“Strong Production Growth, Top Quartile Well Results and Lowest Corporate Cash Costs in the Montney Underpins Glacier Plant Expansion Plans to 350 MMcf/d (58,330 Boe/d)”
ADVANTAGE AT A GLANCE

TSX, NYSE: AAV

TSX 52-week trading range
$5.85 - $8.36

Shares Outstanding (basic)
184.4 million

2016 Annual Production Target
200 mmcfe/d (33,300 boe/d)

39% Annual Production Growth

Market Capitalization @ July 8, 2016
$1.4 billion

Estimated as of June 30, 2016:

- Bank Debt (50% drawn on $400 million Credit Facility)
  $194 million

- Total Debt (including working capital deficit)
  $210 million

Total Year-end Debt /Trailing Cash Flow
1.2x(1)

(based on 2016 Budget at AECO Cdn $2.00/mcf)

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(1) Estimated debt and cash flow based on Advantage’s 2016 Budget & Guidance assumptions

View of Glacier Plant Process Train – approximately 1000 feet long
FOCUSED ON GLACIER DEVELOPMENT SINCE 2008
ADDITIONAL MONTNEY LANDS PROVIDES FUTURE UPSIDE

- Current development at Glacier including dry and liquids rich gas drilling with a future drilling inventory >1,000 locations
- New Montney lands at Valhalla, Wembley & Progress contain multiple layers and requires delineation
- Total 138 net Montney sections (88,480 net acres)
ADVANTAGE’S GROWTH & ACHIEVEMENTS...

2008 - 2009
- Resource Appraisal
  - Gen 1 Fracs (6-10 frac stages)
  - First 25 mmcfe/d

2010 - 2011
- U&L Montney Delineation
  - Gen 2 Fracs (10-14 frac stages)
  - Opex costs <$0.38/mcfe

2012 - 2013
- Middle Montney Liquids
  - Gen 3 Fracs
    - (16-18 frac stages, slickwater, OH packers)

2014 - 2015
- 30%↑ Well IP30 + EUR(1)
  - $0.82/mcfe Total Cash Costs
  - 250 mmcfe/d Plant expansion

2016+
- Record Low Cash Costs $0.60/mcfe
  - Gen 4 Fracs (ports, 25+ frac stages)
  - 350 mmcfe/d Plant expansion plan in progress

2014 to 2016
- 130 to 180 mmcfe/d

2008 - 2015
- 50 to 100 mmcfe/d

2009 - 2016
- 25 to 50 mmcfe/d

2016+
- 180 to 200 mmcfe/d

2009 - 2016+
- 130 to 180 mmcfe/d

2016+
- 58,330 Boe/d

2008 to 2016+
- 200 to 350 mmcfe/d

(1) IP30 is initial average well 30 day production rate and 2P Estimated Ultimate Recovery per Management estimates. Comparison is made to prior Management estimated average well type curve.
...IS BASED ON A SOLID FOUNDATION FOR PROFITABLE & SUSTAINABLE GROWTH...

World Class Montney Asset

Lowest Cash Cost Montney Producer

Own & Operate 100% Plant & Infrastructure

Hedged to Protect Future Cash Flow

Strong Balance Sheet
1.2x D/CF(1) 2016

Operating & Financial Flexibility

Growth from 200 mmcfe/d to 350 mmcfe/d
(58,330 Boe/d) Underway

(1) Total debt to trailing cash flow based on 2016 Advantage Budget & Guidance @ AECO Cdn $2.00/mcf – See Advantage press release December 16, 2015
(2) % of estimated annual production net of royalties, 52% @ $3.62 Cdn/mcf, 36% @ $3.24 Cdn/mcf 2017, 13% @ $3.10 Cdn/mcf 2018
(3) Total corporate cash cost estimate of $0.60/mcfe Q2 2016
Management estimated initial 30 day average well production rate (IP30). Additional 14 wells remain drilled and uncompleted.

<table>
<thead>
<tr>
<th>Surplus Well Productivity from 10 Completed Standing Wells&lt;sup&gt;(1)&lt;/sup&gt;</th>
<th>&gt;70 mmcf/d</th>
</tr>
</thead>
<tbody>
<tr>
<td>Currently Available Glacier Plant Capacity</td>
<td>50 mmcf/d</td>
</tr>
<tr>
<td>Plant Expansion plan to 350 mmcf/d in progress</td>
<td>100 mmcf/d</td>
</tr>
<tr>
<td>Additional Sales Gas Pipeline Capacity, Total 400 mmcf/d capacity</td>
<td>200 mmcf/d</td>
</tr>
<tr>
<td>Facilities Ownership</td>
<td>100%</td>
</tr>
<tr>
<td>Total Firm Natural Gas Transportation Service by 2019</td>
<td>293 mmcf/d</td>
</tr>
<tr>
<td>Well Pads Planned to 2019</td>
<td></td>
</tr>
</tbody>
</table>

<sup>(1)</sup> Management estimated initial 30 day average well production rate (IP30). Additional 14 wells remain drilled and uncompleted.

Glacier Gas Plant
Current Capacity 250 mmcf/d
May 2016
CONTINUOUS IMPROVEMENT HAS CREATED INDUSTRY LEADING EFFICIENCIES...

Glacier Production

Production Growth to 210 mcmce/d
(35,000 boe/d)

Jan/08 Jan/09 Jan/10 Jan/11 Jan/12 Jan/13 Jan/14 Jan/15 2016

2P F&D Costs

2015 YE Reserves:
2P F&D $0.77/mcfe
3 Year Avg 2P F&D $1.10/mcfe
Reserve Replacement 390%
Recycle Ratio 3.3x

Operating Costs

92% Reduction in Operating Costs to $0.30/mcfe

Operating Costs ($/mce)


Upper & Lower Montney Well Performance

Continuous Improvement Since 2008

Raw Gas Production Rate (mcf/d)

Cumulative Raw Gas Production (Bcf)

2010/14
2019/12
2008-2010
2016 Highlights

40% Production Growth

190 to 210 mmcfe/d Annual Average Production (31,670 – 35,000 Boe/d)

$0.65/mcf Total Cash Costs(2)

15% Cash Flow Per Share Growth(2)

Capital Program Includes Wells for 2017 Production

(1) Cash Flow estimates includes Advantage’s current hedging positions. AECO Cdn $1.25/mcf sensitivity case assumes full year at $1.25/mcf for 2016

(2) Based on AECO Cdn $2.00/mcf, updated as of July 2016
STRONG NETBACKS & RECYCLE RATIOS ARE ACHIEVABLE EVEN WITHOUT HEDGING

Select Montney Natural Gas Producers
Total Corporate Cash Cost Structure - Q1 2016

Glacier Netbacks
Revenue (Realized Price) $1.80 (1) $2.80 (1)
Royalties ($0.09) ($0.14)
Operating Costs ($0.30) ($0.30)
Transportation Costs (2) ($0.03) ($0.03)
Operating Netback $1.38 $2.33
G&A ($0.10) ($0.10)
Finance Expense & other ($0.12) ($0.12)
Cash Flow Netback $1.16/mcfe or $2.11/mcfe $6.96/boe $12.66/boe

Recycle Ratio 2015
2P F&D @ $0.77/mcfe (3) 1.5x 2.7x

“NO HEDGING INCLUDED”
Illustrative AECO Cdn Illustrative AECO Cdn
Illustrative AECO Cdn
Illustrative AECO Cdn

| Source: RBC Capital Markets, Public Disclosures |

(1) Revenue includes adjustments for heat value offset by natural gas transportation costs of $0.27/mcf as required by accounting standards.
(2) Natural Gas liquids transportation costs.
(3) 2P F&D includes Future Development Capital and is based on Sproule’s 2015 year-end 2P reserves report.
“Surplus Cash Flow Above AECO $1.85/Mcf”
(NO HEDGING INCLUDED)

- Based on average well type curve (1): $105 million
- Based on top quartile type well (2): $85 million

<table>
<thead>
<tr>
<th>Maintenance Capital at 245 mmcfe/d</th>
<th>Cash Flow at AECO $1.85/Mcf</th>
<th>Cash Flow at AECO $2.50/Mcf</th>
<th>Cash Flow at AECO $3.00/Mcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>$105 million</td>
<td>$105 million</td>
<td>$160 million</td>
<td>$205 million</td>
</tr>
</tbody>
</table>

Notes:
(1) Assumes 7.2 mmcfd /7.2 Bcf for Upper/Lower Montney wells and 4.5 mmcfd /4.5 Bcf for Middle Montney wells
(2) Assumes 9 mmcfd /9 Bcf for Upper/Lower Montney wells and 6 mmcfd /6 Bcf for Middle Montney wells
ADVANTAGE DEVELOPMENT PLAN – 2015 THROUGH 2017

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### Annual Average Production (mmcfe/d)

<table>
<thead>
<tr>
<th></th>
<th>2015 Actual</th>
<th>2016 Budget</th>
<th>2017 Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>141</td>
<td>200</td>
<td>235</td>
</tr>
<tr>
<td>2016</td>
<td>40%</td>
<td>18%</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td></td>
<td></td>
<td></td>
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</tbody>
</table>

CAGR (2) 22%

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### Capital Spending ($ millions)

<table>
<thead>
<tr>
<th></th>
<th>2015 Actual</th>
<th>2016 Budget</th>
<th>2017 Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$165</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td></td>
<td>$120</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>$485 million Total (original estimate $700 million)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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### Cash Flow per Share

<table>
<thead>
<tr>
<th></th>
<th>2015 Actual</th>
<th>2016 Budget @ $2.00 Cdn AECO/mcf</th>
<th>2017 Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$0.72</td>
<td>15%</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>$0.83</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>$1.04</td>
<td>25%</td>
<td></td>
</tr>
</tbody>
</table>

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### ALL-IN Capital Efficiency ($/boe/d)

<table>
<thead>
<tr>
<th></th>
<th>2015 Actual</th>
<th>2016 Budget</th>
<th>2017 Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$485 million Total (original estimate $700 million)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>$13,300 per boe/d</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>Average Capital Efficiency</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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**Notes:**

1. Price assumptions: 2016 AECO $2.00/mcf and 2017 AECO $2.75/mcf. See Appendix pg. 22 for Plan details
2. Compound annual growth rate.
3. Capital Efficiency calculated using 30% per annum decline and includes total annual capital expenditures
Current hedging program reduces downside risk and maintains upside torque.

**Total Debt to Trailing Cash Flow Sensitivity**

<table>
<thead>
<tr>
<th>Year</th>
<th>AECO $2.00/mcf</th>
<th>AECO $2.50/mcf</th>
<th>AECO $3.00/mcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016</td>
<td>1.2</td>
<td>0.8</td>
<td>1.0</td>
</tr>
<tr>
<td>2017</td>
<td>1.5</td>
<td>0.6</td>
<td>1.0</td>
</tr>
</tbody>
</table>

**Period** | **Production** | **Average AECO Floor Price**
--- | --- | ---
2016 | 52% | $3.62/mcf
2017 | 36% | $3.24/mcf
2018 | 13% | $3.04/mcf

**Notes:**
1. Includes Advantage’s current hedges
2. % of estimated annual production, net of royalties
SIGNIFICANT DRILLING INVENTORY INCLUDES DRY AND LIQUIDS RICH NATURAL GAS LOCATIONS AT GLACIER

- Capable of maintaining 245 mmcfe/d (40,830 boe/d) for >50 years (1)
- >1,000 Future Drill Locations at Glacier supports future growth (1)
- 297 undeveloped locations booked in 2P reserves Year End 2015 (2)

### Drilled Wells by Layer

- Upper Montney: 104 wells
- Middle Montney: 23 wells
- Lower Montney: 42 wells

### >1000 Future Drilling Locations

- Drilled Wells: 169
- 2P Reserves Undeveloped Wells: 297

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(1) Management Estimates
(2) Based on Sproule December 31, 2015 Glacier Reserves Report
(3) As of Dec. 31, 2015
OPERATIONAL EXCELLENCE
IMPROVING WELL PERFORMANCE AND LOWER WELL COSTS THROUGH DRILLING & COMPLETION TECHNOLOGY

Recent “TOP Quartile” Wells

Increasing frac count has improved long term production performance in all layers.

Well Costs Reduced ($ millions)

**UPPER MONTNEY**
- **2014 (18 fracs)**: $5.5
- **2016 (25 fracs)**: $4.5

**MIDDLE MONTNEY**
- **2014 (18 fracs)**: $6.6
- **2016 (25 fracs)**: $5.4

**LOWER MONTNEY**
- **2014 (18 fracs)**: $5.8
- **2016 (25 fracs)**: $5.1

"2016 Annual Target of 200 mmcfe/d attainable with current standing inventory of wells"

10 Wells Currently Completed & Standing
14 Wells Drilled & Uncompleted

(1) Initial on production rate based on approximately first ten days of in line test at gas gathering system pressure. Wells are then choked to ≤10 mmcf/d to manage frac sand flow back per AAV operating practices.
UPPER & LOWER MONTNEY WELLS OUTPERFORM LONG TERM PRODUCTION EXPECTATIONS

New wells are normally restricted to ≤10 mmcf/d for frac sand flowback control during initial 6 months

Wells tested, not on-production.

13 recent wells are demonstrating strong performance

Production from 22 previously completed slick water wells (2013)

Data: updated to June 28, 2016
IMPROVING LIQUIDS RICH MIDDLE MONTNEY WELL PERFORMANCE AT GLACIER

10 New MM wells could exceed type curve

Wells tested, not on-production

New 12-3 well (2014)
cumulative production > 1.4
Bcf in 8 months (restricted)

12-2 well (2013) cumulative production
> 3.0 Bcfe (restricted) with current
flowing pressure ~ 1,000 psi.

Middle Montney Budget Type Curve
(IP30 4.5 mmcf/d & 4.5 Bcf)

Middle Montney Top Quartile Type Curve
(IP30 6.0 mmcf/d & 6.0 Bcf)

Data: updated to June 28, 2016
ROBUST UPPER & LOWER MONTNEY DRY GAS WELL ECONOMICS

Upper & Lower Montney (Dry Gas)

- Type Curve & Cost: 59%
- Higher IP & EUR Case: 89%
- Assumptions:
  - Management Estimates of IP30, 2P EUR & Capital Costs for the next phase of drilling
  - Cdn Aeco $3.00/mcf, flat
  - Cdn $40/bbl blended C3+ price based on $55 U.S./bbl WTI

Middle Montney (50 bbls/mmcf C3+, 45% C5+)

- Type Curve & Cost: 45%
- Higher IP & EUR Case: 81%
- IP30: 7.2/7.2 @ $4.9MM
- Bcf: 9/9 @ $4.9MM
- Well Cost (DC&E): 4.5/4.5 @ $5.4MM
- Advanced achieved >20% DC & E well cost reduction & despite increasing frac count
GROWTH BEYOND 350 MMCF/D CAN BE ACCOMMODATED ON EXISTING PLANT SITE

100% Owned Glacier Gas Plant – Positioned for Production Ramp-up

Room for Additional Expansion Beyond 350 mmcf/d

To be expanded from 250 mmcf/d to 350 mmcf/d Dry & Liquids gas processing capacity

Glacier Gas Plant Site near Major Natural Gas & Liquids Pipelines & Rail Access

2016 Sales Pipeline Loop increases capacity to 400 mmcf/d (Glacier plant to NW TCPL Mainline)

Total TCPL Natural Gas Firm Transportation Service of 293 mmcf/d by 2019 Secured
APPENDIX
FULLY FUNDED GLACIER GROWTH PLAN DETAILS:
22% ANNUAL AVERAGE PRODUCTION GROWTH FOR 2015 TO 2017

### Annual Average Production (mmcfe/d)

- **2015 Actual**: 141
- **2016 Budget**: 200
- **2017 Estimate**: 235

### Production Growth

- **Annual average (mmcfe/d)**
  - Growth (3) 39%
- **Exit rate (mmcfe/d)**
  - Growth (3) 18%
- **2016 budgeted production includes up to an average of 1,200 bbls/d of natural gas liquids.**

### Wells Drilled (net)

- **2015 Actual**: 38
- **2016 Budget**: 17
- **2017 Estimate**: 13

### Commodity Prices (4)

- **NYMEX ($US/mmbtu)**
  - 2014: $4.41 2015: $2.66 2016: $2.35 2017: $2.75
- **AECO ($/mcf)**
  - 2014: $4.49 2015: $2.69 2016: $2.50 2017: $2.75
- **WTI ($US/bbl)**
  - 2014: $93.26 2015: $48.69 2016: $42.00 2017: $48.00

### Financial

- **Capital ($ millions)**
- **Funds from operations ($ millions)**
- **Bank debt ($ millions)**
  - 2014: $0.97 2015: $0.72 2016: $0.90 2017: $1.04
- **Bank debt multiple of cash flow**
  - 2014: 0.7x 2015: 2.3x 2016: 0.9x 2017: 0.8x
- **Total debt ($ millions)**
- **Total debt multiple of cash flow**
  - 2014: 1.5x 2015: 2.4x 2016: 1.0x 2017: 0.9x

### Notes

1. All capital and operating input parameters are based on mid-point of estimates.
2. Development Plan presented pro forma the offering of an additional 13.5 million Common Shares for net proceeds of $95 million that was completed on Mar. 8, 2016.
3. Growth or CAGR represents the Compound Annual Growth Rate during the period (2014 growth calculation excludes production from asset dispositions completed in 2013).
5. Basic Common Shares outstanding was 184.3 million on Mar. 8, 2016.
6. Estimated bank debt and total debt at the end of each calendar year. Total debt includes bank debt and working capital. Multiple of cash flow is based on the calendar year’s funds from operations.
UPPER AND LOWER MONTNEY WELLS - IMPROVING PERFORMANCE SINCE 2008

Data: updated to June 2016

Budget Type Curve (IP30 7.2 mmcf/d & 7.2 Bcf)
EXCEPTIONAL UPPER & LOWER MONTNEY WELL ECONOMICS

Management estimates. NPV 10% pre-tax capital of $4.9 million per well based on management’s estimate of Capital Cost for our next phase of drilling.

Natural gas and NGL prices and costs escalated at 1.5%. Average C3+ Cdn NGL price of $40/bbl based on $55 U.S./bbl WTI.

Budget Type Curve. Some recent Upper & Lower Montney wells are outperforming type curve.
Middle Montney at 50 bbls/mmcf C3+ (2)

- **ROR**: 141%
- **NPV (10%)**: $11.0 million
- **ROR**: 81%
- **NPV (10%)**: $7.7 million
- **ROR**: 45%
- **NPV (10%)**: $4.6 million

Budget type curve. Some recent MM wells are exceeding type curve.

---

1. Management estimates. NPV 10% pre-tax
2. Capital of $5.4 million per well based on management’s estimate of Capital Cost for our next phase of drilling
3. Natural gas and NGL prices and costs escalated at 1.5%. Average C3+ Cdn NGL price of $40/bbl based on U.S.$55/bbl WT1. C3+ NGL yields of 50 bbls/mmcf raw gas
Based on C₃+ shallow cut liquids extraction process yields from well test data. Middle Montney wells to date illustrate higher liquid content from west to east across Glacier. 2014 Middle Montney program focused on higher liquid content in East Glacier.

**2014 Well 8-9**
- 5.7 mmcf/d
- 83 bbls/mmcf

**2014 Well 12-20**
- 9.3 mmcf/d
- 43 bbls/mmcf

**2014 Well 13-17**
- 9.8 mmcf/d
- 54 bbls/mmcf

**2014 Well 8-35**
- 18 mmcf/d
- 47 bbls/mmcf

**Glacier C₅+ 57 deg API**
- 6.6
- >9
- 50
- 45%

MM wells drilled in 2014 program at Glacier. MMCF/D average final test rate from ten completed 2014 wells. MMCF/D demonstrated by 3 of the 10 wells. BBLs/MMCF of C₃+ liquids yield average East Glacier. Average condensate in liquid yield.

(1) Based on C₃+ shallow cut liquids extraction process yields from well test data.
GLACIER MONTNEY ASSIGNED 2P EUR PER WELL & INTERVAL

2P Recoveries per Interval

<table>
<thead>
<tr>
<th>Interval</th>
<th># of Gross HZ Wells</th>
<th>2P Recovery [bcf/well]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Developed</td>
<td>Undeveloped</td>
</tr>
<tr>
<td>1 UM</td>
<td>73</td>
<td>83</td>
</tr>
<tr>
<td>2 MM</td>
<td>5</td>
<td>6</td>
</tr>
<tr>
<td>3 MM</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>4 MM</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>5 LM</td>
<td>15</td>
<td>22</td>
</tr>
<tr>
<td>Total</td>
<td>94</td>
<td>115</td>
</tr>
</tbody>
</table>

(1) Based on Sproule 2015 year-end reserve report. Indicated raw gas volumes per well.
GLACIER – LOCATED IN THE HEART OF THE MONTNEY RESOURCE PLAY

Montney Siltstone Comparison:
- 700 times more permeability
- 4x more formation thickness
- Very low clay content
- Liquids & improved well efficiencies ➔ strong economics

<table>
<thead>
<tr>
<th>Reservoir Attribute</th>
<th>Glacier Montney</th>
<th>Haynesville</th>
<th>Marcellus</th>
<th>Eagle Ford</th>
<th>Barnett</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Thickness (m)</td>
<td>~290</td>
<td>40 – 110</td>
<td>25 – 90</td>
<td>15 – 85</td>
<td>25 – 180</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>2-10</td>
<td>5 – 12</td>
<td>5 – 13</td>
<td>4 – 12</td>
<td>3 – 9</td>
</tr>
<tr>
<td>Permeability (nD)</td>
<td>2,000 – 300,000</td>
<td>&lt;100</td>
<td>20 – 55</td>
<td>50 – 1200</td>
<td>250</td>
</tr>
<tr>
<td>Mineralogy (% Non-Clay)</td>
<td>88 – 90</td>
<td>45 – 65</td>
<td>60 – 80</td>
<td>75 – 85</td>
<td>70 – 90</td>
</tr>
<tr>
<td>Liquids (bbls/MMcf)</td>
<td>Up to 83 bbls/MMcf</td>
<td>nil</td>
<td>Up to 200 bbls/MMcf</td>
<td>Up to 20 bbls/MMcf</td>
<td></td>
</tr>
</tbody>
</table>
2012 CORE AND COMPLETION STUDIES: INCREASED RESOURCE AND IMPROVED WELL RESULTS

Completion Study included 135 wells and over 1,400 fracs in the immediate Glacier area covering the EnCana Swan and Murphy Tupper properties.

Findings revealed that high frac pump rates and open hole packer system resulted in optimal performance.

Core study determined original density porosity logs have to be recalibrated.

Re-calibration aligned log to actual core porosities evident through entire 290 meters of Montney formation at Glacier.

Well tests in all the Montney layers proved gas saturation and productivity.

IP30’s on open hole wells improved by 1.6x

First year cumulative production improved by 1.7x from 0.7 bcf to 1.2 bcf

IP30’s with pump rates > 4m$^3$/minute improved by 1.7x

First year cumulative production improved by 2.4x from 0.7 bcf to 1.7 bcf

(1) Composite log and core from several wells located across the Glacier land block
Certain statements contained in this presentation constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. In particular, this presentation contains forward-looking statements pertaining to, but not limited to, the following: details of the Corporation's 2015 to 2017 development plan including expected production growth, estimate debt to cash flow ratio, expected capital expenditures, expected wells to be drilled, expected operating costs, expected economics, expected resulting free cash flow and expected number of drilling locations and inventory; expected number of wells required to be drilled to achieve certain levels of production; expected details and timing of the Glacier gas plant expansion; expected well economics associated with certain type curves; expected future production levels; expected sensitivities in cash flow per share and debt to cash flow levels to changes in commodity prices; expected effect of refinement of drilling and completion technique; Advantage's guidance in respect of anticipated production levels, exit production rates, royalty rates, operating costs and netbacks; and projections of market prices and costs. In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described can be profitably produced in the future. These statements involve substantial known and unknown risks and uncertainties, certain of which are beyond Advantage's control, including, but not limited to: changes in general economic, market and business conditions; industry conditions; actions by governmental or regulatory authorities including increasing taxes or royalties; and changes in investment or other regulations; the effect of acquisitions; Advantage's success at acquisition, exploitation and development of reserves; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; fluctuations in commodity prices and foreign exchange and interest rates; stock market volatility and market valuations; volatility in market prices for oil and natural gas; unexpected drilling results, changes in commodity prices, currency exchange rates, capital expenditures, reserves or reserves estimates and debt service requirements; the occurrence of unexpected events involved in the exploration for, and the operation and development of, oil and gas properties; hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; changes or fluctuations in production levels; delays in anticipated timing of drilling and completion of wells; individual well productivity; competition from other producers; the lack of availability of qualified personnel or management; credit risk; our ability to comply with current and future environmental or other laws; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; ability to obtain required approvals of regulatory authorities; ability to access sufficient capital from internal and external sources. Many of these risks and uncertainties and additional risk factors are described in the Corporation's Annual Information Form which is available at www.sedar.com and www.advantageog.com. Readers are also referred to risk factors described in other documents Advantage files with Canadian securities authorities. With respect to forward-looking statements contained in this presentation, Advantage has made assumptions regarding, but not limited to: conditions in general economic and financial markets; effects of regulation by governmental agencies; current commodity prices and royalty regimes; future exchange rates; royalty rates; future operating costs; current commodity prices and royalty regimes; availability of skilled labor; availability of drilling and related equipment; timing and amount of capital expenditures; the impact of increasing competition; the price of crude oil and natural gas; that the Corporation will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Corporation's conduct and results of operations will be consistent with its expectations; that the Corporation will have the ability to develop the Corporation's properties in the manner currently contemplated; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated; and the estimates of the Corporation's production and reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects. Advantage's actual decisions, activities, results, performance or achievement could differ materially from those expressed in, or implied by, such forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur or, if any of them do, what benefits that Advantage will derive from them. Except as required by law, Advantage undertakes no obligation to publicly update or revise any forward-looking statements. For additional risk factors in respect of Advantage and its business, please refer to its Annual Information Form dated March 25, 2015 which is available on SEDAR at www.sedar.com and www.advantageog.com.

References in this presentation to initial test production rates, production type curves, initial "productivity", initial "flow" rates, final gas flow rates, average gas flow rates, average type curves, "flush" production rates and "30 day IP rates" and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not
determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for Advantage. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Corporation cautions that the test results should be considered to be preliminary.

Certain type curves presented herein represent estimates of the production decline and ultimate volumes expected to be recovered from wells over the life of the well. The 7.2 mmcf/d IP (which represents the average 30 day initial production rate) & 7.2 Bcf (which represents the ultimate volumes expected to be recovered from the wells over the life of the well based on the type curve) Upper and Lower Montney type curve and the 4.5 mmcf/d IP and 4.5 Bcf Middle Montney type curve are management generated type curves based on a combination of historical performance of older wells and management’s expectation of what might be achieved from future wells. The type curves represent what management thinks an average well will achieve. Individual wells may be higher or lower but over a larger number of wells management expects the average to come out to the type curve. Over time type curves can and will change based on achieving more production history on older wells or more recent completion information on newer wells.

Other type curves presented herein, including the 9 mmcf/d IP & 9 Bcf Upper and Lower Montney type curve have been provided to demonstrate the economics associated with wells that could potentially have that type of productivity and recovery but do not represent management estimates of how such wells will actually perform.

This presentation discloses certain future drilling locations that have not been booked in Advantage’s most recent independent reserves evaluation as prepared by Sproule as of December 31, 2015. Such drilling locations are internal estimates based on Advantage’s prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Such locations do not have attributed reserves or resources. Such drilling locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Advantage will drill all drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the drilling locations have been derisked by drilling existing wells in relative close proximity to such drilling locations, other drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Throughout this presentation the terms boe (barrels of oil equivalent), mcfe (thousand of cubic feet of gas equivalent), mmcfe (millions of cubic feet of gas equivalent), bce (billion of cubic feet of gas equivalent) and Tcfe (trillion of cubic feet of gas equivalent) are used. Such terms may be misleading, particularly if used in isolation. The conversion ratio used herein of six thousand cubic feet per barrel (6 mcf: 1 bbl) of natural gas to barrels of oil equivalent and the conversion ratio used herein of 1 barrel per six thousand cubic feet (1 bbl: 6 mcf) of barrels of oil to natural gas equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas 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.

The Corporation discloses several financial measures that do not have any standardized meaning prescribed under International Financial Reporting Standards (“IFRS”). These financial measures include funds from operations, total debt to cash flow ratio and operating netbacks. Management believes that these financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Corporation’s principal business activities. Investors should be cautioned that these measures should not be construed as an alternative to net income, cash provided by operating activities or other measures of financial performance as determined in accordance with IFRS. Advantage’s method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to similar measures used by other companies. Funds from operations, as presented, is based on cash provided by operating activities, adjusted for expenditures on decommissioning liability, changes in non-cash working capital and interest on bank indebtedness. Total debt to cash flow ratio is calculated as indebtedness under Advantage’s credit facilities plus working capital deficit divided by funds from operations. Operating netbacks are calculated by deducting royalties and operating costs from revenue on a unit (boe or mcfe) basis. Please see the Corporation’s most recent Management’s Discussion and Analysis, which is available at www.sedar.com and www.advantageog.com for additional information about certain of these financial measures, including a reconciliation of funds from operations to cash provided by operating activities.
The following abbreviations used in this press release, including in the appendices hereto, have the meanings set forth below:

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>bbls</td>
<td>barrels</td>
</tr>
<tr>
<td>bbls/d</td>
<td>barrels per day</td>
</tr>
<tr>
<td>mbbls</td>
<td>thousand barrels</td>
</tr>
<tr>
<td>boe</td>
<td>barrels of oil equivalent of natural gas, on the basis of 1 barrel of oil or NGLs for 6 thousand cubic feet of natural gas</td>
</tr>
<tr>
<td>mboe</td>
<td>thousands of barrels of oil equivalent</td>
</tr>
<tr>
<td>boe/d</td>
<td>barrels of oil equivalent per day</td>
</tr>
<tr>
<td>2P</td>
<td>proved plus probable reserves</td>
</tr>
<tr>
<td>NGLs</td>
<td>natural gas liquids</td>
</tr>
<tr>
<td>mcf</td>
<td>thousand cubic feet</td>
</tr>
<tr>
<td>mmcf</td>
<td>million cubic feet</td>
</tr>
<tr>
<td>mmcf/d</td>
<td>million cubic feet per day</td>
</tr>
<tr>
<td>bcf</td>
<td>billion cubic feet</td>
</tr>
<tr>
<td>bcfe</td>
<td>billion cubic feet of natural gas equivalent on the basis of 1 barrel of oil or NGLs to 6 thousand cubic feet of natural gas</td>
</tr>
<tr>
<td>tcf</td>
<td>trillion cubic feet</td>
</tr>
<tr>
<td>tcf e</td>
<td>trillion cubic feet of natural gas equivalent on the basis of 1 barrel of oil to 6 thousand cubic feet of natural gas</td>
</tr>
</tbody>
</table>

Where any disclosure of reserves data and resources is made in this presentation that does not reflect all reserves of Advantage, the reader should note that the estimates of reserves, future net revenue and resources for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

This presentation includes calculations of finding and development ("F&D") costs which have been calculated in accordance with Section 5.15 of NI 51-101 by adding together exploration costs, development costs and the change in future development costs and dividing the sum by reserves additions. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

In this presentation certain financial and operating metrics of other issuers are presented to compare such metrics to Advantage’s results. Such other issuers were included to show how Advantage’s performance compares to some of its peers. The financial and operating metrics of such issuers have been obtained from public sources and have not been independently verified by Advantage. Readers should not base an investment decision for the securities of such issuers based on the information available herein. Advantage disclaims any responsibility or liability for the accuracy of the information relating to such other issuers presented herein.

This presentation contains projections of production growth based on drilling and recompletion opportunities identified by management of Advantage. Certain of the drilling opportunities identified have no associated reserves or resources which can presently be classified as recoverable. As such the initial rates of production and reserves per well identified herein do not represent estimates of future production or reserves associated with the drilling opportunities. The initial rates of production, reserves per well and the capital costs associated with drilling and recompletion identified below are based on Advantage’s historical results and analogous public information received from other producers using similar technologies as Advantage intends to use in the same or similar areas and formations. The initial rates of production, reserves per well and capital costs associated with the wells have been provided herein to give an indication of management’s assumptions used for budgeting, planning and forecasting purposes. The initial rates of production, reserves and capital costs will most likely be different than projected.
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