



**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 2006

Commission File Number 333-111396

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 Form 40-F

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

Indicate by check mark 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 No

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

Included herein:

1. Interim consolidated financial statements of North American Energy Partners Inc. for the three months ended June 30, 2006.
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/ Chris Hayman

Name: Chris Hayman

Title: Vice President, Finance

Date: August 29, 2006



NORTH AMERICAN ENERGY PARTNERS INC.

Interim Consolidated Financial Statements

For the three months ended June 30, 2006
(Expressed in thousands of Canadian dollars)
(Unaudited)



NORTH AMERICAN ENERGY PARTNERS INC.

Interim Consolidated Balance Sheets
(in thousands of Canadian dollars)

	<u>June 30, 2006</u> (unaudited)	<u>March 31, 2006</u>
Assets		
Current assets:		
Cash and cash equivalents	\$ 44,993	\$ 42,704
Accounts receivable	76,302	67,235
Unbilled revenue	38,119	43,494
Inventory	13	57
Prepaid expenses	3,798	1,796
Future income taxes	10,291	5,583
	<u>173,516</u>	<u>160,869</u>
Future income taxes	16,790	23,367
Plant and equipment (note 4)	191,269	185,566
Goodwill	198,549	198,549
Intangible assets, net of accumulated amortization of \$17,209 (March 31, 2006 - \$17,026)	589	772
Deferred financing costs, net of accumulated amortization of \$6,891 (March 31, 2006 - \$6,004)	17,001	17,788
	<u>\$ 597,714</u>	<u>\$ 586,911</u>
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable	\$ 53,503	\$ 54,088
Accrued liabilities	20,463	24,603
Billings in excess of costs on uncompleted contracts	6,616	5,124
Current portion of capital lease obligations	3,433	3,046
Advances from parent company	464	482
Future income taxes	4,882	5,583
	<u>89,361</u>	<u>92,926</u>
Capital lease obligations	8,504	7,906
Senior notes	290,436	304,007
Derivative financial instruments	71,030	63,611
Redeemable preferred shares	43,513	42,568
Future income taxes	23,435	23,367
	<u>526,279</u>	<u>534,385</u>
Shareholder's equity:		
Common shares	127,500	127,500
Contributed surplus (note 9)	1,869	1,557
Deficit	(57,934)	(76,531)
	<u>71,435</u>	<u>52,526</u>
United States generally accepted accounting principles (note 11)		
Subsequent events (note 12)		
	<u>\$ 597,714</u>	<u>\$ 586,911</u>

See accompanying notes to unaudited interim consolidated financial statements.



NORTH AMERICAN ENERGY PARTNERS INC.
Interim Consolidated Statements of Operations and Deficit
(in thousands of Canadian dollars)
(unaudited)

	For the three months ended	
	June 30, 2006	June 30, 2005
Revenue	\$ 138,100	\$ 104,359
Project costs	67,009	66,546
Equipment costs	23,935	17,014
Operating lease expense	7,200	2,898
Depreciation	7,312	4,989
	<u>105,456</u>	<u>91,447</u>
Gross profit	32,644	12,912
General and administrative	9,232	7,248
Loss on disposal of plant and equipment	113	272
Amortization of intangible assets	183	183
Operating income	<u>23,116</u>	<u>5,209</u>
Interest expense (note 6)	9,468	49,863
Foreign exchange (gain) loss	(13,466)	1,221
Realized and unrealized loss on derivative financial instruments	7,996	1,282
Financing costs	—	2,095
Other income	(583)	(200)
	<u>3,415</u>	<u>54,261</u>
Income (loss) before income taxes	19,701	(49,052)
Income taxes (note 5):		
Current income taxes	(132)	150
Future income taxes	1,236	—
	<u>1,104</u>	<u>150</u>
Net income (loss) for the period	18,597	(49,202)
Deficit, beginning of period	<u>(76,531)</u>	<u>(54,595)</u>
Deficit, end of period	<u>\$ (57,934)</u>	<u>\$ (103,797)</u>

See accompanying notes to unaudited interim consolidated financial statements.



NORTH AMERICAN ENERGY PARTNERS INC.

Consolidated Statements of Cash Flows
(in thousands of Canadian dollars)
(unaudited)

	<u>For the three months ended</u>	
	<u>June 30,</u> <u>2006</u>	<u>June 30,</u> <u>2005</u>
Cash provided by (used in):		
Operating activities:		
Net income (loss) for the period	\$ 18,597	\$ (49,202)
Items not affecting cash:		
Depreciation	7,312	4,989
Amortization of intangible assets	183	183
Amortization of deferred financing costs	887	672
Loss on disposal of plant and equipment	113	272
Unrealized foreign exchange (gain) loss on senior notes	(13,571)	928
Unrealized loss on derivative financial instruments	7,419	587
Stock-based compensation expense (note 9)	312	188
Accretion and change in redemption value of redeemable preferred shares	945	41,507
Future income taxes	1,236	—
Decrease in allowance for doubtful accounts	—	(67)
Financing costs	—	2,095
Net changes in non-cash working capital (note 7(b))	(8,679)	(18,280)
	<u>14,754</u>	<u>(16,128)</u>
Investing activities:		
Purchase of plant and equipment	(11,843)	(5,693)
Proceeds on disposal of plant and equipment	473	388
Net changes in non-cash working capital (note 7(b))	(204)	2,350
	<u>(11,574)</u>	<u>(2,955)</u>
Financing activities:		
Repayment of capital lease obligations	(773)	(434)
Financing costs	(100)	(7,381)
Advances to parent company	(18)	—
Issuance of 9% senior secured notes	—	76,345
Repayment of senior secured credit facility	—	(61,257)
Issuance of Series B preferred shares	—	7,500
	<u>(891)</u>	<u>14,773</u>
Increase (decrease) in cash and cash equivalents	2,289	(4,310)
Cash and cash equivalents, beginning of period	42,704	17,922
Cash and cash equivalents, end of period	<u>\$ 44,993</u>	<u>\$ 13,612</u>

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, 2006

(Amounts in thousands of Canadian dollars unless otherwise specified)

(Unaudited)

1. Nature of operations

North American Energy Partners Inc. (the "Company") was incorporated under the Canada Business Corporations Act on October 17, 2003. The Company had no operations prior to November 26, 2003. The Company completes all forms of civil projects including contract mining, industrial and commercial site development, pipeline and piling installations. The Company is a wholly-owned subsidiary of NACG Preferred Corp. which in turn is a wholly-owned subsidiary of NACG Holdings Inc.

2. Basis of presentation

These unaudited interim consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") 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 unaudited interim consolidated financial statements requires the use of estimates and assumptions. In the opinion of management, these unaudited interim consolidated financial statements have been prepared within reasonable limits of materiality. Except as noted below, these unaudited interim consolidated 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, 2006 and should be read in conjunction with those financial statements. Material items that give rise to measurement differences to the consolidated financial statements under United States GAAP are outlined in note 11.

These interim consolidated financial statements include the accounts of the Company, its wholly-owned subsidiaries, NACG Finance LLC and North American Construction Group Inc. ("NACGI"), the Company's joint venture, Noramac Ventures Inc. and the following subsidiaries of NACGI:

	<u>% owned</u>
• North American Caisson Ltd.	100%
• North American Construction Ltd.	100%
• North American Engineering Ltd.	100%
• North American Enterprises Ltd.	100%
• North American Industries Inc.	100%
• North American Mining Inc.	100%
• North American Maintenance Ltd.	100%
• North American Pipeline Inc.	100%
• North American Road Inc.	100%
• North American Services Inc.	100%
• North American Site Development Ltd.	100%
• North American Site Services Inc.	100%
• Griffiths Pile Driving Inc.	100%



NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three months ended June 30, 2006

(Amounts in thousands of Canadian dollars unless otherwise specified)
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3. Recent Canadian accounting pronouncements not yet adopted

a) Financial instruments:

In January 2005, the Canadian Institute of Chartered Accountants (“CICA”) issued Handbook Section 3855, “Financial Instruments – Recognition and Measurement”, Handbook Section 1530, “Comprehensive Income”, and Handbook Section 3865, “Hedges”. The new standards are effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006, specifically April 1, 2007 for the Company. Earlier adoption is permitted. The new standards will require presentation of a separate statement of comprehensive income under specific circumstances. Foreign exchange gains and losses on the translation of the financial statements of self-sustaining subsidiaries previously recorded in a separate section of shareholder’s equity will be presented in comprehensive income. Derivative financial instruments will be recorded in the balance sheet at fair value and the changes in fair value of derivatives designated as cash flow hedges will be reported in comprehensive income. The Company is currently assessing the impact of the new standards.

4. Plant and equipment

<u>June 30, 2006</u>	<u>Cost</u>	<u>Accumulated depreciation</u>	<u>Net book value</u>
Heavy equipment	\$178,517	\$ 34,885	\$ 143,632
Major component parts in use	6,129	2,363	3,766
Spare component parts	3,678	—	3,678
Other equipment	13,480	4,568	8,912
Licensed motor vehicles	20,156	9,195	10,961
Office and computer equipment	3,459	1,675	1,784
Buildings	15,927	65	15,862
Leasehold improvements	2,972	339	2,633
Assets under construction	41	—	41
	<u>\$244,359</u>	<u>\$ 53,090</u>	<u>\$ 191,269</u>

<u>March 31, 2006</u>	<u>Cost</u>	<u>Accumulated depreciation</u>	<u>Net book value</u>
Heavy equipment	\$174,042	\$ 31,347	\$ 142,695
Major component parts in use	4,922	2,091	2,831
Spare component parts	1,170	—	1,170
Other equipment	13,074	4,186	8,888
Licensed motor vehicles	18,223	8,410	9,813
Office and computer equipment	3,362	1,493	1,869
Leasehold improvements	2,959	247	2,712
Assets under construction	15,588	—	15,588
	<u>\$233,340</u>	<u>\$ 47,774</u>	<u>\$ 185,566</u>

Buildings are amortized over their estimated useful life on a straight-line basis over 10 years.



NORTH AMERICAN ENERGY PARTNERS INC.

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The above amounts include \$16,317 (March 31, 2006 – \$14,559) of assets under capital lease and accumulated depreciation of \$5,109 (March 31, 2006 – \$4,479) related thereto. During the three months ended June 30, 2006, additions of plant and equipment included \$1,758 of assets that were acquired by means of capital leases (three months ended June 30, 2005 – \$981). Depreciation of equipment under capital leases of \$630 (three months ended June 30, 2005 – \$540) is included in depreciation expense.

5. Income taxes

Due to the elimination of the Canadian Federal Large Corporations Tax, the Company has recorded a current income tax recovery of \$132 to reverse amounts expensed during the fourth quarter of fiscal 2006.

Future income tax expense for the three months ended June 30, 2006 includes a recovery of \$5,858 resulting from the elimination of the valuation allowance. Management considers the scheduled reversals of future income tax liabilities, the character of income tax assets and available tax planning strategies of the Company and its subsidiaries when evaluating the expected realization of future income tax assets. Based on management’s estimate of the expected realization of future income tax assets during the current period, the Company eliminated the valuation allowance recorded against future income tax assets to reflect that it is more likely than not that the future income tax assets will be realized.

6. Interest expense

	Three months ended June 30	
	2006	2005
Interest on senior notes	\$ 7,346	\$ 6,535
Interest on senior secured credit facility	—	564
Interest on capital lease obligations	154	89
Accretion and change in redemption value of Series B preferred shares	928	41,498
Accretion of Series A preferred shares	16	9
Interest on long-term debt	8,444	48,695
Amortization of deferred financing costs	887	672
Other interest	137	496
	<u>\$ 9,468</u>	<u>\$ 49,863</u>



NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three months ended June 30, 2006

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7. Other information

a) Supplemental cash flow information:

	<u>Three months ended June 30</u>	
	<u>2006</u>	<u>2005</u>
Cash paid during the period for:		
Interest	\$ 15,844	\$ 14,671
Income taxes	190	163
Cash received during the period for:		
Interest	486	108
Non-cash transactions:		
Capital leases	1,758	981
Issuance of Series A preferred shares	—	321

b) Net change in non-cash working capital:

	<u>Three months ended June 30</u>	
	<u>2006</u>	<u>2005</u>
Operating activities:		
Accounts receivable	\$ (9,067)	\$ 3,463
Unbilled revenue	5,375	(6,740)
Inventory	44	26
Prepaid expenses	(2,002)	(957)
Accounts payable	(511)	(5,031)
Accrued liabilities	(4,010)	(8,194)
Billings in excess of costs and estimated earnings	1,492	(847)
	<u>\$ (8,679)</u>	<u>\$ (18,280)</u>
Investing activities:		
Accounts payable	\$ (74)	\$ 1,398
Accrued liabilities	(130)	952
	<u>\$ (204)</u>	<u>\$ 2,350</u>



NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three months ended June 30, 2006

(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

8. Segmented information

a) General overview:

The Company conducts business in three business segments: Mining and Site Preparation, Piling and Pipeline.

- *Mining and Site Preparation:*

The Mining and Site Preparation 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 Western 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.

b) Results by business segment:

<u>Three months ended June 30, 2006</u>	<u>Mining and Site Preparation</u>	<u>Piling</u>	<u>Pipeline</u>	<u>Total</u>
Revenues from external customers	\$ 111,387	\$23,276	\$ 3,437	\$138,100
Depreciation of plant and equipment	4,947	648	132	5,727
Segment profits	24,127	7,976	659	32,762
Segment assets	338,280	82,632	40,541	461,453
Expenditures for segment plant and equipment	6,984	1,330	—	8,314

<u>Three months ended June 30, 2005</u>	<u>Mining and Site Preparation</u>	<u>Piling</u>	<u>Pipeline</u>	<u>Total</u>
Revenues from external customers	\$ 82,637	\$20,030	\$ 1,692	\$104,359
Depreciation of plant and equipment	2,347	432	87	2,866
Segment profits	11,689	2,838	309	14,836
Segment assets	321,492	83,293	39,606	444,391
Expenditures for segment plant and equipment	3,115	192	—	3,307



NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three months ended June 30, 2006

(Amounts in thousands of Canadian dollars unless otherwise specified)
(unaudited)

c) Reconciliations

i. Income (loss) before income taxes:

	<u>Three months ended June 30</u>	
	<u>2006</u>	<u>2005</u>
Total profit for reportable segments	\$ 32,762	\$ 14,836
Unallocated corporate expenses	(12,830)	(61,624)
Unallocated equipment costs	(231)	(2,264)
Income (loss) before income taxes	<u>\$ 19,701</u>	<u>\$ (49,052)</u>

ii. Total assets:

	<u>June 30, 2006</u>	<u>March 31, 2006</u>
Total assets for reportable segments	\$461,453	\$460,771
Corporate assets	136,261	126,140
Total assets	<u>\$597,714</u>	<u>\$586,911</u>

The Company's goodwill was assigned to the Mining and Site Preparation, Piling and Pipeline segments in the amounts of \$125,447, \$40,349, and \$32,753, respectively.

Substantially all of the Company's assets are located in Western Canada and the activities are carried out throughout the year.

d) Customers:

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

	<u>Three months ended June 30</u>	
	<u>2006</u>	<u>2005</u>
Customer A	20%	1%
Customer B	15%	34%
Customer C	11%	15%
Customer D	8%	14%

This revenue by major customer was earned in the Mining and Site Preparation and Piling segments.

9. Stock-based compensation plan

Under the 2004 Share Option Plan, Directors, Officers, employees and service providers to the Company are eligible to receive stock options to acquire common shares in NACG Holdings Inc. The stock options expire 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 per cent vest on each of the five following award date anniversaries. The maximum number of common shares issuable under this plan may not exceed 105,000, of which 1,458 are still available for issue as at June 30, 2006.



NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three months ended June 30, 2006

(Amounts in thousands of Canadian dollars unless otherwise specified)

(unaudited)

	Three months ended June 30			
	2006		2005	
	Number of options	Weighted average exercise price (\$ per share)	Number of options	Weighted average exercise price (\$ per share)
Outstanding, beginning of period	103,318	\$ 100.00	76,242	\$ 100.00
Granted	6,388	100.00	—	—
Exercised	—	—	—	—
Forfeited	(6,164)	100.00	(2,000)	100.00
Outstanding, end of period	<u>103,542</u>	<u>\$ 100.00</u>	<u>74,242</u>	<u>\$ 100.00</u>

At June 30, 2006, the weighted average remaining contractual life of outstanding options is 8.2 years (March 31, 2006 – 8.2 years). The Company recorded \$312 of compensation expense related to the stock options in the three months ended June 30, 2006 (three months ended June 30, 2005 – \$188) with such amount being credited to contributed surplus.

The fair value of each option granted by NACG Holdings Inc. was estimated on the grant date using the Black-Scholes option-pricing model with the following assumptions:

	Three months ended June 30	
	2006	2005
Number of options granted	6,388	20,000
Weighted average fair value per option granted (\$)	61.51	80.86
Weighted average assumptions		
Dividend yield	nil%	nil%
Expected volatility	nil%	nil%
Risk-free interest rate	4.63%	4.18%
Expected life (years)	10	10

The Company has offered to accelerate the vesting of 11,104 options held by certain members of its Board of Directors, providing for the options to become immediately exercisable on the condition that such options be exercised by September 30, 2006. The vesting period for stock options held by any Director that does not accept the Company’s offer will remain unchanged. The accounting impact of the short term inducement (including the impact on the vesting period) will be recorded when the directors exercise their options.

10. 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 Mining and Site Preparation and Pipeline segments declines when frost leaves the ground and many secondary roads are temporarily rendered incapable of supporting the weight of heavy equipment. The duration of this period is referred to as “spring breakup” and has a direct impact on the Company’s activity levels. Revenues during the fourth quarter of each fiscal year are typically highest as ground conditions are most favorable in the Company’s operating regions. As a result, full-year results are not likely to be a direct multiple of any particular quarter or combination of quarters.



NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

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(Amounts in thousands of Canadian dollars unless otherwise specified)

(unaudited)

11. United States generally accepted accounting principles (“U.S. GAAP”)

These consolidated financial statements have been prepared in accordance with Canadian GAAP, which differs in certain respects from U.S. GAAP. If U.S. GAAP were employed, the Company’s net income (loss) would be adjusted as follows:

	<u>Three months ended June 30</u>	
	<u>2006</u>	<u>2005</u>
Net income (loss) - Canadian GAAP	\$ 18,597	\$ (49,202)
Capitalized interest (a)	249	107
Depreciation of capitalized interest (a)	(44)	—
Amortization using effective interest method (b)	135	43
Realized and unrealized loss on derivative financial instruments (e)	(159)	—
Accretion of Series B preferred shares (f)	928	—
Income (loss) before income taxes	19,706	(49,052)
Income taxes:		
Deferred income taxes	(381)	—
Net income (loss) – U.S. GAAP	<u>\$ 19,325</u>	<u>\$ (49,052)</u>

The cumulative effect of these adjustments on the consolidated shareholder’s equity of the Company is as follows:

	<u>June 30,</u> <u>2006</u>	<u>March 31,</u> <u>2006</u>
Shareholder’s equity – Canadian GAAP	\$71,435	\$52,526
Capitalized interest (a)	1,096	847
Depreciation of capitalized interest (a)	(44)	—
Amortization using effective interest method (b)	725	590
Realized and unrealized loss on derivative financial instruments (e)	(643)	(484)
Excess of fair value of amended Series B preferred shares over carrying value of original Series B preferred shares (f)	(3,707)	(3,707)
Cumulative difference between accretion of Series B preferred shares under Canadian GAAP and U.S. GAAP (f)	90	—
Deferred income taxes	(381)	—
Shareholders’ equity – U.S. GAAP	<u>\$68,571</u>	<u>\$49,772</u>

The areas of material difference between Canadian and U.S. GAAP and their impact on the Company’s consolidated financial statements are described below:

a) Capitalization of interest:

U.S. GAAP requires capitalization of interest costs as part of the historical cost of acquiring certain qualifying assets that require a period of time to prepare for their intended use. This is not required under Canadian GAAP. Accordingly, the capitalized amount is subject to depreciation in accordance with Company’s policies.



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b) *Deferred charges:*

Under Canadian GAAP, the Company defers and amortizes debt issuance costs on a straight-line basis over the stated term of the related debt. Under U.S. GAAP, the Company is required to amortize financing costs over the stated term of the related debt using the effective interest method resulting in a consistent interest rate over the term of the debt in accordance with Accounting Principles Board Opinion No. 21 ("APB 21").

c) *Reporting comprehensive income:*

Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income" ("SFAS 130") establishes standards for the reporting and display of comprehensive income and its components in a full set of general purpose financial statements. Comprehensive income equals net income (loss) for the period as adjusted for all other non-owner changes in shareholders' equity. SFAS 130 requires that all items that are not required to be recognized under accounting standards as components of comprehensive income be reported in a financial statement. The only component of comprehensive income (loss) is the net income (loss) for the period.

d) *Stock-based compensation:*

Up until April 1, 2006, the Company followed the provisions of Statement of Financial Accounting Standards No. 123, "Stock-Based Compensation" for U.S. GAAP purposes. As the Company uses the fair value method of accounting for all stock-based compensation payments under Canadian GAAP there were no differences between Canadian and U.S. GAAP prior to April 1, 2006. On April 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R), "Share-Based Payment" ("SFAS 123R"). As the Company used the minimum value method for purposes of complying with Statement of Financial Accounting Standards No. 123, it was required to adopt SFAS 123(R) prospectively.

The methodology for determining the expense to be recognized in each period that is prescribed by SFAS 123(R) differs from that prescribed by Canadian GAAP. Canadian GAAP permits accounting for forfeitures of share-based payments as they occur while U.S. standards require an estimate of forfeitures to be made at the date of grant and thereafter until the requisite service period has been completed or the awards are cancelled. The required adjustment under U.S. GAAP to account for estimated forfeitures was not significant for all periods presented.

During the three months ended June 30, 2006, the Company granted 6,388 stock options to an employee and director. In determining the grant-date fair value of these stock options, the Company included an expected volatility of 40%. The additional compensation cost for these stock options under U.S. GAAP was not significant.

e) *Derivative financial instruments:*

Statement of Financial Accounting Standard No. 133, Accounting for Derivative Instruments and Hedging Activities ("SFAS 133") establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts and debt instruments) be recorded in the balance sheet as either an asset or liability measured at its fair value. On November 26, 2003, the Company issued 8^{3/4}% senior notes for US\$200 million (Canadian \$263 million) and on May 19, 2005 the Company issued 9% senior secured notes for US\$60.4 million (Canadian \$76.3 million). Both of these issuances included certain contingent embedded derivatives which provided for the acceleration of redemption by the holder at a premium in certain instances. These embedded derivatives met the criteria for bifurcation from the debt contract and separate



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measurement at fair value. The embedded derivatives have been measured at fair value and classified as part of the carrying amount of the Senior Notes on the consolidated balance sheet, with changes in the fair value being recorded in net income (loss) as realized and unrealized (gain) loss on derivative financial instruments for the period under U.S. GAAP. Under Canadian GAAP, separate accounting of embedded derivatives from the host contract is not permitted by CICA Emerging Issues Committee Abstract No. 117.

f) Series B preferred shares:

Under Canadian GAAP, the Company classifies the Series B preferred shares as a liability and accretes the carrying amount of \$42.2 million on their amendment date (March 30, 2006) to the December 31, 2011 redemption value of \$69.6 million using the effective interest method. Under U.S. GAAP, the Company recognized the fair value of the amended Series B preferred shares as temporary equity in accordance with Emerging Issues Task Force Topic D-98 ("EITF D-98"). Under U.S. GAAP, the Company accretes the initial fair value of the amended Series B preferred shares of \$45.9 million recorded on their amendment date (March 30, 2006) to the December 31, 2011 redemption value of \$69.6 million using the effective interest method, however, the accretion charge is recognized as a charge to retained earnings rather than as interest expense.

g) United States accounting pronouncements recently adopted:

The impact of the adoption of SFAS 123(R) is described in Note 11(d).

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections" ("SFAS 154") which replaces Accounting Principles Board Opinion No. 20 "Accounting Changes" and Statement of Financial Accounting Standards No. 3, "Reporting Accounting Changes in Interim Financial Statements – An Amendment of APB Opinion No. 28." SFAS 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. SFAS 154 is effective for the Company for accounting changes and corrections of errors made by the Company in its fiscal year beginning on April 1, 2006. The adoption of this standard did not have a material impact on the Company's consolidated financial statements.



NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three months ended June 30, 2006

(Amounts in thousands of Canadian dollars unless otherwise specified)

(unaudited)

h) Recent United States accounting pronouncements not yet adopted:

Statement of Financial Accounting Standards No. 155, "Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140" ("SFAS 155") was issued February 2006. This Statement is effective for all financial instruments acquired, issued, or subject to a remeasurement (new basis) event occurring after the beginning of an entity's first fiscal year that begins after September 15, 2006. The fair value election provided for in paragraph 4(c) of this Statement may also be applied upon adoption of this Statement for hybrid financial instruments that had been bifurcated under paragraph 12 of Statement 133 prior to the adoption of this Statement. This states that an entity that initially recognizes a host contract and a derivative instrument may irrevocably elect to initially and subsequently measure that hybrid financial instrument, in its entirety, at fair value with changes in fair value recognized in earnings. SFAS 155 is applicable for all financial instruments acquired or issued in the Company's 2008 fiscal year although early adoption is permitted. The Company is currently reviewing the impact of this statement.

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109" ("FIN 48") which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes". FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition requirements. The Company is currently reviewing the impact of this Interpretation. FIN 48 is effective for the Company's fiscal year beginning April 1, 2007.

12. Subsequent events

- a) On July 19, 2006, the Company amended and restated its existing credit agreement to provide for borrowings of up to \$55.0 million, subject to borrowing base limitations, under which revolving loans and letters of credit may be issued. Prime rate revolving loans under the amended and restated agreement will bear interest at the Canadian prime rate plus 2.0% per annum and swing line revolving loans will bear interest at the Canadian prime rate plus 1.5% per annum. Canadian bankers' acceptances have stamping fees equal to 3.0% per annum and letters of credit are subject to a fee of 3.0% per annum.

Advances under the amended and restated agreement are margined with a borrowing base calculation defined as the aggregate of 60.0% of the net book value of the Company's plant and equipment, 75.0% of eligible accounts receivable and un-pledged cash in excess of \$15.0 million. The sum of all borrowings (including issued letters of credit) and the mark-to-market value of the Company's liability under existing swap agreements must not exceed the borrowing base. The amended and restated credit facility is secured by a first priority lien on substantially all of the Company's existing and after-acquired property.

The facility contains certain restrictive covenants including, but not limited to, incurring additional debt, transferring or selling assets, making investments (including acquisitions), paying dividends or redeeming shares of capital stock. The Company is also required to meet certain financial covenants.



NORTH AMERICAN ENERGY PARTNERS INC.

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For the three months ended June 30, 2006

(Amounts in thousands of Canadian dollars unless otherwise specified)

(unaudited)

During the three months ended June 30, 2006, financing fees of \$100 were incurred in connection with the amended and restated credit agreement and were recorded as deferred financing costs.

- b) On July 21, 2006, NACG Holdings Inc. filed an initial registration statement with the U.S. Securities and Exchange Commission and a preliminary prospectus with securities commissions in every jurisdiction in Canada relating to the initial public offering of voting common shares.

Prior to, or concurrent with, the consummation of the proposed offering, NACG Holdings Inc., NACG Preferred Corp. and the Company are planning to amalgamate into one new entity, North American Energy Partners Inc. In addition, NACG Holdings Inc. is planning a share split prior to the proposed offering being completed. The voting common shares of the new entity, North American Energy Partners Inc., will be the shares offered in the proposed offering.

Prior to the amalgamation referred to above, it is the Company's intention to repurchase the Series A preferred shares for their redemption value of \$1.0 million and to cancel the consulting and advisory services agreement with the Sponsors, under which the Company has received ongoing consulting and advisory services with respect to the organization of the companies, employee benefit and compensation arrangements, and other matters. The consideration to be paid for the cancellation of the consulting and advisory services agreement is still to be negotiated between the parties. In addition, it is planned that each holder of the Company's Series B preferred shares will, for each Series B preferred share held, receive five common shares (the number of common shares will be adjusted for the planned share split) in the amalgamated North American Energy Partners Inc. As part of the amalgamation, existing common and non-voting common shareholders of NACG Holdings Inc. will receive common and non-voting common shares of the amalgamated North American Energy Partners Inc.

The anticipated net proceeds from the offering, after deducting underwriting fees and estimated offering expenses, are being proposed to be used to purchase certain equipment currently under operating leases and tender for all or a portion of the outstanding principal of and accrued interest on the Company's 9% senior secured notes due 2010. The balance of the anticipated net proceeds would be available for general corporate purposes including working capital, capital expenditures and potential acquisitions.

The completion of the proposed offering, including the planned reorganization described above, is subject to a number of approvals by the shareholders of the Company, NACG Preferred Corp. (including preferred shareholders of NACG Preferred Corp.) and NACG Holdings Inc. and the acceptance of the registration statement and prospectus by securities regulatory authorities in the United States and Canada.

- c) Subsequent to June 30, 2006, the Company was informed by the Canadian Revenue Agency and taxation officials from Alberta, Ontario and Quebec that certain financing arrangements and tax structures, which a wholly-owned subsidiary had taken part in, are being reviewed and challenged. If the tax authorities are successful in their challenge, the potential future tax liability is estimated to be \$1 million, including estimated interest and penalties. The Company is satisfied that its tax structure met the technical requirements of the tax laws and regulations and the related tax benefit was properly recognized; accordingly, no liability has been accrued as at June 30, 2006. The Company is currently assessing its response to this challenge.



NORTH AMERICAN ENERGY PARTNERS INC.

**Management's Discussion and Analysis
For the three months ended June 30, 2006**

Management's Discussion and Analysis

For the Three Months Ended June 30, 2006

The following discussion should be read in conjunction with the attached unaudited interim consolidated financial statements for the three months ended June 30, 2006 and audited consolidated financial statements for the year ended March 31, 2006. This document contains forward-looking statements. The Company's forward-looking statements involve known and unknown risks, uncertainties 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 statements. Forward-looking statements are those that do not relate strictly to historical or current facts, and can be identified by the use of the future tense or other forward-looking words such as "believe," "expect," "anticipate," "intend," "plan," "estimate," "should," "may," "objective," "projection," "forecast," "believes," "continue," "strategy," "position," or the negative of those terms or other variations of them or comparable terminology. Forward-looking statements included in this document include statements regarding: financial resources; capital spending; the outlook for our business; and our results generally. Factors that could cause actual results to vary from those in the forward-looking statements include: the effectiveness of our internal controls; our ability to comply with the terms of our credit agreement or our indentures, or in the event of our breach of such terms, our ability to receive waivers or amendments from the lenders under our credit agreement or the trustee under our indentures; potential alternative financing arrangements; our ability to continue to bid successfully on new projects and accurately forecast costs associated with unit-price or lump sum contracts; our ability to obtain surety bonds as required by some of our customers; decreases in outsourcing work by our customers; changes in oil and gas prices; shut-downs or cutbacks at major businesses that use our services; changes in laws or regulations, third party relations and approvals, and decisions of courts, regulators and governmental bodies that may adversely affect our business or the business of the customers we serve; our ability to purchase or lease equipment; our ability to hire and retain a skilled labor force; provincial, regional and local economic, competitive and regulatory conditions and developments; technological developments; capital markets conditions; inflation rates; foreign currency exchange rate fluctuations; interest rates; weather conditions; the timing and success of business development efforts; and our ability to successfully identify and acquire new businesses and assets and integrate them into our existing operations and the other risk factors set forth herein under "Risk Factors." You are cautioned not to put undue reliance on any forward-looking statements, and we undertake no obligation to update those statements.

Prospectus Filing

On July 21, 2006, our ultimate parent, NACG Holdings Inc. filed an initial registration statement with the U.S. Securities and Exchange Commission and a preliminary prospectus with securities commissions in every jurisdiction in Canada relating to the initial public offering of voting common shares.

Prior to, or concurrent with, the consummation of the proposed offering, NACG Holdings Inc., NACG Preferred Corp. and the Company are planning to amalgamate into one new entity, North American Energy Partners Inc. In addition, NACG Holdings Inc. is planning a share split prior to the proposed offering being completed. The voting common shares of the new entity, North American Energy Partners Inc., will be the shares offered in the proposed offering.

Prior to the amalgamation referred to above, it is the Company's intention to repurchase the Series A preferred shares for their redemption value of \$1.0 million and to cancel the consulting and advisory services agreement with the Sponsors, under which the Company has received ongoing consulting and advisory services with respect to the organization of the companies, employee benefit and compensation arrangements, and other matters. The consideration to be paid for the cancellation of the consulting and advisory services agreement is still to be negotiated between the parties. In addition, it is planned that each holder of the Company's Series B preferred shares will receive, for each Series B preferred share held, five common shares (the number of common shares will be adjusted for the planned share split) in the amalgamated North American Energy Partners Inc. As part of the amalgamation, existing common and non-voting common shareholders of NACG Holdings Inc. will receive common and non-voting common shares, respectively, of the amalgamated North American Energy Partners Inc.

The anticipated net proceeds from the offering, after deducting underwriting fees and estimated offering expenses, are proposed to be used to purchase certain equipment currently under operating leases and to tender for all or a portion of the outstanding principal of and accrued interest on the Company's 9% senior secured notes due 2010 (the redemption is subject to certain redemption provisions). The balance of the anticipated net proceeds would be available for general corporate purposes including working capital, capital expenditures and potential acquisitions.

The completion of the proposed offering, including the planned reorganization described above, is subject to a number of approvals by the shareholders (including the preferred shareholders of NACG Preferred Corp. and the Company) and the effectiveness of the registration statement in the United States and the acceptance of the prospectus by securities regulatory authorities in Canada.



NORTH AMERICAN ENERGY PARTNERS INC.
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Overview

We provide services primarily to major oil and natural gas, and other natural resource companies operating in western Canada. These services are offered through three operating segments: Mining and Site Preparation, Piling and Pipeline.

The Mining and Site Preparation operating segment, accounting for 80.7% of revenues for the three months ended June 30, 2006, is involved in a variety of activities, including: surface mining for oil sands and other natural resources, including overburden removal, hauling sand and gravel and supplying labor and equipment to support customers' mining operations; construction of infrastructure associated with mining operations and reclamation activities; clearing, stripping, excavating and grading for mining operations and industrial site construction mega-projects; and underground utility installation for plant, refinery and commercial building construction.

The Piling operating segment, accounting for 16.9% of revenues for the three months ended June 30, 2006, installs all types of driven and drilled piles, caissons and earth retention and stabilization systems for industrial projects primarily focused in the oil sands and related petrochemical or refinery complexes, as well as commercial buildings and infrastructure projects.

The Pipeline operating segment, accounting for 2.4% of revenues for the three months ended June 30, 2006, installs transmission and distribution pipe made of various materials for oil, natural gas and water.

Description of Components of Statement of Operations

Revenue

Revenue includes all amounts earned from the performance of our projects, including amounts arising from change orders and claims. For a description of our revenue recognition policy, refer to note 2(c) to our consolidated financial statements for the year ended March 31, 2006.

Project costs

Included in project costs are all direct expenses incurred in the execution of our projects, including direct labor, short-term equipment rentals, materials and subcontractors expenses.

Equipment costs

Included in equipment costs are parts, shop labor and overhead related to the maintenance of our equipment fleet. Equipment insurance premiums and demobilization costs are also included in equipment costs.

Operating lease expense

Lease payments on plant and equipment, other than payments on capital leases, are recorded as operating lease expense.

Depreciation

Depreciation includes amortization of our plant and equipment. For a description of our depreciation policy, please see note 2(g) to our consolidated financial statements for the year ended March 31, 2006.

General and administrative

General and administrative expenses include administrative and other expenses that are not directly attributable to the execution of our contracts. These would include, but are not limited to, management and administrative salaries and wages; non-equipment related insurance, professional fees, office and computer expenses, travel and stock based compensation.



NORTH AMERICAN ENERGY PARTNERS INC.
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Amortization of intangible assets

Amortization of intangible assets includes the amortization of our intangible assets, being customer contracts, trade names, non-competition agreements and employee arrangements.

Interest expense

Interest expense includes the interest on our 9% senior secured notes, 8³/₄% senior notes, revolving credit facility and capital lease obligations. Interest expense also includes amortization of deferred financing costs, the change in redemption value of the Series B preferred shares until March 30, 2006 and the accretion of the Series A preferred shares and Series B preferred shares (subsequent to March 30, 2006) to their redemption values.

Foreign exchange gain

Foreign exchange gain includes realized and unrealized foreign currency gains or losses on our 9% senior secured notes and 8³/₄% senior notes, as well as miscellaneous currency gains or losses realized on the settlement of payables in the normal course of operations. The foreign currency risk relating to both the principal and interest payments on the 8³/₄% senior notes has been managed with a cross currency swap and interest rate swaps which went into effect concurrent with the issuance of the same notes. The swaps on the 8³/₄% senior notes do not qualify for hedge accounting under CICA Accounting Guideline 13 and are remeasured at fair value each reporting period and the changes in fair value are recorded under the caption "Realized and unrealized loss on derivative financial instruments" in our consolidated financial statements. For more information regarding our derivative financial instruments, refer to note 19(c) to our consolidated financial statements for the year ended March 31, 2006.

Financing costs

Costs incurred in the course of financing or refinancing debt obligations, and which cannot be deferred for accounting purposes, are included in financing costs. Deferred financing costs associated with debt that has been retired are also written off and recorded as financing costs.

Realized and unrealized loss on derivative financial instruments

Derivative financial instruments are carried on the balance sheet at fair value, and periodic unrealized changes in fair value are recorded as realized and unrealized loss on derivative financial instruments. For more information regarding our derivative financial instruments, refer to note 19(c) to our consolidated financial statements for the year ended March 31, 2006.

Other Income

Other income is non-operating revenue resulting from interest income and other miscellaneous income sources

Income taxes

Income and capital taxes, as well as the impact of changes in our future income tax assets and liabilities are included in income taxes.



NORTH AMERICAN ENERGY PARTNERS INC.
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Consolidated Financial Results

	Three Months Ended June 30			
	2006		2005	
	(In millions)			
Revenue	\$ 138.1	100.0 %	\$ 104.4	100.0 %
Project costs	67.1	48.6 %	66.6	63.8 %
Equipment costs	23.9	17.3 %	17.0	16.3 %
Operating lease expense	7.2	5.2 %	2.9	2.8 %
Depreciation	7.3	5.3 %	5.0	4.8 %
Gross profit	32.6	23.6 %	12.9	12.4 %
General and administrative	9.2	6.7 %	7.2	6.9 %
Loss on disposal of plant and equipment	0.1	0.1 %	0.3	0.3 %
Amortization of intangible assets	0.2	0.1 %	0.2	0.2 %
Operating income	23.1	16.7 %	5.2	5.0 %
Interest expense	9.5	6.9 %	49.9	47.9 %
Foreign exchange gain	(13.5)	-9.8 %	1.2	1.1 %
Realized and unrealized loss on derivative financial instruments	8.0	5.8 %	1.3	1.1 %
Financing costs	—	0.0 %	2.1	2.0 %
Other income	(0.6)	-0.4 %	(0.2)	-0.2 %
Income (loss) before income taxes	19.7	14.3 %	(49.1)	-47.0 %
Income taxes	1.1	0.8 %	0.1	0.1 %
Net income (loss)	\$ 18.6	13.5 %	\$ (49.2)	-47.1 %
EBITDA(1)	\$ 36.7	26.6 %	\$ 6.0	5.8 %
Consolidated EBITDA(1)	\$ 31.5	22.8 %	\$ 8.7	18.3 %
Segmented Results of Operations				
Revenue by operating segment:				
Mining and site preparation	\$ 111.4	80.7 %	\$ 82.7	79.2 %
Piling	23.3	16.9 %	20.0	19.2 %
Pipeline	3.4	2.4 %	1.7	1.6 %
Total	\$ 138.1	100.0 %	\$ 104.4	100.0 %
Profit by operating segment:				
Mining and site preparation	\$ 24.1	73.5 %	\$ 11.7	79.1 %
Piling	8.0	24.4 %	2.8	18.9 %
Pipeline	0.7	2.1 %	0.3	2.0 %
Total	\$ 32.8	100.0 %	\$ 14.8	100.0 %
Equipment hours by operating segment:				
Mining and site preparation	236,098	95.1 %	187,951	92.9 %
Piling	11,097	4.5 %	9,707	4.8 %
Pipeline	1,102	0.4 %	4,669	2.3 %
Total	248,297	100.0 %	202,327	100.0 %

¹ EBITDA is calculated as net income (loss) before interest expense, income taxes, depreciation and amortization. Consolidated EBITDA is defined as EBITDA, excluding the effects of foreign exchange gain or loss, realized and unrealized gain or loss on derivative financial instruments, non-cash stock-based compensation expense and loss or gain on disposal of plant and equipment. We believe that Consolidated 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 Consolidated EBITDA to determine whether capital assets are being allocated efficiently. In addition, our revolving credit facility contains financial covenants based on a definition of Consolidated EBITDA. Non-compliance with this financial covenant could result in our being required to immediately repay all amounts outstanding under our revolving credit facility. We are required to maintain a minimum rolling twelve month Consolidated EBITDA through December 31, 2006 of \$65.5 million, with this minimum amount increasing periodically until maturity. The Company's Consolidated EBITDA for the twelve months ended June 30, 2006 is in excess of \$65.5 million. However, Consolidated EBITDA is not a measure of performance under Canadian GAAP or U.S. GAAP and our computations of



Consolidated EBITDA may vary from others in our industry. Consolidated EBITDA should not be considered as an alternative to operating income or net income as a measure of operating performance or cash flow as a measure of liquidity. Consolidated EBITDA has important limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our results as reported under Canadian GAAP or U.S. GAAP.

For example, EBITDA and Consolidated EBITDA:

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

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



NORTH AMERICAN ENERGY PARTNERS INC.
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A reconciliation of net income (loss) to EBITDA and Consolidated EBITDA is as follow:

	Three Months Ended June 30	
	2006	2005
(In millions)		
Net income (loss)	\$ 18.6	\$ (49.2)
Adjustments:		
Interest expense	9.5	49.9
Amortization of intangible assets	0.2	0.2
Depreciation	7.3	5.0
Income taxes	1.1	0.1
EBITDA	36.7	6.0
Adjustments:		
Foreign exchange (gain) loss on senior notes	(13.6)	0.9
Loss on disposal of plant and equipment	0.1	0.3
Stock-based compensation	0.3	0.2
Realized and unrealized loss on derivative financial instruments	8.0	1.3
Consolidated EBITDA	\$ 31.5	\$ 8.7

For the Three Months Ended June 30, 2006 Compared to the Three Months Ended June 30, 2005

Revenue. Revenue increased by \$33.7 million, or 32.3%, from \$104.4 million for the three months ended June 30, 2005 to \$138.1 million for the three months ended June 30, 2006.

- **Mining and Site Preparation.** Mining and Site Preparation revenue increased by \$28.8 million, or 34.8%, from \$82.6 million for the three months ended June 30, 2005 to \$111.4 million for the three months ended June 30, 2006, primarily due to increased activity in 2006 related to a large site preparation project for Shell and the continued ramp up on the CNRL overburden removal project in the Fort McMurray region. Additionally, there was a claim settlement arising from a site preparation project completed during 2005 in which \$6.1 million was recognized as revenue in the current reporting period.
- **Piling.** Piling revenue increased by \$3.3 million, or 16.5%, from \$20.0 million for the three months ended June 30, 2005 to \$23.3 million for the three months ended June 30, 2006, primarily due to a higher volume of projects in the Fort McMurray and Calgary regions because of strong economic and construction activities.
- **Pipeline.** Pipeline revenue increased by \$1.7 million, or 100.0%, from \$1.7 million for the three months ended June 30, 2005 to \$3.4 million for the three months ended June 30, 2006 due to an increase in work performed for EnCana.

Project costs. Project costs increased by \$0.5 million, or 0.8%, from \$66.6 million for the three months ended June 30, 2005 to \$67.1 million for the three months ended June 30, 2006. The small increase in project costs in relation to the large increase in revenue is primarily due to better performance on projects and the claim settlement as discussed above. As a percentage of revenue, project



NORTH AMERICAN ENERGY PARTNERS INC.
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costs were 48.6% in the three months ended June 30, 2006 as compared to 63.8% in the three months ended June 30, 2005. This improvement was primarily due to better margins on site preparation projects and a changing project work mix from more labor-intensive projects in the three months ended June 30, 2005 to more equipment-intensive projects during the three months ended June 30, 2006.

Equipment costs. Equipment costs increased by \$6.9 million, or 40.6%, from \$17.0 million for the three months ended June 30, 2005 to \$23.9 million for the three months ended June 30, 2006, primarily due to increased activity levels and higher repair and maintenance costs caused by increased usage of larger equipment and increased overhead and shop costs. As a percentage of revenue, equipment costs were 17.3% during the three months ended June 30, 2006 as compared to 16.3% during the three months ended June 30, 2005.

Operating lease expense. Operating lease expense increased by \$4.3 million, or 148.3%, from \$2.9 million for the three months ended June 30, 2005 to \$7.2 million for the three months ended June 30, 2006, primarily due to the addition of new leased equipment to support new projects, including the 10-year CNRL overburden project.

Depreciation. Depreciation expense increased by \$2.3 million, or 46.0%, from \$5.0 million for the three months ended June 30, 2005 to \$7.3 million for the three months ended June 30, 2006. The increase was primarily due to the additional equipment hours related to higher activity levels, as our heavy equipment fleet is depreciated based on operated hours. As a percentage of revenue, depreciation increased to 5.3% from 4.8% primarily due to our use of more leased equipment relative to owned equipment.

Gross profit. Gross profit increased by \$19.7 million, or 152.7%, from \$12.9 million for the three months ended June 30, 2005 to \$32.7 million for the three months ended June 30, 2006. As a percentage of revenue, gross profit increased to 23.6% for the fiscal period ended June 30, 2006 from 12.4% for the fiscal period ended June 30, 2005, primarily due to a claim settlement, improved performance on site preparation projects, increased activity levels and more efficient use of equipment as discussed above.

Segment profit

- **Mining and Site Preparation.** Mining and Site Preparation operating segment profit increased by \$12.4 million over the three months ended June 30, 2005. This was primarily due to increased project activity and better margins over the comparative period's project work, as discussed above.
- **Piling.** Piling operating segment profit increased \$5.1 million due to increased volume and higher margin work primarily in the Fort McMurray and Calgary regions as discussed above.
- **Pipeline.** Pipeline operating segment profit increased by \$0.4 million compared to the three months ended June 30, 2005. Increased volume of work was the primary contributor to the increase in operating segment profit.

General and administrative expenses. General and administrative expenses increased by \$2.0 million, or 27.7%, from \$7.2 million for the three months ended June 30, 2005 to \$9.2 million for the three months ended June 30, 2006. The increase was primarily due to increased salaries as a result of bonus accruals resulting from our improved financial performance and higher professional fees for audit, legal and general consulting requirements compared to the three months ended June 30, 2005. As a percentage of revenue, general and administrative expenses were 6.7% for the three months ended June 30, 2006, compared to 6.9% for the three months ended June 30, 2005.

Amortization of intangible assets. Amortization of intangible assets was the same as the prior year period at \$0.2 million for the three months ended June 30, 2006. The amortization of intangible assets during the three months ended June 30, 2006 and 2005 was related to trade names, a non-competition agreement and employee arrangements. Substantially all of the intangible assets had been amortized as of March 31, 2006 as the majority of the cost related to customer contracts in progress that were amortized at a rapid rate due to their short-term nature.

Operating income. Operating income increased by \$17.9 million, or 344.2%, from \$5.2 million for the three months ended June 30, 2005 to \$23.1 million for the three months ended June 30, 2006. The increase was primarily due to the \$19.7 million increase in gross profit, in addition there were \$0.2 million less in losses from the disposal of plant and equipment, partially offset by the \$2.0 million increase in general and administrative expenses.

Interest expense. Interest expense decreased by \$40.5 million, or 81.0%, from \$49.9 million for the three months ended June 30, 2005



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to \$9.5 million for the three months ended June 30, 2006. The reduction in interest expense was primarily due to the issuance of the Series B preferred shares in May 2005 and the requirement to record changes in the redemption value of the Series B preferred shares from the date of issuance to June 30, 2005 as interest expense. The shares were issued May 19, 2005 for cash proceeds of \$7.5 million and by the end of June 30, 2005 the redemption value was \$49.0 million, resulting in interest expense of \$41.5 million for the three months ended June 30, 2005. Due to the amendment of the Series B preferred shares on March 30, 2006, interest expense is now being accreted from the carrying value on that date of \$42.2 million to their redemption amount of 69.6 million in 2011.

Foreign exchange gain. We recognized a foreign exchange gain of \$13.5 million for the three months ended June 30, 2006 as compared to a loss of \$1.2 million for the prior period ending June 30, 2005. Substantially all of the gain in the current period relates to the exchange difference between the Canadian and U.S. dollar on translation of the US\$60.5 million of 9% senior secured notes issued in May 2005 and the US\$200.0 million of 8³/₄% senior notes.

Financing costs. Financing costs were \$nil for the three months ended June 30, 2006, a decrease of \$2.1 million from the prior period ending June 30, 2005. During the three months ended June 30, 2005, financing costs included \$0.3 million representing the issuance of the Series A preferred shares in May 2005, plus a charge of \$1.8 million relating to the write off of deferred financing costs related to our previous senior secured credit facility that was repaid in May 2005.

Realized and unrealized loss on derivative financial instruments. The realized and unrealized loss on derivative financial instruments totaled \$8.0 million for the three months ended June 30, 2006. The loss relates primarily to the change in the fair value of the derivatives, which are economic hedges related to our 8³/₄% senior notes. The realized and unrealized loss on the derivative financial instruments totaled \$1.2 million for the three months ended June 30, 2005.

Income taxes. Income tax expense was \$1.1 million for the three months ended June 30, 2006, as compared to \$0.1 million for the three months ended June 30, 2005. Income tax expense as a percentage of income before tax for the three months ended June 30, 2006 differs from the statutory rate of 33.6% primarily due to the elimination of the valuation allowance of \$5.9 million during the current quarter. For the quarter ended June 30, 2005, current income tax expense reflects only the federal large corporation tax, which is a form of minimum tax as a full valuation allowance was recorded against our net future tax asset given the uncertainty of recognizing the benefit of the net future tax asset.

Comparative Quarterly Results

A number of factors contribute to variations in our results between periods, such as weather, customer capital spending on large oil sands and natural gas related 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.

	Fiscal Year	Fiscal Year 2006				Fiscal Year 2005		
	2007	Q4	Q3	Q2	Q1	Q4	Q3	Q2
	Q1							
			(In millions of dollars, except equipment hours)					
Revenue	\$ 138.1	\$ 142.3	\$ 121.5	\$ 124.0	\$ 104.4	\$ 122.7	\$ 81.0	\$ 82.7
Gross profit	32.6	31.7	13.8	21.9	12.9	24.0	(5.7)	9.8
Net income (loss)	18.6	13.7	2.1	11.5	(49.2)	(0.1)	(32.4)	(4.7)
Equipment hours	248,297	231,633	221,355	234,649	185,751	241,727	191,555	193,205

Consolidated Financial Position

At June 30, 2006, we had net working capital of \$84.2 million compared to \$67.9 million at March 31, 2006. The increase was primarily due to increased cash and cash equivalents of \$2.3 million, increased work in progress generating higher accounts receivable and unbilled revenues of \$3.7 million, an increase in prepaid expenses of \$2.0 million, a decrease in accounts payable and accrued liabilities of \$4.7 million, partially offset by an increase of \$1.5 million in billings in excess of costs on uncompleted projects and an increase in the current portion of capital lease obligations of \$0.4 million.



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Plant and equipment net of depreciation increased by \$5.7 million at June 30, 2006 from March 31, 2006 primarily due to the addition of large construction equipment to support growing operations.

Capital lease obligations, including the current portion, increased by \$1.0 million at June 30, 2006 from March 31, 2006 due to the addition of new leased vehicles and a drill rig to support new projects.

Liquidity and Capital Resources

Operating activities

Operating activities for the three months ended June 30, 2006 resulted in a net increase in cash of \$14.8 million. Increased income was partially offset by an increase in accounts receivable and a decrease in accrued liabilities. The net usage of cash in operating activities for the three months ended June 30, 2005 was \$16.1 million primarily due to lower margin work on a major site grading project offset by favorable working capital changes.

Investing activities

During the three months ended June 30, 2006, we invested \$4.7 million in sustaining capital expenditures and \$7.1 million in growth capital expenditures, for total capital expenditures of \$11.8 million. In the three months ended June 30, 2005, we invested \$1.3 million in sustaining capital expenditures and \$4.4 million in growth capital expenditures, for total capital expenditures of \$5.7 million.

Sustaining capital expenditures are those that are required to keep our existing fleet of equipment at its optimum average age through maintenance or replacement. Growth capital expenditures relate to equipment additions required to perform increased sizes or numbers of projects.

Financing activities

Financing activities during the three months ended June 30, 2006 resulted in a cash outflow of \$0.9 million, primarily as a result of capital lease repayments. Financing activities during the three months ended June 30, 2005 resulted in a net cash inflow of \$14.8 million. This was a result of the proceeds from the issuance of the US\$60.5 million of 9% senior secured notes and \$7.5 million of Series B preferred shares which were used to repay the amount outstanding under our senior secured credit facility and to pay for the fees and expenses related to the refinancing.

Liquidity Requirements

Our primary uses of cash are to purchase plant and equipment, fulfill debt repayment and interest payment obligations and finance working capital requirements.

We have outstanding US\$200 million of 8³/₄% senior notes due 2011. The foreign currency risk relating to both the principal and interest payments on the 8³/₄% senior notes has been managed with a cross-currency swap and interest rate swaps which went into effect concurrent with the issuance. Interest of US\$8.8 million is payable semi-annually in June and December of each year until the notes mature on December 1, 2011. The swap agreements are economic hedges of the changes in the Canadian dollar-U.S. dollar exchange rate, but they do not meet the criteria to qualify for hedge accounting. There are no principal payments required on the 8³/₄% senior notes until maturity.

Our US\$60.5 million of 9% senior secured notes were issued on May 19, 2005 pursuant to a private placement. On July 26, 2005, we registered substantially identical notes with the United States Securities and Exchange Commission and exchanged them for the notes issued in the private placement. The foreign currency risk relating to both the principal and interest payments on the 9% senior secured notes has not been hedged. Interest of US\$2.7 million is payable semi-annually in June and December of each year until the notes mature on June 1, 2010. There are no principal payments required on the 9% senior secured notes until maturity.



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One of our major contracts allows the customer to request up to \$50 million in letters of credit. While this level has not been requested to date, we would either have to lower other letters of credit or cash collateralize other obligations to provide this amount of letters of credit.

We maintain a significant equipment and vehicle fleet comprised of units with various remaining useful lives. Once units reach the end of their useful lives, it becomes cost prohibitive to continue to maintain them and, therefore, they must be replaced. As a result, we are continually acquiring new equipment to replace retired units and to expand the fleet to meet growth as new projects are awarded to us. It is important to adequately maintain the 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. In order to conserve cash, we have financed our recent purchases of large pieces of heavy construction equipment through operating leases. In addition, we continue to lease a portion of our motor vehicle fleet.

Our cash requirements during the three months ended June 30, 2006 increased due to continued growth and additional operating and capital expenditures associated with new projects. Our cash requirements for fiscal 2007 include funding operating lease obligations, debt and interest repayment obligations and working capital as activity levels are expected to continue to increase. In addition, we will require capital to finance further vehicle and equipment acquisitions for upcoming new projects.

We expect our sustaining capital expenditures to range from \$10 million to \$15 million per year over the next two years. We expect our total capital expenditures to range from \$50 million to \$60 million in fiscal 2007. It is our belief that working capital will be sufficient to meet these requirements.

Sources of Liquidity

Our principal sources of cash are funds from operations and borrowings under our revolving credit facility. On July 19, 2006, we amended and restated our revolving credit facility to provide for borrowings and the issuance of letters of credit of up to \$55.0 million, subject to borrowing base limitations. As of July 19, 2006, we had approximately \$37.0 million of available borrowings under the revolving credit facility after taking into account \$18.0 million of outstanding and undrawn letters of credit to support bonding requirements and performance guarantees associated with customer contracts and operating leases. The facility bears interest at the Canadian prime rate plus 2% or Canadian bankers' acceptance rate plus 3%. The indebtedness under the revolving credit facility, including the liability under the swaps used to manage the foreign currency risk on the 8³/₄% senior notes, is secured by substantially all of our assets and those of our subsidiaries.

Our revolving credit facility contains covenants that restrict our activities, including restrictions on creating liens, engaging in mergers, consolidations and sales of assets, incurring additional indebtedness, giving guaranties, engaging in different businesses, making loans and investments, making certain capital expenditures and making certain dividend, debt and other restricted payments. Under the revolving credit facility, we also are required to satisfy certain financial covenants, including a minimum interest coverage ratio, a maximum leverage ratio and a minimum consolidated EBITDA requirement. Consolidated EBITDA is defined in the credit facility as the sum, without duplication, of (1) consolidated net income, (2) consolidated interest expense, (3) provisions 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, 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 expenditures 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 GAAP. The required minimum Consolidated EBITDA through December 31, 2006 is \$65.5 million, and this minimum amount increases periodically until the credit facility matures. We believe Consolidated EBITDA as defined in the credit facility is an important measure of our liquidity.

The Series B preferred shares were initially issued for net cash proceeds of \$7.5 million on May 19, 2005 to existing NACG Holdings Inc. common shareholders. For additional information on the Series B preferred shares, see note 14(a) (ii) to our consolidated financial statements for the year ended March 31, 2006.

Between March 31, 2004 and May 19, 2005, it was necessary to obtain a series of waivers and amend our then-existing credit agreement to avoid or to cure our default of various covenants contained in that credit agreement. We ultimately replaced that credit agreement with a new credit agreement on May 19, 2005, which we replaced with our current amended and restated credit agreement on July 19, 2006.



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Our inability to file our financial statements for the periods ended December 31, 2004, March 31, 2005 and September 30, 2005 with the SEC within the deadlines imposed by covenants in the indentures governing our 8^{3/4}% senior notes and our 9% senior secured notes caused us to be out of compliance with such covenants. In each case, we filed our financial statements before the lack of compliance became an event of default under the indentures.

Contractual Obligations and Other Commitments

Our principal contractual obligations relate to our long-term debt (8^{3/4}% senior notes and 9% senior secured notes), preferred shares, capital and operating leases. The following table summarizes our future contractual obligations, excluding interest payments unless otherwise noted, as of June 30, 2006.

	Payments Due by Fiscal Year					2011 and After
	Total	2007	2008	2009	2010	
	(In millions)					
Long-term debt	\$290.4	\$ —	\$ —	\$ —	\$ —	\$ 290.4
Series A preferred shares(a)	1.0	—	—	—	—	1.0
Series B preferred shares(a)	69.6	—	—	—	—	69.6
Capital leases (including interest)	13.1	4.0	3.7	3.1	2.1	0.2
Operating leases	55.7	17.5	18.1	9.8	8.1	2.2
Total contractual obligations	<u>\$429.8</u>	<u>\$21.5</u>	<u>\$21.8</u>	<u>\$12.9</u>	<u>\$10.2</u>	<u>\$ 363.4</u>

(a) Reflected at redemption value.

Off-Balance Sheet Arrangements

As of June 30, 2006, we had \$18.0 million of outstanding, undrawn letters of credit issued under our revolving credit facility.

Stock-Based Compensation

Some of our directors, officers, employees and service providers have been granted options to purchase common shares of NACG Holdings Inc., our ultimate parent company, under the stock-based compensation plan. The plan and outstanding balances are disclosed in note 9 to our interim consolidated financial statements for the three months ended June 30, 2006.

Critical Accounting Policies and 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 the contracts are generally less than one year in duration, we do have several long-term contracts.

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- *Cost-plus.* A cost-plus contract is where all 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 project. 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. Revenue recognition is based on actual incurred costs to date plus an applicable fee that represents profit.
- *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 incurring expenses in excess of a specific component of the agreed upon rate. Therefore, any cost overrun must come out of the fixed margin included in the rates. Revenue is recognized as the labor, equipment, materials, subcontract costs and other services are supplied to the customer.
- *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. Revenue on unit-price contracts is recognized using the percentage-of-completion method, measured by the ratio of costs incurred to date to estimated total cost.
- *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 required than were estimated in the established price. The price is fixed regardless of the amount of work required to complete the project. Revenue on lump sum contracts is recognized using the percentage-of-completion method, measured by the ratio of costs incurred to date to estimated total cost.

The mix of contract types varies year-by-year. For the three months ended June 30, 2006, our contracts consisted of 16% cost-plus, 43% time-and-materials, 34% unit-price and 6% 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. 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. Revenue in excess of costs from unpriced change orders, extra work and variations in the scope of work is recognized after both the costs are incurred or services are provided and realization is assured beyond a reasonable doubt. Claims are included in total estimated contract revenue, only to the extent that contract costs related to the claim have been incurred, when it is probable that the claim will result in a bona fide addition to contract value and the amount of revenue can be reliably estimated. Costs incurred for bidding and obtaining contracts are expensed as incurred.

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. We believe our experience allows us to produce materially reliable estimates. However, our projects can be highly complex, and in almost every case, the profit margin estimates for a project will either increase or decrease to some extent from the amount that was originally estimated at the time of the related bid. Because we have many projects of varying levels of complexity and size in progress at any given time, these changes in estimates can offset each other without materially impacting our profitability. However, large changes in cost estimates, particularly in the bigger, 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;



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- 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.

Plant and equipment

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

Another key estimate is the expected cash flows from the use of an asset and the expected disposal proceeds in applying CICA Handbook Section 3063 "Impairment of Long-Lived Assets" and Section 3475 "Disposal of Long-Lived Assets and Discontinued Operations." These standards require the recognition of an impairment loss for a long-lived asset to be held and used 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. Equally important is the expected fair value of assets that are available-for-sale.

Goodwill

We perform our annual goodwill impairment test on December 31 of each year, and more frequently if events or changes in circumstances indicate that an impairment loss may have been incurred. 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 values 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.

Derivative financial instruments

We use derivative financial instruments to manage economic risks from fluctuations in exchange rates and interest rates. These instruments include cross-currency swap agreements and interest rate swap agreements. These instruments are only used for risk management purposes. We do not hold or issue derivative financial instruments for trading or speculative purposes. Derivative financial instruments are subject to standard credit terms and conditions, financial controls, management and risk monitoring procedures.

Our derivative financial instruments are recorded on the balance sheet at fair value, which is determined based on values quoted by the counterparties to the agreements.

Series B Preferred Shares

Prior to our amendment of the terms of the Series B preferred shares on March 30, 2006, the definition of the redemption price of the Series B preferred shares included a calculation tied to the fair value of the common shares of North American Energy Partners Inc.



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Under the redemption price, any increase or decrease in the fair value of North American Energy Partners' common shares could result in an increase or decrease in the redemption value of the Series B preferred shares based on 25% of the change in fair value of the common shares and, as a consequence, fluctuations in interest expense. The amendment eliminated this calculation from the definition of redemption price. As a result, the Series B preferred shares will now be accreted from \$42.2 million to their December 31, 2011 redemption value of \$69.6 million, with corresponding periodic charges to interest expense. Please see note 14 (a) to our consolidated financial statements for the year ended March 31, 2006 for more information on the Series B Preferred Shares.

Recent Canadian Accounting Pronouncements Not Yet Adopted

Financial instruments

In January 2005, the CICA issued Handbook Section 3855, "Financial Instruments — Recognition and Measurement", Handbook Section 1530, "Comprehensive Income", and Handbook Section 3865, "Hedges". The new standards are effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006, specifically for the fiscal year beginning April 1, 2007 for us. Earlier adoption is permitted. The new standards will require presentation of a separate statement of comprehensive income under specific circumstances. Foreign exchange gains and losses on the translation of the financial statements of self-sustaining subsidiaries previously recorded in a separate section of shareholder's equity will be presented in comprehensive income. Derivative financial instruments will be recorded in the balance sheet at fair value and the changes in fair value of derivatives designated as cash flow hedges will be reported in comprehensive income. We are currently assessing the impact of the new standards.

U.S. Generally Accepted Accounting Principles

Our interim consolidated financial statements have been prepared in accordance with Canadian GAAP, which differs in certain material respects from U.S. GAAP. The nature and effect of these differences are set out in note 11 to our interim consolidated financial statements three months ended June 30, 2006.

United States accounting pronouncements recently adopted

Statement of Financial Accounting Standards No. 123R, "Share-Based Payment" ("SFAS 123R") requires companies to recognize in the income statement, the grant-date fair value of stock options and other equity-based compensation issued to employees. The fair value of liability-classified awards is remeasured subsequently at each reporting date through the settlement date, while the fair value of equity-classified awards is not subsequently remeasured. The revised standard is effective for non-public companies beginning with the first annual reporting period that begins after December 15, 2005, which in our case is the period beginning April 1, 2006. We have used the fair value method under Statement 123 since its inception. We adopted SFAS 123(R) prospectively since we use the minimum value method for purposes of complying with Statement 123. The adoption of this standard did not have a significant impact on our consolidated financial statements.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections" ("SFAS 154") which replaces Accounting Principles Board Opinions No. 20 "Accounting Changes" and Statement of Financial Accounting Standards No. 3, "Reporting Accounting Changes in Interim Financial Statements — An Amendment of APB Opinion No. 28." SFAS 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. SFAS 154 was effective for accounting changes and corrections of errors made in our fiscal year beginning April 1, 2006. The adoption of SFAS 154 did not have a material impact on the Company's consolidated financial statements.



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Recent United States accounting pronouncements not yet adopted

Statement of Financial Accounting Standards No. 155, "Accounting for Certain Hybrid Financial Instruments — an amendment of FASB Statements No. 133 and 140" ("SFAS 155") was issued February 2006. This Statement is effective for all financial instruments acquired, issued, or subject to a remeasurement (new basis) event occurring after the beginning of an entity's first fiscal year that begins after September 15, 2006. The fair value election provided for in paragraph 4(c) of this Statement may also be applied upon adoption of this Statement for hybrid financial instruments that had been bifurcated under paragraph 12 of Statement 133 prior to the adoption of this Statement. This states that an entity that initially recognizes a host contract and a derivative instrument may irrevocably elect to initially and subsequently measure that hybrid financial instrument, in its entirety, at fair value with changes in fair value recognized in earnings. SFAS 155 is applicable for all financial instruments acquired or issued in our 2008 fiscal year although early adoption is permitted. We are currently reviewing the impact of this Statement.

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109" ("FIN 48") which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes". FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition requirements. The Company is currently reviewing the impact of this interpretation. FIN 48 is effective for fiscal years beginning after December 15, 2006, specifically, April 1, 2007 for the Company.

Risk Factors

Anticipated major projects in the oil sands may not materialize.

Notwithstanding industry estimates regarding new investment and growth in the Canadian oil sands, planned and anticipated projects in the oil sands and other related projects may not materialize. The underlying assumptions on which the projects are based are subject to significant uncertainties, and actual investments in the oil sands could be significantly less than estimated. Projected investments and new projects may be postponed or cancelled for any number of reasons, including among others:

- changes in the perception of the economic viability of these projects;
- shortage of pipeline capacity to transport production to major markets;
- lack of sufficient governmental infrastructure to support growth;
- shortage of skilled workers in this remote region of Canada; and
- cost overruns on announced projects.

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.

Due to the amount of capital investment required to build an oil sands project, or construct a significant expansion to an existing project, investment decisions by oil sands operators are based upon long-term views of the economic viability of the project. Economic viability is dependent upon the anticipated revenues the project will produce, the anticipated amount of capital investment required and the anticipated cost of operating the project. One of the most important considerations is the price of oil. The long-term outlook for the price of oil is influenced by many factors, including the condition of developed and developing economies and the resulting demand for oil and gas, the level of supply of oil and gas, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political conditions in oil producing nations, including those in the Middle East, war or the threat of war in oil producing regions and the availability of fuel from alternate sources. If our customers believe the long-term outlook for the price of oil is not favorable or believe oil sands projects are not viable for any other reason, they may delay, reduce or cancel plans to construct new oil sands projects or expansions to existing projects. Delays, reductions or cancellations of major oil sands projects could have a material adverse impact on our financial condition and results of operations.

Insufficient pipeline and refining capacity could cause our customers to delay, reduce or cancel plans to construct new oil sands projects or expansions to existing projects, which would, in turn, reduce our revenue from those customers.

For our customers to operate successfully in the oil sands, they must be able to transport the bitumen produced to upgrading

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facilities and transport the upgraded oil to refineries. Some oil sands projects have upgraders at the mine site and others transport bitumen to upgraders located elsewhere. While current pipeline and upgrading capacity is sufficient to upgrade current bitumen production and transport such production to refineries, future increases in production from new oil sands projects and expansions to existing projects will require increased upgrading and pipeline capacity. If these increases do not materialize, whether due to inadequate economics for the sponsors of such projects, shortages of labor or materials or any other reason, our customers may be unable to efficiently deliver increased production to market and may therefore delay, reduce or cancel planned capital investment. Such delays, reductions or cancellations of major oil sands projects would adversely affect our prospects and could have a material adverse impact on our financial condition and results of operations.

Lack of sufficient governmental infrastructure to support the growth in the oil sands region could cause our customers to delay, reduce or cancel their future expansions, which would, in turn, reduce our revenue from those customers.

The development in the oil sands region has put a great strain on the existing government infrastructure, necessitating substantial improvements to accommodate the growth in the region. The local government having responsibility for a majority of the oil sands region has been exceptionally impacted by this growth and is not currently in a position to provide the necessary additional infrastructure. In an effort to delay further development until infrastructure funding issues are resolved, the local governmental authority has sought to intervene in a hearing in July 2006 to consider an application by a major oil sands company to the Energy Utility Board (EUB) for approval to expand its operations and may take similar action with respect to any future applications. If the necessary infrastructure is not put in place, future growth of our customers' operations could be delayed, reduced or canceled which could in turn adversely affect our prospects and could have a material adverse impact on our financial condition and results of operations.

Shortages of qualified personnel or significant labor disputes could adversely affect our business.

Alberta, and in particular the oil sands area, has had and continues to have a shortage of skilled labor and other qualified personnel. New mining projects in the area will only make it more difficult for us and our customers to find and hire all the employees required to work on these projects. We are continuously seeking ways to hire the people we need, including more project managers, trades people and other employees with the required skills. We have expanded our efforts to find qualified candidates outside of Canada who might relocate to our area. In addition, we have undertaken more extensive training of existing employees and we are enhancing our use of technology and developing programs to provide better working conditions. We believe the labor shortage, which affects us and all of our major customers, will continue to be a challenge for everyone in the mining and oil and gas industries in western Canada for the foreseeable future. If we are not able to recruit and retain enough employees with the appropriate skills, we may be unable to maintain our customer service levels, and we may not be able to satisfy any increased demand for our services. This, in turn, could have a material adverse effect on our business, financial condition and results of operations. If our customers are not able to recruit and retain enough employees with the appropriate skills, they may be unable to develop projects in the oil sands area.

Substantially all of our hourly employees are subject to collective bargaining agreements to which we are a party or are otherwise subject. Any work stoppage resulting from a strike or lockout could have a material adverse effect on our business, financial condition and results of operations. In addition, our customers employ workers under collective bargaining agreements. Any work stoppage or labor disruption experienced by our key customers could significantly reduce the amount of our services that they need.

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.

Oil sands development projects require substantial capital expenditures. In the past, several of our customers' projects have experienced significant cost overruns, impacting their returns. As new projects are contemplated or built, if cost overruns continue to challenge our customers, they could reassess future projects and expansions which could adversely affect the amount of work we receive from our customers.

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

Our ability to grow our business is in part dependent upon obtaining equipment on a timely basis. Due to the long production lead times of our suppliers of large mining equipment, we must forecast our demand for equipment many months or even years in advance. If we fail to forecast accurately, we could suffer equipment shortages or surpluses, which could have a material adverse impact on our financial condition and results of operations.





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Global demand for tires of the size and specifications we require is exceeding the available supply. For example, we currently have four trucks that we cannot utilize because we cannot get tires of the appropriate size and specifications. We expect the supply/demand imbalance for certain tires to continue for several years. Our inability to procure tires to meet the demands for our existing fleet as well as to secure tires to meet new demand for our services could have an adverse effect on our ability to grow our business.

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.

We receive most of our revenues from providing services to a small number of major oil sands mining companies. Revenue from our five largest customers represented approximately 63% and 76% of our total revenue for the three months ended June 30, 2006 and 2005, respectively, and those customers are expected to continue to account for a significant percentage of our revenues in the future. For the three months ended June 30, 2006, Shell, CNRL and Syncrude were our three largest customers, accounting for 20%, 15% and 11%, respectively, of our total revenue. For the last five fiscal years, the majority of our revenues in our pipeline business resulted from work performed for EnCana. If we lose or experience a significant reduction of business from one or more of our significant customers, we may not be able to replace the lost work with work from other customers. Our long-term contracts typically allow our customers to unilaterally reduce or eliminate the work which we are to perform under the contract. Our contracts generally allow the customer to terminate the contract without cause. The loss of or significant reduction in business with one or more of our major customers, whether as a result of completion of a contract, early termination or failure or inability to pay amounts owed to us, could have a material adverse effect on our business and results of operations.

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.

Most of our customers are Canadian energy companies. A downturn in the Canadian energy industry could cause our customers to slow down or curtail their current production and future expansions which would, in turn, reduce our revenue from those customers. Such a delay or curtailment could have a material adverse impact on our financial condition and results of operations.

Lump sum and unit-price contracts expose us to losses when our estimates of project costs are too low or when we fail to perform within our cost estimates.

Approximately 39% and 63% of our revenue for the three months ended June 30, 2006 and 2005, respectively, was derived from lump sum and unit-price contracts. See "Management's Discussion and Analysis — Critical Accounting Policies and Estimates — Revenue Recognition." Lump sum and unit-price contracts require us to guarantee the price of the services we provide and thereby expose us to losses if our estimates of project costs are lower than the actual project costs we incur. Our profitability under these contracts is dependent upon our ability to accurately predict the costs associated with our services. The costs we actually incur may be affected by a variety of factors beyond our control. Factors that may contribute to actual costs exceeding estimated costs and which therefore affect profitability include, without limitation:

- site conditions differing from those assumed in the original bid;
- 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;
- inability or failure of our customers to perform their contractual commitments;
- equipment availability and productivity and timing differences resulting from project construction not starting on time; and



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- the general coordination of work inherent in all large projects we undertake.

When we are unable to accurately estimate the costs of lump sum and unit-price contracts, or when we incur unrecoverable cost overruns, the related projects result in lower margins than anticipated or may incur losses, which could adversely impact our results of operations, financial condition and cash flow.

Until we establish and maintain effective internal controls over financial reporting, we cannot assure you that we will have appropriate procedures in place to eliminate future financial reporting inaccuracies and avoid delays in financial reporting.

We have financial reporting obligations arising from the indentures governing our 8³/₄% senior notes and 9% senior secured notes. We have had continuing problems providing accurate and timely financial information and reports and have restated our financial statements three times since the beginning of our 2005 fiscal year. In April of 2005, we had to restate our financial statements for the first and second quarters of fiscal 2005 to properly account for costs incurred in those quarters. During fiscal 2006, we had to restate our financial statements for each period after November 26, 2003 to eliminate the impact of hedge accounting with respect to the derivative financial instruments. We also had to restate our financial statements for the first quarter of fiscal 2006 to correct the accounting for various aspects of the refinancing transactions which occurred in May 2005. Each of these restatements resulted in our inability to file our financial statements within the deadlines imposed by covenants in the indentures governing our 8³/₄% senior notes and 9% senior secured notes.

In connection with the audit of our fiscal 2006 financial statements, our auditors identified a number of significant weaknesses (as defined under Canadian auditing standards) in our financial reporting processes and internal controls. As a result, there can be no assurance that we will be able to generate accurate financial reports in a timely manner. Failure to do so would cause us to breach the reporting requirements of U.S. and Canadian securities regulations in the future as well as the covenants applicable to our indebtedness. This could, in turn, have a material adverse effect on our business and financial condition. Until we establish and maintain effective internal controls and procedures for financial reporting, we may not have appropriate measures in place to eliminate financial statement inaccuracies and avoid delays in financial reporting.

Our substantial debt could adversely affect us, make us more vulnerable to adverse economic or industry conditions and prevent us from fulfilling our debt obligations.

We have a substantial amount of debt outstanding and significant debt service requirements. As of June 30, 2006, we had outstanding, approximately \$302.0 million of debt, including approximately \$79.3 million of secured indebtedness and capital leases. We also have cross-currency and interest rate swaps with a balance sheet liability of \$71.0 million as of June 30, 2006 and which are secured equally and ratably with our revolving credit facility. We also had \$18.0 million of outstanding, undrawn letters of credit, which reduce the amount of available borrowings under our revolving credit facility. Our substantial indebtedness could have serious consequences, such as:

- limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements, potential growth or other purposes;
- limiting our ability to use operating cash flow in other areas of our business;
- limiting our ability to post surety bonds required by some of our customers;
- placing us at a competitive disadvantage compared to competitors with less debt;
- increasing our vulnerability to, and reducing our flexibility in planning for, adverse changes in economic, industry and competitive conditions; and

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- increasing our vulnerability to increases in interest rates because borrowings under our revolving credit facility and payments under some of our equipment leases are subject to variable interest rates.

The potential consequences of our substantial indebtedness make us more vulnerable to defaults and place us at a competitive disadvantage. Further, if we do not have sufficient earnings to service our debt, we would need to refinance all or part of our existing debt, sell assets, borrow more money or sell securities, none of which we can guarantee we will be able to achieve on commercially reasonable terms, if at all.

The terms of our debt agreements may restrict our current and future operations, particularly our ability to respond to changes in our business or take certain actions.

Our revolving credit facility and the indentures governing our notes limit, among other things, our ability and the ability of our subsidiaries to:

- incur or guarantee additional debt, issue certain equity securities or enter into sale and leaseback transactions;
- pay dividends or distributions on our shares or repurchase our shares, redeem subordinated debt or make other restricted payments;
- incur dividend or other payment restrictions affecting certain of our subsidiaries;
- issue equity securities of subsidiaries;
- make certain investments or acquisitions;
- create liens on our assets;
- enter into transactions with affiliates;
- consolidate, merge or transfer all or substantially all of our assets; and
- transfer or sell assets, including shares of our subsidiaries.

Our revolving credit facility and some of our equipment lease programs also require us, and our future credit facilities may require us, to maintain specified financial ratios and satisfy specified financial tests, some of which become more restrictive over time. Our ability to meet these financial ratios and tests can be affected by events beyond our control, and we may be unable to meet those tests.

As a result of these covenants, our ability to respond to changes in business and economic conditions and to obtain additional financing, if needed, may be significantly restricted, and we may be prevented from engaging in transactions that might otherwise be considered beneficial to us. The breach of any of these covenants could result in a default under our revolving credit facility or any future credit facilities or under the indentures governing our notes. Upon the occurrence of an event of default under our revolving credit facility or future credit facilities, the lenders could elect to stop lending to us or declare all amounts outstanding under such credit facilities to be immediately due and payable. Similarly, upon the occurrence of an event of default under the indentures governing our notes, the outstanding principal and accrued interest on the notes may become immediately due and payable. If amounts outstanding under such credit facilities and indentures were to be accelerated, or if we were not able to borrow under our revolving credit facility, we could become insolvent or be forced into insolvency proceedings.

Between March 31, 2004 and May 19, 2005, it was necessary to obtain a series of waivers and amend our then-existing credit agreement to avoid or to cure our default of various covenants contained in that credit agreement. We ultimately replaced that credit agreement with a new credit agreement on May 19, 2005, which we replaced with our current amended and restated credit agreement on July 19, 2006.



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Our inability to file our financial statements for the periods ended December 31, 2004, March 31, 2005 and September 30, 2005 with the SEC within the deadlines imposed by covenants in the indentures governing our 8^{3/4}% senior notes and our 9% senior secured notes caused us to be out of compliance with such covenants. In each case, we filed these financial statements before the lack of compliance became an event of default under the indentures.

We may not be able to generate sufficient cash flow to meet our debt service and other obligations due to events beyond our control.

Our ability to generate sufficient operating cash flow to make scheduled payments on our indebtedness and meet other capital requirements will depend on our future operating and financial performance. Our future performance will be impacted by a range of economic, competitive and business factors that we cannot control, such as general economic and financial conditions in our industry or the economy generally.

A significant reduction in operating cash flows resulting from changes in economic conditions, increased competition, reduced work or other events could increase the need for additional or alternative sources of liquidity and could have a material adverse effect on our business, financial condition, results of operations, prospects and our ability to service our debt and other obligations. If we are unable to service our indebtedness, we will be forced to adopt an alternative strategy that may include actions such as selling assets, restructuring or refinancing our indebtedness, seeking additional equity capital or reducing capital expenditures. We may not be able to effect any of these alternative strategies on satisfactory terms, if at all, or they may not yield sufficient funds to make required payments on our indebtedness.

Currency rate fluctuations could adversely affect our ability to borrow under our revolving credit facility and to repay our 8^{3/4}% senior notes and 9% senior secured notes and may affect the cost of goods we purchase.

Our ability to borrow under our revolving credit facility is limited, in part, by the derivative financial instruments recorded as liabilities. If the Canadian dollar increases in value against the U.S. dollar, as it has in the recent past, the derivative financial instruments under the swap agreements will increase, which may adversely affect our liquidity or even cause a default under our revolving credit facility if the derivative financial instruments recorded as liabilities were to increase to the extent that the amount of outstanding borrowings and letters of credit would exceed the reduced availability under our revolving credit facility.

We have entered into cross-currency and interest rate swaps that represent economic hedges of our 8^{3/4}% senior notes, which are denominated in U.S. dollars. The current exchange rate between the Canadian and U.S. dollars as compared to the rate implicit in the swap agreement has resulted in a large liability on the balance sheet under the caption "derivative financial instruments." If the Canadian dollar increases in value or remains at its current value against the U.S. dollar, then if we repay the 8^{3/4}% senior notes prior to their maturity in 2011, we will have to pay this liability.

Substantially all of our revenues and costs are incurred in Canadian dollars. However, the obligation represented by our 9% senior secured notes is denominated in U.S. dollars. If the Canadian dollar loses value against the U.S. dollar while other factors remain constant, our ability to pay interest and principal on these notes may be diminished.

Exchange rate fluctuations may also cause the price of goods to increase or decrease for us. For example, a decrease in the value of the Canadian dollar compared to the U.S. dollar would proportionately increase the cost of equipment which is sold to us or priced in U.S. dollars. Between January 1, 2006 and June 30, 2006, the Canadian dollar/U.S. dollar exchange rate varied from a high of 0.9100 Canadian dollars per U.S. dollar to a low of 0.8528 Canadian dollars per U.S. dollar.

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

We are at times required to post a bid or performance bond issued by a financial institution, known as a surety, to secure our performance commitments. The surety industry experiences periods of unsettled and volatile markets, usually in the aftermath of substantial loss exposures or corporate bankruptcies with significant surety exposure. Historically, these types of events have caused reinsurers and sureties to reevaluate their committed levels of underwriting and required returns. If for any reason, whether because of our financial condition, our level of secured debt or general conditions in the surety bond market, our bonding capacity becomes insufficient to satisfy our future bonding requirements, our business and results of operations could be adversely affected.



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Some of our customers require letters of credit to secure our performance commitments. Our revolving credit facility provides for the issuance of letters of credit up to \$55.0 million, and at June 30, 2006, we had \$18.0 million of issued letters of credit outstanding. One of our major contracts allows the customer to request up to \$50.0 million in letters of credit. While this level has not been requested to date, we would either have to lower other letters of credit or cash collateralize other obligations to provide this amount of letters of credit. If we were unable to provide letters of credit in the amount requested by this customer, we could lose business from such customer and our business and cash flow would be adversely affected. In addition, the company that provides our surety bonds currently requires \$10.0 million of security in the form of either letters of credit, cash collateralization or a combination thereof. If our capacity to issue letters of credit under our revolving credit facility and our cash on hand are insufficient to satisfy our customers and surety, our business and results of operations could be adversely affected.

A change in strategy by our customers to reduce outsourcing could adversely affect our results.

Outsourced mining and site preparation services constitute a large portion of the work we perform for our customers. For example, our mining and site preparation project revenues constituted approximately 80% of our revenues in each of the three months ending June 30, 2006 and June 30, 2005. The election by one or more of our customers to perform some or all of these services themselves, rather than outsourcing the work to us, could have a material adverse impact on our business and results of operations.

Our operations are subject to weather-related factors that may cause delays in our completion of projects.

Because our operations are located in western Canada and northern Ontario, we are often subject to extreme weather conditions. While our operations are not significantly affected by normal seasonal weather patterns, extreme weather, including heavy rain and snow, can cause us to delay the completion of a project, which could adversely impact our results of operations.

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.

A portion of our equipment fleet is currently leased from third parties. Further, we anticipate leasing substantial amounts of equipment to perform the work on contracts for which we have been engaged in the upcoming year, particularly the overburden removal contract with CNRL. Other projects on which we are engaged in the future may require us to lease additional equipment. If equipment lessors are unable or unwilling to provide us with the equipment we need to perform our work, our results of operations will be materially adversely affected.

Competitors may outbid us on major projects that are awarded based on bid proposals.

Approximately 80% of the major projects that we pursue are awarded to us based on bid proposals, and projects are typically awarded based in large part on price. We often compete for these projects against companies that have substantially greater financial and other resources than we do and therefore can better bear the risk of underpricing projects. We also compete against smaller competitors that may have lower overhead cost structures and, therefore, may be able to provide their services at lower rates than we can. In addition, we expect the growth in the oil sands region will attract new and sometimes larger competitors to enter the region and compete against us for projects. Our business may be adversely impacted to the extent that we are unable to successfully bid against these companies.

A significant amount of our revenue is generated by providing non-recurring services.

More than 57% of our revenue for the three months ended June 30, 2006 was derived from projects which we consider to be non-recurring. This revenue primarily relates to site preparation and piling services provided for the construction of extraction, upgrading and other oil sands mining infrastructure projects. Future revenues from these types of services will depend upon customers expanding existing mines and developing new projects.

Penalty clauses in our customer contracts could expose us to losses if total project costs exceed original estimates or if projects are not completed by specified completion date milestones.

A portion of our revenue is derived from contracts which have performance incentives and penalties depending on the total cost of a project as compared to the original estimate. We could incur significant penalties based on cost overruns. In addition, the total



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project cost as defined in the contract may include not only our work, but also work performed by other contractors. As a result, we could incur penalties due to work performed by others over which we have no control. We may also incur penalties if projects are not completed by specified completion date milestones. These penalties, if incurred, could have a significant impact on our profitability under these contracts.

Demand for our services may be adversely impacted by regulations affecting the energy industry.

Our principal customers are energy companies involved in the development of the oil sands and in natural gas production. The operations of these companies, including their mining operations in the oil sands, are subject to or impacted by a wide array of regulations in the jurisdictions where they operate, including those directly impacting mining activities and those indirectly affecting their businesses, such as applicable environmental laws. As a result of changes in regulations and laws relating to the energy production industry, including the operation of mines, our customers' operations could be disrupted or curtailed by governmental authorities. The high cost of compliance with applicable regulations may cause customers to discontinue or limit their operations, and may discourage companies from continuing development activities. As a result, demand for our services could be substantially affected by regulations adversely impacting the energy industry.

Environmental laws and regulations may expose us to liability arising out of our operations or the operations of our customers.

Our operations are subject to numerous environmental protection laws and regulations that are complex and stringent. We regularly perform work in and around sensitive environmental areas such as rivers, lakes and forests. Significant fines and penalties may be imposed on us or our customers for non-compliance with environmental laws and regulations, and our contracts generally require us to indemnify our customers for environmental claims suffered by them as a result of our actions. In addition, some environmental laws impose strict, joint and several liability for investigative and remediation costs in relation to releases of harmful substances. These laws may impose liability without regard to negligence or fault. We also may be subject to claims alleging personal injury or property damage if we cause the release of, or any exposure to, harmful substances.

We own or lease, and operate, several properties that have been used for a number of years for the storage and maintenance of equipment and other industrial uses. Fuel may have been spilled, or hydrocarbons or other wastes may have been released on these properties. Any release of substances by us or by third parties who previously operated on these properties may be subject to laws which impose joint and several liability for clean-up, without regard to fault, on specific classes of persons who are considered to be responsible for the release of harmful substances into the environment.

Failure by our customers to obtain required permits and licenses may affect the demand for our services.

The development of the oil sands requires our customers to obtain regulatory or other permits and licenses from various governmental licensing bodies. Our customers may not be able to obtain all necessary permits and licenses that may be required for the development of the oil sands on their properties. In such a case, our customers' projects will not proceed, thereby adversely impacting demand for our services.

Our projects expose us to potential professional liability, product liability, warranty or other claims.

We install deep foundations, often in congested and densely populated areas, and provide construction management services for significant projects. Notwithstanding the fact that we generally will not accept liability for consequential damages in our contracts, any catastrophic occurrence in excess of insurance limits at projects where our structures are installed or services are performed could result in significant professional liability, product liability, warranty or other claims against us. Such liabilities could potentially exceed our current insurance coverage and the fees we derive from those services. A partially or completely uninsured claim, if successful and of a significant magnitude, could result in substantial losses.

We may not be able to achieve the expected benefits from any future acquisitions, which would adversely affect our financial condition and results of operations.

We intend to pursue selective acquisitions as a method of expanding our business. However, we may not be able to identify or successfully bid on businesses that we might find attractive. If we do find attractive acquisition opportunities, we might not be able to acquire these businesses at a reasonable price. If we do acquire other businesses, we might not be able to successfully integrate these



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businesses into our then-existing business. We might not be able to maintain the levels of operating efficiency that acquired companies will have achieved or might achieve separately. Successful integration of acquired operations will depend upon our ability to manage those operations and to eliminate redundant and excess costs. Because of difficulties in combining operations, we may not be able to achieve the cost savings and other size-related benefits that we hoped to achieve after these acquisitions. Any of these factors could harm our financial condition and results of operations.

Aboriginal peoples may make claims against our customers or their projects regarding the lands on which their projects are located.

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Any claims that may be asserted against our customers, if successful, could have an adverse effect on our customers which may, in turn, negatively impact our business.

Unanticipated short term shutdowns of our customers' operating facilities may result in temporary cessation or cancellation of projects in which we are participating.

The majority of our work is generated from the development, expansion and ongoing maintenance of oil sands mining, extraction and upgrading facilities. Unplanned shutdowns of these facilities due to events outside our control or the control of our customers, such as fires, mechanical breakdowns and technology failures, could lead to the temporary shutdown or complete cessation of projects in which we are working. When these events have happened in the past, our business has been adversely affected. Our ability to maintain revenues and margins may be affected to the extent these events cause reductions in the utilization of equipment.

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.

We recently made several significant changes to our senior management team. In May 2005, we hired a new Chief Executive Officer and promoted our Vice President, Operations to Chief Operating Officer. In January 2005 we hired a new Treasurer, who is now our Vice President, Finance. In June 2006, we hired a new Vice President, Human Resources, Health, Safety and Environment. We are currently searching for a Chief Financial Officer. As a result of these and other recent changes in senior management, many of our officers have only worked together as a management team for a short period of time and do not have a long history with us. Because our senior management team is responsible for the management of our business and operations, failure to successfully integrate our senior management team could have an adverse impact on our business, financial condition and results of operations.

Quantitative and Qualitative Disclosures Regarding Market Risk

Foreign currency risk

We are subject to currency exchange risk as our 8^{3/4}% senior notes and 9% senior secured notes are denominated in U.S. dollars and all of our revenues and most of our expenses are denominated in Canadian dollars. We have entered into cross currency swap and interest rate swap agreements to manage the foreign currency risk on the 8^{3/4}% senior notes. The hedging instrument consists 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 that results in us mitigating our exposure to the variability of cash flows caused by currency fluctuations relating to the US\$200 million senior notes. The hedges can be cancelled at the counterparty's option at any time after December 1, 2007 if the counterparty pays a cancellation premium. The premium is equal to 4.375% of the US\$200 million if exercised between December 1, 2007 and December 1, 2008; 2.1875% if exercised between December 1, 2008 and December 1, 2009; and 0.000% if cancelled after December 1, 2009. We have not hedged the foreign currency risk on the 9% senior secured notes. Each \$0.01 increase or decrease in the U.S. dollar-Canadian dollar exchange rate would change the interest cost on the 9% senior secured notes by \$0.05 million per year.



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Interest rate risk

We are subject to interest rate risk in connection with our revolving credit facility. The facility bears interest at variable rates based on the Canadian prime rate plus 2% or Canadian bankers' acceptance rate plus 3%. Assuming our then-existing revolving credit facility was fully drawn at \$40 million, excluding the \$18 million of outstanding letters of credit at June 30, 2006, each 1.0% increase or decrease in the applicable interest rate would have changed the interest cost by \$0.4 million per year. In the future, we may enter into interest rate swaps involving the exchange of floating for fixed rate interest payments to reduce interest rate volatility.

We also lease equipment with a variable lease payment tied to prime rates. At June 30, 2006, for each 1.0% annual fluctuation in this rate, annual lease expense will change by \$0.2 million.

Inflation

The rate of inflation has not had a material impact on our operations as many of our contracts contain a provision for annual escalation. If inflation remains at its recent levels, it is not expected to have a material impact on our operations in the foreseeable future if we are able to pass cost increases along to our customers.

Outlook

We have developed a strong business foundation through our relationships with the key organizations in the Canadian oil sands area of Alberta (Syncrude, CNRL, Suncor, Albian Sands, etc.) coupled with the long-term overburden work at CNRL. Our ability to build on this solid foundation continues to be enhanced as world economic growth underpins high prices in the oil and gas industries.

Activity in the Fort McMurray area remains very high and a number of high profile projects have been announced, including the acceleration of CNRL's expansion plans, Shell's Jackpine Mine and the Petro-Canada/UTS Fort Hills project. Accordingly, activity levels are expected to remain strong.

Over the last twelve months ended June 30, 2006, the Company's financial performance has improved as a result of completing a number of initiatives. We have completed the refinancing of our debt, the management team has been restructured and a number of processes that have strengthened the financial and operating controls have been implemented. Concurrent with these general changes, the Company launched a major business improvement initiative and re-organization aimed at increasing productivity and equipment utilization. These initiatives, coupled with the acquisition of new equipment ideally suited to heavy earth moving in the oil sands area, have strengthened our ability to bid competitively and profitably into the expanding market.

With respect to the Mining and Site Preparation operating segment, we are actively pursuing a strategy of retaining our leading position as a provider of mining and construction services in the Fort McMurray oil sands area while concurrently reducing risk by bidding into opportunities in resource areas outside the oil sands and in other Canadian provinces. Significant work at DeBeers' Victor diamond project in Northern Ontario supports this strategy. At the same time, our Piling segment remains a strong business, with the level of construction in the western provinces alone, it is considered likely that the work load will remain high in the foreseeable future. While the Pipeline segment had reduced activity for the fiscal year ended March 31, 2006, the three months ended June 30, 2006 has benefited from increased activity. Recent awarded projects as well as a multitude of announced projects to be commenced in this business area over the next two years auger well for this division to secure a considerable level of valuable work in the coming months.

We are not aware of any events, trends, uncertainties, demands or commitments that would materially affect our forecasted revenues, profitability, liquidity or capital resources or that would cause reported financial information not to be indicative of future operating results or financial condition.