IVANHOE ENERGY INC
Form 10-Q
May 10, 2005

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

FORM 10-Q

þ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.**

For the quarterly period ended March 31, 2005

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)

(604) 688-8323
(registrant s telephone number, including area code)

Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report:
Not Applicable

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 an accelerated filer (as defined in Rule 12b-2 of the Exchange Act)

Yes þ No o

The number of shares of the registrant s capital stock outstanding as of March 31, 2005 was 169,892,413 Common Shares, no par value.

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Part I Financial Information

Item 1 Financial Statements

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

	March 31, 2005	December 31, 2004
Assets		
Current Assets		
Cash and cash equivalents	**$ 9,335**	$ 9,322
Notes and accounts receivable	**6,253**	5,377
Prepaid and other current assets	**719**	812
	16,307	15,511
Long term assets	**7,409**	6,424
Oil and gas properties and investments, net	**106,621**	96,551
	$ 130,337	$ 118,486
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 16,826**	$ 9,845
Note payable current portion	**1,667**	1,667
Convertible loan	**6,000**	
	24,493	11,512
Long term debt	**2,222**	2,639
Asset retirement obligations	**747**	749
Commitments and contingencies		
Shareholders Equity		
Share capital, issued 169,892,413 common shares; December 31, 2004 169,664,911 common shares	**184,102**	183,617
Contributed surplus	**2,035**	1,748
Accumulated deficit	**(83,262)**	(81,779)
	102,875	103,586

	$	**130,337**	$	118,486

(See accompanying notes)

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

	2005	2004
Revenue		
Oil and gas revenue	**$ 5,693**	$ 3,292
Interest income	**43**	40
	5,736	3,332
Expenses		
Operating costs	**1,762**	1,275
General, administrative and business development	**3,130**	1,880
Depletion and depreciation	**2,207**	1,446
Interest expense	**120**	23
	7,219	4,624
Net Loss	**1,483**	1,292
Deficit, beginning of period	**81,779**	61,054
Deficit, end of period	**$ 83,262**	$ 62,346
Net Loss per share Basic and Diluted	**$ 0.01**	$ 0.01
Weighted Average Number of Shares (in thousands)	**169,816**	162,127

(See accompanying notes)

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

	2005	2004
Operating Activities		
Net loss	**$ (1,483)**	$ (1,292)
Items not requiring use of cash		
Depletion and depreciation	**2,207**	1,446
Stock based compensation	**296**	239
Changes in non-cash working capital items	**(244)**	(1,439)
	776	(1,046)
Investing Activities		
Capital investments and other	**(12,534)**	(10,423)
Equity investment and other related costs	**(730)**	(500)
Changes in non-cash working capital items	**6,883**	598
	(6,381)	(10,325)
Financing Activities		
Shares issued on private placements, net of share issue costs		20,428
Shares issued on exercise of options	**35**	139
Proceeds from debt obligations	**6,000**	10,000
Repayments of debt obligations	**(417)**	
	5,618	30,567
Increase in cash and cash equivalents, for the period	**13**	19,196
Cash and cash equivalents, beginning of period	**9,322**	14,491
Cash and cash equivalents, end of period	**$ 9,335**	$ 33,687
Included in the above are the following:		
Taxes paid	**$ 2**	$ 3
Interest paid	**$ 56**	$ 14
Changes in non-cash working capital items		
Operating Activities:		
Accounts receivable	**$ (39)**	$ (1,234)
Prepaid and other current assets	**(130)**	38
Accounts payable and accrued liabilities	**(75)**	(243)

		(244)		(1,439)
Investing Activities				
Accounts receivable		**(837)**		322
Prepaid and other current assets		**223**		(10)
Accounts payable and accrued liabilities		**7,497**		286
		6,883		598
	$	**6,639**	$	(841)

(See accompanying notes)

Notes to the Condensed Consolidated Financial Statements
March 31, 2005
(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 12. The unaudited condensed consolidated financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2004 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, 2004 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 consolidated financial statements. Actual results may differ from those estimates.

Certain items in the 2004 financial statements have been reclassified for comparison to the 2005 presentation.

2. OIL AND GAS PROPERTIES AND INVESTMENTS

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

	As at March 31, 2005				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 81,902	$ 42,294	$	$	$ 124,196
Unproved	20,966	13,610			34,576
	102,868	55,904			158,772
Accumulated depletion	(12,102)	(7,697)			(19,799)
Accumulated provision for impairment	(50,350)				(50,350)
	40,416	48,207			88,623
GTL and EOR Investments:					
GTL master license			10,000		10,000
Feasibility studies and other deferred costs			4,008	3,804	7,812
			14,008	3,804	17,812

Furniture and equipment	435	91		12	538
Accumulated depreciation	(326)	(25)		(1)	(352)
	109	66		11	186
	$ 40,525	$ 48,273	$ 14,008	$ 3,815	$ 106,621

	As at December 31, 2004				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 81,648	$ 35,771	$	$	$ 117,419
Unproved	20,447	10,581			31,028
	102,095	46,352			148,447
Accumulated depletion	(10,956)	(6,663)			(17,619)
Accumulated provision for impairment	(50,350)				(50,350)
	40,789	39,689			80,478
GTL and EOR Investments:					
GTL master license			10,000		10,000
Feasibility studies and other deferred costs			3,793	2,091	5,884
			13,793	2,091	15,884
Furniture and equipment	417	84		11	512
Accumulated depreciation	(300)	(22)		(1)	(323)
	117	62		10	189
	$ 40,906	$ 39,751	$ 13,793	$ 2,101	$ 96,551

Included in proved properties as at March 31, 2005 and December 31, 2004 is $0.6 million of costs associated with future asset retirement and abandonment of oil and gas properties in the U.S.

Costs as at March 31, 2005 and December 31, 2004 of $34.6 million and $31.0 million, respectively, related to unproved oil and gas properties were excluded from the depletion and ceiling test calculations.

For the three-month periods ended March 31, 2005 and 2004, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities, and investments in GTL and EOR projects of $0.9 million and $0.7 million, respectively, were capitalized.

3. LONG TERM ASSETS

During 2004, the Company acquired a 15% equity interest in Ensyn Petroleum International Ltd. (**EPIL**) and exclusive rights to use the proprietary Ensyn RTP™ Technology (**RTP™ Technology**) in key international markets. The RTP™ Technology, patented in the U.S., Canada and other countries, upgrades the quality of heavy oil by producing lighter, more valuable crude oil. In December 2004, the Company and Ensyn Group, Inc. (**Ensyn**), the parent company of EPIL, announced the signing of an Agreement and Plan of Merger (**Merger Agreement**) in which Ensyn will be merged with the Company (**Merger**) and Ensyn will become a wholly owned subsidiary of the Company. With this Merger, the Company will gain full ownership of EPIL and the exclusive right to employ the RTP™ Technology for petroleum process applications worldwide (See Note 11).

The cost to acquire the 15% equity interest in Ensyn Petroleum International Ltd. of $3.0 million plus $3.2 million and $2.5 million of costs as at March 31, 2005 and December 31, 2004, respectively, incurred by the Company associated with the Merger are included in long-term assets.

4. SEGMENT INFORMATION

The following tables present the Company s interim segment information for the three-month periods ended March 31, 2005 and 2004 and identifiable assets as at March 31, 2005 and December 31, 2004:

	Three-Month Period Ended March 31, 2005					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 2,869	$ 2,824	$	$	$	$ 5,693
Interest income	6	2			35	43
	2,875	2,826			35	5,736
Operating costs	1,116	646				1,762
General, administrative and business development	157	224	404	315	2,030	3,130
Depletion and depreciation	1,167	1,034	3	2	1	2,207
Interest expense	70				50	120
	2,510	1,904	407	317	2,081	7,219
Net (Income) Loss	$ (365)	$ (922)	$ 407	$ 317	$ 2,046	$ 1,483
Capital Investments	$ 799	$ 9,806	$ 215	$ 1,714	$	$ 12,534
Identifiable Assets (As at March 31, 2005)	$ 47,602	$ 54,501	$ 14,056	$ 3,891	$ 10,287	$ 130,337
Identifiable Assets (As at December 31, 2004)	$ 49,465	$ 44,960	$ 13,867	$ 2,441	$ 7,753	$ 118,486

	Three-Month Period Ended March 31, 2004					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 1,793	$ 1,499	$	$	$	$ 3,292
Interest income	2	3			35	40
	1,795	1,502			35	3,332
Operating costs	755	520				1,275
General, administrative and business development	106	256	277		1,241	1,880
Depletion and depreciation	863	577	5		1	1,446
Interest expense	22				1	23
	1,746	1,353	282		1,243	4,624

Net (Income) Loss	$ (49)	$ (149)	$ 282	$	$ 1,208	$ 1,292
Capital Investments	$ 3,118	$ 6,875	$ 67	$ 363	$	$ 10,423

5. SHARE CAPITAL

Following is a summary of the changes in share capital and stock options outstanding for the three-month period ended March 31, 2005:

	Common Shares			**Stock Options**	
	Number (thousands)	**Amount**	**Contributed Surplus**	**Number (thousands)**	**Weighted Average Exercise Price Cdn.$**
Balance December 31, 2004	169,665	$ 183,617	$ 1,748	8,246	$ 2.65
Shares issued for services	192	441			
Shares issued on exercise of options	35	44	(9)	(35)	$ 1.42
Options granted				363	$ 3.12
Options expired				(60)	$ 1.42
Stock based compensation			296		$
Balance March 31, 2005	169,892	$ 184,102	$ 2,035	8,514	$ 2.68

As at March 31, 2005, the following purchase warrants are exercisable to purchase additional common shares through the anniversary dates of the special warrant financing at the price per share as indicated:

Year of Special Warrant Financing	Price per Special Warrant (U.S.$)	Number of Purchase Warrants Issued	Remaining Number of Purchase Warrants (thousands)	Number of Common Shares	Second Anniversary Date	Second Anniversary Price per Share (US$)
2003	$ 1.00	3,000	3,000	1,500	July 3, 2005	$ 1.10
2003	$ 1.00	3,000	3,000	1,500	August 18, 2005	$ 1.10
2003	$ 1.70	3,529	3,029	1,515	August 21, 2005	$ 1.87
2003	$ 4.00	1,250	1,250	1,250	October 31, 2005	$ 4.30
2004	$ 2.90	5,449	5,449	2,725	February 18, 2006	$ 3.20
2004	$ 2.90	1,724	1,724	862	March 5, 2006	$ 3.20
		17,952	17,452	9,352		

6. STOCK BASED COMPENSATION

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

For the three-month periods ended March 31, 2005 and 2004, the Company expensed $0.3 million and $0.2 million, respectively, in stock based compensation, which is included in general and administrative expense.

7. NOTE AND ADVANCE PAYABLE

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 note is repayable over three years starting August 2004 with interest at 0.5% above the bank s prime rate or 3.0% over the London Inter-Bank Offered rate (**LIBOR**), at the option of the Company. The note is secured by all the Company s rights and interests in the South Midway properties. The note balance, as at March 31, 2005 and December 31, 2004, was $3.9 million and $4.3 million, respectively, with a six-month fixed LIBOR rate of 5.25% per annum as at March 31, 2005.

The scheduled maturities of the bank note payable as at March 31, 2005 were as follows:

2005	$ 1,250
2006	1,667

2007	972
	3,889
Less: current portion	1,667
	$ 2,222

In March 2004, the Company received a $10.0 million advance as part of a $20.0 million up-front payment due to a farm-in to the Company s Dagang oil project. Upon finalization of the farm-in agreement in June 2004, the Company s farm-in partner elected to apply $10.0 million of the up-front payment due to the Company against the advance.

8. CONVERTIBLE LOAN

The $6.0 million unsecured convertible loan bears interest at 8.0% per annum and is due upon the earliest of i.) five days following receipt of proceeds from a private placement or public offering of Company common shares ii.) ninety days following written demand for repayment from lender or iii.) August 23, 2005. During the term of the loan the lender may convert at its option unpaid principal and interest, in whole or in part, to the Company s common shares at $2.25 per share. The fair value of the convertible loan approximates its carrying value due to the short-term maturity. No value was assigned to the equity component of the loan. The lender waived its right to have the loan repaid from the proceeds of the special warrant financing described in Note 11.

9. ASSET RETIREMENT OBLIGATIONS

The undiscounted amount of expected cash flows required to settle the Company s asset retirement obligations as at March 31, 2005 was estimated at $1.3 million to be settled over a twelve-year period starting in 2010. The liability for the expected cash flows, as reflected in the financial statements, has been discounted at 5% to 7%.

10. COMMITMENTS AND CONTINGENCIES

Zitong Exploration Commitment

With the signing of the production-sharing contract in September 2002 for the Zitong block, the Company is obligated to conduct a minimum exploration program during the first three years, which will include acquiring seismic data, reprocessing existing seismic and drilling two exploration wells. At the end of the three-year period, if the Company does not complete the minimum exploration program, and elects not to continue, it will be obligated to pay, to PetroChina within 30 days, a cash equivalent of the deficiency in the work program. The remaining cost of the minimum exploration program is estimated to be $9.4 million as at March 31, 2005.

Northwest Lost Hills Abandonment

The Company has temporarily abandoned the Northwest Lost Hills #1-22 well pending the identification of one or more partners to share the costs of the testing program. If the well were permanently abandoned, the Company would be obligated for its share of the costs to plug and abandon the well, which is estimated to be $1.1 million. There is no provision in the balance sheet for this conditional obligation.

11. SUBSEQUENT EVENTS

On April 15, 2005, the Company and Ensyn completed the Merger (as more fully described in the Company s 2004 Annual Report filed on Form 10-K) in which the Company paid $10.0 million in cash and issued 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 will be held to secure certain obligations on the part of the former Ensyn stockholders to indemnify the Company for damages arising from any breaches of warranties and covenants in the Merger Agreement and certain liabilities.

The estimated total purchase consideration and cost of acquisition was $89.0 million as follows:

Purchase Consideration	
29,999,886 Company shares at $2.50 per share	$ 75,000
Cash	10,000
	85,000
Acquisition related costs	4,000
Total purchase consideration and cost of acquisition	$ 89,000

Net Assets Acquired	
Net current liabilities	$ (96)
Tangible assets	4,465
Intangible assets	87,631
Less : previous investment in EPIL	(3,000)
	$ 89,000

Intangible assets consist of the underlying value of the exclusive, perpetual license to deploy the RTP™ Technology for petroleum process applications worldwide. The intangible assets are subject to periodic tests for impairment.

On April 15, 2005, the Company closed a $10.3 million special warrant financing, by way of a private placement, with six institutional and individual investors. Proceeds from the financing were used to complete the acquisition of Ensyn and for general corporate purposes. The financing consisted of 4,100,000 special warrants at Cdn.$3.10 per special warrant. Each special warrant entitles the holder to receive, at no additional cost, one common share and one common share purchase warrant before or immediately following the filing and regulatory acceptance of a Canadian prospectus, or four months after the closing date, which ever occurs first. Two common share purchase warrants will entitle the holder to purchase one common share at a price of Cdn.$3.50 exercisable until the first anniversary date of the closing.

12. ADDITIONAL DISCLOSURE REQUIRED UNDER U.S. GAAP

The consolidated financial statements have been prepared in accordance with Canadian GAAP, which conforms to U.S. GAAP except as described below:

Condensed Consolidated Balance Sheets

Shareholders Equity and Oil and Gas Properties and Investments

	As at March 31, 2005				
	Oil and Gas Properties and Investments	Share Capital	Shareholders Equity Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 106,621	$ 184,102	$ 2,035	$ (83,262)	$ 102,875
Adjustment for reduction in stated capital		74,455		(74,455)	
Adjustment to ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358			1,358
Provision for impairment	(8,650)			(8,650)	(8,650)
Depletion adjustments due to differences in provision for impairment	654			654	654
GTL and EOR development costs expensed	(7,812)			(7,812)	(7,812)
Adjustment for change in accounting for stock based compensation		(300)	(1,892)	2,192	
U.S. GAAP	$ 92,171	$ 259,615	$ 143	$ (171,333)	$ 88,425

	As at December 31, 2004				
	Oil and Gas Properties and Investments	Share Capital	Shareholders Equity Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 96,551	$ 183,617	$ 1,748	$ (81,779)	$ 103,586
Adjustment for reduction in stated capital		74,455		(74,455)	

Adjustment to ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358			1,358
Provision for impairment	(8,650)			(8,650)	(8,650)
Depletion adjustments due to differences in provision for impairment	482			482	482
GTL and EOR development costs expensed	(5,884)			(5,884)	(5,884)
Adjustment for change in accounting for stock based compensation		(300)	(1,660)	1,960	
U.S. GAAP	$ 83,856	$ 259,130	$ 88	$ (168,326)	$ 90,892

Share Capital and Accumulated Deficit

In June 1999, the shareholders approved a reduction of stated capital in respect of the common shares by an amount of $74.4 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the accumulated deficit such as this is not recognized except in the case of a quasi reorganization. The effect of this is that under U.S. GAAP, share capital and accumulated deficit are increased by $74.4 million as at March 31, 2005 and December 31, 2004.

Oil and Gas Properties and Investments

As more fully described in our financial statements in Item 8 of our 2004 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 2004 an impairment provision of $15.0 million was required on its U.S. oil and gas properties compared to a $16.3 million impairment provision under Canadian GAAP. For 2001, a $10.0 million provision for impairment was required, for U.S. GAAP purposes, in connection with the Company s China oil and gas properties. These differences result in accumulated net additional impairment provisions of $8.7 million for U.S. GAAP purposes as at March 31, 2005 and December 31, 2004.

The differences in the amount of impairment provisions between Canadian and U.S. GAAP resulted in a reduction in accumulated depletion of $0.7 million and $0.5 million as at March 31, 2005 and December 31, 2004, respectively.

As more fully described in our financial statements in Item 8 of our 2004 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 operations with a corresponding reduction in the investments in GTL and EOR assets.

For U.S. GAAP, feasibility, marketing and related costs are considered to be research and development and are expensed as incurred. As at March 31, 2005 and December 31, 2004, the Company capitalized $7.8 million and $5.9 million, respectively, for Canadian GAAP, which was expensed for U.S. GAAP purposes.

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. For the year ended December 31, 2004, a ceiling test impairment of $1.0 million of the U.S. GAAP difference related to royalty rights was recognized in the results of operations.

Condensed Consolidated Statements of Loss

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

	Three-Month Periods Ended March 31,			
	2005		2004	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ 1,483	$ 0.01	$ 1,292	$ 0.01
Stock based compensation expense	(232)		(229)	
	(172)		(23)	

Depletion adjustments due to differences in provision for impairment					
GTL and EOR development costs expensed, net	1,929	0.01	430		
U.S. GAAP	$ 3,008	0.02	$ 1,470	$	0.01
Weighted Average Number of Shares under U.S. GAAP (in thousands)		169,816			162,127

As discussed under Oil and Gas Properties and Investments in this note, there is a difference in performing the

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ceiling test evaluation under the full cost method of accounting between U.S. and Canadian GAAP. Application of the ceiling test evaluation under U.S. GAAP resulted in accumulated net additional impairment provisions of $8.7 million for U.S. GAAP purposes as at March 31, 2005 and December 31, 2004. The net increase in impairment provisions resulted in lower depletion rates for U.S. GAAP purposes and a reduction of $0.2 million in the net loss for the three-month period ended March 31, 2005 and a minimal reduction in the net loss for the three-month period ended March 31, 2004.

For Canadian GAAP, the Company accounts for all stock options granted 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, the Company continues to apply APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and does not recognize compensation costs in its financial statements for stock options issued to employees and directors. For U.S. GAAP purposes, this resulted in a reduction of $0.2 million in the net losses for the three-month periods ended March 31, 2005 and 2004.

As described under Oil and Gas Properties and Investments in this note, for Canadian GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are capitalized and are subsequently written down upon determination that a project s future value has been impaired. For U.S. GAAP, such costs are considered to be research and development and are expensed as incurred. For the three-month periods ended March 31, 2005 and 2004, the Company expensed $1.9 million and $0.4 million, respectively, of GTL and EOR development costs for U.S. GAAP purposes.

Stock Based Compensation

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, Accounting for Stock Based Compensation , the Company s net loss and net loss per share would have been increased to the pro forma amounts indicated below:

	Three-Month Periods Ended March 31,	
	2005	**2004**
Net loss under U.S. GAAP	$ 3,008	$ 1,470
Stock-based compensation expense determined under the fair value based method for employee and director awards	263	494
Pro forma net loss under U.S. GAAP	$ 3,271	$ 1,964
Basic loss per common share under U.S. GAAP:		
As reported	$ 0.02	$ 0.01
Pro forma	$ 0.02	$ 0.01
Weighted Average Number of Shares under U.S. GAAP (in thousands)	169,816	162,127

Stock based compensation for U.S. GAAP was calculated in accordance with the Black Scholes option-pricing model using the same assumptions as used for Canadian GAAP.

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 flow as reported would result in a cash deficiency from operating activities of $1.2 million and $1.5 million for the three-month periods ended March 31, 2005 and 2004, respectively. Additionally, capital investments reported under investing activities would be $10.6 million and $10.0 million for the same periods ended, respectively.

Impact of New and Pending Canadian GAAP Accounting Standards

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

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

Effective January 1, 2005, the Company adopted revised Canadian Institute of Chartered Accountants (**CICA**) Accounting Guideline 15 (**AcG 15**), Consolidation of Variable Interest Entities . AcG 15 is harmonized in all material respects with U.S. GAAP and provides guidance for applying consolidation principles to certain entities (defined as VIEs) that are subject to control on a basis other than ownership of voting interests. An entity is a VIE when, by design, one or both of the following conditions exist: (a) total equity investment at risk is insufficient to permit that entity to finance its activities without additional subordinated support from other parties; (b) as a group, the holders of the equity investment at risk lack certain essential characteristics of a controlling financial interest. AcG 15 requires consolidation by a business of VIEs in which it is the primary beneficiary. The primary beneficiary is defined as the party that has exposure to the majority of the expected losses and/or expected residual returns of the VIE. AcG 15 does not impact us at this time.

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

In June 2004, the Financial Accounting Standards Board (**FASB**) issued an exposure draft of a proposed statement, Fair Value Measurements to provide guidance on how to measure the fair value of financial and non-financial assets and liabilities when required by other authoritative accounting pronouncements. The proposed statement attempts to address concerns about the ability to develop reliable estimates of fair value and inconsistencies in fair value guidance provided by current U.S. GAAP, by creating a framework that clarifies the fair value objective and its application in GAAP. In addition, the proposal expands disclosures required about the use of fair value to re-measure assets and liabilities. The standard would be effective for financial statements issued for fiscal years beginning after June 15, 2005.

In December 2004, the 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 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 applies APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for awards issued from our stock option plan and does not recognize compensation costs in its U.S. GAAP financial statements for stock options issued to its employees and directors. This statement is effective for the first fiscal year that begins after June 15, 2005 and may be implemented on a modified prospective or retrospective basis. The Company has elected to implement this statement on a modified prospective basis starting in the first quarter of 2006. Under the modified prospective basis the Company would recognize stock based compensation in its U.S. GAAP results of operations for the unvested portion of awards outstanding as of January 1, 2006 and for all awards granted after January 1, 2006.

In March 2005, the FASB issued Interpretation No. 47 (**FIN 47**) Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143 . A conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. FIN 47 requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). Retrospective application for interim financial information is permitted but is not required. The Company has a conditional asset retirement obligation with respect to the abandonment of its Northwest Lost Hills # 1-22 well. Had the Company implemented FIN 47 for the three-month period ended March 31, 2005, it would have recognized approximately $0.7 million in additional asset retirement costs and asset retirement obligations and approximately $0.1 million of cumulative accretion expense in its results of operations.

The following standards issued by the FASB do not impact the Company at this time:

SFAS No. 151, Inventory Costs an amendment of ARB No. 43, Chapter 4 effective for inventory costs incurred during fiscal years beginning after June 15, 2005.

SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29 effective for nonmonetary asset exchanges occurring in fiscal years beginning after June 15, 2005.

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

Forward-Looking Statements

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

The following should be read in conjunction with the Company s consolidated financial statements contained herein and in the Form 10-K for the year ended December 31, 2004, along with Management s Discussion and Analysis of Financial Condition and Results of Operations contained in such Form 10-K. Any terms used but not defined in the following discussion have the same meaning given to them in the Form 10-K. The unaudited condensed consolidated financial statements in this Quarterly Report filed on Form 10-Q have been prepared in accordance with generally accepted accounting principles in Canada. The impact of significant differences between Canadian and U.S. accounting principles on the unaudited condensed consolidated financial statements is disclosed in Note 12. The date of this discussion is April 29, 2005.

Executive Overview of 2005 Results

Although our revenues for the first quarter of 2005 improved significantly over those achieved during the comparable period in 2004, our net loss increased $0.2 million from the comparable period in 2004. Oil and gas revenues for the first quarter of 2005 increased by 73% to $5.7 million due equally to an increase in production volumes as well as higher oil and gas prices. However, this improvement was offset by increased costs related to our significant EOR and HTL business development activities, professional fees related to our assessment of the effectiveness of the design and operation of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 and higher depletion costs. Despite these cost increases, we achieved positive cash flow from operations of $0.8 million for the first quarter of 2005 compared to a deficit of $1.0 million for the comparable period in 2004.

We are excited about the progress we made in the first quarter of 2005 and ongoing developments in our EOR projects including our HTL initiatives. The RTP™ Commercial Demonstration Facility (**RTP™ CDF**) near Bakersfield, California was successfully tested and we completed our merger with Ensyn in April 2005 whereby Ensyn became a wholly-owned subsidiary of Ivanhoe and Ensyn changed its name to Ivanhoe Energy HTL Inc.

With the completion of the Merger we have the exclusive right to employ the RTP Technology for petroleum process applications worldwide and we are actively pursing opportunities for the commercial deployment of the technology in a number of countries. Our single goal remains the building of oil and gas reserves and production. We intend to use the RTP Technology as a tool to acquire and develop heavy oil reserves around the world.

The following table sets forth certain selected consolidated data for the first quarters of 2005 and 2004:

	Three-Month Periods Ended March 31,	
(stated in thousands of U.S. dollars, except per share and production amounts)	**2005**	**2004**
Oil and gas revenue	$ 5,693	$ 3,292
Net loss	$ 1,483	$ 1,292
Net loss per share	$ 0.01	$ 0.01
Average production (Mboe/d)	1,664	1,195
Capital investments	$ 12,534	$ 10,423
Cash flow (deficit) from operating activities	$ 776	$ (1,046)

Financial Results Quarter to Quarter Change in Net Loss

The following provides an analysis of our changes in net losses for the first quarter of 2005 when compared to the same period for 2004:

(stated in thousands of U.S. Dollars)		**2005 vs. 2004**
Net Loss for the three-month period ended March 31, 2004	$	1,292
Favorable (unfavorable) variances:		
Cash Items:		
Net Operating Revenues:		
Production volumes		1,237
Oil and gas prices		1,164
Less: Operating costs		(487)
		1,914
General, administrative and business development		(1,193)
Net interest		(94)
Total Cash Variances		627
Non-Cash Items:		
Depletion and depreciation		(761)
Stock based compensation		(57)
Total Non-Cash Variances		(818)
Net Loss for the three-month period ended March 31, 2005	$	1,483

Our net loss for the first quarter of 2005 was $1.5 million ($0.01 per share) compared to our net loss for the same period in 2004 of $1.3 million ($0.01 per share). The increase in our net loss from 2004 to 2005 of $0.2 million is mainly due to $1.3 million increase in general, administrative and business development expense, including stock based compensation, and an increase of $0.8 in depletion and depreciation. This is partially offset by a $1.9 million increase in net operating revenues.

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

<u>Net Operating Revenues</u>

Production Volumes 2005 vs. 2004

Net production volumes for the first quarter of 2005 increased 38% when compared to the same period in 2004 due to 43% and 33% increases in production volumes in our China and U.S. properties, respectively, resulting in increased revenues of $1.2 million.

Net production volumes at the Dagang field increased 46% in the first quarter of 2005 compared to the same period in 2004 despite the farm-out of a 40% working interest in June 2004. In the first quarter of 2005, we placed an additional 6 wells on production bringing the total wells on production or available for production to 28 wells at quarter-end. However, our gross production exit rate at the Dagang field decreased 21% from the end of 2004 to March 31, 2005 as we experienced higher water cuts, particularly in the older wells, and our most productive well was shut-in due to a maintenance workover at the end of the first quarter of 2005. Additionally, results from the new wells drilled in the northern blocks of the Dagang field have been less than expected, with initial unstimulated production of approximately 75 Bopd per well.

We continue to benefit from the expanded Daqing development program and the royalty interest we hold. Royalty volumes for the first quarter of 2005 increased 32% over the same 2004 period.

Net production volumes in the U.S. increased 33% mainly from our Citrus and Knights Landing fields. Three Citrus wells were on production in the first quarter of 2005 compared to only 1 well for the same period in 2004. We farmed into the Knights Landing gas field in northern California in February 2004 with a 50% working interest in 4 producing natural gas wells, which started production in April 2004. In December 2004, we increased our working interest to between 80% and 100% in 12 Knights Landing natural gas wells capable of production. We continue to see increased production rates from our successful drilling and steaming operations at our South Midway field. We drilled 4 producing South Midway wells in the second quarter of 2004, increased our steam injection in the primary area of South Midway in the third quarter of 2004 and started a continuous steam injection pilot program in the southern expansion of South Midway in the fourth quarter of 2004, all of which have contributed to the increased production rates at South Midway for the first quarter of 2005.

The following is a comparison of changes in production volumes for the first quarter of 2005 when compared to the same period in 2004:

	Average Net Boe s		Percentage
	2005	**2004**	**Change**
China:			
Dagang	60,236	41,260	46%
Daqing	11,999	9,102	32%
	72,235	50,362	43%
U.S.:			
South Midway	49,768	43,151	15%
Citrus	9,528	3,433	178%
Knights Landing	11,300		100%
Others	6,941	11,782	-41%
	77,537	58,366	33%
	149,772	108,728	38%

Oil and Gas Prices 2005 vs. 2004

Oil and gas prices increased 26% per Boe for the first quarter of 2005 generating $1.2 million in additional revenue as compared to the same period in 2004. We realized an average of $39.09 per Boe from our operations in China during the first quarter of 2005, which is an increase of $9.33 per Boe for the same period in 2004 and accounts for $0.7 million of our increase in revenues. From the U.S. operations, we realized an average of $37.00 per Boe during the first quarter of 2005, which is an increase of $6.29 per Boe and accounts for $0.5 million of our increased revenues.

Operating Costs 2005 vs. 2004

For the first quarter of 2005, operating costs, including production taxes and engineering support, increased $0.5 million in absolute terms from the same period in 2004 or $0.04 on a per barrel of oil equivalent basis.

Operating costs in China, including engineering support, decreased 13% or $1.38 per Boe for the first quarter of 2005 when compared to the same period in 2004 due mainly to an increase in production from the Dagang field in relation to the level of engineering support required to operate the field.

Operating costs in the U.S., including engineering support and production taxes, increased 11% or $1.46 per Boe for first quarter of 2005 when compared to the same period in 2004. Field operating costs increased $1.58 per Boe due mainly to an increase in fuel costs incurred for the increased level of cyclic and continuous steam operations at South Midway. Engineering support increased $0.56 per Boe due mainly to the start up of production operations at Citrus in late first quarter of 2004 and also at Knights Landing where we became the operator in December 2004. Production taxes are down $0.68 per Boe due mainly to a reassessment of property values at South Midway.

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

	Three-Months Periods Ended March 31,					
	2005			2004		
	U.S.	China	Total	U.S.	China	Total
Net Production:						
BOE	77,537	72,235	149,772	58,366	50,362	108,728
BOE/day	862	803	1,664	641	553	1,195
		Per Boe			Per Boe	
Oil and gas revenue	$ 37.00	$ 39.09	$ 38.01	$ 30.71	$ 29.76	$ 30.27
Operating costs	10.76	7.76	9.31	9.18	7.38	8.35
Production taxes	0.50		0.26	1.18		0.63
Engineering support	3.13	1.18	2.19	2.57	2.94	2.74
	14.39	8.94	11.76	12.93	10.32	11.72
Net revenue before depletion	22.61	30.15	26.25	17.78	19.44	18.55
Depletion	14.77	14.30	14.54	14.33	11.43	12.99
Net revenue from operations	$ 7.84	$ 15.85	$ 11.71	$ 3.45	$ 8.01	$ 5.56

General, Administration and Business Development

Our changes in general, administrative and business development expenses, including stock based compensation expense, by segment for the first quarter of 2005 when compared to the same period for 2004 were as follows:

Favorable (unfavorable) variances:

Oil and Gas Activities:	
U.S.	$ (51)
China	32
GTL	(127)
EOR	(315)
Corporate	(789)
	$ (1,250)

General, Administrative and Business Development 2005 vs. 2004

General, administrative and business development expenses increased $1.3 million for the first quarter of 2005 compared to the same period in 2004. Corporate general and administrative expenses increased $0.8 million due mainly to professional fees incurred during the first quarter of 2005 to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002. Business development expenses increased $0.4 million for the first quarter of 2005 due mainly to increased activities in Egypt, Iraq and other Northern Africa and Middle East countries.

Depletion and Depreciation

Depletion and Depreciation 2005 vs. 2004

Depletion and depreciation increased $0.8 million for the first quarter of 2005 when compared to the same period in 2004, which was primarily due to an increase in production rates resulting in a $0.5 million increase in depletion. Additionally, depletion rates increased $1.55 per Boe to $14.54 per Boe in the first quarter of 2005 compared to $12.99 per Boe in 2004.

The China depletion rate for the first quarter of 2005 was $14.30 per Boe, a 25% increase from the same period in 2004, due mainly to a downward revision of our share of proved reserves at Dagang as a result of continued increases in oil prices. During periods of increasing oil prices our share of proved oil reserves decreases, as fewer barrels of oil are required to recover our costs under our production-sharing contract.

Capital Investments

The following provides an analysis of our capital investment activities for the first quarter of 2005 when compared to the same period for 2004:

	Three-Month Periods Ended March 31,		
	2005	2004	(Increase) Decrease
Oil and Gas Activities:			
U.S.	$ 799	$ 3,118	$ 2,319
China	9,806	6,875	(2,931)
GTL	215	67	(148)
EOR	1,714	363	(1,351)
	$ 12,534	$ 10,423	$ (2,111)

Oil and Gas Activities U.S.

Capital investment in the U.S. is down $2.3 million for the first quarter 2005 when compared to the same period in 2004, due mainly to $1.5 million and $0.8 million decreases in our development activities in the Knights Landing and Citrus fields, respectively.

In February 2004, we farmed into the Knights Landing gas field, which is a 13,000-acre block located in the Sutter and Yolo counties, in northern California. Subsequent to the construction of gas gathering, surface treatment facilities and meters to connect 4 commercial wells to an existing pipeline system in the first quarter of 2004 we drilled 9 wells during the second and third quarters of 2004. Three of these new wells were successful and by April 2005 had been tied into the existing pipeline system and were on production. Due to weather and scheduling delays we do not expect to start our 3-D seismic acquisition program at Knights Landing until the fourth quarter of 2005. Drilling activities in Knights Landing will recommence after interpretation of the 3-D seismic.

We completed the drilling of Citrus # 1 in the first quarter of 2004 and we continue to assess drilling an additional horizontal leg in this well later this year to fully evaluate the potential of the Upper Antelope zone in this section of our Citrus acreage.

During the first quarter of 2005, we discovered natural gas at the Peach prospect in the North Antelope Hills area in Kern County, California. The prospect is 50 miles west of Bakersfield, in a major hydrocarbon-producing region along the west side of the San Joaquin Basin. We farmed out part of our 1,800-acre Peach prospect in November 2004 for 100% of the drilling costs of the first Peach well 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 expect to drill an appraisal well to the discovery during the second quarter of 2005. Production of the discovery well and connection to a gas sales pipeline is pending the results of the appraisal well.

Oil and Gas Activities China

Capital investment in China for the first quarter of 2005 was $9.8 million, a $2.9 million or 43% increase compared to the same period in 2004 primarily due to increased drilling activities at Dagang.

Expenditures at Dagang increased $2.4 million to $6.8 million during the first quarter of 2005. By the end of the quarter, we completed 3 wells, drilled and completed 1 well, drilled 4 wells that are awaiting completion, re-completed 1existing well and converted 1 well to an injector. By the end of the first quarter of 2005, 3 wells were in the process of drilling. The wells drilled in the first quarter 2005 were all located in the northern 2 blocks of the Dagang field. Post completion results from the wells in this area have been less than expected, with initial unstimulated production of approximately 75 Bopd per well. We are currently analyzing core samples to develop a stimulation program for the wells in the northern blocks. We expect to initiate this program in the second quarter of 2005. If this initial stimulation program is successful, we anticipate stimulating additional wells in these northern blocks to increase production.

Our capital investment for our Zitong block was $3.0 million during the first quarter of 2005, an increase of $0.5 million from the same period in 2004. We spent $1.9 million during the first quarter of 2005 for the completion of the remaining 160 miles of our 700-mile seismic acquisition program, which we commenced in 2004. Additionally, we incurred $1.1 million during the first quarter of 2005 to acquire right-of-ways, build a road and well location and purchase all tubular equipment required to drill our first well in the Zitong block, Dingyuan 1, which commenced drilling April 1, 2005. The well is expected to take 60 days to drill to a target depth of 8,700 feet. A second exploratory well in the Zitong block is planned for later in 2005.

Enhanced Oil Recovery and Heavy-To-Light Oil Activities

We incurred $1.4 million more in capital investment activities on EOR and HTL projects for the first quarter of 2005 compared to the same period in 2004.

In Iraq, we incurred $0.4 million to further our study of the Qaiyarah heavy oil field. The fields reservoirs contain a large proven accumulation of 17.1º API heavy oil at a depth of about 1,000 feet. The studies include the potential response of the Qaiyarah heavy 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. Additionally, we incurred $0.2 million on costs to bid on a fourth engineering, design and procurement contract for a gas field in Iraq.

We incurred $0.3 million to further our study of the heavy crudes from the large Castilla and Chichimene oil fields in Colombia. This included 10 runs of heavy oil samples from these two fields at Ensyn s RTP™ pilot plant in Ottawa, Canada.

In March 2005, the performance testing of the RTP CDF was completed successfully and the results of the test were verified by independent consulting firms Muse, Stancil & Co. and Purvin & Gertz, & Co. The RTP CDF demonstrated an overall processing capacity of approximately 1,000 barrels-per-day of raw, heavy oil and a hot section capacity of 300 barrels-per-day. This successful test of the RTP CDF and verification of the liquid product quality, volume yield and by-product energy by Muse Stancil & Co. facilitated the completion of the Merger between Ivanhoe and Ensyn (**IE HTL**) in April 2005. We incurred $0.5 million during the first quarter of 2005 for a preliminary design package being prepared by Colt Engineering Corporation for a 10,000 to 15,000 barrels-per-day of raw, heavy oil (5,000 barrels per day hot-section) commercial RTP plant. The design work for this commercial RTP plant is expected to be completed in the third quarter of 2005.

We intend to apply the leading-edge RTP™ Technology to upgrade heavy oil in plants located in the field to produce lighter, more valuable crude oil at lower costs and in smaller size plants than required by conventional technologies. The upgraded heavy oil, similar to less viscous conventional light crude oil, brings a higher price and can be easily transported. In addition to a dramatic improvement in oil quality, an RTP™ plant can yield large amounts of surplus energy for producing steam and electricity used in heavy-oil production. The thermal energy from the process provides heavy-oil producers with an alternative to high-priced natural gas that now is widely used to generate steam. The RTP™ Technology offers an excellent opportunity to optimize the development of mature heavy oil fields and also enables the development of stranded heavy oil deposits.

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

Gas-To-Liquids Activities

We spent $0.1 million more in capital investment activities on GTL projects for the first quarter of 2005 compared to the same period in 2004. We are updating the design for a 45,000 and 90,000 barrels-per-day GTL plant for a designated site in Egypt. The objective is to develop full plant design documentation and associated cost estimates based upon improvements in Syntroleum s GTL process and catalysts as well as equipment technology in general. After completing the plant design and economics update we will present a proposal for a GTL plant to Egypt s Ministry of Petroleum. Additionally, we plan to update our marketing study that will provide GTL product price forecasts and identify end users for these products from this plant.

Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents was basically unchanged for the first quarter of 2005 compared to an increase of $19.2 million for the same period in 2004. Our operating activities provided $0.8 million in cash for the first quarter of 2005 compared to a deficit of $1.0 million for the same period in 2004 due mainly to a 38% increase in our production volumes and a 26% increase in oil and gas prices compared to the same period in 2004. The increase in net revenues for the first quarter of 2005 was partially offset by a $1.2 million increase in general, administrative and business development expenses. Our capital investing activities, less changes in non-cash working capital associated with our capital investing activities, decreased $3.9 million for the first quarter of 2005 compared to the same period in 2004. Cash from financing activities decreased $25.0 million for the first quarter of 2005 compared to the same period in 2004. We raised $6.0 million from debt facilities in the first quarter of 2005 less $0.4 million for payments on notes. For the same period in 2004, we raised $20.6 million from two special warrant financings and from the exercise of stock options and $10.0 million for an advance payment related to the farm-out of a 40% working interest in the Dagang field.

	Three Months Ended March 31,	
	2005	**2004**
Cash flow (deficit) from operating activities	$ 776	$ (1,046)
Investing Activities		
Capital investments, after changes in non-cash working capital	(5,651)	(9,825)
Equity investment and other related costs	(730)	(500)
	(6,381)	(10,325)
Financing Activities		
Private placements, net of share issue costs		20,428
Proceeds from exercise of options	35	139
Net debt financing	5,583	10,000
	5,618	30,567
Net Sources of Cash	$ 13	$ 19,196

Outlook for 2005

Our capital investments for the first quarter of 2005 were $12.5 million and are expected to be $54.2 million for all of 2005. This compares to a capital investment budget of $18.2 million for the first quarter of 2005 and $79.0 million for all of 2005. The reduction in capital investments of $5.7 million for the first quarter of 2005 compared to our budget was primarily due to a slippage to 2006 in additional drilling at our Knights Landing and Citrus properties until after the planned acquisition and interpretation of our 3-D seismic data in the fourth quarter of 2005 at Knights Landing and the evaluation of the potential of the Upper Antelope zone with the drilling of an additional horizontal leg in Citrus #1. Additionally, drilling of our first well in the Zitong block was delayed into the second quarter of 2005 but we anticipate our 2005 capital investment program in the Zitong block to remain unchanged from our original budget. The $24.8 million reduction in our capital investment program for all of 2005 is primarily due to a reduction in our Dagang drilling schedule for the remainder of 2005 pending evaluation of the stimulation program for the wells drilled in the northern blocks of the Dagang field. Our 2005 capital investment budget is also expected to be reduced due to the slippage to 2006 of our drilling programs at our Knights Landing and Citrus fields as previously mentioned.

Our capital investment budget for the remainder of 2005 is $41.7 million. We plan to seek financing on an as needed basis, from equity markets, project lenders, joint ventures or other potential financing sources to pursue our 2005 capital investment program, acquisitions of proven and probable reserves and to deploy our HTL and GTL technologies. In addition, we, together with our 40% partner in the Dagang project, are in active discussions with European and Chinese lending banks to provide funding for the development of the Dagang field.

In October 2003, we filed a base shelf prospectus with Canadian securities regulatory authorities and a shelf registration statement with the U.S. Securities and Exchange Commission to qualify for potential future sale in Canada and the U.S. up to $100 million of various types of securities, including common shares, preferred shares, warrants and debt securities. These shelf filings, which expire in November 2005 but which may be renewed, are expected to give us greater flexibility to fund our expansion and capital programs and will allow us to take advantage of a broader range of financing opportunities on a timelier basis. A combination of such equity financing, as well as convertible loan, debt and mezzanine financing and joint venture partner participation, will be required to complete our future capital programs. We cannot assure you that we will be successful in raising the additional funds necessary or securing joint venture partners to complete our capital programs. If we are unsuccessful, we will have to prioritize our capital programs, which may result in delaying and potentially losing some valuable business opportunities.

Contractual Obligations

The table below summarizes the contractual obligations that are reflected in our Unaudited Condensed Consolidated Balance Sheet as at March 31, 2005 and/or disclosed in the accompanying Notes:

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	**2005**	**2006**	**2007**	**2008**	**After 2008**
Purchase Agreement:	$ 150	$ 50	$ 100	$	$	$
Consolidated Balance Sheets:						
Note payable current portion *(Note 7)*	1,667	1,250	417			
Long term debt *(Note 7)*	2,222		1,250	972		
Convertible loan *(Note 8)*	6,000	6,000				
Other Commitments:						
Interest payable	497	381	99	17		
Lease commitments	2,036	471	551	344	287	383
Zitong exploration commitment *(Note 10)*	9,400	9,400				
Total	$ 21,972	$ 17,552	$ 2,417	$ 1,333	$ 287	$ 383

Off Balance Sheet Arrangements

At March 31, 2005 and December 31, 2004, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us, or our related parties, except as disclosed herein.

Outstanding Share Data

As at April 29, 2005, there were 199,902,299 common shares of the Company issued and outstanding which included 29,999,886 common shares issued by the Company on April 15, 2005 in connection with its merger with Ensyn. Additionally, the Company had 21,551,826 share purchase warrants outstanding and exercisable to purchase 11,400,913 common shares which included 4,100,000 special purchase warrants issued by way of a private placement on April 15, 2005 for the purchase of 2,050,000 common shares at a price of Cdn.$3.50 exercisable until the first anniversary date of the closing. As at April 29, 2005, there were 8,504,257 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							
	2005	2004				2003		
	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr
Total revenue	$ 5,736	$ 6,212	$ 4,932	$ 3,521	$ 3,332	$ 2,330	$ 2,423	$ 2,338
Net loss Canadian GAAP	$ 1,483	$ 17,184	$ 951	$ 1,298	$ 1,292	$ 23,154	$ 1,330	$ 4,587
Net loss U.S. GAAP	$ 3,008	$ 15,736	$ 980	$ 1,510	$ 1,470	$ 23,270	$ 1,306	$ 1,325
Net loss per share Canadian	$ 0.01	$ 0.09	$ 0.01	$ 0.01	$ 0.01	$ 0.15	$ 0.01	$ 0.03
Net loss per share U.S. GAAP	$ 0.02	$ 0.09	$ 0.01	$ 0.01	$ 0.01	$ 0.15	$ 0.01	$ 0.01

The 2003 quarterly earnings for Canadian GAAP have been restated to give effect to the retroactive application of CICA Section 3870 Stock Based Compensation and Other Stock Based Payments , which is more fully described in Note 2 under Stock Based Compensation in the Company s 2004 Annual Report on Form 10-K. The net losses in the fourth quarter of 2004, for Canadian and U.S. GAAP, were primarily due to impairment provisions of $16.3 million and $15.0 million, respectively, for U.S. oil and gas properties. The net losses in the fourth quarter of 2003, for both Canadian and U.S. GAAP, were primarily due to an impairment provision of $20.0 million for U.S. oil and gas properties. The net loss under Canadian GAAP for the second quarter of 2003 included a $3.3 million write-down of costs associated with the unsuccessful negotiations of a GTL contract in Qatar. For U.S. GAAP, these costs are expensed as they are incurred. 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.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

No material changes since December 31, 2004.

Item 4. Controls and Procedures

The Company s management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of March 31, 2005. 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.

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined under Rule 13a-15(f) under the Securities Exchange Act of 1934. During the fiscal 2004 implementation of Section 404 of the Sarbanes-Oxley Act of 2002, management identified two material weaknesses in the Company s internal control over financial reporting (this section of Item 4. Controls and Procedures should be read in conjunction with Item 9A. Controls and Procedures, included in the Company s Annual Report filed on Form 10-K for the fiscal year ended December 31, 2004 and as amended on Form 10-K/A filed on May 2, 2005). In the first quarter of fiscal 2005, management took several steps to address the identified weaknesses.

Specifically, the Company implemented the following changes in internal control over financial reporting:

Prior to March 31, 2005, we engaged an independent firm to handle all complaints, whether from employees or third parties with respect to concerns regarding accounting or auditing matters and any perceived violations of our Code of Business Conduct and Ethics. By means of a secure website or telephone, all issues raised will be automatically directed to the Chairman of our Audit Committee who will have primary responsibility for responding to and pursuing all reported matters.

As part of our new complaint process, we have formally communicated the roles and responsibilities related to internal control over financial reporting to all employees.

As part of our responsibilities under Section 404 of the Sarbanes-Oxley Act of 2002, there will be an annual and extensive formal review to monitor and detect control deficiencies related to internal control over financial reporting.

With respect to financial reporting, prior to December 31, 2004 and since that date, we have formalized our financial reporting processes, instituted changes in the division of financial reporting responsibilities and are changing our policies and procedures to require written documentation of our approvals and reviews in those financial reporting processes where deficiencies have been identified.

Part II Other Information

Item 1. Legal Proceedings: None

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds:

On April 15, 2005, we issued the following securities which were not registered under the Securities Act of 1933 (the **Act**):

4,100,000 special warrants at a price of Cdn.$3.10 per special warrant to institutional and individual investors in a transaction exempt from registration under Rule 903 of the Act. Each special warrant entitles the holder to receive, at no additional cost, one common share and one common share purchase warrant before or immediately following the filing and regulatory acceptance of a Canadian prospectus, or four months after the closing date, which ever occurs first. Two common-share purchase warrants will entitle the holder to purchase one common share at a price of Cdn.$3.50 exercisable until the first anniversary date of the closing.

29,999,886 common shares were issued in exchange for all of the issued and outstanding Ensyn common shares as part of an Agreement and Plan of Merger dated December 11, 2004 in a transaction not subject to registration pursuant to an exemption under Section 3(a)(10) of the Act. Ten million of the common shares issued were deposited in an escrow fund and will be held to secure certain obligations on the part of the former Ensyn stockholders to indemnify the Company for damages arising from any breaches of warranties and covenants in the Merger Agreement and certain liabilities

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 and Reports on Form 8-K

(a) Exhibits

EXHIBIT NUMBER	DESCRIPTION
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

EXHIBIT NUMBER	DESCRIPTION
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

(b) Reports on Form 8-K: None

SIGNATURE

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

IVANHOE ENERGY INC.

By: /s/ W. Gordon Lancaster
Name: W. Gordon Lancaster
Title: Chief Financial Officer

Dated: May 5, 2005

INDEX TO EXHIBITS

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