First Quarter Report
Three months ended March 31, 2010

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2010 YEAR TO DATE ACTIVITY HIGHLIGHTS

- Spent $78 million in capital expenditures of which $56 million was directed toward drilling, completion and tie-in operations, running 11 rigs throughout each of our core areas, drilling 48 (21.1 net) wells, of which 75 percent were horizontal oil wells.
- Participated in 11 Cardium oil wells focused on the Garrington area, which continue to deliver volumes consistent with expectations and achieving rates of return in the 30 – 50 percent range.
- Delineated a new pool discovery at Hoffer in SE Saskatchewan, which was drilled during the fourth quarter 2009. The initial well came on at a first month average production rate of 300 bbls/d and continues to produce at approximately 150 bbls/d after six months (Trust 50 percent working interest).
- Drilled one natural gas well at Fireweed, BC (Trust 100 percent working interest). Initial production from the Fireweed Doig horizontal commenced in April at a rate of 1,000 boe/d. Results in Fireweed have validated the significant resource potential of this liquids rich gas pool.
- Opportunistically added strategic land in existing core areas, spending approximately $20 million on land and seismic in the Edson area of Alberta and in the Torquay and Hoffer areas in SE Saskatchewan.
- Delivered record quarterly production volumes in the first quarter, averaging 30,120 boe per day.
- Reduced operating costs by 10 percent to $10.81 per boe compared to $11.95 per boe for the quarter ended March 31, 2009. Operating costs continue to trend down driven by lower natural gas prices impacting the cost of power and continued gains from an aggressive optimization program in field operations.
- Renewed the Trust's fully secured revolving credit facility at the current level of $550 million, approximately $350 million of which is currently available after taking the recent equity financing into consideration.
- Completed a $100 million equity financing, with approximately $10 – 15 million of the proceeds to be directed toward second half 2010 drilling and $20 million dedicated toward strategic land acquisitions in NAL's core areas. NAL remains active in evaluating property and corporate acquisitions.

2010 UPDATED GUIDANCE

Based on first quarter performance and the recently completed $100 million equity financing, the Trust has increased its capital expenditure guidance for 2010 and lowered its operating cost forecast.

	May 2010 Guidance	January 2010 Guidance
Production (boe/d)	29,500 – 30,500	29,500 – 30,500
Net capital expenditures ($MM)	210	175
Operating costs ($/boe)	10.75 – 11.25	11.00 – 11.50

FINANCIAL AND OPERATING HIGHLIGHTS

Three months ended
(thousands of dollars, except per unit and boe data)
(unaudited)

	March 31, 2010	March 31, 2009	December 31,2009
FINANCIAL			
Revenue (1)	$ 136,883	$ 80,662	$ 111,477
Cash flow from operating activities	63,648	66,546	53,060
Cash flow per unit - basic	0.46	0.69	0.45
Cash flow per unit - diluted	0.44	0.67	0.44
Funds from operations	73,242	62,024	62,953
Funds from operations per unit - basic	0.53	0.64	0.53
Funds from operations per unit - diluted	0.51	0.62	0.51
Net income	29,349	4,724	5,634
Distributions declared	37,185	29,816	32,625
Distributions per unit	0.27	0.31	0.27
Basic payout ratio:			
based on cash flow from operating activities	58%	45%	61%
based on funds from operations	51%	48%	52%
Basic payout ratio including capital expenditures (2):			
based on cash flow from operating activities	181%	99%	130%
based on funds from operations	158%	107%	110%
Units outstanding (000's)			
Period end	137,881	96,181	137,471
Weighted average	137,660	96,181	118,174
Capital expenditures (3)	78,317	36,936	36,764
Property acquisitions (dispositions), net	(12,702)	1,314	(17,255)
Corporate acquisitions, net (4)	309	-	310,051
Net debt, excluding convertible debentures (5)	309,136	324,614	282,727
Convertible debentures (at face value)	194,744	79,744	194,744
OPERATING			
Daily production (6)			
Crude oil (bbl/d)	11,788	9,990	10,290
Natural gas (Mcf/d)	93,328	68,966	78,265
Natural gas liquids (bbl/d)	2,777	2,352	2,413
Oil equivalent (boe/d)	30,120	23,836	25,748
OPERATING NETBACK ($/boe)			
Revenue before hedging gains (losses)	50.49	37.60	47.06
Royalties	(8.54)	(6.59)	(8.95)
Operating costs	(10.81)	(11.95)	(10.21)
Other income (7)	0.16	0.20	0.15
Operating netback before hedging	31.30	19.26	28.05
Hedging gains (losses)	0.63	12.95	4.71
Operating netback	31.93	32.21	32.76

(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 $0.1 million (2009 - $0.6) for the three months ended March 31, 2010, attributable to the Tiberius and Spear properties.
(3) Excludes property and corporate acquisitions, and is net of drilling incentive credits of $2.4 million for the quarter ended March 31, 2010.
(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.

PRESIDENT'S MESSAGE

Following positive performance in 2009, NAL's active first quarter delivered results that are on target with guidance announced earlier this year. Operationally and financially, the Trust has built on the momentum created in 2009 by completing the Trust's most active capital spending program in its 14 year history. Overall, results were positive and build on management's track record of delivering consistent performance. NAL delivered record quarterly production volumes in the first quarter, averaging 30,120 boe per day and cash flow per unit of $0.53 was generally higher than forecast due to stronger oil differentials, and lower overall royalties and operating costs.

Operationally, the Trust spent $78 million which represents 37 percent of the revised 2010 capital program of $210 million. Of the $78 million, $56 million was directed toward drilling, completion and tie-in operations, operating 11 rigs, drilling 48 (21.1 net) wells, of which 75 percent were horizontal oil wells in central Alberta and southeast Saskatchewan. Of the remaining capital expenditures, the Trust opportunistically added strategic land in existing core areas, spending approximately $20 million on land and seismic in the Edson area of Alberta and in the Torquay and Hoffer areas in southeast Saskatchewan.

Financially, the Trust's balance sheet strength and capability were enhanced in the quarter through the successful completion of a $100 million equity financing and the renewal of our credit lines at the existing $550 million level. With approximately $350 million of available credit today, NAL continues to actively evaluate assets that will add opportunity to the portfolio and create value for our unitholders.

Corporate Conversion

Currently, NAL plans to convert to a dividend paying corporation in the fall of 2010. By itself, the change from a trust to a corporation, does not affect our business plan or our disciplined operational and financial focus.

NAL's Board will continue to assess the Trust's dividend and payout policy based upon commodity prices, NAL's asset base and opportunities, and other market factors. Assuming commodity prices remain consistent with current levels, the Trust has no plans to change the $0.09 per month distribution in 2010. After conversion, the Trust's total return will be driven by a combination of yield and growth, with yield remaining a strong component of the overall return. Specific payout and dividend levels will be established closer to the time of conversion.

I would like to thank the Trust's staff in our field operations and in the Calgary office for their continued dedication and efforts. As a result of their commitment, NAL remains well positioned for strong performance in 2010 and beyond. On behalf of the Executive and the Board, I thank you for your interest and ongoing support of NAL Oil & Gas Trust.

Andrew B. Wiswell
President & Chief Executive Officer

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("MD&A") should be read in conjunction with the interim unaudited consolidated financial statements for the three months ended March 31, 2010 and the audited consolidated financial statements and MD&A for the year ended December 31, 2009 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 more 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:

	Three months ended March 31	
$(000s)	**2010**	2009
Cash flow from operating activities	**$ 63,648**	$ 66,546
Add back change in non-cash working capital	**9,594**	(4,522)
Funds from operations	**$ 73,242**	$ 62,024

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 corporate conversion 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 and development 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; 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.

EXPLORATION & DEVELOPMENT ACTIVITIES

The Trust spent $56.0 million on drilling, completion and tie-in operations during the first quarter of 2010 compared to $30.5 million during the first quarter of 2009. There were 48 (21.1 net) wells drilled in the first quarter compared to 26 (9.8 net) wells during the same period in 2009 which is consistent with an expanded capital program year over year. Operations were conducted across NAL's operations with 22 wells drilled in Saskatchewan, two in British Columbia and 24 in Alberta.

The Trust participated in 36 (18 net) horizontal wells with 85 percent of the activity focused on oil projects across Saskatchewan and Alberta. There were two (1.5 net) water injectors drilled in East Prairie for pressure support in an existing oil pool and one (0.5 net) dry and abandoned Leduc well drilled in the Sylvan Lake area. The Trust will continue to focus on horizontal oil drilling for the remainder of the year with significant programs in the Cardium drilling 15 (10 net) additional wells and in the Mississippian throughout southeast Saskatchewan drilling 40 (19 net) wells.

First Quarter Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	33	16.0	2	1.5	2	1.5	1	0.5	38	19.5
Non-operated wells	6	0.7	4	0.9	0	0	0	0	10	1.6
Total wells drilled	39	16.7	6	2.4	2	1.5	1	0.5	48	21.1

Southeast Saskatchewan

In Saskatchewan, there were 22 (10.1 net) horizontal oil wells drilled during the first quarter with activity focused on the Mississippian in Alida, Nottingham and Hoffer.

A new pool discovery at Hoffer was drilled in the fourth quarter of 2009. The 1D15-31/1D7-6-2-15W2 well has had cumulative oil production of 34,000 bbls over a six month period with a water cut less than 30 percent and is expected to capture over 200,000 bbls of oil reserves. Current production from this well is 150 bbls of oil per day. The Trust has successfully completed the first program of delineation drilling with five additional wells on stream in April at rates of 75 - 200 bbls of oil per day. Seismic and mapping support significant running room on this play over a large contiguous land block (35 sections at 50 percent working interest) which NAL controls. Additional capital of $5 million has been layered in to support step out drilling over the next three quarters allowing NAL to test the continuity and extent of the play. It is expected that the Trust will drill between 10 - 15 gross wells in this area over the remainder of the year. Plans to build a full scale battery are in the preliminary stages with expectations for construction starting in the first quarter of 2011. These wells qualify for the 100,000 bbl royalty holiday in Saskatchewan which, coupled with current oil prices, yield netbacks of approximately $45/boe and a recycle ratio of three times.

A successful 10 well drilling program in Alida and Nottingham continues to deliver efficient production additions to existing infrastructure where incremental operating costs are less than $5/bbl and capital efficiency is between $10 - 15/boe. This program will continue with an expectation of 10 additional wells being drilled over the next three quarters.

Alberta

In Alberta, NAL participated in drilling 24 (9.6 net) locations including 11 (6 net) Cardium wells: six (3.5 net) at Garrington and five (2.5 net) at Pine Creek with production expected to commence during the second quarter. The Trust is currently drilling a three well pad through break up in Garrington and it is expected that another three well pad will be drilled in July. The 16-9-34-4W5M well was completed using water and has been on production for 14 days. Early results appear to be in line with surrounding wells completed using oil which lends support for a broader application of water as a completion fluid in this area. Savings are anticipated to be $300,000 – $400,000 per well, but we will continue to monitor well performance to get more history before we move forward with a change in completion practices. Cardium well results to date continue to meet production expectations with first month average actual production rates of 166 boe/d and six month average rates at 77 boe/d. These production rates combined with drill and completion costs of $2.5 - 3.0 million yield 40 percent rates of return at current prices which continue to support an active development program going forward.

NAL has updated its' corporate presentation that lists those Cardium wells in the Garrington area which have at least one month of production history. NAL's corporate presentation may be found on the website at www.nal.ca.

In Pine Creek, drilling and completion costs were higher in the Cardium than expected due to lower penetration rates and increased rock stress creating additional difficulties for placing proppant / sand during completion operations. Outcomes are highly variable and the Trust will be monitoring results from recent wells before considering an expanded program.

NAL is planning a three well Cardium program at Lochend/North Cochrane in order to evaluate the considerable land base in the area. Drilling is expected to commence in July.

The Trust has the financial capability and prospect inventory to capture the maximum drilling incentives available in the current Alberta program through the end of the first quarter in 2011 with a focus on resource style oil drilling. The continuation of the five percent royalty program and a reduction in the cap on maximum royalty rates for oil from 50 to 40 percent and natural gas from 50 to 36 percent will continue to support competitive economics and encourage activity in Alberta.

Northeast British Columbia

There were two (1.5 net) wells drilled in Fireweed and Trutch during the first quarter. Production from the Fireweed Doig horizontal A-A086-I/094-A-12 commenced in April at a rate of 1,000 boe/d (5 mmcf/d + 40 bbls/mmcf of free condensate) at a flowing tubing pressure of 12 mpa. Continued good results in Fireweed have validated the significant resource potential of this pool. A second Fireweed well at D-B007-A/94-A-12 was rig released in April with completion activity to commence in June and production expected in the third quarter. The Trutch halfway horizontal C-A024-I/094-G-10 was testing at rates of 2.2 mmcf/d and is expected to be tied in by the end of the third quarter depending on access conditions.

In Sukunka, the d-27-F well was shut in for March and most of April to repair a casing leak resulting in a 130 boe/d negative impact to average production in the first and second quarters. The well is now back on stream and producing 400 boe/d net to the Trust.

CAPITAL EXPENDITURES

Capital expenditures, before property acquisitions and dispositions, for the quarter ended March 31, 2010 totaled $78.3 million compared with $36.9 million for the quarter ended March 31, 2009. The year-over-year increase is tied to the corresponding increase in wells drilled as well as a continued shift towards horizontal drilling and multi stage frac completions which significantly increases per well costs. First quarter land expenditures of $18.1 million represent a combination of Crown and private land purchases adding 26.5 net sections to core positions in the Pine Creek and Edson area of Alberta and contiguous lands on trend with Hoffer and Torquay in southeast Saskatchewan.

Capital Expenditures ($000s)

	Three months ended March 31	
	2010	2009
Drilling, completion and production equipment	**55,993**	30,464
Plant and facilities	**427**	2,859
Seismic	**1,661**	89
Land	**18,149**	1,975
Total exploitation and development	**76,230**	35,387
Office equipment	**290**	238
Capitalized G&A	**1,524**	1,159
Capitalized unit-based compensation	**275**	152
Total other capital	**2,089**	1,549
Total capitalized expenditures before acquisitions	**78,319**	36,936
Property acquisitions (dispositions), net	**(12,702)**	1,314
Total capitalized expenditures	**65,617**	38,250

PRODUCTION

First quarter 2010 production of 30,120 boe/d was slightly above the guidance mid-point of 30,000 boe/d after taking into account 100 boe/d of dispositions. This production level represents an increase of 26 percent over production of 23,836 boe/d in the comparable period of 2009. The increase is due to the ongoing execution of the Trust's capital program as well as the impact of acquisitions completed in 2009.

Average Daily Production Volumes

	Three months ended March 31	
	2010	2009
Oil (bbl/d)	**11,788**	9,990
Natural gas (Mcf/d)	**93,328**	68,966
NGLs (bbl/d)	**2,777**	2,352
Oil equivalent (boe/d)	**30,120**	23,836

Oil equivalent volumes of 30,120 boe/d for the first quarter of 2010 include 301 boe/d (2009 – 442 boe/d), attributable to the non-controlling interest in the Tiberius and Spear properties (see "Related Party Transactions").

For the quarter ended March 31, 2010, oil and natural gas liquids production represented 48 percent of total production volume with natural gas representing 52 percent of total production volume.

Production Weighting

	Three months ended March 31	
	2010	2009
Oil	**39%**	42%
Natural gas	**52%**	48%
NGLs	**9%**	10%

REVENUE

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs and prior to hedging, totaled $136.9 million for the three months ended March 31, 2010, 70 percent higher than the first quarter of 2009. The increase is due to a 26 percent increase in production and a 34 percent increase in the average realized price per boe, driven by a 69 percent increase in the realized crude oil price partially offset by a five percent decrease in the realized natural gas price. The increase in realized prices reflects higher West Texas Intermediate ("WTI") prices, slightly offset by a stronger Canadian dollar.

Revenue

	Three months ended March 31	
	2010	2009
Revenue [(1)] ($000s)		
Oil	**81,085**	40,684
Gas	**42,064**	32,576
NGLs	**13,752**	6,977
Sulphur	**(18)**	425
Total revenue	**136,883**	80,662
$/boe	**50.49**	37.60

(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 first quarter average realized Canadian crude oil price per barrel, net of transportation costs excluding hedging, was $76.43, as compared to $45.25 for the comparable quarter of 2009. The increase in realized price quarter-over-quarter of 69 percent, or $31.18/bbl, was primarily driven by a 83 percent increase in the WTI price (U.S.$/bbl) over the comparable period, partially offset by a 16 percent increase in the value of the Canadian dollar.

For the first quarter of 2010, NAL's crude oil price differential was 93 percent, an increase of nine percentage points from the comparable period in 2009. The differential is calculated as realized price as a percentage of the WTI price stated in Canadian dollars. The increase in 2010 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 first quarter.

Natural gas liquids averaged $55.02/bbl in the first quarter of 2010, a 67 percent increase from the $32.96/bbl realized in 2009.

NATURAL GAS MARKETING

Approximately 70 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 30 percent tied to NYMEX or other indexed reference prices.

For the three months ended March 31, 2010, the Trust's natural gas sales averaged $5.01/Mcf compared to $5.25/Mcf in the comparable period of 2009, a decrease of five percent. The quarter-over-quarter decrease in gas price was largely attributable to marketing a portion of natural gas based on the monthly benchmark. The AECO monthly price decreased five percent quarter-over-quarter, compared to a one percent increase in the daily AECO price.

Prices for Lake Erie natural gas decreased to $5.70/Mcf in the first quarter of 2010, compared to $6.32/Mcf in 2009, a decrease of ten percent. Lake Erie production of 3.2 mmcf/d accounted for three percent of the Trust's natural gas production in the first quarter of 2010, as compared to five percent in the comparable period of 2009. Natural gas sales from the Lake Erie property generally receive a higher price due to the close proximity of the Ontario and Northeastern U.S. markets.

Average Pricing
(net of transportation charges)

	Three months ended March 31	
	2010	2009
Liquids		
WTI (US$/bbl)	**78.69**	43.08
NAL average oil (Cdn$/bbl)	**76.43**	45.25
NAL natural gas liquids (Cdn$/bbl)	**55.02**	32.96
Natural Gas (Cdn$/mcf)		
AECO – daily spot	**4.96**	4.92
AECO – monthly	**5.36**	5.63
NAL Western Canada natural gas	**4.98**	5.19
NAL Lake Erie natural gas	**5.70**	6.32
NAL average natural gas	**5.01**	5.25
NAL Oil Equivalent before hedging (Cdn$/boe – 6:1)	**50.49**	37.60
Average Foreign Exchange Rate (Cdn$/US$)	**1.041**	1.245

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. Management's practice is to hedge more near-term volumes on a six to 12 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 March 31, 2010, NAL had several financial WTI oil contracts and AECO natural gas contracts in place.

NAL hedges floating rate debt for periods of up to five years. As at March 31, 2010, NAL had several interest rate swaps outstanding with a total notional value of US$139 million.

NAL's foreign exchange hedging policy currently provides authorization to hedge up to 50 percent of US dollar exposure for up to 24 months. As at March 31, 2010, NAL had several exchange rate swaps outstanding with a total notional value of US$72 million.

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

Realized gains on derivative contracts were $1.4 million for the first quarter of 2010, compared to $27.8 million in the comparable quarter of 2009. Gains are lower due primarily to rising oil prices versus hedge positions and lower gains on gas positions due to lower gas prices. Oil losses are somewhat offset by foreign exchange gains related to a rising Canadian dollar.

All derivative contracts are recorded on the balance sheet at fair value based upon forward curves at March 31, 2010. Changes in the fair value of the derivative contracts are recognized in net income for the period.

Fair value is calculated at a point in time based on an approximation of the amounts that would be received or paid to settle these instruments, with reference to forward prices at March 31, 2010. 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 March 31, 2010 was a net asset of $16.0 million, comprised of a $19.0 million asset on gas contracts, partially offset by a $11.3 million liability on oil contracts, a $5.7 million asset on foreign exchange contracts and a $2.7 million asset on interest rate swaps.

First quarter income for 2010 includes an $18.5 million unrealized gain on derivatives resulting from the change in the fair value of the derivative contracts during the quarter from an unrealized loss of $2.5 million at December 31, 2009 to an unrealized gain of $16.0 million at March 31, 2010. The $18.5 million unrealized gain was comprised of a $1.5 million unrealized gain on crude oil contracts, a $0.2 million unrealized gain on interest rate swaps, a $15.0 million unrealized gain on natural gas contracts and a $1.8 million unrealized gain on foreign exchange swaps.

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

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

	Three months ended March 31	
	2010	2009
Unrealized gain (loss):		
Crude oil contracts	**$ 1,546**	$ (21,198)
Natural gas contracts	**15,021**	2,701
Interest rate swaps	**191**	(678)
Exchange rate swaps	**1,751**	671
Unrealized gain (loss)	**18,509**	(18,504)
Realized gain (loss):		
Crude oil contracts	**(2,082)**	20,752
Natural gas contracts	**2,497**	6,956
Interest rate swaps	**(257)**	(29)
Exchange rate swaps	**1,290**	83
Realized gain	**1,448**	27,762
Gain on derivative contracts	**$ 19,957**	$ 9,258

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

Realized Gain (Loss) on Derivative Contracts

	Three months ended March 31	
	2010	2009
Commodity contracts:		
Average crude volumes hedged (bbl/d)	**6,366**	3,603
Crude oil realized gain (loss) ($000s)	**(2,082)**	20,752
Gain (loss) per bbl hedged ($)	**(3.63)**	63.99
Average natural gas volumes hedged (GJ/d)	**37,967**	29,000
Natural gas realized gain ($000s)	**2,497**	6,956
Gain per GJ hedged ($)	**0.73**	2.67
Average BOE hedged (boe/d)	**12,363**	8,185
Total realized commodity contracts gain ($000s)	**415**	27,708
Gain per boe hedged ($)	**0.37**	37.61
Gain per boe ($)	**0.15**	12.91
Exchange rate swaps realized gain ($000s)	**1,290**	83
Gain per boe ($)	**0.48**	0.04
Interest rate swaps realized gain (loss) ($000s)	**(257)**	(29)
Gain (loss) per boe ($)	**(0.09)**	(0.01)
Total realized gain ($000s)	**1,448**	27,762
Gain per boe ($)	**0.54**	12.94

Average hedged boes for the first quarter of 2010 were 12,363 as compared to 10,226 for the fourth quarter of 2009.

NAL has the following interest rate risk management contracts outstanding:

INTEREST RATE CONTRACT	Remaining Term	Amount (millions) (1)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Mar 2010 – Dec 2011	$ 39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Jan 2013	$ 22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 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 exchange rate risk management contracts outstanding:

EXCHANGE RATE CONTRACT	Remaining Term	Amount (1) (US$ MM)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Apr – Dec 2010	$ 8.0	1.0966	BofC Average Noon Rate

(1) Notional US$ denominated commodity sales per month.

From April 1 to December 31, 2010, NAL also has a commitment to sell US$9 million ($1 million/month) at 1.045 if the monthly Bank of Canada average noon rate exceeds 1.045. NAL is paid a premium of approximately $10,000 a month when the average noon rate falls between 0.95 and 1.045.

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q2-10	Q3-10	Q4-10	Q1-11	Q2-11
US$ Collar Contracts					
$US WTI Collar Volume (bbl/d)	3,700	2,800	2,600	800	800
Bought Puts – Average Strike Price ($US/bbl)	$ 63.59	$ 65.63	$ 65.87	$ 81.25	$ 81.25
Sold Calls – Average Strike Price ($US/bbl)	$ 74.94	$ 77.55	$ 78.05	$ 94.47	$ 94.47
US$ Swap Contracts					
$US WTI Swap Volume (bbl/d)	2,800	3,200	3,300	-	-
Average WTI Swap Price ($US/bbl)	$ 79.45	$ 83.91	$ 83.82	-	-
Total Oil Volume (bbl/d)	6,500	6,000	5,900	800	800

NATURAL GAS	Q2-10	Q3-10	Q4-10	Q1-11	Q2-11
Swap Contracts					
AECO Swap Volume (GJ/d)	39,000	40,000	27,337	4,000	4,000
AECO Average Price ($Cdn/GJ)	$ 5.60	$ 5.61	$ 5.66	$ 5.78	$ 5.78
Total Natural gas Volume (GJ/d)	39,000	40,000	27,337	4,000	4,000

For the remainder of 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 $23.1 million for the three months ended March 31, 2010. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 16.9 percent for the quarter ended March 31, 2010, a decrease from the 17.5 percent experienced in the same period of the previous year.

Royalties increased to $8.54 per boe for the first quarter of 2010, an increase of 30 percent compared to the first quarter of 2009. The increase is attributable to higher commodity prices on a quarter-over-quarter basis.

On March 11, 2010 the Alberta Government announced measures to improve the Province of Alberta's competitive position in the oil and gas industry. The current royalty framework for natural gas and conventional oil will be modified for all production effective January 1, 2011. The government will make the five percent maximum royalty rate during the first year of production incentive permanent and the maximum royalties paid on oil and gas production will be lowered from 50 percent to 40 percent for oil and 36 percent for natural gas.

For the quarter ended March 31, 2010, 45 percent of crude oil and 67 percent of natural gas production was from Alberta.

Royalty Expenses

	Three months ended March 31	
	2010	2009
Royalties ($000s)	**23,146**	14,134
As % of revenue	**16.9**	17.5
$/boe	**8.54**	6.59

OPERATING COSTS

Operating costs averaged $10.81 per boe for the quarter ended March 31, 2010, down 10 percent from $11.95 per boe for the quarter ended March 31, 2009. Operating costs continue to trend down driven by lower natural gas prices impacting the cost of power and continued gains from an aggressive optimization program in field operations. Based on emerging cost trends the Trust has lowered its guidance for operating costs to a range of $10.75 - 11.25 per boe.

Operating Costs

	Three months ended March 31	
	2010	2009
Operating costs ($000s)	**29,304**	25,640
As a % of revenue	**21.4**	31.8
$/boe	**10.81**	11.95

OTHER INCOME

Other income was $0.12 per boe for the first quarter of 2010 compared to $0.45 per boe in the comparable quarter of 2009. 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"). In the first quarter of 2010, interest expense totaled $0.1 million, as compared to net interest income of $0.5 million for the comparable period of 2009, the decrease being attributable to the repayment of a note receivable from MFC in the first quarter of 2009.

Other Income

	Three months ended March 31	
	2010	2009
Interest on notes with MFC ($000s)	**(112)**	544
Other ($000s)	**443**	420
Total other income ($000s)	**331**	964
As a % of revenue	**0.2**	1.20
Interest on notes with MFC ($/boe)	**(0.04)**	0.25
Other ($/boe)	**0.16**	0.20
Total other income ($/boe)	**0.12**	0.45

OPERATING NETBACK

For the quarter ended March 31, 2010, NAL's operating netback, before hedging gains, was $31.30 per boe, an increase of 63 percent from $19.26 per boe for the quarter ended March 31, 2009. The increase was due to higher revenues, a result of higher crude oil prices, and decreased operating costs, partially offset by increased royalty expense. Hedging gains, related to commodity and exchange rate derivative contracts, were $0.63 per boe in the first quarter of 2010, as compared to $12.95 per boe in 2009, the decrease in 2010 attributable mainly to higher realized crude oil prices.

Operating Netback

	Three months ended March 31	
	2010	2009
AVERAGE DAILY PRODUCTION		
Oil (bbl/d)	**11,788**	9,990
Gas (Mcf/d)	**93,328**	68,966
NGLs (bbl/d)	**2,777**	2,352
Total (boe/d)	**30,120**	23,836
REVENUE		
Oil ($/bbl)	**76.43**	45.25
Gas ($/Mcf)	**5.01**	5.25
NGLs ($/bbl)	**55.02**	32.96
Total ($/boe)	**50.49**	37.60
ROYALTIES		
Oil ($/bbl)	**15.11**	8.62
Gas ($/Mcf)	**0.47**	0.77
NGLs ($/bbl)	**12.54**	7.73
Total ($/boe)	**8.54**	6.59
OPERATING EXPENSES		
Oil ($/bbl)	**10.92**	11.36
Gas ($/Mcf)	**1.83**	2.16
NGLs ($/bbl)	**9.28**	9.59
Total ($/boe)	**10.81**	11.95
OTHER INCOME (1)		
Oil ($/bbl)	**0.25**	0.24
Gas ($/Mcf)	**0.02**	0.03
NGLs ($/bbl)	**0.18**	0.19
Total ($/boe)	**0.16**	0.20
OPERATING NETBACK, BEFORE HEDGING		
Oil ($/bbl)	**50.65**	25.51
Gas ($/Mcf)	**2.73**	2.35
NGLs ($/bbl)	**33.38**	15.83
Total ($/boe)	**31.30**	19.26
HEDGING GAINS/(LOSSES) (2)		
Oil ($/bbl)	**(0.75)**	23.17
Gas ($/Mcf)	**0.30**	1.12
NGLs ($/bbl)	**-**	-
Total ($/boe)	**0.63**	12.95
OPERATING NETBACK, AFTER HEDGING		
Oil ($/bbl)	**49.90**	48.68
Gas ($/Mcf)	**3.03**	3.47
NGLs ($/bbl)	**33.38**	15.83
Total ($/boe)	**31.93**	32.21

(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 March 31, 2010, G&A expenses were $4.4 million, compared with $2.6 million in the comparable quarter of 2009. In addition, $1.5 million of G&A costs relating to exploitation and development activities were capitalized in the first quarter of 2010, compared with $1.2 million in the first quarter of 2009. G&A expense per boe was $1.61 in the quarter, as compared to $1.22 for the same period in 2009.

The year-over-year increase in total G&A of $2.1 million is attributable to a lower payout under the 2008 short term incentive plan of the Manager than was provided for at December 31, 2008, resulting in lower charges in the first quarter of 2009 ($0.8 million), plus slightly higher compensation costs in the first quarter of 2010 as compared to 2009.

General and Administrative Expenses

	Three months ended March 31	
	2010	2009
G&A ($000s)		
Expensed	**4,359**	2,618
Capitalized	**1,524**	1,159
Total G&A ($000s)	**5,883**	3,777
Expensed G&A costs:		
($/boe)	**1.61**	1.22
As % of revenue	**3.2**	3.2
Per trust unit ($)	**0.03**	0.03

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 first quarter of 2010, the Trust recorded a $0.7 million charge for unit-based incentive compensation that reflects the impact of vesting, additional notional units and an increase in the PTU performance multiplier for the 2009 grant. These factors were partially offset by a decrease in the unit price of the Trust of six percent, from $13.74 at December 31, 2009 to $12.95 at March 31, 2010. A decrease in unit price results in previously accrued amounts being reversed to the extent not vested.

Unit-based incentive compensation increased by 57 percent compared to the first quarter of 2009, from $0.5 million in 2009 to $0.7 million in 2010. The increase is a reflection of a 90 percent increase in unit price used to determine the compensation, year-over-year, from $6.80 a unit at March 31, 2009 to $12.95 at March 31, 2010. In addition, during the first quarter of 2010 the unit price decreased from the December 31, 2009 unit price by six percent, resulting in a decrease to previously accrued amounts.

At March 31, 2010, the unit price used to determine unit-based incentive compensation was $12.95. The closing unit price of the Trust on the Toronto Stock Exchange on May 3, 2010 was $12.67.

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 March 31, 2010, the Trust has recorded a total accumulated liability for unit-based incentive compensation in the amount of $10.2 million, of which $5.4 million is recorded as current as it is payable in December 2010, and $4.8 million is long-term as it is payable in December 2011 and December 2012.

Unit-Based Compensation

	Three months ended March 31	
	2010	2009
Unit-based compensation ($000s):		
Expensed	**439**	302
Capitalized	**275**	152
Total unit-based compensation	**714**	454
Expensed unit-based compensation:		
As % of revenue	**0.3**	0.37
$/boe	**0.16**	0.14
Per trust unit ($)	**-**	-

RELATED PARTY TRANSACTIONS

The Trust is managed by the Manager. The Manager is a wholly-owned subsidiary of Manulife Financial Corporation ("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. 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 $3.6 million (2009 - $1.9 million) for the reimbursement of G&A expenses during the first quarter. 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 $6.9 million was paid in the first quarter of 2010, representing units that vested on November 30, 2009 (2009 - $2.3 million).

At March 31, 2010 the Trust owed the Manager $1.7 million for the reimbursement of G&A and had a payable to NAL Resources of $0.8 million, 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.

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 Partnership then paid an equal distribution of $49.6 million to MFC. This resulted in a $49.6 million reduction to the non-controlling interest on the balance sheet.

As at March 31, 2010, there is a note payable of $8.3 million to 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 this note of $0.1 million was payable by the Trust for the first quarter of 2010 (2009 - $0.5 million net interest income) and is reported as other income.

INTEREST

Interest on bank debt includes the interest rate charge on borrowings, plus a standby fee, a stamping fee and the fee for renewal. Interest on bank debt for the first quarter of 2010 was $3.1 million, an increase of $1.1 million from $2.0 million for the comparable period in 2009. The increase was due to an increase in average effective interest rates, partially offset by a decrease in average debt levels. Average outstanding bank debt for the first quarter of 2010 was $232.5 million, $63.9 million lower than the $296.4 million outstanding for the first quarter of 2009. NAL's effective interest rate averaged 5.39 percent during the first quarter of 2010, compared to 2.58 percent during the comparable period in 2009. The increase in the rate from the first quarter of 2009 is attributable to increases in the bank fees that are included in debt costs. NAL's interest is calculated based upon a floating rate before the effect of any interest rate swaps.

Interest on convertible debentures represents interest charges of $3.1 million for the three months ended March 31, 2010 as compared to $1.3 million for the same period in 2009. The interest includes the interest on the 2007 debentures at 6.75 percent and the interest on the debentures issued in December 2009 at 6.25 percent. Accretion of the debt discount was $1.0 million for the three months ended March 31, 2010 as compared to $0.4 million for the same period in 2009. The increase in interest and accretion is due to the December 2009 issuance of convertible debentures.

Interest and Debt

	Three months ended March 31	
	2010	2009
Interest on bank debt ($000s) [1]	**3,086**	1,963
Interest and accretion on convertible debentures ($000s)	**4,133**	1,724
Total interest ($000)	**7,219**	3,687
Bank debt outstanding at period end ($000s)	**244,695**	304,918
Convertible debentures at period end ($000s) [2]	**178,624**	74,382
$/boe:		
Interest on bank debt	**1.14**	0.92
Interest on convertible debentures	**1.16**	0.63
Accretion on convertible debentures	**0.37**	0.17
Total interest	**2.67**	1.72

(1) Excludes interest rate contract impact.
(2) Debt component of the debentures, as reported on the balance sheet.

CASH FLOW NETBACK

For the quarter ended March 31, 2010, NAL's cash flow netback was $27.73 per boe, a six percent decrease from $29.54 per boe for the comparable period in 2009. The decrease was due to a lower operating netback after hedging, higher G&A expenses, including unit-based incentive compensation, and higher interest charges.

Cash Flow Netback ($/boe)

	Three months ended March 31	
	2010	2009
Operating netback, after hedging	**31.93**	32.21
G&A expenses, including unit-based incentive compensation	**(1.77)**	(1.36)
Interest on bank debt and convertible debentures [1]	**(2.30)**	(1.55)
Interest on notes with MFC [2]	**(0.04)**	0.25
Realized loss on interest rate derivative contracts	**(0.09)**	(0.01)
Cash flow netback	**27.73**	29.54

(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 March 31, 2010, depletion on property, plant and equipment and accretion on the asset retirement obligations was $23.86 per boe, 14 percent higher than the $20.99 per boe for the same period in 2009. The increase in depletion rate per boe in 2010 reflects a higher depletion rate associated with the oil and gas properties of Breaker Energy Ltd. which was acquired in December 2009.

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

Depletion, Depreciation and Accretion Expenses

	Three months ended March 31	
	2010	2009
Depletion and depreciation ($000s)	**62,036**	43,208
Accretion of asset retirement obligation ($000s)	**2,631**	1,828
Total DDA ($000s)	**64,667**	45,036
DDA rate per boe ($)	**23.86**	20.99

TAXES

In the first quarter of 2010, NAL had a future income tax recovery of $2.2 million compared to a $6.1 million recovery in the corresponding period of the prior year.

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

As at March 31, 2010, 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, 21 percent represented UCC, with the balance represented by CEE, CDE, trust unit issue costs and non-capital loss carry forwards.

Estimated Tax Pools ($ millions)

	March 31, 2010	December 31, 2009
Canadian exploration expense	51	50
Canadian development expense	412	379
Canadian oil and gas property expense	440	436
Undepreciated capital costs	272	274
Other (including loss carry forwards)	123	128
Total estimated tax pools	1,298	1,267

Based on current strip prices at March 31, 2010, 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 March 31	
	2010	2009
Net profits interest expense (income)	618	243
Share of net income attributable to MFC	174	616
	792	859

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 first quarter of 2010 was $29.3 million compared to $4.7 million for the comparable period in 2009. The increase of $24.6 million was mainly due to increased revenues net of royalties ($47.8 million) and increased gains on derivative contracts ($10.7 million), offset by increased operating costs ($3.7 million), increased G&A ($1.7 million), increased DD&A expense ($18.8 million), a lower tax recovery ($4.0 million) and increased interest charges ($3.5 million).

Net Income ($000s)

	Three months ended March 31	
	2010	2009
Net income	29,349	4,724

CAPITAL RESOURCES AND LIQUIDITY

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

As at March 31, 2010, NAL had 137,880,631 trust units outstanding, compared with 137,471,209 trust units as at December 31, 2009. The increase from December 31, 2009 is attributable to 409,422 units issued under the Trust's distribution reinvestment plan ("DRIP").

Under NAL's distribution reinvestment plan (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 13.9 percent for this quarter.

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

On April 14, 2010, the Trust issued pursuant to a bought deal offering 7,550,000 trust units at a price of $13.25 per unit for aggregate gross proceeds of $100.0 million.

As at March 31, 2010 the Trust had net debt of $503.9 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 $309.1 million, compared with $282.7 million at December 31, 2009. The increase in net debt, excluding convertible debentures, of $26.4 million during 2010 is attributable to increased bank debt of $14.0 million and a negative change in working capital of $12.4 million.

Bank debt outstanding was $244.7 million at March 31, 2010 compared with $230.7 million as at December 31, 2009. Of the $244.7 million outstanding at March 31, 2010, all is outstanding under the production facility.

At the end of the first quarter, the Trust had a net debt (excluding convertible debentures) to 12 months trailing cash flow ratio of 1.28 times and a total net debt (including convertible debentures) to 12 months trailing cash flow ratio of 2.08 times.

Subsequent to quarter end, the Trust renewed its credit facility at the previously approved amount of $550 million. The credit facility is a fully secured, extendible, revolving facility and will revolve until April 30, 2011 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 May 1, 2012.

The Trust has two series of convertible debentures currently outstanding.

On December 3, 2009, the Trust issued $115 million principal amount of 6.25 percent 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 percent convertible extendible unsecured subordinated debentures. 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 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 $1.0 million (2009 - $0.4 million) of accretion of the debt discount in the first quarter of 2010.

As at May 3, 2010, the Trust has 145,599,324 trust units and $194.7 million in convertible debentures outstanding.

Capitalization

	March 31, 2010	December 31, 2009	March 31, 2009
Trust unit equity ($000s)	**891,380**	894,192	532,171
Bank debt ($000s)	**244,695**	230,713	304,918
Working capital deficit (surplus) (1) ($000s)	**64,441**	52,014	21,057
Net debt excluding convertible debentures	**309,136**	282,727	325,975
Convertible debentures ($000s) (2)	**194,744**	194,744	79,744
Net debt	**503,880**	477,471	405,719
Net debt excluding convertible debentures to trailing 12-month cash flow (3)	**1.28**	1.23	1.10
Total net debt to trailing 12-month cash flow (3)	**2.08**	2.07	1.37
Trust units outstanding (000s)	**137,881**	137,471	96,181

(1) Working capital and other liabilities, excludes derivative contract, future income tax and notes with MFC.
(2) Convertible debentures included at face value.
(3) Calculated as net debt divided by funds from operations for the previous 12 months.

The Trust actively manages its payout ratio (including capital) to ensure that its capital program can be executed and distribution levels are maintained. The targeted payout ratios may change over time in response to market conditions and opportunities available to the Trust. In addition to cash generated from operations, the Trust may use a combination of equity and debt to take advantage of opportunities, both internally generated and acquisitions. The recent equity offering will be used to repay indebtedness incurred in connection with certain acquisitions and to fund the Trust's expanded 2010 capital program. Funds from operations is a non-GAAP measure used by management as an indicator of the Trust's ability to generate cash from operations. Currently, the Trust has a bank line of $550 million of which $245 million is drawn down at March 31, 2010, leaving available capacity of $305 million.

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$82.54 per boe on fixed price contracts. On collared contracts, crude volumes are hedged at an average ceiling price of US$76.63 per boe and at an average floor price of US$64.87 per boe. For natural gas, remaining 2010 hedges total approximately 44 percent of net budgeted production volumes hedged at an average floor price in excess of $5.62 per GJ ($5.93 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 $210 million capital program. 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.

Fluctuations in commodity prices, market conditions or potential growth opportunities may make it necessary to adjust forecasted capital expenditures and/or distributions levels.

Under the tax legislation regarding the change in the taxation of income trusts, the Trust has a grandfathering period to 2011, when the rules come into effect. The grandfathering period restricts "undue expansion" of the Trust by placing growth limits for issuances of equity and convertible debt, based on the market capitalization of the Trust on October 31, 2006, the date of the announcement of the changes in the tax legislation. For the remainder of 2010, the Trust has approximately $428 million of safe harbour available, after taking into consideration the equity offering that closed subsequent to quarter end.

ASSET RETIREMENT OBLIGATION

At March 31, 2010, the Trust reported an asset retirement obligation ("ARO") balance of $131.9 million ($127.9 million as at December 31, 2009) for future abandonment and reclamation of the Trust's oil and gas properties and facilities. The ARO balance was increased by $2.3 million due to liabilities incurred and revisions to estimates and $2.6 million from accretion expense, and was reduced by $0.9 million for actual abandonment and reclamation expenditures incurred during the first quarter.

DISTRIBUTIONS TO UNITHOLDERS

For the three months ended March 31, 2010, the Trust distributed 58 percent of its cash flow from operating activities, as compared to 45 percent for the same period in 2009. 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 2010, 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, ongoing capital expenditures are required in order to manage 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 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 a combination of debt and equity. Fluctuations in commodity prices, other market factors, or growth opportunities may make it necessary to adjust forecasted capital expenditures or distributions 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 as well as the opportunities for capital expenditures. The future sustainability of this distribution policy will be dependent upon maintaining productive capacity through both capital expenditures and acquisitions. A significant further decrease in commodity prices 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 March 31 2010	2009
Cash flow from operating activities	**63,648**	66,546
Net income	**29,349**	4,724
Actual cash distributions paid or payable	**37,185**	29,816
Excess of cash flow from operating activities over cash distribution paid	**26,463**	36,730
Percentage of cash flow from operations distributed	**58%**	45%
Excess (shortfall) of net income over cash distributions paid	**(7,836)**	(25,092)

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

For the three months ended March 31, 2010, funds from operations amounted to $73.2 million, compared with $62.0 million for the three months ended March 31, 2009. The 18 percent increase is due to higher revenues resulting from higher crude oil prices. On a per trust unit basis, funds from operations decreased 17 percent from $0.64 in 2009 to $0.53 in 2010.

Funds from Operations

	Three months ended March 31 2010	2009
Funds from operations ($000s)	**73,242**	62,024
Funds from operations per trust unit	**0.53**	0.64
Payout ratio based on funds from operations	**51%**	48%

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 March 31, 2010, the Trust had spent $3.6 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 $30 million in the first year and $50 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 March 31, 2010, the Trust has spent $15.6 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)	3,116	3,505	3,505	3,482	3,414
Office lease – Clipper and Breaker (2)	1,633	2,184	2,192	358	-
Transportation agreement	3,544	-	-	-	-
Processing agreement (3)	1,529	2,242	401	384	-
Convertible debentures (4)	-	-	79,744	-	115,000
Bank debt	-	-	146,817	97,878	-
Total	9,822	7,931	232,659	102,102	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 64 percent) of the expense on a monthly basis.

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

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

(4) Principal amount.

QUARTERLY INFORMATION

	2010	2009				2008		
($000s, except per unit and production amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue, net of royalties (1)	**135,662**	88,165	85,988	60,922	77,791	161,156	234,993	58,861
Per unit	**0.99**	0.75	0.77	0.60	0.81	1.68	2.46	0.63
Cash flow from operations	**63,648**	53,060	52,999	63,690	66,546	77,326	98,860	73,295
Per unit	**0.46**	0.45	0.47	0.63	0.69	0.80	1.03	0.78
Funds from operations (2)	**73,242**	62,953	53,766	51,998	62,024	67,040	79,233	88,578
Per unit	**0.53**	0.53	0.48	0.51	0.64	0.70	0.83	0.94
Net income (loss)	**29,349**	5,634	8,249	(9,407)	4,724	55,374	111,045	(17,572)
Per unit								
basic	**0.21**	0.05	0.07	(0.09)	0.05	0.58	1.16	(0.19)
diluted	**0.21**	0.05	0.07	(0.09)	0.05	0.56	1.11	(0.19)
Average oil equivalent production (boe/d – 6:1)	**30,120**	25,748 (3)	23,418	23,049	23,836	23,984	23,808	23,791

(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

DISCLOSURE CONTROLS AND PROCEDURES (“DC&P”)

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

INTERNAL CONTROL OVER FINANCIAL REPORTING (“ICFR”)

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR, as such term is defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings. The control framework NAL’s officers used to design NAL’s ICFR is the Internal Control -- Integrated Framework (the “COSO Framework”) published by The Committee of Sponsoring Organizations of the Treadway Commission (“COSO”).

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, 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 provides reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

There has not been any change in NAL’s internal control over financial reporting during the first three months of 2010 that has materially affected, or is reasonably likely to materially affect, NAL’s internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by NAL are disclosed in the notes to NAL’s December 31, 2009 audited consolidated financial statements. Certain accounting policies require that management make appropriate decisions when formulating estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The Manager reviews the estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes in estimated amounts that differ materially from current estimates. NAL might realize different results from the application of new accounting standards published, from time to time, by various regulatory bodies. An assessment of NAL’s significant accounting estimates is discussed in the MD&A filed with NAL’s audited consolidated financial statements for the year ended December 31, 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. During the first quarter of 2010, the review of all other IFRS standards where potential differences between Canadian GAAP and IFRS exist has been completed, including financial instruments, interests in joint ventures and income taxes, with recommendations for accounting policies developed, subject to Board approval.

Next steps include the review of presentation and disclosure standards.

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 finalized 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: May 4, 2010

CONSOLIDATED BALANCE SHEETS

(thousands of dollars) (unaudited)	As at March 31, 2010	As at December 31, 2009
Assets		
Current assets		
Cash	$ 5,042	$ 1,604
Accounts receivable	51,255	61,631
Prepaids and other receivables	11,301	15,663
Derivative contracts (Note 11)	24,714	6,285
Future income tax asset	-	3,132
	92,312	88,315
Derivative contracts (Note 11)	2,652	2,461
Goodwill	14,722	14,722
Property, plant and equipment (Note 3)	1,511,167	1,503,952
	$ 1,620,853	$ 1,609,450
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 111,495	$ 110,897
Note payable (Note 2)	8,331	8,907
Distributions payable to unitholders	12,409	12,372
Derivative contracts (Note 11)	11,342	11,231
Future income tax liability	1,665	-
	145,242	143,407
Bank debt (Note 4)	244,695	230,713
Convertible debentures (Note 5)	178,624	177,977
Other liabilities (Note 6)	8,135	7,643
Asset retirement obligations (Note 8)	131,917	127,872
Future income tax liability	17,818	24,778
Non-controlling interest (Note 9)	3,042	2,868
	729,473	715,258
Unitholders' equity		
Unitholders' capital (Note 10)	1,487,053	1,482,029
Equity component of convertible debentures (Note 5)	12,628	12,628
Deficit (Note10)	(608,301)	(600,465)
	891,380	894,192
	$ 1,620,853	$ 1,609,450
Commitments (Note 12)		
Subsequent event (Note 13)		
Trust units outstanding (000s)	137,881	137,471

See accompanying notes.

CONSOLIDATED STATEMENTS OF INCOME, COMPREHENSIVE INCOME AND DEFICIT

Three months ended March 31,

(thousands of dollars, except per unit amounts) (unaudited)	2010	2009
Revenue		
Oil, natural gas and liquid sales	$ 138,520	$ 81,703
Crown royalties	(17,105)	(10,611)
Freehold and other royalties	(6,041)	(3,523)
	115,374	67,569
Gain (loss) on derivative contracts (Note 11):		
Realized gain	1,448	27,762
Unrealized gain (loss)	18,509	(18,504)
	19,957	9,258
Other income	331	964
	135,662	77,791
Expenses		
Operating	29,304	25,640
Transportation	1,637	1,041
General and administrative	4,359	2,618
Unit-based incentive compensation (Note 7)	439	302
Interest on bank debt	3,086	1,963
Interest and accretion on convertible debentures	4,133	1,724
Depletion, depreciation and amortization	62,036	43,208
Accretion on asset retirement obligations	2,631	1,828
	107,625	78,324
Income (loss) before taxes and non-controlling interest	28,037	(533)
Income tax recovery (expense)	(59)	1
Future income tax reduction	2,163	6,115
Total income tax reduction	2,104	6,116
Income before non-controlling interest	30,141	5,583
Non-controlling interest (Note 9)	(792)	(859)
Net income and comprehensive income	29,349	4,724
Deficit, beginning of period	(600,465)	(489,512)
Net income	29,349	4,724
Distributions declared	(37,185)	(29,816)
Deficit, end of period	$ (608,301)	$ (514,604)
Net income per trust unit (Note 10)		
Basic	$ 0.21	$ 0.05
Diluted	$ 0.21	$ 0.05
Weighted average trust units outstanding (000s)	137,660	96,181

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Three months ended March 31,

(thousands of dollars) (unaudited)	2010	2009
Operating Activities		
Net income	$ 29,349	$ 4,724
Items not involving cash:		
Depletion, depreciation and amortization	62,036	43,208
Accretion on asset retirement obligations	2,631	1,828
Unrealized loss (gain) on derivative contracts	(18,509)	18,504
Future income tax reduction	(2,163)	(6,115)
Non-cash accretion expense on convertible debentures	991	378
Non-controlling interest	174	616
Lease amortization	(376)	-
Abandonment and reclamation	(891)	(1,119)
Change in non-cash working capital	(9,594)	4,522
	63,648	66,546
Financing Activities		
Distributions paid to unitholders	(31,969)	(36,549)
Increase in bank debt	13,982	22,586
Issue of trust units, net of issue costs	(155)	-
Note repayment from MFC (Note 2)	-	49,599
Partnership distribution paid to MFC	-	(49,802)
Issuance of convertible debentures, net of issue costs	(344)	-
Change in non-cash working capital	-	33
	(18,486)	(14,133)
Investing Activities		
Additions to property, plant and equipment	(78,319)	(36,936)
Property acquisitions	(1,974)	(1,314)
Proceeds from dispositions	14,676	-
Disposition of Spearpoint	(309)	-
Change in non-cash working capital	24,202	(7,132)
	(41,724)	(45,382)
Increase in cash	3,438	7,031
Cash, beginning of period	1,604	5,584
Cash, end of period	$ 5,042	$ 12,615
Supplementary disclosure of cash flow information:		
Cash paid (received) during the period for:		
Interest	$ 6,796	$ 4,678
Tax	$ 59	$ (72)

Refer to Notes 8 and 10 for significant non-cash amounts not included in the cash flow statement.

See accompanying notes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Three months ended March 31, 2010
(Tabular amounts in thousands of dollars, except per unit amounts)
(unaudited)

1. SUMMARY OF ACCOUNTING POLICIES

Management prepared the interim consolidated financial statements of NAL Oil & Gas Trust ("NAL" or the "Trust") in accordance with accounting principles generally accepted in Canada and following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2009. The following disclosure is incremental to the disclosure included within the annual financial statements. Please read the interim consolidated financial statements in conjunction with the consolidated financial statements and notes thereto in NAL's annual report for the year ended December 31, 2009.

2. RELATED PARTY TRANSACTIONS

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

The Manager provides certain services to the Trust pursuant to an administrative services and cost sharing agreement. This agreement requires the Trust to reimburse the Manager, at cost, for general and administrative ("G&A") expenses incurred by the Manager on behalf of the Trust. The Trust paid $3.6 million (2009 - $1.9 million) for the reimbursement of G&A expenses during the first quarter. 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 $6.9 million was paid relating to notional units that vested on November 30, 2009 (2009 - $2.3 million).

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

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

During the first quarter of 2009, MFC repaid the note receivable to the Partnership for $49.6 million. The 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 9). In addition, during 2009 the Partnership paid distributions to its partners, MFC's share being $5.0 million (Note 9).

As at March 31, 2010, there is a note payable of $8.3 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 this note of $0.1 million was payable by the Trust for the first quarter of 2010 (2009 - $0.5 million net interest income) and is reported as other income.

The following amounts are due to and from related parties as at March 31, 2010 and have been included in prepaids and other receivables, accounts payable and accrued liabilities and note payable on the balance sheet:

		March 31, 2010		December 31, 2009
Due from (to) NAL Resources Limited	$	(757)	$	1,731
Due from (to) NAL Resources Management Limited		(1,660)		(8,753)
Due from (to) Manulife Financial Corporation (1)		(9,187)		(9,472)
	$	(11,604)	$	(16,494)

(1) Included on consolidation, eliminated through non-controlling interest. Represents note payable of $8.3 million (2009: $8.9 million), plus amounts due from (to) MFC of ($0.9) million (2009: ($0.6) million), presented in accounts payable/accounts receivable, relating to the net interest and NPI amounts due.

3. PROPERTY, PLANT AND EQUIPMENT

		March 31, 2010		December 31, 2009
Petroleum and natural gas properties, at cost	$	2,648,519	$	2,579,268
Less: Accumulated depletion and depreciation		(1,137,352)		(1,075,316)
	$	1,511,167	$	1,503,952

The calculation of first quarter depletion and depreciation included future development costs for proved reserves of $209.2 million (2009 - $46.3 million) and excluded costs associated with undeveloped land and unproved properties of $141.0 million (2009 - $40.1 million)

During the three months ended March 31, 2010, the Trust capitalized $1.5 million (2009 - $1.2 million) of G&A costs and $0.3 million (2009 - $0.2 million) of unit-based incentive compensation that were directly related to exploitation and development programs.

4. BANK DEBT

		March 31, 2010		December 31, 2009
Production loan facility	$	244,695	$	230,713
Working capital facility		-		-
Total debt outstanding	$	244,695	$	230,713

The Trust maintains a fully secured, extendible, revolving term credit facility with a syndicate of Canadian chartered banks and one U.S. based lender. The facility consists of a $535 million production facility and a $15 million working capital facility. The total amount of the facility is determined by reference to a borrowing base. The borrowing base is calculated by the bank syndicate and is based on the net present value of the Trust's oil and gas reserves and other assets. Given that the borrowing base is dependent on the Trust's reserves and future commodity prices, lending limits are subject to change on renewal.

The credit facility is fully secured by first priority security interests in all existing and future acquired properties and assets of the Trust and its subsidiary and affiliated entities. The facility will revolve until April 30, 2011 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 2011, 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 May 1, 2012.

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 March 31, 2010 and December 31, 2009 all amounts outstanding were in Canadian dollars.

On March 31, 2010 the effective interest rate on amounts outstanding under the credit facility was 3.33 percent (2009 – 1.80 percent). The Trust's interest charge includes this fixed interest rate component, plus a standby fee, a stamping fee and the fee for renewal.

5. CONVERTIBLE DEBENTURES

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

	Three months ended March 31, 2010			Year ended December 31, 2009		
	6.25%	**6.75%**	**Total**	6.25%	6.75%	Total
Principal, beginning of period	**$115,000**	**$ 79,744**	**$194,744**	$ -	$ 79,744	$ 79,744
Issued during period	**-**	**-**	**-**	115,000	-	115,000
Principal, end of period	**$115,000**	**$ 79,744**	**$194,744**	$115,000	$ 79,744	$194,744
Debt component, beginning of period	**$102,450**	**$ 75,527**	**$177,977**	$ -	$ 74,004	$ 74,004
Issued during period	**-**	**-**	**-**	106,965	-	106,965
Issue costs	**(344)**	**-**	**(344)**	(4,714)	-	(4,714)
Accretion	**605**	**386**	**991**	199	1,523	1,722
Debt component, end of period	**$102,711**	**$ 75,913**	**$178,624**	$102,450	$ 75,527	$177,977
Equity component, beginning of period	**$ 8,036**	**$ 4,592**	**$ 12,628**	$ -	$ 4,592	$ 4,592
Issued during period	**-**	**-**	**-**	8,036	-	8,036
Equity component, end of period	**$ 8,036**	**$ 4,592**	**$ 12,628**	$ 8,036	$ 4,592	$ 12,628

6. OTHER LIABILITIES

	March 31, 2010	December 31, 2009
Unit-based incentive compensation (Note 7)	**$ 4,847**	$ 3,935
Excess office lease obligations (1)	**3,288**	3,708
	$ 8,135	$ 7,643

(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 $0.7 million, under the base price adjustment clause.

7. UNIT-BASED INCENTIVE COMPENSATION PLAN

The Trust recorded a total compensation expense of $0.7 million in the first three months of 2010, of which $0.4 million was recorded as an expense and $0.3 million as property, plant and equipment ($8.8 million was expensed and $3.7 million recorded as property, plant and equipment for the year ended December 31, 2009). The compensation expense was based on the March 31, 2010 trust unit price of $12.95 (December 31, 2009 - $13.74), 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:

	Three months ended March 31, 2010	Year ended December 31, 2009
Balance, beginning of period	**$ 16,411**	$ 6,274
Increase in liability	**714**	12,461
Cash payout, relating to units vested	**(6,944)**	(2,324)
Balance, end of period	**$ 10,181**	$ 16,411
Current portion of liability (1)	**$ 5,334**	$ 12,476
Long-term liability (2)	**$ 4,847**	$ 3,935

(1) Included in accounts payable and accrued liabilities.
(2) Included in other liabilities.

8. ASSET RETIREMENT OBLIGATIONS

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

	Three months ended March 31, 2010	Year ended December 31, 2009
Balance, beginning of period	$ 127,872	$ 90,844
Accretion expense	2,631	7,856
Revisions to estimates	(569)	558
Liabilities incurred	954	1,522
Liabilities acquired	2,062	32,311
Liabilities disposed	(142)	-
Liabilities settled	(891)	(5,219)
Balance, end of period	$ 131,917	$ 127,872

NAL's estimated credit-adjusted risk-free rate of eight to nine percent (2009 – eight to nine percent) and an inflation rate of two percent (2009 – two percent) were used to calculate the present value of the asset retirement obligations.

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

	Three months ended March 31, 2010	Year ended December 31, 2009
Non-controlling interest, beginning of period	$ 2,868	$ 56,380
Net income attributable to non-controlling interest	174	1,040
Distributions to MFC [1]	-	(54,552)
Non-controlling interest, end of period	$ 3,042	$ 2,868

(1) Includes $49.6 million distribution paid following settlement of note receivable (Note 2).

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

	Three months ended March 31	
	2010	2009
Net profits interest expense	$ 618	$ 243
Share of net income attributable to MFC	174	616
	$ 792	$ 859

10. UNITHOLDERS EQUITY

Units Issued:

	Three months ended March 31, 2010		Year ended December 31, 2009	
	Units	Amount	Units	Amount
Balance, beginning of the period	137,471	$ 1,482,029	96,181	$ 1,042,183
Equity offering	-	-	9,603	86,422
Issued on corporate acquisitions	-	-	30,453	345,075
Less issue expenses (net of tax)	-	(155)	-	(3,565)
Issued from Distribution Reinvestment Plan	410	5,179	1,234	11,914
Balance, end of the period	137,881	$ 1,487,053	137,471	$ 1,482,029

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 issueable on the conversion of the convertible debentures. For the three months ended March 31, 2010 and 2009, the trust units potentially issueable 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 ended March 31, 2010 were 12,665,697 (2009 – 5,696,000). As at March 31, 2010, the convertible debentures outstanding are convertible to 12,665,697 trust units.

Deficit

The deficit is comprised of the following:

	Three months ended March 31, 2010	Year ended December 31, 2009
Accumulated income	$ 591,580	$ 562,231
Accumulated cash distributions	(1,199,881)	(1,162,696)
	$ (608,301)	$ (600,465)

11. FINANCIAL RISK MANAGEMENT

Foreign currency exchange rate risk

NAL has the following foreign exchange rate derivative contracts outstanding:

EXCHANGE RATE CONTRACT	Remaining Term	Amount (US$ MM) [1]	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Apr – Dec 2010	$ 8.0	1.0966	BofC Average Noon Rate

(1) Notional US$ denominated commodity sales per month.

From April 1 to December 31, 2010, NAL also has a commitment to sell US$9 million ($1 million/month) at 1.045 if the monthly Bank of Canada average noon rate exceeds 1.045. NAL is paid a premium of approximately $10,000 a month when the average noon rate for the day falls between 0.95 and 1.045.

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 March 31, 2010, 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

NAL has the following commodity derivative contracts outstanding:

CRUDE OIL	Q2-10	Q3-10	Q4-10	Q1-11	Q2-11
US$ Collar Contracts					
$US WTI Collar Volume (bbl/d)	3,700	2,800	2,600	800	800
Bought Puts – Average Strike Price ($US/bbl)	$ 63.59	$ 65.63	$ 65.87	$ 81.25	$ 81.25
Sold Calls – Average Strike Price ($US/bbl)	$ 74.94	$ 77.55	$ 78.05	$ 94.47	$ 94.47
US$ Swap Contracts					
$US WTI Swap Volume (bbl/d)	2,800	3,200	3,300	-	-
Average WTI Swap Price ($US/bbl)	$ 79.45	$ 83.91	$ 83.82	-	-
Total Oil Volume (bbl/d)	6,500	6,000	5,900	800	800

NATURAL GAS	Q2-10	Q3-10	Q4-10	Q1-11	Q2-11
Swap Contracts					
AECO Swap Volume (GJ/d)	39,000	40,000	27,337	4,000	4,000
AECO Average Price ($Cdn/GJ)	$ 5.60	$ 5.61	$ 5.66	$ 5.78	$ 5.78
Total Natural gas Volume (GJ/d)	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 March 31, 2010, 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 $2.4 million higher, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had oil and natural gas liquids prices been $1.00 per barrel higher and natural gas $0.10 per Mcf higher.

Interest rate risk

NAL has the following interest rate derivative contracts outstanding:

INTEREST RATE CONTRACT	Remaining Term	Amount (millions) (1)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Mar 2010 – Dec 2011	$ 39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Jan 2013	$ 22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 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 March 31, 2010, if interest rates had been one percent lower, with all other variables held constant, net income for the period would have been $4.2 million lower, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had exchange rates been one percent higher.

Fair Value of Derivative Contracts

Derivative contracts are recorded at fair value on the balance sheet as current or long-term, assets or liabilities, based on their fair values on a contract by contract basis. The fair value of commodity contracts is determined as the difference between the contracted prices and published forward curves (ranging from US$83.76 per barrel to US$86.04 per barrel for oil and $3.44 per GJ to $4.82 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 0.539 percent to 2.766 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 1.0146 to 1.0208) 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:

	Three months ended March 31, 2010	Year ended December 31, 2009
Fair value of commodity contracts	**$ 7,635**	$ (8,932)
Fair value of interest rate swaps	**2,652**	2,461
Fair value of foreign exchange rate swaps	**5,737**	3,986
	$ 16,024	$ (2,485)

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

Gain / (Loss) on Derivative Contracts

	Three months ended March 31	
	2010	2009
Unrealized gain (loss):		
Crude oil contracts	**$ 1,546**	$ (21,198)
Natural gas contracts	**15,021**	2,701
Interest rate swaps	**191**	(678)
Exchange rate swaps	**1,751**	671
Unrealized gain (loss)	**18,509**	(18,504)
Realized gain (loss):		
Crude oil contracts	**(2,082)**	20,752
Natural gas contracts	**2,497**	6,956
Interest rate swaps	**(257)**	(29)
Exchange rate swaps	**1,290**	83
Realized gain	**1,448**	27,762
Gain on derivative contracts	**$ 19,957**	$ 9,258

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

	Three months ended March 31, 2010		December 31, 2009	
Current unrealized loss on derivative contracts	$	(11,342)	$	(11,231)
Current unrealized gain on derivative contracts		24,714		6,285
Current unrealized gain (loss) on derivative contracts		13,372		(4,946)
Long term unrealized gain on derivative contracts		2,652		2,461
Net fair value of derivative contracts	$	16,024	$	(2,485)

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

	Three months ended March 31			
		2010		2009
Unrealized gain (loss), beginning of period	$	(2,485)	$	65,406
Unrealized gain, end of period		16,024		46,902
Unrealized gain (loss) for the period		18,509		(18,504)
Realized gain in the period		1,448		27,762
Gain on derivative contracts	$	19,957	$	9,258

12. 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, 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 March 31, 2010, the Trust had spent $3.6 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 $30 million in the first year and $50 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 March 31, 2010, the Trust has spent $15.6 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)	**3,116**	3,505	3,505	3,482	3,414
Office lease – Clipper and Breaker (2)	**1,633**	2,184	2,192	358	-
Transportation agreement	**3,544**	-	-	-	-
Processing agreement (3)	**1,529**	2,242	401	384	-
Convertible debentures (4)	**-**	-	79,744	-	115,000
Bank debt	**-**	-	146,817	97,878	-
Total	**9,822**	7,931	232,659	102,102	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 64 percent) of the expense on a monthly basis.

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

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

(4) Principal amount.

13. SUBSEQUENT EVENT

On April 14, 2010, the Trust issued pursuant to a bought deal offering 7,550,000 trust units at a price of $13.25 per unit for aggregate gross proceeds of $100 million.

Trading Performance

	For the Quarter Ended			
	March 31, 2010	December 31, 2009	March 31, 2009	December 31, 2008
PRICE				
High	**$ 14.95**	$ 14.00	$ 8.99	$ 13.14
Low	**$ 12.50**	$ 10.75	$ 5.38	$ 5.90
Close	**$ 12.95**	$ 13.74	$ 6.80	$ 8.05
Daily Average Volume	**589,149**	490,127	359,591	475,410

NAL Oil & Gas Trust provides investors with a yield-oriented opportunity to participate in the Canadian Upstream 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".

Corporate Information

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Irvine J. Koop, Vice Chairman
Donald R. Ingram
Barry D. Stewart
Gordon S. Lackenbauer
William J. Eeuwes
Andrew B. Wiswell

Legal Counsel
Bennett Jones LLP

Auditors
KPMG LLP

Independent Engineers
McDaniel and Associates Consultants Ltd.

Officers
Andrew B. Wiswell,
President and Chief Executive Officer

Keith A. Steeves,
Vice President, Finance and Chief Financial Officer

Marlon J. McDougall,
Vice President, Operations and Chief Operations Officer

John C. Koyanagi,
Vice President, Business Development

John H. Kousinioris,
Corporate Secretary

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