North American Energy Partners Inc.
Form 6-K
February 14, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

Report of Foreign Private Issuer
Pursuant to Rule 13a-16 or 15d-16
under
the Securities Exchange Act of 1934
For the month of February 2008
Commission File Number 001-33161
NORTH AMERICAN ENERGY PARTNERS INC.
Zone 3 Acheson Industrial Area
2-53016 Highway 60
Acheson, Alberta
Canada T7X 5A7
(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F x Form 40-F o

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1): ___

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): ___

Indicate by check mark whether by furnishing the information contained in this Form, the registrant is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes o No x

If Yes is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82- ___

Included herein:

1. Interim consolidated financial statements of North American Energy Partners Inc. for the three and nine months ended December 31, 2007.

2. Management s Discussion and Analysis of Financial Condition and Results of Operations.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTH AMERICAN ENERGY PARTNERS INC.

By: /s/ David Blackley
Name: David Blackley
Title: Vice President, Finance

Date: February 14, 2008

NORTH AMERICAN ENERGY PARTNERS INC.
Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Expressed in thousands of Canadian dollars)
(Unaudited)

NORTH AMERICAN ENERGY PARTNERS INC.
Interim Consolidated Balance Sheets
(in thousands of Canadian dollars)

	December 31, 2007 (unaudited)	March 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 21,243	$ 7,895
Accounts receivable	115,512	93,220
Unbilled revenue	73,447	82,833
Inventory	114	156
Asset held for sale		8,268
Prepaid expenses and deposits	6,975	11,932
Other assets	3,376	10,164
Future income taxes	3,165	14,593
	223,832	229,061
Future income taxes (note 3(a))	30,059	14,364
Plant and equipment (note 5 and 6)	284,762	255,963
Goodwill (note 5)	200,056	199,392
Intangible assets, net of accumulated amortization, of $19,181 (March 31, 2007 $17,608) (notes 3(a), 5 and 7(a))	2,447	600
Deferred financing costs, net of accumulated amortization, of $nil (March 31, 2007 $7,595) (note 3(a))		11,356
	$ 741,156	**$ 710,736**
Liabilities and Shareholders Equity		
Current liabilities:		
Revolving credit facility (note 7(a))	$ 20,000	$ 20,500
Accounts payable	102,994	94,548
Accrued liabilities	16,097	23,393
Billings in excess of costs incurred and estimated earnings on uncompleted contracts	3,619	2,999
Current portion of capital lease obligations	3,915	3,195
Current portion of derivative financial instruments (note 11(b))	4,640	2,669
Future income taxes	10,065	4,154
	161,330	151,458
Deferred lease inducements (note 8)	967	

Capital lease obligations		7,840		6,514
Senior notes (notes 3(a) and 7(b))		190,546		230,580
Derivative financial instruments (notes 3(a) and 11(b))		96,676		58,194
Future income taxes (note 3(a))		21,551		19,712
		478,910		466,458
Shareholders equity:				
Common shares (authorized unlimited number of voting and non-voting common shares; issued and outstanding 35,951,684 voting common shares (March 31, 2007 35,192,260 voting common shares and 412,400 non-voting common shares)) (note 9(a))		298,481		296,198
Contributed surplus (note 9(b))		3,945		3,606
Deficit		(40,180)		(55,526)
		262,246		244,278
Guarantee (note 17)				
	$	**741,156**	**$**	**710,736**

See accompanying notes to unaudited interim consolidated financial statements.

NORTH AMERICAN ENERGY PARTNERS INC.
Interim Consolidated Statements of Operations, Comprehensive Income and Deficit
(in thousands of Canadian dollars, except per share amounts)
(unaudited)

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Revenue	**$ 274,894**	**$ 155,858**	**$ 666,096**	**$ 424,024**
Project costs	167,323	92,023	397,262	232,115
Equipment costs	44,231	29,244	131,582	78,777
Equipment operating lease expense	4,825	2,088	12,329	15,657
Depreciation	7,885	6,531	24,179	18,665
Gross profit	**50,630**	**25,972**	**100,744**	**78,810**
General and administrative costs	17,009	11,647	48,996	30,894
Loss on disposal of plant and equipment	5	381	850	839
Loss on disposal of asset held for sale			316	
Amortization of intangible assets	443	127	766	492
Operating income before the undernoted	**33,173**	**13,817**	**49,816**	**46,585**
Interest expense (note 10)	7,399	9,292	20,333	29,786
Foreign exchange (gain) loss	(1,784)	10,897	(33,136)	(2,497)
Realized and unrealized (gain) loss on derivative financial instruments (note 11(a))	(5,419)	(13,315)	39,766	(1,533)
Gain on repurchase of NACG Preferred Corp. Series A preferred shares		(9,400)		(9,400)
Loss on extinguishment of debt		10,875		10,928
Other income	(115)	(233)	(351)	(824)
Income before income taxes	**33,092**	**5,701**	**23,204**	**20,125**
Income taxes (note 12(c)):				
Current income taxes	8		29	(2,844)
Future income taxes	7,707	(938)	6,053	3,193
Net income and comprehensive income for the period	**25,377**	**6,639**	**17,122**	**19,776**
Deficit, beginning of period as previously reported	(65,557)	(63,409)	(55,526)	(76,546)
Change in accounting policy related to financial instruments (note 3(a))			(1,776)	
Premium on repurchase of common shares		(59)		(59)
Deficit, end of period	**$ (40,180)**	**$ (56,829)**	**$ (40,180)**	**$ (56,829)**

Net income per share basic (note 9(c))	**$**	**0.71**	**$**	**0.27**	**$**	**0.48**	**$**	**0.96**
Net income per share diluted (note 9(c))	**$**	**0.69**	**$**	**0.26**	**$**	**0.46**	**$**	**0.90**

See accompanying notes to unaudited interim consolidated financial statements.

NORTH AMERICAN ENERGY PARTNERS INC.
Consolidated Statements of Cash Flows
(in thousands of Canadian dollars)
(Unaudited)

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Cash provided by (used in):				
Operating activities:				
Net income for the period	$ 25,377	$ 6,639	$ 17,122	$ 19,776
Items not affecting cash:				
Depreciation	7,885	6,531	24,179	18,665
Write-down of other assets to replacement cost			1,848	
Amortization of intangible assets	443	127	766	492
Amortization of deferred lease inducements	(26)		(78)	
Amortization of deferred financing costs		853		2,688
Loss on disposal of plant and equipment	5	381	850	839
Loss on disposal of asset held for sale			316	
Unrealized foreign exchange (gain) loss on senior notes	(1,612)	10,956	(32,626)	(2,537)
Amortization of bond issue costs (notes 3(a) and 10)	162		669	
Unrealized (gain) loss on derivative financial instruments	(6,086)	(13,856)	37,764	(3,418)
Stock-based compensation expense (note 14)	276	621	1,023	1,742
Gain on repurchase of NACG Preferred Corp. Series A preferred shares		(9,400)		(8,000)
Accretion and change in redemption value of mandatorily redeemable preferred shares		1,204		3,114
Loss on extinguishment of debt		10,680		10,680
Future income taxes	7,707	(938)	6,053	3,193
Net changes in non-cash working capital (note 12(b))	(1,294)	(37,819)	3,531	(52,496)
	32,837	**(24,021)**	**61,417**	**(5,262)**
Investing activities:				
Acquisition, net of cash acquired (note 5)			(1,581)	(1,496)
Purchase of plant and equipment	(8,021)	(78,398)	(51,566)	(97,707)
Additions to asset held for sale			(2,248)	
Proceeds on disposal of plant and equipment	120	2,882	4,036	3,454
Proceeds on disposal of asset held for sale			10,200	
Net changes in non-cash working capital (note 12(b))	(18,976)	6,600	(4,727)	6,600
	(26,877)	**(68,916)**	**(45,886)**	**(89,149)**
Financing activities:				
Increase (decrease) in revolving credit facility	20,000	15,000	(500)	15,000

Repayment of capital lease obligations	(900)	(3,652)	(2,508)	(5,273)
Retirement of 9% senior secured notes		(74,748)		(74,748)
Repurchase of NAEPI Series A preferred shares		(1,000)		(1,000)
Repurchase of NACG Preferred Corp. Series A preferred shares		(27,000)		(27,000)
Financing costs (note 7(a))	(7)	(267)	(774)	(1,347)
Share issue costs		(16,197)		(18,138)
Repurchase of common shares for cancellation		(84)		(84)
Issue of common shares (note 9(a))	859	171,165	1,599	171,304
	19,952	**63,217**	**(2,183)**	**58,714**
Increase (decrease) in cash and cash equivalents	**25,912**	**(29,720)**	**13,348**	**(35,697)**
Cash and cash equivalents (cheques issued in excess of cash deposits), beginning of period	(4,669)	36,827	7,895	42,804
Cash and cash equivalents, end of period	**$ 21,243**	**$ 7,107**	**$ 21,243**	**$ 7,107**

Supplemental cash flow information (note 12(a))

See accompanying notes to unaudited interim consolidated financial statements.

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(Unaudited)

1. Nature of operations

On November 26, 2003, North American Energy Partners Inc. (the Company) purchased all the issued and outstanding shares of North American Construction Group Inc. (NACGI), including subsidiaries of NACGI, from Norama Ltd. which had been operating continuously in Western Canada since 1953. The Company had no operations prior to November 26, 2003.

The Company undertakes several types of projects including contract heavy construction and mining, pipeline and piling installations in Canada.

2. Basis of presentation

These unaudited interim consolidated financial statements (the financial statements) are prepared in accordance with Canadian generally accepted accounting principles (GAAP) for interim financial statements and do not include all of the disclosures normally contained in the Company s annual consolidated financial statements. Since the determination of many assets, liabilities, revenues and expenses is dependent on future events, the preparation of these financial statements requires the use of estimates and assumptions. In the opinion of management, these financial statements have been prepared within reasonable limits of materiality. Except as disclosed in note 3, these financial statements follow the same significant accounting policies as described and used in the most recent annual consolidated financial statements of the Company for the year ended March 31, 2007 and should be read in conjunction with those consolidated financial statements.

These financial statements include the accounts of the Company, its wholly-owned subsidiary, NACGI, the Company s joint venture, Noramac Ventures Inc. and the following wholly-owned subsidiaries of NACGI:

North American Caisson Ltd.
North American Construction Ltd.
North American Engineering Ltd.
North American Enterprises Ltd.
North American Industries Inc.
North American Mining Inc.
North American Maintenance Ltd.
North American Pipeline Inc.
North American Road Inc.
North American Services Inc.
North American Site Development Ltd.
North American Site Services Inc.
North American Pile Driving Inc.

3. Accounting policy changes

a) Financial instruments recognition and measurement

Effective April 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3855, Financial Instruments Recognition and Measurement , and Handbook Section 3865, Hedges . These standards have been applied retroactively without restatement as discussed below and, accordingly, comparative amounts for prior periods have not been restated.

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

On April 1, 2007, the Company made the following transitional adjustments to the consolidated balance sheet to adopt the new standards:

		Increase (decrease)
Deferred financing costs	$	(11,356)
Intangible assets		1,622
Long-term future income tax asset		2,588
Senior notes		(12,634)
Derivative financial instruments		7,246
Long-term future income tax liability		18
Opening deficit		1,776

CICA Handbook Sections 3855 and 3865 provide guidance on when a financial asset, financial liability or non-financial derivative is to be recognized on the balance sheet of the Company and on what basis these assets, liabilities and derivatives should be valued. Under the standards:

Financial assets are classified as loans and receivables, held-to-maturity, held-for-trading or available-for-sale. Loans and receivables include all loans and receivables and are accounted for at amortized cost. Held-to-maturity classification is restricted to fixed maturity instruments that the Company intends and is able to hold to maturity and is accounted for at amortized cost. Held-for-trading instruments are recorded at fair value with realized and unrealized gains and losses reported in net income. The remaining financial assets are classified as available-for-sale. These are recorded at fair value with unrealized gains and losses reported in other comprehensive income until the investment is derecognized at which time the amounts would be recorded in net income. On adoption of the standard, the Company has classified its cash and cash equivalents, unbilled revenue and accounts receivable as loans and receivables. The Company did not hold any financial assets that were held-for-trading, available-for-sale or held-to-maturity;

Financial liabilities are classified as either held-for-trading or other financial liabilities. Held-for-trading instruments are recorded at fair value with realized and unrealized gains and losses reported in net income. Other financial liabilities are accounted for at amortized cost with gains and losses reported in net income in the period that the liability is derecognized. The Company has classified its revolving credit facility, accounts payable, accrued liabilities, capital lease obligations and senior notes as other financial liabilities; and

Derivative financial instruments, including non-financial derivatives, are classified as held-for-trading and measured at fair value unless designated as hedging instruments or exempted from derivative treatment as a normal purchase and sale. Certain derivatives embedded in other contracts are also measured at fair value.

In determining the fair value of financial instruments, the Company used a variety of methods and assumptions that are based on market conditions and risks existing on each reporting date. Counterparty confirmations and standard market conventions and techniques, such as discounted cash flow analysis and option pricing models, are used to determine the fair value of the Company s financial instruments, including derivatives. All methods of fair value measurement result in a general approximation of value and such value may never actually be realized.

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

The Company elected April 1, 2003 as the transition date for identifying contracts with embedded derivatives. The adoption of these standards resulted in the following adjustments as of April 1, 2007 in accordance with the transition provisions:

Transaction costs that are directly attributable to the acquisition or issue of financial assets or liabilities are accounted for as a part of the respective asset or liability s carrying value at inception. Deferred financing costs related to the issue of the senior notes that were previously presented as a separate asset on the consolidated balance sheet are now included in the carrying value of the senior notes and are being amortized using the effective interest method over the remaining term of the debt. Prior to April 1, 2007, these deferred financing costs were amortized on a straight line basis over the term of the debt. As a result of the change in method of accounting, financing costs were re-measured on April 1, 2007 using the effective interest method. This re-measurement resulted in a $9,734 decrease in deferred financing costs, a decrease of $9,815 in senior notes, a decrease of $63 in opening deficit and an increase of $18 in the future income tax liability.

Transaction costs incurred in connection with the Company s revolving credit facility of $1,622 were reclassified from deferred financing costs to intangible assets on April 1, 2007 and these costs continue to be amortized on a straight-line basis over the term of the facility.

The Company determined that the issuer s early prepayment option included in the senior notes should be bifurcated from the host contract, along with a contingent embedded derivative in the senior notes that provide for accelerated redemption by the holders in certain instances. These embedded derivatives were measured at fair value at the inception of the senior notes and the residual amount of the proceeds was allocated to the debt. Changes in fair value of the embedded derivatives are recognized in net income and the carrying amount of the senior notes is accreted to par value over the term of the notes using the effective interest method and is recognized as interest expense. At transition on April 1, 2007, the Company recorded the fair value of $8,519 related to these embedded derivatives and a corresponding decrease in opening deficit of $7,305, net of future income taxes of $1,214. The impact of the bifurcation of these embedded derivatives at issuance of the senior notes resulted in an increase of senior notes of $5,700 and an increase in opening deficit of $3,963, net of income taxes of $1,737 after applying the effective interest method to the premium resulting from the bifurcation of these embedded derivatives on April 1, 2007.

The Company determined that a price escalation feature in a revenue construction contract is an embedded derivative that is not closely related to the host contract. The embedded derivative has been measured at fair value and included in derivative financial instruments on the consolidated balance sheet, with changes in the fair value recognized in net income. The Company recorded the fair value of $7,246 related to this embedded derivative on April 1, 2007, with a corresponding increase in opening deficit of $5,181, net of future income taxes of $2,065.

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

b) Financial instruments disclosure and presentation

Revised CICA Handbook Section 3861, Financial Instruments Disclosure and Presentation replaces CICA Handbook Section 3860, Financial Instruments Disclosure and Presentation , and establishes standards for presentation of financial instruments and non-financial derivatives, and identifies information that should be disclosed. There was no material effect on the Company s financial statements upon adoption of CICA Handbook Section 3861 on April 1, 2007.

c) Comprehensive income and equity

CICA Handbook Section 1530, Comprehensive Income establishes standards for the reporting and display of comprehensive income. The new section defines other comprehensive income to include revenues, expenses, and gains and losses that, in accordance with primary sources of GAAP, are recognized in comprehensive income but excluded from net income. The standard does not address issues of recognition or measurement for comprehensive income and its components. The adoption of CICA Handbook Section 1530 on April 1, 2007 did not have a material impact on the Company s financial statement presentation in the current period.

CICA Handbook Section 3251, Equity establishes standards for the presentation of equity and changes in equity during the reporting period. The requirements in this section are in addition to those of Section 1530 and recommend that an enterprise should present separately the following components of equity: retained earnings, accumulated other comprehensive income, the total for retained earnings and accumulated other comprehensive income, contributed surplus, share capital and reserves. The adoption of CICA Handbook Section 3251 on April 1, 2007 did not have an impact on the Company s financial statement presentation in the current period. The Company currently has no accumulated other comprehensive income components.

d) Accounting changes

In July 2006, the CICA revised Handbook Section 1506, Accounting Changes , which requires that: (1) voluntary changes in accounting policy are made only if they result in the financial statements providing reliable and more relevant information; (2) changes in accounting policy are generally applied retrospectively; and (3) prior period errors are corrected retrospectively. This guidance was adopted by the Company on April 1, 2007 and did not have a material impact on the consolidated financial statements.

e) Accounting policy choice for transaction costs

In June 2007, the CICA issued Emerging Issues Committee Abstract No. 166, Accounting Policy Choice for Transaction Costs (EIC-166). CICA Handbook Section 3855 requires that when an entity acquires a financial asset or incurs a financial liability classified other than as held-for-trading, it adopts an accounting policy for transaction costs of either: (a) recognizing all transaction costs in net income; or (b) adding transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability to the carrying amount of the financial instrument. EIC-166 clarifies that the same accounting policy choice should be made for all similar instruments classified as other than held-for-trading, but that a different accounting policy choice may be made for financial instruments that are not

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

similar. This guidance was adopted by the Company on April 1, 2007 and did not have a material impact on the consolidated financial statements.

f) ***Goodwill***

In October 2007, the Company changed the date of its annual impairment test for goodwill from December 31 to October 1 of each year. This change in accounting policy was applied on a retrospective basis and had no impact on the consolidated financial statements.

4. Recent accounting pronouncements not yet adopted

a) Financial instruments

In March 2007, the CICA issued Handbook Section 3862, Financial Instruments Disclosures , which replaces CICA Handbook Section 3861 and provides expanded disclosure requirements that provide additional detail by financial asset and liability categories. This standard harmonizes disclosures with International Financial Reporting Standards. The standard applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007, specifically April 1, 2008 for the Company. The Company is currently evaluating the impact of this standard.

In March 2007, the CICA issued Handbook Section 3863, Financial Instruments Presentation , which replaces CICA Handbook Section 3861, to enhance financial statement users understanding of the significance of financial instruments to an entity s financial position, performance and cash flows. This section establishes standards for presentation of financial instruments and non-financial derivatives. It deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, gains and losses, and the circumstances in which financial assets and financial liabilities are offset. This standard harmonizes disclosures with International Financial Reporting Standards and applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007, specifically April 1, 2008 for the Company. The Company is currently evaluating the impact of this standard.

b) Capital disclosures

In December 2006, the CICA issued Handbook Section 1535, Capital Disclosures . This standard requires that an entity disclose information that enables users of financial statements to evaluate an entity s objectives, policies and processes for managing capital, including disclosures of any externally imposed capital requirements and the consequences of non-compliance. The new standard applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007, specifically April 1, 2008 for the Company. The Company is currently evaluating the impact of this standard.

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

c) Inventories

In June 2007, the CICA issued Handbook Section 3031, Inventories to harmonize accounting for inventories under Canadian GAAP with International Financial Reporting Standards. This standard requires the measurement of inventories at the lower of cost and net realizable value and includes guidance on the determination of cost, including allocation of overheads and other costs to inventory. The standard also requires the consistent use of either first-in, first out (FIFO) or weighted average cost formula to measure the cost of other inventories and requires the reversal of previous write-downs to net realizable value when there is a subsequent increase in the value of inventories. The new standard applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008, specifically April 1, 2008 for the Company. The Company is currently evaluating the impact of this standard.

d) Going concern

In April 2007, the CICA approved amendments to Handbook Section 1400, General Standards of Financial Statement Presentation . These amendments require management to assess an entity s ability to continue as a going concern. When management is aware of material uncertainties related to events or conditions that may cast doubt on an entity s ability to continue as a going concern, those uncertainties must be disclosed. In assessing the appropriateness of the going concern assumption, the standard requires management to consider all available information about the future, which is at least, but not limited to, twelve months from the balance sheet date. The new requirements of the standard are applicable for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008, specifically April 1, 2008 for the Company. The Company is currently evaluating the impact of this standard.

e) Goodwill and Intangible Assets

In February 2008, the CICA issued Handbook Section 3064, (CICA 3064) Goodwill and Intangible Assets. CICA 3064, which replaces Section 3062, Goodwill and Intangible Assets, and Section 3450, Research and Development Costs, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions of International Financial Reporting Standard IAS 38, Intangible Assets. This new standard is effective for the Company s interim and annual consolidated financial statements commencing April 1, 2009. The Company is currently evaluating the impact of this standard.

5. Acquisition

On May 1, 2007, the Company acquired all of the assets of Active Auger Services 2001 Ltd., a piling company specializing in the design and installation of screw piles in north central Saskatchewan, for total cash consideration and acquisition costs of $1,581. The transaction has been accounted for by the purchase method with the results of operations included in the financial statements from the date of acquisition. The details of the acquisition are as follows:

Net assets acquired at assigned values:	
Plant and equipment	$ 700
Intangible assets	217
Goodwill	664
	$ 1,581

The allocation of the purchase price to the fair value of the assets acquired and liabilities assumed is preliminary and is subject to adjustment. The goodwill related to this transaction is deductible for tax purposes.

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

6. Plant and equipment

December 31, 2007	Cost	Accumulated depreciation	Net book value
Heavy equipment	$ 284,094	$ 57,465	$ 226,629
Major component parts in use	9,960	3,307	6,653
Other equipment	19,167	6,919	12,248
Licensed motor vehicles	27,851	14,566	13,285
Office and computer equipment	7,046	3,163	3,883
Buildings	17,048	1,412	15,636
Leasehold improvements	6,169	983	5,186
Assets under construction	1,242		1,242
	$ 372,577	$ 87,815	$ 284,762

March 31, 2007	Cost	Accumulated depreciation	Net book value
Heavy equipment	$ 254,107	$ 46,609	$ 207,498
Major component parts in use	7,884	2,489	5,395
Other equipment	16,001	5,651	10,350
Licensed motor vehicles	23,345	12,121	11,224
Office and computer equipment	4,841	2,249	2,592
Buildings	16,443	716	15,727
Leasehold improvements	2,992	664	2,328
Assets under construction	849		849
	$ 326,462	$ 70,499	$ 255,963

The above amounts include $19,904 (March 31, 2007 $15,422) of assets under capital lease and accumulated depreciation of $9,231 (March 31, 2007 $7,302) related thereto. During the three and nine months ended December 31, 2007, additions of plant and equipment included $4,255 and $4,553, respectively, for capital leases (three and nine months ended December 31, 2006 $758 and $3,952 respectively). Depreciation of equipment under capital leases of $783 and $1,929 for the three and nine months ended December 31, 2007, respectively, is included in deprecation expense (three and nine months ended December 31, 2006 $614 and $1,956 respectively).

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

7. Debt

a) Revolving credit facility

On June 7, 2007, the Company modified its amended and restated credit agreement to provide for borrowings of up to the lesser of a restricted covenant resulting in a current ratio of 1.25 times and $125.0 million (previously $55.0 million) under which revolving loans and letters of credit may be issued. Based upon the Company s current credit rating, prime rate and swing line revolving loans under the agreement will bear interest at the Canadian prime rate plus 0.25% per annum, Canadian bankers acceptances have stamping fees equal to 1.75% per annum and letters of credit are subject to a fee of 1.25% per annum.

The credit facility is secured by a first priority lien on substantially all the Company s existing and after-acquired property and contains certain restrictive covenants including, but not limited to, incurring additional debt, transferring or selling assets, making investments including acquisitions or to pay dividends or redeem shares of capital stock. The Company is also required to meet certain financial covenants under the new credit agreement.

As of December 31, 2007, the Company had $20.0 million outstanding borrowings under the revolving credit facility and had issued $20.0 million in letters of credit to support performance guarantees associated with customer contracts. The Company s unused borrowing availability under the facility was $33.8 million at December 31, 2007.

During the three and nine months ended December 31, 2007, financing fees of $7 and $774, respectively, were incurred in connection with the modifications to the amended and restated credit agreement and were recorded as intangible assets.

b) Senior notes

	December 31, 2007	March 31, 2007
Principal outstanding ($US)	$ 200,000	$ 200,000
Unrealized foreign exchange	(2,410)	30,580
Unamortized financing costs and discounts (premiums), net	(3,082)	
Fair value of embedded prepayment and early redemption options	(3,962)	
	$ 190,546	$ 230,580

Effective April 1, 2007, the Company adopted CICA Handbook Section 3855 as described in note 3(a). The standards have been applied retroactively without restatement and, accordingly, comparative amounts for prior periods have not been restated. The senior notes have an effective interest rate of 9.4%.

8. Deferred lease inducements

Lease inducements applicable to lease contracts are deferred and amortized as a reduction of general and administrative costs on a straight-line basis over the lease term, which includes the initial lease term and renewal periods only where renewal is determined to be reasonably assured. During the nine months ended December 31, 2007, the Company received inducements from a lessor in the form of leasehold improvements to an office facility of $1,045.

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

9. Shares

a) Common shares

Authorized:
Unlimited number of common voting shares

Unlimited number of common non-voting shares
Issued:

	Number of Shares	Amount
Common voting shares		
Outstanding at March 31, 2007	35,192,260	$294,136
Issued on exercise of options	347,024	1,599
Transferred from contributed surplus on exercise of options		684
Conversion of common non-voting shares	412,400	2,062
Outstanding at December 31, 2007	35,951,684	$298,481
Common non-voting shares		
Outstanding at March 31, 2007	412,400	$ 2,062
Conversion to common voting shares	(412,400)	(2,062)
Outstanding at December 31, 2007		$
Total common shares	35,951,684	$298,481

On July 27, 2007, the Company s non-voting common shares were exchanged for voting common shares. Each holder of the non-voting common shares received one voting common share for each non-voting share held on the exchange date.

b) Contributed surplus

Balance, March 31, 2007	$3,606
Stock-based compensation (note 14)	1,023
Transferred to common shares on exercise of options	(684)

Balance, December 31, 2007	$3,945

13

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

c) ***Net income per share***

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Basic net income per share				
Net income available to common shareholders	$ 25,377	$ 6,639	$ 17,122	$ 19,776
Weighted average number of common shares	35,809,141	24,728,170	35,744,406	20,669,517
Basic net income per share	$ 0.71	$ 0.27	$ 0.48	$ 0.96
Diluted net income per share				
Net income available to common shareholders	$ 25,377	$ 6,639	$ 17,122	$ 19,776
Net income, assuming dilution	25,377	6,639	17,122	19,776
Weighted average number of common shares	35,809,141	24,728,170	35,744,406	20,669,517
Dilutive effect of:				
Stock options	919,297	818,425	1,110,011	1,381,368
Weighted average number of diluted common shares	36,728,438	25,546,595	36,854,417	22,050,885
Diluted net income per share	$ 0.69	$ 0.26	$ 0.46	$ 0.90

For the three and nine months ended December 31, 2007, stock options of 276,384 and 217,409, respectively, were excluded from the calculation of diluted net income per share as the options average exercise price was greater than the average market price of the common shares for the year.

10. Interest expense

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006

Interest on senior notes	$ 5,834	$ 6,802	$ 17,503	$ 21,582
Interest on capital lease obligations	165	164	497	480
Interest on NACG Preferred Corp. Series A preferred shares				1,400
Accretion and change in redemption value of NAEPI Series B preferred shares		612		2,489
Accretion of NAEPI Series A preferred shares		592		625
Interest on long-term debt	5,999	8,170	18,000	26,576
Amortization of bond issue costs	162		669	
Amortization of deferred financing costs		853		2,688
Interest on revolving credit facility and other interest	1,238	269	1,664	522
	$ 7,399	$ 9,292	$ 20,333	$ 29,786

14

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

11. Derivative financial instruments

a) Realized and unrealized (gain) loss on derivative financial instruments

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Realized and unrealized (gain) loss on cross-currency and interest rate swaps	$ (3,925)	$ (13,315)	$ 26,248	$ (1,533)
Unrealized (gain) loss on embedded price escalation clauses in long-term revenue construction contract	(2,630)		8,961	
Unrealized loss on embedded prepayment and early redemption options on senior notes	1,136		4,557	
	$ (5,419)	$ (13,315)	$ 39,766	$ (1,533)

b) Fair value of derivative financial instruments

December 31, 2007	Derivative financial instruments	Senior notes
Cross-currency and interest rate swaps	$ 85,109	$
Embedded price escalation clauses in long-term revenue construction contract	16,207	
Embedded prepayment and early redemption options on senior notes		(3,962)
Total fair value of derivative financial instruments	101,316	(3,962)
Less: current portion	(4,640)	
	$ 96,676	$ (3,962)

April 1, 2007	Derivative financial instruments	Senior notes

Cross-currency and interest rate swaps	$ 60,863	$
Embedded price escalation clauses in long-term revenue construction contract	7,246	
Embedded prepayment and early redemption options on senior notes		(8,519)
Total fair value of derivative financial instruments	68,109	(8,519)
Less: current portion	(2,669)	
	$ 65,440	$ (8,519)

15

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

12. Other information

a) Supplemental cash flow information

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Cash paid during the period for:				
Interest	$ 13,787	$ 16,476	$ 27,551	$ 33,182
Income taxes	8		29	342
Cash received during the period for:				
Interest	97	195	282	1,092
Non-cash transactions:				
Capital leases	4,255	758	4,553	3,952
Lease inducements			1,045	

b) Net change in non-cash working capital

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Operating activities:				
Accounts receivable	$ 8,454	$ (25,312)	$ (22,374)	$ (30,347)
Allowance for doubtful accounts	82		82	24
Unbilled revenue	(758)	295	9,386	4,404
Inventory	40	(143)	42	(99)
Prepaid expenses and deposits	212	(2,930)	4,957	(18,587)
Other assets	2,092	(1,859)	4,940	(11,290)
Accounts payable	(8,086)	10,069	13,174	13,142
Accrued liabilities	(4,970)	(18,300)	(7,296)	(13,411)
Billings in excess of costs and estimated earnings	1,640	361	620	3,668
	$ (1,294)	$ (37,819)	$ 3,531	$ (52,496)
Investing activities:				
Accounts payable	$ (18,976)	$ 6,600	$ (4,727)	$ 6,600
	$ (18,976)	$ 6,600	$ (4,727)	$ 6,600

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

c) Income taxes

Income tax expense as a percentage of income before income taxes for the three and nine months ended December 31, 2007 differs from the statutory rate of 31.47% primarily due to the impact of enacted rate changes during the period and the impact of new accounting standards for the recognition and measurement of financial instruments as certain embedded derivatives are considered capital in nature for income tax purposes. Income tax as a percentage of income before income taxes for the nine months ended December 31, 2006 differed from the statutory rate of 32.12% primarily due to the elimination of the valuation allowance of $5,858 that was recorded during that period offset by permanent differences relating to certain financing transactions which are not deductible for tax purposes and accruals for certain tax exposure items.

13. Segmented information

a) General overview

The Company operates in the following reportable business segments, which follow the organization, management and reporting structure within the Company.

Heavy Construction and Mining:

The Heavy Construction and Mining segment provides mining and site preparation services, including overburden removal and reclamation services, project management and underground utility construction, to a variety of customers throughout Canada.

Piling:

The Piling segment provides deep foundation construction and design build services to a variety of industrial and commercial customers throughout Western Canada.

Pipeline:

The Pipeline segment provides both small and large diameter pipeline construction and installation services to energy and industrial clients throughout Western Canada.

Certain business units of the Company have been aggregated into the Heavy Construction and Mining segment as they do meet quantitative thresholds for separate disclosure and have similar economic characteristics. These business units are considered to have similar economic characteristics based on similarities in the nature of the services provided, the customer base and the similarities in the production process and the resources used to provide these services.

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

b) Results by business segment

Three months ended December 31, 2007	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 154,402	$ 43,751	$ 76,741	$ 274,894
Depreciation of plant and equipment	5,563	817	419	6,799
Segment profits	28,097	11,386	12,934	52,417
Segment assets	439,487	116,195	98,473	654,155
Expenditures for segment plant and equipment	5,462	1,890	44	7,396

Three months ended December 31, 2006	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 111,416	$ 29,164	$ 15,278	$ 155,858
Depreciation of plant and equipment	3,875	1,023	275	5,173
Segment profits (loss)	8,922	10,322	(1,776)	17,468
Segment assets	449,594	94,410	52,405	596,409
Expenditures for segment plant and equipment	68,748	1,954	1,122	71,824

Nine months ended December 31, 2007	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 431,140	$ 121,698	$ 113,258	$ 666,096
Depreciation of plant and equipment	16,676	2,534	721	19,931
Segment profits	68,631	31,725	14,154	114,510
Segment assets	439,487	116,195	98,473	654,155
Expenditures for segment plant and equipment	30,210	10,878	4,923	46,011

Nine months ended December 31, 2006	Heavy Construction and Mining	Piling	Pipeline	Total

Revenues from external customers	$ 323,048	$ 79,394	$ 21,582	$ 424,024
Depreciation of plant and equipment	11,917	2,459	514	14,890
Segment profits (loss)	47,550	25,573	(710)	72,413
Segment assets	449,594	94,410	52,405	596,409
Expenditures for segment plant and equipment	79,168	6,264	1,904	87,336

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

c) Reconciliations

i. Income before income taxes

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Total profit for reportable segments	$ 52,417	$ 17,468	$ 114,510	$ 72,413
General and Administrative costs	(17,009)	(11,647)	(48,996)	(30,894)
Interest expense	(7,399)	(9,292)	(20,333)	(29,786)
Realized and unrealized (loss) gain on foreign exchange and derivative financial instruments	7,203	2,418	(6,630)	4,030
Other unallocated corporate costs	(333)	(1,750)	(1,581)	(2,036)
Over allocated (unallocated) equipment costs	(1,787)	8,504	(13,766)	6,398
Income before income taxes	$ 33,092	$ 5,701	$ 23,204	$ 20,125

ii. Total assets

	December 31, 2007	March 31, 2007
Total assets for reportable segments	$ 654,155	$ 621,636
Corporate assets	87,001	89,100
Total assets	$ 741,156	$ 710,736

The Company s goodwill was assigned to the Heavy Construction and Mining, Piling and Pipeline segments in the amounts of $125,447, $41,856 and $32,753, respectively.
Substantially all of the Company s assets are located in Western Canada and the activities are carried out throughout the year.

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

iii. Depreciation of plant and equipment

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Total depreciation for reportable segments	$ 6,799	$ 5,173	$ 19,931	$ 14,890
Depreciation for corporate assets	1,086	1,358	4,248	3,775
Total depreciation	$ 7,885	$ 6,531	$ 24,179	$ 18,665

iv. Capital expenditures for plant and equipment

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Total capital expenditures for reportable segments	$ 7,396	$ 71,824	$ 46,011	$ 87,336
Capital expenditures for corporate assets	625	6,574	5,555	10,371
Total capital expenditures	$ 8,021	$ 78,398	$ 51,566	$ 97,707

Prior year segmented capital expenditures have been adjusted to reflect the reclassification of assets between reported segments and corporate assets.

d) Customers

The following customers accounted for 10% or more of total revenues:

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Customer A	27%		14%	
Customer B	24%	31%	31%	21%
Customer C	14%	7%	13%	7%
Customer D	12%	17%	13%	18%
Customer E	11%	13%	12%	12%

This revenue by major customer was earned in the Heavy Construction and Mining, Piling and Pipeline segments.

14. Stock-based compensation plans

a) Employer stock option plan

Under the 2004 Amended and Restated Share Option Plan, directors, officers, employees and certain service providers to the Company are eligible to receive stock options to acquire voting common shares in the Company. Each stock option provides the right to acquire one common share in the Company and expires ten years from the grant date or on termination of employment. Options may be exercised at a price determined at the time the option is awarded, and vest as follows: no options vest on the award date and twenty percent vest on each subsequent anniversary date.

	Three months ended December 31			
	2007		2006	
	Number of options	Weighted average exercise price ($ per share)	Number of options	Weighted average exercise price ($ per share)
Outstanding, beginning of period	1,927,440	$ 6.14	2,230,840	$ 5.99
Granted	315,100	13.50		
Exercised	(199,624)	(5.00)		
Forfeited	(75,000)	(17.53)	(44,000)	(5.00)
Outstanding, end of period	1,967,916	$ 7.00	2,186,840	$ 6.01

20

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

	Nine months ended December 31			
	2007		2006	
	Number of options	Weighted average exercise price ($ per share)	Number of options	Weighted average exercise price ($ per share)
Outstanding, beginning of period	2,146,840	$ 6.03	2,066,360	$ 5.00
Granted	315,100	13.50	315,520	11.61
Exercised	(347,024)	(5.00)	(27,760)	(5.00)
Forfeited	(147,000)	(11.39)	(167,280)	(5.00)
Outstanding, end of period	1,967,916	$ 7.00	2,186,840	$ 6.01

At December 31, 2007, the weighted average remaining contractual life of outstanding options is 7.8 years (March 31, 2007 7.7 years). The Company recorded $276 and $1,023 of compensation expense related to the stock options in the three and nine months ended December 31, 2007, respectively (three and nine months ended December 31, 2006 $621 and $1,742 respectively), with such amount being credited to contributed surplus.
The fair value of each option granted by the Company was estimated on the grant date using the Black Scholes option-pricing model with the following weighted average assumptions:

	Three months ended December 31		Nine months ended December 31	
	2007	2006	2007	2006
Number of options granted	315,100		315,100	315,520
Weighted average fair value per option granted ($)	6.42		6.42	9.91
Weighted average assumptions:				
Dividend yield	nil%		nil%	nil%
Expected volatility	40.90%		40.90%	24.73%
Risk-free interest rate	4.00%		4.00%	4.30%
Expected life (years)	6.5		6.5	6.4

NORTH AMERICAN ENERGY PARTNERS INC.
Notes to the Interim Consolidated Financial Statements
For the three and nine months ended December 31, 2007
(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

b) Directors deferred stock unit plan

On November 27, 2007, the Company approved a Directors Deferred Stock Unit (DDSU) Plan, which became effective January 1, 2008. Under the DDSU Plan, non-employee or officer directors of the Company shall receive 50% of their annual fixed remuneration (which is included in general and administrative expenses in the consolidated statement of operations) in the form of DDSUs and may elect to receive all or a part of their annual fixed remuneration in excess of 50% in the form of DDSUs. The DDSUs vest immediately upon grant and are redeemable, in cash, equal to the difference between the market value of the Company s common stock at maturity (Maturity occurs when the director resigns or retires) and the market value of the Company s common stock on the grant date. DDSUs must be redeemed within 60 days following maturity. Directors, who are not US taxpayers, may elect to defer the maturity date until a date no later than December 1st of the calendar year following the year in which the maturity date falls.

15. Related party transactions

The Company may receive consulting and advisory services provided by companies in which directors of the corporation may have an interest of the Corporation with respect to the organization of the companies, employee benefit and compensation arrangements, and other matters, and no fee is charged for these consulting and advisory services.

In order for the companies to provide such advice and consulting we provide reports, financial data and other information. This permits them to consult with and advise our management on matters relating to our operations, company affairs and finances. In addition this permits them to visit and inspect any of our properties and facilities. The transactions are in the normal course of operations and are measured at the exchange amount of consideration established and agreed to by the related parties.

16. Seasonality

The Company generally experiences a decline in revenues during the first quarter of each fiscal year due to seasonality, as weather conditions make operations in the Company s operating regions difficult during this period. The level of activity in the Heavy Construction and Mining and Pipeline segments declines when frost leaves the ground and many secondary roads are temporarily rendered incapable of supporting the weight of heavy equipment. The duration of this period is referred to as spring breakup and has a direct impact on the Company s activity levels. Revenues during the fourth quarter of each fiscal year are typically highest as ground conditions are most favorable in the Company s operating regions. As a result, full-year results are not likely to be a direct multiple of any particular quarter or combination of quarters.

17. Guarantee

At December 31, 2007, in connection with a heavy equipment financing agreement, the Company has guaranteed a $0.9 million debt owed to the equipment manufacturer by a third party finance company. The Company s guarantee of this indebtedness will expire when the equipment is commissioned, which is expected to be February 28, 2008. The Company has determined that the fair value of this financial instrument at inception and December 31, 2007 was minimal.

18. Comparative figures

Certain of the comparative figures have been reclassified to conform to the current period s presentation.

22

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

The following discussion and analysis is as of February 14, 2008 and should be read in conjunction with the attached unaudited interim consolidated financial statements for the three and nine months ended December 31, 2007 and the audited consolidated financial statements included in our annual report on Form 20-F for the fiscal year ended March 31, 2007, which have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). Additional information relating to our business is available on SEDAR at www.sedar.com and EDGAR at www.sec.gov. Except where otherwise specifically indicated, all dollar amounts are expressed in Canadian dollars.
February 14, 2008

Prior Year Comparisons

On November 28, 2006 we completed an initial public offering (IPO) of common shares in Canada and the U.S. We became publicly traded on the Toronto Stock Exchange and New York Stock Exchange under the symbol NOA . Prior to the consummation of the IPO, the predecessor company was amalgamated with its parent companies and we undertook certain transactions that resulted in changes to our capital structure. Upon completion of the IPO, we used the proceeds to undertake additional transactions, which further changed our capital structure. As a result, comparisons of current periods to prior periods are impacted by the amalgamation and capital restructuring transactions. For a description of the amalgamation and IPO transactions see note 2 in our annual report on Form 20-F for the fiscal year ended March 31, 2007.

Consolidated Financial Highlights

	Three Months Ended Dec 31,			
	2007	% of Revenue	**2006**	% of Revenue
(dollars in thousands, except per share information)				
Revenue	$ 274,894	*100.0%*	$ 155,858	*100.0%*
Gross profit	50,630	*18.4%*	25,972	*16.7%*
General & administrative costs	17,009	*6.2%*	11,647	*7.5%*
Operating income	33,173	*12.1%*	13,817	*8.9%*
Net income	25,377	*9.2%*	6,639	*4.3%*
Per share information				
Net income basic	$ 0.71		$ 0.27	
Net income diluted	0.69		0.26	

Building on our solid performance in the second quarter we achieved even stronger financial results in the third quarter (three months ended December 31, 2007). Growth in all three segments of our business helped boost consolidated revenue to $274.9 million, up 76.4% from the previous year. Consolidated gross profit increased at an even faster pace, rising 94.9% over the prior year to $50.6 million. The improvement in gross profit reflects increased sales as well as an increase in profit margin from 16.7% to 18.4%. The higher gross profit margin reflects the return to profitability in our Pipeline segment, an advantageous mix of projects and solid execution across our entire portfolio of projects. General and administrative (G&A) cost performance improved during the period with G&A costs representing 6.2% of revenue compared to 7.5% a year ago. The combination of higher revenue, improved margins and better G&A cost performance contributed to a 140.1% increase in third quarter operating income. Net income climbed to $25.4 million or $0.71 per share, basic, from $6.6 million or $0.27 per share, basic, last year. Non-cash, after-tax unrealized gains on foreign exchange and derivative financial instruments positively impacted reported net income by $5.7 million ($0.16 per share, basic) compared to a $2.1 million ($0.09 per share, basic) favourable impact in the prior year.

Overview and Outlook

Demand for our services continued to grow in the third quarter with increased volumes of work in the Alberta oil sands, increased activity on a major pipeline project and strong commercial construction markets in Western Canada. Our business divisions responded effectively to these opportunities, achieving record revenue and operating income on both a consolidated and segmented basis. While we typically benefit from seasonally high activity levels during the third quarter, our results for the period were virtually free of claims, unusual expenses and other factors that can skew results either positively or negatively. Accordingly, we believe these third quarter results provide a clear picture of our performance capabilities.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

Our Heavy Construction and Mining segment, which, in the third quarter, accounted for 56.2% and 53.6% of consolidated revenues and segment profits, respectively, continued to benefit from robust oil sands activity. We further expanded our equipment fleet with an additional 14 mining trucks. We provided a record level of industrial construction and mining services to long-term customers including Suncor Energy Inc. (Suncor), Albian Sands Energy (Albian), Syncrude Canada Ltd. (Syncrude) and Canadian Natural Resources Ltd. (Canadian Natural). We also initiated services to Petro-Canada s Fort Hills oil sands project and we are actively tendering additional work on that site. The intense level of activity, combined with an excellent project mix and tight cost control, supported higher revenues and significantly improved profitability from this segment during the third quarter. On the cost side, our results began to show the benefit of a strategic shift to mid-sized mining trucks. Tires for these trucks are currently in better supply and available at lower costs than for larger-sized trucks, which in turn, has helped to stabilize our maintenance costs.

Our Piling division, which, in the third quarter, accounted for 15.9% and 21.7% of consolidated revenues and segment profits, respectively, achieved year-over-year revenue growth of 53.3%. Oil sands development and a high level of commercial and industrial construction activity were key factors in the revenue gain, supported by our acquisition of Midwest Foundation Technologies Inc. (Midwest Micropile) in September, 2006 and the opening of a new branch office in Saskatoon in May, 2007. As anticipated, margins in our Piling segment have returned to a more typical 26%, after peaking at 35% a year earlier on an unusually profitable project mix. We view the current margin level as more sustainable.

Our Pipeline division, which, in the third quarter, accounted for 27.9% and 24.7% of consolidated revenues and segment profits, respectively, achieved dramatically improved performance compared to the third quarter of last year. Revenue expanded by over five times and segment profits improved significantly to $12.9 million, compared to a $1.8 million loss last year, as we undertook a large portion of work on the Trans Mountain Expansion (TMX) Anchor Loop project for Kinder Morgan Canada (Kinder Morgan). We have now completed approximately 50% of this $185 million contract.

Overall, we are very pleased with our third quarter performance. We have attracted an excellent mix of short and long-term projects and our execution and cost control for these projects has been of a very high standard.

Looking forward, we expect our operating performance will remain strong through the balance of the fiscal year. The fourth quarter is typically strong and we anticipate a high level of activity in all three of our operating segments.*

Our Heavy Construction and Mining segment continues to respond effectively to opportunities in the Alberta oil sands. Despite recent changes to Alberta royalty rates affecting natural gas, conventional oil and oil sands producers, development of the oil sands continues to expand. Suncor, a major customer of ours for 31 years, recently announced it will spend over $20 billion on its Voyageur expansion. We have already initiated work at the Voyageur project under a five-year multiple-use contract with Suncor and we anticipate this project will create additional demand for our services. In addition, our activity levels with Syncrude and Albian are increasing, we have six years remaining on a major overburden removal contract with Canadian Natural and as mentioned above, we have recently initiated work at Petro-Canada s Fort Hills project. Beyond the oil sands, our involvement in the De Beers Victor diamond mine in northern Ontario is beginning to wind down as construction draws to a close. In keeping with our strategy of building diversification into our project mix, we will seek to replace this business with other non-oil sands projects. In the mean time, all equipment and people, surplus to our needs at Victor, have been redeployed on other revenue generating work.*

Pipeline results are expected to remain significantly above last year s levels as we continue to execute on the TMX contract with Kinder Morgan. This contract relates to the first of three pipeline expansion phases being undertaken by Kinder Morgan in Western Canada. Phase one, the TMX Anchor Loop project, establishes our company in the large-inch pipeline construction market and improves our competitive position within the rapidly expanding Western

Canadian market for large pipeline construction projects. We see numerous opportunities to continue growing our Pipeline business as the oil and gas transmission industry responds to increasing oil sands production and the resulting demand for additional pipeline capacity. *

In our Piling division, demand levels remain strong as a result of oil sands development and strong construction activity in major Western Canadian centers. The recent announcement of a $120 billion capital spending plan by the Province of Alberta could greatly accelerate demand for piling and construction services as the majority of the funding will be targeted to infrastructure enhancement. *

Overall, our outlook for all three of our business segments remains positive.

* This paragraph contains forward-looking information. Please refer to Forward-Looking Information, Risks and Uncertainties for a discussion of the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

Consolidated Operations

	Three Months Ended Dec 31,				Nine Months Ended Dec 31,			
	2007	% of Revenue	**2006**	% of Revenue	**2007**	% of Revenue	**2006**	% of Revenue
(dollars in thousands, except per share information)								
Revenue	$ 274,894	*100.0%*	$ 155,858	*100.0%*	$ 666,096	*100.0%*	$ 424,024	*100.0%*
Equipment costs	44,231	*16.1%*	29,244	*18.8%*	131,582	*19.8%*	78,777	*18.6%*
Depreciation	7,885	*2.9%*	6,531	*4.2%*	24,179	*3.6%*	18,665	*4.4%*
Gross profit	50,630	*18.4%*	25,972	*16.7%*	100,744	*15.1%*	78,810	*18.6%*
General & administrative costs	17,009	*6.2%*	11,647	*7.5%*	48,996	*7.4%*	30,894	*7.3%*
Operating income	33,173	*12.1%*	13,817	*8.9%*	49,816	*7.5%*	46,585	*11.0%*
Net income	25,377	*9.2%*	6,639	*4.3%*	17,122	*2.6%*	19,776	*4.7%*
Per share information								
Net income basic	$ 0.71		$ 0.27		$ 0.48		$ 0.96	
Net income diluted	0.69		0.26		0.46		0.90	
EBITDA[(1)]	$ 48,819	*17.8%*	$ 21,651	*13.9%*	$ 68,482	*10.3%*	$ 69,068	*16.3%*
Consolidated EBITDA[(1)]	42,069	*15.3%*	24,636	*15.8%*	79,659	*12.0%*	71,921	*17.0%*

(1) EBITDA is calculated as net income (loss) before interest expense, income taxes, depreciation and amortization. Consolidated EBITDA is defined as EBITDA, excluding the effects of foreign exchange gain or loss, realized and

unrealized gain or loss on derivative financial instruments, non-cash stock-based compensation expense, gain or loss on disposal of plant and equipment and certain other non-cash items included in the calculation of net income (loss) (see Sources of liquidity for a detailed definition of Consolidated EBITDA in our credit facility). We believe that EBITDA is a meaningful measure of the performance of our business because it excludes items, such as depreciation and amortization, interest and taxes that are not directly related to the operating performance of our business. Management reviews EBITDA to determine whether plant and equipment are being allocated efficiently. In addition, our revolving credit facility requires us to maintain a minimum interest coverage ratio and a maximum senior leverage ratio, which are calculated using Consolidated EBITDA. Non-compliance with these financial covenants could result in our being required to immediately repay all amounts outstanding under our revolving credit facility. EBITDA and Consolidated EBITDA are not measures of performance under Canadian GAAP or U.S. GAAP and our computations of EBITDA and Consolidated EBITDA may vary from others in our industry. EBITDA and Consolidated EBITDA should not be considered as alternatives to operating income or net income as measures of operating performance or cash flows as measures of liquidity. EBITDA and Consolidated EBITDA have important limitations as analytical tools and should not be considered in isolation or as substitutes for analysis of our results as reported under Canadian GAAP or U.S. GAAP. For example, EBITDA and Consolidated EBITDA:

- do not reflect our cash expenditures or requirements for capital expenditures or capital commitments;
- do not reflect changes in or cash requirements for, our working capital needs;
- do not reflect the interest expense or the cash requirements necessary to service interest or principal payments on our debt;
- exclude tax payments that represent a reduction in cash available to us; and
- do not reflect any cash requirements for assets being depreciated and amortized that may have to be replaced in the future.

In addition, Consolidated EBITDA excludes unrealized foreign exchange gains and losses and unrealized and realized gains and losses on derivative financial instruments, which, in the case of unrealized losses, may ultimately result in a liability that will need to be paid and in the case of realized losses, represents an actual use of cash during the period.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

A reconciliation of net income (loss) to EBITDA and Consolidated EBITDA is as follows:

	Three Months Ended Dec 31,		Nine Months Ended Dec 31,	
	2007	2006	2007	2006
Net income (loss)	$ 25,377	$ 6,639	$ 17,122	$ 19,776
Adjustments:				
Interest expense	7,399	9,292	20,333	29,786
Income taxes	7,715	(938)	6,082	349
Depreciation	7,885	6,531	24,179	18,665
Amortization of intangible assets	443	127	766	492
EBITDA	**$ 48,819**	**$ 21,651**	**$ 68,482**	**$ 69,068**
Adjustments:				
Unrealized foreign exchange (gain) loss on senior notes	(1,612)	10,956	(32,626)	(2,537)
Realized and unrealized (gain) loss on derivative financial instruments	(5,419)	(13,315)	39,766	(1,533)
Loss on disposal of plant and equipment and assets held for sale	5	381	1,166	839
Stock-based compensation	276	621	1,023	1,742
Write-off of deferred financing costs		4,342		4,342
Write-down of other assets to replacement cost			1,848	
Consolidated EBITDA	$ 42,069	$ 24,636	$ 79,659	$ 71,921

Third quarter revenue increased to $274.9 million, a 76.4% increase over the same period last year. While revenue improvements were achieved in all three operating segments, most of the $119.0 million increase was driven by the execution of a major contract in our Pipeline division and by increased Heavy Construction and Mining activity levels in the oil sands. During the nine months ended December 31, 2007, revenue increased to $666.1 million, up 57.1% compared to the same period last year. 82.5% of this $242.1 million revenue increase was driven by growth in our Pipeline and Heavy Construction and Mining segments.

Third quarter gross profit increased to $50.6 million, up 94.9% from last year. As a percentage of revenue, gross profit increased to 18.4% from 16.7% primarily driven by strong third quarter Pipeline segment margins in the current year compared to a third quarter Pipeline segment loss in the prior year. Margins in our Heavy Construction and Mining segment also returned to stronger levels during the quarter, after being negatively impacted by demobilization costs and a lower margin contract in the previous year.

Contributing to stronger current year third quarter gross profit were lower equipment costs and depreciation, both decreasing as a percentage of revenue. The relative reduction in equipment costs reflects higher volumes in the Pipeline segment and a higher utilization of labour and subcontractors in the Heavy Construction and Mining segment, while proportionately lower depreciation reflects the use of more rental equipment in the current year. Overall, third quarter gross margins were higher in the current year due to improved performance on a higher-margin portfolio of contracts. This year-over-year improvement is even more significant in light of the fact that prior year gross profit was positively impacted by a $6.5 million (4.2% of revenue) reversal of accrued overhours related to the buyout of certain rented and leased equipment with proceeds from the IPO.

Nine month gross profit margin decreased to 15.1% of revenue from 18.6% last year. The year-over-year change primarily reflects the negative impact of Pipeline losses relating to a fixed-price contract in the first half as well as higher equipment costs during the nine months. The higher equipment costs primarily reflect the addition of 149 new units of heavy equipment and 148 new support vehicles to our fleet during the first nine months of this year. Equipment costs as a percent of revenue, while lower in the third quarter, increased in the first half, reflecting higher costs for larger-sized truck tires due to a worldwide imbalance in supply and demand. We believe this situation will continue through calendar year 2010. In addition, prior year gross profit margin was positively impacted by the settlement of a $6.1 million claim and an additional $6.5 million reversal of accrued overhours related to the buyout of certain rented and leased equipment with proceeds from the IPO.*

* This paragraph contains forward-looking information. Please refer to Forward-Looking Information, Risks and Uncertainties for a discussion of the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

Third quarter operating income increased to $33.2 million, well over double the prior year operating income of $13.8 million. This improvement reflects the higher gross profit margin as well as a reduction in general and administrative (G&A) costs as a percentage of revenue. At 6.2% of revenue, third quarter G&A expenses were down significantly from 7.5% of revenue in the prior year. In absolute dollars, third quarter G&A increased $5.4 million or 46.0% over the prior year due to increased salary costs related to a 44% increase in our salaried workforce. We have welcomed 81 new salaried employees and 600 new hourly employees since December 31, 2006, bringing our total number of employees to 2,065 at December 31, 2007.

Operating income for the nine months increased 6.9% to $49.8 million reflecting higher revenue, partially offset by the lower gross profit margin discussed above. G&A as a percentage of revenue was also slightly higher at 7.4% compared to 7.3% last year. In absolute dollars, nine month G&A increased $18.1 million or 58.6% year-over-year as a result of higher compensation costs related to discretionary bonuses for past services, which were paid in the first quarter and the higher salary costs related to the increase in our salaried workforce mentioned above. In addition, the company incurred $1.9 million of costs relating to the secondary offering in the second quarter.

Third quarter net income improved to $25.4 million compared to $6.6 million in the same period in the prior year. Unrealized gains and losses on foreign exchange and unrealized gains and losses on derivative financial instruments resulted in a net non-cash, after-tax positive impact of $5.7 million or $0.16 per share, basic, in the current year versus $2.1 million or $0.09 per share, basic, in the prior year.

For the nine months, net income was $17.1 million compared to net income of $19.8 million last year. Unrealized gains and losses on foreign exchange and derivative financial instruments resulted in a net non-cash, after-tax negative impact of $4.6 million or $0.13 per share, basic, in the current year versus a positive impact of $4.7 million or $0.19 per share, basic, in the prior year. The impact of these items on earnings in the current year reflects the adoption of the new Canadian accounting standards with respect to Financial Instruments in the first quarter. The new standards require us to account for changes in the fair value of embedded derivative financial instruments in various contracts and to modify the method of amortizing deferred financing costs. These changes were not in effect in the prior year and have resulted in an incremental non-cash, after-tax charge to net income of $10.3 million or $0.29 per share, basic, in the nine months ended December 31, 2007.

Segment Operations

Segmented profit includes revenue earned from the performance of our projects, including amounts arising from approved change orders and claims that have met the appropriate accounting criteria for recognition, less all direct projects expenses, including direct labour, short-term equipment rentals and materials, payments to subcontractors, indirect job costs and internal charges for use of capital equipment.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

	Three Months Ended Dec 31,				Nine Months Ended Dec 31,			
	2007	% of Total	**2006**	% of Total	**2007**	% of Total	**2006**	% of Total
(dollars in thousands)								
Revenue by operating segment:								
Heavy Construction and Mining	$ 154,402	*56.2%*	$ 111,416	*71.5%*	$ 431,140	*64.7%*	$ 323,048	*76.2%*
Piling	43,751	*15.9%*	29,164	*18.7%*	121,698	*18.3%*	79,394	*18.7%*
Pipeline	76,741	*27.9%*	15,278	*9.8%*	113,258	*17.0%*	21,582	*5.1%*
Total	$ 274,894	*100.0%*	$ 155,858	*100.0%*	$ 666,096	*100.0%*	$ 424,024	*100.0%*
Segment profit:								
Heavy Construction and Mining	$ 28,097	*53.6%*	$ 8,923	*51.1%*	$ 68,631	*59.9%*	$ 47,550	*65.7%*
Piling	11,386	*21.7%*	10,322	*59.1%*	31,725	*27.7%*	25,573	*35.3%*
Pipeline	12,934	*24.7%*	(1,776)	*-10.2%*	14,154	*12.4%*	(710)	*-1.0%*
Total	$ 52,417	*100.0%*	$ 17,469	*100.0%*	$ 114,510	*100.0%*	$ 72,413	*100.0%*

Heavy Construction and Mining

Heavy Construction and Mining revenue climbed to $154.4 million during the third quarter, 38.6% higher than in the same period last year. During the nine months, Heavy Construction and Mining increased revenue to $431.1 million, up 33.5% over the prior year period. The revenue improvement in both the third quarter and nine month periods reflects increased demand from our major oil sands customers. In the most recent period, we continued the site preparation and underground installation at Suncor s Millennium Naphtha Unit project and initiated similar work at Suncor s Voyageur project. We also completed construction of the aerodrome project for Albian and increased our supply of mining support services to this customer. Mining and construction services performed to support Syncrude s operations also increased substantially from prior year levels and included work on a new one-year overburden removal contract. Finally, production under our 10-year mining contract with Canadian Natural continued to ramp up according to plan.

Third quarter Heavy Construction and Mining profit more than tripled to $28.1 million from $8.9 million in the prior year as a result of increased volumes and higher segment margin. A more profitable mix of contracts and solid execution helped to increase this segment s profit margin to 18.2% in the third quarter, a significant improvement over 8.0% in the prior year. For the nine months ended December 31, 2007, segment profit grew to $68.6 million, up 44.3% from the prior year. During this same period, gross profit margin increased to 15.9% from 14.7% reflecting the positive impact of this year s robust third quarter results, partially offset by the benefit of a $6.1 million claim settlement in the prior year.

Piling

Piling revenue in the third quarter increased to $43.8 million, 50.0% higher than in the same period last year. The improvement reflects strong business activity in Calgary and increased activity levels in Saskatchewan following our recent expansion in that province. We also continued to perform work for Shell Canada Ltd. s (Shell) Scotford upgrader expansion in the Edmonton region. For the nine months, Piling segment revenue was $121.7 million, a 53.3% increase over the same period in the prior year, again reflecting the strong market demand.

Piling segment profit rose to $11.4 million on higher volumes in the third quarter, 10.3% above the same period last year. The third quarter profit increase brought the nine month segment profit to $31.7 million, a 24.1% improvement year-over-year. As anticipated, profit margin on the Piling revenue declined to 26.0% in the third quarter and 26.1% in the nine months of the current year from 35.4% in the third quarter and 32.2% in the nine months of last year. This decrease reflects the return to a more balanced project portfolio, which includes both higher-margin fixed-price contracts and lower-margin cost-reimbursable contracts.

Pipeline

Pipeline revenue achieved dramatic growth in the third quarter, climbing to $76.7 million from $15.3 million in the same period last year, as we completed a significant portion of work on Kinder Morgan s TMX Anchor Loop project. The increase in third quarter revenue boosted nine month segment revenue to $113.3 million, over five times the $21.6 million of revenue earned in the nine months of the prior year.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

The Pipeline segment also made a strong return to profitability in the third quarter, reporting segment profit of $12.9 million and a profit margin of 16.9% compared to a loss of $1.8 million last year. These gains reflect strong performance on the TMX Anchor Loop project, which got underway in the second quarter of this year. Results from the previous year were negatively impacted by losses of $1.4 million incurred on fixed-price contracts. Over the nine months, the Pipeline segment reported profit of $14.2 million and a margin of 12.5%, compared to a loss of $0.7 million in the nine months last year. The year-over-year improvement reflects the positive impact of the TMX project, partially offset by losses related to a fixed-price contract in the first half of this year. The prior year was also negatively impacted by losses incurred on fixed-price contracts.

Non-operating expenses (income)

	Three Months Ended Dec 31,		Nine Months Ended Dec 31,	
	2007	**2006**	**2007**	**2006**
(dollars in thousands)				
Interest expense				
Interest on senior debt	$ 5,834	$ 6,802	$ 17,503	$ 21,582
Interest on revolving credit facility and other interest	1,238	269	1,664	522
Interest on capital lease obligations	165	164	497	480
Accretion manditorily redeemable preferred shares		1,204		4,514
Amortization of deferred bond issue costs	162		669	
Amortization of deferred financing costs		853		2,688
Total Interest expense	$ 7,399	$ 9,292	$ 20,333	$ 29,786
Foreign exchange (gain) loss on senior notes	$ (1,784)	$ 10,897	$ (33,136)	$ (2,497)
Realized and unrealized (gain) loss on derivative financial instruments	(5,419)	(13,315)	39,766	(1,533)
Gain on repurchase of NACG Preferred Corp. Series A preferred shares		(9,400)		(9,400)
Loss on extinguishment of debt		10,875		10,928
Other income	(115)	(233)	(351)	(824)
Income tax (recovery) expense	7,715	(938)	6,082	349

Total interest expense decreased by $1.9 million in the third quarter and by $9.5 million in the nine months, compared to the same periods last year, primarily due to the retirement of the senior secured 9% notes with proceeds from our IPO and the exchange of the Series B preferred shares for common shares as part of the amalgamation that occurred prior to the IPO.

The foreign exchange gains and losses recognized in the current and prior-year periods primarily relate to changes in the strength of the Canadian versus the U.S. dollar on conversion of the US$200 million of $8^3/4$% senior notes. The Canadian dollar has strengthened from $0.8674 CAN/US on April 1, 2007 to $1.0120 CAN/US on December 31, 2007.

The realized and unrealized gains on derivative financial instruments in the prior year reflect changes in the fair value of the cross-currency and interest rate swaps that we employ to provide an economic hedge for our 8^{3}/4% senior notes. Changes in the fair value of the swaps generally have an offsetting effect to changes in the value of our 8^{3}/4% senior notes, both caused by variations in the Canadian/US foreign exchange rate. However, the valuation of the derivative financial instruments can also be impacted by changes in interest rates and the remaining present value of scheduled interest payments on the 8^{3}/4% senior notes. Interest payments occur in the first and third quarters. See Liquidity and Capital Resources Liquidity Requirements for further information regarding these derivative financial instruments.

Due to the adoption of a new Canadian accounting standard regarding financial instruments, the current year realized and unrealized gains and losses on derivative financial instruments also includes changes in the fair value of derivatives embedded in our 8^{3}/4% senior notes and in a long-term construction contract. In the current year, the change in the fair value of the swaps was a gain of $3.9 million during the third quarter and a $26.2 million loss in the nine months. The balance of the realized and unrealized gains and losses on derivative financial instruments resulted from gain and losses on derivatives embedded in our 8^{3}/4% senior notes and in a long-term construction contract.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

Effective April 1, 2007, we adopted the new Canadian CICA Handbook Section 3855 Financial Instruments Recognition and Measurement which resulted in the recognition of derivatives embedded in our $8^{3}/4\%$ senior notes and in a long-term construction contract as follows:

> Our $8^{3}/4\%$ senior notes include certain embedded derivatives, notably optional redemption and change of control redemption rights. These embedded derivatives met the criteria for separation from the debt contract and separate measurement at fair value. Upon adoption of Section 3855, we recorded a reduction in the carrying amount of our $8^{3}/4\%$ senior notes of $8.5 million together with related impacts on retained earnings and future income taxes on April 1, 2007. The change in the fair value of these embedded derivatives resulted in a pre-tax charge to earnings of $1.1 million in the third quarter and $4.6 million in the nine months.
>
> A long-term construction contract contains a price escalation feature that represents an embedded foreign currency and price index derivative that meets the criteria for separation from the host contract and separate measurement at fair value. Upon adoption of Section 3855, we recorded a liability of $7.2 million together with related impacts on retained earnings and future income taxes on April 1, 2007. The change in the fair value of the liability resulted in a pre-tax benefit to earnings of $2.6 million in the third quarter and a pre-tax charge to earnings of $9.0 million in the nine months.

With respect to the early redemption provision in the $8^{3}/4\%$ senior notes, the process to determine the fair value of the implied derivative was to compare the rate on the notes to the best financial alternative. The fair value determined as at April 1, 2007 resulted in a positive adjustment to opening retained earnings. The change in fair value in future periods is recognized as a charge to earnings. Changes in fair value result from changes in long-term bond interest rates during that period. The valuation process presumes a 100% probability of our implementing the inferred transaction and does not permit a reduction in the probability if there are other factors that would impact the decision.

With respect to the customer contract, there is a provision that requires an adjustment to billings to our customer to reflect actual exchange rate and price index changes versus the contract amount. The embedded derivative instrument takes into account the impact on revenues but does not consider the impact on costs as a result of fluctuations in these measures.

The new accounting guidelines for embedded derivatives will cause our reported earnings to fluctuate as currency exchange and interest rates change. The accounting for these derivatives will have no impact on operations, Consolidated EBITDA or how we will evaluate performance.

We recorded income tax expense of $7.7 million in the third quarter and $6.1 million in the nine months, as compared to an income tax recovery of $0.9 million and an expense of $0.3 million for the corresponding periods last year. Income tax expense as a percentage of income before tax for the nine months differs from the statutory rate of 31.47% primarily due to the impact of the enacted rate changes during the year and the new accounting standards for the recognition, measurement and disclosure of financial instruments as certain embedded derivatives are considered capital in nature for income tax purposes. Income tax expense as a percentage of income before tax for the nine months last year differs from the statutory rate of 32.12% primarily due to the elimination of the valuation allowance of $5.9 million that was recorded during that period offset by permanent differences relating to certain financing transactions which were not deductible for tax purposes and accruals for certain tax exposure items.

Comparative Quarterly Results

(dollars in millions, except per share amounts)	Fiscal 2008			Fiscal 2007				Fiscal 2006
	Q3	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Revenue	$274.9	$223.6	$167.6	$205.3	$155.9	$130.1	$138.1	$142.3

Gross profit	50.6	35.2	14.9	13.6	26.0	20.2	32.6	31.7
Operating income (loss)	33.2	17.1	(0.4)	4.5	13.8	9.7	23.1	22.4
Net income (loss)	25.4	2.1	(10.3)	1.4	6.6	(4.8)	17.9	13.7
EPS Basic[(1)]	$ 0.71	$ 0.06	$ (0.29)	$ 0.04	$ 0.27	$ (0.26)	$ 0.96	$ 0.73
EPS Diluted[(1)]	0.69	0.06	(0.29)	0.04	0.26	(0.26)	0.71	0.73

(1) Net income (loss) per share for each quarter has been computed based on the weighted average number of shares issued and outstanding during the respective quarter; therefore, quarterly amounts may not add to the annual total. Per share calculations are based on full dollar and share amounts.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

A number of factors contribute to variations in our quarterly results between periods, including weather, capital spending by our customers on large oil sands projects, our ability to manage our project-related business so as to avoid or minimize periods of relative inactivity and the strength of the Western Canadian economy.

By way of example, we generally experience a decline in revenues during the first quarter of each fiscal year (the spring breakup) due to seasonal weather conditions that make many roads unsuitable for the operation of heavy equipment. Conversely, we tend to experience our highest revenues in the latter half of our fiscal year as climatic conditions become favourable to our operating requirements. As a result, full-year results are not likely to be a direct multiple of any particular quarter or combination of quarters.

In addition to revenue variability, gross margins can be negatively impacted in less active periods because we are likely to incur higher maintenance and repair costs due to our equipment being available for service. We incurred higher equipment costs in the first quarter of fiscal 2008 due to the increased equipment repairs and tire costs. Profitability also varies from period to period due to claims and change orders. Claims and change orders are a normal aspect of the contracting business but can cause variability in profit margin due to the unmatched recognition of costs and revenues. For further explanation see *Claims and Unapproved Change Orders.* During the first quarter of fiscal 2007, a $6.1 million dollar claim was recognized causing gross margins to increase above normal levels. The additional costs relating to the claim were incurred in fiscal 2005. During the fourth quarter of fiscal 2007 and the first half of fiscal 2008 we recognized additional costs related to fixed-price contracts in the Pipeline segment and as a result, we are currently working with our clients through the claims process.

During the higher activity periods we have experienced improvements in operating income due to operating leverage. General and administrative costs are generally fixed and we see these costs decrease as a percent of revenue. Net income and EPS are also subject to operating leverage as provided by fixed interest expense, however we have experienced earnings variability in all periods due to the recognition of realized and unrealized non-cash gains and losses on derivative financial instruments and foreign exchange primarily driven by changes in the Canadian and US dollar exchange rates discussed previously.

Consolidated Financial Position

(in thousands)	**December 31, 2007**	**March 31, 2007**	**% Change**
Current assets	$ 223,832	$ 229,061	-2.3%
Current liabilities	161,330	151,458	6.5%
Net working capital	62,502	77,603	-19.5%
Plant and equipment	284,762	255,963	11.3%
Total assets	741,156	710,736	4.3%
Capital Lease obligations (including current portion)	11,754	9,709	21.1%
Total long-term financial liabilities [1]	295,062	295,288	-0.1%

(1) Total long-term financial liabilities exclude the current portions of capital lease obligations, current portions of derivative

financial instruments and both current and non-current future income taxes balances.

At December 31, 2007, we had net working capital (current assets less current liabilities) of $62.5 million compared to $77.6 million at March 31, 2007. The $15.1 million decrease in net working capital resulted largely from decreases in both unbilled revenue and the current portion of the future income tax asset. The additional detective controls implemented in the third quarter have improved the accounting for payments to suppliers. This has resulted in accounts payable returning to normalized levels. Management also undertook a complete review of the procurement to pay process and is developing preventative control procedures that will start to be implemented in the fourth quarter. The current detective controls, that include tasks such as reconciliations of key vendor statements, will remain in place until the new processes are implemented.

Plant and equipment, net of depreciation, increased by $28.8 million in the nine months ended December 31, 2007 primarily due to the purchase of additional haul trucks and piling rigs in the second quarter, partially offset by depreciation and the disposal of surplus equipment in the first quarter.

Capital lease obligations, including the current portion, increased by $2.0 million in the nine months ended December 31, 2007 due to the acquisition of additional support vehicles.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

Liquidity and Capital Resources

	Three Months Ended Dec 31,		Nine Months Ended Dec 31,	
(in thousands)	**2007**	**2006**	**2007**	**2006**
Cash provided by (used in) operating activities	$ 32,837	$ (24,021)	$ 61,417	$ (5,262)
Cash (used in) investing activities	(26,877)	(68,916)	(45,886)	(89,149)
Cash provided by (used in) financing activities	19,952	63,217	(2,183)	58,714
Net increase (decrease) in cash and cash equivalents	$ 25,912	$ (29,720)	$ 13,348	$ (35,697)

Operating activities

Cash provided by operating activities was $32.8 million in the third quarter and $61.4 million in the nine months versus cash used in operating activities of $24.0 million and $5.3 million, respectively, in the comparable periods last year. The cash generated in the third quarter period reflects a combination of higher net income and a lower net increase in non-cash working capital of $1.3 million, compared to $37.8 million in the same period last year. The cash generated in the nine months reflects a net decrease in non-cash working capital of $3.5 million compared to a net increase in non-cash working capital of $52.5 million in the same respective periods last year.

Investing activities

Sustaining capital expenditures are those that are required to keep our existing fleet of equipment at its optimal useful life through capital maintenance or replacement. Growth capital expenditures relate to incremental additions to our fleet of equipment.

Total capital expenditures in the third quarter were $8.0 million, including $3.9 million in sustaining and $4.1 million in growth, compared to total capital expenditures of $78.4 million last year, including $0.9 million in sustaining and $77.5 million in growth. This brings total capital expenditures for the nine months to $51.6 million, including $19.8 million in sustaining and $31.7 million in growth, compared to $97.7 million last year, including $5.9 million in sustaining and $91.8 million in growth. The significantly higher capital expenditure in the prior year is due to the buy out of $44.6 million of certain leased equipment using part of the IPO proceeds. In addition, approximately $30 million of equipment was acquired through operating leases in the third quarter of the current year. Offsetting capital expenditures in the nine months of the current year were proceeds of $14.2 million from the disposal of plant and equipment and assets held for sale, the majority of which was disposed of in the first quarter.

Financing activities

Financing activities in the third quarter resulted in a cash inflow of $20.0 million, primarily reflecting borrowings under our revolving credit facility.

Liquidity Requirements

Our primary uses of cash are for plant and equipment purchases, to fulfill debt repayment and interest payment obligations, to fund operating lease obligations and to finance working capital requirements.

Our long-term debt includes US$200 million of $8^{3}/4$% senior notes due in 2011. The foreign currency risk relating to both the principal and interest portions of these senior notes has been managed with a cross-currency swap and interest rate swaps, which went into effect concurrent with the issuance of the notes on November 26, 2003. The swap agreement is an economic hedge but has not been designated as a hedge for accounting purposes. Interest totaling $13.0 million on the $8^{3}/4$% senior notes and the swap is payable semi-annually in June and December of each year until the notes mature on December 1, 2011. The US$200 million principal amount was hedged at C$1.315=US$1.000, resulting in a principal repayment of $263 million due on December 1, 2011. There are no principal repayments required on the $8^3/4$% senior notes until maturity.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

One of our major contracts allows the customer to require that we provide up to $50 million in letters of credit. As at December 31, 2007, we had $20 million in letters of credit outstanding in connection with this contract. Any change in the amount of the letters of credit required by this customer must be requested by November 1st for an issue date of January 1st, each year for the remaining life of the contract.

We maintain a significant equipment and vehicle fleet comprised of units with remaining useful lives covering a variety of time spans. It is important to adequately maintain our large revenue-producing fleet in order to avoid equipment downtime which can impact our revenue stream and inhibit our ability to satisfactorily perform on our projects. Once units reach the end of their useful lives, they are replaced as it becomes cost prohibitive to continue to maintain them. As a result, we are continually acquiring new equipment to replace retired units and to support our growth as we take on new projects. In order to maintain a balance of owned and leased equipment, we have financed a portion of our heavy construction fleet through operating leases. In addition, we continue to lease our motor vehicle fleet through our capital lease facilities.

We require between $30 million and $40 million of sustaining capital expenditures and our total capital requirements will typically range from $150 million to $175 million depending on our growth capital requirements. We typically finance approximately 30% to 50% of our total capital requirements through our operating lease facilities, 5% to 10% through capital lease facilities and the remainder out of cash flow from operations. We believe our operating and capital lease facilities and cash flow from operations will be sufficient to meet these requirements.*

Sources of Liquidity

Our principal sources of cash are funds from operations and borrowings under our revolving credit facility. Our revolving credit facility provides for borrowings up to the lesser of a restricted covenant resulting in a current ratio of 1.25 times and $125 million under revolving loans and letters of credit. As of December 31, 2007, we had approximately $33 million of available borrowings under the revolving credit facility after taking into account the impact of the restricted covenant, the $20 million drawn on the facility and the $20 million of outstanding and undrawn letters of credit to support performance guarantees associated with a single customer contract as discussed above. The indebtedness under the revolving credit facility is secured by a first priority lien on substantially all of our existing and after-acquired property.

Our revolving credit facility contains covenants that restrict our activities, including but not limited to, incurring additional debt, transferring or selling assets and making investments including acquisitions. Under the revolving credit facility, Consolidated Capital Expenditures during any applicable period cannot exceed 120% of the amount in the capital expenditure plan for such period which is approved from time to time by the Board of Directors of the borrower. In addition, we are required to and did satisfy certain financial covenants, including a minimum interest coverage ratio and a maximum senior leverage ratio, both of which are calculated using Consolidated EBITDA, as well as a minimum current ratio.

Consolidated EBITDA is defined in the credit facility as the sum, without duplication, of (1) consolidated net income, (2) consolidated interest expense, (3) provision for taxes based on income, (4) total depreciation expense, (5) total amortization expense, (6) costs and expenses incurred by us in entering into the credit facility, (7) accrual of stock-based compensation expense to the extent not paid in cash or if satisfied by the issue of new equity, (8) the non-cash currency translation losses or mark-to-market losses on any hedge agreement or any embedded derivative and (9) other non-cash items (other than any such non-cash item to the extent it represents an accrual of or reserve for cash expenditure in any future period), but only, in the case of clauses (2)-(9), to the extent deducted in the calculation of consolidated net income, less other non-cash currency translation gains or mark-to-market gains on any hedge agreement or any embedded derivative to the extent added in the calculation of consolidated net income items added in the calculation of consolidated net income (other than any such non-cash item to the extent it will result in the receipt of cash payments in any future period), all of the foregoing as determined on a consolidated basis for us in conformity with Canadian GAAP.

Interest coverage is determined based on a ratio of Consolidated EBITDA to consolidated interest expense on debt, and the senior leverage is determined as a ratio of senior debt to Consolidated EBITDA. Measured as of the last day of each fiscal quarter on a trailing four-quarter basis, Consolidated EBITDA may not be less than 2.5 times consolidated cash interest expense. Also, measured as of the last day of each fiscal quarter on a trailing four quarter basis, senior leverage may not exceed two times Consolidated EBITDA. These permitted ratios change over time during the term of the revolving credit facility. We believe Consolidated EBITDA as defined in the credit facility is an important measure of our liquidity.

Backlog

Backlog is a measure of the amount of secured work we have outstanding and as such is an indicator of future revenue potential. Backlog is not a GAAP measure. As a result, the definition and determination of a backlog will vary among different organizations ascribing a value to backlog. Although backlog reflects business that we consider to be firm, cancellations or reductions may occur and may reduce backlog and future income.

* This paragraph contains forward-looking information. Please refer to Forward-Looking Information, Risks and Uncertainties for a discussion of the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

We define backlog as that work that has a high certainty of being performed as evidenced by the existence of a signed contract or work order specifying job scope, value and timing. We have also set a policy that our definition of backlog will be limited to contracts or work orders with values exceeding $500,000 and work that will be performed in the next five years, even if the related contracts extend beyond five years.

We work with our customers using cost-plus, time-and-materials, unit-price and lump-sum contracts and the mix of contract types varies year-by-year. For the nine months, our revenue consisted of 50.9% time-and-materials, 40.4% unit-price and 8.7% lump-sum. Our definition of backlog results in the exclusion of cost-plus and time-and-material contracts performed under master service agreements where scope is not clearly defined. While contracts exist for a range of services to be provided, the work scope and value are not clearly defined under those contracts. For the 12 month period ended December 31, 2007, the total amount of revenue earned under the master services agreements that did not qualify for inclusion in our calculation of backlog was $169 million.

Our estimated backlog as at December 31, 2007 and 2006 was (in millions):

By Segment	December 31, 2007	
	2007	**2006**
Heavy Construction & Mining	$ 760.0	$ 677.3
Piling	19.6	13.1
Pipeline	88.9	
Total	**$ 868.5**	**$ 690.4**

By Contract Type	December 31, 2007	
	2007	**2006**
Unit-Price	$ 681.8	$ 619.3
Lump-Sum	7.3	39.8
Time-and-Material, Cost-Plus	179.4	31.3
Total	**$ 868.5**	**$ 690.4**

A contract with a single customer represented approximately $579.9 of the December 31, 2007 backlog. It is expected that approximately $337.1 million of the total backlog will be performed and realized in the 12 months ending December 31, 2008. *

Claims and Unapproved Change Orders

Due to the complexity of the projects we undertake, changes often occur after work has commenced. These changes include but are not limited to:

- Client requirements, specifications and design;
- Materials and work schedules; and
- Changes in ground and weather conditions.

Contract change management processes require that we prepare and submit change orders to the client requesting approval of scope and/or price adjustments to the contract. Accounting guidelines require that management consider changes in cost estimates that have occurred up to the release of the financial statements and reflect the impact of these changes in the financial statements. Conversely, potential revenue associated with increases in cost estimates is not included in financial statements until an agreement is reached with the client or specific criteria for the recognition of revenue from unapproved change orders and claims are met. This can and often does, lead to costs being recognized in one period and revenue being recognized in subsequent periods.

Occasionally, disagreements arise regarding changes, their nature, measurement, timing and other characteristics that impact costs and revenue under the contract. If a change becomes a point of dispute between our customer and us, we then consider it to be a claim. Historical claim recoveries should not be considered indicative of future claim recoveries.

As a result of certain projects experiencing the changed conditions discussed above, at December 31, 2007 we had recognized approximately $16.7 million in additional contract costs from project inception to date, with no associated increase in contract value. We are working with our customers to come to resolution on additional amounts, if any, to be paid to us in respect to these additional costs.

Contractual Obligations and Other Commitments

* This paragraph contains forward-looking information. Please refer to Forward-Looking Information, Risks and Uncertainties for a discussion of the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

Our principal contractual obligations relate to our long-term debt and capital and operating leases. The following table summarizes our future contractual obligations, excluding interest payments, unless otherwise noted, as of December 31, 2007.

	Payments due by fiscal year					
	Total	**2008**	**2009**	**2010**	**2011**	**2012 and after**
(in millions)						
Senior notes [1]	$263.0	$	$	$	$	$263.0
Capital leases (including interest)	12.2	4.3	3.5	2.6	1.7	0.1
Operating leases	76.5	18.5	24.0	18.7	9.3	6.0
Supplier contract [2]	37.3	5.3	5.3	7.5	9.6	9.6
Total contractual obligations	$389.0	$28.1	$32.8	$28.8	$20.6	$278.7

(1) As at December 31, 2007, the exchange rate was C$1.012=US$1.000, resulting in a value of C$202.4 million upon conversion of the principle balance of the US$200 million 8 3/4% senior notes. We have entered into cross-currency and interest rate swaps, which represent an economic hedge of the 8 3/4% senior notes. At maturity, we will be required to pay $263 million in order to retire these senior notes and the swaps. This amount reflects the fixed exchange rate of C$1.315=US$1.00 established as of

November 26, 2003, the inception of the swap contracts. At December 31, 2007, the carrying value of the derivative financial instruments was $85.1 million, inclusive of the interest components.

(2) This contract can be terminated by either party with 30 days notice.

Off-Balance Sheet Arrangements

At December 31, 2007, in connection with a heavy equipment financing agreement, the Company has guaranteed a $0.9 million debt owed to the equipment manufacturer by a third party finance company. The Company s guarantee of this indebtedness will expire when the equipment is commissioned, which is expected to be February 28, 2008. The Company has determined that the fair value of this financial instrument at inception and December 31, 2007 was minimal. *

Outstanding Share Data

We are authorized to issue an unlimited number of voting common shares and an unlimited number of non-voting common shares. As at February 7, 2008, 35,957,236 voting common shares and 1,962,364 options to acquire voting common shares were outstanding compared to 35,951,684 voting common shares and 1,967,916 options outstanding as at December 31, 2007.

Stock-Based Compensation

Some of our directors, officers, employees and service providers have been granted options to purchase common shares under the Amended and Restated 2004 Share Option Plan. There were 315,100 options issued in the first nine month period ending December 31, 2007.

Related party transactions

The Company may receive consulting and advisory services provided by companies in which directors of the Corporation may have an interest of the Corporation with respect to the organization of the companies, employee benefit and compensation arrangements, and other matters, and no fee is charged for these consulting and advisory services.

In order for the companies to provide such advice and consulting we provide reports, financial data and other information. This permits them to consult with and advise our management on matters relating to our operations, company affairs and finances. In addition this permits them to visit and inspect any of our properties and facilities. The transactions are in the normal course of operations and are measured at the exchange amount of consideration established and agreed to by the related parties.

Impairment of Goodwill

In accordance with Canadian Institute of Chartered Accountants Handbook Section 3062, Goodwill and Other Intangible Assets , we review our goodwill for impairment annually or whenever events or changes in circumstances suggest that the carrying amount may not be recoverable. We are required to test our goodwill for impairment at the reporting unit level and we have determined that we have three reporting units. The test for goodwill impairment is a two-step process:

Step 1 We compare the carrying amount of each reporting unit to its fair value. If the carrying amount of a reporting unit exceeds its fair value, we have to perform the second step of the process. If not, no further work is required.

* This paragraph contains forward-looking information. Please refer to "Forward-Looking Information, Risks and Uncertainties" for a discussion of the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

Step 2 We compare the implied fair value of each reporting unit s goodwill to its carrying amount. If the carrying amount of a reporting unit s goodwill exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess.

We completed Step 1 of this test during the quarter ended December 31, 2007 and were not required to record an impairment loss on goodwill. We have conducted our annual assessment of goodwill in October of last year and will continue to do so each year going forward.

Critical Accounting Estimates

Certain accounting policies require management to make significant estimates and assumptions about future events that affect the amounts reported in our financial statements and the accompanying notes. Therefore, the determination of estimates requires the exercise of management s judgment. Actual results could differ from those estimates and any differences may be material to our financial statements.

Revenue recognition

Our contracts with customers fall under the following contract types: cost-plus, time-and-materials, unit-price and lump-sum. While contracts are generally less than one year in duration, we do have several long-term contracts. The mix of contract types varies year-by-year. For the nine months, our revenue consisted of 50.9% time-and-materials, 40.4% unit-price and 8.7% lump-sum.

Profit for each type of contract is included in revenue when its realization is reasonably assured. Estimated contract losses are recognized in full when determined. Claims and unapproved change orders are included in total estimated contract revenue only to the extent that contract costs related to the claim or unapproved change order have been incurred, when it is probable that the claim or unapproved change order will result in a bona fide addition to contract value and the amount of revenue can be reliably estimated.

The accuracy of our revenue and profit recognition in a given period is dependent, in part, on the accuracy of our estimates of the cost to complete each unit-price and lump-sum project. Our cost estimates use a detailed bottom up approach, using inputs such as labour and equipment hours, detailed drawings and material lists. These estimates are updated monthly. We believe our experience allows us to produce materially reliable estimates. However, our projects can be highly complex and in almost every case, the profit margin estimates for a project will either increase or decrease to some extent from the amount that was originally estimated at the time of the related bid. Because we have many projects of varying levels of complexity and size in process at any given time, these changes in estimates can offset each other without materially impacting our profitability. However, sizable changes in cost estimates, particularly in larger, more complex projects, can have a significant effect on profitability.

Factors that can contribute to changes in estimates of contract cost and profitability include, without limitation:

- site conditions that differ from those assumed in the original bid, to the extent that contract remedies are unavailable;
- identification and evaluation of scope modifications during the execution of the project;
- the availability and cost of skilled workers in the geographic location of the project;
- the availability and proximity of materials;
- unfavorable weather conditions hindering productivity;
- equipment productivity and timing differences resulting from project construction not starting on time; and
- general coordination of work inherent in all large projects we undertake.

The foregoing factors, as well as the stage of completion of contracts in process and the mix of contracts at different margins, may cause fluctuations in gross profit between periods and these fluctuations may be significant. These changes in cost estimates and revenue recognition impact all three operating segments, Heavy Construction & Mining, Piling and Pipeline.

Effective April 1, 2005, the Company changed its accounting policy regarding the recognition of revenue on claims. This change in accounting policy has been applied retroactively. Once contract performance is underway, the Company will often experience changes in conditions, client requirements, specifications, designs, materials and work schedule. Generally, a change order will be negotiated with the customer to modify the original contract to approve both the scope and price of the change. Occasionally, however, disagreements arise regarding changes, their nature, measurement, timing and other characteristics that

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

impact costs and revenue under the contract. When a change becomes a point of dispute between the Company and a customer, the Company will then consider it as a claim.

Costs related to change orders and claims are recognized when they are incurred. Change orders are included in total estimated contract revenue when it is probable that the change order will result in a bona fide addition to contract value and can be reliably estimated.

Prior to April 1, 2005, revenue from claims was included in total estimated contract revenue when awarded or received. After April 1, 2005, claims are included in total estimated contract revenue, only to the extent that contract costs related to the claim have been incurred and when it is probable that the claim will result in a bona fide addition to contract value and can be reliably estimated. Those two conditions are satisfied when (1) the contract or other evidence provides a legal basis for the claim or a legal opinion is obtained providing a reasonable basis to support the claim, (2) additional costs incurred were caused by unforeseen circumstances and are not the result of deficiencies in our performance, (3) costs associated with the claim are identifiable and reasonable in view of work performed and (4) evidence supporting the claim is objective and verifiable. No profit is recognized on claims until final settlement occurs. This can lead to a situation where costs are recognized in one period and revenue is recognized when customer agreement is obtained or claim resolution occurs, which can be in subsequent periods. Historical claim recoveries should not be considered indicative of future claim recoveries.

Plant and equipment

The most significant estimates in accounting for plant and equipment are the expected useful life of the asset and the expected residual value. Most of our property, plant and equipment have long lives which can exceed 20 years with proper repair work and preventative maintenance. Useful life is measured in operating hours, excluding idle hours and a depreciation rate is calculated for each type of unit. Depreciation expense is determined monthly based on daily actual operating hours.

Another key estimate is the expected cash flows from the use of an asset and the expected disposal proceeds in applying Canadian Institute of Chartered Accountants Handbook Section 3063 Impairment of Long-Lived Assets and Section 3475 Disposal of Long-Lived Assets and Discontinued Operations . These standards require the recognition of an impairment loss for a long-lived asset when changes in circumstances cause its carrying value to exceed the total undiscounted cash flows expected from its use. An impairment loss, if any, is determined as the excess of the carrying value of the asset over its fair value.

Goodwill

Impairment is tested at the reporting unit level by comparing the reporting unit s carrying amount to its fair value. The process of determining fair value is subjective and requires us to exercise judgment in making assumptions about future results, including revenue and cash flow projections at the reporting unit level and discount rates. The Company previously tested goodwill annually on December 31. For the current fiscal year the Company completed the goodwill impairment testing on October 1. This change in timing was made to reduce conflict between the impairment testing and the company s financial reporting close process for the fiscal period ending December 31. It is the Company s intention to continue to complete subsequent goodwill impairment testing on October 1 going forward. This change in accounting policy was applied on a retrospective basis and has no impact on the consolidated financial statements.

Financial instruments

Our derivative financial instruments related to cross-currency and interest rate swaps are not designated as hedges for accounting purposes and are recorded on the balance sheet at fair value, which is determined based on values quoted by the counterparties to the agreements. The primary factors affecting fair value are the changes in the interest rate term structures in the US and Canada, the life of the swaps and the CAD/USD foreign exchange spot rate.

Effective April 1, 2007, we adopted the new standards issued by the CICA on financial instruments, hedges and comprehensive income. Section 1530, Comprehensive income , Section 3855, Financial instruments-recognition and measurement , Section 3861, Financial instruments-disclosure and presentation and Section 3865, Hedges , were effective for our first quarter of fiscal 2007. We were not required to restate prior results.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

On April 1, 2007, we made the following transitional adjustments to our consolidated balance sheet to adopt the new standards (in thousands of dollars):

	Increase (decrease)
Deferred financing costs	$ (11,356)
Intangible assets	1,622
Long-term future income tax asset	2,588
Senior notes	(12,634)
Derivative financial instruments	7,246
Long-term income tax liability	18
Opening deficit	1,776

The details of the transitional adjustments are noted below.

The impact of the new standards on our income before income taxes for the three and nine months ended December 31, 2007 is as follows (in thousands of dollars):

	Three Months Ended Dec 31, 2007	Nine Months Ended Dec 31, 2007
Decrease in interest expense due to change in method of amortizing deferred financing costs and discounts (premiums), net	$ (360)	$ (897)
Increase in unrealized foreign exchange gain on senior notes	28	334
Increase (decrease) in unrealized loss on derivative financial instruments	(1,494)	13,518
Decrease (increase) in income before income taxes	$ (1,826)	$ 12,955

The new standards require all financial assets and liabilities to be carried at fair value in our consolidated balance sheet, except for loans and receivables, held-to-maturity investments and other financial liabilities, which are carried at their amortized cost. We do not currently have any financial assets designated as available-for-sale. On adoption of the standard, we have classified our cash and cash equivalents, certain accounts receivable and unbilled revenue as loans and receivables and revolving credit facility, accounts payable, certain accrued liabilities, capital lease obligations and senior notes as other financial liabilities.

All derivatives, including embedded derivates that must be separately accounted for, are measured at fair value in our consolidated balance sheet. The types of hedging relationships that qualify for hedge accounting have not changed under the new standards. We currently do not designate any of these derivatives as hedging instruments for accounting purposes.

Derivatives may be embedded in financial instruments (the host instrument). Under the new standards, embedded derivatives are treated as separate derivatives when their economic characteristics and risks are not closely related to those of the host instrument, the terms of the embedded derivative are similar to those of a stand-alone derivative and the combined contract is not held-for-trading or designated at fair value. These embedded derivatives are measured at fair value with subsequent changes recognized in income. We have elected April 1, 2003 as our transition date for identifying contracts with embedded derivatives. Currently we have prepayment options that are embedded in our senior notes and foreign exchange rate and price index escalation/de-escalation clauses in a long-term construction contract which meet the criteria for bifurcation. The impact of the prepayment options and escalation/de-escalation clauses on our consolidated financial statements is described under the transitional adjustments below and in note 3(a) in our interim consolidated financial statements for the nine months ended December 31, 2007.

In determining the fair value of our financial instruments, we used a variety of valuation methods and assumptions that are based on market conditions and risks existing on each reporting date. Standard market conventions and techniques, such as discounted cash flow analysis and option pricing models, are used to determine the fair value of our financial instruments, including derivatives. All methods of fair value measurement result in a general approximation of value and such value may never actually be realized.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

The transitional impact of adopting the new financial instruments standards as at April 1, 2007 on our consolidated financial statements is as follows:

Embedded derivatives:

We determined that the issuer s early prepayment option included in the senior notes should be bifurcated from the host contract, along with a contingent embedded derivative in the senior notes that provides for accelerated redemption by the holders in certain instances. These embedded derivatives were measured at fair value at the inception of the senior notes and the residual amount of the proceeds was allocated to the debt. Changes in fair value of the embedded derivatives are recognized in net income and the carrying amount of the senior notes is accreted to the par value over the term of the notes using the effective interest method and is recognized as interest expense. At transition on April 1, 2007, we recorded the fair value of $8.5 million related to these embedded derivatives and a corresponding decrease in opening deficit of $7.3 million, net of future income taxes of $1.2 million. The impact of the bifurcation of these embedded derivatives at issuance of the senior notes resulted in an increase in senior notes of $5.7 million and an increase in opening deficit of $4.0 million, net of income taxes of $1.7 million after applying the effective interest method to the premium resulting from the bifurcation of these embedded derivatives on April 1, 2007.

We also have foreign exchange rate and price index escalation/de-escalation clauses in a long-term construction contract that qualify as an embedded derivative. These amounts must be separated for reporting in accordance with the new standards. As at April 1, 2007, we separated the fair value of the embedded derivative liability of $7.2 million from the long-term construction contract, resulting in a corresponding increase to opening deficit of $5.2 million, net of future income taxes of $2.0 million.

Effective interest method:

We incurred underwriting commissions and expenses relating to our senior notes offering. Previously, these costs were classified as deferred assets under deferred financing costs and amortized on a straight-line basis over the term of the debt. The new standard requires us to reclassify the costs as a reduction in the cost of debt and to use the effective interest rate method to amortize the deferred amounts to interest expense. As at April 1, 2007, we reclassified $9.7 million of unamortized costs from deferred financing costs to long-term debt and recorded an adjustment to the unamortized cost balance as if the effective interest rate method had been used since inception. Transaction costs incurred in connection with the Company s revolving credit facility of $1,622 were reclassified from deferred financing costs to intangible assets on April 1, 2007 and these costs continue to be amortized on a straight-line basis over the term of the facility.

Revised CICA Handbook Section 3861, Financial Instruments Disclosure and Presentation replaces CICA Handbook Section 3860, Financial Instruments Disclosure and Presentation and establishes standards for presentation of financial instruments and non-financial derivatives and identifies information that should be disclosed. There was no material effect on our financial statements upon adoption of CICA Handbook Section 3861 effective April 1, 2007.

CICA Handbook Section 1530, Comprehensive Income establishes standards for the reporting and display of comprehensive income. The new section defines other comprehensive income to include revenues, expenses and gains and losses that, in accordance with primary sources of GAAP, are recognized in comprehensive income but excluded from net income. The standard does not address issues of recognition or measurement for comprehensive income and its components. The adoption of CICA Handbook Section 1530 effective April 1, 2007 did not have a material impact on our financial statement presentation in the current period.

Forward Looking Information and Risks and Uncertainties

Forward-Looking Information

This document contains forward-looking information that is based on expectations and estimates as of the date of this document. Our forward-looking information is information that is subject to known and unknown risks and other factors that may cause future actions, conditions or events to differ materially from the anticipated actions, conditions or events expressed or implied by such forward-looking information. Forward-looking information is information that does not relate strictly to historical or current facts, and can be identified by the use of the future tense or other forward-looking words such as believe , expect ,

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

anticipate , intend , plan , estimate , should , may , objective , projection , forecast , continue , strategy negative of those terms or other variations of them or comparable terminology.

Examples of such forward looking information in this document include but are not limited to the following, each of which is subject to significant risks and uncertainties and is based on a number of assumptions which may prove to be incorrect:

(A) information related to our operating performance and our level of activity in our operating segments, including (1) the demand for services from Suncor under a five-year multiple-use contract, and (2) the demand for piling and construction services related to the capital spending plan announced by the Province of Alberta; this is subject to the risk and uncertainty that anticipated major projects in the oil sands may not materialize due to changes in the long-term view of oil prices, there may be insufficient pipeline upgrading and refining capacity, there may be insufficient governmental infrastructure to support the growth in the oil sands region and there may be cost overruns by our customers on their projects, which may cause our customers to terminate future projects and is based on the assumption that long-term views of the economic viability of oil sands projects will not significantly change;

(B) the anticipated higher costs for larger-sized truck tires; this is subject to the risk and uncertainty that there may be a significant change in the global demand and/or supply of truck tires of the size and specification that we require and is based on the assumption that the current supply/demand imbalance for truck tires of the size and specification that we require continues for several years;

(C) our anticipated sustaining capital expenditures and the expected manner of financing such expenditures; this is subject to the risk and uncertainty that we may not be able to generate sufficient cash flow to meet our debt service and capital requirements and we may not be able to secure financing under operating and capital lease facilities and is based on the assumption that operating cash flow will not be impacted from changes in economic conditions, increased competition, reduced work or other events that would increase the need for additional sources of liquidity;

(D) the expected amount of our backlog to be performed and realized in the 12 months ending December 31, 2008 (such estimate assists us in planning our activity level and may not be suitable for other purposes); this is subject to the risk and uncertainty of a significant change to the long-term views of the economic viability of oil sands projects, loss of a major customer, unanticipated shut-downs of our customer s operating facilities resulting in cessation or cancellation of the projects, a shortage of qualified personnel and our inability to obtain equipment and is based on the assumption that the Company will be able to obtain the qualified personnel and obtain the equipment required to execute the work in accordance with the contract and there are no unplanned shutdowns or cancellations of current contracts and

(E) the expected commissioning date of February 28, 2008 for a piece of heavy equipment and the corresponding expiry of a guarantee of a third party s obligations in the amount of $0.9 million; this is subject to the risk and uncertainty that the equipment may not be assembled and in working order due to harsh weather conditions and/or labour availability .

While we anticipate that subsequent events and developments may cause our views to change, we do not have an intention to update this forward looking information, except as required by applicable securities laws. This forward-looking information represents our views as of the date of this document and such information should not be relied upon as representing our views as of any date subsequent to the date of this document. We have attempted to identify important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking information. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current expectations. **There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those expected or estimated in such statements. Accordingly, readers should not place undue**

reliance on forward-looking information. These factors are not intended to represent a complete list of the factors that could affect us. See Risks and Uncertainties below and risk factors highlighted in materials filed with the securities regulatory authorities filed in the United States and Canada from time to time, including but not limited to our most recent annual information form filed on Form 20-F.

Risks and Uncertainties

For the nine month period ended December 31, 2007, there has been no significant change in our risk factors from those described in our Prospectus dated July 31, 2007 and Management s Discussion and Analysis for the year ended March 31, 2007 other than those noted below. In addition, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to affect, our internal control over financial reporting.

As discussed in the Prospectus dated July 31, 2007 and our Management s Discussion and Analysis for the year ended March 31, 2007, we have identified a number of significant weaknesses (as defined under Canadian auditing standards) in our financial reporting process and internal controls. Certain detective controls were implemented in the procurement process during the third quarter to mitigate the weaknesses identified previously. These processes included reconciliations of vendor statements and investigation of subsequent payments to ensure that liabilities were recorded in the correct period. Management also undertook a complete review of the procurement processes and is developing new procedures and preventative controls. These controls will start to be implemented

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

over the next two quarters. Current detective controls will remain in place until the new processes are implemented and stabilized. Management continues to address the IT and general control weaknesses. Specific actions to address weaknesses include changes to the security structure which is expected to be implemented by the middle of the fourth quarter.

In addition, during the quarter ended June 30, 2007, we were required to implement new Canadian accounting standards regarding financial instruments. In order to record the related transactions, very complex and non-routine accounting and valuation procedures were undertaken. On review, we determined that we did not apply certain of these procedures correctly. This, therefore, represents a weakness in internal control as it had the potential to result in a material misstatement of the financial statements. This weakness will be addressed in the future by engaging third-party experts; however, there can be no assurance that we will be able to generate accurate financial reports in a timely manner. Failure to do so would cause us to breach the reporting requirements of Canadian and U.S. securities regulations in the future as well as the covenants applicable to our indebtedness. This could, in turn, have a material adverse effect on our business and financial condition. Until we establish and maintain effective internal controls and procedures for financial reporting, we may not have appropriate measures in place to eliminate financial statement inaccuracies and avoid delays in financial reporting.

Recently Adopted Canadian Accounting Pronouncements

Financial instruments

In January 2005, the CICA issued Handbook Section 3855, Financial Instruments Recognition and Measurement , Handbook Section 3861, Financial Instruments Disclosure and Presentation (CICA 3861), Handbook Section 1530, Comprehensive Income and Handbook Section 3865, Hedges . The new standards are effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006, specifically April 1, 2007 for us. The impact of the adoption of the new standard for the Company is discussed above under the heading Financial Instruments .

Equity

On April 1, 2007, we adopted CICA Handbook Section 3251, Equity , which establishes standards for the presentation of equity and changes in equity during the reporting period. The requirements in this section are in addition to those of CICA Handbook Section 1530 and recommend that an enterprise should present separately the following components of equity: retained earnings, accumulated other comprehensive income and the total for retained earnings and accumulated other comprehensive income, contributed surplus, share capital and reserves. The standard did not have a material impact of our consolidated financial statements in the current period.

Accounting changes

In July 2006, the CICA revised Handbook Section 1506, Accounting Changes , which requires that: (1) voluntary changes in accounting policy are made only if they result in the financial statements providing reliable and more relevant information; (2) changes in accounting policy are generally applied retrospectively; and (3) prior period errors are corrected retrospectively. This revised standard is effective for fiscal years beginning on or after January 1, 2007, specifically April 1, 2007 for us and did not have a material impact on our consolidated financial statements.

Accounting policy choice for transaction costs

In June 2007, the CICA issued Emerging Issues Committee Abstract No. 166, Accounting Policy Choice For Transaction Costs (EIC-166). CICA Handbook Section 3855 requires that when an entity acquires a financial asset or incurs a financial liability classified other than as held-for-trading, it adopts an accounting policy for transaction costs of either: (a) recognizing all transaction costs in net income; or (b) adding transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability to the carrying amount of the financial instrument. EIC-166 clarifies that the same accounting policy choice should be made for all similar instruments classified as other than held-for-trading but that a different accounting policy choice may be made for financial instruments that are not similar. We adopted this guidance on April 1, 2007, which did not have a material impact on our consolidated financial statements.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

Recent Canadian accounting pronouncements not yet adopted

Financial Instruments

In March 2007, the CICA issued Handbook Section 3862, Financial Instruments Disclosures , which replaces CICA 3861 and provides expanded disclosure requirements that provide additional detail by financial assets and liability categories. This standard harmonizes disclosures with International Financial Reporting Standards. The standard applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007, specifically April 1, 2008 for us. We are currently evaluating the impact of this standard.

In March 2007, the CICA issued Handbook Section 3863, Financial Instruments Presentation , which replaces CICA 3861 to enhance financial statement users understanding of the significance of financial instruments to an entity s financial position, performance and cash flows. This Section establishes standards for presentation of financial instruments and non-financial derivatives. It deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, gains and losses and the circumstances in which financial assets and financial liabilities are offset. This standard harmonizes disclosures with International Financial Reporting Standards and applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007, specifically April 1, 2008 for us. We are currently evaluating the impact of this standard.

Capital disclosures

In December 2006, the CICA issued Handbook Section 1535, Capital Disclosures . This standard requires that an entity disclose information that enables users of its financial statements to evaluate an entity s objectives, policies and processes for managing capital, including disclosures of any externally imposed capital requirements and the consequences of non-compliance. The new standard applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007, specifically April 1, 2008 for us. We are currently evaluating the impact of this standard.

Inventories

In June 2007, the CICA issued Handbook Section 3031, Inventories to harmonize accounting for inventories under Canadian GAAP with International Financial Reporting Standards. This standard requires the measurement of inventories at the lower of cost and net realizable value and includes guidance on the determination of cost, including allocation of overheads and other costs to inventory. The standard also requires the consistent use of either first-in, first-out (FIFO) or weighted average cost formula to measure the cost of other inventories and requires the reversal of previous write-downs to net realizable value when there is a subsequent increase in the value of inventories. The new standard applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008, specifically April 1, 2008 for us. We are currently evaluating the impact of this standard.

Going concern

In April 2007, the CICA approved amendments to Handbook Section 1400, General Standards Of Financial Statement Presentation . These amendments require management to assess an entity s ability to continue as a going concern. When management is aware of material uncertainties related to events or conditions that may cast doubt on an entity s ability to continue as a going concern, those uncertainties must be disclosed. In assessing the appropriateness of the going concern assumption, the standard requires management to consider all available information about the future, which is at least but not limited to, twelve months from the balance sheet date. The new requirements of the standard are applicable for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008, specifically April 1, 2008 for us. We are currently evaluating the impact of this standard.

Goodwill and intangible assets

In February 2008, the CICA issued Handbook Section 3064, (CICA 3064) Goodwill and Intangible Assets. CICA 3064, which replaces Section 3062, Goodwill and Intangible Assets, and Section 3450, Research and Development

Costs, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions of International Financial Reporting Standard IAS 38, Intangible Assets. This new standard is effective for our interim and annual consolidated financial statements commencing April 1, 2009. We are currently evaluating the impact of this standard.

NORTH AMERICAN ENERGY PARTNERS INC.
Management s Discussion and Analysis
For the three and nine months ended December 31, 2007

U.S. Generally Accepted Accounting Principles

Our consolidated financial statements have been prepared in accordance with Canadian GAAP, which differs in certain material respects from U.S. GAAP. The nature and effect of these differences are set out in note 27 to our consolidated financial statements for the year ended March 31, 2007.

Quantitative and Qualitative Disclosures Regarding Market Risk

Foreign currency risk

We are subject to currency exchange risk as our $8^{3}/4$% senior notes are denominated in U.S. dollars and all of our revenues and most of our expenses are denominated in Canadian dollars. To manage the foreign currency risk and potential cash flow impact on our $200 million in U.S. dollar-denominated notes, we have entered into currency swap and interest rate swap agreements. These financial instruments consist of three components: a U.S. dollar interest rate swap; a U.S. dollar-Canadian dollar cross-currency basis swap; and a Canadian dollar interest rate swap. The cross currency and interest rate swap agreements can be cancelled at the counterparty s option at any time after December 1, 2007 if the counterparty pays a cancellation premium. The premium is equal to 4.375% of the US$200 million if exercised between December 1, 2007 and December 1, 2008; 2.1875% if exercised between December 1, 2008 and December 1, 2009; and repurchased at par if cancelled after December 1, 2009.

Interest rate risk

We are exposed to interest rate risk on the revolving credit facility, capital lease obligations and certain operating leases with a variable payment that is tied to prime rates. We do not use derivative financial instruments to reduce our exposure to these risks. The estimated financial impact as a result of fluctuations in interest rates is not significant.

Inflation

Inflation can have a material impact on our operations due to increasing parts, equipment replacement and labour costs; however, many of our contracts contain provisions for annual price increases. Inflation can have a material impact on our operations if the rate of inflation and cost increases remains above levels that we are able to pass to our customers.

Additional Information

Additional information relating to us, including our 2007 Annual Information Form on Form 20-F, as amended, can be found on the Canadian Securities Administrators System for Electronic Document Analysis and Retrieval (SEDAR) database at www.sedar.com and the website of the Securities and Exchange Commission at www.sec.gov.