
<td>~$20</td>
<td>$225</td>
<td></td>
</tr>
<tr>
<td>Operating Income $MM</td>
<td>$180</td>
<td>~$130</td>
<td>~$315</td>
<td></td>
</tr>
</tbody>
</table>

ATHABASCA – BEST IN CLASS FOR OIL EXPOSURE

UNPARALLELED TORQUE TO OIL

- Athabasca a standout producer for oil exposure
  - ~90% liquids
- Run-rate unhedged funds flow sensitivity
  - ~C$80MM for US$5 WTI
  - ~C$45MM for US$2.50 WCS diff

ATTRACTIVE VALUATION AND LOW LEVERAGE

- 2019 metrics (US$60 WTI & US$17.50 diff)
  - $1/sh implies 3.3 EV/DACF & 1.5x D/CF
- Significant share price upside with multiple compression
  - $65 WTI & $17.50 diff: 2.3x EV/DACF & 0.8x D/CF
  - $70 WTI & $17.50 diff: 1.7x EV/DACF & 0.4x D/CF
  - $75 WTI & $17.50 diff: 1.3x EV/DACF & 0.1x D/CF

2019 CASH FLOW SENSITIVITY

- ATH
- US
- CDN Large Cap
- CDN Intermediate/Small Cap

IMPLIES VALUATION (SHARE PRICE)

- Peer Group Multiple (4.9x EV/DACF) $4.10/sh
- Maintain Multiple (3.3x EV/DACF @ US$60 WTI) $3.32/sh
- ATH $1.71/sh

Source: Peters Crude Sensitivity 09-27-2018
Base: US$60 WTI & US$22 WCS diff; Upside: US$70 WTI & US$26 WCS diff

Average intermediate peer multiple Peters Comps 01-22-2019
**DUVERNAY – KAYBOB REGIONAL OVERVIEW**

**DUVERNAY HIGHLIGHTS (30% WI)**
- 200,000 gross acres; ~1,000 potential locations\(^1\) (mgmt est)
- Exposure to liquids rich & volatile oil fairways (200 – 1,000 bbl/mmcf)
- Supermajors remain active

### GREATER KAYBOB MAP

**KAYBOB DUVERNAY PRODUCTION***

<table>
<thead>
<tr>
<th>Year</th>
<th>Raw Gas mboe/d</th>
<th>Liquids</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2013</td>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>2014</td>
<td>40</td>
<td>30</td>
</tr>
<tr>
<td>2015</td>
<td>60</td>
<td>50</td>
</tr>
<tr>
<td>2016</td>
<td>80</td>
<td>70</td>
</tr>
<tr>
<td>2017</td>
<td>100</td>
<td>90</td>
</tr>
<tr>
<td>2018</td>
<td>120</td>
<td>110</td>
</tr>
</tbody>
</table>

**DUVERNAY INDUSTRY ACTIVITY**

- Industry remains active
- ~675 spuds since 2014
- ~125 spuds within 1 year

---

* Generated from public AER data with internal estimates for liquids mapping on single stream reporting

---

**FOOTNOTES**
- \(^1\) mgmt est

---

**ATHABASCA OIL (TSX:ATH)**

Footnotes and additional information included in the back as endnotes
**LIGHT OIL – INFRASTRUCTURE**

- **Gas Pipeline (gross)**
  - Gas Capacity: Up to 180 MMcf/d
  - Dually connected to regional gas plants

- **Total Battery Capacity (gross)**
  - Oil Capacity: 36,000 bbl/d
  - Gas Capacity: 154 MMcf/d, expandable to >169 MMcf/d
  - Condensate connected to Pembina’s Peace Pipeline

### Table: 2019 vs 2020 Gas and Liquids

<table>
<thead>
<tr>
<th></th>
<th>2019</th>
<th>2020</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Gas (mmcf/d)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alliance</td>
<td>25</td>
<td>25</td>
<td>Chicago &amp; Alberta ATP sales point</td>
</tr>
<tr>
<td>TCPL</td>
<td>15</td>
<td>35</td>
<td>AECO sales point</td>
</tr>
<tr>
<td><strong>Liquids (bbl/d)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pembina Cond. / Oil</td>
<td>6,000</td>
<td>6,000</td>
<td>Saxon, Placid, Kaybob West &amp; East egress</td>
</tr>
<tr>
<td>Pembina NGL</td>
<td>1,000</td>
<td>1,000</td>
<td>NGL egress from Keyera Simonette plant</td>
</tr>
</tbody>
</table>

- Flexibility with takeaway options; scalable for future growth

---

AOC owns and operates regional midstream infrastructure

- Kaybob East
- Keyera
- Simonette
- Placid

**AOC 91 km Pipeline**

**Fort McMurray**

**Edmonton**

**Calgary**

**Pipeline Map:**
- Gas pipelines (TCPL/Alliance)
- Oil pipelines (Pembina)
- Diluent pipelines (Inter Pipeline)
MANAGEMENT TEAM

Robert Broen, P.Eng.
President & Chief Executive Officer

Kim Anderson, CA
Chief Financial Officer

Angela Avery
VP, General Counsel & Business Development

Karla Ingoldsby, P. Eng.
VP Thermal Oil

Dave Stewart
VP Operations

Matt Taylor, CFA
VP Capital Markets & Communications

BOARD OF DIRECTORS

Ronald Eckhardt
Chair of the Board, member of the Reserves Committee

Robert Broen, P.Eng.
President & Chief Executive Officer

Bryan Begley
Chair of the Compensation & Governance Committee and member of the Reserves Committee

Anne Downey, P. Eng.
Chair of the Reserves Committee

Thomas Ebbern
Member of the Compensation & Governance Committee and member of the Audit Committee

Carlos Fierro
Member of the Compensation & Governance Committee and member of the Audit Committee

Marshall McRae, CA
Chair of the Audit Committee
Multi-year outlook price assumptions:

<table>
<thead>
<tr>
<th></th>
<th>2018e</th>
<th>2019e</th>
<th>2020e</th>
<th>2021e</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTI US$/bbl</td>
<td>$65.50</td>
<td>$65.00</td>
<td>$65.00</td>
<td>$65.00</td>
</tr>
<tr>
<td>FX C$/US$</td>
<td>0.77</td>
<td>0.75</td>
<td>0.75</td>
<td>0.75</td>
</tr>
<tr>
<td>Heavy Diff US$/bbl</td>
<td>$26.31</td>
<td>$20.00</td>
<td>$18.00</td>
<td>$18.00</td>
</tr>
<tr>
<td>WCS C$/bbl</td>
<td>$50.61</td>
<td>$60.00</td>
<td>$62.67</td>
<td>$62.67</td>
</tr>
<tr>
<td>MSW Diff US$/bbl</td>
<td>-$11.13</td>
<td>-$10.00</td>
<td>-$7.50</td>
<td>-$7.50</td>
</tr>
<tr>
<td>MSW (Ed. Par. Light Oil) C$/bbl</td>
<td>$70.27</td>
<td>$73.33</td>
<td>$76.67</td>
<td>$76.67</td>
</tr>
<tr>
<td>C5 Diff US$/bbl</td>
<td>-$4.17</td>
<td>-$7.50</td>
<td>-$5.00</td>
<td>-$5.00</td>
</tr>
<tr>
<td>Condensate C$/bbl</td>
<td>$79.34</td>
<td>$76.67</td>
<td>$80.00</td>
<td>$80.00</td>
</tr>
<tr>
<td>AECO C$/mcf</td>
<td>$1.48</td>
<td>$1.50</td>
<td>$1.50</td>
<td>$1.50</td>
</tr>
</tbody>
</table>

1 (1) Consolidated reserves as at December 31, 2017

1/7 (1) Gross Montney inventory based on management estimate of 4 wells per section; see reader advisory “Drilling Locations” for more detail

1/9/17 (1) Gross Duvernay acres and inventories. Well inventory based on management estimate of 4-6 wells per section; see reader advisory “Drilling Locations” for more detail

13 (1) 1,169mmboe consolidated 2P thermal oil reserves. McDaniel & Associates Consultants Ltd. reserve evaluation as at December 31, 2017 (988mmboe 2P reserves at Leismer and Corner; 181mmboe 2P reserves at Hangingstone)

### 2019

<table>
<thead>
<tr>
<th>WTI / WCS Differential</th>
<th>Q1 2019</th>
<th>Q2 2019</th>
<th>Q3 2019</th>
<th>Q4 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Financial Swaps</td>
<td>16,300</td>
<td>(27.30)</td>
<td>(20.53)</td>
<td>18,000</td>
</tr>
</tbody>
</table>

FX Forward - February 2019 US$ 22.2 MM interest payment hedged at 1.2505 US/CAD rate
US$ price converted at 1.33 US/CAD rate
Forward Looking Statements

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”, “believe”, “contemplate”, “target”, “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, strategies, estimates, assumptions and projections about the Company’s industry, business and future operating and 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 contains forward-looking information pertaining to, but not limited to, the following: the Company’s 2018/19 guidance and multi-year outlook; type well economic metrics; estimated recovery factors and reserve life index; and other matters. Information relating to “reserves” is also deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. With respect to forward-looking information contained in this Presentation, assumptions have been made regarding, among other things: commodity outlook; the regulatory framework in the jurisdictions in which the Company conducts business; the Company’s financial and operational flexibility; the Company’s capital expenditure outlook, financial sustainability and ability to access sources of funding; geological and engineering estimates in respect of Athabasca’s reserves and resources; and other matters. 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 Annual Information Form (“AIF”) dated March 7, 2018 that is available on SEDAR at www.sedar.com, including, but not limited to: fluctuations in commodity prices, foreign exchange and interest rates; political and general economic, market and business conditions in Alberta, Canada, the United States and globally; changes to royalty and tax regimes, environmental risks and hazards; the potential for management estimates, assumptions and regulatory interpretations to be inaccurate; the dependence on Murphy as the operator of the Company’s Duvernay assets; the capital requirements of Athabasca’s projects and the ability to obtain financing; operational and business interruption risks; failure by counterparties to make payments or perform their operational or other obligations to Athabasca in compliance with the terms of contractual arrangements; aboriginal claims; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; uncertainties inherent in estimating quantities of reserves and resources; litigation risk; environmental risks and hazards; reliance on third party infrastructure; hedging risks; insurance risks; claims made in respect of Athabasca’s operations, properties or assets; risks related to Athabasca’s amended credit facilities and senior secured notes; and risks related to Athabasca's common shares.

For important additional information regarding Athabasca’s reserves and resources estimates and the evaluations that were conducted by McDaniel & Associates, please see “Independent Reserve and Resource Evaluations” in the Company’s most recent AIF. The forward-looking statements included in this presentation are expressly qualified by this cautionary statement. The forward looking statements contained herein are made as of the date hereof and Athabasca does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

Drilling Locations: The 1,000 Duvernay drilling locations referenced in this presentation include: 64 proved undeveloped or non-producing locations and 35 probable undeveloped locations for a total of 99 undeveloped booked locations with the balance being unbooked locations. The 200 Montney drilling locations referenced include: 84 proved undeveloped locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are anticipated to be derived from the Company’s most recent independent reserves evaluation as prepared by McDaniel as of December 31, 2017 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca’s multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geophysical, reservoir engineering, production and reserves information. There is no certainty that the Company will drill all undeveloped drilling locations if drilled and there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, oil and natural gas prices, provincial fiscal and royalty policies, costs, actual drilling results and additional reservoir information that is obtained and other factors.

Additional Oil and Gas Information:

"BOEeq" 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.

Non-GAAP Financial Measures:

The "Adjusted Funds Flow", "Light Oil Operating Income", "Light Oil Operating Netback", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", "Consolidated Operating Income", "Consolidated Operating Netback", "Consolidated Capital Expenditures Net of Capital-Carry" and “Net Debt” financial measures contained in this Presentation do not have standardized meanings which are prescribed by IFRS and are considered to be non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS. Complete definitions are outlined in the Company’s Q3 MD&A and financials available on SEDAR (www.sedar.com) or the Company’s website (www.atha.com).