FOR IMMEDIATE RELEASE
November 10, 2016

Athabasca Oil Corporation Reports 2016 Third Quarter Results and Closing of the Upsized $257 Million Contingent Bitumen Royalty

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or "the Company") is pleased to provide its 2016 third quarter results and an operations update. Athabasca has closed the previously announced upsized Contingent Bitumen Royalty (the "Royalty") with Burgess Energy Holdings L.L.C. ("Burgess Energy").

Athabasca's strategy positions the Company for strong growth and financial sustainability into the future:

- **Defined and Material Growth in Light Oil –** a scalable operated Montney position and funded Duvernay development through the joint venture with Murphy Oil Company Ltd. ("Murphy").
- **Thermal Oil Leverage to Commodity Prices –** continued ramp-up of Hangingstone Project 1, a low decline asset with significant cash flow torque and minimal capital requirements in the initial years of operations.
- **Financial Sustainability –** a current cash positon of approximately $700 million and a $150 million net cash position (adjusted for outstanding debt).

Notable recent highlights include:

- **Q3 2016 Operating Highlights –** Corporate production averaged 11,848 boe/d (86% liquids), an increase of 63% year-over-year. Capital expenditures were approximately $18 million in the quarter.
- **Upsized Contingent Bitumen Royalty –** Athabasca has closed the upsized Royalty with Burgess Energy on its Thermal assets for an additional $128.5 million of cash consideration, bringing total proceeds received to $257 million. This unique Royalty does not encumber the assets at low commodity prices and further supports the significant long-term value of Athabasca's Hangingstone and other thermal assets.
- **Balance Sheet Update –** Throughout 2016, Athabasca has successfully undertaken a series of transactions which have secured a funding model for its assets and position the Company to further deleverage and optimize its capital structure. Consideration for these transactions has totaled $743 million, including $524 million of cash proceeds. Athabasca's final refinancing plans are underway and are expected to be completed prior to the end of 2016.
- **Placid Montney** – In the Light Oil division, Athabasca currently has two rigs active in Placid. The second half 2016 program includes drilling 12 development wells, the completion and tie-in of a four well pad and initial construction and long lead commitments on an oil battery to accommodate mid-term growth plans. The Montney program is anticipated to drive strong economic growth through the first half of 2017 as the wells are placed on production.

- **Greater Kaybob Duvernay –** The joint venture is finalizing 2017 operating plans which will be released in conjunction with the Company's corporate budget in December. Murphy is expected to spud a two well pad in the gas condensate window in Q4 2016 with on-stream timing in late Q1 2017. The joint development agreement contemplates approximately $1 billion of Duvernay gross investment over the next four to five years of which Athabasca's net capital exposure is approximately $75 million.
- **Hangingstone –** Third quarter volumes averaged 8,830 bbl/d and September production averaged 8,922 bbl/d. The project has successfully recovered from downtime during the Fort McMurray wildfires, with updated reservoir simulations predicting reaching design capacity of 12,000 bbl/d in 2018 and no anticipated impact to long-term oil recoveries.

FINANCIAL AND OPERATING HIGHLIGHTS

($ Thousands, except per share and boe amounts)		3 months ended Sept. 30 2016	3 months ended Sept. 30 2015	9 months ended Sept. 30 2016	9 months ended Sept. 30 2015
CONSOLIDATED PRODUCTION					
Petroleum and natural gas volumes (boe/d)		11,848	7,250	12,098	6,207
LIGHT OIL DIVISION					
Petroleum and natural gas sales volumes (boe/d)		3,018	5,145	5,019	5,491
Light Oil operating income[1]	$	5,511	6,096	17,632	23,376
Light Oil operating netback[1] ($/boe)	$	19.85	12.88	12.82	15.60
Capital expenditures	$	18,920	31,465	55,095	125,667
Recovery of capital-carry through capital expenditures	$	(4,286)	-	(5,760)	-
THERMAL OIL DIVISION					
Bitumen production (bbl/d)		8,830	2,105	7,079	716
Bitumen sales volumes (bbl/d)		9,744	1,956	7,138	660
Thermal Oil operating income (loss)[1, 2]	$	(6,088)	(12,146)	(41,079)	(12,146)
Thermal Oil operating netback[1, 2] ($/bbl)	$	(6.80)	(73.67)	(20.99)	(73.67)
Capital expenditures	$	3,754	9,366	6,857	111,073
CASH FLOWS AND FUNDS FLOW					
Cash flow from operating activities	$	(18,990)	(17,933)	(51,297)	(12,031)
Cash flow from operating activities per share (basic & diluted)	$	(0.05)	(0.04)	(0.13)	(0.03)
Funds flow from operations[1]	$	(15,778)	(24,223)	(84,622)	(17,035)
Funds flow from operations per share (basic & diluted)	$	(0.04)	(0.06)	(0.21)	(0.04)
NET LOSS AND COMPREHENSIVE LOSS					
Net loss and comprehensive loss	$	(33,032)	(38,241)	(157,331)	(92,398)
Net loss and comprehensive loss per share (basic & diluted)	$	(0.08)	(0.09)	(0.39)	(0.23)
SHARES OUTSTANDING					
Weighted average shares outstanding (basic & diluted)		405,556,092	403,396,304	405,357,248	402,933,671
FINANCING AND DIVESTITURES					
Promissory note proceeds	$	133,892	150,000	133,892	450,000
Cash proceeds from sales of assets	$	(1,944)	610	390,394	646
Repayment of long-term debt	$	-	(746)	(285,441)	(2,082)
Derivative proceeds upon repayment of long-term debt	$	-	-	40,956	-

As at ($ Thousands)		Sept. 30, 2016	December 31, 2015
BALANCE SHEET ITEMS			
Cash and cash equivalents	$	535,477	559,487
Short-term investments	$	35,000	-
Promissory note	$	-	133,892
Restricted cash	$	103,827	-
Capital-carry receivable (current & LT portion – discounted)[3]	$	188,448	-
Total assets	$	3,017,285	3,462,442
Long-term debt	$	545,126	838,205
Shareholders' equity	$	2,333,523	2,482,140

1) For additional information on Non-GAAP Financial Measures, refer to "Advisories and Other Guidance" in Athabasca's Management Discussion & Analysis dated November 10, 2016 which is available on SEDAR at www.sedar.com.
2) Negative Operating Netbacks are customary during ramp-up of a SAGD project as revenues from lower initial production are more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes. Athabasca anticipates that operating and transportation costs per barrel from Hangingstone Project 1 will continue to improve as production increases.
3) $213.5 million undiscounted capital carry.

Operations Update

Light Oil

Production averaged 3,018 boe/d (46% liquids) in the third quarter of 2016. Capital expenditures totaled $14.6 million (net of capital carry of $4.3 million) with activity primarily focused on commencing development at Placid.

Greater Placid Area– (70% Montney working interest; Q3 1,818 boe/d net)

The Company has established a scalable, operated position which has competitive returns relative to other North American plays. Activity to date has defined a higher liquids trend on Athabasca's acreage with high initial free liquids cuts between 200 – 300 bbl/mmcf.

In July, the Company spud a four well pad at surface location 7-30-60-23W5 ("7-30"). The pad was rig released in September achieving regional pace setter results with drill times averaging approximately 17 days spud to total depth with average lateral lengths of 2,415 meters. This marks a significant improvement over the 2014/15 winter drilling season average of 23 days. On the 7-30 pad the Company estimates average drilling costs of C$3.15 million per well, down 15% from the previous year's program. Completion operations commenced in late October which will test a new completion design. The Company is planning two wells with a standard ball drop design and trialing two wells with a plug and perf system. The plug and perf completion design allows more discrete completion intervals and has shown an extended production uplift in other liquids rich Montney analogs. Average completion cost per well is estimated at C$3.1 million for the ball drop design and C$4.3 million for the plug and perf design. The pad is expected to be placed on production before year-end.

The Company currently has two drilling rigs active at surface locations 12-19-60-23W5 ("12-19") and 16-30-60-23W5 ("16-30"). Both four well pads are expected to be rig released before year-end with completions operations to follow in Q1 2017 and on-stream timing before spring breakup. Athabasca has operational flexibility to run between one to two rigs through the balance of the winter program.

Extended production data from last winter's program continues to support management's type curve expectations with the wells exhibiting modest declines as initial rates were restricted during the clean-up period. The latest five wells have had average IP30s of 805 boe/d (64% liquids), IP90s of 686 boe/d (56% liquids) and IP180s of 587 boe/d (53% liquids).

The Company remains on track to commission an oil battery at Placid in April 2017 which will accommodate liquids handling through 2018.

As Placid operations transition to pad development the play is expected to drive competitive capital efficiencies. Athabasca will remain focused on economically growing production while delineating both Montney intervals and growing the aerial extent of the play. With no near-term land expiries and operated egress, Placid is set up with significant flexibility to control the pace of development going forward. Athabasca has high-graded exposure to approximately 25,000 gross acres of prospective Montney land. The development inventory is estimated between 150 – 200 gross locations which could drive organic growth in excess of five years under an accelerated two rig development scenario.

Greater Kaybob Area – (30% Duvernay working interest; Q3 1,200 boe/d net)

Athabasca and Murphy closed the $486 million light oil joint venture on May 13, 2016. Integration of operations is substantially complete with Murphy now operating wells in the field.

At Kaybob West, in the condensate rich gas window, the Company completed fracturing operations in July on a previously drilled four well pad at Section 36-63-20W5. With input from Murphy, completion intensity on this pad was increased to approximately 2,000 lbs/ft, up from the prior design of approximately 1,100 lbs/ft. Final drill and completion costs were C$8.3 million per well (previously estimated at ~C$9.5 million) with average drilled lateral lengths of approximately 1,370 meters. Through September, the wells were placed on production sequentially with Murphy operating. The wells have been heavily restricted with IP30s averaging 253 boe/d (72% liquids) and have since increased to in excess of 400 boe/d (62% liquids). In line with production practices employed by Murphy in the liquids rich portions of the Eagle Ford, the wells were initially restricted to assess enhancement of liquids recoveries in the higher CGR regions of the Duvernay. Murphy intends to further optimize well design in the 2017 program by testing higher proppant intensity in longer laterals.

Joint venture drilling operations are expected to commence in the fourth quarter with a two well pad at surface location 01-18-64-20W5 offsetting the 1-7-64-20W5 drilled by Athabasca in 2014. The joint development agreement contemplates approximately $200 million of gross capital ($15 million net) in 2017 with the majority of spending directed towards drilling and completion operations. These plans include a mix of continued resource delineation in the volatile oil window and pad operations in lower risk more defined areas of the play. More details on activity levels will be provided with the 2017 budget in December.

The joint development agreement is designed to maximize land retention, delineate the volatile oil window and progress the entire asset to the self-funding stage post the initial carry period. The $219 million capital carry amount ($213.5 million currently remaining) will minimize Athabasca's financial exposure in the mid-term, with Murphy funding 75% of the Company's 30% working interest on the first $1 billion of investment ($75 million net exposure) over the next four to five years in this play.

Thermal Oil - Hangingstone

In the Thermal Oil Division, Hangingstone Project 1 is approximately fifteen months into its production ramp-up with 23 well pairs converted to SAGD production.

Bitumen production for the third quarter averaged 8,830 bbl/d with volumes recovering from three weeks of downtime during the Fort McMurray wildfires in May. Both water rates and oil cuts have returned to pre-fire conditions. The Company is progressing planned pump changes moving the field to ESPs (electrical submersible pumps) to manage higher emulsion rates as the steam chambers mature and as production ramps up. September production averaged 8,922 bbl/d with a steam oil ratio ("SOR") of 4.6.

Athabasca has completed an update to the Company's internal reservoir simulation that is based on a detailed geological interpretation of the reservoir from extensive delineation drilling prior to sanctioning the project, continuous temperature and pressure monitoring across the field and an annual 4D seismic monitoring program. Data supports that the reservoir is bounded, pressure has stabilized and steam conditions are continuing to grow vertically which will drive higher oil volumes and lower SORs with time. The revised model reflects continued but slower vertical steam chamber growth than previously expected with the facility projected to achieve design capacity of 12,000 bbl/d in 2018. This revised outlook is not anticipated to impact long-term oil recoveries.

Upsized Contingent Bitumen Royalty

On November 3, 2016, Athabasca announced the upsizing of the Royalty with Burgess Energy on its Thermal assets. The transaction closed on November 10, 2016 and the Company received an additional $128.5 million of cash consideration, bringing total proceeds received to $257 million. The upsized Royalty further supports the significant long-term value of Hangingstone and Athabasca's other thermal assets.

The Royalty will be calculated on a sliding scale ranging from 0% – 12% (previously 0% – 6%) of Athabasca's realized bitumen price (C$) for each Thermal Oil asset (see table below). The realized bitumen price is to be determined net of diluent, transportation and storage costs. The Royalty has been structured so that the assets will not be encumbered at lower pricing levels. For example, at Hangingstone, oil prices would have to reach approximately US$75/bbl WTI (at nameplate capacity of 12,000 bbl/d) before the first 2% Royalty is triggered. At this pricing level, Hangingstone Project 1 is estimated to have an annual operating netback of approximately $120 million (net of a $4 million Royalty). The Royalty is not expected to materially impact economics of future Hangingstone expansion phases or other future Thermal Oil development projects and there are no associated commitments for future development.

Hangingstone		
Realized Bitumen Price	Royalty	Implied WTI*
$C/bbl	*%*	*US$/bbl*
Below $50/bbl	0%	
$50/bbl to $69.99/bbl	2%	$75-91
$70/bbl to $89.99/bbl	4%	$91-108
$90/bbl to $109.99/bbl	6%	$108-124
$110/bbl to $129.99/bbl	8%	$124-141
$130/bbl to $149.99/bbl	10%	$141-157
$150/bbl and above	12%	>$157

Other Thermal Assets		
Realized Bitumen Price	Royalty	Implied WTI*
$C/bbl	*%*	*US$/bbl*
Below $60/bbl	0%	
$60/bbl to $79.99/bbl	2%	$78-94
$80/bbl to $99.99/bbl	4%	$94-110
$100/bbl to $119.99/bbl	6%	$110-126
$120/bbl to $139.99/bbl	8%	$126-142
$140/bbl to $159.99/bbl	10%	$142-159
$160/bbl and above	12%	>$159

** Implied WTI based on a 0.8 US$/C$ FX assumption & US$15/bbl heavy differential.*
Royalties calculated & payable on a monthly basis.

2016 Budget and Outlook

In the Light Oil division, Athabasca maintains its $102 million net capital budget which reflects the previously announced expanded Montney program at Placid. Annual Light Oil production is estimated at approximately 4,500 boe/d and the Company anticipates strong Montney growth through the first half of 2017 as the wells are placed on production.

In the Thermal Oil division, the wildfire impact, unplanned maintenance downtime year to date and planned pump changes in Q4 has impacted production volumes with annual guidance estimated at approximately 7,300 bbl/d on an unchanged capital budget of $11 million.

The 2017 budget will be announced in December.

2016 Capital Budget[1] ($ millions)	Full Year
LIGHT OIL	Net
Greater Kaybob[2] (Duvernay)	$8
Greater Placid[3] (Montney)	94
Total Light Oil	**$102**
THERMAL OIL	
Hangingstone Maintenance	$7
Other Thermal	4
Total Thermal	**$11**
Capitalized G&A	$8
TOTAL CAPITAL SPENDING	**$121**

1) Figures may not add up due to rounding.
2) Greater Kaybob net capital reflects Athabasca's 30% interest following the application of the capital carry (Murphy funds 75% of Athabasca's 30% working interest).
3) Greater Placid net capital reflects Athabasca's 70% working interest.

2016 Operational & Financial Guidance	Full Year
LIGHT OIL (net)	
Production (boe/d)	4,500
Liquids Weighting (%)	49%
Operating Income ($MM)	~$23
Operating Netback ($/boe)	~$14
THERMAL OIL	
Bitumen Production (bbl/d)	7,300
Operating Income ($MM)	~($49)
CORPORATE	
Production (boe/d)	11,800 (~81% liquids)
Funds Flow from Operations ($MM)	~($103)
Year-end Cash & Equivalents[1] ($MM)	~$620
COMMODITY ASSUMPTIONS *(strip pricing as at Oct. 5, 2016)*	
WTI (US$/bbl)	$42.30
Edmonton Par (C$/bbl)	$51.43
Western Canadian Select (C$/bbl)	$37.29
AECO Gas (C$/mcf)	$2.03
FX (US$/C$)	0.76

1) Excludes $104 million of restricted cash.

Financial Outlook

Throughout 2016, Athabasca has successfully undertaken a series of transactions, including the Murphy joint venture and the Thermal Oil Royalty, which have secured a funding model for its assets and position the Company to further deleverage and optimize its capital structure in the coming months. Consideration for these transactions has totaled $743 million, including $524 million of cash proceeds. The Company now has a cash balance of approximately $700 million (excluding $104 million of restricted cash) with a net cash position of approximately $150 million (adjusted for outstanding debt). The Company also has approximately $213.5 million of further funding available through the capital carry balance with Murphy on its Duvernay joint venture lands.

Since the beginning of 2016, Athabasca has reduced its term debt outstanding by approximately $250 million, and plans to direct the proceeds from the upsizing of the Royalty towards debt repayment, further deleveraging the Company and reducing borrowing costs. Athabasca's final refinancing plans are underway and are expected to be completed prior to the end of 2016. The Company is targeting a capital structure that is well aligned with its future strategic plans and provides a multi-year funding outlook with significant flexibility for the future.

About Athabasca Oil Corporation

Athabasca Oil Corporation is a Canadian energy company with a focused strategy on the development of thermal and light oil assets. Situated in Alberta's Western Canadian Sedimentary Basin, the Company has amassed a significant land base of extensive, high quality resources. Athabasca's common shares trade on the TSX under the symbol "ATH". For more information, visit www.atha.com.

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Reader Advisory:

This News Release 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 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 News Release should not be unduly relied upon. This information speaks only as of the date of this News Release. In particular, this News Release may contain forward-looking information pertaining to the following: the benefits expected to be realized by the Company from its light oil joint venture with Murphy (the "Murphy Transaction"), including the impact on the Company's financial position and balance sheet strength and the benefits expected to be realized from the joint venture's development plans; the growth potential of and the economic returns expected to be realized from the Company's Montney lands in the Placid area; the Company's expectation that its Duvernay interests will be self-funding after Murphy's payment of the Capital Carry; the scope and timing of drilling, completion and commissioning operations in the Company's Light Oil division and the costs of such drilling and completion operations; the timing that the Company's production will come on-stream; the benefits expected to be realized from the use of recovery technologies in the Company's Light Oil division, as well from well designs used by the Company and intended to be used by Murphy in the Light Oil joint venture; the Company's expected flexibility in its pace of development; the Company's production guidance from its Light Oil and Thermal Oil projects; the timing that that Placid oil battery will be commissioned; the impact that the Company's grant of the Royalty will have on Athabasca; the Company's forecasted annual operating netbacks of Hangingstone Project 1, the Company's forecasted price of oil before the Royalty is payable; the Company's use of the proceeds from the grant of the Royalty; the timing of the ramp-up of production and of achieving plateau production from Hangingstone Project 1; the Company's expectation that the revised ramp-up profile of Hangingstone Project 1 will not impact long-term oil recoveries; the Company's expectation that the shut-down of Hangingstone Project 1 operations as a result of the regional Fort McMurray fires will have no long lasting effects on the reservoir; that only minimal maintenance capital will be needed in respect of Hangingstone Project 1 in the initial years of operations; the Company's estimated future commitments; the Company's business and financing strategies and plans, including its plan to reduce its debt over the next several months; expectations regarding the Company's 2016 and 2017 capital budgets; and the future allocation of capital.

With respect to forward-looking information contained in this News Release, assumptions have been made regarding, among other things: commodity prices for petroleum and natural gas; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct its business and the effects that such regulatory framework will have on the Company, including on the Company's financial condition and results of operations; the Company's financial and operational flexibility; the Company's financial sustainability, the Company's ability to accelerate development when prices recover; Athabasca's cash-flow break-even commodity price; geological and engineering estimates in respect of Athabasca's reserves and resources; the applicability of technologies for the recovery and production of the Company's reserves and resources; the Company's ability to demonstrate the quality of its asset base and to build large-scale projects; future capital expenditures to be made by the Company; future sources of funding for the Company's capital programs; the Company's future debt levels; the Company's ability to obtain equipment in a timely and cost-efficient manner; the geography of the areas in which the Company is conducting exploration and development activities; and the Company's ability to obtain equipment in a timely and cost-efficient manner.

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 10, 2016 that is available on SEDAR at www.sedar.com, including, but not limited to: fluctuations in market prices for crude oil, natural gas and bitumen blend; political and general economic, market and business conditions in Alberta, Canada, the United States and globally; changes to royalty regimes, environmental risks and hazards; alternatives to and changing demand for petroleum products; the potential for management estimates and assumptions to be inaccurate; dependence on Murphy as the Company's joint venture participant in the Company's Duvernay and Montney assets; dependence on Murphy as the operator of the Company's Duvernay assets; the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements; operational and business interruption risks associated with the Company's facilities; failure by counterparties to make payments or perform their operational or other obligations to Athabasca in compliance with the terms of contractual arrangements between Athabasca and such counterparties, including in respect of the Murphy Transaction, and the possible consequences thereof; the potential for adverse consequences in the event that the Company defaults under certain of the agreements in respect of the Murphy Transaction or in respect of the Royalty; long term reliance on third parties; aboriginal claims; 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; uncertainties inherent in estimating quantities of reserves and resources; changes to Athabasca's status given the current stage of development; litigation risk; risks and uncertainties inherent in SAGD and other bitumen recovery processes; risks related to hydraulic fracturing, including those related to induced seismicity; 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 costs could make Athabasca's projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; environmental risks and hazards; failure to accurately estimate abandonment and reclamation costs; reliance on third party infrastructure; seasonality; hedging risks; risks associated with maintaining systems of internal controls; insurance risks; claims made in respect of Athabasca's operations, properties or assets; competition for, among other things, capital, export 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 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 GLJ and D&M, please see "Independent Reserve and Resource Evaluations" in the Company's most recent Annual Information Form ("AIF") dated March10, 2016 that is available on SEDAR at www.sedar.com. The forward-looking statements included in this News Release 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.

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 News Release should be considered to be preliminary. Test results and initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery.

Drilling Locations: the ~150 - 200 Montney inventory referenced in this News Release includes 8 probable undeveloped locations, with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ Petroleum Consultants Ltd. as of December 31, 2015 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 geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked 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 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. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked 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.