IVANHOE ENERGY INC
Form 10-Q
May 10, 2006

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2006

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________

Commission file number 000-30586

IVANHOE ENERGY INC.

(Exact name of registrant as specified in its charter)

Yukon, Canada	**98-0372413**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
Suite 654 999 Canada Place	
Vancouver, British Columbia, Canada	**V6C 3E1**
(Address of principal executive office)	*(zip code)*

(604) 688-8323

(registrant s telephone number, including area code)

No Changes

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark whether the registrant is large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o Accelerated filer þ Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

The number of shares of the registrant s capital stock outstanding as of March 31, 2006 was 229,430,769 Common Shares, no par value.

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Part I Financial Information

Item 1 Financial Statements
IVANHOE ENERGY INC.
Unaudited Condensed Consolidated Balance Sheets
(stated in thousands of U.S. Dollars, except share amounts)

	March 31, 2006	**December 31, 2005**
Assets		
Current Assets		
Cash and cash equivalents	**$ 7,460**	$ 6,724
Accounts receivable (net of allowance for doubtful accounts of $116 and $83 as at March 31, 2006 and December 31, 2005, respectively)	**7,193**	9,994
Prepaid and other current assets	**607**	338
	15,260	17,056
Oil and gas properties and investments, net	**138,893**	119,654
Intangible assets technology	**102,077**	102,068
Long term assets	**2,232**	2,099
	$ 258,462	$ 240,877
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 22,328**	$ 25,791
Notes payable current portion	**3,689**	1,667
Asset retirement obligations current portion	**950**	950
	26,967	28,408
Long term debt	**8,919**	4,972
Asset retirement obligations	**840**	830
Long term obligation	**1,900**	1,900
Commitments and contingencies		
Shareholders Equity		
Share capital, issued 229,430,769 common shares; December 31, 2005 220,779,335 common shares	**311,237**	291,088
Purchase warrants	**5,150**	5,150
Contributed surplus	**4,116**	3,820
Accumulated deficit	**(100,667)**	(95,291)

		219,836		204,767
	$	**258,462**	$	240,877

(See accompanying notes)

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IVANHOE ENERGY INC.
Unaudited Condensed Consolidated Statements of Operations and Accumulated Deficit
Three-Month Periods Ended March 31
(stated in thousands of U.S. Dollars, except per share amounts)

	2006	2005
Revenue		
Oil and gas revenue	**$ 9,826**	$ 5,693
Interest income	**38**	43
	9,864	5,736
Expenses		
Operating costs	**2,716**	1,762
General and administrative	**2,000**	2,411
Business and product development	**1,662**	719
Depletion and depreciation	**7,847**	2,207
Interest expense and financing costs	**265**	120
Provision for impairment	**750**	
	15,240	7,219
Net Loss	**5,376**	1,483
Accumulated Deficit, beginning of period	**95,291**	81,779
Accumulated Deficit, end of period	**$ 100,667**	$ 83,262
Net Loss per share Basic and Diluted	**$ 0.02**	$ 0.01
Weighted Average Number of Shares (in thousands)	**224,547**	169,816

(See accompanying notes)
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IVANHOE ENERGY INC.
Unaudited Condensed Consolidated Statements of Cash Flow
Three-Month Periods Ended March 31
(stated in thousands of U.S. Dollars)

	2006	2005
Operating Activities		
Net loss	**$ (5,376)**	$ (1,483)
Items not requiring use of cash:		
Depletion and depreciation	**7,847**	2,207
Provision for impairment	**750**	
Stock based compensation	**353**	296
Other	**98**	16
Changes in non-cash working capital items	**(1,592)**	56
	2,080	1,092
Investing Activities		
Capital investments	**(4,892)**	(12,287)
Merger and acquisition related costs	**(177)**	(730)
Proceeds from sale of assets	**5,350**	
Advance payments		(300)
Other	**(9)**	
Changes in non-cash working capital items	**(1,085)**	6,883
	(813)	(6,434)
Financing Activities		
Proceeds from exercise of options	**91**	35
Proceeds from debt obligations		6,000
Payments of debt obligations	**(622)**	(417)
Other		(263)
	(531)	5,355
Increase in cash and cash equivalents, for the period	**736**	13
Cash and cash equivalents, beginning of period	**6,724**	9,322
Cash and cash equivalents, end of period	**$ 7,460**	$ 9,335

(See accompanying notes)

Notes to the Condensed Consolidated Financial Statements
March 31, 2006
(all tabular amounts are expressed in thousands of U.S. dollars except per share amounts)
(Unaudited)

1. BASIS OF PRESENTATION

The Company s accounting policies are in accordance with accounting principles generally accepted in Canada. These policies are consistent with accounting principles generally accepted in the U.S., except as outlined in Note 16. The unaudited condensed consolidated financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2005 consolidated financial statements. These interim condensed consolidated financial statements do not include all disclosures normally provided in annual consolidated financial statements and should be read in conjunction with the most recent annual consolidated financial statements. The December 31, 2005 condensed consolidated balance sheet was derived from the audited consolidated financial statements, but does not include all disclosures required by generally accepted accounting principles (**GAAP**) in Canada and the U.S. In the opinion of management, all adjustments (which included normal recurring adjustments) necessary for the fair presentation for the interim periods have been made. The results of operations and cash flows are not necessarily indicative of the results for a full year.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts and other disclosures in these condensed consolidated financial statements. Actual results may differ from those estimates.

2. SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

As more fully described in Note 13, on April 15, 2005 the Company acquired all the issued and outstanding common shares of Ensyn Group, Inc. (**Ensyn**) pursuant to a merger between Ensyn and a wholly owned subsidiary of the Company (**Merger**) in accordance with an Agreement and Plan of Merger dated December 11, 2004 (**Merger Agreement**). This acquisition was accounted for using the purchase method. These condensed consolidated financial statements include the accounts of Ivanhoe Energy Inc. and its subsidiaries, including those acquired in the Merger, all of which are wholly owned.

The Company conducts most exploration, development and production activities in its oil and gas business jointly with others. Our accounts reflect only the Company s proportionate interest in the assets and liabilities of these joint ventures.

All inter-company transactions and balances have been eliminated for the purposes of these condensed consolidated financial statements.

3. OIL AND GAS PROPERTIES AND INVESTMENTS

Capital assets categorized by geographical location and business segment are as follows:

	As at March 31, 2006				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 94,740	$ 102,337	$	$	$ 197,077
Unproved	10,578	5,756			16,334
	105,318	108,093			213,411
Accumulated depletion	(17,095)	(21,458)			(38,553)
Accumulated provision for impairment	(50,350)	(5,750)			(56,100)
	37,873	80,885			118,758
GTL and EOR Investments:					
Feasibility studies and other deferred costs			4,788	6,495	11,283
Commercial demonstration facility				9,929	9,929
Accumulated depreciation				(1,229)	(1,229)
			4,788	15,195	19,983
Furniture and equipment	487	95		15	597
Accumulated depreciation	(396)	(41)		(8)	(445)
	91	54		7	152
	$ 37,964	$ 80,939	$ 4,788	$ 15,202	$ 138,893

	As at December 31, 2005				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 99,721	$ 71,760	$	$	$ 171,481
Unproved	9,676	5,320			14,996
	109,397	77,080			186,477
Accumulated depletion	(15,920)	(16,036)			(31,956)
Accumulated provision for impairment	(50,350)	(5,000)			(55,350)
	43,127	56,044			99,171
GTL and EOR Investments:					
Feasibility studies and other deferred costs			4,570	6,142	10,712
Commercial demonstration facility				9,599	9,599
			4,570	15,741	20,311

Furniture and equipment	485	95		15	595
Accumulated depreciation	(380)	(37)		(6)	(423)
	105	58		9	172
	$ 43,232	$ 56,102	$ 4,570	$ 15,750	$ 119,654

Costs as at March 31, 2006 and December 31, 2005 of $16.3 million and $15.0 million, respectively, related to unproved oil and gas properties were excluded from the depletion and ceiling test calculations.

For the three-month periods ended March 31, 2006 and 2005, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities, and investments in gas-to-liquids (**GTL**) and enhanced oil recovery (**EOR**) projects of $0.8 million and $0.9 million, respectively, were capitalized.

The Company re-acquired a 40% working interest in the Dagang oil project in February of 2006 (See Note 13). The total purchase price was $28.3 million and has been included in China s proved properties as at March 31, 2006.

The Company sold its interest in certain California properties for $5.4 million with an effective sale date of February 1, 2006. This sale did not significantly alter the depletion rate, therefore the proceeds were credited to U.S. proved properties with no gain or loss recognized.

As at March 31, 2006 and December 31, 2005, EOR investments included $9.9 million and $9.6 million, respectively, of costs associated with the rapid thermal processing technology (**RTPTM Technology**) commercial demonstration facility located in California s San Joaquin Basin. The RTPTM commercial demonstration facility (**RTPTM CDF**) was in a commissioning phase as at December 31, 2005 and, as such, was not depreciated, nor impaired, for the year ended December 31, 2005. The commissioning phase ended in January 2006 and the RTPTM CDF was placed into service. There was no revenue associated with the RTPTM CDF operations for the three-month periods ended March 31, 2006 and 2005. For the three-month period ended March 31, 2006, $1.2 million of depreciation was recorded for the RTPTM CDF. Depreciation of the RTPTM CDF is calculated using the straight-line method over its useful life of one year.

4. INTANGIBLE ASSETS TECHNOLOGY

The Company s intangible assets consist of the following:

RTPTM Technology

In the Merger with Ensyn, the Company acquired an exclusive, irrevocable license to deploy, worldwide, the RTPTM Technology for petroleum applications as well as the exclusive right to deploy RTPTM Technology in all applications other than biomass. The RTPTM Technology upgrades the quality of heavy oil by producing lighter, more valuable crude oil. The heaviest hydrocarbon fraction is consumed as fuel to generate the steam used to enhance recovery of heavy crude. The lighter crude has improved viscosity that permits more efficient pumping through pipeline networks and potentially reduces transportation costs to marketing points. The RTPTM Technology uses readily available plant and process components. The Company s carrying value of the RTPTM Technology as at March 31, 2006 and December 31, 2005 was $92.1 million.

Syntroleum Master License

The Company owns a master license from Syntroleum Corporation (**Syntroleum**) permitting the Company to use Syntroleum s proprietary GTL process in an unlimited number of projects around the world. The Company s master license expires on the later of April 2015 or five years from the effective date of the last site license issued to the Company by Syntroleum. The Syntroleum GTL process converts natural gas into synthetic liquid hydrocarbons that can be utilized to develop, among other things, clean-burning diesel fuel. In July 2003, the master license was amended in respect of GTL projects in which both the Company and Syntroleum participate such that no additional license fees or royalties will be payable by the Company and that Syntroleum will contribute, to any such project, the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but the Company would be required to pay the normal license fees and royalties in such projects. The Company s carrying value of the Syntroleum master license as at March 31, 2006 and December 31, 2005 was $10.0 million.

These intangible assets were not amortized and their carrying values were not impaired for the three-month periods ended March 31, 2006 and 2005.

5. NOTES PAYABLE

Notes payable consisted of the following as at:

	March 31, 2006	December 31, 2005
Variable rate bank note, 7.375% as at March 31, 2006 and December 31, 2005, due 2006 though 2007	$ 2,222	$ 2,639
8% promissory note, due 2007	4,000	4,000
Non-interest bearing promissory note, due 2006 through 2009	6,385	
	12,608	6,639
Less:		
Unamortized discount	(795)	
Current maturities	(3,689)	(1,667)
	(4,484)	(1,667)
	$ 8,123	$ 4,972

Bank Note

In February 2003, the Company obtained a bank facility for up to $5.0 million to develop the southern expansion of its South Midway field. The bank facility was fully drawn in July 2004 and repayment of the principal and interest commenced in August 2004 with interest at 0.5% above the bank s prime rate or 3.0% over the London Inter-Bank Offered rate, at the option of the Company. The principal and interest are repayable, monthly, over a three-year period ending July 2007. The note is secured by all the Company s rights and interests in the South Midway properties.

Promissory Notes

As at December 31, 2004, the Company had a stand-by loan facility for $6.0 million. In February 2005, the Company borrowed the full amount of this stand-by loan facility and amended the loan agreement to provide the lender the right to convert, at the lender s election, unpaid principal and interest during the loan term to the Company s common shares at $2.25 per share. In May 2005, the Company finalized a second convertible loan agreement with the same lender for $2.0 million which provided the lender the right to convert, at the lender s election, unpaid principal and interest during the loan term to the Company s common shares at $2.15 per share.

In November 2005, the Company signed an agreement with the lender of the convertible debt to repay $4.0 million of the convertible debt with 2,453,988 common shares of the Company at $1.63 per share. Additionally, the residual $4.0 million of convertible debt was refinanced with a $4.0 million promissory note due November 23, 2007 with interest payable monthly at a rate of 8% per annum. The previously granted conversion rights attached to the convertible debt were cancelled and the Company granted the lender 2,000,000 purchase warrants, each of which entitles the holder to purchase one common share at a price of $2.00 per share until November 2007 (See Note 8). This note was repaid in April 2006 (See Note 15).

In February 2006, the Company re-acquired the 40% working interest in the Dagang oil project not already owned by the Company. Part of the consideration was a non-interest bearing, unsecured note payable issued by the Company of approximately $7.4 million. The note is payable in 36 equal monthly installments commencing March 31, 2006 (See Note 13).

Revolving Line of Credit

The Company has a revolving credit facility for up to $1.25 million from a related party, repayable with interest at U.S. prime plus 3%. The Company did not draw down any funds from this credit facility for the three-month periods ended March 31, 2006 and 2005.

The scheduled maturities of the notes payable, excluding unamortized discount, as at March 31, 2006 were as follows:

2006	$ 3,095
2007	7,432
2008	2,460
2009	416
	$ 13,403

6. ASSET RETIREMENT OBLIGATIONS

The Company provides for the expected costs required to abandon its producing U.S. oil and gas properties and the RTP^{TM} CDF. The undiscounted amount of expected future cash flows required to settle the Company s asset retirement obligations for these assets as at March 31, 2006 was estimated at $2.3 million. The liability for the expected future cash flows, as reflected in the financial statements, has been discounted at 5% to 7% and the changes in the Company s liability for the three-month period ended March 31, 2006 were as follows:

Balance as at December 31, 2005	$ 1,780
Liabilities transferred	(32)
Accretion expense	13
Revisions in estimated cash flows	29
Balance as at March 31, 2006	1,790
Less: current portion	(950)
	$ 840

The current portion of the asset retirement obligation at March 31, 2006 was the Company s provision for the cost to abandon the Northwest Lost Hills # 1-22 well in 2006.

7. COMMITMENTS AND CONTINGENCIES

Zitong Block Exploration Commitment

With the signing of the production-sharing contract for the Zitong block, the Company was obligated to conduct a minimum exploration program during the first three years ending December 1, 2005 (**Phase 1**). The Phase 1 work program included acquiring approximately 300 miles of new seismic lines, reprocessing approximately 1,250 miles of existing seismic and drilling a minimum of approximately 23,000 feet. The Company completed Phase 1 with the exception of drilling approximately 13,800 feet. The first Phase 1 exploration well drilled in 2005 was suspended, having found no commercial quantities of hydrocarbons. In December 2005, the Company was granted an extension of Phase 1 to May 31, 2006 and in April, 2006, a further extension was granted provided the second Phase 1 exploration well is spud before November 30, 2006.

In January 2006, the Company farmed-out 10% of its working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**) for $4.0 million subject to the approval of China National Petroleum Corporation (**CNPC**) and PetroChina. Mitsubishi has the option to increase its participating interest to 20% by paying $0.4 million plus costs per percentage point prior to any discovery, or $8.0 million plus costs for an additional 10% interest after completion and testing of the first well drilled under the farm-out agreement. The Company and Mitsubishi (the **Zitong Partners**) are planning to spud a second Phase 1 exploration well before November 30, 2006 after which a decision will be made whether or not to enter into the next three-year exploration phase (**Phase 2**). If the Company elects not to enter into Phase 2, it will be required to pay CNPC, within 30 days after its election, a cash equivalent of its share of the deficiency in the work program estimated to be $0.3 million after the drilling of the second Phase 1 well. If the Company elects not to enter Phase 2, the costs related to the

Zitong block in the approximate amount of $5.8 million, which are not already included in the depletable base of the China full cost pool, will be subject to the ceiling test. This could result in a ceiling test impairment related to the China full cost pool in an amount, which is not determinable at this time.

If the Zitong Partners elect to participate in Phase 2, they must complete a minimum work program consisting of new seismic lines equal to approximately 200 miles and drill approximately 23,000 feet, with estimated minimum expenditures for the program of $16 million. Following the completion of Phase 2, the Zitong Partners must relinquish all of the property except any areas identified for development and production. If the Zitong Partners elect to enter into Phase 2, they must complete the minimum work program or will be obligated to pay to CNPC the cash equivalent of the deficiency in the work program for that exploration phase.

Long Term Obligation

As part of the Merger with Ensyn, the Company assumed an obligation to pay $1.9 million in the event, and at such time that, the sale of units incorporating the RTP™ Technology for petroleum applications reach a total of $100 million. This obligation was recorded in the Company s consolidated balance sheet as at March 31, 2006 and December 31, 2005 as part of the net assets acquired in the Merger.

Other Commitments

The Company assumed an obligation to advance to a subsidiary of Ensyn Corporation, formed from the spin-off of Ensyn s Renewables Business immediately prior to the Merger, up to approximately $0.4 million if this subsidiary cannot meet certain debt servicing ratios required under a Canadian municipal government loan agreement. The loan principal is repayable in nine equal annual installments commencing April 1, 2006 and ending April 1, 2014. Ensyn Corporation has agreed to indemnify the Company for any amounts advanced to the subsidiary under the loan agreement.

The Company may provide indemnifications, in the course of normal operations, that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid. The Company s management is of the opinion that any resulting settlements relating to potential litigation matters or indemnifications would not materially affect the financial position of the Company.

8. SHARE CAPITAL

Following is a summary of the changes in share capital and stock options outstanding for the three-month period ended March 31, 2006:

	Common Shares			Stock Options	
	Number (thousands)	Amount	Contributed Surplus	Number (thousands)	Weighted Average Exercise Price Cdn.$
Balance December 31, 2005	220,779	$ 291,088	$ 3,820	10,278	$ 2.21
Shares issued for:					
Acquisition of oil and gas assets	8,592	20,000			
Exercise of options	60	149	(57)	(60)	$ 1.98
Options:					
Granted				80	$ 3.53
Stock based compensation			353		
Balance March 31, 2006	229,431	$ 311,237	$ 4,116	10,298	$ 2.10

Purchase Warrants

The following reflects the changes in the Company s purchase warrants and common shares issuable upon the exercise of the purchase warrants for the three-month period ended March 31, 2006:

	Purchase Warrants	Common Shares Issuable
	(thousands)	
Balance December 31, 2005	25,469	21,883
Purchase warrants expired	(7,173)	(3,587)
Balance March 31, 2006	18,296	18,296

As at March 31, 2006, the following purchase warrants were exercisable to purchase common shares of the Company until the expiry date at the price per share as indicated below:

			Purchase Warrants				
Year of Issue	Price per Special Warrant	Issued	Exercisable	Common Shares Issuable	Value ($U.S. 000)	Expiry Date	Exercise Price per Share
			(thousands)				
2005	Cdn. $3.10	4,100	4,100	4,100	$ 2,412	April 2007	Cdn. $3.50
2005	Cdn. $3.10	1,000	1,000	1,000	534	July 2007	Cdn. $3.50
2005	U.S. $1.63	11,196	11,196	11,196	1,891	November 2007	U.S. $2.50
2005	n/a	2,000	2,000	2,000	313	November 2007	U.S. $2.00
		18,296	18,296	18,296	$ 5,150		

The weighted average exercise price of the exercisable purchase warrants, as at March 31, 2006 was U.S. $2.58 per share.

9. STOCK BASED COMPENSATION

The Company accounts for all stock options granted using the fair value based method of accounting. This method was adopted effective January 1, 2004 for stock options granted to employees and directors after January 1, 2002. Under this method, compensation costs are recognized in the financial statements over the stock options vesting period using an option-pricing model for determining the fair value of the stock options at the grant date.

For the three-month periods ended March 31, 2006 and 2005, the Company expensed $0.4 million and $0.3 million, respectively, in stock based compensation.

10. PROVISION FOR IMPAIRMENT

On March 25, 2006, the Ministry of Finance of the Peoples Republic of China (**PRC**) issued the Administrative Measures on Collection of Windfall Gain Levy on Oil Exploitation Business (the **Windfall Levy Measures**). According to the Windfall Levy Measures, effective as of March 26, 2006, enterprises exploiting and selling crude oil in the PRC are subject to a windfall gain levy (the **Windfall Levy**) if the monthly weighted average price of crude oil is above $40 per barrel. The Windfall Levy is imposed at progressive rates from 20% to 40% on the portion of the weighted average sales price exceeding $40 per barrel. The Company understands that the Windfall Levy will be deductible for corporate income tax purposes in the PRC and will be eligible for cost recovery under the Company s production sharing contract with CNPC in respect of the Dagang project. Although management has not yet fully assessed the financial impact of the Windfall Levy, at current oil sales prices of approximately $60 per barrel, the application of the Windfall Levy is expected to reduce the Company s revenue by approximately $0.3 million per month. However, its effect may, in part, be offset by recent increases in the price of oil in world markets. In addition, we evaluate the carrying value of our oil and gas properties for impairment and recognize any impairment on a quarterly basis (**ceiling test**). The imposition of the Windfall Levy resulted in an impairment of the Company s oil and gas properties of $0.8 million for the three-month period ended March 31, 2006.

11. SEGMENT INFORMATION

The Company has three reportable business segments: Oil and Gas, GTL and EOR.

Oil and Gas

The Company explores for, develops and produces crude oil and natural gas in the U.S. and in China. In the U.S., the Company s exploration, development and production activities are primarily conducted in California and Texas. In China, the Company s development and production activities are conducted at the Dagang oil field located in Hebei Province and exploration activities in the Zitong block located in Sichuan Province.

GTL

The Company holds a master license from Syntroleum to use its proprietary GTL technology to convert natural gas into synthetic fuels. The master license allows the Company to use Syntroleum s proprietary process in an unlimited number of GTL projects throughout the world to convert natural gas into an unlimited volume of ultra clean transportation fuels and other synthetic petroleum products. The Company does not currently own or operate any GTL projects but in the fourth quarter of 2005 entered into a memorandum of understanding (**MOU**) with Egyptian National Gas Holding Company to prepare a feasibility study to construct and operate a GTL plant in Egypt. Plant capacity options of 47,000 and 94,000 barrels per day have been evaluated.

EOR

The Company seeks projects requiring relatively low initial capital outlays to which it can apply innovative technology and enhanced recovery techniques in developing them. The most significant element of the Company s EOR segment is the application of the RTP™ Technology to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. In addition, an RTP™ facility can yield surplus energy for producing steam and electricity used in heavy-oil production. The thermal energy from the RTP™ process provides heavy-oil producers with an alternative to natural gas that now is widely used to generate steam.

The Company maintains a corporate office in Canada with its operational office in the U.S. For this note, any amounts for the corporate office in Canada are included in Corporate**.**

The following tables present the Company s interim segment information for the three-month periods ended March 31, 2006 and 2005 and identifiable assets as at March 31, 2006 and December 31, 2005:

	Three-Month Period Ended March 31, 2006					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 2,991	$ 6,835	$	$	$	$ 9,826
Interest income	14	2			22	38
	3,005	6,837			22	9,864
Operating costs	1,204	1,512				2,716
General and administrative	373	345			1,282	2,000
Business and product development			352	1,310		1,662
Depletion and depreciation	1,188	5,424	3	1,231	1	7,847
Interest expense and financing costs	62	45		1	157	265
Write-downs and provision for impairment		750				750
	2,827	8,076	355	2,542	1,440	15,240
Net (Income) Loss	$ (178)	$ 1,239	$ 355	$ 2,542	$ 1,418	$ 5,376
Capital Investments	$ 1,274	$ 2,717	$ 218	$ 683	$	$ 4,892
Identifiable Assets (As at March 31, 2006)	$ 46,441	$ 87,223	$ 14,822	$ 107,316	$ 2,660	$ 258,462
Identifiable Assets (As at December 31, 2005)	$ 48,070	$ 65,020	$ 14,609	$ 107,869	$ 5,309	$ 240,877

	Three-Month Period Ended March 31, 2005					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 2,869	$ 2,824	$	$	$	$ 5,693
Interest income	6	2			35	43
	2,875	2,826			35	5,736
Operating costs	1,116	646				1,762
General and administrative	157	224			2,030	2,411
Business and product development			404	315		719

Depletion and depreciation	1,167	1,034	3	2	1	2,207
Interest expense and financing costs	70				50	120
	2,510	1,904	407	317	2,081	7,219
Net (Income) Loss	$ (365)	$ (922)	$ 407	$ 317	$ 2,046	$ 1,483
Capital Investments	$ 807	$ 9,551	$ 215	$ 1,714	$	$ 12,287

12. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information for the three-month periods ended March 31,:

	2006	2005
Cash paid during the period for:		
Income taxes	**$ 6**	$ 2
Interest	**$ 171**	$ 56
Investing and Financing activities, non-cash:		
Acquisition of oil and gas assets		
Shares issued	**$ 20,000**	$
Debt issued	**6,547**	
Receivable applied to acquisition	**1,746**	
	$ 28,293	$
Changes in non-cash working capital items		
Operating Activities:		
Accounts receivable	**$ (1,021)**	$ 261
Prepaid and other current assets	**(254)**	(130)
Accounts payable and accrued liabilities	**(317)**	(75)
	(1,592)	56
Investing Activities		
Accounts receivable	**2,076**	(837)
Prepaid and other current assets	**(15)**	223
Accounts payable and accrued liabilities	**(3,146)**	7,497
	(1,085)	6,883
	$ (2,677)	$ 6,939

13. MERGER AND ACQUISITIONS

On April 15, 2005, the Company and Ensyn completed the Merger (as more fully described in the Company s 2005 Annual Report filed on Form 10-K) in which the Company paid $10.0 million in cash and issued approximately 30 million Ivanhoe common shares (**Merger Shares**) in exchange for all of the issued and outstanding Ensyn common shares. Ten million of the Merger Shares issued were deposited in an escrow fund and are being held to secure certain obligations on the part of the former Ensyn stockholders to indemnify the Company for damages in the event of any breaches of representations, warranties and covenants in the Merger Agreement and certain liabilities, including those arising from any failure by Ensyn to meet certain development milestones set out in the Merger Agreement.

The January 2004 Dagang field farm-out agreement between the Company and Richfirst Holdings Limited (**Richfirst**), provided Richfirst with the right to convert its working interest in the Dagang field for the Company s common shares at any time prior to eighteen months after closing the farm-out agreement. Richfirst elected to convert its 40% working interest in the Dagang field and in February 2006 the Company re-acquired Richfirst s 40% working interest for a total of $28.3 million consisting of 8,591,434 of the Company s common shares for $20.0 million, a non-interest bearing, unsecured note payable of approximately $7.4 million ($6.5 million after being discounted to net present value) and the forgiveness of $1.8 million of unpaid joint venture receivables. The note is payable in 36 equal monthly installments commencing March 31, 2006. The Company has the right, during the three-year loan repayment period, to require Richfirst to convert the remaining balance of the loan into common shares of Sunwing Energy Ltd (**Sunwing**), the Company s wholly-owned subsidiary, or another company owning all of the outstanding shares of Sunwing, subject to Sunwing or the other company having obtained a listing of its common shares on a prescribed stock exchange. The number of shares issued would be determined by dividing the then outstanding loan balance by the issue price of the newly listed company less a 10% discount.

In February 2006, the Company signed a non-binding MOU regarding a proposed merger of Sunwing with China Mineral Acquisition Corporation (**CMA**), a U.S. public corporation. CMA will effectively acquire all of the issued and outstanding shares of Sunwing for an aggregate acquisition price of $100 million subject to working capital and long-term debt adjustments at closing. The Company will receive common stock of CMA and it is expected that the Company will own between 75% and 80% of the issued and outstanding shares of CMA after the merger. The transaction is expected to be accounted for as a reverse acquisition. This transaction is subject to regulatory approval, negotiation of definitive documentation, completion of satisfactory due diligence, board approvals and the approval of CMA shareholders. There is no assurance that the agreement will be completed or completed in the form described above.

14. ENSYN AGREEMENTS

ConocoPhillips Canada Resources Corp.

Under a pre-existing agreement between Ensyn (which changed its name following the Merger to Ivanhoe Energy HTL Inc. (**IE HTL**)) and ConocoPhillips Canada Resources Corp. (**ConocoPhillips Canada**), certain non-exclusive rights to use the RTP Technology for petroleum applications in Canada were granted. ConocoPhillips Canada has the right, through August 2010, to place orders for RTP facilities with input capacity of up to 250,000 barrels-per-day. Should ConocoPhillips Canada install RTP facilities, IE HTL is entitled to receive royalties per barrel after the first 50,000 barrels-per day of feedstock input capacity.

15. SUBSEQUENT EVENT

On April 7, 2006, the Company closed a special warrant financing by way of private placement for $25.4 million. The financing consisted of 11,400,000 special warrants issued for cash at $2.23 per special warrant. Each special warrant entitles the holder to receive, at no additional cost, one common share and one common share purchase warrant. Each common share purchase warrant entitles the holder to purchase one common share at a price of $2.63 per share until the fifth anniversary date of the closing.

A portion of the proceeds of the financing, in the amount of $4.0 million, has been used to pay down long term debt. The balance of the proceeds will be used to pursue opportunities for the commercial deployment of its heavy oil upgrading technology, to advance its oil and gas operations, and for general corporate purposes.

16. ADDITIONAL DISCLOSURE REQUIRED UNDER U.S. GAAP

The Company s consolidated financial statements have been prepared in accordance with GAAP as applied in Canada. In the case of the Company, Canadian GAAP conforms in all material respects with U.S. GAAP except for certain matters, the details of which are as follows:

Condensed Consolidated Balance Sheets

Shareholders Equity and Oil and Gas Properties and Investments

	As at March 31, 2006				
			Shareholders Equity		
	Oil and Gas Properties and Investments	**Share Capital and Warrants**	**Contributed Surplus**	**Accumulated Deficit**	**Total**
Canadian GAAP	$ 138,893	$ 316,387	$ 4,116	$ (100,667)	$ 219,836
Adjustments for:					
Reduction in stated capital		74,455		(74,455)	
Accounting for stock based compensation		(373)	(3,375)	3,748	
Ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358			1,358
Provision for impairment	(14,600)			(14,600)	(14,600)
Depletion adjustments due to differences in provision for impairment	1,847			1,847	1,847
GTL and EOR development costs expensed	(11,283)			(11,283)	(11,283)
U.S. GAAP	$ 116,215	$ 391,827	$ 741	$ (195,410)	$ 197,158

	As at December 31, 2005				
			Shareholders Equity		
	Oil and Gas Properties and Investments	**Share Capital and Warrants**	**Contributed Surplus**	**Accumulated Deficit**	**Total**
Canadian GAAP	$ 119,654	$ 296,238	$ 3,820	$ (95,291)	$ 204,767
Adjustments for:					
Reduction in stated capital		74,455		(74,455)	
Accounting for stock based compensation		(316)	(3,432)	3,748	
Ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358			1,358
Provision for impairment	(8,150)			(8,150)	(8,150)
Depletion adjustments due to differences in provision for impairment	1,562			1,562	1,562
GTL and EOR development costs expensed	(10,712)			(10,712)	(10,712)
U.S. GAAP	$ 103,712	$ 371,735	$ 388	$ (183,298)	$ 188,825

Shareholders Equity

In June 1999, the shareholders approved a reduction of stated capital in respect of the common shares by an amount of $74.4 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the accumulated deficit such as this is not recognized except in the case of a quasi reorganization. The effect of this is that under U.S. GAAP, share capital and accumulated deficit are increased by $74.4 million as at March 31, 2006 and December 31, 2005.

For Canadian GAAP, the Company accounts for all stock options granted to employees and directors since January 1, 2002 using the fair value based method of accounting. Under this method, compensation costs are recognized in the financial statements over the stock options vesting period using an option-pricing model for determining the fair value of the stock options at the grant date. For U.S. GAAP, prior to January 1, 2006 the Company applied APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and did not recognize compensation costs in its financial statements for stock options issued to employees and directors. This resulted in a reduction of $3.7 million in the accumulated deficit as at March 31, 2006, and December 31, 2005, equal to accumulated stock based compensation for stock options granted to employees and directors since January 1, 2002 and expensed through December 31, 2005 under Canadian GAAP.

In December 2004, the Financial Accounting Standards Board (**FASB**) issued a revision to SFAS No. 123, Accounting for Stock Based Compensation which supersedes APB No. 25, Accounting for Stock Issued to Employees . This statement (**SFAS No. 123(R)**) requires measurement of the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant and recognition of the cost in the results of operations over the period during which an employee is required to provide service in exchange for the award. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. The Company elected to implement this statement on a modified prospective basis starting in the first quarter of 2006. Under the modified prospective basis the Company began recognizing stock based compensation in its U.S. GAAP results of operations for the unvested portion of awards outstanding as at January 1, 2006 and for all awards granted after January 1, 2006. There were no differences in the Company s stock based compensation expense in its financial statements for Canadian GAAP and U.S. GAAP for the three-month period ended March 31, 2006.

Oil and Gas Properties and Investments

For U.S. GAAP purposes, the aggregate value attributed to the acquisition of U.S. royalty rights during 1999 and 2000 was $1.4 million higher, due to the difference between Canadian and U.S. GAAP in the value ascribed to the shares issued, primarily resulting from differences in the recognition of effective dates of the transactions.

As more fully described in our financial statements in Item 8 of our 2005 Annual Report filed on Form 10-K, there are differences between the full cost method of accounting for oil and gas properties as applied in Canada and as applied in the U.S. The principal difference is in the method of performing ceiling test evaluations under the full cost method of accounting rules. The Company performed the ceiling test in accordance with U.S. GAAP and determined that for the three-months ended March 31, 2006 an impairment provision of $7.2 million was required on its China properties compared to a $0.8 million impairment provision under Canadian GAAP. The differences in the ceiling test impairments by period for the U.S. and China properties between U.S. and Canadian GAAP as at March 31, 2006 were as follows:

	Ceiling Test Impairments		(Increase)
	U.S. GAAP	Canadian GAAP	Decrease
U.S. Properties			
Prior to 2004	$ 34,000	$ 34,000	$
2004	15,000	16,350	1,350
2005	2,800		(2,800)
2006			
	51,800	50,350	(1,450)
China Properties			
Prior to 2004	10,000		(10,000)
2004			
2005	1,700	5,000	3,300
2006	7,200	750	(6,450)
	18,900	5,750	(13,150)
	$ 70,700	$ 56,100	$ (14,600)

The differences in the amount of impairment provisions between U.S. and Canadian GAAP resulted in a reduction in accumulated depletion of $1.8 million and $1.6 million as at March 31, 2006 and December 31, 2005, respectively.

As more fully described in our financial statements in Item 8 of our 2005 Annual Report filed on Form 10-K, for Canadian GAAP, the Company capitalizes certain costs incurred for GTL and EOR projects subsequent to executing a memorandum of understanding to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects   products. If no definitive agreement is reached, then the project   s capitalized costs, which are deemed to have no future value, are written down and charged to the results of operations with a corresponding reduction in the investments in GTL and EOR assets. For U.S. GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are considered to be research and development and are expensed as incurred. As at March 31, 2006 and December 31, 2005, the Company capitalized $11.3 million and $10.7 million, respectively, for Canadian GAAP, which was expensed for U.S. GAAP purposes.

Condensed Consolidated Statements of Operations

The application of U.S. GAAP had the following effects on net loss and net loss per share as reported under Canadian GAAP:

	Three-Month Periods Ended March 31,			
	2006		**2005**	
	Net Loss	**Net Loss Per Share**	**Net Loss**	**Net Loss Per Share**
Canadian GAAP	$ 5,376	$ 0.02	$ 1,483	$ 0.01
Stock based compensation expense			(232)	
Provision for impairment	6,450	0.03		
Depletion adjustments due to differences in provision for impairment	(285)		(172)	
GTL and EOR development costs expensed, net	571		1,929	0.01
U.S. GAAP	$ 12,112	0.05	$ 3,008	$ 0.02
Weighted Average Number of Shares under U.S. GAAP (in thousands)		224,547		169,816

As discussed under Shareholders Equity in this note, for U.S. GAAP, the Company applied APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and did not recognize compensation costs in its financial statements for stock options issued to employees and directors prior to January 1, 2006. This resulted in a reduction of $0.2 million in the net losses for the three-month period ended March 31, 2005. Also, discussed under Shareholders Equity in this note, for U.S. GAAP, the Company implemented SFAS 123(R) on January 1, 2006 which resulted in no differences in stock based compensation expense for the three-month period ended March 31, 2006.

As discussed under Oil and Gas Properties and Investments in this note, there is a difference in performing the ceiling test evaluation under the full cost method of the accounting rules between U.S. and Canadian GAAP. Application of the ceiling test evaluation under U.S. GAAP has resulted in an accumulated net increase in impairment provisions on the Company s U.S. and China oil and gas properties of $14.6 million as at March 31, 2006. This net increase in U.S. GAAP impairment provisions has resulted in lower depletion rates for U.S. GAAP purposes and a reduction of $0.3 million and $0.2 million in the net losses for the three-month periods ended March 31, 2006 and 2005, respectively.

As more fully described under Oil and Gas Properties and Investments in this note, for Canadian GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are capitalized and are subsequently written down upon determination that a project s future value has been impaired. For U.S. GAAP, such costs are considered to be research and development and are expensed as incurred. For the three-month periods ended March 31, 2006 and 2005, the Company expensed $0.6 million and $1.9 million, respectively, in excess of the Canadian GAAP write-downs during those corresponding periods.

Stock Based Compensation

The Company has an Employees and Directors Equity Incentive Plan under which it can grant stock options to directors and eligible employees to purchase common shares, issue common shares to directors and eligible employees for bonus awards and issue shares under a share purchase plan for eligible employees. The total shares under this plan can not exceed 20 million.

Stock options are issued at not less than the fair market value on the date of the grant and are conditional on continuing employment. Expiration and vesting periods are set at the discretion of the Board of Directors. Stock options granted prior to March 1, 1999 vested over a two-year period and expire ten years from date of issue. Stock options granted after March 1, 1999 vest over four years and expire five to ten years from the date of issue.

The fair value of each option award is estimated on the date of grant using the Black-Scholes (**B-S**) option-pricing formula and amortized on a straight-line attribution approach with the following weighted-average assumptions for the three-month period ended March 31, 2006:

Expected term (in years)	4.00
Expected volatility	83.42%
Dividend yield	0.00%
Risk-free rate	4.08%

The Company s expected term represents the period that the Company s stock-based awards are expected to be outstanding and was determined based on historical experience of similar awards, giving consideration to the contractual terms of the stock-based awards, vesting schedules and expectations of future employee behavior as influenced by changes to the terms of is stock-based awards. The fair value of stock-based payments were valued using the B-S valuation method with an expected volatility factor based on the Company s historical stock prices. The B-S valuation model calls for a single expected dividend yield as an input. The Company has not paid and does not anticipate paying any dividends in the near future. The Company bases the risk-free interest rate used in the B-S valuation method on the implied yield currently available on Canadian zero-coupon issue bonds with an equivalent remaining term. When estimating forfeitures, the Company considers historical voluntary termination behavior as well as future expectations of workforce reductions. The Company recognizes compensation costs only for those equity awards expected to vest.

The summary of option activity as at March 31, 2006, and changes during the three-month period then ended is presented below:

	Number of Stock Options (thousands)	**Weighted-Average Exercise Price (Cdn.$)**	**Weighted-Average Contractual Term**	**Aggregate Intrinsic Value (Cdn.$ in thousands)**
Outstanding as at December 31, 2005	10,278	$ 2.21		
Granted	80	$ 3.53		
Exercised	(60)	$ 1.98		
Outstanding as at March 31, 2006	10,298	$ 2.22	2.9	$ 12,390
Options exercisable as at March 31, 2006	6,612	$ 1.76	2.4	$ 11,036

The total intrinsic value of options exercised during the three-month period ended March 31, 2006 was $0.1 million.

A summary of the Company s unvested options as at March 31, 2006, and changes during the three-month period ended March 31, 2006, is presented below:

	Number of Stock Options (thousands)	Weighted-Average Grant Date Fair Value (Cdn.$)
Unvested as at December 31, 2005	3,731	$ 1.47
Granted	80	$ 1.68
Vested	(125)	$ 1.57
Unvested as at March 31, 2006	3,686	$ 1.47

As at March 31, 2006, there was $3.4 million of total unrecognized compensation costs related to unvested share-based compensation arrangements granted by the Company. That cost is expected to be recognized over a weighted-average period of 1.8 years. The total fair value of shares vested during the three-month period ended March 31, 2006 was $0.2 million.

Had stock based compensation expense been determined based on fair value at the stock option grant date, consistent with the method of SFAS No. 123 prior to January 1, 2006 the Company s net loss and net loss per share would have been increased to the pro forma amounts indicated below:

For the three-month period ended March 31, 2005:	
Net loss under U.S. GAAP	$ 3,008
Stock-based compensation expense determined under the fair value based method for employee and director awards	263
Pro forma net loss under U.S. GAAP	$ 3,271
Basic loss per common share under U.S. GAAP:	
As reported	$ 0.02
Pro forma	$ 0.02
Weighted Average Number of Shares under U.S. GAAP (in thousands)	169,816

Prior to January 1, 2006 stock based compensation for U.S. GAAP was calculated in accordance with the B-S option-pricing model using the same assumptions as used for Canadian GAAP.

Pro Forma Effect of Merger and Acquisition

The Company s U.S. GAAP consolidated results of operations for the three-month period ended March 31, 2005 do not include any amounts associated with the operations acquired from Ensyn as the completion of the Merger was on April 15, 2005. Had the Merger been completed on January 1, 2005, the pro forma revenue, net loss and net loss per share of the merged entity for the three-month period ended March 31, 2005 would have been as follows:

	Three-Month Period Ended March 31, 2005		
	Revenue	Net Loss	Net Loss Per Share
As reported	$ 5,736	$ 3,008	$ 0.02
Pro forma adjustments	730	180	

	$ 6,466	$ 3,188	$ 0.02
Weighted Average Number of Shares (in thousands)			192,127

Had the acquisition of Richfirst s 40% working interest in the Dagang field been completed January 1, 2006 or 2005, the U.S. GAAP pro forma revenue, net loss and net loss per share of the consolidated operations for the three-month periods ended March 31, 2006 and 2005 would have been as follows:

	Three Months Ended March 31, 2006			Three Months Ended March 31, 2005		
	Revenue	Net (Income) Loss	Net (Income) Loss Per Share	Revenue	Net (Income) Loss	Net (Income) Loss Per Share
As reported	$ 9,864	$ 12,112	$ 0.05	$ 5,736	$ 3,008	$ 0.02
Pro forma adjustments	1,051	(809)		1,535	(305)	(0.01)
	$ 10,915	$ 11,303	$ 0.05	$ 7,271	$ 2,703	$ 0.01
Weighted Average Number of Shares (in thousands)			229,415			178,407

Condensed Consolidated Statements of Cash Flow

As a result of the write-down of GTL and EOR development costs required under U.S. GAAP, the statements of cash flows as reported would result in a cash surplus from operating activities of $1.5 million for the three-month period ended March 31, 2006 and a cash deficiency of $0.8 million for the three-month period ended March 31, 2005. Additionally, capital investments reported under investing activities would be $4.3 million and $10.3 million for the three-month periods ended March 31, 2006 and 2005, respectively.

Impact of New and Pending Canadian GAAP Accounting Standards

In January 2005, the CICA approved Section 1530 Comprehensive Income (**S.1530**), Section 3855 Financial Instruments Recognition and Measurement (**S.3855**) and Section 3865 Hedges (**S.3865**) to harmonize financial instrument and hedge accounting with U.S. GAAP and introduce the concept of comprehensive income. S.1530 requires presentation of certain gains and losses outside of net income, such as unrealized gains and losses related to hedges or other derivative instruments. S.3855 establishes standards for recognizing and measuring financial assets and financial liabilities and non-financial derivatives as required to be disclosed under Section 3861 Financial Instruments Disclosure and Presentation . S.3865 establishes standards for how and when hedge accounting may be applied. The Company applies SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities for U.S. GAAP purposes and will implement S.3865 for Canadian GAAP for hedging activities. These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and are not expected to have a material impact on the Company s financial statements.

In January 2005, the CICA approved Section 3251 Equity which establishes standards for the presentation of equity and changes in equity during a reporting period. This section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and is not expected to have a material impact on the Company s financial statements.

Impact of New and Pending U.S. GAAP Accounting Standards

In May 2005, the FASB issued SFAS No. 154 (**SFAS No. 154**) Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3 . SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle. APB Opinion No. 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS No. 154 requires retrospective application to prior periods financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 applies to all voluntary changes in accounting principle. SFAS No. 154 also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS No. 154 carries forward without change to the guidance contained in APB Opinion No. 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. SFAS No. 154 also carries forward the guidance in APB Opinion No. 20 requiring justification of a change in accounting principle on the basis of preferability. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments an amendment of FASB statements No. 133 and 140 (**SFAS No. 155**). SFAS No. 155 resolves issues surrounding the application of the bifurcation requirements to beneficial interests in securitized financial assets. In general, this statement permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006.

On July 14, 2005, the FASB published an exposure draft entitled Accounting for Uncertain Tax Positions an interpretation of SFAS No. 109. The proposed interpretation is intended to reduce the significant diversity in practice associated with recognition and measurement of income taxes by establishing consistent criteria for evaluating uncertain tax positions. The proposed interpretation would be effective for the first fiscal year beginning after December 15, 2006. Earlier application would be encouraged. Only tax positions meeting the probable recognition threshold at that date would be recognized. The transition adjustment resulting from application of this interpretation would be recorded as a cumulative-effect change in the income statement as of the end of the period of adoption. Restatement of prior periods or pro forma disclosures under APB Opinion No. 20, Accounting Changes would not be permitted. The implementation of this exposure draft is not expected to impact the Company at this time.

On September 30, 2005, the FASB issued an Exposure Draft that would amend SFAS No. 128, Earnings per Share , to clarify guidance for mandatorily convertible instruments, the treasury stock method, contracts that may be settled in cash or shares and contingently issuable shares. The proposed Statement would be effective for interim and annual periods ending after June 15, 2006. Retrospective application would be required for all changes to SFAS No. 128, except that retrospective application would be prohibited for contracts that were either settled in cash to prior adoption to require cash settlement. Management is in the process of reviewing the requirements of this recent exposure draft.

On January 25, 2006, the FASB issued an exposure draft entitled The Fair Value Option for Financial Assets and Financial Liabilities (including an amendment of FASB Statement No. 115) . The proposed statement would create a fair value option under which an entity may irrevocably elect fair value as the initial and subsequent measurement attribute for certain financial assets and financial liabilities on a contract-by-contract basis, with changes in fair value recognized in earnings as those changes occur. Management is in the process of reviewing the requirements of this recent exposure draft.

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

Forward-Looking Statements

With the exception of historical information, certain matters discussed in this Form 10-Q are forward looking statements that involve risks and uncertainties. Certain statements contained in this Form 10-Q, including statements which may contain words such as could , should , expect , believe , will and similar expressions and statements rel to matters that are not historical facts are forward-looking statements. Such statements involve known and unknown risks and uncertainties which may cause our actual results, performances or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Although we believe that our expectations are based on reasonable assumptions, we can give no assurance that our goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, our ability to raise capital as and when required, the timing and extent of changes in prices for oil and gas, competition, environmental risks, drilling and operating risks, uncertainties about the estimates of reserves and the potential success of heavy-to light and gas-to-liquids development technologies, the prices of goods and services, the availability of drilling rigs and other support services, legislative and government regulations, political and economic factors in countries in which we operate and implementation of our capital investment program.

The following should be read in conjunction with the Company s consolidated financial statements contained herein and in the Form 10-K for the year ended December 31, 2005, along with Management s Discussion and Analysis of Financial Condition and Results of Operations contained in such Form 10-K. Any terms used but not defined in the following discussion have the same meaning given to them in the Form 10-K. The unaudited condensed consolidated financial statements in this Quarterly Report filed on Form 10-Q have been prepared in accordance with generally accepted accounting principles in Canada. The impact of significant differences between Canadian and U.S. accounting principles on the unaudited condensed consolidated financial statements is disclosed in Note 15.

Executive Overview of 2006 Results

Although our revenues for the three-month period ended March 31, 2006 improved significantly over those achieved during the comparable period in 2005, our net loss increased $3.1 million from the same period a year ago. Oil and gas revenues for the three- month period ended March 31, 2006 increased by 73% or $4.1 million to $9.8 million. Increased oil and gas prices were responsible for $2.9 million of this increase with the balance attributable to increased production. This improvement was offset in part by $0.9 million of increased costs related to our business and product development activities and by a $5.6 million increase in depletion and depreciation. Despite these cost increases, we achieved positive cash flow from operations of $2.1 million for the three-month period ended March 31, 2006 compared to a $1.1 million for the comparable period in 2005.

We believe that we have made significant progress in the first quarter of 2006 in ongoing developments in our EOR projects, in particular our HTL initiatives. The RTP™ CDF near Bakersfield, California met some key benchmarks and we are actively pursing opportunities for the commercial deployment of the technology in a number of countries. Our single goal remains the building of oil and gas reserves and production. We intend to use the RTP Technology as a tool to acquire and develop heavy oil reserves around the world.

The following table sets forth certain selected consolidated data for the first quarters of 2006 and 2005:

	Three-Month Periods Ended March 31,	
(stated in thousands of U.S. dollars, except per share and production amounts)	**2006**	**2005**
Oil and gas revenue	$ 9,826	$ 5,693
Net loss	$ 5,376	$ 1,483
Net loss per share	$ 0.02	$ 0.01
Average production (Boe/d)	2,013	1,664
Net operating revenue per Boe	$ 39.25	$ 26.25
Capital investments	$ 4,892	$ 12,287
Cash flow from operating activities	$ 2,080	$ 1,092

Financial Results Quarter to Quarter Change in Net Loss

The following provides an analysis of our changes in net losses for the three-month period ended March 31, 2006 when compared to the same period for 2005:

(stated in thousands of U.S. Dollars)	**2006 vs. 2005**
Net Loss for the three-month period ended March 31, 2005	$ 1,483
Favorable (unfavorable) variances:	
Cash Items:	
Net Operating Revenues:	
Production volumes	1,243
Oil and gas prices	2,890
Less: Operating costs	(954)
	3,179
General and administrative	429
Business and product development	(904)
Net interest	(68)
Total Cash Variances	2,636
Non-Cash Items:	
Depletion and depreciation	(5,640)
Stock based compensation	(57)
Impairment of China oil and gas properties	(750)
Other	(82)
Total Non-Cash Variances	(6,529)
Net Loss for the three-month period ended March 31, 2006	$ 5,376

Our net loss for the three-month period ended March 31, 2006 was $5.4 million ($0.02 per share) compared to our net loss for the same period in 2005 of $1.5 million ($0.01 per share). The increase in our net loss from 2005 to 2006 of $3.1 million is mainly due to a $5.6 million increase in depletion and depreciation, a $0.9 million increase in business and product development expenses and a $0.8 million increase in impairment. This is partially offset by a $3.2 million increase in net operating revenues.

Significant variances in our net losses are explained in the sections that follow.

Net Operating Revenues

Production Volumes 2006 vs. 2005

Net production volumes for the three-month period ended March 31, 2006 increased 21% when compared to the same period in 2005 due to a 71% increase in production volumes in our China properties offset by a 26% decrease in our U.S. properties, resulting in increased revenues of $1.2 million.

China

Net production volumes at the Dagang field increased 96% for the three-month period ended March 31, 2006 compared to the same period in 2005. As a result of the 2005 development program, oil production volume increased by 39% or by 22.3 Mboe contributing $0.9 million to the increase in revenues. We placed 22 new wells on production and fracture stimulated 13 wells in the northern block of this project during 2005. We are continuing to evaluate production results of other northern block wells to identify additional wells for fracture stimulation. As at March 31, 2006, we had 42 wells on production, producing 2,450 gross Bop/d (1,870 net Bop/d), compared to 39 wells and 2,310 gross Bop/d (1,080 net Bop/d) as at December 31, 2005.

Additionally, volumes at the Dagang field increased for the three-month period ended March 31, 2006 compared to the same period in 2005 by 57% or 35.4 Mboe due to the re-acquisition of Richfirst s 40% working interest in this project in February 2006. This acquisition contributed $1.3 million to the increase in revenues for 2006.

Our royalty percentage from the Daqing field was reduced from 4% to 2% in May 2005 when the operator of the properties reached payout of its investment. As a result, our share of production volumes decreased 54% for the three-month period ended March 31, 2006 when compared to the same period in 2005. This decrease in volumes resulted in a $0.3 million decrease in revenues for 2006.

U.S.

The 26% decrease in U.S. production volumes for the three-month period ended March 31, 2006 when compared to the same period in 2005 was due mainly to the decline in the Knights Landing field and the sale of our Citrus property. Additionally there was a decrease in the production from South Midway.

As at March 31, 2006, production from the Knights Landing wells had been fully depleted resulting in a decrease of 11.3 Mboe for the three-month period ended March 31, 2006 when compared to the same period in 2005. This decrease in volumes resulted in a $0.4 million decrease in revenues for 2006.

We sold our Citrus property effective February 1, 2006 resulting in a decrease of 5.2 Mboe for the three-month period ended March 31, 2006 when compared to the same period in 2005. This decrease in volumes resulted in a $0.2 million decrease in revenues for 2006.

Our production at South Midway decreased 7%, or 3.7 Mboe, for the three-month period ended March 31, 2006 when compared to the same period in 2005 primarily due to timing of steaming cycles which caused some of the more productive wells to be shut in during the first quarter of 2006. Also, in the first quarter of 2006 in the expansion area the continuous steaming process was interrupted for a short period of time due to equipment repairs. This decrease in volumes resulted in a $0.1 million decrease in revenues. As at March 31, 2006, we were producing 563 gross Boe/d (523 net Boe/d) at South Midway compared to 536 gross Boe/d (499 net Boe/d) as at December 31, 2005.

We consider LAK Ranch to be a pilot program and have offset net operating revenues from the field against our capital investment in LAK Ranch. Accordingly, revenues, operating costs and production volumes from LAK Ranch are not included in this analysis.

The following is a comparison of changes in production volumes for the first quarter of 2006 when compared to the same period in 2005:

	Quarters ended March 31,		
	Net Boe s		Percentage
	2006	**2005**	**Change**
China:			
Dagang	117,915	60,236	96%
Daqing	5,579	11,999	-54%
	123,494	72,235	71%
U.S.:			
South Midway	46,075	49,768	-7%
Citrus	4,341	9,528	-54%
Knights Landing	42	11,300	-100%
Others	7,211	6,941	4%
	57,669	77,537	-26%
	181,163	149,772	21%

Oil and Gas Prices 2006 vs. 2005

Oil and gas prices increased 43% per Boe for the three-month period ended March 31, 2006 generating $2.9 million in additional revenue as compared to the same period in 2005. We realized an average of $55.35 per Boe

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from our operations in China for the three-month period ended March 31, 2006, which is an increase of $16.26 per Boe for the same period in 2005 and accounts for $2.1 million of our increase in revenues. From the U.S. operations, we realized an average of $51.86 per Boe for the three-month period ended March 31, 2006, which is an increase of $14.86 per Boe and accounts for $0.8 million of our increased revenues.

Operating Costs 2006 vs. 2005

For the three-month period ended March 31, 2006, operating costs, including production taxes and engineering support, increased $1.0 million in absolute terms from the same period in 2005 or $3.23 per Boe.

China

Operating costs in China, including engineering support, increased 37% or $3.30 per Boe for the three-month period ended March 31, 2006 when compared to the same period in 2005. Field operating costs, excluding Dagang field office costs, increased $1.05 per Boe or 14% primarily due to higher power costs, increased workover and maintenance costs and increased treatment and processing fees attributed to high water production rates. With the suspension of our drilling activity at our Dagang field in December 2005, a major portion of our Dagang field office costs, which were previously being capitalized, are now being expensed as part of our operating activities. For the three-month period ended March 31, 2006 this amounted to a $2.69 increase per Boe in operating costs when compared to the same period in 2005.

Engineering support for the three-month period ended March 31, 2006 decreased $0.44 per Boe or 37%, compared to the same period in 2005 resulting from the increase in production volumes from the Dagang field in relation to the level of support required to operate the field.

U.S.

Operating costs in the U.S., including engineering support and production taxes, increased 45% or $6.49 per Boe for the three-month period ended 2006 when compared to the same period in 2005. Field operating costs increased $4.76 per Boe primarily resulting from an increase in fuel costs incurred for the increased level of cyclic and continuous steam operations at South Midway. Steaming operations costs increased $2.44 per Boe for the period ended March 31, 2006 when compared to the same period in 2005. In addition, primary operations at South Midway increased by $1.19 per Boe for the period ended March 31, 2006 when compared to the same period in 2005, mainly due to the timing of periodic maintenance of processing facilities. Workovers and other downhole costs at our Spraberry field in West Texas and our Creslenn Ranch property in East Texas resulted in a $0.94 increase in primary operations for this same period. Engineering support increased $0.91 per Boe due mainly to the start up of continuous steaming operations in the southern expansion of South Midway. Production taxes are up $0.82 per Boe largely as the result of an increase in ad valorem taxes at South Midway.

Production and operating information including oil and gas revenue, operating costs and depletion, on a per Boe basis are detailed below:

	Three-Month Periods Ended March 31,					
		2006			2005	
	U.S.	China	Total	U.S.	China	Total
Net Production:						
Boe	57,669	123,494	181,163	77,537	72,235	149,772
Boe/day for the period	641	1,372	2,013	862	803	1,664
		Per Boe			Per Boe	
Oil and gas revenue	$ 51.86	$ 55.35	$ 54.24	$ 37.00	$ 39.09	$ 38.01
Field operating costs	15.52	11.50	12.78	10.76	7.76	9.31
Production taxes	1.32		0.42	0.50		0.26
Engineering support	4.04	0.74	1.79	3.13	1.18	2.19
	20.88	12.24	14.99	14.39	8.94	11.76
Net operating revenue	30.98	43.11	39.25	22.61	30.15	26.25
Depletion	20.37	43.90	36.41	14.77	14.30	14.54
Net revenue from operations	$ 10.61	$ (0.79)	$ 2.84	$ 7.84	$ 15.85	$ 11.71

General and Administrative 2006 vs. 2005

Our changes in general and administrative expenses, before and after considering increases in non-cash stock based compensation, by segment for the three-month period ended March 31, 2006 when compared to the same period for 2005 were as follows:

	2006 vs. 2005
Favorable (unfavorable) variances:	
Oil and Gas Activities:	
China	$ (188)
U.S.	(149)
Corporate	748
	411
Less: stock based compensation	18
	$ 429

General and administrative expenses after allocations decreased by $0.4 million for the period ended March 31, 2006 when compared to the same period in 2005. General and administrative costs related to Corporate activities decreased $0.7 million primarily due to reduced professional fees incurred to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002 (**SOX**). Most of the 2004 SOX review was performed in the first quarter of 2005. In addition, second year costs for SOX are lower as there are no start up costs that we experienced in 2005. General and administrative costs for China and U.S. increased $0.1 million and $0.2 million, respectively, as allocations to capital investments decreased as a result of less capital activity for the three-month period ended March 31, 2006 when compared to the same period in 2005.

Business and Product Development 2006 vs. 2005

Our changes in business and product development expenses, before and after considering increases in non-cash stock based compensation, by segment for the three-month period ended March 31, 2006 when compared to the same period for 2005 were as follows:

		2006 vs. 2005
Favorable (unfavorable) variances:		
GTL	$	52
EOR		(995)
		(943)
Less: stock based compensation		39
	$	(904)

Business and product development expenses increased $0.9 million for the three-month period ended March 31, 2006 compared to the same period in 2005. Much of the focus of our business and product development activities was on EOR opportunities, particularly related to heavy oil processing. Approximately $0.6 million of the above increase in EOR opportunities was related to operating expenses of the RTP™ CDF to develop and identify improvements in the application of the RTP™ Technology. Additionally, $0.3 million of this increase was related to the familiarization of potential joint venture partners to this technology who are seeking methods to economically develop heavy oil reserves.

Depletion and Depreciation 2006 vs. 2005

Depletion and depreciation increased $5.6 million for the three-month period ended March 31, 2006 when compared to the same period in 2005, $4.0 million of which was due to the increase in depletion rates to $36.41 per Boe for the three-month period ended March 31, 2006 compared to $14.54 per Boe for the same period in 2005 and $0.4 million was due to increased production volumes from the comparable period in 2005. Additionally, there was $1.2 million of depreciation for the CDF RTP™ for the three-month period ended March 31, 2006 compared to nil for the same period in 2005.

China

China s depletion rate for the three-month period ended March 31, 2006 was $43.90 per Boe compared to $14.30 per Boe for the same period in 2005, an increase of $29.60 per Boe resulting in a $3.7 million increase in depletion expense for this period. These increases were due mainly to two factors:

As noted in prior periodic reports on Form 10K and in related shareholder communications, we have suspended new drilling activity at our Dagang field in order that we may assess production decline performances on recently drilled wells, as well as maximizing cash flow from these operations. As a result, we have reduced our estimate of the overall development program and our independent engineering evaluators, GLJ Petroleum Consultants Ltd., revised downward their estimate of our proved reserves as at December 31, 2005.

In the second quarter of 2005, we impaired the cost of our first Zitong block exploration well, Dingyuan 1, resulting in $12.2 million of those and other associated costs being included with our proved properties and therefore subject to depletion.

Additionally, increases in production volumes in China accounted for $0.7 million of the increase in depletion expense for the three-month period ended March 31, 2006 when compared to the same period in 2005.

U.S.

The U.S. depletion rate for the three-month period ended March 31, 2006 was $20.37 per Boe compared to $14.77 per Boe for the same period in 2005, an increase of $5.60 per Boe resulting in a $0.3 million increase in depletion expense for this period. This increase was mainly due to the impairment of the remaining cost of our Northwest Lost Hills #1-22 exploration well as at December 31, 2005, resulting in $8.9 million of those costs being included with our proved properties and therefore subject to depletion in the first quarter of 2006. In addition, revisions to reserve estimates at Knights Landing and the sale of Citrus also contributed to the increased rate. Production

volume decreases in the U.S. resulted in a $0.3 million decrease in our depletion expense for the three-month period ended March 31, 2006 when compared to the same period in 2005.

EOR

The RTP™ CDF was in a commissioning phase as at December 31, 2005 and, as such, had not been depreciated as at December 31, 2005. The commissioning phase ended in January 2006 and the RTP™ CDF was placed into service. For the three-month period ended March 31, 2006 $1.2 million of depreciation was recorded for the RTP™ CDF.

Impairment of Oil and Gas Properties 2006 vs. 2005

As more fully described in our financial statements in Item 8 of our 2005 Annual Report filed on Form 10-K, we evaluate each of our cost center s proved oil and gas properties for impairment on a quarterly basis. If as a result of this evaluation, a cost center s carrying value exceeds its expected future net cash flows from its proved and probable reserves then a provision for impairment must be recognized in the results of operations.

We impaired our China oil and gas properties by $0.8 million for the three-month period ended March 31, 2006, compared to no impairment for the same period in 2005. This impairment is mainly due a windfall gain levy established in March 2006 that impacts the amount of future oil revenues from the Company s China operations.

Capital Investments

The following provides an analysis of our capital investment activities for the three-month period ended 2006 when compared to the same period for 2005:

	Three-Month Periods Ended March 31,		
	2006	**2005**	**(Increase) Decrease**
Oil and Gas Activities:			
China	$ 2,716	$ 9,551	$ 6,835
U.S.	1,275	807	(468)
EOR	683	1,714	1,031
GTL	218	215	(3)
	$ 4,892	$ 12,287	$ 7,395

Oil and Gas Activities China

Capital investment in China for the three-month period ending March 31, 2006 was $2.7 million, a $6.8 million or 72% decrease compared to the same period in 2005, primarily due to the suspension of drilling activities at our Dagang field in December 2005.

Expenditures at Dagang decreased $4.3 million to $2.2 million during the three-month period ended March 31, 2006 when compared to the same period in 2005 as drilling activity was essentially suspended in December 2005. We did complete one well and fracture stimulate 5 wells in the northern block of this field during the three-month period ended March 31, 2006. Our stimulation program continues in the northern block where we are further evaluating the results of prior fracture stimulations and production decline in order to choose additional wells for this program and to assist in making critical decisions on resuming our drilling program.

In February 2006, the Company re-acquired Richfirst s 40% working interest in the Dagang oil project for a purchase price of $28.3 million, consisting of a combination of the Company s common shares, a non-interest bearing note payable and unpaid joint venture receivables.

Our capital investment for our Zitong block was $0.5 million during the three-month period ended March 31, 2006, a decrease of $2.5 million from the same period in 2005. This decrease is due mainly to the completion of our 700-mile seismic acquisition program in the three-month period ended March 31, 2005 and to the initial expenditures required in the same period to commence drilling of our first exploration well on this block, which spudded in April 2005. During the three-month period ended March 31, 2006, we continued prospect development of this block using our geological and geophysical data, working towards selecting our next exploration well location.

Oil and Gas Activities U.S.

Capital investment in the U.S. is up $0.5 million for the three-month period ended March 31, 2006 when compared to the same period in 2005, due mainly to $0.3 million and $0.4 million increases in our exploration activities in the Knights Landing field and North Yowlumne prospect, respectively, offset by a $0.2 million decrease in the LAK Ranch field.

Knights Landing

In February 2004, we farmed into the Knights Landing gas field, which is a gross 15,700-acre block located in the Sutter and Yolo counties, in northern California. All existing development wells were fully depleted as at March 31, 2006. In late 2005, a 3-D seismic data program was acquired over 25 square miles covering our Knights Landing acreage block. We completed our seismic acquisition program in December 2005 and have initiated interpretation and processing of the seismic data. We expect to complete this interpretation and processing of the seismic data by the end of the second quarter of 2006 and recommence drilling in the third quarter of 2006. The primary objective of this development and exploration program is the Starkey Sand formation, which is an established producing reservoir in the region that lies between depths of 2,000 to 3,500 feet.

North Yowlumne

In December 2005, drilling commenced on the North Yowlumne prospect to a total depth of 13,000 feet to test the Stevens sand that have produced over 110 million barrels of oil at the nearby Yowlumne field. We hold a 12.5% working interest in this prospect and have farmed out an 87.5% interest in the initial well and prospect. In the event of a discovery, we will own a 56.25% working interest in the well after payout. The test program is proceeding from the lowest zone to the highest zone in the well. The lower zones tested a minimal amount of light oil. A flow rate has yet to be confirmed and preparations are underway to install an artificial lift system to enable the well to be put on a sustained production test before testing the final upper zone of interest. The upper zone had the best log characteristics in the well. Final results of the well are expected to be known during the second quarter of 2006.

LAK Ranch

One vertical well was drilled in the first quarter of 2005 for data collection purposes. We commenced continuous steaming in the fourth quarter of 2005. An early production response was realized from this injection, with oil rates increasing from 10 to 45 bop/d. We plan continuous steam injection throughout 2006, while monitoring the production response. We expect to reach a decision regarding future development by the fourth quarter of 2006.

Citrus

During the three-month period ended March 31, 2006, we sold our interests in the producing Citrus properties for $5.4 million. We felt the offer received exceeded the value of the property based on the existing producing wells.

Northwest Lost Hills

In August 2005, we concluded a farm-out of one-third of our 42% working interest to Aera Energy, LLC, (**Aera**) the operator, to complete and test the Northwest Lost Hills #1-22 deep well at no additional cost to us.

The well was tested in January 2006 and in two tests flowed a non-commercial rate of 400 Mcf/d and 5,000 Bbls/d of water. We anticipate Aera recommending abandonment of the well, with which we concur. We expect abandonment operations will commence in the third quarter of 2006. We have no further plans to explore in this prospect.

Enhanced Oil Recovery and Heavy-To-Light Oil Activities

We incurred $1.0 million less in capital investment activities on EOR and HTL projects for the three-month period ended March 31, 2006 compared to the same period in 2005.

RTP™ Commercial Demonstration Facility

The RTP™ CDF was constructed on Aera s property in the Belridge Field for the purpose of demonstrating the RTP™ Technology on a commercial scale.

During the three-month period ended March 31, 2006, we incurred $0.3 million on an extended program of technical and operational enhancements to the RTP™ CDF. As a result of some of these enhancements a successful extended run was performed in January 2006 that achieved a number of important performance goals. We are now building on these positive test results by expanding our testing of crude oil from potential resource partners with an initial focus on heavy crude oil from California and Western Canada, including bitumen from Canada s Athabasca tar sands region.

The RTP™ CDF runs to date have successfully demonstrated a number of commercial configurations and processing alternatives, including both high yield (once through) and high quality (recycle) modes of operation. A number of process enhancements have been validated during the RTP™ CDF test program, including gas sulphur capture, heavy metals capture and crude acidity reduction.

The RTP™ CDF is being prepared for a series of runs that will demonstrate the processing of Athabasca bitumen and vacuum tower bottoms in a high quality configuration. This configuration, appropriate for numerous resource opportunities around the world, including the tar sands in Western Canada (Athabasca), produces a more fully upgraded product, as well as high amounts of by-product energy.

In order to carry out these runs, a number of upgrades and enhancements to the RTP™ CDF were required. These upgrades were primarily related to peripheral equipment linked to either the disposal of by-product energy or to equipment redundancy for more extended runs. The additional equipment and upgrades were originally expected to take four to six weeks.

As a result of the extremely tight markets in the industry for oilfield personnel and equipment we have experienced longer than usual order and delivery times from suppliers.

We currently anticipate commencing the next set of runs at the end of May. Athabasca bitumen has been delivered from Western Canada and is currently in onsite storage ready for processing.

RTP™ Plant Design Package

For the three-month period ended March 31, 2005, we incurred $0.5 million on a preliminary design package prepared by Colt Engineering Corporation (**Colt**) for a 15,000 barrels-per-day feed of raw, heavy oil (5,000 barrels per day hot-section) commercial RTP™ facility (**RTP Plant**). The design package was completed in the second quarter of 2005. The design package included various studies and costing estimates for both high yield and high quality schemes that would be designed to produce maximum steam or electrical generation for each configuration at varying levels of heavy oil input into the plant. The location that was part of the design basis is Aera s Belridge oil field using the heavy oil produced there as feedstock. This heavy oil is moderately heavy at 13° API and is similar to many target heavy oil resources found worldwide, including Canada s heavy oil from the Cold Lake and Peace River areas of Alberta. The various plant configurations were evaluated as well as the capital estimates that are being used in our economic models. This decrease of $0.5 million in spending was partially offset by a subsequent engineering effort being performed by AMEC Ltd. of $0.1 million for the three-month period ended March 31, 2006. This effort adds to the previous engineering work performed by Colt and completes the preliminary design package for the 15,000 barrels-per-day RTP™ Plant for California.

Iraq

In October 2004, we signed an MOU with the Ministry of Oil of Iraq to study and evaluate the shallow Qaiyarah oil field in Iraq. The field s reservoirs contain a large proven accumulation of 17.9 API heavy oil at a depth of about 1,000 feet.

We will evaluate the potential response of the Qaiyarah oil field to the latest in EOR techniques, along with the potential value that could be added using the RTP™ Technology to produce higher quality, more valuable crude oil. The work will include an assessment of the oil-in-place in the reservoirs, and the optimum EOR and heavy oil processing methods to establish economically recoverable volumes at the Qaiyarah oil field.

The reservoir assessment has been completed and various recovery methods have been evaluated. Facility design work is nearing completion and once complete, an economic evaluation will follow. If the evaluation studies indicate development of the field is economically viable, we will present a development plan and offer a commercial proposal to implement an EOR program for the Qaiyarah oil field. We expect to submit our proposal to the Iraq Ministry of Oil in the second half of 2006. The Iraq Ministry of Oil is under no obligation to execute the project or to enter into formal commercial negotiations at the completion of our study.

The Qaiyarah heavy oil field project resulted in a $0.1 million decrease in capital investments for the three-month period ended March 31, 2006 when compared to the same period in 2005. In addition, we invested $0.7 million less during the three-month period ended March 31, 2006 when compared to the same period in 2005 on other projects in Iraq including submission of four bids for the engineering, design and procurement of oil production facilities and EOR development projects. Two bids were unsuccessful and two are still under consideration by the Iraq Ministry of Oil.

Colombia

In late 2004, we signed an MOU with Ecopetrol S.A. (Ecopetrol) for a study of the heavy crudes from the large Castilla and Chichimene oil fields in Colombia, located about 75 miles southeast of Bogotá in the Central Llanos Basin. We incurred $0.2 million in costs related to this MOU during the three-month period ended March 31, 2005. This bid was unsuccessful as we did not meet the company-size requirements that Ecopetrol specified in its final bidding qualifications for the Llanos Basin Heavy Crude Project , which included the Castilla and Chichimene fields.

Gas-To-Liquids Activities

There was no significant change in capital investment activities on GTL projects for the three-month period ended March 31, 2006 when compared to the same period in 2005. In 2005, we signed a memorandum of understanding (**MOU**) with Egyptian Natural Gas Holding Company (**EGAS**), the state organization charged with the management of Egypt s natural gas resources, to prepare a feasibility study to construct and operate a GTL plant that would convert natural gas to ultra-clean liquid fuels in Egypt. EGAS has agreed to commit up to 4.2 trillion cubic feet of natural gas, or approximately 600 MMcf/d for the anticipated 20-year operating life of the proposed project, if the study indicates that a GTL project is economically feasible. We completed an engineering design of a GTL plant to incorporate the latest advances in Syntroleum GTL technology and have completed market and pricing analysis for GTL products to reflect changes since the original evaluation was completed several years ago. Plant capacity options of 47,000 and 94,000 Bbls/d have been evaluated. If the feasibility study indicates that a GTL plant is economically viable the parties will enter into negotiations for a definitive agreement for the development of a project.

Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents increased by $0.7 million for the three-month period ended March 31, 2006 compared to almost no change for the same period in 2005.

Operating Activities

Our operating activities provided $2.1 million in cash for the three-month period ended March 31, 2006 compared to $1.1 million provided by operating activities for the same period in 2005. The increase in cash from operating activities for the period ended March 31, 2006 were mainly due to increases in net production volumes of 21% and increases in oil and gas prices of 43%. The increases in net revenues for the three-month period ended March 31, 2006 were partially offset by increases of $0.5 million in general and administrative and business and product development expenses, excluding stock based compensation, when compared to the same period in 2005.

Investing Activities

Our investing activities used $0.8 million in cash for the three-month period ended March 31, 2006 compared to $6.4 million used in investing activities for the same period in 2005. For the three-month period ended March 31, 2006, compared to the same period in 2005, we spent $0.5 million less on direct merger and acquisition related costs, and we advanced $0.3 million during 2005 under a consultancy agreement. In addition, we generated $5.4 million of cash from asset sales in the U.S. for the three-month period ended March 31, 2006 and had no sales of assets for the comparable period in 2005.

Financing Activities

Our financing activities used $0.5 million in cash for the three-month period ended March 31, 2006 compared to $5.4 million of cash provided by financing activities for the comparable period in 2005. For the three-month periods ended March 31, 2006 and 2005, we made principal payments on our outstanding debt of $0.6 million and $0.4 million, respectively.

Negotiations with a third party carried out over the last several quarters for a transaction that was to have involved the formation of a joint venture for the deployment, in a specific region of the world, of the GTL and RTP™ technologies we license or own and a potentially significant equity investment in Ivanhoe by the third party have now ended without a definitive agreement having been reached. However, management is engaged in other discussions for potential strategic alliances or partnership arrangements with other entities that the Company believes have the ability to help advance the Company s projects.

In April 2006 the Company closed a private placement of 11.4 million special warrants at $2.23 per special warrant for a total of $25.4 million. Each special warrant entitles the holder to receive, at no additional cost, one common share and one common share purchase warrant. Each common share purchase warrant entitles the holder to purchase one common share at a price of $2.63 per share until the fifth anniversary date of the closing. Of the proceeds, $4.0 million has been used to pay down long-term debt and the balance will be used to pursue opportunities for the commercial deployment of the Company s heavy oil upgrading technology, to advance its oil and gas operations and for general corporate purposes.

	Three Months Ended March 31, 2006	2005
Cash flow from operating activities	$ 2,080	$ 1,092
Investing Activities		
Capital investments, after changes in non-cash working capital	(5,977)	(5,404)
Equity investment and Merger related costs	(177)	(730)
Proceeds from sale of assets	5,350	
Advance payments		(300)
Other	(9)	
	(813)	(6,434)
Financing Activities		
Proceeds from exercise of options	91	35
Net debt financing	(622)	5,583
Other		(263)
	(531)	5,355
Net sources of Cash	$ 736	$ 13

<u>Outlook for 2006</u>

As noted earlier, the Company completed a private placement of special warrants, $4 million of which was used to repay long-term debt and the balance of $21.4 million has been added to working capital to enable us to continue to develop our oil and gas reserves, particularly through the deployment of our proprietary heavy oil upgrading technology. Management s plans include sale of additional equity securities, alliances or other partnership agreements with entities with the resources to support the Company s projects as well as convertible loan, debt and mezzanine financing in order to generate sufficient resources to assure continuation of the Company s operations and achieve its capital investment objectives.

Contractual Obligations

The table below summarizes the contractual obligations that are reflected in our Unaudited Condensed Consolidated Balance Sheet as at March 31, 2006 and/or disclosed in the accompanying Notes:

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	**2006**	**2007**	**2008**	**2009**	**After 2009**
Purchase Agreement:	$ 50	$ 50	$	$	$	$
Consolidated Balance Sheets:						
Note payable current portion	3,689	2,751	938			
Long term debt	8,919		6,182	2,325	412	
Asset retirement obligation	1,790	950	101	148	27	564
Long term obligation	1,900		1,900			
Other Commitments:						

Interest payable	1,433	677	617	135	4	
Lease commitments	2,133	595	611	473	287	167
Zitong exploration commitment	4,300	4,300				
Total	$ 24,214	$ 9,323	$ 10,349	$ 3,081	$ 730	$ 731

Off Balance Sheet Arrangements

At March 31, 2006 and December 31, 2005, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us, or our related parties, except as disclosed herein.

Outstanding Share Data

As at April 29, 2006, there were 229,578,477 common shares of the Company issued and outstanding. Additionally, the Company had 18,296,330 share purchase warrants outstanding and exercisable to purchase 18,296,330 common shares and 11,400,000 special purchase warrants issued by way of a private placement on April 7, 2006 at a price of $2.23 per special purchase warrant. Each of these special warrants is exercisable to acquire, for no additional consideration, one common share and one common share purchase warrant, which is exercisable to purchase one common share at a price of $2.63 per share until the fifth anniversary date of closing. As at April 29, 2005, there were 10,646,194 incentive stock options outstanding to purchase the Company s common shares.

Quarterly Financial Data In Accordance With Canadian and U.S. GAAP (Unaudited)

	QUARTER ENDED							
	2006	**2005**				**2004**		
	1st Qtr	**4th Qtr**	**3rd Qtr**	**2nd Qtr**	**1st Qtr**	**4th Qtr**	**3rd Qtr**	**2nd Qtr**
Total revenue	$ 9,864	$8,651	$8,907	$6,645	$5,736	$ 6,212	$4,932	$3,521
Net loss:								
Canadian GAAP	$ 5,376	$8,885	$2,113	$1,031	$1,483	$17,184	$ 951	$1,298
U.S. GAAP	$12,112	$8,557	$1,843	$1,564	$3,008	$15,736	$ 980	$1,510
Net loss per share:								
Canadian GAAP	$ 0.02	$ 0.04	$ 0.01	$ 0.01	$ 0.01	$ 0.09	$ 0.01	$ 0.01
U.S. GAAP	$ 0.05	$ 0.03	$ 0.01	$ 0.01	$ 0.02	$ 0.09	$ 0.01	$ 0.01

The net losses in the fourth quarter of 2004, for Canadian and U.S. GAAP, were primarily due to impairment provisions of $16.3 million and $15.0 million, respectively, for U.S. oil and gas properties. The differences in the net loss and net loss per share for the first quarter of 2005 was due mainly to GTL and EOR investments, which are capitalized for Canadian GAAP but expensed as incurred for U.S. GAAP. The Canadian GAAP net loss in the fourth quarter of 2005 was primarily due to an impairment provision of $5.0 million for the China oil and gas properties, compared to the combined impairment provision calculated for U.S. GAAP for the China and U.S. oil and gas properties of $5.5 million. The differences in the net loss and net loss per share for the first quarter of 2006 were due mainly to the impairment charged for U.S. GAAP purposes of $7.2 million when compared to $0.8 million calculated for Canadian GAAP.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

No material changes since December 31, 2005.

Item 4. Controls and Procedures

The Company s management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of March 31, 2006. Based upon this evaluation, management concluded that these controls and procedures were (1) designed to ensure that material information relating to the Company is made known to the Company s Chief Executive Officer and Chief Financial Officer and (2) effective, in that they provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

It should be noted that while the Company s principal executive officer and principal financial officer believe that the Company s disclosure controls and procedures provide a reasonable level of assurance that they are effective,

they do not expect that the Company s disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the period ended March 31, 2006, there were no changes in the Company s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II Other Information

Item 1. Legal Proceedings: None

Item 1A. Risk Factors:

As at March 31, 2006, there were no additional material risks and no material changes to the risk factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2005.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds: None

Item 3. Defaults Upon Senior Securities: None

Item 4. Submission of Matters To a Vote of Securityholders: None

Item 5. Other Information: None

Item 6. Exhibits

EXHIBIT NUMBER	DESCRIPTION
4.1	Special Warrant Indenture dated April 7, 2006 between the Company and CIBC Mellon Trust Company
10.1	Terms of Agreement Conversion of Participating Interest by Richfirst Holdings Limited, Pan-China Resources Limited, Sunwing Energy Ltd. and the Company (Incorporated by reference to Exhibit 10.2 of Form 8-K filed with the Securities and Exchange Commission on February 24, 2006).
31.1	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification by the Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

SIGNATURE

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

IVANHOE ENERGY INC.

By: /s/ W. Gordon Lancaster
Name:
W. Gordon Lancaster
Title: Chief Financial Officer
Dated: May 4, 2006

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