



Suite 1000, 550 – 6th Avenue SW
Calgary, Alberta T2P 0S2
Tel: 403.294.3600 Fax: 403.294.3601
Web Site: www.nal.ca Email: Investor.Relations@nal.ca
TSX: NAE.UN

FOR IMMEDIATE RELEASE

NAL OIL & GAS TRUST REPORTS THIRD QUARTER 2009 RESULTS

Media Release No. 31-09

November 3, 2009

CALGARY, ALBERTA – NAL Oil & Gas Trust (“NAL” or the “Trust”) today announced its financial and operational results for the third quarter of 2009. All amounts are in Canadian dollars unless otherwise stated.

On NAL’s third quarter, Mr. Andrew Wiswell stated “After posting another solid quarter, the Trust remains on track to deliver results within guidance for 2009. Over the past twelve months, NAL has created positive momentum through consistent and reliable operations in southeast Saskatchewan, the Cardium oil resource play in central Alberta and the successful execution of several transactions to add attractive opportunities, all while maintaining a strong balance sheet position. The Trust is well positioned to create sustainable value and deliver competitive total returns for its unitholders. As we look toward 2011, we remain committed to a plan of converting to a dividend paying corporation and to continue to deliver results and capture value adding opportunities with our financial partner Manulife Financial Corporation”.

THIRD QUARTER 2009 ACCOMPLISHMENTS

NAL’s overall performance exceeded management’s financial, operational and strategic objectives. Accomplishments include:

- On October 13, 2009, NAL announced the acquisition of Breaker Energy Ltd. (“Breaker”), an oil weighted junior E&P company (see comments below).
- The Trust remains on track to deliver 2009 full year average production volumes consistent with guidance;
- Third quarter operating costs of \$10.52/boe represent a 10 percent decrease from the same period of 2008 and reflect the focus of NAL’s operations teams to reduce costs;
- At September 30, 2009, the Trust currently has approximately \$200 million in available credit on its lines of \$450 million, providing financial flexibility to fund NAL’s capital program and continue to participate selectively in corporate and property acquisitions;
- NAL’s debt to trailing 12 month cash flow ratios remain solid at 1.25 times excluding convertible debentures and 1.59 times including convertible debentures.

ACQUISITION OF BREAKER ENERGY LTD.

On October 13, 2009, NAL announced the acquisition of Breaker for total consideration of approximately \$400 million. The acquisition is consistent with NAL’s strategy to grow by adding quality assets with future upside opportunity while maintaining financial capability. The acquisition is expected to increase NAL’s year-end production by 28 percent to over 31,000 boe/d and increase reserves by more than 30 percent to approximately 96 MMboe. Breaker’s operated assets add significant low risk development projects which complement the Trust’s Cardium horizontal multi-stage frac program.

The acquisition is expected to close December 10, 2009, with full integration expected to occur by the end of the first quarter of 2010.

2009 UPDATED GUIDANCE

Based upon positive year-to-date performance, the Trust has updated its guidance for 2009.

	January 2009 Guidance	August 2009 Guidance	November 2009 Updated Guidance ¹
Production (boe/d)	22,000 – 23,000	23,000 – 24,000	23,500 – 24,000
Net capital expenditures (\$MM)	95	125 -135	135
Operating costs (\$/boe)	11.60- 11.90	11.60 – 11.90	11.30 – 11.60

Note (1) Excludes proposed Breaker acquisition.

OUTLOOK

NAL will outline its 2010 guidance and forecast in mid-January 2010.

FORWARD-LOOKING INFORMATION

Please refer to the disclaimer on forward-looking information set forth under the Management's Discussion and Analysis in this document. The disclaimer is applicable to all forward-looking information in this document, including the guidance for 2009 set forth above.

NON-GAAP MEASURES

Please refer to the discussion of non-GAAP measures set forth under the Management's Discussion and Analysis regarding the use of the following terms: "funds from operations", "payout ratio" and "operating netback".

CONFERENCE CALL DETAILS

At 3:00 p.m. MDT (5:00 p.m. EDT) on November 3, 2009, NAL will hold a conference call to discuss the third quarter 2009 results. Mr. Andrew Wiswell, President and CEO, will host the conference call with other members of the management team. The call is open to analysts, investors and all interested parties. If you wish to participate, call 1-800-769-8320 toll free across North America. The conference call will also be accessible through the internet at <http://events.digitalmedia.telus.com/nal/110309/index.php>

A recorded playback of the call will be available until November 10, 2009 by calling 1-800-408-3053, reservation 3565817.

- Notes: (1) All amounts are in Canadian dollars unless otherwise stated.
 (2) When converting natural gas to barrels of oil equivalent (boe) within this report, NAL uses the widely recognized standard of six thousand cubic feet (Mcf) to one barrel of oil. However, boes may be misleading, particularly if used in isolation. A conversion ratio of 6 Mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

FINANCIAL AND OPERATING HIGHLIGHTS(thousands of dollars, except per unit and boe data)
(unaudited)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
FINANCIAL				
Revenue ⁽¹⁾	86,298	175,448	249,610	507,998
Cash flow from operating activities	52,999	98,860	183,235	242,716
Cash flow per unit - basic	0.47	1.03	1.77	2.59
Cash flow per unit - diluted	0.44	0.99	1.64	2.46
Funds from operations	53,766	79,233	167,788	244,031
Funds from operations per unit - basic	0.48	0.83	1.62	2.60
Funds from operations per unit - diluted	0.44	0.79	1.50	2.48
Net income	8,249	111,045	3,566	107,206
Distributions declared	30,290	45,968	87,528	135,295
Distributions per unit	0.27	0.48	0.85	1.44
Basic payout ratio:				
based on cash flow from operating activities	57%	46%	48%	56%
based on funds from operations	56%	58%	52%	55%
Basic payout ratio including capital expenditures ⁽²⁾ :				
based on cash flow from operating activities	136%	96%	100%	99%
based on funds from operations	134%	119%	109%	98%
Units outstanding (000's)				
Period end	112,327	95,945	112,327	95,945
Weighted average	112,109	95,664	103,444	93,834
Capital expenditures ⁽³⁾	42,375	53,189	96,264	109,260
Property acquisitions (dispositions), net	-	373	2,534	8,209
Corporate acquisitions, net	11,035	14	48,385	58,378
Net debt, excluding convertible debentures ⁽⁴⁾	293,680	303,330	293,680	303,330
Convertible debentures (at face value)	79,744	79,744	79,744	79,744
OPERATING				
Daily production				
Crude oil (bbl/d)	9,467	9,989	9,725	10,176
Natural gas (Mcf/d)	69,706	70,425	68,778	68,847
Natural gas liquids (bbl/d)	2,334	2,081	2,244	2,083
Oil equivalent (boe/d)	23,418	23,808	23,433	23,733
OPERATING NETBACK (boe)				
Revenue before hedging gains	40.06	80.11	39.02	78.12
Royalties	(6.94)	(16.90)	(6.99)	(16.19)
Operating costs	(10.52)	(11.63)	(11.42)	(10.64)
Other income ⁽⁵⁾	0.17	0.12	0.17	0.19
Operating netback before hedging	22.77	51.70	20.78	51.48
Hedging gains (losses)	8.84	(7.59)	10.82	(6.74)
Operating netback	31.61	44.11	31.60	44.74

(1) Oil, natural gas and liquid sales less transportation costs and prior to royalties.

(2) Capital expenditures included are net of non-controlling interest amount of \$0.4 million (2008 - \$4.7) for the three months ended September 30, 2009 and \$1.5 million (2008 - \$5.2) for the nine months ended September 30, 2009, attributable to the Tiberius and Spear properties.

(3) Excludes property and corporate acquisitions.

(4) Bank debt plus working capital and other liabilities, excluding derivative contracts, notes payable/receivable and future income tax balances.

(5) Excludes minimal Trust interest paid on notes with Manulife Financial Corporation.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("MD&A") should be read in conjunction with the interim unaudited consolidated financial statements for the three and nine month periods ended September 30, 2009 and the audited consolidated financial statements and MD&A for the year ended December 31, 2008 of NAL Oil & Gas Trust ("NAL" or the "Trust"). It contains information and opinions on the Trust's future outlook based on currently available information. All amounts are reported in Canadian dollars, unless otherwise stated. Where applicable, natural gas has been converted to barrels of oil equivalent ("boe") based on a ratio of six thousand cubic feet of natural gas to one barrel of oil. The boe rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of boe in isolation may be misleading.

NON-GAAP FINANCIAL MEASURES

Throughout this discussion and analysis, Management uses the terms funds from operations, funds from operations per unit, payout ratio, cash flow from operations per unit, net debt to trailing 12 month cash flow, operating netback and cash flow netback. These are considered useful supplemental measures as they provide an indication of the results generated by the Trust's principal business activities. Management uses the terms to facilitate the understanding of the results of operations. However, these terms do not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). Investors should be cautioned that these measures should not be construed as an alternative to net income determined in accordance with GAAP as an indication of NAL's performance. NAL's method of calculating these measures may differ from other income funds and companies and, accordingly, they may not be comparable to measures used by other income funds and companies.

Funds from operations is calculated as cash flow from operating activities before changes in non-cash working capital. Funds from operations does not represent operating cash flows or operating profits for the period and should not be viewed as an alternative to cash flow from operating activities calculated in accordance with GAAP. Funds from operations is considered by Management to be a meaningful key performance indicator of NAL's ability to generate cash to finance operations and to pay monthly distributions. Funds from operations per unit and cash flow from operations per unit are calculated using the weighted average units outstanding for the period.

Payout ratio is calculated as distributions declared for a period as a percentage of either cash flow from operating activities or funds from operations; both measures are stated.

Net debt to trailing 12 months cash flow is calculated as net debt as a proportion of funds from operations for the previous 12 months. Net debt is defined as bank debt, plus convertible debentures at face value, plus working capital and other liabilities, excluding derivative contracts, notes payable/receivable and future income tax balances.

The following table reconciles cash flows from operating activities to funds from operations:

\$ (000s)	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Cash flow from operating activities	52,999	98,860	183,235	242,716
Add back change in non-cash working capital	767	(19,627)	(15,447)	1,315
Funds from operations	53,766	79,233	167,788	244,031

FORWARD-LOOKING INFORMATION

This discussion and analysis contains forward-looking information as to the Trust's internal projections, expectations and beliefs relating to future events or future performance. Forward looking information is typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "could", "plan", "intend", "should", "believe", "outlook", "project", "potential", "target", and similar words suggesting future events or future performance. In addition, statements relating to "reserves" are forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities estimated and can be profitably produced in the future.

In particular, this MD&A contains forward-looking information pertaining to the following, without limitation: the amount and timing of cash flows and distributions to unitholders; reserves and reserves values; 2009 and 2010 production; future tax treatment of the Trust; future structure of the Trust and its subsidiaries; the Trust's tax pools;

future oil and gas prices; operating, drilling and completion costs; the amount of future asset retirement obligations; future liquidity and future financial capacity; future results from operations; payout ratios; cost estimates and royalty rates; drilling plans; tie-in of wells; future development, exploration and acquisition activities and related expenditures; rates of return; and the successful acquisition of Breaker Energy Ltd.

With respect to forward-looking statements contained in this MD&A and the press release through which it was disseminated, we have made assumptions regarding, among other things: future oil and natural gas prices; future capital expenditure levels; future oil and natural gas production levels; future exchange rates; the amount of future cash distributions that we intend to pay; the cost of expanding our property holdings; our ability to obtain equipment in a timely manner to carry out exploration and development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and exploitation activities.

Although NAL believes that the expectations reflected in the forward-looking information contained in the MD&A and the press release through which it was disseminated, and the assumptions on which such forward-looking information are made, are reasonable, readers are cautioned not to place undue reliance on such forward looking statements as there can be no assurance that the plans, intentions or expectations upon which the forward-looking information are based will occur. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated and which may cause NAL's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance. These risks and uncertainties include, without limitation: changes in commodity prices; unanticipated operating results or production declines; the impact of weather conditions on seasonal demand and NAL's ability to execute its capital program; risks inherent in oil and gas operations; the imprecision of reserve estimates; limited, unfavorable or no access to capital or credit markets; the impact of competitors; the lack of availability of qualified operating or management personnel; the ability to obtain industry partner and other third party consents and approvals, when required; failure to complete the acquisition of Breaker Energy Ltd.; failure to realize the anticipated benefits of acquisitions, including Breaker Energy Ltd.; general economic conditions in Canada, the United States and globally; fluctuations in foreign exchange or interest rates; changes in government regulation of the oil and gas industry, including environmental regulation; changes in royalty rates; changes in tax laws, including the impact of legislation relating to the taxation of "specified investment flow-through" entities; stock market volatility and market valuations; OPEC's ability to control production and balance global supply and demand for crude oil at desired price levels; political uncertainty, including the risk of hostilities in the petroleum producing regions of the world; and other risk factors discussed in other public filings of the Trust including the Trust's current Annual Information Form.

NAL cautions that the foregoing list of factors that may affect future results is not exhaustive. The forward-looking information contained in the MD&A is made as of the date of this MD&A. The forward-looking information contained in the MD&A is expressly qualified by this cautionary statement.

RECENT DEVELOPMENTS

PLAN OF ARRANGEMENT – BREAKER ENERGY LTD.

On October 13, 2009, NAL and Breaker Energy Ltd. ("Breaker") entered into an arrangement agreement pursuant to which NAL will acquire all of the issued and outstanding common shares of Breaker by way of Plan of Arrangement. Under the arrangement, Breaker shareholders will receive 0.475 NAL trust units for each share of Breaker held, resulting in the expected issuance of approximately 24.7 million trust units. The transaction is subject to the approval of the Breaker shareholders, the Court of Queen's Bench of the Province of Alberta and regulatory authorities, and is expected to close on December 10, 2009.

The acquisition is anticipated to add 6,700 boe/d of production to the Trust and 23 million boe of proved plus probable reserves, in addition to 140,000 acres of net undeveloped land and \$270 million of tax pools.

DISPOSITION OF NON-CORE PROPERTY

The sale of a non-operated property is expected to close in the fourth quarter for net proceeds of \$15 million, subject to final adjustments.

ACQUISITION OF SPEARPOINT ENERGY CORP.

Effective August 10, 2009, the Trust acquired all of the issued and outstanding common shares of Spearpoint Energy Corp. ("Spearpoint") for cash of \$10.6 million, prior to acquisition costs. The assets of Spearpoint include natural gas production in Alberta and a farm-in agreement with BP Canada Energy Company.

Concurrent with the corporate acquisition, the Trust entered into an Asset Purchase and Sale Agreement ("PSA") with Manulife Financial Corporation ("MFC"), pursuant to which MFC acquired a 40 percent working interest in all of the Spearpoint petroleum and natural gas properties and the farm-in agreement for a base price of \$6.5 million payable in cash.

Included within the PSA is a base price adjustment clause that ensures the Trust and MFC share 60 percent / 40 percent, respectively, in all assets or liabilities related to Spearpoint that pertain to periods on or prior to the effective date of the acquisition, regardless of their date of discovery or disclosure. The base price adjustment calculation adjusts the purchase price that MFC pays the Trust for any change in working capital from amounts determined at the time the base price of \$6.5 million was established. As at September 30, 2009, the Trust had a receivable from MFC of \$0.3 million relating to these price adjustments.

After taking into effect the MFC disposition and MFC's share of the assets and liabilities to be settled under the base price adjustment clause, the Trust acquired property, plant and equipment of \$10.7 million and a future income tax asset of \$0.5 million and assumed liabilities including a note payable of \$5.7 million, a working capital deficiency of \$0.9 million and asset retirement obligations of \$0.4 million, for consideration of \$4.2 million.

MFC is a related party to the Trust, see "Related Party Transactions".

ACQUISITION OF ALBERTA CLIPPER ENERGY INC.

Effective June 1, 2009, the Trust acquired all of the issued and outstanding common shares of Alberta Clipper Energy Inc. ("Clipper"), which has interests in petroleum and natural gas properties and undeveloped land in Alberta and northeast British Columbia.

The Trust issued 5.7 million trust units at a price of \$6.45 a trust unit for total consideration, before acquisition costs, of \$36.6 million. The trust unit price was based on the weighted average market price of trust units at the date of announcement, being March 23, 2009. The purchase price included the assumption of \$78.9 million in bank debt.

Concurrent with the corporate acquisition, the Trust entered into an Asset Purchase and Sale Agreement (the "Clipper PSA") with MFC, pursuant to which MFC acquired a 50 percent working interest in all of the Clipper petroleum and natural gas properties for a base price of \$52.5 million payable in cash. The proceeds received from MFC were used to partially repay the assumed bank debt.

Included within the Clipper PSA is a base price adjustment clause that ensures the Trust and MFC share equally in all assets or liabilities related to Clipper that pertain to periods on or prior to the effective date of the acquisition, regardless of their date of discovery or disclosure. The base price adjustment calculation will adjust the purchase price that MFC pays the Trust for any change in working capital from amounts determined at the time the base price of \$52.5 million was established. In addition, the costs associated with contracts outstanding at the date of acquisition will be equally shared between both parties on an ongoing basis, as the obligations are settled by the Trust. The amounts due under this base price adjustment clause are to be settled no more frequently than quarterly commencing December 2009. As at September 30, 2009, the Trust had a receivable from MFC of \$0.8 million relating to these price adjustments.

As a result, after taking into effect the MFC disposition and MFC's share of the assets and liabilities to be settled under the base price adjustment clause, the Trust acquired property, plant and equipment of \$55.4 million, a derivative contract of \$0.4 million and a future tax asset (reflecting the excess of tax pools over book value) of \$17.9 million, representing assets totaling \$73.7 million, and assumed liabilities including asset retirement obligations of \$7.3 million, bank debt of \$26.4 million, a working capital deficiency of \$1.1 million and a lease obligation of \$1.5 million, for consideration of \$37.4 million, including estimated acquisition costs of \$0.8 million.

EXPLORATION & DEVELOPMENT ACTIVITIES

The Trust spent \$34.6 million on drilling, completion and tie-in operations during the third quarter of 2009, compared to \$39.2 million during the third quarter of 2008 and drilled 26 (12.3 net) wells as compared to 33 (15.7 net) wells during the same period in 2008.

Drilling in the quarter was focused on horizontal oil wells in Saskatchewan and Alberta. The Trust is expecting to drill 78 (37 net) wells for full year 2009 including 57 (25 net) that have been drilled year-to-date and a 21 (12 net) well program to be executed in the fourth quarter. The remaining drilling program will also be heavily weighted to oil including 8 (6 net) Cardium and 11 (5 net) Mississippian horizontals. Full year estimates consist of 17 (4 net) gas wells and 61 (33 net) oil wells of which 24 (16 net) will be Cardium and 32 (15 net) will be Mississippian wells.

Third Quarter Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	19	11.3	0	0	0	0	0	0	19	11.3
Non-operated wells	1	0.2	6	0.8	0	0	0	0	7	1.0
Total wells drilled	20	11.5	6	0.8	0	0	0	0	26	12.3

Southeast Saskatchewan

In Saskatchewan, there were 10 (4.7 net) horizontal oil wells drilled during the third quarter. Activity was focused on the Mississippian in Alida, Torquay and Nottingham with initial production rates ranging from 50-250 bbls/d. The Trust intends to drill 11 (5.0 net) horizontal Mississippian oil wells in the fourth quarter following up on successful new pool discoveries, infills and extensions. While the Cardium play in Alberta has recently been the focus of market attention, the economics in Mississippian light oil projects remain as good or better and is the reason the Trust continues to balance its capital expenditures between the two distinctly different resource plays. The Nottingham gas plant expansion was commissioned in October and plans to bring on incremental volumes in November are currently underway.

Alberta

In Alberta, NAL participated in drilling 15 (7.4 net) wells including 10 (6.7 net) wells in the Cardium at Garrington, Cochrane and Pine Creek. Many completion and tie-in operations were running through the end of the quarter with first month production numbers after load fluid recovery expected in November. Overall, results remain in-line with expectations and management remains encouraged by the potential of this resource. For the remainder of the year, the Trust intends to drill 8 (6 net) horizontal Cardium oil wells in Garrington and Pine Creek to delineate significant Cardium acreage related to recently announced transactions. Reduced drilling and completion costs coupled with execution efficiency gains continue to be a focus for NAL and it is expected that costs will be lower as the program matures. Current drill, completion and tie-in costs for Cardium horizontal wells are in the \$3.0 million range.

Northeast British Columbia

Production in Sukunka was significantly impacted by failures related to third party operated gathering systems and several unplanned outages at the Pine River Plant. This down time equated to 600 boe/d of lost production in the quarter. However, due to low gas prices throughout the period, funds flow from operations was only impacted by \$330,000. The first week of production in October was back at full capability, producing approximately 2,600 boe/d. The non-operated well at a-100-c (Trust 20 percent working interest) reached total depth during the quarter, initial completion work was done and the well is currently standing while further completion operations are being evaluated.

FOCUS OF FUTURE ACTIVITY

Commodity prices have been challenging in 2009 but NAL's strong balance sheet, balanced production mix, hedging strategy and support from its partner MFC have positioned the Trust well to take advantage of challenging market conditions. Upon the completion of the recently announced acquisition of Breaker, the Trust will have completed four significant transactions during 2009, increasing production and reserves by more than 30 percent and adding access to a broad land position of more than 1.5 million gross acres. The Trust has also added significant prospecting capability with the addition of key technical staff. Efforts are underway to catalogue a multi-year oil and gas drilling inventory from this significantly expanded land portfolio.

The use of cost effective horizontal drilling techniques with multi-stage fracturing has unlocked significant low risk oil reserves and value for our unitholders. NAL is well positioned in the Cardium oil resource with acreage at Garrington, Cochrane and Pine Creek in central Alberta, and in Mississippian oil in southeast Saskatchewan with

new opportunities added in the Wabamun formation (at Irricana) and Leduc formation (at Millard Lake) through the proposed Breaker transaction. Current oil prices coupled with provincial royalty incentive programs drive compelling economics for oil development that produce recycle ratios exceeding two times, rates of return in the 30 - 50 percent range, and attractive netbacks. The Trust currently intends to remain focused on an oil weighted program through 2010, but retains significant leverage and flexibility to shift capital toward gas projects should a recovery in natural gas prices emerge.

NAL continues to build gas inventory on its expanded land position but will wait on a gas price recovery which yields economics that can compete with the Trust's expanded oil portfolio. The use of horizontal drilling and multi stage fracturing will play a large part in any gas development program in the future as the Trust currently has catalogued more than 100 ready-to-drill horizontal wells in the Rock Creek, Falher, Halfway, Viking, Doig and Mannville zones. It is expected that NAL will spend 20 – 30 percent of its exploration and development budget in 2010 on strategic gas drilling to prove up reserves. Selective prospects with high initial gas rate potential and high liquid yields that deliver competitive economic returns will be considered in the program to take advantage of attractive government incentives.

CAPITAL EXPENDITURES

Capital expenditures, before property acquisitions, for the quarter ended September 30, 2009 totaled \$42.4 million compared with \$53.2 million for the quarter ended September 30, 2008. The decrease in capital spending year-over-year is largely a function of relatively higher land and facilities spending during the third quarter of 2008. NAL is on track with plans to evaluate the significant oil opportunities that have been compiled over the course of the year through strategic partnerships and land acquisitions. Crude prices in the quarter have continued to be relatively strong, supporting increased spending, with full year capital expenditures expected to be \$135 million excluding acquisitions.

On a year-to-date basis, capital expenditures, before property acquisitions, totaled \$96.3 million compared to \$109.3 million in the comparable period of 2008.

Capital Expenditures (\$000s)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Drilling, completion and production equipment	34,599	39,237	72,685	79,520
Plant and facilities	1,264	4,542	9,654	11,249
Seismic	806	69	1,053	876
Land	2,829	8,293	5,290	12,115
Total exploitation and development	39,498	52,141	88,682	103,760
Office equipment	128	562	508	1,181
Capitalized G&A	1,266	824	4,260	3,167
Capitalized unit-based compensation	1,484	(338)	2,814	1,152
Total other capital	2,878	1,048	7,582	5,500
Total capitalized expenditures before acquisitions	42,376	53,189	96,264	109,260
Property acquisitions (dispositions), net	-	373	2,534	8,209
Total capitalized expenditures	42,376	53,562	98,798	117,469

PRODUCTION

Third quarter 2009 production was 23,418 boe/d, compared to production of 23,808 boe/d in the same period of 2008. This two percent decline was entirely attributed to unplanned third party facilities outages at Sukunka that negatively impacted the quarter by 600 boe/d. The Trust's internal forecast was 23,700 boe/d for the third quarter and, without this outage volumes would have been in the 24,000 boe/d range. It is anticipated that fourth quarter production will be 24,000-24,400 boe/d dependent on the timing of new production tie-ins. Full year average production is still expected to be at the higher end of our guidance of 23,000 - 24,000 boe/d. Provided the proposed Breaker acquisition closes as scheduled, the Trust anticipates fourth quarter average production to be 25,000 – 25,500 boe/d, with the impact on full year average volumes being muted due to the December 10, 2009 close date. Year-over-year, oil production was down five percent in the quarter which was mainly attributable to production declines in Saskatchewan. The development program in Saskatchewan was reduced in response to substantially

lower commodity prices during the first quarter of 2009 and the program was not ramped back up until after spring break-up.

Average Daily Production Volumes

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Oil (bbl/d)	9,467	9,989	9,725	10,176
Natural gas (Mcf/d)	69,706	70,425	68,778	68,847
NGLs (bbl/d)	2,334	2,081	2,244	2,083
Oil equivalent (boe/d)	23,418	23,808	23,433	23,733

Oil equivalent volumes of 23,418 boe/d for the third quarter of 2009 and 23,433 boe/d year-to-date include 370 boe/d (2008 – 379 boe/d) and 412 boe/d (2008 – 343 boe/d), respectively, attributable to the non-controlling interest in the Tiberius and Spear properties (see “Related Party Transactions”). The Trust’s net production, after deducting the non-controlling interest, is 23,048 boe/d for the third quarter of 2009 (2008 - 23,429 boe/d) and 23,021 boe/d (2008 - 23,390 boe/d) year-to-date.

Oil and natural gas liquids totaled 51 percent of production with natural gas at 49 percent during the first nine months of 2009.

Production Weighting

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Oil	40%	42%	41%	43%
Natural gas	50%	49%	49%	48%
NGLs	10%	9%	10%	9%

REVENUE

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs and prior to hedging, totaled \$86.3 million for the three months ended September 30, 2009, 51 percent lower than the third quarter of 2008. The decrease is due to a two percent decrease in production and a 50 percent decrease in the average realized price per boe, driven by a 41 percent decrease in the realized crude oil price and a 63 percent decrease in the realized natural gas price. The decrease in realized prices reflects lower West Texas Intermediate (“WTI”) prices, partially offset by a weaker Canadian dollar, and lower AECO prices in the third quarter of 2009.

For the nine month period ended September 30, 2009, revenue after transportation costs totaled \$249.6 million, a decrease of 51 percent from the comparable period in 2008. The decrease is attributable to a 50 percent decrease in the average realized price per boe and a one percent decrease in production. The decrease in realized price reflects lower WTI prices, partially offset by a weaker Canadian dollar, and lower AECO prices in 2009.

Revenue

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Revenue ⁽¹⁾ (\$000s)				
Oil	58,543	104,949	154,024	297,894
Gas	19,718	53,152	73,834	165,392
NGLs	8,069	15,034	21,199	41,805
Sulphur	(32)	2,313	553	2,907
Total revenue	86,298	175,448	249,610	507,998
\$/boe	40.06	80.11	39.02	78.12

(1) Oil, natural gas and liquid sales less transportation costs and prior to royalties and hedging.

OIL MARKETING

NAL markets its crude oil based on refiners’ posted prices at Edmonton, Alberta and Cromer, Manitoba adjusted for transportation and the quality of crude oil at each field battery. The refiners’ posted prices are influenced by the

WTI benchmark price, transportation costs, exchange rates and the supply/demand situation of particular crude oil quality streams during the year.

NAL's third quarter average realized Canadian crude oil price per barrel, net of transportation costs excluding hedging, was \$67.22, as compared to \$114.20 for the comparable quarter of 2008. The decrease in realized price quarter-over-quarter of 41 percent, or \$46.98/bbl, was primarily driven by a 42 percent decrease in WTI (U.S.\$/bbl) over the comparable period, partially offset by a five percent decrease in the value of the Canadian dollar.

For the third quarter of 2009, NAL's crude oil price differential was 90 percent, a decrease of three percentage points from the comparable period in 2008. The differential is calculated as realized price as a percentage of WTI stated in Canadian dollars. The decrease in 2009 resulted from a wider differential between WTI and Edmonton/Cromer posted prices, due to lower demand for light crude in western Canada during the third quarter.

For the nine months ended September 30, 2009, NAL's average oil price was \$58.01 per barrel as compared to \$106.84 for the comparable period in 2008. The 46 percent decrease in realized price was driven by a 50 percent decrease in WTI (US\$/bbl) and a decrease in crude oil differentials to 87 percent from 92 percent in 2008, partially offset by a 15 percent decrease in the value of the Canadian dollar.

Natural gas liquids averaged \$37.58/bbl in the third quarter of 2009, a 52 percent decrease from the \$78.53/bbl realized in 2008. For the nine months ended September 30, 2009, natural gas liquids averaged \$34.60/bbl, a decrease of 53 percent from the comparable period in 2008.

NATURAL GAS MARKETING

Approximately 75 percent of NAL's current gas production is sold under marketing arrangements tied to the Alberta monthly or daily spot price ("AECO"), with the remaining 25 percent tied to NYMEX or other indexed reference prices.

For the three months ended September 30, 2009, the Trust's natural gas sales averaged \$3.07/Mcf compared to \$8.20/Mcf in the comparable period of 2008, a decrease of 63 percent. The quarter-over-quarter decrease in gas prices was attributable to a 61 percent decrease in the benchmark AECO daily spot prices.

Prices for Lake Erie natural gas decreased to \$3.77/Mcf in the third quarter of 2009, compared to \$9.98/Mcf in 2008, a decrease of 62 percent. Lake Erie production of 3.5 mmcf/d accounted for five percent of the Trust's natural gas production in the third quarter of 2009, the same percentage experienced during the comparable period of 2008. Natural gas sales from the Lake Erie property generally receive a higher price due to the proximity of the Ontario and Northeastern U.S. markets.

For the nine months ended September 30, 2009, NAL averaged \$3.93/Mcf, a 55 percent decrease from the \$8.77/Mcf realized in the comparable period of 2008. The decrease in natural gas prices was attributable to a 56 percent decrease in the benchmark AECO daily spot prices.

Average Pricing (net of transportation charges)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Liquids				
WTI (US\$/bbl)	68.30	117.98	57.00	113.29
NAL average oil (Cdn\$/bbl)	67.22	114.20	58.01	106.84
NAL natural gas liquids (Cdn\$/bbl)	37.58	78.53	34.60	73.25
Natural Gas (Cdn\$/mcf)				
AECO – daily spot	2.98	7.73	3.78	8.64
AECO – monthly	3.02	9.25	4.11	8.55
NAL Western Canada natural gas	3.04	8.11	3.88	8.68
NAL Lake Erie natural gas	3.77	9.98	5.05	10.44
NAL average natural gas	3.07	8.20	3.93	8.77
NAL oil equivalent before hedging (Cdn\$/boe – 6:1)	40.06	80.11	39.02	78.12
Average foreign exchange rate (Cdn\$/US\$)	1.0974	1.0418	1.1698	1.0186

RISK MANAGEMENT

NAL employs risk management practices to assist in managing cash flows and to support capital programs and distributions. NAL currently has derivative contracts in place to assist in managing the risks associated with commodity prices, interest rates and foreign exchange rates.

NAL's commodity hedging policy currently provides authorization to hedge up to 60 percent of forecasted total production, net of royalties. This was increased from 50 percent to 60 percent at the November 3, 2009 Board meeting. Management's practice is to hedge more near-term volumes on a six month forward basis with more limited volumes hedged in future periods. The execution of NAL's commodity hedging program is layered in using a combination of swaps and collars. As at September 30, 2009, NAL had several financial WTI oil contracts and AECO natural gas contracts in place.

NAL's interest rate hedging policy currently provides authorization to hedge up to 50 percent of outstanding debt for periods of up to five years. As at September 30, 2009, NAL had several interest rate swaps outstanding with a total notional value of \$139 million.

NAL's foreign exchange hedging policy currently provides authorization to hedge up to 50 percent of the Trust's U.S. dollar exposure for periods of up to 24 months. As at September 30, 2009, NAL had several exchange rate swaps outstanding with a total notional value of U.S.\$64.0 million.

All derivative contract counterparties are Canadian chartered banks in the Trust's lending syndicate.

All derivative contracts are recorded on the balance sheet at fair value based upon forward curves at September 30, 2009. Changes in the fair value of the derivative contracts are recognized in net income for the period.

Fair value is calculated at a point in time based on an approximation of the amounts that would be received or paid to settle these instruments, with reference to forward prices at September 30, 2009. Accordingly, the magnitude of the unrealized gain or loss will continue to fluctuate with changes in commodity prices, interest rates and foreign exchange rates.

The fair value of the derivatives at September 30, 2009 was a net asset of \$12.3 million, comprised of a \$2.5 million asset on interest rate swaps, a \$4.8 million asset on gas contracts and a \$5.4 million asset on foreign exchange contracts, partially offset by a \$0.4 million liability on oil contracts.

Third quarter income for 2009 includes a \$5.5 million unrealized loss on derivatives resulting from the change in the fair value of the derivative contracts during the quarter from an unrealized gain of \$17.8 million at June 30, 2009, to an unrealized gain of \$12.3 million at September 30, 2009. The \$5.5 million unrealized loss was comprised of a \$0.2 million unrealized loss on crude oil contracts, an \$8.2 million unrealized loss on natural gas contracts and a \$0.4 million unrealized loss on interest rate swaps, partially offset by a \$3.3 million unrealized gain on foreign exchange swaps.

For the nine months ended September 30, 2009, income includes an unrealized loss of \$53.5 million, resulting from the change in the fair value of the derivative contracts during the period, from an unrealized gain of \$65.4 million at December 31, 2008 and a \$0.4 million unrealized gain acquired with Clipper, to an unrealized gain of \$12.3 million at September 30, 2009. The unrealized loss was comprised of a \$56.1 million unrealized loss on crude oil contracts and a \$5.6 million unrealized loss on natural gas contracts, partially offset by a \$2.8 million unrealized gain on interest rate swaps and a \$5.4 million unrealized gain on foreign exchange swaps.

The risk management policies for 2010 are expected to remain consistent with 2009. The Trust's current positions are summarized in the tables below.

The gain/loss on all forward derivative contracts is as follows:

Gain / (Loss) on Derivative Contracts (\$000s)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Unrealized gain (loss):				
Crude oil contracts	(184)	70,892	(56,151)	13,236
Natural gas contracts	(8,251)	40,161	(5,560)	5,134
Interest rate swaps	(374)	-	2,776	-
Exchange rate swaps	3,310	-	5,448	-
Unrealized gain (loss)	(5,499)	111,053	(53,487)	18,370
Realized gain (loss):				
Crude oil contracts	7,526	(13,119)	44,179	(38,151)
Natural gas contracts	8,331	(3,508)	19,794	(5,697)
Interest rate swaps	(226)	-	(433)	-
Exchange rate swaps	3,188	-	5,200	-
Realized gain (loss)	18,819	(16,627)	68,740	(43,848)
Gain (loss) on derivative contracts	13,320	94,426	15,253	(25,478)

The following is a summary of the realized gains and losses on risk management contracts:

Realized Gain (Loss) on Derivative Contracts

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Commodity contracts:				
Average crude volumes hedged (bbl/d)	4,733	5,100	4,362	4,712
Crude oil realized gain (loss) (\$000s)	7,526	(13,119)	44,179	(38,151)
Gain (loss) per bbl hedged (\$)	17.28	(27.96)	37.10	(29.55)
Average natural gas volumes hedged (GJ/d)	23,130	30,000	20,850	26,735
Natural gas realized gain (loss) (\$000s)	8,331	(3,508)	19,794	(5,697)
Gain (loss) per GJ hedged (\$)	3.92	(1.27)	3.48	(0.78)
Average BOE hedged (boe/d)	8,387	9,839	7,656	8,936
Total realized commodity contracts gain (\$000s)	15,857	(16,627)	63,973	(43,848)
Gain (loss) per boe hedged (\$)	20.55	(18.37)	30.61	(17.91)
Gain (loss) per boe (\$)	7.36	(7.59)	10.00	(6.74)
Interest rate swaps realized loss (\$000s)	(226)	-	(433)	-
Loss per boe (\$)	(0.10)	-	(0.07)	-
Exchange rate swaps realized gain (\$000s)	3,188	-	5,200	-
Gain per boe (\$)	1.48	-	0.82	-
Total realized gain (loss) (\$000s)	18,819	(16,627)	68,740	(43,848)
Gain (loss) per boe (\$)	8.74	(7.59)	10.75	(6.74)

Average hedged boes for the third quarter of 2009 were 8,387 as compared to 6,394 for the second quarter of 2009.

NAL has the following interest rate risk management contracts outstanding:

INTEREST RATE	Remaining Term	Amount (Cdn\$ MM) ⁽¹⁾	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Oct 2009 – Dec 2011	\$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Oct 2009 – Jan 2013	\$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Oct 2009 – Jan 2014	\$22.0	1.5100%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2013	\$14.0	1.8500%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2013	\$14.0	1.8750%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2014	\$14.0	1.9300%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2014	\$14.0	1.9850%	CAD-BA-CDOR (3 months)

(1) Notional debt amount

NAL has the following exchange rate risk management contracts outstanding:

EXCHANGE RATE	Remaining Term	Amount ⁽¹⁾ (US\$ MM)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Oct 2009 – Nov 2009	\$4.0	1.2730	BofC Average Noon Rate
Swaps-floating to fixed	Oct 2009 – Nov 2009	\$4.0	1.2875	BofC Average Noon Rate
Swaps-floating to fixed	Oct 2009 – Nov 2009	\$4.0	1.2625	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1583	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1100	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1200	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1225	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1300	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1420	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1525	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1000	BofC Average Noon Rate

(1) Notional US\$ denominated commodity sales

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q4-09	Q1-10	Q2-10	Q3-10	Q4-10
<u>US\$ Collar Contracts</u>					
\$US WTI Collar Volume (bbl/d)	300	3,500	3,300	2,600	2,400
Bought Puts – Average Strike Price (\$US/bbl)	\$62.67	\$61.86	\$62.27	\$64.90	\$65.10
Sold Calls – Average Strike Price (\$US/bbl)	\$71.85	\$72.90	\$73.23	\$76.42	\$76.88
<u>US\$ Swap Contracts</u>					
\$US WTI Swap Volume (bbl/d)	1,700	700	1,200	-	-
Average WTI Swap Price (\$US/bbl)	\$61.94	\$75.36	\$75.67	-	-
<u>Cdn\$ Collar Contracts</u>					
\$Cdn WTI Collar Volume (bbl/d)	1,500	300	-	-	-
Bought Puts – Average Strike Price (\$Cdn/bbl)	\$102.07	\$66.00	-	-	-
Sold Calls – Average Strike Price (\$Cdn/bbl)	\$137.63	\$80.17	-	-	-
<u>Cdn\$ Swap Contracts</u>					
\$Cdn WTI Swap Volume (bbl/d)	1,300	-	-	-	-
Average WTI Swap Price (\$Cdn/bbl)	\$92.55	-	-	-	-
Total Oil Volume (bbl/d)	4,800	4,500	4,500	2,600	2,400
<u>NATURAL GAS</u>					
<u>Collar Contracts</u>					
AECO Collar Volume (GJ/d)	1,685	-	-	-	-
Bought Puts – AECO Average Strike Price (\$Cdn/GJ)	\$8.90	-	-	-	-
Sold Calls – AECO Average Strike Price (\$Cdn/GJ)	\$11.44	-	-	-	-
<u>Swap Contracts</u>					
AECO Swap Volume (GJ/d)	32,663	30,000	30,000	31,000	14,337
AECO Average Price (\$Cdn/GJ)	\$5.57	\$5.86	\$5.60	\$5.62	\$5.67
Total Natural Gas Volume (GJ/d)	34,348	30,000	30,000	31,000	14,337

For the remainder of 2009, the Trust has outstanding contracts representing approximately 49 percent of its net liquids and natural gas production after royalties, assuming a royalty rate of 17.5 percent.

ROYALTY EXPENSES

Crown, freehold and overriding royalties were \$15.0 million for the three months ended September 30, 2009. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 17.3 percent for the quarter ended September 30, 2009, a decrease from the 21.1 percent experienced in the same period of the previous year.

Royalties decreased to \$6.94 per boe for the third quarter of 2009, a decrease of 59 percent compared to the third quarter of 2008. The decrease is attributable to lower commodity prices on a quarter-over-quarter basis.

On a year-to-date basis, royalties were \$44.7 million, down from \$105.3 million in the comparable period of 2008. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 17.9 percent as compared to 20.7 percent in the comparable period of 2008.

On January 1, 2009, the new royalty framework for Alberta became effective. This new framework, first announced on October 25, 2007, provides for conventional oil and gas royalties calculated on a sliding scale that is determined by commodity price and production volumes. Natural gas royalty rates have increased from 35 percent to 50 percent, with rates capped at \$16.59/GJ. Crude oil royalty rates have increased from 35 percent to 50 percent, with rates capped at \$120/bbl.

In response to the economic downturn, on November 19, 2008 the Government of Alberta announced special transitional rates for some conventional oil and gas wells. The lower transitional rates apply to newly drilled oil and gas wells at depths between 1,000 and 3,500 metres.

On March 3, 2009, the Government of Alberta announced a new three point incentive program for the energy sector. Firstly, there is a drilling royalty credit for new conventional oil and natural gas wells. The credit is on a sliding scale, based on prior year production levels, to a maximum of \$200 per metre drilled or 50 percent of the royalties owed. Secondly, there is a new well incentive program that provides for a maximum five percent royalty rate for the first 12 months of production up to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. The 12 month period starts on the date of production provided it occurs between April 1, 2009 and March 31, 2010. Thirdly, the province will invest \$30 million in a fund committed to abandoning and reclaiming old well sites, to encourage the clean up of inactive oil and gas wells. On June 25, 2009, the Government of Alberta announced a one year extension to the drilling royalty credit and new well incentive program to March 31, 2011. The five percent royalty rate incentive is reported within royalties and the \$200 per metre drilling credit is reported against capital.

For the nine months ended September 30, 2009, 29 percent of crude oil and 70 percent of natural gas production is from Alberta.

Royalty Expenses

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Royalties (\$000s)	14,950	37,015	44,692	105,267
As % of revenue	17.3	21.1	17.9	20.7
\$/boe	6.94	16.90	6.99	16.19

OPERATING COSTS

Operating costs averaged \$10.52 per boe for the quarter ended September 30, 2009, a ten percent decrease from \$11.63 per boe for the quarter ended September 30, 2008. Year-over-year operating cost decreases are a direct result of an aggressive program focused on cost reduction in NAL's operations. Reduced power costs as a result of significantly lower natural gas prices have also been a large contributor to lower costs in 2009.

On a year-to-date basis, operating costs were \$11.42 per boe compared to \$10.64 per boe in 2008. The Trust expects costs to continue to moderate with full year operating costs anticipated to be in the range of \$11.30 - \$11.60 per boe.

Operating Costs

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Operating costs (\$000s)	22,657	25,463	73,056	69,179
As a % of revenue	26.3	14.51	29.3	13.62
\$/boe	10.52	11.63	11.42	10.64

OTHER INCOME

Other income was \$0.11 per boe for the third quarter of 2009 compared to \$0.53 per boe in the comparable quarter of 2008. Other income includes gas processing fees, blending income, other miscellaneous income and fees and interest income and interest expense on notes due from and to MFC (see "Related Party Transactions"). The note receivable from MFC was settled in the first quarter of 2009, resulting in interest expense on the note payable in the third quarter of 2009 of \$0.1 million, as compared to net interest income of \$0.9 million in the third quarter of 2008.

On a year-to-date basis interest on notes totaled \$0.3 million compared to \$2.1 million for the comparable period of 2008, the decrease being attributable to the MFC note repayment in March 2009.

Other Income

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Interest on notes with MFC (\$000s)	(125)	890	289	2,109
Other (\$000s)	370	255	1,099	1,224
Total other income (\$000s)	245	1,145	1,388	3,333
As a % of revenue	0.28	0.65	0.55	0.66
Interest on notes with MFC (\$/boe)	(0.06)	0.41	0.05	0.32
Other (\$/boe)	0.17	0.12	0.17	0.19
Total other income (\$/boe)	0.11	0.53	0.22	0.51

OPERATING NETBACK

For the quarter ended September 30, 2009, NAL's operating netback, before hedging gains, was \$22.77 per boe, a decrease of 56 percent from \$51.70 per boe for the quarter ended September 30, 2008. The decrease was due to lower revenues as a result of lower commodity prices, partially offset by decreased royalty expense and operating costs. Hedging gains, related to commodity and exchange rate derivative contracts, were \$8.84 per boe in the third quarter of 2009, as compared to a loss of \$7.59 per boe in 2008, attributable mainly to lower realized commodity prices in 2009.

On a year-to-date basis, NAL's operating netback, before hedging gains, was \$20.78 per boe compared to \$51.48 per boe in 2008. The decrease was due to lower revenue as a result of lower commodity prices, and slightly higher operating costs, partially offset by lower royalty expense. Hedging gains, related to commodity and exchange rate derivative contracts, were \$10.82 for the nine months ended September 30, 2009, as compared to a loss of \$6.74 per boe in 2008, attributable mainly to lower realized commodity prices in 2009.

Operating Netback (\$/boe)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Revenue	40.06	80.11	39.02	78.12
Royalties	(6.94)	(16.90)	(6.99)	(16.19)
Operating expenses	(10.52)	(11.63)	(11.42)	(10.64)
Other income ⁽¹⁾	0.17	0.12	0.17	0.19
Operating netback, before hedging	22.77	51.70	20.78	51.48
Hedging gains (losses) ⁽²⁾	8.84	(7.59)	10.82	(6.74)
Operating netback, after hedging	31.61	44.11	31.60	44.74

(1) Excludes interest on notes with MFC.

(2) Realized hedging gains/losses on commodity and exchange rate derivative contracts

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative ("G&A") expenses include direct costs incurred by the Trust plus the reimbursement of the G&A expenses incurred by NAL Resources Management Limited (the "Manager") on the Trust's behalf.

For the three months ended September 30, 2009, G&A expenses were \$4.1 million, compared with \$3.8 million in the comparable quarter of 2008. In addition, \$1.3 million of G&A costs relating to exploitation and development activities were capitalized in the third quarter of 2009, compared with \$0.8 million in the third quarter of 2008. G&A expense per boe was \$1.90 in the quarter, as compared to \$1.72 for the same period in 2008.

For the nine months ended September 30, 2009, G&A expenses decreased eight percent to \$10.8 million from \$11.7 million in the comparable period in 2008. In addition, on a year-to-date basis \$4.3 million of G&A costs relating to exploitation and development activities were capitalized, compared with \$3.2 million in the comparable period of 2008. G&A expense per boe was \$1.68 in 2009 as compared to \$1.79 in 2008.

Total G&A is comparable year-over-year at \$15.0 million for the nine months ended September 30, 2009 compared to \$14.8 million for the same period in 2008.

General and Administrative Expenses

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
G&A expenses (\$000s)				
G&A	4,095	3,792	10,753	11,547
Retention bonus	-	(35)	-	106
Expensed G&A (\$000s)	4,095	3,757	10,753	11,653
Capitalized G&A (\$000s)	1,266	824	4,260	3,167
Total G&A (\$000s)	5,361	4,581	15,013	14,820
Expensed G&A costs:				
G&A, excluding retention bonus (\$/boe)	1.90	1.73	1.68	1.77
Retention bonus (\$/boe)	-	(0.01)	-	0.02
Total G&A expenses (\$/boe)	1.90	1.72	1.68	1.79
As % of revenue	4.7	2.1	4.3	2.3
Per trust unit (\$)	0.04	0.04	0.10	0.12

UNIT-BASED INCENTIVE COMPENSATION PLAN

The employees of the Manager are all members of a unit-based incentive plan (the “Plan”). The Plan results in employees receiving cash compensation based upon the value and overall return of a specified number of notional trust units. The Plan consists of Restricted Trust Units (“RTUs”) and Performance Trust Units (“PTUs”). RTUs vest as to one third of the amount of the grant on November 30 in each of three years after the date of grant. PTUs vest on November 30, three years from the date of grant. Distributions paid on the Trust’s outstanding trust units during the vesting period are assumed to be paid on the awarded notional trust units and reinvested in additional notional units on the date of distribution. Upon vesting, the employee is entitled to a cash payout based on the trust unit price at the date of vesting of the units held. In addition, the PTUs have a performance multiplier which is based on the Trust’s performance relative to its peers and may range from zero to two times the market value of the notional trust units held at vesting.

During the third quarter of 2009, the Trust recorded a \$5.3 million charge for unit-based incentive compensation that reflects the impact of vesting and increase in the unit price. The unit price of the Trust increased by 36 percent, from \$9.37 at June 30, 2009 to \$12.70 at September 30, 2009. An increase in unit price results in previously accrued amounts being increased.

Unit-based incentive compensation increased from a recovery of \$0.9 million in the third quarter of 2008 to a charge of \$5.3 million in 2009. This increase is a reflection of the increase in unit price used to determine the compensation during the third quarter of 2009, as compared to a decline in unit price during the third quarter of 2008 (from \$16.89 at June 30, 2008 to \$12.53 at September 30, 2008). A decrease in unit price results in previously accrued amounts being reversed.

On a year-to-date basis, the Trust has accrued \$9.7 million compared to \$4.0 million in the comparable period of 2008. The increase period-over-period is mainly attributable to a 58 percent increase in unit price during 2009 as compared to an eight percent increase in unit price during 2008.

At September 30, 2009, the unit price used to determine unit-based incentive compensation was \$12.70. The closing unit price of the Trust on the Toronto Stock Exchange on November 2, 2009 was \$11.27.

The calculation of unit-based compensation expense is made at the end of each quarter based on the quarter end trust unit price and estimated performance factors. The compensation charges relating to the units granted are recognized over the vesting period based on the trust unit price, number of RTUs and PTUs outstanding, and the expected performance multiplier. As a result, the expense recorded in the accounts will fluctuate in each quarter and over time.

At September 30, 2009, the Trust has recorded a total accumulated liability for unit-based incentive compensation in the amount of \$13.6 million, of which \$7.0 million is recorded as current as it is payable in December 2009, and \$6.6 million is long-term as it is payable in December 2010 and December 2011.

Unit-Based Compensation

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Unit-based compensation (\$000s):				
Expensed	3,805	(561)	6,865	2,816
Capitalized	1,484	(338)	2,814	1,152
Total unit-based compensation	5,289	(899)	9,679	3,968
Expensed unit-based compensation:				
As % of revenue	4.4	(0.3)	2.8	0.6
\$/boe	1.77	(0.26)	1.07	0.43
Per trust unit (\$)	0.03	(0.01)	0.07	0.03

RELATED PARTY TRANSACTIONS

The Trust is managed by the Manager. The Manager is a wholly-owned subsidiary of MFC and also manages NAL Resources Limited (“NAL Resources”), another wholly-owned subsidiary of MFC. NAL Resources and the Trust maintain ownership interests in many of the same oil and natural gas properties in which NAL Resources is the joint operator. As a result, a significant portion of the net operating revenues and capital expenditures during the year are based on joint amounts from NAL Resources. These transactions are in the normal course of joint operations and are measured using the fair value established through the original transactions with third parties.

The Manager provides certain services to the Trust and its subsidiary entities pursuant to an Administrative Services and Cost Sharing Agreement (the “Agreement”). This agreement requires the Trust to reimburse the Manager at cost for G&A and unit-based compensation expenses incurred by the Manager on behalf of the Trust calculated on a unit of production basis. The Agreement does not provide for any base or performance fees to be payable to the Manager.

The Trust paid \$3.4 million (2008 - \$3.1 million) for the reimbursement of G&A expenses during the third quarter and \$8.7 million (2008 - \$9.6 million) year-to-date. The Trust also pays the Manager its share of unit-based incentive compensation expense when cash compensation is paid to employees under the terms of the Plan, of which \$2.3 million was paid in the first quarter of 2009, representing units that vested on November 30, 2008 (2008 - \$1.8 million). These reimbursements are included in the G&A and unit-based compensation amounts discussed above.

At September 30, 2009 the Trust owed the Manager \$1.8 million for the reimbursement of G&A and had a receivable from NAL Resources of \$2.8 million, \$1.7 million relating to net operating revenues less capital expenditures and \$1.1 million relating to the base price adjustment clauses, arising from the disposition of 50 percent of the working interest of Clipper and 40 percent of the working interest of Spearpoint to MFC.

The Trust and a wholly owned subsidiary of MFC jointly own a limited partnership (the “Partnership”). This Partnership holds the assets acquired from the acquisitions of Tiberius Exploration Inc. (“Tiberius”) and Spear Exploration Inc. (“Spear”) in February 2008. In addition, both the Trust and MFC entered into net profit interest royalty agreements (“NPI”) with the Partnership. These agreements entitle each royalty holder to a 49.5 percent interest in the cash flow from the Partnership’s reserves. In exchange for this interest, the royalty holders each paid \$49.6 million to the Partnership by way of promissory notes in 2008. Although the MFC note resided in the Partnership, it was consolidated by virtue of the Trust having control over the Partnership as described below.

The Trust, by virtue of being the owner of the general partner of the Partnership under the partnership agreement, is required to consolidate the results of the Partnership into its financial statements on the basis that the Trust has control over the Partnership. Accordingly, the Trust reports all revenues, expenses, assets and liabilities of the Partnership, together with its wholly-owned subsidiaries and partnerships, in its consolidated financial statements. The 50 percent share of net income and net assets of the Partnership attributable to MFC is then deducted from net income and net assets as a one-line entry, in the income statement and balance sheet, ensuring that the bottom line net income and net assets reported represent only the Trust’s interest.

During the first quarter of 2009, MFC repaid the note receivable to the Partnership of \$49.6 million. The note receivable bore interest at prime plus three percent. The Partnership then paid an equal distribution of \$49.6 million to MFC. This resulted in a \$49.6 million reduction to the non-controlling interest on the balance sheet.

As at September 30, 2009, there is a note payable of \$9.2 million with MFC arising from the Tiberius and Spear acquisition. The note payable is included on consolidation of the Partnership, but is effectively eliminated through the non-controlling interest. The note is due on demand, unsecured and bears interest at prime plus three percent. The amount of the note payable to MFC is adjusted to reflect MFC's share of the capital expenditures of the Partnership which MFC has funded, less any loan repayments made.

Net interest expense on these notes of \$0.1 million was payable by the Trust for the third quarter of 2009 (2008 - \$0.9 million net interest income), and net interest income of \$0.3 million, year-to-date (2008 - \$2.1 million), was received by the Trust, and is reported as other income.

INTEREST

Interest on bank debt includes charges on borrowings, plus standby fees on the unused portion of the bank credit facility. Interest on bank debt for the third quarter of 2009 was \$2.8 million, a decrease of \$0.5 million from \$3.3 million for the comparable period in 2008. The decrease was due to a lower average effective interest rate and lower average debt levels. Average outstanding bank debt for the third quarter of 2009 was \$248.4 million, \$46.3 million lower than the \$294.7 million outstanding during the third quarter of 2008. NAL's effective interest rate averaged 4.41 percent during the third quarter of 2009, compared to 4.44 percent during the comparable period in 2008. The decrease in the rate from the third quarter of 2008 is attributable to lower overall borrowing rates in the market. NAL's interest is calculated based upon a floating rate.

Similar trends are noted for the nine months ended September 30, 2009, as interest on bank debt decreased \$3.5 million to \$7.7 million, compared to \$11.2 million in 2008. Average outstanding debt for the nine months ended September 30, 2009 decreased to \$279.4 million compared to \$301.3 million for the corresponding period of 2008. In addition, the effective interest rate averaged 3.68 percent in 2009 compared to 4.88 percent in 2008.

Interest on convertible debentures represents interest charges of \$1.7 million for the three months ended September 30, 2009 (\$5.2 million for the nine months ended September 30, 2009) compared to \$1.7 million (\$6.0 million for the nine months ended September 30, 2008), based on interest at 6.75 percent, and accretion of the debt discount of \$0.4 million (2008 - \$0.3 million) for the three months ended September 30, 2009, and \$1.1 million (2008 - \$1.3 million) for the nine months ended September 30, 2009. The decrease in interest and accretion in 2009 is due to conversions of debentures to trust units that occurred during 2008.

Interest and Debt

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Interest on bank debt (\$000s) ⁽¹⁾	2,761	3,295	7,686	11,155
Interest and accretion on convertible debentures (\$000s)	1,727	1,739	5,176	5,952
Total interest (\$000)	4,488	5,034	12,862	17,107
Bank debt outstanding at period end (\$000s)	246,892	270,982	246,892	270,982
Convertible debentures at period end (\$000s) ⁽²⁾	75,144	73,628	75,144	73,628
\$/boe:				
Interest on bank debt	1.28	1.50	1.20	1.72
Interest on convertible debentures	0.62	0.62	0.63	0.71
Accretion on convertible debentures	0.18	0.17	0.18	0.21
Total interest	2.08	2.29	2.01	2.64

(1) Excludes interest rate hedge impact.

(2) Debt component of the debentures, as reported on the balance sheet.

CASH FLOW NETBACK

For the quarter ended September 30, 2009, NAL's cash flow netback was \$25.88 per boe, a 37 percent decrease from \$40.94 per boe for the comparable period in 2008. The decrease was due to a lower operating netback after hedging, higher G&A expenses, including unit-based incentive compensation and the swing from interest income to interest expense on the notes with MFC, partially offset by lower interest charges.

For the nine months ended September 30, 2009, NAL's cash flow netback was \$27.00 per boe, a 33 percent decrease from \$40.41 per boe in 2008. The decrease was due to a lower operating netback after hedging, lower interest income on the notes with MFC and higher G&A expenses, including unit-based incentive compensation, offset by lower interest charges.

Cash Flow Netback (\$/boe)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Operating netback, after hedging	31.61	44.11	31.60	44.74
G&A expenses, including unit-based incentive compensation	(3.67)	(1.46)	(2.75)	(2.22)
Interest on bank debt and convertible debentures ⁽¹⁾	(1.90)	(2.12)	(1.83)	(2.43)
Interest on notes with MFC ⁽²⁾	(0.06)	0.41	0.05	0.32
Realized loss on interest rate derivative contracts	(0.10)	-	(0.07)	-
Cash flow netback	25.88	40.94	27.00	40.41

(1) Excludes non-cash accretion on convertible debentures.

(2) Reported as other income.

DEPLETION, DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATIONS (“DDA”)

Depletion of oil and natural gas properties, including the capitalized portion of the asset retirement obligations, and depreciation of equipment is provided for on a unit-of-production basis using estimated proved reserves volumes.

For the quarter ended September 30, 2009, depletion on property, plant and equipment and accretion on the asset retirement obligations was \$22.38 per boe, six percent lower than the \$23.71 per boe for the same period in 2008. The decrease in depletion rate per boe in 2009 reflects an increase in proved reserves volumes and a decrease in the related cost base, year-over-year. Similar trends are noted for the nine months ended September 30, 2009.

The DDA rate will fluctuate period-over-period depending on the amount and type of capital expenditures and the amount of reserves added.

Depletion, Depreciation and Accretion Expenses

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Depletion and depreciation (\$000s)	46,209	50,092	132,196	143,151
Accretion of asset retirement obligation (\$000s)	2,003	1,833	5,717	5,458
Total DDA (\$000s)	48,212	51,925	137,913	148,609
DDA rate per boe (\$)	22.38	23.71	21.56	22.85

TAXES

In the third quarter of 2009, NAL had a future income tax recovery of \$7.4 million compared to a \$27.5 million expense in the corresponding period of the prior year. For the nine month period ended September 30, 2009, NAL had a future income tax recovery of \$25.8 million compared to an \$8.1 million expense in 2008.

The Trust is a taxable entity and files a trust income tax return annually. The Trust’s taxable income consists of royalty income, distributions from a subsidiary trust and interest and dividends from other subsidiaries, less deductions for the Trust’s G&A expenses, Canadian Oil and Gas Property Expense (“COGPE”), and issue costs. In addition, Canadian Exploration Expense (“CEE”), Canadian Development Expense (“CDE”) and Undepreciated Capital Cost (“UCC”) are incurred and deducted by the Trust’s subsidiaries. The Trust is taxable only on remaining income, if any, that is not distributed to unitholders.

As at September 30, 2009, the Trust’s (including all subsidiaries) estimated tax pools (unaudited) available for deduction from future taxable income approximated \$964.1 million, of which approximately 35 percent represented COGPE and 22 percent represented UCC, with the remaining balance represented by CEE, CDE, trust unit issue costs and non-capital loss carry forwards.

Estimated Tax Pools (\$ millions)

	September 30, 2009	December 31, 2008
Canadian exploration expense	44	12
Canadian development expense	270	202
Canadian oil and gas property expense	339	301
Undepreciated capital costs	212	209
Other (including loss carry forwards)	99	14
Total estimated tax pools	964	738

Based on current strip prices at September 30, 2009, the Trust is not expected to be taxable in 2009.

Under the specified investment flow-through (“SIFT”) legislation, effective January 1, 2011, distributions to unitholders will not be deductible against income by publicly traded income trusts and, as a result, the Trust will be taxed on its income similar to corporations. These measures are considered enacted for purposes of GAAP. Accordingly, the Trust has measured future income tax assets and liabilities under the SIFT tax rules. The scheduling of the reversal of temporary differences is based on management’s best estimates and current assumptions, which may change. Bill C-10, containing the legislation for the provincial SIFT rate, received Royal Assent on March 12, 2009. The Alberta provincial tax rate for 2011 is expected to be 10 percent. This will result in an effective combined SIFT rate of 26.5 percent in 2011 and 25.0 percent in 2012, a three percent decrease from that in the original legislation.

NON-CONTROLLING INTEREST

The Trust has recorded a non-controlling interest in respect of the 50 percent ownership interest held by MFC in the Partnership holding the Tiberius and Spear assets (see “Related Party Transactions”).

The operations attributable to the Tiberius and Spear assets were as follows:

(\$000s)	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009 ⁽¹⁾	Net Impact to Trust ⁽²⁾	2009 ⁽¹⁾	Net Impact to the Trust ⁽²⁾
Total production volumes (boes)	68,042	34,021	224,558	112,279
Production volumes (boe/d)	740	370	823	412
Oil, natural gas and liquid sales	4,230	2,115	12,367	6,184
Royalties	(463)	(232)	(1,540)	(770)
Operating costs	(569)	(284)	(2,993)	(1,496)
General and administrative	(79)	(40)	(240)	(120)
Unit-based incentive compensation	(114)	(57)	(216)	(108)
Interest income (expense), net	(250)	(125)	580	290
Depletion, depreciation and accretion	(1,125)	(562)	(3,337)	(1,669)
Net profit interest expense	(1,471)	(736)	(3,046)	(1,523)
Net income	159	79	1,575	788

(1) Total results of the Partnership consolidated into the results of the Trust

(2) Net impact to the Trust, removing 50 percent of results attributable to MFC

The non-controlling interest presented in the statement of income has two components: the royalty paid to MFC under the NPI, being a cash payment to the royalty holder, and 50 percent of net income remaining in the Partnership, after NPI expense, attributable to MFC. This share of net income attributable to MFC is a non-cash item.

The non-controlling interest in the consolidated statement of income is comprised of:

Non-Controlling Interest (\$000s)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Net profits interest expense	736	2,010	1,523	7,071
Share of net income attributable to MFC	80	1,151	788	2,107
	816	3,161	2,311	9,178

NET INCOME

Net income is a measure impacted by both cash and non-cash items. The largest non-cash items impacting the Trust's net income are DDA, unrealized gains or losses on derivative contracts and future income taxes.

Net income for the third quarter of 2009 was \$8.2 million compared to \$111.0 million for the comparable period in 2008. The decrease of \$102.8 million was mainly due to decreased gains on derivative contracts (\$81.1 million), decreased revenues net of royalties (\$67.0 million) and increased unit-based compensation (\$4.4 million), partially offset by decreased operating costs (\$2.8 million), lower depletion (3.9 million), a future income tax recovery (\$34.9 million) and no bad debt expense in 2009 (\$6.9 million).

Net income for the nine months ended September 30, 2009 of \$3.6 million was \$103.6 million less than the net income of the comparable period of 2008. The decrease in 2009 is attributable to decreased revenues net of royalties (\$197.6 million), increased operating costs (\$3.9 million) and increased unit-based compensation \$(4.0 million), partly offset by increased gains on derivative contracts (\$40.7 million), decreased future income taxes (\$33.9 million), decreased DDA expense (\$11.0 million), decreased interest expense (\$4.2 million) and no bad debt expense in 2009 (\$6.9 million).

Net Income (\$000s)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Net Income	8,249	111,045	3,566	107,206

CAPITAL RESOURCES AND LIQUIDITY

The capital structure of the Trust is comprised of trust units, bank debt and convertible debentures.

As at September 30, 2009, NAL had 112,327,078 trust units outstanding, compared with 96,181,397 as at December 31, 2008. The increase from December 31, 2008 is attributable to 5,675,834 units issued on the acquisition of Clipper, 9,602,500 issued under an equity offering and 867,347 units issued under the Trust's distribution reinvestment program ("DRIP").

On May 28, 2009, the Trust closed an equity offering of 9,602,500 trust units at a price of \$9.00 per trust unit for total gross proceeds of \$86.4 million, which included the exercise in full of the over-allotment option granted to the underwriters as part of the offering.

Under the DRIP, unitholders may elect to reinvest distributions or make optional cash payments to acquire trust units from treasury under the DRIP at 95 percent of the average market price with no additional fees or commissions. The operation of the DRIP was reinstated effective with the March distribution payable on April 15, 2009, following suspension of the program in October 2008. Participation in the DRIP has averaged 13.6 percent since reinstatement.

The premium distribution reinvestment plan ("Premium DRIP") allows unitholders to exchange such units for a cash payment, from the plan broker, equal to 102 percent of the monthly distribution. The Premium DRIP program has been suspended since March 10, 2006.

As at September 30, 2009, the Trust had net debt of \$373.4 million (net of working capital and other liabilities, excluding derivative contracts, note payable with MFC and future income taxes) including the convertible debentures at face value of \$79.7 million. Excluding the convertible debentures, net debt was \$293.7 million, compared with \$319.9 million at December 31, 2008. The decrease in net debt, excluding convertible debentures, of \$26.2 million during 2009 is attributable to decreased bank debt of \$35.4 million, offset by a negative change in working capital of \$9.2 million.

Bank debt outstanding was \$246.9 million at September 30, 2009 compared with \$282.3 million as at December 31, 2008. Of the \$246.9 million outstanding at September 30, 2009, all is outstanding under the production facility.

At the end of the third quarter, the Trust had a net debt (excluding convertible debentures) to 12 months trailing cash flow ratio of 1.25 times and a total net debt (including convertible debentures) to 12 months trailing cash flow ratio of 1.59 times.

During the second quarter, the Trust renewed its credit facility at the previously approved amount of \$450 million. The credit facility is a fully secured, extendible, revolving facility and will revolve until April 28, 2010 at which time it is extendible for a further 364-day revolving period upon agreement between the Trust and the bank syndicate. The facility consists of a \$440 million production facility and a \$10 million working capital facility. The credit facility is fully secured by first priority security interests in all present and after acquired properties and assets of the Trust and its subsidiary and affiliated entities. The purpose of the facility is to fund property acquisitions and capital expenditures. Principal repayments to the bank are not required at this time. Should principal repayments become mandatory, and in the absence of refinancing arrangements, the Trust would be required to repay the facility in five equal quarterly installments commencing April 29, 2011.

The Trust has outstanding \$79.7 million principal amount of 6.75% convertible extendible unsecured subordinated debentures. Interest on the debentures is paid semi-annually in arrears, on February 28 and August 31, and the debentures are convertible at the option of the holder, at any time, into fully paid trust units at a conversion price of \$14.00 per trust unit. The debentures mature on August 31, 2012 at which time they are due and payable. The debentures are redeemable by the Trust at a price of \$1,050 per debenture on or after September 1, 2010 and on or before August 31, 2011, and at a price of \$1,025 per debenture on or after September 1, 2011 and on or before August 31, 2012. On redemption or maturity, the Trust may opt to satisfy its obligation to repay the principal by issuing trust units. If all of the outstanding debentures were converted at the conversion price, an additional 5.7 million trust units would be required to be issued.

The convertible debentures are classified as debt on the balance sheet with a portion of the proceeds allocated to equity, representing the value of the conversion feature. As the debentures are converted to trust units, a portion of the debt and equity amounts are transferred to Unitholders' Capital. The debt component of the convertible debentures is carried net of issue costs of \$4 million. The debt balance, net of issue costs, accretes over time to the principal amount owing on maturity. The accretion of the debt discount and the interest paid to debenture holders are expensed each period as part of the line item "interest and accretion on convertible debentures" in the consolidated statement of income.

The Trust recognized \$0.4 million (2008 - \$0.3 million) of accretion of the debt discount in the third quarter of 2009 and \$1.1 million (2008 - \$1.3 million) year-to-date.

As at November 2, 2009, the Trust has 112,456,063 trust units and \$79.7 million in convertible debentures outstanding.

Capitalization

	Sept. 30, 2009	Dec. 31, 2008	Sept. 30, 2008
Trust unit equity (\$000s)	600,404	557,263	545,551
Bank debt (\$000s)	246,892	282,332	270,982
Working capital deficit (surplus) ⁽¹⁾ (\$000s)	46,788	37,602	32,348
Net debt excluding convertible debentures (\$000s)	293,680	319,934	303,330
Convertible debentures (\$000s) ⁽²⁾	79,744	79,744	79,744
Net debt (\$000s)	373,424	399,678	383,074
Net debt excluding convertible debentures to trailing 12-month cash flow ⁽³⁾	1.25	1.03	1.00
Total net debt to trailing 12-month cash flow ⁽³⁾	1.59	1.28	1.26
Trust units outstanding (000s)	112,327	96,181	95,945

(1) Working capital and other liabilities, excluding derivative contracts, future income taxes and notes with MFC.

(2) Convertible debentures included at face value.

(3) Calculated as net debt divided by funds from operations for the previous 12 months.

The current economic slowdown, reduced availability of credit, and challenging equity markets have resulted in the Trust setting its objective for 2009 to operating within forecasted funds from operations and targeting an annual total payout ratio of not more than 110 percent (distributions plus capital expenditures). Funds from operations is a non-GAAP measure used by management as an indicator of the Trust's ability to generate cash from operations. Currently, the Trust has a bank line of \$450 million of which \$247 million is drawn down at September 30, 2009, leaving available capacity of \$203 million.

On March 11, 2009, the Trust announced a reduction in distributions from \$0.11 per unit to \$0.09 per unit commencing with the distribution to be paid on April 15, 2009. This reduction was made in response to declining commodity prices, taking into account the needs of the ongoing capital program and the maintenance of a strong balance sheet.

For 2009, the Trust is benefiting from an active hedging program at prices above current market levels. Currently, the Trust has in place oil hedges for approximately 44 percent of net forecasted production (after royalty) for the remaining three months of 2009. Volumes are hedged at an average floor price of \$85.14 per boe. For natural gas, remaining 2009 hedges total approximately 54 percent of net budgeted production volumes hedged at an average floor price in excess of \$5.73 per GJ (or \$6.04 per Mcf).

NAL's capital program for 2009 has been designed to be scalable and flexible in response to commodity prices and market conditions. The initial plan for a \$110 million capital program, with the expectation to drill approximately 82 (40 net) wells, was reduced in February by \$15 million in response to weaker commodity prices. Based upon positive second quarter performance and the opportunities added, the Trust increased its capital program to \$125 - \$135 million. The Trust, through the Manager, operates over 90 percent of the assets to which the capital program is directed, allowing for significant flexibility over the timing and scale of the program.

Fluctuations in commodity prices, other market factors and growth opportunities may make it necessary to adjust planned capital expenditures or distribution levels.

Under the tax legislation regarding the change in the taxation of income trusts, the Trust has a grandfathering period to 2011, when the rules come into effect. The grandfathering period restricts "undue expansion" of the Trust by placing growth limits for issuances of equity and convertible debt, based on the market capitalization of the Trust on October 31, 2006, the date of the announcement of the changes in the tax legislation. For the remainder of 2009 and 2010, the Trust has approximately \$965.7 million of available safe harbour, excluding the impact of the Breaker acquisition, all of which is currently available.

ASSET RETIREMENT OBLIGATION

At September 30, 2009, the Trust reported an asset retirement obligation ("ARO") balance of \$102.8 million (\$90.8 million as at December 31, 2008) for future abandonment and reclamation of the Trust's oil and gas properties and facilities. The ARO balance was increased by \$7.7 million in relation to the acquisition of Clipper and Spearpoint, \$1.7 million due to liabilities incurred and revisions to estimates and \$5.7 million from accretion expense, and was reduced by \$3.1 million for actual abandonment and environmental expenditures incurred during the first nine months.

DISTRIBUTIONS TO UNITHOLDERS

For the three and nine months ended September 30, 2009, the Trust distributed 57 percent and 48 percent of its cash flow from operating activities, respectively, as compared to 46 percent and 56 percent for the same periods in 2008. The payout associated with cash flow from operating activities will fluctuate significantly period over period as cash flow from operating activities includes changes in non-cash working capital associated with operating activities. The Trust has distributed in excess of its net income in each period, due to the non-cash charges included in net income. Cash flow from operations usually exceeds net income, as net income includes non-cash charges such as DDA, future income tax expense and unrealized gains and losses on derivative contracts.

The Board of Directors of NAL Energy Inc. sets distribution levels taking into consideration commodity prices, the forecasted cash flow of the Trust, financial market conditions, availability of financing, internal capital investment opportunities and taxability.

Given that distributions have exceeded net income during 2009, the excess could be considered to be an economic return of capital to the unitholders. The Trust's business model is such that it distributes a certain proportion of its cash flow while retaining cash to execute planned capital programs. As a result of the depleting nature of oil and gas assets, some capital expenditure is required in order to minimize production declines as well as to invest in facilities and infrastructure. NAL's 2009 capital program may not fully replace production. When the Trust sets distribution levels, depletion expense is not considered to be an indicative measure for maintaining productive capacity and, therefore, net income is not considered a driver of distribution levels. The Trust grows its productive capacity and sustains its cash flow through development activities and acquisitions. NAL's productive capacity and future cash flow will be dependent on its ability to acquire assets and continue to find economic reserves. Acquisitions are financed through equity, debt or a combination of the two.

Generally, the capital expenditures of the Trust and the distributions in any given period exceed the cash flow from operating activities. The shortfall is financed from the credit facility. However, given the current economic slowdown, the Trust is targeting cash flow to be no more than 110 percent of distributions and capital expenditures on an annual basis in order to preserve the Trust's balance sheet. Fluctuations in commodity prices, other market factors and growth opportunities may make it necessary to adjust forecasted capital expenditures or distribution levels.

NAL intends to continue to make cash distributions to unitholders. However, these cash distributions cannot be guaranteed. The primary drivers of the level of distributions are the factors that contribute to cash flow, namely production, operating costs and commodity prices. The future sustainability of this distribution policy will be dependent upon maintaining productive capacity through both capital expenditures and acquisitions. A significant further decrease in commodity prices or continuing low commodity prices may impact cash from operating activities, access to credit facilities and the Trust's ability to fund operations and maintain distributions.

Distributions

(\$000s except for percentages)	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Cash flow from operating activities	52,999	98,860	183,235	242,716
Net income	8,249	111,045	3,566	107,206
Actual cash distributions paid or payable	30,290	45,968	87,528	135,295
Excess of cash flow from operating activities over cash distribution paid	22,709	52,892	95,707	107,421
Percentage of cash flow from operations distributed	57%	46%	48%	56%
Excess (shortfall) of net income over cash distributions paid	(22,041)	65,077	(83,962)	(28,089)

As stated in the non-GAAP measures section of the MD&A, NAL uses funds from operations as a key performance indicator to measure the ability of the Trust to generate cash from operations and to pay monthly distributions.

For the three months ended September 30, 2009, funds from operations amounted to \$53.8 million, compared with \$79.2 million for the three months ended September 30, 2008. The 32 percent decrease is primarily due to lower revenues resulting from lower commodity prices. On a per trust unit basis, funds from operations decreased 42 percent from \$0.83 in 2008 to \$0.48 in 2009.

For the nine months ended September 30, 2009, funds from operations decreased 31 percent to \$167.8 from \$244.0 million for the comparable period of 2008. The decrease is primarily due to lower revenues driven by lower commodity prices, offset by realized hedging gains of \$68.8 million.

Funds from Operations

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Funds from operations (\$000s)	53,766	79,233	167,788	244,031
Funds from operations per trust unit	0.48	0.83	1.62	2.60
Payout ratio based on funds from operations	56%	58%	52%	55%

VARIABLE INTEREST ENTITIES

NAL has no variable interest entities.

CONTRACTUAL OBLIGATIONS

Joint Venture Partnership Agreement:

Effective April 20, 2009, the Trust and MFC entered into a joint venture partnership agreement with a senior industry partner. The arrangement consists of a three year commitment to spend \$50 million to earn an interest in freehold and crown acreage. The Trust has a 65 percent interest in this agreement and MFC a 35 percent interest and therefore the Trust's net commitment is \$32.5 million. The agreement is exclusive and structured to be extendible for up to an additional six years for a total potential commitment of \$150 million (\$97.5 million net) to earn an interest in over 150 sections (97.5 net) of freehold and crown acreage. If the capital spending commitments are not met, interests in the freehold and crown acreage will not be earned and the Trust will not be required to pay

unspent commitment amounts to the senior industry partner. As at September 30, 2009, the Trust had spent \$2.4 million under this arrangement.

Farm-in Agreement:

Effective August 10, 2009, the Trust and MFC entered into a Farm-in Agreement with a senior industry partner. The arrangement consists of a two year initial commitment, with a minimum capital commitment of \$40 million in the first year and \$57 million in the second year, with an option for a third year, at NAL's election, for an additional \$50 million commitment. The Trust has a 60 percent interest in this agreement and MFC a 40 percent interest. The Agreement provides the opportunity to earn an interest in approximately 1,400 gross sections of undeveloped oil and gas rights in Alberta held by the partner. If the capital spending commitments are not met, interest in the acreage will not be earned and the Trust will not be required to pay any unspent amounts under the Agreement. As at September 30, 2009, no amounts have been spent under this agreement.

Flow-through shares:

In conjunction with the acquisition of Clipper, the Trust assumed flow-through share obligations related to common shares issued by Clipper on December 4, 2008. As a result, the Trust must incur qualifying resource expenditures amounting to \$7.5 million before December 31, 2009. The related tax impact was recorded on the acquisition of Clipper. The qualifying expenditures were renounced to shareholders of Clipper as at December 31, 2008. The obligation remaining for this flow-through share issue was \$2.6 million as at September 30, 2009.

Other:

NAL has entered into several contractual obligations as part of conducting day-to-day business. NAL has the following commitments for the next five years:

(\$000s)	2009	2010	2011	2012	2013
Office lease ⁽¹⁾	1,036	3,798	-	-	-
Office lease – Clipper ⁽²⁾	173	692	699	703	234
Transportation agreement	680	1,317	1,317	306	-
Processing agreement ⁽³⁾	84	428	414	401	384
Convertible debentures ⁽⁴⁾	-	-	-	79,744	-
Bank debt	-	-	148,135	98,757	-
Total	1,973	6,235	150,565	179,911	618

(1) Represents the full amount of office lease commitments, including both base rent and operating costs, in relation to the lease held by the Manager, of which the Trust is allocated a pro rata share (currently approximately 58 percent) of the expense on a monthly basis.

(2) Represents the full amount of the office lease assumed with the acquisition of Clipper. MFC will reimburse the Trust for 50 percent of the obligation under the base price adjustment clause (see "Acquisition of Alberta Clipper Energy Inc.")

(3) Represents a gas processing agreement with a take or pay component.

(4) Principal amount.

QUARTERLY INFORMATION

(\$000s, except per unit and production amounts)	2009				2008			
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue, net of royalties ⁽¹⁾	85,988	60,922	77,791	161,156	234,993	58,861	89,611	86,262
Per unit	0.77	0.60	0.81	1.68	2.46	0.63	0.98	0.96
Funds from operations ⁽²⁾	53,766	51,998	62,024	67,040	79,233	88,578	76,220	59,537
Per unit	0.48	0.51	0.64	0.70	0.83	0.94	0.83	0.66
Net income (loss)	8,249	(9,407)	4,724	55,374	111,045	(17,572)	13,733	10,556
Per unit								
basic	0.07	(0.09)	0.05	0.58	1.16	(0.19)	0.15	0.12
diluted	0.07	(0.09)	0.05	0.56	1.11	(0.19)	0.15	0.12
Average oil equivalent production (boe/d – 6:1)	23,418	23,049	23,836	23,984	23,808	23,791	23,601	23,656

(1) Represents revenue, net of royalties, plus gain (loss) on derivative contracts

(2) Represents cash flow from operating activities prior to the change in non-cash working capital items

DISCLOSURE CONTROLS AND PROCEDURES ("DC&P")

NAL's certifying officers have designed DC&P, or caused them to be designed under their supervision, to provide reasonable assurance that all material information required to be disclosed by NAL in its interim filings is processed, summarized and reported within the time periods specified in applicable securities legislation.

INTERNAL CONTROL OVER FINANCIAL REPORTING ("ICFR")

NAL's certifying officers are responsible for establishing and maintaining ICFR. They have designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The control framework the officers used to design NAL's ICFR is the *Internal Control – Integrated Framework* published by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

While management believes that NAL's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P or ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

There were no material changes in the Trust's ICFR for the quarter ended September 30, 2009.

CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by NAL are disclosed in the notes to NAL's December 31, 2008 audited consolidated financial statements. Certain accounting policies require that management make appropriate decisions when formulating estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The Manager reviews the estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes in estimated amounts that differ materially from current estimates. NAL might realize different results from the application of new accounting standards published, from time to time, by various regulatory bodies. An assessment of NAL's significant accounting estimates is discussed in the MD&A filed with NAL's audited consolidated financial statements for the year ended December 31, 2008.

NEW ACCOUNTING STANDARDS

Goodwill and Intangible Assets

Effective January 1, 2009, the Trust implemented the provisions of CICA Handbook Section 3064, "Goodwill and Intangible Assets". Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets. Standards concerning goodwill are unchanged from the previous standards, resulting in no impact to the consolidated financial statements of the Trust from the implementation of this Section.

Financial Instruments - Disclosures

In May 2009, the CICA amended Section 3862, "Financial Instruments – Disclosures", to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments became effective for NAL on December 31, 2009.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards ("IFRS")

The Trust continues to prepare for the forthcoming conversion to IFRS. 2009 activities to date have concentrated on an in-depth review of the significant Canadian GAAP differences and their related policy choices. Other areas being addressed include the impacts on information systems, internal controls, financial reporting, debt covenants and compensation arrangements. For further details on the transition plan please refer to the annual MD&A.

Dated: November 3, 2009

CONSOLIDATED BALANCE SHEETS

(thousands of dollars) (unaudited)

	As at September 30, 2009	As at December 31, 2008
Assets		
Current assets		
Cash and cash equivalents	\$5,004	\$5,584
Accounts receivable and other	52,989	57,825
Note receivable (Note 3)	-	49,599
Derivative contracts (Note 12)	10,835	65,680
	68,828	178,688
Derivative contracts (Note 12)	5,508	-
Future income tax asset	7,721	-
Goodwill	14,722	14,722
Property, plant and equipment (Notes 2 and 4)	1,051,494	1,017,187
	\$1,148,273	\$1,210,597
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$87,194	\$84,732
Note payable (Note 3)	9,227	9,609
Distributions payable to unitholders	10,109	15,389
Future income tax liability	1,172	16,788
	107,702	126,518
Bank debt (Note 5)	246,892	282,332
Convertible debentures (Note 6)	75,144	74,004
Derivative contracts (Note 12)	4,016	274
Other liabilities (Note 7)	7,478	890
Asset retirement obligations (Note 9)	102,771	90,844
Future income tax liability	-	22,092
Non-controlling interest (Note 10)	3,866	56,380
	547,869	653,334
Unitholders' equity		
Unitholders' capital (Note 11)	1,169,286	1,042,183
Equity component of convertible debentures (Note 6)	4,592	4,592
Deficit (Note 11)	(573,474)	(489,512)
	600,404	557,263
	\$1,148,273	\$1,210,597
Commitments (Note 13)		
Subsequent event (Note 14)		
Trust units outstanding (000s)	112,327	96,181

See accompanying notes.

CONSOLIDATED STATEMENTS OF INCOME, COMPREHENSIVE INCOME AND DEFICIT

(thousands of dollars, except per unit amounts) (unaudited)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Revenue				
Oil, natural gas and liquid sales	\$87,373	\$176,437	\$252,752	\$510,877
Crown royalties	(9,563)	(27,415)	(30,917)	(78,097)
Freehold and other royalties	(5,387)	(9,600)	(13,775)	(27,170)
	72,423	139,422	208,060	405,610
Gain (loss) on derivative contracts (Note 12):				
Realized gain (loss)	18,819	(16,627)	68,740	(43,848)
Unrealized gain (loss)	(5,499)	111,053	(53,487)	18,370
	13,320	94,426	15,253	(25,478)
Other income	245	1,145	1,388	3,333
	85,988	234,993	224,701	383,465
Expenses				
Operating	22,657	25,463	73,056	69,179
Transportation	1,075	989	3,142	2,879
General and administrative	4,095	3,757	10,753	11,653
Unit-based incentive compensation (Note 8)	3,805	(561)	6,865	2,816
Interest on bank debt	2,761	3,295	7,686	11,155
Interest and accretion on convertible debentures	1,727	1,739	5,176	5,952
Bad debt expense	-	6,901	-	6,901
Depletion, depreciation and amortization	46,209	50,092	132,196	143,151
Accretion on asset retirement obligations	2,003	1,833	5,717	5,458
	84,332	93,508	244,591	259,144
Income (loss) before taxes and non-controlling interest	1,656	141,485	(19,890)	124,321
Income tax recovery	-	209	1	203
Future income tax reduction (expense)	7,409	(27,488)	25,766	(8,140)
Total income tax reduction (expense)	7,409	(27,279)	25,767	(7,937)
Income before non-controlling interest	9,065	114,206	5,877	116,384
Non-controlling interest (Note 10)	(816)	(3,161)	(2,311)	(9,178)
Net income and comprehensive income	8,249	111,045	3,566	107,206
Deficit, beginning of period	(551,433)	(563,796)	(489,512)	(470,630)
Net income	8,249	111,045	3,566	107,206
Distributions declared	(30,290)	(45,968)	(87,528)	(135,295)
Deficit, end of period	\$(573,474)	\$(498,719)	\$(573,474)	\$(498,719)
Net income per trust unit (Note 11)				
Basic	\$0.07	\$1.16	\$0.03	\$1.14
Diluted	\$0.07	\$1.11	\$0.03	\$1.13
Weighted average trust units outstanding (000s)	112,109	95,664	103,444	93,834

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of dollars) (unaudited)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Operating Activities				
Net income	\$8,249	\$111,045	\$3,566	\$107,206
Items not involving cash:				
Depletion, depreciation and amortization	46,209	50,092	132,196	143,151
Accretion on asset retirement obligations	2,003	1,833	5,717	5,458
Unrealized loss (gain) on derivative contracts	5,499	(111,053)	53,487	(18,370)
Future income tax (reduction) expense	(7,409)	27,488	(25,766)	8,140
Non-cash accretion expense on convertible debentures	382	379	1,140	1,320
Non-controlling interest	80	1,151	788	2,107
Lease amortization	(217)	-	(217)	-
Abandonment and environmental expenditures	(1,030)	(1,702)	(3,123)	(4,981)
Change in non-cash working capital	(767)	19,627	15,447	(1,315)
	52,999	98,860	183,235	242,716
Financing Activities				
Distributions paid to unitholders	(25,828)	(38,918)	(85,178)	(113,550)
Increase (decrease) in bank debt	2,569	(37,133)	(114,292)	(4,648)
Issue of trust units, net of issue costs	(424)	-	81,593	(14)
Note repayment from MFC (Note 3)	-	-	49,599	-
Partnership distribution paid to MFC	-	(1,500)	(53,302)	(1,500)
Change in non-cash working capital	(5,697)	-	(5,615)	(426)
	(29,380)	(77,551)	(127,195)	(120,138)
Investing Activities				
Additions to property, plant and equipment	(42,376)	(53,189)	(96,264)	(109,260)
Property acquisitions	-	(373)	(2,799)	(8,249)
Proceeds from dispositions	-	-	265	40
Acquisition of Clipper (Note 2)	(84)	-	(833)	-
Disposition of Clipper (Note 2)	645	-	53,302	-
Acquisition of Spearpoint (Note 2)	(9,749)	-	(9,749)	-
Disposition of Spearpoint (Note 2)	6,772	-	6,772	-
Acquisition of Tiberius and Spear	-	(14)	-	(77,369)
Disposition of Tiberius and Spear	-	-	-	58,221
Acquisition of Seneca	-	-	-	337
Change in non-cash working capital	16,196	21,909	(7,314)	14,817
	(28,596)	(31,667)	(56,620)	(121,463)
Increase (decrease) in cash and cash equivalents	(4,977)	(10,358)	(580)	1,115
Cash and cash equivalents, beginning of period	9,981	12,867	5,584	1,394
Cash and cash equivalents, end of period	\$5,004	\$2,509	\$5,004	\$2,509
Supplementary disclosure of cash flow information:				
Cash paid (received) during the period for:				
Interest	\$4,883	\$4,913	\$14,161	\$14,777
Tax	\$(206)	\$2,202	\$(278)	\$6,905
Cash and cash equivalents is comprised of:				
Cash	\$5,004	\$2,509	\$5,004	\$2,509
Short term investments	-	-	-	-
	\$5,004	\$2,509	\$5,004	\$2,509

Refer to Notes 2, 9 and 11 for significant non-cash amounts not included in the cash flow statement.

See accompanying notes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Nine months ended September 30, 2009

(Tabular amounts in thousands of dollars, except per unit amounts)

(unaudited)

1) SUMMARY OF ACCOUNTING POLICIES

Management prepared the interim consolidated financial statements of NAL Oil & Gas Trust (“NAL” or the “Trust”) in accordance with accounting principles generally accepted in Canada and following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2008. The following disclosure is incremental to the disclosure included within the annual financial statements. Please read the interim consolidated financial statements in conjunction with the consolidated financial statements and notes thereto in NAL’s annual report for the year ended December 31, 2008.

Financial Instruments - Disclosures

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, “Financial Instruments – Disclosures”, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments became effective for NAL on December 31, 2009.

2) CORPORATE ACQUISITIONS

i) Alberta Clipper Energy Inc.

Effective June 1, 2009, the Trust acquired all of the issued and outstanding common shares of Alberta Clipper Energy Inc. (“Clipper”), which has interests in petroleum and natural gas properties and undeveloped land in Alberta and northeast British Columbia.

As consideration the Trust issued 5.7 million trust units at a price of \$6.45 a trust unit for total consideration, before acquisition costs, of \$36.6 million. The trust unit price was based on the weighted average market price of trust units at the date of announcement, being March 23, 2009. This purchase price included the assumption of \$78.9 million in bank debt.

The results of Clipper have been included in the accounts of the Trust from June 1, 2009. The transaction was accounted for using the purchase method of accounting. The fair values assigned to the net assets, and the consideration paid by the Trust, are as follows:

Net Assets acquired:	
Working capital deficiency (including cash of \$2)	\$(1,886)
Derivative contract	408
Property, plant and equipment	115,945
Future income taxes	17,858
Excess office lease obligation ⁽¹⁾	(1,446)
Asset retirement obligations	(14,592)
Bank debt	(78,852)
	<u>\$37,435</u>
Consideration:	
Issuance of trust units	\$36,600
Acquisition costs	835
	<u>\$37,435</u>

(1) Represents the present value of an office lease obligation, in excess of the value of a sublease.

The above amounts are estimates made by management based on currently available information. Amendments may be made to the purchase allocation as cost estimates and balances are finalized.

Concurrent with the acquisition, the Trust entered into a Purchase and Sale Agreement (“PSA”) with Manulife Financial Corporation (“MFC”), pursuant to which MFC acquired a 50% working interest in the Clipper petroleum and natural gas properties for a cash base price of \$52.5 million. The cash received from MFC was used to partially repay the assumed bank debt.

Included within the PSA is a base price adjustment clause that ensures the Trust and MFC share equally in all assets or liabilities related to Clipper that pertain to periods on or prior to the effective date of the acquisition, regardless of their date of discovery or disclosure. The base price adjustment calculation will adjust the purchase price that MFC pays the Trust for any change in working capital from amounts determined at the time the base price of \$52.5 million was established. In addition, the costs associated with contracts outstanding at the date of acquisition will be equally shared between both parties on an ongoing basis as the obligations are settled by the Trust. The amounts due under this base price adjustment clause are to be settled no more than quarterly commencing December 2009. As at September 30, 2009, the Trust had a receivable from MFC of \$0.8 million relating to the base price adjustment.

As a result, after taking into effect the MFC disposition and MFC’s share of the assets and liabilities to be settled under the base price adjustment clause, the Trust acquired property, plant and equipment of \$55.4 million, a derivative contract of \$0.4 million and a future tax asset of \$17.9 million and assumed asset retirement obligations of \$7.3 million, bank debt of \$26.4 million, a working capital deficiency of \$1.1 million and a lease obligation of \$1.5 million, for consideration of \$37.4 million, including estimated acquisition costs.

ii) Spearpoint Energy Corp.

Effective August 10, 2009, the Trust acquired all of the issued and outstanding common shares of Spearpoint Energy Corp. (“Spearpoint”) for cash of \$10.6 million, prior to acquisition costs. The fair values assigned to the net assets, and the consideration paid by the Trust, are as follows:

Net Assets acquired:	
Cash	\$1,201
Working capital deficiency	(2,183)
Property, plant and equipment	17,792
Future income taxes	525
Asset retirement obligation	(685)
Note payable	(5,700)
	<u>\$10,950</u>
Consideration:	
Cash	\$10,590
Acquisition costs	360
	<u>\$10,950</u>

The above amounts are estimates made by management based on currently available information. Amendments may be made to the purchase allocation as cost estimates and balances are finalized.

Concurrent with the acquisition, the Trust entered into a Purchase and Sale Agreement (the “Spearpoint PSA”) with MFC, pursuant to which MFC acquired a 40 percent working interest in all of the Spearpoint petroleum and natural gas properties and the farm-in agreement for a base price of \$6.5 million payable in cash.

Included within the Spearpoint PSA is a base price adjustment clause that ensures the Trust and MFC share 60 percent / 40 percent, respectively, in all assets or liabilities related to Spearpoint that pertain to periods on or prior to the effective date of the acquisition, regardless of their date of discovery or disclosure. The base price adjustment calculation will adjust the purchase price that MFC pays the Trust for any change in working capital from amounts determined at the time the base price of \$6.5

million was established. As at September 30, 2009, the Trust had a receivable from MFC of \$0.3 million relating to these price adjustments.

As a result, after taking into effect the MFC disposition and MFC's share of the assets and liabilities to be settled under the base price adjustment clause, the Trust acquired property, plant and equipment of \$10.7 million and a future income tax asset of \$0.5 million and assumed a note payable of \$5.7 million, asset retirement obligations of \$0.4 million and a working capital deficiency of \$0.9 million, for consideration of \$4.2 million.

3) RELATED PARTY TRANSACTIONS

The Trust is managed by NAL Resources Management Limited (the "Manager"). The Manager is a wholly-owned subsidiary of MFC and also manages on their behalf NAL Resources Limited, another wholly-owned subsidiary of MFC.

The Manager provides certain services to the Trust pursuant to an administrative services and cost sharing agreement. This agreement requires the Trust to reimburse the Manager, at cost, for general and administrative ("G&A") expenses incurred by the Manager on behalf of the Trust. The Trust paid \$3.4 million (2008 - \$3.1 million) for the reimbursement of G&A expenses during the third quarter and \$8.7 million (2008 - \$9.6 million) in the year-to-date. The Trust also pays the Manager its share of unit-based compensation expense when cash compensation is paid to employees under the terms of the Manager's incentive compensation plans, of which, \$2.3 million has been paid year-to-date relating to notional units that vested on November 30, 2008 (2008 - \$1.8 million).

The Trust and a wholly owned subsidiary of MFC jointly own a limited partnership (the "Partnership"). This Partnership holds the assets acquired from the acquisition of Tiberius Exploration Inc. and Spear Exploration Inc. ("Tiberius and Spear") in February 2008. Both the Trust and MFC have entered into net profit interest royalty agreements ("NPI") with the Partnership. These agreements entitle each royalty holder to a 49.5 percent interest in the cash flow from the Partnership's reserves. In exchange for this interest, the royalty holders each paid \$49.6 million to the Partnership by way of promissory notes in 2008. Although the MFC note resided in the Partnership, it was consolidated by virtue of the Trust having control of the Partnership as described below.

The Trust, by virtue of being the owner of the general partner under the partnership agreement, is required to consolidate the results of the Partnership into its financial statements on the basis that the Trust has control over the Partnership.

During the first quarter of 2009, MFC repaid the note receivable to the Partnership for \$49.6 million. The note receivable bore interest at prime plus three percent. The Partnership then paid an equal distribution of \$49.6 million to MFC. This resulted in a \$49.6 million reduction to the non-controlling interest (Note 10).

As at September 30, 2009, there is a note payable of \$9.2 million with MFC arising from the Tiberius and Spear acquisition. The note payable is included on consolidation of the Partnership, but is effectively eliminated through the non-controlling interest. The note is due on demand, unsecured and bears interest at prime plus three percent. The amount of the note payable to MFC is adjusted to reflect MFC's share of the capital expenditures of the Partnership which MFC has funded, less any loan repayments made.

Net interest expense on these notes of \$0.1 million was payable by the Trust for the third quarter of 2009 (2008 - \$0.9 million net interest income), and net interest income of \$0.3 million (2008 - \$2.1 million) year-to-date was received by the Trust and is reported as other income.

The following amounts are due to and from related parties as at September 30, 2009 and December 31, 2008 and have been included in accounts receivable, note receivable, accounts payable and accrued liabilities and note payable on the balance sheet:

	September 30, 2009	December 31, 2008
Due to NAL Resources Limited ⁽¹⁾	\$2,782	\$(10,042)
Due to NAL Resources Management Limited	(1,776)	(3,881)
Due (to) from Manulife Financial Corporation ⁽²⁾	(9,979)	45,512
	\$(8,973)	\$31,589

- (1) Includes base price adjustment due (to) from MFC, relating to the Clipper and Spearpoint asset dispositions to MFC, of \$1.1 million (Note 2).
- (2) Included on consolidation, eliminated through non-controlling interest. Represents note payable \$9.2 million (2008 - \$9.6 million), plus amounts due from (to) MFC of (\$0.8) million (2008 - \$5.5 million), presented in accounts payable/ accounts receivable, relating to the net interest and NPI amounts due.

4. PROPERTY, PLANT AND EQUIPMENT

	September 30, 2009	December 31, 2008
Petroleum and natural gas properties, at cost	\$2,076,027	\$1,909,524
Less: Accumulated depletion and depreciation	(1,024,533)	(892,337)
	\$1,051,494	\$1,017,187

Costs associated with undeveloped land and unproved properties of \$46.8 million (2008 - \$34.3 million) have been excluded from the depletion calculation for the nine months ended September 30, 2009.

Future development costs for proved reserves of \$41.8 million (2008 - \$49.8 million) have been included in the depletion calculation.

During the nine months ended September 30, 2009, the Trust capitalized \$4.3 million (2008 - \$3.2 million) of G&A costs and \$2.8 million (2008 - \$1.2 million) of unit-based incentive compensation that were directly related to exploitation and development programs.

5. BANK DEBT

	September 30, 2009	December 31, 2008
Production loan facility	\$246,892	\$281,984
Working capital facility	-	348
Total debt outstanding	\$246,892	\$282,332

The Trust maintains a fully secured, extendible, revolving term credit facility with a syndicate of Canadian chartered banks and one U.S. based lender. The facility consists of a \$440 million production facility and a \$10 million working capital facility. The total amount of the facility is determined by reference to a borrowing base. The borrowing base is calculated by the bank syndicate and is based on the net present value of the Trust's oil and gas reserves and other assets. Given that the borrowing base is dependent on the Trust's reserves and future commodity prices, lending limits are subject to change on renewal.

The credit facility is fully secured by first priority security interests in all existing and future acquired properties and assets of the Trust and its subsidiary and affiliated entities. The facility will revolve until April 28, 2010 at which time it may be extended for a further 364-day revolving period upon agreement between the Trust and the bank syndicate. If the credit facility is not extended in April 2010, the amounts outstanding at that time will be converted to a two-year term loan. The term loan will be payable in five equal quarterly installments commencing April 29, 2011.

The Trust is restricted under the credit facility from making distributions to its unitholders in excess of its consolidated operating cash flow during the 18 month period preceding the distribution date. The Trust is in compliance with this covenant.

Amounts are advanced under the credit facility in Canadian dollars by way of prime interest rate based loans and by issues of bankers' acceptances and in U.S. dollars by way of U.S. based interest rate and Libor based loans. The interest charged on advances is at the prevailing interest rate for bankers' acceptances, Libor loans, lenders' prime or U.S. base rates plus an applicable margin or stamping fee. The applicable margin or stamping fee, if any, varies based on the consolidated debt-to-cash flow ratio of the Trust. As at September 30, 2009 and December 31, 2008 all amounts outstanding were in Canadian dollars.

On September 30, 2009 the effective interest rate on amounts outstanding under the credit facility was 3.68 percent (2008 - 4.52 percent). The Trust's interest charge includes this fixed interest rate component, plus a standby fee, a stamping fee and the fee for renewal.

6. CONVERTIBLE DEBENTURES

The following table reconciles the principal amount, debt component and equity component of the convertible debentures.

	Principal amount of debentures	Debt component of debentures	Equity component of debentures
Balance, December 31, 2007	\$100,000	\$90,876	\$5,759
Conversion to trust units	(20,256)	(18,568)	(1,167)
Accretion	-	1,696	-
Balance, December 31, 2008	\$79,744	\$74,004	\$4,592
Accretion	-	1,140	-
Balance, September 30, 2009	\$79,744	\$75,144	\$4,592

7. OTHER LIABILITIES

	September 30, 2009	December 31, 2008
Unit-based incentive compensation	\$6,600	\$890
Excess office lease obligation (Note 2) ⁽¹⁾	878	-
	\$7,478	\$890

(1) Represents the present value of the long-term portion of the office lease obligation, in excess of a sub-lease, assumed on the acquisition of Clipper. MFC will reimburse the Trust for 50 percent of the obligation under the base price adjustment clause (Note 2).

8. UNIT-BASED INCENTIVE COMPENSATION PLAN

The Trust recorded a total compensation expense of \$9.7 million in the first nine months of 2009, of which \$6.9 million was recorded as an expense and \$2.8 million as property, plant and equipment (\$1.8 million was expensed and \$0.8 million recorded as property, plant and equipment for the year ended December 31, 2008). The compensation expense was based on the September 30, 2009 trust unit price of \$12.70 (December 31, 2008 - \$8.05), accrued distributions, performance factors and the number of units vesting on maturity.

The following table reconciles the change in total accrued trust unit-based incentive compensation relating to the plan:

	Nine months ended Sept. 30, 2009	Year ended December 31, 2008
Balance, beginning of period	\$6,274	\$5,311
Increase in liability	9,679	2,730
Cash payout, relating to units vested	(2,324)	(1,767)
Balance, end of period	\$13,629	\$6,274
Current portion of liability ⁽¹⁾	\$7,029	\$5,384
Long-term liability ⁽²⁾	\$6,600	\$890

(1) Included in accounts payable and accrued liabilities.

(2) Included in other liabilities.

9. ASSET RETIREMENT OBLIGATIONS

The following table reconciles the Trust's asset retirement obligations.

	Nine months ended Sept. 30, 2009	Year ended December 31, 2008
Balance, beginning of period	\$90,844	\$89,602
Accretion expense	5,717	7,299
Revisions to estimates	559	(262)
Liabilities incurred	1,067	1,422
Liabilities acquired, net (Note 2)	7,707	1,636
Liabilities settled	(3,123)	(8,853)
Balance, end of period	\$102,771	\$90,844

NAL's estimated credit-adjusted risk-free rate of nine percent (2008 – eight to nine percent) and an inflation rate of two percent (2008 – two percent) were used to calculate the present value of the asset retirement obligations.

10. NON-CONTROLLING INTEREST

The Trust has recorded a non-controlling interest in respect of the 50 percent ownership interest held by MFC in the Partnership holding the Tiberius and Spear assets (Note 3). The non-controlling interest on the balance sheet represents 50 percent of the net assets of the Partnership as follows:

	Nine months ended Sept. 30, 2009	Year ended December 31, 2008
Non-controlling interest, beginning of period	\$56,380	\$-
Non-controlling interest on acquisition	-	54,057
Net income attributable to non-controlling interest	788	3,823
Distributions to MFC ⁽¹⁾	(53,302)	(1,500)
Non-controlling interest, end of period	\$3,866	\$56,380

(1) Includes \$49.6 million distribution paid following settlement of note receivable (Note 3).

The non-controlling interest in the statement of income is comprised of:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Net profits interest expense	\$736	\$2,010	\$1,523	\$7,071
Share of net income attributable to MFC	80	1,151	788	2,107
	\$816	\$3,161	\$2,311	\$9,178

11. UNITHOLDERS EQUITY

Units Issued:

	Nine months ended Sept. 30, 2009		Year ended December 31, 2008	
	Units	Amount	Units	Amount
Balance, beginning of the period	96,181	\$1,042,183	90,494	\$969,588
Equity offering	9,603	86,422	-	-
Issued on corporate acquisition (Note 2)	5,676	36,600	2,409	29,496
Less issue expenses (net of tax of \$1,280)	-	(3,549)	-	(29)
Issued from Distribution Reinvestment Plan	867	7,630	1,831	23,393
Issued on conversion of debentures	-	-	1,447	19,735
Balance, end of the period	112,327	\$1,169,286	96,181	\$1,042,183

Per Unit Information

Basic net income per trust unit is calculated using the weighted average number of trust units outstanding. The calculation of diluted net income per trust unit includes the weighted average trust units potentially issuable on the conversion of the convertible debentures. For the three and nine months ended September 30, 2009, the trust units potentially issuable on the conversion of the convertible debentures are anti-dilutive and are therefore excluded from the calculation. Total weighted average trust units issuable on conversion of the convertible debentures and excluded from the diluted net income per trust unit calculation for the three and nine months ended September 30, 2009 were 5,696,000. For the three and nine months ended September 30, 2008, an additional 5,723,975 and 6,557,840 trust units, respectively, were included in the diluted income per trust unit calculation. As at September 30, 2009, the total convertible debentures outstanding were immediately convertible to 5,696,000 trust units.

Deficit

The deficit is comprised of the following:

	Nine months ended Sept. 30, 2009	Year ended December 31, 2008
Accumulated income	\$556,597	\$553,031
Accumulated cash distributions	(1,130,071)	(1,042,543)
	\$(573,474)	(\$489,512)

12. FINANCIAL RISK MANAGEMENT

Foreign currency exchange rate risk

During 2009 the Trust has entered into foreign exchange rate derivative contracts. NAL's management has authorization to fix the exchange rate on up to 50 percent of the Trust's U.S. dollar exposure for periods of up to 24 months.

EXCHANGE RATE	Remaining Term	Amount ⁽¹⁾ (US\$ MM)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Oct 2009 – Nov 2009	\$4.0	1.2730	BofC Average Noon Rate
Swaps-floating to fixed	Oct 2009 – Nov 2009	\$4.0	1.2875	BofC Average Noon Rate
Swaps-floating to fixed	Oct 2009 – Nov 2009	\$4.0	1.2625	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1583	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1100	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1200	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1225	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1300	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1420	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1525	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1000	BofC Average Noon Rate

(1) Notional US\$ denominated commodity sales

The fair value of foreign exchange derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income as unrealized gain (loss). As at September 30, 2009, if exchange rates had strengthened by \$0.01, with all other variables held constant, net income for the period would have been \$0.6 million higher, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had exchange rates been \$0.01 weaker.

Commodity price risk

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q4-09	Q1-10	Q2-10	Q3-10	Q4-10
<u>US\$ Collar Contracts</u>					
\$US WTI Collar Volume (bbl/d)	300	3,500	3,300	2,600	2,400
Bought Puts – Average Strike Price (\$US/bbl)	\$62.67	\$61.86	\$62.27	\$64.90	\$65.10
Sold Calls – Average Strike Price (\$US/bbl)	\$71.85	\$72.90	\$73.23	\$76.42	\$76.88
<u>US\$ Swap Contracts</u>					
\$US WTI Swap Volume (bbl/d)	1,700	700	1,200	-	-
Average WTI Swap Price (\$US/bbl)	\$61.94	\$75.36	\$75.67	-	-
<u>Cdn\$ Collar Contracts</u>					
\$Cdn WTI Collar Volume (bbl/d)	1,500	300	-	-	-
Bought Puts – Average Strike Price (\$Cdn/bbl)	\$102.07	\$66.00	-	-	-
Sold Calls – Average Strike Price (\$Cdn/bbl)	\$137.63	\$80.17	-	-	-
<u>Cdn\$ Swap Contracts</u>					
\$Cdn WTI Swap Volume (bbl/d)	1,300	-	-	-	-
Average WTI Swap Price (\$Cdn/bbl)	\$92.55	-	-	-	-
Total Oil Volume (bbl/d)	4,800	4,500	4,500	2,600	2,400
<u>NATURAL GAS</u>					
<u>Collar Contracts</u>					
AECO Collar Volume (GJ/d)	1,685	-	-	-	-
Bought Puts – AECO Average Strike Price (\$Cdn/GJ)	\$8.90	-	-	-	-
Sold Calls – AECO Average Strike Price (\$Cdn/GJ)	\$11.44	-	-	-	-
<u>Swap Contracts</u>					
AECO Swap Volume (GJ/d)	32,663	30,000	30,000	31,000	14,337
AECO Average Price (\$Cdn/GJ)	\$5.57	\$5.86	\$5.60	\$5.62	\$5.67
Total Natural Gas Volume (GJ/d)	34,348	30,000	30,000	31,000	14,337

The fair value of commodity derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income as unrealized gain (loss). As at September 30, 2009, if oil and natural gas liquids prices had been \$1.00 per barrel lower and natural gas prices \$0.10 per Mcf lower, with all other variables held constant, net income for the period would have been \$2.7 million higher, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had oil and natural gas liquids prices been \$1.00 per barrel higher and natural gas \$0.10 per Mcf higher.

Interest rate risk

NAL has the following interest rate derivative contracts outstanding:

INTEREST RATE	Remaining Term	Amount (Cdn\$MM) ⁽¹⁾	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Oct 2009 – Dec 2011	\$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Oct 2009 – Jan 2013	\$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Oct 2009 – Jan 2014	\$22.0	1.5100%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2013	\$14.0	1.8500%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2013	\$14.0	1.8750%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2014	\$14.0	1.9300%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2014	\$14.0	1.9850%	CAD-BA-CDOR (3 months)

(1) Notional debt amount

The fair value of interest rate derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income as unrealized gain (loss). As at September 30, 2009, if interest rates had been one percent lower, with all other variables held constant, net income for the period would have been \$4.2 million lower, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had interest rates been one percent higher.

Fair Value of Derivative Contracts

Derivative contracts are recorded at fair value on the balance sheet as current or long-term, assets or liabilities, based on their fair values on a contract-by-contract basis. The fair value of commodity contracts is determined as the difference between the contracted prices and published forward curves (ranging from US\$70.61 per barrel to US\$75.99 per barrel for oil and \$5.45 per GJ to \$7.98 per GJ for natural gas) as of the balance sheet date, using the remaining contracted oil and natural gas volumes. The fair value of the interest rate swaps is determined by discounting the difference between the contracted interest rate and forward bankers' acceptances rates (ranging from 2.002 percent to 2.643 percent) as of the balance sheet date, using the notional debt amount and outstanding term of the swap. The fair value of the exchange rate derivatives is calculated as the discounted value of the difference between the contracted exchange rate and the market forward exchange rates (ranging from 1.0679 to 1.0686) as of the balance sheet date, using the notional U.S. dollar amount and outstanding term of the swap. The fair value of the derivative contracts is as follows:

	Nine months ended Sept. 30, 2009	Year ended December 31, 2008
Fair value of commodity contracts	\$4,377	\$65,680
Fair value of interest rate swaps	2,502	(274)
Fair value of foreign exchange rate swaps	5,448	-
	\$12,327	\$65,406

The gain/(loss) on derivative contracts is as follows:

Gain / (Loss) on Derivative Contracts

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Unrealized gain (loss):				
Crude oil contracts	\$(184)	\$70,892	\$(56,151)	\$13,236
Natural gas contracts	(8,251)	40,161	(5,560)	5,134
Interest rate swaps	(374)	-	2,776	-
Exchange rate swaps	3,310	-	5,448	-
Unrealized gain (loss)	(5,499)	111,053	(53,487)	18,370
Realized gain (loss):				
Crude oil contracts	7,526	(13,119)	44,179	(38,151)
Natural gas contracts	8,331	(3,508)	19,794	(5,697)
Interest rate swaps	(226)	-	(433)	-
Exchange rate swaps	3,188	-	5,200	-
Realized gain (loss)	18,819	(16,627)	68,740	(43,848)
Gain (loss) on derivative contracts	\$13,320	\$94,426	\$15,253	\$(25,478)

These contracts are presented on the balance sheet as short term / long term, assets and liabilities as follows:

	Sept. 30, 2009	December 31, 2008
Long term unrealized loss on derivative contracts	\$(4,016)	\$(274)
Long term unrealized gain on derivative contracts	5,508	-
Net long term unrealized gain (loss) on derivative contracts	1,492	(274)
Current unrealized gain on derivative contracts	10,835	65,680
Net fair value of derivative contracts	\$12,327	\$65,406

The following table reconciles the movement in the fair value of the Trust's derivative contracts:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Unrealized gain (loss), beginning of period	\$17,826	\$(102,267)	\$65,406	\$(9,584)
Unrealized gain acquired ⁽¹⁾	-	-	408	-
Unrealized gain, end of period	12,327	8,786	12,327	8,786
Unrealized gain (loss) for the period	(5,499)	111,053	(53,487)	18,370
Realized gain (loss) in the period	18,819	(16,627)	68,740	(43,848)
Gain (loss) on derivative contracts	\$13,320	\$94,426	\$15,253	\$(25,478)

(1) Assumed on acquisition of Clipper (Note 2)

13. COMMITMENTS

(i) Joint Venture Partnership Agreement

Effective April 20, 2009, the Trust and MFC entered into a joint venture partnership agreement with a senior industry partner. The arrangement consists of a three year commitment to spend \$50 million on or before August 31, 2012, that provides the Trust and MFC an opportunity to earn an interest in freehold and crown acreage. The Trust has a 65 percent interest in this agreement and MFC a 35 percent interest. The three year commitment to the Trust is \$32.5 million. The agreement is exclusive and structured to be extendible for up to an additional six years for a total potential commitment of \$150 million (\$97.5 million net) to earn an interest in over 150 (97.5 net) sections of freehold and crown acreage. If the capital spending commitments are not met, interests in the freehold and crown acreage will not be earned and the Trust will not be required to pay unspent commitment amounts under the arrangement. As at September 30, 2009, the Trust has spent \$2.4 million under this agreement.

(ii) Farm-in Agreement

Effective August 10, 2009, the Trust and MFC entered into a Farm-in Agreement with a senior industry partner. The arrangement consists of a two year initial commitment, with a minimum capital commitment of \$40 million in the first year and \$57 million in the second year, with an option for a third year, at NAL's election, for an additional commitment of \$50 million. The Trust has a 60 percent interest in this agreement and MFC a 40 percent interest. The Agreement provides the opportunity to earn an interest in approximately 1,400 gross sections of undeveloped oil and gas rights in Alberta held by the partner. If the capital spending commitments are not met, interest in the acreage will not be

earned and the Trust will not be required to pay any unspent amounts. As at September 30, 2009, no amounts have been spent under this agreement.

(iii) Flow-through Shares

In conjunction with the acquisition of Clipper, the Trust assumed flow-through share obligations related to common shares issued by Clipper on December 4, 2008. As a result, the Trust must incur qualifying resource expenditures amounting to \$7.5 million before December 31, 2009. The related tax impact was recorded on the acquisition of Clipper. The qualifying expenditures were renounced to shareholders of Clipper as at December 31, 2008. The obligation remaining for this flow-through share issue was \$2.6 million as at September 30, 2009.

(iv) Other

NAL has entered into several contractual obligations as part of conducting day-to-day business. NAL has the following commitments for the next five years:

(\$000s)	2009	2010	2011	2012	2013
Office lease ⁽¹⁾	1,036	3,798	-	-	-
Office lease – Clipper ⁽²⁾	173	692	699	703	234
Transportation agreement	680	1,317	1,317	306	-
Processing agreement ⁽³⁾	84	428	414	401	384
Convertible debentures ⁽⁴⁾	-	-	-	79,744	-
Bank debt	-	-	148,135	98,757	-
Total	1,973	6,235	150,565	179,911	618

(1) Represents the full amount of office lease commitments, including both base rent and operating costs, in relation to the lease held by the Manager, of which the Trust is allocated a pro rata share (currently approximately 58 percent) of the expense on a monthly basis.

(2) Represents the full amount of the office lease assumed with the acquisition of Clipper. MFC will reimburse the Trust for 50 percent of the obligation under the base price adjustment clause (Note 2).

(3) Represents a gas processing agreement with a take or pay component.

(4) Principal amount.

14. SUBSEQUENT EVENT

Plan of Arrangement – Breaker Energy Ltd.

On October 13, 2009, NAL and Breaker Energy Ltd. (“Breaker”) entered into an arrangement agreement pursuant to which NAL will acquire all of the issued and outstanding common shares of Breaker by way of Plan of Arrangement. Under the arrangement, Breaker shareholders will receive 0.475 NAL trust units for each share of Breaker held, resulting in the expected issuance of approximately 24.7 million trust units. The transaction is subject to the approval of the Breaker shareholders, the Court of Queen’s Bench of the Province of Alberta and regulatory authorities, and is expected to close on December 10, 2009.

TRADING PERFORMANCE

	For the Quarter Ended			
	30-Sept-09	30-Jun-09	30-Sept-08	30-Jun-08
PRICE				
High	\$12.75	\$10.53	\$17.10	\$17.09
Low	\$8.48	\$6.63	\$11.50	\$13.12
Close	\$12.70	\$9.37	\$12.53	\$16.89
Daily Average Volume	439,319	459,603	380,141	447,401

NAL Oil & Gas Trust provides investors with a yield-oriented opportunity to participate in the Canadian Upstream Conventional Oil and Gas Industry. The Trust generates monthly cash distributions for its Unitholders by pursuing a strategy of acquiring, developing, producing and selling crude oil, natural gas and natural gas liquids from pools in southeastern Saskatchewan, central Alberta, northeastern British Columbia and Lake Erie, Ontario. Trust units trade on the Toronto Stock Exchange under the symbol "NAE.UN".

For further information:

Investor Relations

Telephone: 403.294.3600
Toll Free: 888.223.8792
Fax: 403.294.3601

Email: Investor.Relations@nal.ca
Website: www.nal.ca