IVANHOE ENERGY INC
Form 10-Q
August 09, 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 June 30, 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 June 30, 2006 was 241,173,798 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)

	June 30, 2006	December 31, 2005
Assets		
Current Assets		
Cash and cash equivalents	**$ 25,808**	$ 6,724
Accounts receivable (net of allowance for doubtful accounts of $116 and $83 as at June 30, 2006 and December 31, 2005, respectively)	**7,967**	9,994
Prepaid and other current assets	**391**	338
	34,166	17,056
Oil and gas properties and investments, net	**133,130**	119,654
Intangible assets technology	**102,111**	102,068
Long term assets	**2,367**	2,099
	$ 271,774	$ 240,877
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 15,179**	$ 25,791
Project advance from partner	**3,249**	
Notes payable current portion	**3,730**	1,667
Asset retirement obligations current portion		950
	22,158	28,408
Long term debt	**3,971**	4,972
Asset retirement obligations	**1,525**	830
Long term obligation	**1,900**	1,900
Commitments and contingencies		
Shareholders Equity		
Share capital, issued 241,173,798 common shares; December 31, 2005 220,779,335 common shares	**318,673**	291,088
Purchase warrants	**23,955**	5,150
Contributed surplus	**4,664**	3,820

Accumulated deficit		**(105,072)**		(95,291)
		242,220		204,767
	$	**271,774**	$	240,877

(See accompanying notes)

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IVANHOE ENERGY INC.
Unaudited Condensed Consolidated Statements of Operations and Accumulated Deficit
(stated in thousands of U.S. Dollars, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Revenue				
Oil and gas revenue	**$ 12,814**	$ 6,617	**$ 22,640**	$ 12,310
Interest income	**270**	28	**308**	71
	13,084	6,645	**22,948**	12,381
Expenses				
Operating costs	**3,858**	1,771	**6,574**	3,533
General and administrative	**2,727**	1,506	**4,727**	3,917
Business and product development	**1,454**	1,178	**3,116**	1,897
Depletion and depreciation	**9,189**	2,567	**17,036**	4,774
Interest expense and financing costs	**261**	375	**526**	495
Write-down and provision for impairment		279	**750**	279
	17,489	7,676	**32,729**	14,895
Net Loss	**4,405**	1,031	**9,781**	2,514
Accumulated Deficit, beginning of period	**100,667**	83,262	**95,291**	81,779
Accumulated Deficit, end of period	**$ 105,072**	$ 84,293	**$ 105,072**	$ 84,293
Net Loss per share Basic and Diluted	**$ 0.02**	$ 0.01	**$ 0.04**	$ 0.01
Weighted Average Number of Shares (in thousands)	**235,388**	195,200	**229,997**	183,621

(See accompanying notes)

IVANHOE ENERGY INC.
Unaudited Condensed Consolidated Statements of Cash Flow
(stated in thousands of U.S. Dollars)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Operating Activities				
Net loss	**$ (4,405)**	$ (1,031)	**$ (9,781)**	$ (2,514)
Items not requiring use of cash:				
Depletion and depreciation	**9,189**	2,567	**17,036**	4,774
Write-down and provision for impairment		279	**750**	279
Stock based compensation	**716**	534	**1,069**	830
Other	**409**	24	**507**	40
Changes in non-cash working capital items	**(2,287)**	(499)	**(3,879)**	(744)
	3,622	1,874	**5,702**	2,665
Investing Activities				
Capital investments	**(3,710)**	(12,068)	**(8,602)**	(24,355)
Merger, net of cash acquired		(9,979)		(9,979)
Merger and acquisition related costs	**(325)**	(957)	**(502)**	(1,687)
Proceeds from sale of assets			**5,350**	
Advance payments	**(50)**	(300)	**(50)**	(600)
Other	**(60)**	(76)	**(69)**	(76)
Changes in non-cash working capital items	**(1,770)**	2,729	**(2,855)**	9,912
	(5,915)	(20,651)	**(6,728)**	(26,785)
Financing Activities				
Shares issued on private placements, net of share issue costs	**25,315**	10,153	**25,315**	10,153
Proceeds from exercise of options and warrants	**358**	1,690	**449**	1,725
Share issue costs on shares issued for Merger		(93)		(93)
Proceeds from debt obligations		2,000		8,000
Payments of debt obligations	**(5,032)**	(417)	**(5,654)**	(833)
Other		(163)		(426)
	20,641	13,170	**20,110**	18,526
Increase (decrease) in cash and cash equivalents, for the period	**18,348**	(5,607)	**19,084**	(5,594)
Cash and cash equivalents, beginning of period	**7,460**	9,335	**6,724**	9,322
Cash and cash equivalents, end of period	**$ 25,808**	$ 3,728	**$ 25,808**	$ 3,728

(See accompanying notes)

Notes to the Condensed Consolidated Financial Statements
June 30, 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 14. 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 June 30, 2006				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 94,687	$ 104,354	$	$	$ 199,041
Unproved	11,058	5,674			16,732
	105,745	110,028			215,773
Accumulated depletion	(18,355)	(27,695)			(46,050)
Accumulated provision for impairment	(50,350)	(5,750)			(56,100)
	37,040	76,583			113,623
GTL and EOR Investments:					
Feasibility studies and other deferred costs			4,942	6,655	11,597
Commercial demonstration facility				10,600	10,600
Accumulated depreciation				(2,893)	(2,893)
			4,942	14,362	19,304
Furniture and equipment	487	107		73	667
Accumulated depreciation	(400)	(46)		(18)	(464)
	87	61		55	203
	$ 37,127	$ 76,644	$ 4,942	$ 14,417	$ 133,130

	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 June 30, 2006 and December 31, 2005 of $16.7 million and $15.0 million related to unproved oil and gas properties have been excluded from the depletion calculations.

For the three-month and six-month periods ended June 30, 2006, 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 $1.6 million were capitalized. During those same periods in 2005, $1.2 million and $2.1 million 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 June 30, 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.

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As at June 30, 2006 and December 31, 2005, EOR investments included $10.6 million and $9.6 million of costs associated with the rapid thermal processing technology (**RTP™ Technology**) commercial demonstration facility located on Aera Energy LLC s (**Aera**) property in California s San Joaquin Basin. The RTP™ commercial demonstration facility (**RTP™ 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 RTP™ CDF was placed into service. There was no revenue associated with the RTP™ CDF operations for the three-month and six-month periods ended June 30, 2006 and 2005. For the three-month and six-month periods ended June 30, 2006, $1.7 million and $2.9 million of depreciation were recorded for the RTP™ CDF. Depreciation of the RTP™ CDF is calculated using the straight-line method over its current useful life of one year which is based on the existing term of the agreement with Aera to use their property to test the RTP™ CDF.

4. INTANGIBLE ASSETS TECHNOLOGY

The Company s intangible assets consist of the following:

RTP™ Technology

In the Merger with Ensyn, the Company acquired an exclusive, irrevocable license to deploy, worldwide, the RTP™ Technology for petroleum applications as well as the exclusive right to deploy RTP™ Technology in all applications other than biomass. The carrying value of the RTP™ Technology as at June 30, 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 carrying value of the Syntroleum master license as at June 30, 2006 and December 31, 2005 was $10.0 million. These intangible assets were not amortized and there was no indication of impairment for the three-month and six-month periods ended June 30, 2006 and 2005.

5. NOTES PAYABLE

Notes payable consisted of the following as at:

	June 30, 2006	December 31, 2005
Non-interest bearing promissory note, due 2006 through 2009	$ 6,566	$
Variable rate bank note, 8.375% as at June 30, 2006 and 7.375% as at December 31, 2005, due 2006 though 2007	1,806	2,639
8% promissory note, due 2007		4,000
	8,372	6,639
Less:		
Unamortized discount	(671)	
Current maturities	(3,730)	(1,667)
	(4,401)	(1,667)
	$ 3,971	$ 4,972

Promissory Notes

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 ($6.5 million after being discounted to net present value). The note is payable in 36 equal monthly installments commencing March 31, 2006 (See Note 13).

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 loan to repay $4.0 million of this loan with 2,453,988 common shares of the Company at $1.63 per share. Additionally, the residual $4.0 million of the convertible loan 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 loan 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. This note was repaid in April 2006 (See Note 8).

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.

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 and six-month periods ended June 30, 2006 and 2005.

The scheduled maturities of the notes payable, excluding unamortized discount, as at June 30, 2006 were as follows:

2006	$ 2,064
2007	3,432
2008	2,460
2009	416
	$ 8,372

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 June 30, 2006 was estimated at $2.1 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 six-month period ended June 30, 2006 were as follows:

Balance as at December 31, 2005	$ 1,780
Liabilities transferred	(32)
Accretion expense	34
Revisions in estimated cash flows	(257)
Balance as at June 30, 2006	$ 1,525

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 to November 30, 2006 provided the second Phase 1 exploration well is spud before that date.

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. The farm-out agreement became effective when this approval was obtained in May 2006 and with Mitsubishi advancing the Company $4.0 million dollars to drill the second exploration well. 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**). The $4.0 million advance from Mitsubishi will be used to pay for the well and the balance of $3.2 million is recorded as project advance from partner as at June 30, 2006. 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, costs related to the Zitong block in the approximate amount of $5.7 million will be required to be included in the depletable base of the China full cost pool. This may result in a ceiling test impairment related to the China full cost pool in a future period.

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

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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 $100.0 million. This obligation has been recorded in the Company s consolidated balance sheet.

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 six-month period ended June 30, 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			
Private placements, net of share issue costs	11,400	6,510			
Services	148	401			
Exercise of options	255	674	(225)	(255)	$ 2.13
Options:					
Granted				1,799	$ 3.15
Expired				(401)	$ 3.56
Stock based compensation			1,069		
Balance June 30, 2006	241,174	$ 318,673	$ 4,664	11,421	$ 2.31

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 six-month period ended June 30, 2006:

	Purchase Warrants	Common Shares Issuable
	(thousands)	
Balance December 31, 2005	25,469	21,883
Purchase warrants expired	(7,173)	(3,587)
Private placements	11,400	11,400
Balance June 30, 2006	29,696	29,696

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.

As at June 30, 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
2006	U.S. $2.23	11,400	11,400	11,400	18,805	April 2011	U.S. $2.63
		29,696	29,696	29,696	23,955		

The weighted average exercise price of the exercisable purchase warrants, as at June 30, 2006 was U.S. $2.63 per share.

The Company calculated a value of $18.8 million for the purchase warrants issued in 2006. This value was calculated in accordance with the Black-Scholes (**B-S**) pricing model using a weighted average risk-free interest rate of 4.4%, a dividend yield of 0.0%, a weighted average volatility factor of 75.26% and an expected life of 5 years.

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 and six-month periods ended June 30, 2006, the Company expensed $0.7 million and $1.1 million in stock based compensation. During those same periods in 2005, $0.5 million and $0.8 million were expensed.

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 amounts paid for the Windfall Levy are included with operating expenses in the accompanying statements of operations. The Company understands that the Windfall Levy will be deductible for corporate income tax purposes in the PRC and will not be eligible for cost recovery under the Company s production sharing contract with CNPC in respect of the Dagang project. In addition, we evaluate the carrying value of our oil and gas properties for impairment and recognize any impairment on a quarterly basis. The imposition of the Windfall Levy resulted in an impairment of the Company s oil and gas properties of nil and $0.8 million for the three-month and six-month periods ended June 30, 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 (EGAS) to prepare a feasibility study to construct and operate a GTL plant in Egypt. The feasibility study has been completed and presented as a report to EGAS along with three commercial proposals in May 2006. These proposals are currently under consideration by EGAS.

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.

Corporate

The Company s corporate office is 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 and six-month periods ended June 30, 2006 and 2005 and identifiable assets as at June 30, 2006 and December 31, 2005:

	Three-Month Period Ended June 30, 2006					
	Oil and Gas					
	U.S.	**China**	**GTL**	**EOR**	**Corporate**	**Total**
Oil and gas revenue	$ 3,068	$ 9,746	$	$	$	$ 12,814
Interest income	52	13			205	270
	3,120	9,759			205	13,084
Operating costs	912	2,946				3,858
General and administrative	549	334			1,844	2,727
Business and product development			417	1,037		1,454
Depletion and depreciation	1,273	6,239	2	1,673	2	9,189
Interest expense and financing costs	67	61		2	131	261
	2,801	9,580	419	2,712	1,977	17,489
Net (Income) Loss	$ (319)	$ (179)	$ 419	$ 2,712	$ 1,772	$ 4,405
Capital Investments	$ 788	$ 1,934	$ 155	$ 833	$	$ 3,710

	Six-Month Period Ended June 30, 2006					
	Oil and Gas					
	U.S.	**China**	**GTL**	**EOR**	**Corporate**	**Total**
Oil and gas revenue	$ 6,059	$ 16,581	$	$	$	$ 22,640
Interest income	66	15			227	308
	6,125	16,596			227	22,948
Operating costs	2,116	4,458				6,574
General and administrative	922	679			3,126	4,727
Business and product development			769	2,347		3,116
Depletion and depreciation	2,461	11,663	5	2,904	3	17,036
Interest expense and financing costs	129	106		3	288	526
Write-downs and provision for impairment		750				750
	5,628	17,656	774	5,254	3,417	32,729

Net (Income) Loss	$ (497)	$ 1,060	$ 774	$ 5,254	$ 3,190	$ 9,781
Capital Investments	$ 2,065	$ 4,651	$ 372	$ 1,514	$	$ 8,602
Identifiable Assets (As at June 30, 2006)	$ 43,920	$ 87,577	$ 14,974	$ 106,548	$ 18,755	$ 271,774
Identifiable Assets (As at December 31, 2005)	$ 48,070	$ 65,020	$ 14,609	$ 107,869	$ 5,309	$ 240,877

	Three-Month Period Ended June 30, 2005					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 3,294	$ 3,323	$	$	$	$ 6,617
Interest income	4	1			23	28
	3,298	3,324			23	6,645
Operating costs	1,152	619				1,771
General and administrative	258	137			1,111	1,506
Business and product development			319	859		1,178
Depletion and depreciation	1,315	1,237	3	9	3	2,567
Interest expense	84				291	375
Write-downs and provision for impairment			279			279
	2,809	1,993	601	868	1,405	7,676
Net (Income) Loss	$ (489)	$ (1,331)	$ 601	$ 868	$ 1,382	$ 1,031
Capital Investments	$ 1,722	$ 8,700	$ 516	$ 1,130	$	$ 12,068

	Six-Month Period Ended June 30, 2005					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 6,163	$ 6,147	$	$	$	$ 12,310
Interest income	10	3			58	71
	6,173	6,150			58	12,381
Operating costs	2,269	1,264				3,533
General and administrative	414	362			3,141	3,917
Business and product development			723	1,174		1,897
Depletion and depreciation	2,483	2,271	6	11	3	4,774
Interest expense	154				341	495
Write-downs and provision for impairment			279			279
	5,320	3,897	1,008	1,185	3,485	14,895

Net (Income) Loss	$ (853)	$ (2,253)	$ 1,008	$ 1,185	$ 3,427	$ 2,514
Capital Investments	$ 2,529	$ 18,251	$ 731	$ 2,844	$	$ 24,355

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12. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information for the three-month and six-month periods ended June 30:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Cash paid during the period for:				
Income taxes	**$**	$ 2	**$ 6**	$ 4
Interest	**$ 127**	$ 14	**$ 298**	$ 265
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**	$
Shares issued for Merger	**$**	$ 75,000	**$**	$ 75,000
Changes in non-cash working capital items				
Operating Activities:				
Accounts receivable	**$ (835)**	$ (275)	**$ (1,856)**	$ (314)
Prepaid and other current assets	**157**	85	**(97)**	(45)
Accounts payable and accrued liabilities	**(1,609)**	(309)	**(1,926)**	(385)
	(2,287)	(499)	**(3,879)**	(744)
Investing Activities				
Accounts receivable	**61**	732	**2,137**	195
Prepaid and other current assets	**59**	127	**44**	350
Accounts payable and accrued liabilities	**(5,139)**	1,870	**(8,285)**	9,367
Project advance from partner	**3,249**		**3,249**	
	(1,770)	2,729	**(2,855)**	9,912
	$ (4,057)	$ 2,230	**$ (6,734)**	$ 9,168

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. Subject to

any prior claims by the Company for indemnification, one-half of the Merger Shares in this escrow fund will be released to the Ensyn shareholders no later than 20 days from (i) the date a definitive agreement with an unaffiliated third party for the construction or use of a process plant equipped with RTP™ Technology and having a minimum daily input processing capacity of 10,000 Bop/d or (ii) the second anniversary of the closing date of the Merger, whichever is earlier. The balance of the Merger Shares will be released at the earliest of five dates that are either tied to a second definitive agreement or an anniversary of the dates set out in the first release of shares.
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. In May 2006 the parties entered a definitive agreement for the transaction. CMA will effectively acquire all of the issued and outstanding shares of Sunwing for a deemed estimated value 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 a substantial majority 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 transaction will be completed or completed in the form described above.

14. 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 June 30, 2006				
	Oil and Gas Properties and Investments	Shareholders Equity			
		Share Capital and Warrants	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 133,130	$ 342,628	$ 4,664	$ (105,072)	$ 242,220
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	2,584			2,584	2,584
GTL and EOR development costs expensed	(11,597)			(11,597)	(11,597)
U.S. GAAP	$ 110,875	$ 418,068	$ 1,289	$ (199,392)	$ 219,965

	As at December 31, 2005				
	Oil and Gas Properties	Shareholders Equity			
	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 $74.5 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 $74.5 million as at June 30, 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 June 30, 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 and six-month periods ended June 30, 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 and six-months ended June 30, 2006 an impairment provision of nil and $7.2 million was required on its China properties compared to nil and a $0.8 million impairment provision under Canadian GAAP for those same periods. The differences in the ceiling test impairments by period for the U.S. and China properties between U.S. and Canadian GAAP as at June 30, 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 $2.6 million and $1.6 million as at June 30, 2006 and December 31, 2005.

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 June 30, 2006 and December 31, 2005, the Company capitalized $11.6 million and $10.7 million 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 June 30,			
	2006		2005	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ 4,405	$ 0.02	$ 1,031	$ 0.01
Stock based compensation expense			(566)	
Depletion adjustments due to differences in provision for impairment	(737)		(256)	
GTL and EOR development costs expensed, net	314		1,355	
U.S. GAAP	$ 3,982	$ 0.02	$ 1,564	$ 0.01
Weighted Average Number of Shares under U.S. GAAP (in thousands)		235,388		195,200

	Six Month Periods Ended June 30,			
	2006		2005	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ 9,781	$ 0.04	$ 2,514	$ 0.01
Stock based compensation expense			(798)	
Provision for impairment	6,450	0.03		
Depletion adjustments due to differences in provision for impairment	(1,022)		(428)	
GTL and EOR development costs expensed, net	885		3,284	0.02
U.S. GAAP	$ 16,094	$ 0.07	$ 4,572	$ 0.03
Weighted Average Number of Shares under U.S. GAAP (in thousands)		229,997		183,621

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 $0.6 million and $0.8 million in the net loss for the three-month and six-month periods ended June 30, 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 and six-month periods ended June 30, 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 June 30, 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 $0.7 million and $1.0 million in the net losses for the three-month and six-month periods ended June 30, 2006 and a reduction of $0.3 million and $0.4 million in the net losses for the three-month an six-month periods ended June 30, 2005.

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 and six-month periods ended June 30, 2006 the Company expensed $0.3 million and $0.9 million and expensed $1.4 million and $3.3 million for those same periods in 2005 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 cannot 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 generally 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 B-S option-pricing formula and amortized on a straight-line attribution approach with the following weighted-average assumptions for the six-month period ended June 30, 2006:

Expected term (in years)	4.00
Volatility	81.80%
Dividend Yield	0.00%
Risk-free rate	4.20%

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 estimated forfeiture rate as at June 30, 2006 is 22.6%. The Company recognizes compensation costs only for those equity awards expected to vest.

The summary of option activity as at June 30, 2006, and changes during the six-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 at December 31, 2005	10,278	$ 2.21		
Granted	1,799	$ 3.15		
Exercised	(255)	$ 2.13		
Cancelled/forfeited	(401)	$ 3.56		
Outstanding at June 30, 2006	11,421	$ 2.31	3.0	$ 8,889
Options exercisable at June 30, 2006	7,291	$ 1.85	2.1	$ 8,654

The total intrinsic value of options exercised during the six-month period ended June 30, 2006 was $0.2 million.

A summary of the Company s unvested options as at June 30, 2006, and changes during the six-month period ended June 30, 2006, is presented below:

	Number of Stock Options (thousands)	Weighted-Average Grant Date Fair Value (Cdn.$)
Outstanding at December 31, 2005	3,731	$ 1.47
Granted	1,799	$ 1.42
Vested	(1,204)	$ 1.30
Cancelled/forfeited	(196)	$ 1.12
Outstanding at June 30, 2006	4,130	$ 1.53

As at June 30, 2006, there was $4.8 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 1.9 years. The total fair value of shares vested during the six-month period ended June 30, 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 June 30, 2005:	
Net loss under U.S. GAAP	$ 1,564
Stock-based compensation expense determined under the fair value based method for employee and director awards	597
Pro forma net loss under U.S. GAAP	$ 2,161
Basic loss per common share under U.S. GAAP:	
As reported	$ 0.01
Pro forma	$ 0.01
Weighted Average Number of Shares under U.S. GAAP (in thousands)	195,200
For the six-month period ended June 30, 2005:	
Net loss under U.S. GAAP	$ 4,572
Stock-based compensation expense determined under the fair value based method for employee and director awards	860
Pro forma net loss under U.S. GAAP	$ 5,432
Basic loss per common share under U.S. GAAP:	
As reported	$ 0.03
Pro forma	$ 0.03

Weighted Average Number of Shares under U.S. GAAP (in thousands)	183,621

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 and six-month periods ended June 30, 2005 included a net loss of $0.6 million, or nil per share, associated with the operations acquired from Ensyn after the completion of the Merger on April 15, 2005. Had the Merger been completed on January 1, 2005, the U.S. GAAP pro forma revenue, net loss and net loss per share of the merged entity for the three-month and six-month periods ended June 30, 2005 would have been as follows:

	Three-Month Period Ended June 30, 2005		
	Revenue	Net Loss	Net Loss Per Share
As reported	$ 6,645	$ 1,564	$ 0.01
Pro forma adjustments	6	550	
	$ 6,651	$ 2,114	$ 0.01
Weighted Average Number of Shares (in thousands)			200,145

	Six-Month Period Ended June 30, 2005		
	Revenue	Net Loss	Net Loss Per Share
As reported	$ 12,381	$ 4,572	$ 0.03
Pro forma adjustments	736	730	
	$ 13,117	$ 5,302	$ 0.03
Weighted Average Number of Shares (in thousands)			200,527

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 and six-month periods ended June 30, 2006 and 2005 would have been as follows:

	Three Months Ended June 30,					
	2006			2005		
	Revenue	Net (Income) Loss	Net (Income) Loss Per Share	Revenue	Net (Income) Loss	Net (Income) Loss Per Share
As reported	$ 13,084	$ 3,982	$ 0.02	$ 6,645	$ 1,564	$ 0.02
Pro forma adjustments				1,918	(519)	(0.01)
	$ 13,084	$ 3,982	$ 0.02	$ 8,563	$ 1,045	$ 0.01
Weighted Average Number of Shares (in thousands)			235,388			203,791

	Six Months Ended June 30,	
	2006	2005

	Revenue	Net (Income) Loss	Net (Income) Loss Per Share	Revenue	Net (Income) Loss	Net (Income) Loss Per Share
As reported	$ 22,948	$ 16,094	$ 0.07	$ 12,381	$ 4,572	$ 0.02
Pro forma adjustments	1,051	(809)		3,453	(825)	
	$ 23,999	$ 15,285	$ 0.07	$ 15,833	$ 3,747	$ 0.02
Weighted Average Number of Shares (in thousands)			232,418			192,212

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 $3.3 million and $4.8 million for the three-month and six-month periods ended June 30, 2006. Cash provided by operating activities would be $0.5 million for the three-month period ended June 30, 2005 and a cash deficiency of $0.6 million for the six-month period ended June 30, 2005. Additionally, capital investments reported under investing activities would be $3.4 million and $7.7 million for the three-month and six-month periods ended June 30, 2006 and $10.7 million and

$21.1 million for the three-month and six-month periods ended June 30, 2005.

Impact of New and Pending Canadian GAAP Accounting Standards

Commencing with the Company s 2007 fiscal year, the proposed amended recommendations of the CICA for accounting for business combinations will apply to the Company s business combinations, if any, with an acquisition date of January 1, 2007, or later. Whether the Company would be materially affected by the proposed amended recommendations would depend upon the specific facts of the business combinations, if any, occurring on or after January 1, 2007. Generally, the proposed recommendations will result in measuring business acquisitions at the fair value of the acquired entities and a prospectively applied shift from a parent company conceptual view of consolidation theory (which results in the parent company recording the book values attributable to non-controlling interests) to an entity conceptual view (which results in the parent company recording the fair values attributable to non-controlling interests).

In early 2006, Canada s Accounting Standards Board ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards over a transitional period. During 2006, the Accounting Standards Board is expected to develop and publish a detailed implementation plan with a transition period expected to be approximately five years. As this convergence initiative is very much in its infancy as of the date of these interim consolidated financial statements, it would be premature to currently assess the impact of the initiative, if any, on the Company.

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, in most respects, 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. Earlier adoption will be permitted only as of the beginning of a fiscal year. The impact of implementing these new standards is not yet determinable as it is highly dependent on fair values, outstanding positions and hedging strategies at the time of adoption.

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 June 2006, the FASB issued FASB Interpretation No. 48 (FIN 48) entitled Accounting for Uncertain Tax Positions an interpretation of SFAS No. 109. The interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. The evaluation of a tax position in accordance with this interpretation is a two-step process. Under the recognition step an enterprise determines whether it is more likely than not that a tax position will be sustained upon examination based on the technical merits of the position. Under the measurement step a tax position that meets the more-likely-than-not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 is effective for fiscal years beginning after December 15, 2006. Earlier application of the provisions of this interpretation is encouraged if the enterprise has not yet issued financial statements, including interim financial statements, in the period this interpretation is adopted. Management is in the process of reviewing the requirements of this interpretation.

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 and is not expected to have a material impact on the Company s financial statements.

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.

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 effective date of the proposed Statement is yet to be determined. 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.

In June 2005, the FASB published an exposure draft containing proposals to change the accounting for business combinations. The proposed standards would replace the existing requirements of the FASB s Statement No. 141, Business Combinations. The proposals would result in fewer exceptions to the principle of measuring assets acquired and liabilities assumed in a business combination at fair value. Additionally, the proposals would result in payments to third parties for consulting, legal, audit, and similar services associated with an acquisition being recognized generally as expenses when incurred rather than capitalized as part of the business combination. The FASB also published an exposure draft that proposes, among other changes, that noncontrolling interests be classified as equity within the consolidated financials statements. The FASB s proposed standard is generally consistent with the proposed Canadian standard on business combinations discussed above and would replace Accounting Research Bulletin No. 51, *Consolidated Financial Statements*.

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. There was no material impact upon adoption of this standard.

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, including in Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations, 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 , propose , should , intend , expect , believe , will and similar expressi statements relating to matters that are not historical facts are forward-looking statements. Forward-looking statements can also include discussions relating to future production associated with our RTP™ Technology and our Peach and North Yowlumne prospects. 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 above items and their possible impact are discussed more fully in the section entitled Risk Factors in Item 1 and Quantitative and Qualitative Disclosures About Market Risk in Item 7A of our 2005 Annual Report on Form 10-K.
The following should be read in conjunction with the Company s consolidated financial statements contained herein, the first quarter Form 10-Q for the quarter ended March 31, 2006 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 the Form 10-K and first quarter Form 10-Q. 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 14.
SPECIAL NOTE TO CANADIAN INVESTORS
Ivanhoe Energy is a US Securities and Exchange Commission (SEC) registrant and a Form 10-K and related forms filer. Therefore, our reserves estimates and securities regulatory disclosures generally follow SEC requirements. In 2004, certain Canadian regulatory authorities adopted *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* (NI 51-101) which prescribe that Canadian companies follow certain standards for the preparation and disclosure of reserves and related information. We have been granted certain exemptions from NI 51-101. Please refer to the *Special Note to Canadian Investors* on page 14 of our 2005 Annual Report on Form 10-K.
Unless we indicate otherwise, all dollar amounts ($) are in U.S. dollars, and oil and gas volumes, reserves and related performance measures are presented on a working-interest, before-royalties basis.
As generally used in the oil and gas business and in this throughout the Form 10-Q, the following terms have the following meanings:

Boe	= barrel of oil equivalent
Bbl	= barrel
MBbl	= thousand barrels
MMBbl	= million barrels
Mboe	= thousands of barrels of oil equivalent
Bopd	= barrels of oil per day

Bbls/d	= barrels per day
Boe/d	= barrels of oil equivalent per day
Mboe/d	= thousands of barrels of oil equivalent per day
MBbls/d	= thousand barrels per day
MMBls/d	= million barrels per day
MMBtu	= million British thermal units
Mcf	= thousand cubic feet
MMcf	= million cubic feet
Mcf/d	= thousand cubic feet per day
MMcf/d	= million cubic feet per day

When we refer to oil in **equivalents** , we are doing so to compare quantities of oil with quantities of gas or to express these different commodities in a common unit. In calculating Bbl equivalents, we use a generally recognized industry standard in which one Bbl is equal to six Mcf. Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Electronic copies of our filings with the SEC and the Canadian Securities Commissions (CSC) are available, free of charge, through our web site (www.ivanhoeenergy.com) upon request, by contacting our investor relations department at (604) 688-8323. Alternatively, the SEC and the CSC each maintain a website (www.sec.gov and www.sedar.com) that contains our reports, proxy and information statements and other published information that have been filed or furnished with the SEC and the CSC.

Executive Overview of 2006 Results

Revenues continued to grow, increasing 33% from the first quarter of 2006 and 97% compared to the same quarter in 2005 due to continued high oil prices and higher production; however our net loss increased by $3.4 million and $1.9 million for the same periods. Oil and gas revenues for the three-month and six-month periods ended June 30, 2006 increased by 94% or $6.2 million and 84% or $10.3 million when compared to the same periods in 2005. This improvement was offset in part by $1.3 million and $1.9 million of increased costs related to our business and product development activities and general and administrative expenses for those same periods. Additionally, the improvement in revenue was offset by a $6.6 million and $12.3 million increase in depletion and depreciation for the three and six month periods in 2006 compared to 2005. Despite these cost increases, we achieved positive cash flow from operations of $3.6 million for the three-month period ended June 30, 2006 compared to $1.9 million for the comparable period in 2005, and $5.7 million for the six-month period ended June 30, 2006 compared to $2.7 million for the comparable period in 2005.

We believe that we have made significant progress in the first half 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 pursuing 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 three-month and six-month periods ended June 30, 2006 and 2005:

(stated in thousands of U.S. dollars, except per share and production amounts)	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2006	**2005**	**2006**	**2005**
Oil and gas revenue	$ 12,814	$ 6,617	$22,640	$12,310
Net loss	$ 4,405	$ 1,031	$ 9,781	$ 2,514
Net loss per share	$ 0.02	$ 0.01	$ 0.04	$ 0.01
Average production (Boe/d)	2,280	1,653	2,147	1,659
Net operating revenue per Boe	$ 43.16	$ 32.21	$ 41.34	$ 29.23
Capital investments	$ 3,710	$ 12,068	$ 8,602	$24,355
Cash flow from operating activities	$ 3,622	$ 1,874	$ 5,702	$ 2,665

Financial Results Change in Net Loss

The following provides an analysis of our changes in net losses for the three-month and six-month periods ended June 30, 2006 when compared to the same period for 2005:

(stated in thousands of U.S. Dollars)	Three-Months Ended June 30,	Six-Months Ended June 30,
Net Losses for 2005	$ 1,031	$ 2,514
Favorable (unfavorable) variances:		
Cash Items:		
Net Operating Revenues:		
Production volumes	3,280	4,311
Oil and gas prices	2,917	6,019
Less: Operating costs	(2,087)	(3,041)
	4,110	7,289
General and administrative	(1,113)	(683)
Business and product development	(202)	(1,107)
Net interest	480	408
Total Cash Variances	3,275	5,907
Non-Cash Items:		
Depletion and depreciation	(6,622)	(12,261)
Stock based compensation	(182)	(239)
Write downs of GTL investments	279	279

Impairment of China oil and gas properties		(750)
Other	(124)	(203)
Total Non-Cash Variances	(6,649)	(13,174)
Net Losses for 2006	$ 4,405	$ 9,781

Our net loss for the three-month period ended June 30, 2006 was $4.4 million ($0.02 per share) compared to our net loss for the same period in 2005 of $1.0 million ($0.01 per share). The increase in our net loss from 2005 to 2006 of $3.4 million is mainly due to a $6.6 million increase in depletion and depreciation, and a $1.1 million increase in general and administrative expenses, partially offset by a $4.1 million increase in net operating revenues.

Our net loss for the six-month period ended June 30, 2006 was $9.8 million ($0.04 per share) compared to our net loss for the same period in 2005 of $2.5 million ($0.01 per share). The increase in our net loss from 2005 to 2006 of $7.4 million is mainly due to a $12.3 million increase in depletion and depreciation, a $1.1 million increase in business and product development expenses and a $0.8 million increase in impairment, partially offset by a $7.3 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

The following is a comparison of changes in production volumes for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005:

	Three-Month Periods Ended June 30,			Six-Month Periods Ended June 30,		
	Net Boe s		Percentage	Net Boe s		Percentage
	2006	2005	Change	2006	2005	Change
China:						
Dagang	149,174	58,285	156%	267,090	118,521	125%
Daqing	6,414	7,849	-18%	11,993	19,848	-40%
	155,588	66,134	135%	279,083	138,369	102%
U.S.:						
South Midway	45,138	51,551	-12%	91,213	101,319	-10%
Citrus	78	8,817	-99%	4,419	18,344	-76%
Knights Landing	103	16,624	-99%	146	27,924	-99%
Others	6,612	7,332	-10%	13,823	14,274	-3%
	51,931	84,324	-38%	109,601	161,861	-32%
	207,519	150,458	38%	388,684	300,230	29%

Net production volumes for the three-month and six-month periods ended June 30, 2006 increased 38% and 29% when compared to the same periods in 2005. The increase for the three-month period ended June 30, 2006 was due to a 135% increase in production volumes in our China properties offset by a 38% decrease in our U.S. properties, resulting in increased revenues of $3.3 million. The increase for the six-month period ended June 30, 2006 was due to 102% increase in production volumes in our China properties offset by a 32% decrease in our U.S. properties, resulting in increased revenues of $4.3 million.

<u>China</u>

Net production volumes at the Dagang field increased 156% and 125% for the three-month and six-month periods ended June 30, 2006 compared to the same periods in 2005. As a result of the 2005 development program, oil production volume increased by 54% or by 31.2 Mboe and 45% or 53.5 Mboe for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005 contributing $1.5 million and $2.4 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. In the first six months of 2006 we completed one well, fracture stimulated eight wells and re-completed 11 wells. We are continuing to evaluate production results of other northern block wells to identify additional wells for fracture stimulation. As at June 30, 2006, we had six wells on workover and 38 wells on production, producing 2,383 gross Bop/d (1,856 net Bopd), compared to 39 wells and 2,310 gross Bopd (1,080 net Bopd) as at December 31, 2005 and 42 wells and 2,450 gross Bopd (1,870 net Bopd) at the end of March 31, 2006.

Additionally, volumes at the Dagang field increased for the three-month and six-month periods ended June 30, 2006 compared to the same periods in 2005 by 102% or 59.7 Mboe and 80% or 95.1 Mboe due to the re-acquisition of Richfirst s 40% working interest in this project in February 2006. This acquisition contributed $2.9 million and $4.3 million to the increase in revenues for the three-month and six-month periods ended June 30, 2006 compared to the same periods in 2005.

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 18% and 40% for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005. These decreases in volumes resulted in a $0.1 million and $0.4 million decrease in revenues for the three-month and six-month periods ended June 30, 2006 compared to the same periods in 2005.

U.S.

The 38% and 32% decreases in U.S. production volumes for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005 were mainly due to the decline in production from the South Midway and Knights Landing fields and the sale of our Citrus property.

Our production at South Midway decreased 6.4 Mboe and 10.1 Mboe for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005 primarily due to timing of steaming cycles which caused some of the more productive wells to be shut in during the first six months of 2006. Also, in the first six months of 2006 the continuous steaming process in the expansion area was interrupted for a short period of time due to equipment repairs. These decreases in volumes resulted in a $0.3 million and a $0.4 million decrease in revenues for the three-month and six-month periods ended June 30, 2006 compared to the same periods in 2005. As at June 30, 2006, we were producing 538 gross Boe/d (500 net Boe/d) at South Midway compared to 536 gross Boe/d (499 net Boe/d) as at December 31, 2005.

As at December 31, 2005, production from the Knights Landing wells had been depleted to minimal levels resulting in a decrease of 16.5 Mboe and 27.8 Mboe for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005. These decreases in volumes resulted in a $0.4 million and a $0.8 million decrease in revenues for the three-month and six-month periods ended June 30, 2006 compared to the same periods in 2005.

We sold our Citrus property effective February 1, 2006 resulting in a decrease of 8.7 Mboe and 13.9 Mboe for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005. These decreases in volumes resulted in a $0.4 million and a $0.6 million decrease in revenues for the three-month and six-month periods ended June 30, 2006 compared to the same periods in 2005.

Oil and Gas Prices 2006 vs. 2005

Oil and gas prices increased 40% and 42% per Boe for the three-month and six-month periods ended June 30, 2006 generating $2.9 million and $6.0 million in additional revenue as compared to the same periods in 2005.

China

We realized an average of $62.64 and $59.41 per Boe from our operations in China for the three-month and six-month periods ended June 30, 2006 an increase of $12.39 and $14.99 per Boe over the same period a year ago, which accounts for $2.0 million and $4.3 million of our increase in revenues for the three-month and six-month periods ended June 30, 2006 as compared to the same periods in 2005.

U.S.

From the U.S. operations, we realized an average of $59.08 and $55.28 per Boe for the three-month and six-month periods ended June 30, 2006 an increase of $20.01 and $17.20 per Boe over the same period a year ago, which accounts for $0.9 million and $1.7 million of our increase in revenues for the three-month and six-month periods ended June 30, 2006 as compared to the same periods in 2005.

Operating Costs 2006 vs. 2005

For the three-month and six-month periods ended June 30, 2006, operating costs, including production taxes and engineering support, increased $2.1 million and $3.0 million in absolute terms from the same periods in 2005 or $6.82 and $5.14 per Boe.

China

Operating costs in China, including the Windfall Levy and engineering support, increased 102% or $9.57 per Boe and 75% or $6.84 per Boe for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005. Field operating costs, excluding Dagang field office costs, increased $1.18 per Boe or 14% and $0.77 per Boe or 10% for the three-month and six-month periods ended June 30, 2006 compared to the same periods in 2005. These increases are primarily due to higher power costs, increased workover and maintenance costs and increased treatment and processing fees attributable to higher 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 and six-month periods ended June 30, 2006 this amounted to a $3.04 and $2.88 increase per Boe in operating costs when compared to the same periods in 2005.

Engineering support for the three-month and six-month periods ended June 30, 2006 decreased $0.52 per Boe or 43% and $0.47 per Boe or 39%, when compared to the same periods 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.

As more fully described in Note 10 to the June 30, 2006 Unaudited Condensed Consolidated Financial Statements, beginning March 26, 2006 enterprises exploiting and selling crude oil in China are subject to the Windfall Levy if the monthly weighted average price received for crude oil is above $40 per barrel. For financial statement presentation the Windfall Levy is included in operating costs. For the three and six-month periods ended June 30, 2006 the Windfall Levy amounted to $6.57 and $3.66 per Boe.

U.S.

For the three-month and six-month periods ended June 30, 2006, operating costs in the U.S., including production taxes and engineering support, decreased $0.2 million and $0.1 million in absolute terms from the same periods in 2005. However, on a per Boe basis operating costs increased 28% or $3.89 per Boe and 38% or $5.29 per Boe for the three-month and six-month periods ended 2006 when compared to the same periods in 2005. Field operating costs increased $2.45 and $3.70 per Boe for the three-month and six-month periods ended June 30, 2006, when compared to the same periods in 2005, primarily resulting from decreases in production at South Midway while costs increased. Primary operating costs at South Midway increased mainly due to the timing of periodic maintenance of processing facilities. Reductions to fuel costs in South Midway steaming operations were partially offset by repairs to steam operation equipment. Engineering support increased $0.51 and $0.73 per Boe for the three-month and six-month periods ended June 30, 2006, when compared to the same periods in 2005 due mainly to decreases in production. Production taxes were up $0.93 and $0.86 per Boe for the three-month and six-month periods ended June 30, 2006, when compared to the same periods in 2005, largely as the result of an increase in ad valorem taxes at South Midway and our Spraberry field in West Texas.

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 June 30,					
	2006			2005		
	U.S.	**China**	**Total**	**U.S.**	**China**	**Total**
Net Production:						
Boe	51,931	155,588	207,519	84,324	66,134	150,458
Boe/day for the period	570	1,710	2,280	926	727	1,653
	Per Boe			Per Boe		
Oil and gas revenue	$ 59.08	$ 62.64	$ 61.75	$ 39.07	$ 50.25	$ 43.98
Field operating costs	12.59	11.67	11.90	10.14	8.15	9.26
Production tax and Windfall Levy	1.46	6.57	5.29	0.53		0.30
Engineering support	3.51	0.69	1.40	3.00	1.21	2.21
	17.56	18.93	18.59	13.67	9.36	11.77
Net operating revenue	41.52	43.71	43.16	25.40	40.89	32.21
Depletion	24.52	40.10	36.20	15.38	18.70	16.84
Net revenue from operations	$ 17.00	$ 3.61	$ 6.96	$ 10.02	$ 22.19	$ 15.37

	Six-Month Periods Ended June 30,					
	2006			2005		
	U.S.	**China**	**Total**	**U.S.**	**China**	**Total**
Net Production:						
Boe	109,601	279,083	388,684	161,861	138,369	300,230
Boe/day for the period	605	1,542	2,147	894	765	1,659
	Per Boe			Per Boe		
Oil and gas revenue	$ 55.28	$ 59.41	$ 58.25	$ 38.08	$ 44.42	$ 41.00
Field operating costs	14.14	11.60	12.31	10.44	7.95	9.29
Production tax and Windfall Levy	1.38	3.66	3.02	0.52		0.28
Engineering support	3.79	0.72	1.58	3.06	1.19	2.20
	19.31	15.98	16.91	14.02	9.14	11.77
Net operating revenue	35.97	43.43	41.34	24.06	35.28	29.23
Depletion	22.22	41.79	36.27	15.08	16.40	15.69
Net revenue from operations	$ 13.75	$ 1.64	$ 5.07	$ 8.98	$ 18.88	$ 13.54

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 and six-month periods ended June 30, 2006 when compared to the same periods for 2005 were as follows:

	Three-Months Ended June 30, 2006 vs. 2005	Six-Months Ended June 30, 2006 vs. 2005
Favorable (unfavorable) variances:		
Oil and Gas Activities:		
China	$ (197)	$ (317)
U.S.	(291)	(508)
Corporate	(733)	15
	(1,221)	(810)
Less: stock based compensation	108	127
	$ (1,113)	$ (683)

Including increases for stock based compensation, general and administrative expenses after allocations increased by $1.2 million and $0.8 million for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005.

China

General and administrative costs for China increased $0.2 million and $0.3 million as allocations to capital investments decreased as a result of less capital activity for the three-month and six-month periods ended June 30, 2006 when compared to the same period in 2005.

U.S.

General and administrative costs in the U.S. increased $0.3 million and $0.5 million as allocations to capital investments decreased as a result of less capital activity for the three-month and six-month periods ended June 30, 2006 when compared to the same period in 2005.

Corporate

General and administrative costs related to Corporate activities increased $0.7 million for the three-month period ended June 30, 2006 when compared to the same period in 2005 due mainly to a $0.2 million increase in non-cash stock based compensation and a write off of $0.3 million of deferred financing costs associated with early extinguishment of debt. General and administrative costs for the six-month period ended June 30, 2006 when compared to the same period in 2005 were essentially the same. Increases of $0.3 million for non-cash stock based compensation and $0.2 million for the write off of deferred financing costs associated with early extinguishment of debt were offset by reduced professional fees incurred to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002 (**SOX**) as 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.

Business and Product Development 2006 vs. 2005

Changes in business and product development expenses, before and after considering increases in non-cash stock based compensation, by segment for the three-month and six-month periods ended June 30, 2006 when compared to the same periods for 2005 were as follows:

	Three-Months Ended June 30, 2006 vs. 2005	Six-Months Ended June 30, 2006 vs. 2005
Favorable (unfavorable) variances:		
GTL	$ (98)	$ (46)
EOR	(178)	(1,173)
	(276)	(1,219)
Less: stock based compensation	74	112
	$ (202)	$ (1,107)

Business and product development expenses increased $0.3 million and $1.2 million for the three-month and six-month periods ended June 30, 2006 compared to the same periods in 2005. Much of the focus of our business and product development activities was on EOR opportunities, particularly related to heavy oil processing. Operating expenses of the RTP™ CDF to develop and identify improvements in the application of the RTP™ Technology are a part of our business and product development activities and contributed $0.3 million and $1.0 million to the increase in business and product development expense for the three-month and six-month periods ended June 30, 2006. These increases included hiring of additional personnel in anticipation of additional and extended test runs of the RTP™ CDF.

Depletion and Depreciation 2006 vs. 2005

Depletion and depreciation increased $6.6 million and $12.3 million for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005 primarily due to an increase in depletion rates of $19.36 and $20.58 per Boe resulting in additional depletion expense of $3.8 million and $7.9 million for the three-month and six-month periods ended June 30, 2006. Additionally, higher production rates resulted in increases in depletion of $1.2 million and $1.5 million for the three-month and six-month periods ended June 30, 2006 compared to the same periods in 2005. We began depreciating the CDF RTP™ in 2006 which also contributed to the overall increase in depletion and depreciation for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005.

China

China s depletion rate for the three-month and six-month periods ended June 30, 2006 was $40.10 and $41.79 per Boe compared to $18.70 and $16.40 per Boe for the same periods in 2005. The increases of $21.40 and $25.39 per Boe resulted in a $3.5 million and $7.1 million increase in depletion expense for the three-month and six-month periods ended June 30, 2006. These increases were due mainly to two factors:

- As noted in prior periodic reports on Forms 10K and 10Q and in related shareholder communications, we suspended new drilling activity in December 2005 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 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 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 $12.5 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 $1.7 million and $2.3 million of the increases in depletion expense for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005.

U.S.

The U.S. depletion rate for the three-month and six-month periods ended June 30, 2006 was $24.52 and $22.22 per Boe compared to $15.38 and $15.08 per Boe for the same periods in 2005, an increase of $9.14 and $7.14 per Boe resulting in a $0.5 million and $0.8 million increase in depletion expense compared to these same periods in 2005. 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 $0.5 million and $0.8 decrease in our depletion expense for the three-month and six-month periods ended June 30, 2006 when compared to the same periods 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 and six month periods ended June 30, 2006 $1.7 million and $2.9 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 nil and $0.8 million for the three-month and six-month periods ended June 30, 2006 compared to no impairment for the same periods in 2005. This impairment is mainly due a Windfall 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 and six-month periods ended 2006 when compared to the same periods for 2005:

	Three-Month Periods Ended June 30,			Six-Month Periods Ended June 30,		
	2006	**2005**	**(Increase) Decrease**	**2006**	**2005**	**(Increase) Decrease**
Oil and Gas Activities:						
China	$ 1,934	$ 8,700	$ 6,766	$ 4,651	$ 18,251	$ 13,600
U.S.	788	1,722	934	2,065	2,529	464
EOR	833	1,130	297	1,514	2,844	1,330
GTL	155	516	361	372	731	359
	$ 3,710	$ 12,068	$ 8,358	$ 8,602	24,355	$ 15,753

Oil and Gas Activities China

Capital investment in China for the three-month and six-month periods ending June 30, 2006 was $1.9 million and $4.7 million a $6.8 million or 78% and $13.6 million or 74% decrease compared to the same periods in 2005. These decreases are primarily due to the suspension of new drilling activities at our Dagang field in December 2005. Expenditures at Dagang decreased $4.5 million to $1.8 million and $8.8 million to $4.1 million during the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005. The suspension of new drilling at Dagang accounts for the majority of this decrease. During the three-month period ended June 30, 2006 we fracture stimulated 3 wells, two of which were in the northern block of the project, and re-completed 11 wells, 5 of which were situated in the northern block. The stimulation program initiated in 2005 continues in the northern block. We continue to assess prior fracture stimulations and related production decline rates in order to choose additional wells for this program and to assist in making critical decisions on resuming our drilling program. We are currently in the process of preparing a modified Overall Development Program that will be presented to our Chinese partner in August 2006.

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 in our Zitong block was $0.1 million and $0.6 million for the three-month and six-month periods ended June 30, 2006 compared to $2.4 million and $5.4 million for the same periods in 2005. The decreases are due mainly to the completion of our 700-mile seismic acquisition program in the first quarter 2005 and to the commencement of drilling our first exploration well which spudded in April 2005. During the three-month period ended June 30, 2006, we continued prospect development in this block and selected our second exploration well location, the Yixin #1, which is anticipated to spud in late third quarter of 2006. In May 2006, we received final approval from the Chinese authorities for our farm-out of 10% of the Zitong block to Mitsubishi. Subsequent to the approval, Mitsubishi paid the Company $4.0 million which will be used to drill the Yixin #1 well to a specified depth, at which time Mitsubishi will have earned their 10% working interest in the block.

Oil and Gas Activities U.S.

Capital investment in the U.S. was down $0.9 million and $0.5 million for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005.

The decrease for the three-month period ended June 30, 2006 was due mainly to $0.3 million and $0.5 million decreases in drilling activities at South Midway and the Peach prospect.

The decrease for the six-month period ended June 30, 2006 was due mainly to $0.4 million and $0.5 million decreases in drilling activities at South Midway and the Peach prospect offset by an increase in our exploration activities in the North Yowlumne prospect of $0.5 million.

South Midway

Our development activities at South Midway decreased $0.3 million and $0.4 million for the three-month and six-month periods ended September 30, 2005 compared to the same periods in 2005. We drilled one successful delineation well and two temperature observation wells in the second quarter of 2005. There was no drilling activity during the first six months of 2006, although an 11 well drilling program began in July 2006.

Peach

During the first quarter of 2005, we discovered natural gas at our Peach prospect in the North Antelope Hills area in Kern County, California. The prospect is in a major hydrocarbon-producing region along the west side of the San Joaquin Basin. We farmed-out part of our Peach prospect in November 2004 for 100% of the drilling costs of the first Peach well, Peach # 1, to earn a 50% interest in the prospect. We will retain a 50% interest in this well after payout and will retain a 50% working interest in the prospect. We spent $0.5 million for the three-month and six- month periods ended June 30, 2005 to drill an appraisal well which was drilled to a depth of 4,950 feet and encountered gas shows while drilling. The testing of the appraisal well was unsuccessful and will be abandoned. Construction of a pipeline to sell gas from the Peach #1 well was completed and the well was placed on production. The well produced water and was shut in. The operator of the well is scheduling a workover to attempt to establish gas production. The timeframe for this work is currently unknown.

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 small amount of light oil and associated gas. The operator has installed artificial lift and has attempted to produce the well to establish a commercial production rate. A flow rate has yet to be established in the well, however, due to mechanical problems with the hydraulic pumping equipment. A rig to repair the downhole equipment has been scheduled and it is expected that the well testing will recommence in the third quarter of 2006. Once testing results of the current interval are known, additional testing of an upper interval above the current one will be tested. Final results of the entire testing of the well are expected to be known during the third quarter of 2006.

Enhanced Oil Recovery and Heavy-To-Light Oil Activities

We incurred $0.3 million and $1.3 million less in capital investment activities on EOR and HTL projects for the three-month and six-month periods ended June 30, 2006 compared to the same periods 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 and six-month periods ended June 30, 2006, we incurred $0.7 million and $1.0 million on technical and operational enhancements to the RTP™ CDF. To carry out additional test runs with very difficult feedstocks (further runs with vacuum tower bottoms (VTBs) and runs with Athabasca bitumen), a number of upgrades and enhancements to the RTP™ CDF were made. These upgrades were primarily related to rerouting piping and peripheral vessels, redundancy of peripheral equipment and expansion of control systems.

The facility resumed operation in late June following these enhancements with an extended run of California VTBs which provided performance confirmation of the upgrades and generated data for future test runs.

This test program will continue with 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 and include flue gas de-suphurization, heavy metals capture and crude acidity reduction.

The RTP™ CDF is now being prepared for an additional run of California VTBs and to process Athabasca bitumen in a high quality configuration. This high quality configuration, appropriate for numerous heavy oil 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. 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 and six-month periods ended June 30, 2005, we incurred $0.4 million and $0.8 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 designed to produce maximum steam or electrical generation for each configuration at varying levels of heavy oil input into the plant. The design was based on the location of the plant in 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 oils found worldwide, including Canada s heavy oil from the Cold Lake and Peace River areas of Alberta. Various plant configurations were evaluated as well as the capital estimates that are being used in our economic models. These decreases in spending due to the completion of the Colt design package in 2005 were partially offset by engineering work performed by AMEC Ltd. of $0.2 million and $0.3 million for the three-month and six-month periods ended June 30, 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 prepare a study to 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.

The study evaluated 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 included an assessment of the oil-in-place in the reservoirs, and the optimum EOR and heavy oil processing methods to establish economically recoverable volumes.

The reservoir assessment has been completed and various recovery methods have been evaluated. Facility design work is complete and an economic evaluation is underway. If the economic evaluation studies indicate development of the field is economically viable, we propose to 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.

The Qaiyarah heavy oil field project resulted in a $0.5 million decrease in capital investments for the three-month and six-month periods ended June 30, 2006 when compared to the same periods in 2005. In addition, we invested $0.1 million and $0.3 million during the three-month and six-month periods ended June 30, 2005 and nil during those same periods in 2006 on other projects in Iraq including submission of four bids for the engineering, design and procurement of oil production facilities and EOR development projects.

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 and $0.4 million in costs related to this MOU during the three-month and six-month periods ended June 30, 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

We spent $0.4 million less in capital investment activities on GTL projects for the three-month and six-month periods ended June 30, 2006 when compared to the same periods 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. The feasibility study has been completed and presented as a report to EGAS along with three commercial proposals in May 2006. EGAS has reviewed all of what we have presented to them and they are now ready to choose their preferred proposal and begin defining the principles of a term sheet which could lead to 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 for the three-month period ended June 30, 2006 by $18.3 million compared to a decrease of $5.6 million for the same period in 2005. Our net cash and cash equivalents increased for the six-month period ended June 30, 2006 by $19.1 million compared to a decrease of $5.6 million for the same period in 2005.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Cash flow from operating activities	$ 3,622	$ 1,874	$ 5,702	$ 2,665
Investing Activities				
Capital investments, after changes in non-cash working capital	(8,729)	(9,339)	(14,706)	(14,443)
Merger, net of cash acquired		(9,979)		(9,979)
Merger and acquisition related costs	(325)	(957)	(502)	(1,687)
Proceeds from sale of assets			5,350	
Project advance from partner	3,249		3,249	
Advance payments	(50)	(300)	(50)	(600)
Other	(60)	(76)	(69)	(76)
	(5,915)	(20,651)	(6,728)	(26,785)
Financing Activities				
Proceeds from private placements, net of all share issue costs	25,315	10,060	25,315	10,060
Proceeds from exercise of options and warrants	358	1,690	449	1,725
Proceeds/redememption of advances from partner				
Net debt financing	(5,032)	1,583	(5,654)	7,167
Other		(163)		(426)
	20,641	13,170	20,110	18,526
Net Source (Use) of Cash	$ 18,348	$ (5,607)	$ 19,084	$ (5,594)

Operating Activities

Our operating activities provided $3.6 million in cash for the three-month period ended June 30, 2006 compared to $1.9 million for the same period in 2005. Our operating activities provided $5.7 million in cash for the six-month period ended June 30, 2006 compared to $2.7 million for the same period in 2005. The increases in cash from operating activities for the three-month and six-month periods ended June 30, 2006 were mainly due to increases in net production volumes of 38% and 21% and increases in oil and gas prices of 40% and 42% when compared to the same periods in 2005. The increases in net revenues for the three-month and six-month periods ended June 30, 2006 were partially offset by increases of $1.3 million and $1.8 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 $5.9 million in cash for the three-month period ended June 30, 2006 compared to $20.7 million for the same period in 2005. We spent $10.6 million more on Merger and acquisition related activities in the three-month period ended June 30, 2005, compared to the same period in 2006. This decrease in spending was coupled with a $3.2 million net inflow from a project advance from a partner in the three-month period ended June 30, 2006. Our investing activities used $6.7 million in cash for the six-month period ended June 30, 2006 compared to $26.8 million for the same period in 2005 for a $20.1 million decrease in cash used in investing activities. This decrease was primarily due to a decrease of $11.2 million of cash used in Merger and acquisition related activities. In addition, $5.4 million in proceeds from sale of assets and a $3.2 million net inflow from a project advance from a partner in the six-month period ended June 30, 2006 contributed to the reduction in the use of cash.

Financing Activities

Our financing activities provided $20.6 million in cash for the three-month period ended June 30, 2006 compared to $13.2 million of cash provided by financing activities for the comparable period in 2005. The $7.4 million increase in cash from financing activities is mainly due to a $13.9 million increase in cash from private placements and exercises of warrants and options less a $6.6 million decrease in net debt financing. Our financing activities provided $20.1 million in cash for the six-month period ended June 30, 2006 compared to $18.5 million of cash provided by financing activities for the comparable period in 2005. The $1.6 million increase in cash from financing activities is mainly due to a $14.0 million increase in cash from private placements and exercises of warrants and options less a $12.8 million decrease in net debt financing.

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.

Outlook for 2006

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 alliances or other partnership agreements with entities who we believe will provide additional resources to support the Company s projects as well as the sale of additional equity securities, loans and debt financing in order to generate sufficient funds 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 June 30, 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**
Consolidated Balance Sheets:						
Note payable current portion	$ 3,730	**$ 1,844**	$ 1,886	$	$	$
Long term debt	3,971		1,234	2,325	412	
Asset retirement obligation	1,525		102	822	27	574
Long term obligation	1,900		1,900			
Other Commitments:						
Interest payable	759	**280**	340	135	4	
Lease commitments	1,933	**392**	611	475	287	168
Zitong exploration commitment	3,870	**3,870**				
Total	$ 17,688	**$ 6,386**	$ 6,073	$ 3,757	$ 730	$ 742

Off Balance Sheet Arrangements

As at June 30, 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 July 29, 2006, there were 241,173,798 common shares of the Company issued and outstanding. Additionally, the Company had 29,696,330 share purchase warrants outstanding and exercisable to purchase 29,696,330 common shares. As at July 29, 2006, there were 12,318,336 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	
	2nd Qtr	**1st Qtr**	**4th Qtr**	**3rd Qtr**	**2nd Qtr**	**1st Qtr**	**4th Qtr**	**3rd Qtr**
Total revenue	$13,084	$ 9,864	$8,651	$8,907	$6,645	$5,736	$ 6,212	$4,932
Net loss:								
Canadian GAAP	$ 4,405	$ 5,376	$8,885	$2,113	$1,031	$1,483	$17,184	$ 951
U.S. GAAP	$ 3,982	$12,112	$8,557	$1,843	$1,564	$3,008	$15,736	$ 980
Net loss per share:								
Canadian GAAP	$ 0.02	$ 0.02	$ 0.04	$ 0.01	$ 0.01	$ 0.01	$ 0.09	$ 0.01
U.S. GAAP	$ 0.02	$ 0.05	$ 0.03	$ 0.01	$ 0.01	$ 0.02	$ 0.09	$ 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 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 the China oil and gas properties 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 June 30, 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 June 30, 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 June 30, 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
10.1	Employment Agreement, by and between the Company and Joseph I. Gasca, dated as of May 15, 2006 (Incorporated by reference to Exhibit 10.1 of Form 8-K filed with the Securities and Exchange Commission on May 26, 2006).
10.2	Stock Purchase Agreement, by and among Ivanhoe Energy Inc., Sunwing Holding Corporation, Sunwing Energy Ltd. and China Mineral Acquisition Corporation, dated as of May 12, 2006 (Incorporated by reference to Exhibit 10.1 of Form 8-K filed with the Securities and Exchange Commission on May 12, 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: August 3, 2006

INDEX TO EXHIBITS

Exhibit Number	Description
10.1	Employment Agreement, by and between the Company and Joseph I. Gasca, dated as of May 15, 2006 (Incorporated by reference to Exhibit 10.1 of Form 8-K filed with the Securities and Exchange Commission on May 26, 2006).
10.2	Stock Purchase Agreement, by and among Ivanhoe Energy Inc., Sunwing Holding Corporation, Sunwing Energy Ltd. and China Mineral Acquisition Corporation, dated as of May 12, 2006 (Incorporated by reference to Exhibit 10.1 of Form 8-K filed with the Securities and Exchange Commission on May 12, 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