IVANHOE ENERGY INC
Form 10-Q
August 11, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2008

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________

Commission file number 000-30586

IVANHOE ENERGY INC.

(Exact name of registrant as specified in its charter)

Yukon, Canada	**98-0372413**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
Suite 654 999 Canada Place Vancouver, British Columbia, Canada	**V6C 3E1**
(Address of principal executive office)	*(zip code)*

(604) 688-8323

(registrant s telephone number, including area code)

No Changes

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. þ Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The number of shares of the registrant s capital stock outstanding as of June 30, 2008 was 245,540,784 Common Shares, no par value.

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Part I Financial Information

Item 1 Financial Statements
IVANHOE ENERGY INC.
Unaudited Condensed Consolidated Balance Sheets
(stated in thousands of U.S. Dollars, except share amounts)

	June 30, 2008	December 31, 2007
Assets		
Current Assets:		
Cash and cash equivalents	$ 10,214	$ 11,356
Accounts receivable	11,893	9,376
Advance	725	825
Prepaid and other current assets	461	602
Future income tax assets	2,286	
	25,579	22,159
Oil and gas properties and development costs, net	104,555	111,853
Intangible assets technology	102,153	102,153
Long term assets	2,870	751
	$ 235,157	$ 236,916
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 10,992	$ 9,538
Debt current portion	11,636	6,729
Derivative instruments	27,863	9,432
	50,491	25,699
Long term debt	9,484	9,812
Asset retirement obligations	3,673	2,218
Long term obligation	1,900	1,900
	65,548	39,629
Commitments and contingencies		
Shareholders Equity:		
Share capital, issued 245,540,784 common shares; December 31, 2007 244,873,349 common shares	325,168	324,262
Purchase warrants	18,805	23,078
Contributed surplus	15,901	9,937
Accumulated deficit	(190,265)	(159,990)
	169,609	197,287

	$	**235,157**	$	236,916

(See accompanying notes)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Revenue				
Oil and gas revenue	**$ 17,979**	$ 9,789	**$ 33,022**	$ 19,385
Loss on derivative instruments	**(20,787)**	(316)	**(24,733)**	(775)
Interest income	**36**	116	**108**	236
	(2,772)	9,589	**8,397**	18,846
Expenses				
Operating costs	**6,614**	4,223	**12,006**	7,908
General and administrative	**4,084**	3,384	**7,749**	6,256
Business and technology development	**1,914**	2,348	**3,671**	4,510
Depletion and depreciation	**8,129**	6,024	**16,495**	12,916
Interest expense and financing costs	**504**	189	**1,037**	382
	21,245	16,168	**40,958**	31,972
Loss before Income Taxes	**(24,017)**	(6,579)	**(32,561)**	(13,126)
Future income tax recovery	**2,286**		**2,286**	
Net Loss and Comprehensive Loss	**(21,731)**	(6,579)	**(30,275)**	(13,126)
Accumulated Deficit, beginning of period	**(168,534)**	(127,330)	**(159,990)**	(120,783)
Accumulated Deficit, end of period	**$ (190,265)**	$ (133,909)	**$ (190,265)**	$ (133,909)
Net Loss per share Basic and Diluted	**$ (0.09)**	$ (0.03)	**$ (0.12)**	$ (0.05)
Weighted Average Number of Shares (in thousands)	**245,250**	241,443	**245,063**	241,338

(See accompanying notes)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	**2007**	**2008**	**2007**
Operating Activities				
Net loss and comprehensive loss	**$ (21,731)**	$ (6,579)	**$ (30,275)**	$ (13,126)
Items not requiring use of cash:				
Depletion and depreciation	**8,129**	6,024	**16,495**	12,916
Stock based compensation	**793**	1,053	**1,911**	1,855
Unrealized loss on derivative instruments	**16,433**	286	**18,431**	952
Future income tax recovery	**(2,286)**		**(2,286)**	
Other	**268**	161	**459**	330
Changes in non-cash working capital items	**1,020**	(746)	**908**	(127)
	2,626	199	**5,643**	2,800
Investing Activities				
Capital investments	**(2,593)**	(8,123)	**(7,916)**	(13,457)
Proceeds from sale of assets	**100**		**100**	1,000
Recovery of HTL™ investments		9,000		9,000
Advance repayments	**100**	200	**100**	400
Other	**(73)**		**(103)**	75
Changes in non-cash working capital items	**(1,402)**	(481)	**(2,532)**	(1,494)
	(3,868)	596	**(10,351)**	(4,476)
Financing Activities				
Proceeds from exercise of options	**686**	165	**686**	165
Proceeds from debt obligations, net of financing costs	**5,472**		**5,472**	
Payments of debt obligations	**(615)**	(615)	**(1,230)**	(1,230)
Payments of deferred financing costs	**(1,480)**	(62)	**(2,064)**	(62)
Changes in non-cash working capital items	**702**		**702**	
	4,765	(512)	**3,566**	(1,127)
Increase (decrease) in cash and cash equivalents, for the period	**3,523**	283	**(1,142)**	(2,803)
Cash and cash equivalents, beginning of period	**6,691**	10,793	**11,356**	13,879
Cash and cash equivalents, end of period	**$ 10,214**	$ 11,076	**$ 10,214**	$ 11,076

(See accompanying notes)

Notes to the Condensed Consolidated Financial Statements
June 30, 2008
(all tabular amounts are expressed in thousands of U.S. dollars except per share amounts)
(Unaudited)

1. BASIS OF PRESENTATION

Ivanhoe Energy Inc s (the **Company** or **Ivanhoe Energy**) accounting policies are in accordance with accounting principles generally accepted in Canada. These policies are consistent with accounting principles generally accepted in the U.S., except as outlined in Note 15. The unaudited condensed consolidated financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2007 consolidated financial statements except as discussed in Note 2. 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, 2007 condensed consolidated balance sheet was derived from the audited consolidated financial statements, but does not include all disclosures required by generally accepted accounting principles (**GAAP**) in Canada and the U.S. In the opinion of management, all adjustments (which included normal recurring adjustments) necessary for the fair presentation for the interim periods have been made. The results of operations and cash flows are not necessarily indicative of the results for a full year.

The Company currently anticipates incurring substantial expenditures to further its capital development programs, particularly those related to the recently completed acquisition of two oilsands leases in Alberta. The continued existence of the Company is dependent upon its ability to obtain capital to fund further development and to meet obligations to preserve its interests in its existing Alberta properties and to meet the obligations associated with other potential HTL and GTL projects. The Company intends to finance the future payments required under the Alberta oilsands acquisition and other capital projects from a combination of strategic investors and/or traditional debt and equity markets, either at a parent company level or at the project level. The Company believes that it has sufficient funds to reach final investment decisions on its projects, however significant amounts of new capital will be required.

These interim condensed consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles applicable to a going concern, which assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities in the normal course of operations. If the going concern assumption was not appropriate for these condensed consolidated financial statements, then adjustments would be necessary to the carrying values of assets and liabilities, the reported expenses and the balance sheet classifications used.

2. CHANGES IN ACCOUNTING POLICIES

2008 Accounting Changes

On January 1, 2008 the Company adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants (**CICA**): Handbook Section 1535 Capital Disclosures (**S.1535**), Handbook Section 3862 Financial Instruments Disclosures (**S.3862**), and Handbook Section 3863 Financial Instruments Presentation (**S.3863**). S.1535 establishes standards for disclosing information about an entity s capital and how it is managed. The objective of S.3862 is to require entities to provide disclosures in their financial statements that enable users to evaluate both the significance of financial instruments for the entity s financial position and performance; and the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks. The purpose of S.3863 is to enhance financial statement users understanding of the significance of financial instruments to an entity s financial position, performance and cash flows. The latter two replaced S.3861. The Company has adopted the new standards on January 1, 2008 with additional disclosures included in these condensed consolidated financial statements. There was no transitional adjustment to the condensed consolidated financial statements as a result of having adopted these standards.

Impact of New and Pending Canadian GAAP Accounting Standards

In February 2008, the CICA issued Handbook Section 3064, Goodwill and Intangible assets, (**S.3064**) replacing Handbook Section 3062, Goodwill and Other Intangible Assets (**S.3062**) and Handbook Section 3450, Research and Development Costs . Various changes have been made to other sections of the CICA Handbook for consistency purposes. S.3064 will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Company will adopt the new standards for its fiscal year beginning January 1, 2009. The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous S.3062. Management has concluded that the requirements of this new Section as they relate to goodwill will not have a material impact on its consolidated financial statements; however, management is still evaluating the impact of the requirements related to development costs.

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada s Accounting Standards Board (**AcSB**) ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards (**IFRS**) over a transitional period. The AcSB has developed and published a detailed implementation plan, with a required changeover date for fiscal years beginning on or after January 1, 2011. This convergence initiative is in its early stages as of the date of these financial statements. Management has commenced a program of analyzing the Company s historical financial information in order to assess the impact of the convergence on its financial statements.

3. OIL AND GAS PROPERTIES AND DEVELOPMENT COSTS

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

	As at June 30, 2008				
	Oil and Gas				
	U.S.	China	HTL™	GTL	Total
Oil and Gas Properties:					
Proved	$ 110,316	$ 137,698	$	$	$ 248,014
Unproved	4,394	4,019			8,413
	114,710	141,717			256,427
Accumulated depletion	(30,228)	(70,582)			(100,810)
Accumulated provision for impairment	(50,350)	(16,550)			(66,900)
	34,132	54,585			88,717
HTL™ and GTL Development Costs:					
Feasibility studies and other deferred costs			527	5,054	5,581
Feedstock test facility			5,505		5,505
Commercial demonstration facility			11,083		11,083
Accumulated depreciation			(6,476)		(6,476)
			10,639	5,054	15,693
Furniture and equipment	547	119	113		779
Accumulated depreciation	(468)	(79)	(87)		(634)
	79	40	26		145
	$ 34,211	$ 54,625	$ 10,665	$ 5,054	$ 104,555

	As at December 31, 2007				
	Oil and Gas				
	U.S.	China	HTL™	GTL	Total
Oil and Gas Properties:					
Proved	$ 107,040	$ 134,648	$	$	$ 241,688
Unproved	4,373	3,297			7,670
	111,413	137,945			249,358

Accumulated depletion	(27,091)	(58,583)			(85,674)
Accumulated provision for impairment	(50,350)	(16,550)			(66,900)
	33,972	62,812			96,784
HTL™ and GTL Development Costs:					
Feasibility studies and other deferred costs			389	5,054	5,443
Feedstock test facility			4,724		4,724
Commercial demonstration facility			9,903		9,903
Accumulated depreciation			(5,159)		(5,159)
			9,857	5,054	14,911
Furniture and equipment	529	119	107		755
Accumulated depreciation	(449)	(77)	(71)		(597)
	80	42	36		158
	$ 34,052	$ 62,854	$ 9,893	$ 5,054	$ 111,853

Costs as at June 30, 2008 of $8.4 million ($7.7 million at December 31, 2007), related to unproved oil and gas properties have been excluded from costs subject to depletion and depreciation. Included in that same depletion calculation were $15.1 million for future development costs associated with proven undeveloped reserves as at June 30, 2008 ($8.9 million at December 31, 2007).

For the three-month and six-month periods ended June 30, 2008, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities of $0.6 million and $1.2 million ($0.9 million and $1.8 million for those same periods in 2007) were capitalized.

4. INTANGIBLE ASSETS TECHNOLOGY

The Company s intangible assets consist of the following:

HTL™ Technology

The Company owns an exclusive, irrevocable license to deploy, worldwide, the patented rapid thermal processing process (**RTP™ Process**) for petroleum applications as well as the exclusive right to deploy the RTP™ Process in all applications other than biomass. The Company s carrying value of the RTP™ Process for heavy oil upgrading (**HTL™ Technology** or **HTL™**) as at June 30, 2008 and December 31, 2007 was $92.2 million. Since the Company acquired the technology, it has continued to expand its patent coverage to protect innovations to the HTL Technology as they are developed and to significantly extend the Company s portfolio of HTL intellectual property. The Company is the assignee of three granted patents and currently has five patent applications pending in the U.S. The Company also has multiple patents pending in numerous other countries.

Syntroleum Master License

The Company owns a master license from Syntroleum Corporation (**Syntroleum**) permitting the Company to use Syntroleum s proprietary gas-to-liquids (**GTL Technology** or **GTL**) process in an unlimited number of projects around the world. The Company s master license expires on the later of April 2015 or five years from the effective date of the last site license issued to the Company by Syntroleum. In respect of GTL projects in which both the Company and Syntroleum participate no additional license fees or royalties will be payable by the Company and Syntroleum will contribute, to any such project, the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but the Company would be required to pay the normal license fees and royalties in such projects. The Company s carrying value of the Syntroleum GTL master license as at June 30, 2008 and December 31, 2007 was $10.0 million.

Recovery of capitalized costs related to potential HTL™ and GTL projects is dependent upon finalizing definitive agreements for, and successful completion of, the various projects. These intangible assets were not amortized and their carrying values were not impaired for the three-month and six-month periods ended June 30, 2008 and 2007.

5. LONG TERM DEBT

Notes payable consisted of the following as at:

	June 30, 2008	December 31, 2007
Variable rate bank note, (5.70% - 5.85% at June 30, 2008), due 2008	$ 5,200	$ 4,500
Variable rate bank note (6.29% at June 30, 2008) due 2010	10,000	10,000
Non-interest bearing promissory note, due 2006 through 2009	1,646	2,876
Demand loan at 8% due August 2008	4,936	
	21,782	17,376
Less:		
Unamortized discount	(48)	(139)
Unamortized deferred financing costs	(614)	(696)
Current maturities	(11,636)	(6,729)

	(12,298)	(7,564)
	$ 9,484	$ 9,812

Bank Loans

In October 2006 the Company arranged a Senior Secured Revolving/Term Credit Facility of up to $15 million with an initial borrowing base of $8 million. The facility is a revolving facility and is due in October 2008. Depending on the drawn amount, interest, at the Company s option, will be either at 1.75% to 2.25%, above the bank s base rate or 2.75% to 3.25% over the London Inter-Bank Offered Rate (**LIBOR**). The loan terms include the requirement for the Company to enter into two-year commodity derivative contracts (See Note 10) covering up to 14,700 Bbls of the Company s production from its South Midway property in California and its Spraberry property in West Texas. As part of reestablishing the borrowing base amount, the Company was required to enter into an additional commodity derivative contract (See Note 10). The facility is secured by a mortgage on both of these properties.

In September 2007 the Company arranged an additional Revolving/Term Credit Facility of up to $30 million with an initial borrowing base of $10 million. The facility is a revolving facility with a three-year term with interest payable only during the term. Interest will be three-month LIBOR plus 3.75%. The loan terms include the requirement for the Company to enter into three-year commodity derivative contracts (See Note 10) covering up to 18,000 Bbls per month of the Company s production from its Dagang field in China. The facility is secured by a security interest in the revenue from the Company s monthly oil sales in China and by a pledge of shares of the Company s Chinese subsidiaries.

Promissory Notes

In February 2006, the Company re-acquired the 40% working interest in the Dagang oil project not already owned by the Company. Part of the consideration was the issuance by the Company of a non-interest bearing, unsecured promissory note in the principal amount of approximately $7.4 million ($6.5 million after being discounted to net present value). The note is payable in 36 equal monthly installments commencing March 31, 2006. The Company has the right, during the three-year loan repayment period, to require the holder of the promissory note, Richfirst Holdings Limited (**Richfirst**), to convert the remaining unpaid balance of the promissory note into common shares of the Company s wholly-owned subsidiary, Sunwing Energy Ltd (**Sunwing**), or another company owning all of the outstanding shares of Sunwing, subject to Sunwing or the other company having obtained a listing of its common shares on a prescribed stock exchange. The number of shares issued would be determined by dividing the then outstanding principal balance under the promissory note by the issue price of shares of the newly listed company issued in the transaction that results in the listing, less a 10% discount.

Demand Loan

In April 2008, the Company obtained a loan from a third party finance company in the amount of Cdn. $5.0 million bearing interest at 8% per annum. The principal and accrued and unpaid interest matures and is repayable in August 2008. The lender has the option to convert the outstanding balance, in whole or in part, into the Company s common shares at a conversion price of Cdn.$2.24 per share.

The scheduled maturities of the Company s long term debt, excluding unamortized discount and unamortized deferred financing costs, as at June 30, 2008 were as follows:

2008	11,366
2009	416
2010	10,000
	$ 21,782

6. ASSET RETIREMENT OBLIGATIONS

The Company provides for the expected costs required to abandon its producing U.S. oil and gas properties and the HTL^{TM} commercial demonstration facility (**CDF**). The undiscounted amount of expected future cash flows required to settle the Company s asset retirement obligations for these assets as at June 30, 2008 was estimated at $6.3 million. These payments are expected to be made over the next 30 years; with over half of the payments between 2010 and 2025. To calculate the present value of these obligations, the Company used an inflation rate of 3% and the expected future cash flows have been discounted using a credit-adjusted risk-free rate of 6%. The changes in the Company s liability for the six-month period ended June 30, 2008 were as follows:

2008

Carrying balance as of January 1, 2008	$ 2,218
Liabilities incurred	218
Accretion expense	78
Revisions in estimated cash flows	1,159
Carrying balance as of June 30, 2008	$ 3,673

7. COMMITMENTS AND CONTINGENCIES

Zitong Block Exploration Commitment

At December 31, 2005, the Company held a 100% working interest in a thirty-year production-sharing contract with China National Petroleum Corporation (**CNPC**) in a contract area, known as the Zitong Block, located in the northwestern portion of the Sichuan Basin. In January 2006, the Company farmed-out 10% of its working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**) for $4.0 million.

The Company has completed the first phase of this project and in December 2007, the Company and Mitsubishi (the **Zitong Partners**) made a decision to enter into the next three-year exploration phase (**Phase 2**) of the project. By electing to participate in Phase 2 the Zitong Partners must relinquish 30%, plus or minus 5%, of the Zitong block acreage and complete a minimum work program involving the acquisition of approximately 200 miles of new seismic lines and the drilling of approximately 23,700 feet of new wellbore, (including a 700 foot shortfall from the first phase), with total estimated minimum expenditures for this program of $25.0 million. The Phase 2 seismic line acquisition commitment was fulfilled in the first phase exploration program and no further seismic acquisition is required by the contract. The Zitong Partners must complete the minimum work program by December 31, 2010, or will be obligated to pay to CNPC the cash equivalent of the deficiency in the work program for that exploration phase. The recent earthquake in China s Sichuan Province has resulted in some delays in analyzing and reviewing geophysical data. The Company will be evaluating whether these delays will prohibit it from completing the work program within the required time frame and address whether or not an extension of that time frame is needed in the near future. Following the completion of Phase 2, the Zitong Partners must relinquish all of the remaining property except any areas identified for development and production.

Long Term Obligation

As part of its 2005 merger with Ensyn Group, Inc., the Company assumed an obligation to pay $1.9 million in the event, and at such time that, the sale of units incorporating the HTL™ Technology for petroleum applications reach a total of $100.0 million. This obligation is recorded in the Company s consolidated balance sheet.

Income Taxes

The Company s income tax filings are subject to audit by taxation authorities, which may result in the payment of income taxes and/or a decrease its net operating losses available for carry-forward in the various jurisdictions in which the Company operates. While the Company believes its tax filings do not include uncertain tax positions, except as noted below, the results of potential audits or the effect of changes in tax law cannot be ascertained at this time.

The Company has an uncertain tax position related to the commencement of when tax deductions associated with development costs are taken. In March 2007, the Company received a preliminary indication from local Chinese tax authorities as to a potential change in the rule under which development costs are deducted from taxable income effective for the 2006 tax year. The Company discussed this matter with Chinese tax authorities and subsequently filed its 2006 tax return for Sunwing s wholly-owned subsidiary Pan-China Resources Ltd. (**Pan-China**) taking a new filing position in which development costs are capitalized and amortized on a straight line basis over six years starting in the year the development costs are incurred rather than deducted in their entirety in the year incurred. This change resulted in a $50.3 million reduction in tax loss carry-forwards in 2007 with an equivalent increase in the tax basis of development costs available for application against future Chinese income. The Company has received no formal notification of this rule change, however it will continue to file tax returns under this new approach. To the extent that there is a different interpretation in the timing of the deductibility of developmental costs this could potentially result in a reduction in the net operating losses of Pan-China and a current tax provision of $0.6 million.

The Company has an uncertain tax position related to calculation of a gain on the consideration received from two farm-out transactions (Richfirst January 2004 See Note 5 and Mitsubishi January 2006 See under Zitong Block Exploration Commitment in this Note 7) and the designation of whether the taxable gains may be subject to a withholding tax of 10% pursuant to Chinese tax law for income derived by a foreign entity. The Company is waiting for the Chinese tax authorities to reply to its request to validate in writing that its current treatment of such tax position is appropriate. To the extent that the calculation of a gain is interpreted differently and the amounts are subject to withholding tax there would be an additional current tax provision of approximately $0.7 million.

No amounts have been recorded in the financial statements related to the above mentioned uncertain tax positions as management has determined the likelihood of an unfavorable outcome to the Company to be low.

Other Commitments

The Company has contracted with Zeton Inc. (**Zeton**) to construct a Feedstock Test Facility (**FTF**) that has been designed to process small quantities of heavy oil. The FTF is a small (15-20 Bbls/d), highly flexible state-of-the-art HTL™ facility which will permit more cost-effective screening of feedstock crudes for current and potential partners in smaller volumes and at lower costs than required at the CDF. The contract is considered a lump-sum turn-key contract with scheduled payments tied to milestones. Should Zeton meet all of the remaining milestones, the Company will be obligated to pay $1.9 million in addition to what has been paid to date.

From time to time the Company enters into consulting agreements whereby a success fee may be payable if and when either a definitive agreement is signed or certain other contractual milestones are met. Under the agreements, the consultant may receive cash, Company shares, stock options or some combination thereof. These fees are not considered to be material in relation to the overall capital costs and funding requirements of the future individual projects.

The Company may provide indemnities to third parties, in the ordinary course of business, that are customary in certain commercial transactions such as purchase and sale agreements. The terms of these indemnities will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid. The Company s management is of the opinion that any resulting settlements relating to potential litigation matters or indemnities would not materially affect the financial position of the Company.

8. SHARE CAPITAL AND WARRANTS

Following is a summary of the changes in share capital and stock options outstanding for the six-month period ended June 30, 2008:

	Common Shares			Stock Options	
	Number (thousands)	Amount	Contributed Surplus	Number (thousands)	Weighted Average Exercise Price Cdn.$
Balance December 31, 2007	244,873	$ 324,262	$ 9,937	12,945	$ 2.37
Shares issued for:					
Exercise of options	668	906	(220)	(781)	$ 1.35
Options:					
Granted			1,911	3,782	$ 1.77
Expired				(139)	$ 2.04
Purchase warrants expired			4,273		
Balance June 30, 2008	245,541	$ 325,168	$ 15,901	15,807	$ 2.28

Purchase Warrants

The only changes to the number of the Company s purchase warrants and common shares issuable upon the exercise of the purchase warrants for the six-month period ended June 30, 2008 were the expiration of 4.1 million, and 11.0 million, purchase warrants in April and May 2008. The combined value of $4.3 million associated with these warrants was reclassified from Purchase Warrants to Contributed Surplus at the time of expiration.

As at June 30, 2008, the following purchase warrants were exercisable to purchase common shares of the Company until the expiry date at the price per share as indicated below:

	Purchase Warrants		
Price per Special	Common Shares	Exercise Price per	Value on Exercise

Warrant	Issued	Exercisable (thousands)	Issuable	Value ($U.S. 000)	Expiry Date	Share	($U.S. 000)
U.S.$2.23	11,400	11,400	11,400	18,805	May 2011	Cdn. $2.93 (1)	32,973

(1) Each common share purchase warrant originally entitled the holder to purchase one common share at a price of $2.63 per share until the fifth anniversary date of the closing of the transaction. In September 2006, these warrants were listed on the Toronto Stock Exchange and the exercise price was changed to Cdn. $2.93.

Also see Note 14 Subsequent Events .

9. SEGMENT INFORMATION

The Company has three reportable business segments: Oil and Gas, HTL™ and GTL.

Oil and Gas

The Company explores for, develops and produces crude oil and natural gas in China and in the U.S. The Company seeks projects to which it can apply innovative technology and enhanced recovery techniques in developing them. In China, the Company s development and production activities are conducted at the Dagang oil field located in Hebei Province and its exploration activities are conducted on the Zitong block located in Sichuan Province. In the U.S., the Company s exploration, development and production activities are primarily conducted in California and Texas.

HTL™

The Company seeks to increase its oil reserves through the deployment of our HTL™ Technology. The technology is intended to be used to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. In addition, an HTL™ facility can yield surplus energy for producing steam and electricity used in heavy-oil production. The thermal energy from the RTP™ Process provides heavy-oil producers with an alternative to natural gas that now is widely used to generate steam.

GTL

The Company holds a master license from Syntroleum to use its proprietary GTL Technology to convert natural gas into synthetic fuels. The master license allows the Company to use Syntroleum s proprietary process in GTL projects throughout the world to convert natural gas into ultra clean transportation fuels and other synthetic petroleum products.

Corporate

The Company s corporate office is in Canada with its operational office in the U.S. For this note, any amounts for the corporate office in Canada are included in Corporate.

The following tables present the Company s interim segment information for the three-month and six-month periods ended June 30, 2008 and 2007 and identifiable assets as at June 30, 2008 and December 31, 2007:

	Three-Month Period Ended June 30, 2008					
	Oil and Gas					
	China	**U.S.**	**HTL™**	**GTL**	**Corporate**	**Total**
Oil and gas revenue	$ 11,747	$ 6,232	$	$	$	$ 17,979
Loss on derivative instruments	(15,009)	(5,778)				(20,787)
Interest income	11	22			3	36
	(3,251)	476			3	(2,772)
Operating costs	5,303	1,311				6,614
General and administrative	697	520			2,867	4,084
Business and technology development			1,885	29		1,914
Depletion and depreciation	5,794	1,698	634		3	8,129
Interest expense and financing costs	149	132	22		201	504
	11,943	3,661	2,541	29	3,071	21,245
Loss before Income Taxes	(15,194)	(3,185)	(2,541)	(29)	(3,068)	(24,017)

Future income tax recovery	2,286					2,286
Net Loss and Comprehensive Loss	$ (12,908)	$ (3,185)	$ (2,541)	$ (29)	$ (3,068)	$ (21,731)
Capital Investments	$ 1,646	$ 713	$ 231	$	$ 3	$ 2,593

	Six-Month Period Ended June 30, 2008					
	Oil and Gas					
	China	U.S.	HTL™	GTL	Corporate	Total
Oil and gas revenue	$ 22,635	$ 10,387	$	$	$	$ 33,022
Loss on derivative instruments	(17,691)	(7,042)				(24,733)
Interest income	25	66			17	108
	4,969	3,411			17	8,397
Operating costs	9,613	2,393				12,006
General and administrative	1,263	882			5,604	7,749
Business and technology development			3,605	66		3,671
Depletion and depreciation	12,000	3,154	1,334	3	4	16,495
Interest expense and financing costs	473	280	32		252	1,037
	23,349	6,709	4,971	69	5,860	40,958
Loss before Income Taxes	(18,380)	(3,298)	(4,971)	(69)	(5,843)	(32,561)
Future income tax recovery	2,286					2,286
Net Loss and Comprehensive Loss	$ (16,094)	$ (3,298)	$ (4,971)	$ (69)	$ (5,843)	$ (30,275)
Capital Investments	$ 3,771	$ 3,196	$ 946	$	$ 3	$ 7,916
Identifiable Assets (As at June 30, 2008)	$ 72,530	$ 41,001	$ 103,066	$ 15,088	$ 3,472	$ 235,157
Identifiable Assets (As at December 31, 2007)	$ 73,298	$ 40,726	$ 102,456	$ 15,073	$ 5,363	$ 236,916

	Three-Month Period Ended June 30, 2007					
	Oil and Gas					
	China	U.S.	HTL	GTL	Corporate	Total
Oil and gas revenue	$ 6,990	$ 2,799	$	$	$	$ 9,789
Loss on derivative instruments		(316)				(316)
Interest income	8	39			69	116

	6,998	2,522			69	9,589
Operating costs	3,288	935				4,223
General and administrative	623	795			1,966	3,384
Business and technology development			2,135	213		2,348
Depletion and depreciation	4,328	1,482	211	2	1	6,024
Interest expense and financing costs		98	6		85	189
	8,239	3,310	2,352	215	2,052	16,168
Net Loss and Comprehensive Loss	$ (1,241)	$ (788)	$ (2,352)	$ (215)	$ (1,983)	$ (6,579)
Capital Investments	$ 6,516	$ 981	$ 626	$	$	$ 8,123

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	Six-Month Period Ended June 30, 2007					
	Oil and Gas					
	China	**U.S.**	**HTL**	**GTL**	**Corporate**	**Total**
Oil and gas revenue	$ 13,875	$ 5,510	$	$	$	$ 19,385
Loss on derivative instruments		(775)				(775)
Interest income	19	61			156	236
	13,894	4,796			156	18,846
Operating costs	5,771	2,137				7,908
General and administrative	1,030	1,183			4,043	6,256
Business and technology development			4,152	358		4,510
Depletion and depreciation	9,054	3,096	759	5	2	12,916
Interest expense and financing costs	5	185	13		179	382
	15,860	6,601	4,924	363	4,224	31,972
Net Loss and Comprehensive Loss	$ (1,966)	$ (1,805)	$ (4,924)	$ (363)	$ (4,068)	$ (13,126)
Capital Investments	$ 10,318	$ 1,793	$ 1,346	$	$	$ 13,457

10. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS
The accounting classification of each category of financial instruments, and their carrying amounts, are set out below.

	As at June 30, 2008				
	Loans and receivables	Available-for-sale financial assets	Held-for-trading	Financial liabilities measured at amortized cost	Total carrying amount
Financial Assets:					
Cash and cash equivalents	$	$	$ 10,214	$	$ 10,214
Accounts receivable	11,893				11,893
Advance	725				725
Financial Liabilities:					
Accounts payable and accrued liabilities				(10,992)	(10,992)
Derivative instruments			(27,863)		(27,863)
Long term debt			(4,874)	(16,246)	(21,120)

	$ 12,618	$	$ (22,523)	$ (27,238)	$ (37,143)

	As at December 31, 2007				
	Loans and receivables	Available-for-sale financial assets	Held-for-trading	Financial liabilities measured at amortized cost	Total carrying amount
Financial Assets:					
Cash and cash equivalents	$	$	$ 11,356	$	$ 11,356
Accounts receivable	9,376				9,376
Advance	825				825
Financial Liabilities:					
Accounts payable and accrued liabilities				(9,538)	(9,538)
Derivative instruments			(9,432)		(9,432)
Long term debt				(16,541)	(16,541)
	$ 10,201	$	$ 1,924	$ (26,079)	$ (13,954)

Financial Risk Factors

The Company is exposed to a number of different financial risks arising from typical business exposures as well as its use of financial instruments including market risk relating to commodity prices, foreign currency exchange rates and interest rates, credit risk and liquidity risk. There have been no significant changes to the Company s exposure to risks nor to management s objectives, policies and processes to manage risks from the previous year. The risks associated with our main financial instruments and our policies for minimizing these risks are detailed below.

Market Risk

Market risk is the risk that the fair value or future cash flows of our financial instruments will fluctuate because of changes in market prices. Components of market risk to which we are exposed are discussed below.

Commodity Price Risk

Commodity price risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to the changes in market commodity prices. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals. The Company may periodically use different types of derivative instruments to manage its exposure to price volatility as well as being a requirement of the Company s lenders.

The Company entered into costless collar derivatives to minimize variability in its cash flow from the sale of up to 14,700 Bbls per month of the Company s production from its South Midway Property in California and Spraberry Property in West Texas over a two-year period starting November 2006 and a six-month period starting November 2008. The derivatives had a ceiling price of $65.20, and $70.08, per barrel and a floor price of $63.20, and $65.00, per barrel, respectively, using WTI as the index traded on the NYMEX. The Company also entered into a costless collar derivative to minimize variability in its cash flow from the sale of up to 18,000 Bbls per month of the Company s production from its Dagang field in China over a three-year period starting September 2007. This derivative had a ceiling price of $84.50 per barrel and a floor price of $55.00 per barrel using WTI as the index traded on the NYMEX.

During the three-month and six-month periods ended June 30, 2008, the Company had $4.4 million and $6.3 million of realized losses (nil and $0.2 million of realized gains in 2007), on these derivative transactions, and $16.4 million and $18.4 million, respectively, of unrealized losses ($0.3 million and $1.0 million in 2007). Both realized and unrealized gains and losses on derivatives have been recognized in the results of operations.

On June 30, 2008, the Company s open positions on the derivatives referred to above had a fair value of $27.9 million. A 10% increase in oil prices would increase the fair value, and consequently increase the net loss, by approximately $6.2 million, while a 10% decrease in prices would reduce the fair value, and consequently reduce the net loss, by approximately $5.4 million. The fair value change assumes volatility based on prevailing market parameters at June 30, 2008.

Foreign Currency Exchange Rate Risk

Foreign currency risk refers to the risk that the value of a financial commitment, recognized asset or liability will fluctuate due to changes in foreign currency rates. The main underlying economic currency of the Company s cash flows is the U.S. dollar. This is because the Company s major product, crude oil, is priced internationally in U.S. dollars. Accordingly, we do not expect to face foreign exchange risks associated with our production revenues. However, the Company s cash flow stream relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. The majority of the operating costs incurred in our Chinese operations are paid in Chinese renminbi. The majority of costs incurred in our administrative offices in Vancouver and Calgary, as well as some business development costs, are paid in Canadian dollars. Disbursement transactions denominated in Chinese renminbi and Canadian dollars are converted to U.S. dollar equivalents based on the exchange rate as of the transaction date. Foreign currency gains and losses also come about when monetary assets and liabilities, mainly short term payables and receivables, denominated in foreign currencies are translated at the end of each month. The estimated impact of a 10% strengthening or weakening of the Chinese renminbi, and Canadian dollar, as of June 30, 2008 on net loss and accumulated deficit for the six-month period ended June 30, 2008 is a $0.4 million increase, and a $0.3 million decrease, respectively. To help reduce our exposure to foreign currency risk we seek to maximize our expenditures and contracts denominated in U.S. dollars and minimize those denominated in other currencies.

Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to the changes in market interest rates. Interest rate risk arises from interest-bearing borrowings which have a variable interest rate. Interest-bearing financial assets are not considered significant. The Company currently has two separate bank loan facilities with fluctuating interest rates. We estimate that our net loss and accumulated deficit for the six-month period ended June 30, 2008 would have changed $0.1 million for every 1% change in interest rates as of June 30, 2008. The Company is not currently actively attempting to manage this interest rate risk given the limited amount and term of our borrowings and the current global interest rate cycle.

Credit Risk

The Company is exposed to credit risk with respect to its cash held with financial institutions, accounts receivable and advance balances. The Company believes its exposure to credit risk related to cash held with financial institutions is minimal due to the large size of the institutions where the cash is held. Most of the Company s accounts receivable balances relate to oil and natural gas sales and are exposed to typical industry credit risks. In addition, accounts receivable balances consist of costs billed to joint venture partners where the Company is the operator and advances to partners for joint operations where the Company is not the operator. The advance balance relates to an arrangement whereby scheduled advances were made to a third party contractor associated with negotiating an HTL™ and/or GTL project for the Company. The Company manages its credit risk by entering into sales contracts with only established entities and reviewing its exposure to individual entities on a regular basis. Of the $11.9 million trade receivables balance as at June 30, 2008, $8.4 million is due from customer A and $2.1 million is due from customer B. There are no other customers who represent more than 5% of the total balance of trade receivables. As noted below, included in the Company s trade receivable and advance balance are debtors with a carrying amount of $1.5 million which are past due at the reporting date for which the Company has not provided an allowance as there has not been a significant change in credit quality and the amounts are still considered recoverable. Losses associated with credit risk have been immaterial for all periods presented.

	June 30, 2008	**December 31, 2007**
Accounts Receivable:		
Neither impaired nor past due	$ 11,110	$ 8,259
Impaired (net of valuation allowance)		
Not impaired and past due in the following periods:		
within 30 days	19	347
31 to 60 days	27	
61 to 90 days	11	4
over 90 days	726	766
	11,893	9,376
Advance		
Not impaired and past due over 90 days	725	825
	$ 12,618	$ 10,201

Our maximum exposure to credit risk is based on the recorded amounts of our financial assets above.

Liquidity Risk

Liquidity risk is the risk that suitable sources of funding for the Company s business activities may not be available, which means we may be forced to sell financial assets or non-financial assets, refinance existing debt, raise new debt or issue equity. The Company s present plans include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt financing or the sale of equity securities in order to generate sufficient resources to assure continuation of the Company s operations and achieve its capital investment objectives.

The contractual maturity of our fixed and floating rate financial liabilities and derivatives are show in the table below. The amounts presented represent the future undiscounted principal and interest cash flows and therefore do not equate to the values presented in the balance sheet.

	As at June 30, 2008 Contractual Maturity (Nominal Cash Flows)				As at December 31, 2007 Contractual Maturity (Nominal Cash Flows)			
	Less than 1 year	1 to 2 years	2 to 5 years	Over 5 years	Less than 1 year	1 to 2 years	2 to 5 years	Over 5 years
Derivative financial liabilities:								
Costless Collars oil price commodity	$ 19,478	$ 8,385	$	$	$ 7,156	$ 2,276	$	$
Non derivative financial liabilities:								
Trade accounts payable	$ 5,714	$	$	$	$ 6,897	$	$	$
Accruals	$ 5,278	$	$	$	$ 2,641	$	$	$
Long term debt	$ 12,363	$ 859	$ 10,139	$	$ 8,240	$ 1,541	$ 10,277	$

11. CAPITAL MANAGEMENT

The Company manages its capital so that the Company and its subsidiaries will be able to continue as a going concern and to create shareholder value through exploring, appraising and developing its assets including the major initiative of implementing multiple, full-scale, commercial HTL heavy-oil projects in Canada and internationally. There have been no significant changes in management s objectives, policies and processes to manage capital or the components of capital from the previous year.

The Company defines capital as total equity or deficiency plus cash and cash equivalents and long-term debt. Total equity is comprised of share capital, warrants, shares to be issued and accumulated deficit as disclosed in Note 8. Cash and cash equivalents consist of $10.2 million and $11.4 million at June 30, 2008 and December 31, 2007. Long-term debt is disclosed in Note 5.

The Company s management reviews the capital structure on a regular basis to maintain the most optimal debt to equity balance. In order to maintain or adjust its capital structure, the Company may refinance its existing debt, raise new debt, seek cost sharing arrangements with partners or issue new shares. The Company believes that it met its objectives for the first six months of 2008.

The Company s U.S. and Chinese oil and gas subsidiaries are subject to financial covenants, such as interest coverage ratios, under each of their revolving/term credit facilities which are measured on a quarterly or semi-annual basis. The Company is in compliance with all financial covenants for the quarter ended June 30, 2008.

12. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2008	**2007**	**2008**	**2007**
Supplemental Cash Flow Information:				
Cash paid during the period for:				
Income taxes	**$**	$	**$ 6**	$ 5
Interest	**$ 239**	$ 73	**$ 605**	$ 34
Changes in non-cash working capital items				
Operating Activities:				
Accounts receivable	**$ (1,365)**	$ (540)	**$ (2,549)**	$ 469
Prepaid and other current assets	**23**	69	**131**	251
Accounts payable and accrued liabilities	**2,362**	(275)	**3,326**	(847)
	1,020	(746)	**908**	(127)
Investing Activities				
Accounts receivable	**(5)**	(19)	**32**	(134)
Prepaid and other current assets	**31**	17	**10**	60
Accounts payable and accrued liabilities	**(1,428)**	(479)	**(2,574)**	(1,420)
	(1,402)	(481)	**(2,532)**	(1,494)
Financing Activities				
Accounts payable and accrued liabilities	**702**		**702**	

	$ 320	$ (1,227)	**$ (922)**	$ (1,621)

Cash and cash equivalents at June 30, 2008 and December 31, 2007 are composed entirely of bank balances in checking or savings accounts.

13. INCOME TAXES

The Company has concluded that it is more likely than not to be able to utilize the tax deductions associated with future income tax assets related to its Pan-China operations. This resulted in a future income tax recovery in the second quarter of 2008 of $2.3 million.

14. SUBSEQUENT EVENTS

In July 2008 the Company completed a Cdn.$88.0 million private placement consisting of 29,334,000 Special Warrants (**Special Warrants**) at Cdn.$3.00 per Special Warrant (the **Offering**). Each Special Warrant entitled the holder to one common share of the Company upon exercise of the Special Warrant. The estimated net proceeds from the Offering of the Special Warrants were approximately Cdn.$83.4 million after deducting the agents commission of Cdn.$4.0 million and the expenses of the Offering estimated at Cdn.$600,000. The Company used Cdn.$22.5 million of the net proceeds of the Offering to complete the cash component of the Talisman lease acquisition described immediately below. The Company intends to use the remaining net proceeds from the Offering for its planned 2008 winter drilling and geotechnical program, its HTL™ Technology development program and for working capital purposes.

The Offering was completed concurrently with the acquisition of Talisman Energy Canada s (**Talisman**) 100% working interests in two leases located in the Athabasca oilsands region in the Province of Alberta, Canada. The total purchase price is Cdn.$90.0 million, of which an initial payment of Cdn.$22.5 million was made from the proceeds of the Offering noted above. In addition to this initial payment the Company issued a promissory note to Talisman in the principal amount of Cdn.$12.5 million bearing interest at a rate per annum equal to the prime rate plus 2%, calculated daily and not compounded, and maturing on December 31, 2008 (the **2008 Note**). The Company also issued a second promissory note to Talisman in the principal amount of Cdn.$40.0 million bearing interest at a rate per annum equal to the prime rate plus 2%, calculated daily and not compounded, and payable semi-annually, maturing in July 2011 and convertible (as to the outstanding principal amount), at Talisman s option, into 12,779,552 common shares of the Company at Cdn.$3.13 per common share(the **Convertible Note**).

The Company will also make a cash payment to Talisman of Cdn.$15 million if the requisite government and other approvals necessary to develop the northern border of one of the leases (the **Contingent Payment**) are obtained.

The Company had also agreed to acquire Talisman s 75% working interest in a third oilsands lease, subject to the remaining working interest holder not exercising its right of first refusal to acquire Talisman s interest. The third party right of first refusal was exercised and Ivanhoe did not acquire Talisman s interest in this lease. Pursuant to the asset transfer agreement, Ivanhoe and Talisman have agreed that if the remaining working interest holder in the lease does not complete the acquisition of Talisman s interest by November 30, 2008, within 30 days after notice from Talisman, Ivanhoe will acquire such interest from Talisman for a purchase price of Cdn.$15 million.

Ivanhoe s obligations under the 2008 Note, the Convertible Note and the Contingent Payment are secured by a first fixed charge and security interest in favor of Talisman against the acquired Talisman leases and the related assets acquired by Ivanhoe pursuant to the Talisman lease acquisition, and a subordinate security interest in and to all other present and after-acquired property of Ivanhoe other than the shares of any subsidiary of Ivanhoe (whether direct or indirect, current or future). Talisman also has no security interest in any assets of any subsidiary of Ivanhoe (whether direct or indirect, current or future).

Talisman retains a back-in right (the **Back-in Right**), exercisable once per lease until July 11, 2011, to acquire up to a 20% undivided interest in each lease. The purchase price payable by Talisman were it to exercise the Back-in Right in respect of a particular lease would be an amount equal to 20% of:

(a) 100% of the Company s acquisition cost and certain expenses in respect of the relevant lease if the Back-in Right is exercised on or before July 11, 2009;

(b) 150% of the Company s acquisition cost and certain expenses in respect of the relevant lease if the Back-in Right is exercised after July 11, 2009 but on or before July 11, 2010; and

(c) 200% of the Company s acquisition cost and certain expenses in respect of the relevant lease if the Back-in Right is exercised after July 11, 2010 but on or before July 11, 2011.

Until July 11, 2011, Talisman will also have the right of first offer to acquire any interests in heavy oil projects in the Province of Alberta that the Company or any of its subsidiaries wishes to sell, excluding the acquired leases

15. ADDITIONAL DISCLOSURE REQUIRED UNDER U.S. GAAP

The Company s consolidated financial statements have been prepared in accordance with GAAP as applied in Canada. In the case of the Company, Canadian GAAP conforms in all material respects with U.S. GAAP except for certain matters, the details of which are as follows:

Condensed Consolidated Balance Sheets

Shareholders Equity and Oil and Gas Properties and Development Costs

	As at June 30, 2008					
	Assets	Liabilities	Shareholders Equity			
	Oil and Gas Properties and Development Costs	Derivative Instruments	Share Capital and Warrants	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 104,555	$ 27,863	$ 343,973	$ 15,901	$ (190,265)	$ 169,609
Adjustments for:						
Reduction in stated capital (i)			74,455		(74,455)	
Accounting for stock based compensation (ii)			(435)	(3,313)	3,748	
Fair value adjustment of warrants (iii)		21,157	(5,575)	(2,977)	(12,605)	(21,157)
Ascribed value of shares issued for U.S. royalty interests, net (iv)	1,358		1,358			1,358
Provision for impairment (v)	(25,990)				(25,990)	(25,990)
Depletion adjustments due to differences in provision for impairment (vi)	11,641				11,641	11,641
HTL™ and GTL development costs expensed, (vii)	(5,795)				(5,795)	(5,795)
U.S. GAAP	$ 85,769	$ 49,020	$ 413,776	$ 9,611	$ (293,721)	$ 129,666

	As at December 31, 2007					
	Assets	Liabilities	Shareholders Equity			
	Oil and Gas Properties and Development Costs	Derivative Instruments	Share Capital and Warrants	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 111,853	$ 9,432	$ 347,340	$ 9,937	$ (159,990)	$ 197,287

Adjustments for:						
Reduction in stated capital (i)			74,455		(74,455)	
Accounting for stock based compensation (ii)			(396)	(3,352)	3,748	
Fair value adjustment of warrants (iii)		5,786	(7,988)	(564)	2,766	(5,786)
Ascribed value of shares issued for U.S. royalty interests, net (iv)	1,358		1,358			1,358
Provision for impairment (v)	(25,990)				(25,990)	(25,990)
Depletion adjustments due to differences in provision for impairment (vi)	9,334				9,334	9,334
HTL™ and GTL development costs expensed, (vii)	(5,658)				(5,658)	(5,658)
U.S. GAAP	$ 90,897	$ 15,218	$ 414,769	$ 6,021	$ (250,245)	$ 170,545

Shareholders Equity

(i) In June 1999, the shareholders approved a reduction of stated capital in respect of the common shares by an amount of $74.5 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the accumulated deficit such as this is not recognized except in the case of a quasi reorganization. The effect of this is that under U.S. GAAP, share capital and accumulated deficit are increased by $74.5 million as at June 30, 2008 and December 31, 2007.

(ii) For Canadian GAAP, the Company accounts for all stock options granted to employees and directors since January 1, 2002 using the fair value based method of accounting. Under this method, compensation costs are recognized in the financial statements over the stock options vesting period using an option-pricing model for determining the fair value of the stock options at the grant date. For U.S. GAAP, prior to January 1, 2006 the Company applied APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and did not recognize compensation costs in its financial statements for stock options issued to employees and directors. This resulted in a reduction of $3.7 million in the accumulated deficit as at June 30, 2008, and December 31, 2007, equal to accumulated stock based compensation for stock options granted to employees and directors since January 1, 2002 and expensed through December 31, 2005 under Canadian GAAP.

In December 2004, the Financial Accounting Standards Board (**FASB**) issued a revision to SFAS No. 123, Accounting for Stock Based Compensation which supersedes APB No. 25, Accounting for Stock Issued to Employees . This statement (**SFAS No. 123(R)**) requires measurement of the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant and recognition of the cost in the results of operations over the period during which an employee is required to provide service in exchange for the award. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. The Company elected to implement this statement on a modified prospective basis starting in the first quarter of 2006 whereby the Company began recognizing stock based compensation in its U.S. GAAP results of operations for the unvested portion of awards outstanding as at January 1, 2006 and for all awards granted after January 1, 2006. There were no differences in the Company s stock based compensation expense in its financial statements for Canadian GAAP and U.S. GAAP for the three-month and six-month periods ended June 30, 2008 and 2007.

(iii) The Company accounts for purchase warrants as equity under Canadian GAAP. As more fully described in our financial statements in Item 8 of our 2007 Annual Report filed on Form 10-K, in 2006, the accounting treatment of warrants under U.S. GAAP reflects the application of Statement of Financial Accounting Standard No. 133 Accounting for Derivative Instruments and Hedging Activities (**SFAS No. 133**). Under SFAS No. 133, share purchase warrants with an exercise price denominated in a currency other than a company s functional currency are accounted for as derivative liabilities. Changes in the fair value of the warrants are required to be recognized in the statement of operations each reporting period for U.S. GAAP purposes. At the time that the Company s share purchase warrants are exercised, the value of the warrants will be reclassified to shareholders equity for U.S. GAAP purposes. Under Canadian GAAP, the fair value of the warrants on the issue date is recorded as a reduction to the proceeds from the issuance of common shares, with the offset to the warrant component of equity. The warrants are not revalued to fair value under Canadian GAAP. When such warrants expire unexercised, there is no adjustment for U.S. GAAP as the fair value of the liability is zero. Under Canadian GAAP the value of the warrants is reclassified to contributed surplus upon expiry. This GAAP difference resulted in an increase in derivative instruments of $21.2 million and $5.8 million, a decrease in share capital and warrants of $5.6 million and $8.0 million and a decrease in contributed surplus of $3.0 million and $0.6 million at June 30, 2008 and December 2007.

Oil and Gas Properties and Development Costs

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

(v) There are certain 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. In the ceiling test evaluation for U.S. GAAP purposes, the Company limits, on a country-by-country basis, the capitalized costs of oil and gas properties, net of accumulated depletion, depreciation and amortization and deferred income taxes, to (a) the estimated future net cash flows from proved oil and gas reserves using period-end, non-escalated prices and costs, discounted to present value at 10% per annum, plus (b) the cost of properties not being amortized (e.g. major development projects) and (c) the lower of cost or fair value of unproved properties included in the costs being amortized less (c) income tax effects related to the difference between the book and tax basis of the properties referred to in (b) and (c) above. If capitalized costs exceed this limit, the excess is charged as a provision for impairment. Unproved properties and major development projects are assessed on a quarterly basis for possible impairments or reductions in value. If a reduction in value has occurred, the impairment is transferred to the carrying value of proved oil and gas properties. The Company performed the ceiling test in accordance with U.S. GAAP and determined that for the three-month and six-month periods ended June 30, 2008 no impairment provision was required and no impairment provision was required under Canadian GAAP. The cumulative differences in the amount of impairment provisions between U.S. and Canadian GAAP were $26.0 million at June 30, 2008 and December 31, 2007.

(vi) The cumulative differences in the amount of impairment provisions between U.S. and Canadian GAAP resulted in a reduction in accumulated depletion of $11.6 million and $9.3 million as at June 30, 2008 and December 31, 2007.

(vii) As more fully described in our financial statements in Item 8 of our 2007 Annual Report filed on Form 10-K, for Canadian GAAP, the Company capitalizes certain costs incurred for HTL™ and GTL projects subsequent to executing a memorandum of understanding to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products. If no definitive agreement is reached, then the project s capitalized costs, which are deemed to have no future value, are written down and charged to the results of operations with a corresponding reduction in HTL™ and GTL development costs. For U.S. GAAP, feasibility, marketing and related costs incurred prior to executing an HTL™ or GTL definitive agreement are considered to be research and development and are expensed as incurred. As at June 30, 2008 and December 31, 2007, the Company capitalized $5.8 and $5.7 million for Canadian GAAP, which was expensed for U.S. GAAP purposes.

Deferred Financing Costs

As more fully described in our financial statements in Item 8 of our 2007 Annual Report filed on Form 10-K, for Canadian GAAP the Company accounts for deferred financing costs, or transaction costs, as a reduction from the related liability and accounted for using the effective interest method. For U.S. GAAP purposes, these costs are classified as other assets resulting in an increase of $0.6 million, and $0.7 million, in long-term debt and other assets for U.S. GAAP purposes when compared to Canadian GAAP as at June 30, 2008 and December 31, 2007.

Condensed Consolidated Statements of Operations

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

	Three Month Periods Ended June 30, 2008		2007	
	Net Loss	**Net Loss Per Share**	**Net Loss**	**Net Loss Per Share**
Canadian GAAP	$ (21,731)	$ (0.09)	$ (6,579)	$ (0.03)
Fair value adjustment of derivative instruments (iii)	(12,204)	(0.05)	(1,904)	
Depletion adjustments due to differences in provision for impairment (viii)	1,082	0.01	1,111	
HTL™ and GTL development costs expensed, net of write downs, (ix)	(128)		(118)	
Recovery of HTL™ investments (ix)			6,279	0.03
U.S. GAAP	$ (32,981)	$ (0.13)	$ (1,211)	$
Weighted Average Number of Shares under U.S. GAAP (in thousands)		245,250		241,443

	Six-Month Periods Ended June 30, 2008		2007	
	Net Loss	**Net Loss Per Share**	**Net Loss**	**Net Loss Per Share**
Canadian GAAP	$ (30,275)	$ (0.12)	$ (13,126)	$ (0.05)
Fair value adjustment of warrants (iii)	(15,371)	(0.07)	(4,096)	(0.03)
	2,307	0.01	2,414	0.01

Depletion adjustments due to differences in provision for impairment (viii)				
HTL™ and GTL development costs expensed, net of write downs, (ix)	(137)		(118)	
Recovery of HTL™ investments (ix)			6,279	0.03
U.S. GAAP	$ (43,476)	$ (0.18)	$ (8,647)	$ (0.04)
Weighted Average Number of Shares under U.S. GAAP (in thousands)		245,063		241,338

(viii) As discussed under Oil and Gas Properties and Development Costs in this note, there is a difference in performing the ceiling test evaluation under the full cost method of the accounting rules between U.S. and Canadian GAAP. Application of the ceiling test evaluation under U.S. GAAP has resulted in an accumulated net increase in impairment provisions on the Company s U.S. and China oil and gas properties of $26.0 million as at June 30, 2008 and December 31, 2007. This net increase in U.S. GAAP impairment provisions has resulted in lower depletion rates for U.S. GAAP purposes and a reduction of $1.1 million and $2.3 million in the net losses for the three-month and six-month periods ended June 30, 2008 and a reduction of $1.1 million and $2.4 million in the net losses for the three-month and six-month periods ended June 30, 2007.

(ix) As more fully described under Oil and Gas Properties and Development Costs in this note, for Canadian GAAP, feasibility, marketing and related costs incurred prior to executing an HTL™ or GTL 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. The Company expensed $0.1 million in excess of the Canadian GAAP write-downs for the three-month and six-month periods ended June 30, 2008, and the Company expensed nil in excess of the Canadian GAAP write-downs during those corresponding periods in 2007.

The Company and INPEX Corporation (**INPEX**) signed an agreement to jointly pursue the opportunity to develop a heavy oil field in Iraq that Ivanhoe believes is a suitable candidate for its patented HTL™ heavy oil upgrading technology. In the second quarter of 2007, the Company received a $9.0 million payment related to this agreement which was credited to the carrying value of its Iraq and CDF HTL™ Development Costs related to this project for Canadian GAAP purposes. The prior costs for Iraq projects had previously been expensed for U.S. GAAP purposes and therefore that portion of the proceeds, $6.3 million, was credited to the statement of operations for U.S. GAAP purposes.

Condensed Consolidated Statements of Cash Flow

There would be no material difference in cash flow presentation between Canadian and U.S. GAAP for the three-month and six-month periods ended June 30, 2008. As a result of expensing of HTL™ and GTL development costs required under U.S. GAAP and recovery of such costs, the statements of cash flows as reported would result in a cash surplus from operating activities of $6.6 million and $9.2 million for the three-month and six-month period ended June 30, 2007 for U.S. GAAP purposes. Additionally, capital investments reported under investing activities would be $8.0 million and $13.3 million for the three-month and six-month period ended June 30, 2007.

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

In May 2008, the Financial Accounting Standards Board (**FASB**) issued Statement of Financial Accounting Standards No. 162, The Hierarchy of Generally Accepted Accounting Principles (**SFAS No. 162**). This Statement identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (**GAAP**) in the United States (the **GAAP hierarchy**). The FASB is responsible for identifying the sources of accounting principles and providing entities with a framework for selecting the principles used in the preparation of financial statements that are presented in conformity with GAAP. The current GAAP hierarchy, as set forth in the American Institute of Certified Public Accountants (**AICPA**) Statement on Auditing Standards No. 69, The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles , has been criticized because (1) it is directed to the auditor rather than the entity, (2) it is complex, and (3) it ranks FASB Statements of Financial Accounting Concepts, which are subject to the same level of due process as FASB Statements of Financial Accounting Standards, below industry practices that are widely recognized as generally accepted but that are not subject to due process. The FASB believes that the GAAP hierarchy should be directed to entities because it is the entity (not its auditor) that is responsible for selecting accounting principles for financial statements that are presented in conformity with GAAP. Accordingly, the FASB concluded that the GAAP hierarchy should reside in the accounting literature established by the FASB and is issuing this Statement to achieve that result. SFAS No. 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles .

In March 2008, the FASB issued Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities (**SFAS No. 161**). The new standard is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity s financial position, financial performance, and cash flows. It is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. Management is currently evaluating the impact of the adoption of this new standard on its financial statements.

In December 2007, the FASB issued Statement of Financial Accounting Standards No. 141 (revised 2007), Business Combinations (**SFAS No. 141(R)**) and Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements (**SFAS No. 160**). Effective for fiscal years beginning after December 15, 2008, the standards will improve, simplify, and converge internationally the accounting for business combinations and the reporting of noncontrolling interests in consolidated financial statements. SFAS 141(R) requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 160 requires all entities to report noncontrolling (minority) interests in subsidiaries in the same way as equity in the consolidated financial statements. Management is currently evaluating the impact of the adoption of these new standards on its financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, Fair Value Measurements (**SFAS No. 157**). This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement does not require any new fair value measurements; however, for some entities the application of this statement will change current practice. The Company adopted the provisions of SFAS No. 157 effective January 1, 2008. The implementation of this standard did not have a material impact on the consolidated financial statements as our current policy on accounting for fair value measurements is consistent with this guidance. We have, however, provided additional prescribed disclosures not required under Canadian GAAP.

SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The three levels of the fair value hierarchy are described below:

Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.

Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.

Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

As required by SFAS No. 157 when the inputs used to measure fair value fall within different levels of the hierarchy, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measure in its entirety.

The following table presents the company s fair value hierarchy for those assets and liabilities measured at fair value on a recurring basis as of June 30, 2008.

	As at June 30, 2008			
	Level 1	Level 2	Level 3	Total
Derivative instruments liabilities	$ 21,157	$ 27,863	$	$ 49,020
Long term debt		4,874		4,874
	$ 21,157	$ 32,737	$	$ 53,894

The fair value measurement of derivative instruments liabilities related to our costless collars and of our convertible debt are considered Level 2 and the fair value measurement of derivative instruments liabilities related to our purchase warrants denominated in Cdn.$ are considered Level 1.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations
Forward-Looking Statements

With the exception of historical information, certain matters discussed in this Form 10-Q, including in this Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations, are forward looking statements that involve risks and uncertainties. Certain statements contained in this Form 10-Q, including statements which may contain words such as anticipate , could , propose , should , intend , seeks to , is pursuing , expect and similar expressions and statements relating to matters that are not historical facts are forward-looking statements. Forward-looking statements can also include discussions relating to Ivanhoe Energy s agreement with Talisman to acquire all of Talisman s working interest in two oil sand leases, Ivanhoe Energy s ability to obtain the financing to pay the principal and interest on the notes delivered by Ivanhoe Energy at the acquisition closing, Ivanhoe Energy s plan to establish its first integrated HTL heavy-oil project on Lease 10, the anticipated production capacity of the proposed HTL plant, the anticipated quantities of recoverable barrels of bitumen and other statements which are not historical facts and to future production associated with our HTL™ Technology, GTL Technology and EOR techniques. Such statements involve known and unknown risks and uncertainties which may cause our actual results, performances or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Although we believe that our expectations are based on reasonable assumptions, we can give no assurance that our goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, our ability to raise capital as and when required, the timing and extent of changes in prices for oil and gas, competition, environmental risks, drilling and operating risks, uncertainties about the estimates of reserves and the potential success of heavy-to light and gas-to-liquids technologies, the prices of goods and services, the availability of drilling rigs and other support services, legislative and government regulations, political and economic factors in countries in which we operate and implementation of our capital investment program.

The above items and their possible impact are discussed more fully in the section entitled Risk Factors in Item 1A and Quantitative and Qualitative Disclosures About Market Risk in Item 7A of our 2007 Annual Report on Form 10-K.

The following should be read in conjunction with the Company s unaudited condensed consolidated financial statements contained herein, and the consolidated financial statements, and the Management s Discussion and Analysis of Financial Condition and Results of Operations, contained in the Form 10-K for the year ended December 31, 2007. 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 GAAP in Canada. The impact of significant differences between Canadian GAAP and U.S. GAAP on the unaudited condensed consolidated financial statements is disclosed in Note 15.

SPECIAL NOTE TO CANADIAN INVESTORS

The Company is a registrant under the Securities Exchange Act of 1934 and voluntarily files reports with the U.S. Securities and Exchange Commission (**SEC**) on Form 10-K, Form 10-Q and other forms used by registrants that are U.S. domestic issuers. Therefore, our reserves estimates and securities regulatory disclosures generally follow SEC requirements. In 2004, the Canadian Securities Administrators (**CSA**) adopted *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* (NI 51-101) which prescribes certain standards for the preparation and disclosure of reserves and related information by Canadian issuers. We have been granted certain exemptions from NI 51-101. Please refer to the *Special Note to Canadian Investors* on page 10 of our 2007 Annual Report on Form 10-K.

OUR DISCUSSION AND ANALYSIS OF OUR OIL AND GAS ACTIVITIES WITH RESPECT TO OIL AND GAS VOLUMES, RESERVES AND RELATED PERFORMANCE MEASURES IS PRESENTED ON OUR WORKING INTEREST BASIS AFTER ROYALTIES. ALL TABULAR AMOUNTS ARE EXPRESSED IN THOUSANDS OF U.S. DOLLARS, EXCEPT PER SHARE AND PRODUCTION DATA INCLUDING REVENUES AND COSTS PER BOE.

As generally used in the oil and gas business and in this throughout the Form 10-Q, the following terms have the following meanings:

Boe	= barrel of oil equivalent

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

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

Electronic copies of our filings with the SEC and the CSA are available, free of charge, through our web site (www.ivanhoeenergy.com) or, upon request, by contacting our investor relations department at (604) 688-8323. Alternatively, the SEC and the CSA each maintains a website (www.sec.gov and www.sedar.com) that contains our periodic reports and other public filings with the SEC and the CSA.

Ivanhoe Energy s Business

Ivanhoe Energy is an independent international heavy oil development and production company focused on pursuing long-term growth in its reserve base and production using advanced technologies, including its proprietary, patented rapid thermal processing process (**RTP™ Process**) for heavy oil upgrading (**HTL™ Technology** or **HTL™**). The recently announced acquisition of two leases located in the heart of the Athabasca oilsands region in Alberta, Canada will provide the site for the first commercial application of the Company s HTL Technology in a major, integrated heavy oil project (see Implementation Strategy and the Talisman Lease Acquisition below).

In addition, the Company seeks to expand its reserve base and production through conventional exploration and production (**E&P**) of oil and gas. Finally, the Company is exploring an opportunity to monetize stranded gas reserves through the application of the conversion of natural gas-to-liquids using a technology (**GTL Technology** or **GTL**) licensed from Syntroleum Corporation. Our core operations are in Canada, the United States and China, with business development opportunities worldwide.

Corporate Strategy

Importance of the Heavy Oil Segment of the Oil and Gas Industry

The global oil and gas industry is operating near capacity, driven by sharp increases in demand from developing economies and the declining availability of replacement low cost reserves. This has resulted in a significant increase in the relative price of oil and marked shifts in the demand and supply landscape. These shifts include demand moving toward China and India, while supply has shifted towards the need to develop higher cost/lower value resources, including heavy oil.

Heavy oil developments can be segregated into two types: conventional heavy oil that flows to the surface without steam enhancement and non-conventional heavy oil and bitumen. While we focus on the non-conventional heavy oil, both play an important role in Ivanhoe s corporate strategy.

Production of conventional heavy oil has been steadily increasing worldwide, led by Canada and Latin America but with significant contributions from most oil basins, including the Middle East and the Far East, as producers struggle to replace declines in light oil reserves. Even without the impact of the large non-conventional heavy oil projects in Canada and Venezuela, world oil production has been getting heavier. Refineries, on the other hand, have not been able to keep up with the need for deep conversion capacity, and heavy-light price differentials have widened significantly.

With regard to non-conventional heavy oil and bitumen, the dramatic increase in interest and activity has been fueled by higher prices, in addition to various key advances in technology, including improved remote sensing, horizontal drilling, and new thermal techniques. This has enabled producers to more effectively access the extensive, heavy oil resources around the world.

These newer technologies, together with higher oil prices, have generated increased access to heavy oil resources, although for profitable exploitation, key challenges remain, with varied weightings, project by project: 1) the requirement for steam and electricity to help extract heavy oil, 2) the need for diluent to move the oil once it is at the surface, 3) the wide heavy-light price differentials that the producer is faced with when the product gets to market, and 4) conventional upgrading technologies limited to very large scale, high capital cost facilities. These challenges can lead to distressed assets, where economics are poor, or to stranded assets, where the resource cannot be economically produced and lies fallow.

Ivanhoe s Value Proposition

Ivanhoe s application of the HTL™ Technology seeks to address the four key heavy oil development challenges outlined above, and can do so at a relatively small minimum economic scale.

Ivanhoe s HTL upgrading is a partial upgrading process that is designed to operate in facilities as small as 10,000-30,000 barrels per day. This is substantially smaller than the minimum economic scale for conventional stand-alone upgraders such as delayed cokers, which typically operate at scales of well over 100,000 barrels per day. Ivanhoe s HTL Technology is based on carbon rejection, a tried and tested concept in heavy oil processing. The key advantage of HTL is that it is a very fast process processing times are typically under a few seconds. This results in smaller, less costly facilities and eliminates the need for hydrogen addition, an expensive, large minimum scale step typically required in conventional upgrading. Ivanhoe s HTL Technology has the added advantage of converting the byproducts from the upgrading process into onsite energy, rather than generating large volumes of low value coke.

The HTL process offers significant advantages as a field-located upgrading alternative, integrated with the upstream heavy oil production operation. HTL provides four key benefits to the producer:

1. Virtual elimination of external energy requirements for steam generation and/or power for upstream operations.

2. Elimination of the need for diluent or blend oils for transport.

3. Capture of the majority of the heavy-light oil value differential.

4. Relatively small minimum economic scale of operations suited for field upgrading and for smaller field developments.

The business opportunities available to Ivanhoe correspond to the challenges each potential heavy oil project faces. In Canada, Ecuador, California, Iraq and Oman, all four of the HTL™ advantages identified above come into play. In others, including certain identified opportunities in Colombia and Libya, the heavy oil naturally flows to the surface, but transport is the key problem.

The economics of a project are effectively dictated by the advantages that HTL™ can bring to a particular opportunity. The more stranded the resource and the fewer monetization alternatives that the resource owner has, the greater the opportunity the Company will have to establish the Ivanhoe value proposition.

Implementation Strategy and the Talisman Lease Acquisition

In July, the Company announced the completion of the acquisition of Talisman Energy Canada s (**Talisman** **)** 100% working interests in two leases (Leases 10 and 6) located in the heart of the Athabasca oilsands region in the Province of Alberta, Canada. Lease 10 is a 6,880-acre contiguous block located approximately 10 miles (16 km) northeast of Fort McMurray. Lease 6 is a small, undelineated, 680-acre block, 1 mile (1.6km) south of Lease 10.

The acquisition of Lease 10 will provide the site for the first commercial application of Ivanhoe Energy s proprietary, HTL heavy-oil upgrading technology in a major, integrated heavy-oil project. Lease 10 has a relatively high level of delineation (four wells per section). It is believed to be a high-quality reservoir and an excellent candidate for thermal recovery production using the SAGD (steam-assisted gravity drainage) process. The high quality of the asset is expected to provide for favorable projected operating costs, including attractive steam-oil ratios (SOR) using SAGD development techniques.

Ivanhoe s HTL plant on Lease 10 is projected ultimately to be capable of operating at production rates of at least 30,000 barrels per day for approximately 25 years. Ivanhoe intends to integrate established SAGD thermal recovery techniques with its patented HTL upgrading process, producing and marketing a light, synthetic sour crude.

Ivanhoe has already commenced planning its Lease 10 winter 2008 delineation program in preparation for the submission of permits for an integrated HTL project. In general, thermal oilsands projects, including SAGD projects, require a period of initial development, including delineation, permitting and field development, which is followed by relatively stable operations for many years

The Company s continuing strategy includes the following:

1. ***Build a portfolio of major HTL™ projects.*** We will continue to deploy our personnel and our financial resources in support of our goal to capture additional opportunities for development projects utilizing our HTL™ Technology.

2. ***Advance the technology.*** Additional development work will continue as we advance the technology through the first commercial application and beyond.

3. ***Enhance our financial position in anticipation of major projects.*** Implementation of large projects requires significant capital outlays. We are refining our financing plans and establishing the relationships required for

the development activities that we see ahead.

4. ***Build internal capabilities.*** During recent months, the Company has made significant progress in building its execution teams in preparation for the Talisman acquisition. The upstream team consists of a number of Calgary-based, experienced heavy-oil engineers and geologists complemented by a core team of petroleum engineers and geologists located in Ivanhoe s offices in Bakersfield, California, a number of who are expected to move to Calgary. The Houston-based HTL technology team also has been strengthened. The Company expects to continue filling key positions in its execution mode.

5. ***Build the relationships that we will need for the future.*** Commercialization of our technologies demands close alignment with partners, suppliers, host governments and financiers.

Talisman retains back-in rights of up to 20% in the acquired leases for a period of three years. During this period, Talisman also will have the right of first offer to acquire any participation interests in heavy-oil projects in Alberta that Ivanhoe wishes to sell, excluding the acquired leases, on mutually agreeable terms. In addition, Ivanhoe and Talisman have signed an HTL Data Monitoring Agreement to allow Talisman to effectively monitor the commercial effectiveness of the Company s HTL technology.

The Company plans to establish a number of geographically focused entities. The parent company, Ivanhoe Energy Inc., will pursue HTL opportunities in the Athabasca oilsands of Western Canada and will hold and manage the core HTL technology. Two new subsidiaries have been established, one for Latin America and one for the Middle East & North Africa, complementing Sunwing Energy Ltd., the Company s existing, wholly-owned company for China. Ivanhoe Energy Inc. owns 100% of each of these subsidiaries, although the percentages are expected to decline as they develop their respective businesses and raise capital independently.

This structure will allow the development and financing of multiple HTL projects around the world, while minimizing dilution of the Company s existing shareholders. In addition, the alignment with principal energy-producing regions will facilitate financing from region-specific strategic investors, some of which already have been identified, and also will enhance flexibility in accessing global capital markets.

Executive Overview of 2008 Results

The following table sets forth certain selected consolidated data for the three-month and six-month periods ended June 30, 2008 and 2007:

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2008	**2007**	**2008**	**2007**
Oil and gas revenue	$ 17,979	$ 9,789	$ 33,022	$ 19,385
Net loss	$ (21,731)	$ (6,579)	$ (30,275)	$ (13,126)
Net loss per share	$ (0.09)	$ (0.03)	$ (0.12)	$ (0.05)
Average production (Boe/d)	1,891	1,824	1,899	1,929
Net operating revenue per Boe	$ 66.05	$ 33.53	$ 60.80	$ 32.87
Cash flow from operating activities	$ 2,626	$ 199	$ 5,643	$ 2,800
Capital investments	$ 2,593	$ 8,123	$ 7,916	$ 13,457

Financial Results Change in Net Loss

The following provides an analysis of our changes in net losses for the three-month and six-month periods ended June 30, 2008 when compared to the same periods for 2007:

	Three-Month Periods Ended June 30,			Six-Month Periods Ended June 30,		
	2008	*Favorable (Unfavorable) Variances*	2007	2008	*Favorable (Unfavorable) Variances*	2007
Summary of Net Loss by Significant Components:						
Oil and Gas Revenues:	$ 17,979		$ 9,789	$ 33,022		$ 19,385
Production volumes		*$ 336*			*$ (207)*	
Oil and gas prices		*7,854*			*13,844*	
Realized gain (loss) on derivative instruments	(4,354)	*(4,324)*	(30)	(6,302)	*(6,479)*	177
Operating costs	(6,614)	*(2,391)*	(4,223)	(12,006)	*(4,098)*	(7,908)
General and administrative, less stock based compensation	(3,533)	*(1,010)*	(2,523)	(6,291)	*(1,543)*	(4,748)
Business and technology development, less stock based compensation	(1,672)	*484*	(2,156)	(3,218)	*945*	(4,163)
Net interest	(259)	*(250)*	(9)	(605)	*(577)*	(28)
Unrealized loss on derivative instruments	(16,433)	*(16,147)*	(286)	(18,431)	*(17,479)*	(952)
Depletion and depreciation	(8,129)	*(2,105)*	(6,024)	(16,495)	*(3,579)*	(12,916)
Stock based compensation	(793)	*260*	(1,053)	(1,911)	*(56)*	(1,855)
Future income tax recovery	2,286	*2,286*		2,286	*2,286*	
Other	(209)	*(145)*	(64)	(324)	*(206)*	(118)
Net Loss	$ (21,731)	*$ (15,152)*	$ (6,579)	$ (30,275)	*$ (17,149)*	$ (13,126)

Our net loss for the three-month period ended June 30, 2008 was $21.7 million ($0.09 per share) compared to our net loss for the same period in 2007 of $6.6 million ($0.03 per share). The increase in our net loss from 2007 to 2008 of $15.2 million was mainly due to a $16.2 million increase in unrealized loss on derivative instruments, a $2.1 million increase for depletion and depreciation and an increase in operating costs of $2.4 million. These increases were partially offset by an increase of $3.9 million in combined oil and gas revenues and realized loss on derivative instruments, in addition to a future income tax recovery of $2.3 million, in connection with the Company s ability to utilize tax deductions associated with future income tax assets in China, a future income tax recovery of $2.3 million.

Our net loss for the six-month period ended June 30, 2008 was $30.3 million ($0.12 per share) compared to our net loss for the same period in 2007 of $13.1 million ($0.05 per share). The increase in our net loss from 2007 to 2008 of $19.4 million was mainly due to a $17.5 million increase in unrealized loss on derivative instruments, a $3.6 million increase for depletion and depreciation and an increase in operating costs of $4.1 million. These increases were partially offset by an increase of $7.2 million in combined oil and gas revenues and realized loss on derivative instruments, in addition to a future income tax recovery of $2.3 million, in connection with the Company s ability to utilize tax deductions associated with future income tax assets in China, a future income tax recovery of $2.3 million.

Significant variances are explained in the sections that follow.

Revenues and Operating Costs

The following is a comparison of changes in production volumes for the three-month and six-month periods ended June 30, 2008 when compared to the same periods in 2007:

	Three-Month Periods Ended June 30,			Six-Month Periods Ended June 30,		
	Net Boe s		Percentage	Net Boe s		Percentage
	2008	**2007**	**Change**	**2008**	**2007**	**Change**
China:						
Dagang	111,662	110,680	1%	231,490	231,356	0%
Daqing	4,845	5,257	-8%	9,988	10,897	-8%
	116,507	115,937	0%	241,478	242,253	0%
U.S.:						
South Midway	52,020	44,195	18%	95,697	95,968	0%
Spraberry	3,215	5,345	-40%	7,724	10,038	-23%
Others	352	474	-26%	767	853	-10%
	55,587	50,014	11%	104,188	106,859	-2%
	172,094	165,951	4%	345,666	349,112	-1%

Net production volumes for the three-month period ended June 30, 2008 increased 4% when compared to the same period in 2007 mainly due to an increase in production volumes in our U.S. properties of 11%, resulting in increased revenues of $0.3 million. Production volumes for the six-month period ended June 30, 2008 decreased 1% when compared to the same period in 2007 which resulted in decreased revenues of $0.2 million.

Oil and gas prices increased 77%, and 72%, per Boe for the three-month and six-month periods ended June 30, 2008 generating $7.9 million, and $13.8 million, in additional revenue as compared to the same periods in 2007. We realized an average of $100.82, and 93.74, per Boe from operations in China during these periods, which were increases of $40.53, and 36.47, per Boe from 2007 prices and accounted for $4.7 million, and $8.8 million, of our increase in revenues. From the U.S. operations, we realized an average of $112.12, and $99.69, per Boe during these periods, which were increases of $56.16, and $48.13, per Boe and accounted for $3.2 million, and $5.0 million, of our increased revenues. We expect crude oil prices and natural gas prices to remain volatile throughout 2008.

The increased revenues from oil and gas price increases during the three-month and six-month periods ended June 30, 2008 were offset by settlements from our costless collar derivative instruments. As benchmark prices rise above the ceiling price established in the contract the Company is required to settle monthly (see further details on these contracts below under Unrealized Loss on Derivative Instruments). The Company realized a net loss on these settlements during these periods of $4.4 million and $6.3 million, $2.2 million, and $3.4 million, of which were from the U.S. segment, with the balance from the China segment. This compares to a minimal loss, and a $0.2 million net realized gain, in the same periods in 2007 for our U.S. contracts.

For the three-month and six-month periods ended June 30, 2008, operating costs, including production taxes and engineering and support costs, increased 51%, and 53%, per Boe compared to the same periods in 2007. Of the total $2.4 million, and $4.1 million, increase in these costs, $1.9 million, and $3.5 million, were a result of the Windfall Levy which is explained in more detail below under the China Operating Costs section.

China

Production Volumes

Overall, net production volumes at the Dagang field during the three-month and six-month periods ended June 30, 2008 were consistent with those for the same periods in 2007. Normal field decline was offset by the production of 275 Gross Bopd from five new development wells completed and put on production in the second half of 2007. We expect that additional perforations, fracture stimulations and water flooding will help offset declines due to increasing water production in 2008. The expected production rates for 2008 will be similar to those averaged in 2007.

Operating Costs

Operating costs in China, including engineering and support costs and Windfall Levy, increased 61%, and 67%, per Boe during the three-month and six-month periods ended June 30, 2008 when compared to the same periods in 2007. Field operating costs increased $0.83, and $1.55, per Boe. These increases were mainly a result of a higher percentage of field office costs were allocated to operations versus capital as capital activity has decreased and higher power costs resulting from greater water injection in 2008 when compared to the same periods in 2007. These increases were offset by decreases resulting from one-time maintenance projects in 2007 and attrition of certain managers. Enterprises exploiting and selling crude oil in the Peoples Republic of China are subject to a windfall gain levy (the **Windfall Levy**) if the monthly weighted average price of crude oil is above $40 per barrel. The Windfall Levy is imposed at progressive rates from 20% to 40% on the portion of the weighted average sales price exceeding $40 per barrel. Consequently as oil prices increased period over period the amount of the Windfall Levy also increased significantly, resulting in a $16.12, and $14.38, per Boe increase for 2008 when compared to the same periods in 2007. With the exception of the Windfall Levy, we expect costs during the remainder of 2008 to remain consistent on a per barrel basis as compared to 2007. Decreases resulting from one-time maintenance projects in 2007 and the ability to charge CNPC for its share of operating costs, expected to be in the fourth quarter of 2008 once we reach commercial production , will be offset by an increase in office costs allocated to operations as we continue to reduce the number of capital projects.

U.S.

Production Volumes

There was an 11% increase in U.S. production volumes for the three-month period ended June 30, 2008 when compared to the same period in 2007 while the volumes decreased when comparing the six-month period ended June 30, 2008 to the same period in the prior year. The overall changes to our U.S. production volumes were mainly due the timing of drilling programs at South Midway. The 2006 fall drilling program resulted in an increase in the first quarter of 2007 production, and the 2008 first quarter drilling program results are beginning to be reflected in the second quarter of 2008. In addition to an increase in production in 2008 due to abnormal downtimes in our steaming operations in 2007, we expect the current drilling program at South Midway to offset natural declines within this field and to provide additional future drilling locations.

Operating Costs

Operating costs in the U.S., including engineering and support costs and production taxes, increased 26%, and 15%, per Boe for the three-month and six-month periods ended June 30, 2008 when compared to the same periods in 2007. Field operating costs increased $6.19, and $3.76, per Boe mainly due to an increase in our steaming operation at South Midway. Both generators were down in the latter part of the first quarter and through the second quarter of 2007 in addition to the price of natural gas being significantly higher in 2008 when compared to 2007. Additional maintenance costs and workovers at our Spraberry field in West Texas in the second quarter of 2008 added to the overall increase in costs. We anticipate operating expense to continue to increase in 2008 mainly as a result of the steaming operations at South Midway operating at full capacity versus a reduced capacity in 2007. We expect the second half 2008 operating costs at Spraberry to be consistent with the first and second quarters of 2008.

* * *

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

	Three-Month Periods Ended June 30,					
	2008			**2007**		
	China	**U.S.**	**Total**	**China**	**U.S.**	**Total**
Net Production:						
Boe	116,507	55,587	172,094	115,937	50,014	165,951
Boe/day for the period	1,280	611	1,891	1,274	550	1,824
	Per Boe			Per Boe		
Oil and gas revenue	$ 100.82	$ 112.12	$ 104.48	$ 60.29	$ 55.96	$ 58.98
Field operating costs	22.06	18.41	20.88	21.23	12.22	18.52
Production tax (U.S.) and Windfall Levy (China)	21.92	1.15	15.21	5.80	1.19	4.41
Engineering and support costs	1.54	4.03	2.34	1.33	5.28	2.52

	45.52	23.59	38.43	28.36	18.69	25.45
Net operating revenue	55.30	88.53	66.05	31.93	37.27	33.53
Depletion	49.72	30.39	43.48	37.28	29.38	34.90
Net revenue from operations	$ 5.58	$ 58.14	$ 22.57	$ (5.35)	$ 7.89	$ (1.37)

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	Six-Month Periods Ended June 30,					
	2008			2007		
	China	**U.S.**	**Total**	**China**	**U.S.**	**Total**
Net Production:						
Boe	241,478	104,188	345,666	242,253	106,859	349,112
Boe/day for the period	1,327	572	1,899	1,339	590	1,929
		Per Boe			Per Boe	
Oil and gas revenue	$ 93.74	$ 99.69	$ 95.54	$ 57.27	$ 51.56	$ 55.53
Field operating costs	19.42	17.31	18.79	17.87	13.55	16.55
Production tax (U.S.) and Windfall Levy (China)	19.11	1.31	13.75	4.73	1.20	3.65
Engineering and support costs	1.28	4.35	2.20	1.23	5.25	2.46
	39.81	22.97	34.74	23.83	20.00	22.66
Net operating revenue	53.93	76.72	60.80	33.44	31.56	32.87
Depletion	49.69	30.11	43.79	37.35	28.75	34.72
Net revenue (loss) from operations	$ 4.24	$ 46.61	$ 17.01	$ (3.91)	$ 2.81	$ (1.85)

General and Administrative

Changes in general and administrative expenses, before and after considering increases in non-cash stock based compensation, by segment for the three-month and six-month periods ended June 30, 2008 when compared to the same periods for 2007 were as follows:

	Three Months Ended June 30, 2008 vs. 2007	**Six Months Ended June 30, 2008 vs. 2007**
Favorable (unfavorable) variances:		
Oil and Gas Activities:		
China	$ (74)	$ (233)
U.S.	275	301
Corporate	(901)	(1,561)
	(700)	(1,493)
Less: stock based compensation	(310)	(50)
	$ (1,010)	$ (1,543)

China

General and administrative expenses related to the China operations increased $0.1 million, and $0.2 million, for the three-month and six-month periods ended June 30, 2008 when compared to the same periods in 2007 partially due to an increase in rent and facility costs and partially due to foreign exchange loss, offset by a decrease resulting from discretionary bonuses being paid in the second quarter of 2007 compared to none in 2008.

U.S.

General and administrative expenses related to the U.S. operations decreased $0.3 million for both of the three-month and six-month periods ended June 30, 2008 when compared to the same periods in 2007 mainly resulting from discretionary bonuses being paid in the second quarter of 2007, compared to none in 2008 offset by less allocation to capital and operations.

Corporate

General and administrative costs related to Corporate activities increased $0.9 million, and $1.6 million, for the three-month and six-month periods ended June 30, 2008 when compared to the same periods in 2007. The increase for the three-month period resulted from the accrual of severance for an executive of $0.3 million, additional legal fees of $0.2 million and corporate aircraft of $0.4 million. These second quarter increases along with the following increases in the first quarter of 2008 combined for the overall year-to-date 2008 increase: a $0.2 million increase in salaries and benefits resulting from an increase in stock based compensation and the addition of key personnel added later in 2007 offset by a decrease resulting from discretionary bonuses paid in 2007. In addition, various corporate overhead costs increased $0.2 million and third party recruiting fees increased by $0.3 million.

Business and Technology Development

Changes in business and technology development expenses, before and after considering increases in non-cash stock based compensation, by segment for the three-month and six-month periods ended June 30, 2008 when compared to the same periods for 2007 were as follows:

	Three Months Ended June 30, 2008 vs. 2007		Six Months Ended June 30, 2008 vs. 2007	
Favorable (unfavorable) variances:				
HTL™	$	250	$	547
GTL		184		292
		434		839
Less: stock based compensation		50		106
	$	484	$	945

Business and technology development expenses decreased $0.4 million, and $0.8 million, for the three-month and six-month periods ended June 30, 2008 compared to the same periods in 2007 mainly as a result of a decrease in CDF operating costs due to several heavy oil upgrading runs in the first and second quarters of 2007. In addition, there was a decrease resulting from discretionary bonuses being paid in the second quarter of 2007 compared to none in 2008. These decreases were offset by increases in compensation costs for the addition of key personnel, as we continue to build our core technology team.

Net Interest

Interest expense increased $0.3 million, and $0.7 million, for the three-month and six-month periods ended June 30, 2008 when compared to the same periods in 2007 partially due to an additional draw on our U.S. loan and borrowings under a new loan for our China operations in the fourth quarter of 2007.

Unrealized Loss on Derivative Instruments

As required by the Company s lenders, the Company entered into costless collar derivatives to minimize variability in its cash flow from the sale of approximately 75% of the Company s estimated production from its South Midway property in California and Spraberry property in West Texas over a two-year period starting November 2006 and a six-month period starting November 2008. The derivatives have a ceiling price of $65.20, and $70.08, per barrel and a floor price of $63.20, and $65.00, per barrel, respectively, using WTI as the index traded on the NYMEX. The Company s lenders also required the Company to enter into a costless collar derivative to minimize variability in its cash flow from the sale of approximately 50% of the Company s estimated production from its Dagang field in China over a three-year period starting September 2007. This derivative has a ceiling price of $84.50 per barrel and a floor price of $55.00 per barrel using WTI as the index traded on the NYMEX.

The Company accounts for these contracts using mark-to-market accounting. As forecasted benchmark prices exceed the ceiling prices set in the contract, the contracts have negative value or a liability. These benchmark prices reached record highs during the second quarter of 2008. For the three-month period ended June 30, 2008, the Company had $3.6 million unrealized losses in its U.S. segment and $12.9 million unrealized losses in its China segment on these derivative transactions. For the six-month period ended June 30, 2008, the Company had $3.6 million unrealized losses in its U.S. segment and $14.8 million unrealized losses in its China segment on these derivative transactions. The minimal unrealized loss, and $0.2 million unrealized gain, for the three-month and six-month periods ended June 30, 2007 were related to the U.S. segment.

Depletion and Depreciation

Depletion and depreciation increased $2.1 million, and $3.6 million, for the three-month and six-month periods ended June 30, 2008 when compared to the same periods in 2007 partially due to a $0.4 million, and $0.6 million, increase in depreciation of the CDF, increases in depletion related to depletion rates for China and increases in depletion of $0.2 million, and $0.1 million, in the U.S.

China

China s depletion rate increased $12.44, and $12.34, per Boe for the three-month and six-month periods ended June 30, 2008 when compared to the same periods in 2007. This resulted in a $1.5 million, and $3.0 million, increase in depletion expense for the three-month and six-month periods ended June 30, 2008. The increase in the rates from period to period was mainly due to an impairment of the drilling and completion costs associated with the second Zitong exploration well in the fourth quarter of 2007.

Financial Condition, Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents increased for the three-month period ended June 30, 2008 by $3.5 million compared to $0.3 million for the same period in 2007. Our net cash and cash equivalents decreased for the six-month period ended June 30, 2008 by $1.1 million compared to $2.8 million for the same period in 2007.

Operating Activities

Our operating activities provided $2.6 million in cash for the three-month period ended June 30, 2008 compared to $0.2 million for the same period in 2007. Our operating activities provided $5.6 million in cash for the six-month period ended June 30, 2008 compared to $2.8 million for the same period in 2007. The increase in cash from operating activities for the three-month and six-month periods ended June 30, 2008 was mainly due to an increase in oil and gas production prices offset by an increase in expenses, as well as an increase in changes in working capital when compared to the same periods in 2007.

Investing Activities

Our investing activities used $3.9 million in cash for the three-month period ended June 30, 2008 compared to cash provided of $0.6 million for the same period in 2007. Our investing activities used $10.4 million in cash for the six-month period ended June 30, 2008 compared to cash provided of $4.5 million for the same period in 2007. The main reason for the differences is due to the $9.0 million received from INPEX as payment for the Company s past costs related to its Iraq project and HTL™ Technology development costs in the second quarter of 2007. This decrease in cash inflow was offset by a decrease in capital asset expenditures of $5.5 million for both the three-month and six-month periods ended June 30, 2008 when compared to those same periods in 2007.

For the three-month period ended June 30, 2008, as compared to the same period in 2007, there was a decrease in our investment in China of $4.9 million, a decrease of $0.2 million in our investment in the U.S and a decrease of $0.4 million in our HTL™ segment. For the six-month period ended June 30, 2008, as compared to the same period in 2007, there was a decrease in our investment in China of $6.5 million and a decrease of $0.4 million in our HTL™ segment offset by an increase of $1.4 million in our investment in the U.S.

China

The decrease in our investment in China in the second quarter of 2008 compared to 2007 was the result of a $3.1 million decrease in capital spending at Zitong and a $1.8 million decrease in capital spending at Dagang. The decrease in our investment in China for the six-month period ended June 30, 2008 was the result of a $5.9 million decrease in capital spending at Zitong and a $0.6 million decrease in capital spending at Dagang. Our spending at Zitong during 2008 was limited to expenditures relating to the commencement of the second phase of our exploration program, which were relatively minor compared to the drilling and completion costs we incurred during 2007 in completing the first phase of the program, which was concluded in December 2007. At Dagang, we increased capital spending during the first quarter of 2008 over the same period in 2007 by completing several fracture stimulation jobs, but in the second quarter of 2007 we spud three development wells compared to no new drilling in 2008.

U.S.

The decrease in our U.S. capital spending in the second quarter of 2008 compared to 2007 was mainly due to majority of our facility work in our steam operations at South Midway in 2007 compared to the final stages of our 8 well drilling program at South Midway in 2008. The majority of the expenditures we incurred in carrying out an 8 well drilling program at South Midway were in the first quarter of 2008 and far exceeded those of the facility work in 2007.

HTL™

The overall decrease in expenditures for the HTL™ segment was in part due to decreased costs related to the CDF as all significant modification to that facility have been completed and also decreased costs related to the Feedstock Test Facility (**FTF**) for the three-months period ended June 30, 2008. Costs for the FTF were unchanged for the six-month period comparison.

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Financing Activities

Financing activities for the three-month and six-month periods ended June 30, 2008 and 2007 consisted mainly of scheduled repayment of long-term debt in the amount of $0.6 million and $1.2 million. In addition, there were $0.8 million, and $1.4 million, net of changes in non-cash working capital, in professional fees and expenses associated with the pursuit of corporate financing initiatives by the Company s Chinese subsidiary, Sunwing. These cash outflows were more than offset by $5.5 in net proceeds from debt obligations in the second quarter of 2008. In April 2008, the Company obtained a loan from a third party finance company in the amount of Cdn. $5.0 million bearing interest at 8% per annum. The principal and accrued and unpaid interest matures and is repayable in August 2008. The lender has the option to convert the outstanding balance, in whole or in part, into the Company s common shares at a conversion price of Cdn.$2.24 per share. The Company also had a draw in the amount of $0.7 million from its existing facility secured by its U.S. properties.

Outlook for balance of 2008

The Company intends to utilize revenue from existing operations to continue funding the transition of the Company to a heavy oil exploration, production and upgrading company and grow our existing operations where appropriate to sustain operating cash flow and our financial position. In addition, the Company is actively engaged in the process of leveraging or monetizing the non-heavy oil related investments in our portfolio, including bank and similar financing, to capture value and provide maximum return for the Company.

In July 2008 the Company completed a Cdn.$88.0 million private placement consisting of 29,334,000 Special Warrants at Cdn.$3.00 per Special Warrant. Each Special Warrant entitled the holder to one common share of the Company upon exercise of the Special Warrant. The net proceeds from the Offering of the Special Warrants were approximately Cdn.$83.4 million after deducting the agents commission of Cdn.$4.0 million and the expenses of the Offering estimated to be Cdn.$600,000. The Company used Cdn.$22.5 million of the net proceeds of the Offering to complete the cash component of the Talisman lease acquisition. In addition, future payments will be required to be made by the Company to Talisman under the Talisman lease acquisition.

The Company currently anticipates incurring substantial expenditures to further the development of its newly acquired Lease 10 asset and various other projects. The Company s cash flow from operating activities will not be sufficient to both satisfy its current obligations and meet the requirements of these capital investment programs. Ivanhoe intends to finance such future payments from a combination of strategic investors and/or traditional debt and equity markets, either at the Ivanhoe parent company level or at the project level. Recovery of capitalized costs related to potential HTL™ and GTL projects is dependent upon finalizing definitive agreements for, and successful completion of, the various projects. Management s plans also include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt and mezzanine financing or the sale of equity securities in order to generate sufficient resources to assure continuation of the Company s operations and achieve its capital investment objectives.

Contractual Obligations

The table below summarizes the contractual obligations that are reflected in our Unaudited Condensed Consolidated Balance Sheet as at June 30, 2008 and/or disclosed in the accompanying Notes:

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	**2008**	**2009**	**2010**	**2011**	**After 2011**
Consolidated Balance Sheets:						
Note payable current portion	11,636	11,224	412			
Long term debt	9,484			9,484		
Asset retirement obligation	3,673		15	1,883		1,775
Long term obligation	1,900		1,900			
Other Commitments:						
Interest payable	2,238	724	859	655		

Lease commitments	2,891	540	893	773	549	136
Zitong exploration commitment	22,500	2,500	9,000	11,000		
Total	$ 54,322	$ 14,988	$ 13,079	$ 23,795	$ 549	$ 1,911

Off Balance Sheet Arrangements

As at June 30, 2008 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. We currently 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 August 1, 2008, there were 246,494,046 common shares of the Company issued and outstanding. Additionally, the Company had 11,400,000 share purchase warrants outstanding and exercisable to purchase 11,400,000 common shares. As at August 1, 2008, there were 14,544,753 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							
	2008		2007				2006	
	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr
Total revenue	$ (2,772)	$ 11,169	$ 5,848	$ 8,823	$ 9,589	$ 9,257	$ 11,137	$14,015
Net loss:								
Canadian GAAP	$(21,731)	$ (8,544)	$(18,849)	$(7,232)	$(6,579)	$(6,547)	$(11,323)	$ (4,388)
U.S. GAAP	$(32,981)	$(10,495)	$(16,094)	$(2,551)	$(1,211)	$(7,536)	$(18,255)	$ (5,422)
Net loss per share:								
Canadian GAAP	$ (0.09)	$ (0.03)	$ (0.07)	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.05)	$ (0.02)
U.S. GAAP	$ (0.13)	$ (0.04)	$ (0.07)	$ (0.01)	$	$ (0.03)	$ (0.08)	$ (0.03)

The differences in the net loss and net loss per share for the third quarter of 2006 were due mainly to the impairment charged for the U.S. Oil and Gas Properties for U.S. GAAP purposes of $3.1 million when compared to nil calculated for Canadian GAAP, offset by a $1.7 million additional fair value adjustment of derivative instruments for U.S. GAAP. The differences in the net loss and net loss per share for the fourth quarter of 2006 were due mainly to the impairment charged for U.S. GAAP purposes of $8.1 million ($4.5 million relates to the U.S. Oil and Gas Properties and $3.6 million for the China Oil and Gas Properties) when compared to $12.8 million calculated for Canadian GAAP. The differences in the net loss and net loss per share for the second quarter of 2007 were due mainly to the treatment of the payment by INPEX for past costs paid by the Company related to its Iraq project and HTL™ Technology development costs. Approximately $6.3 million of this payment was applied to capital balances for Canadian GAAP purposes and as reduction to net loss for U.S. GAAP purposes. The differences in the net loss and net loss per share for the third quarter of 2007 were mainly due to an additional $3.6 million fair value adjustment of derivative instruments for U.S. GAAP. The differences in the net loss and net loss per share for the second quarter of 2008 were mainly due to an additional $12.2 million fair value adjustment of derivative instruments for U.S. GAAP.

Status of our Transition to International Financial Reporting Standards (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian Generally Accepted Accounting Principles (**GAAP**) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. At this time, the impact on our future financial position and results of operations is not reasonably determinable or estimable.

We commenced our IFRS conversion project in 2007 with a significant phase being the conversion to IFRS of the Canadian GAAP financial statements of our China subsidiaries. As we move to the company-wide project, we will establish a more formal project governance structure that will provide regular reporting to senior executive management and to the Audit Committee of our Board of Directors.

We have completed a high level review of the major differences between current Canadian GAAP and IFRS but have not yet determined those areas of accounting difference with the highest potential to impact our company. As well, we will evaluate the impacts of the IFRS transition on other business activities including our major financial systems. We will also ensure there are strong communications between our IFRS project and staff accountable for disclosure controls and internal control over financial reporting. Control requirements will be reevaluated as our IFRS project progresses.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Commodity price risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to the changes in market commodity prices. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals. The Company may periodically use different types of derivative instruments to manage its exposure to price volatility and as well as a result of a requirement of the Company s lenders.

The Company entered into costless collar derivatives to minimize variability in its cash flow from the sale of up to 14,700 Bbls per month of the Company s production from its South Midway Property in California and Spraberry Property in West Texas over a two-year period starting November 2006 and a six-month period starting November 2008. The derivatives had a ceiling price of $65.20, and $70.08, per barrel and a floor price of $63.20, and $65.00, per barrel, respectively, using WTI as the index traded on the NYMEX. The Company also entered into a costless collar derivative to minimize variability in its cash flow from the sale of up to 18,000 Bbls per month of the Company s production from its Dagang field in China over a three-year period starting September 2007. This derivative had a ceiling price of $84.50 per barrel and a floor price of $55.00 per barrel using WTI as the index traded on the NYMEX.

During the three-month and six-month periods ended June 30, 2008, the Company had $4.4 million and $6.3 million of realized losses (nil and $0.2 million of realized gains in 2007), on these derivative transactions, and $16.4 million and $18.4 million, respectively, of unrealized losses ($0.3 million and $1.0 million in 2007). Both realized and unrealized gains and losses on derivatives have been recognized in the results of operations.

On June 30, 2008, the Company s open positions on the derivatives referred to above had a fair value of $27.9 million. A 10% increase in oil prices would increase the fair value, and consequently increase the net loss, by approximately $6.2 million, while a 10% decrease in prices would reduce the fair value, and consequently reduce the net loss, by approximately $5.4 million. The fair value change assumes volatility based on prevailing market parameters at June 30, 2008.

Foreign Currency Exchange Rate Risk

Foreign currency risk refers to the risk that the value of a financial commitment, recognized asset or liability will fluctuate due to changes in foreign currency rates. The main underlying economic currency of the Company s cash flows is the U.S. dollar. This is because the Company s major product, crude oil, is priced internationally in U.S. dollars. Accordingly, we do not expect to face foreign exchange risks associated with our production revenues. However, the Company s cash flow stream relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. The majority of the operating costs incurred in our Chinese operations are paid in Chinese renminbi. The majority of costs incurred in our administrative offices in Vancouver and Calgary, as well as some business development costs, are paid in Canadian dollars. Disbursement transactions denominated in Chinese renminbi and Canadian dollars are converted to U.S. dollar equivalents based on the exchange rate as of the transaction date. Foreign currency gains and losses also come about when monetary assets and liabilities, mainly short term payables and receivables, denominated in foreign currencies are translated at the end of each month. The estimated impact of a 10% strengthening or weakening of the Chinese renminbi, and Canadian dollar, as of June 30, 2008 on net loss and accumulated deficit for the six-month period ended June 30, 2008 is a $0.4 million increase, and a $0.3 million decrease, respectively. To help reduce our exposure to foreign currency risk we seek to maximize our expenditures and contracts denominated in U.S. dollars and minimize those denominated in other currencies.

Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to the changes in market interest rates. Interest rate risk arises from interest-bearing borrowings which have a variable interest rate. Interest-bearing financial assets are not considered significant. The Company currently has two separate bank loan facilities with fluctuating interest rates. We estimate that our net loss and accumulated deficit for the six-month period ended June 30, 2008 would have changed $0.1 million for every 1% change in interest rates as of June 30, 2008. The Company is not currently actively attempting to manage this interest rate risk given the limited amount and term of our borrowings and the current global interest rate cycle.

Item 4. Controls and Procedures

The Company s management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of June 30, 2008. 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 as appropriate to allow timely decisions regarding disclosure and (2) effective, in that they provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

It should be noted that while the Company s principal executive officer and principal financial officer believe that the Company s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Company s disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the quarter ended June 30, 2008, there were no changes in the Company s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II Other Information

Item 1. Legal Proceedings: None

Item 1A. Risk Factors:

In connection with the issuance of Special Warrants and the concurrent Talisman lease acquisition, our risk factors have been updated. As a result, the following risk factors should be reviewed and given careful consideration in addition to the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2007.

Future Payments and Security granted to Talisman under the Talisman Lease Acquisition. Future payments will be required to be made by Ivanhoe to Talisman under the Talisman Lease Acquisition, including: (i) Cdn.$12,500,000 principal owing by Ivanhoe on the 2008 Note which is due to be repaid on December 31, 2008; (ii) Cdn.$40,000,000 principal owing by Ivanhoe on the Convertible Note which is due July 11, 2011 unless and to the extent such principal is converted into Common Shares before such due date; (iii) up to Cdn.$15,000,000 may be payable by Ivanhoe in respect of the Contingent Payment if requisite governmental and other approvals necessary to develop the northern border of Lease 10 are obtained; and (iv) a further Cdn.$15,000,000 could become payable by Ivanhoe to acquire Talisman s 75% interest in Lease 50 in 2008 if the remaining working interest holder does not complete the acquisition of Talisman s interest in certain circumstances. Ivanhoe intends to finance such future payments from a combination of strategic investors and/or traditional debt and equity markets, either at the Ivanhoe parent company level or at the project level. There can be no assurance that such financing will be obtained by Ivanhoe on favorable terms or at all and any future equity issuances may be dilutive to investors. Failure to obtain such additional financing or failure to meet ongoing covenants or default terms could result in the default of the Company under the terms of the security granted by Ivanhoe in favor of Talisman under the Talisman Lease Acquisition. This security includes a first fixed charge and security interest in favor of Talisman over the Acquired Talisman Leases and a subordinate security over certain present and after acquired property of Ivanhoe. In the case of such default, Talisman could foreclose on the assets of the Company so secured, including the Acquired Talisman Leases.

Capital Requirements and Additional Financing. Any future costs of the development of an HTL plant and field development costs are currently intended to be sourced from a combination of strategic investors and/or traditional debt and equity markets, either at an Ivanhoe parent company level or project level. Capital requirements are subject to oil and natural gas prices and capital market risks, primarily the availability and cost of capital. There can be no assurance that any such plant will be completed or capable of operating at any specified level or that any or all of such required financing will be obtained by the Company on favorable terms or at all.

Resources. No reserves have yet been established in respect of the Acquired Talisman Leases. No resource estimates have been established in respect of Lease 10 beyond the contingent resource estimates from the most recent evaluations conducted by independent reservoir engineers retained by Talisman which have an effective date of August 31, 2007. Lease 6 has not been independently evaluated. There are numerous uncertainties inherent in estimating quantities of bitumen resources, including many factors beyond Ivanhoe s control, and no assurance can be given that any level or resources or recovery of bitumen will be realized. In general, estimates of recoverable bitumen resources are based upon a number of assumptions made as of the date on which the resource estimates were determined, many of which are subject to change and are beyond the Company s control. All estimates are, to some degree, uncertain and classifications of resources are only attempts to define the degree of uncertainty involved. No assurance can be provided as to the gravity or quality of bitumen that may be produced from the Acquired Talisman Leases.

Estimates with respect to resources that may be developed and produced in the future are often based upon volumetric calculations, probabilistic methods and upon analogy to similar types of resources, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same resources based upon production history will result in variations, which may be material, in the estimated resources.

Stage of Development. While Ivanhoe plans to establish an initial integrated HTL project on Lease 10, such project is currently at a very early stage of development and, accordingly, no feasibility or engineering studies have been produced. There can be no assurances that such project will be completed on any time frame or within the parameters of any determined capital cost. Ivanhoe has not yet established a defined schedule for financing and developing such project. Development of the project may suffer delays, interruption of operations or increased costs due to many factors, including, without limitation: breakdown or failure of equipment or processes; construction performance falling below expected levels of output or efficiency, design errors, challenges to proprietary technology, contractor or operator errors; non-performance by third party contractors; labour disputes, disruptions or declines in productivity; increases in materials or labour costs; inability to attract sufficient numbers of qualified workers; delays in obtaining, or conditions imposed by, regulatory approvals; violation of permit requirements; disruption in the supply of energy; and catastrophic events such as fires; earthquakes, storms or explosions.

Nature of Oil Sands Exploration and Development and Operational Risks. Oil sands exploration and development is very competitive and involves many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. As with any petroleum property, there can be no assurance that bitumen will be produced from the lands underlying the Acquired Talisman Leases. Furthermore, the viability and marketability of any production from the Acquired Talisman Leases would be affected by numerous factors beyond Ivanhoe s control. These factors include, but are not limited to, market fluctuations of prices, proximity and capacity of pipelines and processing equipment, electricity transmission and distribution system, transportation arrangements, equipment availability and government regulations (including, without limitation, regulations relating to prices, taxes, royalties, land tenure, allowable production, importing and exporting of oil and gas and environmental protection). The extent of these factors cannot be accurately predicted. In the event that Ivanhoe s proposed HTL project on Lease 10 is developed and becomes operational, there is no assurance that such project will have production in any specific quantities or within any defined framework of costs, or that it will not cease producing entirely in certain circumstances. Because operating costs for production from oil sands may be substantially higher than operating costs to produce conventional crude oil, an increase in such costs may render the extraction of bitumen resources from the proposed project uneconomical. Moreover, it is possible that other developments, such as increasingly strict environmental and safety laws and regulations and enforcement policies thereunder and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities, delays or an inability to complete the proposed project or the abandonment of the proposed project. Changing oil prices in the future could render development of the Acquired Talisman Leases uneconomical.

SAGD Bitumen Recovery Process and Technology Risks. Ivanhoe intends to integrate established SAGD thermal recovery techniques with its patented HTL upgrading process. There are risks associated with the implementation of the HTL process and no commercial-scale HTL based on Ivanhoe s technology has been constructed to date. In addition, the recovery of bitumen using the SAGD process is subject to technical and financial uncertainty and positioning these technologies as conceptualized may result in unforeseen issues and challenges that may require engineering remediation. There is no assurance that capital and operating cost performance as anticipated from the integration technologies will be realized.

Regulations Permits, Leases and Licenses. Oil sands development in Alberta is subject to substantial regulation under Canadian federal, provincial and municipal laws relating to the exploration for, and the development, production, upgrading, marketing, pricing, taxation, and transportation of oil sands bitumen and related products and other matters, including environmental protection.

Legislation and regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing legislation and regulations, the implementation of new legislation or regulations or the amendment of existing legislation and regulations affect the crude oil and natural gas industry generally or oil sands operations in particular could materially increase the costs of developing the Acquired Talisman Leases and could have a material adverse impact on the business of Ivanhoe. More particularly, there can be no assurance that income tax laws, royalty regulations and government incentive programs related to Ivanhoe s proposed development of the Acquired Talisman Leases and the oil sands industry generally, will not be changed in a manner which may adversely affect such development and cause delays, inability to complete or abandonment of the proposed project.

Failure to obtain all necessary permits, leases, licenses and approvals, or failure to obtain them on a timely basis, could result in delays or restructuring of the project and increased costs, all of which could have a material adverse affect on the Company.

Construction, operation and decommissioning of any project on the Acquired Talisman Leases will be conditional upon the receipt of necessary permits, leases, licenses and other approvals from applicable governmental and regulatory authorities. The approval process can involve stakeholder consultation, environmental impact assessments, public hearings and appeals to tribunals and courts, among other things. An inability to secure local and regional community support could result in the necessary approvals being delayed or stopped. There is no assurance such approvals will be issued, or if granted, will not be appealed or cancelled or will be renewed upon expiry or will not contain terms and conditions that adversely affect the final design or economics of the project.

Royalty Regime. In the event that a project is developed by Ivanhoe in respect and becomes operational, Ivanhoe s revenue and expenses in respect of the Acquired Talisman Leases will be directly affected by the royalty regime applicable to such project. The economic benefit of future capital expenditures for such project is, in many cases, dependent on a satisfactory royalty regime.

On October 25, 2007, the Government of Alberta announced a new proposed royalty regime applicable to oil sands projects. The new regime, proposed to be effective January 1, 2009, would introduce new royalties for conventional oil, natural gas and oil sands production that are linked to price and production levels and would apply to both new and existing oil sands projects. Currently, in respect of oil sands projects having regulatory approval, a royalty of one percent of gross bitumen revenue is payable prior to the payout of specified allowed costs, including certain exploration and development costs, operating costs and a return allowance. Once such allowed costs have been recovered, a royalty of the greater of (i) one percent of gross bitumen revenue and (ii) 25 percent of net bitumen revenue, is levied. The new regime would retain the pre-payout gross royalty and post-payout net revenue royalty framework and introduces price sensitivity to establish royalty rates. It would apply a royalty of between one and nine percent on gross bitumen production revenue before payout and between 25 and 40 percent on net bitumen production revenue after payout, dependent on the price of crude oil. The minimum rates (one percent pre-payout and 25 percent post-payout) apply when the Canadian dollar equivalent of the US dollar West Texas Intermediate (**WTI**) posted crude oil price is at or below $55 per barrel. The maximum rates (nine percent pre-payout and 40 percent post-payout) would apply when the Canadian dollar equivalent of the US dollar WTI posted crude oil price is $120 per barrel or higher at the time of production. The royalty rates would adjust pro-rateably when the Canadian dollar equivalent of the WTI crude oil price is between $55 and $120 per barrel.

Implementation of the proposed changes to the Alberta royalty regime is subject to certain risks and uncertainties. The significant changes to the royalty regime require new legislation, changes to existing legislation and regulation and development of proprietary software to support the calculation and collection of royalties. Additionally, certain proposed changes contemplate further public and/or industry consultation. There may be modifications introduced to the proposed royalty structure prior to the implementation thereof.

An increase in royalties may reduce the Company s future earnings, if any, and could make future capital expenditures or Ivanhoe s operations in respect of the Acquired Talisman Leases uneconomic and could materially reduce the value of the associated assets.

There is no assurance that the federal government and the Province of Alberta will adopt or maintain a royalty regime that will make development of the Acquired Talisman Leases economic.

Environmental Regulation. Oil sands extraction, upgrading and transportation operations are subject to extensive regulation concerning environmental matters pursuant to federal, provincial and local legislation and regulations, and various approvals are required thereunder in respect of such activities. Such laws provide for restrictions and prohibitions on releases or emissions of various substances produced or used in association with oil sands activities, and address the decommissioning, abandonment and reclamation of oil sands properties at the end of their economic life. Compliance with such laws and the terms and conditions of any such approvals, if obtained, both now and in the future, could increase the cost of carrying out Ivanhoe s business plans in respect of the Acquired Talisman Leases, necessitate alteration of those plans, require a change in or cessation of operations thereon (if commenced) or result in delays. The effect on

Ivanhoe could be material and adverse. A violation of any such law may result in the issuance of remedial orders, the suspension of approvals or the imposition of significant fines or penalties.

No assurance can be given with respect to the impact of future environmental laws or the approvals, processes or other requirements thereunder on Ivanhoe s ability to develop or operate the Acquired Talisman Leases or any other affected properties. It is noted that Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder, which requires signatory nations to reduce their nation wide emissions of carbon dioxide and other greenhouse gases (**GHGs**). Extraction or upgrading operations in respect of the Acquired Talisman Leases is likely to produce a significant amount of certain GHGs covered by the convention.

In order to meet its obligations under the Kyoto Protocol, the Canadian federal government will - likely implement domestic legislation that applies to companies operating facilities in Canada. In April 2007, the federal government published its Regulatory Framework for Air Emissions (Framework), which outlines proposed new requirements governing the emission of GHGs and other industrial air pollutants through mandatory emissions reductions on a sector-by-sector basis. Sector-specific regulations are expected to come into force in 2010 and targets would be set relative to units of production rather than absolute reductions. The Framework also proposes a credit emissions trading system and creates an incentive to deploy carbon capture and storage measures.

GHG regulation can take place at the provincial and municipal level. For example, Alberta introduced the Climate Change and Emissions Management Act, which provides a framework for managing GHG emissions from facilities in that province by reducing specified gas emissions relative to gross domestic product to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulation, the Specified Gas Emitters Regulation, effective July 1, 2007, requires emissions reductions through the use of emission intensity targets (emission intensity is the amount of GHG emissions per unit of production or output). The Canadian federal government proposes to enter into equivalency agreements with provinces that establish a regulatory regime to ensure consistency of provincial GHG initiatives with the federal plan, although the success of any such plan is dependent on the prevailing political climate and Ivanhoe and other industry members may face multiple, overlapping levels of GHG regulation. The direct and indirect costs of these regulations, including any tax that the federal or provincial government may levy on GHG emissions, may adversely affect Ivanhoe s operations and financial condition.

Any mandatory emission intensity reductions to which Ivanhoe may be subject, whether in respect of the Acquired Talisman Leases or otherwise, may not be technically or economically feasible to implement. Failure to meet any such requirements or successfully engage alternative compliance mechanisms (such as emissions credits) could materially adversely affect the Company s ability to carry on the affected business.

Title Risks and Aboriginal Claims. Ivanhoe has not obtained title opinions in respect of the Acquired Talisman Leases and, accordingly, its ownership of the Acquired Talisman Leases may be subject to prior unregistered agreements or interests or undetected claims or interests that could defeat or subordinate the Company s interest therein. If this occurred, Ivanhoe s entitlement to the resources (or any reserves or production, if any, associated with the Acquired Talisman Leases), could be jeopardized, which could have a material adverse effect on the Company s financial condition, results of operations and ability to execute its business plan in a timely manner or at all.

In addition, aboriginal peoples have claimed aboriginal title and rights to large areas of land in western Canada where crude oil and natural gas operations are conducted, including a claim filed against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray where most of the oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on Ivanhoe and the Acquired Talisman Leases.

Human Resources. Development of the Acquired Talisman Leases will require experienced employees with particular areas of expertise. Currently, there are other oil sands projects and expansions underway or placed in the Fort McMurray area of Alberta. Ivanhoe s proposed development project may compete with these other projects for experienced employees resulting in payment of increased compensation to such employees or increase Ivanhoe s reliance and associated costs from partnering or outsourcing arrangements. In addition, there can be no assurance that all of the required employees with the necessary abilities and expertise will be available.

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

In compliance with Rule 903 of Regulation S under the U.S. Securities Act of 1933, as amended, on April 17, 2008, the Company obtained a loan from Wolmar Finance & Investment Ltd. (the Lender) in the amount of Cdn. $5.0 million bearing interest at 8% per annum. The principal and accrued and unpaid interest matures and is repayable in August 2008. The Lender has the option to convert the outstanding balance, in whole or in part, into the Company s common shares at a conversion price of Cdn.$2.24 per share.

Item 3. Defaults Upon Senior Securities: None

Item 4. Submission of Matters To a Vote of Security Holders:

The Company held its Annual General Meeting of Shareholders (**AGM**) on May 29, 2008. The term of office of each incumbent director expired at the conclusion of the AGM. The following individuals were elected at the AGM as directors of the Company for a term expiring as of the conclusion of the Company s next AGM:

Name of Director Nominee	**Votes in Favor**	**Votes Withheld**
A. Robert Abboud	167,012,125	1,751,064
Howard Balloch	167,257,781	1,505,408
Brian F. Downey	167,151,828	1,611,361
Robert M. Friedland	167,225,182	1,538,007
Robert G. Graham	166,055,520	2,707,669
Robert A. Pirraglia	159,352,624	9,410,565
Peter Meredith	167,204,610	1,558,579

Each of the following matters was also voted upon at the AGM:

Deloitte & Touche LLP were re-appointed as the Company s auditors for remuneration to be determined by the Company s Board of Directors (166,739,706 Common Shares voted in favor and 1,224,688 Common Shares withheld from voting); and

An ordinary resolution was passed authorizing the Company to: (a) amend and restate its Employees and Directors Equity Incentive Plan (the Incentive Plan) to (i) increase the maximum number of common shares available for issuance thereunder from 24,000,000 common shares to 29,250,000 common shares; (ii) increase the maximum number of common shares of the Company which may be allocated for issuance under the Bonus Plan component of the Incentive Plan from 2,400,000 common shares to 2,900,000 common shares; and (iii) make certain technical amendments to the Incentive Plan; and (b) to ratify the grant of excess stock options made pursuant to the Incentive Plan (88,223,504 Common Shares voted in favor 15,546,219 Common Shares voted against and 34,500 Common Shares withheld from voting).

Item 5. Other Information: None

Item 6. Exhibits

EXHIBIT NUMBER	DESCRIPTION
10.1	Asset Transfer Agreement dated July 11, 2008 between Ivanhoe Energy Inc. and Talisman Energy Canada.
10.2	Back-In Agreement dated July 11, 2008 between Ivanhoe Energy Inc. and Talisman Energy Canada.
31.1	Certification by the Principal 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 Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

SIGNATURE

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

IVANHOE ENERGY INC.

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

Dated: August 11, 2008

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