North American Energy Partners Inc.
Form 6-K
August 13, 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 August 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 of Form 20-F or Form 40-F.

Form 20-F o Form 40-F þ

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): 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)(7): o

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 þ

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

Documents Included as Part of this Report

1. Interim consolidated financial statements of North American Energy Partners Inc. for the three months ended June 30, 2008.

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/ Peter Dodd
Name: Peter Dodd
Title: Chief Financial Officer

Date: August 13, 2008

NORTH AMERICAN ENERGY PARTNERS INC.

Interim Consolidated Financial Statements
For the three months ended June 30, 2008
(Expressed in thousands of Canadian dollars)
(Unaudited)

NORTH AMERICAN ENERGY PARTNERS INC.

Interim Consolidated Balance Sheets
(In thousands of Canadian dollars)

	June 30, 2008 (Unaudited)	March 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 51,332	$ 32,871
Accounts receivable	127,554	166,002
Unbilled revenue	89,533	70,883
Inventory (note 3(c))	6,900	110
Prepaid expenses and deposits	8,594	9,300
Other assets (note 3(c))		3,703
Future income taxes	10,563	8,217
	294,476	291,086
Future income taxes	8,889	18,199
Assets held for sale	860	1,074
Plant and equipment (note 5)	331,575	281,039
Goodwill	200,072	200,072
Intangible assets, net of accumulated amortization of $2,383 (March 31, 2008 $2,105)	1,850	2,128
	$ 837,722	**$ 793,598**
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	148,578	113,143
Accrued liabilities	30,025	45,078
Billings in excess of costs incurred and estimated earnings on uncompleted contracts	12,328	4,772
Current portion of capital lease obligations	4,747	4,733
Current portion of derivative financial instruments (note 10(a))	4,803	4,720
Future income taxes	9,467	10,907
	209,948	183,353
Deferred lease inducements	915	941
Capital lease obligations	9,968	10,043
Director deferred stock unit liability	459	190
Senior notes (note 6(b))	195,613	198,245
Derivative financial instruments (note 10(a))	90,978	93,019
Asset retirement obligation (note 7)	726	
Future income taxes	24,620	24,443

	533,227	510,234
Shareholders equity:		
Common shares (authorized unlimited number of voting and non-voting common shares; issued and outstanding 36,036,476 voting common shares (March 31, 2008 35,929,476 voting common shares) (note 8(a))	299,871	298,436
Contributed surplus (note 8(b))	3,824	4,215
Retained earnings (deficit)	800	(19,287)
	304,495	283,364
Guarantee (note 16)		
	$ 837,722	**$ 793,598**

See accompanying notes to unaudited interim consolidated financial statements.

NORTH AMERICAN ENERGY PARTNERS INC.

Interim Consolidated Statements of Operations, Comprehensive Income (Loss) and Retained Earnings (Deficit)
(In thousands of Canadian dollars, except per share amounts)
(Unaudited)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007 Restated (see note 4)
Revenue	**$ 258,987**	**$ 167,627**
Project costs	148,631	94,673
Equipment costs	45,811	45,139
Equipment operating lease expense	8,798	3,935
Depreciation	8,158	8,976
Gross profit	**47,589**	**14,904**
General and administrative costs	19,215	14,627
Loss on disposal of plant and equipment	1,144	269
Loss on disposal of asset held for sale	22	316
Amortization of intangible assets	278	70
Operating income before the undernoted	**26,930**	**(378)**
Interest expense (note 9)	6,449	6,809
Foreign exchange gain	(1,641)	(17,100)
Realized and unrealized (gain)/loss on derivative financial instruments (note 10(a))	(2,265)	21,514
Other income	(18)	(108)
Income (loss) before income taxes	**24,405**	**(11,493)**
Income taxes (note 12(c)):		
Current income taxes		21
Future income taxes (recovery)	5,309	(2,932)
Net income (loss) and comprehensive income (loss) for the period	**19,096**	**(8,582)**
Deficit, beginning of period as previously reported	(19,287)	(55,526)
Change in accounting policy related to financial instruments (note 4)		(3,545)
Change in account policy related to inventories (note 3(c))	991	
Retained Earnings (deficit), end of period	**$ 800**	**$ (67,653)**
Net income (loss) per share basic (note 8(c))	**$ 0.53**	**$ (0.24)**
Net income (loss) per share diluted (note 8(c))	**$ 0.52**	**$ (0.24)**

See accompanying notes to unaudited interim consolidated financial statements.

NORTH AMERICAN ENERGY PARTNERS INC.

Interim Consolidated Statements of Cash Flows
(In thousands of Canadian dollars)
(Unaudited)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007 Restated (see note 4)
Cash provided by (used in):		
Operating activities:		
Net income (loss) for the period	$ 19,096	$ (8,582)
Items not affecting cash:		
Depreciation	8,158	8,976
Amortization of intangible assets	278	70
Amortization of deferred lease inducements	(26)	
Amortization of deferred financing costs		71
Loss on disposal of plant and equipment	1,144	269
Loss on disposal of assets held for sale	22	316
Unrealized foreign exchange gain on senior notes	(1,831)	(17,150)
Amortization of bond issue costs, premiums and financing costs	174	397
Unrealized change in the fair value of derivative financial instruments	(2,933)	20,846
Stock-based compensation expense (note 14)	636	359
Accretion expense asset retirement obligation	49	
Future income taxes	5,309	(2,932)
Net changes in non-cash working capital (note 12(b))	3,265	4,764
	33,341	**7,404**
Investing activities:		
Acquisition, net of cash acquired		(1,581)
Purchase of plant and equipment	(59,349)	(10,193)
Additions to assets held for sale		(2,248)
Proceeds on disposal of plant and equipment	1,352	3,690
Proceeds on disposal of assets held for sale	192	10,200
Net changes in non-cash working capital (note 12(b))	43,473	(4,358)
	(14,332)	**(4,490)**
Financing activities:		
Decrease in revolving credit facility		(500)
Repayment of capital lease obligations	(1,225)	(802)
Issue of common shares		740
Stock options exercised (note 8(a))	677	
Financing costs		(767)

	(548)	**(1,329)**
Increase in cash and cash equivalents	**18,461**	**1,585**
Cash and cash equivalents, beginning of period	32,871	7,895
Cash and cash equivalents, end of period	**$ 51,332**	**$ 9,480**

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 months ended June 30, 2008
(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)
(Unaudited)

1. Nature of operations

North American Energy Partners Inc. was incorporated under the Canada Business Corporations Act on October 17, 2003. 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 heavy construction, industrial and commercial site development, 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, 2008 and should be read in conjunction with those consolidated financial statements.

These financial statements include the accounts of the Company, its wholly-owned subsidiaries, North American Construction Group Inc. and NACG Finance LLC, the Company s joint venture, Noramac Ventures Inc. and the following 100% 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. Recently adopted Canadian accounting pronouncements

a) Financial instruments disclosure and presentation

Effective April 1, 2008, the Company prospectively adopted the Canadian Institute of Chartered Accountants (CICA) Sections 3862, Financial Instruments Disclosures , which replaces CICA 3861 and provides expanded disclosure requirements that enable users to evaluate the significance of financial instruments on the entity s financial position and its performance and the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet, and how the entity manages those risks. This standard harmonizes disclosures with International Financial Reporting Standards. The Company has

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

provided the additional required disclosures in note 10 to its interim consolidated financial statements for the three months ended June 30, 2008.

Effective April 1, 2008, the Company adopted CICA issued Handbook Section 3863, Financial Instruments Presentation . 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. The adoption of this standard did not have a material impact on the presentation of financial instruments in the Company s financial statements.

b) Capital disclosures

Effective April 1, 2008, the Company prospectively adopted CICA Section 1535, Capital Disclosures , which requires disclosure of qualitative and quantitative information that enables users to evaluate the Company s objectives, policies and process for managing capital. The Company has provided the additional required disclosures in note 11 to its interim consolidated financial statements for the three months ended June 30, 2008.

c) Inventories

Effective April 1, 2008, the Company retrospectively adopted CICA Section 3031, Inventories without restatement. This standard requires inventories to be measured at the lower of cost and net realizable value and provides guidance on the determination of cost, including the allocation of overheads and other costs to inventories, the requirement for an entity to use a consistent cost formula for inventory of a similar nature and use, and the reversal of previous write-downs to net realizable value when there is subsequent increases in the value of inventories. This new standard also clarifies that spare component parts that do not qualify for recognition as property, plant and equipment should be classified as inventory. Effective April 1, 2008, the Company reversed a tire impairment that was previously recorded at March 31, 2008 in other assets of $1,383 with a corresponding decrease to opening deficit of $991 net of future taxes of $392. The Company then reclassified $5,086 of tires and spare component parts from other assets to inventory . As at June 30, 2008, inventory is comprised of tires and spare component parts of $6,790 and job materials of $110. The Company carries inventory at the lower of weighted average cost and net realizable value. The carrying amount of inventories pledged as security for borrowings under the revolving credit facility is approximately $6,900 as at June 30, 2008.

d) Going concern

Effective April 1, 2008, the Company prospectively adopted CICA 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 adoption of this standard did not have a material impact on the presentation and disclosures within the Company s consolidated financial statements.

e) Recent Canadian accounting pronouncements not yet adopted

i. 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

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

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 Accounting 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.

4. Restatement

In preparing the financial statements for the year ended March 31, 2008, the Company determined that its previously issued interim unaudited consolidated financial statements for the three months ended June 30, 2007 did not properly account for an embedded derivative that is not closely related to the host contract with respect to price escalation features in a supplier maintenance contract. As disclosed in the annual consolidated statements, the Company has restated its original transition adjustment on adoption of CICA Handbook Section 3855, Financial Instruments Recognition and Measurement disclosed in the financial instruments for the three months ended June 30, 2007 and recorded the fair value of $2,474 related to this embedded derivative on April 1, 2007, with corresponding increase in opening deficit of $1,769, net of future income taxes of $705.

The embedded derivative is measured at fair value and included in derivative financial instruments on the consolidated balance sheet with changes in fair value recognized in net income since April 1, 2007 and the comparative figures for the quarter ended June 30, 2007 have been restated to account for this embedded derivative.

The impact of this restatement on the Interim Consolidated Statements of Operations, Comprehensive Income (Loss) and Deficit is as follows:

Three Months Ended June 30, 2007	**As Previously Reported**	**Adjustments**	**As Restated**
Realized and unrealized loss (gain)	$ 23,949	$ (2,435)	$ 21,514
Future income taxes	(3,626)	694	(2,932)
Net income (loss)	(10,323)	1,741	(8,582)
Change in accounting policy related to financial instruments	$ (1,776)	$ (1,769)	$ (3,545)
Deficit, end of period	(67,625)	(28)	(67,653)
Basic and diluted earnings per share	(0.29)	0.05	(0.24)

The impact of this restatement on the Interim Consolidated Balance Sheets is as follows:

As at June 30, 2007	**As Previously Reported**	**Adjustments**	**As Restated**
Derivative financial instruments	$ 87,763	$ 39	$ 87,802
Future income taxes (long-term asset)	22,990	11	23,001
Deficit	(67,625)	(28)	(67,653)

The impact of this restatement on the Consolidated Statements of Cash Flows is as follows:

Three Months Ended June 30, 2007	As Previously Reported	Adjustments	As Restated
Net income (loss)	$ (10,323)	$ 1,741	$ (8,582)
Unrealized loss on derivative financial instruments	23,281	(2,435)	20,846
Future income taxes	(3,626)	694	(2,932)

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

5. Plant and equipment

June 30, 2008	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Heavy equipment	$ 329,739	$ 67,339	$ 262,400
Major component parts in use	16,204	2,391	13,813
Other equipment	18,058	6,679	11,379
Licensed motor vehicles	8,769	5,863	2,906
Office and computer equipment	9,938	3,876	6,062
Buildings	20,267	3,852	16,415
Leasehold improvements	6,342	1,261	5,081
Assets under capital lease	23,842	10,323	13,519
	$ 433,159	$ 101,584	$ 331,575

March 31, 2008	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Heavy equipment	$ 281,975	$ 62,539	$ 219,436
Major component parts in use	12,291	4,797	7,494
Other equipment	17,086	6,232	10,854
Licensed motor vehicles	8,981	6,110	2,871
Office and computer equipment	9,016	3,479	5,537
Buildings	19,530	3,443	16,087
Leasehold improvements	6,272	1,107	5,165
Assets under capital lease	23,271	9,676	13,595
	$ 378,422	$ 97,383	$ 281,039

During the three months ended June 30, 2008, additions of plant and equipment included $1,164 for capital leases (three months ended June 30, 2007 $13). Depreciation of equipment under capital leases of $648 (three months ended June 30, 2007 $533) is included in depreciation expense.

6. 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 $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 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 June 30, 2008, the Company had outstanding borrowings of $nil under the revolving credit facility and had issued $20.7 million in letters of credit to support bonding requirements and performance guarantees associated

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

with customer contracts and operating leases. The Company s borrowing availability under the facility was $104.3 million at June 30, 2008.

b) ***Senior notes***

	June 30, 2008	March 31, 2008
Principal outstanding ($US)	$ 200,000	$ 200,000
Unrealized foreign exchange	3,720	5,574
Unamortized financing costs and premiums, net	(2,861)	(3,059)
Fair value of embedded prepayment and early redemption options	(5,246)	(4,270)
	$ 195,613	$ 198,245

The 83/4% senior notes were issued on November 26, 2003 in the amount of US$200 million (Canadian $263 million). These notes mature on December 1, 2011 with interest payable semi-annually on June 1 and December 1 of each year.

The 83/4% senior notes are unsecured senior obligations and rank equally with all other existing and future unsecured senior debt and senior to any subordinated debt that may be issued by the Company or any of its subsidiaries. The notes are effectively subordinated to all secured debt to the extent of the outstanding amount of such debt.

The 83/4% senior notes are redeemable at the option of the Company, in whole or in part, at any time on or after: December 1, 2007 at 104.4% of the principal amount; December 1, 2008 at 102.2% of the principal amount; December 1, 2009 at 100.00% of the principal amount; plus, in each case, interest accrued to the redemption date.

If a change of control occurs, the Company will be required to offer to purchase all or a portion of each holder s 83/4% senior notes, at a purchase price in cash equal to 101.0% of the principal amount of the notes offered for repurchase plus accrued interest to the date of purchase.

As at June 30, 2008, the Company s effective weighted average interest rate on its 83/4% senior notes, including the effect of financing costs and premiums, net, was approximately 9.42%.

7. Asset retirement obligation

During the three months ended June 30, 2008, the Company recorded an asset retirement obligation related to the future retirement of a facility on leased land. Accretion expense associated with this obligation is included in Equipment Costs in the Interim Consolidated Statements of Operations, Comprehensive Income (Loss) and Retained Earnings (Deficit).

At June 30, 2008, estimated undiscounted cash flows required to settle the obligation were $1,454. The credit adjusted risk-free rate assumed in measuring the asset retirement obligation was 8.75%. The Company expects to settle this obligation in 2021.

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

8. 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, 2008	35,929,476	$ 298,436
Issued on exercise of options	107,000	677
Transferred from contributed surplus on exercise of options		758
Outstanding at June 30, 2008	36,036,476	$ 299,871

b) *Contributed surplus*

Balance, March 31, 2008	$ 4,215
Stock-based compensation (note 14)	254
Deferred performance share unit plan (note 14)	113
Transferred to common shares on exercise of options	(758)
Balance, June 30, 2008	$ 3,824

c) *Net income (loss) per share*

	Three Months Ended June 30, 2008	2007 (Restated)
Basic net income (loss) per share		
Net income (loss) available to common shareholders	$ 19,096	$ (8,582)

Weighted average number of common shares		35,968,046		35,671,220
Basic net income (loss) per share	$	0.53	$	(0.24)
Diluted net income (loss) per share				
Net income (loss) available to common shareholders	$	19,096	$	(8,582)
Weighted average number of common shares		35,968,046		35,671,220
Dilutive effect of:				
Stock options		1,011,713		
Weighted average number of diluted common shares		36,979,759		35,671,220
Diluted net income (loss) per share	$	0.52	$	(0.24)

For the three months ended June 30, 2007 the effect of outstanding stock options on loss per share was anti-dilutive. As such, the effect of outstanding stock options used to calculate the diluted net loss per share has not been disclosed.

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

9. Interest expense

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007
Interest on senior notes	$ 5,834	$ 5,834
Amortization of bond issue costs and premiums	174	397
Interest on capital lease obligations	282	181
Interest on long-term debt	6,290	6,412
Amortization of deferred financing costs		71
Other interest	159	326
	$ 6,449	$ 6,809

10. Financial instruments and risk management

a) Fair value and classification of financial instruments

Based on the measurement categories set out in CICA Handbook Section 3855, Financial Instruments Recognition and Measurement, the Company s financial instruments are classified as follows:

Cash and cash equivalents are classified as financial assets held for trading and are recorded at fair value, with realized and unrealized gains and losses reported in net income;

Accounts receivable and unbilled revenue are classified as loans and receivables and are initially recorded at fair value and subsequent to initial recognition are accounted for at amortized cost using the effective interest method;

The Company has classified amounts due under its revolving credit facility, accounts payable, accrued liabilities, and senior notes as other financial liabilities. Other financial liabilities are accounted for on initial recognition at fair value and subsequent to initial recognition at amortized cost using the effective interest method with gains and losses reported in net income in the period that the liability is derecognized; and

Derivative financial instruments, including non-financial derivatives, are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses on derivatives recognized in the Consolidated Statement of Operations, Comprehensive Income (Loss) and Deficit, unless exempted from derivative treatment as a normal purchase or sale.

In determining the fair value of financial instruments, the Company uses 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.

The fair values of the Company s accounts receivable, unbilled revenue, accounts payable and accrued liabilities approximate their carrying amounts due to the relatively short periods to maturity for the instruments.

The fair values of amounts due under the revolving credit facility and capital leases are based on management estimates which are determined by discounting cash flows required under the instruments at the interest rate currently estimated to be available for loans with similar terms. Based on these estimates, the fair value of amounts due under the revolving credit facility and capital leases as at June 30, 2008 and March 31, 2008 are not significantly different than their carrying values.

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

The fair values of the Company s cross-currency and interest rate swap agreements are based on values quoted by the counterparties to the agreements. The fair values of the Company s embedded derivatives are based on appropriate price modeling commonly used by market participants to estimate fair value. Such modeling includes option pricing models and discounted cash flow analysis, using observable market based inputs to estimate fair value. Fair value determined using valuation models requires the use of assumptions concerning the amount and timing of future cash flows. Fair value amounts reflect management s best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates and discount rates for time value. It is possible that the assumption used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

	June 30, 2008		March 31, 2008	
Asset (Liability)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Senior notes(i)	(195,613)	(205,757)	(198,245)	(209,178)

(i) The fair value of the US $ denominated 83/4% senior notes is based upon their period end closing market price as at June 30, 2008 and March 31, 2008.

Derivative financial instruments that are used for risk management purposes, as described in Note 10(b) under Risk Management consist of the following:

June 30, 2008	**Derivative Financial Instruments**	**Senior Notes**
Cross-currency and interest rate swaps	$ 80,526	
Embedded price escalation features in a long-term revenue construction contract	14,187	
Embedded price escalation features in a long-term supplier contract	1,068	
Embedded prepayment and early redemption options on senior notes		(5,246)
Total fair value of derivative financial instruments	95,781	(5,246)
Less: current portion	4,803	
	90,978	(5,246)

March 31, 2008	**Derivative Financial Instruments**	**Senior Notes**

Cross-currency and interest rate swaps	81,649	
Embedded price escalation features in a long-term revenue construction contract	14,821	
Embedded price escalation features in a long-term supplier contract	1,269	
Embedded prepayment and early redemption options on senior notes		(4,270)
Total fair value of derivative financial instruments	97,739	(4,270)
Less: current portion	4,720	
	93,019	(4,270)

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

The realized and unrealized gain/loss on derivative financial instruments is as follows:

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007 (Restated - Note 4)
Realized and unrealized (gain) loss on cross-currency and interest rate swaps	(454)	14,321
Unrealized (gain) loss on embedded price escalation features in a long-term revenue construction contract	(634)	6,001
Unrealized gain on embedded price escalation features in a long-term supplier contract	(201)	(2,435)
Unrealized (gain) loss on embedded prepayment and early redemption options on senior notes	(976)	3,627
	(2,265)	21,514

b) Risk Management

The Company is exposed to market, credit and liquidity risks associated with its financial instruments. The Company will from time to time use various financial instruments to reduce market risk exposures from changes in foreign currency exchange rates and interest rates. The Company does not hold or use any derivatives instruments for trading or speculative purposes.

Overall, the Company s Board of Directors has responsibility for the establishment and approval of the Company s risk management policies. Management performs a risk assessment on a continual basis to ensure that all significant risks related to the Company and its operations have been reviewed and assessed to reflect changes in market conditions and the Company s operating activities.

Market Risk

Market risk is the risk of loss that results from changes in market factors such as foreign currency exchange rates and interest rates. The level of market risk to which the Company is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and composition of the Company s financial assets and liabilities held, non-trading physical assets and contract portfolios.

To manage the exposure related to changes in market risk, the Company uses various risk management techniques including the use of derivative instruments. Such instruments may be used to establish a fixed price for a commodity, an interest-bearing obligation or a cash flow dominated in a foreign currency. Market risk exposures are monitored regularly and tolerances and control processes are in place to monitor that only authorized activities are undertaken.

The sensitivities provided below are hypothetical and should not be considered to be predictive of future performance or indicative of earnings on these contracts.

*i. **Foreign exchange risk***

The Company has 83/4% senior notes denominated in U.S. dollars in the amount of US$200 million. In order to reduce its exposure to changes in the U.S. to Canadian dollar exchange rate, the Company entered into a cross-currency swap agreement to manage this foreign currency exposure for both the principal balance due on December 1, 2011 as well as the semi-annual interest payments from the issue date to the maturity date. In conjunction with the cross-currency swap agreement, the Company also entered into a U.S. dollar interest rate swap and a Canadian dollar interest rate swap as discussed in note 10(b)(ii) below. These derivative financial instruments

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

were not designated as hedges for accounting purposes. At June 30, 2008 and March 31, 2008, the notional principal amount of the cross-currency swaps was US$200 million.

The Company also regularly transacts in foreign currencies when purchasing equipment, spare parts as well as certain general and administrative goods and services. These exposures are generally of a short-term nature and the impact of changes in exchange rates has not been significant in the past. The Company attempts to fix its exposure in either the Canadian dollar or the U.S. dollar for these short-term transactions, if material.

With other variables unchanged, a 100 basis point increase (decrease) of the Canadian dollar to the U.S. dollar related to the U.S. dollar denominated senior notes would decrease (increase) net income by approximately $1.7 million. With other variables unchanged, a 100 basis point increase (decrease) in the Canadian to the U.S. dollar related to the cross-currency swap would increase (decrease) net income by approximately $1.9 million. The impact on short-term exposures would be insignificant. There would be no impact to other comprehensive income.

ii. Interest rate risk

The Company is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. Amounts outstanding under the Company s revolving credit facility are subject to a floating rate. The Company s senior notes are subject to a fixed rate.

In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. The Company may use derivative instruments to manage interest rate risk.

In conjunction with the cross-currency swap agreement discussed in note 10(b)(i) above, the Company also entered into a U.S. dollar interest rate swap and a Canadian dollar interest rate swap with the net effect of economically converting the 8.75% rate payable on the 83/4% senior notes into a fixed rate of 9.765% for the duration that the 83/4% senior notes are outstanding. On May 19, 2005 in connection with the Company s new revolving credit facility at that time, this fixed rate was increased to 9.889%. These derivative financial instruments were not designated as a hedge for accounting purposes.

At June 30, 2008 and March 31, 2008, the notional principal amounts of the interest rate swaps were US$200 million and Canadian $263 million.

As at June 30, 2008, holding all other variables constant, a 1% increase (decrease) to Canadian interest rates would impact the fair value of the interest rate swaps by $7,038 with this change in fair value being recorded in net income. As at June 30, 2008, holding all other variables constant, a 1% increase (decrease) to US interest rates would impact the fair value of the interest rate swaps by $3,292 with this change in fair value being recorded in net income. As at June 30, 2008, holding all other variables constant, a 1% increase (decrease) of Canadian to US interest rate volatility would impact the fair value of the interest rate swaps by $2,105 with this change in fair value being recorded in net income.

At June 30, 2008 the Company did not hold any floating rate debt. As at June 30, 2008, holding all other variables constant, a 1% increase (decrease) to interest rates would not have an impact on net income or other comprehensive income. This assumes that the amount and mix of fixed and floating rate debt remains unchanged from that which was held at June 30, 2008.

As at June 30, 2008 the Company is party to an interim financing agreement related to the manufacture of a piece of heavy equipment. While the equipment is under construction, the progress payments made to the manufacturer by the third party finance company are subject to a floating interest rate. This borrowing cost will be capitalized by the third party finance company until the equipment is commissioned, which is expected to be November 1, 2008. This borrowing cost will be factored into the Company s future operating lease payments. A 1% increase (decrease) in interest rates would result in an insignificant increase (decrease) to the borrowing cost which

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

will be capitalized by the third party finance company. This additional (reduced) cost will impact the Company s net income through the increased (reduced) operating lease payments in future periods.

iii. Credit Risk

Credit risk is the financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company manages the credit risk associated with its cash by holding its funds with reputable financial institutions. The Company is exposed to credit risk through its accounts receivable and unbilled revenue. Credit risk for trade and other accounts receivables, and unbilled revenue are managed through established credit monitoring activities.

The Company has a concentration of customers in the oil and gas sector. The concentration risk is mitigated by the customers being large investment grade organizations. The credit worthiness of new customers is subject to review by management by considering such items as the type of customer and the size of the contract.

At June 30, 2008 and March 31, 2008, the following customers represented 10% or more of accounts receivable and unbilled revenue:

	June 30, 2008	**March 31, 2008**
Customer A	24%	19%
Customer B	12%	9%
Customer C	8%	17%
Customer D	8%	11%
Customer E	5%	11%

The Company reviews its accounts receivable accounts regularly and amounts are written down to their expected realizable value when outstanding amounts are determined not to be fully collectible. This generally occurs when the customer has indicated an inability to pay, the Company is unable to communicate with the customer over an extended period of time, and other methods to obtain payment have been considered and have not been successful. Bad debt expense is charged to net income in the period that the account is determined to be doubtful. Estimates of the allowance for doubtful accounts are determined on a customer-by-customer evaluation of collectability at each reporting date taking into consideration the following factors: the length of time the receivable has been outstanding, specific knowledge of each customer s financial condition and historical experience.

The Company s maximum exposure to credit risk for trade accounts receivable is the carrying value of $121,448 as at June 30, 2008 (March 31, 2008 $157,237), other receivables is the carrying value of $6,106 (March 31, 2008 $8,765) and unbilled revenue is the carrying value of $89,533 as at June 30, 2008 (March 31, 2008 $70,883). On a geographic basis as at June 30, 2008, approximately 95% (March 31, 2008 89%) of the balance of trade accounts receivable (before considering the allowance for doubtful accounts) was due from customers based in Western Canada.

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

Payment terms are generally net 30 days. As at June 30, 2008 and March 31, 2008 trade receivables are aged as follows:

	June 30, 2008	March 31, 2008
Not past due	$ 75,986	$ 124,211
Past due 1-30 days	19,362	19,790
Past due 31-60 days	18,610	1,896
More than 61 days	7,490	11,340
Total	121,448	157,237

As at June 30, 2008, the Company has recorded an allowance for doubtful accounts of $751 (March 31, 2008 $742) of which 100% relates to amounts that are more than 61 days past due.

The allowance is an estimate of the June 30, 2008 trade receivable balances that are considered uncollectible. Changes to the allowance during the three months ended June 30, 2008 consisted of payments received on outstanding balances of $68 (three months ended June 30, 2007 $nil), write off of trade accounts receivable balances not collected of $nil (three months ended June 30, 2007 - $nil), and bad debt expense of $77 (three months ended June 30, 2007 $nil).

Credit risk on cross-currency and interest rate swap agreements arises from the possibility that the counterparties to the agreements may default on their respective obligations under the agreements. This credit risk only arises in instances where these agreements have positive fair value for the Company.

iv. Liquidity Risks

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company manages liquidity risk through management of its capital structure and financial leverage, as outlined in note 11 to the unaudited interim consolidated financial statements. It also manages liquidity risk by continuously monitoring actual and projected cash flows to ensure that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company s reputation. The Company believes that forecasted cash flows from operating activities, along with the available lines of credit, will provide sufficient cash requirements to cover the Company s forecasted normal operating and budgeted capital expenditures.

The Company s principal sources of cash are funds from operations and borrowings under our revolving credit facility.

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 agreement Consolidated Capital Expenditures during any applicable period cannot exceed 120% of the amount in the capital expenditure plan. In addition, we are required to 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 defined in the revolving credit agreement, as well as a minimum current ratio.

At June 30, 2008 the Company was in compliance with its senior leverage, its interest coverage, and working capital covenants.

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

The following are the undiscounted contractual maturities of financial liabilities and other contractual commitments measured at period end exchange rates:

	Carrying Amount	Contractual Cash Flows	Less Than 1 Year	1 - 3 Years	3 - 5 Years	After 5 Years
Accounts payable and accrued liabilities	178,603	178,603	178,603			
Capital lease obligations (including interest)	14,715	16,509	5,606	7,977	2,926	
Senior notes	195,612	203,720			203,720	
Interest on senior notes		80,543	11,506	46,025	23,012	
Cross-currency and interest rate swaps	80,527	73,485	1,498	5,991	65,996	
Total	469,457	552,860	197,213	59,993	295,654	

11. Capital disclosures

The Company s objectives in managing capital are to ensure sufficient liquidity to pursue its strategy of organic growth combined with strategic acquisitions and to provide returns to its shareholders. The Company defines capital that it manages as the aggregate of its debt and shareholders equity, which is comprised of issued capital, contributed surplus, accumulated other comprehensive income (loss) and retained earnings (deficit). The Company manages its capital structure and makes adjustments to it in light of general economic conditions, the risk characteristics of the underlying assets and the Company s working capital requirements. In order to maintain or adjust its capital structure, the Company, upon approval from its Board of Directors, may issue or repay long-term debt, issue shares, repurchase shares through a normal course issuer bid, pay dividends or undertake other activities as deemed appropriate under the specific circumstances. The Board of Directors reviews and approves any material transactions out of the ordinary course of business, including proposals on acquisitions or other major investments or divestitures, as well as capital and operating budgets.

The Company monitors debt leverage ratios as part of the management of liquidity and shareholders return and to sustain future development of the business. The Company is also subject to externally imposed capital requirements under its revolving credit facility and indenture agreement governing the U.S. dollar denominated 83/4% senior notes, which 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 s overall strategy with respect to capital risk management remains unchanged from the year ended March 31, 2008.

The Company is subject to restrictive covenants under its banking agreements with its principal lenders related to its revolving credit facility (note 6(a)), its capital lease obligations and senior notes (note 6(b)) that are measured on a quarterly basis. These covenants include, but are not limited to a working capital ratio, senior leverage ratio, and interest coverage ratio.

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

12. Other information

a) Supplemental cash flow information

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007
Cash paid during the period for:		
Interest	$ 13,468	$ 13,397
Income taxes		22
Cash received during the period for:		
Interest	7	106
Income taxes		
Non-cash transactions:		
Acquisition of plant and equipment by means of capital leases	1,164	13
Lease inducements		1,500

b) Net change in non-cash working capital

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007
Operating activities:		
Accounts receivable	$ 38,439	$ (17,342)
Allowance for doubtful accounts	9	
Unbilled revenue	(18,650)	25,804
Inventory	(5,407)	
Prepaid expenses and deposits	706	3,684
Other assets	3,703	3,834
Accounts payable	(8,038)	(8,870)
Accrued liabilities	(15,053)	(4,806)
Billings in excess of costs incurred and estimated earnings on uncompleted contracts	7,556	2,460
	$ 3,265	$ 4,764
Investing activities:		
Accounts payable	$ 43,473	$ (4,358)

c) Income taxes

Income tax expense as a percentage of income before income taxes for the three months ended June 30, 2008 differs from the statutory rate of 29.38% primarily due to the benefit from changes in the timing of the reversal of temporary differences. Income tax as a percentage of income before income taxes for the three months ended June 30, 2007 differed from the statutory rate of 31.72% primarily due to the impact of the 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.

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

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 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.

b) Results by business segment

Three Months Ended June 30, 2008	**Heavy Construction and Mining**	**Piling**	**Pipeline**	**Total**
Revenues from external customers	$ 189,405	$ 42,503	$ 27,079	$ 258,987
Depreciation of plant and equipment	5,223	820	227	6,270
Segment profits	21,402	8,661	8,925	38,988
Segment assets	529,431	123,108	74,975	727,514
Expenditures for segment plant and equipment	48,842	5,830	4,649	59,321

Heavy
Construction

Three Months Ended June 30, 2007	and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 126,914	$ 35,522	$ 5,191	$ 167,627
Depreciation of plant and equipment	4,320	846	109	5,275
Segment profits	19,489	9,247	(1,189)	27,547
Segment assets	438,030	104,981	51,683	594,694
Expenditures for segment plant and equipment	7,677	364	358	8,399

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

c) Reconciliations

i. Income (loss) before income taxes

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007 (Restated note 4)
Total profit for reportable segments	$ 38,988	$ 27,547
Unallocated corporate expenses:		
General and administrative expense	(19,215)	(14,627)
Loss on disposal of plant and equipment	(1,144)	(269)
Loss on disposal of assets held for sale	(22)	(316)
Amortization of intangibles	(278)	(70)
Interest expense	(6,449)	(6,809)
Foreign exchange gain	1,641	17,100
Realized and unrealized loss (gain) on derivative financial instruments	2,265	(21,514)
Other income	18	108
Unallocated equipment recovery & (costs)(1)	8,601	(12,643)
Income (loss) before income taxes	$ 24,405	$ (11,493)

(1) Unallocated equipment costs represent actual equipment costs, including non-cash items such as depreciation, which have not been allocated to reportable segments.

ii. Total assets

	June 30, 2008	March 31, 2008
Total assets for reportable segments	$ 727,514	$ 698,966
Corporate assets:		
Cash	51,332	32,871
Plant & equipment	28,828	26,785
Future income taxes	19,452	26,416
Other	10,596	8,560
Total corporate assets	110,208	94,632

Total assets	$ 837,722	$ 793,598

The Company s goodwill was assigned to the Heavy Construction and Mining, Piling and Pipeline segments in the amounts of $125,447, $41,872, and $32,753, respectively.

All of the Company s assets are located in Canada and the activities are carried out throughout the year.

iii. Depreciation of plant and equipment

	June 30, 2008	**June 30, 2007**
Total depreciation for reportable segments	$ 6,270	$ 5,275
Depreciation for corporate assets	1,888	3,701
Total depreciation	8,158	8,976

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

d) Customers

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

	Three Months Ended June 30, 2008	2007
Customer A	24%	28%
Customer B	22%	13%
Customer C	15%	16%
Customer D	15%	15%

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

14. Stock-based compensation

Share 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 June 30, 2008			2007		
	Number of Options		Weighted Average Exercise Price ($ per Share)	Number of Options		Weighted Average Exercise Price ($ per Share)
Outstanding, beginning of period	2,036,364	$	7.54	2,146,840	$	6.03
Granted						
Exercised	(107,000)		(6.32)	(147,400)		(5.00)
Forfeited	(101,000)		(10.58)			
Outstanding, end of period	1,828,364	$	7.44	1,999,440	$	6.10

At June 30, 2008, the weighted average remaining contractual life of outstanding options is 7.6 years (March 31, 2008 7.6 years). The Company recorded $254 of compensation expense related to the stock options in the three months ended June 30, 2008 (2007 $359) with such amount being credited to contributed surplus.

Deferred performance share unit plan

On March 19, 2008, the Company approved a Deferred Performance Share Unit (DPSU) Plan which became effective April 1, 2008.

DPSUs will be granted effective April 1 of each fiscal year in respect of services to be provided in that fiscal year and the following two fiscal years. The DPSUs vest at the end of a three-year term and are subject to the performance criteria approved by the Compensation Committee of the Board of Directors at the date of grant. Such performance criterion includes the passage of time and is based upon return on invested capital calculated on operating income and average operating assets. The date of the third fiscal year-end following the date of the grant of DPSUs shall be the Maturity Date for such DPSUs. At the maturity date the Compensation Committee shall

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

assess the participant against the performance criteria and determine the number of DPSUs that have been earned (earned DPSUs).

The settlement of the participant s entitlement shall be made in either cash at the value of the earned DPSUs equivalent to the number of earned DPSUs at the value of the Company s voting shares at the date of maturity or in a number of common shares equal to the number of earned DPSUs. If settled in common shares, the common shares shall be purchased on the open market or through the issuance of shares from treasury, subject to shareholder approval.

The fair value of each unit under the DPSU Plan was estimated on the date of the grant using Black-Scholes option pricing model. The weighted average assumptions used in estimating the fair value of the share options issued under the DPSU Plan at April 1, 2008 are as follows:

Number of options granted	111,020
Weighted average fair value per option granted ($)	12.34
Weighted average assumptions:	
Dividend yield	nil%
Expected volatility	56.25%
Risk-free interest rate	2.83%
Expected life (years)	3.00

At June 30, 2008, the weighted average remaining contractual life of outstanding DPSUs is 2.75 years. For the three months ended June 30, 2008, the Company granted 111,020 under the Plan and recorded compensation expense of $113 included in general and administrative costs. As at June 30, 2008, there was approximately $1,256 of total unrecognized compensation cost related to nonvested share-based payment arrangements under the DPSU Plan, which is expected to be recognized over a weighted average period of 2.75 years.

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 and the market value of the Company s common stock on the grant date (maturity occurs when the director resigns or retires). 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 actual maturity date occurred. As at June 30, 2008, an expense of $269 (June 30, 2007 $nil) was recorded relating to 20,774 (March 31, 2008 11,882) outstanding units that were granted during the year.

15. 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

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements (Continued)

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.

16. Guarantee

At June 30, 2008, in connection with a heavy equipment financing agreement, the Company has guaranteed $4.5 million of 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 November 1, 2008. The Company has determined that the fair value of this financial instrument at inception and June 30, 2008 was not significant.

17. Claims revenue

On June 25, 2008, the Company reached an agreement with a customer to settle all outstanding claims arising from a pipeline project completed in fiscal 2008 for $8,000. The Company had previously recognized claims revenue of $2,744 related to such outstanding claims as at March 31, 2008 and it has recognized the excess of the settlement over previously recognized claims revenue of $5,256 as revenue in the quarter ended June 30, 2008.

18. Comparative figures

The comparative consolidated financial statements have been reclassified from statements previously presented to conform to the presentation of the current year consolidated financial statements.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis
For the three months ended June 30, 2008

The following discussion and analysis is as of August 13, 2008 and should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended June 30, 2008 and the audited consolidated financial statements for the fiscal year ended March 31, 2008. These statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and, except where otherwise specifically indicated, all dollar amounts are expressed in Canadian dollars. The consolidated financial statements and additional information relating to our business are available on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

August 13, 2008

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

Prior Year Comparisons

In preparing the financial statements for the year ended March 31, 2008, we determined that the previously issued interim unaudited consolidated financial statements for the three months ended June 30, 2007 did not properly account for an embedded derivative with respect to price escalation features in a supplier maintenance contract.

The embedded derivative has been measured at fair value and included in derivative financial instruments on the consolidated balance sheet with changes in fair value recognized in net income. The impact of this restatement on the Interim Consolidated Balance Sheet for the three months ended June 30, 2007 is an immaterial change to future income taxes (long-term assets), derivative financial instruments and retained earnings (all adjustments less than $0.1 million). The impact on the interim consolidated financial statements for the three months ended June 30, 2007 is an adjustment to unrealized loss on derivative financial instruments and income tax expense. This resulted in an improvement to net income of $1.7 million (restated as a loss of $8.6 million)

A. Business Overview and Strategy

Business Overview

We are a leading resource services provider to major oil, natural gas and other natural resource companies, with a primary focus on the Alberta oil sands. We provide a wide range of heavy construction and mining, piling and pipeline installation services to our customers across the entire lifecycle of their projects. We are the largest provider of contract mining services in the oil sands area and we believe we are one of the largest piling foundations installer in Western Canada. In addition, we believe that we operate the largest fleet of equipment of any contract resource services provider in the oil sands. Our total fleet includes over 845 pieces of diversified heavy construction equipment supported by over 925 ancillary vehicles. While our expertise covers heavy earth moving, site preparation, underground industrial piping, piling and pipeline installation in any location, we have a specific capability operating in the harsh climate and difficult terrain of the oil sands and northern Canada.

We believe that our significant knowledge, experience, equipment capacity and scale of operations in the oil sands differentiate us from our competition. We provide services to every company in the Alberta oil sands that uses surface mining techniques in their production. These surface mining techniques account for over 65% of total oil sands production. We also provide site construction services for in-situ producers, which use horizontally drilled wells to inject steam into deposits and pump bitumen to the surface.

Our principal oil sands customers include all three of the producers that are currently mining bitumen in Alberta: Syncrude Canada Ltd. (Syncrude), Suncor Energy Inc. (Suncor) and Albian Sands Energy Inc. (Albian), a joint venture amongst Shell Canada Limited, Chevron Canada Limited and Marathon Oil Canada Corporation. We are also working with customers that are in the process of developing bitumen-mining projects, including Canadian Natural Resources Limited (Canadian Natural) and Fort Hills (a joint venture between UTS Energy, Teck Cominco and Petro-Canada).

We have long-term relationships with most of our customers. For example, we have been providing services to Syncrude and Suncor since they pioneered oil sands development over 30 years ago. Approximately 39% of our revenues in fiscal 2008 were derived from recurring work and long-term contracts, which assist in providing stability in our operations.

We believe that we have demonstrated our ability to successfully export knowledge and technology gained in the oil sands and put it to work in other resource development projects across Canada. As an example, our Heavy Construction and Mining division successfully completed the development of a diamond mine site in 2008. This three-year project required us to operate effectively in a remote location under difficult weather conditions. As a

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

result of our successful work on this project, we believe we have attracted the attention of resource developers and we are currently looking at other potential projects, including those in the high arctic regions.

Our piling division installs all types of driven, drilled and screw piles, caissons, earth retention and stabilization systems. Operating throughout Western Canada, this division has a solid record of performance on both small and large- scale projects. Our piling division also has experience with industrial projects in the oil sands and related petrochemical and refinery complexes and has been involved in the development of commercial and infrastructure projects.

Our Pipeline division installs penstocks as well as steel, fiberglass, and plastic pipe in sizes up to 52 in diameter. This division is experienced with jobs of varying magnitude for some of Canada s largest energy companies. Our experience includes the recent construction of a new pipeline that goes through the Rocky Mountains, from Alberta to British Columbia. Undertaken as part of Kinder Morgan s Trans Mountain Expansion (TMX), this project involves the construction of a 160 kilometer pipeline through ecologically sensitive environments, including Jasper National Park, with minimal impact to the environment.

Canadian Oil Sands

Oil sands are grains of sand covered by a thin layer of water and coated by heavy oil, or bitumen. Bitumen, because of its structure, does not flow, and therefore requires non-conventional extraction techniques to separate it from the sand and other foreign matter. There are currently two main methods of extraction: open pit mining, where bitumen deposits are sufficiently close to the surface to make it economically viable to recover the bitumen by treating mined sand in a surface plant; and in-situ, where bitumen deposits are buried too deep for open pit mining to be cost effective, and operators instead inject steam into the deposit so that the bitumen can be separated from the sand and pumped to the surface. We currently provide most of our services to companies operating open pit mines to recover bitumen reserves. These customers utilize our services for surface mining, site preparation, overburden removal, piling, pipe installation, site maintenance, equipment and labor supply and land reclamation.

Oil Sands Outlook

Demand for our services is primarily driven by the development, expansion and operation of oils sands projects. The oils sands operators capital investment decisions are driven by a number of factors, with what we believe is one of the most important being the expected long-term price of oil. The development, expansion and operation of oils sands projects and related public infrastructure spending play a key role in influencing our business activities.

On October 25, 2007, the Alberta government announced increases to the Alberta royalty rates affecting natural gas, conventional oil and oil sands producers. The announced increases were significant but lower than increases recommended to the government by the Royalty Review Panel. While some of our customers have announced their intentions to reduce oil and gas investment in Alberta as a result of the increased royalties, to date, the areas affected by these investment reductions do not include oil sands mining projects. Given the long-term nature and capital investment requirement to develop an oil sands mining operation, we anticipate that there is limited risk that the royalty changes will cause our customers to cancel, delay or reduce the scope of any significant mining developments currently underway.*

We are continuing to experience increasing requests for services under existing contracts with our major oil sands customers in spite of the recent royalty changes. Our recent acquisitions of new equipment ideally suited to heavy earth moving in the oil sands area, together with the addition of a significant number of new employees, has

* This paragraph contains forward-looking statements. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

strengthened our ability to bid competitively and profitably into this expanding market and we have secured contracts on many of these new projects.

According to the Canadian Association of Petroleum Producers (CAPP), approximately $55.2 billion was invested in the oil sands from 1998 through 2006. According to the Canadian Energy Research Institute s (CERI) November 2007 report, Canadian Oil Sands Supply Costs and Development Projects (2007 2027) , an additional $228 billion of capital expenditures will be required between 2007 and 2015 to achieve production levels projected under their constrained scenario. According to the CERI, as of November 2007, there were 23 mining and upgrader projects in various stages, ranging from announcement to construction, with start-up dates through 2014. Beyond 2014, several new multi-billion dollar projects and a number of smaller multimillion dollar projects are being considered by various oil sands operators. We intend to pursue business opportunities from these projects.*

Strategy

Our strategy is to be an integrated service provider for the developers of resource-based industries in a broad and often challenging range of environments. This strategy is focused on the following priorities:

Capitalize on growth opportunities in the Alberta oil sands: We intend to build on our market leadership position and successful track record with our customers to benefit from any continued growth in this market. We intend to increase our fleet size to be ready to meet the challenges from the projected growth opportunities in oil sands development.*

Leverage our complementary services: Our complementary service segments, including site preparation, pipeline installation, piling and other mining services allow us to compete for many different forms of business. We intend to build on our first-in position to cross-sell our other services and pursue selective acquisition opportunities that expand our complementary service offerings.*

Increase our recurring revenue base: We provide services both during the construction phase and once the project is in operation. Many of the services provided once the project is in operation, including overburden removal, reclamation, road construction and maintenance and mining services are recurring in nature and provide more stable recurring revenues. It is our intention to continue the expansion of our business in these areas to provide a larger, more stable revenue base in the future.*

Leverage our long- term relationships with customers: Several of our oil sands customers have announced intentions to increase their production capacity by expanding the infrastructure at their sites. We intend to continue to build on our relationships with these and other existing oil sands customers to win a substantial share of the heavy construction and mining, piling and pipeline services outsourced in connection with these projects.*

Increase our presence outside the oil sands: We intend to increase our presence outside the oil sands and extend our services to other resource industries across Canada. Canada has significant natural resources and we believe that we have the equipment and the experience to assist with developing those natural resources.*

Enhance operating efficiencies to improve revenues and margins: We aim to increase the availability and efficiency of our equipment through enhanced maintenance, providing the opportunity for improved revenue, margins and profitability.*

* This paragraph contains forward-looking statements. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

Operations

As discussed above we provide our services through three interrelated yet distinct business units: (i) Heavy Construction and Mining, (ii) Piling and (iii) Pipeline. Our services include initial advice and consulting to customers as they develop plans to exploit resources. We believe that we have the skills and equipment to build infrastructure in new locations or to expand existing sites for heavy construction projects. We are currently involved in assisting with on-site mining services, overburden removal and plant upgrades. We are also able to respond to customer needs for site reclamation services once a site s resources are depleted.

The table below shows the revenues generated by each operating segment for the three month periods ended June 30, 2006 through June 30, 2008:

	Three Months Ended June 30,					
	2008 (Q1-FY2009)	**% of Total**	**2007 (Q1-FY2008)**	**% of Total**	**2006 (Q1-FY2007)**	**% of Total**
	(Dollars in thousands)					
Revenue by operating segment:						
Heavy Construction and Mining	$ 189,405	*73.1%*	$ 126,914	*75.7%*	$ 111,387	*80.7%*
Piling	42,503	*16.4%*	35,522	*21.2%*	23,276	*16.9%*
Pipeline	27,079	*10.5%*	5,191	*3.1%*	3,437	*2.5%*
Total	$ 258,987	*100.0%*	$ 167,627	*100.0%*	$ 138,100	*100.0%*

B. Financial Results

Consolidated Results (Three Months)

	Three Months Ended June 30,			
	2008 (Q1-FY2009)	**% of Revenue**	**2007 (Q1-FY2008) (Restated)**	**% of Revenue**
	(Dollars in thousands, except per share information)			
Revenue	$ 258,987	*100.0%*	$ 167,627	*100.0%*
Project costs	148,631	*57.4%*	94,673	*56.5%*
Equipment costs	45,811	*17.7%*	45,139	*26.9%*
Equipment operating lease expense	8,798	*3.4%*	3,935	*2.3%*

Depreciation	8,158	*3.1%*	8,976	*5.4%*
Gross profit	47,589	*18.4%*	14,904	*8.9%*
General & administrative costs	19,215	*7.4%*	14,627	*8.7%*
Operating income (loss)	26,930	*10.4%*	(378)	*(0.2)%*
Net income (loss)	19,096	*7.4%*	(8,582)	*(5.1)%*
Per share information				
Net income (loss) basic	$ 0.53		$ (0.24)	
Net income (loss) diluted	0.52		(0.24)	
EBITDA(1)	$ 39,290	*15.2%*	$ 4,362	*2.6%*
Consolidated EBITDA(1) (as defined within the revolving credit agreement)	36,727	*14.2%*	9,670	*5.8%*

5

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

(1) Non GAAP Financial measures

The body of generally accepted accounting principles applicable to us is commonly referred to as GAAP. A non-GAAP financial measure is generally defined by the Securities and Exchange Commission (SEC) and by the Canadian securities regulatory authorities as one that purports to measure historical or future financial performance, financial position or cash flows, but excludes or includes amounts that would not be so adjusted in the most comparable GAAP measures. EBITDA is calculated as net income (loss) before interest expense, income taxes, depreciation and amortization. Consolidated EBITDA (as defined within the revolving credit agreement) is a measure defined by our revolving credit facility. This measure is defined as EBITDA, excluding the effects of unrealized 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). 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 our 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.

Consolidated EBITDA excludes unrealized foreign exchange gains and losses and realized and unrealized 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. The term as defined within the revolving credit agreement replaces the term per bank used in prior filings. The definition of Consolidated EBITDA has not changed.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

A reconciliation of net income (loss) to EBITDA and Consolidated EBITDA (as defined within the revolving credit agreement) is as follows:

	Three Months Ended June 30,	
	2008 (Q1-FY2009)	**2007 (Q1-FY2008) (Restated)**
	(Dollars in thousands)	
Net income (loss)	$ 19,096	$ (8,582)
Adjustments:		
Interest expense	6,449	6,809
Income taxes	5,309	(2,911)
Depreciation	8,158	8,976
Amortization of intangible assets	278	70
EBITDA	**$ 39,290**	**$ 4,362**
Adjustments:		
Unrealized foreign exchange (gain) on senior notes	(1,831)	(17,150)
Realized and unrealized (gain) loss on derivative financial instruments	(2,265)	21,514
Loss on disposal of plant and equipment and assets held for sale	1,166	585
Stock-based compensation	636	359
Director deferred stock unit compensation	(269)	
Consolidated EBITDA (as defined within the revolving credit agreement)	**$ 36,727**	**$ 9,670**

Analysis of Results:

Revenues of $259.0 million for the three months ended June 30, 2008 (first quarter fiscal 2009) were $91.4 million (or 55%) higher than in the same period last year. Strong revenue performance in Heavy Construction and Mining (up $62.5 million) together with higher Pipeline revenue as a result of the TMX project (up $21.9 million), were key contributors to the year-over-year improvements.

First quarter gross profit increased to $47.6 million or 18.4% percent of revenue, compared to $14.9 million or 8.9% of revenue in the prior year. In addition to the contribution of increased revenue, the key factors in the year-over-year improvement included the return to profitability of the Pipeline segment, a partial recovery of losses incurred on a pipeline contract executed in fiscal 2007, lower repair and maintenance costs and improvements to the management and purchasing of tires. Increased activity levels have delayed the timing of repairs costs to the second quarter. First quarter equipment leasing costs of $8.8 million increased $4.9 million year-over-year reflecting the March 2008 commissioning of the new electric cable shovel at our long-term overburden project together with increased leasing of major capital equipment during the latter part of fiscal 2008. Depreciation in the first quarter of fiscal 2008 included a $3.0 million charge for accelerated depreciation for equipment that was being removed from service compared to a

$0.6 million similar charge in the first quarter of fiscal 2009. General and administrative (G&A) costs, as a percentage of revenue, dropped to 7.4% from 8.7% in the prior year. The increase of $4.6 million in costs, year-over-year, was a result of the addition of new employees as we built capacity to support our higher activity levels.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

First quarter net income of $19.1 million increased by $27.7 million compared to the same period in fiscal 2008. The increase was driven by the stronger revenue and gross profit combined with the positive net effects of non-operating items. Basic earnings per share for the quarter were $0.53, compared to a loss of $0.24 per share in the first quarter of fiscal 2008. Improvements in net income were enhanced by non-cash gains on derivative financial instruments and foreign exchange of $3.9 million, net of tax, compared to a negative impact of $3.6 million, net of tax, in the first quarter of fiscal 2008. Excluding these items, basic earnings per share would have been $0.42 per share for the first quarter of fiscal 2009 compared to a loss of $0.14 per share for the same period in fiscal 2008.

Segment Results (Three Months)

Segment profits include 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 project expenses, including direct labour, short-term equipment rentals and materials, payments to subcontractors, indirect job costs and internal charges for use of capital equipment.

Heavy Construction and Mining

	Three Months Ended June 30,			
	2008 (Q1-FY2009)	% of Revenue	2007 (Q1-FY2008)	% of Revenue
	(Dollars in thousands)			
Segment revenue	$ 189,405		$ 126,914	
Segment profit	$ 21,402	*11.3%*	$ 19,489	*15.4%*

First quarter fiscal 2009 Heavy Construction and Mining revenues of $189.4 million were $62.5 million higher than in the same period in fiscal 2008. Strong demand for our site services work was the primary factor in this improvement. Construction work on the Suncor Voyageur and Millennium Naptha Unit sites together with site preparation work on the Petro Canada Fort Hills project added to revenues during the period. Segment margins declined to 11.3% of revenues for the current fiscal quarter, from 15.4% in the same quarter of fiscal 2008. Production challenges related to unfavourable haul road conditions and site congestion at a single mining project negatively affected segment margins during the period lessening the effect of the higher-margin site services and site preparation work in the project mix.

Piling

	Three Months Ended June 30,			
	2008 (Q1-FY2009)	% of Revenue	2007 (Q1-FY2008)	% of Revenue
	(Dollars in thousands)			
Segment revenue	$ 42,503		$ 35,522	

Segment profit	$ 8,661	*20.4%*	$ 9,247	*26.0%*

First quarter fiscal 2009 piling revenues of $42.5 million were $7.0 million better than in the same period in fiscal 2008. Major contracts for oil sands-related plant and upgrader projects were a significant contributor to the revenue growth. Delays in approval of change orders resulted in segment margin declining to 20.4% from 26.0% year-over-year.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

Pipeline

	Three Months Ended June 30,			
	2008 (Q1-FY2009)	% of Revenue	2007 (Q1-FY2008)	% of Revenue
	(Dollars in thousands)			
Segment revenue	$ 27,079		$ 5,191	
Segment profit	$ 8,925	*33.0%*	$ (1,189)	(22.9)%

The TMX project continued to drive revenue growth in the Pipeline division during the first quarter of fiscal 2009. The segment also benefited from the settlement of claims revenue of $5.3 million related to losses incurred on a fixed-price contract that negatively impacted the 2007 fiscal year. The claims revenue, in part, increased segment profit to $8.9 million (33.0% of revenue) compared to a $1.2 million loss in the first quarter of fiscal 2008. Excluding the impact of the claim settlement, the margin for the first quarter of fiscal 2009 was 16.3%.

Non-operating expense (income)

	Three Months Ended June 30,	
	2008 (Q1-FY2009)	2007 (Q1-FY2008) (Restated)
	(Dollars in thousands)	
Interest expense		
Interest on senior notes	$ 5,834	$ 5,834
Interest on capital lease obligations	282	181
Amortization of bond issue costs and premiums	174	468
Other interest	159	326
Total Interest expense	$ 6,449	$ 6,809
Foreign exchange (gain) on senior notes	$ (1,641)	$ (17,100)
Realized and unrealized (gain) loss on derivative financial instruments	(2,265)	21,514
Other income	(18)	(108)
Income tax (recovery) expense	5,309	(2,911)

Total interest expense decreased by $0.4 million in the first quarter of fiscal 2009, compared to the same period last year, primarily due to the reduction in the amortization of bond issue costs. 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 83/4% senior notes. The value of the Canadian dollar relative to the U.S. dollar remained relatively stable during the first quarter period, with only a minimal increase from $0.9729 CAN/US on March 31, 2008 to $0.9817 CAN/US on June 30, 2008. By comparison, the exchange rate increased from

$0.8667 CAN/US on March 31, 2007 to $0.9481 CAN/US on June 30, 2007.

The realized and unrealized gains on derivative financial instruments reflect changes in the fair value of the cross-currency and interest rate swaps that we employ to provide an economic hedge for our U.S. dollar denominated 83/4% senior notes. Changes in the fair value of the swaps generally have an offsetting effect to changes in the value of our 83/4% senior notes (and resulting foreign exchange gains and losses), 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 83/4% senior notes. Interest payments occur in the first and third quarters of each year until maturity.

Due to our first quarter fiscal 2008 adoption of the CICA standards regarding financial instruments, realized and unrealized gains and losses on derivative financial instruments for the first quarter of both fiscal 2008 and 2009 include changes in the fair value of derivatives embedded in our US$ denominated 83/4% senior notes, in a long-term construction contract and in a supplier maintenance agreement. The change in the realized and unrealized value of

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

the cross-currency and interest swaps resulted in a gain of $0.5 million in the fiscal 2009 first quarter period. The balance of the realized and unrealized gains and losses on derivative financial instruments resulted from gains on derivatives embedded in our 83/4% senior notes, in a long-term construction contract and in the supplier maintenance agreement.

With respect to the early redemption provision in the 83/4% 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.

With respect to the supplier maintenance contract, there is a provision that requires a price adjustment to reflect actual exchange rate and price index changes versus the contract amount. The embedded derivative instrument takes into account the impact on costs as a result of fluctuations in these measures.

The measurement of embedded derivatives, as required by the accounting standards, cause our reported earnings to fluctuate as currency exchange and interest rates change. The accounting for these derivatives has no impact on operations, Consolidated EBITDA (as defined within the revolving credit agreement) or how we evaluate performance.

We recorded income tax expense of $5.3 million in the first quarter of fiscal 2009 compared to an income tax recovery of $2.9 million (restated) for the same period last year.

First quarter fiscal 2009 income tax expense as a percentage of income before income taxes differs from the statutory rate of 29.38%, primarily due to the impact of the benefit from changes in the timing of the reversal of temporary differences during the period.

First quarter fiscal 2008 income tax expense as a percentage of income before income taxes differed from the statutory rate of 31.72% 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. Under the new accounting standards, certain embedded derivatives are considered capital in nature for income tax purposes.

Summary of Quarterly Results

	Fiscal 2009		Fiscal 2008				Fiscal 2007	
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2

	30-Jun-08	31-Mar-08	31-Dec-07	30-Sep-07	30-Jun-07 (Restated)	31-Mar-07	31-Dec-06	30-Sep-06
	(Dollars in millions, except per share amounts)							
Revenue	$ 259.0	$ 323.6	$ 274.9	$ 223.6	$ 167.6	$ 205.4	$ 155.9	$ 130.1
Gross profit	47.6	62.6	50.6	35.2	14.9	13.6	26.0	20.2
Operating income (loss)	26.9	42.6	33.2	17.1	(0.4)	4.5	13.8	9.7
Net income (loss)	19.1	22.7	25.4	2.1	(8.6)	1.3	6.6	(4.6)
EPS Basic(1)	$ 0.53	$ 0.63	$ 0.71	$ 0.06	$ (0.24)	$ 0.04	$ 0.27	$ (0.26)
EPS Diluted(1)	0.52	0.62	0.69	0.06	(0.24)	0.04	0.26	(0.26)

(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 (Continued)

As discussed previously, a number of factors have the potential to 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. For a detailed discussion regarding seasonality and its impact on us see Key Trends section below.

The timing of large projects can influence quarterly revenue. For example, Pipeline revenues were $31.3 million in the second quarter of 2008 (up $28.5 million from fiscal 2007), $76.7 million in the third quarter of fiscal 2008 (up $61.5 million compared to fiscal 2007), $87.5 million in the fourth quarter of 2008 (up $62.0 million compared to fiscal 2007) and $27.1 million in the first quarter of fiscal 2009 (up $21.9 million compared to fiscal 2008). Heavy Construction and Mining experienced increased revenues from the second quarter of fiscal 2008 through the first quarter of fiscal 2009. This increase related to the execution of work at Suncor Millennium Naphtha Unit project under our five-year site services agreement and the construction of an aerodrome for Albian, along with increased demand under our master service agreements with Albian and Syncrude. Timing of work under the site services agreements can vary based on our customers production and project activities.

In addition to revenue variability, gross margins can be negatively impacted by the timing of maintenance costs. The timing of these costs are dependant on when management can make the equipment available for service without adversely affecting billable equipment hours.

Profitability also varies from period-to-period due as a result of 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 Change Orders . During the first quarter of fiscal 2009 a $5.3 million claim was recognized causing gross margins for the Pipeline segment to increase above what they would otherwise have been. The additional costs relating to the claim were incurred in fiscal 2007 and the first quarter of fiscal 2008.

Variations in quarterly results also result from our operating leverage. During the higher activity periods we have experienced improvements in operating income as certain costs, which are generally fixed, including general and administrative expenses, are spread over higher revenue levels. Net income and EPS are also subject to operating leverage as provided by fixed interest expense.

We have, however, experienced earnings variability in all periods due to the recognition of unrealized non-cash gains and losses on derivative financial instruments and foreign exchange primarily driven by changes in the Canadian and U.S. dollar exchange rates.

Consolidated Financial Position

	June 30, 2008 Q1-FY2009	March 31, 2008 Q4-FY2008	% Change
	(Dollars in thousands)		

Current assets	$ 294,476	$ 291,086	1.2%
Current liabilities	(209,948)	(183,353)	14.5%
Net working capital	84,528	107,733	(21.5)%
Plant and equipment	331,575	281,039	18.0%
Total assets	837,722	793,598	5.6%
Capital Lease obligations (including current portion)	14,715	14,776	(0.4)%
Total long-term financial liabilities(1)	(297,744)	(301,497)	(1.2)%

(1) Total long-term financial liabilities exclude the current portions of capital lease obligations, current portions of derivative financial instruments, long-term lease inducements and both current and non-current future income taxes balances.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

At June 30, 2008 net working capital (current assets less current liabilities) was $84.5 million compared to $107.7 million at March 31, 2008, a decrease of $23.2 million. Positive cash flow increased our overall cash balance by $18.5 million to $51.3 million. Collections improved on both trade receivables (reduced by $20.4 million since March 31, 2008) and holdbacks (reduced by $13.9 million since March 31, 2008) offset by increased unbilled revenue (up by $18.7 million since March 31, 2008). First quarter equipment purchases of $43.5 million are scheduled to be paid after the quarter-end, thus increasing the balance of accounts payable for the quarter. The semi-annual payment of the senior note interest during the current period reduced the accrued interest balance by $5.8 million.

For the first quarter of fiscal 2009, plant and equipment net of depreciation, increased by $50.5 million compared to the same period a year ago. This is a result of the capital investment for the quarter offset by equipment disposals of $2.5 million (net book value) and depreciation.

Total long-term financial liabilities decreased by $3.8 million between June 30, 2008 and March 31, 2008 due to the decreased value of embedded derivatives contained within the senior notes (a decrease of $2.6 million) and the reduction in both the value of the derivative financial instruments from the cross-currency and interest swap agreement and the embedded derivatives from a long-term construction contract and supplier maintenance agreement (a decrease of $2.0 million).

Claims and 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 we 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 some of the changes discussed above, at June 30, 2008 we had approximately $9.7 million in costs for claims and unsigned change orders from project inception, with no associated increase in contract value or revenue. 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.

In June 2008 the Pipeline division successfully settled a claim related to a project in fiscal 2007. The claim was settled for $8.0 million, of which $5.3 million was recognized as revenue in the first quarter of fiscal 2009 with the balance of $2.7 million previously recognized as revenue.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

C. Key Trends

Seasonality

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.

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. 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 Change Orders .

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 percentage 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 U.S. dollar exchange rates.

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.

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. 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 first quarter of fiscal 2009, the total amount of revenue earned under the master services agreements was $129.0 million.

Our estimated backlog as at June 30, 2008 and 2007 was:

By Segment	As at June 30, 2008 (Q1-FY2009)	2007 (Q1-FY2008)
	(In millions)	
Heavy Construction & Mining	$ 593.3	$ 711.0
Piling	22.8	26.0
Pipeline	59.0	192.0
Total	$ 675.1	$ 929.0

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

By Contract Type	As at June 30, 2008 (Q1-FY2009) (In millions)	As at June 30, 2007 (Q1-FY2008) (In millions)
Unit-Price	$ 598.5	$ 739.0
Lump-Sum	17.6	6.0
Time & Materials, Cost-Plus	59.0	184.0
Total	$ 675.1	$ 929.0

A contract with a single customer represented approximately $524 million of the June 30, 2008 backlog. It is expected that approximately $316.0 million of the total backlog will be performed and realized in the 12 months ending June 30, 2009.*

Revenue Sources

We have experienced a steady growth in master services agreements as oil sands development continues to grow. While there is no long-term commitment from customers regarding this work as described below, we expect these trends to continue through fiscal 2009 as we continue to provide services to Syncrude and Suncor and benefit from growth at the Shell sites.*

Revenue by Category

Long-term contracts. This category of revenue is generated from long-term contracts (greater than one year) with total contract values greater than $20 million. These contracts are for work that supports the operations of our

* This paragraph contains forward-looking statements. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

customers and are therefore considered to be recurring including long-term contracts for overburden removal and reclamation. This revenue is typically generated under unit-price contracts and is included in our calculation of backlog.

Major Projects. This category includes revenue generated from projects with contract values greater than $20 million and durations of greater than six months. This category of revenue is typically generated supporting major capital construction projects and is therefore considered to be non-recurring. This revenue can be generated under lump-sum, unit-price, time-and-materials and cost-plus contracts. This revenue can be included in backlog if generated under lump-sum, unit-price or time-and-materials contracts.

Master Services Agreements. This category includes revenue generated from the master services agreements in place with Syncrude and Albian. This category of revenue is also generated by supporting the operations of our customers and is therefore considered to be recurring. This revenue is not guaranteed under contract and would not be included in our calculation of backlog. This revenue is primarily generated under time and materials contracts.

Other Projects. This category includes revenue generated from contracts with values of less than $20 million and durations of, typically, less than six months. This category of revenue is generally driven by capital construction and is therefore non-recurring. This revenue can be generated under lump-sum, unit-price, time-and-materials and cost-plus contracts. This revenue is included in backlog if generated under lump-sum, unit-price contracts or time and materials contracts and the job scope, value and timing is known.

Revenue by End Market

Projects in the oil sands increased our work volumes during fiscal 2008 and into the first quarter of fiscal 2009. The pipeline installation project for Kinder Morgan increased our revenues in the conventional oil and gas sector. Minerals mining work slowed at the end of fiscal 2008 and into the first quarter of fiscal 2009 as we completed the work on the DeBeers diamond mine project.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

Revenue by Contract Type

Contracts

We complete work under the following types of contracts: cost-plus, time-and-materials, unit-price and lump-sum. Each contract contains a different level of risk associated with its formation and execution.

Cost-plus. A cost-plus contract is a contract in which all the work is completed based on actual costs incurred to complete the work. These costs include all labor, equipment, materials and any subcontractor s costs. In addition to these direct costs, all site and corporate overhead costs are charged to the job. An agreed upon fee in the form of a fixed percentage is then applied to all costs charged to the project. This type of contract is utilized where the project involves a large amount of risk or the scope of the project cannot be readily determined.

Time-and-materials. A time-and-materials contract involves using the components of a cost-plus job to calculate rates for the supply of labor and equipment. In this regard, all components of the rates are fixed and we are compensated for each hour of labor and equipment supplied. The risk associated with this type of contract is the estimation of the rates and incurrence of expenses in excess of a specific component of the agreed-upon rate. Any cost overrun in this type of contract must come out of the fixed margin included in the rates.

Unit-price. A unit-price contract is utilized in the execution of projects with large repetitive quantities of work and is commonly utilized for site preparation, mining and pipeline work. We are compensated for each unit of work we perform (for example, cubic meters of earth moved, lineal meters of pipe installed or completed piles). Within the unit-price contract, there is an allowance for labor, equipment, materials and any subcontractor s costs. Once these costs are calculated, we add any site and corporate overhead costs along with an allowance for the margin we want to achieve. The risk associated with this type of contract is in the calculation of the unit costs with respect to completing the required work.

Lump-sum. A lump-sum contract is utilized when a detailed scope of work is known for a specific project. Thus, the associated costs can be readily calculated and a firm price provided to the customer for the execution of the work. The risk lies in the fact that there is no escalation of the price if the work takes longer or more resources are

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

required than were estimated in the established price, as the price is fixed regardless of the amount of work required to complete the project.

Major Suppliers

We have long-term relationships with the following equipment suppliers: Finning International Inc. (45 years), Wajax Income Fund (20 years) and Brandt Tractor Ltd. (30 years). Finning is a major Caterpillar heavy equipment dealer for Canada. Wajax is a major Hitachi equipment supplier to us for both mining and construction equipment. We purchase or rent John Deere equipment, including excavators, loaders and small bulldozers, from Brandt Tractor. In addition to the supply of new equipment, each of these companies is a major supplier for equipment rentals, parts and service labor.

Tire supply remains a challenge for our haul truck fleet. We prefer to use radial tires from proven manufacturers but the shortage of supply has forced us to increase the use of bias tires and radial tires from new manufacturers. Bias tires have a shorter usage life and are of a lower quality than radial tires. This affects operations as we are forced to reduce operating speeds and loads to compensate for the quality of the tires. During the quarter ended June 30, 2008 we continued to reduce our inventory of bias tires for the 150-ton haul trucks and are now acquiring radial tires for these trucks as required. Preliminary findings from the use of the bias tires have shown that these tires are accumulating reasonable life hours, or in some cases better-than-expected life hours. Tires for the 240-ton haul trucks continue to be in short supply. To address this shortfall, we are purchasing bias tires from new manufacturers and radial tires from non-dealer sources at a large premium above dealer prices. We were able to negotiate a five-year contract (commencing in 2008) with Bridgestone Firestone Canada Inc. to secure a tire allotment for select tire sizes for the 240-ton to 320-ton haul trucks, which will alleviate some of the shortage. We are continuing negotiations with Bridgestone to improve the security of tire supply. We have also been successful in acquiring radial tires with new trucks as they are delivered and hope to continue this practice in fiscal 2009 and fiscal 2010. Suppliers have improved overall tire supply, but we believe the tire shortage will remain an issue for the foreseeable future.*

Competition

Our industry is highly competitive in each of our markets. Historically, the majority of our new business was awarded to us based on past client relationships without a formal bidding process, in which, typically, a small number of pre-qualified firms submit bids for the project work. Recently, in order to generate new business with new customers, we have had to participate in formal bidding processes. As new major projects arise, we expect to have to participate in bidding processes on a meaningful portion of the work available to us on these projects. Factors that impact competition include price, safety, reliability, scale of operations, equipment and labour availability and quality of service. Most of our clients and potential clients in the oil sands area operate their own heavy mining equipment fleet. However, these operators have historically outsourced a significant portion of their mining and site preparation operations and other construction services.*

Our principal competitors in the Heavy Construction and Mining segment include Cow Harbour Construction Ltd., Cross Construction Ltd., Klemke Mining Corporation, Ledcor Construction Limited, Peter Kiewit and Sons Co., Tercon Contractors Ltd., Sureway Construction Ltd. and Thompson Bros. (Construction) Ltd. In underground utilities installation (a part of our Heavy Construction and Mining segment) Voice Construction Ltd., Ledcor Construction Limited and I.G.L. Industrial Services are our major competitors. The main competition to our deep foundation piling operations comes from Agra Foundations Limited, Double Star Co. and Ruskin Construction Ltd.

* This paragraph contains forward-looking statements. Plese refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

The primary competitors in the pipeline installation business include Ledcor Construction Limited, Washcuk Pipe Line Construction Ltd. and Willbros.

In the public sector, we compete against national firms and there is usually more than one competitor in each local market. Most of our public sector customers are local governments that are focused on serving only their local regions. Competition in the public sector continues to increase, and we typically choose to compete on projects only where we can utilize our equipment and operating strengths to secure profitable business.

D. Outlook

Continued development of the oil sands is expected to drive a significant portion of our fiscal 2009 revenue. In addition to existing mining and site services contracts with customers including Canadian Natural, Suncor, Syncrude, Albian and Petro-Canada, we also anticipate increased demand for our services at Petro-Canada s Fort Hills site as that project progresses.*

Outside of the oil sands, we continue to provide constructability assistance to a number of potential mining customers for developments across Canada. Our success with the Albian aerodrome project, meanwhile, has resulted in significant interest from customers looking to develop airstrips in northern Alberta.*

Demand for our piling services is expected to remain strong in fiscal 2009 with commercial construction activity at a high level in Western Canada. A number of upgrader facilities are also being considered for the Edmonton area, providing opportunities to bid on larger-scale piling contracts.*

While we anticipate a temporary slowdown in our pipeline activity once the TMX project concludes in October 2008, we see significant long-term opportunities for this division. More than five major new pipeline projects are planned for Western Canada to relieve limited capacity and accommodate growing oil sands production. We believe our success on the large and environmentally-demanding TMX project positions us to compete effectively as the new pipeline projects are tendered.*

Overall, our outlook for the remainder of fiscal 2009 remains very positive.

E. Legal and Labour Matters

Laws and Regulations and Environmental Matters

Many aspects of our operations are subject to various federal, provincial and local laws and regulations, including, among others:

- permitting and licensing requirements applicable to contractors in their respective trades;
- building and similar codes and zoning ordinances;
- laws and regulations relating to consumer protection; and

laws and regulations relating to worker safety and protection of human health.

We believe we have all material required permits and licenses to conduct our operations and are in substantial compliance with applicable regulatory requirements relating to our operations. Our failure to comply with the applicable regulations could result in substantial fines or revocation of our operating permits.

Our operations are subject to numerous federal, provincial and municipal environmental laws and regulations, including those governing the release of substances, the remediation of contaminated soil and groundwater, vehicle

* This paragraph contains forward-looking statements. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

emissions and air and water emissions. These laws and regulations are administered by federal, provincial and municipal authorities, such as Alberta Environment, Saskatchewan Environment, the British Columbia Ministry of Environment, and other governmental agencies. The requirements of these laws and regulations are becoming increasingly complex and stringent, and meeting these requirements can be expensive.

The nature of our operations and our ownership or operation of property exposes us to the risk of claims with respect to environmental matters, and there can be no assurance that material costs or liabilities will not be incurred with such claims. For example, some laws can impose strict, joint and several liability on past and present owners or operators of facilities at, from or to which a release of hazardous substances has occurred, on parties who generated hazardous substances that were released at such facilities and on parties who arranged for the transportation of hazardous substances to such facilities. If we were found to be a responsible party under these statutes, we could be held liable for all investigative and remedial costs associated with addressing such contamination, even though the releases were caused by a prior owner or operator or third party. We are not currently named as a responsible party for any environmental liabilities on any of the properties on which we currently perform or have performed services. However, our leases typically include covenants which obligate us to comply with all applicable environmental regulations and to remediate any environmental damage caused by us to the leased premises. In addition, claims alleging personal injury or property damage may be brought against us if we cause the release of, or any exposure to, harmful substances.

Our construction contracts require us to comply with all environmental and safety standards set by our customers. These requirements cover such areas as safety training for new hires, equipment use on site, visitor access on site and procedures for dealing with hazardous substances.

Capital expenditures relating to environmental matters during the fiscal years ended March 31, 2006, 2007 and 2008 were not material. We do not currently anticipate any material adverse effect on our business or financial position as a result of future compliance with applicable environmental laws and regulations. Future events, however, such as changes in existing laws and regulations or their interpretation, more vigorous enforcement policies of regulatory agencies or stricter or different interpretations of existing laws and regulations may require us to make additional expenditures which may be material.*

Employees and Labor Relations

As of June 30, 2008, we had over 300 salaried employees and over 1,900 hourly employees. Our hourly workforce will fluctuate according to the seasonality of our business from an estimated low of 1,500 employees in the spring to a high of approximately 2,400 employees over the winter. We also utilize the services of subcontractors in our construction business. An estimated 8% to 10% of the construction work we do is performed by subcontractors. Approximately 2,000 employees are members of various unions and work under collective bargaining agreements. The majority of our work is done through employees governed by our mining overburden collective bargaining agreement with the International Union of Operating Engineers Local 955, the primary term of which expires on October 31, 2009. A small portion of our employees work under an industrial collective bargaining agreement with the Alberta Road Builders and Heavy Construction Association and the International Union of Operating Engineers Local 955, the primary term of which expires February 28, 2009. In June 2008 we signed an agreement with the International Union of Operating Engineers Local 955 covering the small group of employees working in our Acheson shop, which will expire June 30, 2011. We are subject to other industry and specialty collective agreements under which we complete work, and the primary terms of all of these agreements are currently in effect. We believe that our relationships with all our employees, both union and non-union, are satisfactory. We have not yet experienced a strike or lockout.*

* This paragraph contains forward-looking statements. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

F. Resources and Systems

Outstanding Share Data

We are authorized to issue an unlimited number of common voting shares and an unlimited number of common non-voting shares. As at August 13, 2008 36,038,476 common voting shares were outstanding (36,036,476 as at June 30, 2008) This compares to 35,929,476 common voting shares as at March 31, 2008 and 35,192,260 common voting shares and 412,400 non-voting common shares outstanding as at March 31, 2007.

Liquidity

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.

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 for sustaining capital expenditures and our total capital requirements will typically range from $125 million to $200 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 our 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.*

Our long-term debt includes US$200 million of 83/4% 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 agreements are an economic hedge but have not been designated as hedges for accounting purposes. Interest totaling $13.0 million on the 83/4% 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 83/4% senior notes until maturity.

One of our major contracts allows the customer to require that we provide up to $50 million in letters of credit. As at June 30, 2008, we had $20.0 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.

Sources of liquidity

Our principal sources of cash are funds from operations and borrowings under our revolving credit facility. As of June 30, 2008, we had approximately $104.3 million of available borrowings under the revolving credit facility

* This paragraph contains forward-looking statements. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

after taking into account $20.7 million of outstanding and undrawn letters of credit to support performance guarantees associated with customer contracts.

Revolving credit facility

We entered into an amended and restated credit agreement dated on June 7, 2007 with a syndicate of lenders that provides us with a $125.0 million revolving credit facility. Our revolving credit facility provides for an original principal amount of up to $125.0 million under which revolving loans may be made and under which letters of credit may be issued. The facility will mature on June 7, 2010, subject to possible extension. The credit facility is secured by a first priority lien on substantially all of our and our subsidiaries existing and after-acquired property (tangible and intangible), including, without limitation, accounts receivable, inventory, equipment, intellectual property and other personal property, and real property, whether owned or leased, and a pledge of the shares of our subsidiaries, subject to various exceptions.

The facility bears interest on each prime loan at variable rates based on the Canadian prime rate plus the applicable pricing margin (as defined in the credit agreement). Interest on U.S. base rate loans is paid at a rate per annum equal to the U.S. base rate plus the applicable pricing margin. Interest on prime and U.S. base rate loans is payable monthly in arrears and computed on the basis of a 365- or 366-day year, as the case may be. Interest on LIBOR loans is paid during each interest period at a rate per annum, calculated on a 360-day year, equal to the LIBOR rate with respect to such interest period plus the applicable pricing margin.

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 (as defined in the credit agreement) during any applicable period cannot exceed 120% of the amount in the capital expenditure plan. In addition, we are required to 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 defined within the revolving credit agreement), as well as a minimum current ratio.

Consolidated EBITDA (as defined within the revolving credit agreement) 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, and (8) 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)-(8), to the extent deducted in the calculation of consolidated net income, less other non-cash 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 (as defined within the revolving credit agreement) to consolidated cash interest expense 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 shall not be less than 2.5 times consolidated cash interest expense (2.35 times at June 30, 2007). Also, measured as of the last day of each fiscal quarter on a trailing four-quarter basis, senior leverage shall not exceed twice Consolidated EBITDA. We believe Consolidated EBITDA is an important measure of our performance and liquidity.

The credit facility may be prepaid in whole or in part without penalty, except for bankers acceptances, which will not be pre-payable prior to their maturity. However, the credit facility requires prepayments under various circumstances, such as: (i) 100% of the net cash proceeds of certain asset dispositions, (ii) 100% of the net cash

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

proceeds from our issuance of equity (unless the use of such securities proceeds is otherwise designated by the applicable offering document) and (iii) 100% of all casualty insurance and condemnation proceeds, subject to exceptions.

Working capital fluctuations effect on cash

The seasonality of our work may result in a slow down in cash collections between December and early February which may result in an increase in our working capital requirements. Our working capital is also significantly affected by the timing of completion of projects. Our customers are permitted to withhold payment of a percentage of the amount owing to us for a stipulated period of time (such percentage and time period usually defined by the contract and in some cases provincial legislation). This amount acts as a form of security for our customers and is referred to as a holdback. We are only entitled to collect payment on holdbacks once substantial completion of the contract is performed, there are no outstanding claims by subcontractors or others related to work performed by us and we have met the time period specified by the contract (usually 45 days after completion of the work). As at June 30, 2008 holdbacks totaled $21.1 million down from $35.0 million as at March 31, 2008. Holdbacks represent 16.5% of our total Accounts Receivable outstanding as at June 30, 2008 (21.0% as at March 31, 2008). This decrease is attributable to the seasonal reduction of revenue compared to the previous two quarters and the collection of holdbacks outstanding as at March 31, 2008 including the DeBeers holdback for $11.0 million. As at June 30, 2008 we carried $12.8 million in holdbacks for three large customers.

Debt Ratings

In December 2007 Standard & Poor s upgraded our debt rating to B+ (from B) with a stable outlook following a review of our current and prospective business risk and financial risk profiles. Our senior unsecured notes are also rated B+ with a recovery rating of 4 indicating an expectation for an average of (30% 50%) recovery in the event of a payment default.

In December 2007 Moody s maintained our debt rating at B2 with a stable outlook (the upgrade to B2 was issued in December 2006 following our IPO). Moody s rates our senior unsecured notes at B3 with a loss given default rating of 5.

Cash Flow and Capital Resources

	Three Months Ended June 30,		
	2008 (Q1-FY2009)	2007 (Q1-FY2008) (Restated)	2006 (Q1-FY2007)
	(Dollars in thousands)		
Cash provided by operating activities	$ 33,341	$ 7,404	$ 15,050
Cash (used in) investing activities	(14,332)	(4,490)	(11,370)
Cash (used in) financing activities	(548)	(1,329)	(1,391)

Net increase in cash and cash equivalents	$ 18,461	$ 1,585	$ 2,289

Operating activities

Cash provided by operating activities for the first quarter of fiscal 2009 was $33.3 million compared to $7.4 million and $15.1 million for the comparable periods in the two prior years. Operating activities in the three month period ended June 30, 2008 (first quarter of fiscal 2009) benefitted from favourable cash collections and holdback reductions. The lower cash generated in the first quarters of the preceding fiscal years was a result of lower earnings for those periods and higher trade receivables.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

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 equipment additions required to perform larger or a greater number of projects.

During the first quarter of fiscal 2009, we invested $4.4 million in sustaining capital expenditures (Q1 fiscal 2008 $5.7 million; Q1 fiscal 2007 $4.7 million) and invested $54.9 million in growth capital expenditures (Q1 fiscal 2008 $4.5 million; Q1 fiscal 2007 $7.1 million), for total capital expenditures of $59.3 million (Q1 fiscal 2008 $10.2 million; Q1 fiscal 2007 $11.8 million). Accounts payable included $43.5 million for capital expenditures that are scheduled to be paid subsequent to quarter-end. Proceeds from asset disposals of $1.5 million in the first quarter of fiscal 2009 (Q1 fiscal 2008 $13.9 million; Q1 fiscal 2007 $0.5 million) lessened the effect of capital purchases resulting in net cash invested of $14.3 million for the first quarter of fiscal 2009 (Q1 fiscal 2008 $4.5; Q1 fiscal 2007 $11.4 million). Operating leases used to fund equipment purchases added $21.3 million in the first quarter of fiscal 2009 (not reflected in capital spend) compared to no new operating lease additions in the first quarter of fiscal 2008.

Financing activities

Financing activities in the first quarter of fiscal 2009 resulted in a cash outflow of $0.5 million due to the repayment of capital leases offset by proceeds received from the exercise of stock options. Cash outflow in the first quarter of fiscal 2008 of $1.3 million was a result of increases to the revolving credit facility costs, financing costs and capital lease repayments offset by an inflow of cash from stock options being exercised. Cash outflow in the first quarter of fiscal 2007 of $1.3 million was a result of financing costs and the repayment of capital leases.

Capital Commitments

Contractual Obligations and Other Commitments

Our principal contractual obligations relate to our long-term debt, capital and operating leases and supplier contracts. The following table summarizes our future contractual obligations, excluding interest payments unless otherwise noted, as of June 30, 2008.

	Total	2009	2010	2011	2012	2013 and after
			(in millions)			
Senior notes(a)	$ 263.0	$ 0.0	$ 0.0	$ 0.0	$ 263.0	$ 0.0
Capital leases (including interest)	16.5	5.6	4.8	3.2	2.5	0.4
Operating leases	107.5	26.7	30.4	20.8	14.6	15.0
Supplier contracts	35.4	4.1	6.0	8.2	9.8	7.3
Total contractual obligations	**$ 422.4**	**$ 36.4**	**$ 41.2**	**$ 32.2**	**289.9**	**$ 22.7**

(a) We have entered into cross-currency and interest rate swaps, which represent an economic hedge of the 83/4% senior notes. At maturity, we will be required to pay $263.0 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 June 30, 2008 the carrying value of the derivative financial instruments was $80.5 million, inclusive of the interest components.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements in place at this time.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

Cash Requirements

As of June 30, 2008 our cash balance of $51.3 million was $18.5 million higher than our cash balance on March 31, 2008. We anticipate that we will continue to generate a net cash surplus in fiscal 2009. In the event that we require additional funding, we believe that any such funding requirements would be satisfied by the funds available from our revolving credit facility.*

Internal Systems and Processes

Overview of information systems

We currently use JDE (Enterprise One) as our Enterprise Resource Planning (ERP) tool and deploy the financial system, payroll, procurement, job-costing and equipment maintenance modules from this tool. We supplement this functionality with either third-party software (for our estimating system) or in-house developed tools (for project management).

In fiscal 2008 we focused on developing systems and processes using our ERP system to increase the automation of transactional activities and improve management information. The proper identification of costs is a critical part of our ability to recognize revenues and we have focused resources to addressing this issue. Throughout 2008 we concentrated on the development of better cost tracking tools through the implementation of a procure-to-pay process in our ERP system. We also started work on improving the process for tracking and reporting equipment and maintenance costs. Despite some initial implementation hurdles over the summer and fall of 2007, we are seeing some improvements in the identification and tracking of our procurement costs.

We are currently performing a user-needs analysis and comparing this to the functionality of our ERP system. We have extended the analysis into the second quarter of fiscal 2009 to determine if we can implement additional modules or commence a review of industry-specific software to supplement our existing ERP functionality.

In the first quarter of fiscal 2009 we reorganized the financial reporting team and recruited for both technical expertise and financial reporting experience. We are currently evaluating and revamping our financial reporting processes.

Evaluation of Disclosure Controls and Procedures

Management has evaluated whether there were changes in our internal controls over financial reporting during the three month period ended June 30, 2008 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. No material changes were identified.

As of March 31, 2008, we identified material weaknesses in internal controls over financial reporting as described below. We did not maintain effective processes and controls related to the following;

Specific to complex and non routine transactions and period end controls: There was a lack of sufficient accounting and finance personnel with an appropriate level of technical accounting knowledge and training commensurate with the complexity of the Company s financial accounting and reporting requirements.

Complex and non routine financial report matters that would be affected by this deficiency include the identification of embedded derivatives and preparation of the Company s US GAAP reconciliation note. Additionally, we did not adequately perform period end controls related to the review and approval of account analysis, verification of inputs and reconciliations. The accounts that would be affected these deficiencies are cash, senior notes, contributed surplus, stock-based compensation expense, foreign exchange and related financial statement disclosures.

* This paragraph contains forward-looking statements. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

Specific to revenue recognition: A formal process to track claims and unapproved change orders and sufficient monitoring controls over the completeness and accuracy of forecasts, including the consideration of project changes subsequent to the end of each reporting period, were not effectively implemented. The accounts that would be affected by these deficiencies are revenue, project costs, unbilled revenue and billings in excess of costs incurred and estimated earning on uncompleted contracts.

Specific to accounts payable and procurement We did not have an effectively implemented procurement process to track purchase commitments, reconcile vendor accounts and accurately accrue costs not invoiced by vendor at each reporting date. The accounts that would be affected by these deficiencies are accounts payable, accrued liabilities, unbilled revenue, billings in excess of costs incurred and estimated earnings on uncompleted contracts, revenue, project costs, equipment costs, general and administrative costs and other expenses.

As of June 30, 2008, these material weaknesses have not been remediated. For a discussion of our remediation plans, which are ongoing, and for a discussion of the risks associated with such weaknesses, please see our most recent annual Management s Discussion and Analysis.

Significant Accounting Policies

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 first quarter of fiscal 2009, our revenue consisted of 49.8% time-and-materials, 42.5% unit-price and 7.7% 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 have noted a material weakness related to our procurement processes as previously identified in the fiscal year-end March 31, 2008 Management s Discussion and Analysis. To address these weaknesses we implemented monitoring and review controls to assist with the determination of our cost estimates. These controls require a significant review of our payable activities after the month-end to ensure that we have identified project costs in the correct period. Given the time delay in identifying costs we may misstate revenues. However, we believe our experience allows us to produce materially reliable estimates. 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

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

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 business segments, Heavy Construction and Mining, Piling and Pipeline.

Once contract performance is underway, we 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 impact costs and revenue under the contract. When a change becomes a point of dispute between us and a customer, we 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. 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 that 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.

* This paragraph contains forward-looking statements. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

Another key estimate is the expected cash flows from the use of an asset and the expected disposal proceeds in applying CICA 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

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. We previously tested goodwill annually on December 31. For fiscal year 2008 we completed the goodwill impairment testing on October 1. This change in timing was made to reduce conflict between the impairment testing and our financial reporting close process for the fiscal period ending December 31. It is our 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 had no impact on the consolidated financial statements.

Related Parties

We may receive consulting and advisory services provided by the principals or employees of companies owned or operated by our directors (the Sponsors) with respect to the organization of our companies employee benefit and compensation arrangements, and other matters, and no fee is charged for these consulting and advisory services.

In order for the Sponsors 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.

Recently Adopted Accounting Policies

Financial Instruments Disclosure and Presentation

Effective April 1, 2008, we prospectively adopted the Canadian Institute of Chartered Accountants (CICA) Sections 3862, Financial Instruments Disclosures , which replaces CICA 3861 and provides expanded disclosure requirements that enable users to evaluate the significance of financial instruments on our financial position and its performance and the nature and extent of risks arising from financial instruments to which we are exposed during the period and at the balance sheet, and how we manage those risks. This standard harmonizes disclosures with International Financial Reporting Standards. We have provided the additional required disclosures in note 10 to its interim consolidated financial statements for the three months ended June 30, 2008.

Effective April 1, 2008, we adopted CICA issued Handbook Section 3863, Financial Instruments Presentation . 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. The adoption of this standard did not have a material impact on the presentation of financial instruments in our financial statements.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

Capital Disclosures

Effective April 1, 2008, we prospectively adopted CICA Section 1535, Capital Disclosures , which requires disclosure of qualitative and quantitative information that enables users to evaluate our objectives, policies and process for managing capital. We have provided the additional required disclosures in our interim consolidated financial statements for the three months ended June 30, 2008 (first quarter of fiscal 2009).

Inventories

Effective April 1, 2008, we retrospectively adopted CICA Section 3031, Inventories without restatement. This standard requires inventories to be measured at the lower of cost and net realizable value and provides guidance on the determination of cost, including the allocation of overheads and other costs to inventories, the requirement for an entity to use a consistent cost formula for inventory of a similar nature and use, and the reversal of previous write-downs to net realizable value when there is subsequent increases in the value of inventories. This new standard also clarifies that spare component parts that do not qualify for recognition as property, plant and equipment should be classified as inventory. Effective April 1, 2008, we reversed a tire impairment that was previously recorded at March 31, 2008 in other assets of $1,383 with a corresponding decrease to opening deficit of $991 net of future taxes of $392. We then reclassified $5,086 of tires and spare component parts from other assets to inventory . As at June 30, 2008, inventory is comprised of tires and spare component parts of $6,790 and job materials of $110. We carry inventory at the lower of weighted average cost and net realizable value. The carrying amount of inventories pledged as security for borrowings under the revolving credit facility is approximately $6,900 as at June 30, 2008.

Going Concern

Effective April 1, 2008, we prospectively adopted CICA Section 1400, General Standards of Financial Statement Presentation . These amendments require us to assess our ability to continue as a going concern. When we are aware of material uncertainties related to events or conditions that may cast doubt on our ability to continue as a going concern, those concerns must be disclosed. In assessing the appropriateness of the going concern assumption, the standard requires us to consider all available information about the future, which is at least, but not limited to, twelve months from the balance sheet date. The adoption of this standard did not have a material impact on the presentation and disclosures with our consolidated financial statements.

Recent Accounting Pronouncements Not Yet Adopted

Goodwill and Other Intangible Assets

In February 2008, the CICA issued Section 3064, Goodwill and Other Intangible Assets , replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs . The new pronouncement establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. This new standard is effective for our interim and annual consolidated financial statements commencing April 1, 2009. We are currently evaluating the impact of adopting the standard.

G. Forward-Looking Information and Risk Factors

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

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

tense or other forward-looking words such as believe , expect , anticipate , intend , plan , estimate , should , n would, target, objective , projection , forecast , continue , strategy , intend, position or the negative of th variations of them or comparable terminology.

Examples of such forward-looking information in this document include but are not limited to statements with respect 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) the limited risk that royalty changes will cause our customers to cancel, delay or reduce the scope of any significant mining developments presently underway;

(b) the expected continued rapid growth of operators in the oil sands business, their planned projects and our intention to pursue and win business opportunities from these projects;

(c) our intention to increase our fleet size to be ready to meet the challenges from the projected growth in oil sands;

(d) that acquisition opportunities will materialize that will allow us to expand our complementary service offerings which we will be able to cross-sell with our existing services;

(e) our intention to build on our relationships with our existing oil sands customers to win a substantial share of the heavy construction and mining, piling and pipeline services outsourced in connection with these projects;

(f) our intention to increase our presence outside the oil sands and extend our services to other resource industries across Canada;

(g) the success of the enhancements to maintenance practices resulting in improved availability through reduced repair time and increased utilization of our equipment with a consequent improvement in our revenue, margins and profitability;

(h) the amount of our backlog expected to be performed and realized in the twelve months ending June 30, 2009;

(i) the expected growth in master services agreements through 2009 and our continued work with Syncrude, Suncor and Shell;

(j) the arrival of new major projects and our required participation for work on these projects;

(k) the continued development of the oil sands and the expectation that it will drive a significant portion of our 2009 revenue;

(l) the anticipated increased demand for our services at Petro-Canada s Fort Hills site;

(m) our expected increased involvement with Baffinland Iron Mines Corp.;

(n) demand for our piling services remaining strong in fiscal 2009;

(o) the anticipated temporary slowdown in our pipeline activity once the TMX project concludes in October 2008 and significant long-term opportunities for this division;

(p) our expected generation of a net cash surplus in fiscal 2009;

(q) our operating and capital lease facilities and cash flow from operations are sufficient to meet capital expenditure requirements; and

(r) our ability to produce materially reliable estimates;

(s) our experience allows us to produce materially reliable estimates.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this quarterly Management s Discussion and Analysis include, but are not limited to:

The forward-looking information in paragraphs (a), (b), (j), (k), (l), (m), (n) and (s) rely on certain market conditions and demand for our services and are based on the assumptions that; the global economy remains strong and the demand for commodities, particularly oil, remains high; high demand for commodities results in strong prices which drive the development of Canada s natural resources, in particular the oil sands; the oil sands continue to be an economically viable source of energy and our customers and potential customers continue to invest in the oil sands and other natural resources developments; our customers and potential customers will continue to outsource the type of activities for which we are capable of providing service; and the Western Canadian economy continues to develop with additional investment in commercial and public construction; and are subject to the risks and uncertainties that:

- anticipated major projects in the oil sands may not materialize;
- demand for our services may be adversely impacted by regulations affecting the energy industry;
- failure by our customers to obtain required permits and licenses may affect the demand for our services;
- changes in our customers perception of oil prices over the long-term could cause our customers to defer, reduce or stop their investment in oil sands projects, which would, in turn, reduce our revenue from those customers;
- insufficient pipeline, upgrading and refining capacity or lack of sufficient governmental infrastructure to support growth in the oil sands region could cause our customers to delay, reduce or cancel plans to construct new oil sands projects or expand existing projects, which would, in turn, reduce our revenue from those customers;
- a change in strategy by our customers to reduce outsourcing could adversely affect our results;
- cost overruns by our customers on their projects may cause our customers to terminate future projects or expansions which could adversely affect the amount of work we receive from those customers;
- because most of our customers are Canadian energy companies, a downturn in the Canadian energy industry could result in a decrease in the demand for our services;
- shortages of qualified personnel or significant labour disputes could adversely affect our business; and
- unanticipated short term shutdowns of our customers operating facilities may result in temporary cessation or cancellation of projects in which we are participating.

The forward-looking information in paragraphs (c), (d), (e), (f), (g), (h), (i), (j), (k), (m), (n), (o), (p), (q), (r) and (s) rely on our ability to execute our growth strategy and are based on the assumptions that the management team can successfully manage the business; we can maintain and develop our relationships with our current customers; we will be successful in developing relationships with new customers; we will be successful in the competitive bidding process to secure new projects; that we will identify and implement improvements in our maintenance and fleet management practices; and are subject to the risks and uncertainties that:

our ability to grow our operations in the future may be hampered by our inability to obtain long lead time equipment and tires, which are currently in limited supply;

if we are unable to obtain surety bonds or letters of credit required by some of our customers, our business could be impaired;

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

- we are dependent on our ability to lease equipment, and a tightening of this form of credit could adversely affect our ability to bid for new work and/or supply some of our existing contracts;
- our business is highly competitive and competitors may outbid us on major projects that are awarded based on bid proposals;
- our customer base is concentrated, and the loss of or a significant reduction in business from a major customer could adversely impact our financial condition;
- lump-sum and unit-price contracts expose us to losses when our estimates of project costs are lower than actual costs;
- our operations are subject to weather-related factors that may cause delays in our project work;
- environmental laws and regulations may expose us to liability arising out of our operations or the operations of our customers; and
- many of our senior officers have either recently joined the company or have just been promoted and have only worked together as a management team for a short period of time.

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 Risk Factors 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 management s discussion and analysis.

Risks Factors

For first quarter of fiscal 2009 other than noted below, there has been no significant change in our risk factors from those described in Management s Discussion and Analysis referenced in Form 40-F for the fiscal year ended March 31, 2008. For a detailed discussion of these risk factors see Risk Factors in our Management Discussion and Analysis for the year ended March 31, 2008, available on SEDAR at www.sedar.com. As previously disclosed, the key financial reporting risks include:

Foreign currency risk

We are subject to currency exchange risk as our 83/4% 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

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

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 for the revolving credit facility, capital lease obligations and certain operating leases.

In conjunction with the cross-currency swap agreement we entered into a U.S. dollar interest rate swap and a Canadian dollar interest rate swap with the net effect of economically converting the 8.75% rate payable on the 83/4% senior notes into a fixed rate of 9.765% for the duration that the 83/4% senior notes were outstanding. On May 19, 2005 in connection with our Company s new revolving credit facility at that time, this fixed rate was increased to 9.889%. These derivative financial instruments were not designated as a hedge for accounting purposes.

At June 30, 2008 and March 31, 2008, the notional principal amounts of the interest rate swaps were US$200 million and Canadian $263 million.

As at June 30, 2008, holding all other variables constant, a 1% increase (decrease) to Canadian interest rates would impact the fair value of the interest rate swaps by $7,038 with this change in fair value being recorded in net income. As at June 30, 2008, holding all other variables constant, a 1% increase (decrease) to US interest rates would impact the fair value of the interest rate swaps by $3,292 with this change in fair value being recorded in net income. As at June 30, 2008, holding all other variables constant, a 1% increase (decrease) to Canadian to US interest rate volatility would impact the fair value of the interest rate swaps by $2,105 with this change in fair value being recorded in net income.

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.

Credit risk

Credit risk is the financial loss to us if a customer or counterparty to a financial instrument fails to meet its contractual obligations. We are exposed to credit risk through our cash and equivalents, accounts receivable and unbilled revenue. We managed the credit risk associated with our cash and cash equivalents by holding our funds with reputable financial institutions. Credit risk for trade and other accounts receivables and unbilled revenue are managed through established credit monitoring activities. We review our trade receivable accounts regularly for collectability and payment performance.

We have a concentration of customers in the oil and gas sector. The concentration risk is mitigated by the customers being large investment grade organizations. Losses under trade accounts receivable have historically been insignificant. Decisions to extend credit to new customers are approved by management.

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis (Continued)

H. General Matters

History and Development of the Company

NACG Holdings Inc. (Holdings) was formed in October 2003 in connection with the Acquisition discussed below. Prior to the Acquisition, NACG Holdings Inc. had no operations or significant assets and the Acquisition was primarily a change of ownership of the businesses acquired.

On October 31, 2003, two wholly owned subsidiaries of Holdings, as the buyers, entered into a purchase and sale agreement with Norama Ltd. and one of its subsidiaries, as the sellers. On November 26, 2003, pursuant to the purchase and sale agreement, Norama Ltd. sold to the buyers the businesses comprising North American Construction Group in exchange for total consideration of approximately $405.5 million, net of cash received and including the impact of certain post-closing adjustments (the Acquisition). The businesses we acquired from Norama Ltd. have been in operation since 1953. Subsequent to the Acquisition, we have operated the businesses in substantially the same manner as prior to the Acquisition.

On November 28, 2006, prior to the consummation of the initial public offering (IPO) discussed below, Holdings amalgamated with its wholly-owned subsidiaries, NACG Preferred Corp and North American Energy Partners Inc. The amalgamated entity continued under the name North American Energy Partners Inc. The voting common shares of the new entity, North American Energy Partners Inc., were the shares sold in the IPO and related secondary offering. On November 28, 2006, we completed the IPO in the United States and Canada of 8,750,000 voting common shares and a secondary offering of 3,750,000 voting common shares for $18.38 per share (U.S. $16.00 per share).

On November 22, 2006 our common shares commenced trading on the New York Stock Exchange and on the Toronto Stock Exchange on an if, as and when issued basis. On November 28, 2006, our common shares became fully tradable on the Toronto Stock Exchange.

Net proceeds from the IPO were $140.9 million (gross proceeds of $158.5 million, less underwriting discounts and costs and offering expenses of $17.6 million). On December 6, 2006, the underwriters exercised their option to purchase an additional 687,500 common shares from us. The net proceeds from the exercise of the underwriters option were $11.7 million (gross proceeds of $12.6 million, less underwriting fees of $0.9 million). Total net proceeds were $152.6 million (total gross proceeds of $171.1 million less total underwriting discounts and costs and offering expenses of $18.5 million).

As of June 30, 2008, our authorized capital consists of an unlimited number of voting and non-voting common shares, of which 36,036,476 voting common shares were issued and outstanding (35,929,476 as at March 31, 2008).

Our head office is located at Zone 3, Acheson Industrial Area, 2 53016 Hwy 60, Acheson, Alberta, T7X 5A7. Our telephone and facsimile numbers are (780) 960-7171 and (780) 960-7103, respectively.

Additional Information

Additional information relating to us, including our Annual Information Form dated June 20, 2008, 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.

FORM 52-109F2

CERTIFICATION OF INTERIM FILINGS

I, Rodney J. Ruston, the President and Chief Executive Officer of North American Energy Partners Inc., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers Annual and Interim Filings*) of North American Energy Partners Inc. (the issuer) for the interim period ending June 30, 2008;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings;

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings;

4. The issuer s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

   (a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the interim filings are being prepared; and

   (b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer s GAAP; and

5. I have caused the issuer to disclose in the interim MD&A any change in the issuer s internal control over financial reporting that occurred during the issuer s most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer s internal control over financial reporting.

Date: August 13, 2008

/s/ Rodney J. Ruston
Name: Rodney J. Ruston
Title: President and Chief Executive Officer

FORM 52-109F2

CERTIFICATION OF INTERIM FILINGS

I, Peter R. Dodd, the Chief Financial Officer of North American Energy Partners Inc., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers Annual and Interim Filings*) of North American Energy Partners Inc. (the issuer) for the interim period ending June 30, 2008;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings;

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings;

4. The issuer s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

   (a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the interim filings are being prepared; and

   (b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer s GAAP; and

5. I have caused the issuer to disclose in the interim MD&A any change in the issuer s internal control over financial reporting that occurred during the issuer s most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer s internal control over financial reporting.

Date: August 13, 2008

/s/ Peter R. Dodd
Name: Peter R. Dodd
Title: Chief Financial Officer