FOR IMMEDIATE RELEASE
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Athabasca Oil Corporation Reports Second Quarter 2014 Financial and Operating Results

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or "the Company") is pleased to report its second quarter 2014 financial and operating results.

Second quarter highlights:

- produced an average of 5,767 barrels of oil equivalent per day ("boe/d") with 52% liquids, in line with guidance of 5,500 to 6,000 boe/d;
- obtained extended production results from two additional Duvernay wells at Kaybob West; 8-29-64-20W5 had an established 30-day restricted rate of 784 boe/d with a free condensate yield of 763 barrels per million cubic feet ("bbls/mmcf") and the second well at 4-29-64-20W5 had an established 30-day restricted rate of 615 boe/d with a free condensate yield of 710 bbls/mmcf. Both wells support the Company's interpretation of the prospectivity of the volatile oil window where Athabasca has substantial acreage;
- reached 89% completion on Hangingstone Project 1, Athabasca's 12,000 barrels per day ("bbls/d") steam assisted gravity drainage ("SAGD") project; and
- entered into new credit facilities providing for approximately $425 million of committed funding for three to five year terms.

The Company confirms that it continues to work with Phoenix Energy Holdings Limited ("Phoenix") to close the Dover put transaction in accordance with the terms of the Put/Call Option Agreement. The parties have a mutually understood path to closing the transaction, including targeted timelines.

"Athabasca is working diligently to advance the closing of the Dover put transaction and we appreciate the ongoing patience of our shareholders," says Sveinung Svarte, President and CEO. "Operationally, we remain very encouraged by the results of our Duvernay wells and are pleased with the advancement of Hangingstone Project 1, which is progressing as planned. We continue to be committed to strong capital discipline and look forward to releasing an updated corporate strategy and capital plans following the closing of the Dover transaction."

Athabasca has filed its financial statements and management's discussion and analysis ("MD&A") for the three and six months ended June 30, 2014. These documents are available on the Company's website www.atha.com and later this morning from SEDAR www.sedar.com. An updated investor presentation has also been posted on the Company's website. Selected financial and operating information is outlined below and should be read in conjunction with Athabasca's audited financial statements and MD&A.

($ Thousands, except per share and boe amounts)	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
LIGHT OIL NETBACK[1]				
Petroleum and natural gas sales	$ 34,626	$ 35,717	$ 69,272	$ 63,722
Midstream revenues	755	257	1,558	360
Royalties	(2,794)	(2,812)	(7,822)	(4,229)
Operating expenses and transportation	(8,380)	(8,768)	(17,859)	(17,370)
	$ 24,207	$ 24,394	$ 45,149	$ 42,483
CASH FLOWS				
Funds Flow from Operations[1]	$ 4,882	$ 1,368	$ 8,714	$ (6,918)
Funds Flow from Operations per share (basic and diluted)	$ 0.01	$ 0.00	$ 0.02	$ (0.02)
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$ (56,766)	$ (29,986)	$ (78,119)	$ (55,476)
Net loss and comprehensive loss per share (basic & diluted)	$ (0.14)	$ (0.07)	$ (0.19)	$ (0.14)
SALES VOLUMES				
Oil (bbls/d)	2,184	2,695	2,297	2,742
Natural gas (mcf/d)	16,563	21,942	18,282	19,080
Natural gas liquids (bbls/d)	823	906	688	729
Total (boe/d)	5,767	7,258	6,032	6,651
Oil and Natural gas liquids %	52%	50%	49%	52%
REALIZED PRICES				
Oil ($/bbl)	$ 104.04	$ 88.22	$ 96.50	$ 84.72
Natural gas ($/mcf)	5.01	4.08	5.67	3.74
Natural gas liquids ($/bbl)	85.46	71.92	83.37	67.07
Realized price ($/boe)	65.97	54.08	63.45	52.98
Royalties ($/boe)	(5.32)	(4.26)	(7.16)	(3.52)
Operating expenses and transportation[2] ($/boe)	(14.53)	(12.89)	(14.93)	(14.19)
Light Oil Netback[1] ($/boe)	$ 46.12	$ 36.93	$ 41.36	$ 35.28
CAPITAL EXPENDITURES				
Light Oil Division	$ 14,847	$ 47,461	$ 92,296	$ 223,420
Thermal Oil Division	90,556	87,401	248,514	166,633
Assets held for sale	2,600	4,800	6,600	9,383
Corporate	1,053	3,048	2,508	7,655
	$ 109,056	$ 142,710	$ 349,918	$ 407,091

(1) Refer to "Advisories and Other Guidance" on page 18 of the MD&A for additional information on Non-GAAP Financial Measures.

(2) For the six months ended June 30, 2014, operating expenses and transportation expenses in the Netback figure includes midstream revenues of $1.43/boe (2013 - $0.25/boe) and for the three months ended June 30, 2014, $1.44/boe (2013 - $0.39/boe).

As at ($ Thousands)	June 30, 2014	December 31, 2013
LIQUIDITY		
Cash and cash equivalents	$ 182,499	$ 298,995
Short-term investments	-	23,795
Add: Undrawn credit facilities	125,000	350,000
Add: Term Loan – delayed draw (US$50.0 million)	53,380	-
Available liquidity[1]	360,879	672,790
BALANCE SHEET		
Total assets	4,459,943	4,342,325
Long-term debt	764,788	533,210
Shareholders' equity	$ 3,301,011	$ 3,373,957

(1) Refer to "Advisories and Other Guidance" on page 18 of the MD&A for additional information on Non-GAAP Financial Measures.

Operations Update

Light Oil

Athabasca's light oil production averaged 5,767 boe/d with 52% liquids in the second quarter of 2014. Production was in line with prior guidance of 5,500 to 6,000 boe/d which incorporated a planned third-party downtime of 10 days. The Company was able to achieve guidance despite an additional seven days of unplanned third-party downtime. The combined third-party plant outages of 17 days impacted production by approximately 1,000 boe/d for the quarter. Production volumes were supported by the winter Duvernay program which included four horizontal wells that are now on stream with extended production periods exceeding 30 days. The Company recognized a light oil netback of $46.12/boe in the second quarter of 2014. Light Oil capital expenditures were $15 million in the second quarter of 2014 primarily consisting of facility and base maintenance projects and commissioning of the new Duvernay wells.

Duvernay Update

In the Kaybob West area, the final two Duvernay wells that were completed in the first quarter were brought on production in the second half of June following a planned extended shut in (soak period) subsequent to the wells' completion and initial flow back. The 8-29-64-20W5 well was soaked for 77 days and averaged a restricted rate of 784 boe/d (644 bbls/d of condensate, 844 mcf/d of gas) in the first 30 days with a free condensate yield of 763 bbls/mmcf. The second Duvernay well at 4-29-64-20W5 was soaked for 69 days and when brought on production, averaged a restricted rate of 615 boe/d (498 bbls/d of condensate, 702 mcf/d of gas) in the first 30 days with a free condensate yield of 710 bbls/mmcf. Both wells continued to flow at restricted rates at the end of the 30-day period.

The Duvernay well located at 1-7-64-20W5 in Kaybob West continues to perform well at a restricted rate. Average production for this well was 625 boe/d (442 bbls/d of condensate, 1.1 mmcf/d of gas) in the first 90 days with a free condensate yield of 418 bbls/mmcf. This compares to the restricted IP30 of 750 boe/d (550 bbls/d and 1.2 mmcf/d) released in May 2014.

At Simonette, Athabasca's 1-25-62-25W5 well continues to be a top producer in the Duvernay fairway. Production through permanent facilities commenced in May and in the first 60 days the well has produced an average restricted rate of 1,286 boe/d (820 bbls/d of condensate, 2.8 mmcf/d of gas) with a free condensate yield of 294 bbls/mmcf. This compares to the restricted IP30 of 1,461 boe/d (945 bbls/d and 3.0 mmcf/d).

The Company believes production practices have a considerable influence on the initial productivity and ultimate recovery of Duvernay wells. Athabasca's practices include a post-completion soak period resulting in higher initial flowing pressures and reduced flow back water production. By restricting rates the Company also observes sustained production at lower pressure decline rates.

The focus of the Duvernay program to date has been to retain land, prove the resource extent and understand the basin. In total, Athabasca has now drilled eight horizontal Duvernay wells in the fairway, of which seven were on production by the end of the second quarter of 2014. The Company holds 200,000 net acres of high-graded Duvernay land which contain greater than 20 meters of shale pay and lie in the heart of the Kaybob Duvernay fairway. Approximately two-thirds of the Duvernay acreage is extended into the intermediate term and an additional five wells are required over the next drilling season to extend approximately 95% of the acreage into the intermediate term. The upcoming Duvernay program will shift to prioritizing production and cash flow growth from the Saxon, Simonette and Kaybob West areas where Athabasca and industry have demonstrated commercial well performance.

Athabasca anticipates a significant reduction in well costs as the play moves towards the development stage. Cost learnings are well documented across North American shale plays. The Company's Duvernay costs have ranged between $15 to $19 million per well to drill and complete single well pads. This includes vertical strat, core work and in some cases micro seismic monitoring. Athabasca is confident in its ability to reduce costs, particularly with pad drilling, and expects horizontal well costs to be $10 to 15 million in future development phases of its drilling program.

Infrastructure Update

In regard to Light Oil infrastructure, Athabasca completed the installation of a pipeline connecting Athabasca's Kaybob West facility to SemCAMS' KA gas plant. The installation was completed on behalf of a third-party, with Athabasca retaining a 10% working interest in the 10-inch line with no capital outlay. The Company views its regional infrastructure as a competitive advantage providing egress to two large midstream plants and facilitating growth into the mid-term. Ownership in infrastructure remains a strategic advantage for Athabasca in controlling pace of development.

Thermal Oil

In the second quarter of 2014, Thermal Oil capital expenditures totaled $91 million including $88 million on Hangingstone and $3 million on Thermal Oil exploration areas. This excludes $3 million of capital expenditures associated with the Company's 40% interest in the Dover oil sands project.

During the second quarter of 2014, Athabasca advanced its development of Hangingstone Project 1. The drilling and completions program is 100% complete and has delivered better than expected cost and schedule performance. The reservoir quality is consistent with expectations derived from Athabasca's extensive appraisal drilling and reservoir modeling.

At the end of June 30, 2014, Hangingstone Project 1 was approximately 89% complete with costs closely aligned with the sanctioned budget of $565 million. The focus for construction is on the completion of the central plant. Commissioning and operations readiness plans are progressing as planned. The teams will be ready to transition from construction near the end of the year to achieve first steam which remains targeted towards the end of the first quarter of 2015.

Corporate

Dover Oil Sands Project
Athabasca is working diligently to close the sale of its 40% interest in the Dover oil sands project to Phoenix. Athabasca exercised its put option under the Put/Call Option Agreement on April 17, 2014, requiring Phoenix to purchase the Company's Dover interests in accordance with the terms of the Put/Call Option Agreement. The parties are jointly working toward the closing of the transaction and have a mutually understood path to closing the transaction, including targeted timelines. As previously disclosed, the current net purchase price payable by Phoenix is $1,234 million.

The Company has also made a separate provision for $49 million in respect of a potential settlement of certain claims made by Phoenix for indemnification under the PetroChina Transaction Agreements and the AOSC MacKay Share Purchase Agreement in relation to future thermal abandonment costs associated with petroleum and natural gas wells located in the Dover and MacKay River areas. The Company's payment under this settlement is contingent upon the successful closing of the Dover Put Option.

Liquidity
On May 7, 2014 Athabasca entered into new credit facilities, including term loans and a revolving credit facility, which combined provide for approximately $425 million of committed funding for three to five year terms. The new credit facilities replaced the Company's previous $350 million revolving credit facility which had a maturity date of December 31, 2014, providing Athabasca with longer term sources of committed funding which better match the development profile of its assets as well as more flexible covenants.

At June 30, 2014, Athabasca had liquidity of approximately $361 million, including cash and cash equivalents, short-term investments, its undrawn $125 million revolving credit facility and a $50 million (U.S) delayed draw term loan.

Outlook

The 2014 capital budget remains at $527 million, excluding capitalized interest and capitalized general and administrative expenses. Second half 2014 production guidance is between 6,000 – 6,500 boe/d. The Company will release full capital plans, details on its strategy and a preliminary 2015 outlook following receipt of the Dover proceeds.

Athabasca views joint ventures as a mechanism to help reduce risk, accelerate development and leverage partner expertise. As the Company advances the development and operations of its Light Oil and Thermal Oil assets, its strong results, scalable position and understanding of the play will continue to attract interest from potential long-term partners.

2014 Capital Budget[1] ($ Millions)	Full Year 2014	Q3/Q4 2014
THERMAL OIL DIVISION		
Hangingstone Project	$ 227	$ 81
Hangingstone regional infrastructure and production support	58	15
Hangingstone Expansion	48	28
Other	15	10
	348	134
LIGHT OIL DIVISION		
Duvernay	108	40
Montney	16	5
Other	21	13
	145	58
CORPORATE	14	12
DOVER JOINT VENTURE	20	13
TOTAL CAPITAL SPENDING	$ 527	$ 217

(1) The capital budget figures above exclude capitalized interest, financing costs, and general & administrative costs ("G&A"). Athabasca anticipates that capitalized G&A for 2014 will be approximately $50 million.

2014 Light Oil Operations	Six months ended June 30, 2014	Guidance Q3/Q4 2014
Light oil production (boe/d)	6,032	6,000 - 6,500
Oil and natural gas liquids (%)	49	56

Conference Call, August 6, 2014
7:30 am Mountain Time (9:30 am Eastern Time)

A conference call to discuss the first quarter will be held for the investment community and media on August 6, 2014 at 7:30 a.m. MT (9:30 a.m. ET). To participate, please dial 888-231-8191 (toll-free in North America) or 647-427-7450 approximately 15 minutes prior to the conference call. An archived recording of the call will be available from approximately 12:30 p.m. ET on August 6 until midnight on August 13, 2014 by dialing 855-859-2056 (toll-free in North America) or 416-849-0833 and entering conference password 62777713.

An audio webcast of the conference call will also be available on Athabasca's website, www.atha.com or the following link below:
http://www.newswire.ca/en/webcast/detail/1374275/1523963.

About Athabasca Oil Corporation

Athabasca Oil Corporation is a Canadian energy company with a diverse portfolio 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", "should", "believe", "predict", "pursue" and "potential" and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company's current plans, objectives, goals, 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 receipt of sale proceeds from the sale of the Dover Investment as a result of the Company's exercise of the Dover Put Option; the settlement of claims made by Phoenix Energy Holdings Limited ("Phoenix") for indemnification under the agreements relating to the Company's joint venture with Phoenix ("PetroChina Transaction Agreements"); the expected timing of the completion of the construction of Hangingstone Project 1 and of first steam into Hangingstone Project 1; the expected timing of the first significant production from the Thermal Oil Division, which is expected to come from Hangingstone Project 1; the anticipated regulatory review/approval process in respect of the Hangingstone Expansion; the timing of the construction of the facilities and infrastructure related to the Hangingstone Projects, including the completion of the Hangingstone Project 1 central plant and the Enbridge and IPF pipelines; estimated production and production goals in respect of the Company's projects, including the anticipated production from the Company's Light Oil division; the estimated quantity of the Company's Proved and Probable Reserves and Contingent Resources; the potential for future joint venture opportunities, the Company's drilling and development plans, including in particular with respect to the Montney and Duvernay formations; the Company's capital expenditure programs and expected future capital expenditures; the Company's other plans for, and results of, exploration and development activities with respect to the Thermal Oil and Light Oil assets and the expected benefits to be received by Athabasca from such assets; and allocations of capital.

With respect to forward-looking information contained in this News Release, assumptions have been made regarding, among other things: the receipt of the sale proceeds from the Company's sale of of its interest in the Dover oil sands project in a timely manner; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct its business; the applicability of technologies for the recovery and production of the Company's reserves and resources; 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 financing and/or enter into joint venture arrangements, on acceptable terms; geological and engineering estimates in respect of the Company's reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities; and the impact that the PetroChina Transaction Agreements will have on the Company, including on the Company's financial condition and results of operations.

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company's most recent Annual Information Form ("AIF") dated March 18, 2014, available on SEDAR at www.sedar.com, including, but not limited to: the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements; the potential for adverse consequences in the event that Athabasca defaults under certain of the PetroChina Transaction Agreements; failure by counterparties (including, without limitation, PetroChina International and Phoenix) to make payments or perform their obligations to the Company in compliance with the terms of contractual arrangements between the Company and such counterparties, including in compliance with the expressed or implied time schedules set out in such contractual arrangements, and the possible consequences thereof; aboriginal claims; fluctuations in market prices for crude oil, natural gas and bitumen blend; general economic, market and business conditions in Canada, the United States and globally; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; dependence on Phoenix as the joint venture participant in the Dover oil sands project; 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; global financial uncertainty; uncertainties inherent in estimating quantities of reserves and resources; changes to status given the current stages of development; uncertainties inherent in SAGD, TAGD and other bitumen recovery processes; 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, including the production of oil sands reserves and resources using SAGD, TAGD or other in-situ technologies; risks related to gathering and processing facilities and pipeline systems; availability of drilling and related equipment and limitations on access to Athabasca's assets; increases in operating costs could make Athabasca's projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; gas over bitumen issues affecting operational results; environmental risks and hazards and the cost of compliance with environmental regulations, including greenhouse gas regulations and potential Canadian and U.S. climate change legislation; extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time; risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments; changes to royalty regimes; political risks; failure to accurately estimate abandonment and reclamation costs; exploration, development and production risks inherent in crude oil and natural gas operations, including the production of crude oil and natural gas using multi-stage hydraulic fracture and other stimulation technologies; the potential for management estimates and assumptions to be inaccurate; long term reliance on third parties; reliance on third party infrastructure for project facilities; seasonality; hedging risks; risks associated with establishing and maintaining systems of internal controls; insurance risks; claims made in respect of Athabasca's operations, properties or assets; the effect of a change of control under the PetroChina Transaction Agreements; competition for, among other things, capital, the acquisition of reserves and resources, 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; failure to satisfy certain conditions in connection with the Company's debt and credit facilities; breaches of confidentiality; costs of new technologies; alternatives to and changing demand for petroleum products; risks related to the Common Shares; and risks pertaining to the Company's debt facilities.

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.