IVANHOE ENERGY INC
Form 10-Q
November 06, 2003

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

Form 10-Q

x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.
For the quarterly period ended September 30, 2003

or

o Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.
For the transition period from ______________ to ______________

Commission file number 000-30586

Ivanhoe Energy Inc.

(Exact name of registrant as specified in its charter)

Yukon, Canada	**98-0372413**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

Suite 654 999 Canada Place
Vancouver, British Columbia, Canada
V6C 3E1

(Address of principal executive office)

(604) 688-8323

(registrant s telephone number, including area code)

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

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

Yes þ No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act)

Yes þ No o

The number of shares of the registrant s capital stock outstanding as of September 30, 2003 was 156,692,939 Common Shares, no par value.

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Part I Financial Information

Item 1. Financial Statements

IVANHOE ENERGY INC.
Consolidated Balance Sheets
(stated in thousands of U.S. Dollars)

	September 30, 2003	December 31, 2002
	(unaudited)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 7,686**	$ 3,980
Accounts receivable	**2,562**	2,519
Other	**128**	691
	10,376	7,190
Long term assets	**599**	462
Oil and gas properties, equipment and GTL investments, net	**102,529**	99,436
	$ 113,504	$ 107,088
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 4,880**	$ 4,797
Notes payable	**1,000**	500
Convertible debenture		1,000
	5,880	6,297
Asset retirement obligation	**510**	243
Shareholders Equity		
Share capital, issued 156,693,000 common shares; December 31, 2002 144,466,000	**144,347**	131,112
Deficit	**(37,233)**	(30,564)
	107,114	100,548
	$ 113,504	$ 107,088

(see accompanying notes)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	**2002**	**2003**	**2002**
Revenue				
Oil and gas revenue	**$ 2,405**	$ 2,328	**$ 7,269**	$ 5,972
Interest income	**18**	22	**60**	94
	2,423	2,350	**7,329**	6,066
Expenses				
Operating costs	**1,148**	1,070	**2,993**	2,938
General and administrative	**1,566**	1,095	**5,098**	4,083
Depletion and depreciation	**915**	813	**2,586**	2,301
Write down of GTL investments		2,436	**3,321**	2,436
	3,629	5,414	**13,998**	11,758
Net Loss	**1,206**	3,064	**6,669**	5,692
Deficit, beginning of period	**36,027**	26,123	**30,564**	23,495
Deficit, end of period	**$ 37,233**	$ 29,187	**$ 37,233**	$ 29,187
Net Loss per share	**$ 0.01**	$ 0.02	**$ 0.05**	$ 0.04
Weighted Average Number of Shares (in thousands)	**151,088**	144,631	**146,940**	141,546

(see accompanying notes)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	**2002**	**2003**	**2002**
Operating Activities				
Net (loss)	**$ (1,206)**	$ (3,064)	**$ (6,669)**	$ (5,692)
Items not requiring use of cash:				
Depletion and depreciation	**915**	813	**2,586**	2,301
Write down of GTL investments		2,436	**3,321**	2,436
Changes in non-cash working capital items	**(1,258)**	(757)	**1,101**	(3,133)
	(1,549)	(572)	**339**	(4,088)
Investing Activities				
Capital spending	**(4,097)**	(4,639)	**(8,870)**	(16,471)
Proceeds from sale of assets		2,560		3,760
	(4,097)	(2,079)	**(8,870)**	(12,711)
Financing Activities				
Shares issued on private placements	**11,603**		**11,603**	9,964
Shares issued on exercise of options	**134**		**134**	119
Proceeds from notes			**1,750**	
Payments of notes	**(1,250)**		**(1,250)**	
	10,487		**12,237**	10,083
Increase (decrease) in cash and cash equivalents, for the period	**4,842**	(2,651)	**3,706**	(6,716)
Cash and cash equivalents, beginning of period	**2,845**	5,632	**3,980**	9,697
Cash and cash equivalents, end of period	**$ 7,686**	$ 2,981	**$ 7,686**	$ 2,981
Included in the above are the following:				
Taxes paid	**$**	$	**$ 6**	$
Interest paid	**$ 43**	$ 21	**$ 85**	$ 56
Decrease (increase) in non-cash working capital items:				
Accounts receivable	**$ (423)**	$ (853)	**$ (43)**	$ (960)
Other current assets	**51**	(503)	**563**	(356)
Accounts payable and accrued liabilities	**(886)**	599	**581**	(1,817)
	$ (1,258)	$ (757)	**$ 1,101**	$ (3,133)

(see accompanying notes)

Notes to the Consolidated Financial Statements
September 30, 2003
(all tabular amounts are expressed in thousands of U.S. dollars except per share data)
(Unaudited)

1. GENERAL

The unaudited consolidated financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2002 consolidated financial statements, except for a change in the policy of accounting for asset retirement obligations, and should be read in conjunction therewith. The December 31, 2002 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. All adjustments which are, in the opinion of management, necessary for a fair presentation of the Company s financial position as at September 30, 2003 and December 31, 2002 and the results of operations and cash flows for the three and nine-month periods ended September 30, 2003 and 2002 have been included. The results of operations and cash flows are not necessarily indicative of the results for a full year.

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

2. SIGNIFICANT ACCOUNTING POLICIES

Asset Retirement

Prior to January 2003, the Company had estimated its future site restoration and abandonment costs associated with its oil and gas properties and amortized this estimate to operations using the unit-of-production method based upon estimated proved reserves. The provision was included with depletion and depreciation expense.

For fiscal years beginning after January 1, 2004, Canadian GAAP requires that asset retirement costs and liabilities associated with site restoration and abandonment of tangible long-lived assets be initially measured at a fair value which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement cost are recognized in the results of operations.

The Company has elected early implementation of this accounting policy. Accordingly, effective January 1, 2003, the Company changed its accounting policy to capitalize asset retirement costs as part of the carrying value of its oil and gas properties and adjusted the amount of its site restoration liability to the present value of the liability for the corresponding asset retirement obligation as of this date. The Company has adopted the policy without retroactive adjustment of prior years because implementation of this change had an immaterial effect on the Company s financial position and results of operations in prior years or in the current period (See notes 3 and 10).

U.S. GAAP for asset retirement obligations conforms in all material respects to Canadian GAAP. Implementation for U.S. GAAP is required for fiscal years beginning after June 2002.

The asset retirement costs are being amortized using the unit of production method based on estimated proved reserves. The amortization expenses and accretion of the liability for the asset retirement obligation are included with depletion and depreciation expense.

3. OIL AND GAS PROPERTIES

Oil and gas properties, equipment and gas-to-liquids (GTL) investments are net of accumulated depletion and depreciation of $9.0 million and $6.6 million as well as a provision for impairment of oil and gas properties of $14.0 million as at September 30, 2003 and December 31, 2002, respectively.

Effective January 2003, the Company capitalized $0.3 million as a result of implementation of a new accounting policy on asset retirement obligations. For the three and nine-month periods ended September 30, 2003 $0.1 million of asset retirement costs were capitalized.

In May 2003, discussions were terminated between Qatar Petroleum and the Company in the negotiation of an agreement to develop a block in Qatar s North Field to produce natural gas liquids and GTL products. As a result, the Company took a charge to income of $3.3 million for the write down of its investment in Qatar.

4. DERIVATIVE ACTIVITIES

The Company s results of operations are sensitive mainly to fluctuations in oil and natural gas prices. The Company may periodically use different types of derivative instruments to manage its exposure to price volatility, thus mitigating fluctuations in commodity-related cash flows.

The Company entered into a costless collar derivative to hedge its cash flow from the sale of 500 barrels of oil production per day over two six-month periods starting October 2002 and June 2003. The derivatives have ceiling prices of $30.45 and $28.95 per barrel for the June 2003 and October 2002 contracts, respectively, and a floor price of $24.00 per barrel using WTI as the index traded on the NYMEX. Gains and losses on derivatives are recognized in earnings as they are realized. For the nine-month period ended September 30, 2003, the Company had realized losses of $0.2 million on derivative transactions. The Company had no realized derivative losses for the three-month period ended September 30, 2003. The derivative losses are included in oil and gas revenue.

5. SEGMENT INFORMATION

The following tables present the Company s interim segment information for the three and nine-month periods ended September 30:

	Nine Month Periods Ended September 30,					
	2003			2002		
	U.S.	China	Total	U.S.	China	Total
Oil and gas revenue	$ 4,074	$ 3,195	$ 7,269	$ 3,759	$ 2,213	$ 5,972
Interest income	60		60	94		94
	4,134	3,195	7,329	3,853	2,213	6,066
Operating costs	1,643	1,350	2,993	1,880	1,058	2,938
Depletion and depreciation	1,576	1,010	2,586	1,415	886	2,301
	3,219	2,360	5,579	3,295	1,944	5,239
Segment income before the following	$ 915	$ 835	1,750	$ 558	$ 269	827
Write down of GTL investments			3,321			2,436
General and administrative			5,098			4,083
Net loss			$ 6,669			$ 5,692
Capital Expenditures:						
Oil and gas	$ 5,500	$ 2,835	$ 8,335	$ 12,270	$ 2,486	$ 14,756
Gas-to-liquids			535			1,715
			$ 8,870			$ 16,471

	As at September 30, 2003			As at December 31, 2002		
Identifiable Assets:						
Oil & gas	$ 71,801	$ 27,432	$ 99,233	$ 64,448	$ 25,281	$ 89,729
Gas-to-liquids			14,271			17,359
			$ 113,504			$ 107,088

	Three Month Periods Ended September 30,	
	2003	2002

	U.S.	China	Total	U.S.	China	Total
Oil and gas revenue	$ 1,385	$ 1,020	$ 2,405	$ 1,454	$ 874	$ 2,328
Interest income	18		18	22		22
	1,403	1,020	2,423	1,476	874	2,350
Operating costs	630	518	1,148	710	360	1,070
Depletion and depreciation	588	327	915	518	295	813
	1,218	845	2,063	1,228	655	1,883
Segment income before the following	$ 185	$ 175	360	$ 248	$ 219	467
Write down of GTL investments						2,436
General and administrative			1,566			1,095
Net loss			$ 1,206			$ 3,064
Capital Expenditures:						
Oil and gas	$ 2,831	$ 1,144	$ 3,975	$ 3,515	$ 758	$ 4,273
Gas-to-liquids			122			366
			$ 4,097			$ 4,639

6. SHARE CAPITAL

Following is a summary of the changes in share capital and stock options outstanding for the nine-month period ended September 30, 2003:

	Common Shares		Stock Options	
	Number (thousands)	Amount	Number (thousands)	Weighted Average Exercise Price Cdn.$
Balance December 31, 2002	144,466	$ 131,112	10,265	$ 2.69
Shares issued on private placements	9,529	11,603		
Shares issued for service	578	498		
Shares issued for convertible debenture	2,000	1,000		
Shares issued on exercise of options	120	134	(120)	$ 1.52
Options issued			150	$ 1.42
Options cancelled/forfeited			(584)	$ 4.48
Balance September 30, 2003	156,693	$ 144,347	9,711	$ 2.58

During the three-month period ended September 30, 2003, the Company closed two special warrant financings to advance its ongoing E&P and EOR activities in the U.S. and China, to continue its ongoing pursuit of GTL project opportunities, to pay down or restructure certain business indebtedness and for general working capital purposes. The financings consisted of 6.0 million special warrants at U.S.$1.00 per special warrant and 3.5 million special warrants at U.S.$1.70 per special warrant. Each special warrant entitled the holder to acquire one common share and one purchase warrant at no additional cost. Two purchase warrants are exercisable to purchase an additional common share. Six million purchase warrants are exercisable at U.S.$1.00 until August 2004 and at U.S.$1.10 until August 2005 and 3.5 million purchase warrants are exercisable at U.S.$1.70 until August 2004 and at U.S.$1.87 until August 2005. The net proceeds from the special warrant financing have been apportioned to the common shares. No amounts have been apportioned to the purchase warrants.

In October 2003, the Company arranged a special warrant financing to advance the Company s worldwide oil and gas operations, GTL initiatives, and for general corporate purposes. The financing consists of 3.125 million special warrants at US$4.00 per special warrant. Each special warrant entitles the holder to acquire one common share and one purchase warrant at no additional cost. Two and a half purchase warrants are exercisable to purchase an additional common share at U.S.$4.00 until the first anniversary of closing and at U.S.$4.30 until the second anniversary of closing.

7. STOCK BASED COMPENSATION

The Company accounts for its stock-based compensation plans using the intrinsic-value of the options. Under this method, compensation costs are not recognized in the financial statements for share options granted to employees and directors when issued at market value. Had stock based compensation expense been determined based on the fair value at the option grant date, the Company s net loss and net loss per share for the three and nine-month periods ended September 30 would have been as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Pro forma net loss	$ 1,316	$ 3,269	$ 6,999	$ 6,064
Pro forma net loss per share	$ 0.01	$ 0.02	$ 0.05	$ 0.04

The foregoing is calculated in accordance with the Black-Scholes options pricing model, using the following data and assumptions: 72% price volatility, using the prior two years weekly average prices of the Company s common shares; expected dividend yield of 0%; option terms to expiry of 5 years, as defined by the option agreements; risk-free rate of return as of the date of the grant of 4.4% to 5.6%, based on one and five year Canada Bond yields.

8. NOTES PAYABLE

In February 2003, the Company obtained a bank facility for up to $5.0 million to drill 30 new oil wells and upgrade surface transmission and steam injection facilities in the southern expansion of South Midway. Interest only is payable in the first year of the loan at 0.25% above the bank s prime rate or 2.75% over the London Inter-Bank Offered Rate (LIBOR) at the option of the Company. After the first year, the loan is repayable over three years plus interest at 0.50% above the bank s prime rate or 3.0% over LIBOR, at the option of the Company. The loan is secured by all the Company s rights and interests in the South Midway properties. In June 2003, the Company borrowed $1.0 million against the bank loan for a six-month fixed LIBOR rate of 3.87%.

As at September 30, 2003, the Company repaid $1.25 million in related party loans plus accrued interest and has negotiated a revolving credit facility to re-establish or extend that loan in the future as needs arise.

9. CONVERTIBLE DEBENTURE

In June 2003, the lender elected to convert the $1.0 million unsecured convertible debenture into 2 million of the Company s common shares at $0.50 per share. All accrued interest on the debenture has been paid as of the conversion date.

10. ASSET RETIREMENT OBLIGATION

Effective January 2003, the Company changed its policy on accounting for liabilities associated with site restoration and abandonment of its oil and gas properties. The undiscounted amount of expected cash flows required to settle the asset retirement obligations is estimated at $1.0 million to be settled over a twelve-year period starting in 2010. The liability for the expected cash flows, as reflected in the financial statements, has been discounted at 7%. Implementation of the policy resulted in an additional provision for asset retirement of $0.2 million. For the three and nine month periods ended September 30, 2003 $0.1 million was added to the carrying amount of the asset retirement obligations.

11. CLAIMS AND CONTINGENCIES

The Company and Aera Energy LLC (Aera) are in a dispute concerning certain costs and cost overruns incurred during the drilling of the Northwest Lost Hills # 1-22 well in the amount of approximately $2.7 million. Aera had initiated arbitration proceedings over the issues. Agreement has been reached over payment of the disputed amounts. The Company paid $1.5 million, of the amount owed, in September 2003 and intends to pay the remaining $1.2 million on or before December 1, 2003. Discussions aimed at resolving certain other issues between the Company and Aera, in respect of the Aera Exploration Agreement, remain ongoing.

12. ADDITIONAL DISCLOSURE REQUIRED UNDER U.S. GAAP

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

Consolidated Balance Sheets

	As at September 30, 2003		As at December 31, 2002	
	Oil and Gas Properties	Shareholders' Equity	Oil and Gas Properties	Shareholders' Equity
Canadian GAAP	$102,529	$ 107,114	$99,436	$ 100,548
Adjustment to ascribed value of shares issued for royalty interests	1,358	1,358	1,358	1,358
Impairment provision for China properties, net	(9,856)	(9,856)	(9,922)	(9,922)
Write off of GTL development costs	(3,817)	(3,817)	(6,603)	(6,603)
OCI derivative mark-to-market adjustment		(30)		(102)
U.S. GAAP	$ 90,214	$ 94,769	$84,269	$ 85,279

Under U.S. GAAP, changes in the fair value of derivative instruments that meet specific cash-flow hedge accounting criteria are reported in other comprehensive income (OCI). The gains and losses on cash-flow derivative transactions that are reported in OCI are reclassified to earnings in the period in which earnings are affected by changes in the cash flow of the underlying hedged item. The Company s derivative contracts qualify for hedge accounting treatment.

Under U.S. GAAP, the transfer of deficit to share capital, which occurred in 1999, would not be recognized and Shareholders Equity would be presented as follows:

	September 30, 2003	December 31, 2002
Share capital (including adjustments above)	$ 220,160	$ 206,925
Deficit (including adjustments above)	(125,361)	(121,544)
Accumulated other comprehensive income	(30)	(102)
	$ 94,769	$ 85,279

	Nine Month Periods Ended September 30,			
	2003		2002	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ 6,669	$ 0.05	$ 5,692	$ 0.04
Depletion adjustment China	(66)		(56)	
GTL development costs written off, net	(2,786)	(0.02)	1,279	0.01
U.S. GAAP	$ 3,817	$ 0.03	$ 6,915	$ 0.05

Weighted Average Number of Shares under U.S. GAAP (in thousands)	146,940	141,546

	Three Month Periods Ended September 30,			
	2003		2002	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ 1,206	$ 0.01	$ 3,064	$ 0.02
Depletion adjustment China	(22)		(18)	
GTL development costs written off, net	122		(70)	
U.S. GAAP	$ 1,306	$ 0.01	$ 2,976	$ 0.02
Weighted Average Number of Shares under U.S. GAAP (in thousands)		151,088		144,631

Stock Based Compensation

Had compensation expense been determined based on fair value of options issued to employees and directors 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 as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net loss under U.S. GAAP	$ 1,306	$ 2,976	$ 3,817	$ 6,915
Stock-based compensation expense determined under fair-value method for employee awards	428	475	1,235	1,410
Pro forma net loss under U.S. GAAP	$ 1,734	$ 3,451	$ 5,052	$ 8,325
Basic loss per common share under U.S. GAAP:				
As reported	$ 0.01	$ 0.02	$ 0.03	$ 0.05
Pro forma	$ 0.01	$ 0.02	$ 0.03	$ 0.06
Weighted Average Number of Shares under U.S. GAAP (in thousands)	151,088	144,631	146,940	141,546

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

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments. This statement is effective for contracts entered into or modified after June 30, 2003. Management does not believe that SFAS No. 149 will have a material impact on the Company s financial statements.

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 relating 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 gas-to-liquids development technology, 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, 2002, 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.

Results of Operations

For the three-month period ended September 30, 2003, the net loss was $1.2 million ($0.01 per share) compared to a net loss of $3.1 million ($0.02 per share) for the same period in 2002. The net loss for the nine-month period ended September 30, 2003 was $6.7 million ($0.05 per share) compared to a net loss of $5.7 million ($0.04 per share) for the same period in 2002. The net loss for the nine-month periods ended September 30, 2003 and 2002 includes a $3.3 million ($0.02 per share) and a $2.4 million ($0.02 per share), respectively, for write downs of our investments in GTL projects.

Cash from operating activities for the three and nine-month periods ended September 30, 2003 was a $1.5 million deficit and a $0.3 million surplus, respectively, compared to cash deficits from operating activities of $0.6 million and $4.1 million for the same periods in 2002. Our cash position increased $3.7 million for the first nine months of 2003 primarily due to net proceeds received from private placements of $11.6 million and net loan proceeds of $0.5 million. This is partially offset by $8.9 million of capital spending for the first nine-month period of 2003. Cash for the comparable period in 2002 decreased $6.7 million primarily due to $16.5 million of capital spending and $4.1 million cash deficit from operating activities, partially offset by the $3.8 million proceeds from the sale of our Daqing and Spraberry assets and the net proceeds from a private placement of $10.0 million.

Production and Operations

Oil and gas revenues for the three and nine-month periods ended September 30, 2003 were $2.4 million and $7.3 million, respectively. This represents an increase of $0.1 million and $1.3 million from the comparable periods in 2002 primarily as a result of an increase in oil and gas prices. Oil and gas prices were up $1.55/boe and $5.23/boe for the three and nine-month periods ended September 30, 2003, respectively, compared to the same periods in 2002.

For the three and nine-month periods ended September 30, 2003, net production from the U.S was down 8% and 6%, respectively, compared to the same periods in 2002 due to the loss in production from Spraberry as a result of the sale of certain Spraberry interests in the second half of 2002. This loss was partially offset by an increase in production from South Midway of 28% and 38% for the three and nine-month periods ended September 30, 2003, respectively, as a result of the success of the cyclic steaming operations and increased drilling in 2002 and the first nine months of 2003. Production levels in China are up 6% for the three and nine-month periods ended September 30, 2003 primarily due to an increase in production related to our Daqing royalty interest.

Operating costs per boe in the U.S. are up 6% and 4% for the three and nine-month periods ended September 30, 2003, respectively, compared to the same periods in 2002. Operating costs per boe in South Midway increased 7% and 29% for the three and nine-month periods ended September 30, 2003, respectively, as a result of additional costs associated with the full-scale cyclic steaming program. These increases were mostly offset by a decrease in operating costs per boe at Spraberry due to a maturing of those operations and continuing cost controls. U.S. production taxes and engineering support are down 21% and 24% for the three and nine-month periods, respectively, compared to the same periods in 2002 as a result of the sale of certain Spraberry interests in the second half of 2002. U.S. depletion costs per boe increased 27% and 21% for the three and nine-month periods ended September 30, 2003, respectively, compared to the same periods in 2002 primarily due to the partial impairment of Northwest Lost Hills and certain other California and Texas properties during the first nine months of 2003. This increase in depletion costs has been partially offset as a result of an increase in proved reserves at South Midway.

Operating costs per boe in China increased 39% and 38% for the three and nine-month periods ended September 30, 2003, respectively, compared to the same periods in 2002 as a result of increased workover, routine maintenance and utility costs in 2003. Depletion per boe in China increased 5% and 9% for the three and nine-month periods ended September 30, 2003, respectively, compared to the same periods in 2002 primarily due to a downward revision of our proved reserves at Dagang as a result of increased oil prices.

Production and operating information are detailed below:

	Nine Month Periods Ended September 30,					
	2003			2002		
	U.S.	China	Total	U.S.	China	Total
Net Production:						
BOE	159,713	111,606	271,319	170,774	106,303	277,077
BOE/day for the year	585	409	994	626	389	1,015
	Per BOE			Per BOE		
Oil and gas revenue	$ 25.51	$ 28.63	$ 26.79	$ 22.01	$ 20.82	$ 21.55
Operating costs	7.29	8.18	7.65	7.04	5.93	6.61
Production taxes	0.94		0.55	1.42		0.88
Engineering support	2.07	3.92	2.83	2.55	4.02	3.11
	10.30	12.10	11.03	11.01	9.95	10.60
Net Revenue before depletion	15.21	16.53	15.76	11.00	10.87	10.95
Depletion	9.45	9.05	9.29	7.80	8.34	8.01
Net Revenue from operations	$ 5.76	$ 7.48	$ 6.47	$ 3.20	$ 2.53	$ 2.94

	Three Month Periods Ended September 30,					
	2003			2002		
	U.S.	China	Total	U.S.	China	Total
Net Production:						
BOE	53,929	37,850	91,779	58,566	35,858	94,424
BOE/day for the year	586	411	998	637	390	1,026
	Per BOE			Per BOE		
Oil and gas revenue	$ 25.69	$ 26.96	$ 26.21	$ 24.83	$ 24.38	$ 24.66
Operating costs	8.32	8.77	8.51	7.86	6.31	7.27
Production taxes	0.91		0.53	1.79		1.11
Engineering support	2.45	4.91	3.46	2.48	3.71	2.94
	11.68	13.68	12.50	12.13	10.02	11.32
Net Revenue before depletion	14.01	13.28	13.71	12.70	14.36	13.34
Depletion	10.47	8.65	9.72	8.25	8.24	8.25
Net Revenue from operations	$ 3.54	$ 4.63	$ 3.99	$ 4.45	$ 6.12	$ 5.09

General and Administrative

For the three and nine-month periods ended September 30, 2003, general and administrative costs increased by $0.5 million and $1.0 million, respectively, compared to the same periods in 2002 primarily due to a decrease in such costs being allocated to our exploration, development and GTL activities due to a reduction in capital spending activity during 2003.

Exploration and Development Activities

Spending on these activities for the three and nine-month periods ended September 30, 2003 was $4.1 million and $8.9 million, a decrease of $0.5 million and $7.6 million, respectively, over the amounts spent during the comparable periods in 2002. These decreases are primarily due to the completion of our exploration drilling at Northwest Lost Hills #1-22 in August 2002 and a cessation of our Spraberry drilling program partially offset by an increase in spending in our South Midway field and continuation of seismic reprocessing in our Zitong project in China.

In the South Midway expansion project, the first phase of drilling, which included 15 producing wells in the second and third quarters of 2003, has been completed. It is anticipated that the second phase will begin by the end of the first quarter of 2004 with the drilling of 13 additional wells. Peak production for the project is expected to occur in the fourth quarter of 2004. In addition to the recent drilling activity, facilities have been expanded to gather, test and cycle-steam the new production. A steam generator was purchased and installed to accelerate the steam stimulation of producing wells and reduce leasing costs. Net proved reserves in the southern expansion area have increased 0.5 million barrels in 2003 as a result of the continued success with cyclic steam injection and drilling program.

A contract was signed in the second quarter with Ensyn Petroleum International (Ensyn), to test their Rapid Thermal Pyrolysis (RPT) technology to upgrade the quality of heavy oil by producing lighter, more valuable crude oil. The process also has the potential of supplying heat to generate steam for the cyclic process being used in South Midway. We have the rights to test our crude oil in a 250 barrels per day demonstration plant, which is currently under construction. The test should be completed by the first quarter of 2004 and provide enough data to give a clear indication of the capital and operating costs that could be used for scale up as well as to demonstrate the upgraded product value.

We expect to begin drilling the first well on our Citrus prospect in the San Joaquin Valley California in November. The Citrus #1 well will appraise the potential for light oil and natural gas in the Upper Antelope Shale directly offsetting existing production by other companies. The Upper Antelope Shale is located at a depth of approximately 7,000 feet and additional potential may exist in the deeper Antelope and McDonald Shale formations down to 9,000 feet. The Citrus prospect will test the southern extension of the currently producing Lost Hills field, which is unrelated to the deep-gas prospect at Northwest Lost Hills located 15 miles to the north. We acquired an interest in over 1,700 potentially productive acres offsetting Lost Hills field where there has been recent development drilling. We will be the operator and hold leases ranging between 83% and 100% in the prospect leases. We expect to have the well completed and tested by year-end. The horizontal drilling techniques planned for the well at Citrus are similar to those that have successfully developed other Antelope Shale reservoirs in the nearby North Shafter and Rose fields. If further development is warranted, we estimate that there could be up to 20 additional horizontal drilling locations at Citrus. We may also plan future wells to test deeper formations.

Northwest Lost Hills # 1-22 has been temporarily abandoned until we can identify one or more partners to share the costs of the testing program. Temporary abandonment will permit reentering the well at a later date for testing. Until it is tested, the well s commercial potential, if any, cannot be determined.

In East Texas, contracts to farm-out shallow zones at Creslenn Ranch and at Lone Star have been completed. Testing of the Pettit at Creslenn Ranch has begun with the completion of one well as a commercial gas producer and testing of the second well is currently underway. If successful, up to five additional wells could be drilled at Creslenn Ranch. At Lone Star, testing of the Cotton Valley and Travis Peak zones will commence during the last two weeks of October 2003. We continue our search for farm-out partners in our other East Texas prospects in return for exploration drilling commitments.

Final approval of our Dagang Overall Development Program was received in the second quarter 2003. Pre-drilling activities commenced in the third quarter of 2003 and the first of our development wells was spud in September. Plans are to spud a total of six surface holes and to complete drilling of two development wells prior to year-end. The surface holes are being drilled as planned in order to facilitate the introduction of an advanced drilling fluid system. At our Zitong project, we continue the seismic reprocessing activities as part of the first three-year exploration period and will commence a new geophysical survey prior to year-end.

Gas-to-Liquids Activities

Spending on GTL projects for the three and nine-month periods ended September 30, 2003 was $0.1 million and $0.5 million a decrease of $0.2 million and $1.2 million, respectively, over the amounts spent during the comparable periods in 2002. These decreases are due to the completion of technical and commercial feasibility studies for both the Qatar and Egypt projects. In May 2003, negotiations with Qatar Petroleum to construct and operate a GTL production facility, terminated without reaching an agreement and we wrote down $3.3 million of our GTL investments for expenditures incurred in connection with these negotiations.

In Egypt, proposals for alternative plant designs are being reviewed by the Ministry of Petroleum. We are pursuing a GTL fuels, specialty products and lubricants plant with Syntroleum. Discussions are ongoing that could lead to an agreement with the Ministry of Petroleum and the initiation of a commercialization study for a 45,000-barrel-per-day GTL plant.

In July 2003, we signed an agreement with Repsol-YPF Bolivia S.A. and Syntroleum for a study to build a 90,000-barrel-per-day GTL plant in Bolivia. The commercialization study is underway including an analysis of alternative plant sites, transportation logistics and project economics. Upon determination that the project is economically feasible and meets financing requirements, the three parties will enter into discussions regarding a joint-venture agreement prior to undertaking definitive engineering and design work.

Enhanced Oil Recovery (EOR)

We continue to pursue EOR opportunities in South America and the Middle East including in the country of Iraq where our executives have had prior experience and have recently opened up communications. Our contract with Ensyn gives us exclusive rights to apply their RPT technology in two prospective foreign countries where heavy oil fields have been proven but not fully developed.

Liquidity and Capital Resources

As at September 30, 2003 our cash position was $7.7 million as a result of net bank and related party financings of $0.5 million and closing two special warrant financings in the third quarter of 2003, which generated net proceeds of $11.6 million. Our cash position and liquidity will be further enhanced from the sale of 3.125 million shares for $12.5 million through a special warrant financing we arranged in late October 2003. Additionally, we spent $2.0 million on the expansion of our South Midway field during the third quarter of 2003, which we could have but did not draw from our bank financing for the development of this project. We plan to draw down such funds before the end of 2003.

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 will 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 more timely basis.

Our current cash position will enable us to execute our short-term objectives of exploration in East Texas and Zitong and to initiate the development programs in our Citrus and Dagang fields as well as further our GTL initiatives.. We are also looking at acquisitions of proven and probable reserves as a means of supplementing our growth strategy. However, to complete the development of these fields and to execute our growth strategy and other short and medium term objectives we will require additional funding. We plan to seek such financing through a combination of equity, convertible debentures, debt, mezzanine financing and joint venture partner participation. We cannot assure you that we will be successful in raising the additional funds necessary or securing joint venture partners to complete our expansion and capital programs. If we are unsuccessful, we will have to prioritize such programs, which may result in delaying and potentially losing some valuable business opportunities.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

In June 2003 we took steps to mitigate fluctuations in our cash flows as a result of changes in oil prices by entering into a costless collar hedge with a ceiling price of $30.45 per barrel and a floor price of $24.00 per barrel using WTI as the index traded on the NYMEX. The hedge is on the first 500 barrels of oil produced per day for a six-month period starting June 2003.

Item 4. Controls and Procedures

The Company carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s CEO and CFO, of the effectiveness of the design and operation of the Company s disclosure controls and procedures pursuant to the 1934 Securities Exchange Act. Based upon that evaluation, the CEO and CFO concluded that, as of September 30, 2003, the Company s disclosure controls and procedures are effective in timely alerting them to material information required to be included in the Company s periodic SEC filings relating to the Company (including its consolidated subsidiaries). There were no significant changes in the Company s internal control over financial reporting or in other factors that could significantly affect its internal controls during the period ended September 30, 2003, nor any significant deficiencies or material weaknesses in such internal controls requiring corrective actions. As a result, no corrective actions were taken.

Part II Other Information

Item 1. Legal Proceedings:

This item incorporates by reference the information regarding legal proceedings in Note 11 to the consolidated financial statements in Part I of this Form 10-Q.

Item 2. Changes in 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 and Reports on Form 8-K

(a) Exhibits

Exhibit Number	Description
31.1	Certification by the Chief Executive Officer Relating to Internal Disclosure Controls and Procedures
31.2	Certification by the Chief Financial Officer Relating to Internal Disclosure Controls and Procedures
32.1	Certification by the Chief Executive Officer Relating to a Periodic Report Containing Financial Statements
32.2	Certification by the Chief Financial Officer Relating to a Periodic Report Containing Financial Statements

(b) Reports on Form 8-K.

None

SIGNATURE

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

IVANHOE ENERGY INC.

By: /s/ John O Keefe

Name: John O Keefe
Title: Executive Vice-President and Chief
Financial Officer

Dated: November 5, 2003

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