IVANHOE ENERGY INC
Form 10-Q
May 11, 2009

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

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

For the quarterly period ended March 31, 2009

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). o 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 definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

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 May 7, 2009 was 279,381,187 Common Shares, no par value.

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Part I Financial Information

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

	March 31, 2009	December 31, 2008
Assets		
Current Assets:		
Cash and cash equivalents	**$ 28,364**	$ 39,265
Accounts receivable	**5,790**	4,870
Prepaid and other current assets	**1,631**	1,658
Derivative instruments	**1,167**	2,159
	36,952	47,952
Oil and gas properties and development costs, net	**174,684**	176,550
Intangible assets HTL^{TM} technology	**92,153**	92,153
Long term assets	**671**	620
	$ 304,460	$ 317,275
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 8,481**	$ 10,093
Income tax payable	**2,286**	650
Debt current portion	**5,200**	5,612
	15,967	16,355
Long term debt	**37,007**	37,855
Asset retirement obligations	**3,972**	3,738
Long term obligation	**1,900**	1,900
	58,846	59,848
Commitments and contingencies *(Note 7)*		
Going concern and basis of presentation *(Note 2)*		
Shareholders Equity:		
Share capital, issued 279,381,187 common shares	**413,857**	413,857
Purchase warrants	**18,805**	18,805
Contributed surplus	**17,323**	16,862
Convertible note	**2,086**	2,086
Accumulated deficit	**(206,457)**	(194,183)

		245,614		257,427
	$	**304,460**	$	317,275

(See accompanying notes)

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

	Three Months Ended March 31, 2009	2008
Revenue		
Oil and gas revenue	**$ 7,699**	$ 15,043
Gain (loss) on derivative instruments	**268**	(3,946)
Interest income	**13**	72
	7,980	11,169
Expenses		
Operating costs	**3,727**	5,392
General and administrative	**4,954**	3,946
Business and technology development	**2,037**	1,476
Depletion and depreciation	**7,632**	8,366
Interest expense and financing costs	**259**	533
	18,609	19,713
Loss before Income Taxes	**(10,629)**	(8,544)
Current provision for income taxes	**(1,645)**	
Net Loss and Comprehensive Loss	**(12,274)**	(8,544)
Accumulated Deficit, beginning of period	**(194,183)**	(159,990)
Accumulated Deficit, end of period	**$ (206,457)**	$ (168,534)
Net Loss per share Basic and Diluted	**$ (0.04)**	$ (0.03)
Weighted Average Number of Shares (in thousands) Basic and Diluted	**279,381**	244,873

(See accompanying notes)

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Operating Activities		
Net loss and comprehensive loss	**$ (12,274)**	$ (8,544)
Items not requiring use of cash:		
Depletion and depreciation	**7,632**	8,366
Stock based compensation	**461**	1,118
Unrealized loss on derivative instruments	**992**	1,998
Unrealized foreign exchange gain	**(974)**	
Other	**134**	191
Changes in non-cash working capital items	**(59)**	(112)
	(4,088)	3,017
Investing Activities		
Capital investments	**(5,452)**	(5,323)
Other		(30)
Changes in non-cash working capital items	**(816)**	(1,130)
	(6,268)	(6,483)
Financing Activities		
Payments of debt obligations	**(416)**	(615)
Other	**(75)**	(584)
Changes in non-cash working capital items	**(23)**	
	(514)	(1,199)
Foreign Exchange Loss on Cash and Cash Equivalents Held in a Foreign Currency	**(31)**	
Decrease in Cash and Cash Equivalents, for the period	**(10,901)**	(4,665)
Cash and cash equivalents, beginning of period	**39,265**	11,356
Cash and Cash Equivalents, end of period	**$ 28,364**	$ 6,691

(See accompanying notes)

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Notes to the Unaudited Condensed Consolidated Financial Statements
March 31, 2009
(all tabular amounts are expressed in thousands of U.S. dollars except per share amounts)
(Unaudited)

1. GOING CONCERN AND 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 14. The unaudited condensed consolidated financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2008 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, 2008 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 s financial statements as at and for the three month period ended March 31, 2009 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. The Company incurred a net loss of $12.3 million for the three-month period ended March 31, 2009, and as at March 31, 2009, had an accumulated deficit of $206.5 million and positive working capital of $21.0 million. The Company currently anticipates incurring substantial expenditures to further its capital development programs, particularly those related to the development of two recently acquired oil sands leases in Alberta and the development of a heavy oil field in Ecuador. 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. 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 these properties and to meet the obligations associated with other potential HTL projects. The Company intends to finance the future payments required for its 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. Traditional debt and equity markets may not be accessible now or in the foreseeable future and, as such, the Company s ability to obtain financing cannot be predicted with certainty at this time. Without access to financing, the Company may not be able to continue as a going concern. These consolidated financial statements do not include any adjustments to the amounts and classification of assets and liabilities that may be necessary should the Company be unable to continue as a going concern.

2. CHANGES IN ACCOUNTING POLICIES

2009 Accounting Changes

In February 2008, the Canadian Institute of Chartered Accountants (**CICA**) issued Handbook Section 3064, Goodwill and Intangible assets, (**S.3064**) replacing Handbook Section 3062, Goodwill and Other Intangible Assets (**S.3062**) a Handbook Section 3450, Research and Development Costs . S.3064 is applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. 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.

Also in February 2008, the CICA amended portions of Handbook Section 1000, Financial Statement Concepts , which the CICA concluded permitted deferral of costs that did not meet the definition of an asset. The amendments apply to annual and interim financial statements relating to fiscal years beginning on or after October 1, 2008. Upon adoption of S.3064 and the amendments to Section 1000 on January 1, 2009, capitalized amounts that no longer meet the definition of an asset are expensed retrospectively.

The Company adopted the new standards on January 1, 2009 with no transitional adjustment to the condensed consolidated financial statements as a result of having adopted these standards.

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3. OIL AND GAS PROPERTIES AND DEVELOPMENT COSTS

Capital assets categorized by segment are as follows:

	As at March 31, 2009					
	Oil and Gas				Business and Technology Development	Total
	Integrated		Conventional			
	Canada	Ecuador	China	U.S.		
Oil and Gas Properties:						
Proved	$	$	$ 142,554	$ 113,278	$	$ 255,832
Unproved	83,288	2,066	4,924	3,088		93,366
	83,288	2,066	147,478	116,366		349,198
Accumulated depletion			(86,991)	(34,874)		(121,865)
Accumulated provision for impairment			(16,550)	(50,350)		(66,900)
	83,288	2,066	43,937	31,142		160,433
Development Costs:						
Feasibility studies and other deferred costs:						
HTL™					948	948
GTL					5,054	5,054
Accumulated provision for impairment					(5,054)	(5,054)
Feedstock test facility					9,879	9,879
Commercial demonstration facility					11,222	11,222
Accumulated depreciation					(8,341)	(8,341)
					13,708	13,708
Furniture and equipment	13	133	120	904	43	1,213
Accumulated depreciation	(5)	(14)	(80)	(534)	(37)	(670)
	8	119	40	370	6	543
	$ 83,296	$ 2,185	$ 43,977	$ 31,512	$ 13,714	$ 174,684

	As at December 31, 2008					
	Oil and Gas				Business and Technology Development	Total
	Integrated		Conventional			
	Canada	Ecuador	China	U.S.		
Oil and Gas Properties:						
Proved	$	$	$ 141,089	$ 113,002	$	$ 254,091

Unproved	81,090	1,454	5,233	3,067		90,844
	81,090	1,454	146,322	116,069		344,935
Accumulated depletion			(81,717)	(33,197)		(114,914)
Accumulated provision for impairment			(16,550)	(50,350)		(66,900)
	81,090	1,454	48,055	32,522		163,121
Development Costs:						
Feasibility studies and other deferred costs:						
HTL™					801	801
GTL					5,054	5,054
Accumulated provision for impairment					(5,054)	(5,054)
Feedstock test facility					8,770	8,770
Commercial demonstration facility					11,036	11,036
Accumulated depreciation					(7,713)	(7,713)
					12,894	12,894
Furniture and equipment	20	90	120	538	406	1,174
Accumulated depreciation	(6)		(80)	(476)	(77)	(639)
	14	90	40	62	329	535
	$ 81,104	$ 1,544	$ 48,095	$ 32,584	$ 13,223	$ 176,550

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Costs as at March 31, 2009 of $93.4 million ($90.8 million at December 31, 2008), related to unproved oil and gas properties, have been excluded from costs subject to depletion and depreciation. Included in the depletion calculation is $5.9 million for future development costs associated with proven undeveloped reserves as at March 31, 2009 ($6.7 million at December 31, 2008).

For the three-months ended March 31, 2009, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities of $0.9 million ($0.5 million for 2008) were capitalized.

For the three months ended March 31, 2009, interest on debt related to oil and gas acquisition activities of $0.5 million (nil for the same period in 2008) was capitalized.

4. INTANGIBLE ASSETS HTL™ TECHNOLOGY

In the 2005 merger with Ensyn Group, Inc. (**Ensyn**), the Company acquired 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 March 31, 2009 and December 31, 2008 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.

Recovery of capitalized costs related to potential HTL™ projects is dependent upon finalizing definitive agreements for, and successful completion of, the various projects. This intangible asset was not amortized and its carrying value was not impaired for the three-month periods ended March 31, 2009 and 2008.

5. LONG TERM DEBT

Notes payable consisted of the following as at:

	March 31, 2009	December 31, 2008
Variable rate bank note, (4.29% at March 31, 2009), due May 2009	$ 5,200	$ 5,200
Variable rate bank note (5.05% at March 31, 2009) due September 2010	7,000	7,000
Non-interest bearing promissory note, final payment February 2009		416
Convertible note (4.50% at March 31, 2009) due July 2011	31,701	32,787
	43,901	45,403
Less:		
Unamortized discount	(1,302)	(1,484)
Unamortized deferred financing costs	(392)	(452)
Current maturities	(5,200)	(5,612)
	(6,894)	(7,548)
	$ 37,007	$ 37,855

The scheduled maturities of the Company s long term debt, excluding unamortized discount and unamortized deferred financing costs, as at March 31, 2009 were as follows:

2009	$ 5,200
2010	7,000

2011		31,701
	$	43,901

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6. ASSET RETIREMENT OBLIGATIONS

The Company provides for the expected costs required to abandon its producing U.S. oil and gas properties, the HTL™ commercial demonstration facility (**CDF**) and the HTL™ Feedstock Test Facility (**FTF**). The undiscounted amount of expected future cash flows required to settle the Company s asset retirement obligations for these assets as at March 31, 2009 was estimated at $6.8 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 2 and 3% and the expected future cash flows have been discounted using a credit-adjusted risk-free rate of 4 and 6% for the respective periods shown below. A reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties, the CDF and the FTF were as follows:

	As at March 31, 2009	As at December, 31 2008
Carrying balance, beginning of year	$ 3,738	$ 2,218
Liabilities incurred	185	236
Accretion expense	49	171
Revisions in estimated cash flows		1,113
Carrying balance, end of period	$ 3,972	$ 3,738

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 approximately 23,700 feet of drilling (including the Phase 1 shortfall), with total gross remaining estimated minimum expenditures for this program of $27.4 million. The Zitong Partners have relinquished 25% of the Block to complete the Phase I relinquishment requirement. The Phase 2 seismic line acquisition commitment was fulfilled in the Phase 1 exploration program. Drilling is planned to commence in late 2009 with drilling, completion and evaluation of this prospect expected to be finalized in 2010. The Zitong Partners must complete the minimum work program by the end of the Phase 2 period, 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. 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 in 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 in China related to when its entitlement to take tax deductions associated with development costs commenced. 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 development costs this could potentially result in an increase in the current tax provision of $1.3 million.

The Company has an uncertain tax position related to the calculation of a gain on the consideration received from two farm-out transactions 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

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.

In July 2008, the Company completed the acquisition of Talisman Energy Canada s (**Talisman**) 100% working interests in two leases located in the Athabasca oil sands region in the Province of Alberta, Canada. In addition to the total purchase price of Cdn.$90.0 million, the Company may also be required to 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. No amount is recorded in the financial statements for this payment as at March 31, 2009 as the chance of occurrence can not be determined at this time.

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 shareholder s equity (excluding accumulated deficit) and stock options outstanding for the three-month period ended March 31, 2009:

	Common Shares					**Stock Options**	
	Number (thousands)	**Amount**	**Purchase Warrants**	**Contributed Surplus**	**Convertible Note**	**Number (thousands)**	**Wtd. Avg Exercise Price Cdn.$**
Balance December 31, 2008	279,381	$ 413,857	$ 18,805	$ 16,862	$ 2,086	11,913	$ 2.32
Options:							
Cancelled/forfeited						(167)	$ 2.16
Compensation calculated for stock option grants				461			
Balance March 31, 2009	279,381	$ 413,857	$ 18,805	$ 17,323	$ 2,086	11,746	$ 2.32

There were no changes to the number of the Company s purchase warrants and common shares issuable upon the exercise of the purchase warrants for the three-month period ended March 31, 2009.

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As at March 31, 2009, 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						
Year of Issue	Price per Special Warrant	Issued	Exercisable (thousands)	Common Shares Issuable	Value ($U.S. 000)	Expiry Date	Exercise Price per Share	Cash Value on Exercise ($U.S. 000)
2006	U.S.$2.23	11,400	11,400	11,400	18,805	May 2011	Cdn. $2.93 (1)	26,472

(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.

9. SEGMENT INFORMATION

The Company has four reportable business segments: Oil and Gas Integrated, Oil and Gas - Conventional, Business and Technology Development and Corporate. These segments are different than those reported in the Company s previous financial statements included in its Form 10-Qs and as such the presentation has been changed to conform to the new segments. Due to newly established geographically focused entities and the initiation of two new integrated projects in the second half of 2008, new segments are being reported to reflect how management now analyzes and manages the Company.

Oil and Gas

Integrated

Projects in this segment will have two primary components. The first component consists of conventional exploration and production activities together with enhanced oil recovery techniques such as steam assisted gravity drainage. The second component consists of the deployment of the HTL™ Technology which will be used to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. The Company has two such projects currently reported in this segment a heavy oil project in Alberta and a heavy oil project in Ecuador.

<u>*Conventional*</u>

The Company explores for, develops and produces crude oil and natural gas in China and in the U.S. 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.

Business and Technology Development

The Company incurs various costs in the pursuit of projects throughout the world. Such costs incurred prior to signing a memorandum of understanding (**MOU**) or similar agreement, are considered to be business and technology development and are expensed as incurred. Upon executing a MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the project s products, the Company assesses whether the feasibility and related costs incurred have potential future value, are likely to lead to a definitive agreement for the exploitation of proved reserves and should be capitalized.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the technologies it owns or licenses. The cost of equipment and facilities acquired, or construction costs for such purposes, are capitalized as development costs and amortized over the expected economic life of the equipment or facilities, commencing with the start up of commercial operations for which the equipment or facilities are intended.

Corporate

The Company s corporate segment consists of costs associated with the board of directors, executive officers, corporate debt, financings and other corporate activities.

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The following tables present the Company s segment information for the three-month periods ended March 31, 2009 and 2008 and identifiable assets as at March 31, 2009 and December 31, 2008:

	Three Month Period Ended March 31, 2009						
	Oil and Gas				Business and Technology Development	Corporate	Total
	Integrated		Conventional				
	Canada	Ecuador	China	U.S.			
Revenue							
Oil and gas revenue	$	$	$ 5,733	$ 1,966	$	$	$ 7,699
Gain on derivative instruments			82	186			268
Interest income			1	2		10	13
			5,816	2,154		10	7,980
Expenses							
Operating costs			2,701	1,026			3,727
General and administrative	139	518	418	125		3,754	4,954
Business and technology development	294				1,743		2,037
Depletion and depreciation	1	14	5,274	1,713	629	1	7,632
Interest expense and financing costs			148	82	25	4	259
	434	532	8,541	2,946	2,397	3,759	18,609
Loss before Income Taxes	(434)	(532)	(2,725)	(792)	(2,397)	(3,749)	(10,629)
Current provision for income taxes			(1,636)	(9)			(1,645)
Net Loss and Comprehensive Loss	$ (434)	$ (532)	$ (4,361)	$ (801)	$ (2,397)	$ (3,749)	$ (12,274)
Capital Investments	$ 2,068	$ 656	$ 1,156	$ 298	$ 1,274	$	$ 5,452
Identifiable Assets:							
As at March 31, 2009	$ 83,370	$ 2,520	$ 59,165	$ 36,141	$ 106,145	$ 17,119	$ 304,460

As at December 31, 2008	$ 81,126	$ 1,766	$ 64,901	$ 37,480	$ 105,587	$ 26,415	$ 317,275

Three-Month Period Ended March 31, 2008

	Oil and Gas				Business and Technology Development	Corporate	Total
	Integrated		Conventional				
	Canada	Ecuador	China	U.S.			
Revenue							
Oil and gas revenue	$	$	$ 10,888	$ 4,155	$	$	$ 15,043
Loss on derivative instruments			(2,682)	(1,264)			(3,946)
Interest income			14	44		14	72
			8,220	2,935		14	11,169
Expenses							
Operating costs			4,310	1,082			5,392
General and administrative	280	1	566	362		2,737	3,946
Business and technology development	31				1,445		1,476
Depletion and depreciation			6,206	1,456	703	1	8,366
Interest expense and financing costs			324	148	10	51	533
	311	1	11,406	3,048	2,158	2,789	19,713
Net Loss and Comprehensive Loss	$ (311)	$ (1)	$ (3,186)	$ (113)	$ (2,158)	$ (2,775)	$ (8,544)
Capital Investments	$	$	$ 2,125	$ 2,483	$ 715	$	$ 5,323

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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 March 31, 2009				
	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	$	$	$ 28,364	$	$ 28,364
Accounts receivable	5,790				5,790
Derivative instruments			1,167		1,167
Financial Liabilities:					
Accounts payable and accrued liabilities				(8,481)	(8,481)
Long term obligation				(1,900)	(1,900)
Long term debt				(42,207)	(42,207)
	$ 5,790	$	$ 29,531	$ (52,588)	$ (17,267)

	As at December 31, 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	$	$	$ 39,265	$	$ 39,265
Accounts receivable	4,870				4,870
Derivative instruments			2,159		2,159
Financial Liabilities:					
Accounts payable and accrued liabilities				(10,093)	(10,093)
Long term obligation				(1,900)	(1,900)
Long term debt				(43,467)	(43,467)
	$ 4,870	$	$ 41,424	$ (55,460)	$ (9,166)

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 or to management s objectives, policies and processes to manage risks from the previous year except the availability of financing is dependent in part on the return of the credit and equity markets to normalized conditions. During the fourth quarter of 2008, and the first quarter of 2009, as a result of the global economic crisis, the terms and availability of equity and debt capital have been materially restricted and financing may not be available when required or on commercially acceptable terms.

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, Ecuador and elsewhere internationally as business opportunities arise. 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.

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12. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information for the three-month periods ended March 31:

	Three Months Ended March 31, 2009	2008
Cash paid during the period for		
Income taxes	$	$ 6
Interest	$ 1,929	$ 366
Changes in non-cash working capital items		
Operating Activities		
Accounts receivable	$ (999)	$ (1,184)
Prepaid and other current assets	(42)	108
Accounts payable and accrued liabilities	(654)	964
Income tax payable	1,636	
	(59)	(112)
Investing Activities		
Accounts receivable	80	37
Prepaid and other current assets	69	(21)
Accounts payable and accrued liabilities	(965)	(1,146)
	(816)	(1,130)
Financing Activities		
Accounts payable and accrued liabilities	(23)	
	$ (898)	$ (1,242)

Cash and cash equivalents at March 31, 2009 and December 31, 2008, are composed entirely of bank balances in checking accounts with excess cash in money market accounts which invest primarily in government securities with less than 90 day maturities.

13. INCOME TAXES

In April 2009, the Chinese State Tax Administration Bureau issued, Circular [2009] No. 49 (the "**Circular**) on depletion, depreciation and amortization expense by oil and gas companies. One of the changes to the existing rules included in the Circular that affects the Company was the increase of the minimum depreciation and amortization period from six years to eight years. The implementation of the new rules was retroactive to January 1, 2008. Consequently, upon reviewing the tax effect of the Circular, the Company has revised its 2008 current tax payable in China to $2.1 million from the $0.7 million that was recorded in 2008. In addition, a current Chinese income tax payable of $0.2 million was recorded for the three-month period ended March 31, 2009.

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14. 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

The application of U.S. GAAP has the following effects on consolidated balance sheet items as reported under Canadian GAAP:

	As at March 31, 2009				As at December 31, 2008			
	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP
Assets								
Current Assets:								
Cash and cash equivalents	$ 28,364	$		$ 28,364	$ 39,265	$		$ 39,265
Accounts receivable	5,790			5,790	4,870			4,870
Prepaid and other current assets	1,631			1,631	1,658			1,658
Derivative instruments	1,167			1,167	2,159			2,159
Total Current Assets	36,952			36,952	47,952			47,952
Oil and gas properties and development costs, net	174,684	1,358	(iv)	124,044	176,550	1,358	(iv)	122,071
		(67,850)	(v)			(67,850)	(v)	
		17,408	(vi)			13,031	(vi)	
		(1,164)	(vii)			(1,018)	(vii)	
		(392)	(viii)					
Intangible assets technology	92,153			92,153	92,153			92,153
Long term assets	671	392	(xi)	1,063	620	451	(xi)	1,071
Total Assets	$ 304,460	$ (50,248)		$ 254,212	$ 317,275	$ (54,028)		$ 263,247
Liabilities and Shareholders Equity								
Current Liabilities:								
Accounts payable and accrued liabilities	$ 8,481	$		$ 8,481	$ 10,093	$		$ 10,093
Income tax payable	2,286			2,286	650			650
Debt current portion	5,200			5,200	5,612			5,612
Derivative instruments		3,162	(iii)	3,162		1,121	(iii)	1,121
Total Current Liabilities	15,967	3,162		19,129	16,355	1,121		17,476

Long term debt	37,007	392	(xi)	38,701	37,855	451	(xi)	40,392
		1,694	(viii)			2,086	(viii)	
		(392)	(viii)					
Asset retirement obligations	3,972			3,972	3,738			3,738
Long term obligation	1,900			1,900	1,900			1,900
Total Liabilities	58,846	4,856		63,702	59,848	3,658		63,506
Shareholders Equity:								
Share capital	413,857	74,455	(i)	502,372	413,857	74,455	(i)	502,372
		(498)	(ii)			(498)	(ii)	
		1,358	(iv)			1,358	(iv)	
		13,200	(iii)			13,200	(iii)	
Purchase warrants	18,805	(18,805)	(iii)		18,805	(18,805)	(iii)	
Contributed surplus	17,323	(3,250)	(ii)	11,126	16,862	(3,250)	(ii)	10,665
		(2,947)	(iii)			(2,947)	(iii)	
Convertible note	2,086	(2,086)	(viii)		2,086	(2,086)	(viii)	
Accumulated deficit	(206,457)	(116,531)		(322,988)	(194,183)	(119,113)		(313,296)
Total Shareholders Equity	245,614	(55,104)		190,510	257,427	(57,686)		199,741
Total Liabilities and Shareholders Equity	$ 304,460	$ (50,248)		$ 254,212	$ 317,275	$ (54,028)		$ 263,247

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.

(ii) Under 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. Under U.S. GAAP, prior to January 1, 2006 the Company applied Accounting Principles Board (**APB**) Opinion No. 25, as interpreted by the Financial Accounting Standards Board (**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. Beginning January 1, 2006 the Company applied the revision to the Statement of Financial Accounting Standards (**SFAS**) No. 123, Accounting for Stock Based Compensation which supersedes APB No. 25, Accounting for Stock Issued to Employees . 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 are no significant differences between the accounting for stock options under Canadian GAAP and U.S. GAAP.

(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 2008 Annual Report filed on Form 10-K, the accounting treatment of warrants under U.S. GAAP reflects the application of SFAS 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.

Oil and Gas Properties and Development Costs

(iv) Under U.S. GAAP, 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 DD&A 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 (d) 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 period ended March 31, 2009 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 $67.9 million at March 31, 2009 and December 31, 2008.

(vi) The cumulative differences in the amount of impairment provisions between U.S. and Canadian GAAP resulted in a reduction in accumulated depletion.

(vii) As more fully described in our financial statements in Item 8 of our 2008 Annual Report filed on Form 10-K, under Canadian GAAP, the Company capitalizes certain development costs incurred for 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 development costs. Under U.S. GAAP, feasibility, marketing and related costs incurred prior to executing a definitive agreement are considered to be research and development and are expensed as incurred.

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(viii) As more fully described in Note 5 of our financial statements in Item 8 of our 2008 Annual Report filed on Form 10-K, under Canadian GAAP we were required to bifurcate the value of a convertible note, allocating a portion to long term debt and a portion to equity. Under U.S. GAAP, the convertible debt securities in their entirety are classified as debt. Under Canadian GAAP this discount accretion was capitalized. To reconcile to U.S. GAAP the entire $2.1 million recorded in equity is reversed as well as the unamortized discount of $1.7 million and the accreted discount that was capitalized in the amount of $0.4 million. In addition, because the convertible note is not denominated in U.S. currency the remeasurement of the different carrying value for U.S. GAAP results in an increase to net income. The foreign exchange gain of $0.4 million is shown as a separate amount in the U.S. GAAP reconciliation of the Company s balance sheet shown above and is adjusted to the General and Administrative Expense line item in the U.S. GAAP reconciliation of the statement of operations below.

Deferred Financing Costs

(xi) As more fully described in our financial statements in Item 8 of our 2008 Annual Report filed on Form 10-K, under 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. Under U.S. GAAP purposes, these costs are classified as other assets and amortized over the expected term of the financial liability.

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 Months Ended March 31, 2009				Three Months Ended March 31, 2008			
	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP
Revenue								
Oil and gas revenue	$ 7,699			$ 7,699	$ 15,043			$ 15,043
Gain (loss) on derivative instruments	268	(2,041)	(iii)	(1,773)	(3,946)	(3,167)	(iii)	(7,113)
Interest income	13			13	72			72
Total Revenue	7,980	(2,041)		5,939	11,169	(3,167)		8,002
Expenses								
Operating costs	3,727			3,727	5,392			5,392
General and administrative	4,954	(392)	(viii)	4,562	3,946			3,946
Business and technology development	2,037			2,037	1,476			1,476
Depletion and depreciation	7,632	(4,377)	(ix)	3,255	8,366	(1,226)	(ix)	7,140
Interest expense and financing costs	259			259	533			533
Provision for impairment of HTL™ development costs		146	(x)	146		9	(x)	9
Total Expenses	18,609	(4,623)		13,986	19,713	(1,217)		18,496

Loss before Income Taxes	(10,629)	2,582	(8,047)	(8,544)	(1,950)	(10,494)
Current provision for income taxes	(1,645)		(1,645)			
Net Loss and Comprehensive Loss	(12,274)	2,582	(9,692)	(8,544)	(1,950)	(10,494)
Accumulated Deficit, beginning of year	(194,183)	(119,113)	(313,296)	(159,990)	(90,255)	(250,245)
Accumulated Deficit, end of year	$ (206,457)	$ (116,531)	$ (322,988)	$ (168,534)	$ (92,205)	$ (260,739)
Net Loss per share - Basic and Diluted	$ (0.04)	$ 0.01	$ (0.03)	$ (0.03)	$ (0.01)	$ (0.04)
Weighted Average Number of Shares (in thousands) Basic and Diluted	279,381		279,381	244,873		244,873

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(ix) As discussed under Oil and Gas Properties and Development Costs in this note, there is a difference between U.S. and Canadian GAAP in performing the ceiling test evaluation under the full cost method of the accounting rules. 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. This net increase in U.S. GAAP impairment provisions has resulted in lower depletion rates for U.S. GAAP purposes and a reduction in the net loss for the three-month periods ended March 31, 2009 and 2008.
(x) As more fully described under Oil and Gas Properties and Development Costs in this note, under Canadian GAAP, feasibility, marketing and related costs incurred prior to executing a definitive agreement are capitalized and are subsequently written down upon determination that a project s future value has been impaired. Under U.S. GAAP, such costs are considered to be research and development and are expensed as incurred.

Condensed Consolidated Statement of Cash Flow

As a result of the expensing of HTL™ development costs as required under U.S. GAAP the statement of cash flows as reported would result in a cash deficiency of $4.2 million for the three-month period ended March 31, 2009. Additionally, capital investments reported under investing activities would be $5.3 million for the three-month period ended March 31, 2009 if reported under U.S. GAAP. There would be no material difference in cash flow presentation between Canadian and U.S. GAAP for the three-month period ended March 31, 2008.

Additional U.S. GAAP Disclosures

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 March 31, 2009.

	As at March 31, 2009			
	Level 1	Level 2	Level 3	Total
Derivative instruments assets	$	$ 1,167	$	$ 1,167
Derivative instruments liabilities	$ 3,162	$	$	$ 3,162

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

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

In March 2008, the FASB issued SFAS 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 beginning January 1, 2009. Management has complied with the disclosure requirements of this recent statement below:

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. All of the above contacts were put in place as part of the Company s bank loan facilities.

Results of these derivative transactions for the three-month periods ended March 31, 2009 and 2008:

	Three-Month Periods Ended March 31,	
	2009	**2008**
Realized gains (losses) on derivative transactions	$ 1,260	$ (1,948)
Unrealized losses on derivative transactions	(992)	(1,998)
	$ 268	$ (3,946)

Both realized and unrealized gains and losses on derivatives have been recognized in the results of operations.

On March 31, 2009, the Company s open positions on the derivative assets referred to above had a fair value of $1.2 million. The fair value change assumes volatility based on prevailing market parameters at March 31, 2009.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations . The standard 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. In April 2009, the FASB issued FASB Staff Position (**FSP**) FAS 141(R)-1 which amends and clarifies SFAS No. 141(R) to address application issues raised by preparers, auditors and members of the legal profession on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This statement shall be applied prospectively. The implementation of SFAS No. 141(R) and FSP FAS 141(R)-1, effective January 1, 2009, did not have a material impact on the company s consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements . The standard requires all entities to report noncontrolling (minority) interests as equity in consolidated financial statements. SFAS No. 160 eliminates the diversity that currently exists in accounting for transactions between an entity and noncontrolling interests by requiring they be treated as equity transactions. This statement shall be applied prospectively. The implementation of SFAS No. 160, effective January 1, 2009, did not have a material impact on the company s consolidated financial statements.

In February 2008, the FASB issued FASB Staff Position No. FAS 157-2, Effective Date of FASB Statement No. 157 (FSP FAS 157-2). FSP FAS 157-2 amends SFAS No. 157 to delay the effective date of SFAS No. 157 for non-financial assets and non-financial liabilities until fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis. The implementation of FSP FAS 157-2, effective January 1, 2009, did not have a material impact on the company s consolidated financial statements.

In December 2008, the FASB announced that on July 1, 2009, the *FASB Accounting Standards Codification* (the Codification) is expected to officially become the single source of authoritative US GAAP (other than guidance issued by the US Securities and Exchange Commission), superseding existing FASB, American Institute of Certified Public Accountants, Emerging Issues Task Force (EITF), and related literature. After that date, only one level of authoritative US GAAP will exist. All other literature will be considered non-authoritative. The Codification does not change US GAAP; instead, it introduces a new structure that is organized in an easily accessible, user-friendly online research system. Following the FASB Board s approval of the Codification, expected as of July 1, 2009, the company will be required to reference the Codification when discussing authoritative US GAAP in the company s consolidated financial statements issued subsequent to this date.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting to revise the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. In addition, the new disclosure requirements require a company to (a) disclose its internal control over reserves estimation and report the independence and qualification of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserve audit and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The provisions of this final ruling will become effective for disclosures in our Annual Report on Form 10-K for the year ended December 31, 2009. Management is still evaluating the impact of these changes on its financial statements.

In April 2009, the FASB issued FSP FAS 157-e, Determining Whether a Market Is Not Active and a Transaction Is Not Distressed and FSP FAS 115-a, FAS 124-a and EITF 99-20-b, Recognition and Presentation of Other-Than-Temporary Impairments . FSP FAS 157-e provides amended and enhanced guidance on fair value measurement in inactive markets. The new guidance specifically addresses determining whether or not a market is inactive and whether a transaction in that market is considered to be distressed. FSP FAS 115-a, FAS 124-a and EITF-99-20-b, require an entity to assess the likelihood of disposing of certain debt securities prior to recovering its cost basis. When an entity does not intend to sell the security and it is more likely than not that the entity will not have to sell the security before recovery of its cost basis, it will recognize only the credit loss component of an other-than-temporary impairment of a debt security in earnings and the remaining portion in other comprehensive income. Both of these FSPs are effective for interim and fiscal periods ending after June 15, 2009, with early adoption permitted for periods ending March 15, 2009.

Also, in April 2009, the FASB issued FSP FAS 107-b and APB 28-a, Interim Disclosure about Fair Value of Financial Instruments . This statement amends SFAS No. 107 to require disclosures about fair value of financial instruments in interim financial statements. The statement is effective for interim and annual periods beginning after June 15, 2009, with early adoption permitted for periods ending March 15, 2009. The FASB concluded that early adoption is available only if FSB FAS 157-e, FSP FAS 115-e, FAS 124-a and EITF-99-20-b and FSP FAS 107-b and APB 28-a are adopted simultaneously. The company is currently reviewing the guidance to determine the potential impact, if any, on its consolidated financial statements.

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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 , expec 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 Ecuador s agreement with Petroecuador and Petroproduccion to develop Block 20 in Ecuador, Ivanhoe Energy s ability to obtain the financing to pay the principal and interest on the notes delivered by Ivanhoe Energy to Talisman as partial consideration for Talisman s interest in two oil sands leases and obtain the financing necessary to fund the Ecuador project, Ivanhoe Energy s plan to establish integrated HTL™ heavy oil projects on Talisman Lease 10 and Ecuador Block 20, the anticipated production capacity of the proposed HTL™ plants, the anticipated quantities of recoverable barrels of bitumen and other statements which are not historical facts and to future production associated with the HTL™ Technology and Enhanced Oil Recovery (EOR) techniques. Such statements involve known and unknown risks and uncertainties which may cause the 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 the Company believes that its expectations are based on reasonable assumptions, it can give no assurance that its 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, the 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 the Company operates and implementation of its 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 the Company s 2008 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, 2008. 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 14.

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, the Company s reserves estimates and securities regulatory disclosures generally follow SEC requirements. In 2004 and amended in 2008, 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. The Company has been granted certain exemptions from NI 51-101. Please refer to the *Special Note to Canadian Investors* on page 9 of the 2008 Annual Report on Form 10-K.

THE DISCUSSION AND ANALYSIS OF THE COMPANY S OIL AND GAS ACTIVITIES WITH RESPECT TO OIL AND GAS VOLUMES, RESERVES AND RELATED PERFORMANCE MEASURES IS PRESENTED ON NET OF WORKING INTEREST 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:

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

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Oil equivalents compare quantities of oil with quantities of gas or express these different commodities in a common unit. In calculating Bbl equivalents (Boe), the generally recognized industry standard is 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 the Company s filings with the SEC and the CSA are available, free of charge, through its web site (www.ivanhoeenergy.com) or, upon request, by contacting its 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 the Company s 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 HTL™ Technology. In mid-2008, the Company acquired two leases located in the heart of the Athabasca oil sands region in Alberta, Canada and in October 2008 signed a contract with Petroproduccion and Petroecuador for the appraisal and development of a heavy oil property in Ecuador. It is anticipated that these sites will provide for the first commercial applications of the Company s HTL Technology in major, integrated heavy oil projects (see Implementation Strategy below). In addition, the Company seeks to selectively expand its reserve base and production through conventional exploration and production of oil and gas.

Core operations are in Canada, the United States, China and Ecuador, with business development opportunities worldwide.

The Company has established a number of geographically focused entities. Ivanhoe Energy Inc. will pursue HTL™ opportunities in the Athabasca oil sands of Western Canada and will hold and manage the core HTL™ Technology as well as shares in geographically-focused subsidiaries. One subsidiary exclusively focused on business opportunities in Latin America signed a contract for the appraisal and development of a heavy oil property in Ecuador and another has been established to undertake activities in the Middle East and North Africa. These companies complement Sunwing Energy Ltd., the Company s existing, wholly-owned subsidiary established for activities in China and Southeast Asia. Ivanhoe Energy owns 100% of each of these subsidiaries, although its ownership interest will be diluted as they develop their respective businesses and raise equity capital independently.

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

The Company s four reportable business segments are: Oil and Gas Integrated, Oil and Gas - Conventional, Business and Technology Development and Corporate. These segments are different than those reported in the Company s previous Form 10-Q Quarterly Reports and as such the presentation has been changed to conform to the new segments. Due to newly established geographically focused entities and the initiation of two new integrated projects in the second half of 2008, new segments are being reported to reflect how management analyzes and manages the Company.

Oil and Gas

Integrated

Projects in this segment have two primary components. The first component consists of conventional exploration and production activities together with enhanced oil recovery techniques such as steam assisted gravity drainage. The second component consists of the deployment of the HTL™ Technology which will be used to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. The Company has two such projects currently reported in this segment - a heavy oil project in Alberta and a heavy oil project in Ecuador.

Conventional

The Company explores for, develops and produces crude oil and natural gas in China and in the U.S. 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.

Business and Technology Development

The Company incurs various costs in the pursuit of projects throughout the world. Such costs incurred prior to signing a MOU or similar agreement, are considered to be business and technology development and are expensed as incurred. Upon executing a MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products, the Company assesses whether the feasibility and related costs incurred have potential future value, are likely to lead to a definitive agreement for the exploitation of proved reserves and should be capitalized.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the technologies it owns or licenses. The cost of equipment and facilities acquired, or construction costs for such purposes, are capitalized as development costs and amortized over the expected economic life of the equipment or facilities, commencing with the start up of commercial operations for which the equipment or facilities are intended.

Corporate

The Company s corporate segment consists of costs associated with the board of directors, executive officers**,** corporate debt, financings and related corporate activities.

Our authorized capital consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

We were incorporated pursuant to the laws of the Yukon Territory of Canada, on February 21, 1995 under the name 888 China Holdings Limited. On June 3, 1996, we changed our name to Black Sea Energy Ltd., and on June 24, 1999, we changed our name to Ivanhoe Energy Inc.

Our principal executive office is located at Suite 654 999 Canada Place, Vancouver, British Columbia, V6C 3E1, and our registered and records office is located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9.

Corporate Strategy

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

The global oil and gas industry is being impacted by the declining availability of replacement low-cost reserves. This has resulted in volatility in oil markets and marked shifts in the demand and supply landscape. Although there has been a great deal of volatility in the price of oil and significant recent price declines, we believe that long term demand and the natural decline of conventional oil production will see the development of higher cost 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 the Company focuses on the non-conventional heavy oil, both play an important role in Ivanhoe Energy 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 other oil basins, including the Middle East and Asia, 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 heavy oil production has become increasingly more common. Refineries, on the other hand, have not been able to keep up with the need for deep conversion capacity and are restricted to conventional technologies that require very large scale and have high per-barrel costs.

With regard to non-conventional heavy oil and bitumen, the increased interest and activity has been impacted by 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. While these newer technologies have generated increased access to heavy oil resources, profitable exploitation requires key challenges to be addressed, including: 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 versus light oil price differentials that the producer is faced with when the product gets to market, and 4) conventional upgrading technologies typically require 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.

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Ivanhoe s Value Proposition

The Company 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 Energy s HTL Technology involves a partial upgrading process that is designed to operate in facilities as small as 10,000 to 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 over 100,000 barrels per day. The Company 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, as processing times are typically under a few seconds. In addition, the process does not require hydrogen, catalysts or significant pressure. This results in smaller, less costly facilities than conventional upgrading. The Company 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 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 versus 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 the Company 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 flows naturally to the surface, but transport is the key problem.

The economics of any given 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 Energy value proposition.

Implementation Strategy

We are an oil and gas company with a unique technology which addresses several major problems confronting the oil and gas industry today and we believe that we have a competitive advantage because of our patented technology. In addition, because we have experienced thermal recovery teams in Bakersfield and Calgary, we are in a position to add value and leverage our technology advantage by working with partners on stranded heavy oil resources around the world.

The Company s continuing strategy is as follows:

1. ***Execute.*** Execute on the two initial HTL™ projects: Tamarack in Canada and Pungarayacu in Ecuador.

2. ***Additional projects.*** Build on our two initial projects by capturing additional projects worldwide using the Company s HTL™ Technology.

3. ***Advance the technology.*** Continue to advance the HTL™ Technology through the first commercial application and beyond as well as continue the development of the technology and our intellectual property portfolio with our fully functional, third generation HTL™ processing facility, our feedstock test facility (**FTF**) in San Antonio.

4. ***Finance initial projects.*** Secure key partnerships and financing related to the initial two projects. The Company is actively working on various financing plans and establishing the relationships required for the development of Tamarack, Pungarayacu and additional projects in the future.

5. ***Build internal capabilities.*** We have made significant progress in building execution teams in order to execute the Company s first HTL™ projects. The Calgary based upstream team consists of a number of experienced heavy oil petroleum engineers, geologists and geotechnical experts attracted from major firms in Canada, complemented by thermal experts from the Company s Bakersfield office. The upstream team working on Pungarayacu consists primarily of the Company s Bakersfield based team that has many years of South American experience with firms such as Occidental Petroleum. In addition, the Company s Houston-based HTL™ technology team consists of a number of engineers that have an extensive background in chemical and petroleum refining, project engineering and the development and management of intellectual property. The Company expects to continue filling key positions in its execution mode.

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Executive Overview of 2009 Results

The following table sets forth certain selected consolidated data for the three-month periods ended March 31, 2009 and 2008:

	Three-Month Periods ended March 31,			
		2009		2008
Oil and gas revenue	$	7,699	$	15,043
Net loss	$	(12,274)	$	(8,544)
Net loss per share basic and diluted	$	(0.04)	$	(0.03)
Average production (Boe/d)		2,095		1,907
Net operating revenue per Boe	$	21.06	$	55.60
Cash flow provided (used) by operating activities	$	(4,088)	$	3,017
Capital investments	$	(5,452)	$	(5,323)

Financial Results Change in Net Loss

The following provides an analysis of the changes in net losses for the three-month periods ended March 31, 2009 as compared to the same period for 2008:

	Three-Month Periods Ended March 31,					
		2009		*Favorable (Unfavorable) Variances*		2008
Summary of Net Loss by Significant Components:						
Oil and Gas Revenues:	$	7,699			$	15,043
Production volumes			*$*	*1,263*		
Oil and gas prices				*(8,607)*		
Realized gain (loss) on derivative instruments		1,260		*3,208*		(1,948)
Operating costs		(3,727)		*1,665*		(5,392)
General and administrative, less stock based compensation		(4,520)		*(1,481)*		(3,039)
Business and technology development, less stock based compensation		(2,009)		*(744)*		(1,265)
Net interest		(138)		*208*		(346)
Current income tax provision		(1,645)		(1,645)		
Unrealized loss on derivative instruments		(992)		*1,006*		(1,998)
Depletion and depreciation		(7,632)		*734*		(8,366)
Stock based compensation		(461)		*657*		(1,118)
Other		(109)		*6*		(115)
Net Loss	$	(12,274)	*$*	*(3,730)*	$	(8,544)

The net loss for the three-month period ended March 31, 2009 was $12.3 million ($0.04 net loss per share) compared to a net loss for the same period in 2008 of $8.5 million ($0.03 net loss per share). The increase in net loss from 2008 to 2009 of $3.7 million was primarily due to a $4.1 million decrease in combined oil and gas revenues, realized gain/loss in derivative instruments and a $1.6 million increase in the current provision for income taxes offset by decreases in unrealized losses on derivative instruments, depletion and depreciation and stock based compensation.

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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 period ended March 31, 2009 as compared to the same period in 2008:

	Three-Month Periods Ended March 31,		
	Net Boe s		Percentage
	2009	2008	Change
China:			
Dagang	128,478	119,828	7%
Daqing	2,600	5,143	-49%
	131,078	124,971	5%
U.S.:			
South Midway	54,877	43,677	26%
Spraberry	2,376	4,509	-47%
Others	246	415	-41%
	57,499	48,601	18%
	188,577	173,572	9%

Net production volumes for the three-month period ended March 31, 2009 increased 9% when compared to the same period in 2008 primarily due to an increase in production volumes in both our U.S. and China properties. Total volume changes in the quarter resulted in increased revenues of $1.3 million.

Oil and gas prices decreased 53%, per Boe for the three-month period ended March 31, 2009 resulting in an $8.6 million reduction in revenue when compared to the same period in 2008. For the China operations, the average realized price was $43.74 per Boe during the period in 2009, which was a decrease of $43.38 per Boe from the price in the comparable period in 2008. Average realized prices in China accounted for $5.7 million of the decrease in revenues for the three-month period ended March 31, 2009. For the U.S. operations, the average realized price was $34.19 per Boe during the first quarter of 2009, which was a decrease of $51.30 per Boe from the price in the comparable period in 2008. The average realized price in the U.S. accounted for $3.0 million of the decrease in revenue for the three-month period ended March 31, 2009. Crude oil prices and natural gas prices will likely remain volatile throughout 2009.

The decreased revenues that resulted from decreases to oil and gas prices during the three-month period ended March 31, 2009 were partially offset by the realized gain on derivatives resulting from the settlements from the costless collar derivative instruments. As benchmark prices fall below the floor price established in the contract, the Company is required to settle monthly (see further details on these contracts below under Unrealized Gain (Loss) on Derivative Instruments). The realized net gain on these settlements increased by $3.2 million during the three-month period ended March 31, 2009 when compared to the same period in 2008. Changes in these realized settlement losses by segment are detailed below:

	Three Months Ended March 31, 2009	*Favorable (Unfavorable) Variances*	Three Months Ended March 31, 2008
China	$ 536	*$ 1,259*	$ (723)

U.S.		724		*1,949*		(1,225)
	$	1,260	*$*	*3,208*	$	(1,948)

For the three-month period ended March 31, 2009, operating costs, including Windfall Levy (the **Windfall Levy**) and production taxes and engineering and support costs, decreased 36% per Boe compared to the same periods in 2008. Of the total $1.7 million decrease in these costs, $1.9 million was the result of the change in Windfall Levy which is explained in more detail below under the China Operating Costs section.

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China

Production Volumes

Overall, net production volume at the Dagang field during the three-month period ended March 31, 2009 increased by 8.7 MBbls/d when compared to the same period in 2008 with the exit rate at March 31, 2009 being 1,840 Bopd. The normal field decline from 2008 to 2009 was offset by productivity increases from adding new perforations, fracture stimulations and water flood response. With no additional drilling planned for 2009 we expect future production rates for the remainder of 2009 to be less than that averaged for the first three months. The fracture stimulations planned for the remainder of 2009 will help offset this field decline.

Operating Costs

Operating costs in China, including engineering and support costs and Windfall Levy, decreased 40% per Boe during the three-month period ended March 31, 2009 as compared to the same period in 2008. The majority of this decrease relates to a 94% per Boe drop in the Windfall Levy as oil prices decreased substantially from 2008. 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. For the three-month period ended March 31, 2009 this resulted in rates between 20%-25% or $0.95 per Boe as compared to a 40% levy rate or $16.49 per Boe for the same period in 2008. Offsetting this decrease, field operating costs increased $2.00 or 12% per Boe in 2009 over 2008. Additionally, effective January 1, 2009 the Dagang field reached Commercial Production status as defined by the Production Sharing Contract with China National Petroleum Company and as agreed to by the partners. The effect of this change is that the Company no longer pays 100% of operating costs but now pays 82%, representing the pre-cost recovery proportionate share. Had the Company paid the lower proportionate share noted above in the 2008 period, field operating costs would have increased $5.04 or 36% in 2009. This increase is mainly due to higher maintenance and workover costs, higher road and lease costs which are weather related, increased power grid costs and an increase in oil processing rates charged. On an absolute dollar basis, operating costs for the remainder of 2009 are expected to remain at approximately the same levels incurred in the first three months, however on a per Boe basis, costs are expected to increase as the number of barrels of oil produced decreases while the total level of fluid produced remains constant.

U.S.

Production Volumes

There was an 18% increase in U.S. production volume for the three-month period ended March 31, 2009 when compared to the same period in 2008. The overall increase to the U.S. production volumes was due to a decline in the first quarter of 2008 as result of the steam cycle program being taken offline due to a drilling program along with an increase in 2009 due to a continuous steam cycle program in the southern extension area at South Midway.

Operating Costs

Operating costs in the U.S., including engineering and support costs and production taxes, decreased 20% per Boe for the three-month period ended March 31, 2009 when compared to the same period in 2008. Field operating costs decreased $1.73 per Boe mainly due to a decrease in steaming operation costs at South Midway resulting from a significant decrease in the price of natural gas. Engineering and support costs also decreased as personnel were reallocated to the Company s new business segments in Canada and Ecuador. With the exception of the steaming operations at South Midway, the Company anticipates that operating expense for the remainder of 2009 will be consistent with the first three months of 2009. The Company anticipates natural gas prices to remain volatile for the remainder of 2009 together with the related operating costs associated with the steaming operations at South Midway.

* * *

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

	Three Months Ended March 31,					
		2009			2008	
	China	U.S.	Total	China	U.S.	Total
Net Production:						
Boe	131,078	57,499	188,577	124,971	48,601	173,572
Boe/day for the period	1,456	639	2,095	1,373	534	1,907
		Per Boe			Per Boe	
Oil and gas revenue	$ 43.74	$ 34.19	$ 40.83	$ 87.12	$ 85.49	$ 86.67
Field operating costs	18.95	14.33	17.54	16.95	16.06	16.71
Windfall Levy (China) and Production tax (U.S.)	0.95	0.82	0.91	16.49	1.50	12.29
Engineering and support costs	0.71	2.70	1.32	1.04	4.71	2.07
	20.61	17.85	19.77	34.48	22.27	31.07
Net operating revenue	23.13	16.34	21.06	52.64	63.22	55.60
Depletion	40.23	29.17	36.86	49.66	29.79	44.10
Net revenue (loss) from operations	$ (17.10)	$ (12.83)	$ (15.80)	$ 2.98	$ 33.43	$ 11.50

General and Administrative

Changes in general and administrative expenses, before and after considering a decrease in non-cash stock based compensation, by segment for the three-month period ended March 31, 2009 as compared to the same period for 2008 were as follows:

	2009 vs. 2008
Favorable (unfavorable) variances:	
Oil and Gas Activities:	
Canada	$ 141
Ecuador	(517)
China	148
U.S.	237
Corporate	(1,017)
	(1,008)
Less: stock based compensation	(473)
	$ (1,481)

Canada

The Company acquired working interests in two leases located in Alberta, Canada in July 2008. Certain general and administrative costs, including salaries and benefits, related to Canada are now being capitalized.

Ecuador

In the fourth quarter of 2008 the Company signed a contract to explore and develop Block 20. General and administrative costs incurred prior to signing this contract were minimal.

China

The decrease in general and administrative expenses related to the China operations for the three-month period ended March 31, 2009 as compared to the same period in 2008 mainly resulted from a reduction in legal expense.

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U.S.

General and administrative expenses related to the U.S. operations decreased for the three-month period ended March 31, 2009 as compared to the same period in 2008 mainly resulting from a reallocation of resources to the Company s new business segments in Canada and Ecuador.

Corporate

General and administrative costs related to Corporate activities increased $1.0 million for the three-month period ended March 31, 2009 when compared to the same period in 2008. The following were areas where costs increased: $2.9 million for one-time legal and related fees (see Item 1 to Part II of this Form 10Q) and corporate aircraft costs of $0.3 million. The following details areas where costs decreased partially offsetting the increase in general and administrative expenses: decrease in foreign exchange loss of $1.0 million, reallocation of certain executive salaries to business development activities at the beginning of the third quarter 2008 of $0.3 million, a decrease in stock based compensation due to a significant grant in the first quarter of 2008 in the amount of $0.5 million and recruiting fees for a key executive in 2008 of $0.3 million.

Business and Technology Development

Business and technology development expenses increased $0.6 million (including changes in stock based compensation) for the three-month period ended March 31, 2009 when compared to the same period in 2008 mainly as a result of a reallocation of certain executive salaries to business development activities at the beginning of the third quarter 2008 and several project financing initiatives in the first quarter of 2009.

Net Interest

Interest expense decreased $0.3 million for the three-month period ended March 31, 2009 when compared to the same period in 2008 mainly due to a decrease in our long term debt resulting from a $3.0 million repayment on our loan for our China operations in the fourth quarter of 2008.

Unrealized Gain (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 and are a liability; conversely forecasted benchmark prices fall below the floor prices set in the contract, the contracts have a positive value and are an asset. Changes in these unrealized settlement (losses) and gains by segment are detailed below:

	Three Months Ended March 31, 2009	*Favorable (Unfavorable) Variances*	Three Months Ended March 31, 2008
China	$ (455)	*$ 1,503*	$ (1,958)
U.S.	(537)	*(497)*	(40)
	$ (992)	*$ 1,006*	$ (1,998)

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Depletion and Depreciation

Depletion and depreciation decreased $0.7 million for the three-month period ended March 31, 2009 as compared to the same period in 2008, respectively. This is mainly due to decreases in depletion rates for China.

China

China s depletion rate decreased $9.43 per Boe for the three-month period ended March 31, 2009 when compared to the same period in 2008. This decrease in the rates from period to period was mainly due to lower future oil prices estimated at January 1, 2009 compared to January 1, 2008. This price reduction will delay full cost recovery in the Dagang field, which will result in an increase in net reserves. Lower estimated future capital expenditures to develop proved undeveloped reserves also attributed to the decrease in the rate. These reductions were partially offset by an additional impairment to the Sichuan exploration costs added to the depletable base in the first quarter of 2009.

Financial Condition, Liquidity and Capital Resources

Sources and Uses of Cash

Net cash and cash equivalents decreased for the three-month period ended March 31, 2009 by $10.9 million compared to $4.7 million for the same period in 2008.

Operating Activities

Operating activities used $4.1 million in cash for the three-month period ended March 31, 2009 compared to $3.0 million cash provided for the same period in 2008. The decrease in cash from operating activities for the three-month period ended March 31, 2009 was mainly due to a decrease in oil and gas prices and an increase in general and administrative and business and technology development expenses when compared to the same period in 2008.

Investing Activities

Investing activities used $6.3 million in cash for the three-month period ended March 31, 2009 compared to $6.5 million for the same period in 2008.

Changes in capital investments by segment are detailed below:

	Three-Month Periods Ended March 31,		
	2009	**2008**	**(Increase) Decrease**
Oil and Gas Activities:			
Canada	$ 2,068	$	$ (2,068)
Ecuador	656		(656)
China	1,156	2,125	969
U.S.	298	2,483	2,185
Business and Technology Development	1,274	715	(559)
	$ 5,452	$ 5,323	$ (129)

Canada

As noted above, two leases located in Canada were acquired in the third quarter of 2008. Capital investments this quarter consisted of seismic/ERT, environmental work and capitalized interest.

Ecuador

The increase in 2009 of investment activities is due to a new project s activities related to the signing of a contract to explore and develop Ecuador s Pungarayacu heavy-oil field using our HTL™ upgrading technology including the commencement of environmental assessment.

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China

Capital asset expenditures decreased 46% or $1.0 million in the three-month period ended March 31, 2009 as compared to the same period in 2008. Expenditures in the Dagang field decreased $0.8 million as fewer fracture stimulations were performed in 2009 compared to 2008. Expenditures in the Sichuan project decreased slightly from 2008 levels by $0.2 million as we continue to move forward and determine drilling locations for phase two of the exploration program.

U.S.

The $2.2 million decrease in U.S. capital spending in the three-month period ended March 31, 2009 compared to 2008 was mainly due to the eight well drilling program in place at South Midway in 2008 compared to minimal capital activity occurring in 2009.

Business and Technology Development

The increase in capital spending during the three-month period ending March 31, 2009 when compared to 2008 was due to the timing of costs relating to the construction and delivery of the FTF.

Financing Activities

Financing activities for the three-month period ended March 31, 2009 consisted mainly of the final debt payments of a long term note. During this same period in 2008 financing activities consisted of debt payments and professional fees and expenses associated with the pursuit of corporate financing initiatives by the Company s Chinese subsidiary, Sunwing Energy.

Outlook for balance of 2009

Our primary focus for the balance of 2009 will be to accelerate the initial stages of execution of the Tamarack Project in Canada and the Pungarayacu Project in Ecuador. This task includes permitting, initial engineering, geotechnical work, downstream HTL engineering, and, in the case of Ecuador, appraisal drilling.

In addition, we will be dedicating significant attention to securing the key strategic and financing partnerships to allow us to develop these projects while maximizing shareholder value for the Company s shareholders.

In addition to the two identified projects, Tamarack and Pungarayacu, we are selectively pursuing other HTL opportunities in the Middle East, including Iraq and elsewhere around the world. Our goal is to develop a manageable portfolio of high quality, heavy oil opportunities on a worldwide basis.

With regard to Tamarack, the balance of 2009 will be dedicated to completing the geophysical work in advance of final delineation drilling, and advancing the permitting process to allow us to submit a regulatory application for a two-stage 50,000 barrel per day project. In addition, the HTL team, working with AMEC, our London-based tier one contractor, is anticipating completing a basic engineering and design package for the HTL portion of the Tamarack Project by the end of 2009.

With regard to Pungarayacu, Ecuador, the balance of 2009 will be dedicated to finalizing environmental permits, drilling between 3 and 6 appraisal wells and acquiring initial 2-D seismic information. This will allow us to better characterize the oil and the reservoir in order to proceed with the full appraisal program in 2010.

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Contractual Obligations

The table below summarizes the contractual obligations that are reflected in the Unaudited Condensed Consolidated Balance Sheet as at March 31, 2009 and/or disclosed in the accompanying Notes:

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	**2009**	**2010**	**2011**	**2012**	**After 2012**
Consolidated Balance Sheets:						
Note payable current portion	$ 5,200	$ 5,200	$	$	$	$
Long term debt	37,007		6,609	30,398		
Asset retirement obligation	3,972		1,966			2,006
Long term obligation	1,900				1,900	
Other Commitments:						
Interest payable	5,535	1,979	2,488	1,068		
Lease commitments	2,990	878	994	665	327	126
Zitong exploration commitment	24,694	13,123	11,571			
Total	$ 81,298	$ 21,180	$ 23,628	$ 32,131	$ 2,227	$ 2,132

Off Balance Sheet Arrangements

As at March 31, 2009, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us, or our related parties, except as disclosed herein.

Outstanding Share Data

As at May 7, 2009, there were 279,381,187 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 May 7, 2009, there were 12,296,373 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							
	2009	**2008**				**2007**		
	1st Qtr	**4th Qtr**	**3rd Qtr**	**2nd Qtr**	**1st Qtr**	**4th Qtr**	**3rd Qtr**	**2nd Qtr**
Total revenue								
Canadian GAAP	$ 7,980	$ 25,143	$ 35,626	$ (2,772)	$ 11,169	$ 5,848	$ 8,823	$ 9,589
U.S. GAAP	$ 5,939	$ 30,538	$ 50,267	$ (14,975)	$ 8,001	$ 6,966	$ 12,393	$ 7,685
Net income (loss):								
Canadian GAAP	$ (12,274)	$ (13,980)	$ 10,062	$ (21,731)	$ (8,544)	$ (18,849)	$ (7,232)	$ (6,579)
U.S. GAAP	$ (9,692)	$ (45,399)	$ 25,824	$ (32,981)	$ (10,495)	$ (16,094)	$ (2,551)	$ (1,211)
Net income (loss) per share:								
Canadian GAAP	$ (0.04)	$ (0.05)	$ 0.04	$ (0.09)	$ (0.03)	$ (0.07)	$ (0.03)	$ (0.03)
U.S. GAAP	$ (0.03)	$ (0.17)	$ 0.10	$ (0.13)	$ (0.04)	$ (0.07)	$ (0.01)	$

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 negative $12.2 million fair value adjustment of derivative instruments for U.S. GAAP. The differences in the net income and net income per share for the third quarter of 2008 were mainly due to an additional $14.6 million positive 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 2008 were mainly due to the additional ceiling test write downs for U.S. GAAP. The differences in the net income and net income per share for the first quarter of 2009 were mainly due to an additional $2.0 million negative fair value adjustment of derivative instruments for U.S. GAAP offset by reduced depletion of $4.4 million.

Transition to International Financial Reporting Standards (IFRS)

In April 2008, the CICA published the exposure draft Adopting IFRSs in Canada . The exposure draft proposes to incorporate International Financial Reporting Standards (**IFRS**) into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS.

Under IFRS, the primary audience is capital markets and, as a result, there is significantly more disclosure required, specifically for quarterly reporting. Further, while IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policy which must be addressed. The Company has not completed development of its IFRS changeover plan, which will include project structure and governance, deployment of resources and training, analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS as well as potential IFRS 1 exemptions. The Company hopes to complete its project scoping, which will include a timetable for assessing the impact on data systems, internal controls over financial reporting, and business activities, such as financing and compensation arrangements, once the exemptions as described below relating to full cost oil and gas companies have been determined.

The International Accounting Standards Board (**IASB**) has stated that it plans to issue an exposure draft relating to certain amendments to IFRS 1 in order to make it more useful to Canadian entities adopting IFRS for the first time. One such exemption relating to full cost oil and gas accounting is expected to result in a reduced administrative transition from the current Canadian AcG-16 to IFRS. It is anticipated that this exposure draft will not result in an amended IFRS 1 standard until sometime during 2009. The amendment will potentially permit the Company to apply IFRS prospectively to its full cost pool, rather than the retrospective assessment of capitalized exploration and development expenses, with the proviso that a ceiling test, under IFRS standards, be conducted at the transition date.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

No material changes from December 31, 2008. Further information presented on market risks can be found in our 2008 Form 10-K.

Item 4. Controls and Procedures

The Company s management, including its Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of March 31, 2009. 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 March 31, 2009, 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.

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Part II Other Information

Item 1. Legal Proceedings:

The Company is a defendant in a lawsuit filed November 20, 2008 in the U.S. District Court for the District of Colorado by Jack J. Grynberg and three affiliated companies that alleges bribery and other misconduct and challenges the propriety of a contract awarded to the Company s wholly-owned subsidiary Ivanhoe Energy Ecuador Inc. to develop Ecuador s Pungarayacu heavy oil field. The plaintiff s claim is for unspecified damages or ownership of the Company s interest in the Pungarayacu field. The action is at an early stage and the parties are preparing their defense. All defendants have filed motions to dismiss the lawsuit for lack of jurisdiction. While the Company intends to rigorously defend the interest of the Company and its shareholders, the likelihood of any ultimate loss or gain, if any, is not determinable at this time.

Item 1A. Risk Factors:

No changes from December 31, 2008.

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

Item 3. Defaults Upon Senior Securities: None

Item 4. Submission of Matters To a Vote of Security Holders: None

Item 5. Other Information: None

Item 6. Exhibits

EXHIBIT NUMBER	DESCRIPTION
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

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SIGNATURE

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

IVANHOE ENERGY INC.

By: /s/ W. Gordon Lancaster

Name: W. Gordon Lancaster
Title: Chief Financial Officer

Dated: May 11, 2009

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INDEX TO EXHIBITS

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