IVANHOE ENERGY INC
Form 10-Q
November 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 September 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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No þ

The number of shares of the registrant s capital stock outstanding as of September 30, 2005 was 208,563,005 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)

	September 30, 2005	December 31, 2004
Assets		
Current Assets		
Cash and cash equivalents	**$ 3,800**	$ 9,322
Notes and accounts receivable	**8,222**	5,377
Prepaid and other current assets	**248**	812
	12,270	15,511
Long term assets	**613**	6,424
Oil and gas properties and investments, net	**126,212**	96,551
Intangible asset	**89,944**	
	$ 229,039	$ 118,486
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 19,846**	$ 9,845
Note payable current portion	**1,667**	1,667
Convertible loans	**8,000**	
	29,513	11,512
Long term debt	**1,389**	2,639
Asset retirement obligations	**1,725**	749
Commitments and contingencies	**1,900**	
Shareholders Equity		
Share capital, issued 208,563,005 common shares; December 31, 2004 169,664,911 common shares	**272,872**	183,617
Purchase Warrants	**2,413**	
Special Warrants	**2,492**	
Contributed surplus	**3,141**	1,748
Accumulated deficit	**(86,406)**	(81,779)

		194,512		103,586
	$	**229,039**	$	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 September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Revenue				
Oil and gas revenue	**$ 8,883**	$ 4,874	**$ 21,193**	$ 11,638
Interest income	**24**	58	**95**	147
	8,907	4,932	**21,288**	11,785
Expenses				
Operating costs	**1,731**	1,257	**5,264**	3,688
General and administrative	**2,411**	1,808	**6,328**	4,874
Business development	**1,504**	457	**3,401**	1,156
Depletion and depreciation	**4,476**	2,290	**9,250**	5,239
Interest expense	**541**	71	**1,036**	119
Write down of GTL and EOR investments	**357**		**636**	250
	11,020	5,883	**25,915**	15,326
Net Loss	**2,113**	951	**4,627**	3,541
Accumulated Deficit, beginning of period	**84,293**	63,644	**81,779**	61,054
Accumulated Deficit, end of period	**$ 86,406**	$ 64,595	**$ 86,406**	$ 64,595
Net Loss per share Basic and Diluted	**$ 0.01**	$ 0.01	**$ 0.02**	$ 0.02
Weighted Average Number of Shares (in thousands)	**206,629**	169,534	**191,374**	166,935

(See accompanying notes)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	**2005**	2004
Operating Activities				
Net loss	**$ (2,113)**	$ (951)	**$ (4,627)**	$ (3,541)
Items not requiring use of cash				
Depletion and depreciation	**4,476**	2,290	**9,250**	5,239
Write down of GTL and EOR investments	**357**		**636**	250
Stock based compensation	**594**	430	**1,424**	911
Write off of debt financing costs	**857**		**857**	
Changes in non-cash working capital items	**(1,671)**	(1,969)	**(2,415)**	(1,725)
	2,500	(200)	**5,125**	1,134
Investing Activities				
Capital investments	**(9,769)**	(8,497)	**(34,106)**	(33,673)
Merger, net of working capital	**(117)**		**(10,096)**	
Equity investment and Merger related costs		(653)	**(1,687)**	(3,153)
Proceeds from sale of assets				13,458
Other	**(6)**	108	**(60)**	(72)
Changes in non-cash working capital items	**1,064**	(4,559)	**10,376**	572
	(8,828)	(13,601)	**(35,573)**	(22,868)
Financing Activities				
Proceeds from private placements, net of share issue costs	**2,399**		**12,552**	20,428
Proceeds from exercise of options and warrants	**4,504**	289	**6,229**	1,664
Share issue costs on shares issued for Merger			**(93)**	
Proceeds from debt obligations		2,000	**8,000**	14,000
Repayments of debt obligations	**(417)**	(278)	**(1,250)**	(10,278)
Other	**(86)**		**(512)**	
	6,400	2,011	**24,926**	25,814
Increase (decrease) in cash and cash equivalents, for the period	**72**	(11,790)	**(5,522)**	4,080
Cash and cash equivalents, beginning of period	**3,728**	30,361	**9,322**	14,491
Cash and cash equivalents, end of period	**$ 3,800**	$ 18,571	**$ 3,800**	$ 18,571

Supplementary Information Regarding Non-Cash Transactions				
Financing activities, non-cash:				
Shares issued for Merger	**$**	$	**$ (75,000)**	$
Included in the above are the following:				
Taxes paid	**$ 13**	$	**$ 17**	$ 3
Interest paid	**$ 107**	$ 52	**$ 372**	$ 80
Changes in non-cash working capital items				
Operating Activities:				
Notes and accounts receivable	**$ (2,830)**	$ (849)	**$ (3,144)**	$ (1,705)
Prepaid and other current assets	**101**	40	**56**	71
Accounts payable and accrued liabilities	**1,058**	(1,160)	**673**	(91)
	(1,671)	(1,969)	**(2,415)**	(1,725)
Investing Activities				
Notes and accounts receivable	**504**	655	**99**	(498)
Prepaid and other current assets	**158**		**508**	
Accounts payable and accrued liabilities	**402**	(5,214)	**9,769**	1,070
	1,064	(4,559)	**10,376**	572
	$ (607)	$ (6,528)	**$ 7,961**	$ (1,153)

(See accompanying notes)

Notes to the Condensed Consolidated Financial Statements
September 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 16. The unaudited condensed consolidated financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 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 nine-month periods ended September 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 $4.6 million for the nine-month period ended September 30, 2005, and, as at September 30, 2005, had an accumulated deficit of $86.4 million and negative working capital of $17.2 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 continuing 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 12, 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 heavy oil upgrading rapid thermal processing (**RTP™**) commercial demonstration facility (**RTP™ CDF**) located in California s San Joaquin Basin as well as certain rights to manufacture RTP™ facilities (See Note 13). 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 (**RTP™ Technology**) for petroleum applications. The Company will assign the carrying value of the RTP™ Technology to the number of RTP™ facilities it expects to develop that will use the RTP™ Technology. The amount of the carrying value of the RTP Technology assigned to each RTP™ facility will be amortized to earnings on a basis related to the operations of the RTP™ facility from the date on which the facility is placed into service. The carrying value of the RTP Technology is 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 RTP™ 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 project s 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 RTP™ 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 RTP™ 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 geographic locations and business segments are as follows:

	As at September 30, 2005				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 85,207	$ 61,543	$	$	$ 146,750
Unproved	22,962	8,924			31,886
	108,169	70,467			178,636
Accumulated depletion	(14,666)	(12,117)			(26,783)
Accumulated provision for impairment	(50,350)				(50,350)
	43,153	58,350			101,503
GTL and EOR Investments:					
GTL master license			10,000		10,000
Commercial demonstration facility				4,668	4,668
Feasibility studies and other deferred costs			4,491	5,365	9,856
			14,491	10,033	24,524
Furniture and equipment	475	95		15	585
Accumulated depreciation	(362)	(33)		(5)	(400)
	113	62		10	185
	$ 43,266	$ 58,412	$ 14,491	$ 10,043	$ 126,212

	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

Costs as at September 30, 2005 and December 31, 2004 of $31.9 million and $31.0 million, respectively, related to unproved oil and gas properties were separately assessed for impairment and excluded from the depletion and ceiling test calculations.

For the three-month and nine-month periods ended September 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 $3.1 million, respectively, were capitalized. For the same periods ended September 30, 2004, $0.7 million and $2.3 million, respectively, were capitalized.

As at September 30, 2005, the GTL and EOR Investments include $4.7 million of costs associated with the RTP™ CDF acquired in the Merger including $0.1 million in improvements made to the facility. 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 13).

For the nine-month period ended September 30, 2005, the Company wrote down $0.3 million related to its GTL project in Bolivia and, in the three-month period ended September 30, 2005, $0.3 million related to its MOU with Ecopetrol S.A. (**Ecopetrol**) for the Llanos Heavy Basin Crude Project . The Company wrote down its investment in 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 and its investment in the MOU with Ecopetrol as the Company did not meet the company-size requirements specified by Ecopetrol in their final bidding qualifications for the Llanos Basin Heavy Crude Project , which included the Castilla and Chichimene field developments. For the nine-month period ended September 30, 2004, GTL investments of $0.3 million were written down related to a study for a GTL fuels plant in Oman 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 $3.0 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 September 30, 2005. An additional $1.5 million of Merger related costs were incurred in 2005. The $4.0 million of Merger related costs were allocated among the net assets acquired in the Merger (See Note 12).

As at December 31, 2004, long term assets includes $0.4 million of deferred costs to obtain debt financing for the Company s Dagang development project in China. The Company incurred an additional $0.5 million of such costs during the nine-month period ended September 30, 2005. As the Company is presently assessing current production levels and future drilling activity in this project, the Company has suspended current project-financing discussions with potential lending institutions and has written off the $0.9 million of deferred financing costs in the three month-period ended September 30, 2005.

As at September 30, 2005 and December 31, 2004, long term assets consisted of the following:

	September 30, 2005	December 31, 2004
Investment in EPIL	$	$ 3,000
Merger related costs		2,513
Drilling deposits	400	400
Deferred debt financing costs	27	384
Other long term deposits and assets	186	127
	$ 613	$ 6,424

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 the exclusive right to deploy RTP™ Technology in all applications other than bio-mass (See Note 12). This intangible

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asset is not currently being amortized and its carrying value was not impaired for the three-month and nine-month periods ended September 30, 2005.

6. SEGMENT INFORMATION

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

	Three-Month Period Ended September 30, 2005					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 4,336	$ 4,547	$	$	$	$ 8,883
Interest income	8	3			13	24
	4,344	4,550			13	8,907
Operating costs	1,180	551				1,731
General and administrative	210	1,050			1,151	2,411
Business development			296	1,208		1,504
Depletion and depreciation	1,286	3,185	3	1	1	4,476
Interest expense	79			2	460	541
Write down of GTL and EOR investments				357		357
	2,755	4,786	299	1,568	1,612	11,020
Net (Income) Loss	$ (1,589)	$ 236	$ 299	$ 1,568	$ 1,599	$ 2,113
Capital Investments	$ 2,770	$ 5,860	$ 246	$ 893	$	$ 9,769

	Nine-Month Period Ended September 30, 2005					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 10,500	$ 10,693	$	$	$	$ 21,193
Interest income	18	6			71	95
	10,518	10,699			71	21,288
Operating costs	3,448	1,816				5,264
General and administrative	624	1,412			4,292	6,328
Business development			1,019	2,382		3,401
Depletion and depreciation	3,768	5,457	8	12	5	9,250
Interest expense	233			2	801	1,036
			279	357		636

Write down of GTL and EOR investments						
	8,073	8,685	1,306	2,753	5,098	25,915
Net (Income) Loss	$ (2,445)	$ (2,014)	$ 1,306	$ 2,753	$ 5,027	$ 4,627
Capital Investments	$ 5,282	$ 24,111	$ 977	$ 3,736	$	$ 34,106
Identifiable Assets (As at September 30, 2005)	$ 47,564	$ 64,612	$ 14,533	$ 100,080	$ 2,250	$ 229,039
Identifiable Assets (As at December 31, 2004)	$ 49,465	$ 44,960	$ 13,867	$ 2,441	$ 7,753	$ 118,486

	Three-Month Period Ended September 30, 2004					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 2,628	$ 2,246	$	$	$	$ 4,874
Interest income	4	6			48	58
	2,632	2,252			48	4,932
Operating costs	863	394				1,257
General and administrative	163	182			1,463	1,808
Business development			315	142		457
Depletion and depreciation	1,600	683	3	2	2	2,290
Interest expense	70				1	71
	2,696	1,259	318	144	1,466	5,883
Net (Income) Loss	$ 64	$ (993)	$ 318	$ 144	$ 1,418	$ 951
Capital Investments	$ 3,508	$ 4,480	$	$ 509	$	$ 8,497

	Nine-Month Period Ended September 30, 2004					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 6,428	$ 5,210	$	$	$	$ 11,638
Interest income	7	12			128	147
	6,435	5,222			128	11,785
Operating costs	2,294	1,394				3,688
General and administrative	572	613			3,689	4,874
Business development			1,014	142		1,156
Depletion and depreciation	3,459	1,760	14	2	4	5,239
Interest expense	115				4	119
Write down of GTL and EOR investments			250			250
	6,440	3,767	1,278	144	3,697	15,326
Net (Income) Loss	$ 5	$ (1,455)	$ 1,278	$ 144	$ 3,569	$ 3,541
Capital Investments	$ 13,351	$ 18,632	$ 66	$ 1,624	$	$ 33,673

7. SHARE CAPITAL

Following is a summary of the changes in share capital, contributed surplus and stock options outstanding for the nine-month period ended September 30, 2005:

	Common Shares			Stock Options	
	Number (thousands)	Amount	Contributed Surplus	Number (thousands)	Weighted Avg. Exercise Price Cdn.$
Balance December 31, 2004	169,665	$ 183,617	$ 1,748	8,246	$ 2.65
Shares issued for:					
Merger, net of share issue costs	30,000	74,907			
Private placements, net of share issue costs	4,100	7,647			
Exercise of purchase warrants	4,515	6,133			
Services	192	441			
Exercise of options	91	127	(31)	(91)	$ 1.50
Options:					
Granted				3,114	$ 2.95
Expired				(1,417)	$ 6.15
Stock based compensation			1,424		
Balance September 30, 2005	208,563	$ 272,872	$ 3,141	9,852	$ 2.25

Private Placements

In April and July 2005, the Company closed two special warrant financings by way of private placements for Cdn.$15.8 million (U.S.$12.6 million, net of U.S.$0.2 million in share issue costs). Proceeds from the financings were used to complete the Merger and 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 financings consisted of 5,100,000 special warrants at Cdn.$3.10 per special warrant. The April 2005 special warrant financing for 4,100,000 special warrants entitled the holders to receive, for each special warrant and at no additional cost, one common share and one common share purchase warrant which were issued on July 4, 2005. The July 2005 special warrant financing for 1,000,000 special warrants entitles the holder to receive, for each special warrant and at no additional cost, one common share and one common share purchase warrant four months after the closing date. Each common share purchase warrant entitles the holder to purchase one common share at a price of Cdn.$3.50 until the second anniversary date of the closings.

Warrants

Purchase warrants as at September 30, 2005 were $2.4 million for the value of the 4,100,000 common share purchase warrants outstanding, associated with the April 2005 private placement. This value was calculated in accordance with the Black-Scholes pricing model using a risk-free interest rate of 2.6%, a dividend yield of 0.0%, a volatility factor of 60.1% and an expected life of 2 years.

Special warrants as at September 30, 2005 were $2.5 million for the July 2005 special warrant financing for which common shares had not been issued as at September 30, 2005. The common shares and common share purchase warrants for the July 2005 financing will be issued on November 8, 2005.

For the nine-month period ended September 30, 2005, 9,029,412 common share purchase warrants were exercised for the purchase of 4,514,706 common shares at an average exercise price of $1.36 (Cdn.$1.64) for a total of $6.1 million.

As at September 30, 2005, the following common share 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	Number of Common Shares	Expiry Date	Exercise Price per Share
			(thousands)			
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
		12,523	12,523	8,937		

8. 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 nine-month periods ended September 30, 2005, the Company incurred $0.6 million and $1.4 million, respectively, in stock based compensation costs. For the same periods ended September 30, 2004, the Company incurred $0.4 million and $0.9 million, respectively.

9. 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 September 30, 2005 and December 31, 2004, was $3.1 million and $4.3 million, respectively, with a six-month fixed LIBOR rate of 7.375% per annum effective October 13, 2005.

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

2005	$ 417
2006	1,667
2007	972
	3,056
Less: current portion	1,667
	$ 1,389

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.

10. 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. Accrued and unpaid interest as at September 30, 2005 was $0.3 million. The loans, originally due on August 23, 2005, were extended for up to three months and are currently due upon the earliest of i.) five days following receipt of proceeds from a private placement or public offering of Company common shares ii.) thirty days following written demand for repayment from lender or iii.) November 23, 2005. A 3% extension fee of approximately $0.3 million is payable on the unpaid principal and interest at maturity and has been accrued as at September 30, 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. However, if the Company completes a private placement or public offering of Company common shares during the term of the loans at a price per share that is less than either of the loans conversion rates of $2.25 per share and $2.15 per share and the lender elects to convert the loans, in whole or in part, to the Company s common shares then the Company will, at its election, either i.) convert the loans to the Company s common shares at a conversion rate equal to the share price obtained from a private placement or public offering of Company common shares or ii.) pay the lender, in cash, the difference between the loans conversion rates and the share price obtained from a private placement or public offering of Company common shares times the number of the Company s common shares to be issued to the lender based on the lender s election.

The fair value of the convertible loans approximates their carrying values due to the short-term maturity. No value was assigned to the equity component of the loans.

11. ASSET RETIREMENT OBLIGATIONS

The undiscounted amount of expected cash flows required to settle the Company s asset retirement obligations as at September 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.

12. 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 in the event of any breaches of representations, warranties and covenants in the Merger Agreement and certain liabilities, including those arising from any failure by Ensyn to meet certain development milestones set out in the Merger Agreement.

As at September 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 *(Note 13)*	(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.

The Company s consolidated results of operations for the three-month and nine-month periods ended September 30, 2005 included a net loss of $0.7 million, or nil per share and $1.3 million, or $0.01 per share, respectively, 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 nine-month periods ended September 30, 2005 and 2004 would have been as follows:

	Three-Month Periods Ended September 30,					
	2005			**2004**		
	Revenue	**Net Loss**	**Net Loss Per Share**	**Revenue**	**Net Loss**	**Net Loss Per Share**
As reported	$ 8,907	$ 2,113	$ 0.01	$ 4,932	$ 951	$ 0.01
Pro forma adjustments				90	635	
	$ 8,907	$ 2,113	$ 0.01	$ 5,022	$ 1,586	$ 0.01

Weighted Average Number of Shares (in thousands)	206,629	199,534

	Nine-Month Periods Ended September 30,					
	2005			2004		
	Revenue	Net Loss	Net Loss Per Share	Revenue	Net Loss	Net Loss Per Share
As reported	$ 21,288	$ 4,627	$ 0.02	$ 11,785	$ 3,541	$ 0.02
Pro forma adjustments	736	730		264	1,240	
	$ 22,024	$ 5,357	$ 0.02	$ 12,049	$ 4,781	$ 0.02
Weighted Average Number of Shares (in thousands)			202,583			196,935

13. 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 sale 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 nine-month periods ended September 30, 2005. The Company has included its 50% interest in the RTP™ CDF in its balance sheet as at September 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.

14. COMMITMENTS AND CONTINGENCIES

Zitong Exploration Commitment

With the signing of the production-sharing contract for the Zitong block, the Company is obligated to conduct a minimum exploration program during the first three years ending December 1, 2005 (**Phase 1**). The Phase 1 work program includes acquiring approximately 300 miles of new seismic lines, reprocessing approximately 1,250 miles of existing seismic and drilling a minimum of approximately 23,000 feet. The Company has completed Phase 1 with the exception of drilling approximately 13,800 feet. On October 20, 2005, the Company requested an extension of Phase 1 to assess its election to proceed into the next three-year exploration phase (**Phase 2**) as further review and mapping of the Company s seismic data is necessary. In addition, the Company is in active discussion with two potential partners who have indicated an interest in participating in the Zitong block exploration program. The Company expects to receive the extension by the end of 2005 and is planning to drill a second Phase 1 exploration well with its partner(s) upon receipt of such extension after which an election would be made as to its decision to enter into Phase 2. If an extension were not granted, the Company could elect not to enter Phase 2 and would be required to pay China National Petroleum Corporation (**CNPC**), within 30 days after its election, a cash equivalent of the deficiency in the work program estimated at $4.3 million as at September 30, 2005. If the Company did not elect to enter Phase 2, the aggregate costs related to the Zitong block in the approximate amount of $13.2 million , including the $4.3 million cash requirement, would be included in the depletable base of the China full cost pool and would be subject to the ceiling test. This could result in a ceiling test impairment related to the China full cost pool in an amount which is not determinable at this time.

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 September 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.

15. SUBSEQUENT EVENTS

On November 7, 2005, the Company closed a special warrant financing by way of private placement for $15.75 million. The financing consisted of 7,208,599 special warrants issued for cash and 2,453,988 issued for the repayment of convertible loans, both at U.S.$1.63 per special warrant. Each special warrant entitles the holder to receive, at no additional cost, one common share and one common share purchase warrant. Each common share purchase warrant entitles the holder to purchase one common share at a price of U.S. $2.50 per share until the second anniversary date of the closing.

A portion of the proceeds of the financing, in the amount of $6.75 million, has been used to acquire the 50% interest in the RTP Joint Venture not already owned by the Company (see Note 13).

A further portion of the proceeds of the financing will be used to pay interest and an extension fee of approximately $ 0.7 million accrued to date on the convertible loans (See Note 10). As noted above, the Company has agreed with the holder of $8.0 million of convertible loans to convert $4.0 million of the loans into 2,453,988 common shares of the Company at U.S.$1.63 per share under the private placement. Additionally, the repayment period of the remaining $4.0 million of convertible loans has been extended until November 23, 2007 with interest payable monthly at a rate of 8% per annum. The previously granted conversion rights attached to the convertible loans will be cancelled and, subject to regulatory approval, the Company will grant the holder of the convertible loans 2,000,000 common share purchase warrants, each of which will entitle the holder to purchase one common share at a price of U.S. $2.00 per share until November 23, 2007.

The balance of the private placement proceeds of $4.3 million will be used for working capital and general corporate purposes.

16. ADDITIONAL DISCLOSURE REQUIRED UNDER U.S. GAAP

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

Condensed Consolidated Balance Sheets

Shareholders Equity and Oil and Gas Properties and Investments

	As at September 30, 2005				
	Oil and Gas Properties and Investments	Shareholders Equity: Share Capital and Warrants	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 126,212	$ 277,777	$ 3,141	$ (86,406)	$ 194,512
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	1,328			1,328	1,328
GTL and EOR development costs expensed	(9,856)			(9,856)	(9,856)
Adjustment for change in accounting for stock based compensation		(306)	(2,992)	3,298	
U.S. GAAP	$ 110,392	$ 353,284	$ 149	$ (174,741)	$ 178,692

	As at December 31, 2004				
	Oil and Gas Properties and Investments	Shareholders Equity: Share Capital	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 96,551	$ 183,617	$ 1,748	$ (81,779)	$ 103,586
Adjustment for reduction in stated capital		74,455		(74,455)	
Adjustment to ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358			1,358
Provision for impairment	(8,650)			(8,650)	(8,650)
	482			482	482

Depletion adjustments due to differences in provision for impairment					
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

Shareholders Equity

In June 1999, the shareholders approved a reduction of stated capital in respect of the common shares by an amount of $74.4 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the accumulated deficit such as this is not recognized except in the case of a quasi reorganization. The effect of this is that under U.S. GAAP, share capital and accumulated deficit are increased by $74.4 million as at September 30, 2005 and December 31, 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. This resulted in a reduction of $3.3 million and $2.0 million in the accumulated deficit as at September 30, 2005 and December 31, 2004, respectively, equal to accumulated stock based compensation for stock options granted to employees and directors since January 1, 2002 expensed under Canadian GAAP.

Oil and Gas Properties and Investments

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

As more fully described in our financial statements in Item 8 of our 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 September 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 $1.3 million and $0.5 million as at September 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 an MOU 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 a 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 September 30, 2005 and December 31, 2004, the Company capitalized $9.9 million and $5.9 million, respectively, for Canadian GAAP, which was expensed for U.S. GAAP purposes.

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 September 30, 2005		2004	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ 2,113	$ 0.01	$ 951	$ 0.01
Stock based compensation expense	(540)		(416)	
Depletion adjustments due to differences in provision for impairment	(418)		(64)	
GTL and EOR development costs expensed, net	688		509	
U.S. GAAP	$ 1,843	$ 0.01	$ 980	$ 0.01
Weighted Average Number of Shares under U.S. GAAP (in thousands)		206,629		169,534

	Nine-Month Periods Ended September 30, 2005		2004	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ 4,627	$ 0.02	$ 3,541	$ 0.02
Stock based compensation expense	(1,338)	(0.01)	(877)	
Depletion adjustments due to differences in provision for impairment	(846)		(144)	
GTL and EOR development costs expensed, net	3,972	0.02	1,440	
U.S. GAAP	$ 6,415	$ 0.03	$ 3,960	$ 0.02
Weighted Average Number of Shares under U.S. GAAP (in thousands)		191,374		166,935

As discussed under Shareholders Equity in this note, 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. This resulted in a reduction of $0.5 and $1.3 million in the net losses for the three-month and nine-month periods ended September 30, 2005, respectively, and a reduction of $0.4 million and $0.9 million in the net losses for the three-month and nine-month periods ended September 30, 2004, respectively.

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 September 30, 2005 and December 31, 2004. The net increase in impairment provisions resulted in lower depletion rates for U.S. GAAP purposes, a reduction of $0.4 million and $0.8 million in the net losses for the three-month and nine-month periods ended September 30, 2005, respectively, and a reduction of $0.1 million each in the net losses for the three-month and nine-month periods ended September 30, 2004.

As described under Oil and Gas Properties and Investments in this note, for Canadian GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are capitalized and are subsequently written down upon determination that a project s future value has been impaired. For U.S. GAAP, such costs are considered to be research and development and are expensed as incurred. For the three-month and nine-month periods ended September 30, 2005, the Company expensed $0.7 million and $4.0 million, respectively, of GTL and EOR development costs for U.S. GAAP purposes and $0.5 million and $1.4 million for the three-month and nine-month periods ended September 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 September 30, 2005	2004	Nine-Month Periods Ended September 30, 2005	2004
Net loss under U.S. GAAP	$ 1,843	$ 980	$ 6,415	$ 3,960
Stock-based compensation expense determined under the fair value based method for employee and director awards	570	507	1,430	1,499
Pro forma net loss under U.S. GAAP	$ 2,413	$ 1,487	$ 7,845	$ 5,459
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	$ 0.04	$ 0.03
Weighted Average Number of Shares under U.S. GAAP (in thousands)	206,629	169,534	191,374	166,935

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 and nine-month periods ended September 30, 2005 included a net loss of $0.7 million, or nil per share and a net loss of $1.3 million, or $0.01 per share, respectively, 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 nine-month periods ended September 30, 2005 and 2004 would have been as follows:

	Three-Month Periods Ended September 30, 2005 Revenue	Net Loss	Net Loss Per Share	2004 Revenue	Net Loss	Net Loss Per Share
As reported	$ 8,907	$ 1,843	$ 0.01	$ 4,932	$ 980	$ 0.01
Pro forma adjustments				90	635	
	$ 8,907	$ 1,843	$ 0.01	$ 5,022	$ 1,615	$ 0.01
Weighted Average Number of Shares (in thousands)			206,629			199,534

Nine-Month Periods Ended September 30,

2005 **2004**

	Revenue	Net Loss	Net Loss Per Share	Revenue	Net Loss	Net Loss Per Share
As reported	$ 21,288	$ 6,415	$ 0.03	$ 11,785	$ 3,960	$ 0.02
Pro forma adjustments	736	730		264	1,240	
	$ 22,024	$ 7,145	$ 0.03	$ 12,049	$ 5,200	$ 0.02
Weighted Average Number of Shares (in thousands)			202,583			196,935

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 would result in cash provided by operating activities of $1.4 million and $0.5 million for the three-month and nine-month periods ended September 30, 2005, respectively and cash deficiency from operating activities of $0.7 million and $0.5 million for the three-month and nine-month periods ended September 30, 2004, respectively. Additionally, capital investments reported under investing activities would be $8.7 million and $29.5 million for the three-month and nine-month periods ended September 30, 2005, respectively, and $7.8 million and $32.0 million for the three-month and nine-month periods ended September 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.

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 for 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. SFAS 154 also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS 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 16. The date of this discussion is November 7, 2005.

Executive Overview of 2005 Results

Despite significant increases in our revenues for the third quarter and for the first three quarters of 2005, we continue to generate net losses both in the current quarter and year to date, 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 nine-month periods ended September 30, 2005 compared to the same periods for 2004 due to increases in oil and gas prices and increased production volumes from our field development programs at Dagang, South Midway, Citrus and Knights Landing.

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

(stated in thousands of U.S. dollars, except per share and production amounts)	Three-Month Periods Ended September 30, 2005	2004	Nine-Month Periods Ended September 30, 2005	2004
Oil and gas revenue	8,883	4,874	21,193	11,638
Net loss	2,113	951	4,627	3,541
Net loss per share	0.01	0.01	0.02	0.02
Average production (Boe/d)	1,902	1,466	1,741	1,277
Capital investments	9,769	8,497	34,106	33,673
Cash flow from (used in) operating activities	2,500	(200)	5,125	1,134

Financial Results Change in Net Losses

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

(stated in thousands of U.S. Dollars)	Three-Months Ended September 30,	Nine-Months Ended September 30,
Net Losses for 2004	$ 951	$ 3,541
Favorable (unfavorable) variances:		
Cash Items:		
Net Operating Revenues:		
Production volumes	1,217	3,763
Oil and gas prices	2,792	5,792
Less: Operating costs	(474)	(1,576)
	3,535	7,979
General and administrative	(530)	(1,081)
Business development	(956)	(2,105)
Net interest	(504)	(969)
Total Cash Variances	1,545	3,824
Non-Cash Items:		
Depletion and depreciation	(2,186)	(4,011)
Stock based compensation	(164)	(513)
Write down of GTL and EOR investments	(357)	(386)
Total Non-Cash Variances	(2,707)	(4,910)

Net Losses for 2005	$	2,113	$	4,627

Our net loss for the three-month period ended September 30, 2005 was $2.1 million ($0.01 per share) compared to a net loss for the same period in 2004 of $1.0 million ($0.01 per share). The $1.1 million increase in our net loss for the third quarter of 2005 was mainly due to a $0.7 million increase in general and administrative expenses, including stock based compensation, an increase of $0.9 million in business development expense, an increase of $0.5 million in net interest expense, an increase of $2.2 in depletion and depreciation and $0.3 million for the write down of GTL and EOR investments. This is partially offset by a $3.5 million increase in net operating revenues.

Our net loss for the nine-month period ended September 30, 2005 was $4.6 million ($0.02 per share) compared to a net loss for the same period in 2004 of $3.5 million ($0.02 per share). The increase in our net loss from 2004 to 2005 of $1.1 million was mainly due to a $2.1 million increase in business development expense, an increase of $1.6 million in general and administrative, including stock based compensation, an increase of $1.0 million in net interest expense, an increase of $4.0 million in depletion and depreciation and $0.4 million for the write down of GTL and EOR investments. This is partially offset by an $8.0 million increase in net operating revenues.

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 nine-month periods ended September 30, 2005 increased 30% and 36%, respectively, when compared to the same periods in 2004. The increase for the three-month period ended September 30, 2005 was due to 39% and 21% increases in production volumes in our China and U.S. properties, respectively, resulting in increased revenues of $1.2 million. The increase for the nine-month period ended September 30, 2005 was due to 42% and 30% increases in production volumes in our China and U.S. properties, respectively, resulting in increased revenues of $3.8 million.

China

Net production volumes for the three-month and nine-month periods ended September 30, 2005 at the Dagang field increased 61% and 59%, respectively, when compared to the same periods in 2004 despite the farm-out of a 40% working interest in June 2004. During the nine-month period ended September 30, 2005, we placed 20 wells on production bringing the total wells on production, or available for production, to 41 wells. We stimulated 9 wells in the northern blocks during the nine-month period ended September 30, 2005, where we had been experiencing less than expected results. Five of the stimulated wells currently have production rates of between 60 and 160 Bopd while 3 of the other 4 wells are in post-stimulation clean up and stabilized production will not be known until the fourth quarter 2005. The fourth well is expected to be re-stimulated in the fourth quarter of 2005 and we expect to stimulate an additional 2 to 3 wells during the remainder of 2005. At the end of September 30, 2005, there were 3 producing wells down for maintenance and one well was awaiting stimulation. As at September 30, 2005, we were producing 2,025 Bopd (950 net Bopd), a 22% increase from the year-end 2004 exit rate of 1,655 Bopd (774 net Bopd).

Our royalty percentage from the Daqing project was reduced from 4% to 2% in May 2005 when the operator of the properties reached payout of its investment. As a result, our share of production volumes decreased 50% and 21% for the three-month and nine-month periods ended September 30, 2005, respectively, when compared to the same periods in 2004.

U.S.

Net production volumes for the three-month and nine-month periods ended September 30, 2005 in the U.S. increased 21% and 30%, respectively, when compared to the same periods in 2004. The increase in U.S. production rates for the three-month and nine-month periods were due mainly to increased production at our Knights Landing gas field in northern California. We farmed into Knights Landing 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 September 30, 2005, we were producing 185 gross Boe/d (110 net Boe/d) at Knights Landing. Our production at Citrus for the nine-month period ended September 30, 2005 was up 62% compared to the same period in 2004 as two of the three Citrus wells were not placed on production until early in the third quarter of 2004. For the three-month period ended September 30, 2005, production at Citrus was down 21% compared to the same period in 2004 due to natural decline in the wells. As at September 30, 2005, we were producing 100 gross Boe/d (85 Boe/d net) at Citrus. Our production at South Midway increased 9% for the nine-month period ended September 30, 2005 compared to the same period in 2004 as a result of our continuous steam injection program in the southern expansion of South Midway. Additionally, in the second quarter of 2005 we drilled one in-fill well in the southern expansion, which contributed to the increase in production. For the three-month period ended September 30, 2005, production levels at South Midway decreased 4% compared to the same period in 2004 primarily due to wells taken off production in the primary area for cyclic steaming operations. As at

September 30, 2005, we were producing 610 gross Boe/d (570 net Boe/d) at South Midway. The decrease in production volumes in other U.S. properties for the three-month and nine-month periods ended September 30, 2005 compared to the same periods in 2004 were primarily due to the natural decline in production rates from our Spraberry field in west Texas and as a result of the sale of our interest in the Sledge Hamar property in the fourth quarter of 2004.

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

	Three-Month Periods Ended September 30, Average Net Boe s			**Nine-Month Periods Ended September 30, Average Net Boe s**		
	2005	**2004**	**Percentage Change**	**2005**	**2004**	**Percentage Change**
China:						
Dagang	80,799	50,067	61%	199,320	125,405	59%
Daqing	6,087	12,222	-50%	25,935	32,748	-21%
	86,886	62,289	39%	225,255	158,153	42%
U.S.:						
South Midway	46,994	48,869	-4%	148,314	136,167	9%
Citrus	8,463	10,710	-21%	26,807	16,580	62%
Knights Landing	24,559	4,145	493%	52,482	8,045	552%
Others	8,102	8,903	-9%	22,376	31,049	-28%
	88,118	72,627	21%	249,979	191,841	30%
	175,004	134,916	30%	475,234	349,994	36%

Oil and Gas Prices 2005 vs. 2004

Oil and gas prices increased 41% and 34% per Boe generating $2.8 million and $5.8 million in additional revenue for the three-month and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004.

China

We realized an average of $52.33 and $47.47 per Boe from our operations in China for the three-month and nine-month periods ended September 30, 2005, respectively, an increase of $16.28 and $14.53 per Boe which accounts for $1.4 million and $3.4 million of our increase in revenues from price increases for the three-month and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004.

U.S.

From the U.S. operations, we realized an average of $49.21 and $42.00 per Boe for the three-month and nine-month periods ended September 30, 2005, respectively, an increase of $13.02 and $8.49 which accounts for $1.4 million and $2.4 million of our increased revenues for the three-month and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004.

Operating Costs 2005 vs. 2004

For the three-month and nine-month periods ended September 30, 2005, operating costs, including production taxes and engineering support, increased $0.5 million and $1.6 million, respectively, in absolute terms from the same periods in 2004 or $0.57 and $0.54, respectively, on a per Boe basis.

China

Operating costs in China, including engineering support, were basically the same on a Boe basis for the three-month periods ended September 30, 2005 and 2004 and decreased 9% or $0.76 per Boe for the nine-month period ended September 30, 2005, when compared to the same period in 2004. For the three-month period ended September 30, 2005, the increase in field operating costs were offset by a decrease in engineering support due to increased production from the Dagang field in relation to the level of engineering support required to operate the field. For the nine-month period ended September 30, 2005, field operating costs increased $0.76/boe due to higher power costs, permanent land fees on producing wells and increased treatment and processing costs due to higher water production rates partially offset by a reduction of well workover and maintenance costs. Additionally, engineering support decreased $1.52/Boe resulting from an increase in production from the Dagang field in relation to the level of engineering support required to operate the field.

U.S.

Operating costs in the U.S., including engineering support and production taxes, increased 13% or $1.51 and 15% or $1.84 per Boe for the three-month and nine-month periods ended September 30, 2005, respectively, when compared to the same periods in 2004. Field operating costs increased $1.15 and $1.65 per Boe, for the three-month and nine-month periods ended September 30, 2005, respectively, due mainly to an increase in fuel costs incurred for the increased level of cyclic and continuous steam operations at South Midway and workovers at Knights Landing. Engineering support increased $0.61 and $0.68 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 were down $0.25 and $0.49 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 September 30,					
	2005			**2004**		
	U.S.	**China**	**Total**	**U.S.**	**China**	**Total**
Net Production:						
Boe	88,118	86,886	175,004	72,627	62,289	134,916
Boe/day for the period	958	944	1,902	789	677	1,466
		Per Boe			Per Boe	
Oil and gas revenue	$ 49.21	$ 52.33	$ 50.76	$ 36.19	$ 36.05	$ 36.13
Field operating costs	9.85	5.82	7.85	8.70	4.96	6.98
Production taxes	0.70		0.35	0.95		0.51
Engineering support	2.84	0.52	1.69	2.23	1.36	1.83
	13.39	6.34	9.89	11.88	6.32	9.32
Net revenue before depletion	35.82	45.99	40.87	24.31	29.73	26.81
Depletion	14.38	36.63	25.43	21.58	10.99	16.69
Net Revenue from operations	$ 21.44	$ 9.36	$ 15.44	$ 2.73	$ 18.74	$ 10.12

	Nine-Month Periods Ended September 30,					
		2005			2004	
	U.S.	China	Total	U.S.	China	Total
Net Production:						
Boe	249,979	225,255	475,234	191,841	158,153	349,994
Boe/day for the period	916	825	1,741	700	577	1,277
		Per Boe			Per Boe	
Oil and gas revenue	$ 42.00	$ 47.47	$ 44.59	$ 33.51	$ 32.94	$ 33.25
Field operating costs	10.23	7.13	8.76	8.58	6.37	7.58
Production taxes	0.58		0.31	1.07		0.59
Engineering support	2.98	0.93	2.01	2.30	2.45	2.37
	13.79	8.06	11.08	11.95	8.82	10.54
Net revenue before depletion	28.21	39.41	33.51	21.56	24.12	22.71
Depletion	14.84	24.21	19.28	17.56	11.12	14.66
Net revenue from operations	$ 13.37	$ 15.20	$ 14.23	$ 4.00	$ 13.00	$ 8.05

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 nine-month periods ended September 30, 2005 when compared to the same periods for 2004 were as follows:

(stated in thousands of U.S. Dollars)	Three-Months Ended September 30,	Nine-Months Ended September 30,
General and Administrative for 2004	$ 1,808	$ 4,874
Favorable (unfavorable) variances:		
Oil and Gas Activities:		
China	(868)	(799)
U.S.	(47)	(52)
Corporate	312	(603)
	(603)	(1,454)
General and Administrative for 2005	$ 2,411	$ 6,328

General and administrative costs increased $0.6 million for the three-month period ended September 30, 2005 compared to the same period in 2004 due mainly to the write off of $0.9 million of deferred costs associated with project financing discussions with European and Chinese lending banks to provide funding for our Dagang development project which we suspended as a result of our decision to temporarily suspend the development of this field. This is partially offset by a $0.3 million reduction in professional fees to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002 as we enter our second year of compliance including a reduction in insurance costs for directors and officers liability.

General and administrative costs increased $1.5 million for the nine-month period ended September 30, 2005 compared to the same period in 2004 due mainly to the write off of $0.9 million of deferred costs associated with project financing discussions for our Dagang development project and $0.6 million in professional fees incurred in the first half of 2005 to complete our first year of compliance 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 nine-month periods ended September 30, 2005 when compared to the same periods for 2004 were as follows:

(stated in thousands of U.S. Dollars)	Three-Months Ended September 30,	Nine-Months Ended September 30,
Business Development for 2004	$ 457	$ 1,156
Favorable (unfavorable) variances:		
GTL	19	(5)
EOR	(1,066)	(2,240)
	(1,047)	(2,245)
Business Development for 2005	$ 1,504	$ 3,401

Business development expense increased by $1.0 million and $2.2 million for the three-month and nine-month periods ended September 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 primarily related to EOR activities. 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 $0.5 million and $0.9 to the increases in business development for the three-month and nine-month periods ended September 30, 2005.

Depletion and Depreciation 2005 vs. 2004

Depletion and depreciation increased $2.2 million and $4.0 million for the three-month and nine-month periods ended September 30, 2005, respectively, when compared to the same periods for 2004 primarily due to an increase in depletion rates of $8.74 and $4.62 per Boe resulting in additional depletion expense of $1.6 million and $2.2 million for the three-month and nine-month periods ended September 30, 2005, respectively. Additionally, higher production rates resulted in increases in depletion of $0.6 million and $1.8 million for the three-month and nine-month periods ended September 30, 2005, respectively, compared to the same periods in 2004.

China

In China, the $25.64 and $13.09 per Boe increases in depletion rates for the three-month and nine-month periods ended September 30, 2005, respectively, were due mainly to three factors:

As noted in our periodic report on Form 10-Q for the quarterly period ended June 30, 2005 and in related shareholder communications, as a result of the work completed in the northern blocks of the Dagang project, we stated that we were assessing our drilling program for the Dagang field, were anticipating a reduction in wells drilled in the northern blocks of the field and would be reducing our internally estimated proved reserves. In order that we may assess production decline performance of recently drilled wells, as well as maximizing cash flow from these operations, we have temporarily suspended new drilling activity. As a result, we have reduced our estimate of the overall development program and revised our internal estimate of total proved reserves downward accordingly.

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

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.

U.S.

Depletion rates in the U.S. decreased $7.20 and $2.72 per Boe for the three-month and nine-month periods ended September 30, 2005, respectively, compared to the same periods in 2004. Our U.S. depletion rates were significantly higher in the third quarter of 2004 as a result of increases in the carrying costs of our evaluated U.S.

oil and gas assets primarily in Northwest Lost Hills, East Texas, Knights Landing and North South Forty as well as a decrease in estimated reserves at Knights Landing.

Capital Investments

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

	Three-Month Periods Ended September 30,			**Nine-Month Periods Ended September 30,**		
(stated in thousands of U.S. Dollars)	**2005**	**2004**	**(Increase) Decrease**	**2005**	**2004**	**(Increase) Decrease**
Oil and Gas Activities:						
China	$ 5,860	$ 4,480	$ (1,380)	$ 24,111	$ 18,632	$ (5,479)
U.S.	2,770	3,508	738	5,282	13,351	8,069
EOR	893	509	(384)	3,736	1,624	(2,112)
GTL	246		(246)	977	66	(911)
	$ 9,769	$ 8,497	$ (1,272)	$ 34,106	$ 33,673	$ (433)

Oil and Gas Activities China

Our capital investment in China increased $1.4 million and $5.5 million for the three-month and nine-month periods ended September 30, 2005, respectively, compared to the same periods in 2004 primarily due to increased development drilling activities in Dagang.

Dagang

For our field development activities at Dagang we spent $5.1 million and $18.0 million, an increase of $0.8 million and $5.2 million, for the three-month and nine-month periods ended September 30, 2005, respectively, compared to the same periods in 2004. For the nine-month period ended September 30, 2005, we completed 3 wells drilled in 2004, drilled and completed 14 new wells, re-completed 5 existing wells and drilled three wells that are either awaiting completion or in the process of drilling as at September 30, 2005. The wells drilled in the third quarter of 2005 were in the southern blocks of the contract area.

Review of test results in our most northerly block of the Dagang field, confirmed the presence of significant faulting and poor reservoir continuity, eliminating the potential for economic development in that block. We continued our successful stimulation program in the second of the northern blocks, during the third quarter of 2005 by stimulating 4 additional wells, and we anticipate stimulating additional 2 to 3 wells in the fourth quarter of 2005. After drilling and completing 3 wells planned in the fourth quarter of 2005, we will have drilled and completed 40 wells in the Dagang field as compared to the estimated 115 wells set out in the approved Overall Development Program submitted in 2003. We have decided to suspend the current development-drilling program in the Dagang field to allow for detailed evaluation of well productivity and production decline performance. Initial rates of production have been less than expected, and unless decline rates are reduced, future drilling may not meet our profitability thresholds. Suspending our drilling operations at this time will also maximize our cash flow from current production from the Dagang field of approximately $1 million per month before development drilling costs.

Zitong

Our capital investment on our Zitong block increased $0.6 million and $0.3 million during the three-month and nine-month periods ended September 30, 2005, respectively, compared to the same periods in 2004. We spent $5.9 million in the first nine months of 2004 for 540 miles of new seismic data. For the nine-month period ended September 30, 2005, we spent $3.2 million to acquire the remaining 160 miles of our 700 mile acquisition program, to complete interpretation work and $2.9 million to drill our first well, Dingyuan 1. The well was not commercially viable and cement plugs were set that will allow us to use the surface location and re-enter the well bore for a potential directional hole. On October 20, 2005, we requested an extension of Phase 1 of the Zitong block exploration program, which expires December 1, 2005 to assess our election to proceed into Phase 2 as further review and mapping of our seismic data is necessary. In addition, we are in active discussion with two potential partners who have indicated an interest in participating in the Zitong block exploration program. We expect to receive the extension by the end of 2005 and are planning to drill a second Phase 1 exploration well with our partner(s) upon receipt of such extension after which an election would be made as to our decision to enter into Phase 2. If an extension were not granted, we could elect not to enter Phase 2 and would be required to pay CNPC, within 30 days after our election, a cash equivalent of the deficiency in the work program estimated at $4.3 million as at September 30, 2005. If we did not elect to enter Phase 2, the aggregate costs related to the Zitong block in the approximate amount of $13.2 million, including the $4.3 million cash requirement, would be included in the depletable base of the China full cost pool and would be subject to the ceiling test. This could result in a ceiling test impairment related to the China full cost pool in an amount which is not determinable at this time. We have a 100% working interest in the Zitong block**.**

Oil and Gas Activities U.S.

Capital investment in the U.S. was down $0.7 million and $8.1 million for the three-month and nine-month periods ended September 30, 2005, respectively, compared to the same periods in 2004.

The decrease for the three-month period ended September 30, 2005 was due mainly to a $2.6 million reduction in our development activities at our Citrus field as we completed drilling of Citrus #2 and #3 in the third quarter of 2004. These decreases are partially offset by a $1.9 million increase in capital investments related to drilling activities at LAK Ranch in Wyoming and Northwest Lost Hills, South Midway, North Salt Creek, Peach and other California exploration prospects during the third quarter of 2005.

The decrease for the nine-month period ended September 30, 2005 was due mainly to a $9.1 million reduction in our development activities in the Knights Landing and Citrus fields, compared to the same period in 2004, in addition to a $0.7 million net reduction in exploration drilling in our other California exploration prospects. These decreases were partially offset by a $1.7 million increase in capital investments related to drilling activities at Northwest Lost Hills, North Salt Creek and Peach during the first three quarters of 2005.

Knights Landing

Our development activities at Knights Landing decreased $3.9 million for the nine-month period ended September 30, 2005 compared to the same period in 2004. In February 2004, we farmed into the Knights Landing gas field, which is 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 our 3-D seismic acquisition program was delayed until the fourth quarter of 2005. The seismic surveying is 50% complete and drilling of shot holes has begun. The seismic shoot should start by the end of November 2005 and be completed by the end of 2005. Drilling activities in Knights Landing will recommence after interpretation of the 3-D seismic in 2006**.**

Citrus

Our development activities at Citrus decreased $2.6 million and $5.1 million for the three-month and nine-month periods ended September 30, 2005, respectively, compared to the same periods in 2004. We completed the drilling of three Citrus wells in the first six months of 2004 with Citrus # 2 and Citrus #3 being completed and placed on production in the third quarter of 2004. We have not drilled any additional wells at Citrus in 2005 but we concluded negotiations for a farm-out agreement to drill three undeveloped blocks in Citrus covering approximately 1,920 gross acres. Plans are to spud the first well prior to the end of 2005 that will extend expiring leases. We have an average of a 92% working interest in approximately 3,400 developed and undeveloped gross acres at Citrus.

South Midway

Our development activities at South Midway decreased $0.4 million for the nine-month period ended September 30, 2005 compared to the same period in 2004. We drilled one successful delineation well and two temperature observation wells in the second quarter of 2005. Additionally, we drilled one successful exploration well adjacent to the primary area of South Midway in the third quarter of 2005. Plans are underway to steam this discovery well to stimulate production. This compares to six delineation wells and one exploratory well drilled in the first nine months of 2004, which resulted in the completion of four producing oil wells.

Northwest Lost Hills

In August 2005, we concluded a farm-out of 1/3rd of our working interest to Aera Energy LLC (**Aera**) to complete and test the Northwest Lost Hills # 1-22 deep gas well. This well was drilled to a depth of approximately 20,000 feet in August 2002 and was designed to fully evaluate the natural gas and condensate reserve potential of the deep Temblor formation. While drilling the well, we encountered several high-pressure intervals, which indicated the presence of natural gas, and decided to set liner to 19,620 feet in preparation for testing. In 2003, the well was temporarily abandoned pending the identification of one or more partners to share the costs of the testing program currently estimated at $7.7 million. Our share of completion equipment, of approximately $1.0 million, previously purchased by the joint venture partners will be used in the completion and testing of the well. The rig is on location and work has commenced to re-enter and test the well. The current operation is running 4 1/2-inch liner over the open hole to a depth of 21,000 feet. Testing of the well should commence in late November 2005 and is expected to be completed before the end of 2005. We will retain a 28% working interest in the Northwest Lost Hills # 1-22 well and the block.

LAK Ranch

Our development activities at LAK Ranch increased $0.4 million for the three-month period ended September 30, 2005 with no change in spending for the nine-month period ended September 30, 2005 compared to the same periods in 2004. We drilled one vertical well in the first quarter of 2005 for data collection purposes and completed the interpretation of our ultra-high resolution 3-D seismic program. We drilled three steam injection wells in the third quarter of 2005 to provide continuous steam injection above the existing horizontal wells. We commenced continuous steaming operations in the fourth quarter of 2005 and initial oil production has increased in response. Profiles of steam through the pay section will be measured as part of the evaluation of the effectiveness of the process, with volumes and quality of steam monitored and adjusted as necessary. Production improvements will be monitored over the next several months. We currently have a 42% working interest at LAK Ranch.

North Salt Creek

We spent $0.1 million and $0.3 million for the three-month and nine-month periods ended September 30, 2005, respectively, to drill a discovery natural gas well and build a pipeline at our North Salt Creek prospect. The prospect is located at the north end of the Cymric Oil Field in the San Joaquin Basin of California. The 2,500-foot North Salt Creek well tested in the Fitzgerald sand and encountered oil and gas bearing horizons in the Diatomite and Etchegoin formations. Natural gas sales commenced September 1, 2005 and the well is currently producing 1,000 Mcf/day. We plan to drill two offset wells to this discovery during the fourth quarter of 2005 depending on rig availability. We are the operator of the well and own a 24% working interest in the well and the prospect.

Peach

During the first quarter of 2005, we discovered natural gas at our Peach prospect in the North Antelope Hills area in Kern County, California. The prospect is in a major hydrocarbon-producing region along the west side of the San Joaquin Basin. We farmed-out part of our Peach prospect in November 2004 for 100% of the drilling costs of the first Peach well, Peach # 1, to earn a 50% interest in the prospect. We will retain a 50% interest in this well after payout and will retain a 50% working interest in the prospect. We spent $0.1 million and $0.6 million for the three-month and nine-month periods ended September 30, 2005, respectively, to drill an appraisal well which was drilled to a depth of 4,950 feet and encountered gas shows while drilling. The testing of the appraisal well was unsuccessful and will be abandoned. Construction of a pipeline to sell gas from the Peach #1 well is underway.

Other California Exploration

Our exploration activities in California increased $0.2 million for the three-month period ended September 30, 2005 and decreased $0.7 million for the nine-month period ended September 30, 2005 compared to the same periods in 2004. We spent $0.3 million in the third quarter of 2005 to drill an unsuccessful exploration well at Kings River in northern California. This was partially offset by a $0.1 million decrease in exploration and development activities in our Sledge Hamar prospect, which we sold in the fourth quarter of 2004, and unsuccessful wells at the McCloud River and Pistachio prospects. For the nine-month period ended September 30, 2005, our spending decreased $1.0 million for exploration and development activities at Sledge Hamar, McCloud River and Pistachio, partially offset by the $0.3 million exploration well drilled at Kings River.

Enhanced Oil Recovery and Heavy Oil Processing Activities

We incurred $0.4 and $2.1 million more in capital investment activities on EOR and RTP™ projects for the three-month and nine-month periods ended September 30, 2005, respectively, when compared to the same periods in 2004.

Iraq

In Iraq, we continue to further our study of the Qaiyarah heavy oil field which resulted in increases in capital investments of $0.5 million and $1.3 million for the three-month and nine-month periods ended September 30, 2005, respectively, compared to the same periods in 2004. The field s reservoirs contain a large proven accumulation of 16-17º 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 and/or power generation. Reservoir characterization work was completed during the third quarter of 2005 and engineering analysis and preliminary development planning is progressing.

The Qaiyarah capital investment increases were offset by a reduction in spending of $0.3 million and $0.5 million for the three-month and nine-month periods ended September 30, 2005, respectively, on other Iraq projects including for engineering, design and procurement contract bids submitted in 2004, which are currently being considered by the Iraqi government. During 2005, we prepared and submitted a commercial and technical proposal for the development of the Kormor gas field. Following meetings with representatives of the Iraq Ministry of Oil in September 2005 we provided clarification on our bid and submitted a revised commercial and technical proposal for their consideration**.**

Colombia

Our capital investments increased $0.3 million for the nine-month period ended September 30, 2005 compared to the same period in 2004 to complete our MOU with Ecopetrol for the study of heavy crudes from the large Castilla and Chichimene oil fields. We did not meet the company-size requirements that Ecopetrol specified in their final bidding qualifications for the Llanos Basin Heavy Crude Project , which includes the Castilla and Chichimene field developments and wrote down our $0.3 million investment in this project in the third quarter of 2005. We are, however, reviewing the potential for other EOR heavy oil upgrading opportunities in Colombia.

RTP™CDF

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 the independent consulting firms Muse, Stancil & Co. and Purvin & Gertz Inc. 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 $0.2 million and $0.9 million for the three-month and nine-month periods ended September 30, 2005, respectively, for modifications to the RTP™ CDF and 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 (**RTP™ Unit**). We continue to run critical tests on target crudes at the RTP CDF to develop data required for the design of an RTP™ Unit.

RTP™Technology

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 an 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 Units with input capacity of up to 250,000 barrels-per-day. Should ConocoPhillips Canada install RTP Units, 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™ Unit 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 $0.2 and $1.0 million more in capital investment activities on GTL projects for the three-month and nine-month periods ended September 30, 2005, respectively, compared to the same periods in 2004.

Egypt

We signed a memorandum of understanding with Egyptian Natural Gas Holding Company (**EGAS**), the state organization charged with the management of Egypt s natural gas resources, to prepare a feasibility study to construct and operate a GTL plant that would convert natural gas to ultra-clean liquid fuels in Egypt. EGAS has agreed to commit up to 4.2 trillion cubic feet of natural gas, or approximately 600 million cubic feet per day for the anticipated 20-year operating life of the proposed project, if the study indicates that a GTL project is economically feasible. We commenced the engineering design of a GTL plant to incorporate the latest advances in the GTL technology. We are also is in the process of obtaining an updated market analysis for GTL products to reflect changes since the original evaluation was completed several years ago. Plant capacity options of 45,000 and 90,000 barrels per day will be evaluated. If the feasibility study indicates that a GTL plant is economically viable the parties will enter into negotiations for a definitive agreement for the development of a project.

Mongolia

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 have completed a marketing study for CTL products to be sold in northern and eastern China and will be presenting economics and a proposal to the private owner of the coal deposit.

Bolivia

As a result of our on-going evaluation of our GTL investments, $0.3 million of our investments were written down for the nine-month period ended September 30, 2005 related to our GTL project in Bolivia due to the impact that political and fiscal uncertainty in Bolivia could have on the viability of a GTL plant.

Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents increased for the three-month period ended September 30, 2005 by $0.1 million compared to a decrease of $11.8 million for the same period in 2004. Our net cash and cash equivalents decreased for the nine-month period ended September 30, 2005 by $5.5 million compared to an increase of $4.1 million for the same period in 2004. We incurred a net loss of $4.6 million for the nine-month period ended September 30, 2005, and, as at September 30, 2005 had an accumulated deficit of $86.4 million and negative working capital of $17.2 million.

Operating Activities

Our operating activities provided $2.5 million in cash for the three-month period ended September 30, 2005 compared to a use of cash by operating activities of $0.2 million for the same period in 2004. Our operating activities provided $5.1 million in cash for the nine-month period ended September 30, 2005 compared to $1.1 million for the same period in 2004.The increases in cash from operating activities for the three-month and nine-month periods ended September 30, 2005 are mainly due to increases in net production volumes of 30% and 36%, respectively, and increases in oil and gas prices of 41% and 44%, respectively, when compared to the same periods in 2004. The increases in net revenues for the three-month and nine-month periods ended September 30, 2005 were partially offset by increases of $0.6 million and $2.3 million, respectively, in general and administrative expenses, excluding stock based compensation, and business development expenses compared to the same periods for 2004.

Investing Activities

Our investing activities used $8.8 million in cash for the three-month period ended September 30, 2005 compared to $13.6 million for the comparable period in 2004 for a $4.8 million decrease in cash used in investing activities. Although our capital investing increased by $1.3 million for the third quarter of 2005, our working capital for investing activities decreased $5.6 million due mainly to an increase in our level of accounts payable and accrued liabilities associated with our capital investments. Additionally, we spent $0.4 million less on Merger related activities in the third quarter of 2005. For the nine-month period ended September 30, 2005, our investing activities used $35.6 million in cash compared to a use of $22.9 million for the comparable period in 2004 for a $12.7 million increase in cash used in investing activities. This increase is primarily due to a $13.5 million reduction in proceeds from assets sold in 2004 and an increase of $8.6 million of cash used in Merger related activities. This is partially offset by a net decrease of $9.4 million in cash used for capital investments as our level of accounts payable and accrued liabilities associated with our capital investments have increased.

Financing Activities

Our financing activities provided $6.4 million in cash for the three-month period ended September 30, 2005 compared to $2.0 million of cash for the comparable period in 2004. The $4.4 million increase in cash from financing activities is mainly due to a $6.6 million increase in cash from private placements and exercises of warrants and options less $2.2 million net decrease in debt financing and other related activities. For the nine-month period ended September 30, 2005, our financing activities provided $24.9 million in cash compared to $25.8 million for the comparable period in 2004. The $0.9 million decrease in cash from financing activities is due mainly to a $3.4 million reduction in cash from private placements and exercises of warrants and options partially offset by a $2.5 million increase in cash from debt financing and other related activities.

In November 2005, the Company closed a special warrant financing by way of private placement for $15.75 million. The financing consisted of 7,208,599 special warrants issued for cash and 2,453,988 issued for the repayment of convertible loans, both at U.S. $1.63 per special warrant. Each special warrant entitles the holder to receive, at no additional cost, one common share and one common share purchase warrant. Each common share purchase warrant entitles the holder to purchase one common share at a price of U.S. $2.50 per share until the second anniversary date of the closing. Further information on this financing is contained in Note 15 to the consolidated financial statements.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(stated in thousands of U.S. Dollars)	**2005**	**2004**	**2005**	**2004**
Cash flow from operating activities	$ 2,500	$ (200)	$ 5,125	$ 1,134
Investing Activities				
Capital investments, after changes in non-cash working capital	(8,705)	(13,056)	(23,730)	(33,101)
Merger, net of working capital	(117)		(10,096)	
Equity investment and Merger related costs		(653)	(1,687)	(3,153)
Proceeds from sale of assets				13,458
Other	(6)	108	(60)	(72)
	(8,828)	(13,601)	(35,573)	(22,868)
Financing Activities				
Proceeds from private placements, net of all share issue costs	2,399		12,459	20,428
Proceeds from exercise of options and warrants	4,504	289	6,229	1,664
Net debt financing	(417)	1,722	6,750	3,722
Other	(86)		(512)	
	6,400	2,011	24,926	25,814

Net Source (Use) of Cash	$ 72	$ (11,790)	$ (5,522)	$ 4,080

Outlook

We continue to focus our efforts on the commercial implementation of the heavy oil upgrading process we acquired last quarter. The Company is continuing discussions with a number of heavy oil resource owners and others for the potential commercial deployment of the RTP heavy oil upgrading technology in heavy oil fields around the world. These discussions are at various stages and contemplate a number of different contract formats, including potential production sharing, profit sharing or other joint venture arrangements. These projects would benefit significantly from the value added by our proprietary technology.

Our capital investments for the first nine months of 2005 were $34.1 million and our outlook for the remainder of 2005 is approximately $8.6 million. This compares to a budget of $60.9 million and $18.1 million for the same periods, respectively. The reduction in capital investments of $36.3 million for all of 2005 is due mainly to a reduction in our drilling program in Dagang and our plans to seek a farm-out partner for the second well at Zitong. Additionally, drilling at Knights Landing budgeted for 2005 has been delayed until after the completion of our planned acquisition and interpretation of 3-D seismic data by the end of the fourth quarter of 2005 and at Citrus until after we have evaluated performance of the current producing wells in an effort to improve production levels. We plan to seek financing on an as needed basis, from equity markets, project lenders, joint ventures or other potential financing sources to pursue our 2005 and 2006 capital investment program, acquisitions of proven and probable reserves and to deploy our HTL and GTL technologies. Although we have suspended our current discussions with European and Chinese lending banks to provide funding for the development of the Dagang field, this operation, excluding drilling costs, generates a positive cash flow of approximately $1 million per month and will provide a reasonable basis for resuming borrowing discussions with existing or different lenders.

In October 2003, we filed a base shelf prospectus with Canadian securities regulatory authorities and a shelf registration statement with the U.S. Securities and Exchange Commission to qualify for potential future sale in Canada and the U.S. up to $100 million of various types of securities, including common shares, preferred shares, warrants and debt securities. These shelf filings, which expire in November 2005 but which may be renewed, are expected to give us greater flexibility to fund our expansion and capital programs and will allow us to take advantage of a broader range of financing opportunities on a timelier basis. A combination of such equity financing, as well as convertible loan, debt and mezzanine financing and joint venture partner participation, will be required to complete our future capital programs.

We incurred a net loss of $4.6 million for the nine-month period ended September 30, 2005, and, as at September 30, 2005, had an accumulated deficit of $86.4 million and negative working capital of $17.2 million. We expect to incur substantial expenditures to further our capital investment programs and our cash flow from operating activities will not be sufficient to satisfy our current obligations and meet our capital investment objectives. Our plans include sale of additional equity securities, alliances or other partnership agreements with entities with the resources to support our projects as well as convertible loan, debt and mezzanine financing in order to generate sufficient resources to assure continuation of our operations and achieve our capital investment objectives. We are continuing 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 we license or own. 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 we and the third party with whom we are presently negotiating will successfully conclude this potential transaction nor that we 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 we are unable to obtain adequate additional financing or enter into such business alliances, we will be required to sharply curtail our operations, which may include the sale of assets.

Contractual Obligations

The table below summarizes the contractual obligations that are reflected in our Unaudited Condensed Consolidated Balance Sheet as at September 30, 2005 and/or disclosed in the accompanying Notes:

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	**2005**	**2006**	**2007**	**2008**	**After 2008**
Purchase Agreement:	$ 100	$	$ 100	$	$	$
Consolidated Balance Sheets:						
Note payable current portion *(Note 9)*	1,667	417	1,250			
Long term debt *(Note 9)*	1,389		417	972		
Convertible loans *(Note 10)*	8,000	8,000				
Other Commitments:						
Interest payable	791	648	122	21		
Lease commitments	2,182	154	649	477	375	527
Zitong exploration commitment *(Note 14)*	4,300	4,300				
Contingent obligation *(Note 14)*	1,900		1,900			
Total	$ 20,329	$ 13,519	$ 4,438	$ 1,470	$ 375	$ 527

Off Balance Sheet Arrangements

As at September 30, 2005 and December 31, 2004, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us, or our related parties, except as disclosed herein.

Outstanding Share Data

As at November 1, 2005, there were 208,583,005 common shares of the Company issued and outstanding. Additionally, the Company had 11,272,414 common share purchase warrants outstanding and exercisable to purchase 7,686,207 common shares and 1,000,000 special warrants issued by way of a private placement on July 7, 2005 at a price of Cdn.$3.10 per special warrant. Each of these special warrants is exercisable to acquire, for no additional consideration, one common share and one common share purchase warrant, which is exercisable to purchase one common share at a price of Cdn.$ 3.50 until July 7, 2007. As at November 1, 2005, there were 10,382,468 incentive stock options outstanding to purchase the Company s common shares.

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

	QUARTER ENDED							
	2005			**2004**				**2003**
	3rd Qtr	**2nd Qtr**	**1st Qtr**	**4th Qtr**	**3rd Qtr**	**2nd Qtr**	**1st Qtr**	**4th Qtr**
Total revenue	$8,907	$6,645	$5,736	$ 6,212	$4,932	$3,521	$3,332	$ 2,330
Net loss								
Canadian GAAP	$2,113	$1,031	$1,483	$17,184	$ 951	$1,298	$1,292	$23,154
U.S. GAAP	$1,843	$1,564	$3,008	$15,736	$ 980	$1,510	$1,470	$23,270
Net loss per share								
	$ 0.01	$ 0.01	$ 0.01	$ 0.09	$ 0.01	$ 0.01	$ 0.01	$ 0.15

Canadian GAAP								
U.S. GAAP	$ 0.01	$ 0.01	$ 0.02	$ 0.09	$ 0.01	$ 0.01	$ 0.01	$ 0.15

The 2003 quarterly earnings for Canadian GAAP have been restated to give effect to the retroactive application of CICA Section 3870 Stock Based Compensation and Other Stock Based Payments , which is more fully described in Note 2 under Stock Based Compensation in the Company s 2004 Annual Report on Form 10-K. The net losses in the fourth quarter of 2004, for Canadian and U.S. GAAP, were primarily due to impairment provisions of $16.3 million and $15.0 million, respectively, for U.S. oil and gas properties. The net losses in the fourth quarter of 2003, for Canadian and U.S. GAAP, were primarily due to an impairment provision of $20.0 million for U.S. oil and gas properties. The differences in the net loss and net loss per share for the first quarter of 2005 were due mainly to GTL and EOR investments, which are capitalized for Canadian GAAP but expensed as

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incurred for U.S. GAAP.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

No material changes since December 31, 2004.

Item 4. Controls and Procedures

The Company s management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of September 30, 2005. Based upon this evaluation, management concluded that these controls and procedures were (1) designed to ensure that material information relating to the Company is made known to the Company s Chief Executive Officer and Chief Financial Officer and (2) effective, in that they provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

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

Part II Other Information

Item 1. Legal Proceedings: None

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

Item 3. Defaults Upon Senior Securities: None

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

Item 5. Other Information: None

Item 6. Exhibits

EXHIBIT NUMBER	DESCRIPTION
31.1	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification by the Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

SIGNATURE

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

IVANHOE ENERGY INC.
By: /s/ W. Gordon Lancaster
Name: W. Gordon Lancaster
Title: Chief Financial Officer
Dated: November 7, 2005

INDEX TO EXHIBITS

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