



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

FOR IMMEDIATE RELEASE

NAL OIL & GAS TRUST REPORTS RECORD PRODUCTION VOLUMES AND CASH FLOWS IN THE SECOND QUARTER

Media Release No. 22-08

August 6, 2008

CALGARY, ALBERTA – NAL Oil & Gas Trust (“NAL” or the “Trust”) today announced its financial and operational results for the second quarter ended June 30, 2008. All amounts are in Canadian dollars unless otherwise stated.

On NAL’s second quarter results, President and CEO Andrew Wiswell commented: “the Trust reported its highest production volume and cash flows in its twelve year history. The Board has authorized a further \$8 million increase (for a full year total of \$152 million net to the Trust) in opportunity capital to position projects in 2009 and beyond.”

Summary of Second Quarter

- Production volumes increased 25 percent in the second quarter to 23,791 barrels per day (boe/d), up from 19,094 in the second quarter 2007, driven primarily by the corporate acquisitions of Seneca Energy Canada Inc. (“Seneca”), Tiberius Exploration Inc. (“Tiberius”) and Spear Exploration Inc. (“Spear”) and the ongoing execution of our core business and capital program. Production mix was 52 percent crude oil and natural gas liquids and 48 percent natural gas.
- Funds from operations (“FFO”) equaled \$88.6 million in the quarter, an increase of 65 percent from \$54.2 million a year earlier driven by higher volumes and stronger netbacks from higher commodity prices. On a per unit basis, FFO of \$0.94 (\$0.89 fully diluted) compared favourably with \$0.69 (\$0.69 fully diluted), an increase of 36 percent year-over-year.
- Operating netbacks before corporate hedging programs equaled \$58.82 per boe versus \$35.76 in second quarter a year earlier, an increase of 64 percent. These higher netbacks are driven primarily by our high quality crude and were achieved despite higher operating costs due to inflationary pressure in the industry. At \$10.37/boe in Q2, NAL’s operating costs remain better than the trust sector average.
- Capital expenditures increased to \$27.7 million in the second quarter versus \$18.9 million a year earlier, taking advantage of higher cash flows and broader opportunities in our asset base.
- Convertible debt outstanding decreased from \$100.0 million to \$82.3 million at the end of the second quarter as \$17.7 million of debentures converted to units. At June 30, 2008, total net debt (including convertible debentures) represented 1.1 times annualized first half 2008 FFO.

2008 Guidance and Outlook

Production volumes during the second quarter were curtailed by tie in delays, extended plant turnarounds, weather related road bans and lower capital spending compared to plan due to inability to access drilling and completion locations. Currently, the Trust has 900 boe/d of production in the completion and tie in phase. With 60% of its capital program still to be spent in Q3 and Q4, the Trust is forecasting production within our 2008 full year guidance range with an expected exit rate in excess of 25,000 boe/d.

NAL provides the following update to the outlook for full year 2008:

	2008 Full Year Outlook		
	January 23, 2008	May 1, 2008	August 6, 2008
Production (boe/d)	23,000 – 24,000	24,400 – 24,800 ⁽¹⁾	24,400-24,800 ⁽¹⁾
Net capital expenditures (\$MM)	110 – 120	140 – 150	150 - 160
Operating costs (\$/boe)	9.50 – 9.80	9.50 – 9.80	10.00 – 10.50

(1) Includes non-controlling interest.

NAL outlines the following 2008 full year financial forecast based upon certain assumptions:

2008 Forecast Assumptions	Key Assumptions		
WTI oil price (U.S.\$/bbl) ⁽³⁾	100.00	120.00	130.00
AECO natural gas price (C\$/GJ) ⁽³⁾	8.00	8.50	9.00
Exchange rate (Cdn/USD) ⁽³⁾	1.02	1.02	0.98
Capital expenditures (C\$ MM) ⁽⁴⁾	160	160	160
Production (boe/d)	24,400 ⁽¹⁾⁽²⁾	24,400 ⁽¹⁾⁽²⁾	24,400 ⁽¹⁾⁽²⁾
Monthly distribution (\$/unit)	0.16	0.16	0.16

(1) Including February 2008 acquisitions of Tiberius/Spear.

(2) Includes non-controlling interest.

(3) Commodity and exchange rate forecasts assumptions for the July-December 2008 period.

(4) Includes non-controlling interest capital of \$8 million, resulting in trust net capital of \$152 million.

2008 Financial Forecasts	Sensitivities		
Funds from operation (\$MM) ⁽¹⁾	333	349	353
Funds from operation (\$/unit – basic)	\$3.51	\$3.68	\$3.73
Funds from operation (\$/unit – fully diluted)	\$3.32	\$3.49	\$3.53
Payout ratio (%)	55	52	51
Payout with capital (%)	100	96	95
Payout with DRIP (%)	92	87	86
Debt / cash flow (x)	0.9 / 1.1 ⁽²⁾	0.8 / 1.0 ⁽²⁾	0.8 / 1.0 ⁽²⁾

(1) Includes impact of hedging gains and losses

(2) Includes convertible debentures.

FORWARD-LOOKING INFORMATION

Please refer to our disclaimer on forward-looking information set forth under the Management's Discussion and Analysis in this document. The disclaimer is applicable to all forward-looking information in this document, including the outlook for full year 2008 and the 2008 full year financial forecasts set forth above.

NON-GAAP MEASURES

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

CONFERENCE CALL DETAILS

At 3:30 p.m. MST (5:30 p.m. EST) on Wednesday, August 6, 2008, NAL will hold a conference call to discuss the second quarter 2008 results. Mr. Andrew Wiswell, President and CEO, will host the conference call with other members of the Management Team. The call is open to analysts, investors, and all interested parties. If you wish to participate, call 1-866-300-4047 toll free across North America. The conference call will also be accessible by internet at <http://events.onlinebroadcasting.com/nal/080608/index.php>

A recorded playback of the call will be available until August 13, 2008 by calling 1-800-408-3053, reservation 3265792.

Notes: All amounts are in Canadian dollars unless otherwise stated.

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

FINANCIAL AND OPERATING HIGHLIGHTS

(thousands of dollars, except per unit and boe data)

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
FINANCIAL				
Gross revenue, net of royalties, before hedging gains (losses)	149,356	77,197	266,188	151,764
Cash flow from operating activities	73,295	56,021	143,856	108,987
Cash flow per unit - basic	0.78	0.71	1.55	1.39
Cash flow per unit - diluted	0.74	0.71	1.47	1.39
Funds from operations	88,578	54,156	164,798	108,391
Funds from operations per unit - basic	0.94	0.69	1.77	1.38
Funds from operations per unit - diluted	0.89	0.69	1.68	1.38
Net income (loss)	(17,572)	21,390	(3,839)	38,100
Distributions declared	45,302	37,877	89,327	75,483
Distributions per unit	0.48	0.48	0.96	0.96
Payout ratio:				
based on cash flow from operating activities	62%	68%	62%	69%
based on funds from operations	51%	70%	54%	70%
Units outstanding (000's)				
Period end	95,277	79,086	95,277	79,086
Weighted average	94,101	78,824	92,909	78,543
Capital expenditures	27,714	18,925	63,907	45,984
Corporate acquisitions	-	-	58,363	
Net debt ⁽¹⁾	288,201	222,408	288,201	222,408
Convertible debentures (at face value)	82,259	-	82,259	-
OPERATING				
Daily production ⁽²⁾				
Crude Oil (bbl/d)	10,286	9,114	10,270	9,240
Natural gas (mcf/d)	68,890	47,461	68,050	47,821
Natural gas liquids (bbl/d)	2,023	2,071	2,084	2,116
Oil equivalent (boe/d)	23,791	19,094	23,696	19,326
OPERATING NETBACK (boe)				
Revenue before hedging gains (losses)	86.53	55.88	77.11	54.71
Royalties	(17.99)	(11.79)	(15.83)	(11.66)
Operating costs	(10.37)	(8.60)	(10.14)	(8.31)
Other income	0.65	0.27	0.51	0.35
Operating netback before hedging	58.82	35.76	51.65	35.09
Hedging gains (losses)	(10.04)	0.49	(6.31)	0.89
Operating netback	48.78	36.25	45.34	35.98

(1) Excluding convertible debentures.

(2) Includes royalty income volumes.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("MD&A") should be read in conjunction with the interim consolidated financial statements for the three and six month periods ended June 30, 2008 and the audited consolidated financial statements and MD&A for the year ended December 31, 2007 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 and financial position. 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, excluding derivative contracts, notes payable/receivable and future income tax balances.

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

\$(000s)	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Cash flow from operating activities	73,295	56,021	143,856	108,987
Add back change in non-cash working capital	15,283	(1,865)	20,942	(596)
Funds from operations	88,578	54,156	164,798	108,391

FORWARD-LOOKING INFORMATION

This discussion and analysis contains forward-looking information as to the Trust's internal projections, expectations or 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" or "resources" are forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources 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; 2008 production; future tax treatment of the Trust; future structure of the Trust and its subsidiaries; the Trust's tax pools; future oil and gas prices; the amount

of future asset retirement obligations; future liquidity and future financial capacity; future results from operations; payout ratios; cost estimates and royalty rates; drilling plans; tie in of wells; future development, exploration, and acquisition and development activities and related expenditures.

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 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 risk and uncertainties include, without limitation: changes in commodity prices; unanticipated operating results or production declines; the impact of weather conditions on seasonal demand and ability to execute the capital program; risks inherent in oil and gas operations; imprecision of reserve estimates; limited, unfavorable or no access to capital markets; the impact of competitors; the lack of availability of qualified operating or management personnel; the ability to obtain industry partner and other third party consents and approvals, when required; failure to 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 the royalty rates, particularly in light of the Alberta government's royalty review; changes in tax laws; including the impact of legislation relating to the taxation of "specified investment flow-through" entities and proposed amendments to the Income Tax Act (Canada) to permit the conversion of income trusts into corporations by the Federal government; 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 and MD&A for the year ended December 31, 2007.

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

ACQUISITION OF TIBERIUS EXPLORATION INC. AND SPEAR EXPLORATION INC.

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

On February 29, 2008 the Trust transferred the assets into a newly formed limited partnership ("Partnership") in exchange for a 50 percent partnership interest and a note receivable of \$3.7 million. A wholly owned subsidiary of Manulife Financial Corporation ("MFC") acquired the remaining 50 percent share in the Partnership and a note receivable of \$3.7 million, by payment in cash of one half of the total purchase price for Tiberius and Spear. MFC is a related party to the Trust, see "Management Contract and Fees".

The net acquisition cost to the Trust for its 50 percent share in the acquired properties is \$57.8 million, before acquisition costs, comprised of \$28.3 million in cash and \$29.5 million from the issuance of 2.4 million trust units at a price of \$12.24 per unit. The unit price was based on the average market price of the units at the announcement date for the acquisition of February 11, 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. The equivalent carrying amounts of property, plant and equipment related to this interest is recorded on the books of each royalty holder and was removed from the books of the Partnership.

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. 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 are 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.

Consequently, substantially all analysis in the MD&A includes 100 percent of the results of the Partnership, with 50 percent of these results being removed through the non-controlling interest.

The results of operations from the Tiberius and Spear properties have been included in the consolidated financial statements of the Trust commencing February 27, 2008, the closing date of the transaction.

The fair values assigned to the net assets acquired from Tiberius and Spear and the consideration paid by the Trust is as follows:

	Total Acquisition	Disposition to Manulife	Trust, net Acquisition	NPI ⁽¹⁾	Net to Trust
Net assets acquired \$(000s):					
Cash	\$9,734	\$-	\$9,734	\$-	\$9,734
Working capital deficiency	(5,620)	-	(5,620)	-	(5,620)
Notes receivable, net from MFC	-	(3,750)	(3,750)	49,599	45,849
Property, plant and equipment	111,258	-	111,258	(49,599)	61,659
Future income taxes	(23,389)	11,588	(11,801)	-	(11,801)
Asset retirement obligations	(1,636)	-	(1,636)	-	(1,636)
Goodwill	26,238	(12,003)	14,235	-	14,235
Non-controlling interest	-	(54,057)	(54,057)	-	(54,057)
	\$116,585	\$(58,222)	\$58,363	\$-	\$58,363
Consideration:					
Cash	\$86,118	\$(57,807)	\$28,311	\$-	\$28,311
Issuance of trust units	29,496	-	29,496	-	29,496
Acquisition costs	971	(415)	556	-	556
	\$116,585	\$(58,222)	\$58,363	\$-	\$58,363

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

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

\$(000s)	Three months ended June 30, 2008 ⁽¹⁾	Net Impact to Trust ⁽²⁾	Year-to- date ⁽¹⁾	Net Impact to Trust ⁽²⁾
Total production volumes (boes)	79,707	39,854	118,387	59,194
Production volumes (boe/d)	876	438	650	325
Oil, natural gas and liquid sales	\$9,244	\$4,622	\$13,154	\$6,577
Royalties	(834)	(417)	(1,372)	(686)
Operating costs	(867)	(434)	(1,188)	(594)
General and administrative	(142)	(71)	(170)	(85)
Unit-based incentive compensation	(61)	(30)	(81)	(41)
Interest income, net	1,806	903	2,452	1,226
Depletion, depreciation and accretion	(562)	(281)	(761)	(380)
Net profit interest expense	(7,165)	(3,583)	(10,122)	(5,061)
Net income	\$1,419	\$709	\$1,912	\$956

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

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

The non-controlling interest presented in the statement of income has two components: the royalty paid to MFC under the NPI agreement, 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:

\$(000s)	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Net profits interest expense	\$3,583	\$-	\$5,061	\$-
Share of net income attributable to MFC	709	-	956	-
	\$4,292	\$-	\$6,017	\$-

EXPLORATION & DEVELOPMENT ACTIVITIES

The Trust spent \$17.8 million on drilling operations during the second quarter of 2008, versus \$14.2 million in 2007 and participated in the drilling of 23 (11.1 net) wells during the second quarter of 2008, compared to seven (3.8 net) wells during the same period in 2007. Drilling activity was up year over year but below expectations by \$5 million due to weather and surface lease acquisition delays. Although fewer locations were drilled than expected during the quarter, the program was successful with all wells being cased for completion. Activity is expected to remain high through the third and fourth quarters with an additional 25 to 30 net wells expected to be drilled.

Historically, NAL's assets have been concentrated in southeast Saskatchewan and central Alberta. The purchase of Seneca in 2007 added a new core area at Monkman in northeast British Columbia and expanded the Trust's W4M operations in the Hanna to Drumheller area of Alberta. The Tiberius/Spear acquisition added to NAL's Nottingham/Alida operations in southeast Saskatchewan.

Second Quarter Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	18	8.8	3	1.7	0	0.0	0	0.0	21	10.5
Non-operated wells	2	0.6	0	0	0	0.0	0	0.0	2	0.6
Total wells drilled	20	9.4	3	1.7	0	0.0	0	0.0	23	11.1

Year to Date Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	40	20.9	9	6.4	0	0.0	0	0.0	49	27.3
Non-operated wells	10	1.0	6	1.1	0	0.0	0	0.0	16	2.1
Total wells drilled	50	21.9	15	7.5	0	0.0	0	0.0	65	29.4

Southeast Saskatchewan (Alida, Nottingham, Rosebank, Midale, Elswick)

In Saskatchewan, there were 16 (7.7 net) oil wells drilled during the second quarter. Activity was primarily focused in the Mississippian at Alida, Nottingham, Rosebank and Midale. The Trust expects to have two drilling rigs working for the remainder of the year on Mississippian and Bakken prospects in the area.

As at July 31, 2008, we have drilled three wells at Hoffer and they are currently being completed and evaluated.

Field operations were forced to shut in production of 300 boe/d on average for the quarter on the newly acquired Tiberius and Spear properties. This shut in occurred during April and May as a result of road bans which prevented the Trust from hauling production to our processing facilities from single well batteries. Planning and procurement for new facilities to link these properties into the Trust's Nottingham and Alida gathering systems are under way and construction is expected to be completed during the third and fourth quarters of this year.

Engineering and procurement work are completed for the Nottingham gas plant expansion which will increase capacity from 13 mmcf/d to 18 mmcf/d. It is expected that equipment delivery and construction will commence in October, with commissioning and start up to occur in early 2009.

Alberta (Garrington, Westward Ho, Drumheller, Pine Creek, Lacombe, Medicine River, Sylvan Lake)

In Alberta, NAL drilled seven (3.4 net) wells during the quarter with results meeting expectations. The Trust expects to have one rig working through the rest of the year drilling 10 - 15 stacked Mannville opportunities in Pine Creek and the greater Sylvan Lake area with a second rig used to drill three horizontal Cardium oil wells in the Garrington/Sylvan areas.

Two Glauconite oil wells were brought on production at a combined rate of 200 boe/d (net to the Trust) in the Hussar area of southern Alberta. Three additional wells to be drilled in 2008 are expected to delineate this new pool. The Trust has finished five recompletions in the Drumheller area as part of a wellbore optimization program and results have been positive with total production of 200 boe/d added.

The second quarter was significantly impacted by six extended turnarounds at operated and third party facilities across central Alberta. Volumes for the quarter were negatively impacted in excess of NAL's forecasted amounts by an average of 300 boe/d for the quarter. Most turnarounds were anticipated but several were extended and slow to come back up to capacity. NAL had planned to redirect 650 boe/d of production to another third party plant during one extended turnaround but capacity became unavailable at that plant due to an outage that was unknown at the time of our forecast.

Northeast British Columbia (Monkman)

In the Monkman area, the focus for 2008 is to participate in three wells and tie in the a-26-E discovery. The exploration drill at c-21-K (Trust 10 percent WI) has reached intermediate casing point and drilling information to date is encouraging with rig release expected in October. The a-37-F well (Trust 10 percent WI) is approaching intermediate casing point and is also expected to be rig released in October. One additional location (Trust 20 percent WI) is expected to commence drilling in the fourth quarter using one of the existing rigs. NAL expects to test successful wells during the fourth quarter, but is not forecasting production from these wells in 2008.

The 2007 exploration drill at a-26-E was successfully tested in two intervals at combined rates in excess of 60 mmcf/d gross raw gas and has been subsequently tied into the Spectra Pine River Gas plant. The well was on stream in May 2008, and is currently flowing at 40 - 45 mmcf/d gross raw gas (approximately 7.5mmcf/d net sales gas for the Trust) from one interval. Currently, the b-60-E well is being curtailed due to operating efficiency being affected as the plant is approaching capacity. Production from b-60-E and the second interval at a-26-E provide ample deliverability to fill all additional interruptible capacity that may become available through the current 40 mmcf/d expansion and decline in total volumes going to the facility. .

At the time of our January 2008 guidance, there was significant work left to complete in order to get a-26-E on stream. This operation took a month longer than expected and was finalized at the end of April rather than April 1. As a result, production was below forecast by 850 boe/d for April representing 283 boe/d average for the second quarter of 2008.

CAPITAL EXPENDITURES

Capital expenditures for the quarter ended June 30, 2008 totaled \$27.7 million (including \$1.0 million of property acquisitions) compared with \$18.9 million for the quarter ended June 30, 2007.

On a year-to-date basis, capital expenditures totaled \$63.9 million compared to \$46.0 million in the comparable period of 2007. Included in 2008 is \$7.8 million of net property acquisitions.

The Board of Directors has approved an \$8 million (net to the Trust) increase to the capital budget for the full year 2008. This new capital is intended to fund repositioning activities for land, seismic and strategic drilling, setting up additional activity for 2009. The production impact from any of this new capital spent on drilling will be late in the year and have limited impact on NAL's production volumes for full year 2008.

Year-to-date, NAL has spent 42 percent of its \$152.0 million capital budget (net to the Trust) and expects an active second half of 2008. NAL's strategy of building future opportunities into its portfolio for 2009 - 2010 has resulted in 21 percent of its exploitation and development capital being spent on plant and facilities, seismic and land in the

first six months of 2008 as compared to 12 percent a year earlier. Over the balance of 2008, NAL expects that trend to continue as it executes its capital program.

Capital Expenditures (\$000s)

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Drilling, completion and production equipment	17,754	14,198	40,284	37,849
Plant and facilities	3,476	2,143	6,707	4,395
Seismic	51	268	807	527
Land	2,828	106	3,822	357
Total exploitation and development	24,109	16,715	51,620	43,128
Office equipment	303	230	618	274
Capitalized G&A	1,401	1,669	2,343	2,436
Capitalized unit-based compensation	935	311	1,490	171
Total other capital	2,639	2,210	4,451	2,881
Property acquisitions (dispositions), net	966	-	7,836	(25)
Total capitalized expenditures	27,714	18,925	63,907	45,984

PRODUCTION

Second quarter 2008 production of 23,791 boe/d exceeded production of 19,094 boe/d in the comparable period of 2007 by 25 percent. This increase is attributable to the acquisition of Seneca, Tiberius and Spear production as well as the ongoing execution of the Trust's capital program.

For the six months ended June 30, 2008, production of 23,696 boe/d exceeded the 19,326 boe/d for the comparable period in 2007, by a margin of 23 percent for the same reasons.

Delay and unexpected down time had a significant impact on the quarter as production was 880 boe/d below expectations due to the impact of increased turnarounds, shut in production for road bans in Saskatchewan and a one month start up delay at Monkman, British Columbia. As a result of these timing issues, the Trust expects to meet the lower end of production guidance (24,400 – 24,800 boe/d) for the full year 2008.

June production (24,061 boe/d) gives management confidence that production for the balance of 2008 is expected to be on plan.

As of July 31, 2008, the Trust had 900 boe/d of production in the completion and tie in phase that will come on stream during the third quarter. The main contributing areas for this production are Pine Creek (300 boe/d), central Alberta (400 boe/d), and southeast Saskatchewan (200 boe/d).

It is anticipated that the December 2008 production exit rate will be in the 25,000 – 25,500 boe/d range.

Average Daily Production Volumes

	Three months ended June 30		Six months ended June 30	
	2008 ⁽¹⁾	2007 ⁽¹⁾	2008 ⁽¹⁾	2007 ⁽¹⁾
Oil (bbl/d)	10,286	9,114	10,270	9,240
Natural gas (Mcf/d)	68,890	47,461	68,050	47,821
NGLs (bbl/d)	2,023	2,071	2,084	2,116
Oil equivalent (boe/d)	23,791	19,094	23,696	19,326

(1) Volumes include royalty income volumes.

The oil equivalent volumes of 23,791 boe/d for the second quarter of 2008 and 23,696 boe/d year-to-date include 438 boe/d and 325 boe/d, respectively, attributable to the non-controlling interest in the Tiberius and Spear

properties. The Trust's net production, after deducting the non-controlling interest, is 23,353 boe/d for the second quarter of 2008 and 23,371 boe/d year-to-date.

Oil and natural gas liquids totaled 52 percent of production with natural gas increasing to 48 percent of production as a result of the natural gas weighted Seneca acquisition.

Production Weighting

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Oil	43%	48%	43%	48%
Natural gas	48%	41%	48%	41%
NGLs	9%	11%	9%	11%

REVENUE

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs, totaled \$187.3 million for the three months ended June 30, 2008, 93 percent higher than the second quarter of 2007. The increase is due to a 25 percent increase in production as a result of acquisitions and the ongoing execution of our capital program, as well as a 55 percent increase in the average realized price per boe. The Trust's realized commodity prices increased for all production, highlighted by a 73 percent quarter-over-quarter increase in realized crude oil prices.

For the six month period ended June 30, 2008, revenue after transportation costs totaled \$332.6 million, an increase of 74 percent from the comparable period in 2007. The increase is attributable to a 23 percent increase in production, due to acquisitions, and an increase of 41 percent in the average realized price per boe.

Revenue

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Revenue ⁽¹⁾ (\$000s)	187,341	97,090	332,550	191,374
\$/boe	86.53	55.88	77.11	54.71

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

OIL MARKETING

NAL sells 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 West Texas Intermediate ("WTI") benchmark price, transportation costs, exchange rates and the supply/demand situation of particular crude oil quality streams during the year.

NAL's second quarter average realized Canadian crude oil price per barrel, net of transportation costs, was \$116.51, as compared to \$67.18 for the comparable quarter of 2007. The increase in realized price quarter-over-quarter of 73 percent, or \$49.33/bbl, was primarily driven by a 91 percent increase in WTI (U.S.\$/bbl) over the comparable period, offset by a strengthening Canadian dollar.

For the second quarter of 2008, NAL's crude oil price differential compared to WTI priced in Canadian dollars was 93 percent, a one percentage point decrease from the comparable period in 2007. The differential is calculated as realized price as a percentage of WTI stated in Canadian dollars.

For the six months ended June 30, 2008, NAL's average oil price was \$103.23 per barrel as compared to \$64.37 for the comparable period in 2007. The increase in realized price was driven by an 80 percent increase in WTI (US\$/bbl). Differentials were consistent year-over-year at 92 percent.

Natural gas liquids averaged \$78.01/bbl in the second quarter of 2008, a 61 percent increase from \$48.33/bbl realized in 2007. For the six months ended June 30, 2008, natural gas liquids averaged \$70.58/bbl, an increase of 51 percent from the comparable period in 2007.

On July 22, 2008, SemGroup L.P. announced that it and certain of its North American subsidiaries had filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code as well as an application for creditor protection under the Companies' Creditors Arrangement Act in Canada.

NAL has a maximum net potential exposure of \$7.0 million from oil, butane and condensate sales to SemCanada Crude Company ("SemCanada"), a subsidiary of SemGroup, L.P. for the marketing of a portion of NAL's production. NAL management has retained legal counsel and continues to have discussions with SemCanada and its Monitor to best manage and resolve this matter. NAL is currently uncertain what portion of the exposure may be collectible, but the amount is not considered significant to NAL's financial position. Further, no provision has been made in the financial statements against this receivable as at June 30, 2008, since a reasonable determination of impairment can not be made at this time.

NATURAL GAS MARKETING

Approximately 74 percent of NAL's current gas production is sold under marketing arrangements tied to the Alberta monthly or daily spot price ("AECO"), with the remaining 26 percent tied to NYMEX or other indexed reference prices.

For the three months ended June 30, 2008, the Trust's natural gas sales averaged \$10.12/mcf compared to \$7.40/mcf in the comparable period of 2007, an increase of 37 percent. The quarter-over-quarter increase in gas prices was attributable to a 44 percent increase in the benchmark AECO daily spot prices.

Prices for Lake Erie natural gas increased to \$12.12/mcf in the second quarter of 2008, compared to \$8.99/mcf in 2007, an increase of 35 percent. Lake Erie production of 3.48 mmcf/d accounted for five percent of the Trust's natural gas production in the second quarter of 2008, compared to seven percent in the same period of 2007; the decrease is attributable to the gas weighted Seneca acquisition effective September 1, 2007. Natural gas sales from the Lake Erie property receive a higher price due to the close proximity to the Ontario and Northeastern U.S. markets.

For the six months ended June 30, 2008, NAL averaged \$9.06/mcf, a 19 percent increase from the \$7.59/mcf realized in the comparable period in 2007.

Average Pricing (net of transportation charges)

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Liquids				
WTI (US\$/bbl)	123.99	65.03	110.94	61.60
NAL average oil (Cdn\$/bbl)	116.51	67.18	103.23	64.37
NAL natural gas liquids (Cdn\$/bbl)	78.01	48.33	70.58	46.82
Natural Gas (Cdn\$/Mcf)				
AECO – daily spot	10.20	7.07	9.09	7.24
AECO – monthly	9.35	7.37	8.21	7.42
NAL Western Canada natural gas	10.01	7.27	8.98	7.40
NAL Lake Erie natural gas	12.12	8.99	10.67	9.88
NAL average natural gas	10.12	7.40	9.06	7.59
NAL Oil Equivalent before hedging (Cdn\$/boe – 6:1)	86.53	55.88	77.11	54.71
Average Foreign Exchange Rate (Cdn\$/U.S.\$)	1.010	1.098	1.007	1.135

RISK MANAGEMENT

NAL employs risk management practices to assist in managing cash flows and to support capital programs and distributions. NAL's management has authorization to hedge up to 50 percent of budgeted total production, net of royalties, for a period of up to two years. Management's practice is to hedge more near-term volumes on a rolling 12 month forward basis with more limited volumes hedged in the 13 – 24 month forward period. The execution of

NAL's hedging program is layered in over time in small increments using a combination of swaps and collars. As at June 30, 2008, NAL had several financial WTI oil contracts and AECO natural gas contracts in place. The following is a summary of the realized gains and losses on risk management contracts:

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Average crude volumes hedged (bbl/d)	4,833	2,300	4,516	2,300
Crude oil realized gain (loss) (\$000's)	(18,001)	700	(25,032)	2,937
Gain (loss) per bbl hedged	(40.93)	3.34	(30.45)	7.06
Average natural gas volumes hedged (GJ/d)	29,330	16,000	25,085	15,250
Natural gas realized gain (loss) (\$000's)	(3,729)	148	(2,189)	185
Gain (loss) per GJ hedged	(1.40)	0.10	(0.48)	0.07
Average BOE hedged (boe/d)	9,466	5,113	8,479	4,981
Total realized gain (loss) (\$000's)	(21,730)	848	(27,221)	3,122
Gain (loss) per boe hedged	(25.23)	1.82	(17.64)	3.46
Gain (loss) per boe	(10.04)	0.49	(6.31)	0.89

All derivative contracts are recorded on the balance sheet at fair value. The Trust has not designated any of its derivative contracts as effective accounting hedges, even though the Trust considers all commodity contracts to be effective economic hedges. Therefore, 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. Accordingly, the magnitude of the unrealized gain or loss will continue to fluctuate with changes in commodity prices.

The fair value of the derivatives at June 30, 2008 was a liability of \$102.3 million, comprised of a \$70.6 million liability on oil contracts and a \$31.7 million liability on gas contracts.

Second quarter income for 2008 includes a \$70.2 million unrealized loss on derivatives resulting from the change in the fair value of the derivative contracts during the quarter from a liability of \$32.1 million at March 31, 2008 to a liability of \$102.3 million at June 30, 2008. The \$70.2 million unrealized loss was comprised of a \$53.9 million unrealized loss on crude oil contracts, and a \$16.3 million unrealized loss on natural gas contracts. The unrealized loss in the second quarter is primarily attributable to higher crude oil forward prices compared to March 31, 2008. Average hedged boes for the second quarter were 9,466 as compared to 7,492 for the first quarter of 2008.

For the six months ended June 30, 2008, income includes an unrealized loss of \$92.7 million, resulting from the change in the fair value of the derivatives during the period. The unrealized loss was comprised of a \$57.7 million unrealized loss on crude oil contracts, and a \$35.0 million unrealized loss on natural gas contracts. The unrealized loss in the period is reflective of the significant increase in commodity prices since December 31, 2007.

The gain/loss on derivative contracts is as follows:

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

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Unrealized gain (loss)				
Crude oil contracts	(53,893)	(1,811)	(57,656)	(5,340)
Natural gas contracts	(16,255)	5,177	(35,027)	956
Unrealized gain (loss)	(70,148)*	3,366	(92,683)*	(4,384)
Realized gain (loss)	(21,730)	848	(27,221)	3,122
Reclassification from other comprehensive income	-	1,394	-	2,773
Gain (loss) on derivative contracts	(91,878)	5,608	(119,904)	1,511

* Based on the August 5, 2008, forward strip pricing, the unrealized losses would be \$9,457 for the three months ended June 30, 2008, and \$31,992 for the six months ended June 30, 2008, representing an improvement of \$60,691.

For the remainder of 2008, NAL has the following risk management contracts outstanding:

CRUDE OIL	U.S.\$	CDN\$
Swap (bbls)	337,300	361,900
Swap (bbl/d)	1,833	1,967
\$/bbl	\$91.71	\$91.64
Collars (bbls)	110,400	128,800
Collars (bbl/d)	600	700
\$/bbl	\$84.17 - \$95.75	\$91.93 - \$109.03
Total (bbls)	447,700	490,700
Total (bbl/d)	2,433	2,667

NATURAL GAS		CDN\$
Swap (GJ)		4,665,000
Swap (GJ/d)		25,353
\$/GJ		\$7.42
Collars (GJ)		855,000
Collars (GJ/d)		4,647
\$/GJ		\$8.00 - \$9.70
Total GJ		5,520,000
Total (GJ/d)		30,000

For 2009, NAL has the following risk management contracts outstanding:

CRUDE OIL	U.S.\$	CDN\$
Swap (bbls)	272,900	209,100
Swap (bbl/d)	748	573
\$/bbl	\$105.24	\$100.21
Collars (bbls)	364,500	105,900
Collars (bbl/d)	998	290
\$/bbl	\$109.91 - \$156.39	\$105.60 - \$125.82
Total (bbls)	637,400	315,000
Total (bbl/d)	1,746	863

NATURAL GAS		CDN\$
Swap (GJ)		1,598,000
Swap (GJ/d)		4,378
\$/GJ		\$8.20
Collars (GJ)		2,510,000
Collars (GJ/d)		6,877
\$/GJ		\$8.44 - \$10.36
Total GJ		4,108,000
Total (GJ/d)		11,255

ROYALTY EXPENSES

Crown, freehold and overriding royalties were \$38.9 million for the three months ended June 30, 2008. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 20.8 percent for the quarter ended June 30, 2008, down from 21.1 percent experienced in the comparable period of the previous year.

Royalties increased to \$17.99 per boe for the second quarter of 2008, an increase of 53 percent compared to the second quarter of 2007. The increase is attributable to significantly higher commodity prices on a quarter-over-quarter basis.

On a year-to-date basis, royalties were \$68.3 million, up from \$40.8 million in the comparable period of 2007. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 20.5 percent as compared to 21.3 percent in the comparable period in 2007.

Royalty Expenses

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Royalties (\$000s)	38,941	20,487	68,252	40,801
As % of revenue	20.8	21.1	20.5	21.3
\$/boe	17.99	11.79	15.83	11.66

OPERATING COSTS

Operating costs averaged \$10.37 per boe for the quarter ended June 30, 2008, a 21 percent increase from the \$8.60 per boe for the quarter ended June 30, 2007. On a year-to-date basis, operating costs were \$10.14 per boe as compared to \$8.31 in 2007.

Operating costs are projected to be \$10.00 - \$10.50 per boe for the full year 2008. Costs have climbed steadily through 2007 and into 2008 with operations receiving ongoing cost increase notices from the Trust's vendors resulting in a significant departure from year-over-year spending profiles. Approximately \$0.50 per boe of the current increase is attributable to the full year effect of higher costs associated with the Seneca production. The remaining \$1.27 per boe increase is mainly due to higher than forecast escalation in contract services, property taxes, fuel, electricity and third party processing costs that have occurred in the increasing commodity price environment.

Operating Costs

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Operating costs (\$000s)	22,443	14,952	43,716	29,078
As a % of revenue	11.98	15.40	13.14	15.19
\$/boe	10.37	8.60	10.14	8.31

OPERATING NETBACK

For the quarter ended June 30, 2008, NAL's operating netback before hedging gains (losses) was \$58.82 per boe, an increase of \$23.06 from \$35.76 per boe for the quarter ended June 30, 2007. The increase was due to higher revenues driven by stronger commodity prices, partially offset by increases in royalties and operating expenses. Hedging losses were \$10.04 per boe in the second quarter of 2008, as compared to a gain of \$0.49 per boe in 2007.

On a year-to-date basis, similar trends resulted in an operating netback, before hedging, of \$51.65 per boe as compared to \$35.09 per boe in 2007.

Operating Netback (\$/boe)

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Revenue	86.53	55.88	77.11	54.71
Royalties	(17.99)	(11.79)	(15.83)	(11.66)
Operating expenses	(10.37)	(8.60)	(10.14)	(8.31)
Other income	0.65	0.27	0.51	0.35
Operating netback, before hedging	58.82	35.76	51.65	35.09
Hedging gains (losses)	(10.04)	0.49	(6.31)	0.89
Operating netback, after hedging	48.78	36.25	45.34	35.98

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 June 30, 2008, G&A expenses were \$4.5 million, compared with \$3.8 million in the comparable quarter of 2007. In addition, \$1.4 million of G&A costs relating to exploitation and development

activities were capitalized in the second quarter of 2008 compared with \$1.7 million in the second quarter of 2007. G&A expense per boe, excluding retention bonus, was \$2.08 in the quarter, representing no change as compared to the equivalent quarter in 2007.

For the six months ended June 30, 2008, G&A expense increased seven percent to \$8.3 million from \$7.8 million in the comparable period in 2007. In addition, on a year-to-date basis, \$2.3 million of G&A costs relating to exploitation and development activities were capitalized, compared with \$2.4 million in 2007. Year-to-date total G&A increased only \$0.4 million despite a 23 percent increase in production year-over-year due to acquisitions, which has resulted in lower G&A per boe rates. The retention bonus program concluded on June 30, 2008, (\$0.03 per boe year-to-date) and there will be no further expense relating to this program.

General and Administrative Expenses

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
G&A expenses (\$000s)				
G&A	4,494	3,614	8,135	6,975
Retention bonus	45	230	141	784
Expensed G&A (\$000s)	4,539	3,844	8,276	7,759
Capitalized G&A (\$000s)	1,401	1,669	2,343	2,436
Total G&A (\$000s)	5,940	5,513	10,619	10,195
Expensed G&A costs:				
G&A, excluding retention bonus (\$/boe)	2.08	2.08	1.89	1.99
Retention bonus (\$/boe)	0.02	0.13	0.03	0.22
Total G&A expenses (\$/boe)	2.10	2.21	1.92	2.21
As % of revenue	2.4	4.0	2.5	4.1
Per trust unit (\$)	0.05	0.05	0.09	0.10

UNIT-BASED INCENTIVE COMPENSATION PLAN

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

During the second quarter of 2008, the Trust accrued \$2.8 million of unit-based incentive compensation charges as compared to a \$1.0 million in the comparable quarter of 2007. The increase in unit-based compensation in 2008 reflects an increase in unit price and the performance factors attached to the PTUs.

On a year-to-date basis, the Trust has accrued \$4.5 million compared to \$0.8 million in the comparable period in 2007. The increase in unit-based compensation in 2008 is a result of an increase in the unit price and an increase in the performance factors attached to the PTUs, as compared to 2007 when the unit price and performance factors were decreasing.

This calculation is made at the end of each quarter based on the quarter end trust unit price and 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 June 30, 2008, the Trust has recorded a liability for unit-based incentive compensation in the amount of \$7.7 million, of which \$3.2 million is recorded as current as it is payable in December 2008, and \$4.5 million is long-term as it is payable in December 2009 and December 2010.

Unit-Based Compensation

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Unit-based compensation:				
Expensed (\$000s)	1,889	688	2,997	664
Capitalized (\$000s)	935	311	1,490	171
Total unit-based compensation (\$000s)	2,824	999	4,487	835
Expensed unit-based compensation:				
As % of revenue	1.0	0.70	0.90	0.34
\$/boe	0.87	0.40	0.69	0.19
Per trust unit (\$)	0.02	0.01	0.03	0.01

Full year 2008 G&A guidance of \$1.90 - \$2.10 per boe includes unit-based compensation expense. On a year-to-date basis, G&A expense, including \$0.69 of unit-based compensation expense, was \$2.61 per boe, exceeding guidance as a result of a higher than estimated trust unit price and stronger relative performance factors.

MANAGEMENT CONTRACT AND FEES

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

The Manager provides certain services to the Trust and its subsidiary entities pursuant to a management contract. This contract provides for no base or performance fees and requires the Trust to reimburse the Manager at cost for general and administrative and unit-based compensation expenses incurred by the Manager on behalf of the Trust calculated on a unit of production basis.

The Trust paid \$3.5 million (2007 - \$3.1 million) for the reimbursement of G&A expenses during the second quarter, and \$6.5 million (2007 - \$6.0 million) year-to-date. The Trust also pays the Manager its share of unit-based incentive compensation expense when cash compensation is paid to employees under the terms of the Plan, of which \$1.8 million has been paid year-to-date, representing units that vested November 30, 2007 (2007 - \$2.2 million).

INTEREST

Interest on bank debt includes charges on borrowings, plus standby fees on the unused portion of the bank credit facility. NAL’s average outstanding bank debt for the second quarter of 2008 was \$313.6 million, compared to \$234.0 million for the second quarter of 2007. The increase in average debt levels is primarily attributable to the debt required for the acquisitions of Seneca (\$31.8 million) and Tiberius and Spear (\$28.3 million) and increased working capital. NAL’s effective interest rate averaged 4.87 percent during the second quarter of 2008, compared to 5.46 percent during the comparable period in 2007. The decrease in the rate from the second quarter of 2007 is attributable to rate decreases in the market. NAL’s interest is at a floating rate.

For the six months ended June 30, 2008, NAL’s average debt was \$304.6 million, compared to \$228.8 million for the corresponding period in 2007. NAL’s effective interest rate averaged 5.10 percent in 2008, compared to 5.20 percent in 2007.

Interest on bank debt for the second quarter of 2008 was \$3.9 million, an increase of \$0.8 million from \$3.1 million for the comparable period in 2007. The increase was due to the higher average debt levels, partially offset by the decrease in the average effective interest rate for the second quarter of 2008. A similar trend is noted for the six months ended June 30, 2008.

Interest on convertible debentures represents interest charges, at 6.75 percent, of \$1.6 million (\$3.3 million for the six months ended June 30, 2008) and accretion of the debt discount of \$0.4 million (\$0.9 million for the six months ended June 30, 2008) for the second quarter of 2008. The debentures were issued on August 28, 2007.

As at August 6, 2008, the Trust has 95,515,513 trust units and \$79.8 million in convertible debentures outstanding.

Interest and Debt

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Interest on bank debt (\$000s)	3,879	3,137	7,860	5,996
Interest and accretion on convertible debentures (\$000s)	2,071	-	4,213	-
Total interest (\$000)	5,950	3,137	12,073	5,996
Bank debt outstanding at period end (\$000s)	308,115	233,517	308,115	233,517
Convertible debentures at period end (\$000s)	75,561	-	75,561	-
\$/boe:				
Interest on bank debt	1.79	1.81	1.82	1.71
Interest on convertible debentures	0.74	-	0.76	-
Accretion on convertible debentures	0.22	-	0.22	-
Total interest	2.75	1.81	2.80	1.71

CASH FLOW NETBACK

For the quarter ended June 30, 2008, NAL's cash flow netback was \$43.28 per boe, a 36 percent increase from \$31.83 for the comparable period in 2007. The increase is due to higher operating netbacks after hedging in 2008, partially offset by an increase in G&A, including unit-based incentive compensation, (\$0.36 per boe), and interest charges (\$0.72 per boe). Similar trends are noted for the six months ended June 30, 2008.

Cash Flow Netback (\$/boe)

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Operating netback, after hedging	48.78	36.25	45.34	35.98
G&A expenses, including unit-based incentive compensation	(2.97)	(2.61)	(2.61)	(2.40)
Interest on bank debt and convertible debentures ⁽¹⁾	(2.53)	(1.81)	(2.58)	(1.71)
Cash flow netback	43.28	31.83	40.15	31.87

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

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 June 30, 2008, depletion on property, plant and equipment and accretion on the asset retirement obligations increased by nine percent on a boe basis over the comparable period in 2007. The increase in the DDA rate per boe is largely attributable to the acquisition of Seneca in August 2007 and Tiberius and Spear in February 2008. Similar trends are noted for the six months ended June 30, 2008.

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

Depletion, Depreciation and Accretion Expenses

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Depletion and depreciation (\$000s)	47,347	34,822	93,059	69,250
Accretion of asset retirement obligation (\$000s)	1,827	1,302	3,625	2,599
Total DDA (\$000s)	49,174	36,124	96,684	71,849
DDA rate per boe (\$)	22.71	20.79	22.42	20.54

TAXES

In the second quarter of 2008, NAL had a future income tax reduction of \$12.8 million compared with a \$2.5 million provision in the corresponding period for the prior year. For the six month period ended June 30, 2008, NAL had a future income tax reduction of \$19.3 million compared to \$0.2 million in 2007.

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. The Trust does not expect to incur any cash taxes in 2008.

As at June 30, 2008, the Trust's (including all subsidiaries) estimated tax pools (unaudited) available for deduction from future taxable income approximated \$689.2 million, of which approximately 45 percent represented COGPE and 30 percent UCC, with the remaining balance represented by CEE, CDE, trust unit issue costs and non-capital loss carry forwards.

Based on current strip prices at June 30, 2008, and our forecast for year-end tax pools, the Trust is not expected to be taxable in 2008. This is in part attributable to the deferral of a small portion of partnership income to the following year.

On June 22, 2007, the *Budget Implementation Act, 2007* (Canada) was enacted to, among other things, implement the October 31, 2006 announcement of the changes to taxability of income trusts made by the Department of Finance. Under this legislation, distributions to unitholders will not be deductible by publicly traded income trusts and, as a result, the Trust will be taxed on its income similar to corporations. These measures are now considered enacted for purposes of GAAP. Accordingly, the Trust has measured future income tax assets and liabilities associated with this new tax. During the second quarter of 2008, \$5.0 million of future income tax liability has been recognized in the financial statements. The future tax recognition in the second quarter of 2008 is attributable to higher commodity prices resulting in a small portion of temporary differences reversing after 2010. It is expected that all remaining taxable temporary differences will reverse prior to January 1, 2011, the date the taxation changes take effect. The scheduling of the reversal of temporary differences is based on management's best estimates and current assumptions, which may change.

Effective for the third quarter of 2008, the Trust income tax rate is expected to decrease by three percent from the current 29.5 percent to 26.5 percent once the new provincial SIFT tax rate is enacted. The impact of this rate reduction is not expected to be significant for the Trust.

NET INCOME (LOSS)

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 depletion, accretion, unrealized gains or losses on derivative contracts and future income taxes.

The net loss for the second quarter of 2008 was (\$17.6) million compared to net income of \$21.4 million for the comparable period in 2007. The decrease of \$39.0 million is primarily due to an increased loss on derivative contracts of \$97.5 million, increased depletion of \$12.5 million, increased operating costs of \$7.5 million, partially offset by higher revenues, net of royalties, of \$72.2 million and a future tax reduction of \$15.3 million.

Net loss for the six months ended June 30, 2008 of (\$3.8) million was \$41.9 million lower than the comparable period of 2007. The decrease is due to similar trends as noted for the second quarter of 2008.

Net Income (loss) (\$000s)

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Net income (loss)	(17,572)	21,390	(3,839)	38,100

CAPITAL RESOURCES AND LIQUIDITY

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

As at June 30, 2008, NAL had 95,277,293 trust units outstanding, compared with 90,494,151 trust units at December 31, 2007. The increase from December 31, 2007 is attributable to 2,408,898 trust units issued on the acquisition of Tiberius and Spear, 1,267,204 trust units issued on the conversion of outstanding convertible debentures and 1,107,040 trust units issued under the Trust's distribution reinvestment program ("DRIP").

Under the equity issuance associated with the acquisition of Tiberius and Spear, 2.4 million trust units were issued at a price of \$12.24 per trust unit for a total consideration of \$29.5 million.

For the six months ended June 30, 2008, the DRIP resulted in 1.1 million trust units being issued at an average price of \$12.58 per trust unit for total proceeds of \$13.9 million.

Unitholders electing to reinvest distributions or make optional cash payments to acquire trust units from treasury under the DRIP may do so at 95 percent of the average market price with no additional fees or commissions. 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.

The participation rate in the regular DRIP averaged 16 percent over the six months ended June 30, 2008, consistent with recent experience. The Trust continues to monitor the participation in this plan in conjunction with its capital requirements.

As at June 30, 2008 the Trust had net debt of \$370.5 million (net of working capital and excluding derivative contracts, notes payable/receivable with MFC and future income tax asset), including convertible debentures at face value of \$82.3 million. Excluding the convertible debentures, net debt was \$288.2 million, compared with \$291.1 million at December 31, 2007, and \$222.4 million as at June 30, 2007. The decrease in net debt, excluding convertible debentures, of \$2.9 million during the first half of 2008 is attributable to a \$35.3 million positive change in working capital offset by increased bank debt of \$32.4 million.

Bank debt outstanding was \$308.1 million at June 30, 2008 compared with \$275.6 million as at December 31, 2007. The \$308.1 million is comprised of \$302.9 under the production facility and \$5.2 million under the working capital facility. The increase in the bank debt during the first six months of 2008 is due to the acquisition of Tiberius and Spear, of which \$28.3 million was funded by debt. During the second quarter, the Trust reduced bank debt by \$5.3 million. During the first half of 2008, working capital increased \$35.3 million, which is a reflection of the increase in funds from operations over the period. Funds from operations increased to \$164.8 million in the first six months of 2008 from \$110.4 million in the last six months of 2007, an increase of \$54.4 million or 49 percent. The increase in funds from operations was driven by increased commodity prices.

At the end of the second quarter, the Trust had a net debt (excluding convertible debentures) to 12 months trailing cash flow ratio of 1.05 times and a total net debt (including convertible debentures) to 12 months trailing cash flow ratio of 1.35 times.

During the second quarter, the current banking group agreed to expand the bank group through the addition of two new banks and increase the credit facility by \$50 million to \$450 million, subject to final documentation approval, reflecting the Tiberius and Spear acquisitions. The credit facility is a fully secured, extendible, revolving facility and will revolve until April 29, 2009 at which time it is extendible for a further 364-day revolving period upon agreement between the Trust and the bank syndicate. The facility will consist of a \$440 million production facility and a \$10 million working capital facility. The credit facility is fully secured by first priority security interests in all

present and after acquired properties and assets of the Trust and its subsidiary and affiliated entities. The purpose of the facility is to fund property acquisitions and capital expenditures. Principal repayments to the bank are not required at this time. Should principal repayments become mandatory, and in the absence of refinancing arrangements, the Trust would be required to repay the facility in four equal quarterly installments commencing May 2010.

The Trust has outstanding \$82.3 million principal amount of 6.75% 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. During the second quarter of 2008, face value \$17.7 million in debentures were converted at \$14.00 per unit into 1,267,204 trust units. 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. Assuming conversion of all outstanding debentures at the conversion price, an additional 5.9 million trust units would be required to be issued.

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

The Trust recognized \$0.9 million of accretion of the debt discount in the first six months of 2008.

As at August 6, 2008, the Trust has 95,515,513 trust units and \$79.8 million in convertible debentures outstanding.

Capitalization

	June 30, 2008	Dec 31, 2007	June 30, 2007
Trust unit equity (\$000s)	471,221	504,717	433,510
Bank debt (\$000s)	308,115	275,630	233,517
Working capital deficit (surplus) ⁽¹⁾ (\$000s)	(19,914)	15,429	(11,109)
Net debt	288,201	291,059	222,408
Convertible debentures (\$000s) ⁽²⁾	82,259	100,000	-
Total Net debt ⁽²⁾	370,460	391,059	222,408
Net debt to trailing 12 month cash flow ⁽³⁾	1.05	1.33	1.02
Total Net debt to trailing 12 month cash flow ⁽²⁾	1.35	1.79	1.02
Trust units outstanding (000s)	95,277	90,494	79,086

(1) Working capital excludes derivative contracts, the future income tax asset, and notes payable/receivable with MFC.

(2) Convertible debentures included at face value.

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

Subject to fluctuations in commodity prices, the Trust anticipates that it will continue to maintain adequate liquidity to fund planned capital spending during 2008 through a combination of funds from operations, funds received from its DRIP and bank debt.

If assumptions underlying the forecast, including commodity prices and production, change, the Trust may be required to reconsider its financing, distribution level or capital expenditures.

Under the tax legislation regarding the change in the taxability 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 remaining six

months of 2008, the Trust has approximately \$554 million of available safe harbour and, for each of 2009 and 2010, an additional \$280 million.

ASSET RETIREMENT OBLIGATION

At June 30, 2008, the Trust reported an asset retirement obligation (“ARO”) balance of \$92.0 million (\$89.6 million as at December 31, 2007) for future abandonment and reclamation of the Trust’s oil and gas properties and facilities. The ARO balance was increased by \$1.6 million due to the Tiberius and Spear acquisitions, \$0.5 million due to liabilities incurred and revisions to estimates, and \$3.6 million from accretion expense and was reduced by \$3.3 million for actual abandonment and environmental expenditures incurred in 2008.

DISTRIBUTIONS TO UNITHOLDERS

For the three and six months ended June 30, 2008 the Trust distributed 62 percent of its cash flow from operating activities, as compared to 68 percent and 69 percent for the same periods in 2007. 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 (loss) each period, due to the non-cash charges included in net income (loss). Cash flow from operations usually exceeds net income, as net income includes non-cash charges such as depletion, depreciation, accretion, future income tax expense and unrealized gains and losses on derivative contracts.

The Trust bases its distributions on the cash flow of the Trust, commodity prices, financial market conditions, internal capital investment opportunities and the resulting impact on taxability. The Trust develops an annual forecast, which is updated regularly by management. The Board sets distributions at a level it believes will be sustainable for a period of time and formally reviews distribution levels quarterly.

Given that distributions exceed net income (loss), the excess could be considered to be an economic return of capital to the unitholders. The Trust’s business model is such that it distributes a certain proportion of its cash flow while retaining cash to execute planned capital programs. As a result of the depleting nature of oil and gas assets some capital expenditure is required in order to minimize production declines as well as to invest in facilities and infrastructure. NAL’s 2008 capital program may not fully replace production. When the Trust sets distribution levels, depletion expense is not considered to be indicative of a 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 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 proceeds from the DRIP and debt. Over the medium term, fluctuations in commodity prices, other market factors, or development opportunities may make it necessary to fund the excess of distributions and capital expenditures over cash, from the credit facility. The credit facility and other sources of cash are expected to be sufficient to meet NAL’s near term capital requirements, sustain distributions and provide for the resources to pursue potential growth opportunities.

NAL intends to continue to make cash distributions to unitholders. However, these cash distributions cannot be guaranteed. The intent is to continue to distribute a certain proportion of cash flow from operating activities, the level of distributions being dependent on the drivers of cash flow, namely production and commodity prices. The implication of this policy is that the Trust is likely to continue to distribute in excess of its net income for any given period. The future sustainability of this distribution policy will be dependent upon maintaining productive capacity through both capital expenditures and acquisitions. A significant decrease in commodity prices could 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 June 30		Six months ended June 30	
	2008	2007	2008	2007
Cash flow from operating activities	73,295	56,021	143,856	108,987
Net income (loss)	(17,572)	21,390	(3,839)	38,100
Actual cash distributions paid or payable	45,302	37,877	89,327	75,483
Excess of cash flow from operating activities over cash distribution paid	27,993	18,144	54,529	33,504
Percentage of cash flow from operations distributed	62%	68%	62%	69%
Shortfall of net income over cash distributions paid	(62,874)	(16,487)	(93,166)	(37,383)

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 June 30, 2008, funds from operations amounted to \$88.6 million, compared with \$54.2 million for the three months ended June 30, 2007. The 63 percent increase is due to increased revenue driven by higher production and pricing offset partially by higher costs. On a per trust unit basis, funds from operations increased 36 percent from \$0.69 in 2007 to \$0.94 in 2008, the increase in funds from operations being partially offset by the increase in the number of trust units outstanding due to equity issuances associated with the acquisitions of Seneca, Tiberius and Spear.

For the six months ended June 30, 2008, funds from operations increased 52 percent to \$164.8 from \$108.4 for the comparable period in 2007. The increase is primarily due to increased revenues driven by higher prices and production.

Funds from Operations

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Funds from operations (\$000s)	88,578	54,156	164,798	108,391
Funds from operations per trust unit	0.94	0.69	1.77	1.38
Payout ratio based on funds from operations	51%	70%	54%	70%

VARIABLE INTEREST ENTITIES

NAL has no variable interest entities.

CONTRACTUAL OBLIGATIONS

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)	2008	2009	2010	2011	2012	Thereafter
Office lease ⁽¹⁾	2,018	4,036	3,700	-	-	-
Transportation agreement	955	881	881	-	-	-
Processing agreement ⁽²⁾	236	446	428	414	401	384
Total	3,209	5,363	5,009	414	401	384

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

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

QUARTERLY INFORMATION

(\$000s, except per unit and production amounts)	2008				2007			2006	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	
Revenue, net of royalties	58,861	89,611	86,262	78,573	83,268	71,231	75,358	75,798	
Per unit	0.63	0.98	0.96	0.95	1.06	0.91	0.97	0.98	
Funds from operations ⁽¹⁾	88,578	76,220	59,537	50,817	54,156	54,234	55,795	54,107	
Per unit	0.94	0.83	0.66	0.61	0.69	0.69	0.72	0.70	
Net income (loss)	(17,572)	13,733	10,556	7,801	21,390	16,710	20,472	20,473	
Per unit – basic and diluted	(0.19)	0.15	0.12	0.09	0.27	0.21	0.26	0.27	
Average oil equivalent production (boe/d – 6:1)	23,791	23,601	23,656	20,369	19,094	19,561	19,517	19,079	

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

FINANCIAL REPORTING DISCLOSURE CONTROLS

Management has designed and evaluated the effectiveness of the Trust's financial reporting disclosure controls and procedures as at June 30, 2008 and has concluded that such controls and procedures were effective as at that date.

While NAL's management believes that the Trust's disclosure controls and procedures provide a reasonable level of assurance with respect to their effectiveness, they do not expect that such controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, provides only reasonable, and not absolute assurance that the objectives of the control system are met.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management has designed or caused to be designed under its supervision, internal controls over financial reporting related to the Trust and its subsidiaries, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

There were no changes to the Trust's internal controls over financial reporting since December 31, 2007 that have materially affected, or are reasonably likely to materially affect, the Trust'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, 2007 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, 2007.

NEW ACCOUNTING STANDARDS

Effective January 1, 2008, the Trust implemented the provisions of CICA Handbook Section 1535 "Capital Disclosures", Section 3862 "Financial Instruments – Disclosures", and Section 3863 "Financial Instruments – Presentation".

Section 1535 establishes standards for disclosing information about an entity's capital and how it is managed. This Section specifies disclosure about objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and if it has not complied, the consequences of such non-compliance. Sections 3862 and 3863 establish standards for the presentation and disclosure of information that enable users to evaluate the significance of financial instruments to the entity's financial position, and the nature and extent of risks arising from financial instruments and how the entity manages those risks.

The implementation of these new standards did not impact the Trust's financial results but did, however, result in additional disclosures.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards ("IFRS")

In February 2008, the Canadian Accounting Standards Board ("AcSB"), confirmed that the changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011. The AcSB issued the "omnibus" exposure draft of IFRS with comments due by July 31, 2008, wherein early adoption by Canadian entities is also permitted. The Canadian Securities Administrators ("CSA") have also issued Concept Paper 52-402, which requested feedback on the early adoption of IFRS as well as the continued use of US GAAP by domestic issuers. The eventual changeover to IFRS represents a change due to new accounting standards. The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Trust's reported financial results.

The International Accounting Standards Board ("IASB") has stated that it plans to issue an exposure draft relating to certain amendments and exemptions to IFRS 1 in order to make it more useful to Canadian entities adopting IFRS for the first time. One such exemption relating to full cost oil and gas accounting is expected to reduce the administrative burden in the transition from the current Canadian Accounting Guideline 16 to IFRS. It is anticipated that this exposure draft will not result in an amended IFRS 1 standard until late 2009. The amendment will potentially permit the Trust to apply IFRS prospectively to its full cost pool, rather than performing retrospective assessment of capitalized exploration and development expenses, with the provision that a ceiling test, under IFRS standards, be conducted at the transition date.

Although the Trust has not completed its IFRS changeover plan, an initial evaluation of IFRS 1 has been completed. NAL is planning detailed reviews, in the third quarter, of the significant differences between IFRS and Canadian GAAP as they apply to the Trust. During the remainder of 2008, NAL will finalize its changeover plan, which will include project structure and governance, resourcing and training, a complete analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS, as well as potential IFRS 1 exemptions. The Trust anticipates completing its project scoping, which will include a timetable for assessing the impact on data systems, internal controls over financial reporting, and business activities, such as financing and compensation arrangements, by the end of 2008.

Dated: August 6, 2008

CONSOLIDATED BALANCE SHEETS

(thousands of dollars) (unaudited)

	As at June 30, 2008	As at December 31, 2007
Assets		
Current assets		
Cash and cash equivalents	\$12,867	\$1,394
Accounts receivable and other	111,182	70,791
Note receivable (Note 3)	49,599	-
Derivative contracts (Note 12)	-	3,389
Future income tax asset	21,656	2,602
	195,304	78,176
Future income tax asset	-	4,096
Goodwill (Note 3)	14,235	-
Property, plant and equipment (Notes 3 and 5)	1,014,640	980,888
	\$1,224,179	\$1,063,160
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$88,893	\$73,135
Note payable (Note 3)	3,935	-
Distributions payable to unitholders	15,242	14,479
Derivative contracts (Note 12)	84,218	12,973
	192,288	100,587
Bank debt (Note 6)	308,115	275,630
Convertible debentures (Note 7)	75,561	90,876
Derivative contracts (Note 12)	18,049	-
Unit-based incentive compensation (Note 8)	4,489	1,748
Asset retirement obligations (Note 9)	92,032	89,602
Future income tax liability	7,411	-
	697,945	558,443
Non-controlling interest (Note 10)	55,013	-
Unitholders' equity		
Unitholders' capital (Note 11)	1,030,280	969,588
Equity component of convertible debentures (Note 7)	4,737	5,759
Deficit	(563,796)	(470,630)
	471,221	504,717
	\$1,224,179	\$1,063,160
Trust units outstanding (000s)	95,277	90,494

See accompanying notes.

CONSOLIDATED STATEMENTS OF INCOME (LOSS), COMPREHENSIVE INCOME (LOSS) AND DEFICIT

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

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Revenue				
Oil, natural gas and liquid sales	\$188,297	\$97,684	\$334,440	\$192,565
Crown royalties	(28,834)	(14,757)	(50,682)	(29,786)
Freehold and other royalties	(10,107)	(5,730)	(17,570)	(11,015)
	149,356	77,197	266,188	151,764
Gain (loss) on derivative contracts (Note 12):				
Realized gain (loss)	(21,730)	848	(27,221)	3,122
Unrealized gain (loss)	(70,148)	3,366	(92,683)	(4,384)
Reclassification from other comprehensive income	-	1,394	-	2,773
	(91,878)	5,608	(119,904)	1,511
Other income	1,383	463	2,188	1,224
	58,861	83,268	148,472	154,499
Expenses				
Operating	22,443	14,952	43,716	29,078
Transportation	956	594	1,890	1,191
General and administrative	4,539	3,844	8,276	7,759
Unit-based incentive compensation (Note 8)	1,889	688	2,997	664
Interest on bank debt	3,879	3,137	7,860	5,996
Interest and accretion on convertible debentures	2,071	-	4,213	-
Depletion, depreciation and amortization	47,347	34,822	93,059	69,250
Accretion on asset retirement obligations	1,827	1,302	3,625	2,599
	84,951	59,339	165,636	116,537
Income (loss) before taxes and non-controlling interest	(26,090)	23,929	(17,164)	37,962
Income tax provision	(10)	(84)	(6)	(108)
Future income tax reduction (provision)	12,820	(2,455)	19,348	246
Total income tax reduction (provision)	12,810	(2,539)	19,342	138
Income (loss) before non-controlling interest	(13,280)	21,390	2,178	38,100
Non-controlling interest (Note 10)	(4,292)	-	(6,017)	-
Net income (loss)	(17,572)	21,390	(3,839)	38,100
Other comprehensive income:				
Reclassification to net income, net of tax	-	(979)	-	(1,946)
Comprehensive income (loss)	(17,572)	20,411	(3,839)	36,154
Deficit, beginning of period	(500,922)	(389,382)	(470,630)	(368,486)
Net income (loss)	(17,572)	21,390	(3,839)	38,100
Distributions declared	(45,302)	(37,877)	(89,327)	(75,483)
Deficit, end of period	\$(563,796)	\$(405,869)	\$(563,796)	\$(405,869)
Net income (loss) per trust unit – basic and diluted (Note 11)	\$(0.19)	\$0.27	\$(0.04)	\$0.49
Weighted average trust units outstanding (000s)	94,101	78,824	92,909	78,543

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of dollars) (unaudited)

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Operating Activities				
Net income (loss)	\$(17,572)	\$21,390	\$(3,839)	\$38,100
Items not involving cash:				
Depletion, depreciation and amortization	47,347	34,822	93,059	69,250
Accretion on asset retirement obligations	1,827	1,302	3,625	2,599
Unrealized loss (gain) on derivative contracts	70,148	(3,366)	92,683	4,384
Reclassification from other comprehensive income	-	(1,394)	-	(2,773)
Future income tax provision (reduction)	(12,820)	2,455	(19,348)	(246)
Non-cash accretion expense on convertible debentures	464	-	941	-
Non-controlling interest	709	-	956	-
Abandonment and environmental expenditures	(1,525)	(1,053)	(3,279)	(2,923)
Change in non-cash working capital	(15,283)	1,865	(20,942)	596
	73,295	56,021	143,856	108,987
Financing Activities				
Distributions paid to unitholders	(38,256)	(37,789)	(74,632)	(75,305)
Issue of trust units, net of issue costs	-	6,608	(14)	13,165
Increase (decrease) in bank debt	(5,255)	3,884	32,485	12,732
Change in non-cash working capital	-	-	(426)	915
	(43,511)	(27,297)	(42,587)	(48,493)
Investing Activities				
Acquisition of Tiberius and Spear (Note 3)	(371)	-	(77,355)	-
Disposition of Tiberius and Spear (Note 3)	115	-	58,222	-
Acquisition of Seneca	-	-	337	-
Additions to property, plant and equipment	(26,748)	(18,925)	(56,071)	(46,009)
Property acquisitions	(1,006)	-	(7,876)	-
Proceeds from dispositions	40	-	40	25
Change in non-cash working capital	(4,124)	(9,853)	(7,093)	(15,736)
	(32,094)	(28,778)	(89,796)	(61,720)
Increase (decrease) in cash and cash equivalents	(2,310)	(54)	11,473	(1,226)
Cash and cash equivalents, beginning of period	15,177	5,123	1,394	6,295
Cash and cash equivalents, end of period	\$12,867	\$5,069	\$12,867	\$5,069
Supplementary disclosure of cash flow information:				
Cash paid during the period for:				
Interest	\$3,342	\$3,069	\$9,864	\$5,900
Tax	\$1,971	\$84	\$2,579	\$108
Cash and cash equivalents is comprised of:				
Cash	\$2,864	\$76	\$2,864	\$76
Short term investments	10,003	4,993	10,003	4,993
	\$12,867	\$5,069	\$12,867	\$5,069

See accompanying notes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Six months ended June 30, 2008

(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, 2007, except as described below. 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, 2007.

2. CHANGES IN ACCOUNTING POLICIES

New Accounting Standards

Effective January 1, 2008 the Trust implemented the provisions of CICA Handbook Section 1535 “Capital Disclosures”, Section 3862 “Financial Instruments – Disclosures”, and Section 3863 “Financial Instruments – Presentation”.

Section 1535 establishes standards for disclosing information about an entity’s capital and how it is managed. This Section specifies disclosure about objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with all capital requirements, and if it has not complied, the consequences of such non-compliance. Sections 3862 and 3863 establish standards for the presentation and disclosure of information that enable users to evaluate the significance of financial instruments to the entity’s financial position, and the nature and extent of risks arising from financial instruments and how the entity manages those risks.

The implementation of these new standards did not impact the Trust’s financial results but did, however, result in additional disclosures, as provided in Note 12.

IFRS

In February 2008, the AcSB, confirmed that the changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011. The AcSB issued the “omnibus” exposure draft of IFRS with comments due by July 31, 2008, wherein early adoption by Canadian entities is also permitted. The CSA have also issued Concept Paper 52-402, which requested feedback on the early adoption of IFRS as well as the continued use of US GAAP by domestic issuers. The eventual changeover to IFRS represents a change due to new accounting standards. The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Trust’s reported financial position and results of operations.

The IASB has stated that it plans to issue an exposure draft relating to certain amendments and exemptions to IFRS 1 in order to make it more useful to Canadian entities adopting IFRS for the first time. One such exemption relating to full cost oil and gas accounting is expected to reduce the administrative burden in the transition from the current Canadian Accounting Guideline 16 to IFRS. It is anticipated that this exposure draft will not result in an amended IFRS 1 standard until late 2009. The amendment will potentially permit the Trust to apply IFRS prospectively to its full cost pool, rather than the performing retrospective assessment of capitalized exploration and development expenses, with the provision that a ceiling test, under IFRS standards, be conducted at the transition date.

Although the Trust has not completed its IFRS changeover plan, an initial evaluation of IFRS 1 has been completed. NAL is planning detailed reviews, in the third quarter, of the significant differences between IFRS and Canadian GAAP as they apply to the Trust. During the remainder of 2008, NAL will finalize the changeover plan, which will include project structure and governance, resourcing and training, a complete analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS as well as

potential IFRS 1 exemptions. The Trust anticipates completing its project scoping, which will include a timetable for assessing the impact on data systems, internal controls over financial reporting, and business activities, such as financing and compensation arrangements, by the end of 2008.

Basis of Presentation

The Trust's financial statements include the accounts of the Trust and all its subsidiaries and partnerships. All inter-entity transactions and balances have been eliminated. Non-controlling interests in subsidiaries and partnerships are presented as separate line items on the consolidated balance sheet and the consolidated statement of income, comprehensive income and deficit.

Goodwill

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

Comparative Information

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

3. CORPORATE ACQUISITIONS

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

On February 29, 2008, the Trust transferred the assets into a limited partnership ("Partnership") in exchange for a 50 percent partnership interest and a note receivable of \$3.7 million. A wholly owned subsidiary of Manulife Financial Corporation ("MFC") acquired the remaining 50 percent share in the Partnership and a note receivable of \$3.7 million, by payment in cash of one half of the total purchase price for Tiberius and Spear. Accordingly, the net acquisition cost to the Trust for its 50 percent share in the acquired properties is \$57.8 million, before acquisition costs, comprised of \$28.3 million in cash and \$29.5 million from the issuance of 2.4 million trust units at a price of \$12.24 per unit. The unit price was based on the weighted average market price of the units at the announcement date for the acquisition of February 11, 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. The equivalent carrying amount of property, plant and equipment related to this interest in the reserves is recorded on the books of each royalty holder.

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

The transaction was accounted for using the purchase method of accounting. The fair values assigned to the net assets, and the consideration paid by the Trust are as follows:

	Total	Disposition	Trust, net		
Net assets acquired:	Acquisition	to Manulife	Acquisition	NPI ⁽¹⁾	Net to Trust
Cash	\$9,734	\$-	\$9,734	\$-	\$9,734
Working capital deficiency	(5,620)	-	(5,620)	-	(5,620)
Notes receivable, net from MFC	-	(3,750)	(3,750)	49,599	45,849
Property, plant and equipment	111,258	-	111,258	(49,599)	61,659
Future income taxes	(23,389)	11,588	(11,801)	-	(11,801)
Asset retirement obligations	(1,636)	-	(1,636)	-	(1,636)
Goodwill	26,238	(12,003)	14,235	-	14,235
Non-controlling interest	-	(54,057)	(54,057)	-	(54,057)
	\$116,585	\$(58,222)	\$58,363	\$-	\$58,363
Consideration:					
Cash	\$86,118	\$(57,807)	\$28,311	\$-	\$28,311
Issuance of trust units	29,496	-	29,496	-	29,496
Acquisition costs	971	(415)	556	-	556
	\$116,585	\$(58,222)	\$58,363	\$-	\$58,363

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

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

4. RELATED PARTY TRANSACTIONS

The Trust is managed by the Manager. The Manager is a wholly-owned subsidiary of MFC and manages on their behalf NAL Resources Limited (“NAL Resources”), another wholly-owned subsidiary of Manulife. The disposition of a 50 percent interest in the Partnership holding the Tiberius and Spear assets was to MFC, as outlined in Note 3.

The Manager provides certain services to the Trust pursuant to a management contract. This contract 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 \$3.5 million (2007 - \$3.1 million) for the reimbursement of G&A expenses during the second quarter, and \$6.5 million (2007 - \$6.0 million) year-to-date. The Trust also pays the Manager its share of unit-based compensation expense when cash compensation is paid to employees under the terms of the Plan, of which \$1.8 million has been paid year-to-date, representing units that vested on November 30, 2007 (2007 - \$2.2 million).

The notes payable and receivable due to/from MFC, are due on demand and bear interest at prime plus three percent. Net interest of \$1.2 million relating to these notes was received by the Trust for the six months ended June 30, 2008 and is reported as other income.

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

	June 30, 2008	December 31, 2007
Due from NAL Resources Limited	\$26,431	\$14,203
Due to NAL Resources Management Limited	(1,507)	(2,826)
Due from Manulife Financial Corporation ⁽¹⁾	43,631	-
	\$68,555	\$11,377

(1) Included on consolidation, eliminated through non-controlling interest.

5. PROPERTY, PLANT AND EQUIPMENT

	June 30, 2008	December 31, 2007
Petroleum and natural gas properties, at cost	\$1,814,142	\$1,687,331
Less: Accumulated depletion and depreciation	(799,502)	(706,443)
	\$1,014,640	\$980,888

Costs associated with undeveloped land of \$26.7 million (2007 - \$nil) have been excluded from the depletion calculation for the six months ended June 30, 2008.

Future development costs for proved reserves of \$49.8 million (2007 - \$27.3 million) have been included in the depletion calculation.

During 2008, the Trust capitalized \$2.3 million (2007 - \$2.4 million) of G&A costs and \$1.5 million (2007 - \$0.2 million) of unit-based incentive compensation that were directly related to exploitation and development programs.

6. BANK DEBT

	June 30, 2008	December 31, 2007
Production loan facility	\$302,908	\$273,528
Working capital facility	5,207	2,102
Total debt outstanding	\$308,115	\$275,630

The Trust maintains a fully secured, extendible, revolving term credit facility with a syndicate of Canadian chartered banks. The current facility consists of a \$390 million production facility and a \$10 million working capital facility. The current bank group has agreed to expand the bank group by two banks and increase the production facility, by \$50 million, to \$440 million while maintaining the current working capital facility of \$10 million, subject to final documentation approval. 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 a function of the net present value of the Trust's oil and gas reserves and other assets.

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 29, 2009 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 2009, the amounts outstanding at that time will be converted to a two-year term loan. The term loan will be payable in four equal quarterly installments commencing May 2010 with a final residual payment, if any, in May 2011.

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

Amounts are advanced under the credit facility in Canadian dollars by way of prime interest rate based loans and by issues of bankers' acceptances and in U.S. dollars by way of U.S. based interest rate and Libor based loans. The interest charged on advances is at the prevailing interest rate for bankers' acceptances, Libor loans, lenders' prime or U.S. base rates plus an applicable margin or stamping fee. The applicable margin or stamping fee, if any, varies based on the consolidated debt-to-cash flow ratio of the Trust. As at June 30, 2008 and December 31, 2007 all amounts outstanding were in Canadian dollars.

On June 30, 2008 the effective interest rate on amounts outstanding under the credit facility was 4.57 percent (2007 - 5.41 percent).

7. CONVERTIBLE DEBENTURES

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

	Principal amount of debentures	Debt component of debentures	Equity component of debentures
August 28, 2007 issuance	\$100,000	\$94,241	\$5,759
Issue costs	-	(4,000)	-
Accretion	-	635	-
Balance, December 31, 2007	100,000	90,876	5,759
Conversion to trust units	(17,741)	(16,256)	(1,022)
Accretion	-	941	-
Balance, June 30, 2008	\$82,259	\$75,561	\$4,737

8. UNIT-BASED INCENTIVE COMPENSATION PLAN

The Trust recorded a total compensation expense of \$4.5 million in the first six months of 2008, of which \$3.0 million was recorded as an expense and \$1.5 million as property, plant and equipment (\$2.1 million expensed and \$0.9 million as property, plant and equipment for the year ended December 31, 2007). The compensation expense was based on the June 30, 2008 trust unit price of \$16.89 (2007 - \$11.60), 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:

	Six months ended June 30, 2008	Year ended December 31, 2007
Balance, beginning of period	\$4,996	\$4,153
Increase in liability	4,487	3,027
Cash payout, relating to units vested	(1,767)	(2,184)
Balance, end of period	7,716	\$4,996
Current portion of liability ⁽¹⁾	3,227	\$3,248
Long-term liability	\$4,489	\$1,748

(1) Included in accounts payable and accrued liabilities.

9. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by the Manager based on the Trust's net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. NAL has estimated the net present value of its asset retirement obligations to be \$92.0 million as at June 30, 2008 (2007 - \$89.6 million) based on a total undiscounted and inflated amount of cash flows required to settle its asset retirement obligations of \$276.6 million (2007 - \$270.5 million). These costs are expected to be made over the next 44 years with the majority of the costs incurred between 2008 and 2033. NAL's credit-adjusted risk-free rate of eight percent (2007 - eight percent) and an inflation rate of two percent (2007 - two percent) were used to calculate the present value of the asset retirement obligations.

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

	Six months ended June 30, 2008	Year ended December 31, 2007
Balance, beginning of period	\$89,602	\$65,574
Accretion expense	3,625	5,533
Revisions to estimates	(261)	10,294
Liabilities incurred	709	1,079
Liabilities acquired (Note 3)	1,636	12,625
Liabilities settled	(3,279)	(5,503)
Balance, end of period	\$92,032	\$89,602

10. NON-CONTROLLING INTEREST

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

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Net profits interest	\$3,583	\$-	\$5,061	\$-
Share of net income attributable to MFC	709	-	956	-
	\$4,292	\$-	\$6,017	\$-

11. UNITHOLDERS EQUITY

Units Issued:

	Six months ended June 30, 2008		Year ended December 31, 2007	
	Units	Amount	Units	Amount
Balance, beginning of the period	90,494	\$969,588	77,971	\$824,986
Issued on corporate acquisition (Note 3)	2,409	29,496	10,246	125,001
Less issue expenses		(14)		(7,134)
Issued from Distribution Reinvestment Plan	1,107	13,932	2,277	26,735
Issued on conversion of debentures	1,267	17,278		
Balance, end of the period	95,277	\$1,030,280	90,494	\$969,588

Per Unit Information

Basic net income (loss) per trust unit is calculated using the weighted average number of trust units outstanding. The calculation of diluted net income (loss) per trust unit excludes the convertible debentures as the trust units potentially issuable on the conversion of the convertible debentures are anti-dilutive for the three and six months ended June 30, 2008. Total weighted average trust units issuable on conversion of the convertible debentures and excluded from the diluted net income (loss) per trust unit calculation for the three and six months ended June 30, 2008 were 6,815,850 and 6,979,354, respectively.

12. FINANCIAL RISK MANAGEMENT

Overview

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

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

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

Credit Risk

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Trust's receivables. The Trust is managed by the Manager. The Manager is a wholly-owned subsidiary of MFC and manages on their behalf NAL Resources, another wholly-owned subsidiary of MFC. NAL Resources and the Trust maintain ownership interests in many of the same oil and natural gas properties in which NAL Resources is the operator. As a result, a significant portion of the Trust's net operating revenues represent joint operations from NAL Resources. Accordingly, accounts receivable include amounts due from NAL Resources for oil, natural gas and

natural gas liquids sales. Oil and gas marketing is conducted by the Manager on behalf of the Trust and NAL Resources generally with large creditworthy purchasers, for which the Trust views the credit risk as low. Except as noted below, NAL Resources, and ultimately the Trust, have not historically experienced any collection issues with its oil and gas marketers. The Manager does not obtain collateral from oil and natural gas marketers or joint venture partners.

Cash and cash equivalents consist of cash bank balances and short-term deposits maturing in less than 90 days. The Trust manages the credit exposure related to short-term investments by selecting established counter parties with high credit ratings and monitors all investments, avoiding complex investment vehicles with higher risks such as asset backed commercial paper.

The Trust does not have an allowance for doubtful accounts as at June 30, 2008 and did not write-off any receivables during the first half of 2008. The Trust does not have any receivable balances past due as at June 30, 2008.

On July 22, 2008 SemCanada Crude Company (“SemCanada”) filed application for creditor protection under the Companies Creditors Arrangement Act in Canada. SemCanada marketed a portion of the Trust’s oil, butane and condensate sales. NAL estimates that it has a maximum net potential exposure of \$7.0 million. A reasonable determination of impairment, if any, cannot yet be made. NAL management has concluded that its existing credit policy remains appropriate with the exception of more regular review of purchasers. The events for this particular credit issue could not have been foreseen. However, management is currently reviewing all existing purchasers against its credit policy to ensure credit worthiness given the current market conditions.

Liquidity Risk

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

The Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as necessary. As well, the Manager utilizes authorizations for expenditure on both operated and non-operated projects. Furthermore, the Manager operates a high percentage of the Trust’s properties, which allows for significant control over future expenditures. To support the capital spending program, the Trust maintains a fully secured, extendible, revolving term credit facility, as outlined in Note 6.

The following are the contractual maturities of financial liabilities and associated interest payments as at June 30, 2008.

Financial Liability	<1 Year	1 – 2 Years	2 – 5 Years
Accounts payable and accrued liabilities	\$88,893	\$-	\$-
Distributions payable	15,242	-	-
Unit-based incentive compensation	-	3,839	650
Note payable	3,935	-	-
Derivative contracts	84,218	18,049	-
Bank debt, principal (May 2010)	-	77,029	231,086
Convertible debentures, principal	-	-	82,259
Total	\$192,288	\$98,917	\$313,995

(1) Amount due within one year classified in accounts payable and accrued liabilities.

Market risk

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

Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Trust’s oil and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian and U.S. dollar. As at June 30, 2008, if the Canadian dollar had weakened \$0.10 against the U.S. dollar, with all other variables held constant, net income would have been \$3.4 million lower due to changes in the foreign exchange component of U.S. dollar denominated

commodity contracts. An equal and opposite impact would have occurred to net income had the Canadian dollar improved \$0.10 against the U.S. dollar.

The Trust had no material foreign exchange related derivative contracts in place as at, or during the six months ended, June 30, 2008.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and U.S. dollar, but also macroeconomic events that dictate the levels of supply and demand. The Trust has attempted to mitigate commodity price risk by entering into financial derivative contracts. The Trust's policy is to enter into commodity contracts to a maximum of 50 percent of forecasted, net of royalty, production volumes for a period of up to two years.

NAL currently has the following WTI oil contracts in place for 2008, denominated in U.S. dollars:

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put U.S.\$/bbl	Sold Call U.S.\$/bbl	Swap U.S.\$/bbl
COLLARS						
July-December	2-way	100	18,400	85.00	100.00	-
July-December	2-way	100	18,400	83.00	100.00	-
July-December	2-way	100	18,400	75.00	85.50	-
July-December	2-way	100	18,400	76.00	87.00	-
July-December	2-way	100	18,400	94.00	100.50	-
July-December	2-way	100	18,400	92.00	101.50	-
Weighted Average			110,400	84.17	95.75	-

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put U.S.\$/bbl	Sold Call U.S.\$/bbl	Swap U.S.\$/bbl
SWAPS						
July-December	swap	100	18,400	-	-	73.50
July-December	swap	100	18,400	-	-	94.00
July-December	swap	100	18,400	-	-	92.18
July-December	swap	100	18,400	-	-	87.10
July-December	swap	100	18,400	-	-	79.10
July-December	swap	100	18,400	-	-	71.00
July-December	swap	100	18,400	-	-	80.75
July-October	swap	100	12,300	-	-	88.10
July-December	swap	100	18,400	-	-	94.50
July-December	swap	100	18,400	-	-	94.04
July-December	swap	100	18,400	-	-	92.00
July-December	swap	100	18,400	-	-	98.50
July-December	swap	100	18,400	-	-	98.25
July-December	swap	100	18,400	-	-	98.10
July-December	swap	100	18,400	-	-	97.25
July-December	swap	100	18,400	-	-	96.75
July-December	swap	100	18,400	-	-	100.00
November-December	swap	100	6,100	-	-	100.03
November-December	swap	100	6,100	-	-	103.00
July-December	swap	100	18,400	-	-	108.00
Weighted Average			337,300	-	-	91.71

NAL currently has the following WTI oil contracts in place for 2008, denominated in Canadian dollars:

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
COLLARS						
July-December	2-way	100	18,400	85.00	94.40	-
July-December	2-way	100	18,400	85.00	96.00	-
July-December	2-way	100	18,400	87.10	97.35	-
July-December	2-way	100	18,400	72.40	77.54	-
July-December	2-way	100	18,400	103.00	132.75	-
July-December	2-way	100	18,400	104.00	134.75	-
July-December	2-way	100	18,400	107.00	130.45	-
Weighted Average			128,800	91.93	109.03	-

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
SWAPS						
July-December	swap	100	18,400	-	-	84.90
July-December	swap	100	18,400	-	-	90.05
July-December	swap	100	18,400	-	-	90.15
July-December	swap	100	18,400	-	-	90.05
July-December	swap	100	18,400	-	-	90.20
July-December	swap	100	18,400	-	-	89.05
July-December	swap	100	18,400	-	-	87.00
July-December	swap	100	18,400	-	-	83.80
July-December	swap	100	18,400	-	-	73.55
July-December	swap	100	18,400	-	-	93.00
July-December	swap	100	18,400	-	-	90.70
July-December	swap	100	18,400	-	-	91.00
July-October	swap	100	12,300	-	-	87.50
July-December	swap	100	18,400	-	-	96.50
July-December	swap	100	18,400	-	-	97.00
July-December	swap	100	18,400	-	-	94.00
July-December	swap	200	36,800	-	-	97.00
July-December	swap	100	18,400	-	-	98.50
July-December	swap	100	18,400	-	-	110.50
Weighted Average			361,900	-	-	91.64

NAL currently has the following AECO natural gas contracts in place for 2008:

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
COLLARS						
November-December	2-way	1,000	61,000	7.30	8.50	-
November-December	2-way	1,000	61,000	7.75	9.05	-
November-December	2-way	1,000	61,000	7.55	9.10	-
November-December	2-way	1,000	61,000	7.55	9.05	-
November-December	2-way	1,000	61,000	7.30	8.60	-
November-December	2-way	1,000	61,000	7.85	9.25	-
November-December	2-way	1,000	61,000	8.00	9.50	-
November-December	2-way	1,000	61,000	8.00	9.50	-
November-December	2-way	1,000	61,000	8.25	9.50	-
November-December	2-way	1,000	61,000	8.25	9.75	-
November-December	2-way	1,000	61,000	8.25	10.00	-
July-October	2-way	1,000	123,000	8.50	11.00	-
November-December	2-way	1,000	61,000	9.00	12.00	-
Weighted Average			855,000	8.00	9.70	-

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
SWAPS						
July-December	swap	2,000	368,000	-	-	7.60
July-December	swap	1,000	184,000	-	-	7.40
July-December	swap	2,000	368,000	-	-	7.40
July-December	swap	1,000	184,000	-	-	7.31
July-December	swap	2,000	368,000	-	-	7.26
July-December	swap	1,000	184,000	-	-	7.05
July-December	swap	1,000	184,000	-	-	7.20
July-December	swap	1,000	184,000	-	-	7.10
July-December	swap	1,000	184,000	-	-	7.15
July-December	swap	1,000	184,000	-	-	7.10
July-December	swap	1,000	184,000	-	-	7.05
July-December	swap	1,000	184,000	-	-	7.23
July-October	swap	1,000	123,000	-	-	7.35
July-October	swap	1,000	123,000	-	-	7.60
July-October	swap	1,000	123,000	-	-	7.85
July-December	swap	1,000	184,000	-	-	7.30
July-October	swap	1,000	123,000	-	-	7.65
July-October	swap	1,000	123,000	-	-	7.43
July-December	swap	1,000	184,000	-	-	7.10
July-October	swap	1,000	123,000	-	-	7.20
July-October	swap	1,000	123,000	-	-	7.09
July-October	swap	1,000	123,000	-	-	7.80
November-December	swap	1,000	61,000	-	-	8.66
July-October	swap	1,000	123,000	-	-	7.90
July-October	swap	1,000	123,000	-	-	8.02
July-October	swap	1,000	123,000	-	-	8.25
July-October	swap	1,000	123,000	-	-	8.40
Weighted Average			4,665,000	-	-	7.42

For 2009, NAL has the following WTI oil contracts in place, denominated in U.S. dollars:

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put U.S.\$/bbl	Sold Call U.S.\$/bbl	Swap U.S.\$/bbl
COLLARS						
January-December	2-way	100	36,500	92.00	101.50	-
January-June	2-way	100	18,100	94.00	100.50	-
January-June	2-way	100	18,100	95.00	105.00	-
January-June	2-way	100	18,100	110.00	152.40	-
April-September	2-way	100	18,300	100.00	157.50	-
January-June	2-way	100	18,100	115.00	162.00	-
April-September	2-way	100	18,300	110.00	170.00	-
January-June	2-way	200	36,200	110.00	176.50	-
July-December	2-way	200	36,800	115.00	164.25	-
January-June	2-way	200	36,200	115.00	167.65	-
July-December	2-way	200	36,800	110.00	173.00	-
January-December	2-way	100	36,500	120.00	175.00	-
July-December	2-way	100	18,400	120.00	181.50	-
January-June	2-way	100	18,100	120.00	182.25	-
Weighted Average			364,500	109.91	156.39	-

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put U.S.\$/bbl	Sold Call U.S.\$/bbl	Swap U.S.\$/bbl
SWAPS						
January-June	swap	100	18,100	-	-	97.25
January-December	swap	100	36,500	-	-	96.75
January-June	swap	100	18,100	-	-	100.00
January-June	swap	100	18,100	-	-	100.03
January-June	swap	100	18,100	-	-	103.00
January-December	swap	100	36,500	-	-	102.00
January-June	swap	100	18,100	-	-	97.50
January-June	swap	100	18,100	-	-	102.00
January-March	swap	100	9,000	-	-	101.50
April-June	swap	100	9,100	-	-	103.25
April-June	swap	100	9,100	-	-	103.27
January-June	swap	100	18,100	-	-	104.25
July-September	swap	100	9,200	-	-	105.00
July-December	swap	200	36,800	-	-	134.89
Weighted Average			272,900	-	-	105.24

For 2009, NAL has the following WTI oil contracts in place, denominated in Canadian dollars:

Term	Contract	Volume Bbl/d	Total Volume Bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
COLLARS						
January-June	2-way	100	18,100	100.00	115.00	-
January-June	2-way	100	18,100	100.00	114.00	-
January-June	2-way	100	18,100	100.00	113.05	-
January-May	2-way	100	15,100	103.00	132.75	-
January-December	2-way	100	36,500	115.00	140.50	-
Weighted Average			105,900	105.60	125.82	-

Term	Contract	Volume Bbl/d	Total Volume Bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
SWAPS						
January-September	swap	100	27,300	-	-	96.50
January-December	swap	200	73,000	-	-	97.00
January-September	swap	100	27,300	-	-	97.00
January-March	swap	100	9,000	-	-	102.00
January-March	swap	100	9,000	-	-	102.75
January-March	swap	100	9,000	-	-	106.10
April-June	swap	100	9,100	-	-	105.10
January-March	swap	100	9,000	-	-	105.02
January-March	swap	100	9,000	-	-	106.05
April-June	swap	100	9,100	-	-	105.50
April-September	swap	100	18,300	-	-	108.00
Weighted Average			209,100	-	-	100.21

For 2009, NAL has the following AECO natural gas contracts in place:

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
COLLARS						
January-March	2-way	1,000	90,000	8.00	9.50	-
January-March	2-way	1,000	90,000	7.75	9.05	-
January-March	2-way	1,000	90,000	7.85	9.25	-
January-March	2-way	1,000	90,000	7.55	9.10	-
January-March	2-way	1,000	90,000	7.55	9.05	-
January-March	2-way	1,000	90,000	7.30	8.60	-
January-March	2-way	1,000	90,000	7.30	8.50	-
January-March	2-way	1,000	90,000	8.00	9.50	-
January-March	2-way	1,000	90,000	8.25	9.50	-
January-March	2-way	1,000	90,000	8.25	9.75	-
January-March	2-way	1,000	90,000	8.25	10.00	-
January-March	2-way	1,000	90,000	8.50	10.00	-
January-March	2-way	1,000	90,000	8.50	9.50	-
January-March	2-way	1,000	90,000	8.65	9.75	-
January-March	2-way	1,000	90,000	8.75	9.75	-
January-March	2-way	1,000	90,000	9.00	12.00	-
April-October	2-way	1,000	214,000	8.50	11.26	-
April-October	2-way	1,000	214,000	9.00	11.25	-
April-October	2-way	1,000	214,000	9.00	11.55	-
April-October	2-way	1,000	214,000	9.00	12.10	-
April-October	2-way	1,000	214,000	9.00	11.05	-
Weighted Average			2,510,000	8.44	10.36	-
SWAPS						
January-March	swap	1,000	90,000	-	-	7.40
January-March	swap	1,000	90,000	-	-	7.05
January-March	swap	1,000	90,000	-	-	7.05
January-March	swap	1,000	90,000	-	-	7.10
January-March	swap	1,000	90,000	-	-	7.15
January-March	swap	1,000	90,000	-	-	7.23
January-March	swap	1,000	90,000	-	-	7.31
January-March	swap	1,000	90,000	-	-	7.30
January-March	swap	1,000	90,000	-	-	8.66
January-March	swap	1,000	90,000	-	-	9.00
January-March	swap	1,000	90,000	-	-	9.10
January-March	swap	1,000	90,000	-	-	9.16
January-March	swap	1,000	90,000	-	-	9.23
April-October	swap	1,000	214,000	-	-	8.00
April-October	swap	1,000	214,000	-	-	10.00
Weighted Average			1,598,000	-	-	8.20

These contracts and the contracts expired for the six months ended June 30, 2008 resulted in settlement losses of \$27.2 million (2007 - \$3.1 million gain). The unrealized gain or loss from derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income. As at June 30, 2008, 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

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust is exposed to interest rate fluctuations on its bank debt, which bears a floating rate of interest. As at June 30, 2008, if interest rates had been one percentage point lower, with all other variables held constant, net income for the quarter would have been \$0.7 million (\$1.3 million for the six months ended June 30, 2008)

higher, due to lower interest expense. An equal and opposite impact would have occurred to net income had interest rates been one percentage point higher.

The Trust had no interest related derivative contracts in place as at, or during the six months ended, June 30, 2008.

Fair Values

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

The notes payable and receivable due to/from MFC, are due on demand and bear interest at prime plus three percent. As the notes bear interest at a floating market rate, the fair market value approximates the carrying amount.

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

The fair value of the Trust's convertible debentures at June 30, 2008 was \$98.4 million, based on market price.

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 derivative contracts is determined by discounting the difference between the contracted prices and published forward curves as of the balance sheet date, using the remaining contracted oil and natural gas volumes.

	Six months ended June 30, 2008	Year ended December 31, 2007
Long term unrealized loss on derivative contracts	\$(18,049)	\$-
Current unrealized gain on derivative contracts	-	3,389
Current unrealized loss on derivative contracts	(84,218)	(12,973)
Current unrealized loss on derivative contracts	(84,218)	(9,584)
Fair value of derivative contracts	\$(102,267)	\$(9,584)

As at June 30, 2008, the total fair value of derivative contracts was a liability of \$102.3 million. The change in the fair value for six months ended June 30, 2008 of \$92.7 million has been recognized as an unrealized loss in the statement of income.

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

	Three months ended June 30		Six months ended June 30	
	2008	2007	2008	2007
Unrealized loss, beginning of period	\$(32,119)	\$(3,229)	\$(9,584)	\$-
Unrealized gain on adoption of new accounting standards	-	-	-	4,521
Unrealized gain (loss), end of period	(102,267)	137	(102,267)	137
Unrealized gain (loss)	(70,148)	3,366	(92,683)	(4,384)
Realized gain (loss) in the period	(21,730)	848	(27,221)	3,122
Reclassification from other comprehensive income	-	1,394	-	2,773
Gain (loss) on derivative contracts	\$(91,878)	\$5,608	\$(119,904)	\$1,511

Capital Management

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

The Trust manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Trust considers its capital structure to include unitholders' capital, bank debt, convertible debentures and working capital (excluding derivative contracts, notes with MFC and future income tax). In order to maintain or adjust its capital structure, the Trust

may adjust the amount of distributions paid to unitholders, issue new trust units, adjust its capital spending to modify debt levels, or suspend/resume its DRIP or premium DRIP programs.

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

As at June 30, 2008, the Trust had a net debt to 12 months trailing funds from operations ratio of 1.35 to 1.0, as calculated in the table below. At December 31, 2007, the Trust had a net debt to 12 months trailing funds from operations ratio of 1.79 to 1, primarily attributable to borrowings incurred to fund the Seneca acquisition.

The credit facility is determined by reference to the reserves of the Trust (see Note 6) and is therefore commodity price sensitive. The Trust is restricted under its credit facility from making distributions to its unitholders in excess of its consolidated operating cash flow during the 18 month period preceding the distribution date. As at June 30, 2008, the Trust is in full compliance with this external restriction on distributions.

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

There has been no change in the approach to capital management during 2008.

Capitalization

	June 30, 2008	December 31, 2007
Trust unit equity (\$000s)	471,221	504,717
Bank debt (\$000s)	308,115	275,630
Working capital deficit (surplus) ⁽¹⁾ (\$000s)	(19,914)	15,429
Net debt	288,201	291,059
Convertible debentures (\$000s) ⁽²⁾	82,259	100,000
Total net debt (\$000s) ⁽²⁾	370,460	391,059
Cash flow from operating activities for last 12 months (\$000s)	250,233	215,364
Add back change in non-cash working capital (\$000s)	24,919	3,381
Trailing 12 months funds from operations (\$000s)	275,152	218,745
Net debt to trailing 12 month funds from operations ⁽³⁾	1.05	1.33
Total net debt to trailing 12-month funds from operations ⁽²⁾	1.35	1.79

(1) Working capital excludes derivative contracts, the future income tax asset and the notes receivable/payable with MFC.

(2) Convertible debentures included at face value.

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

TRADING PERFORMANCE

	30-Jun-08	For the Quarter Ended		
		31-Mar-08	30-Jun-07	31-Mar-07
PRICE				
High	\$17.09	\$13.47	\$13.80	\$13.00
Low	\$13.12	\$10.81	\$11.45	\$10.86
Close	\$16.89	\$13.25	\$12.57	\$11.75
Daily Average Volume	447,401	321,650	247,533	256,104

NAL Oil & Gas Trust is an open-ended investment trust that generates distributions through the acquisition, development, production and marketing of oil, natural gas and natural gas liquids. The Trust owns high quality assets in British Columbia, Alberta, Saskatchewan and Ontario. Trust units trade on the Toronto Stock Exchange under the symbol "NAE.UN".

For further information:

Investor Relations

Telephone: 403.294.3600

Toll Free: 888.223.8792

Fax: 403.294.3601

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