IVANHOE ENERGY INC
Form 10-Q
August 09, 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 June 30, 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 June 30, 2005 was 201,432,299 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, 2005	December 31, 2004
Assets		
Current Assets		
Cash and cash equivalents	**$ 3,728**	$ 9,322
Notes and accounts receivable	**5,998**	5,377
Prepaid and other current assets	**512**	812
	10,238	15,511
Long term assets	**1,392**	6,424
Oil and gas properties and investments, net	**121,238**	96,551
Intangible asset	**89,932**	
	$ 222,800	$ 118,486
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 18,611**	$ 9,845
Note payable current portion	**1,667**	1,667
Convertible loans	**8,000**	
	28,278	11,512
Long term debt	**1,806**	2,639
Asset retirement obligations	**1,688**	749
Commitments and contingencies	**1,900**	
Shareholders Equity		
Share capital, issued 201,432,299 common shares; December 31, 2004 169,664,911 common shares	**260,709**	183,617
Warrants	**10,153**	
Contributed surplus	**2,559**	1,748
Accumulated deficit	**(84,293)**	(81,779)
	189,128	103,586

	$	**222,800**	$	118,486

(See accompanying notes)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	**2005**	2004
Revenue				
Oil and gas revenue	**$ 6,617**	$ 3,472	**$ 12,310**	$ 6,764
Interest income	**28**	49	**71**	89
	6,645	3,521	**12,381**	6,853
Expenses				
Operating costs	**1,771**	1,157	**3,533**	2,431
General and administrative	**1,506**	1,462	**3,917**	3,066
Business development	**1,178**	422	**1,897**	699
Depletion and depreciation	**2,567**	1,503	**4,774**	2,949
Interest expense	**375**	25	**495**	48
Write down of GTL investments	**279**	250	**279**	250
	7,676	4,819	**14,895**	9,443
Net Loss	**1,031**	1,298	**2,514**	2,590
Accumulated Deficit, beginning of period	**83,262**	62,346	**81,779**	61,054
Accumulated Deficit, end of period	**$ 84,293**	$ 63,644	**$ 84,293**	$ 63,644
Net Loss per share Basic and Diluted	**$ 0.01**	$ 0.01	**$ 0.01**	$ 0.02
Weighted Average Number of Shares (in thousands)	**195,200**	169,116	**183,621**	165,622

(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,	
	2005	2004	**2005**	2004
Operating Activities				
Net loss	**$ (1,031)**	$ (1,298)	**$ (2,514)**	$ (2,590)
Items not requiring use of cash				
Depletion and depreciation	**2,567**	1,503	**4,774**	2,949
Write down of GTL investments	**279**	250	**279**	250
Stock based compensation	**534**	242	**830**	481
Changes in non-cash working capital items	**(499)**	602	**(744)**	244
	1,850	1,299	**2,625**	1,334
Investing Activities				
Capital investments	**(12,057)**	(14,821)	**(24,337)**	(25,176)
Merger, net of cash acquired	**(9,979)**		**(9,979)**	
Equity investment and Merger related costs	**(957)**	(2,000)	**(1,687)**	(2,500)
Proceeds from sale of assets		13,458		13,458
Other	**(63)**	(112)	**(54)**	(180)
Changes in non-cash working capital items	**2,429**	5,614	**9,312**	5,131
	(20,627)	2,139	**(26,745)**	(9,267)
Financing Activities				
Proceeds from private placements, net of share issue costs	**10,153**		**10,153**	20,428
Proceeds from exercise of options and warrants	**1,690**	1,236	**1,725**	1,375
Share issue costs on shares issued for Merger	**(93)**		**(93)**	
Proceeds from debt obligations	**2,000**	2,000	**8,000**	12,000
Repayments of debt obligations	**(417)**	(10,000)	**(833)**	(10,000)
Other	**(163)**		**(426)**	
	13,170	(6,764)	**18,526**	23,803
Increase (decrease) in cash and cash equivalents, for the period	**(5,607)**	(3,326)	**(5,594)**	15,870
Cash and cash equivalents, beginning of period	**9,335**	33,687	**9,322**	14,491
Cash and cash equivalents, end of period	**$ 3,728**	$ 30,361	**$ 3,728**	$ 30,361
Supplementary Information Regarding Non-Cash Transactions				
Financing activities, non-cash:				
Shares issued for Merger	**$ (75,000)**	$	**$ (75,000)**	$

Included in the above are the following:				
Taxes paid	**$ 2**	$	**$ 4**	$ 3
Interest paid	**$ 265**	$ 14	**$ 14**	$ 28
Changes in non-cash working capital items				
Operating Activities:				
Notes and accounts receivable	**$ (275)**	$ (266)	**$ (314)**	$ (856)
Prepaid and other current assets	**85**	3	**(45)**	31
Accounts payable and accrued liabilities	**(309)**	865	**(385)**	1,069
	(499)	602	**(744)**	244
Investing Activities				
Notes and accounts receivable	**432**	(831)	**(405)**	(1,153)
Prepaid and other current assets	**127**		**350**	
Accounts payable and accrued liabilities	**1,870**	6,445	**9,367**	6,284
	2,429	5,614	**9,312**	5,131
	$ 1,930	$ 6,216	**$ 8,568**	$ 5,375

(See accompanying notes)

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Notes to the Condensed Consolidated Financial Statements
June 30, 2005
(all tabular amounts are expressed in thousands of U.S. dollars except per share amounts)
(Unaudited)

1. BASIS OF PRESENTATION AND LIQUIDITY

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 15. 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 Company s financial statements as at and for the three-month and six-month periods ended June 30, 2005 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities and commitments in the normal course of business. The Company incurred a net loss of $2.5 million for the six-month period ended June 30, 2005, and, as at June 30, 2005, had an accumulated deficit of $84.3 million and negative working capital of $18.0 million. The Company expects to incur substantial expenditures to further its capital investment programs and the Company s cash flow from operating activities will not be sufficient to satisfy its current obligations and meet its capital investment objectives. Management s plans include sale of additional equity securities, alliances or other partnership agreements with entities with the resources to support the Company s projects as well as convertible loan, debt and mezzanine financing in order to generate sufficient resources to assure continuation of the Company s operations and achieve its capital investment objectives. The Company is presently in active negotiation with a third party for the formation of a joint venture for the deployment, in a specific region of the world, of the GTL and RTP technologies it licenses or owns. The transaction that is being discussed would, if consummated, include a potentially significant equity investment in the Company by the third party. No assurances can be given that the Company and the third party with whom it is presently negotiating will successfully conclude this potential transaction nor that the Company will be able to raise additional capital or enter into one or more alternative business alliances with other parties if this potential transaction is not successfully concluded. If the Company is unable to obtain adequate additional financing or enter into such business alliances, management will be required to sharply curtail the Company s operations, which may include the sale of assets.

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.

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

2. SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

As more fully described in Note 11, 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 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. As part of the Merger, the Company acquired a 50% interest in a joint venture, which owns a rapid thermal processing (**RTPTM**) commercial demonstration facility (**RTPTM CDF**) located in California s San Joaquin Basin as well as certain rights to manufacture RTPTM facilities (See Note 12). 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.

Intangible Assets

Intangible assets are initially recognized and measured at cost. Intangible assets with finite lives are amortized over their useful lives whereas intangible assets with indefinite useful lives are not amortized unless it is subsequently determined to have a finite useful life. Intangible assets are reviewed annually for impairment, or when events or changes in circumstances indicate that the carrying value of an intangible asset may not be recoverable. If the carrying value of an intangible asset exceeds its fair value or expected future discounted cash flows, the excess is written down to the results of operations with a corresponding reduction in the carrying value of the intangible asset.

In the Merger, the Company acquired an intangible asset in the form of an exclusive, irrevocable license to employ rapid thermal processing technology (**RTPTM Technology**) for petroleum applications. The Company will assign the carrying value of the RTPTM Technology to the number of RTPTM facilities it expects to develop that will use the RTPTM Technology. The amount of the carrying value of the RTP Technology assigned to each RTPTM facility will be amortized to earnings on a basis related to the operations of the RTPTM facility from the date on which the facility is placed into service. The carrying value of the RTP Technology will be evaluated for impairment annually, or as changes in circumstances indicate the intangible asset might be impaired, based on an assessment of its fair market value.

Development Costs

The Company incurs various costs in the pursuit of gas-to-liquids (**GTL**) and enhanced oil recovery (**EOR**), including RTPTM Technology for heavy oil processing, projects throughout the world. Such costs incurred prior to signing a memorandum of understanding (**MOU**), or similar agreements, are considered to be business development and are expensed as incurred. Upon executing an MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products, the Company assumes the feasibility and related costs incurred have potential future value, are probable of leading to a definitive agreement for the exploitation of proved reserves and should be capitalized as development costs. If a definitive agreement is not subsequently reached, then the project s capitalized development costs, which are deemed to have no future value, are written down to the results of operations with a corresponding reduction in the investments in GTL and EOR assets.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the GTL and RTPTM technologies it licenses or owns. The cost of equipment and facilities acquired or constructed for such purposes are capitalized development costs and amortized over the expected economic life of the equipment or facilities commencing with the start up of commercial operations for which the equipment or facilities are intended. The Company reviews the recoverability of such capitalized development costs annually, or as changes in circumstances indicate the development costs might be impaired, through an evaluation of the expected future discounted cash flows from the associated projects. If the carrying value of such capitalized development costs exceeds the expected future discounted cash flows, the excess is written down to the results of operations with a corresponding reduction in the investments in GTL and EOR assets.

Costs incurred in the operation of equipment and facilities used to develop or enhance GTL and RTPTM technologies prior to commencing commercial operations are business development expenses and are charged to the results of operations in the period incurred.

3. OIL AND GAS PROPERTIES AND INVESTMENTS
Capital assets categorized by geographical location and business segment are as follows:

	As at June 30, 2005				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 83,733	$ 51,029	$	$	$ 134,762
Unproved	21,670	13,576			35,246
	105,403	64,605			170,008
Accumulated depletion	(13,398)	(8,934)			(22,332)
Accumulated provision for impairment	(50,350)				(50,350)
	41,655	55,671			97,326
GTL and EOR Investments:					
GTL master license			10,000		10,000
Commercial demonstration facility				4,572	4,572
Feasibility studies and other deferred costs			4,245	4,923	9,168
			14,245	9,495	23,740
Furniture and equipment	438	95		15	548
Accumulated depreciation	(343)	(29)		(4)	(376)
	95	66		11	172
	$ 41,750	$ 55,737	$ 14,245	$ 9,506	$ 121,238

	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

For the three-month period ended June 30, 2005, the Company capitalized $0.9 million of costs associated with future asset retirement and abandonment of the Northwest Lost Hills #1-22, which was temporarily abandoned in 2003.
Costs as at June 30, 2005 and December 31, 2004 of $35.2 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 and six-month periods ended June 30, 2005, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities, and investments in GTL and EOR projects of $1.0 million and $1.9 million, respectively, were capitalized. For the same periods ended June 30, 2004 $0.9 million and $1.6 million, respectively, were capitalized.
As at June 30, 2005, the GTL and EOR Investments include $4.6 million of costs associated with the fair value

of the RTP™ CDF acquired in the Merger. The RTP™ CDF is being used to develop and identify improvements in the application of the RTP™ Technology by processing and testing heavy crude feedstock of prospective customers until such time as the RTP™ CDF is sold or dismantled and redeployed (See Note 12).

As a result of the Company s on-going evaluation of its GTL investments, $0.3 million of its investments were written down for the three-month period ended June 30, 2005 related to its GTL project in Bolivia due to the impact that political and fiscal uncertainty in Bolivia could have on the viability of a GTL plant. For the three-month period ended June 30, 2004, GTL investments of $0.3 million were written down as the opportunity to build a 45,000 bpd GTL fuels plant in Oman failed to materialize due to a lack of sufficient uncommitted gas volumes to support a plant of that size.

4. LONG TERM ASSETS

During 2004, prior to entering into the Merger Agreement, the Company acquired from Ensyn a 15% equity interest in Ensyn Petroleum International Ltd. (**EPIL**) and exclusive rights to use the RTP™ Technology for petroleum applications in key international markets. Ensyn, the parent company of EPIL, retained the remaining 85% of EPIL. The $3 million cost to acquire the 15% equity interest in EPIL plus $2.5 million of costs incurred by the Company in connection with the Merger, including $1.0 million to acquire an option to purchase an additional 5% of EPIL (which expired, unexercised, in January 2005) are included in long-term assets as at December 31, 2004. The Merger was completed on April 15, 2005 and the 15% equity interest in EPIL was eliminated upon consolidating the accounts of the Company and its subsidiaries as at June 30, 2005 (See Note 11).

5. INTANGIBLE ASSET

The Company s intangible asset consists of the underlying value of an exclusive, irrevocable license acquired in the Merger with Ensyn to deploy, worldwide, the RTP™ Technology for petroleum applications as well as exclusive right to deploy RTP™ Technology in all applications other than bio-mass (See Note 11). This intangible asset is not currently being amortized and its carrying value was not impaired for the three-month and six-month periods ended June 30, 2005.

6. SEGMENT INFORMATION

The following tables present the Company s interim segment information for the three-month and six-month periods ended June 30, 2005 and 2004 and identifiable assets as at June 30, 2005 and December 31, 2004:

	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 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	$ 1,711	$ 8,700	$ 516	$ 1,130	$	$ 12,057

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	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 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	$ 2,511	$ 18,251	$ 731	$ 2,844	$	$ 24,337
Identifiable Assets (As at June 30, 2005)	$ 45,854	$ 59,856	$ 14,289	$ 99,657	$ 3,144	$ 222,800
Identifiable Assets (As at December 31, 2004)	$ 49,465	$ 44,960	$ 13,867	$ 2,441	$ 7,753	$ 118,486

	Three-Month Period Ended June 30, 2004					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 2,006	$ 1,466	$	$	$	$ 3,472
Interest income	1	3			45	49
	2,007	1,469			45	3,521
Operating costs	677	480				1,157
General and administrative	302	174			986	1,462
Business development			422			422
Depletion and depreciation	994	501	7		1	1,503
Interest expense	23				2	25
			250			250

Write-downs and provision for impairment						
	1,996	1,155	679		989	4,819
Net (Income) Loss	$ (11)	$ (314)	$ 679	$	$ 944	$ 1,298
Capital Investments	$ 6,793	$ 7,277	$	$ 751	$	$ 14,821

	Six-Month Period Ended June 30, 2004					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 3,800	$ 2,964	$	$	$	$ 6,764
Interest income	3	6			80	89
	3,803	2,970			80	6,853
Operating costs	1,431	1,000				2,431
General and administrative	409	430			2,227	3,066
Business development			699			699
Depletion and depreciation	1,859	1,077	11		2	2,949
Interest expense	45				3	48
Write-downs and provision for impairment			250			250
	3,744	2,507	960		2,232	9,443
Net (Income) Loss	$ (59)	$ (463)	$ 960	$	$ 2,152	$ 2,590
Capital Investments	$ 9,843	$ 14,152	$ 67	$ 1,114	$	$ 25,176

6. SHARE CAPITAL

Following is a summary of the changes in share capital and stock options outstanding for the three-month period ended June 30, 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 Merger	30,000	74,907			
Shares issued for exercise of warrants	1,500	1,650			
Shares issued for services	192	441			
Shares issued on exercise of options	75	94	(19)	(75)	$ 1.42
Options granted				2,364	$ 3.03
Options expired				(943)	$ 6.17
Stock based compensation			830		$
Balance June 30, 2005	201,432	$ 260,709	$ 2,559	9,592	$ 2.40

On April 15, 2005, the Company closed a Cdn.$12.7 million (U.S.$10.2 million, net of U.S.$0.1 million in share issue costs), special warrant financing by way of a private placement, with six institutional and individual investors.

Proceeds from the financing were used to complete the Merger and for general corporate purposes. The financing consisted of 4,100,000 special warrants at Cdn.$3.10 per special warrant. Each special warrant entitled 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 Cdn.$3.50 until April 15, 2007. Common shares and share purchase warrants were issued for the exercise of the 4,100,000 special warrants on July 4, 2005.

In June 2005, 3,000,000 share purchase warrants, issued on July 3, 2003, were exercised for the purchase of 1,500,000 common shares at U.S.$1.10 per share. As at June 30, 2005, the following purchase warrants were exercisable to purchase additional common shares until the expiry date at the price per share as indicated:

Year of Special Warrant Financing	Price per Special Warrant	Number of Purchase Warrants Issued	Remaining Number of Purchase Warrants (thousands)	Number of Common Shares	Expiry Date	Exercise Price per Share
2003	U.S.$1.00	3,000	3,000	1,500	September 8, 2005	U.S.$1.10
2003	U.S.$1.70	3,529	3,029	1,515	September 8, 2005	U.S.$1.87
2003	U.S.$4.00	1,250	1,250	1,250	October 31, 2005	U.S.$4.30
2004	U.S.$2.90	5,449	5,449	2,725	February 18, 2006	U.S.$3.20
2004	U.S.$2.90	1,724	1,724	862	March 5, 2006	U.S.$3.20
2005	Cdn.$3.10	4,100	4,100	4,100	April 15, 2007	Cdn.$3.50
		19,052	18,552	11,952		

7. 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, 2005, the Company expensed $0.5 million and $0.8 million, respectively, in stock based compensation, which is included in general and administrative expense. For the same periods ended June 30, 2004, $0.2 million and $0.5 million, respectively, was expensed.

8. 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 its South Midway properties. The note balance, as at June 30, 2005 and December 31, 2004, was $3.5 million and $4.3 million, respectively, with a six-month fixed LIBOR rate of 6.5% per annum as at June 30, 2005.

The scheduled maturities of the bank note payable as at June 30, 2005 were as follows:

2005	$ 834
2006	1,667
2007	972
	3,473
Less: current portion	1,667
	$ 1,806

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.

9. CONVERTIBLE LOANS

The Company has two unsecured convertible loans, of $6.0 million and $2.0 million, which bear interest at 8.0% per annum and are 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 loans 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 as to the $6.0 million loan and $2.15 per share as to the $2.0 million loan. The fair value of the convertible loans approximate their carrying values due to the short-term maturity. No value was assigned to the equity component of the loans. The lender waived its right to have the loans repaid from the proceeds of the April 15, 2005 and July 7, 2005 special warrant financings described in Notes 6 and 14.

10. ASSET RETIREMENT OBLIGATIONS

The undiscounted amount of expected cash flows required to settle the Company s asset retirement obligations as at June 30, 2005 was estimated at $3.0 million, which includes $0.1 million for dismantlement and site restoration of the RTP™ CDF and $1.5 million to permanently abandon the Northwest Lost Hills # 1-22 well. The liability for the expected cash flows, as reflected in the financial statements, has been discounted at 5% to 7% and is estimated to be settled over a twelve-year period starting in 2010.

11. MERGER

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 are being 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 Company s consolidated results of operations for the three-month period 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 or 2004, the 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 and 2004 would have been as follows:

	Three-Month Periods Ended June 30,					
	2005			**2004**		
	Revenue	**Net Loss**	**Net Loss Per Share**	**Revenue**	**Net Loss**	**Net Loss Per Share**
As reported	$ 6,645	$ 1,031	$ 0.01	$ 3,521	$ 1,298	$ 0.01
Pro forma adjustments	6	550		36	330	
	$ 6,651	$ 1,581	$ 0.01	$ 3,557	$ 1,628	$ 0.01
Weighted Average Number of Shares (in thousands)			200,145			199,116

	Six-Month Periods Ended June 30,					
	2005			**2004**		
	Revenue	**Net Loss**	**Net Loss Per Share**	**Revenue**	**Net Loss**	**Net Loss Per Share**
As reported	$ 12,381	$ 2,514	$ 0.01	$ 6,853	$ 2,590	$ 0.02
Pro forma adjustments	736	730		174	605	
	$ 13,117	$ 3,244	$ 0.01	$ 7,027	$ 3,195	$ 0.02
Weighted Average Number of Shares (in thousands)			200,527			195,621

As at June 30, 2005, the Company incurred $4.0 million of costs associated with the Merger, including $1.0 million to acquire an option to purchase an additional 5% of EPIL, which expired, unexercised, in January 2005. The total purchase consideration and cost of the Merger was $89.0 million and has been allocated to the net assets acquired from Ensyn as follows:

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

Net Assets Acquired	
Cash	$ 21
Non-cash working capital, net	(117)
Oil and gas properties and investments	4,561
Intangible asset	89,531
Asset retirement obligation	(96)
Contingent obligation	(1,900)
Less : previous investment in EPIL	(3,000)
	$ 89,000

The allocation of the purchase consideration and cost of the Merger is preliminary and subject to change.

12. ENSYN AGREEMENTS

RTP™ Joint Venture

In the Merger, the Company acquired a 50% interest in a joint venture (**RTP™ Joint Venture**), which owns the RTP™ CDF and exclusive right to use the RTP™ Technology to manufacture RTP™ facilities, at cost plus 25%, or be paid a fixed fee if the RTP™ facilities are manufactured by any party other than the RTP™ Joint Venture. The fixed fee is a one-time fee for each RTP™ facility installed determined based on factors including the capacity and application of the RTP™ facility. The RTP™ Joint Venture must include in the purchase price for RTP™ facilities a royalty of $500/barrel of capacity of each installed RTP™ facility payable in a lump sum and pay such royalty to the Company or alternately, at the Company s option, the royalty may be paid to the Company by the purchaser of the RTP™ facility. The Company has a 50% interest in the profits and losses of the RTP™ Joint Venture.

In 2003, Ensyn (which changed its name following the Merger to Ivanhoe Energy HTL Inc. (**IE HTL**)) entered into an agreement with Aera Energy LLC (**Aera**) providing for the construction of an RTP™ CDF on Aera s property in California s San Joaquin Basin to demonstrate the commercial viability of the RTP™ Technology. The RTP™ Joint Venture partners agreed to fund the construction of an RTP™ CDF to be owned and operated by the RTP™ Joint Venture up until its redeployment to another site or sale to a third party. Within six months after completing the RTP™ CDF s testing and demonstration period, the Company is responsible for dismantling the facility and restoring the Aera site to its original condition.

No royalties were paid by the RTP™ Joint Venture to the Company for the construction of the RTP™ CDF.

Other than the RTP™ CDF and exclusive right to use the RTP™ Technology to manufacture RTP™ facilities, the RTP™ Joint Venture had no assets, liabilities, revenues or net income for the three-month and six-month periods ended June 30, 2005. The Company has included its 50% interest in the RTP™ CDF in its balance sheet as at June 30, 2005.

ConocoPhillips Canada Resources Limited

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

13. 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 includes 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 $6.7 million as at June 30, 2005.

Contingent Obligations

As part of the Merger, the Company assumed a contingent obligation to pay $1.9 million in the event, and at such time that, the sale of units incorporating the RTP™ Technology for petroleum applications reach a total of $100 million. This contingent obligation was recorded in the Company s balance sheet as at June 30, 2005 as part of the net assets acquired in the Merger. Additionally, the Company assumed a contingent 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.

14. SUBSEQUENT EVENT

Private Placement

On July 7, 2005, the Company closed a Cdn.$3.1 million (U.S.$ 2.4 million) special warrant financing, by way of a private placement, with an institutional investor. Proceeds from the financing will be used to pursue opportunities for the commercial deployment of the Company s RTP Technology as well as funding the ongoing development of its oil and gas projects in China and for general corporate purposes. The financing consisted of 1,000,000 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 immediately following the filing and regulatory acceptance of a Canadian prospectus, or four months after the closing date, which ever occurs first. One common share purchase warrant will entitle the holder to purchase one common share at a price of Cdn.$3.50 exercisable until the second anniversary date of the closing.

15. 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

	Oil and Gas Properties and Investments	Share Capital and Warrants	Contributed Surplus	Accumulated Deficit	Total
			As at June 30, 2005		
			Shareholders' Equity		
Canadian GAAP	$ 121,238	$ 270,862	$ 2,559	$ (84,293)	$ 189,128
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	910			910	910
GTL and EOR development costs expensed	(9,168)			(9,168)	(9,168)
Adjustment for change in accounting for stock based compensation		(300)	(2,458)	2,758	
U.S. GAAP	$ 105,688	$ 346,375	$ 101	$ (172,898)	$ 173,578

	Oil and Gas Properties and Investments	Share Capital	Contributed Surplus	Accumulated Deficit	Total
			As at December 31, 2004		
			Shareholders' Equity		
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	$ 83,857	$ 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 June 30, 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 June 30, 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 $0.9 million and $0.5 million as at June 30, 2005 and December 31, 2004, respectively.

As more fully described in Note 2 to these consolidated financial statements, 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 June 30, 2005 and December 31, 2004, the Company capitalized $9.2 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 to acquire the royalty rights, 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 June 30,			
	2005		2004	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ 1,031	$ 0.01	$ 1,298	$ 0.01
Stock based compensation expense	(566)		(232)	
Depletion adjustments due to differences in provision for impairment	(256)		(57)	
GTL and EOR development costs expensed, net	1,355		501	
U.S. GAAP	$ 1,564	$ 0.01	$ 1,510	$ 0.01
Weighted Average Number of Shares under U.S. GAAP (in thousands)		195,200		169,116

	Six-Month Periods Ended June 30,			
	2005		2004	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ 2,514	$ 0.01	$ 2,590	$ 0.02
Stock based compensation expense	(798)		(461)	
Depletion adjustments due to differences in provision for impairment	(428)		(80)	
GTL and EOR development costs expensed, net	3,284	0.02	931	
U.S. GAAP	$ 4,572	0.03	$ 2,980	$ 0.02
Weighted Average Number of Shares under U.S. GAAP (in thousands)		183,621		165,622

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 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 June 30, 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 $0.3 million and $0.4 million in the net losses for the three-month and six-month periods ended June 30, 2005, respectively, and reductions of $0.1 million each in the net losses for the three-month and six-month periods ended June 30, 2004.

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, 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 $0.6 million and $0.8 million in the net losses for the three-month and six-month periods ended June 30, 2005, respectively, and a reduction of $0.2 million and $0.5 million in the net losses for the three-month and six-month periods ended June 30, 2004, respectively.

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 and six-month periods ended June 30, 2005, the Company expensed $1.4 million and $3.3 million, respectively, of GTL and EOR development costs for U.S. GAAP purposes and $0.5 million and $0.9 million for the three-month and six-month periods ended June 30, 2004, respectively.

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 June 30,		**Six-Month Periods Ended June 30,**	
	2005	**2004**	**2005**	**2004**
Net loss under U.S. GAAP	$ 1,564	$ 1,510	$ 4,572	$ 2,980
Stock-based compensation expense determined under the fair value based method for employee and director awards	597	498	860	992
Pro forma net loss under U.S. GAAP	$ 2,161	$ 2,008	$ 5,432	$ 3,972
Basic loss per common share under U.S. GAAP:				
As reported	$ 0.01	$ 0.01	$ 0.03	$ 0.02
Pro forma	$ 0.01	$ 0.01	$ 0.03	$ 0.02
Weighted Average Number of Shares under U.S. GAAP (in thousands)	195,200	169,116	183,621	165,622

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.

Pro Forma Effect of Merger

The Company s U.S. GAAP consolidated results of operations for the three-month period 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 or 2004, 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 and 2004 would have been as follows:

	Three-Month Periods Ended June 30,					
	2005			2004		
	Revenue	Net Loss	Net Loss Per Share	Revenue	Net Loss	Net Loss Per Share
As reported	$ 6,645	$ 1,564	$ 0.01	$ 3,521	$ 1,510	$ 0.01
Pro forma adjustments	6	550		36	330	
	$ 6,651	$ 2,114	$ 0.01	$ 3,557	$ 1,840	$ 0.01
Weighted Average Number of Shares (in thousands)			200,145			199,116

	Six-Month Periods Ended June 30,					
	2005			2004		
	Revenue	Net Loss	Net Loss Per Share	Revenue	Net Loss	Net Loss Per Share
As reported	$ 12,381	$ 4,572	$ 0.03	$ 6,853	$ 2,980	$ 0.02
Pro forma adjustments	736	730		174	605	
	$ 13,117	$ 5,302	$ 0.03	$ 7,027	$ 3,585	$ 0.02
Weighted Average Number of Shares (in thousands)			200,527			195,621

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 cash provided by operating activities of $1.0 million for the three-month period ended June 30, 2005 and a cash deficiency from operating activities of $0.9 million for the six-month period ended June 30, 2005. Cash provided by operating activities would be $0.5 million and $0.2 million for the three-month and six-month periods ended June 30, 2004, respectively. Additionally, capital investments reported under investing activities would be $10.2 million and $20.8 million for the three-month and six-month periods ended June 30, 2005, respectively, and $14.2 million and $24.2 million for the three-month and six-month periods ended June 30, 2004, respectively.

Impact of New and Pending Canadian GAAP Accounting Standards

In January 2005, the Canadian Institute of Chartered Accountants (**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 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 (**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 applies APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for awards issued from its 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 at January 1, 2006 and for all awards granted after January 1, 2006.

To assist in the implementation of SFAS No. 123(R), the SEC issued SAB No. 107, Share-Based Payment . While SAB No. 107 addresses a wide range of issues, the largest area of focus is valuation methodologies and the selection of assumptions. Notably, SAB No. 107 lays out simplified methods for developing certain assumptions. In addition to providing the SEC staff s interpretive guidance on SFAS No. 123(R), SAB No. 107 addresses the interaction of SFAS No. 123(R) with existing SEC guidance (e.g., the interaction with the SEC s guidance dealing with non-GAAP disclosures). Its intent is to clarify, not change, any of SFAS No. 123(R) s guidance.

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 conditional event with respect to the abandonment of the Northwest Lost Hills # 1-22 well materialized during the three-month period ended June 30, 2005 and the Company recorded $0.9 million in asset retirement costs and asset retirement obligations.

In May 2005, the FASB issued SFAS No. 154 (**SFAS 154**) Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3 . SFAS 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 154 requires retrospective application to prior periods financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 applies to all voluntary changes in accounting principle. It 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 154 carries forward without change 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 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 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

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 non-controlling interests be classified as equity within the consolidated financial statements. The FASB s proposed standard would replace Accounting Research Bulletin No. 51, Consolidated Financial Statements .

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 oil 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 15. The date of this discussion is July 29, 2005.

Executive Overview of 2005 Results

Despite significant increases in our revenues for the first two quarters of 2005, we continue to generate net losses at approximately the same levels as the comparable periods in 2004 primarily as a result of increases in non-cash expenses such as depletion and stock based compensation and from cash items such as general and administrative and business development expenses. Our net operating revenues and cash flow from operating activities have almost doubled for the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods for 2004 due mainly to increases in oil and gas prices but also due to increased volumes generated from our field development programs at Dagang, Citrus and Knights Landing.

The following table sets forth certain selected consolidated data for the three-month and six-month periods ended June 30, 2005 and 2004:

(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,**	
	2005	**2004**	**2005**	**2004**
Oil and gas revenue	$ 6,617	$ 3,472	$ 12,310	$ 6,764
Net loss	$ 1,031	$ 1,298	$ 2,514	$ 2,590
Net loss per share	$ 0.01	$ 0.01	$ 0.01	$ 0.02
Average production (Mboe/d)	1,653	1,169	1,659	1,182
Capital investments	$ 12,057	$ 14,821	$ 24,337	$ 25,176
Cash flow from operating activities	$ 1,850	$ 1,299	$ 2,625	$ 1,334

Financial Results Change in Net Losses

The following provides an analysis of our changes in net losses for the three-month and six-month periods ended June 30, 2005 when compared to the same periods for 2004:

(stated in thousands of U.S. Dollars)	Three-Months Ended June 30,	Six-Months Ended June 30,
Net Losses for 2004	$ 1,298	$ 2,590
Favorable (unfavorable) variances:		
Cash Items:		
Net Operating Revenues:		
Production volumes	1,336	2,536
Oil and gas prices	1,809	3,010
Less: Operating costs	(614)	(1,102)
	2,531	4,444
General and administrative	248	(502)
Business development	(756)	(1,198)
Net interest	(371)	(465)
Total Cash Variances	1,652	2,279
Non-Cash Items:		
Depletion and depreciation	(1,064)	(1,825)
Stock based compensation	(292)	(349)
Write downs of GTL investments	(29)	(29)
Total Non-Cash Variances	(1,385)	(2,203)
Net Losses for 2005	$ 1,031	$ 2,514

Our net loss for the three-month period ended June 30, 2005 was $1.0 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 decrease in our net loss from 2004 to 2005 of $0.3 million is mainly due to a $2.5 million increase in net operating revenues. This is partially offset by a $0.7 million increase in business development expense, an increase of $0.4 million in net interest expense and an increase of $1.1 in depletion and depreciation.

Our net loss for the six-month period ended June 30, 2005 was $2.5 million ($0.01 per share) compared to our net loss for the same period in 2004 of $2.6 million ($0.01 per share). The decrease in our net loss from 2004 to 2005 of $0.1 million is mainly due to a $4.4 million increase in net operating revenues. This is partially offset by a $1.2 million increase in business development expense, an increase of $0.8 million in general and administrative, including stock based compensation, an increase of $0.5 million in net interest expense and an increase of $1.8 million in depletion and depreciation.

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

Net Operating Revenues

Production Volumes 2005 vs. 2004

Net production volumes for the three-month and six-month periods ended June 30, 2005 increased 41% and 40%, respectively, when compared to the same periods in 2004. The increase for the three-month period ended June 30, 2005 is due to 45% and 39% increases in production volumes in our China and U.S. properties, respectively, resulting in increased revenues of $1.3 million. The increase for the six-month period ended June 30, 2005 is due to 44% and 36% increases in production volumes in our China and U.S. properties, respectively, resulting in increased revenues of

$2.5 million.

Net production volumes for the three-month and six-month periods ended June 30, 2005 at the Dagang field increased 71% and 57%, respectively, when compared to the same periods in 2004 despite the farm-out of a 40% working interest in June 2004. During the six-month period ended June 30, 2005, we placed 16 wells on production bringing the total wells on production or available for production to 37 wells. Production rates decreased 22% during the first quarter of 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. Additionally, results from the new wells drilled in the northern blocks of the Dagang field had been less than expected, with initial unstimulated production of approximately 75 Bopd per well. During the second quarter of 2005, we stimulated 5 of the northern block wells of which 2 wells have stabilized at rates between 110 Bopd and 190 Bopd. The remaining 3 wells are currently in post-stimulation clean up and stabilized production rates will not be known until the third quarter of 2005. We are currently reviewing well data and expect to stimulate an additional 4 to 6 wells in the northern blocks during the remainder of 2005. Primarily as a result of the well stimulation program, current production rates at Dagang were approximately 2,025 Bopd (950 net Bopd), a 22% increase from the year-end 2004 exit rate of 1,655 Bopd (774 net Bopd).

We realize a significant benefit from the expanded Daqing development program and the royalty interest we hold. Our royalty percentage was 4% but was reduced to 2% in May 2005 when the operator of the Daqing properties reached payout of its investment. As a result, our share of production volumes decreased 31% and 3% for the three-month and six-month periods ended June 30, 2005, respectively, when compared to the same periods in 2004.

Net production volumes for the three-month and six-month periods ended June 30, 2005 in the U.S. increased 39% and 36%, respectively, when compared to the same periods in 2004 mainly from our Citrus and Knights Landing fields. Three Citrus wells were on production during the six-month period ended June 30, 2005 compared to only 1 Citrus well for the same period in 2004. As at June 30, 2005, we were producing 150 gross Boe/d (120 net Boe/d) at Citrus. 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. In April 2005, three Knights Landing wells that were drilled and completed in 2004 were connected to a gas sales line and placed on production. As at June 30, 2005, we were producing 420 gross Boe/d (270 net Boe/d) at Knights Landing. We continue to see increased production rates from our successful drilling and steaming operations at our South Midway field. The increased production for the six months of 2005 was a result of drilling 4 producing South Midway wells in the second quarter of 2004, increasing our steam injection in the primary area of South Midway in the third quarter of 2004 and initiating a continuous steam injection pilot program in the southern expansion of South Midway in the fourth quarter of 2004. As at June 30, 2005, we were producing 600 gross Boe/d (560 net Boe/d) at South Midway.

The following is a comparison of changes in production volumes for the three-month and six-month periods ended June 30, 2005 when compared to the same periods in 2004:

	Three-Month Periods Ended June 30,			**Six-Month Periods Ended June 30,**		
	Average Net Boe's		**Percentage**	**Average Net Boe's**		**Percentage**
	2005	**2004**	**Change**	**2005**	**2004**	**Change**
China:						
Dagang	58,285	34,078	71%	118,521	75,338	57%
Daqing	7,849	11,424	-31%	19,848	20,526	-3%
	66,134	45,502	45%	138,369	95,864	44%
U.S.:						
South Midway	51,551	44,149	17%	101,319	87,299	16%
Citrus	8,817	2,437	262%	18,344	5,870	213%
Knights Landing	16,624	3,900	326%	27,924	3,900	616%
Others	7,332	10,362	-29%	14,274	22,145	-36%
	84,324	60,848	39%	161,861	119,214	36%
	150,458	106,350	41%	300,230	215,078	40%

Oil and Gas Prices

2005 vs. 2004

Oil and gas prices increased 35% and 30% per Boe generating $1.8 million and $3.0 million in additional revenue for the three-month and six-month periods ended June 30, 2005, respectively, as compared to the same periods in 2004. We realized an average of $50.25 and $44.42 per Boe from our operations in China for the three-month and six-month periods ended June 30, 2005, respectively, an increase of $18.04 and $13.50 per Boe which accounts for $1.2 million and $1.9 million of our increase in revenues for the three-month and six-month periods ended June 30, 2005, respectively, as compared to the same periods in 2004. From the U.S. operations, we realized an average of $39.07 and $38.08 per Boe for the three-month and six-month periods ended June 30, 2005, respectively, an increase of $6.10 and $6.20 which accounts for $0.6 million and $1.1 million, of our increased revenues for the three-month and six-month periods ended June 30, 2005, respectively, as compared to the same periods in 2004.

Operating Costs 2005 vs. 2004

For the three-month and six-month periods ended June 30, 2005, operating costs, including production taxes and engineering support, increased $0.6 million and $1.1, respectively, in absolute terms from the same periods in 2004 or $0.90 and $0.47, respectively, on a per barrel of oil equivalent basis.

Operating costs in China, including engineering support, decreased 11% or $1.19 and 12% or $1.29 per Boe for the three-month and six-month periods ended June 30, 2005, respectively, when compared to the same periods in 2004 due mainly to decreases in workover and maintenance costs and increased production from the Dagang field in relation to the level of engineering support required to operate the field. These decreases were partially offset by increases in power costs and permanent land fees on producing wells.

Operating costs in the U.S., including engineering support and production taxes, increased 23% or $2.56 and 17% or $2.02 per Boe for the three-month and six-month periods ended June 30, 2005, respectively, when compared to the same periods in 2004. Field operating costs increased $2.27 and $1.93 per Boe, respectively, due mainly to an increase in fuel costs incurred for the increased level of cyclic and continuous steam operations at South Midway. In addition, we completed four workovers at Knights Landing during the first six months of 2005. Engineering support increased $0.88 and $0.72 per Boe, respectively, 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 $0.59 and $0.63 per Boe, respectively, 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-Month Periods Ended June 30,					
		2005			2004	
	U.S.	**China**	**Total**	**U.S.**	**China**	**Total**
Net Production:						
BOE	84,324	66,134	150,458	60,848	45,502	106,350
BOE/day for the year	927	727	1,653	669	500	1,169
		Per BOE			Per BOE	
Oil and gas revenue	$ 39.07	$ 50.25	$ 43.98	$ 32.97	$ 32.21	$ 32.65
Operating costs	10.14	8.15	9.26	7.87	7.17	7.57
Production taxes	0.53		0.30	1.12		0.64
Engineering support	3.00	1.21	2.21	2.12	3.38	2.66
	13.67	9.36	11.77	11.11	10.55	10.87
Net Revenue before depletion	25.40	40.89	32.21	21.86	21.66	21.78
Depletion	15.38	18.70	16.84	15.85	11.01	13.78
Net Revenue from operations	$ 10.02	$ 22.19	$ 15.37	$ 6.01	$ 10.65	$ 8.00

	Six-Month Periods Ended June 30,					
		2005			2004	
	U.S.	China	Total	U.S.	China	Total
Net Production:						
BOE	161,861	138,369	300,230	119,214	95,864	215,078
BOE/day	894	764	1,659	655	527	1,182
		Per Boe			Per Boe	
Oil and gas revenue	$ 38.08	$ 44.42	$ 41.00	$ 31.88	$ 30.92	$ 31.45
Operating costs	10.44	7.95	9.29	8.51	7.28	7.96
Production taxes	0.52		0.28	1.15		0.64
Engineering support	3.06	1.19	2.20	2.34	3.15	2.70
	14.02	9.14	11.77	12.00	10.43	11.30
Net revenue before depletion	24.06	35.28	29.23	19.88	20.49	20.15
Depletion	15.08	16.40	15.69	15.11	11.22	13.37
Net revenue from operations	$ 8.98	$ 18.88	$ 13.54	$ 4.77	$ 9.27	$ 6.78

General and Administrative 2005 vs. 2004

Our changes in general and administrative expenses, including stock based compensation expense, by segment for the three-month and six-month periods ended June 30, 2005 when compared to the same periods for 2004 were as follows:

(stated in thousands of U.S. Dollars)	Three-Months Ended June 30,	Six-Months Ended June 30,
General and Administrative for 2004	$ 1,462	$ 3,066
Favorable (unfavorable) variances:		
Oil and Gas Activities:		
U.S.	44	(5)
China	37	68
Corporate	(125)	(914)
	(44)	(851)
General and Administrative for 2005	$ 1,506	$ 3,917

General and administrative increased slightly for the three-month period ended June 30, 2005 and increased $0.9 million for the six-month period ended June 30, 2005 compared to the same periods in 2004. Corporate general and administrative expenses increased $0.1 million and $0.9 million, respectively, due mainly to professional fees incurred in 2005 to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002.

Business Development 2005 vs. 2004

Our changes in business development expenses by segment for the three-month and six-month periods ended June 2005 when compared to the same periods for 2004 were as follows:

(stated in thousands of U.S. Dollars)	Three-Months Ended June 30,	Six-Months Ended June 30,
Business Development for 2004	$ 422	$ 699
Favorable (unfavorable) variances:		
GTL	103	(24)
EOR	(859)	(1,174)
	(756)	(1,198)
Business Development for 2005	$ 1,178	$ 1,897

Business development expense increased by $0.8 million and $1.2 million for the three-month and six-month periods ended June 30, 2005, respectively, when compared to the same periods in 2004 due mainly to increased activities in Egypt, Iraq and other Northern Africa and Middle East countries. In addition, operating expenses of the RTP™ CDF to develop and identify improvements in the application of the RTP™ Technology are a part of our business development activities and contributed $0.4 million to the increases in business development for the three-month and six-month periods ended June 30, 2005.

Depletion and Depreciation 2005 vs. 2004

Depletion and depreciation increased $1.1 million and $1.8 million for the three-month and six-month periods ended June 30, 2005, respectively, when compared to the same periods for 2004 primarily due to higher production rates resulting in increases in depletion of $0.6 million and $1.1 million, respectively. Additionally, depletion rates increased $3.06 and $2.03 per Boe resulting in additional depletion expense of $0.5 million and $0.7 million for the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods in 2004.

The increases in depletion rates are due mainly to three factors associated with our operations in China:

- 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 Dagang production-sharing contract.

- Following an internal review of the results of our current development program at Dagang, and especially the results from the work completed in the northern blocks over the past six months, we have revised our estimate of total proved reserves downward. At year-end 2005, our current internal estimate of reserves at Dagang will be confirmed or further revised, by a full independent review by Gilbert Laustsen Jung Associates, our independent reserve evaluator for our China properties.

- We impaired the cost of our first Zitong block exploration well, the Dingyuan 1, which was plugged and suspended in the three-month period ended June 30, 2005 resulting in those well costs being included with our proved properties and therefore subject to depletion.

Capital Investments

The following provides an analysis of our capital investment activities for the three-month and six-month periods ended June 30, 2005 when compared to the same periods for 2004:

	Three-Month Periods Ended June 30,			Six-Month Periods Ended June 30,		
	2005	2004	(Increase) Decrease	2005	2004	(Increase) Decrease
Oil and Gas Activities:						
U.S.	$ 1,711	$ 6,793	$ 5,082	$ 2,511	$ 9,843	$ 7,332
China	8,700	7,277	(1,423)	18,251	14,152	(4,099)
GTL	516		(516)	731	67	(664)
EOR	1,130	751	(379)	2,844	1,114	(1,730)
	$ 12,057	$ 14,821	$ 2,764	$ 24,337	$ 25,176	$ 839

Oil and Gas Activities U.S.

Capital investment in the U.S. is down $5.1 million and $7.3 million for the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods in 2004. The decrease for the three-month period ended June 30, 2005 is due mainly to a $5.0 million reduction in our development activities in the Knights Landing, Citrus, LAK Ranch and South Midway fields compared to the same period in 2004. Further reductions in capital investments for the three-month period ended June 30, 2005 resulted from drilling one exploration well each at Sledge Hamar $0.4 million and McCloud River $0.2 million during the comparative period in 2004. Both properties were disposed of in 2004. These decreases are partially offset by a $0.5 million increase in capital investments related to drilling activities at our Peach and North Salt Creek prospects during the second quarter of 2005. The decrease for the six-month period ended June 30, 2005 is due mainly to a $7.2 million reduction in our development activities in the Knights Landing, Citrus, LAK Ranch and South Midway fields, compared to the same period in 2004, in addition to the $0.6 million reduction in exploration activities at Sledge Hamar and McCloud River prospects. These decreases are partially offset by a $0.5 million increase in capital investments related to drilling activities at our Peach and North Salt Creek prospects during the second quarter of 2005.

Our development activities at Knights Landing decreased $2.6 million and $3.9 million for the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods in 2004. 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.

Our development activities at Citrus decreased $1.7 million and $2.5 million for the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods in 2004. We completed the drilling of three Citrus wells in the six months of 2004. We have not drilled any additional wells at Citrus but we continue to assess drilling an additional horizontal leg in the Citrus # 1 well later in 2005 to fully evaluate the potential of the Upper Antelope zone in this section of our Citrus acreage.

Our development activities at South Midway decreased $0.5 million and $0.4 million for the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods in 2004. We drilled one successful delineation well and two temperature observation wells in the second quarter of 2005. This compares to six delineation wells and one exploratory well drilled in the second quarter of 2004, resulting in the completion of four producing oil wells.

Our development activities at LAK Ranch decreased $0.2 million and $0.4 million for the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods in 2004. We drilled one vertical well in the first quarter of 2005 for data collection purposes and continue to analyze and interpret the ultra-high resolution 3-D seismic we acquired at the end of 2004. The pilot steam flood at LAK Ranch will be expanded during the third quarter of 2005 with the drilling of three steam injection wells. The new wells will provide for continuous injection of steam above the existing horizontal wells. The pilot program to date has consisted of three cycles of steam injected into a horizontal producing well. Temperature has been monitored in an adjacent horizontal well, located approximately 25 feet above the injection well. Gross oil production has increased with each cycle and is currently averaging 10 barrels per day following the third steam cycle.

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 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. In the second quarter of 2005, an appraisal well was drilled to a depth of 4,950 feet and encountered gas shows while drilling. We are currently waiting on a rig to complete a test program. Production of the discovery and appraisal wells and connection to a gas sales pipeline is pending the results of the appraisal well test.

During the second quarter of 2005, we discovered natural gas at our North Salt Creek prospect in the Cymric area in Kern County, California. The prospect is 45 miles west of Bakersfield, in a major hydrocarbon-producing region along the west side of the San Joaquin Basin. The 2,500-foot North Salt Creek well tested in the Fitzgerald sand and flowed gas at a rate of 810 Mcf/day. We are in negotiations with two purchasers to sell gas from this well. We plan to sell gas and drill two offset wells to this discovery during the fourth quarter of 2005. We are the operator of the well and own a 24% working interest in the well and the 370-acre prospect.

Oil and Gas Activities China

Capital investment in China increased $1.4 million and $4.1 million for the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods in 2004 primarily due to increased drilling activities at Dagang.

Our development activities at Dagang increased $2.1 million and $4.4 million during the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods in 2004. For the six-month period ended June 30, 2005, we completed 3 wells drilled in 2004, drilled and completed 10 new wells, re-completed 5 existing wells and drilled 2 wells that are awaiting completion as at June 30, 2005. We also commenced drilling two wells in late June 2005, which were in process as at June 30, 2005. The wells drilled in the first quarter of 2005 were located in the two northern blocks of the Dagang field. The wells drilled in the second quarter of 2005 were in the southern blocks as we commenced a stimulation program in the northern block wells. We estimate drilling an additional 8 wells during the remainder of 2005. We are currently assessing our drilling program for the Dagang field and anticipate a reduction in wells drilled in the northern blocks of the field.

Our capital investment for our Zitong block decreased $0.7 million and $0.3 million during the three-month and six-month periods ended June 2005, respectively, when compared to the same periods in 2004. We spent $5.7 million in the first six months of 2004 to complete phase one of our 700-mile seismic acquisition program. For the six-month period ended June 30, 2005, we spent $2.5 million to complete the interpretation of our seismic data and $2.9 million to drill our first well, Dingyuan 1, in the Zitong block. The well reached a total depth of 9,022 feet and based on our testing, no commercial volumes of hydrocarbons were conclusively detected. Selective cement plugs have been set in the wellbore to allow use of the surface location and wellbore for a potential directional hole following the second exploration well which is planned for later in 2005. The Company has a 100% working interest in the project, however, we plan to seek a farm-out partner for the second exploration well.

Enhanced Oil Recovery and Heavy Oil Processing Activities

We incurred $0.4 and $1.7 million more in capital investment activities on EOR and RTP™ projects for the three-month and six-month periods ended June 30, 2005, respectively, when compared to the same periods in 2004. In Iraq, we continue to further our study of the Qaiyarah heavy oil field which resulted in increases in capital investments of $0.4 million and $0.8 million for the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods in 2004. The field s reservoirs contain a large proven accumulation of 16-17° API heavy oil at a depth of approximately 1,000 feet. Our 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 as well as providing steam for EOR or power generation. These increases were offset by a reduction in spending of $0.4 million and $0.2 million, respectively, on other Iraq projects including for engineering, design and procurement contract bids, which are currently being considered by the Iraqi government.

Our capital investments increased $0.1 million and $0.4 million for the three-month and six-month periods ended June 30, 2005, respectively, compared to the same periods in 2004 to further our study of the heavy crudes from the large Castilla and Chichimene oil fields in Colombia. We completed 10 runs of heavy oil samples from these two fields at Ensyn s RTP™ pilot plant in Ottawa, Canada as well as lab analysis of those samples. We are continuing to explore our options related to Ecopetrol S.A. s Llanos Basin Heavy Crude Project , which includes the Castilla and Chichimene field development and upgrading options and several exploration blocks.

In 2004, an RTP™ CDF was constructed on Aera s property in the Belridge Field for the purpose of demonstrating the RTP™ Technology on a commercial scale. Aera provides heavy crude oil for testing the RTP™ CDF and in return receives upgraded oil product including the results from testing the RTP™ CDF. Additionally, Aera will be provided steam produced by Company owned RTP™ facilities installed in the State of California at a price equal to the lowest price charged to other customers. 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 (now IE HTL) in April 2005. We incurred $0.3 million and $0.7 million for the three-month and six-month periods ended June 30, 2005, respectively, for a preliminary design package prepared by Colt Engineering Corporation for a 15,000 barrels-per-day feed of raw, heavy oil (5,000 barrels per day hot-section) commercial RTP facility. The design work for this commercial RTP facility was completed in June of 2005.

In August 2004, IE HTL and Aera signed an agreement that set out the financial and operational parameters for a commercial heavy oil project using the RTP Technology in Aera s California heavy oil fields. We continue negotiations for a definitive agreement to build a 15,000-barrel per day processing facility (**RTP™ Unit**) that would yield upgraded, heavy oil and excess thermal energy. The excess thermal energy from this RTP™ Unit would provide Aera an alternative to volatile natural gas prices and thereby lower Aera s operating expense associated with steam generation, the most significant component of their operating expense. The RTP™ Unit, if completed, will be owned and operated by IE HTL. Additional RTP™ Units, with a combined heavy oil throughput of up to 45,000 barrels per day, may be located on Aera s properties if the performance of the initial RTP™ Unit meets expectations. Aera, a California limited liability company owned by affiliates of Shell and ExxonMobil, is one of California s leading oil producers with approximately 250,000 barrels per day of oil production.

Under a preexisting agreement between IE HTL and 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 facilities, IE HTL is entitled to receive royalties per barrel after the first 50,000 barrels-per day of feedstock input capacity.

We intend to apply the leading-edge RTP™ Technology to upgrade heavy oil in facilities located in the field to produce lighter, more valuable crude oil at lower costs and in smaller size facilities 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™ facility 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 improve the economics in mature heavy oil fields and also enables the development of stranded heavy oil deposits.

Gas-To-Liquids Activities

We spent $0.5 and $0.7 million more in capital investment activities on GTL projects for the three-month and six-month periods ended June 2005, respectively, compared to the same periods in 2004. We updated the design for a 45,000 barrels-per-day GTL plant for a designated site in Egypt and, for now, have stopped work on a 90,000 barrels-per-day design while the Egyptian Petroleum Ministry assesses reserves. The objective is to develop full plant design documentation and associated cost estimates to maximize efficiency of capital and gas utilization using the latest technological advancements from Syntroleum for process design and catalyst formulation as well as improvements in 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 once they have completed an assessment of their reserves, which is expected near the end of 2005. Additionally, we have updated our marketing study that will provide GTL product price forecasts and identify end users for these products from this plant.

We have prepared an engineering feasibility study for the application of the Syntroleum Fischer Tropsch process to a coal-to-liquids (**CTL**) project in southern Mongolia. We are currently completing a marketing study for the CTL products to be sold in northern China and will be presenting economics and a proposal to the private owner of the coal deposit.

As a result of the Company s on-going evaluation of its GTL investments, $0.3 million of its investments were written down for the three-month period ended June 30, 2005 related to its GTL project in Bolivia due to the impact that political and fiscal uncertainty in Bolivia could have on the viability of a GTL plant. For the three-month period ended June 30, 2004, GTL investments of $0.3 million were written down as the opportunity to build a 45,000 bpd GTL fuels plant in Oman failed to materialize due to a lack of sufficient uncommitted gas volumes to support a plant of that size.

Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents decreased for the three-month period ended June 30, 2005 by $5.6 million compared to $3.3 million for the same period in 2004. Our net cash and cash equivalents decreased for the six-month period ended June 30, 2005 by $5.6 million compared to an increase of $15.9 million for the same period in 2004. The Company incurred a net loss of $2.5 million for the six-month period ended June 30, 2005, and, as at June 30, 2005 had an accumulated deficit of $84.3 million and negative working capital of $18.0 million.

Our operating activities provided $1.9 million and $2.6 million in cash for the three-month and six-month periods ended June 30, 2005, respectively, compared to $1.3 million for the same periods in 2004. The increases in cash from operating activities for the three-month and six-month periods ended June 30, 2005 are mainly due to increases in net production volumes of 41% and 40%, respectively, and increases in oil and gas prices of 35% and 30%, respectively, when compared to the same periods in 2004. The increases in net revenues for the three-month and six-month periods ended June 30, 2005 were partially offset by increases of $0.5 million and $1.7 million, respectively, in general and administrative and business development expenses compared to the same periods for 2004.

Our investing activities used $20.6 million in cash for the three-month period ended June 30, 2005 compared to providing cash of $2.1 million for the comparable period in 2004. The $22.7 million increase in the use of cash is mainly due to an increase in our capital investing and Merger activities of $9.4 million and a $13.5 million reduction in proceeds from the sale of assets associated with the farm-out of a 40% interest in our Dagang field in June 2004. For the six-month period ended June 30, 2005, our investing activities used $26.7 million in cash compared to a use of $9.3 million for the comparable period in 2004. The $17.4 million increase in the use of cash is mainly due to an increase in our capital investing and Merger activities of $4.1 million and a $13.5 million reduction in proceeds from the sale of assets.

Our financing activities provided $13.2 million in cash for the three-month period ended June 30, 2005 compared to a use of $6.8 million of cash for the comparable period in 2004. The $20.0 million increase in cash from financing activities is mainly due to a $10.5 million increase in cash from private placements and exercises of warrants and options plus $10.6 million increase in cash from debt financing. For the six-month period ended June 30, 2005, our financing activities provided $18.5 million in cash compared to $23.8 million for the comparable period in 2004. The $5.3 million decrease in cash from financing activities is mainly due to a $10.0 million reduction in cash from private placements and exercises of warrants and options partially offset by a $5.2 million increase in cash from debt financing.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Cash flow from operating activities	$ 1,850	$ 1,299	$ 2,625	$ 1,334
Investing Activities				
Capital investments, after changes in non-cash working capital	(9,628)	(9,207)	(15,025)	(20,045)
Merger, net of cash acquired	(9,979)		(9,979)	
Equity investment and Merger related costs	(957)	(2,000)	(1,687)	(2,500)
Proceeds from sale of assets		13,458		13,458
Other	(63)	(112)	(54)	(180)