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FOR IMMEDIATE RELEASE

NAL OIL & GAS TRUST REPORTS FOURTH QUARTER AND YEAR-END 2009 RESULTS

Media Release No. 06-10

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CALGARY, ALBERTA – NAL Oil & Gas Trust (“NAL” or the “Trust”) today announced its financial and operational results for the fourth quarter and year ended December 31, 2009 as well as 2009 year-end reserves. All amounts are in Canadian dollars unless otherwise stated.

SUMMARY

2009 was another strong year for NAL as we continued the transition toward a dividend paying corporation. On the Trust’s accomplishments in 2009, Mr. Andrew Wiswell, President and CEO commented, “the NAL team achieved a total return of 85 percent and established a leadership position in the emerging Cardium oil resource play in central Alberta. This performance was realized by delivering operating results consistent with guidance and achieving solid capital efficiency metrics. We added key technical capabilities and completed acquisitions while maintaining financial flexibility to fund future organic and transaction opportunities. Our active focus on assets, opportunities and people will continue in 2010 with a goal to provide consistent performance for our unitholders”.

2009 RESERVES AND FINDING & DEVELOPMENT HIGHLIGHTS

- Year-end proved plus probable reserves increased 41 percent from 73.1 million boe at year-end 2008 to 103.0 million boe at the end of 2009.
- NAL replaced 131 percent of its 2009 production through discoveries, extensions, infill drilling, well recompletions and technical revisions spending only 57 percent of funds from operations. Including acquisitions, and net of dispositions, the Trust replaced 445 percent of production in 2009, versus 156 percent in 2008.
- The Trust continued its solid finding and development (“F&D”) performance in 2009 which supported the three year average costs of \$15.66 per proved boe and \$17.21 per proved plus probable boe, including changes in future development costs (“FDC”), resulting in a proved recycle ratio of 2.3 times and proved plus probable recycle ratio of 2.1 times utilizing the Trust’s three year average operating netback.
- The Trust’s proved plus probable reserve life index (“RLI”) now stands at 9.2 years, an increase from 8.8 last year and from 8.2 at the end of 2007. An increase in RLI is one of the key strategic objectives of the Trust and has been achieved even though the production forecast used in the calculation has increased by 34 percent over that same three year period.
- NAL’s total proved reserves represent approximately 70 percent of total proved plus probable reserves and proved producing reserves represent approximately 85 percent of the total proved category. The reserves mix remains consistent year-over-year at approximately 50 percent crude oil and natural gas liquids and 50 percent natural gas.

CONFERENCE CALL DETAILS

At 3:30 p.m. MDT (5:30 p.m. EDT) on March 10, 2010, NAL will hold a conference call to discuss the fourth quarter and year-end 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/031010/index.php>

A recorded playback of the call will be available until March 17, 2010 by calling 1-800-408-3053, reservation 7388315.

2009 RESERVES AND CAPITAL EFFICIENCY SUMMARY⁽¹⁾

	2009	2008	2007
Reserves (MMboe)			
Proved	71.4	52.4	49.6
Proved + Probable ("P+P")	103.0	73.1	68.2
P+P Reserves per unit (boe per unit)	0.749	0.760	0.754
Reserve Life Index (years)			
P+P	9.2	8.8	8.2
Reserves Replacement Ratio			
P+P (excluding A&D)	131%	116%	96%
P+P (including A&D)	445%	156%	234%

	2009	2008	2007	Three Year Weighted Average 2007 – 2009
Including Changes in Future Development Capital				
Finding & Development Costs (\$/boe)				
Proved	18.52	14.18	13.99	15.66
P+P	17.86	16.24	17.71	17.21
F&D Recycle Ratio⁽²⁾				
Proved	1.7	3.0	2.4	2.3
P+P	1.8	2.6	1.9	2.1
Finding, Development & Acquisition Costs (\$/boe)				
Proved	27.87	19.41	23.20	24.76
P+P	22.33	19.66	21.67	21.65

	2009	2008	2007	Three Year Weighted Average 2007 – 2009
Excluding Changes in Future Development Capital				
Finding & Development Costs (\$/boe)				
Proved	13.06	13.96	12.75	13.27
P+P	12.34	12.77	16.56	13.51
F&D Recycle Ratio⁽²⁾				
Proved	2.4	3.0	2.7	2.7
P+P	2.6	3.3	2.1	2.7
Finding, Development & Acquisition Costs (\$/boe)				
Proved	22.24	18.99	22.32	21.60
P+P	15.95	16.06	20.81	17.19
Operating Netback Including Hedging (\$/boe)	31.91	42.25	33.95	36.12

(1) All reserves and production volumes data exclude royalty interest volumes.

(2) Recycle ratio is defined as operating netback divided by F&D and FD&A, respectively, including changes in FDC.

2009 ACCOMPLISHMENTS & HIGHLIGHTS

- The Trust's total return performance of approximately 85 percent was top quartile among dividend paying corporations and trust peers in 2009.
- During 2009 NAL continued its transition toward becoming an E&P company and established its position as a leader in identifying and developing the Cardium oil resource play in central Alberta.
- The Trust delivered production volumes at guidance ranges and operating costs per boe lower than forecast.
- NAL completed its most active year for acquisitions, completing several significant transactions including the corporate acquisitions of Alberta Clipper Energy, Breaker Energy and Spearpoint Energy that added production and acreage in key strategic areas and specifically in the Cardium oil resource at Garrington, Pine Creek and Lochend.
- NAL retains significant financial flexibility heading into 2010 with approximately \$319 million in available capacity on credit lines of \$550 million and a 2010 forecast net debt to cash flow ratio of 1.0 times (total debt to cash flow ratio of 1.7 times).

2009 SCORECARD & 2010 GUIDANCE

	2009 Guidance	2009 Actual	2010 Guidance
Production (boe/d)	23,500 – 24,000	24,016	29,500 – 30,500
Operating Costs (\$/boe)	11.30 – 11.60	11.09	11.00 – 11.50
Net Capital Expenditures (\$ MM)	135	133	175

CORPORATE CONVERSION UPDATE

The board of directors and management of NAL understand that 2010 is a year that holds an element of uncertainty for unitholders. Management is committed to keeping the investment community up to date on the Trust's intentions with respect to its eventual conversion to a corporate structure. Currently, the planned conversion is expected to occur in late 2010 or early 2011. The business model of NAL following conversion will be focused on delivering returns through a combination of yield and growth. NAL's future payout ratio and distributions will be driven by its business plan, its assets and opportunity base, future commodity prices, royalty and incentive structures in Western Canada as well as financial and balance sheet considerations.

It is important for unitholders to be aware that it is currently contemplated that the Trust will conduct its conversion within frameworks endorsed by the existing tax legislation in Canada that will permit unitholders to exchange their trust units for shares of the new corporation on a non-taxable basis.

AT-THE-MARKET EQUITY FINANCING PROGRAM

The Trust presently intends to establish an "at-the-market" trust unit financing program during the course of 2010, pursuant to which up to \$25,000,000 of trust units may be sold directly on the Toronto Stock Exchange. The volume and timing of sales, if any, will be at NAL's discretion. The trust units will be distributed at market prices prevailing at the time of sale and, as a result, prices may vary between purchasers and during the period of distribution. The net proceeds of any given distribution of trust units are currently expected to be used to repay certain outstanding indebtedness, to fund capital expenditures and for general corporate purposes.

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 2010 full year guidance 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 netbacks".

- Notes:
- (1) All amounts are in Canadian dollars unless otherwise stated.
 - (2) When converting natural gas to barrels of oil equivalent (boe) within this press release, 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 December 31		Years ended December 31	
	2009	2008	2009	2008
FINANCIAL				
Revenue ⁽¹⁾	111,477	107,041	361,087	615,039
Cash flow from operating activities	53,060	77,326	236,295	320,042
Cash flow per unit - basic	0.45	0.80	2.21	3.39
Cash flow per unit – diluted	0.44	0.77	2.14	3.24
Funds from operations	62,953	67,040	230,741	311,071
Funds from operations per unit - basic	0.53	0.70	2.15	3.29
Funds from operations per unit – diluted	0.51	0.67	2.09	3.15
Net income	5,634	55,374	9,200	162,580
Distributions declared	32,625	46,167	120,153	181,462
Distributions per unit	0.27	0.48	1.12	1.92
Basic payout ratio:				
based on cash flow from operating activities	61%	60%	51%	57%
based on funds from operations	52%	69%	52%	58%
Basic payout ratio including capital expenditures ⁽²⁾ :				
based on cash flow from operating activities	130%	110%	106%	101%
based on funds from operations	110%	126%	109%	104%
Units outstanding (000's)				
Period end	137,471	96,181	137,471	96,181
Weighted average	118,174	96,145	107,157	94,415
Capital expenditures ⁽³⁾	36,764	41,212	133,028	150,472
Property acquisitions (dispositions), net	(17,255)	(127)	(14,721)	8,082
Corporate acquisitions, net ⁽⁴⁾	310,051	315	351,664	58,356
Net debt, excluding convertible debentures ⁽⁵⁾	282,727	319,934	282,727	319,934
Convertible debentures (at face value)	194,744	79,744	194,744	79,744
OPERATING				
Daily production ⁽⁶⁾				
Crude oil (bbl/d)	10,290	10,223	9,868	10,188
Natural gas (Mcf/d)	78,265	69,049	71,169	68,898
Natural gas liquids (bbl/d)	2,413	2,254	2,287	2,126
Oil equivalent (boe/d)	25,748	23,984	24,016	23,797
OPERATING NETBACK (boe)				
Revenue before hedging gains	47.06	48.51	41.19	70.62
Royalties	(8.95)	(9.59)	(7.52)	(14.52)
Operating costs	(10.21)	(11.67)	(11.09)	(10.90)
Other income ⁽⁷⁾	0.15	0.18	0.17	0.19
Operating netback before hedging	28.05	27.43	22.75	45.39
Hedging gains (losses)	4.71	7.49	9.16	(3.14)
Operating netback	32.76	34.92	31.91	42.25

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

(2) Capital expenditures included are net of non-controlling interest amount of \$0.4 million (2008 - \$2.7) for the three months ended December 31, 2009 and \$1.8 million (2008 - \$7.9) for the year ended December 31, 2009, attributable to the Tiberius and Spear properties.

(3) Excludes property and corporate acquisitions, and is net of drilling incentive credits of \$3.3 million for the year ended December 31, 2009, (no drilling credits recorded in the fourth quarter of 2009).

(4) Represents total consideration for corporate acquisitions including fees.

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

(6) Includes royalty interest volumes.

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

OIL AND GAS RESERVES

NAL's 2009 year-end reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), independent engineering consultants in Calgary, in accordance with National Instrument ("NI") 51-101. At December 31, 2009, the Trust's proved reserves totaled 71.4 million barrels of oil equivalent ("boe") and proved plus probable ("P+P") reserves amounted to 103.0 million boe.

NAL has a Reserves Committee, composed entirely of independent directors, which is responsible for appointing the Trust's independent engineering consultants, determining the scope of the annual reserves review and reviewing the results.

Some key points regarding NAL's 2009 reserves summary are:

- Additions for "improved recovery", which includes discoveries, extensions, infill drilling and well recompletions, amounted to 5,123 Mboe of proved and 9,428 Mboe of P+P reserves. This represents new reserves added related to development activities, over and above volumes that were previously booked in the reserves report. These reserves additions occurred across all of NAL's core areas, with the larger ones resulting from successful drilling results in various Saskatchewan oil pools, the Cardium oil development programs in the Pine Creek, Garrington and Westward Ho areas in Alberta, as well as the gas development program in the Pine Creek area.
- Overall technical revisions amounted to 5,303 Mboe for proved and 1,910 Mboe for P+P reserves. The technical revisions were widespread among all producing areas, and were largely the result of positive performance trends observed in numerous producing wells and the reclassification of reserves from probable to proved to reflect increased levels of certainty.
- The Trust added 18,006 Mboe of proved reserves and 28,169 Mboe of P+P reserves during 2009 from acquisitions, approximately 80 percent of which related to the acquisition of Breaker Energy which closed in December 2009.
- The total P+P reserves additions for improved recovery and technical revisions amount to 11,338 Mboe, which represents an approximately 131 percent replacement ratio on 2009 production of 8,681 Mboe. Including acquisitions (net of dispositions), the Trust's total reserves replacement ratio for 2009 was approximately 445 percent.
- Approximately 70 percent of the Trust's total P+P reserves were in the proved category, and approximately 85 percent of the proved reserves were in the proved producing category. NAL's proved undeveloped reserves increased from 1,775 Mboe at year-end 2008 to 9,552 Mboe at year-end 2009, largely due to the new Cardium horizontal drilling opportunities in the Garrington and Westward Ho areas, along with a significant number of gas and oil development opportunities in the Fireweed, Irricana and Millard Lake areas from the Breaker Energy acquisition.
- NAL's reserves are evenly balanced between liquids and gas, with approximately 50 percent of the P+P reserves being comprised of oil and natural gas liquids while approximately 50 percent is natural gas.
- Using the P+P reserves of 102,994 Mboe and the number of outstanding trust units at December 31, 2009 of 137,471,209, the P+P reserves at year-end 2009 amounted to 0.749 boe per unit, relatively consistent with 0.760 boe per unit at year-end 2008.

The following tables summarize NAL's estimated reserves volumes and values using McDaniel's January 1, 2010 price forecasts. Gross reserves volumes are based on the Trust's working interests before deduction of royalties payable, and exclude any wells or properties in which NAL has only a royalty interest. Net reserves represent the Trust's working interest reserves after deducting royalties payable, plus royalty interest reserves. The Natural Gas category includes non-associated gas, solution gas from oil wells and coal bed methane volumes, as the solution gas and coal bed methane volumes are not considered material in terms of requiring separate reporting. For the properties acquired in the Tiberius Exploration Inc. ("Tiberius") and Spear Exploration Inc. ("Spear") corporate acquisitions (completed in 2008), the gross reserves reported represent the totals for NAL Energy Limited Partnership, as NAL is the controlling partner in the partnership holding those assets. A related party owns a 50 percent non-controlling interest in the partnership, and as such, receives a Net Profits Interest ("NPI") royalty payment from the partnership. This NPI is deducted from NAL's net reserves, such that the resulting net (after royalty) reserves reflect NAL's net share.

Numbers may not add exactly due to rounding.

Summary of Oil and Gas Reserves										
As at December 31, 2009										
Forecast Prices and Costs										
Reserves Category	Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total BOE (6:1)	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Developed Producing	23,936	20,574	326	283	181,406	156,025	6,041	4,178	60,536	51,039
Developed Non-Producing	131	111	0	0	6,109	4,881	153	111	1,303	1,035
Undeveloped	3,654	3,108	499	383	27,742	21,657	775	587	9,552	7,688
Total Proved	27,721	23,793	825	666	215,257	182,563	6,968	4,876	71,391	59,762
Probable	12,241	10,138	837	638	92,182	75,001	3,162	2,191	31,603	25,467
Total Proved Plus Probable	39,962	33,931	1,662	1,304	307,439	257,564	10,130	7,067	102,994	85,229

Net Present Values of Future Net Revenue					
Forecast Prices and Costs					
Before Income Taxes, Discounted at (percent/year)					
Reserves Category	0%	5%	10%	15%	20%
	(million \$)	(million \$)	(million \$)	(million \$)	(million \$)
Proved					
Developed Producing	2,034	1,561	1,274	1,083	947
Developed Non-Producing	35	26	21	18	16
Undeveloped	214	154	113	84	63
Total Proved	2,283	1,741	1,408	1,185	1,026
Probable	1,167	692	462	333	253
Total Proved Plus Probable	3,450	2,433	1,870	1,519	1,280

The table above shows the before-tax net present value (“NPV”) of the Trust’s reserves at various discount rates.

It should not be assumed that the estimated future net revenue is representative of the fair market value of the properties of the Trust. There is no assurance that such price and cost assumptions will be attained and variances could be material.

Summary of Pricing and Inflation Rate Assumptions								
As at December 31, 2009								
Forecast Prices and Costs								
Year	Oil				Natural Gas		Inflation Rates	Exchange Rate
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Hardisty Heavy 12° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)	Natural Gas AECO Spot Price (\$Cdn/MMBtu)	Natural Gas Liquids Edmonton Mix (\$Cdn/bbl)		
2010	80.00	83.20	68.10	76.50	6.05	60.30	2.0	0.950
2011	83.60	87.00	67.60	79.10	6.75	63.50	2.0	0.950
2012	87.40	91.00	68.00	81.80	7.15	66.50	2.0	0.950
2013	91.30	95.00	68.10	85.40	7.45	69.40	2.0	0.950
2014	95.30	99.20	71.10	89.20	7.80	72.50	2.0	0.950
2015	99.40	103.50	74.20	93.10	8.15	75.60	2.0	0.950
Thereafter*	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.950

* Price escalation rates are approximate.

Reconciliation of Company Gross Reserves By Principal Product Type Forecast Prices and Costs										
Factors	Light and Medium Oil		Heavy Oil		Associated and Non- Associated Gas		Natural Gas Liquids		Total BOE	
	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
	(Mbbl)	(Mbbl)	(Mbbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)
December 31, 2008	21,972	31,553	0	0	152,311	206,859	5,022	7,026	52,380	73,055
Improved Recovery*	3,277	5,382	0	0	8,371	18,419	451	977	5,123	9,428
Technical Revisions	1,962	330	0	0	14,977	5,409	845	679	5,303	1,910
Acquisitions	4,741	7,063	837	1,674	65,471	102,661	1,516	2,322	18,006	28,169
Dispositions	(680)	(814)	0	0	(135)	(170)	(38)	(45)	(740)	(887)
Production	(3,551)	(3,551)	(12)	(12)	(25,739)	(25,739)	(828)	(828)	(8,681)	(8,681)
December 31, 2009	27,721	39,962	825	1,662	215,257	307,439	6,968	10,131	71,391	102,994

* Improved Recovery includes discoveries, extensions, infill drilling and well recompletions.

FINDING AND DEVELOPMENT COSTS

Finding and Development (“F&D”) costs are reported below for proved and P+P reserves, in each case after eliminating the effects of acquisitions and dispositions and including changes in future development costs as per NI 51-101 guidelines. The total reserves changes in the improved recovery and technical revisions categories of the reconciliation table, excluding the changes that relate to the acquired properties, are used in the F&D calculation.

The capital spending of \$129.36 million used in the F&D calculation for 2009 represents the Trust’s total expenditures for drilling, completion and production equipment, plant and facility costs (including maintenance capital items that supported NAL’s base production volumes), plus seismic and land costs, capitalized G&A and unit-based incentive costs. The capital that was spent within properties that were acquired in 2009 is not included in the F&D calculation, as it is included in the Finding, Development and Acquisition (“FD&A”) calculation in the section which follows.

The F&D costs for 2009, as shown in the table below, were \$18.52 per boe for proved and \$17.86 per boe for P+P reserves. It should be noted that the aggregate of the development costs incurred during the year and the change in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. As a result, the three-year weighted average, with changes tracked over time, provides a useful indicator of capital effectiveness as it relates to reserves development. As shown in the table below, the weighted average F&D costs for the three-year period from 2007 through 2009 were \$15.66 per boe for proved and \$17.21 per boe for P+P reserves.

		2009		
		Actual Spending During 2009	Change in Estimated Future Development Costs	Total
Capital (\$000s)	Proved	129,360	54,115	183,474
	Proved + Probable	129,360	57,790	187,150
		<u>Improved Recovery</u>	<u>Technical Revisions</u>	<u>Total</u>
Reserves (Mboe)	Proved	4,602	5,303	9,905
	Proved + Probable	8,570	1,910	10,480
F&D (\$/boe)	Proved			18.52
	Proved + Probable			17.86

3-YEAR WEIGHTED AVERAGE

		Actual Spending Over 3 Years	Change in Estimated Future Development Costs	Total
Capital (\$000s)	Proved	370,051	66,593	436,644
	Proved + Probable	370,051	101,326	471,377
		Improved Recovery	Technical Revisions	Total
Reserves (Mboe)	Proved	11,424	16,454	27,878
	Proved + Probable	20,539	6,852	27,391
F&D (\$/boe)	Proved			15.66
	Proved + Probable			17.21

Some reporting issuers report F&D costs excluding changes in future development capital ("FDC"). Excluding changes in FDC, the Trust's F&D costs for 2009 were \$13.06 per boe for proved and \$12.34 per boe for P+P reserves. Another methodology also excludes capitalized G&A costs and unit-based incentive costs from the current year capital. On that basis, NAL's F&D costs for 2009 would use \$120.5 million of capital spending in the F&D calculation, resulting in \$12.16 per boe for proved and \$11.50 per boe for P+P reserves.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

A significant part of NAL's business activity in any given year is the acquisition and, to a lesser degree, the disposition of properties. In order to provide a more representative measure of the Trust's total capital spending as it relates to reserves development, FD&A costs are reported including the effects of acquisitions and dispositions.

During 2009 the Trust completed three corporate acquisitions (Alberta Clipper Energy Inc., Spearpoint Energy Corp. and Breaker Energy Ltd.), along with some minor property acquisitions and dispositions in Alberta and Saskatchewan. The FD&A calculation incorporates all the components used in the F&D calculation, plus the adjustments to capital spending and reserves related to the acquisition and disposition activities completed during the year, as shown in the table below. The FD&A calculation also includes capital expenditures made by NAL within the acquired properties during the year, along with any related reserves changes made to these properties, and the incremental future development costs for the acquired properties.

The FD&A costs for 2009 were \$27.87 per boe for proved and \$22.33 per boe for P+P reserves. The weighted average FD&A costs for the three-year period from 2007 through 2009 were \$24.76 per boe for proved and \$21.65 per boe for P+P reserves. These three-year averages provide a longer term measure of the Trust's overall capital spending effectiveness.

		2009				Total including A&D
		Actual Spending During 2009	Change in Estimated Future Development Costs	Acquisitions	Dispositions	
Capital (\$000s)	Proved	132,336	155,937	501,079	(17,521)	771,831
	Proved + Probable	132,336	246,532	501,079	(17,521)	862,426
		Improved Recovery	Technical Revisions	Acquisitions	Dispositions	Total including A&D
Reserves (Mboe)	Proved	5,123	5,303	18,006	(740)	27,692
	Proved + Probable	9,428	1,910	28,169	(887)	38,620
FD&A (\$/boe)	Proved					27.87
	Proved + Probable					22.33

		3-YEAR WEIGHTED AVERAGE					
		Actual Spending Over 3 Years	Change in Estimated Future Development Costs	Acquisitions	Dispositions	Total including A&D	
Capital (\$000s)	Proved	397,577	174,950	815,783	(17,521)	1,370,789	
	Proved + Probable	397,577	310,098	815,783	(17,521)	1,505,937	
		Improved Recovery	Technical Revisions	Acquisitions	Dispositions	Total including A&D	
Reserves (Mboe)	Proved	12,522	16,597	26,988	(740)	55,367	
	Proved + Probable	22,155	6,361	41,930	(887)	69,560	
FD&A (\$/boe)	Proved					24.76	
	Proved + Probable					21.65	

Excluding changes in FDC, the Trust's FD&A costs for 2009 were \$22.24 per boe for proved and \$15.95 per boe for P+P reserves. If the capitalized G&A and unit based incentive costs are excluded from the current year capital, the calculation would be based on 2009 capital spending of \$123.08 million, resulting in FD&A costs of \$21.91 per boe for proved and \$15.71 per boe for P+P reserves.

RESERVE LIFE INDEX

Reserve Life Index ("RLI") is calculated by dividing the reserves at year-end by the expected annual production for the subsequent year. RLI is useful in making generalized comparisons between companies but does not accurately represent the anticipated life of the Trust's reserves. Due to the natural decline of oil and gas production, the actual producing life of oil and gas properties is expected to be much longer than the RLI calculation would suggest.

In the McDaniel reserves report, the average production forecasted for 2010 in the P+P reserves case is 30,808 boe/d. This number is within NAL's production guidance range for 2010 prior to anticipated dispositions. For consistency, the RLI calculation is based on the reserves at December 31, 2009 and the forecasted annual production for 2010 from the reserves report. Using those numbers, NAL's RLI for P+P reserves has increased from 8.8 years at year-end 2008 to 9.2 years at year-end 2009.

LAND AND SEISMIC

At December 31, 2009, NAL held an average 36.6 percent working interest in 1,486,063 gross acres (544,105 net acres) of undeveloped land. Much of NAL's land is owned in common with Manulife Financial Corporation ("MFC"), which results in NAL operating a majority of its prospective acreage. Based on an internal estimate and using market benchmarks, NAL estimates that the value of its undeveloped land and seismic at December 31, 2009 was approximately \$131.0 million.

NET ASSET VALUE

The following net asset value ("NAV") calculations are based on what is generally referred to as the "produce-out" net present values of the Trust's oil and gas reserves as evaluated by independent engineering consultants in accordance with National Instrument 51-101. The reduction in NAV per unit versus 2008 is largely driven by the lower commodity price forecasts in the McDaniel report at year-end 2009. For comparative purposes, if the McDaniel price forecast used in 2008 were applied to the Trust's reserves for the year ended December 31, 2009, the net asset value per unit would be greater than in 2008.

(\$000s, except per unit data)	December 31, 2009	December 31, 2008
	Using Forecast Prices ⁽⁵⁾	Using Forecast Prices ⁽⁶⁾
Proved plus probable reserves (before tax, discounted at 10 percent)	1,870,482	1,443,004
Undeveloped land and seismic ⁽¹⁾	131,009	114,063
Working capital (deficiency) ⁽²⁾	(52,014)	(37,602)
Long-term debt ⁽³⁾	(408,690)	(356,336)
Asset retirement obligation ⁽⁴⁾	(79,797)	(52,132)
Net asset value	1,460,990	1,110,997
Units outstanding (000s)	137,471.2	96,181.4
NAV per unit (\$)	10.63	11.55

(1) Internal estimate.

(2) Working capital and other liabilities, excluding the fair value of derivative contracts, future income taxes and notes due to/from MFC.

(3) Includes bank debt and amount assigned to debt component of convertible debentures.

(4) The Asset Retirement Obligation ("ARO") is calculated based on the same methodology that was used to calculate the ARO on NAL's year-end financial statements, with two exceptions: future expected ARO costs are discounted at 10 percent and a deduction is made for abandonment costs incorporated in the value of the proved plus probable reserves. The balance on the year-end balance sheets of \$127.9 million for 2009 and \$90.8 million for 2008, when discounted at 10 percent, result in a total discounted ARO of \$110.5 million and \$76.1 million at the respective balance sheet dates. These balances are further reduced by \$30.7 million and \$24.0 million, respectively, relating to abandonment costs incorporated in the reserves value.

(5) McDaniel price forecast as of January 1, 2010.

(6) McDaniel price forecast as of January 1, 2009.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("MD&A") should be read in conjunction with the consolidated financial statements for the years ended December 31, 2009 and 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 December 31		Years ended December 31	
	2009	2008	2009	2008
Cash flow from operating activities	53,060	77,326	236,295	320,042
Add back change in non-cash working capital	9,893	(10,286)	(5,554)	(8,971)
Funds from operations	62,953	67,040	230,741	311,071

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; 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; the initiation of an "at-the-market" financing program; 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; and rates of return.

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 inability to obtain industry partner and other third party consents and approvals, when required; failure to realize the anticipated benefits of acquisitions, 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.

ACQUISITION OF BREAKER ENERGY LTD.

Effective December 11, 2009, the Trust acquired all of the issued and outstanding common shares of Breaker Energy Ltd. ("Breaker"), which has interests in petroleum and natural gas producing properties and undeveloped land in Alberta and northeast British Columbia.

The Trust issued 24.8 million trust units at a price of \$12.45 a trust unit for total consideration, before acquisition costs, of \$308.5 million. The trust unit price was based on the weighted average market price of trust units at the date of the announcement, being October 13, 2009.

In exchange for the consideration of \$310.0 million, which includes estimated acquisition costs, the Trust acquired property, plant and equipment of \$483.3 million, and assumed liabilities including asset retirement obligations of \$25.7 million, bank debt of \$94.5 million, a working capital deficiency of \$11.5 million, a future tax liability of \$37.2 million and a lease obligation of \$4.4 million.

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 December 31, 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 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, resulting in a total purchase price of \$115.5 million.

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. No amounts have been settled by the parties to date. However, as at December 31, 2009, the Trust had a receivable from MFC of \$1.8 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 \$56.5 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 \$74.8 million, and assumed liabilities including asset retirement obligations of \$7.3 million, bank debt of \$26.4 million, a working capital deficiency of \$2.1 million and a lease obligation of \$1.5 million, for consideration of \$37.5 million, including estimated acquisition costs of \$0.9 million.

EXPLORATION & DEVELOPMENT ACTIVITIES

The Trust spent \$32.1 million on drilling, completion and tie-in operations during the fourth quarter of 2009, compared to \$27.8 million during the fourth quarter of 2008 and drilled 37 (13.4 net) wells as compared to 31 (10.8 net) wells during the same period in 2008.

Operated activity for the quarter was again focused on horizontal oil wells in Saskatchewan and Alberta. The Trust drilled 94 (38.2 net) wells for full year 2009 including participation in 34 (4.7 net) non operated wells. Full year drilling activity consisted of 28 (6.9 net) gas wells and 66 (31.3 net) oil wells of which 23 (16 net) were Cardium and 38 (15 net) were Mississippian wells.

Fourth Quarter Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	20	10.4	1	0.2	0	0	0	0	21	10.6
Non-operated wells	5	0.2	11	2.6	0	0	0	0	16	2.8
Total wells drilled	25	10.6	12	2.8	0	0	0	0	37	13.4

Southeast Saskatchewan

In Saskatchewan, there were 13 (5.8 net) horizontal oil wells drilled during the fourth quarter. Activity was focused on the Mississippian in Alida, Hoffer, Torquay and Nottingham with initial production rates ranging from 50 - 300 bbls/d. The Trust plans to drill 60 (30 net) horizontal Mississippian oil wells in 2010 following up on successful new pool discoveries, infills and extensions. While the Cardium play in Alberta continues to have considerable market attention, the economics of Mississippian light oil projects remain very competitive and is the reason the Trust continues to balance its capital expenditures between the two resource plays.

Alberta

In Alberta, NAL participated in drilling 23 (7.2 net) wells including 7 (4.6 net) wells in the Cardium at Garrington and Pine Creek. Overall, results remain in-line with expectations and management remains encouraged by the significant potential of this resource. In 2010, the Trust plans to drill 26 (17 net) horizontal Cardium oil wells in Garrington, Lochend and Pine Creek to delineate and test significant Cardium acreage. 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 approximately \$3.0 million. Following up on three successful outcomes from 2009, the Trust will also participate in drilling several high impact horizontal gas wells in Kakwa and Pine Creek.

Northeast British Columbia

Production at Sukunka, the major producing asset in Northeast BC for the Trust, was in-line with expectations through the fourth quarter at 2,600 boe/d. The Trust drilled one (0.45 net) well in Trutch late in December 2009 and expects to drill three wells during 2010 including two 100 percent working interest high impact liquids rich horizontal Doig gas wells at Fireweed with production expected in the second and third quarter of 2010.

FOCUS OF FUTURE ACTIVITY

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 play with acreage at Garrington, Cochrane and Pine Creek in central Alberta. This activity complements a strong asset base in Mississippian light oil throughout southeast Saskatchewan and new opportunities added from the Breaker acquisition in Wabamun oil at Irricana and Leduc oil at Millard Lake. Current oil prices coupled with provincial royalty incentive programs drive compelling economics for oil development with recycle ratios greater than two times due to very attractive netbacks and rates of return in the 40 – 50+ percent range. The Trust will remain focused on an oil weighted program through 2010.

The Trust currently has catalogued a significant drill ready portfolio of horizontal gas 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 December 31, 2009 totaled \$36.8 million compared with \$41.2 million for the quarter ended December 31, 2008. On a full year basis, capital expenditures, before property acquisitions, totaled \$133.0 million compared to \$150.5 million in 2008. The decrease in capital spending year-over-year is largely a function of relatively higher land spending in southeast Saskatchewan and facilities spending for the Nottingham Gas plant during 2008.

Capital Expenditures (\$000s)

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Drilling, completion and production equipment	32,084	27,766	104,769	107,286
Plant and facilities	1,728	9,760	11,381	21,009
Seismic	168	326	1,222	1,202
Land	419	1,855	5,709	13,970
Total exploitation and development	34,399	39,707	123,081	143,467
Office equipment	183	764	692	1,945
Capitalized G&A	1,315	1,146	5,575	4,313
Capitalized unit-based compensation	867	(405)	3,680	747
Total other capital	2,365	1,505	9,947	7,005
Total capitalized expenditures before acquisitions	36,764	41,212	133,028	150,472
Property acquisitions (dispositions), net	(17,255)	(127)	(14,721)	8,082
Total capitalized expenditures	19,509	41,085	118,307	158,554

PRODUCTION

Fourth quarter 2009 production was 25,748 boe/d, compared to production of 23,984 boe/d in the same period of 2008. This seven percent growth was related to a strong Cardium program through year-end and the addition of Breaker production for the last 20 days in December. Full year average production of 24,016 boe/d is the highest in the Trust's history. Oil volumes were lower for full year 2009 at 9,868 boe/d compared to 2008 as the Cardium program did not start to add significant oil production until the latter half of the year as evidenced by the increase in oil production in the fourth quarter to 10,290 boe/d.

Average Daily Production Volumes

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Oil (bbl/d)	10,290	10,223	9,868	10,188
Natural gas (Mcf/d)	78,265	69,049	71,169	68,898
NGLs (bbl/d)	2,413	2,254	2,287	2,126
Oil equivalent (boe/d)	25,748	23,984	24,016	23,797

Oil equivalent volumes of 25,748 boe/d for the fourth quarter of 2009 and 24,016 boe/d for full year 2009 include 335 boe/d (2008 – 440 boe/d) and 392 boe/d (2008 – 368 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 25,413 boe/d for the fourth quarter of 2009 (2008 - 23,544 boe/d) and 23,624 boe/d (2008 - 23,429 boe/d) for full year 2009.

For the year ended December 31, 2009 oil and natural gas liquids totaled 51 percent of production with natural gas at 49 percent. The proportion of oil production to total production volumes was lower for full year 2009 than in 2008 mostly due to the stronger gas weighting in the acquisitions of Alberta Clipper and Breaker Energy.

Production Weighting

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Oil	40%	43%	41%	43%
Natural gas	51%	48%	49%	48%
NGLs	9%	9%	10%	9%

REVENUE

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs and prior to hedging, totaled \$111.5 million for the three months ended December 31, 2009, four percent higher than the fourth quarter of 2008. The increase is due to a seven percent increase in production offset by a three percent decrease in the average

realized price per boe, which was driven by a 34 percent decrease in the realized natural gas price, partially offset by a 26 percent increase in realized crude oil prices. The decrease in realized prices reflects lower AECO prices in the fourth quarter of 2009.

For the year ended December 31, 2009, revenue after transportation costs totaled \$361.1 million, a decrease of 41 percent from 2008. The decrease is attributable to a 42 percent decrease in the average realized price per boe, offset by a one percent increase 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 December 31		Years ended December 31	
	2009	2008	2009	2008
Revenue ⁽¹⁾ (\$000s)				
Oil	68,305	54,017	222,329	351,911
Gas	32,701	43,393	106,534	208,784
NGLs	10,530	9,009	31,729	50,815
Sulphur	(59)	622	495	3,529
Total revenue	111,477	107,041	361,087	615,039
\$/boe	47.06	48.51	41.19	70.62

(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 fourth quarter average realized Canadian crude oil price per barrel, net of transportation costs excluding hedging, was \$72.15, as compared to \$57.44 for the comparable quarter of 2008. The increase in realized price quarter-over-quarter of 26 percent, or \$14.71/bbl, was primarily driven by a 30 percent increase in WTI (U.S.\$/bbl) over the comparable period and stronger differentials, partially offset by a 13 percent increase in the value of the Canadian dollar.

For the fourth quarter of 2009, NAL's crude oil price differential was 90 percent, an increase of nine 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 increase in the differential in the fourth quarter of 2009 resulted from a tighter differential between WTI and Edmonton/Cromer posted prices, due to relatively strong demand for light crude in western Canada during the fourth quarter.

For the year ended December 31, 2009, NAL's average oil price was \$61.73 per barrel as compared to \$94.38 for the comparable period in 2008. The 35 percent decrease in realized price was driven by a 38 percent decrease in WTI (US\$/bbl) and a decrease in crude oil differentials to 88 percent from 89 percent in 2008, partially offset by a seven percent decrease in the value of the Canadian dollar.

Natural gas liquids averaged \$47.43/bbl in the fourth quarter of 2009, a nine percent increase from the \$43.45/bbl realized in 2008. For the year ended December 31, 2009, natural gas liquids averaged \$38.01/bbl, a decrease of 42 percent from the comparable period in 2008.

NATURAL GAS MARKETING

Approximately 74 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 26 percent tied to NYMEX or other indexed reference prices.

For the three months ended December 31, 2009, the Trust's natural gas sales averaged \$4.54/Mcf compared to \$6.83/Mcf in the comparable period of 2008, a decrease of 34 percent. The quarter-over-quarter decrease in gas prices was attributable to a 32 percent decrease in the benchmark AECO daily spot prices.

Prices for Lake Erie natural gas decreased to \$5.32/Mcf in the fourth quarter of 2009, compared to \$8.47/Mcf in the comparable period in 2008, a decrease of 37 percent. Lake Erie production of 3.2 MMcf/d accounted for four percent of the Trust's natural gas production in the fourth quarter of 2009, as compared to five percent in 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 year ended December 31, 2009, NAL averaged \$4.10/Mcf, a 50 percent decrease from the \$8.28/Mcf realized in the comparable period of 2008. The decrease in natural gas prices was attributable to a 51 percent decrease in the benchmark AECO daily spot prices.

**Average Pricing
(net of transportation charges)**

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Liquids				
WTI (US\$/bbl)	76.19	58.74	61.80	99.65
NAL average oil (Cdn\$/bbl)	72.15	57.44	61.73	94.38
NAL natural gas liquids (Cdn\$/bbl)	47.43	43.45	38.01	65.31
Natural Gas (Cdn\$/mcf)				
AECO – daily spot	4.54	6.69	3.97	8.15
AECO – monthly	4.23	6.79	4.14	8.13
NAL Western Canada natural gas	4.51	6.75	4.05	8.19
NAL Lake Erie natural gas	5.32	8.47	5.12	9.97
NAL average natural gas	4.54	6.83	4.10	8.28
NAL oil equivalent before hedging (Cdn\$/boe – 6:1)	47.06	48.51	41.19	70.62
Average foreign exchange rate (Cdn\$/US\$)	1.0561	1.2125	1.1414	1.0671

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 for management to hedge up to 60 percent of forecasted total production, net of royalties. This authorization 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 December 31, 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 floating rate debt for periods of up to five years. As at December 31, 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 December 31, 2009, NAL had several exchange rate swaps outstanding with a total notional value of U.S.\$94.0 million.

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

Realized gains on derivative contracts were \$10.9 million for the fourth quarter of 2009, compared to \$16.5 million in the comparable quarter of 2008. The decrease in gains is attributable to lower gains on crude oil contracts, mainly due to higher oil prices in 2009.

For full year 2009, realized gains were \$79.7 million compared to a realized loss of \$27.3 million in 2008. The increase in realized gains in 2009 is attributable to lower commodity prices during 2009.

All derivative contracts are recorded on the balance sheet at fair value based upon forward curves at December 31, 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 outstanding instruments, with reference to forward prices at December 31, 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 December 31, 2009 was a net liability of \$2.5 million, comprised of a \$12.9 million liability on oil contracts, partially offset by a \$4.0 million asset on gas contracts, a \$2.4 million asset on interest rate swaps, and a \$4.0 million asset on foreign exchange contracts.

Fourth quarter income for 2009 includes a \$14.8 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 \$12.3 million at September 30, 2009, to an unrealized loss of \$2.5 million at December 31, 2009. The \$14.8 million unrealized loss was comprised of a \$12.4 million unrealized loss on crude oil contracts, a \$0.9 million unrealized loss on natural gas contracts and a \$1.5 million unrealized loss on foreign exchange swaps.

For the year ended December 31, 2009, income includes an unrealized loss of \$68.3 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 loss of \$2.5 million at December 31, 2009. The unrealized loss was comprised of a \$68.6 million unrealized loss on crude oil contracts and a \$6.4 million unrealized loss on natural gas contracts, partially offset by a \$2.7 million unrealized gain on interest rate swaps and a \$4.0 million unrealized gain on foreign exchange swaps.

The risk management policies for 2010 are expected to remain consistent with those in 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 December 31		Years ended December 31	
	2009	2008	2009	2008
Unrealized gain (loss):				
Crude oil contracts	(12,439)	55,438	(68,590)	68,674
Natural gas contracts	(870)	1,456	(6,430)	6,590
Interest rate swaps	(41)	(274)	2,735	(274)
Exchange rate swaps	(1,462)	-	3,986	-
Unrealized gain (loss)	(14,812)	56,620	(68,299)	74,990
Realized gain (loss):				
Crude oil contracts	2,632	13,460	46,811	(24,691)
Natural gas contracts	5,588	3,071	25,382	(2,626)
Interest rate swaps	(223)	-	(656)	-
Exchange rate swaps	2,934	-	8,134	-
Realized gain (loss)	10,931	16,531	79,671	(27,317)
Gain (loss) on derivative contracts	(3,881)	73,151	11,372	47,673

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

Realized Gain (Loss) on Derivative Contracts

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Commodity contracts:				
Average crude volumes hedged (bbl/d)	4,800	5,100	4,472	4,810
Crude oil realized gain (loss) (\$000s)	2,632	13,460	46,811	(24,691)
Gain (loss) per bbl hedged (\$)	5.96	28.69	28.68	(14.03)
Average natural gas volumes hedged (GJ/d)	34,348	30,337	24,252	27,640
Natural gas realized gain (loss) (\$000s)	5,588	3,071	25,382	(2,626)
Gain (loss) per GJ hedged (\$)	1.77	1.10	2.87	(0.26)
Average BOE hedged (boe/d)	10,226	9,893	8,304	9,178
Total realized commodity contracts gain (loss) (\$000s)	8,220	16,531	72,193	(27,317)
Gain (loss) per boe hedged (\$)	8.74	18.16	23.82	(8.13)
Gain (loss) per boe (\$)	3.47	7.49	8.24	(3.14)
Interest rate swaps realized loss (\$000s)	(223)	-	(656)	-
Loss per boe (\$)	(0.09)	-	(0.07)	-
Exchange rate swaps realized gain (\$000s)	2,934	-	8,134	-
Gain per boe (\$)	1.24	-	0.92	-
Total realized gain (loss) (\$000s)	10,931	16,531	79,671	(27,317)
Gain (loss) per boe (\$)	4.62	7.49	9.09	(3.14)

Average hedged boes for the fourth quarter of 2009 were 10,226 as compared to 8,387 for the third 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	Jan 2010 – Dec 2011	\$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2010 – Jan 2013	\$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2010 – 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 foreign exchange rate risk management contracts outstanding:

EXCHANGE RATE	Remaining Term	Amount ⁽¹⁾ (US\$ MM)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1583	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1100	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1200	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1225	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1300	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1420	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1525	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1000	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.0500	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.0640	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.0650	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.0685	BofC Average Noon Rate
Swaps-floating to fixed	Feb 2010 – Dec 2010	\$5.5	1.0575	BofC Average Noon Rate
Swaps-floating to fixed	Feb 2010 – Dec 2010	\$5.5	1.0625	BofC Average Noon Rate
Swaps-floating to fixed	Feb 2010 – Dec 2010	\$5.5	1.0680	BofC Average Noon Rate
Swaps-floating to fixed	Feb 2010 – Dec 2010	\$5.5	1.0740	BofC Average Noon Rate

(1) Notional US\$ denominated commodity sales

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q1-10	Q2-10	Q3-10	Q4-10	Q1-11	Q2-11
<u>US\$ Collar Contracts</u>						
\$US WTI Collar Volume (bbl/d)	3,900	3,700	2,800	2,600	200	200
Bought Puts – Average Strike Price (\$US/bbl)	\$63.15	\$63.59	\$65.63	\$65.87	\$80.00	\$80.00
Sold Calls – Average Strike Price (\$US/bbl)	\$74.56	\$74.94	\$77.55	\$78.05	\$90.00	\$90.00
<u>US\$ Swap Contracts</u>						
\$US WTI Swap Volume (bbl/d)	2,166	2,800	2,900	3,000	-	-
Average WTI Swap Price (\$US/bbl)	\$79.99	\$79.45	\$83.47	\$83.38	-	-
<u>Cdn\$ Collar Contracts</u>						
\$Cdn WTI Collar Volume (bbl/d)	300	-	-	-	-	-
Bought Puts – Average Strike Price (\$Cdn/bbl)	\$66.00	-	-	-	-	-
Sold Calls – Average Strike Price (\$Cdn/bbl)	\$80.17	-	-	-	-	-
Total Oil Volume (bbl/d)	6,366	6,500	5,700	5,600	200	200
<u>NATURAL GAS</u>						
<u>Swap Contracts</u>						
AECO Swap Volume (GJ/d)	37,967	39,000	40,000	27,337	4,000	4,000
AECO Average Price (\$Cdn/GJ)	\$5.80	\$5.60	\$5.61	\$5.66	\$5.78	\$5.78
Total Natural Gas Volume (GJ/d)	37,967	39,000	40,000	27,337	4,000	4,000

For 2010, the Trust has outstanding contracts representing approximately 48 percent of its net liquids and natural gas production after royalties.

ROYALTY EXPENSES

Crown, freehold and overriding royalties were \$21.2 million for the three months ended December 31, 2009. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 19.0 percent for the quarter ended December 31, 2009, a decrease from the 19.8 percent experienced in the same period of the previous year.

Royalties decreased to \$8.95 per boe for the fourth quarter of 2009, a decrease of seven percent compared to the fourth quarter of 2008. The decrease is attributable to lower realized prices on a quarter-over-quarter basis.

For the year ended December 31, 2009, royalties were \$65.9 million, down from \$126.4 million in 2008, attributable to lower realized prices in 2009. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 18.2 percent as compared to 20.6 percent in 2008. The decrease in royalty rate reflects lower commodity prices and the new royalty framework that came into effect January 1, 2009.

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 increased from 35 percent to 50 percent, with rates capped at \$16.59/GJ. Crude oil royalty rates increased from 35 percent to 50 percent, with rates capped at \$120/bbl.

In response to lower commodity prices and a slowdown in activity, 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 near term 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 on 50 percent of the royalties owed. Secondly, there is a new well incentive program that provides for a maximum five per cent 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 initial 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 expenditures.

For the year ended December 31, 2009, 31 percent of crude oil and 69 percent of natural gas production is from Alberta.

Royalty Expenses

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Royalties (\$000s)	21,206	21,163	65,898	126,430
As % of revenue	19.0	19.8	18.2	20.6
\$/boe	8.95	9.59	7.52	14.52

OPERATING COSTS

Operating costs averaged \$10.21 per boe for the quarter ended December 31, 2009, a 13 percent decrease from \$11.67 per boe for the quarter ended December 31, 2008. Year-over-year operating cost decreases are a direct result of an aggressive program focused on cost reduction in NAL's operations coupled with lower power costs associated with lower natural gas prices. Costs in the quarter were also positively impacted by a one time cost reduction of \$0.60 per boe from prior period accruals where actual costs were lower than previously assumed.

On a full year basis, operating costs were \$11.09 per boe for 2009 compared to \$10.90 per boe in 2008. Costs were increasing aggressively in response to very high commodity prices in the middle of 2008 but have been in steady decline since the beginning of 2009 as seen in the fourth quarter comparisons year-over-year. The Trust expects this trend to continue in 2010.

Operating Costs

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Operating costs (\$000s)	24,184	25,749	97,240	94,928
As a % of revenue	21.7	24.1	26.9	15.4
\$/boe	10.21	11.67	11.09	10.90

OTHER INCOME

Other income was \$0.10 per boe for the fourth quarter of 2009 compared to \$0.51 per boe in the comparable quarter of 2008. Other income includes gas processing fees, 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 fourth quarter of 2009 of \$0.1 million, as compared to net interest income of \$0.7 million in the fourth quarter of 2008.

On a year-to-date basis interest income on notes totaled \$0.2 million compared to \$2.8 million for the comparable period of 2008, the decrease being attributable to the MFC note repayment in March 2009.

Other Income

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Interest on notes with MFC (\$000s)	(124)	726	168	2,836
Other (\$000s)	368	405	1,464	1,628
Total other income (\$000s)	244	1,131	1,632	4,464
As a % of revenue	0.2	1.1	0.5	0.7
Interest on notes with MFC (\$/boe)	(0.05)	0.33	0.02	0.33
Other (\$/boe)	0.15	0.18	0.17	0.19
Total other income (\$/boe)	0.10	0.51	0.19	0.52

OPERATING NETBACK

For the quarter ended December 31, 2009, NAL's operating netback, before hedging gains, was \$28.05 per boe, an increase of two percent from \$27.43 per boe for the quarter ended December 31, 2008. The increase was due to lower royalty expense and operating costs, partially offset by lower revenues as a result of lower natural gas prices and lower other income. Hedging gains, related to commodity and exchange rate derivative contracts, were \$4.71 per boe in the fourth quarter of 2009, as compared to \$7.49 per boe in 2008. The lower hedging gains are attributable to higher realized crude oil prices in the fourth quarter of 2009 as compared to the comparable quarter in 2008.

On a full year basis, NAL's operating netback, before hedging gains, was \$22.75 per boe compared to \$45.39 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 \$9.16 per boe for the year ended December 31, 2009, as compared to a loss of \$3.14 per boe in 2008, attributable mainly to lower realized commodity prices in 2009.

Operating Netback (\$/boe)

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Revenue	47.06	48.51	41.19	70.62
Royalties	(8.95)	(9.59)	(7.52)	(14.52)
Operating expenses	(10.21)	(11.67)	(11.09)	(10.90)
Other income ⁽¹⁾	0.15	0.18	0.17	0.19
Operating netback, before hedging	28.05	27.43	22.75	45.39
Hedging gains (losses) ⁽²⁾	4.71	7.49	9.16	(3.14)
Operating netback, after hedging	32.76	34.92	31.91	42.25

(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 December 31, 2009, G&A expenses were \$5.4 million, compared with \$4.0 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 fourth quarter of 2009, compared with \$1.1 million in the fourth quarter of 2008. G&A expense per boe was \$2.29 in the quarter, as compared to \$1.79 for the same period in 2008.

For the year ended December 31, 2009, G&A expenses were \$16.2 million as compared to \$15.6 million in 2008. The \$0.6 million increase in expensed G&A is attributable to increases in the short term incentive plan and consultancy costs. In addition, on a year-to-date basis \$5.6 million of G&A costs relating to exploitation and development activities were capitalized, compared with \$4.3 million in the comparable period of 2008. G&A expense per boe was \$1.84 in 2009 as compared to \$1.79 in 2008.

Total G&A increased year-over-year by nine percent to \$21.7 million in 2009 compared to \$19.9 million in 2008.

General and Administrative Expenses

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
G&A (\$000s):				
Expensed	5,418	3,954	16,171	15,607
Capitalized	1,315	1,146	5,575	4,313
Total G&A	6,733	5,100	21,746	19,920
Expensed G&A costs:				
\$/ (boe)	2.29	1.79	1.84	1.79
As % of revenue	4.9	3.7	4.5	2.5
Per trust unit (\$)	0.05	0.04	0.15	0.17

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 of the Manager 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 of the Manager 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 fourth quarter of 2009, the Trust recorded a \$2.8 million charge for unit-based incentive compensation that reflects the impact of vesting and an increase in the unit price. The unit price of the Trust increased by eight percent, from \$12.70 at September 30, 2009 to \$13.74 at December 31, 2010. An increase in unit price results in previously accrued amounts being increased.

Unit-based incentive compensation increased from a recovery of \$1.2 million in the fourth quarter of 2008 to a charge of \$2.8 million in 2009. This increase is a reflection of the increase in unit price used to determine the compensation during the fourth quarter of 2009, as compared to a decline in unit price during the fourth quarter of 2008 (from \$12.53 at September 30, 2008 to \$8.05 at December 31, 2008). A decrease in unit price results in previously accrued amounts being reversed.

On a year-to-date basis, the Trust has accrued \$12.5 million compared to \$2.7 million in the comparable period of 2008. The increase period-over-period is mainly attributable to a 71 percent increase in unit price during 2009 as compared to a 31 percent decrease in unit price during 2008.

At December 31, 2009, the unit price used to determine unit-based incentive compensation was \$13.74. The closing unit price of the Trust on the Toronto Stock Exchange on March 9, 2010 was \$13.31.

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 December 31, 2009, the Trust has recorded a total accumulated liability for unit-based incentive compensation in the amount of \$16.4 million, of which \$6.8 million was paid in January 2010. The remaining balance represents the Trust’s estimated liability for the unit based incentive plan as at December 31, 2009, with \$5.7 million recorded as a current liability as it is payable in December 2010, and \$3.9 million recorded as a long-term liability as it is payable in December 2011 and December 2012.

Unit-Based Compensation

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Unit-based compensation (\$000s):				
Expensed	1,916	(833)	8,781	1,983
Capitalized	867	(405)	3,680	747
Total unit-based compensation	2,783	(1,238)	12,461	2,730
Expensed unit-based compensation:				
As % of revenue	1.7	(0.8)	2.4	0.3
\$/boe	0.81	(0.37)	1.00	0.23
Per trust unit (\$)	0.02	(0.01)	0.08	0.02

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 \$3.9 million (2008 - \$2.8 million) for the reimbursement of G&A expenses during the fourth quarter and \$12.6 million (2008 - \$12.4 million) for 2009. 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 December 31, 2009 the Trust owed the Manager \$8.8 million for the reimbursement of G&A and unit-based incentive compensation and had a receivable from NAL Resources of \$1.7 million, \$2.1 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, offset by \$0.4 million due to NAL Resources relating to capital expenditures less net operating revenues.

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.

During 2009, the Partnership paid distributions to its partners, MFC's share being \$5.0 million (2008 - \$1.5 million).

As at December 31, 2009, there is a note payable of \$8.9 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 fourth quarter of 2009 (2008 - \$0.7 million net interest income), and net interest income of \$0.2 million (2008 - \$2.8 million) for 2009 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 fourth quarter of 2009 was \$2.7 million, a decrease of \$0.3 million from \$3.0 million for the comparable period in 2008. The decrease was due to lower average debt levels, partially offset by slightly higher average interest rates. Average outstanding bank debt for the fourth quarter of 2009 was \$240.1

million, \$36.4 million lower than the \$276.5 million outstanding during the fourth quarter of 2008. NAL's effective interest rate averaged 4.48 percent during the fourth quarter of 2009, compared to 4.16 percent during the comparable period in 2008. The increase in the interest rate from the fourth quarter of 2008 is attributable to higher stamping fees, slightly offset by lower borrowing fees. NAL's interest is calculated based upon a floating rate before any effects of interest rate swaps.

For the year ended December 31 2009, interest on bank debt decreased \$3.7 million to \$10.4 million, compared to \$14.1 million in 2008. The decrease was due to a lower effective interest rate and lower average debt levels. Average outstanding debt for the year ended December 31, 2009 decreased to \$269.6 million compared to \$295.0 million for the year ended December 31, 2008. In addition, the effective interest rate averaged 3.86 percent in 2009 compared to 4.71 percent in 2008.

Interest on convertible debentures includes interest charges of \$1.9 million for the three months ended December 31, 2009 (\$6.0 million for the year ended December 31, 2009) compared to \$1.3 million (\$5.9 million for the year ended December 31, 2008). The interest includes the interest on the 2007 debentures at 6.75% and the interest on the debentures issued in December 2009 at 6.25%. Accretion of the debt discount was \$0.6 million (2008 - \$0.4 million) for the three months ended December 31, 2009 and \$1.7 million (2008 - \$1.7 million) for the year ended December 31, 2009. For 2010, interest and accretion of the debt discount on debentures outstanding at December 31, 2009 will increase as the debentures issued in December 2009 will be outstanding for the full year.

Interest and Debt

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Interest on bank debt (\$000s) ⁽¹⁾	2,713	2,961	10,399	14,116
Interest and accretion on convertible debentures (\$000s)	2,500	1,679	7,676	7,631
Total interest (\$000)	5,213	4,640	18,075	21,747
Bank debt outstanding at period end (\$000s)	230,713	282,332	230,713	282,332
Convertible debentures at period end (\$000s) ⁽²⁾	177,977	74,004	177,977	74,004
\$/boe:				
Interest on bank debt	1.15	1.34	1.19	1.62
Interest on convertible debentures	0.81	0.59	0.68	0.68
Accretion on convertible debentures	0.24	0.17	0.19	0.20
Total interest	2.20	2.10	2.06	2.50

(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 December 31, 2009, NAL's cash flow netback was \$27.56 per boe, a 14 percent decrease from \$31.90 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, the swing from interest income to interest expense on the notes with MFC, lower interest charges and a realized loss on interest rate derivative contracts.

For the year ended December 31, 2009, NAL's cash flow netback was \$27.15 per boe, a 29 percent decrease from \$38.26 per boe in 2008. The decrease was due to a lower operating netback after hedging, lower interest income on the notes with MFC, higher G&A expenses, including unit-based incentive compensation and a realized loss on interest rate derivative contracts, partially offset by lower interest charges.

Cash Flow Netback (\$/boe)

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Operating netback, after hedging	32.76	34.92	31.91	42.25
G&A expenses, including unit-based incentive compensation	(3.10)	(1.42)	(2.84)	(2.02)
Interest on bank debt and convertible debentures ⁽¹⁾	(1.96)	(1.93)	(1.87)	(2.30)
Interest on notes with MFC ⁽²⁾	(0.05)	0.33	0.02	0.33
Realized loss on interest rate derivative contracts	(0.09)	-	(0.07)	-
Cash flow netback	27.56	31.90	27.15	38.26

(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 December 31, 2009, depletion on property, plant and equipment and accretion on the asset retirement obligations was \$22.34 per boe, 11 percent higher than the \$20.21 per boe for the same period in 2008.

For the year ended December 31, 2009, the DDA rate per boe was \$21.77 as compared to \$22.18 for 2008.

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 December 31		Years ended December 31	
	2009	2008	2009	2008
Depletion and depreciation (\$000s)	50,783	42,743	182,979	185,894
Accretion of asset retirement obligation (\$000s)	2,139	1,841	7,856	7,299
Total DDA (\$000s)	52,922	44,584	190,835	193,193
DDA rate per boe (\$)	22.34	20.21	21.77	22.18

TAXES

In the fourth quarter of 2009, NAL had a future income tax recovery of \$9.0 million compared to a \$25.5 million expense in the corresponding period of the prior year. For the year ended December 31, 2009, NAL had a future income tax recovery of \$34.8 million compared to a \$33.6 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 the remaining income, if any, that is not distributed to unitholders.

As at December 31, 2009, the Trust’s (including all subsidiaries) estimated tax pools (unaudited) available for deduction from future taxable income approximated \$1.3 billion, of which approximately 34 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)

	December 31, 2009	December 31, 2008
Canadian exploration expense	50	12
Canadian development expense	379	202
Canadian oil and gas property expense	436	301
Undepreciated capital costs	274	209
Other (including loss carry forwards)	128	14
Total estimated tax pools	1,267	738

Based on current strip prices at December 31, 2009, the Trust is not expected to be taxable in 2010.

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. The Trust has tax effected all temporary differences.

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 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 December 31		Years ended December 31	
	2009	2008	2009	2008
Net profits interest expense (income)	396	(453)	1,919	6,618
Share of net income attributable to MFC	252	1,716	1,040	3,823
	648	1,263	2,959	10,441

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 fourth quarter of 2009 was \$5.6 million compared to \$55.4 million for the comparable period in 2008. The decrease of \$49.8 million was mainly due to decreased gains on derivative contracts (\$77.0 million), increased G&A and unit-based compensation (\$4.2 million) and higher depletion and accretion (\$8.3 million), partially offset by a future income tax recovery (\$34.5 million) and increased revenues net of royalties (\$4.9 million).

Net income for the year ended December 31, 2009 of \$9.2 million was \$153.4 million less than the net income of the comparable period of 2008. The decrease in 2009 is attributable to decreased revenues net of royalties (\$192.6 million), increased operating costs (\$2.3 million), increased unit-based compensation (\$6.8 million), and decreased gains on derivative contracts (\$36.3 million), partly offset by decreased future income taxes (\$68.4 million), decreased depletion and accretion expense (\$2.4 million), decreased interest expense (\$3.7 million), decreased non-controlling interest (\$7.5 million) and a bad debt recovery in 2009 compared to a bad debt expense in 2008 (\$7.2 million).

Net Income (\$000s)

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Net Income	5,634	55,374	9,200	162,580

CAPITAL RESOURCES AND LIQUIDITY

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

As at December 31, 2009, NAL had 137,471,209 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, 24,777,098 units issued on the acquisition of Breaker, 9,602,500 issued under an equity offering and 1,234,380 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 trust 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 December 31, 2009, the Trust had net debt of \$477.5 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 \$194.7 million. Excluding the convertible debentures, net debt was \$282.7 million, compared with \$319.9 million at December 31, 2008. The decrease in net debt, excluding convertible debentures, of \$37.2 million during 2009 is attributable to decreased bank debt of \$51.6 million, offset by a negative change in working capital of \$14.4 million.

Bank debt outstanding was \$230.7 million at December 31, 2009 compared with \$282.3 million as at December 31, 2008. Of the \$230.7 million outstanding at December 31, 2009, all is outstanding under the production facility.

At the end of the fourth quarter, the Trust had a net debt (excluding convertible debentures) to 12 months trailing cash flow ratio of 1.23 times and a total net debt (including convertible debentures) to 12 months trailing cash flow ratio of 2.07 times.

Effective January 29, 2010, the Trust increased its credit facility by \$100 million to \$550 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 \$535 million production facility and a \$15 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.

On December 3, 2009, the Trust issued \$115 million principal amount of 6.25% convertible unsecured subordinated debentures. Interest on the debentures is paid semi-annually in arrears, on June 30 and December 31, and the debentures are convertible at the option of the holder, at anytime, into fully paid trust units at a conversion price of \$16.50 per trust unit. The debentures mature on December 31, 2014 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 January 1, 2013 and on or before December 31, 2013, and at a price of \$1,025 per debenture on or after January 1, 2014 and on or before December 31, 2014. 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 7.0 million trust units would be required to be issued.

In addition, 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. 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 \$0.6 million (2008 - \$0.4 million) of accretion of the debt discount in the fourth quarter of 2009 and \$1.7 million (2008 - \$1.7 million) during 2009.

As at March 9, 2010, the Trust has 137,725,526 trust units and \$194.7 million in convertible debentures outstanding.

Capitalization

	2009	2008
Trust unit equity (\$000s)	894,192	557,263
Bank debt (\$000s)	230,713	282,332
Working capital deficit (surplus) ⁽¹⁾ (\$000s)	52,014	37,602
Net debt excluding convertible debentures (\$000s)	282,727	319,934
Convertible debentures (\$000s) ⁽²⁾	194,744	79,744
Net debt (\$000s)	477,471	399,678
Net debt excluding convertible debentures to trailing 12-month cash flow ⁽³⁾	1.23	1.03
Total net debt to trailing 12-month cash flow ⁽³⁾	2.07	1.28
Trust units outstanding (000s)	137,471	96,181

(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.

For 2009, given the economic environment, the Trust set an objective of not exceeding a payout ratio of 110 percent (distributions and capital expenditures), an objective that was achieved for 2009. The objective was achieved by actively managing the Trust's funds from operations, distribution levels and 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. For 2010, the Trust is targeting a payout ratio of between 110 and 115 percent. Currently, the Trust has a bank line of \$550 million of which \$231 million is drawn at December 31, 2009, leaving available capacity of \$319 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. The 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.

The Trust benefited from an active hedging program in 2009 at prices above market levels. For 2010, the Trust expects to continue to benefit from an active hedging program. Currently, the Trust has in place oil hedges for approximately 53 percent of net forecasted (after royalty) production for 2010. Crude volumes are hedged at an average price of US\$81.72 per boe on fixed price contracts. On collared contracts, crude volumes are hedged at an average ceiling price of US\$76.18 per boe and at an average floor price of US\$64.45 per boe. For natural gas, 2010 hedges total approximately 45 percent of net budgeted production volumes hedged at an average floor in excess of \$5.67 per GJ (or \$5.98 per Mcf).

NAL's capital program is designed to be scalable and flexible in response to commodity prices and market conditions. For 2010, the Trust plans for a \$175 million capital program and expects to drill approximately 137 (67 net) wells. The Trust, through the Manager, operates approximately 85 percent of the assets to which the capital program is directed, allowing for significant flexibility over the scale and timing of the program.

In the 2010 guidance, released on January 20, 2010, the Trust used pricing assumptions of US\$77 per barrel WTI crude oil price, a 1.05 Cdn/US\$ exchange rate and \$5.00 per GJ natural gas.

Fluctuations in commodity prices, other market factors or growth opportunities may make it necessary to adjust forecasted capital expenditures and/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. As at January 1, 2010, the Trust has approximately \$535 million of safe harbour available.

ASSET RETIREMENT OBLIGATION

At December 31, 2009, the Trust reported an asset retirement obligation (“ARO”) balance of \$127.9 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 \$33.4 million in relation to the acquisitions of Breaker, Clipper and Spearpoint, \$2.1 million due to liabilities incurred and revisions to estimates and \$7.9 million from accretion expense, and was reduced by \$1.1 million for property dispositions and \$5.2 million for actual abandonment and environmental expenditures incurred in 2009.

DISTRIBUTIONS TO UNITHOLDERS

For the three months and full year ended December 31, 2009, the Trust distributed 61 percent and 51 percent of its cash flow from operating activities, respectively, as compared to 60 percent and 57 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 2010 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 to 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 bank credit facility. Given uncertain economic conditions, the Trust is targeting that the total of distributions and capital expenditures on an annual basis not exceed 110 – 115 percent of cash flow, 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 decrease in 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 December 31		Years ended December 31	
	2009	2008	2009	2008
Cash flow from operating activities	\$53,060	77,326	\$236,295	320,042
Net income	5,634	55,374	9,200	162,580
Actual cash distributions paid or payable	32,625	46,167	120,153	181,462
Excess of cash flow from operating activities over cash distribution paid	20,435	31,159	116,142	138,580
Percentage of cash flow from operations distributed	61%	60%	51%	57%
Excess (shortfall) of net income over cash distributions paid	(26,991)	9,207	(110,953)	(18,882)

As stated in the non-GAAP measures section of this 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 December 31, 2009, funds from operations amounted to \$63.0 million, compared with \$67.0 million for the three months ended December 31, 2008. The six percent decrease is primarily due to lower realized gains on derivative contracts and increased G&A and unit based compensation costs. On a per trust unit basis, funds from operations decreased 24 percent from \$0.70 in 2008 to \$0.53 in 2009.

For the year ended December 31, 2009, funds from operations decreased 26 percent to \$230.7 from \$311.1 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 \$79.7 million.

Funds from Operations

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Funds from operations (\$000s)	62,953	67,040	230,741	311,071
Funds from operations per trust unit	0.53	0.70	2.15	3.29
Payout ratio based on funds from operations	52%	69%	52%	58%

VARIABLE INTEREST ENTITIES

NAL has no variable interest entities.

CONTRACTUAL OBLIGATIONS

Joint Venture Agreement:

Effective April 20, 2009, the Trust and MFC entered into a joint venture 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 the Trust) 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 December 31, 2009, the Trust had spent \$3.1 million under this agreement.

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 December 31, 2009, the Trust has spent \$1.7 million under this agreement.

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)	2010	2011	2012	2013	2014
Office lease ⁽¹⁾	4,155	3,505	3,505	3,482	3,414
Office lease – Clipper and Breaker ⁽²⁾	2,177	2,184	2,192	358	-
Transportation agreements	2,805	-	-	-	-
Processing agreements ⁽³⁾	1,859	2,242	401	384	-
Convertible debentures ⁽⁴⁾	-	-	79,744	-	115,000
Bank debt	-	138,428	92,285	-	-
Total	10,996	146,359	178,127	4,224	118,414

(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 and Breaker. MFC will reimburse the Trust for 50 percent of the Clipper obligation under the base price adjustment clause (see "Acquisition of Alberta Clipper Energy Inc.")

(3) Represents gas processing agreements with take or pay components.

(4) Principal amount.

QUARTERLY INFORMATION

(\$000s, except per unit and production amounts)	2009				2008			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue, net of royalties ⁽¹⁾	88,165	85,988	60,922	77,791	161,156	234,993	58,861	89,611
Per unit	0.75	0.77	0.60	0.81	1.68	2.46	0.63	0.98
Funds from operations ⁽²⁾	62,953	53,766	51,998	62,024	67,040	79,233	88,578	76,220
Per unit	0.53	0.48	0.51	0.64	0.70	0.83	0.94	0.83
Net income (loss)	5,634	8,249	(9,407)	4,724	55,374	111,045	(17,572)	13,733
Per unit								
basic	0.05	0.07	(0.09)	0.05	0.58	1.16	(0.19)	0.15
diluted	0.05	0.07	(0.09)	0.05	0.56	1.11	(0.19)	0.15
Average oil equivalent production (boe/d – 6:1)	25,748 ⁽³⁾	23,418	23,049	23,836	23,984	23,808	23,791	23,601

(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

(3) Includes Breaker volumes effective December 11, 2009.

SELECTED ANNUAL INFORMATION

(\$000s except per unit amounts)	Years ended December 31		
	2009	2008	2007
Oil, natural gas and liquid sales	365,760	618,914	416,813
Net income	9,200	162,580	56,457
Net income per trust unit	0.09	1.72	0.68
Net income per trust unit – diluted	0.09	1.69	0.68
Distributions paid and declared	120,153	181,462	158,601
Distributions paid or declared per trust unit	1.12	1.92	1.92
Total assets	1,609,450	1,210,597	1,063,160
Total liabilities	715,258	653,334	558,443
Long term debt ⁽¹⁾	408,690	356,336	366,506
Unitholders' equity	894,192	557,263	504,717
Number of trust units outstanding at year-end	137,471	96,181	90,494

(1) Includes bank debt and convertible debentures.

DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining disclosure controls and procedures (“DC&P”), as such term is defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings* (“NI 52-109”), for NAL. They have, as at the financial year ended December 31, 2009, designed such DC&P, or caused them to be designed under their supervision, to provide reasonable assurance that information required to be disclosed by NAL in its annual filings, interim filings or other reports filed or submitted by NAL under applicable securities legislation is recorded, processed, summarized and reported within the time periods specified in applicable securities legislation and that all material information relating to NAL is made known to them by others, particularly during the period in which NAL's annual and interim filings are being prepared.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, NAL conducted an evaluation of the effectiveness of its DC&P as at December 31, 2009. Based on this evaluation, the officers concluded that as of December 31, 2009, NAL's DC&P provide reasonable assurance that information required to be disclosed by NAL in its annual filings, interim filings or other reports that it files or submits under applicable securities legislation is recorded, processed, summarized and reported within the time periods specified in such legislation and that these controls and procedures also provide reasonable assurance that material information relating to NAL is made known to our Chief Executive Officer and Chief Financial Officer by others.

INTERNAL CONTROL OVER FINANCIAL REPORTING

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining internal control over financial reporting (“ICFR”), as such term is defined in NI 52-109, for NAL. They have, as at the financial year ended December 31, 2009, 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* (COSO Framework) published by The Committee of Sponsoring Organizations of the Treadway Commission (COSO).

NAL's ICFR includes policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions, acquisitions and dispositions of assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer (collectively, the “Officers”), NAL conducted an evaluation of the effectiveness of its ICFR as at December 31, 2009 based on the COSO Framework. Based on this evaluation, the Officers concluded that as of December 31, 2009, NAL's ICFR does provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

It should be noted that while the Officers believe that NAL's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the disclosure controls and procedures or internal controls over financial reporting 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 changes in the Trust's ICFR during the year ended December 31, 2009 that materially affected the Trust's ICFR.

CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by NAL are disclosed in the notes to NAL's December 31, 2009 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 also realize different results from the application of new accounting standards published, from time to time, by various regulatory bodies.

Proved Oil and Gas Reserves

Under National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (“NI 51-101”), “proved” reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (it is possible that the actual remaining quantities recovered will exceed the estimated proved reserves). The level of certainty should result in at least a 90 percent probability at a company aggregate level that the quantities actually recovered will equal or exceed the estimated reserves. In the case of “probable” reserves, which are less certain to be recovered than proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable (“P+P”) reserves. As for certainty, in order to report reserves as P+P, the reporting company must believe that there is at least a 50 percent probability at a company aggregate level that the quantities actually recovered will equal or exceed the sum of the estimated P+P reserves.

The oil and gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in NAL’s plans. The effect of changes in proved oil and gas reserves on the financial results and position of NAL is described under the heading “Impairment of Property, Plant and Equipment” below.

Depletion Expense

NAL uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether or not the activities funded were successful. The aggregate of net capitalized costs and estimated future development costs is amortized using the unit of production method on estimated proved oil and gas reserves.

An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

Unproved Properties

The cost of acquisition and evaluation of unproved properties are initially excluded from the depletion calculation. These properties are assessed to ascertain whether impairment in value has occurred. When proved reserves are assigned or a property is considered to be impaired, the cost of the property or the amount of the impairment will be added to the capitalized costs for the calculation of depletion.

Impairment of Property, Plant & Equipment

NAL is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived oil and gas asset is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the property, plant and equipment is charged to net income.

The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves (see “Proved Oil and Gas Reserves” above), future commodity prices and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices, or an increase in operating costs could result in an impairment of an asset’s carrying value.

Goodwill

Goodwill is subject to impairment tests annually, or as economic events dictate, by comparing the fair value of the reporting entity to its carrying value, including goodwill. If the fair value of the reporting entity is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the implied value of the goodwill. The determination of fair value requires management to make assumptions and estimates about recoverable reserves (see the “Proved Oil and Gas Reserves” discussion above), future commodity prices, operating costs, production profiles and discount rates. Adverse changes in any of these assumptions could result in an impairment of all or a portion of the goodwill carrying value in future periods.

Fair Value of Derivative Instruments

NAL utilizes financial derivatives to manage market risk. The purpose of hedging activity is to provide an element of stability to NAL’s cash flow in a volatile market environment. NAL recognizes the fair value of derivative

contracts on its balance sheet with the change in fair value recognized in net income of the period. The fair value of commodity derivative contracts is based on forward commodity prices. The fair value of interest rate derivative contracts is based on forward interest rates. The fair value of foreign exchange derivative contracts is based on forward exchange rates. Any change in commodity prices, interest rates and foreign exchange rates will impact the fair value of the contracts and therefore net income of the period.

Asset Retirement Obligation

NAL is required to recognize and measure liabilities associated with capital assets. A liability is recognized equal to the discounted fair value of the obligation in the period in which the asset is recorded with an equal offset to the carrying amount of the asset. The liability then accretes to its fair value with the passage of time. Management is required to estimate the timing and future costs to settle liabilities. Changes in the estimated future costs, the timing of these costs, and the discount rate will impact the liability, related asset and expense.

Acquisitions

Acquisitions have been accounted for by the purchase method using fair values. The determination of fair value involves numerous estimates. The valuation of petroleum and natural gas assets is based on NAL's estimate of P+P reserves using estimated forecasted prices at the time of the transaction, plus an estimate of unproved properties. Management also estimates the fair value of other assets and liabilities in these transactions and the balances for tax pools. This valuation could differ materially by altering the various assumptions which would have impacted the composition of the balance sheet.

Legal, Environmental Remediation and Other Contingent Matters

NAL is required to determine whether a loss is probable based on judgment, the interpretation of laws and regulations and whether the loss can reasonably be estimated. When the loss is determined, it is charged to net income. NAL's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

Income Tax Accounting

The determination of NAL's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessments after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Future income taxes are recognized for temporary differences arising in the Trust's subsidiaries and also those arising in the Trust that reverse after 2011. Should the assumptions underlying the estimate of the reversal of temporary differences change, including future commodity prices, payout ratio, capital expenditures and reserves, future taxes recorded may be adjusted for the Trust.

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”)

In February 2008, the Accounting Standards Board confirmed that the transition date to IFRS from Canadian GAAP will be January 1, 2011 for publicly accountable enterprises. Therefore, the Trust will be required to report its results in accordance with IFRS starting in 2011, with comparative disclosure for 2010.

The Trust has an IFRS conversion plan and has established timelines for the completion and execution of the conversion project. The conversion plan includes the following phases:

1. An IFRS diagnostic phase which involves a high level assessment of the differences between Canadian GAAP and IFRS, identifying major impact areas.
2. An in-depth review of GAAP differences and determination of transition policy choices as well as ongoing IFRS accounting policies.
3. The implementation phase where solutions are developed and assessed. This involves an evaluation of information systems, business processes, procedures, internal controls and training to support the new accounting requirements.
4. A post implementation phase which involves the parallel running of 2010 financial results, the preparation of IFRS financial statements and disclosures and a review of processes and controls to make any required changes.

The IFRS diagnostic phase is complete. Phase two progress to date has included an in-depth review of the significant areas of difference in order to identify all specific Canadian GAAP and IFRS differences and to make recommendations to the Board of Directors on IFRS accounting policies.

The Trust considers the significant IFRS differences and majority of the implementation work to be in relation to property, plant equipment (“PP&E”). To date, IFRS policies for PP&E have been developed, subject to Board approval. At this stage, it is premature to provide meaningful numerical analysis on the impact of the anticipated changes. Despite this, implementation steps are being mapped out in anticipation of this approval.

The Trust has also identified a number of other areas where potentially significant differences between Canadian GAAP and IFRS exist for the Trust. Provisions, including asset retirement obligations (“ARO”) and onerous contracts, as well as unit based compensation have been reviewed, accounting policies recommended and implementation steps are being developed. All other IFRS standards, including financial instruments, interests in joint ventures and income taxes, are under review with recommendations and implementation steps to follow.

In July 2009, the International Accounting Standards Board (“IASB”) issued certain amendments and exemptions to IFRS 1 in order to make it more practical for Canadian entities adopting IFRS for the first time. The amendment allows the Trust to elect to measure its oil and gas assets at the date of transition to IFRS using the net book value based on the entity’s previous GAAP at December 31, 2009, allowing for IFRS to be adopted prospectively to its full cost pool, rather than performing retrospective assessment of the oil and gas assets and related expenditures. The Trust intends to use this election on adoption of IFRS.

The most significant change identified will be to PP&E. The Trust, like many other Canadian oil and gas reporting issuers, applies the “full cost” accounting methodology to its oil and gas assets. Under full cost, capital expenditures are maintained in a single cost centre for each country, and the cost centre is subject to a single depletion calculation and impairment test. IFRS will require a much more detailed assessment of oil and gas assets as follows:

- Capital expenditures have to be segregated between exploration and evaluation (“E&E”) and development and production (“D&P”) assets. In addition, assets have to be aggregated at a component level. On transition, this requires establishing the book value of the undeveloped land and unproved properties and then allocating the remaining carrying value to the D&P assets, based on reserve allocations for each component.
- For depletion and depreciation purposes, the Trust must determine an appropriate depletion or depreciation method, and must deplete by component. There is the choice whether to deplete E&E assets or not. In addition, there is the option to deplete using a reserve base of proved reserves or both proved plus probable reserves. NAL has not yet selected the depletion methodology it will use.
- Impairment tests are to be calculated at a cash generating unit level (“CGU”), which is defined as the lowest level of assets that produce independent cash inflows. The Trust must identify its CGU’s for this purpose. An impairment test must be performed individually for all CGU’s when indicators suggest there

may be impairment. There will be more CGU's than the single Canadian full cost pool. The recognition of impairment in a prior year must be reversed should impairment conditions reverse.

Provisions and contingent liabilities and assets, including ARO are identified and calculated somewhat differently under IFRS. ARO calculations are expected to be impacted due to differences in the discount rates to be used to present value the liability. In addition, under IFRS, ARO is required to be revalued each reporting period at the then prevailing interest rate. This may increase or decrease the ARO recorded on the balance sheet depending on the direction of change in interest rates. In addition, onerous contracts will require identification and, to the extent they exist, must be recorded as a liability on the balance sheet.

IFRS would allow the Trust to use IFRS rules for business combinations on a prospective basis rather than restating all business combinations. The IFRS business combination rules converge with the new CICA Handbook Section 1582 that is also effective for NAL on January 1, 2011, however, early adoption is permitted. The Trust intends to elect this exemption on transition to IFRS.

Regular reporting on the status of IFRS is provided to the Board of Directors through the Audit Committee. The expectation is to finalize all policy recommendations for IFRS reporting and to submit these policies to the Board for approval during the second quarter of 2010.

In addition, the Trust has actively engaged its auditors in the conversion project and will continue to engage in ongoing discussions as the project progresses.

The development of the Trust's opening balance sheet in accordance with IFRS, as at January 1, 2010, is in progress. In addition, the Trust expects to commence parallel internal reporting of 2010 results during the second quarter of 2010.

Financial systems have been modified to accommodate the reporting of both Canadian GAAP financial results and IFRS financial results in 2010. In addition, modifications have been made to ensure data is captured with the added level of granularity required under IFRS. As accounting policies are finalized further modifications to the financial systems may be required. Other IT systems that capture data used in the financial system are under review as to whether any modifications are required.

Internal staff have been assigned to lead the transition project, supplemented with consultants as required. Training of key internal finance and accounting personnel has begun both through external IFRS oil and gas training and internal training. As accounting policies are finalized, training will be expanded to other key personnel within the organization.

As accounting policies are established under IFRS, NAL will be assessing the impact on its various business activities, including banking arrangements, compensation arrangements and risk management agreements, during 2010.

Internal business processes and controls are being assessed and developed to enable the collection of information so that data can be attained in the manner necessary to report under IFRS both on an ongoing basis and on transition. For example, processes are currently being developed to enable the monitoring of E&E assets and when the transfer to D&P will occur. As processes are developed or amended, internal controls are being assessed to determine any required changes. This will be an ongoing process throughout 2010 to ensure all changes in accounting policies include appropriate controls and procedures.

In addition, NAL will also ensure that adequate information regarding the transition is provided to all stakeholders on a timely basis. It is anticipated that IFRS information will be provided at investor conferences during the second half of 2010.

The International Accounting Standards Board is currently undertaking an extractive activities project to develop accounting standards specifically related to the oil and gas industry. However, it is not expected that the project will be completed prior to IFRS adoption in Canada.

The transition from Canadian GAAP to IFRS is a significant undertaking that may materially affect our reported financial position and results of operations. As we have not finalized our accounting policies, we are unable to

quantify the impact of adopting IFRS on our financial statements. Notwithstanding this, the Trust is confident that it will meet the requirements for transition by the changeover deadline.

Dated: March 10, 2010

CONSOLIDATED BALANCE SHEETS

(thousands of dollars) (unaudited)

	As at December 31, 2009	As at December 31, 2008
Assets		
Current assets		
Cash	\$1,604	\$5,584
Accounts receivable	61,631	40,321
Prepays and other receivables	15,663	17,504
Note receivable (Notes 4 and 5)	-	49,599
Derivative contracts (Note 15)	6,285	65,680
Future income tax asset (Note 14)	3,132	-
	88,315	178,688
Derivative contracts (Note 15)	2,461	-
Goodwill	14,722	14,722
Property, plant and equipment (Notes 4 and 6)	1,503,952	1,017,187
	\$1,609,450	\$1,210,597
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$110,897	\$84,732
Note payable (Note 4 and 5)	8,907	9,609
Distributions payable to unitholders	12,372	15,389
Derivative contracts (Note 15)	11,231	-
Future income tax liability (Note 14)	-	16,788
	143,407	126,518
Bank debt (Note 7)	230,713	282,332
Convertible debentures (Note 8)	177,977	74,004
Derivative contracts (Note 15)	-	274
Other liabilities (Note 9)	7,643	890
Asset retirement obligations (Note 11)	127,872	90,844
Future income tax liability (Note 14)	24,778	22,092
Non-controlling interest (Note 12)	2,868	56,380
	715,258	653,334
Unitholders' equity		
Unitholders' capital (Note 13)	1,482,029	1,042,183
Equity component of convertible debentures (Note 8)	12,628	4,592
Deficit (Note 13)	(600,465)	(489,512)
	894,192	557,263
	\$1,609,450	\$1,210,597
Commitments (Note 16)		
Subsequent event (Note 17)		
Trust units outstanding (000s)	137,471	96,181

See accompanying notes.

CONSOLIDATED STATEMENTS OF INCOME, COMPREHENSIVE INCOME AND DEFICIT

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

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Revenue				
Oil, natural gas and liquid sales	\$113,008	\$108,037	\$365,760	\$618,914
Crown royalties	(13,767)	(16,438)	(44,684)	(94,535)
Freehold and other royalties	(7,439)	(4,725)	(21,214)	(31,895)
	91,802	86,874	299,862	492,484
Gain (loss) on derivative contracts (Note 15):				
Realized gain (loss)	10,931	16,531	79,671	(27,317)
Unrealized gain (loss)	(14,812)	56,620	(68,299)	74,990
	(3,881)	73,151	11,372	47,673
Other income	244	1,131	1,632	4,464
	88,165	161,156	312,866	544,621
Expenses				
Operating	24,184	25,749	97,240	94,928
Transportation	1,531	996	4,673	3,875
General and administrative	5,418	3,954	16,171	15,607
Unit-based incentive compensation (Note 10)	1,916	(833)	8,781	1,983
Interest on bank debt	2,713	2,961	10,399	14,116
Interest and accretion on convertible debentures	2,500	1,679	7,676	7,631
Bad debt expense (recovery) (Note 15)	(296)	-	(296)	6,901
Depletion, depreciation and amortization	50,783	42,743	182,979	185,894
Accretion on asset retirement obligations	2,139	1,841	7,856	7,299
	90,888	79,090	335,479	338,234
Income (loss) before taxes and non-controlling interest	(2,723)	82,066	(22,613)	206,387
Income tax recovery	1	53	2	256
Future income tax reduction (expense)	9,004	(25,482)	34,770	(33,622)
Total income tax reduction (expense) (Note 14)	9,005	(25,429)	34,772	(33,366)
Income before non-controlling interest	6,282	56,637	12,159	173,021
Non-controlling interest (Note 12)	(648)	(1,263)	(2,959)	(10,441)
Net income and comprehensive income	5,634	55,374	9,200	162,580
Deficit, beginning of period	(573,474)	(498,719)	(489,512)	(470,630)
Net income	5,634	55,374	9,200	162,580
Distributions declared (Note 13)	(32,625)	(46,167)	(120,153)	(181,462)
Deficit, end of period	\$(600,465)	\$(489,512)	\$(600,465)	\$(489,512)
Net income per trust unit (Note 13)				
Basic	\$0.05	\$0.58	\$0.09	\$1.72
Diluted	\$0.05	\$0.56	\$0.09	\$1.69
Weighted average trust units outstanding (000s)	118,174	96,145	107,157	94,415

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of dollars) (unaudited)

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Operating Activities				
Net income	\$5,634	\$55,374	\$9,200	\$162,580
Items not involving cash:				
Depletion, depreciation and amortization	50,783	42,743	182,979	185,894
Accretion on asset retirement obligations	2,139	1,841	7,856	7,299
Unrealized loss (gain) on derivative contracts	14,812	(56,620)	68,299	(74,990)
Future income tax (reduction) expense	(9,004)	25,482	(34,770)	33,622
Non-cash accretion expense on convertible debentures	582	376	1,722	1,696
Non-controlling interest	252	1,716	1,040	3,823
Lease amortization	(149)	-	(366)	-
Abandonment and reclamation	(2,096)	(3,872)	(5,219)	(8,853)
Change in non-cash working capital	(9,893)	10,286	5,554	8,971
	53,060	77,326	236,295	320,042
Financing Activities				
Distributions paid to unitholders	(26,078)	(43,609)	(111,256)	(157,159)
Increase (decrease) in bank debt	(110,660)	11,350	(224,952)	6,702
Issue of trust units, net of issue costs	(16)	(15)	81,577	(29)
Note repayment from MFC (Note 5)	-	-	49,599	-
Partnership distribution paid to MFC	(1,250)	-	(54,552)	(1,500)
Issuance of convertible debentures	110,287	-	110,287	-
Change in non-cash working capital	(85)	-	(5,700)	(426)
	(27,802)	(32,274)	(154,997)	(152,412)
Investing Activities				
Additions to property, plant and equipment	(36,764)	(41,212)	(133,028)	(150,472)
Property acquisitions	-	(8)	(2,800)	(8,122)
Proceeds from dispositions	17,255	135	17,521	40
Acquisition of Breaker (Note 4)	(1,500)	-	(1,500)	-
Acquisition of Clipper (Note 4)	(68)	-	(901)	-
Disposition of Clipper (Note 4)	1,130	-	54,432	-
Acquisition of Spearpoint (Note 4)	-	-	(9,749)	-
Disposition of Spearpoint (Note 4)	(8)	-	6,764	-
Acquisition of Tiberius and Spear (Note 4)	-	(315)	-	(77,684)
Disposition of Tiberius and Spear (Note 4)	-	-	-	58,221
Acquisition of Seneca	-	-	-	337
Change in non-cash working capital	(8,703)	(577)	(16,017)	14,240
	(28,658)	(41,977)	(85,278)	(163,440)
Increase (decrease) in cash	(3,400)	3,075	(3,980)	4,190
Cash, beginning of period	5,004	2,509	5,584	1,394
Cash, end of period	\$1,604	\$5,584	\$1,604	\$5,584
Supplementary disclosure of cash flow information:				
Cash paid (received) during the period for:				
Interest	\$1,892	\$1,959	\$16,053	\$17,130
Tax	\$(238)	\$(586)	\$(516)	\$4,219

Refer to Notes 4, 11 and 13 for significant non-cash amounts not included in the cash flow statement.

See accompanying notes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2009 and 2008

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

(unaudited)

1) STRUCTURE OF THE TRUST

The Trust is an open-ended investment trust formed under the laws of the Province of Alberta. Operations commenced on May 9, 1996. The principal undertakings of the Trust are to indirectly acquire and hold, through its direct and indirect subsidiary entities, interests in oil and natural gas properties and to distribute the net cash generated by such properties to its unitholders.

The Trust is managed by NAL Resources Management Limited (the "Manager"). The Manager is a wholly-owned subsidiary of Manulife Financial Corporation ("MFC") and manages, on their behalf, 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 and, in addition, MFC and the Trust jointly own a limited partnership that holds working interests in certain oil and gas properties. NAL Resources operates these properties on behalf of the Trust and MFC. As a result, a significant portion of the net operating revenues and capital expenditures represent joint operations amounts from NAL Resources. These transactions are in the normal course of joint operations and are based on the original exchange amounts established through transactions with third parties.

2) SUMMARY OF ACCOUNTING POLICIES

Basis of Presentation

The Trust's consolidated financial statements are stated in Canadian dollars and have been prepared by management in accordance with Generally Accepted Accounting Principles ("GAAP") in Canada and they include the accounts of the Trust and its subsidiary entities. All inter-entity transactions and balances have been eliminated. Effective January 1, 2011, the Trust will be required to prepare consolidated financial statements in accordance with International Financial Reporting Standards ("IFRS").

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimated. In particular, the amounts recorded for depletion and depreciation of property, plant and equipment and for the accretion of asset retirement obligations are based on estimates of reserves and future costs. The amounts recorded for unit-based compensation are based on quotes for the price of trust units and performance factors. The fair value estimates for commodity derivatives are based on expected future oil and natural gas prices and expected volatility in these prices while the fair value of interest rate derivatives are based on expected future interest rates and the fair value of foreign exchange rate derivatives are based on expected future exchange rates. The amount recorded for goodwill is based on estimates of the fair value of identifiable assets and liabilities at the date of acquisition, and is subject to impairment testing which is based on estimates of reserves, future commodity prices, future costs, production profiles, discount rates and other relevant assumptions. The ceiling test calculation is based on estimates of reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. Future income taxes are based on estimates as to the timing of the reversal of temporary differences, and tax rates currently substantively enacted. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods.

Property, Plant and Equipment

The Trust follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of acquiring petroleum and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Such costs include land acquisition, geological and geophysical expenditures, costs of drilling both productive and non-productive wells, related plant and production equipment costs and related overhead charges.

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such sale would alter the depletion rate by 20 percent or more.

Depletion of petroleum and natural gas properties and depreciation of equipment is calculated using the unit of production method based on total proved reserves before royalties, as determined by independent petroleum engineers. Natural gas reserves are converted to barrels of oil equivalent based on relative energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing proved reserves and excludes the unimpaired cost of undeveloped land. Costs associated with undeveloped land are not subject to depletion and are assessed periodically to assess whether impairment has occurred. When proved reserves are assigned or the value of the unproved property is considered to be impaired, the cost of the undeveloped land or the amount of impairment is added to the costs subject to depletion.

Petroleum and natural gas properties are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

The carrying amount of petroleum and natural gas properties is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves plus the lower of cost and market of undeveloped land, exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, plus the lower of cost and market of undeveloped land. The cash flows are estimated using expected future commodity prices and costs and discounted using a risk-free rate.

Asset Retirement Obligations

The Trust recognizes the fair value of an asset retirement obligation in the period in which it is incurred, on a discounted basis, with a corresponding increase to the carrying amount of property, plant and equipment. The asset recorded is depleted on a unit of production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to income in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

Income Taxes

The Trust is a taxable entity under the Canadian Income Tax Act and until 2011 is taxable only on income that is not distributed or distributable to unitholders, provided that the Trust continues to adhere to the transition rules provided for under the Federal legislation. The Trust currently meets the criteria qualifying for income tax treatment permitting a tax deduction for distributions paid to the unitholders in addition to other deductions available in the Trust. Beginning in 2011, distributions paid to unitholders will not be deductible for tax purposes and the Trust will be taxed on its income similar to corporations.

The Trust follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the Trust's subsidiaries financial statements and their respective tax bases, using substantively enacted income tax rates. In addition, income tax liabilities and assets are recognized for the estimated tax consequences of temporary differences arising in the Trust that reverse after 2011. The effect of the change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

Financial Instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition, all financial instruments, including derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then dependent on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale or other liabilities. Cash and cash equivalents have been designated as held for trading which are measured at fair value. Accounts receivable and notes receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities, distributions payable, notes payable and bank debt are classified as other liabilities which are measured at amortized cost, which is determined using the effective interest method. The convertible debentures are classified as debt on the balance sheet with a portion of the proceeds allocated to equity. The debt component has been measured at amortized cost.

All derivative contracts are classified as held for trading and are recorded on the balance sheet at fair value, with changes in the fair value recognized in net income, unless specific hedge criteria are met. The Trust has entered into certain derivative contracts in order to reduce its exposure to market risks from fluctuations in commodity prices, interest rates and foreign exchange. These instruments are not used for trading or speculative purposes. The Trust has not designated its derivative contracts as effective accounting hedges, even though the Trust considers all derivative contracts to be effective economic hedges. Therefore, changes in the fair value of the derivative contracts are recognized in net income for the period. Proceeds and costs realized from holding the derivative contracts are recognized in net income at the time each transaction under a contract is settled. The fair value of derivative contracts is based on an approximation of the amounts that would be received or paid to settle these instruments at the end of the period, with reference to forward prices, foreign exchange rates and interest rates.

The Trust will assess at each reporting period whether a financial asset is impaired. An impairment loss, if any, is included in net income.

Transaction costs are frequently attributed to the issue of a financial asset or liability. The Trust has selected a policy of netting all transaction costs with the related financial assets and liabilities, and recording its bank debt net of deferred interest payments. In accordance with this policy convertible debentures are presented net of issue costs and bank debt is presented net of deferred interest payments, with interest recognized in net income on an effective interest basis.

The Trust applies trade date accounting for the recognition of a purchase or sale of short term investments and derivative contracts.

The Trust measures and recognizes embedded derivatives separately from host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative, and when the contract is not measured at fair value. Embedded derivatives are recorded at fair value.

Joint Operations

Substantially all development and production activities are conducted jointly with others and, accordingly, these financial statements reflect only the Trust's proportionate interests in such activities.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to the purchaser.

Unit-Based Incentive Compensation

The Manager has established a unit-based incentive compensation plan (the "Plan") for all employees. Under the Plan, employees receive cash compensation based upon the value and overall return of a specified number of awarded notional trust units on a fixed vesting date. The notional trust unit grants are in the form of Restricted Trust Units ("RTUs") and Performance Trust Units ("PTU's"). Distributions paid on the Trust's outstanding trust units during the vesting period are assumed to be reinvested in the awarded notional trust units on the date of distribution. Compensation expense is determined using the liability method and incorporates the trust unit price and the number of RTUs and PTU's outstanding at each period end. In addition, for the PTU's there is a performance multiplier which is based on the Trust's performance relative to its peers and may range from zero to two times the value of the notional trust units held at vesting.

Compensation expense is recognized over the vesting period and is determined based on the market price of the notional trust units at each period end and an expected performance multiplier with a corresponding increase or decrease in liabilities. Classification between current liabilities and long-term liabilities is dependent on the expected payout date.

The Trust charges the accrued compensation amounts relating to head office employees to general and administrative expenses, the amounts relating to field staff to operating costs, and the amounts relating to exploitation and development personnel to property, plant and equipment.

The Trust has not incorporated an estimated forfeiture rate for units that will not vest and accounts for actual forfeitures as they occur.

Basic and Diluted per Trust Unit Calculation

Basic net income per trust unit is calculated by dividing net income by the weighted average number of trust units outstanding. Diluted net income per unit is calculated using the “if converted method” to determine the dilutive effects of the convertible debentures. Dilutive trust units are arrived at by taking the weighted average trust units and the trust units issuable on conversion of the convertible debentures, giving effect to the potential dilution that would occur had conversion occurred at the beginning of the period or on issuance of the convertible instrument, whichever is later. Interest and accretion on convertible debentures is added back to net income in calculating diluted net income per unit.

Goodwill

Goodwill is recorded on a business acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired business. The goodwill balance is not amortized but, instead, is assessed for impairment annually at year-end, or more frequently if events or changes in circumstances indicate the asset might be impaired. To assess impairment, the fair value of the reporting entity, deemed to be the consolidated Trust, is compared to the carrying value of the reporting entity. If the fair value of the Trust is less than the carrying value, then a second test is performed to determine the amount of impairment. Any impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the implied value of the goodwill. Any excess of the book value of goodwill over the implied value of goodwill is the impairment amount. Any impairment will be charged to net income in the period in which it occurs.

Comparative Information

Certain comparative figures have been reclassified to conform with current year presentation.

3) CHANGES IN ACCOUNTING POLICIES

NEW ACCOUNTING STANDARDS

Financial Instruments Disclosures

Effective December 31, 2009, the Trust adopted CICA amended Section 3862, “Financial Instruments – Disclosures”. The amendments include additional disclosure requirements regarding fair value measurements of financial instruments and broaden the liquidity risk disclosure requirements. The amendments establish a three level hierarchy that reflects the significance of the inputs used in making fair value measurements. All financial instruments measured at fair value must be categorized into one of the three hierarchy levels. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and lowest priority to unobservable inputs. Disclosures required by these amendments are included in Note 15.

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.

FUTURE ACCOUNTING CHANGES

Business Combinations:

In December 2008, the CICA issued Section 1582, “Business Combinations,” replacing Section 1581. Section 1582 includes potentially significant changes to the measurement of purchase consideration in a business combination. Under Section 1582, the fair value ascribed to units issued as consideration will be based on their market value at the date of exchange, as compared to the current standard which prescribes market price for a reasonable period of time before and after the date of announcement of the acquisition. In addition, the majority of acquisition costs will likely have to be expensed. Current standards allow for the capitalization of these costs as part of the purchase price. Section 1582 also addresses contingent liabilities, which will be required to be recognized at fair value on acquisition, and subsequently remeasured at each reporting date until settled. Currently, standards require only contingent liabilities that are payable to be recognized. Section 1582 also requires negative goodwill to be recognized in earnings rather than the current standard of deducting from non-

currents assets in the purchase price allocation. Section 1582 will be effective for the Trust on January 1, 2011, with prospective application. Early adoption is permitted.

Consolidated Financial Statements and Non-Controlling Interest

The CICA issued Handbook Sections 1601 “Consolidated Financial Statements”, and 1602 “Non-Controlling Interests”, which replace existing guidance under Section 1600 “Consolidated Financial Statements”. Section 1601 establishes standards for the preparation of Consolidated Financial Statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in Consolidated Financial Statements subsequent to a business combination. These standards will be effective for the Trust for business combinations occurring on or after January 1, 2011, with early adoption permitted.

4) CORPORATE ACQUISITIONS

i) Breaker Energy Ltd.

Effective December 11, 2009, the Trust acquired all of the issued and outstanding common shares of Breaker Energy Ltd. (“Breaker”), which has interests in petroleum and natural gas properties and undeveloped land in Alberta and northeast British Columbia.

The Trust issued 24.8 million trust units at a price of \$12.45 per trust unit for total consideration, before acquisition costs, of \$308.5 million. The trust unit price was based on the weighted average market price of trust units at the date of announcement, being October 13, 2009.

The results of Breaker have been included in the accounts of the Trust from December 11, 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	\$(11,535)
Property, plant and equipment	483,289
Future income taxes	(37,199)
Excess office lease obligation ¹⁾	(4,396)
Asset retirement obligations	(25,703)
Bank debt	(94,481)
	\$309,975
Consideration:	
Issuance of trust units	\$308,475
Acquisition costs	1,500
	\$309,975

1) Represents the present value of an estimated loss on an office lease obligation.

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

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 results of Spearpoint have been included in the accounts of the Trust from August 10, 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:	
Cash	\$1,201
Working capital deficiency	(2,163)
Property, plant and equipment	17,772
Future income taxes	525
Asset retirement obligations	(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 associated 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 December 31, 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.

iii) 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 per 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)	\$(3,998)
Derivative contract	408
Property, plant and equipment	118,125
Future income taxes	17,858
Excess office lease obligation ⁽¹⁾	(1,446)
Asset retirement obligations	(14,592)
Bank debt	(78,852)
	\$37,503
Consideration:	
Issuance of trust units	\$36,600
Acquisition costs	903
	\$37,503

(1) Represents the present value of an estimated loss on an office lease obligation.

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 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. No amounts have been settled by the parties to date. However, as at December 31, 2009, the Trust had a receivable from MFC of \$1.8 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 \$56.5 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 \$2.1 million and a lease obligation of \$1.5 million, for consideration of \$37.5 million, including estimated acquisition costs.

iv) Tiberius Exploration and Spear Exploration Inc.

Effective February 27, 2008 the Trust acquired all the issued and outstanding common shares of Tiberius Exploration Inc. (“Tiberius”) and Spear Exploration Inc. (“Spear”), which have interests in southeast Saskatchewan.

On February 29, 2008, the Trust transferred the assets into a limited partnership (the “Partnership”) in exchange for a 50 percent partnership interest and a note receivable of \$3.7 million. A wholly-owned subsidiary of MFC acquired the remaining 50 percent share in the Partnership and a note receivable of \$3.7 million, by payment in cash of one half of the total purchase price for Tiberius and Spear. Accordingly, the net acquisition cost to the Trust for its 50 percent share in the acquired properties was \$57.8 million, before acquisition costs, comprised of \$28.3 million in cash and \$29.5 million from the issuance of 2.4 million trust units at a price of \$12.24 per unit. The unit price was based on the weighted average market price of the units at the announcement date for the acquisition, being February 11, 2008.

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. The equivalent carrying amount of property, plant and equipment related to this interest in the reserves is recorded on the books of each royalty holder.

The results of operations from these properties have been included in the consolidated financial statements of the Trust commencing February 27, 2008. A subsidiary of the Trust is the general partner under the partnership agreement governing the Partnership and therefore controls the Partnership. As a result, the Trust is required to consolidate the results into its consolidated financial statements, with the share of net income and net assets attributable to MFC presented as a non-controlling interest.

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:	Total Acquisition	Disposition to Manulife	Trust, net Acquisition	NPI ⁽¹⁾	Net to Trust
Cash	\$9,734	\$-	\$9,734	\$-	\$9,734
Working capital deficiency	(5,622)	-	(5,622)	-	(5,622)
Notes receivable, net from MFC	-	(3,750)	(3,750)	49,599	45,849
Property, plant and equipment	111,258	-	111,258	(49,599)	61,659
Future income taxes	(23,544)	11,588	(11,956)	-	(11,956)
Asset retirement obligations	(1,636)	-	(1,636)	-	(1,636)
Goodwill	26,724	(12,002)	14,722	-	14,722
Non-controlling interest	-	(54,057)	(54,057)	-	(54,057)
	\$116,914	\$(58,221)	\$58,693	\$-	\$58,693
Consideration:					
Cash	\$86,118	\$(57,807)	\$28,311	\$-	\$28,311
Issuance of trust units	29,496	-	29,496	-	29,496
Acquisition costs	1,300	(414)	886	-	886
	\$116,914	\$(58,221)	\$58,693	\$-	\$58,693

(1) Net profits interest agreement entered into with MFC, in exchange for a note receivable.

5) RELATED PARTY TRANSACTIONS

The Trust is managed by the Manager. The Manager is a wholly-owned subsidiary of MFC and also manages on their behalf NAL Resources, 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 \$3.9 million (2008 - \$2.8 million) for the reimbursement of G&A expenses during the fourth quarter and \$12.6 million (2008 - \$12.4 million) for 2009. 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 in 2009 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 the Partnership, described in note 4. This Partnership holds the assets acquired from the acquisitions of Tiberius and Spear in February 2008. Both the Trust and MFC have entered into net profit interest royalty agreements 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 12).

During 2009 the Partnership paid distributions to its partners, MFC's share being \$5.0 million (2008 - \$1.5 million) (Note 12).

As at December 31, 2009, there is a note payable of \$8.9 million (2008 - \$9.6 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 fourth quarter of 2009 (2008 - \$0.7 million net interest income), and net interest income of \$0.2 million (2008 - \$2.8 million) for 2009 was received by the Trust and is reported as other income.

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

	2009	2008
Due from (to) NAL Resources Limited ⁽¹⁾	\$1,731	\$(10,042)
Due to NAL Resources Management Limited	(8,753)	(3,881)
Due (to) from Manulife Financial Corporation ⁽²⁾	(9,472)	45,512
	\$(16,494)	\$31,589

(1) Includes base price adjustment due (to) from MFC, relating to the Clipper and Spearpoint asset dispositions to MFC, of \$2.1 million (Note 4).

(2) Included on consolidation, eliminated through non-controlling interest. Represents note payable of \$8.9 million (2008 - \$9.6 million), plus amounts due from (to) MFC of (\$0.6) million (2008 - \$5.5 million), presented in accounts payable/ accounts receivable, relating to the net interest and NPI amounts due. In addition, 2008 includes the note receivable of \$49.6 million.

6) PROPERTY, PLANT AND EQUIPMENT

	2009	2008
Petroleum and natural gas properties, at cost	\$2,579,268	\$1,909,524
Less: Accumulated depletion and depreciation	(1,075,316)	(892,337)
	\$1,503,952	\$1,017,187

The calculation of 2009 depletion and depreciation included future development costs for proved reserves of \$209.2 million (2008 - \$46.3 million) and excluded costs associated with undeveloped land and unproved properties of \$128.5 million (2008 - \$39.0 million).

During 2009, the Trust capitalized \$5.6 million (2008 - \$4.3 million) of G&A costs and \$3.7 million (2008 - \$0.8 million) of unit-based incentive compensation that were directly related to exploitation and development programs.

The Trust performed a ceiling test calculation at December 31, 2009 to assess the recoverable value of property, plant and equipment. The oil and gas future prices are based on the January 1, 2010 commodity price forecast of the Trust's independent reserve evaluators, adjusted for commodity differentials specific to the Trust. The following table summarizes the benchmark prices used in the ceiling test calculation. Based on these assumptions, the undiscounted value of net reserves from the Trust's proved reserves exceeded the carrying value of property, plant and equipment as at December 31, 2009.

Year	WTI Oil (US\$/bbl)	US\$/Cdn\$ Exchange Rate	WTI Oil (Cdn\$/bbl)	AECO Gas (Cdn\$/MMBtu)
2010	80.00	0.95	84.21	6.05
2011	83.60	0.95	88.00	6.75
2012	87.40	0.95	92.00	7.15
2013	91.30	0.95	96.11	7.45
2014	95.30	0.95	100.32	7.80
Remainder ⁽¹⁾	2%	0.95	2%	2%

(1) Percentage change represents the change in each year after 2014 to the end of the reserve life.

7) BANK DEBT

	2009	2008
Production loan facility	\$230,713	\$281,984
Working capital facility	-	348
Total debt outstanding	\$230,713	\$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. As at December 31, 2009, the facility consisted of a \$440 million production facility and a \$10 million working capital facility. Effective January 29, 2010, the credit facility was increased by \$100 million to \$550 million, consisting of a \$535 million production facility and a \$15 million working capital facility, to reflect the acquisition of Breaker. 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 December 31, 2009 and 2008 all amounts outstanding were in Canadian dollars.

On December 31, 2009 the effective interest rate on amounts outstanding under the credit facility was 3.27 percent (2008 – 3.57 percent). The Trust's interest charge includes this fixed interest rate component, plus a standby fee, a stamping fee and the fee for renewal.

8) CONVERTIBLE DEBENTURES

On August 28, 2007, the Trust issued \$100 million principal amount of 6.75 percent convertible extendible unsecured subordinated debentures, at a price of \$1,000 per debenture. Interest on these 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 anytime into 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.

On December 3, 2009, the Trust issued \$115 million principal amount of 6.25 percent convertible unsecured subordinated debentures, at a price of \$1,000 per debenture. Interest on these debentures is paid semi-annually in arrears, on June 30 and December 31, and the debentures are convertible at the option of the holder at anytime into trust units at a conversion price of \$16.50 per trust unit. The debentures mature on December 31, 2014. The debentures are redeemable by the Trust at a price of \$1,050 per debenture on or after January 1, 2013 and on or before December 31, 2013, and at a price of \$1,025 per debenture on or after January 1, 2014 and on or before December 31, 2014. On redemption or maturity the Trust may opt to satisfy its obligation to repay the principal by issuing trust units.

The 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 will be transferred to Unitholders' Capital. The debt component of the convertible debentures is carried net of issue costs. 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 caption "interest and accretion on convertible debentures" in the consolidated statement of income.

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

	2009			2008		
	6.25%	6.75%	Total	6.25%	6.75%	Total
Principal, beginning of year	\$-	\$79,744	\$79,744	-	\$100,000	\$100,000
Issued during year	115,000	-	115,000	-	-	-
Converted to trust units	-	-	-	-	(20,256)	(20,256)
Principal, end of year	\$115,000	\$79,744	\$194,744	-	\$79,744	\$79,744
Debt component, beginning of year	\$-	\$74,004	\$74,004	-	\$90,876	\$90,876
Issued during year	106,965	-	106,965	-	-	-
Issue costs	(4,714)	-	(4,714)	-	-	-
Accretion	199	1,523	1,722	-	1,696	1,696
Conversion to trust units	-	-	-	-	(18,568)	(18,568)
Debt component, end of year	\$102,450	\$75,527	\$177,977	-	\$74,004	\$74,004
Equity component, beginning of year	\$-	\$4,592	\$4,592	-	\$5,759	\$5,759
Issued during year	8,036	-	8,036	-	-	-
Conversion to trust units	-	-	-	-	\$(1,167)	\$(1,167)
Equity component, end of year	\$8,036	\$4,592	\$12,628	-	\$4,592	\$4,592

9) OTHER LIABILITIES

	2009	2008
Unit-based incentive compensation (Note 10)	\$3,935	\$890
Excess office lease obligations (Note 4) ⁽¹⁾	3,708	-
	\$7,643	\$890

(1) Represents the present value of the long-term portion of office lease obligations, in excess of sub-leases, assumed on the acquisitions of Clipper and Breaker. MFC will reimburse the Trust for 50 percent of the Clipper obligation of \$0.8 million, under the base price adjustment clause (Note 4).

10) UNIT-BASED INCENTIVE COMPENSATION PLAN

The Manager has a long term incentive plan under which employees receive cash compensation based upon the value and overall return of a specified number of awarded notional trust units on a fixed vesting date. The notional trust unit grants are in the form of Restricted Trust Units ("RTU's") and Performance Trust Units ("PTU's"). RTU's vest one third on November 30 in each of the three years after the date of grant. PTU's vest on November 30, three years after the date of grant.

The Trust recorded a total compensation expense of \$12.5 million in 2009, of which \$8.8 million was recorded

as an expense and \$3.7 million as property, plant and equipment (\$2.0 million was expensed and \$0.7 million recorded as property, plant and equipment for the year ended December 31, 2008). The compensation expense was based on the December 31, 2009 trust unit price of \$13.74 (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:

	2009	2008
Balance, beginning of year	\$6,274	\$5,311
Increase in liability	12,461	2,730
Cash payout, relating to units vested	(2,324)	(1,767)
Balance, end of year	\$16,411	\$6,274
Current portion of liability ⁽¹⁾	\$12,476	\$5,384
Long-term liability ⁽²⁾	\$3,935	\$890

(1) Included in accounts payable and accrued liabilities.

(2) Included in other liabilities.

11) ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by the Manager based on the Trust's net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. NAL has estimated the net present value of its asset retirement obligations to be \$127.9 million as at December 31, 2009 (2008 - \$90.8 million) based on a total undiscounted and inflated amount of cash flows required to settle its asset retirement obligations of \$374.8 million (2008 - \$270.9 million). These costs are expected to be made over the next 43 years with the majority of the costs incurred between 2010 and 2033. NAL's estimated credit-adjusted risk-free rate of eight to 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.

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

	2009	2008
Balance, beginning of year	\$90,844	\$89,602
Accretion expense	7,856	7,299
Revisions to estimates	558	(262)
Liabilities incurred	1,522	1,422
Liabilities acquired, net (Note 4)	32,311	1,636
Liabilities settled	(5,219)	(8,853)
Balance, end of year	\$127,872	\$90,844

12) 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 4). The non-controlling interest on the balance sheet represents 50 percent of the net assets of the Partnership as follows:

	2009	2008
Non-controlling interest, beginning of year	\$56,380	\$-
Non-controlling interest on acquisition	-	54,057
Net income attributable to non-controlling interest	1,040	3,823
Distributions to MFC ⁽¹⁾	(54,552)	(1,500)
Non-controlling interest, end of year	\$2,868	\$56,380

(1) Includes \$49.6 million distribution paid following settlement of note receivable (Note 5).

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

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Net profits interest expense (income)	\$396	\$(453)	\$1,919	\$6,618
Share of net income attributable to MFC	252	1,716	1,040	3,823
	\$648	\$1,263	\$2,959	\$10,441

13) UNITHOLDERS EQUITY

Unitholders' Capital

The Trust is authorized to issue 500 million trust units of which 137.5 million units were issued and outstanding as at December 31, 2009 (2008 – 96.2 million). Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the assets of the Trust in the event of termination or winding up of the Trust. All trust units are of the same class with equal rights and privileges.

Redemption

Unitholders may redeem their trust units for cash at any time, up to an aggregate maximum value of \$100,000 in any calendar month, by delivering their trust unit certificates to the Trustee, accompanied by a properly completed notice requesting redemption. The redemption amount per trust unit will be the lesser of 95 percent of the market price of the trust units on the principal market on which the trust units are quoted as trading during the ten-trading day period commencing immediately after the date on which the trust units are surrendered for redemption, and the closing market price of the trust units on the principal market on which the units are quoted for trading on the date that the trust units are tendered for redemption.

Units Issued:

	2009		2008	
	Units	Amount	Units	Amount
Balance, beginning of the year	96,181	\$1,042,183	90,494	\$969,588
Equity offering	9,603	86,422	-	-
Issued on corporate acquisitions (Note 4)	30,453	345,075	2,409	29,496
Less issue expenses (net of tax of \$1,280)	-	(3,565)	-	(29)
Issued from Distribution Reinvestment Plan	1,234	11,914	1,831	23,393
Issued on conversion of debentures	-	-	1,447	19,735
Balance, end of the year	137,471	\$1,482,029	96,181	\$1,042,183

Distribution Reinvestment Plan

The Trust has in place a Distribution Reinvestment Plan (“DRIP”) and a Premium Distribution Reinvestment Plan (“Premium DRIP”). The regular DRIP entitles unitholders to reinvest cash 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 average market price is the arithmetic average of the daily volume weighted average trading price of the trust units during a defined period before the distribution payment date.

The Premium DRIP component of the plan allows unitholders to exchange new trust units, acquired by reinvesting their cash distributions, for a cash payment from the plan broker equal to 102 percent of the monthly distribution on the applicable distribution payment date. The trust units issued under the Premium DRIP component of the plan at a five percent discount to the average market price will be delivered to the plan broker in exchange for 102 percent of the cash distribution payable on the participant’s existing trust units.

At certain times and at the discretion of management, the DRIP and Premium DRIP may be suspended. Currently the Premium DRIP is suspended.

Cash Distributions

The Trust is required to distribute all of its cash available for distribution each calendar month, in accordance with the terms of the Trust Indenture. The cash available for distribution is defined as all cash amounts received less all costs, expenses, liabilities or obligations of the Trust, plus net proceeds from the issuance of units, less any amounts the Trustee, upon recommendations of the Manager, considers it necessary to retain. The amount considered necessary to retain includes: any costs, expenses, liabilities or obligations which are reasonably expected to be incurred such as for property, plant and equipment; amounts required to be retained for

repayment in order to comply with loan agreements; an allowance for contingencies, working capital, investments or acquisitions; or any amount appropriate to retain for a reserve to stabilize distributions. The Trust intends to continue to make cash distributions, however, these cash distributions cannot be guaranteed.

Distributions since the inception of the Trust are as follows:

	Amount
Accumulated distributions at December 31, 2007	\$861,081
2008 distributions	181,462
Accumulated distributions at December 31, 2008	\$1,042,543
2009 distributions	120,153
Accumulated distributions at December 31, 2009	\$1,162,696

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 months and year ended December 31, 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 months and year ended December 31, 2009 were 7,817,212 and 6,230,662, respectively, as they were anti-dilutive. For the three months and year ended December 31, 2008, an additional 5,696,013 and 6,341,206 trust units, respectively, were included in the diluted income per trust unit calculation. Interest and accretion charges of \$1.7 million and \$7.6 million were included in the diluted net income per trust unit calculation as an addition to net income for the three months and year ended December 31, 2008, respectively. As at December 31, 2009, the total convertible debentures outstanding were immediately convertible to 12,665,697 trust units.

Deficit

The deficit is comprised of the following:

	2009	2008
Accumulated income	\$562,231	\$553,031
Accumulated cash distributions	(1,162,696)	(1,042,543)
	\$(600,465)	\$(489,512)

The Trust has historically paid cash distributions in excess of accumulated income as cash distributions are based on cash flow generated in the period whereas accumulated income is based on net income which includes non-cash items such as depletion, depreciation, accretion, future income taxes and unrealized gains and losses on derivative contracts.

14) INCOME TAXES

The provision for income taxes in the consolidated financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to income before taxes as follows:

	2009	2008
Income (loss) before taxes	\$(22,613)	\$206,387
Statutory income tax rate	29.0%	29.5%
Expected income tax expense (reduction)	(6,558)	60,884
Increase (decrease) resulting from:		
Valuation allowance	(2)	(37)
Net income of the Trust	(34,844)	(21,449)
Rate variance	5,151	(3,192)
Other	1,481	(2,840)
Current and future income tax provision (reduction)	(34,772)	\$33,366

The future income tax asset (liability) is comprised of:

	2009	2008
Property, plant and equipment	\$(81,939)	\$(32,323)
Future tax liability resulting from different year ends	(7,807)	(4,038)
Non-capital tax loss carry forward	35,777	5,637
Asset retirement obligations	31,750	9,804
Derivative contracts	621	(16,939)
Other	8,031	357
	\$(13,567)	(37,502)
Valuation allowance	(8,079)	(1,378)
Future income tax liability	\$(21,646)	\$(38,880)
Current asset (liability)	\$3,132	\$(16,788)
Long-term liability	\$(24,778)	\$(22,092)

The Trust has non-capital loss carry forwards of \$138.0 million of which \$2.3 million expire between 2010 and 2015, \$14.8 million expire between 2016 and 2025, and \$120.9 million expire between 2026 and 2029.

The Trust qualifies for income tax treatment permitting a tax deduction for distributions paid to the unitholders, in addition to other deductions available in the Trust. From 2011, following the changes to the taxation of income trusts announced in 2006, the Trust will be taxed on its income similar to corporations. All temporary differences associated the Trust and corporate entities have been tax effected.

15) FINANCIAL RISK MANAGEMENT

Overview

The Trust has exposure to the following risks from its use of financial instruments: credit risk, liquidity risk and market risk.

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Certain other quantitative disclosures are included throughout these financial statements.

The Board of Directors has the responsibility to understand the principal risks of the business and to achieve a proper balance between the risks incurred and the potential return to unitholders. The Board of Directors have oversight for ensuring systems are in place which effectively monitor and manage those risks with a view to the long term viability of the Trust.

Credit risk

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Trust's receivables and note receivable. The Trust is managed by the Manager. The Manager is a wholly-owned subsidiary of MFC and manages on its behalf 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 operator. As a result, a significant portion of the Trust's net operating revenues represent joint operations from NAL Resources. Accordingly, accounts receivable include amounts due from NAL Resources for oil, natural gas and natural gas liquids sales. Oil and gas marketing is conducted by the Manager on behalf of the Trust and NAL Resources generally with large creditworthy purchasers, for which the Trust views the credit risk as low. Except as noted below, NAL Resources, and ultimately the Trust, have not historically experienced any collection issues with its oil and gas marketers. The Manager does not obtain collateral from oil and natural gas marketers.

Cash and cash equivalents, when outstanding, consist of cash bank balances and short-term deposits maturing in less than 90 days. Derivative contracts consist of commodity contracts denominated in U.S. or Canadian dollars for periods of up to two years and interest rate contracts and foreign exchange rate contracts for periods of up to five years. The Trust manages the credit exposure related to short-term investments and derivative contracts by dealing with established counter-parties with high credit ratings and monitors all investments, avoiding complex investment vehicles with higher risks such as asset backed commercial paper. All derivative contract counterparties are Canadian chartered banks in NAL's lending syndicate.

On July 22, 2008 SemCanada Crude Company (“SemCanada”) filed application for creditor protection under the Companies’ Creditors Arrangement Act in Canada. SemCanada marketed a portion of the Trust’s oil, butane and condensate sales. It was determined that the full amount due from SemCanada was unlikely to be received. In 2008, the Trust recorded a bad debt expense of \$6.9 million to write off the entire amount due to the Trust. In the fourth quarter of 2009, NAL received settlement on amounts due of \$0.3 million. This amount is recorded as income. NAL continues to sell to SemCanada under a letter of credit.

NAL management has reviewed its existing credit policy and has implemented more regular reviews of purchasers to ensure credit worthiness given the current market conditions.

The carrying amounts of cash, accounts receivable and derivatives represents the maximum credit exposure.

The Trust considers all amounts greater than 90 days to be past due. Generally, the Trust does not have amounts past due, due to receiving a significant portion of net operating revenues from NAL Resources. However, with the acquisitions completed in 2009, \$0.8 million of receivables were past due as at December 31, 2009 (2008 - \$nil).

Liquidity risk

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they are due. The Trust manages liquidity by ensuring, as far as possible, that it will have sufficient liquidity under both normal and stressed conditions.

The Trust requires significant cash to fund capital programs necessary to maintain or increase production and develop reserves, to acquire strategic oil and gas assets, to repay maturing debt and to pay unit distributions.

The Trust’s capital programs are funded principally by internally generated cash flows and undrawn committed borrowing facilities. The Trust also hedges a portion of its production to protect cash flow in the event of commodity price declines. To support the capital spending program, the Trust maintains a fully secured, extendible, revolving term credit facility, as outlined in Note 7.

The Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as necessary. As well, the Manager utilizes authorizations for expenditures on both operated and non-operated projects. Furthermore, the Manager operates a high percentage of the Trust’s properties, which allows for significant control over future expenditures.

The Trust’s non-derivative financial liabilities include its accounts payable and accrued liabilities, note payable, distributions payable to unitholders, bank debt and convertible debentures. The Trust’s derivative financial liabilities include its commodity contracts. The following table outlines cash flows associated with the maturities of the Trust’s financial liabilities.

The following are the contractual maturities of financial liabilities as at December 31, 2009.

Non-Derivative Financial Liability	<1 Year	1 – 2 Years	2 – 5 Years
Accounts payable and accrued liabilities	\$110,897	\$-	\$-
Note payable	8,907	-	-
Distributions payable to unitholders	12,372	-	-
Bank debt, principal	-	138,428	92,285
Convertible debentures, principal	-	-	194,744
Total	\$132,176	\$138,428	\$287,029
Derivative Financial Liability	<1 Year	1 – 2 Years	2 – 5 Years
Commodity contracts	\$11,231	-	-

Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Trust's net income or the value of financial instruments.

Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Trust's oil and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian and U.S. dollar.

During 2009, the Trust 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.

NAL has the following foreign exchange derivative contracts outstanding:

EXCHANGE RATE	Remaining Term	Amount ⁽¹⁾ (US\$ MM)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1583	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1100	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1200	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1225	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1300	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1420	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1525	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.1000	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.0500	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.0640	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.0650	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2010 – Dec 2010	\$6.0	1.0685	BofC Average Noon Rate
Swaps-floating to fixed	Feb 2010 – Dec 2010	\$5.5	1.0575	BofC Average Noon Rate
Swaps-floating to fixed	Feb 2010 – Dec 2010	\$5.5	1.0625	BofC Average Noon Rate
Swaps-floating to fixed	Feb 2010 – Dec 2010	\$5.5	1.0680	BofC Average Noon Rate
Swaps-floating to fixed	Feb 2010 – Dec 2010	\$5.5	1.0740	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 December 31, 2009, if exchange rates had strengthened by \$0.01, with all other variables held constant, net income for the period would have been \$0.7 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 exchange rates been \$0.01 weaker.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and U.S. dollar, but also macroeconomic events that dictate the levels of supply and demand. The Trust has attempted to mitigate commodity price risk by entering into financial derivative contracts. The Trust's policy is to enter into commodity contracts to a maximum of 60 percent of forecasted, net of royalty, production volumes for a period of up to two years.

NAL has the following commodity risk derivative contracts outstanding:

CRUDE OIL	Q1-10	Q2-10	Q3-10	Q4-10	Q1-11	Q2-11
<u>US\$ Collar Contracts</u>						
\$US WTI Collar Volume (bbl/d)	3,900	3,700	2,800	2,600	200	200
Bought Puts – Average Strike Price (\$US/bbl)	\$63.15	\$63.59	\$65.63	\$65.87	\$80.00	\$80.00
Sold Calls – Average Strike Price (\$US/bbl)	\$74.56	\$74.94	\$77.55	\$78.05	\$90.00	\$90.00
<u>US\$ Swap Contracts</u>						
\$US WTI Swap Volume (bbl/d)	2,166	2,800	2,900	3,000	-	-
Average WTI Swap Price (\$US/bbl)	\$79.99	\$79.45	\$83.47	\$83.38	-	-
<u>Cdn\$ Collar Contracts</u>						
\$Cdn WTI Collar Volume (bbl/d)	300	-	-	-	-	-
Bought Puts – Average Strike Price (\$Cdn/bbl)	\$66.00	-	-	-	-	-
Sold Calls – Average Strike Price (\$Cdn/bbl)	\$80.17	-	-	-	-	-
Total Oil Volume (bbl/d)	6,366	6,500	5,700	5,600	200	200
<u>NATURAL GAS</u>						
	Q1-10	Q2-10	Q3-10	Q4-10	Q1-11	Q2-11
<u>Swap Contracts</u>						
AECO Swap Volume (GJ/d)	37,967	39,000	40,000	27,337	4,000	4,000
AECO Average Price (\$Cdn/GJ)	\$5.80	\$5.60	\$5.61	\$5.66	\$5.78	\$5.78
Total Natural Gas Volume (GJ/d)	37,967	39,000	40,000	27,337	4,000	4,000

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 December 31, 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

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust is exposed to interest rate fluctuations on its bank debt, which bears a floating rate of interest.

During 2009, the Trust entered into several interest rate swaps. The contracts have a combined notional debt amount of \$139 million and require NAL to make fixed quarterly payments. In exchange, the counterparties are required to pay the Trust a floating rate of interest based on the average rate for Canadian dollar bankers' acceptances. The Trust's interest charge includes this fixed interest rate component plus a standby fee, a stamping fee and the fee for renewal. The Trust's policy is to enter into interest rate swap contracts to fix the interest rate on up to 50 percent of outstanding bank debt for periods of up to five years.

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	Jan 2010 – Dec 2011	\$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2010 – Jan 2013	\$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2010 – 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 December 31, 2009, if interest rates had been one percent lower, with all other variables held constant, net income for the year would have been \$4.0 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 Financial Instruments

The carrying amount of the Trust's financial instruments, including accounts receivable, accounts payable and accrued liabilities, and distributions payable to unitholders, approximate their fair value due to their short term to maturity.

The note with MFC is due on demand and bears interest at prime plus three percent. As the note bears interest at a floating market rate and is due on demand, the fair market value approximates the carrying amount.

The Trust's bank debt and cash bear interest at floating market rates and, accordingly, the fair market value approximates the carrying amount.

The fair value of the Trust's convertible debentures at December 31, 2009 was \$203.7 million, based on a quoted and observable market value (2008 - \$67.8 million).

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\$79.36 per barrel to US\$84.13 per barrel for oil and \$5.23 per GJ to \$6.15 per GJ for natural gas) as of the balance sheet date, using the remaining contracted oil and natural gas volumes with option contracts also including an element of volatility. 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 0.444 percent to 2.868 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 1.0458 to 1.0469) 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:

	2009	2008
Fair value of commodity contracts	\$(8,932)	\$65,680
Fair value of interest rate swaps	2,461	(274)
Fair value of foreign exchange rate swaps	3,986	-
	\$(2,485)	\$65,406

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

Gain / (Loss) on Derivative Contracts

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Unrealized gain (loss):				
Crude oil contracts	\$(12,439)	\$55,438	\$(68,590)	\$68,674
Natural gas contracts	(870)	1,456	(6,430)	6,590
Interest rate swaps	(41)	(274)	2,735	(274)
Exchange rate swaps	(1,462)	-	3,986	-
Unrealized gain (loss)	(14,812)	56,620	(68,299)	74,990
Realized gain (loss):				
Crude oil contracts	2,632	13,460	46,811	(24,691)
Natural gas contracts	5,588	3,071	25,382	(2,626)
Interest rate swaps	(223)	-	(656)	-
Exchange rate swaps	2,934	-	8,134	-
Realized gain (loss)	10,931	16,531	79,671	(27,317)
Gain (loss) on derivative contracts	\$(3,881)	\$73,151	\$11,372	\$47,673

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

	2009	2008
Current unrealized loss on derivative contracts	\$(11,231)	\$-
Current unrealized gain on derivative contracts	6,285	65,680
Current unrealized gain (loss) on derivative contracts	(4,946)	65,680
Long term unrealized gain on derivative contracts	2,461	-
Long term unrealized loss on derivative contracts	-	(274)
Net fair value of derivative contracts	\$(2,485)	\$65,406

As at December 31, 2009, the total fair value of derivative contracts was a net liability of \$2.5 million (2008 - net asset of \$65.4 million). The change in the fair value for year ended December 31, 2009 of \$67.9 million plus a \$0.4 million unrealized loss from a derivative contract acquired in the Clipper acquisition, for a total of \$68.3 million, has been recognized as an unrealized loss in the statement of income (2008 - \$75.0 million gain).

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

	Three months ended December 31		Years ended December 31	
	2009	2008	2009	2008
Unrealized gain (loss), beginning of period	\$12,327	\$8,786	\$65,406	\$(9,584)
Unrealized gain acquired ⁽¹⁾	-	-	408	-
Unrealized gain (loss), end of period	(2,485)	65,406	(2,485)	65,406
Unrealized gain (loss) for the period	(14,812)	56,620	(68,299)	74,990
Realized gain (loss) in the period	10,931	16,531	79,671	(27,317)
Gain (loss) on derivative contracts	\$(3,881)	\$73,151	\$11,372	\$47,673

(1) Assumed on acquisition of Clipper (Note 4)

The financial instruments carried at fair value, being the derivative contracts and cash, are required to be classified into a hierarchy that prioritizes the inputs used to measure the fair value. The three levels of the fair value hierarchy are:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2: Inputs other than quoted prices that are observable for the asset or liability either directly or indirectly; and
- Level 3: Inputs that are not based on observable market data.

Fair values are classified as Level 1 when the related derivative is actively traded and a quoted price is available. If different levels of inputs are used to measure a financial instrument's fair value, the classification within the hierarchy is based on the lowest level input that is significant to the fair value measurement. The following table illustrates the classification of the financial instruments within the fair value hierarchy as at December 31, 2009:

	Assets at fair value as at December 31, 2009			
	Level 1	Level 2	Level 3	Total
Cash	\$1,604	\$-	\$-	\$1,604
Foreign exchange rate swaps	-	3,986	-	3,986
Interest rate swaps	-	2,461	-	2,461
Commodity contracts	-	2,299	-	2,299
	\$1,604	\$8,746	\$-	\$10,350

	Liabilities at fair value as at December 31, 2009			
	Level 1	Level 2	Level 3	Total
Commodity contracts	\$-	\$11,231	\$-	\$11,231

Capital Management

The Trust's policy is to maintain a strong and flexible capital base to ensure that distribution levels are sustainable, while at the same time providing the flexibility to take advantage of operational and acquisition opportunities.

The Trust manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Trust considers its capital structure to include Unitholders' Capital, bank debt, convertible debentures, other liabilities, and working capital (excluding derivative contracts, notes with MFC and future income tax) as shown below. In order to maintain or adjust its capital structure, the Trust may adjust the amount of distributions paid to unitholders, issue new trust units, adjust its capital spending to modify debt levels, or suspend/resume its DRIP or Premium DRIP programs.

The Trust monitors its capital based on the ratio of its net debt to 12 months trailing funds from operations. This ratio, which is a non-GAAP measure, is calculated as net debt as a proportion of funds from operations for the previous 12 months. Funds from operations is defined as cash flow from operating activities prior to the change in non-cash working capital. Net debt is defined as bank debt, plus convertible debentures at face value, plus working capital (excluding derivative contracts, notes with MFC and future income tax balances). Net debt is measured with and without convertible debentures. The Trust's strategy is to maintain a conservative net debt to 12 month trailing funds from operations as compared to other oil and gas trusts, both before and after taking into account the convertible debentures. The Trust will, for the appropriate opportunity, increase its debt to funds from operations ratio above the Trust's average. In order to facilitate the management of this ratio, the Trust prepares an annual budget which is approved by the Board of Directors. On a monthly basis a reforecast for the year is prepared based on updated commodity prices, results of operational activity and other events. The monthly forecast is provided to the Board of Directors.

As at December 31, 2009, the Trust had a total net debt to 12 months trailing funds from operations ratio of 2.07, as calculated in the table below. At December 31, 2008, the Trust had a total net debt to 12 months trailing funds from operations ratio of 1.28. The increase in the net debt to 12 months trailing funds from operations ratio in 2009 is attributable to lower funds from operations, primarily due to lower commodity prices, and higher total net debt, due to the acquisitions completed during 2009.

The credit facility is determined based on the reserves of the Trust (see Note 7) and is therefore commodity price sensitive. The Trust is restricted under its 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. As at December 31, 2009 and 2008, the Trust was in full compliance with this external restriction on distributions.

The Trust has no restrictions on the issuance of units other than the authorized limit of 500 million.

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 the announcement of the changes in the tax legislation. For 2010, the Trust has approximately \$535 million of available safe harbour.

There has been no change in the approach to capital management during 2009.

Capitalization

	2009	2008
Trust unit equity	\$894,192	\$557,263
Bank debt	230,713	282,332
Working capital deficit ⁽¹⁾	52,014	37,602
Net debt	282,727	319,934
Convertible debentures ⁽²⁾	194,744	79,744
Total net debt ⁽²⁾	\$477,471	\$399,678
Cash flow from operating activities for last 12 months	\$236,295	\$320,042
Add back change in non-cash working capital	(5,554)	(8,971)
Trailing 12 months funds from operations	\$230,741	\$311,071
Net debt to trailing 12 month funds from operations ⁽³⁾	1.23	1.03
Total net debt to trailing 12-month funds from operations ⁽⁴⁾	2.07	1.28

(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 excluding convertible debentures divided by funds from operations for the previous 12 months.*
- (4) *Calculated as total debt divided by funds from operations for the previous 12 months.*

16) COMMITMENTS

(i) Joint Venture Agreement

Effective April 20, 2009, the Trust and MFC entered into a joint venture 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 the Trust) 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 December 31, 2009, the Trust has spent \$3.1 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 December 31, 2009, the Trust has spent \$1.7 million under this agreement.

(iii) 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)	2010	2011	2012	2013	2014
Office lease ⁽¹⁾	4,155	3,505	3,505	3,482	3,414
Office lease – Clipper and Breaker ⁽²⁾	2,177	2,184	2,192	358	-
Transportation agreement	2,805	-	-	-	-
Processing agreements ⁽³⁾	1,859	2,242	401	384	-
Convertible debentures ⁽⁴⁾	-	-	79,744	-	115,000
Bank debt	-	138,428	92,285	-	-
Total	10,996	146,359	178,127	4,224	118,414

- (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 leases assumed with the acquisitions of Clipper and Breaker. MFC will reimburse the Trust for 50 percent of the Clipper obligation under the base price adjustment clause (Note 4).*
- (3) *Represents gas processing agreements with take or pay components.*
- (4) *Principal amount.*

17) SUBSEQUENT EVENT

On January 25, 2010, the Trust closed the disposition of a non-core property for \$14.5 million.

TRADING PERFORMANCE

	For the Quarter Ended				Full Year	
	31-Dec-09	30-Sept-09	31-Dec-08	30-Sept-08	2009	2008
PRICE						
High	\$14.00	\$12.75	\$13.14	\$17.10	\$14.00	\$17.10
Low	\$10.75	\$8.48	\$5.90	\$11.50	\$5.38	\$5.90
Close	\$13.74	\$12.70	\$8.05	\$12.53	\$13.74	\$8.05
Daily Average Volume	490,127	439,319	475,410	380,141	439,259	406,602

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".

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