IVANHOE ENERGY INC
Form 10-K
March 16, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

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

For the fiscal year ended December 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.)
654-999 Canada Place **Vancouver, British Columbia, Canada** (Address of principal executive offices)	**V6C 3E1** (Zip Code)

(604) 688-8323

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

None

Securities registered pursuant to Section 12(g) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares, no par value	Toronto Stock Exchange NASDAQ Capital Market

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. o Yes þ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. o Yes þ No

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or

information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ
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. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes þ No
As of June 30, 2009, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $346,054,578 based on the average bid and asked price as reported on the National Association of Securities Dealers Automated Quotation System National Market System.
Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	Outstanding at March 10, 2010
Common Shares, no par value	324,928,513 shares

DOCUMENTS INCORPORATED BY REFERENCE

None

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CURRENCY AND EXCHANGE RATES

Unless otherwise specified, all reference to **dollars** or to **$** are to U.S. dollars and all references to **Cdn.$** are to Canadian dollars. The closing, low, high and average noon buying rates in New York for cable transfers for the conversion of Canadian dollars into U.S. dollars for each of the five years ended December 31 as reported by the Federal Reserve Bank of New York were as follows:

	2009	**2008**	**2007**	**2006**	**2005**
Closing	$ 0.96	$ 0.82	$ 1.01	$ 0.86	$ 0.86
Low	$ 0.77	$ 0.77	$ 0.84	$ 0.85	$ 0.79
High	$ 0.97	$ 1.01	$ 1.09	$ 0.91	$ 0.87
Average Noon	$ 0.88	$ 0.94	$ 0.94	$ 0.88	$ 0.83

The average noon rate of exchange reported by the Bank of Canada for conversion of U.S. dollars into Canadian dollars on March 10, 2010 was $.98 ($1.00 = Cdn.$1.02).

ABBREVIATIONS

As generally used in the oil and gas business and in this Annual Report on Form 10-K, the following terms have the following meanings:

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

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

SELECT DEFINED TERMS

Ivanhoe Energy Inc. **Ivanhoe Energy** or **Ivanhoe** or **the Company**

The Company s proprietary, patented rapid thermal processing process (**RTP™ Process**) for heavy oil upgrading (**HTL™ Technology** or **HTL™**)

Syntroleum Corporation s (**Syntroleum**) proprietary technology (**GTL Technology** or **GTL**) to convert natural g into ultra clean transportation fuels and other synthetic petroleum products

United States Securities and Exchange Commission **SEC**

Canadian Securities Administrators **CSA**

The Securities Act of 1933 (the **Act**)

Enhanced oil recovery **EOR**

Steam Assisted Gravity Drainage **SAGD**

Memorandum of Understanding	**MOU**
Toronto Stock Exchange	**TSX**

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document are forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance or achievements, or other future events, to be materially different from any future results, performance or achievements or other events expressly or implicitly predicted by such forward-looking statements. Such risks, uncertainties and other factors include:

- our short history of limited revenue, losses and negative cash flow from our current exploration and development activities in Canada, Ecuador, China and Mongolia;
- our limited cash resources and consequent need for additional financing;
- our ability to raise additional financing when it is required or on acceptable terms;
- the potential success of our heavy-to-light oil upgrading technology;
- the potential success of our oil and gas exploration and development properties in Canada, Ecuador, China and Mongolia;
- oil price volatility;
- oil and gas industry operational hazards and environmental concerns;
- government regulation and requirements for permits and licenses, particularly in the foreign jurisdictions in which we carry on business;
- title matters;
- risks associated with carrying on business in foreign jurisdictions;
- conflicts of interests;
- competition for a limited number of what appear to be promising oil and gas exploration properties from larger, more well-financed oil and gas companies; and
- other statements contained herein regarding matters that are not historical facts.

Forward-looking statements can often be identified by the use of forward-looking terminology such as may , expect , intend , estimate , anticipate , believe or continue or the negative thereof or variations thereon or similar termin We believe that any forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. Except as required by law, we undertake no obligation to update publicly or revise any forward-looking statements contained in this report. All subsequent forward-looking statements, whether written or oral, attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

AVAILABLE INFORMATION

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. The information on our website is not, and shall not be, deemed to be part of this Annual Report on Form 10-K.

ITEMS 1 AND 2 ***BUSINESS AND PROPERTIES***

GENERAL

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 addition, the Company also seeks to selectively expand its conventional oil and gas reserves base and production through conventional exploration and production activities, primarily in the Asia region. In the fourth quarter of 2009 the Company acquired a large, conventional oil exploration block in Mongolia s Nyalga basin to complement the heavy oil properties acquired in 2008.

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Core operations now include Canada, China, Mongolia and Ecuador, with continued business development opportunities worldwide.

Consistent with the Company s intent to organize around geographically based subsidiaries, 2009 saw the addition of senior management talent allowing Canadian activities to organize as a separate subsidiary. The group structure now includes three subsidiaries with active field operations and one dedicated to business development activities. The subsidiaries with active field operations include the Asian subsidiary, Sunwing, with conventional oil production and conventional oil and gas exploration; the new Canadian subsidiary focusing on the Tamarack project and potential step-out opportunities in the Athabasca region; and the Latin American subsidiary focusing on the Pungarayacu field and other business development opportunities throughout Mexico, Central and South America. The Middle East remains an active area for the Company s business development activities. Ivanhoe Energy Inc. owns 100% of each of these subsidiaries, although the percentages are expected to decline as they develop their respective businesses and raise capital independently.

The Company s HTL™ Technology Group operates a state-of-the-art HTL™ testing facility in the Southwest Research Institute in San Antonio, Texas. The research facility and technology group hold dual roles in the Company. They pursue advancements in the HTL™ technology, building and protecting the Company s patent base, and support business development and project execution by upgrading sample heavy oils to lighter crudes to demonstrate the results available to projects employing the HTL™ technology.

This organizational structure has allowed the Company to engage potential strategic investors in targeted discussions about specific assets and regional alliances. Discussions are ongoing.

The Company s four reportable business segments are: Oil and Gas Integrated, Oil and Gas Conventional, Business and Technology Development and Corporate. Revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 11 to the Consolidated Financial Statements.

On December 31, 2008, the SEC issued final rules relating to reserve definitions and related disclosure requirements. The rules are effective for estimates and disclosures made in annual reports on Form 10-K for fiscal years ended on or after December 31, 2009, including those in this report. The impact of the new rules on our reserves estimates also require us to modify our reserves disclosures this year to transition our reserves estimates from the old rules to the new rules. We have chosen to report our transition to the new rules in a manner that we believe best illustrates the impact of the changes on our reserves estimates and allows us to clearly present how our reserves estimates changed during 2009 as a result of our operational activities separate from the adoption of the new rules.

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 property in Ecuador.

Conventional

Post the sale of the Company s U.S. operations it now explores for, develops and produces conventional crude oil and natural gas in China and Mongolia. The Company s development and production activities are conducted at the Dagang oil field located in China s Hebei Province and its exploration activities are conducted on the Zitong block located in Sichuan Province. In Mongolia the company is in the early exploration phase on Block XVI in the Nyalga basin, southeast of the capital Ulaanbaatar.

Business and Technology Development

The Company incurs various costs in the pursuit of HTL™ 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 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.

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Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the HTL™ technology it owns. 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.

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. We believe that long term demand and the natural decline of conventional oil production will see the development of higher cost and lower value resources, including heavy oil.

Heavy oil developments can be segregated into two types: conventional heavy oil that flows to the surface without steam enhancement and non-conventional heavy oil and bitumen. While 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 the Far East, as producers struggle to replace declines in light oil reserves. Even without the impact of the large non-conventional heavy oil projects in Canada and Venezuela, world heavy oil production has been increasingly more common. Refineries, on the other hand, have not been able to keep up with the need for deep conversion capacity, and heavy versus light oil price differentials have widened significantly.

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

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

Ivanhoe s Value Proposition

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.

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Ivanhoe Energy s HTL upgrading is a partial upgrading process that is designed to operate in facilities as small as 10,000 to 30,000 barrels per day produced. 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 produced. 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. This results in smaller, less costly facilities and eliminates the need for hydrogen addition, an expensive, large minimum scale step typically required in conventional upgrading. 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 offers significant advantages as a field-located upgrading alternative, integrated with the upstream heavy oil production operation. HTL provides four key benefits to the producer:

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

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

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

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

The economics of a project are effectively dictated by the advantages that HTL™ can bring to a particular opportunity. The more stranded the resource and the fewer monetization alternatives that the resource owner has, the greater the opportunity the Company will have to establish the Ivanhoe 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, 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. ***Build a portfolio of major HTL™ projects.*** Continue to deploy the personnel and the financial resources in support of our goal to capture additional opportunities for development projects utilizing the Company s HTL™ Technology.

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

3. ***Enhance the Company s financial position in anticipation of major projects.*** Implementation of large projects requires significant capital outlays. The Company is working on various financing plans and establishing the relationships required for the development activities of the future.

4. ***Build internal capabilities.*** During 2009, the Company added two key executives; one to take up the role of President and CEO of its Canadian subsidiary and one to fill the Corporate CFO role, vacated through retirement. In addition, the Company continued to build its internal technical capabilities through the addition of senior subsurface engineering talent as well as senior environmental leadership. These new staff will join existing execution teams as they advance the Company s first HTL™ projects. The existing upstream teams consist of a number of experienced heavy oil petroleum engineers and geologists complemented by a core team of geotechnical experts. The Houston-based HTL™ technology team is built on 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 as its projects advance.

5. ***Build the relationships needed for the future.*** Commercialization of the Company s technologies demands close alignment with partners, suppliers, host governments and financiers.

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INTEGRATED OIL AND GAS PROPERTIES

Tamarack Project

In July 2008, the Company announced the completion of the acquisition of Talisman Energy Canada s (**Talisman**) 100% working interests in two leases (Leases 10 and 6) located in the heart of the Athabasca oil sands region in the Province of Alberta, Canada. Lease 10 is a 6,880-acre contiguous block located approximately ten miles (16 km) northeast of Fort McMurray. Lease 6 is a small, un-delineated, 680-acre block, one mile (1.6 km) south of Lease 10. Once the acquisition was complete the development of Lease 10 became known as the **Tamarack Project** or **Tamarack** .

The Tamarack Project will provide the site for the application of Ivanhoe Energy s proprietary, HTL heavy oil upgrading technology in a major, integrated heavy oil project. Tamarack has a relatively high level of delineation (four wells per section). We believe that a high-quality reservoir is present and is an excellent candidate for thermal recovery utilizing the SAGD process. The high quality of the asset is expected to provide for favorable projected operating costs, including attractive steam-oil ratios (**SOR**) using SAGD development techniques.

The Company s HTL™ plants at Tamarack are projected ultimately to be capable of operating at production rates of approximately 50,000 barrels per day for approximately 25 years. The Company intends to integrate established SAGD thermal recovery techniques with its patented HTL upgrading process, producing and marketing a light, synthetic sour crude.

The Company has commenced planning its Project Tamarack development program in preparation for the submission of permits for an integrated HTL™ project. In general, thermal oil sands projects, including SAGD projects, require a period of initial development, including delineation, permitting and field development, which is followed by relatively stable operations for many years.

Ecuador Project

In October 2008, Ivanhoe Energy Ecuador Inc., an indirect wholly owned subsidiary, signed a contract with the Ecuador state oil companies Petroecuador and Petroproduccion to explore and develop Ecuador s Pungarayacu heavy oil field which is part of Block 20. Block 20 is an area of approximately 426 square miles, approximately 125 miles southeast of Quito, Ecuador s capital.

Under this contract Ivanhoe Energy Ecuador will use the Company s unique and patented HTL™ Technology, as well as provide advanced oilfield technology, expertise and capital to develop, produce and upgrade heavy crude oil from the Pungarayacu field. In addition, Ivanhoe Energy Ecuador has the right to conduct exploration and appraisal for lighter oil in the contract area and to use any light oil that it discovers to blend with the heavy oil for delivery to Petroproduccion.

The contract has an initial term of 30 years and has three phases. The first two phases include the evaluation of the field s production potential and the crude oil characteristics, as well as construction of the first HTL™ plant. The third phase involves full field development and will include drilling additional exploration and development wells. Additional HTL™ capacity will be added as necessary for expected production.

The Company was in the approval phase during the first half of 2009 which included obtaining environmental licenses. The Company succeeded in getting the necessary approvals and subsequently entered into the appraisal phase which would include obtaining permits to drill, undertaking seismic activity and drilling selected locations. Our analyses of old drilling core data from the Pungarayacu field suggest that there may be oil in the field that is lighter than the bitumen oil seeps that occur at the surface. During the drilling campaign undertaken more than 25 years ago, geologists on site reported that the oil in the drilling cores fluoresced colors indicative of lighter oil which would be inconsistent with bitumen. This coloration in other oil fields around the world is usually a sign of lighter oil. We will not be able to confirm this until we have results from our drilling and testing program currently underway.

To recover its investments, costs and expenses, and to provide for a profit, Ivanhoe Energy Ecuador will receive from Petroproduccion a payment of US$37.00 per barrel of oil produced and delivered to Petroproduccion. The payment will be indexed (adjusted) quarterly for inflation, starting from the contract date, using the weighted average of a basket of three U.S. Government-published producer price indices relating to steel products, refinery equipment and upstream oil and gas equipment.

CONVENTIONAL OIL AND GAS PROPERTIES

Following the disposition of our U.S. oil and gas assets, in California and Texas, (see Note 19 to the financial statements included in Item 8 in this Form 10-K), the Company s principal oil and gas properties are located in the Hebei and Sichuan Provinces in China. Set forth below is a description of these properties.

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The following table sets forth the estimated quantities of proved reserves and production attributable to our properties:

Property	Location	2009 Production (in MBoe)	Percentage of Total 2009 Production	12/31/2009 Proved Reserves (in MBoe)	Percentage of Total Estimated Proved Reserves
Dagang	Hebei Province, China	453	97%	1,032	94%
Other	China	13	3%	69	6%
Total		466	100%	1,101	100%

Note: See the Supplementary Disclosures About Oil and Gas Production Activities (Unaudited) , which follow the notes to our consolidated financial statements set forth in Item 8 in this Annual Report on Form 10-K, for certain details regarding the Company s oil and gas proved reserves, the estimation process and production by country. Estimates for our China operations were prepared by independent petroleum consultant GLJ Petroleum Consultants Ltd. We have not filed with nor included in reports to any other U.S. federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

Internal Control over Reserve Reporting

Independent qualified reserves evaluators prepare reserve estimates for each property at least annually and issue a report thereon. The reserve estimates are reviewed by our in-house Senior Engineering Advisor (**SEA**) who is familiar with the property. Our SEA has over 30 years of experience working as a Reservoir Engineering Specialist/Advisor for various international oil companies. His primary responsibilities in these positions included evaluating and recommending well configuration and steaming strategy, conducting reservoir enhancement opportunity assessments and evaluation, simulation of reservoir, reservoir management, development and implementation of depletion strategies, evaluation gas reserves, formulating and implementing reservoir technology development programs, evaluating gas cycling recovery performance and developing surveillance tools and reservoir management programs. He holds a Bachelor s Degree in Engineering Physics, University of Saskatchewan, Canada. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, the Society of Petroleum Engineers and Canadian Institute of Mining, Metallurgy and Petroleum. Our Board of Directors reviews the current reserve estimates and related disclosures as presented by the independent qualified reserves evaluators in their reserve reports with a recommendation for approval. Our Board of Directors has approved the reserve estimates and related disclosures.

Special Note to Canadian Investors

Ivanhoe is a SEC registrant and files annual reports on Form 10-K; accordingly, our reserves estimates and securities regulatory disclosures are prepared based on SEC disclosure requirements. In 2003, certain Canadian securities regulatory authorities adopted *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* (**NI 51-101**) which prescribes certain standards that Canadian companies are required to follow in the preparation and disclosure of reserves and related information. We applied for, and received, exemptions from certain NI 51-101 disclosure requirements based on our adherence to SEC disclosure requirements, which differ in certain respects from the prescribed disclosure standards of NI 51-101.

In 2008, as a result of the enactment of amendments to NI 51-101, we were required to re-apply for, and received, exemptions from certain of the amended NI 51-101 requirements. These exemptions permit us to substitute disclosures based on SEC requirements for much of the annual disclosure required by NI 51-101 and to prepare our reserves estimates and related disclosures in accordance with SEC requirements, generally accepted industry practices in the U.S. as promulgated by the Society of Petroleum Engineers, and the standards of the Canadian Oil and Gas Evaluation Handbook (the **COGE Handbook**) modified to reflect SEC requirements.

The reserves quantities disclosed in this Annual Report on Form 10-K represent net proved reserves calculated on an average, first-day-of-the-month price during the 12-month period preceding the end of the year for 2009, and year-end constant price basis for 2008 and 2007 using the standards contained in SEC Regulations S-X and S-K and Accounting Standards Codification 932 Extractive Activities Oil and Gas-(section 235-55) formerly Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities . Such information differs from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The primary differences between the current SEC requirements and the NI 51-101 requirements are as follows:

SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the U.S. whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;

the SEC mandates disclosure of proved reserves calculated using an average, first-day-of-the-month price during the 12-month period preceding and existing costs only; whereas NI 51-101 requires disclosure of reserves and related future net revenues using forecasted prices, with additional constant pricing disclosure being optional;

the SEC mandates disclosure of reserves by geographic area only whereas NI 51-101 requires disclosure of more reserve categories and product types; and

the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company s board of directors whereas NI 51-101 requires issuers to engage such evaluators.

The foregoing is a general and non-exhaustive description of the principal differences between SEC disclosure requirements and NI 51-101 requirements. Please note that the differences between SEC requirements and NI 51-101 may be material.

China

Production and Development

Our producing property in China is a 30-year production-sharing contract with China National Petroleum Corporation (**CNPC**), covering an area of 10,255 gross acres divided into three blocks in the Kongnan oilfield in Dagang, Hebei Province, China (the **Dagang field**). Under the contract, as operator, we funded 100% of the development costs to earn 82% of the net revenue from oil production until cost recovery. Effective September 1, 2009 the project reached cost recovery and the working interests changed to 51% CNPC and 49% for the Company. Our entire interest in the Dagang field will revert to CNPC at the end of the 20-year production phase of the contract or if we abandon the field earlier.

In January 2004, we negotiated farm-out and joint operating agreements with Richfirst Holdings Limited (**Richfirst**) a subsidiary of China International Trust and Investment Corporation (**CITIC**) whereby Richfirst paid $20.0 million to acquire a 40% working interest in the field after Chinese regulatory approvals, which were obtained in June 2004. The farm-out agreement provided Richfirst with the right to convert its working interest in the Dagang field into common shares in the Company at any time prior to eighteen months after closing the farm-out agreement. Richfirst elected to convert its 40% working interest in the Dagang field and in February 2006 we re-acquired Richfirst s 40% working interest.

From 2001 to the fourth quarter 2006 under the Petroleum Sharing Contract, we completed the pilot phase and entered the development phase and reached agreement with CNPC on a modified Overall Development Plan to reduce the scope of the development from 115 wells to 44 wells. The last 5 wells were drilled and placed on production in 2007. To date there has been 4,366 gross acres of a total of 12,097 acres relinquished through the terms of the contract. Commercial production commenced on January 1, 2009 as agreed by the parties following conversion of two wells to water injection for pressure maintenance purposes. Pursuant to the terms of the agreement, to the Company can recover from CNPC their share of operating costs, which is currently a 51% working interest.

No new development wells were drilled in 2009 or 2008. In 2009, we fracture stimulated 6 wells compared to 12 fracture stimulations in 2008. The year-end 2009 gross production rate was 1,660 Bopd compared to 1,700 Bopd at the end of 2008 and 1,900 Bopd at the end of 2007. We currently sell our crude oil at a three-month rolling average price of Cinta crude which historically averages approximately $3.00 per barrel less than West Texas Intermediate (**WTI**) price.

Exploration

In November 2002, we received final Chinese regulatory approval for a 30-year production-sharing contract (the **Zitong Contract**), with CNPC for the Zitong block, which covers an area of approximately 900,000 acres in the Sichuan basin. Under the Zitong Contract, we agreed to conduct an exploration program on the Zitong block consisting of two phases, each three years in length. The first three-year period was ultimately extended to December 31, 2007. The parties will jointly participate in the development and production of any commercially viable deposits, with production rights limited to a maximum of the lesser of 30 years following the date of the Zitong Contract or 20 years of continuous production. In 2006, we farmed-out 10% of our working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**) for $4.0 million. The Company completed the first phase under the Zitong Contract (**Phase I**). This included reprocessing approximately 1,649 miles of existing 2D seismic data and acquiring approximately 705 miles of new 2D seismic data, and interpreting this data. This was followed by drilling two wells, totaling an aggregate of 22,293 feet. Both wells encountered expected reservoirs and gas was tested on the second well, but neither well demonstrated commercially viable flow rates and both have been suspended. The Company may elect to reenter these wells to stimulate or drill directionally in the future.

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In December 2007, the Company and Mitsubishi (the **Zitong Partners**) made a decision to enter into the next three-year exploration phase (**Phase II**). By electing to participate in Phase II 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 I shortfall), with total gross remaining estimated minimum expenditures for this program of $23.1 million. The Phase II seismic line acquisition commitment was fulfilled in the Phase I exploration program. The Zitong Partners have no plans to acquire additional seismic data in Phase II. The Zitong Partners relinquished 15% of the Block acreage in 2008 and a further 10% was relinquished in 2009 to complete the end of the Phase I relinquishment requirement. The Zitong Partners contracted Sichuan Geophysical Company to conduct a complete review of the seismic data acquired to date on the block to select two Phase II drilling locations. Drilling is to commence in the second quarter of 2010 with expected completed drilling, completion and evaluation of the prospects finalized in late 2010. The Zitong Partners must complete the minimum work program 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 II, the Zitong Partners must relinquish all of the remaining property except areas identified for development and future production. In the event of a discovery, the Zitong Partners believe it could be possible to negotiate to enter into a defined Phase III exploration commitment and ongoing development phase and reduce the amount of land relinquishment at this time.

Mongolia

Exploration

In November 2009, through a merger with PanAsian Petroleum Inc., a privately-owned corporation, the company acquired a Production-Sharing Contract **(the Nyalga contract**) for the Nyalga Block XVI in Mongolia. The block covers an area of approximately 4.2 million acres in the Khenti and Tov provinces and provides the Company with the exclusive rights to explore, develop and produce oil or gas within the block.

The exploration period is for five years in duration and consists of three phases of two years, one year and two years respectively, with the ability to nominate a two year extension following Phase I or Phase II. The minimum work obligations consist of $2.7 million for phase I, $1.0 million for phase II and $2.5 million for phase III. If in one year more than the minimum is expended, the excess can be applied to reduce the minimum expenditure in the next year of that phase. During the initial seismic a portion of the block, representing approximately 16% of the total, was declared by the Mongolian government to be a historical site and operations on that portion, being the Delgerkhaan area, were suspended. The Company received a letter from the Mineral Resources and Petroleum Authority of Mongolia **(the MRPAM)** in May 2008 which stated that the obligations under year one of phase one would be extended for one year from the time the Company is allowed access to the suspended area. To date access has not been allowed and discussions with MRPAM are ongoing. Seismic previously acquired has more than fulfilled the year obligation. The Company s plans are to perform additional 2D seismic in the first quarter 2010, process and interpret the results and to spud an initial exploration well in the last quarter 2010.

BUSINESS AND TECHNOLOGY DEVELOPMENT

Heavy to Light Oil Upgrading

RTP™ License and Patents

In April 2005, the Company acquired all the issued and outstanding common shares of Ensyn Group, Inc. (**Ensyn**) whereby we acquired an exclusive, irrevocable license to Ensyn s RTP™ Process for all applications other than biomass. Since Ivanhoe acquired the HTL™ 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 Ivanhoe s portfolio of HTL™ intellectual property. In the United States, Ivanhoe is the assignee of three granted U.S. patents and currently has three U.S. patent applications pending. Ivanhoe also has multiple patent applications pending in numerous other countries. In addition, Ivanhoe owns exclusive, irrevocable licenses to patents, patent applications, and technology for the rapid thermal processing process of petroleum.

Commercial Demonstration Facility

In 2004, Ensyn constructed a Commercial Demonstration Facility (**CDF**) to confirm earlier pilot test results on a larger scale and to test certain processing options. This facility, acquired by the Company as part of the Ensyn merger, was built in the Belridge field, a large heavy oil field owned by Aera. In March 2005, initial performance testing of the CDF was completed successfully and the results of the test were verified by two large independent consulting firms. The CDF demonstrated an overall processing capacity of approximately 1,000 Bbls/d based on whole oil from the Belridge California heavy oil fields and a hot reaction section capacity of approximately 300 Bbls/d.

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During 2007, technical developments were led by two important test runs at the CDF: a High Quality configuration was demonstrated on Belridge whole oil vacuum tower bottoms (**VTBs**) and a key test was successfully completed processing Athabasca bitumen pursuant to a longstanding technology development agreement with ConocoPhillips Canada Resources Corp. These two key tests were the capstones of the CDF test program and we have now fulfilled the primary technical objectives of the CDF. The goals of the test program were: (1) to confirm in a substantially large facility the key results generated in the early Ensyn pilot plant runs of heavy oil and bitumen which formed the basis of the HTL™ intellectual property, and (2) to provide sufficient data for the design and construction of commercial HTL™ plants.

The Athabasca bitumen CDF test provided important technical information related to the design of full-scale HTL™ facilities. This test coupled with other test run data, correlated the performance of the CDF with earlier runs on the smaller scale pilot facility and validated the assumptions in Ivanhoe Energy s economic models.

Ivanhoe Energy is currently decommissioning of this plant and completion is planned for end of second quarter 2010. All future test work will be carried out in the FTF.

Feedstock Test Facility

The Company initiated the construction of the Feedstock Test Facility (**FTF**) during 2008 and the unit was successfully commissioned in March 2009. The state-of-the-art HTL™ testing facility is being used by Ivanhoe to support detailed engineering and design of commercial-scale HTL™ plants for Ivanhoe s Tamarack Project in Alberta, Canada, and Pungarayacu Project in Ecuador, and to test crudes associated with additional potential HTL™ projects. The FTF was installed at Southwest Research Institute (**SwRI**) in San Antonio, Texas. SwRI is a world-class technology center that operates testing facilities for numerous leading oil companies, as well as other technology-intensive organizations such as NASA, the Department of Energy and the Department of Defense. The FTF is a small 10-15 Bbls/d, highly flexible state-of-the-art HTL™ facility which will permit screening of global crude oil for current and potential partners in smaller volumes and at lower costs than required at the CDF. As we continue to advance our technology, this unit will form an integral part of the ongoing post-commercialization optimization of our products and processes. The FTF will provide additional data and will support the detailed engineering process once the first commercial target location and crude has been established. The FTF will also serve an integral part in supporting all of the Company s commercial operations.

Business Development

The Company pursues HTL™ business development opportunities globally, with an emphasis on creating value from stranded resources or resource accumulations considered too small to be economically viable using other technologies. As part of this strategy to focus on stranded resources the Company has in the past pursued projects incorporating its non-exclusive master license entitling us to use Syntroleum s proprietary GTL Technology to convert natural gas into ultra clean transportation fuels and other synthetic petroleum products in an unlimited number of projects with no limit on production volume. The Company s master license expires on the later of April 2015 or five years from the effective date of the last site license issued to the Company by Syntroleum. No such site licenses have been issued to date. These two technologies have formed the basis for the Company s business development activities in the Middle East. While discussions with various governments have at times reached advanced states, no definitive agreements have ever been signed. The Company continues to actively pursue business opportunities in the Middle East.

CERTAIN FACTORS AFFECTING THE BUSINESS

Competition

The oil and gas industry is highly competitive. Our position in the oil and gas industry, which includes the search for and development of new sources of supply, is particularly competitive. Our competitors include major, intermediate and junior oil and natural gas companies and other individual producers and operators, many of which have substantially greater financial and human resources and more developed and extensive infrastructure than we do. Our larger competitors, by reason of their size and relative financial strength, can more easily access capital markets than we can and may enjoy a competitive advantage in the recruitment of qualified personnel. They may be able to absorb the burden of any changes in laws and regulations in the jurisdictions in which we do business more easily than we can, adversely affecting our competitive position. Our competitors may be able to pay more for producing oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than we can. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, to evaluate and select suitable properties, implement advanced technologies, and to consummate transactions in a highly competitive environment. The oil and gas industry also competes with other industries in supplying energy, fuel and other needs of consumers.

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Environmental Regulations

Our conventional oil and gas and HTL™ operations are subject to various levels of government laws and regulations relating to the protection of the environment in the countries in which we operate. We believe that our operations comply in all material respects with applicable environmental laws.

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. As well, environmental regulations are imposed on the qualities and compositions of the products sold and imported. Environmental legislation also requires that wells, facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties and liability for clean-up costs and damages. We anticipate that changes in environmental legislation may require, among other things, reductions in emissions to the air from our operations and result in increased capital expenditures.

Operations in Canada are governed by comprehensive Federal, Provincial and Municipal regulations. The Company is in the process of preparing a detailed regulatory application and Environmental Impact Assessment for submission to the Alberta Energy Resources Conservation Board and Alberta Environment. In addition, the Company will be required to obtain numerous ancillary approvals prior to commencing operations and will be subject to ongoing environmental monitoring and auditing requirements.

In April 2007, the Government of Canada announced its intent to introduce a set of regulations to limit emissions of greenhouse gas and air pollutants from major industrial facilities in Canada, although the details of the regulations have not been finalized. In the fall of 2009, the Government further expressed its intent that Canadian policy in this area be aligned with that of the U.S., which also remains under development. Consequently, attempts to assess the impact on our company are premature. We will continue to monitor the development of legal requirements in this area.

In the Province of Alberta, regulations governing greenhouse gas emissions from large industrial facilities came into effect July 1, 2007. These regulations cover industrial facilities emitting more than 100,000 tonnes (carbon dioxide equivalent) of greenhouse gas emissions annually and require a reduction by 12 percent in the greenhouse gas emissions per unit of production from each facility s average annual intensity over the period 2003 through 2005. Allowed compliance measures include participation in an Alberta emission-trading system or payment (at a rate of $15 per excess tonne of emissions) to Alberta s Climate Change and Emissions Management Fund. Impact on the overall operations of the company has not been material.

China and Ecuador continue to develop and implement more stringent environmental protection regulations and standards for different industries. Projects are currently monitored by governments based on the approved standards specified in the environmental impact statement prepared for individual projects.

Environmental Provisions

As at December 31, 2009, a $0.2 million provision for the removal of the FTF and $0.8 million for the removal of the CDF and restoration of the Aera site occupied by the CDF. The future cost of these obligations is estimated at $0.5 million and $0.8 million for the FTF and CDF, respectively. We do not make such a provision for our oil and gas production operations in China as there is no obligation on our part to contribute to the future cost to abandon the field and restore the site.

Government Regulations

Our business is subject to certain federal, state/provincial and local laws and regulations in the regions in which we operate relating to the exploration for, and development, production and marketing of, crude oil and natural gas, as well as environmental and safety matters. In addition, the Chinese government regulates various aspects of foreign company operations in China. Such laws and regulations have generally become more stringent in recent years both in the U.S., Canada, Ecuador and China, often imposing greater liability on a larger number of potentially responsible parties. Because the requirements imposed by such laws and regulations are frequently changed, we are not able to predict the ultimate cost of compliance.

EMPLOYEES

As at December 31, 2009, we had 169 employees and consultants actively engaged in the business. None of our employees are unionized.

PRODUCTION, WELLS AND RELATED INFORMATION

See the Supplementary Disclosures About Oil and Gas Production Activities (Unaudited) , which follows the notes to our consolidated financial statements set forth in Item 8 in this Annual Report on Form 10-K, for information with respect to our oil and gas producing activities.

The following tables set forth, for each of the last three fiscal years, our average sales prices and average operating costs per unit of production based on our net interest after royalties. Average operating costs are for lifting costs (which include Windfall Levy) only and exclude depletion and depreciation, income taxes, interest, selling and administrative expenses.

	Average Sales Price			Average Operating Costs		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
Crude Oil ($/Boe)						
China	$ 53.60	$ 98.73	$ 64.86	$ 21.88	$ 43.92	$ 26.88

The following table sets forth the number of productive wells (both producing wells and wells mechanically capable of production) in which we held a working interest at the end of each of the last three fiscal years. Gross wells are the total number of wells in which a working interest is owned and net wells are the sum of fractional working interests owned in gross wells. All of our wells have multiple completions in different zones, but all completions for a well are in the same well bore hole.

	2009				2008				2007			
	Oil Wells		Gas Wells		Oil Wells		Gas Wells		Oil Wells		Gas Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
China	44	21.6(1)			44	36.1			44	36.1		

(1) Net wells were reduced down to 49% after our working interest was decreased when we reached Cost Recovery .

The following two tables set forth, for each of the last three fiscal years, our participation in the completed drilling of net oil and gas wells:

Exploratory

	Productive Wells						Dry Wells					
	2009		2008		2007		2009		2008		2007	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
China												0.9

Development

	Productive Wells						Dry Wells					
	2009		2008		2007		2009		2008		2007	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas

China	4.1

Wells in Progress

For our China operations, we had 2.0 net (4 gross) wells as at December 31, 2009, (3.3 net, 4 gross - 2008 and 3.3 net, 4 gross 2007) which were either in the process of drilling or suspended.

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Acreage

The following table sets forth our holdings of developed and undeveloped oil and gas acreage as at December 31, 2009. Gross acres include the interest of others and net acres exclude the interests of others:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Canada			7,520	7,520
Ecuador			272,639	272,639
China (1)	1,490	730	664,348	595,355
Mongolia			4,161,422	4,161,422

(1) The number of developed acres disclosed in respect of our China properties relates only to those portions of the field covered by our producing operations and does not include the remaining portions of the field previously developed by CNPC.

Notes:

The Tamarack lease in Canada will expire in October 2016, but Ivanhoe has sufficient drill density to be granted a continuation by Alberta Department of Energy one year prior to the expiry or upon first production, whichever comes first. Although we expect to be on production in 2013, in the event the project is delayed we plan to apply for a continuation prior to the lease expiring.

Our contract in Ecuador to develop Block 20 is divided into three phases, appraisal, pilot and exploitation. Under the terms of the contract, at the end of the appraisal phase we are required to declare that (i) we believe that the portion of the block appraised can be commercial and (ii) we commit to move into the pilot phase. The commitment then is for the pilot phase which consists of an HTL plant and reaching a production capacity of a plateau production of +/-30,000 BOPD. If at the end of the pilot phase we elect to enter into the full field development, we will declare commerciality for the whole field and present our full field development plan. We have the right to only develop that portion of the field associated with the pilot and relinquish the balance of the block.

Our two production sharing agreements in China expire in 2027 and 2032. Also see Note 7 to the accompanying financial statements in Item 8 in this Form 10-K.

Our exploration production sharing contract in Mongolia has a term of five years of which we are still in the first year.

ITEM 1A. *RISK FACTORS*

We are subject to a number of risks due to the nature of the industry in which we operate, our reliance on strategies which include technologies that have not been proved on a commercial scale, the present state of development of our business and the foreign jurisdictions in which we carry on business. Some of the following statements are forward-looking and involve risks and uncertainties. Please refer to the Special Note Regarding Forward-Looking

Statements set forth on page 4 of this Form 10-K. Our actual results may differ materially from the results anticipated in these forward-looking statements.

We may not be able to meet our substantial capital requirements

Our business is capital intensive and the advancement of our HTL project development initiatives in Canada and Ecuador will require significant investments in development activities. Our exploration projects in China and Mongolia will also require significant investments in order to progress as planned. Since our revenues from existing operations are insufficient to fund the capital expenditures that will be required to implement our HTL project development initiatives and carry out our planned exploration activities in China and Mongolia, we will need to rely on external sources of financing to meet our capital requirements. We have, historically, relied upon equity capital as our principal source of funding and we completed a significant equity financing transaction in the first quarter of 2010. It is likely that, in the future, we will need to obtain additional financing from external sources. Principal factors that could affect our ability to obtain financing from external sources include the inability to attract strategic investors to our projects on acceptable terms, volatility in equity and debt markets and a sustained decrease in the market price of our common shares. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable project acquisition and development opportunities or default on existing funding commitments to third parties and forfeit or dilute our rights in existing oil and gas property interests. Our limited operating history may make it difficult to obtain future financing.

Our ability to continue as a going concern in the future may be adversely affected by a lack of access to adequate funding sources

Our financial statements have been prepared in accordance with Canadian generally accepted accounting principles applicable to a going concern, which assumes that we will continue in operation for the foreseeable future and will be able to realize our assets and discharge our liabilities in the normal course of operations. We have a history of operating losses and we currently anticipate incurring substantial expenditures to further our capital development programs. Our cash flow from operating activities will not be sufficient to both satisfy our current obligations and meet the requirements of our capital investment programs. Our continued existence is dependent upon our ability to obtain capital to meet our obligations, to preserve our interests in current projects and to meet the obligations associated with future projects. We intend to finance the future payments required for our capital projects from a combination of strategic investors and/or public and private debt and equity markets, either at a parent company level or at the project level. Public and private debt and equity markets may not be accessible now or in the foreseeable future and, as such, our ability to obtain financing cannot be predicted with certainty at this time. Without access to financing, we may not be able to continue as a going concern.

We have fixed and contingent payment obligations to Talisman Energy

We have certain future fixed and contingent payment obligations to Talisman Energy that arose as a result of our acquisition from Talisman Energy of our Athabasca heavy oil leases in 2008. These obligations include a Cdn.$40,000,000 convertible promissory note that, unless converted into Ivanhoe common shares, is due in July, 2011 and a contingent payment of up to Cdn.$15,000,000 that will become due and payable if and when the requisite governmental and other approvals to develop the northern border of one of the Athabasca heavy oil leases are obtained. As with the funds we require for our planned capital expenditures, we intend to finance such future payments through debt and equity markets, arrangements with third parties, either at the Ivanhoe parent company level or at the subsidiary or project level or from the sale of existing assets. There is no assurance that we will be able to obtain such financing on favorable terms or at all and any future equity issuances may be dilutive to investors. Failure to obtain such additional financing could put us in default of our obligations to Talisman Energy, which are secured by a first fixed charge and security interest in favor of Talisman over the Athabasca heavy oil leases and a general security interest in all of our present and after acquired property other than the shares we own in our subsidiaries. In the case of such default, Talisman Energy could foreclose on the secured assets, including the leases.

Our HTL projects in Canada and Ecuador are at a very early stage of development

Our HTL projects in Canada and Ecuador are at varying stages of development. Although we have completed a significant amount of engineering work for the HTL project, we plan to establish on our Athabasca heavy oil leases in Canada and, additional engineering work will be required before we can initiate the process of applying for the regulatory approvals required in order to advance to the next stage of the development process. Our Block 20 project in Ecuador is currently at a very early stage of development and no detailed feasibility or engineering studies have yet been produced. There can be no assurances that either or both of these projects will be completed within any time frame or within the parameters of any determined capital cost. We have yet to establish a defined schedule for financing and fully developing such projects. In our efforts to continue developing these projects, we may experience delays, interruption of operations or increased costs as a result of unanticipated events and circumstances. These include breakdowns or failures of equipment or processes; construction performance falling below expected levels of output or efficiency, design errors, challenges to proprietary technology, contractor or operator errors; non-performance by third party contractors; labor disputes, disruptions or declines in productivity; increases in materials or labor costs; inability to attract sufficient numbers of qualified workers; delays in obtaining, or conditions imposed by, regulatory approvals; violation of permit requirements; disruption in the supply of energy; and catastrophic events such as fires, earthquakes, storms or explosions.

Heavy oil exploration and development involves increased operational risks

Oil sands and heavy oil exploration and development are very competitive and involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. As with any petroleum property, there can be no assurance that commercial quantities of economically marketable oil will be produced. The viability and marketability of any production from the properties may be affected by factors and circumstances beyond our control, fluctuations in the market price of oil, proximity and capacity of pipelines and processing equipment, electricity transmission and distribution systems, transportation arrangements, equipment availability and government regulations (including regulations relating to prices, taxes, royalties, land tenure, allowable production, importing and exporting of oil and gas and environmental protection). The extent to which some or all of these factors will affect our business cannot be accurately predicted. If our proposed HTL projects in Canada and Ecuador are developed and become operational, there is no assurance that they will attain production in any specific quantities or within any defined cost framework, or that they will not cease producing entirely in certain circumstances. Because operating costs for production from oil sands and heavy oil fields may be substantially higher than operating costs to produce conventional crude oil, an increase in such costs may render the development and operation of these projects uneconomical. It is possible that other developments, such as increasingly strict environmental and safety laws and regulations and enforcement policies thereunder and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities, delays or an inability to complete the proposed project or the abandonment of the proposed project.

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SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive and may be unsustainable

Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The performance of the reservoir can also impact the timing and levels of production using this technology. While the technology is now being used by several producers, commercial application of this technology is still in the early stages relative to other methods of production and accordingly, in the absence of an extended operating history, there can be no assurances with respect to the sustainability of SAGD operations.

We might not successfully commercialize our technology, and commercial-scale HTL™ plants based on our technology may never be successfully constructed or operated

We intend to integrate established SAGD thermal recovery techniques with our patented HTL   upgrading process. Heavy oil recovery using the SAGD process is subject to technical and financial uncertainty. No commercial-scale HTL   plant based on our technology has been constructed to date and we may never succeed in doing so. Other developers of competing heavy oil upgrading technologies may have significantly more financial resources than we do and may be able to use this to obtain a competitive advantage. Success in commercializing our HTL   technology depends on our ability to economically design, construct and operate commercial-scale plants and a variety of factors, many of which are outside our control. We currently have insufficient resources to manage the financing, design, construction or operation of commercial-scale HTL   plants, and we may not be successful in doing so.

A breach of confidentiality obligations could put us at competitive risk and potentially damage our business

We regularly enter into confidentiality agreements with third parties in order to facilitate discussions respecting potential business relationships through the exchange of confidential information. A breach by a third party of an obligation of confidentiality could put us at competitive risk and may cause significant damage to our business if confidential operating information or proprietary intellectual property is improperly disclosed. The harm to our business that improper disclosure of confidential operating information or proprietary intellectual property may cause cannot presently be quantified but may be significant and may not be compensable in damages. There is no assurance that, in the event of a breach of a confidentiality obligation, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner or at all in order to prevent or mitigate any damage to our business that such a breach of confidentiality might cause.

Our efforts to commercialize our HTL   Technology may give rise to claims of infringement upon the patents or proprietary rights of others

We own a license to use the HTL   Technology that we are seeking to commercialize but we may not become aware of claims of infringement upon the patents or rights of others in this technology until after we have made a substantial investment in the development and commercialization of projects utilizing it. Third parties may claim that the technology infringes upon past, present or future patented technologies. Legal actions could be brought against the licensor and us claiming damages and seeking an injunction that would prevent us from testing or commercializing the technology. If an infringement action were successful, in addition to potential liability for damages, we and our licensors could be required to obtain a claiming party   s license in order to continue to test or commercialize the technology. Any required license might not be made available or, if available, might not be available on acceptable terms, and we could be prevented entirely from testing or commercializing the technology. We may have to expend substantial resources in litigation defending against the infringement claims of others. Many possible claimants, such as the major energy companies that have or may be developing proprietary heavy oil upgrading technologies competitive with our technology, may have significantly more resources to spend on litigation.

Technological advances could significantly decrease the cost of upgrading heavy oil and, if we are unable to adopt or incorporate technological advances into our operations, our HTL™ Technology could become uncompetitive or obsolete

We expect that technological advances in the processes and procedures for upgrading heavy oil and bitumen into lighter, less viscous products will continue to occur. It is possible that those advances could make the processes and procedures, which are integral to the HTL   Technology that we are seeking to commercialize, less efficient or cause the upgraded product being produced to be of a lesser quality. These advances could also allow competitors to produce upgraded products at a lower cost than that at which our HTL Technology is able to produce such products. If we are unable to adopt or incorporate technological advances, our production methods and processes could be less efficient than those of our competitors, which could cause our HTL Technology facilities to become uncompetitive.

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The development of alternate sources of energy could lower the demand for our HTL Technology

Alternative sources of energy are continually under development and those that can reduce reliance on oil and bitumen may be developed, which may decrease the demand for our HTL Technology upgraded product. It is also possible that technological advances in engine design and performance could reduce the use of oil and bitumen derived products, which would lower the demand for our HTL Technology upgraded product.

The volatility of oil prices may affect our financial results

Our revenues, operating results, profitability and future rate of growth are highly dependent on the price of, and demand for, oil. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Even relatively modest changes in oil prices may significantly change our revenues, results of operations, cash flows and proved reserves. Historically, the market for oil has been volatile and is likely to continue to be volatile in the future.

The price of oil may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, market uncertainty and a variety of additional factors that are beyond our control, such as weather conditions, overall global economic conditions, terrorist attacks or military conflicts, political and economic conditions in oil producing countries, the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls, the level of demand and the price and availability of alternative fuels, speculation in the commodity futures markets, technological advances affecting energy consumption, governmental regulations and approvals, proximity and capacity of oil pipelines and other transportation facilities.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil price movements with any certainty. Declines in oil prices would not only reduce our revenues, but could reduce the amount of oil we can economically produce. This may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition and results of operations. In addition, a substantial long-term decline in oil prices would severely impact our ability to execute a heavy oil development program.

We may be required to take write-downs if oil prices decline, our estimated development costs increase or our exploration results deteriorate

Under generally accepted accounting principles in Canada and the U.S. we may be required to write down the carrying value of our properties if oil prices decline or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. See Critical Accounting Principles and Estimates Impairment of Proved Oil and Gas Properties in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations of this Annual Report.

Our ability to monetize non-core assets and replace revenues generated from any sale of our existing properties depends upon market conditions and numerous uncertainties

We continue to explore opportunities to generate capital for the ongoing development of our core HTL business, which may involve efforts to monetize non-core assets used in other areas of our business, including our exploration, development and production assets in China. There can be no assurance that we will sell or otherwise monetize any such assets nor that any such sale or monetization initiative, if and when made, will generate sufficient capital for the ongoing development of our core HTL business. Our operating revenues and cash flows would likely decrease significantly following the sale of any material portion of our existing producing assets and would likely remain at lower levels until we were able to replace the lost production with production from new properties.

Our heavy oil project in Canada may be exposed to title risks and aboriginal claims

We have not obtained title opinions in respect of the Athabasca heavy oil leases we acquired from Talisman Energy and there is a risk that our ownership of those leases may be subject to prior unregistered agreements or interests or undetected claims or interests that could impair our title. Any such impairment could jeopardize our entitlement to the economic benefits, if any, associated with the leases, which could have a material adverse effect on our financial condition, results of operations and ability to execute our business plans in a timely manner or at all.

Aboriginal peoples have claimed aboriginal title and rights to large areas of land in western Canada where crude oil and natural gas operations are conducted, including a claim filed against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the City of Fort

McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray where most of the oil sands operations in Alberta are located. Such claims, if successful, could affect the title to our heavy oil leases and have a significant adverse effect on our business.

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Our investment in Ecuador may be at risk if the agreement through which we hold our interest in the Block 20 project is challenged or cannot be enforced

We hold our interest in the Block 20 heavy oil project in Ecuador through a services agreement with Petroecuador and its subsidiary Petroproduccion. The agreement is governed by the laws of Ecuador. Although the agreement has been translated into English, the official and governing language of the agreement is Spanish and if any discrepancy exists between the official Spanish version of the agreement and the English translation, the official Spanish version prevails. There may be ambiguities, inconsistencies and anomalies between the official Spanish version of the agreement and the English translation that could materially affect how our rights and obligations under the agreement are conclusively interpreted and such interpretations may be materially adverse to our interests.

The dispute resolution provisions of the Block 20 agreement stipulate that disputes involving industrial property (including intellectual property) and technical or economic issues are subject to international arbitration. Other disputes are subject to resolution through mediation or arbitration in Ecuador. There is a risk that we and the other parties to the Block 20 agreement will be unable to agree upon the proper forum for the resolution of a dispute based on the subject matter of the dispute. There can also be no assurance that the other parties to the Block 20 agreement comply with the dispute resolution provisions of the Block 20 agreement or otherwise voluntarily submit to arbitration.

Government policy in Ecuador may change to discourage foreign investment or requirements not currently foreseen may be implemented. There can be no assurance that our investments and assets in Ecuador will not be subject to nationalization, requisition or confiscation, whether legitimate or not, by any authority or body. While the Block 20 agreement contains provisions for compensation and reimbursement of losses we may suffer under such circumstances, there is no assurance that such provisions would effectively restore the value of our original investment. There can be no assurance that Ecuadorian laws protecting foreign investments will not be amended or abolished or that the existing laws will be enforced or interpreted to provide adequate protection against any or all of the risks described above. There can also be no assurance that the Block 20 agreement will prove to be enforceable or provide adequate protection against any or all of the risks described above.

Estimates of proved reserves and future net revenue may change if the assumptions on which such estimates are based prove to be inaccurate

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment and the assumptions used regarding prices for oil and natural gas, production volumes, required levels of operating and capital expenditures, and quantities of recoverable oil reserves. Oil prices have fluctuated widely in recent years. Volatility is expected to continue and price fluctuations directly affect estimated quantities of proved reserves and future net revenues. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil reserves will vary from those assumed in our estimates, and these variances may be significant. Also, we make certain assumptions regarding future oil prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from the assumptions used could result in the actual quantity of our reserves and future net cash flow being materially different from the estimates we report. In addition, actual results of drilling, testing and production and changes in natural gas and oil prices after the date of the estimate may result in revisions to our reserve estimates. Revisions to prior estimates may be material.

No reserves have yet been established in respect of our HTL   projects in Canada and Ecuador

No reserves have yet been established in respect of our Athabasca heavy oil project in Canada or our Block 20 project in Ecuador. There are numerous uncertainties inherent in estimating reserves, including many factors beyond our control and no assurance can be given that any level of reserves or recovery thereof will be realized. In general, estimates of reserves are based upon a number of assumptions made as of the date on which the estimates were determined, many of which are subject to change and are beyond our control.

Information in this document regarding our future plans reflects our current intent and is subject to change

We describe our current exploration and development plans in this Annual Report. Whether we ultimately implement our plans will depend on availability and cost of capital; receipt of HTL   Technology process test results, additional seismic data or reprocessed existing data; current and projected oil or gas prices; costs and availability of drilling rigs and other equipment, supplies and personnel; success or failure of activities in similar areas; changes in estimates of project completion costs; our ability to attract other industry partners to acquire a portion of the working interest to reduce costs and exposure to risks and decisions of our joint working interest owners.

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We will continue to gather data about our projects and it is possible that additional information will cause us to alter our schedule or determine that a project should not be pursued at all. You should understand that our plans regarding our projects might change.

Our business may be harmed if we are unable to retain our interests in licenses, leases and production sharing contracts

Some of our properties are held under licenses and leases, working interests in licenses and leases or production sharing contracts. If we fail to meet the specific requirements of the instrument through which we hold our interest, it may terminate or expire. We may not be able to meet any or all of the obligations required to maintain our interest in each such license, lease or production sharing contract. Some of our property interests will terminate unless we fulfill such obligations. If we are unable to satisfy these obligations on a timely basis, we may lose our rights in these properties. The termination of our interests in these properties may harm our business.

We may incur significant costs on exploration or development efforts which may prove unsuccessful or unprofitable

There can be no assurance that the costs we incur on exploration or development will result in an economic return. We may misinterpret geologic or engineering data, which may result in significant losses on unsuccessful exploration or development drilling efforts. We bear the risks of project delays and cost overruns due to unexpected geologic conditions, equipment failures, equipment delivery delays, accidents, adverse weather, government and joint venture partner approval delays, construction or start-up delays and other associated risks. Such risks may delay expected production and/or increase costs of production or otherwise adversely affect our ability to realize an acceptable level of economic return on a particular project in a timely manner or at all.

Our business involves many operating risks that can cause substantial losses; insurance may not protect us against all these risks

There are hazards and risks inherent in drilling for, producing and transporting oil and gas. These hazards and risks may result in loss of hydrocarbons, environmental pollution, personal injury claims, and other damage to our properties and third parties and include fires, natural disasters, adverse weather conditions, explosions, encountering formations with abnormal pressures, encountering unusual or unexpected geological formations, blowouts, cratering, unexpected operational events, equipment malfunctions, pipeline ruptures, spills, compliance with environmental and government regulations and title problems.

We are insured against some, but not all, of the hazards associated with our business, so we may sustain losses that could be substantial due to events that are not insured or are underinsured. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse impact on our financial condition and results of operations. We do not carry business interruption insurance and, therefore, the loss and delay of revenues resulting from curtailed production are not insured.

Changes to laws, regulations and government policies in Canada or Ecuador could adversely affect our ability to develop our HTL projects

Our HTL projects in Canada and Ecuador are subject to substantial regulation relating to the exploration for, and the development, production, upgrading, marketing, pricing, taxation, and transportation of bitumen and heavy oil and related products and other matters, including environmental protection.

Legislation and regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing legislation and regulations, the implementation of new legislation or regulations or the amending of existing legislation and regulations affecting the crude oil and natural gas industry generally could materially increase the costs of developing these projects and could have a material adverse impact on our business. There can be no assurance that laws, regulations and government policies relevant to these projects will not be changed in a manner which may adversely affect our ability to develop and operate them. Failure to obtain all necessary permits, leases, licenses and approvals, or failure to obtain them on a timely basis, could result in delays or restructuring of the projects and increased costs, all of which could have a material adverse effect on our business.

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

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Complying with environmental and other government regulations could be costly and could negatively impact our production

Our operations are governed by numerous laws and regulations at various levels of government in the countries in which we operate. Oil sands and heavy oil extraction, upgrading and transportation operations are subject to extensive regulation and various approvals are required before such activities may be undertaken. We are subject to laws and regulations that govern the operation and maintenance of our facilities, the discharge of materials into the environment and other environmental protection issues. These laws and regulations may, among other potential consequences, require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment with drilling and production activities; limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; require that reclamation measures be taken to prevent pollution from former operations; require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remediating contaminated soil and groundwater and require remedial measures be taken with respect to property designated as a contaminated site.

Under these laws and regulations, we could be liable for personal injury, clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages as well as environmental damage that occurs over time. However, we do not believe that insurance coverage for the full potential liability of environmental damages is available at a reasonable cost. Accordingly, we could be liable, or could be required to cease production on properties, if environmental damage occurs.

The costs of complying with environmental laws and regulations in the future may harm our business. Furthermore, future changes in environmental laws and regulations could occur that result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, any of which could have a material adverse effect on our financial condition or results of operations. No assurance can be given with respect to the impact of future environmental laws or the approvals, processes or other requirements thereunder on our ability to develop or operate our projects in a manner consistent with our current expectations.

During 2007 and 2008, the federal government of Canada proposed a regulatory framework and plan for the reduction of Canada s total greenhouse gas emissions from 2006 levels by 20% by 2020 and by 60% to 70% by 2050. Other approaches to reducing greenhouse gases, including a North America-wide cap and trade system have also been proposed. The potential extent and magnitude of any adverse impacts of these proposals cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been implemented and uncertainty exists with respect to which, if any, of the proposals being considered will ultimately be implemented.

In the Province of Alberta, where our Tamarack project is located, the *Climate Change and Emissions Management Act* has a targeted specified gas emission target relative to Alberta s gross domestic product to an amount that is equal to or less than 50% of 1990 levels.

The future federal industrial air pollutant and greenhouse gas emission reduction targets, together with provincial emission reduction requirements in Alberta s *Climate Change and Emissions Management Act*, or emission reduction requirements in future regulatory approvals, may not be technically or economically feasible to implement and the failure to meet such emission intensity reduction requirements or other compliance mechanisms may materially adversely affect our ability to develop and operate the Tamarack project and result in fines, penalties and the suspension of operations. As well, equipment from suppliers which can meet future emission standards may not be available on an economic basis and other compliance methods of reducing emission intensity to required levels in the future may significantly increase our capital and operating costs or reduce output of the project. We may not be able for technical or economic reasons to take advantage of incentives to implement certain capture and storage. Emission reduction or off-set credits may not be available for acquisition by the Tamarack project or may not be available on an economic basis. There is also the risk that governments could impose additional emission or emission intensity reduction requirements or pass legislation which would tax such emissions.

No assurance can be given that environmental laws will not result in a curtailment of project development or a material increase in the costs of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or prospects.

We compete for oil and gas properties with many other exploration and development companies throughout the world who have access to greater resources

We operate in a highly competitive environment in which we compete with other exploration and development companies to acquire a limited number of prospective oil and gas properties. Many of our competitors are much larger than we are and, as a result, may enjoy a competitive advantage in accessing financial, technical and human resources. They may be able to pay more for productive oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical and human resources permit.

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Our principal shareholder may significantly influence our business

As at the date of this Annual Report, our largest shareholder, Robert M. Friedland, owned approximately 15.9% of our common shares. As a result, he has the voting power to significantly influence our policies, business and affairs and the outcome of any corporate transaction or other matter, including mergers, consolidations and the sale of all, or substantially all, of our assets.

In addition, the concentration of our ownership may have the effect of delaying, deterring or preventing a change in control that otherwise could result in a premium in the price of our common shares.

If we lose our key management and technical personnel, our business may suffer

We rely upon a relatively small group of key management personnel. Given the technological nature of our business, we also rely heavily upon our scientific and technical personnel. Our ability to implement our business strategy may be constrained and the timing of implementation may be impacted if we are unable to attract and retain sufficient personnel. We do not maintain any key man insurance. We do not have employment agreements with certain of our key management and technical personnel and we cannot assure you that these individuals will remain with us in the future. An unexpected partial or total loss of their services would harm our business.

Development of our heavy oil projects in Canada and Ecuador will require the recruitment and retention of experienced employees. We compete with other companies to recruit and retain the limited number of individuals who possess the requisite skills and experience in the particular areas of expertise that are relevant to our business. This competition exposes us to the risk that we will have to pay increased compensation to such employees or increase the Company s reliance and associated costs from partnering or outsourcing arrangements. There can be no assurance that all of the employees with the necessary abilities and expertise we require will be available.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

We have no unresolved staff comments from the SEC staff regarding our periodic or current reports filed under the Act.

ITEM 3. *LEGAL PROCEEDINGS*

The Company is a defendant in a lawsuit filed November 20, 2008 in the United States District Court 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. Plaintiffs claims are for unspecified damages or ownership of Ivanhoe Energy Ecuador Inc. s interest in the Pungarayacu field.

All defendants filed motions to dismiss the lawsuit for lack of personal jurisdiction. The Court granted the motions, noted its view that plaintiffs claims are not likely to have merit, and dismissed the case without prejudice. The Court granted the request of defendant Robert M. Friedland to sanction the plaintiffs and the plaintiffs counsel for their conduct related to bringing the suit by awarding Mr. Friedland fees and costs. The defendants comprising the Company and its subsidiaries were awarded their costs in defending the suit. All defendants are now in the process of seeking an award of their attorney fees and costs.

On October 16, 2009, the plaintiffs filed a motion requesting that the Court vacate its judgment and allow discovery on jurisdictional issues on the grounds that plaintiffs had discovered new evidence. The defendants have filed their opposition and the plaintiffs have filed their reply, and the motion is now ready for decision by the Court. The Court has not yet announced a hearing date or indicated when the motion will be resolved. The likelihood of loss or gain resulting from the lawsuit, and the estimated amount of ultimate loss or gain, are not determinable or reasonably estimable at this time.

ITEM 4. *RESERVED*

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PART II

ITEM 5. *MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES*

Market Information

Our common shares trade on the NASDAQ Capital Market and the TSX. The high and low sale prices of our common shares as reported on the NASDAQ and TSX for each quarter during the past two years are as follows:

NASDAQ CAPITAL MARKET (IVAN)
(U.S.$)

	2009				2008			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
High	3.12	2.81	1.85	1.22	1.43	3.51	3.77	1.97
Low	2.02	1.13	1.10	0.45	0.35	1.21	1.79	1.24

TSX (IE)
(CDN$)

	2009				2008			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
High	3.25	2.98	2.16	1.53	1.53	3.37	3.85	1.99
Low	2.20	1.31	1.38	0.57	0.43	1.28	1.82	1.27

On December 31, 2009, the closing prices for our common shares were $2.86 on the NASDAQ Capital Market and Cdn. $2.96 on the TSX.

Exemptions from Certain NASDAQ Marketplace Rules

As a Canadian issuer listed on the NASDAQ Stock Market (**NASDAQ**), we are not required to comply with certain of NASDAQ s Marketplace Rules and instead may comply with applicable Canadian requirements. As a foreign private issuer, we are only required to comply with the following NASDAQ rules: (i) we must have an audit committee that satisfies applicable NASDAQ requirements and that is composed of directors each of whom satisfy NASDAQ s prescribed independence standards; (ii) we must provide NASDAQ with prompt notification after an executive officer of the Company becomes aware of any material non-compliance by us with any applicable NASDAQ Marketplace Rule; (iii) our common shares must be eligible for a Direct Registration Program operated by a clearing agency registered under Section 17A of the Securities Exchange Act of 1934; and (iv) we must provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies quoted on NASDAQ.

Applicable Canadian rules pertaining to corporate governance require us to disclose in our management proxy circular, on an annual basis, our corporate governance practices, including whether or not our independent directors hold regularly scheduled meetings at which only independent directors are present, but there is no legal requirement in Canada for independent directors to hold regularly scheduled meetings at which only independent directors are present.

Although our non-management directors hold meetings from time to time as and when considered necessary or desirable by the independent lead director, such meetings are not regularly scheduled.

Enforceability of Civil Liabilities

We are a company incorporated under the laws of the Yukon Territory of Canada. Some of our directors, controlling shareholders, officers and representatives of the experts named in this Annual Report on Form 10-K reside outside the U.S. and a substantial portion of their assets and our assets are located outside the U.S. As a result, it may be difficult for you to effect service of process within the U.S. upon the directors, controlling shareholders, officers and representatives of experts who are not residents of the U.S. or to enforce against them judgments obtained in the courts of the U.S. based upon the civil liability provisions of the federal securities laws or other laws of the U.S. There is doubt as to the enforceability in Canada against us or against any of our directors, controlling shareholders, officers or experts who are not residents of the U.S., in original actions or in actions for enforcement of judgments of U.S. courts, of liabilities based solely upon civil liability provisions of the U.S. federal securities laws. Therefore, it may not be possible to enforce those actions against us, our directors, officers, controlling shareholders or experts named in this Annual Report on Form 10-K.

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Holders of Common Shares

As at December 31, 2009, a total of 282,558,593 of our common shares were issued and outstanding and held by 233 holders of record with an estimated 29,328 additional shareholders whose shares were held for them in street name or nominee accounts.

Dividends

We have not paid any dividends on our outstanding common shares since we were incorporated and we do not anticipate that we will do so in the foreseeable future. The declaration of dividends on our common shares is, subject to certain statutory restrictions described below, within the discretion of our Board of Directors based on their assessment of, among other factors, our earnings or lack thereof, our capital and operating expenditure requirements and our overall financial condition. Under the *Yukon Business Corporations Act*, our Board of Directors has no discretion to declare or pay a dividend on our common shares if they have reasonable grounds for believing that we are, or after payment of the dividend would be, unable to pay our liabilities as they become due or that the realizable value of our assets would, as a result of the dividend, be less than the aggregate sum of our liabilities and the stated capital of our common shares.

Exchange Controls and Taxation

There is no law or governmental decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to a non-resident holder of our common shares, other than withholding tax requirements.

There is no limitation imposed by the laws of Canada, the laws of the Yukon Territory, or our constating documents on the right of a non-resident to hold or vote our common shares, other than as provided in the *Investment Canada Act* (Canada) (the **Investment Act**), which generally prohibits a reviewable investment by an investor that is not a **Canadian** , as defined, unless after review, the minister responsible for the Investment Act is satisfied that the investment is likely to be of net benefit to Canada. An investment in our common shares by a non-Canadian who is not a **WTO investor** (which includes governments of, or individuals who are nationals of, member states of the World Trade Organization and corporations and other entities which are controlled by them), at a time when we were not already controlled by a WTO investor, would be reviewable under the Investment Act under two circumstances. First, if it was an investment to acquire control (within the meaning of the Investment Act) (a **Cultural Business**) and the value of our assets, as determined under Investment Act regulations, was Cdn.$5 million or more. Second, the investment would also be reviewable if an order for review was made by the federal cabinet of the Canadian government on the grounds that the investment related to Canada s cultural heritage or national identity (as prescribed under the Investment Act), regardless of asset value. Currently, an investment in our common shares by a WTO investor, or by a non-Canadian at a time when we were already controlled by a WTO investor, would be reviewable under the Investment Act if it was an investment to acquire control and the value of our assets, as determined under Investment Act regulations, was not less than a specified amount, which for 2010 is Cdn.$299 million. The Investment Act provides detailed rules to determine if there has been an acquisition of control. For example, a non-Canadian would acquire control of us for the purposes of the Investment Act if the non-Canadian acquired a majority of our outstanding common shares. The acquisition of less than a majority, but one-third or more, of our common shares would be presumed to be an acquisition of control of us unless it could be established that, on the acquisition, we were not controlled in fact by the acquirer through the ownership of common shares. An acquisition of control for the purposes of the Investment Act could also occur as a result of the acquisition by a non-Canadian of all or substantially all of our assets.

The Canadian Federal Government has recently brought forth certain amendments (the Amendments) to the Investment Act. Once they come into force, the Amendments would generally raise the thresholds that trigger governmental review. Specifically, with respect to WTO investors, the Amendments would see the thresholds for the review of direct acquisitions of control of a business which is not a Cultural Business increase from the current Cdn.$299 million (based on book value) to Cdn.$600 million (to be based on the enterprise value of the Canadian business) for the two years after the Amendments come into force, to Cdn.$800 million in the following two years and then to Cdn.$1 billion for the next two years. Thereafter, the threshold is to be adjusted to account for inflation. The Amendments will come into force when the government enacts regulations which, among other things, will provide how the enterprise value is to be determined.

The Investment Act also provides that the Minister of Industry may initiate a review of any acquisition by a non-Canadian of our shares or assets if the Minister considers that the acquisition could be injurious to (Canada s) national security .

Amounts that we may, in the future, pay or credit, or be deemed to have paid or credited, to you as dividends in respect of the common shares you hold at a time when you are not a resident of Canada within the meaning of the *Income Tax Act* (Canada) will generally be subject to Canadian non-resident withholding tax of 25% of the amount paid or credited, which may be reduced under the Canada-U.S. Income Tax Convention (1980), as amended, (the **Convention**). Currently, under the Convention, the rate of Canadian non-resident withholding tax on the gross amount of dividends paid or credited to a U.S. resident that is entitled to the benefits of the Convention is generally 15%. However, if the beneficial owner of such dividends is a U.S. resident corporation that is entitled to the benefits of the Convention and owns 10% or more of our voting stock, the withholding rate is reduced to 5%. In the case of certain tax-exempt entities, which are residents of the U.S. for the purpose of the Convention, the withholding tax on dividends may be reduced to 0%.

Securities Authorized for Issuance under Equity Compensation Plans

See table under Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters set forth in Item 12 in this Annual Report on Form 10-K.

Performance Graph

See table under Executive Compensation set forth in Item 11 in this Annual Report on Form 10-K.

Sales of Unregistered Securities

All securities we issued during the years ended December 31, 2009 and 2008, which were not registered under the Act, have been detailed in previously filed Form 10-Qs and Form 8-Ks.

During the year ended December 31, 2007, we issued securities, which were not registered under the Act of, as follows:

in November 2007, we issued 2,000,000 common shares under Rule 903 of the Act at a price of U.S.$2.00 to an institutional investor pursuant to the exercise of previously issued share purchase warrants.

ITEM 6. *SELECTED FINANCIAL DATA*

The selected financial data set forth below are derived from the accompanying financial statements, which form part of this Annual Report on Form 10-K. The financial statements have been prepared in accordance with generally accepted accounting principles (**GAAP**) applicable in Canada. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations and Note 21 to our financial statements in this Annual Report on Form 10-K for a detailed description of the differences between GAAP applicable in Canada and GAAP applicable in the U.S. as it relates to the Company.

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The following table shows selected financial information for the years indicated:

	December 31				
	2009	**2008**	**2007**	**2006**	**2005**
	(stated in thousands of US dollars, except per share amounts)				
Results of Operations					
Revenues	23,658	50,670	26,689	36,320	15,965
Net loss from continuing operations	(37,731)	(38,476)	(33,433)	(25,677)	(15,983)
Net loss from continuing operations per share basic and diluted	(0.13)	(0.15)	(0.14)	(0.11)	(0.08)
Financial Position					
Total assets	281,763	346,875	266,516	278,144	270,477
Long-term debt	36,934	37,855	9,812	2,737	4,000
Asset retirement obligations long term	195	1,928	739	484	100
Long term obligation	1,900	1,900	1,900	1,900	1,900
Shareholders equity	208,029	257,427	197,287	228,386	204,767
Common shares outstanding (in thousands)	282,559	279,381	244,874	241,216	220,779
Cash Flow					
Cash flow provided by (used in) operating activities	(12,290)	17,053	5,489	14,352	9,870
Capital investments (continuing operations)	(26,373)	(21,063)	(28,585)	(12,296)	(36,741)

All information has been revised as originally presented to conform with the presentation of the discontinued operations 2009 respecting the sale by the Company of all of its oil and gas exploration and production operations in the United States. See Note 19 to our financial statements under Item 8 in this Annual Report on Form 10-K.

Reconciliation to U.S. GAAP

Our financial statements have been prepared in accordance with GAAP applicable in Canada, which differ in certain respects from those principles that we would have followed had our financial statements been prepared in accordance with GAAP in the U.S. The differences between Canadian and U.S. GAAP, which affect our financial statements, are described in detail in Note 21 to our financial statements in this Annual Report on Form 10-K.

Had we followed U.S. GAAP certain selected financial information reported above, in accordance with Canadian GAAP, would have been reported as follows:

	December 31				
	2009	**2008**	**2007**	**2006**	**2005**
	(stated in thousands of US dollars, except per share amounts)				
Results of Operations					
Revenues	17,152	55,335	27,281	35,628	18,831
Net loss from continuing operations	(32,679)	(47,911)	(23,080)	(35,477)	(13,773)
Net loss from continuing operations per share basic and diluted	(0.12)	(0.19)	(0.10)	(0.15)	(0.07)
Financial Position					
Total assets	262,717	292,847	251,627	252,893	254,335
Long-term debt	38,005	40,392	10,412	2,737	4,000
Asset retirement obligations long term	195	1,928	739	484	100
Long term obligation	1,900	1,900	1,900	1,900	1,900
Shareholders equity	179,663	199,741	170,545	189,829	188,745
Cash Flow					
Cash flow provided by (used in) operating activities	(12,441)	16,639	11,501	13,340	5,042
Capital investments (continuing operations)	(26,223)	(20,649)	(28,319)	(11,280)	(31,913)

All information has been revised as originally presented to conform with the presentation of the discontinued operations 2009 respecting the sale by the Company of all of its oil and gas exploration and production operations in the United States. See Note 21 to our financial statements under Item 8 in this Annual Report on Form 10-K.

ITEM 7. ***MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS***

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THE FOLLOWING SHOULD BE READ IN CONJUNCTION WITH THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEAR ENDED DECEMBER 31, 2009. THE CONSOLIDATED FINANCIAL STATEMENTS HAVE BEEN PREPARED IN ACCORDANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (**GAAP**) IN CANADA. THE IMPACT OF SIGNIFICANT DIFFERENCES BETWEEN CANADIAN AND U.S. GAAP ON THE FINANCIAL STATEMENTS IS DISCLOSED IN NOTE 21 TO THE CONSOLIDATED FINANCIAL STATEMENTS.

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

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. Ivanhoe Energy plans to utilize technologically innovative methods designed to significantly improve recovery of heavy oil resources, including the application of HTL™ Technology and EOR techniques. In addition, the Company seeks to expand its reserve base and production through conventional exploration and production of oil and gas. Our core operations are currently carried out in China, Mongolia, Canada and Ecuador, with business development opportunities worldwide. In late 2009, the Company, through a wholly owned subsidiary, acquired PanAsian Petroleum Inc., and acquired a production sharing contract covering the 16,839 square kilometer Block XVI exploration area in the Nyalga basin Mongolia.

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Ivanhoe Energy s proprietary, patented heavy oil upgrading technology upgrades the quality of heavy oil and bitumen by producing lighter, more valuable crude oil, along with by-product energy which can be used to generate steam or electricity. The HTL™ Technology has the potential to substantially improve the economics and transportation of heavy oil. There are significant quantities of heavy oil throughout the world that have not been developed, much of it stranded due to the lack of on-site energy, transportation issues, or poor heavy-light price differentials. In remote parts of the world, the considerable reduction in viscosity of the heavy oil through the HTL™ process will allow the oil to be transported economically by pipelines. In addition to a dramatic improvement in oil quality, an HTL™ facility can yield large amounts of surplus energy for production of the steam and electricity used in heavy oil production. The thermal energy from the HTL™ process would provide heavy oil producers with an alternative to increasingly volatile prices for natural gas that now is widely used to generate steam. Yields of the low-viscosity, upgraded product can be greater than 85% by volume, and high conversion of the heavy residual fraction is achieved. In addition to the liquid upgraded oil product, a small amount of valuable by-product gas is produced, and usable excess heat is generated from the by-product coke.

HTL™ can virtually eliminate cost exposure to natural gas and diluent, solve the transport challenge, and capture a substantial portion of the heavy to light oil price differential for oil producers. HTL™ accomplishes this at a much smaller scale and at lower per barrel capital costs compared with established competing technologies, using readily available plant and process components. As HTL™ facilities are designed for installation near the wellhead, they eliminate the need for diluent and make large, dedicated upgrading facilities unnecessary.

EXECUTIVE OVERVIEW OF 2009 RESULTS

In July 2009 the Company disposed of its U.S. operations and used the proceeds for its ongoing projects. To properly reflect this sale in the Company s 2009 financial statements the results of the U.S. operations have been segregated from ongoing operations and separately disclosed as Discontinued Operations.

In 2009 the Company s oil revenues from continuing operations decreased from $48.4 million in 2008 to $25.0 million in 2009 due primarily to the decline in oil prices between the two years. These results relate specifically to China producing properties which also experienced a decrease in operating costs from $21.5 million to $10.2 million between 2008 and 2009. This decrease in costs relates to a reduction in the Windfall Levy (a windfall profits tax as defined below), and is also driven by the decline in oil prices between 2008 and 2009. General and Administrative costs increased significantly due to several factors including the Company adding key personnel to advance its first HTL™ projects and bolster our executive leadership, the redeployment of many of the U.S. staff from their previous duties at our U.S. operations to focus on advancing our heavy oil business development strategy and one-time legal and related fees (see Item 3 to Part I of this Form 10K).

The 2009 results for discontinued operations was a loss of $23.9 million, including the write-off of a $29.6 million future income tax asset that could no longer be utilized.

In the first half of 2009, in response to the deteriorating global economy and restricted capital markets, the Company focused on husbanding capital while continuing to selectively advance its heavy oil projects in Canada and Ecuador and develop its HTL™ technology. As a result both Tamarack and Pungarayacu development activities continued to advance, albeit at a more deliberate pace, and the Technology Group created a major technical breakthrough in the HTL™ process, reducing the amount of oil recycled through a plant by up to 80 percent.

In the second half of the year, as economic conditions moderated somewhat, the Company completed two key transactions: 1) the acquisition of what we believe to be a high quality exploration block in Mongolia s Nyalga basin, and 2) a divestiture of our U.S. operations. These transactions continued to build the Company in line with our stated strategies as we redeployed capital from our U.S. conventional operations into our heavy oil projects and built our conventional asset base in our Asian operations.

Oil and Gas

Integrated

Projects in this segment will have two primary components. The first 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 s two flagship projects currently report in this segment - a heavy oil project in Alberta (Tamarack) and a heavy oil property in Ecuador (Pungarayacu).

Conventional

The Company explores for, develops and produces conventional crude oil and natural gas in China and Mongolia, having divested its U.S. operations. 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 Mongolia the Company is conducting early phase exploration activities in the Nyalga basin, southeast of the capital Ulaanbaatar. The Company s California and Texas exploration, development and production activities were sold to Seneca South Midway LLC.

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Business and Technology Development

The Company s technology development activities made major strides in 2009. The Feed Stock Test Facility in San Antonio, Texas was commissioned in the first quarter and immediately took up its dual roles of supporting business development and continuing to advance the technology. This facility was a key part of the major technical advancement that eliminated the need to recycle oil through HTL™ facilities, greatly reducing capital costs per barrel of throughput. In addition, the facility also began processing test runs for various heavy oils to support business plans and development opportunities.

Business development successes include the disposition of the Company s U.S. operations, facilitating capital redeployment from the strategically non-core, conventional U.S. arena into our core heavy-oil and conventional Asian operations. The PanAsian merger was also a large advance for our conventional oil and gas strategy, accessing significant exploration opportunities in the Asian arena. Additional opportunities in the Middle East, North and South America are currently being pursued.

Corporate

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

Summary table of financial data

The following table sets forth certain selected consolidated data for the past three years:

	Year ended December 31,		
	2009	**2008**	**2007**
Oil revenues	$ 24,968	$ 48,370	$ 31,365
Net loss from continuing operations	$ (37,731)	$ (38,476)	$ (33,433)
Net loss from continuing operations per share basic and diluted	$ (0.13)	$ (0.15)	$ (0.14)
Net loss and comprehensive loss	$ (61,652)	$ (34,193)	$ (39,207)
Net loss per share basic and diluted	$ (0.22)	$ (0.13)	$ (0.16)
Average production (Boe/d)	1,276	1,339	1,325
Net revenue (loss) from operations per Boe	$ (6.98)	$ 7.59	$ (1.75)
Cash flow provided by (used in) operating activities from continuing operations	$ (14,993)	$ 10,780	$ 1,168
Cash flow provided by (used in) operating activities	$ (12,290)	$ 17,053	$ 5,489
Capital investments (continuing operations)	$ (26,373)	$ (21,063)	$ (28,585)

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FINANCIAL RESULTS YEAR TO YEAR CHANGE IN NET LOSS

The following provides a summary analysis of our net loss for each of the three years ended December 31, 2009 and a summary of year-over-year variances for the year ended December 31, 2009 compared to 2008 and for the year ended December 31, 2008 compared to 2007:

	2009	*Favorable (Unfavorable) Variances*	2008	*Favorable (Unfavorable) Variances*	2007
Summary of Net Loss by Significant Components:					
Oil Revenues:	$ 24,968		$ 48,370		$ 31,365
Production volumes		*$ (2,384)*		*$ 398*	
Oil prices		*(21,018)*		*16,607*	
Realized gain (loss) on derivative instruments	124	*4,554*	(4,430)	*(4,096)*	(334)
Operating costs	(10,191)	*11,324*	(21,515)	*(8,515)*	(13,000)
General and administrative, less stock based compensation	(18,002)	*(6,198)*	(11,804)	*(4,127)*	(7,677)
Business and technology development, less stock based compensation	(9,343)	*(3,458)*	(5,885)	*2,715*	(8,600)
Net interest	(301)	*283*	(584)	*(548)*	(36)
Current income tax provision	(1,757)	(1,103)	(654)	(654)	
Unrealized gain (loss) on derivative instruments	(1,459)	*(7,577)*	6,118	*10,777*	(4,659)
Foreign Exchange Loss	(5,220)	*(3,693)*	(1,527)	*(1,226)*	(301)
Depletion and depreciation	(19,868)	*5,893*	(25,761)	*(5,121)*	(20,640)
Stock based compensation	(3,849)	*(833)*	(3,016)	*135*	(3,151)
Provision for impairment of intangible asset and development costs	(1,903)	*13,151*	(15,054)	*(15,054)*	
Impairment of oil and gas properties				*6,130*	(6,130)
Write off of deferred financing costs		*2,621*	(2,621)	(2,621)	
Future income tax recovery	9,600	*9,600*			
Discontinued operations (net of tax)	(23,921)	*(28,204)*	4,283	*10,057*	(5,774)
Other	(530)	*(417)*	(113)	*157*	(270)
Net Loss	$ (61,652)	*$ (27,459)*	$ (34,193)	*$ 5,014*	$ (39,207)

Our net loss for 2009 was $61.7 million ($0.22 per share) compared to our net loss in 2008 of $34.2 million ($0.13 per share). The decrease in our net loss from 2008 to 2009 of $27.5 million was due to a decrease of $18.8 million in combined oil and gas revenues and realized gain on derivative instruments, a $9.7 million increase in general and administrative and business and technology development expenses excluding stock based compensation and a

$28.2 million increase in loss from discontinued operations. These were offset by decreases in operating costs of $11.3 million, a $13.2 million expense decrease arising from the impairment of assets and a $9.6 million increase in future income tax recovery.

Our net loss for 2008 was $34.2 million ($0.13 per share) compared to our net loss in 2007 of $39.2 million ($0.16 per share). The decrease in our net loss from 2007 to 2008 of $5.0 million was due to an increase of $12.9 million in combined oil and gas revenues and realized loss on derivative instruments, a $10.8 million increase in unrealized gain on derivative instruments and a $10.1 million increase in gain from discontinued operations. These were offset by an increase in operating costs of $8.5 million, a $1.4 million increase in general and administrative and business and technology development expenses excluding stock based compensation and a $8.9 million expense increase arising from the impairment of assets.

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

Revenues and Operating Costs

Asia

Oil Prices 2009 vs. 2008

Oil and gas prices decreased 46% per Boe in 2009 contributing to a $21.0 million decrease in revenue as compared to 2008. We realized an average of $53.60 per Boe during 2009, which was a decrease of $45.13 per Boe from 2008 prices. We expect crude oil prices and natural gas prices to remain volatile in 2010.

Oil Prices 2008 vs. 2007

Oil and gas prices increased 52% per Boe in 2008 contributing to a $16.6 million increase in revenue as compared to 2007. We realized an average of $98.73 per Boe during 2008, which was an increase of $33.87 per Boe from 2007 prices.

Realized Gain (Loss) on Derivatives

The increased revenues from higher oil and gas price in 2008 were offset by the realized loss on derivatives resulting from settlements from our costless collar derivative instruments. As benchmark prices rise above the ceiling price established in the contract the Company is required to settle monthly (see further details on these contracts below under Unrealized Gain (Loss) on Derivative Instruments). Changes in these realized settlement gains (losses) by segment are detailed below:

Year Ended December 31, 2009	*Favorable (Unfavorable) Variances*	Year Ended December 31, 2008	*Favorable (Unfavorable) Variances*	Year Ended December 31, 2007
$ 124	$ 4,554	$ (4,430)	$ (4,096)	$ (334)

Production Volumes

The following is a comparison of changes in production volumes for the year ended December 31, 2009 when compared to the same period in 2008 and for the year ended December 31, 2008 when compared to the same period for 2007:

	Years Ended December 31, Net Boe s		Percentage	Years Ended December 31, Net Boe s		Percentage
	2009	2008	Change	2008	2007	Change
China:						
Dagang	452,573	471,817	-4%	471,817	464,206	2%
Daqing	13,231	18,096	-27%	18,096	19,379	-7%
	465,804	489,913	-5%	489,913	483,585	1%

Production Volumes 2009 vs. 2008

Net production volumes during 2009 decreased by 5%, or 24 Mboe, when compared to 2008, resulting in decreased revenues of $2.4 million. The reduction was attributed to the normal field decline partially offset by the productivity increases from adding new perforations, fracture stimulations and water flood response. In addition, the Dagang project reached cost recovery effective September 1, 2009, at which time the Company s working interest changed from 82% to 49%. It is anticipated that the gross production rates for 2010 will be similar to those averaged in 2009. In Dagang, at the end of 2009, there were 38 wells producing at a rate of 1,660 Bopd, compared to 43 producing wells at the end of 2008 at 1,700 Bopd.

Production Volumes 2008 vs. 2007

Net production volumes during 2008 increased by 1%, or 6 Mboe, when compared to 2007, resulting in increased revenues of $0.4 million. The normal field decline was offset by the production from five new development wells that were completed and put on production in the second half of 2007, as well as productivity increases from adding new perforations, fracture stimulations and water flood response.

Operating Costs 2009 vs. 2008

Operating costs in China, including engineering support costs and Windfall Levy, decreased 50% or $22.05 per Boe for 2009 when compared to 2008. The majority of the decrease relates to an 81% per Boe drop in the Windfall Levy as oil prices decreased substantially from 2008. Field operating costs decreased $4.58 per Boe. Effective January 1, 2009 the Dagang field reached Commercial Production status as defined by the Production Sharing Contract with China National Petroleum Company. The effect of this change is that the Company no longer pays 100% of operating costs but now pays only its proportionate interest. In addition, cost recovery was reached in Dagang effective September 1, 2009. During 2009 the effect of these two changes resulted in the Company paying 82% of operating costs for the first eight months, representing its share based on the commercial production declaration and 49% for the final four months, representing the post cost recovery share. Had the Company paid these lower proportionate shares in 2008, field operating costs would have decreased $0.68 per Boe or 4%, from 2008 levels. Road and lease maintenance costs, which are weather related, and decreased well workover costs were the main contributing factors to the decrease. These were offset by increases in oil treatment costs as total fluid volumes increased in 2009.

In March 2006, the Ministry of Finance of the Peoples Republic of China (**PRC**) issued the Administrative Measures on Collection of Windfall Gain Levy on Oil Exploitation Business (the **Windfall Levy Measures**). According to the Windfall Levy Measures, effective as of March 26, 2006, enterprises exploiting and selling crude oil in the PRC are subject to a windfall gain levy (the **Windfall Levy**) if the monthly weighted average price of crude oil is above $40 per barrel. The Windfall Levy is imposed at progressive rates from 20% to 40% on the portion of the weighted average sales price exceeding $40 per barrel. The cost associated with Windfall Levy has been included in operating costs in our financial statements. With oil prices decreasing in 2009, the Windfall Levy decreased $17.14 per Boe when compared to 2008.

During 2010 the Company has been placed on a production quota at our Dagang project. We therefore expect operating costs in 2010 to increase on a per barrel basis as compared to 2009. The general overall increase is anticipated to be slightly offset with improved maintenance methods currently being implemented in the field.

Operating Costs 2008 vs. 2007

Operating costs in China, including engineering and support costs and Windfall Levy, increased 63% or $17.03 per Boe for 2008 when compared to 2007. Field operating costs increased $3.62 per Boe mainly as a result of a higher percentage of field office costs allocated to operations versus capital as capital activity has decreased. In addition there were more service rig days worked and higher power costs resulting from greater water injection in 2008 when compared to 2007. These increases were offset by decreases resulting from road access costs, insurance coverage and lower project management salaries. As oil prices have increased, the amount of the Windfall Levy also increased significantly, resulting in $13.46 per Boe increase in 2008 when compared to 2007.

* * *

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

	Year ended December 31,		
	2009	**2008**	**2007**
Net Production:			
Boe	465,804	489,913	483,585
Boe/day for the period	1,276	1,339	1,325
		Per Boe	
Oil and gas revenue	$ 53.60	$ 98.73	$ 64.86
Field operating costs	17.02	21.70	18.08
Windfall Levy	4.00	21.14	7.68
Engineering and support costs	0.86	1.08	1.12

	21.88	43.92	26.88
Net operating revenue	31.72	54.81	37.98
Depletion	38.70	47.22	39.73
Net revenue (loss) from operations	$ (6.98)	$ 7.59	$ (1.75)

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General and Administrative

Changes in general and administrative expenses, before and after considering increases in non-cash stock based compensation, by segment for the year ended December 31, 2009 when compared to the same period for 2008 and for the year ended December 31, 2008 when compared to the same period for 2007 were as follows:

	2009 vs. 2008	2008 vs. 2007
Favorable (unfavorable) variances:		
Oil Activities:		
Canada	$ 498	$ (1,627)
Ecuador	(1,611)	(658)
Asia	(810)	(141)
Corporate	(5,518)	(2,023)
	(7,441)	(4,449)
Less: stock based compensation	1,243	322
	$ (6,198)	$ (4,127)

General and Administrative 2009 vs. 2008

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, costs incurred subsequent to signing this contract include setting up an office in Ecuador including local staff as well as redeploying personnel and office costs who previously worked on the business segment in our discontinued operations.

Asia

General and administrative expenses related to the China operations increased $0.8 million for 2009 as compared to 2008. The increase mainly results from a lower amount of general and administrative expenses allocated to capital projects in 2009.

Corporate

General and administrative costs related to Corporate activities increased: $4.5 million for legal and related fees (see Item 3 to Part III of this Form 10K), corporate aircraft costs, and a reallocation of personnel to Corporate previously allocated to our U.S. business segment. These increases were offset by decreases related to salary and benefit related items such as a one-time severance charge in 2008, reallocation of certain executive salaries to business development activities at the beginning of the third quarter 2008, a reduction in salary for an executive that resigned in the second quarter of 2008.

General and Administrative 2008 vs. 2007

Canada

As noted elsewhere in this Annual Report, the Company acquired working interests in two leases located in Alberta, Canada in July 2008. General and administrative costs related to Canada in 2008 consist of hiring key staff, reallocation of existing resources and some initial office setup costs. In prior periods, some of these costs were recorded in the Business and Technology Development segment.

Ecuador

As noted elsewhere in this Annual Report, in the fourth quarter of 2008 the Company signed a contract to explore and develop Block 20. General and administrative costs related to Ecuador in 2008 consist of travel costs, contract services, hiring key staff, reallocation of existing resources and some initial office setup costs.

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Asia

General and administrative expenses related to the China operations increased $0.1 million for 2008 as compared to 2007 mainly resulting from increases in consulting and audit fees, rent and facility costs.

Corporate

General and administrative costs related to Corporate activities increased $2.0 million for 2008 when compared to 2007. The overall increase was mainly due to the following increases; $0.6 million provision for uncollectible accounts, corporate aircraft costs of $1.0 million, and increases in third party recruiting fees of $0.5 million.

Business and Technology Development

Changes in business and technology development costs, before and after considering increases in non-cash stock based compensation, for the year ended December 31, 2009 when compared to 2008 and for the year ended December 31, 2008 when compared to 2007 were as follows:

Business and Technology Development 2009 vs. 2008

Business and technology development expenses increased $3.0 million (including changes in stock based compensation) in 2009 when compared to 2008, mainly as a result of a reallocation of certain executive salaries to business development activities at the beginning of the third quarter 2008, the start up of the FTF, the establishment of an office in Houston in 2008 and several project financing initiatives in the first quarter of 2009.

Business and Technology Development 2007 vs. 2006

Business and technology development expenses decreased $3.2 million (including changes in stock based compensation) in 2008 when compared to 2007, mainly as a result of a decrease in CDF operating costs due to several heavy oil upgrading runs in the first and second quarters of 2007. These decreases were offset by increases in compensation costs as the Company assembled a core HTL™ technology team.

Foreign Exchange Loss

The increase in foreign exchange loss period over period is mainly a result of the unrealized loss on Canadian dollar denominated long-term debt.

Net Interest

Net Interest 2009 vs. 2008

Interest expense decreased $0.5 million for 2009 when compared to 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 and pay off of a short term Corporate note payable in the third quarter of 2008.

Net Interest 2008 vs. 2007

Interest expense increased $0.7 million for 2008 when compared to 2007 partially due to borrowings under a new loan for our China operations in the fourth quarter of 2007 and a short term loan that was outstanding from May 2008 to August 2008. Interest income also increased slightly in 2008 when compared to 2007 due to cash deposits from the July 2008 private placement.

Unrealized Gain (Loss) on Derivative Instruments

As required by the Company s lenders, the Company entered 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 had a ceiling price of $84.50 per barrel and a floor price of $55.00 per barrel using the WTI as the index traded on the NYMEX. In December the Company paid off the lender s outstanding loan balance and this derivative was subsequently cancelled.

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The Company is required to account for these contracts using mark-to-market accounting. As forecasted benchmark prices exceed the ceiling prices set in the contract, the contracts have negative value or a liability. These benchmark prices reached record highs at the beginning of the third quarter of 2008 before steadily declining at the end of the fourth quarter to a level that was the lowest dating back several years. The low benchmark prices continued into the first half of 2009 and recovered in the last half of the year. Changes in these unrealized settlement (losses) and gains by segment are detailed below:

Year Ended December 31, 2009	***Favorable (Unfavorable) Variances***	**Year Ended December 31, 2008**	***Favorable (Unfavorable) Variances***	**Year Ended December 31, 2007**
$ (1,459)	$ (7,577)	$ 6,118	$ 10,777	$ (4,659)

Depletion and Depreciation

The primary expense in this classification is depletion of the carrying values of our oil and gas properties in our China cost centers over the life of their proved oil and gas reserves as determined by independent reserve evaluators. For more information on how we calculate depletion and determine our proved reserves see Critical Accounting Principles and Estimates Oil and Gas Reserves and Depletion in this Item 7.

Depletion and Depreciation 2009 vs. 2008

Asia

China s depletion rate decreased $8.52 per Boe for 2009 when compared to 2008, resulting in a $5.1 million decrease in depletion expense for 2009. The decrease in the rates from year to year was mainly due to an increase in total estimated proved reserves at our Dagang project due to reduced decline rates and improved recovery rates. A decrease of $1.1 million in depletion expense from year to year was related to decreased production.

Business and Technology Development

Depreciation in this segment decreased by $1.0 million in 2009 when compared to 2008 due to the Company the CDF only being depreciated for the first two quarters in 2009, offset by the commencement of depreciation on the FTF carrying balance.

Depletion and Depreciation 2008 vs. 2007

Asia

China s depletion rate increased $7.50 per Boe for 2008 when compared to 2007, resulting in a $3.7 million increase in depletion expense for 2008. The increase in the rates from year to year was mainly due to an impairment of the drilling and completion costs associated with the second Zitong exploration well in the fourth quarter of 2007. The remaining increase of $0.2 million was related to increased production.

Business and Technology Development

Depreciation of the CDF is calculated using the straight-line method over its current useful life which is based on the existing term of the agreement with Aera Energy LLC to use their property to test the CDF. A formal study was conducted in 2008 whereby the estimated salvage value of the property was decreased and the asset retirement obligation was increased resulting in an increased depreciable base.

Provision for Impairment of Intangible Asset and Development Costs

During the third quarter of 2009, the Company determined that the completion and subsequent improvements to its technology showpiece the FTF in San Antonio diminished the business purpose of the CDF to nil. Consequently, the abandonment process commenced and the Company has impaired the net carrying value of the costs associated with the CDF as at September 30, 2009. The carrying value, net of depreciation, for the CDF, of $0.9 million, was reduced to nil with a corresponding reduction in our results of operations. In addition, the Company had $1.0 million in deferred costs on its balance sheet related to the pursuit of projects in the Middle East. In the fourth quarter of 2009, the entire carrying value of these costs were reduced to nil with a corresponding reduction in our results of operations.

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The Company has been pursuing a GTL project for an extended period of time and had not been able to obtain a definitive agreement or appropriate financing. As a result the Company impaired the entire carrying value of the costs associated with GTL as at December 31, 2008. The carrying value for GTL development costs of $5.1 million and intangible GTL license costs of $10.0 million have been reduced to nil with a corresponding reduction in our results of operations. This impairment does not affect the Company s intention to continue to pursue the current GTL project in Egypt.

In 2007, we had no write downs of our intangible assets or development costs.

Write-off of Deferred Financing Costs

The Company incurred professional fees and expenses associated with the pursuit of corporate financing initiatives by the Company s Chinese subsidiary, Sunwing Energy. In the fourth quarter of 2008 this financing initiative was postponed indefinitely and therefore the associated costs were written down to nil with a corresponding reduction in our results of operations.

Provision for Impairment of Oil and Gas Properties

As discussed below in this Item 7 in Critical Accounting Principles and Estimates Impairment of Proved Oil and Gas Properties , we evaluate each of our cost center s proved oil and gas properties for impairment on a quarterly basis. If as a result of this evaluation, a cost center s carrying value exceeds its expected future net cash flows from its proved and probable reserves then a provision for impairment must be recognized in the results of operations.

Impairment of Oil and Gas Properties 2008 vs. 2007

We did not impair our oil and gas properties in 2009 or 2008, compared to $6.1 million impairment of our China oil and gas properties in 2007.

Provision for/Recovery of Income Taxes

Asia

There was a $1.4 million current tax provision for the year ended December 31, 2009 comprised of $0.4 million for the tax year 2009 and a net adjustment of $1.0 million for 2008, as compared to a $0.6 million provision for the same period in 2008. In April 2009, the Chinese State Tax Administration Bureau issued changes to the minimum depreciation and amortization periods for oil and gas companies. The minimum period changed form 6 to 8 years and was effective January 1, 2008. Consequently, when submitting the final 2008 tax return in the second quarter 2009 an additional $1.0 million tax payable was calculated.

Business and Technology Development

Prior to the Company selling its U.S. operating segment in July 2009, as further described in Note 14 to the accompany financial statements, the Company had future tax assets arising from net operating losses carry-forwards generated by this business segment. These future income tax assets were partially offset by certain future income tax liabilities in the U.S. and by a valuation allowance. As at June 30, 2009, as a result of the pending sale of the business segment, the Company was no longer able to offset these tax assets and liabilities but was required to present these future income tax assets as assets from discontinued operations and a future income tax liability both in the amount of $29.6 million in the June 30, 2009 balance sheet. The future income tax assets classified as Assets from discontinued operations were ultimately included in the $23.4 million loss on disposition as described in Note 19. Revisions were made to the future income tax liability during the third quarter of 2009 based on revised projections of taxable income and utilization of net operating loss carryforwards. As at December 31, 2009, the Company s future income tax liability is $20.0 million in the accompanying balance sheet.

Net Income (Loss) from Discontinued Operations

The following applies to the U.S operations only. The sale of the U.S. operations closed July 17, 2009. The U.S. operations have been accounted for as discontinued operations in accordance with Canadian GAAP on a retroactive basis and the results as at December 31, 2008 and for the three years ended December 31, 2008 have been amended accordingly.

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The operating results for this discontinued operation for the periods noted were as follows:

	Year Ended December 31,		
	2009	2008	2007
Revenue			
Oil and gas revenue	$ 5,455	$ 18,120	$ 12,270
Gain (loss) on derivative instruments	189	278	(5,594)
Interest income	8	98	152
	5,652	18,496	6,828
Expenses			
Operating costs	2,132	5,137	4,319
General and administrative	139	2,413	1,972
Depletion and depreciation	3,772	6,143	5,884
Interest expense and financing costs	173	520	427
	6,216	14,213	12,602
Income (Loss) before disposition	(564)	4,283	(5,774)
Loss on disposition (net of tax of $29.6 million for 2009, nil for 2008 and 2007)	(23,357)		
Net Income (Loss) from discontinued operations	$ (23,921)	$ 4,283	$ (5,774)

<u>Revenues and Operating Costs</u>

<u>Prices and gain/loss on derivatives</u>

From the U.S. operations, we realized an average of $44.03 per Boe during 2009, which was a decrease of $44.64 per Boe and accounted for $5.5 million of our decreased revenues, and we realized an average of $88.67 per Boe during 2008, which was an increase of $26.96 per Boe and accounted for $5.5 million of our increased revenues.

The increased revenues from higher oil and gas prices in 2008 were offset by the realized loss on derivatives resulting from settlements from our costless collar derivative instruments. As benchmark prices rise above the ceiling price established in the contract the Company is required to settle monthly (see further details on these contracts below under Unrealized Gain (Loss) on Derivative Instruments). The Company realized a net loss on these settlements in 2008 of $5.2 million, which compares to a realized net loss in 2007 of $1.3 million.

<u>Production Volumes</u>

From the U.S. Operations we produced 124 Mboe compared to 204 Mboe produced in 2008. This decrease was due to the sale of these U.S. operations midway through 2009. There was a 3% increase in U.S. production volume for 2008 as compared to 2007 and accounted for $0.3 million of our increased revenues. The overall changes to the U.S. production volumes were mainly due to the 2008 first quarter drilling program at South Midway. In addition, an increase in production in 2008 was due to increased steaming in the first two months of 2008 and abnormal downtimes in the steaming operations in 2007 due the absence of our two steam generators for extended period of time. The purchase of a second steam generator and the retrofit of an existing generator allowed for a full steaming program in 2008.

<u>Operating Costs</u>

Field operating costs decreased $7.92 per Boe in 2009 mainly due management redeploying technical personnel assigned to this segment to other segments in anticipation of the sale of these operations.

Field operating costs increased $4.21 per Boe in 2008 mainly due to an increase in steaming operations at South Midway. Both steam generators were down in the latter part of the first quarter and through the second quarter of 2007. In addition, the price of natural gas has been significantly higher in 2008 when compared to 2007.

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General and Administrative Expenses

General and administrative expenses decreased significantly in 2009 when compared to 2008, in part because these U.S. Operations were sold midway through 2009 and in part due to non-field assets and personnel being transferred to the parent company.

General and administrative expenses increased $0.4 million in 2008 as compared to 2007. The increase in 2008 was mainly resulting from a lower allocation to capital and operations, provision for uncollectible accounts related to certain joint interest billings, offset by reallocation of staff to business and technology development.

Net Interest

Interest expense increased for 2008 and 2007 when compared to prior years due to additional draws on our loan facility.

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 is required to account for these contracts using mark-to-market accounting. As forecasted benchmark prices exceed the ceiling prices set in the contract, the contracts have negative value or a liability. These benchmark prices reached record highs at the beginning of the third quarter of 2008 before steadily declining at the end of the fourth quarter to a level that is the lowest dating back several years. For the year ended December 31, 2008, the Company had $5.5 million unrealized gains in these derivative transactions. This compares to an unrealized net loss in 2007 of $4.3 million.

Depletion and Depreciation

The depletion rates for 2009, 2008 and 2007 were all within $1.00 of each other. Any fluctuation between years was due to production variances.

Financial Condition, Liquidity and Capital Resources

Sources and Uses of Cash

The following table sets forth a summary of our cash flows from continuing and discontinued operations for the periods indicated:

	Year ended December 31,		
	2009	2008	2007
Net cash provided by (used in) operating activities	$ (12,290)	$ 17,053	$ 5,489
Net cash provided by (used in) investing activities	$ 6,396	$ (49,321)	$ (22,287)
Net cash provided by (used in) financing activities	$ (11,875)	$ 70,751	$ 14,275
Net increase in cash and cash equivalents	$ (17,753)	$ 27,909	$ (2,523)

As reflected in the accompanying unaudited consolidated financial statements, we have losses from operations, negative cash flows from operations and have a substantial accumulated deficit. Historically, we have principally used external sources to fund operations, to fund acquisitions of oil and gas properties and projects, to service long-term liabilities and to develop our technology and major projects. The main source of funds historically has been public and private equity and debt markets. The Company s cash flow from operating activities will not be sufficient to meet its operating and capital obligations, and as such, the Company intends to finance its operating and capital projects from a combination of strategic investors in its projects and/or public and private debt and equity markets, either at a parent company level or at a project level.

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Principal factors that could affect our ability to obtain funds from external sources include:

Inability to attract strategic investors to our projects,

Volatility in the public debt and private and equity markets,

Increases in interest rates or credit spreads, as well as limitations on the availability of credit, that affect our ability to borrow under future potential credit facilities on a secured or unsecured basis, and

A decrease in the market price for our common stock.

Operating Activities

Our operating activities used $12.3 million in cash for the year ended December 31, 2009 compared to $17.1 million and $5.5 million provided in the same periods in 2008 and 2007. The decrease in cash from operating activities for the year ended December 31, 2009 was mainly due to the significant decrease in oil and gas production prices offset by an increase in expenses. The increase in cash from operating activities for the year ended December 31, 2008 was mainly due to a 50% increase in oil and gas production prices offset by an increase in expenses, as well as an increase in changes in non-cash working capital when compared to 2007.

Investing Activities

Our investing activities used $6.4 million in cash for the year ended December 31, 2009 compared to $49.3 million for the same period in 2008 and $22.3 million for 2007. For 2009, the main reason for the differences is $35.3 million cash provided by discontinued operations which is mainly the proceeds from the sale of these operations. For 2008, the main reason for the differences is the $22.3 million paid as part of the cost of the acquisition of the100% working interests in two leases located in the Athabasca oil sands region in the Province of Alberta, Canada (see Note 18 in the accompanying financial statements for more details). In addition the Company received $9.0 million in proceeds from a recovery of development costs in 2007, compared to nil in 2008 and 2009. There was also an increase in capital asset expenditures of $5.3 million for 2009 as compared to 2008 and a decrease of $7.5 million for 2008 when compared to 2007.

Changes in capital investments by segment are detailed below:

	For the Year Ended December 31,			For the Year Ended December 31,		
	2009	2008	(Increase) Decrease	2008	2007	(Increase) Decrease
Oil and Gas Activities:						
Canada	$ 12,756	$ 6,484	$ (6,272)	$ 6,484	$	$ (6,484)
Ecuador	5,380	1,369	(4,011)	1,369		(1,369)
Asia	6,049	8,378	2,329	8,378	23,488	15,110
Business and Technology Development	2,093	4,832	2,739	4,832	5,097	265
Corporate	95		(95)			
	$ 26,373	$ 21,063	$ (5,310)	$ 21,063	$ 28,585	$ 7,522

Canada

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

Ecuador

The increase of investment activities in 2009 is due to the signing of a contract in October 2008 to explore and develop Ecuador s Pungarayacu heavy-oil field using our HTL TM Technology including the completion of environmental assessment activities, the receipt of environmental permits and licenses in May 2009 and preliminary costs related to the start of appraisal drilling activities in the third quarter ended September 30, 2009. The first well was spud during the fourth quarter 2009.

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Asia

Capital asset expenditures decreased $2.3 million in 2009 as compared to the 2008. Expenditures in the Dagang field decreased $2.6 million in 2009 compared to 2008 period as fewer fracture stimulations, and an associated decrease in field office cost allocations, were performed in 2009 versus 2008. Expenditures in the Sichuan project decreased slightly from 2008 levels by $0.7 million for 2009 compared to 2008 due to lower personnel costs and less seismic interpretation costs. Drilling is to commence in the second quarter of 2010 with expected completed drilling, completion and evaluation of the prospects finalized in late 2010.

The decrease in investment in this segment in 2008 compared to 2007 was the result of a $9.6 million decrease in capital spending at Zitong and a $5.5 million decrease in capital spending at Dagang. Spending at Zitong during 2008 was limited to expenditures relating to the commencement of the second phase of the exploration program which were relatively minor compared to the drilling and completion costs incurred during 2007 for completing the first phase of the program which was concluded in December 2007. At Dagang, we spud five new development wells in 2007 compared to 2008 where we only completed a series of fracture stimulation projects.

Business and Technology Development

The decrease in capital spending during 2009 when compared to 2008 was due to the timing of costs relating to the construction and delivery of the FTF. Additionally, in 2009 there were modifications to the FTF to provide the capacity for longer-term runs and enhance the facility s intellectual property development capabilities.

The decrease in capital spending during 2008 when compared to 2007 was due to the timing of costs relating to the construction and delivery of the FTF.

Discontinued Operations

There was minimal capital activity in 2009. The $1.5 million increase in U.S. capital spending in 2008 compared to 2007 was mainly due to the eight well drilling program at South Midway in 2008 compared to the cost of a new steam generator in 2007.

Financing Activities

Financing activities for 2009 consisted mainly of the final debt payments of long-term notes and the repayment of a note associated with discontinued operations. Financing activities for the year ended December 31, 2008 consisted mainly of an equity private placement in the third quarter of 2008. In July 2008, the Company completed a Cdn.$88.0 million private placement consisting of 29,334,000 special warrants (**Special Warrants**) at Cdn.$3.00 per Special Warrant (the **Offering**). Each Special Warrant entitled the holder to one common share of the Company upon exercise of the Special Warrant. In August 2008, all of the Special Warrants were exercised for 29,334,000 common shares. The net proceeds from the Offering of the Special Warrants was approximately Cdn.$83.4 million.

In addition, in April 2008, the Company obtained a loan from a third party finance company in the amount of Cdn.$5.0 million bearing interest at 8% per annum. At the lender s option the principal and accrued and unpaid interest was converted in August 2008 into the Company s common shares at a conversion price of Cdn.$2.24 per share.

These cash inflows were offset by $2.6 million in professional fees and expenses associated with the pursuit of corporate financing initiatives by the Company s Chinese subsidiary, Sunwing Energy and the payment at maturity on December 31, 2008 of a promissory note to Talisman in the principal amount of Cdn.$12.5 million plus accrued interest.

Financing activities for the year ended December 31, 2007 consisted of three draws totaling $13.0 million ($12.4 million net of financing costs) on two separate loan facilities, one associated with our discontinued operations. This increase in borrowings was offset by scheduled debt payments of $2.5 million. Financing activities in 2007 also consisted of $4.0 million received from the exercise of warrants compared to 2006 when there were no warrants exercised but there was a $25.3 million private placement of common shares.

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Outlook for 2010

Our 2010 capital program budget ranges from approximately $100.0 million to $125.0 million and will encompass the following: a) continued advancement of the Tamarack and Pungarayacu heavy oil developments, b) exploration drilling in the Zitong prospect in Sichuan province, China, and c) selected engineering and development costs related to the enhancement of our proprietary HTL™ oil upgrading technology, d) minor maintenance in the Dagang oil field, Hebei province China. Management s plans for financing its 2010 requirements and beyond include a recent Special Warrant private placement, as outlined in Note 20 to the accompanying financial statements and, for the longer term, the potential for alliances or other arrangements with strategic partners as well as future traditional project financing, debt and mezzanine financing or the sale of equity securities.

Discussions with potential strategic partners are focused primarily on national oil companies and other sovereign or government entities from Asian and Middle Eastern countries that have approached the Company and expressed interest in participating in the Company s heavy oil activities in Ecuador, Canada and around the world. However, no assurances can be given that we will be able to enter into one or more alternative business alliances with other parties or raise additional capital. If we are unable to enter into such business alliances or obtain adequate additional financing, we will be required to curtail our operations, which may include the sale of assets.

In addition to Tamarack and Pungarayacu, the Company will continue to pursue ongoing discussions related to other HTL heavy oil opportunities in Canada, North and South America, the Middle East and North Africa.

Contractual Obligations and Commitments

The table below summarizes the contractual obligations that are reflected in our 2009 consolidated balance sheets and/or disclosed in the accompanying Notes:

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	**2010**	**2011**	**2012**	**2013**	**After 2013**
Consolidated Balance Sheets:						
Long term debt	$ 36,934	$	$ 36,934	$	$	$
Asset retirement obligation	948	753				195
Long term obligation	1,900				1,900	
Other Commitments:						
Interest payable	3,535	2,305	1,230			
Lease commitments	3,121	1,448	1,109	438	126	
Zitong exploration commitment	20,830	20,830				
Nyalga exploration commitment	3,350		850	500	2,000	
Total	$ 70,618	$ 25,336	$ 40,123	$ 938	$ 4,026	$ 195

We have excluded our normal purchase arrangements as they are discretionary and/or being performed under contracts which are cancelable immediately or with a 30-day notification period.

Critical Accounting Principles and Estimates

Our accounting principles are described in Note 2 to the Consolidated Financial Statements. We prepare our Consolidated Financial Statements in conformity with GAAP in Canada, which conform in all material respects to U.S. GAAP except for those items disclosed in Note 21 to the Consolidated Financial Statements. For U.S. readers, we have detailed the differences and have also provided a reconciliation of the differences between Canadian and U.S. GAAP in Note 21 to the Consolidated Financial Statements.

The preparation of our financial statements requires us to make estimates and judgments that affect our reported amounts of assets, liabilities, revenue and expenses. On an ongoing basis we evaluate our estimates, including those related to asset impairment, revenue recognition, fair market value of derivatives, allowance for doubtful accounts and contingencies and litigation. These estimates are based on information that is currently available to us and on various other assumptions that we believe to be reasonable under the circumstances. Actual results could vary from those estimates under different assumptions and conditions.

We have identified the following critical accounting policies that affect the more significant judgments and estimates used in preparation of our consolidated financial statements.

Full Cost Accounting We follow Canadian Institute of Chartered Accountants (**CICA**) Handbook Accounting Guideline 16 Oil and Gas Accounting Full Cost (**AcG 16**) in accounting for our oil and gas properties. Under the full cost method of accounting, all exploration and development costs associated with lease and royalty interest acquisition, geological and geophysical activities, carrying charges for unproved properties, drilling both successful and unsuccessful wells, gathering and production facilities and equipment, financing, administrative costs directly related to capital projects and asset retirement costs are capitalized on a country- by-country cost center basis.

The other generally accepted method of accounting for costs incurred for oil and gas properties is the successful efforts method. Under this method, costs associated with land acquisition and geological and geophysical activities are expensed in the year incurred and the costs of drilling unsuccessful wells are expensed upon abandonment.

As a consequence of following the full cost method of accounting, we may be more exposed to potential impairments if the carrying value of a cost center s oil and gas properties exceeds its estimated future net cash flows than if we followed the successful efforts method of accounting. Impairment may occur if a cost center s recoverable reserve estimates decrease, oil and natural gas prices decline or capital, operating and income taxes increase to levels that would significantly affect its estimated future net cash flows. See Impairment of Proved Oil and Gas Properties below.

Oil and Gas Reserves The process of estimating quantities of reserves is inherently uncertain and complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Our reserve estimates are based on current production forecasts, prices and existing economic conditions, operating methods and government regulations. Reserve numbers and values are only estimates and you should not assume that the present value of our future net cash flows from these estimates is the current market value of our estimated proved oil and gas reserves.

Reserve estimates are critical to many accounting estimates and financial decisions including:

- determining whether or not an exploratory well has found economically recoverable reserves. Such determinations involve the commitment of additional capital to develop the field based on current estimates of production forecasts, prices and other economic conditions.

- calculating our unit-of-production depletion rates. Proved reserves are used to determine rates that are applied to each unit-of-production in calculating our depletion expense.

- assessing our proved oil and gas properties for impairment on a quarterly basis. Estimated future net cash flows used to assess impairment of our oil and gas properties are determined using proved and probable reserves(1). See Impairment of Proved Oil and Gas Properties below.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements set out in the definitions in Regulation S-X and the rules in Regulation S-K, generally accepted industry practices in the U.S. as promulgated by the Society of Petroleum Engineers, and the standards of the COGE Handbook modified to reflect SEC requirements.

For details on our reserve estimation process please refer section titled Internal Control over Reserve Reporting in Item 1 and 2 of this Form 10-K.

The estimated discounted future net cash flows from estimated proved reserves included in the Supplementary Financial Information are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows will also be affected by factors such as actual production levels and timing, and changes in governmental regulation or taxation, and may differ materially from estimated cash flows.

(1) Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be

estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

Depletion As indicated previously, our estimate of proved reserves are critical to calculating our unit-of-production depletion rates.

Another critical factor affecting our depletion rate is our determination that an impairment of unproved oil and gas properties has occurred. Costs incurred on an unproved oil and gas property are excluded from the depletion rate calculation until it is determined whether proved reserves are attributable to an unproved oil and gas property or upon determination that an unproved oil and gas property has been impaired. An unproved oil and gas property would likely be impaired if, for example, a dry hole has been drilled and there are no firm plans to continue drilling on the property. Also, the likelihood of partial or total impairment of a property increases as the expiration of the lease term approaches and there are no plans to drill on the property or to extend the term of the lease. We assess each of our unproved oil and gas properties for impairment on a quarterly basis. If we determine that an unproved oil and gas property has been totally or partially impaired we include all or a portion of the accumulated costs incurred for that unproved oil and gas property in the calculation of our unit-of production depletion rate.

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Our depletion rate is also affected by our estimates of future costs to develop the proved reserves. We estimate future development costs using quoted prices, historical costs and trends. It is difficult to predict prices for materials and services required to develop a field particularly over a period of years with rising oil and gas prices during which there is generally increased competition for a limited number of suppliers. We update our estimates of future costs to develop our proved reserves on a quarterly basis.

Impairment of Proved Oil and Gas Properties We evaluate each of our cost centers proved oil and gas properties for impairment on a quarterly basis. The basis for calculating the amount of impairment is different for Canadian and U.S. GAAP purposes.

For Canadian GAAP, AcG 16 requires recognition and measurement processes to assess impairment of oil and gas properties (**ceiling test**). In the recognition of an impairment, the carrying value[1] of a cost center is compared to the undiscounted future net cash flows of that cost center s proved reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation. If the carrying value is greater than the value of the undiscounted future net cash flows of the proved reserves plus the cost of unproved properties excluded from the depletion calculation, then the amount of the cost center s potential impairment must be measured. A cost center s impairment loss is measured by the amount its carrying value exceeds the discounted future net cash flows of its proved and probable reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation and which contain no probable reserves. The net cash flows of a cost center s proved and probable reserves are discounted using a risk-free interest rate adjusted for political and economic risk on a country-by-country basis. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center s oil and gas properties.

For U.S. GAAP, we follow the requirements of the SEC s Regulation S-X Article 4-10(c)4 for determining the limitation of capitalized costs. Accordingly, the carrying value[1] of a cost center s oil and gas properties cannot exceed the (a) present value of estimated future net revenues computed by applying average, first-day-of-the-month price during the 12-month period before the end of the year prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of ten percent and assuming continuation of existing economic conditions plus (b) the cost of properties not being amortized (e.g. major development projects) and (c) the lower of cost or fair value of unproven 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 unamortized capitalized costs within a cost center exceed this limit, the excess is charged as a provision for impairment in the statement of operations. Amounts thus required to be written off shall not be reinstated for any subsequent increase in the cost center ceiling. 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.

(1) For Canadian GAAP, the carrying value includes all capitalized costs for each cost center, including costs associated with asset retirement net of estimated salvage values,

unproved properties and major development projects, less accumulated depletion and ceiling test impairments. This is essentially the same definition according to U.S. GAAP, under Regulation S-X, except that the carrying value of assets should be net of deferred income taxes and costs of major development projects are to be considered separately for purposes of the ceiling test calculation.

Asset Retirement Obligations For Canadian GAAP, we follow CICA Handbook Section 3110, Asset Retirement Obligations which requires asset retirement costs and liabilities associated with site restoration and abandonment of tangible long-lived assets be initially measured at a fair value which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement cost are recognized in the results of operations. We measure the expected costs required to retire our producing U.S. oil and gas properties at a fair value, which approximates the cost a third party would incur in performing the tasks necessary to abandon the field and restore the site. We do not make such a provision for our oil and gas operations in China as there is no obligation on our part to contribute to the future cost to abandon the field and restore the site. Asset retirement costs are depleted using the unit of production method based on estimated proved reserves and are included with depletion and depreciation expense. The accretion of the liability for the asset retirement obligation is included with interest expense.

For U.S. GAAP, we follow Financial Accounting Standards Board (**FASB**) Accounting Standards Codification Manual (**ASC**) Topic 410 Asset Retirement and Environmental Obligations (formerly Statement of Financial Accounting Standards (**SFAS**) No. 143, Accounting for Asset Retirement Obligations) which conforms in all material respects with Canadian GAAP.

Research and Development We incur various expenses in the pursuit of HTL™ and GTL projects, including HTL™ Technology for heavy oil processing, throughout the world. For Canadian GAAP, such expenses incurred prior to signing a MOU, or similar agreements, are considered to be business and technology development expenses and are charged to the results of operations as incurred. Upon executing a MOU to determine the technical and commercial feasibility of a project, including studies for the marketability of the projects products, we assess that the feasibility and related costs incurred have potential future value, are probable of leading to a definitive agreement for the exploitation of proved reserves and should be capitalized. If no definitive agreement is reached, then the capitalized costs, which are deemed to have no future value, are written down to our results of operations with a corresponding reduction in our investments in HTL™ or GTL assets.

Additionally, we incur costs to develop, enhance and identify improvements in the application of the HTL™ and GTL technologies we license or own. We follow CICA Handbook Section 3064, Goodwill and Intangible assets, (**S.3064**) in accounting for the development costs of equipment and facilities acquired or constructed for such purposes. Development costs are capitalized 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. We review the recoverability of such capitalized development costs annually, or as changes in circumstances indicate the development costs might be impaired, through an evaluation of the expected future discounted cash flows from the associated projects. If the carrying value of such capitalized development costs exceeds the expected future discounted cash flows, the excess is written down to the results of operations with a corresponding reduction in the investments in HTL™ and GTL assets.

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

For U.S. GAAP, we follow ASC Topic 720 Research and Development (formerly SFAS No. 2, Research and Development). As with Canadian GAAP, costs of equipment or facilities that are acquired or constructed for research and development activities are capitalized as tangible assets 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. However, for U.S. GAAP such facilities must have alternative future uses to be capitalized. As with Canadian GAAP, expenses incurred in the operation of research and development equipment or facilities prior to commencing commercial operations are business and technology development expenses and are charged to the results of operations in the period incurred. The major difference for U.S. GAAP purposes is that feasibility, marketing and related costs incurred prior to executing a definitive agreement are considered to be research and development costs and are expensed as incurred.

Intangible Assets Our intangible assets consists of the underlying value of an exclusive, irrevocable license to deploy, worldwide, the RTP™ Process for petroleum applications (HTL™ Technology) as well as the exclusive right to deploy the RTP™ Process in all applications other than biomass and a master license from Syntroleum permitting us to use the Syntroleum Process in an unlimited number of projects around the world. For Canadian GAAP, we follow S.3064 whereby intangible assets, acquired individually or with a group of other assets, are initially recognized and measured at cost. Intangible assets with finite lives are amortized over their useful lives whereas intangible assets with indefinite useful lives are not amortized unless it is subsequently determined to have a finite useful life. Intangible assets are reviewed annually for impairment, or when events or changes in circumstances indicate that the carrying value of an intangible asset may not be recoverable. If the carrying value of an intangible asset exceeds its fair value or expected future discounted cash flows, the excess is written down to the results of operations with a corresponding reduction in the carrying value of the intangible asset. The HTL™ Technology and the Syntroleum GTL master license have finite lives, which correlate with the useful lives of the facilities we expect to develop that will use the technologies. The amount of the carrying value of the technologies we assign to each facility will be amortized to earnings on a basis related to the operations of the facility from the date on which the facility is placed into service. We evaluate the carrying values of the HTL™ Technology and the Syntroleum GTL master license annually, or as changes in circumstances indicate the intangible assets might be impaired, based on an assessment of its fair market value.

For U.S. GAAP, we follow ASC Topic 350 Intangibles Goodwill and Other (formerly SFAS No. 142, Goodwill and Other Intangible Assets which conforms in all material respects with Canadian GAAP.

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.

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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 consolidated financial statements as a result of having adopted these standards.

In June 2009, the AcSB issued Accounting Revisions Release No. 54, Improving Disclosures About Financial Instruments Background Information and Basis for Conclusions (Amendments to Financial Instruments Disclosures, Section 3862) , which amended certain disclosure requirements related to financial instrument disclosure in response to disclosure amendments issued by the International Accounting Standards Board. This is consistent with the AcSB s strategy to adopt IFRS and to ensure the current existing disclosure requirements for financial instruments are converged to the extent possible. The new disclosure standards require disclosure of fair values based on a fair value hierarchy as well as enhanced discussion and quantitative disclosure related to liquidity risk. The amended disclosure requirements are effective for annual financial statements relating to fiscal years ending after September 30, 2009 and as such the Company has included the required disclosure in Note 12 for the year ending December 31, 2009.

Impact of New and Pending Canadian GAAP Accounting Standards

In January 2009, the Emerging Issues Committee of the CICA (**EIC**) issued Emerging Issues Committee abstract 173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities which provides guidance on the implications of credit risk in determining the fair value of an entity s financial assets and financial liabilities. The guidance clarifies that an entity s own credit risk and the credit risk of counterparties should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments, for presentation and disclosure purposes. The conclusions of the EIC were effective from the date of issuance of the abstract and did not have any material impact on the Company s consolidated balance sheet or statement of operations, comprehensive loss and accumulated deficit. However, the Company s fair value disclosures in Note 12 incorporated this new guidance.

Also in January 2009, the Accounting Standards Board of the CICA (**AcSB**) issued Handbook Section 1582, Business Combinations (**S.1582**) replacing Handbook Section 1581, Business Combinations . The AcSB revised accounting standards in regards to business combinations with the intent of harmonizing those standards with IFRS. The revised standards require the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction, establish the acquisition date fair value as the measurement objective for all assets acquired and liabilities assumed; and require 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. These standards shall be applied prospectively to business combinations with an acquisition date after the beginning of the first annual reporting period beginning after January 1, 2011. The Company adopted this standard early on January 1, 2009 with no transitional adjustment to the consolidated financial statements as a result of adopting this standard. However, the Company did apply the provisions of this standard to a business combination that occurred in the fourth quarter of 2009 (see Note 18).

Also in January 2009, the AcSB issued Handbook Section 1601, Consolidated Financial Statements (**S.1601**) and Handbook Section 1602, Non-Controlling Interests (**S.1602**), which replace Handbook Section 1600, Consolidated Financial Statements (**S.1600**). S.1601 and S.1602 require all entities to report non-controlling (minority) interests as equity in consolidated financial statements. The standards eliminate the diversity that currently exists in accounting for transactions between an entity and non-controlling interests by requiring they be treated as equity transactions. These standards shall be applied retrospectively effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The Company adopted these standards early on January 1, 2009 with no transitional adjustment to the consolidated financial statements as a result of adopting these standards.

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Convergence of Canadian GAAP with International Financial Reporting Standards

Transition to International Financial Reporting Standards

The Canadian Accounting Standards Board (**AcSB**) announced that Canadian Generally Accepted Accounting Principles (**GAAP**) no longer apply for all publically accountable enterprises as of January 1, 2011. For interim and annual periods beginning on or after January 1, 2011, the Company will be required to report under International Financial Reporting Standards (**IFRS**) as set out by the International Accounting Standards Board (**IASB**). Comparative IFRS information for the 2010 fiscal year will also have to be reported for interim and annual consolidated financial statements issued during 2011 and thus the Company s transition date to IFRS will be January 1, 2010. Any adjustments resulting from a change in policy as a result of the transition to IFRS will be applied retroactively with corresponding adjustment to the Company s opening retained earnings on January 1, 2010. The Company is currently evaluating the impact of these new standards. The implementation of IFRS may result in a significant impact on our accounting policies, measurements and disclosures.

IFRS Transition Overview

The Company is in the process of evaluating the potential impact of IFRS to its consolidated financial statements. This will be an ongoing process as the IASB and the AcSB issue new standards and recommendations and as the Canadian accounting profession interprets those standards and recommendations. The Company s consolidated financial performance and financial position as disclosed in the current Canadian GAAP consolidated financial statements may be significantly different when presented in accordance with IFRS. Additionally, the Company is a foreign private issuer as defined in Rule 3b-4(c) under the United States Securities Exchange Act of 1934, as amended. Historically, the Company has voluntarily filed on domestic forms (Forms 10-K, 10-Q and 8-K) with the United States Securities Exchange Commission (**SEC**) and has presented its consolidated financial statements using Canadian GAAP in U.S. dollars, with a reconciliation to U.S. GAAP. The SEC issued Rule 33-8567 which allows foreign private issuers that voluntarily file on domestic forms to file financial statements prepared under IFRS as issued by the IASB without reconciliation to U.S. GAAP. Accordingly, upon transition to IFRS on January 1, 2011, the Company will not provide a reconciliation to U.S. GAAP in its interim or annual consolidated financial statements.

The Company has identified IFRS versus current Canadian GAAP differences and various policy choices available under IFRS, but continues to assess the implications of such differences and policy choices to its financial reporting. At this time, the Company cannot quantify the impact that the future adoption of IFRS will have on its consolidated financial performance and financial position; however, the impact may be material. The Company also expects the transition to IFRS to impact disclosure controls and procedures, and information and technology systems and processes. While IFRS may also affect internal controls over financial reporting, management does not currently expect such changes to be significant. Additional information will be provided by the Company in quarterly reports issued during 2010.

IFRS Conversion Plan

The Company has established a formal project governance structure with oversight by its IFRS Steering Committee, consisting of senior management. The IFRS Steering Committee provides periodic updates of the status and effectiveness of the IFRS conversion plan to the Company s senior executives and Audit Committee.

Key elements of the Company s IFRS conversion plan include, but are not limited to:

Impact Assessment	Selected Key Activities	Milestones	Progress to Date
Accounting and Financial Reporting	*Identification of IFRS versus Canadian GAAP differences (impact assessment)*	*Assessment and quantification of the significant effects of the conversion will be complete by Q3 2010*	*Completed the identification of significant IFRS differences (impact assessment)*
	Design and implement solutions	*Final selection of accounting policies by Q1 2010 with on-going*	*Selection of one-time transition choices is substantially complete*
	Evaluate and select		

one-time and ongoing accounting policy alternatives *Quantify the effects of the conversion to IFRS* *Prepare mock financial statements and related note disclosures to comply with IFRS* *Engage advisors to assist with conversion*	*assessment based on changes to IFRS* *Complete mock IFRS financial statements by Q2 2010* *Accumulation of data to establish opening balance sheet adjustments*	*Evaluation and selection of accounting policies and alternatives has commenced and will continue to be assessed up to the date of transition* *Identification and quantification of opening balance sheet adjustments have commenced* *Advisors have commenced validation of the Company s technical accounting analysis and impacts*

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Impact Assessment	Selected Key Activities	Milestones	Progress to Date
Process and Systems	*Assess impact of IFRS accounting standards on business activities* *Identify and addresses IFRS differences that require changes to financial systems* *Identify and address additional data capture and reporting requirements to financial systems* *Evaluate and select methods to address dual record keeping during 2010 (IFRS and Canadian GAAP), for 2010 IFRS comparatives*	*Changes to systems and development of reporting to be complete by Q3 2010* *Data capture is ongoing and targeted for completion during the fourth quarter of 2010* *Method to address dual record keeping to be identified by Q1 2010*	*Project management continues to identify critical path tasks, resourcing matters and impact to processes* *Commenced identification of data capture requirements* *Identification of dual record-keeping structure has commenced*
Training and communication	*Provide training to affected employees, resources directly involved in the transition, senior management and Audit Committee* *Communication of progress of conversion plan to internal and external stakeholders*	*Timely training provided to align with work under transition training to be substantially completed by Q4 2010* *Communicate effects of the transition during the course of 2010*	*Detailed training for resources directly engaged in the transition has commenced and will be on-going* *Communications to senior management and Audit Committee have been scheduled* *On-going communication to external stakeholders though MD&A disclosure* *Periodic project status updates will be presented to senior management and Audit Committee*
Internal control over financial reporting and disclosure controls and procedures	*Revise existing control processes and procedures to address significant changes to existing accounting policies*	*Complete design and commence implementation during 2010 and Q1 2011* *Assess process changes*	*IFRS differences with process impacts have been identified and design of significant process changes has commenced*

	throughout 2010
Assess effectiveness	*Update CEO/CFO officer certification process for Q4 2010*

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Impact of Adoption of IFRS

Adoption of IFRS will initially require retrospective application as of the January 1, 2010 transition date, on the basis that an entity has prepared its financial statements in accordance with IFRS since its formation. Certain adoptive relief mechanisms are available under IFRS to assist with difficulties associated with reformulating historical accounting information. The general relief mechanism is to allow for prospective, rather than retrospective treatment, under certain conditions as prescribed by IFRS 1, First-time Adoption of International Financial Reporting Standards . This standard specifies that adjustments arising on the conversion to IFRS from Canadian GAAP should be recognized in opening retained earnings.

IFRS 1: First-time Adoption of International Financial Reporting Standards (IFRS 1)

The adoption of IFRS requires application of IFRS 1, which provides guidance for an entity s initial adoption of IFRS. IFRS 1 generally requires an entity to apply all IFRS s effective at the beginning of its first IFRS reporting period retrospectively. However, IFRS 1 provides certain mandatory exceptions and permits limited optional exemptions in specified areas of certain IFRS standards from this general requirement.

The most relevant first time adoption exemptions and elections available under IFRS 1 which will impact the Company are discussed below:

Oil and Gas Assets

In October 2009, the IASB issued an exemption for oil and gas companies, which follow the full cost method of accounting for oil and gas operations, to use their Canadian GAAP net book values of their oil and gas assets for their opening balances when transitioning to IFRS. The oil and gas assets will need to be categorized separately on the Company s balance sheet as Intangible Exploration and Evaluation assets in accordance with IFRS 6 Exploration for and Evaluation of Mineral Resources (**IFRS 6**) and Oil and Gas Properties and Equipment in accordance with IAS 16 Property, Plant and Equipment (**IAS 16**) as discussed further below. Oil and Gas Properties and Equipment are to include development and production assets the Canadian GAAP net book value of which are to be allocated to Cash Generating Units (**CGU s**) as defined in IAS 36 Impairment of Assets (**IAS 36**) based on either proved reserve proved plus probable reserves at the discretion of the Company. The opening book values of the CGU s will be subject to an impairment test as provide for in IAS 36 and any impairment will be charged to opening retained earnings.

The Company has elected to adopt the deemed cost exemption provided to full cost oil and gas companies and believes this exemption will significantly decrease the impact to the Company s opening balance financial statements presented in accordance with IFRS and the effort required to transition to IFRS.

Property Plant and Equipment (Non-Oil and Gas) and Intangible Assets

IFRS 1 allows an entity to initially measure an item of property, plant and equipment and intangible assets upon transition to IFRS at fair value as deemed cost as opposed to full retroactive application of the cost model under IAS 16 and IAS 38 Intangible Assets (**IAS 38**). Under this option, fair value as deemed cost will become the new cost amount for qualifying assets at transition.

As stated above the Company will elect to adopt the specific deemed cost exemption as it relates to its oil and gas assets. However, for the Company s non-oil and gas property plant and equipment, such as its Feedstock Test Facility, the Company has elected to apply the full retroactive application of the cost model under IAS 16 in establishing opening balances of its non-oil and gas property plant and equipment.

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The Company s intangible assets consist of HTL^{TM} technology and rights which were acquired as part of the business combination with Ensyn in April 2005. As stated below under Business Combinations , the company has elected to apply the requirements of IFRS 3 Business Combinations (**IFRS 3**) prospectively and as a result the recorded value of the intangible assets for Canadian GAAP will be equal to the opening balance upon the transition to IFRS subject to a fair value less costs to sell or value in use impairment test as required by IAS 36.

Business Combinations

In the transition to IFRS, entities may elect to apply the requirements of IFRS 3 retrospectively or prospectively from the date of transition to IFRS (or to restate all business combinations after a selected date). Retrospective application would require an entity to restate all prior transactions that meet the definition of a business combination under IFRS.

The Company has elected to rely upon the exemption provided for in IFRS 1 and apply the requirements of IFRS 3 prospectively and has also decided to early adopt, effective January 1, 2009, Canadian Institute of Chartered Accountants (**CICA**) Handbook Section 1582 Business Combinations , Handbook Section 1601 Consolidated Financial Statements , Handbook Section 1602 Non-Controlling Interests for Canadian GAAP purposes as well as the Financial Accounting Standards Board s FASB 141R Business Combinations for U.S. GAAP purposes as these new standards are consistent with IFRS 3.

Decommissioning Liabilities (Asset Retirement Obligations)

International Financial Reporting Interpretations Committee (**IFRIC**) 1 requires that changes in an existing decommissioning, restoration or similar liability are added to or deducted from the cost of the related asset and the adjusted cost base are amortized over the remaining useful life of those assets. Application of IFRIC 1 would require the Company to complete a historical summary of all such changes that would have been made in relation to a decommissioning liability from inception of that liability and reflect the cumulative changes in the net book value of the related asset on transition to IFRS.

However, the exemption available under IFRS 1 would allow an entity to include in the depreciated cost of the related asset an amount calculated by discounting the decommissioning liability for that asset at the date of transition to IFRS back to, and depreciating it from, when the liability was first incurred.

The Company has elected to adopt the exemption available under IFRS 1 with regard to its decommissioning liabilities.

Share Based Payments

On initial adoption of IFRS, an entity is not required under IFRS 2 Share-Based Payments (**IFRS 2**) to recognize share-based payments settled before the entity s IFRS transition date. Generally, an entity may elect prospective application for stock options granted on or after November 7, 2002, or for stock options granted after November 7, 2002 that vested before the later of: (1) the date of transition to IFRS or (2) January 1, 2005.

The Company has elected to apply the transition provisions of IFRS 2 which would require that IFRS 2 be applied only to equity instruments and liabilities arising from share based payments (stock options) that are not fully vested on the date of transition to IFRS. This election will have no impact on opening balances on January 1, 2010 but would affect the expensing of stock options during 2010 and thereafter as stock options must be expensed on a graded vesting schedule in accordance with IFRS 2 rather than on a straight line basis as has been applied by the Company for Canadian GAAP and US GAAP purposes.

IFRS 1 allows for certain other optional exemptions, however, the Company does not expect such exemptions to be significant to the Company s initial adoption of IFRS.

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

In June 2009, the FASB issued guidance now codified as ASC Topic 105, Generally Accepted Accounting Principles, as the single source of authoritative nongovernmental U.S. GAAP. ASC Topic 105 does not change current U.S. GAAP, but is intended to simplify user access to all authoritative U.S. GAAP by providing all authoritative literature related to a particular topic in one place. All existing accounting standard documents will be superseded and all other accounting literature not included in the FASB Codification will be considered non-authoritative. These provisions of ASC Topic 105 are effective for interim and annual periods ending after September 15, 2009 and, accordingly, are effective for our current fiscal reporting period. The adoption of this pronouncement did not have an impact on the Company s financial position or results of operations, but did impact our financial reporting process by eliminating all references to pre-codification standards. On the effective date of this Statement, the Codification superseded all then-existing non-SEC accounting and reporting standards, and all other non-grandfathered non-SEC accounting literature not included in the Codification became non-authoritative.

As a result of the Company s implementation of this Codification during 2009, previous references to new accounting standards and literature are no longer applicable. In these annual financial statements, the Company has provided reference to both new and old guidance to assist in understanding the impacts of recently adopted accounting literature, particularly for guidance adopted since the beginning of the current fiscal year but prior to the ASC.

Also in June 2009, the FASB issued guidance for Amendments to FAS 46R in ASC Topic 810 (formerly SFAS No. 167) of the Codification, which improves financial reporting by enterprises involved with variable interest entities. The amendments replace the quantitative-based risks and rewards calculation for determining which enterprise, if any, has a controlling financial interest in a variable interest entity with an approach focused on identifying which entity has the power to direct the activities of a variable interest entity that most significantly impact the entity s economic performance and: (1) the obligation to absorb losses of the entity; or, (2) the right to receive benefits from the entity. The amendments are effective as of the beginning of the first annual reporting period that begins after November 15, 2009, and shall be applied prospectively. The Company is currently reviewing the potential impact, if any, this guidance will have on the consolidated financial statements upon adoption.

Also in June 2009, the FASB issued guidance for Accounting for Transfers of Financial Assets, an Amendment to FAS 140 in ASC Topic 860 (formerly SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities-a replacement of FASB Statement No. 125,* as amended by SFAS No. 166, *Accounting for Transfers of Financial Assets An Amendment of FASB Statement No. 140*) of the Codification, which is effective for fiscal years beginning after November 15, 2009, which amends prior principles to require more disclosure about transfers of financial assets and the continuing exposure, retained by the transferor, to the risks related to transferred financial assets, including securitization transactions. It eliminates the concept of a qualifying special-purpose entity, changes the requirements for derecognizing financial assets, and requires additional disclosures. It also enhances information reported to users of financial statements by providing greater transparency about transfers of financial assets and an entity s continuing involvement in transferred financial assets. The Company is currently reviewing the potential impact, if any, this guidance will have on the Company s consolidated financial statements upon adoption.

In May 2009, the FASB issued guidance in the ASC Topic 855 Subsequent Events (formerly SFAS No. 165) of the Codification, which establishes the accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. The guidance was effective for interim or annual periods ending after June 15, 2009. The adoption of this guidance did not have a material impact on the Company s consolidated financial statements. In February 2010, the FASB issued Accounting Standards Update No. 2010-09 Subsequent Events (Topic 855) Amendments to Certain Recognition and Disclosure Requirements which provides amendments to Subtopic 855-10 to alleviate potential conflicts between Subtopic 855-10 and the SEC s requirements with regard to subsequent event disclosures. An entity that is an SEC filer is required to evaluate subsequent events through the date that the financial statements are issued and is not required to disclose the date through which subsequent events have evaluated.

In April 2009, the FASB issued guidance in the ASC Topic 820 Fair Value Measurements and Disclosures (formerly FASB Staff Position (**FSP**) FAS 157-4) of the Codification on determining fair value when the volume and level of activity for an asset or liability have significantly decreased and identifying transactions that are not orderly. The guidance emphasizes that even if there has been a significant decrease in the volume and level of activity, the objective of a fair value measurement remains the same. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction (that is, not a forced liquidation or distressed sale) between market participants. The guidance provides a number of factors to consider when evaluating whether there has been a significant decrease in the volume and level of activity for an asset or liability in relation to normal market activity. In addition, when transactions or quoted prices are not considered orderly, adjustments to those prices based on the weight of available information may be needed to determine the appropriate fair value. The guidance was effective for interim or annual reporting periods ending after June 15, 2009, and shall be applied prospectively. The implementation of this guidance did not have a material impact on the Company s consolidated financial statements.

In April 2009, FASB issued guidance in the ASC Topic 825   Financial Instruments (formerly FSP FAS 107-1 and APB 28-1) of the Codification on interim disclosures about fair value of financial instruments. The guidance requires disclosures about the fair value of financial instruments for both interim reporting periods, as well as annual reporting periods. The guidance was effective for all interim and annual reporting periods ending after June 15, 2009 and shall be applied prospectively. The implementation of this guidance did not have a material impact on the Company s consolidated financial statements as at December 31, 2009, other than the additional disclosure in Note 12.

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In March 2008, FASB issued guidance in the ASC Topic 815 Derivatives and Hedging (formerly SFAS No. 161) of the Codification on improved financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand the effects on an entity s financial position, financial performance and cash flows. The guidance was effective beginning January 1, 2009. Management has complied with the disclosure requirements of this recent statement see additional disclosures under Commodity Price Risks under Note 12 to these financial statements.

In February 2008, FASB issued guidance in the Effective Date of FASB Statement No. 157 ASC Topic 820 (formerly FSP FAS 157-2) of the Codification, which amended 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 this Topic, which was effective January 1, 2009, did not have a material impact on the Company s consolidated financial statements.

In December 2007, the FASB issued guidance in ASC Topic 805 Business Combinations (formerly 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 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 guidance in the ASC Topic 810 Consolidation (formerly SFAS No. 160) of the Codification on the accounting for non-controlling (minority) interests in consolidated financial statements. This guidance clarifies the classification of non-controlling interests in consolidated statements of financial position and the accounting for and reporting of transactions between the reporting entity and holders of such non-controlling interests. This guidance was effective as of the beginning of an entity s first fiscal year that began on or after December 15, 2008 and was required to be adopted prospectively, except for the reclassification of non-controlling interests to equity and the recasting of net income (loss) attributable to both the controlling and non-controlling interests, which were required to be adopted retrospectively. The Company adopted this guidance effective January 1, 2009, and did not have a material impact on the consolidated financial statements.

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 became effective for disclosures in our Annual Report on Form 10-K for the year ended December 31, 2009. The implementation of this Rule, did not have a material impact on the Company s consolidated financial statements.

In August 2009, the FASB issued Accounting Standards Update (**ASU**) 2009 05 Fair Value Measurements and Disclosures (ASC Topic 820) Measuring Liabilities at Fair Value (**ASU 09-05**), which became effective the first reporting period (including interim periods) beginning after issuance. ASU 09-05 requires entities to measure the fair value of liabilities using one or more of several prescribed valuation techniques within the ASU when quoted prices in an active market for the identical liability are not available. The ASU also clarifies that: entities are not required to include separate inputs or adjustments to other inputs relating to the existence of restrictions that prevent the transfer of liabilities when estimating their fair value; and quoted prices in active markets for identical liabilities at the measurement date and the quoted prices for identical liabilities traded as assets in active markets when adjustments to the quoted prices of assets are required are Level 1 fair value measurements. The adoption of this standard did not have a material impact on the Company s financial statements.

Off Balance Sheet Arrangements

At December 31, 2009 and 2008, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. 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.

Related Party Transactions

The Company has entered into agreements with a number of entities which are related or controlled through common directors or shareholders. These entities provide access to an aircraft, the services of administrative and technical personnel, and office space or facilities in Vancouver, London and Singapore. The Company is billed on a cost recovery basis in most cases. For the year ended December 31, 2009 the costs incurred in the normal course of business with respect to the above arrangements amounted to $3.8 million ($3.0 million for 2008 and $3.3 million for 2007), and have been measured at their exchange amount and are recorded in general and administrative and business and technology expense in the statement of operations. As at December 31, 2009 amounts included in accounts payable and accrued liabilities on the balance sheet under these arrangements were $0.1 million ($0.1 million at December 31, 2008).

ITEM 7A. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

We are exposed to normal market risks inherent in the oil and gas business, including equity market risk, commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practicable.

NON-TRADING

Equity Market Risks

We currently have limited production in China, which have not generated sufficient cash from operations to fund our exploration and development activities. Historically, we have relied on the equity markets as the primary source of capital to fund our expansion and growth opportunities. Based on our current plans, we estimate that we will need approximately $100.0 to $125.0million to fund our capital investment programs for 2010.

We can give no assurance that we will be successful in obtaining financing as and when needed. Factors beyond our control, such as the recent credit crisis, may make it difficult or impossible for us to obtain financing on favorable terms or at all. Failure to obtain any required financing on a timely basis may cause us to postpone our development plans, forfeit rights in some or all of our projects or reduce or terminate some or all of our operations.

Commodity Price Risk

Commodity price risk related to crude oil prices is one of our most significant market risk exposures. Crude oil prices and quality differentials are influenced by worldwide factors such as the recent credit crisis, OPEC actions, political events and supply and demand fundamentals. To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices, North American supply and demand and local market conditions. Based on the Company s 2010 estimated worldwide crude oil production levels, a $1.00/Bbl change in the price of oil, would increase or decrease net income and cash from operations for 2010 by $0.2 million.

We periodically engage in the use of derivatives to minimize variability in our cash flow from operations and currently have costless collar contracts put in place as part of our bank loan facilities The Company entered 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 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. See Note 12 to the Consolidated Financial Statements.

On December 31, 2009, the Company had no open positions on the derivatives mentioned above as it had paid off the bank loan and settled all outstanding derivative contracts.

Decreases in oil and natural gas prices would negatively impact our results of operations as a direct result of a reduction in revenues but may also do so in the ceiling test calculation for the impairment of our oil and gas properties. On a quarterly basis, we compare the value of our proved and probable reserves, using estimated future oil and gas prices[(1)], to the carrying value of our oil and gas properties. The ceiling test calculation is sensitive to oil and gas prices and in a period of declining prices could result in a charge to our results of operations as we experienced in 2001 when we recorded a $14.0 million provision for impairment for Canadian GAAP and an additional $10.0 million for U.S. GAAP mainly due to a decline in oil and gas prices. Decreases in oil and gas prices from those used in our ceiling test calculation as at December 31, 2009 as discussed above in Critical Accounting Principles and Estimates Impairment of Proved Oil and Gas Properties may result in additional impairment provisions of our oil and gas properties.

(1) The recoverable value of probable reserves is included only for the measurement of the impairment of the carrying value of oil and gas properties as required under Canadian GAAP but not for U.S. GAAP. Additionally, there are differences for U.S. GAAP see Critical Accounting Principles and Estimates for the difference between Canadian and U.S. GAAP in calculating the impairment provision for oil and gas properties.

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Foreign Currency Rate Risk

Foreign currency risk refers to the risk that the value of a financial commitment, recognized asset or liability will fluctuate due to changes in foreign currency rates. The main underlying economic currency of the Company s cash flows is the U.S. dollar. This is because the Company s major product, crude oil, is priced internationally in U.S. dollars. Accordingly, the Company does not expect to face foreign exchange risks associated with its production revenues. However, some of the Company s cash flow stream relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. The majority of the operating costs incurred in the Chinese operations are paid in Chinese renminbi. The majority of costs incurred in the administrative offices in Vancouver and Calgary, as well as some business development costs, are paid in Canadian dollars. In addition, with the recent property acquisition in Alberta (see Note 18) the Company s Canadian dollar expenditures increased during the last half of 2008 and 2009 when compared to prior periods, along with an increase in cash and debt balances denominated in Canadian dollars. Disbursement transactions denominated in Chinese renminbi and Canadian dollars are converted to U.S. dollar equivalents based on the exchange rate as of the transaction date. Foreign currency gains and losses also come about when monetary assets and liabilities, mainly short term payables and receivables, denominated in foreign currencies are translated at the end of each month. The estimated impact of a 10% strengthening or weakening of the Chinese renminbi, and Canadian dollar, as of December 31, 2009 on net loss and accumulated deficit for the year ended December 31, 2009 is a $4.6 million increase, and a $4.4 million decrease, respectively. To help reduce the Company s exposure to foreign currency risk it seeks to maximize the expenditures and contracts denominated in U.S. dollars and minimize those denominated in other currencies, except for its Canadian activities where it attempts to hold cash denominated in Canadian dollars in order to manage its currency risk related to outstanding debt and current liabilities denominated in Canadian dollars.

Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to the changes in market interest rates. Interest rate risk arises from interest-bearing borrowings which have a variable interest rate. During 2009, the Company had a bank loan facility (as noted above this loan facility was repaid in full in December 2009) and a convertible note with fluctuating interest rates. The Company estimates that its net loss and accumulated deficit for the year ended December 31, 2009 would have changed $0.2 million for every 1% change in interest rates as of December 31, 2009. The Company is not currently actively attempting to mitigate this interest rate risk given the limited amount and term of its borrowings and the current global interest rate environment.

Credit Risk

The Company is exposed to credit risk with respect to its cash held with financial institutions, accounts receivable, derivative contracts and advance balances. The Company believes its exposure to credit risk related to cash held with financial institutions is minimal due to the quality of the institutions where the cash is held and the nature of the deposit instruments. Most of the Company s accounts receivable balances relate to oil sales to foreign national petroleum companies and are exposed to typical industry credit risks. In addition, accounts receivable balances consist of costs billed to joint venture partners where the Company is the operator and advances to partners for joint operations where the Company is not the operator. The Company manages its credit risk by entering into sales contracts only with established entities and reviewing its exposure to individual entities on a regular basis.

Currently, all of the Company s revenues come from CNPC and 80%-95% of the outstanding receivable balances as at December 31, 2009 and 2008, respectively, are due from this same customer.

Included in the Company s trade receivable balance are debtors with a carrying amount of nil as of the year ended December 31, 2009 which are past due at the reporting date for which the Company has not provided an allowance, as there has not been a significant change in credit quality and the amounts are still considered recoverable. In addition, the Company recorded an allowance for the entire outstanding amount of $0.2 million related to an amount owed to the Company by a two separate joint interest partners in the fourth quarter of 2009. These provisions were recorded in General and Administrative expense in the accompanying Statement of Operations and Comprehensive Loss. There were no other changes to the allowance for credit losses account during the three-month period ended December 31, 2009 and no other losses associated with credit risk were recorded during this same period.

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Liquidity Risk

Liquidity risk is the risk that suitable sources of funding for the Company s business activities may not be available, which means it may be forced to sell financial assets or non-financial assets, refinance existing debt, raise new debt or issue equity. The Company s present plans to generate sufficient resources to assure continuation of its operations and achieve its capital investment objectives include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt financing or the sale of equity securities. However, the availability of financing, in particular project funding, is dependent in part on our ability to fund our projects using the credit and equity markets. Despite the Company s recent successful financing efforts (see Note 20 to the Financial Statements included in Item 8 of this Form 10-K), the terms and availability of equity and debt capital, have been materially restricted and financing may not be available when it is required or on commercially acceptable terms.

TRADING

We do not enter into contracts for trading or speculative purposes. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had entered into such contracts.

ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

Index to Financial Statements and Related Information

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of
Ivanhoe Energy Inc.:

We have audited the accompanying consolidated balance sheets of Ivanhoe Energy Inc. and subsidiaries (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations and comprehensive loss, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ivanhoe Energy Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in Canada.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 12, 2010 expressed an unqualified opinion on the Company s internal control over financial reporting.

(signed) Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Canada
March 12, 2010

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

	As at December 31, 2009	2008 (Note 19)
Assets		
Current Assets:		
Cash and cash equivalents *(Note 12)*	$ 21,512	$ 38,477
Accounts receivable *(Note 12)*	5,021	3,802
Note receivable *(Note 12)*	225	
Prepaid and other current assets	771	637
Restricted cash	2,850	850
Derivative instruments *(Note 12)*		1,459
Assets of discontinued operations *(Note 19)*		2,727
	30,379	47,952
Oil and gas properties and development costs, net *(Note 3)*	158,392	143,974
Intangible assets HTL[TM] technology *(Note 4)*	92,153	92,153
Long term assets	839	152
Assets of discontinued operations *(Note 19)*		62,644
	$ 281,763	$ 346,875
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable and accrued liabilities *(Note 12)*	$ 10,779	$ 9,219
Income tax payable *(Note 14)*	530	650
Debt current portion *(Notes 5 and 12)*		412
Asset retirement obligations current portion *(Note 6)*	753	
Liabilities of discontinued operations current portion *(Note 19)*		6,074
	12,062	16,355
Long term debt *(Note 5 and 12)*	36,934	37,855
Asset retirement obligations *(Note 6)*	195	1,928
Long term obligation *(Note 7)*	1,900	1,900
Future income tax liability *(Note 14)*	22,643	29,600
Liabilities of discontinued operations *(Note 19)*		1,810
	73,734	89,448
Commitments and contingencies *(Note 7)*		
Shareholders Equity:		
Share capital, issued 282,558,593 common shares December 31, 2008 279,381,187 common shares	422,322	413,857

Purchase warrants *(Notes 8 and Note 18)*	19,427	18,805
Contributed surplus	20,029	16,862
Convertible note *(Note 8)*	2,086	2,086
Accumulated deficit	(255,835)	(194,183)
	208,029	257,427
	$ 281,763	$ 346,875

(See accompanying Notes to the Consolidated Financial Statements)

Approved by the Board:

(signed) Robert M. Friedland
Director

(signed) Brian F. Downey
Director

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

	Year Ended December 31, 2009	2008 (Note 19)	2007 (Note 19)
Revenue			
Oil revenue	$ 24,968	$ 48,370	$ 31,365
Gain (loss) on derivative instruments	(1,335)	1,688	(4,993)
Interest income	25	612	317
	23,658	50,670	26,689
Expenses			
Operating costs	10,191	21,515	13,000
General and administrative	21,693	14,252	9,803
Business and technology development	9,501	6,453	9,625
Depletion and depreciation	19,868	25,761	20,640
Foreign exchange loss	5,220	1,527	301
Interest expense and financing costs	856	1,309	623
Provision for impairment of intangible asset and development costs *(Notes 3 and 4)*	1,903	15,054	
Write off of deferred financing costs *(Note 13)*		2,621	
Provision for impairment of oil and gas properties *(Note 3)*			6,130
	69,232	88,492	60,122
Loss from continuing operations before income taxes	(45,574)	(37,822)	(33,433)
(Provision for) recovery of income taxes			
Current	(1,757)	(654)	
Future	9,600		
	7,843	(654)	
Net loss from continuing operations	(37,731)	(38,476)	(33,433)
Net income (loss) from discontinued operations (net of tax of $29.6 million for 2009, nil for 2008 and 2007) *(Notes 13 and 14)*	(23,921)	4,283	(5,774)
Net Loss and Comprehensive Loss	$ (61,652)	$ (34,193)	$ (39,207)

Net loss per share

Net loss from continuing operations, basic and diluted	$ (0.13)	$ (0.15)	$ (0.14)
Net income (loss) from discontinued operations, basic and diluted	(0.09)	0.02	(0.02)
Net loss per share, basic and diluted	$ (0.22)	$ (0.13)	$ (0.16)
Weighted average number of Shares (in thousands)			
Basic and Diluted	279,722	258,815	242,362

(See accompanying Notes to the Consolidated Financial Statements)

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IVANHOE ENERGY INC.
Consolidated Statements of Shareholders Equity
(stated in thousands of U.S. Dollars, except share amounts)

	Share Capital		Purchase	Contributed	Convertible	Accumulated	
	Shares (thousands)	Amount	Warrants	Surplus	Note	Deficit	Total
Balance December 31, 2006	241,216	318,725	23,955	6,489		(120,783)	228,386
Net loss and comprehensive loss						(39,207)	(39,207)
Shares issued for:							
Exercise of purchase warrants *(Note 8)*	2,000	4,313	(313)				4,000
Exercise of options *(Note 9)*	1,231	431		(52)			379
Employee bonuses	427	793					793
Expiry of purchase warrants *(Note 8)*			(564)	564			
Compensation calculated for stock option grants *(Note 9)*				2,936			2,936
Balance December 31, 2007	244,874	324,262	23,078	9,937		(159,990)	197,287
Net loss and comprehensive loss						(34,193)	(34,193)
Shares issued for:							
Private placements, net of share issue costs *(Note 8)*	29,334	82,451					82,451
Exercise of convertible debt *(Note 8)*	2,291	4,862					4,862
Exercise of options *(Note 9)*	2,666	1,792		(587)			1,205
Employee bonuses	216	490					490
Convertible note issued *(Note 8)*					2,086		2,086
Expiry of purchase warrants *(Note 8)*			(4,273)	4,273			
Compensation calculated for stock option grants *(Note 9)*				3,239			3,239
Balance December 31, 2008	279,381	413,857	18,805	16,862	2,086	(194,183)	257,427
Net loss and comprehensive loss						(61,652)	(61,652)
Shares issued for:							
	2,683	6,874	622				7,496

Acquisition of a business *(Note 18)*							
Services	81	207					207
Exercise of options *(Note 9)*	414	1,384		(492)			892
Compensation calculated for stock option grants *(Note 9)*				3,659			3,659
Balance December 31, 2009	282,559	$ 422,322	$ 19,427	$ 20,029	$ 2,086	$ (255,835)	$ 208,029

(See accompanying Notes to the Consolidated Financial Statements)

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

	Year Ended December 31, 2009	2008	2007
Operating Activities			
Net loss	$ (61,652)	$ (34,193)	$ (39,207)
Net (income) loss from discontinued operations	23,921	(4,283)	5,774
Items not requiring use of cash:			
Depletion and depreciation	19,868	25,761	20,640
Provision for impairment	1,903	15,054	6,130
Stock based compensation *(Note 9)*	3,849	3,016	3,151
Unrealized (gain) loss on derivative instruments	1,459	(6,118)	4,659
Write off of deferred financing costs *(Note 13)*		2,621	
Unrealized foreign exchange loss	5,109	1,762	
Future income tax recovery	(9,600)		
Provision for uncollectible accounts	174	625	
Other	553	519	381
Abandonment costs settled *(Note 6)*	(118)		
Changes in non-cash working capital items	(459)	6,016	(360)
Net cash provided by (used in) operating activities from continuing operations	(14,993)	10,780	1,168
Net cash provided by (used in) operating activities from discontinued operations	2,703	6,273	4,321
Net cash provided by (used in) operating activities	(12,290)	17,053	5,489
Investing Activities			
Capital investments	(26,373)	(21,063)	(28,585)
Acquisition of oil and gas assets		(22,308)	
Recovery of development costs *(Note 3)*			9,000
Advance repayments		200	500
Increase in restricted cash in escrow	(2,000)	(850)	
Other	(587)	73	(47)
Changes in non-cash working capital items	64	(1,035)	(1,283)
Net cash used in investing activities from continuing operations	(28,896)	(44,983)	(20,415)
Net cash provided by (used in) investing activities from discontinued operations	35,292	(4,338)	(1,872)
Net cash provided by (used in) investing activities	6,396	(49,321)	(22,287)
Financing Activities			
Shares issued on private placements, net of share issue costs		82,451	

Share issue costs on acquisition		(26)				
Proceeds from exercise of options and warrants		893		1,205		4,379
Proceeds from debt obligations, net of financing costs				4,790		9,356
Payments of debt obligations		(7,416)		(15,750)		(2,460)
Payments of deferred financing costs				(2,621)		
Other		(100)		(50)		
Changes in non-cash working capital items		(26)		26		
Net cash provided by (used in) financing activities from continuing operations		(6,675)		70,051		11,275
Net cash provided by (used in) financing activities from discontinued operations		(5,200)		700		3,000
Net cash provided by (used in) financing activities		(11,875)		70,751		14,275
Foreign Exchange gain (loss) on Cash and Cash Equivalents Held in a Foreign Currency		16		(10,574)		
Increase in Cash and Cash Equivalents, for the period		(17,753)		27,909		(2,523)
Cash and cash equivalents, beginning of period		39,265		11,356		13,879
Cash and Cash Equivalents, end of period	$	21,512	$	39,265	$	11,356
Cash and cash equivalents, end of period continuing operations	$	21,512	$	38,477	$	9,060
Cash and cash equivalents, end of period discontinued operations	$		$	788	$	2,296

(See accompanying Notes to the Consolidated Financial Statements)

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IVANHOE ENERGY INC.
Notes to the Consolidated Financial Statements
(all tabular amounts are expressed in thousands of U.S. Dollars, except share and per share amounts)

1. NATURE OF OPERATIONS

Ivanhoe Energy Inc. (the **Company** or **Ivanhoe Energy**), a Canadian company, is an independent international heavy oil development and production company focused on pursuing long-term growth in its reserves and production. Ivanhoe Energy plans to utilize technologically innovative methods designed to significantly improve recovery of heavy oil resources, including the anticipated commercial application of the patented rapid thermal processing process (**RTP™ Process**) for heavy oil upgrading (**HTL™ Technology** or **HTL™**) and enhanced oil recovery (**EOR**) techniques. In addition, the Company seeks to expand its reserve base and production through conventional exploration and production (**E&P**) of oil and gas. Our core operations are currently carried out in China, the United States, Canada and Ecuador.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (**GAAP**). The impact of material differences between Canadian and U.S. GAAP on the consolidated financial statements is disclosed in Note 21.

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

In particular, the amounts recorded for depletion and depreciation of the oil and gas properties and accretion for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment of oil and gas properties and development costs as well as intangible assets, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

Basis of Presentation

The Company s financial statements as at and for the year ended December 31, 2009 have been prepared in accordance with Canadian GAAP 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 $61.7 million for the year ended December 31, 2009, and as at December 31, 2009, had an accumulated deficit of $255.8 million and positive working capital of $18.3 million. The Company currently anticipates incurring substantial expenditures to further its capital development programs, particularly those related to the development of an oil sands project in Alberta and the development of a heavy oil field in Ecuador and exploration drilling in China. 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 public and private debt and equity markets, either at a parent company level or at the project level (see Note 20). Public and private 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, and these adjustments may be material.

Principles of Consolidation

These consolidated financial statements include the accounts of Ivanhoe Energy and its subsidiaries, all of which are wholly owned.

The Company conducts a portion of its exploration, development and production activities in its oil and gas business jointly with others. The Company s accounts reflect only its proportionate interest in the assets and liabilities of these joint ventures.

All inter-company transactions and balances have been eliminated for the purposes of these consolidated financial statements.

Foreign Currency Translation

The functional currency of the Company is the U.S. Dollar since it is the currency in which the worldwide petroleum business is denominated and the majority of our transactions occur in this currency. Monetary assets and liabilities denominated in foreign currencies are converted to the U.S. Dollar at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities at the exchange rates in effect at the time of acquisition or issue. Revenues and expenses are converted to the U.S. Dollar at rates approximating exchange rates in effect at the time of the transactions. Exchange gains or losses resulting from the period-end translation of monetary assets and liabilities denominated in foreign currencies are reflected in the results of operations.

Cash and Cash Equivalents

Cash and cash equivalents include short-term money market instruments with terms to maturity, at the date of issue, not exceeding 90 days.

Oil and Gas Properties

Full Cost Accounting

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development expenditures are capitalized on a country-by-country (cost center) basis. Such expenditures include lease and royalty interest acquisition costs, geological and geophysical expenses, carrying charges for unproved properties, costs of drilling both successful and unsuccessful wells, gathering and production facilities and equipment, financing, administrative costs related to capital projects and asset retirement costs. Proceeds from sales of oil and gas properties are recorded as reductions in the carrying value of proved oil and gas properties, unless such amounts would significantly alter the rate of depreciation and depletion, whereupon gains or losses would be recognized in income. Maintenance and repair costs are expensed as incurred, while improvements and major renovations are capitalized. The amount of interest costs capitalized for qualifying assets is intended to be that portion of the interest cost incurred during the assets acquisition periods that theoretically could have been avoided if expenditures for the assets had not been made. Unusually significant investments in unproved properties and major development projects that are not being currently depreciated, depleted, or amortized and on which exploration or development activities are in progress are assets qualifying for capitalization of interest cost. Similarly, in a cost center with no production, significant properties and projects on which exploration or development activities are in progress are assets qualifying for capitalization of interest costs.

Depletion

The Company s share of costs for proved oil and gas properties accumulated within each cost center, including a provision for future development costs, are depleted using the unit-of-production method over the life of the Company s share of estimated remaining proved oil and gas reserves net of royalties. Costs incurred on an unproved oil and gas property are excluded from the depletion rate calculation until it is determined whether proved reserves are attributable to an unproved oil and gas property or upon determination that an unproved oil and gas property has been impaired. Natural gas reserves and production are converted to a barrels of oil equivalent using a generally recognized industry standard in which six thousand cubic feet of gas is equal to one barrel of oil. 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.

Impairment of Proved Oil and Gas Properties

In the recognition of an impairment, the carrying value of a cost center is compared to the undiscounted future net cash flows of that cost center s proved reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation. If the carrying value is greater than the value of the undiscounted future net cash flows of the proved reserves plus the cost of unproved properties excluded from the depletion calculation, then the amount of the cost center s potential impairment must be measured. A cost center s impairment loss is measured by the amount its carrying value exceeds the discounted future net cash flows of its proved and probable reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation and which contain no probable reserves. The net cash flows of a cost center s proved and probable reserves are discounted using a risk-free interest rate adjusted for political and economic risk on a country-by-country basis. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center s oil and gas properties. 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.

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Asset Retirement Costs

The Company measures the expected costs required to abandon its producing U.S. oil and gas properties and HTL™ facilities at a fair value which approximates the cost a third party would incur in performing the tasks necessary to abandon the field and restore the site. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation as a liability with a corresponding increase in the related asset. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) is recognized in the results of operations and included with interest expense. Actual costs incurred upon settlement of the obligation are charged against the obligation to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the obligation and the recorded liability is recognized as a gain or loss in the carrying balance of the related capital asset in the period in which the settlement occurs.

Asset retirement costs associated with the producing U.S. oil and gas properties are being depleted using the unit of production method based on estimated proved reserves and are included with depletion and depreciation expense. Asset retirement costs associated with the CDF are depreciated over the life of the CDF which commenced when the facility was placed into service.

The Company does not make such a provision for its oil and gas operations in China as there is no obligation on the Company s part to contribute to the future cost to abandon the field and restore the site.

Development Costs

The Company incurs various costs in the pursuit of HTL™ and GTL projects throughout the world. Such costs incurred prior to signing a memorandum of understanding (**MOU**), or similar agreements, 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 that the feasibility and related costs incurred have potential future value, are probable of leading to a definitive agreement for the exploitation of proved reserves and should be capitalized. If no definitive agreement is reached, then the project s capitalized costs, which are deemed to have no future value, are written down in the results of operations with a corresponding reduction in the carrying balance of the HTL™ and GTL development costs.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the HTL™ and GTL technologies it owns or licenses. The cost of equipment and facilities acquired, such as the HTL™ commercial demonstration facility (**CDF**), or construction costs for such purposes such as with the HTL™ Feedstock Test Facility (**FTF**), 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. The FTF will be used to develop and identify improvements in the application of the HTL™ Technology by processing and testing heavy crude feedstock of prospective partners until such time as the FTF is sold, dismantled or redeployed.

The Company reviews the recoverability of such capitalized development costs annually, or as changes in circumstances indicate the development costs might be impaired, through an evaluation of the expected future discounted cash flows from the associated projects. If the carrying value of such capitalized development costs exceeds the expected future discounted cash flows, the excess is written down in the results of operations with a corresponding reduction in the carrying balance of the HTL™ and GTL development costs.

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

Furniture and Equipment

Furniture and fixtures are stated at cost. Depreciation is provided on a straight-line basis over the estimated useful life of the respective assets, at rates ranging from three to five years.

Intangible Assets

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

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The Company owns intangible assets in the form of an exclusive, irrevocable license to employ the RTP™ Process for all applications other than biomass and a non-exclusive master license entitling us to use Syntroleum Corporation s (**Syntroleum**) proprietary technology (**GTL Technology** or **GTL**) to convert natural gas into ultra clean transportation fuels and other synthetic petroleum products. The Company will assign the carrying value of the HTL™ Technology to the number of facilities it expects to develop that will use the HTL™ Technology. The amount of the carrying value of the technologies assigned to each HTL™ facility will be amortized to earnings on a basis related to the operations of the HTL™ from the date on which the facility is placed into service. The carrying value of the HTL™ Technology and the Syntroleum GTL master license are evaluated for impairment annually, or as changes in circumstances indicate the intangible assets might be impaired, based on an assessment of their fair market values. The carrying value of the Syntroleum GTL master license was impaired In 2008, the carrying value for Syntroleum GTL master license of $10.0 million (see Note 4), was reduced to nil with a corresponding reduction in our results of operations.

Oil and Gas Revenue

Sales of crude oil and natural gas are recognized in the period in which the product is delivered to the customer. Oil and gas revenue represents the Company s share and is recorded net of royalty payments to governments and other mineral interest owners.

In China, the Company conducts operations jointly with the government of China in accordance with a production-sharing contract. Under this contract, the Company pays both its share and the government s share of operating and capital costs. The Company recovers the government s share of these costs from future revenues or production over the life of the production-sharing contract. The government s share of operating costs is recorded in operating expense when incurred and capital costs are recorded in oil and gas properties when incurred and expensed to depletion and depreciation in the year recovered.

Earnings or Loss Per Share

Basic earnings or loss per share is calculated by dividing the net earnings or loss to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflects the potential dilution that would occur if stock options, convertible debentures and purchase warrants were exercised. The if converted method is used in calculating diluted earnings per share for the convertible debentures. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options and purchase warrants would be used to purchase common shares at the average market price for the period. The Company does not report diluted loss per share amounts, as the effect would be anti-dilutive to the common shareholders.

Income Taxes

The Company follows the liability method of accounting for future income taxes. Under the liability method, future income taxes are recognized to reflect the expected future tax consequences arising from tax loss carry-forwards and temporary differences between the carrying value and the tax basis of the Company s assets and liabilities. A valuation allowance is recorded against any future income tax asset if the Company is not more likely than not to be able to utilize the tax deductions associated with the future income tax asset. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs, provided that the income tax rates are substantively enacted.

Stock Based Compensation

The Company has an Employees and Directors Equity Incentive Plan consisting of a stock option plan, a bonus plan and an employee share purchase plan. Compensation costs are recognized in the results of operations over the periods in which the stock options vest for all stock options granted based on the fair value of the stock options at the date granted. The Company uses the Black-Scholes option-pricing model for determining the fair value of stock options issued at grant date. As of the date stock options are granted, the Company estimates a percentage of stock options issued to employees and directors it expects to be forfeited. Compensation costs are not recognized for stock option awards forfeited due to a failure to satisfy the service requirement for vesting. Compensation costs are adjusted for the actual amount of forfeitures in the period in which the stock options expire.

Upon the exercise of stock options, share capital is credited for the fair value of the stock options at the date granted with a charge to contributed surplus. Consideration paid upon the exercise of the stock options is also credited to share capital.

Compensation expenses are recognized when shares are issued from the stock bonus plan. The employee share purchase portion of the plan has not yet been activated.

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Financial Assets and Liabilities

Financial assets

The Company s financial assets are comprised of cash and cash equivalents, accounts receivable, advances, restricted cash and derivative instruments. These financial assets are classified as loans and receivables or held for trading financial assets as appropriate. The classification of financial assets is determined at initial recognition. When financial assets are recognized initially, they are measured at fair value, normally being the transaction price. Transaction costs for all financial assets are expensed as incurred.

Financial assets are classified as held for trading if they are acquired for sale in the short term. Cash and cash equivalents, restricted cash and derivatives in a positive fair value position are also classified as held for trading. Held for trading assets are carried on the balance sheet at fair value with gains or losses recognized in the consolidated statement of operations. The estimated fair value of held for trading assets is determined by reference to quoted market prices and, if not available, on estimates from third-party brokers or dealers.

Loans and receivables are non-derivative financial assets with fixed or determinable payments. Accounts receivable, note receivable and advances have been classified as loans and receivables. Such assets are carried at amortized cost, as the time value of money is not significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired.

The Company assesses at each balance sheet date whether a financial asset carried at cost is impaired. If there is objective evidence that an impairment loss exists, the amount of the loss is measured as the difference between the carrying amount of the asset and its fair value. The carrying amount of the asset is reduced with the amount of the loss recognized in earnings.

Financial liabilities

Financial liabilities are classified as held for trading financial liabilities or other financial liabilities as appropriate. Financial liabilities include accounts payable and accrued liabilities, derivative financial instruments, credit facilities, long term obligation and long term debt. The classification of financial liabilities is determined at initial recognition.

Held for trading financial liabilities represent financial contracts that were acquired for sale in the short term or derivatives that are in a negative fair market value position.

The estimated fair value of held for trading liabilities is determined by reference to quoted market prices and, if not available, on estimates from third-party brokers or dealers.

Other financial liabilities are non-derivative financial liabilities with fixed or determinable payments.

Short term other financial liabilities are carried at cost as the time value of money is not significant. Accounts payable and accrued liabilities and credit facilities have been classified as short term other financial liabilities. Gains and losses are recognized in income when the short term other financial liability is derecognized. Transaction costs for short term other financial liabilities are expensed as incurred.

Long term other financial liabilities are measured at amortized cost. Long-term debt and long term obligation have been classified as long term other financial liabilities. Transaction costs for long term other financial liabilities are deducted from the related liability and accounted for using the effective interest rate method.

Derivative Financial Instruments

The Company may periodically use different types of derivative instruments to manage its exposure to price volatility, thus mitigating fluctuations in commodity-related cash flows. The Company has used costless collar derivative instruments to manage this exposure.

Derivative financial instruments are classified as held for trading and recorded on the consolidated balance sheet at fair value, either as an asset or as a liability under current assets or current liabilities, respectively. Changes in the fair value of these financial instruments, or unrealized gains and losses, are recognized in the statement of operations as revenues in the period in which they occur.

Gains and losses related to the settlement of derivative contracts, or realized gains and losses, are recognized as revenues in the statement of operations.

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Contracts to buy or sell non-financial items that are not in accordance with the Company s expected purchase, sale or usage requirements are accounted for as derivative financial instruments.

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 consolidated financial statements as a result of having adopted these standards.

In January 2009, the Emerging Issues Committee of the CICA (**EIC**) issued Emerging Issues Committee abstract 173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities which provides guidance on the implications of credit risk in determining the fair value of an entity s financial assets and financial liabilities. The guidance clarifies that an entity s own credit risk and the credit risk of counterparties should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments, for presentation and disclosure purposes. The conclusions of the EIC were effective from the date of issuance of the abstract and did not have any material impact on the Company s consolidated balance sheet or statement of operations, comprehensive loss and accumulated deficit. However, the Company s fair value disclosures in Note 12 incorporated this new guidance.

In June 2009, the Accounting Standards Board of the CICA (**AcSB**) issued Accounting Revisions Release No. 54, Improving Disclosures About Financial Instruments Background Information and Basis for Conclusions (Amendments to Financial Instruments Disclosures, Section 3862) , which amended certain disclosure requirements related to financial instrument disclosure in response to disclosure amendments issued by the International Accounting Standards Board. This is consistent with the AcSB s strategy to adopt IFRS and to ensure the current existing disclosure requirements for financial instruments are converged to the extent possible. The new disclosure standards require disclosure of fair values based on a fair value hierarchy as well as enhanced discussion and quantitative disclosure related to liquidity risk. The amended disclosure requirements are effective for annual financial statements relating to fiscal years ending after September 30, 2009 and as such the Company has included the required disclosure in Note 12 of these financial statements.

Impact of New and Pending Canadian GAAP Accounting Standards

In January 2009, the AcSB issued Handbook Section 1582, Business Combinations (**S.1582**) replacing Handbook Section 1581, Business Combinations . The AcSB revised accounting standards in regards to business combinations with the intent of harmonizing those standards with IFRS. The revised standards require the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction, establish the acquisition date fair value as the measurement objective for all assets acquired and liabilities assumed; and require 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. These standards shall be applied prospectively to business combinations with an acquisition date after the beginning of the first annual reporting period beginning after January 1, 2011. The Company adopted this standard early on January 1, 2009 with no transitional adjustment to the consolidated financial statements as a result of adopting this standard. However, the Company did apply the provisions of this standard to a business combination that occurred in the fourth quarter of 2009 (see Note 18).

Also in January 2009, the AcSB issued Handbook Section 1601, Consolidated Financial Statements (**S.1601**) and Handbook Section 1602, Non-Controlling Interests (**S.1602**), which replace Handbook Section 1600, Consolidated Financial Statements (**S.1600**). S.1601 and S.1602 require all entities to report non-controlling (minority) interests as equity in consolidated financial statements. The standards eliminate the diversity that currently exists in accounting for transactions between an entity and non-controlling interests by requiring they be treated as equity transactions. These standards shall be applied retrospectively effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The Company adopted these standards early on January 1, 2009 with no transitional adjustment to the consolidated financial statements as a result of adopting these standards.

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3. OIL AND GAS PROPERTIES AND DEVELOPMENT COSTS

In July 2009, the Company sold its U.S. operating segment (see Note 19); consequently, the segment information has been revised to reflect this sale. Capital assets categorized by segment are as follows:

As at December 31, 2009

	Oil and Gas Integrated Canada	Oil and Gas Integrated Ecuador	Conventional Asia	Corporate	Business and Technology Development	Total
Oil and Gas Properties:						
Proved	$	$	$ 148,110	$	$	$ 148,110
Unproved	94,431	6,755	14,411			115,597
	94,431	6,755	162,521			263,707
Accumulated depletion			(99,744)			(99,744)
Accumulated provision for impairment			(16,550)			(16,550)
	94,431	6,755	46,227			147,413
Development Costs:						
Feasibility studies and other deferred costs:						
Iraq and Libya HTL™					834	834
Egypt GTL					5,054	5,054
Accumulated provision for impairment					(5,888)	(5,888)
Feedstock test facility					10,868	10,868
Accumulated depreciation and impairment					(393)	(393)
					10,475	10,475
Furniture and equipment	24	169	135	968	22	1,318
Accumulated depreciation	(8)	(53)	(92)	(650)	(11)	(814)
	16	116	43	318	11	504
	$ 94,447	$ 6,871	$ 46,270	$ 318	$ 10,486	$ 158,392

As at December 31, 2008

	Oil and Gas Integrated Canada	Oil and Gas Integrated Ecuador	Conventional Asia	Corporate	Business and Technology Development	Total
Oil and Gas Properties:						
Proved	$	$	$ 141,089	$	$	$ 141,089

Unproved	81,090	1,454	5,233			87,777
	81,090	1,454	146,322			228,866
Accumulated depletion			(81,717)			(81,717)
Accumulated provision for impairment			(16,550)			(16,550)
	81,090	1,454	48,055			130,599
Development Costs:						
Feasibility studies and other deferred costs:						
Iraq and Libya HTL™					801	801
Egypt 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	13	406	649
Accumulated depreciation	(6)		(79)	(6)	(77)	(168)
	14	90	41	7	329	481
	$ 81,104	$ 1,544	$ 48,096	$ 7	$ 13,223	$ 143,974

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Oil and Gas Properties

Costs as at December 31, 2009 of $115.6 million ($87.8 million at December 31, 2008), related to unproved oil and gas properties have been excluded from costs subject to depletion and depreciation. Included in that same depletion calculation were $3.3 million for future development costs associated with proven undeveloped reserves as at December 31, 2009 ($3.3 million at December 31, 2008). The oil and gas properties in Canada, Ecuador and Mongolia have not had any oil and gas production and have been excluded from the ceiling test as undeveloped land.

For the year ended December 31, 2009, $3.9 million ($1.6 million in 2008 and $0.5 million in 2007) in general and administrative expenses related directly to oil and gas acquisition, exploration and development activities were capitalized.

The Company performed a ceiling test calculation at December 31, 2009, 2008 and 2007 to assess the recoverable value of its Oil and Gas Properties. Based on this calculation, the present value of future net revenue from the Company s proved plus probable reserves exceeded the carrying value of the Company s Oil and Gas Properties in 2009 and 2008, resulting in no impairment in each of those years. However, the Company performed this same calculation at December 31, 2007 which resulted in an impairment of $6.1 million.

West Texas Intermediate prices used in calculating the expected future cash flows were based on the following benchmark prices adjusted for gravity, transportation and other factors as required by sales agreements:

	As at December 31,		
	2009	**2008**	**2007**
	(per Bbl)	(per Bbl)	(per Bbl)
2008	NA	NA	$ 92.00
2009	NA	$ 57.50	$ 88.00
2010	$ 80.00	$ 68.00	$ 84.00
2011	$ 83.00	$ 74.00	$ 82.00
2012	$ 86.00	$ 85.00	$ 82.00
2013	$ 89.00	$ 92.01	$ 82.00
2014	$ 92.00	$ 93.85	$ 82.00
2015	$ 93.84	$ 95.73	$ 82.00
2016	$ 95.72	$ 97.64	$ 82.02
2017	$ 97.64	$ 99.59	$ 83.66
2018	$ 99.59	101.59	2% per year
2019	$ 101.58	2% per year	2% per year
Thereafter	2% per year	2% per year	2% per year

Development Costs

Feasibility Studies and Other Deferred Costs

The Company is exploring an opportunity in Egypt to monetize stranded gas reserves through the application of the GTL Technology. Because the Company has been pursuing this project for an extended period of time and has not been able to obtain a definitive agreement or appropriate project financing, the Company has impaired the carrying value of the costs associated with GTL as at December 31, 2008. In 2008, the carrying value for GTL development costs of $5.1 million and intangible GTL assets of $10.0 million (see Note 4), were reduced to nil with a corresponding reduction in our results of operations. This impairment does not affect the Company s intention to continue to pursue this project.

For the year ended December 31, 2009, the Company impaired the carrying value of its deferred costs associated with its pursuit of HTL™ projects in Iraq and Libya. Impairments (nil in 2008 and 2007) related to its HTL™ Development Costs. These impairments do not affect the Company s intention to continue to pursue these projects.

HTL™ Facilities

During the third quarter of 2009, the Company determined that the completion and subsequent improvements to its technology showpiece the FTF in San Antonio diminished the business purpose of the CDF to nil. Consequently, the abandonment process commenced and the Company has impaired the net carrying value of the costs associated with the CDF as at September 30, 2009. The carrying value, net of depreciation, for the CDF, of $0.9 million, was reduced to nil with a corresponding reduction in our results of operations. Also, see Note 6 below.

As further described above the FTF was entering into the commissioning phase at December 31, 2008 and, as such, was not depreciated, nor impaired for the year ended December 31, 2008. The FTF was placed into service in the first quarter of 2009.

4. INTANGIBLE ASSETS TECHNOLOGY

The Company s intangible assets consist of the following:

HTL™ Technology

In the 2005 merger with the Ensyn Group, Inc. (**Ensyn**), the Company acquired an exclusive, irrevocable license to deploy, worldwide, the 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 HTL™ Technology as at December 31, 2009 and 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. This intangible asset was not amortized and its carrying value was not impaired for the years ended December 31, 2009, 2008 and 2007.

Syntroleum GTL Master License

The Company owns a master license from Syntroleum permitting the Company to use Syntroleum s proprietary GTL process in an unlimited number of projects around the world. The Company s master license expires on the later of April 2015 or five years from the effective date of the last site license issued to the Company by Syntroleum. Both companies have the right to pursue GTL projects independently, but the Company would be required to pay the normal license fees and royalties in such projects. The Company s carrying value of the Syntroleum GTL master license as at December 31, 2009 and 2008 was nil.

Recovery of capitalized costs related to potential HTL™ and GTL projects is dependent upon finalizing definitive agreements for, and successful completion of, the various projects. As described in Note 3 to these financial statements, the GTL intangible asset balance of $10 million was impaired and charged to the results of operations with a corresponding reduction in intangible GTL in 2008.

5. LONG TERM DEBT

Notes payable consisted of the following as at:

	December 31, 2009	**December 31, 2008**
Variable rate bank note (4.00% at December 31, 2009) paid in full December 2009	$	$ 7,000
Non-interest bearing promissory note, final payment February 2009		416
Convertible note (4.25% at December 31, 2009) due July 2011	38,005	32,787
	38,005	40,203
Less:		
Unamortized discount	(1,071)	(4)
Unamortized deferred financing costs		(1,932)
Current maturities		(412)
	(1,071)	(2,348)
	$ 36,934	$ 37,855

Bank Loan

In September 2007 the Company obtained a $30 million Revolving/Term Credit Facility with an initial borrowing base of $10 million. The facility is a revolving facility with a three-year term with interest payable only during the term. In December 2009 the remaining balance in the amount of $7.0 million was repaid in advance of its expiry date and consequently as of December 31, 2009 all security was in the process of being released back to the Company.

Promissory Note

In connection with the acquisition in July 2008 described in Note 18, the Company issued a promissory note (the **2008 Note**) to Talisman Energy Canada (**Talisman**) in the principal amount of Cdn.$12.5 million bearing interest at a rate per year equal to the prime rate plus 2%, calculated daily and not compounded. The 2008 Note matured and the principal and related interest was paid on December 31, 2008.

Convertible Note

Also in connection with the acquisition in July 2008 described in Note 18, the Company issued a convertible promissory note (the **Convertible Note**) to Talisman in the principal amount of Cdn.$40.0 million bearing interest at a rate per year equal to the prime rate plus 2%, calculated daily and not compounded, payable semi-annually and maturing in July 2011. The Convertible Note is convertible (as to the outstanding principal amount), at Talisman s option, into a maximum of 12,779,552 common shares of the Company at Cdn.$3.13 per common share. There were no conversions of this note as of December 31, 2009.

The Convertible Note is assessed based on the substance of the contractual arrangement in determining whether it exhibits the fundamental characteristics of a financial liability or equity. Management has concluded that this debt instrument mainly exhibits characteristics that are liability in nature, however, the embedded conversion feature is equity in nature and is required to be bifurcated and disclosed separately within shareholders equity. Management has applied a residual basis method and has valued the liability component first and assigned the residual value to the equity component. Management has fair valued the liability component by discounting the expected interest and principal payments using an interest rate of 8.75% being management s estimate of the expected interest payments for a similar instrument without the conversion feature. The liability component was valued at Cdn.$37.9 million and the remaining balance of Cdn.$2.1 million was allocated to the equity component. The liability component will be accreted over the three-year maturity period to bring the liability back to Cdn.$40.0 million using the effective interest method.

The Company s obligations under the Convertible Note and the Contingent Payment (see Note 18) are secured by a first fixed charge and security interest in favor of Talisman against the acquired Talisman leases and the related assets acquired by the Company pursuant to the Talisman lease acquisition. The Talisman security interest also does not extend to any assets of any subsidiary of Ivanhoe Energy.

The scheduled maturities of the Company s long term debt, excluding unamortized discount and unamortized deferred financing costs, as at December 31, 2008 were as follows:

2010	$	
2011		38,005
	$	38,005

Interest expense included in Interest Expense and Financing Costs in the statement of operations was $0.8 million for the year ended December 31, 2009 ($1.2 million for 2008 and $0.6 million for 2007). For the year ended December 31, 2009, $2.2 million ($1.7 million in 2008 and nil in 2007) in interest was capitalized to oil and gas properties and development costs in the balance sheet.

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6. ASSET RETIREMENT OBLIGATIONS

The Company provides for the expected costs required to abandon the CDF and FTF. The undiscounted amount of expected future cash flows required to settle the Company s asset retirement obligations for these assets as at December 31, 2009 was estimated at $0.9 million. These payments are expected to be made over the next 20 years; with the majority of the payments to be made within one year. To calculate the present value of these obligations, the Company used an inflation rate of 1% and 3% and the expected future cash flows have been discounted using a credit-adjusted risk-free rate of 5.3% and 5.5% for the respective periods shown below. As noted in Note 3 above, the abandonment process for the CDF commenced in the third quarter of 2009. Management determined that a more cost effective way to handle this dismantlement would be to redeploy Company staff from its discontinued operations as opposed to utilizing external service providers. As a result, there was an adjustment to the estimated future cash flows expected to be needed to abandon this asset. A reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of the CDF and the FTF for the two-year period ended December 31, 2009 is as follows:

	As at December 31, 2009	As at December 31, 2008
Carrying balance, beginning of year	$ 1,928	$ 739
Liabilities incurred	185	
Liabilities settled	(118)	
Accretion expense	79	76
Revisions in estimated cash flows	(1,126)	1,113
Carrying balance, end of period	948	1,928
Less: current portion	753	
Carrying balance, end of year	$ 195	$ 1,928

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.

Under this production-sharing contract, the Company was obligated to conduct a minimum exploration program during the first three years ending December 1, 2005 (**Phase I**). The Company completed Phase I with a drilling shortfall of approximately 700 feet. In December 2007, the Company and Mitsubishi (the **Zitong Partners**) made a decision to enter into the next three-year exploration phase (**Phase II**). The shortfall in Phase I drilling will be carried over into Phase II.

By electing to participate in Phase II 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 I shortfall), with total gross remaining estimated minimum expenditures for this program of $23.1 million. The Zitong Partners have relinquished 25% of the Block to complete the Phase I relinquishment requirement. The Phase II seismic line acquisition commitment was fulfilled in the Phase 1 exploration program. Drilling at two locations is planned to commence in the second quarter of 2010 with expected completed drilling, completion and evaluation of the prospects finalized in late 2010. The Zitong Partners must complete the minimum work program by the end of the Phase II 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. The cash equivalent of the deficiency in the drilling program is defined as the actual average unit cost of the last well drilled multiplied by the footage shortfall. Based on our historical drilling costs, we estimate this deficiency to be $12.5 million at December 31, 2009. Following the completion of Phase II, the Zitong Partners must relinquish all of the remaining property except any areas identified for development and future production.

Nyalga Block Exploration Commitment

The exploration period for the Nyalga Block XVI in Mongolia is for five years in duration and consists of three phases of two years, one year and two years respectively, with the ability to nominate a two year extension following the first or second phase. The minimum work obligations consist of $2.7 million for the first phase with the majority of that commitment in the second year of the phase, $1.0 million for the second phase and $2.5 million for the third phase with the majority of that commitment in the second year of that phase. If, in one year, more than the minimum is expended, the excess can be applied to reduce the minimum expenditure in the next year of that phase. During the initial seismic program, a portion of the block, representing approximately 16% of the total, was declared by the Mongolian government to be an historical site and operations on that portion of the block, the Delgerkhaan area, were suspended. A letter from the Mineral Resources and Petroleum Authority of Mongolia **(the MRPAM)** was received in May 2008 which stated that the obligations under year one of first phase would be extended for one year from the time the Company is allowed access to the suspended area. To date, access has not yet been allowed and discussions with MRPAM are still ongoing not only as to possibility of entering into this suspended area but also as to the exact end date of the first phase. Management believes the end date of the first phase to be April 2010 and as at December 2009 has spent in excess of the commitments for this first phase. The minimum work obligation as at December 31, 2009 was $3.4 million.

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 was recorded in the Company s consolidated balance sheet.

Income Taxes

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

The Company has an uncertain tax position 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 $1.2 million.

The Company has an uncertain tax position related to the calculation of a gain on the consideration received from two farm-out transactions (In January 2004, the Company signed farm-out and joint operating agreements with Richfirst Holdings Limited, to acquire a 40% working interest in the Dagang field for payment of $20.0 million. and the farm-out to Mitsubishi in January 2006 see under Zitong Block Exploration Commitment in this Note 7) and the designation of whether the taxable gains may be subject to a withholding tax of 10% pursuant to Chinese tax law for income derived by a foreign entity. The Company is waiting for the Chinese tax authorities to reply to its request to validate in writing that its current treatment of such tax position is appropriate. To the extent that the calculation of a gain is interpreted differently and the amounts are subject to withholding tax there would be an additional current tax provision of approximately $0.7 million.

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

Other Commitments

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 individual projects.

See Note 18 for a commitments related to acquisition of properties in Alberta.

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.

Lease Commitments

For the year ended December 31, 2009 the Company expended $1.2 million ($1.2 million in 2008 and $1.1 million in 2007) on operating leases relating to the rental of office space, which expire between July 2010 and September 2013. Such leases frequently provide for renewal options and require the Company to pay for utilities, taxes, insurance and maintenance expenses.

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As at December 31, 2009, future net minimum payments for operating leases (excluding oil and gas and other mineral leases) were the following:

2010	$	1,448
2011		1,109
2012		438
2013		126
Thereafter		
	$	3,121

8. SHARE CAPITAL AND WARRANTS

The authorized capital of the Company consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

Special Warrants Offering

A special warrant is a security sold for cash which may be exercised to acquire, for no additional consideration, a common share or, in certain circumstances, a common share and a common share purchase warrant.

In July 2008, the Company completed a Cdn.$88.0 million private placement consisting of 29,334,000 special warrants at Cdn.$3.00 per special warrant (the **Offering**). Each of these special warrants entitled the holder to one common share of the Company upon exercise of the special warrant. In August 2008, all of these special warrants were exercised for 29,334,000 common shares. The net proceeds from the Offering was approximately Cdn.$83.4 million after deducting the agents commission of Cdn.$4.0 million and the expenses of the Offering of Cdn.$0.6 million. The Company used Cdn.$22.5 million of the net proceeds of the Offering to complete the cash component of the Talisman lease acquisition described in Note 18.

Convertible Notes

As described in Note 5, in connection with the acquisition in July 2008, the Company issued the Convertible Note to Talisman in the principal amount of Cdn.$40.0 million bearing interest at a rate per year equal to the prime rate plus 2%, calculated daily and not compounded, and payable semi-annually, maturing in July 2011 and convertible (as to the outstanding principal amount), at Talisman s option, into a maximum of 12,779,552 common shares of the Company at Cdn.$3.13 per common share. Also described in Note 5, management accounted for this convertible note by assigning a portion of the value, Cdn.$2.1 million, of the instrument to equity.

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

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Purchase Warrants

The following reflects the changes in the Company s purchase warrants and common shares issuable upon the exercise of the purchase warrants for the three-year period ended December 31, 2009:

	Purchase Warrants	Shares Issuable
	(thousands)	
Balance December 31, 2006	29,696	29,696
Purchase warrants exercised	(2,000)	(2,000)
Purchase warrants expired	(1,200)	(1,200)
Balance December 31, 2007	26,496	26,496
Purchase warrants expired	(15,096)	(15,096)
Private placements	29,334	29,334
Purchase warrants exercised	(29,334)	(29,334)
Balance December 31, 2008	11,400	11,400
Exchanged as part of acquistion	735	735
Balance December 31, 2009	12,135	12,135

In 2009, 0.7 million purchase warrants were issued in exchange for outstanding warrants of a company the Company acquired. See Note 18 for further details.

For the year ended December 31, 2009, no purchase warrants were exercised (in 2008, 29.3 million purchase warrants were exercised for the purchase of common shares please refer to details under Special Warrants Offering and in 2007 2.0 million warrants were exercised at an average exercise price of U.S. $2.00 per share for a total of $4.0 million).

For the year ended December 31, 2009, no purchase warrants expired (15.1 million with a carrying value of $4.3 million in 2008 and 1.2 million with a carrying value of $0.6 million in 2007). The carrying value is reclassified from Purchase Warrants to Contributed Surplus at the time of expiration.

As at December 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:

Year of Issue	Price per Special Warrant	Purchase Warrants Issued	Exercisable	Common Shares Issuable	Value ($U.S. 000)	Expiry Date	Exercise Price per Share	Cash Value on Exercise ($U.S. 000)
			(thousands)					
2006	U.S.$2.23	11,400	11,400	11,400	18,805	May 2011	Cdn. $2.93 (1)	31,736
2009	NA	735	735	735	622	February 2011	Cdn. $4.05	2,828
		12,135	12,135	12,135	$ 19,427			$ 34,564

(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. In September 2006, these warrants were listed on the Toronto Stock Exchange and the exercise price was changed to Cdn.\$2.93.

The weighted average exercise price of the exercisable purchase warrants as at December 31, 2009 was U.S. \$2.85 per share.

The Company calculated a value of \$0.6 million and \$18.8 million for the purchase warrants issued in 2009 and 2006. This value was calculated in accordance with the Black-Scholes pricing model using a weighted average risk-free interest rate of 0.6% and 4.4%, a dividend yield of 0.0%, a weighted average volatility factor of 104.9% and 75.3% and an expected life of 1and 5 years.

9. STOCK BASED COMPENSATION

The Company has an Employees and Directors Equity Incentive Plan under which it can grant stock options to directors and eligible employees to purchase common shares, issue common shares to directors and eligible employees for bonus awards and issue shares under a share purchase plan for eligible employees. The total number of common shares that may be issued under this plan cannot exceed 29.3 million.

Stock options are issued at not less than the fair market value on the date of the grant and are conditional on continuing employment. Expiration and vesting periods are set at the discretion of the Board of Directors. Stock options granted prior to March 1, 1999 vested over a two-year period and expire ten years from date of issue. Stock options granted after March 1, 1999 generally vest over three to four years and expire five to ten years from the date of issue. Additionally, in 2007, the Company granted share option awards whose vesting is contingent upon meeting various departmental and company-wide goals.

The fair value of each option award is estimated on the date of grant using the Black Scholes option-pricing formula with service condition options amortized on a straight-line attribution approach and performance condition options amortized over the service period both with the following weighted-average assumptions for the years presented:

	2009	2008	2007
Expected term (in years)	4.6	4.0	3.7
Volatility	81.1%	63.5%	73.5%
Dividend Yield	0.0%	0.0%	0.0%
Risk-free rate	2.6%	3.1%	4.1%

The Company s expected term represents the period that the Company s stock-based awards are expected to be outstanding and was determined based on historical experience of similar awards, giving consideration to the contractual terms of the stock-based awards, vesting schedules and expectations of future employee behavior as influenced by changes to the terms of its stock-based awards. The fair values of stock-based payments were valued using the Black Scholes valuation method with an expected volatility factor based on the Company s historical stock prices. The Black Scholes valuation model calls for a single expected dividend yield as an input. The Company has not paid and does not anticipate paying any dividends in the near future. The Company bases the risk-free interest rate used in the Black Scholes valuation method on the implied yield currently available on Canadian zero-coupon issue bonds with an equivalent remaining term. When estimating forfeitures, the Company considers historical voluntary termination behavior as well as future expectations of workforce reductions. The estimated forfeiture rate as at December 31, 2009 is 26.4% (25.9% at December 31, 2008 and 23.1% at December 31, 2007). The Company recognizes compensation costs only for those equity awards expected to vest.

The weighted average grant-date fair value of stock options granted during 2009 was Cdn.$1.62 (Cdn.$0.90 in 2008 and Cdn$1.09 in 2007).

For the years ended December 31, 2009 the Company s stock based compensation related to option awards, share bonus awards and shares issued for services were as follows:

	2009	2008	2007
General and Administrative Expense:			
Option awards	$ 3,484	$ 2,241	$ 1,786
Share bonus awards		207	340
Shares issued for services	207		
	3,691	2,448	2,126
Business and Technology Development Expense:			
Option awards	158	432	774
Share bonus awards		136	251
	158	568	1,025
Discontinued Operations:			
Option awards	17	391	376
Share bonus awards		147	202
	17	538	578
	$ 3,866	$ 3,554	$ 3,729

In addition, nil of the Company s stock based compensation related to option awards was capitalized to oil and gas properties and development costs in the balance sheet during December 31, 2009 ($0.2 million in 2008 and nil in 2007).

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The following table summarizes changes in the Company s outstanding stock options:

	December 31, 2009		December 31, 2008		December 31, 2007	
	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)
Outstanding at beginning of year	11,913	$ 2.32	12,945	$ 2.37	12,370	$ 2.34
Granted	4,188	$ 2.17	3,832	$ 1.79	3,843	$ 1.05
Exercised	(413)	$ 2.46	(3,067)	$ 0.90	(1,477)	$ 0.62
Expired	(114)	$ 2.44	(580)	$ 5.78	(1,017)	$ 3.12
Forfeited	(561)	$ 2.41	(1,217)	$ 3.05	(774)	$ 2.69
Outstanding at end of year	15,013	$ 2.27	11,913	$ 2.32	12,945	$ 2.37
Options exercisable at end of year	7,101	$ 2.48	5,062	$ 2.61	6,932	$ 2.24

The aggregate intrinsic value of total options outstanding as well as options exercisable as at December 31, 2009 was $10.8 million and $3.4 million. The total intrinsic value of options exercised during the year ended December 31, 2009 was $3.0 million ($5.4 million in 2008 and $2.1 million in 2007), and the cash received from exercise of options during the year ended December 31, 2009 was $0.9 million ($1.2 million in 2008 and $0.4 million in 2007).
The following table summarizes information respecting stock options outstanding and exercisable as at December 31, 2009:

	Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices (Cdn.$)	Number Outstanding (thousands)	Weighted-Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price (Cdn.$)	Number Exercisable (thousands)	Weighted-Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price (Cdn.$)
$1.52 to $2.25	9,652	3.8	$ 1.93	2,612	3.3	$ 1.85
$2.29 to $3.44	5,089	2.3	$ 2.85	3,906	1.1	$ 2.89
$3.53 to $3.62	272	1.9	$ 3.56	235	0.8	$ 3.56
$1.52 to $3.62	15,013	3.1	$ 2.27	6,753	2.0	$ 2.51

A summary of the Company s unvested options as at December 31, 2009, and changes during the year then ended, is presented below:

	Number of Stock Options (thousands)	Weighted-Average Grant Date Fair Value (Cdn.$)
Outstanding at December 31, 2008	6,851	$ 0.98

Granted	4,188	$	1.62
Vested	(2,814)	$	0.46
Cancelled/forfeited	(313)	$	0.02
Outstanding at December 31, 2009	7,912	$	1.21

Unvested options outstanding at December 31, 2009 by type:

Based on fulfilling service conditions	6,926
Based on fulfilling performance conditions	986
	7,912

As at December 31, 2009, there was $3.1 million of total unrecognized compensation costs related to unvested share-based compensation arrangements granted by the Company. That cost is expected to be recognized over a weighted-average period of 1.6 years. The total fair value of options vested during the year ended December 31, 2009 was $2.2 million ($3.0 million in 2007 and $2.9 million in 2007).

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10. RETIREMENT PLAN

In 2001, the Company adopted a defined contribution retirement or thrift plan (**401(k) Plan**) to assist U.S. employees in providing for retirement or other future financial needs. Employees contributions (up to the maximum allowed by U.S. tax laws) were matched 100% by the Company in 2009. For the year ended December 31, 2009 the Company s matching contributions to the 401(k) Plan was $0.4 million ($0.5 million in 2008 and $0.5 million in 2007).

11. SEGMENT INFORMATION

The Company has four reportable business segments: Oil and Gas Integrated, Oil and Gas - Conventional, Business and Technology Development and Corporate. In July 2009, the Company sold its U.S. operating segment (see Note 19); consequently, the segment information has been revised to reflect this sale.

Oil and Gas

<u>Integrated</u>

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 (see Note 18) and a heavy oil project in Ecuador (see Note 18). The integrated segments were established in 2008 and therefore there is no comparative information for 2007.

<u>Conventional</u>

The Company explores for, develops and produces crude oil and natural gas in China, and recently acquired an exploration block in Mongolia. 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 Mongolia, the exploration activity is being conducted in Block XVI in the Nyalga Basin. Prior to July 2009, (see Note 18) the Company conducted U.S. exploration, development and production activities primarily 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 project s products, the Company assesses whether the feasibility and related costs incurred have potential future value, are likely of leading 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 years ended December 31, 2009.

	Year Ended December 31, 2009						
	Oil and Gas				Business and Technology Development	Corporate	Total
	Integrated		Conventional				
	Canada	Ecuador	Asia	U.S.			
Revenue							
Oil revenue	$	$	$ 24,968	$	$	$	$ 24,968
Loss on derivative instruments			(1,335)				(1,335)
Interest income			6			19	25
			23,639			19	23,658
Expenses							
Operating costs			10,191				10,191
General and administrative	1,129	2,269	2,777			15,518	21,693
Business and technology development	560				8,941		9,501
Depletion and depreciation	4	53	18,033		1,633	145	19,868
Foreign exchange loss	(8)		71		2	5,155	5,220
Interest expense and financing costs			770		79	7	856
Provision for impairment of development costs					1,903		1,903
	1,685	2,322	31,842		12,558	20,825	69,232
Loss from continuing operations before income taxes	(1,685)	(2,322)	(8,203)		(12,558)	(20,806)	(45,574)
(Provision for) recovery of income taxes							
Current			(1,399)			(358)	(1,757)
Future					9,600		9,600
			(1,399)		9,600	(358)	7,843
	(1,685)	(2,322)	(9,602)		(2,958)	(21,164)	(37,731)

Net loss from continuing operations							
Net loss from discontinued operations (net of tax of $29.6 million)				(23,921)			(23,921)
Net income (loss) and comprehensive income (loss)	$ (1,685)	$ (2,322)	$ (9,602)	$ (23,921)	$ (2,958)	$ (21,164)	$ (61,652)
Capital Investments	$ 12,756	$ 5,380	$ 6,049	$	$ 2,093	$ 95	$ 26,373
Identifiable Assets: As at December 31, 2009	$ 94,594	$ 7,597	$ 57,528	$	$ 102,878	$ 19,166	$ 281,763

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	Year Ended December 31, 2008						
	Oil and Gas				Business and Technology Development	Corporate	Total
	Integrated		Conventional				
	Canada	Ecuador	Asia	U.S.			
Revenue							
Oil revenue	$	$	$ 48,370	$	$	$	$ 48,370
Gain on derivative instruments			1,688				1,688
Interest income			50			562	612
			50,108			562	50,670
Expenses							
Operating costs			21,515				21,515
General and administrative	1,627	658	1,967			10,000	14,252
Business and technology development	189				6,264		6,453
Depletion and depreciation	3		23,135		2,618	5	25,761
Foreign exchange loss	26		278			1,223	1,527
Interest expense and financing costs			821		76	412	1,309
Provion for impairment of GTL intangible assets and development costs					15,054		15,054
Write off of deferred financing costs			2,621				2,621
	1,845	658	50,337		24,012	11,640	88,492
Loss from continuing operations before income taxes	(1,845)	(658)	(229)		(24,012)	(11,078)	(37,822)
Current provision for income taxes			(650)		(2)	(2)	(654)
Net loss from continuing operations	(1,845)	(658)	(879)		(24,014)	(11,080)	(38,476)
				4,283			4,283

Net income from discontinued operations							
Net Income (Loss) and Comprehensive Income (Loss)	$ (1,845)	$ (658)	$ (879)	$ 4,283	$ (24,014)	$ (11,080)	$ (34,193)
Capital Investments	$ 6,484	$ 1,369	$ 8,378	$	$ 4,832	$	$ 21,063
Identifiable Assets: As at December 31, 2008	$ 81,126	$ 1,766	$ 64,901	$ 65,371	$ 105,587	$ 28,124	$ 346,875

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	Year Ended December 31, 2007				
	Oil and Gas Conventional		Business and Technology		
	Asia	U.S.	Development	Corporate	Total
Revenue					
Oil and gas revenue	$ 31,365	$	$	$	$ 31,365
Loss on derivative instruments	(4,993)				(4,993)
Interest income	58			259	317
	26,430			259	26,689
Expenses					
Operating costs	13,000				13,000
General and administrative	1,826			7,977	9,803
Business and technology development			9,625		9,625
Depletion and depreciation	19,222		1,412	6	20,640
Foreign exchange loss	216			85	301
Interest expense and financing costs	281		29	313	623
Provision for impairment of oil and gas properties	6,130				6,130
	40,675		11,066	8,381	60,122
Net loss from continuing operations	(14,245)		(11,066)	(8,122)	(33,433)
Net loss from discontinued operations		(5,774)			(5,774)
Net Loss and Comprehensive Loss	$ (14,245)	$ (5,774)	$ (11,066)	$ (8,122)	$ (39,207)
Capital Investments	$ 23,488	$	$ 5,097	$	$ 28,585

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12. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

The accounting classification of each category of financial instruments, and their carrying amounts, are set out below. Carrying amounts approximate fair value except for long term debt. After taking into account its own credit risk, the Company calculated the fair value of its long term debt to be $36.0 million as at December 31, 2009.

As at December 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	$	$	$ 21,512	$	$ 21,512
Accounts receivable	5,021				5,021
Note receivable	225				225
Restricted cash			2,850		2,850
Financial Liabilities:					
Accounts payable and accrued liabilities				(10,779)	(10,779)
Long term debt				(36,934)	(36,934)
Long term obligation				(1,900)	(1,900)
	$ 5,246	$	$ 24,362	$ (49,613)	$ (20,005)

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	$	$	$ 38,477	$	$ 38,477
Accounts receivable	3,802				3,802
Restricted cash			850		850
Derivative instruments			1,459		1,459
Financial Liabilities:					
Accounts payable and accrued liabilities				(9,219)	(9,219)
Long term debt				(38,267)	(38,267)
Long term obligation				(1,900)	(1,900)
	$ 3,802	$	$ 40,786	$ (49,386)	$ (4,798)

In accordance with CICA Handbook Section 3862, Financial Instruments Disclosures , the Company s financial assets and liabilities recorded at fair value have been categorized based on the following fair value hierarchy:

Level 1: unadjusted quoted prices in active markets for identical assets or liabilities;

Level 2: inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and

Level 3: inputs for the asset or liability that are not based on observable market date (unobservable inputs).

Cash and cash equivalents are considered Level 1 and restricted cash is considered Level 2. There were no significant transfers between Levels 1 and 2 and there were no gains or losses relating to cash and cash equivalents included in the statement of operations.

Financial Risk Factors

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

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Market Risk

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

Commodity Price Risks

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

The Company entered into 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 the WTI as the index traded on the NYMEX. The contracts related to the derivative above were put in place as part of the Company s bank loan facility and consequently all remaining contracts were settled when this loan was repaid in December 2009 (see Note 5).

Results of these derivative transactions for the three years ended December 31, 2009:

	2009	2008	2007
Realized gains (losses) on derivative transactions	$ 124	$ (4,430)	$ (334)
Unrealized gains (losses) on derivative transactions	(1,459)	6,118	(4,659)
	$ (1,335)	$ 1,688	$ (4,993)

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

As noted above, all remaining contracts were settled in December 2009 and consequently the Company had no open positions on the derivative assets referred to above at December 31, 2009.

Foreign Currency Exchange Rate Risk

Foreign currency risk refers to the risk that the value of a financial commitment, recognized asset or liability will fluctuate due to changes in foreign currency rates. The main underlying economic currency of the Company s cash flows is the U.S. dollar. This is because the Company s major product, crude oil, is priced internationally in U.S. dollars. Accordingly, the Company does not expect to face foreign exchange risks associated with its production revenues. However, some of the Company s cash flow stream relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. The majority of the operating costs incurred in the Chinese operations are paid in Chinese renminbi. The majority of costs incurred in the administrative offices in Vancouver and Calgary, as well as some business development costs, are paid in Canadian dollars. In addition, with the recent property acquisition in Alberta (see Note 18) the Company s Canadian dollar expenditures increased during the last half of 2008 and 2009 when compared to prior periods, along with an increase in cash and debt balances denominated in Canadian dollars. Disbursement transactions denominated in Chinese renminbi and Canadian dollars are converted to U.S. dollar equivalents based on the exchange rate as of the transaction date. Foreign currency gains and losses also come about when monetary assets and liabilities, mainly short term payables and receivables, denominated in foreign currencies are translated at the end of each month. The estimated impact of a 10% strengthening or weakening of the Chinese renminbi, and Canadian dollar, as of December 31, 2009 on net loss and accumulated deficit for the year ended December 31, 2009 is a $4.6 million increase, and a $4.4 million decrease, respectively. To help reduce the Company s exposure to foreign currency risk it seeks to maximize the expenditures and contracts denominated in U.S. dollars and minimize those denominated in other currencies, except for its Canadian activities where it attempts to hold cash denominated in Canadian dollars in order to manage its currency risk related to outstanding debt and current liabilities denominated in Canadian dollars.

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Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to the changes in market interest rates. Interest rate risk arises from interest bearing borrowings which have a variable interest rate. During 2009, the Company had a bank loan facility (as noted above, this loan was repaid in full in December 2009) and a convertible note with fluctuating interest rates. The Company estimates that its net loss and accumulated deficit for the year ended December 31, 2009 would have changed $0.2 million for every 1% change in interest rates as of December 31, 2009. The Company is not currently actively attempting to mitigate this interest rate risk given the limited amount and term of its borrowings and the current global interest rate environment.

Credit Risk

The Company is exposed to credit risk with respect to its cash held with financial institutions, accounts receivable, derivative contracts and advance balances. The Company believes its exposure to credit risk related to cash held with financial institutions is minimal due to the quality of the institutions where the cash is held and the nature of the deposit instruments. Most of the Company s accounts receivable balances relate to oil sales to foreign national petroleum companies and are exposed to typical industry credit risks. In addition, accounts receivable balances consist of costs billed to joint venture partners where the Company is the operator and advances to partners for joint operations where the Company is not the operator. The Company manages its credit risk by entering into sales contracts only with established entities and reviewing its exposure to individual entities on a regular basis.

All of the Company s revenues come from one customer and 80% 95% of the outstanding receivable balances as at December 31, 2009 and 2008, respectively, are due from this same customer.

As noted below, included in the Company s trade receivable balance are debtors with a carrying amount of nil as of the year ended December 31, 2009 which are past due at the reporting date for which the Company has not provided an allowance, as there has not been a significant change in credit quality and the amounts are still considered recoverable. The Company defines past due by the specific contract terms associated with each transaction (e.g. oil sales generally have a one - two month lag, joint venture billings generally are between 15 45 days). During the quarter ended September 30, 2008 the Company recorded an allowance associated with the advance balance for the entire outstanding amount of $0.7 million. This advance balance relates to an arrangement whereby scheduled advances were made to a third party contractor associated with negotiating an HTL™ and/or GTL project for the Company. In addition, the Company recorded an allowance for the entire outstanding amount of $0.2 million related to an amount owed to the Company by a two separate joint interest partners in the fourth quarter of 2009. These provisions were recorded in General and Administrative expense in the accompanying Statement of Operations and Comprehensive Loss. There were no other changes to the allowance for credit losses account during the three-month period ended December 31, 2009 and no other losses associated with credit risk were recorded during this same period.

	December 31, 2009	December 31, 2008
Accounts Receivable:		
Neither impaired nor past due	$ 5,004	$ 3,675
Impaired (net of valuation allowance)		
Not impaired and past due in the following periods:		
within 30 days		57
31 to 60 days		37
61 to 90 days		33
over 90 days	17	
	$ 5,021	$ 3,802

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

Liquidity Risk

Liquidity risk is the risk that suitable sources of funding for the Company s business activities may not be available, which means it may be forced to sell financial assets or non-financial assets, refinance existing debt, raise new debt or issue equity. The Company s present plans to generate sufficient resources to assure continuation of its operations and achieve its capital investment objectives include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt financing or the sale of equity securities. However, the availability of financing, in particular project funding, is dependent in part on our ability to fund our projects using the credit and equity markets. Despite the Company s recent successful financing efforts (see Note 20), the terms and availability of equity and debt capital, have been materially restricted and financing may not be available when it is required or on commercially acceptable terms.

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

	As at December 31, 2009 Contractual Maturity (Nominal Cash Flows)				As at December 31, 2008 Contractual Maturity (Nominal Cash Flows)			
	Less than 1 year	1 to 2 years	2 to 5 years	Over 5 years	Less than 1 year	1 to 2 years	2 to 5 years	Over 5 years
Non derivative financial liablities:								
Trade accounts payable	$ 3,767	$	$	$	$ 4,659	$	$	$
Accruals	$ 7,012	$	$	$	$ 4,560	$	$	$
Long term debt and interest	$ 2,305	$ 38,164	$	$	$ 3,483	$ 9,432	$ 33,495	$

13. 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. However, the availability of financing, in particular project funding, is dependent in part on our ability to fund our projects using the credit and equity markets. Despite the Company s recent successful financing efforts (see Note 20), future financing may not be available when it required or on commercially acceptable terms.

The Company defines capital as total equity or deficiency plus cash and cash equivalents and long term debt. Total equity is comprised of share capital, purchase warrants, convertible note, contributed surplus, shares to be issued and accumulated deficit as disclosed in Note 8. Cash and cash equivalents are $21.5 million and $38.5 million at December 31, 2009 and December 31, 2008 and 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. Long term debt is disclosed in Note 5.

The Company s management reviews the capital structure on a regular basis to maintain the most optimal debt to equity balance. In order to maintain or adjust its capital structure, the Company may refinance its existing debt, raise new debt, seek cost sharing arrangements with partners or issue new shares.

In 2008, the Company expensed $2.6 million of deferred financing costs that were directly attributable to a proposed offering of securities for its wholly-owned Chinese subsidiary.

The Company s Chinese oil and gas subsidiary was subject to financial covenants, such as interest coverage ratios, under each of their revolving/term credit facilities which are measured on a quarterly or semi-annual basis. As noted in Note 5, the Company repaid the outstanding balance of this loan in December 2009. The Company was in compliance with all financial covenants for the year ended December 31, 2009.

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14. INCOME TAXES

The Company and its subsidiaries are required to individually file tax returns in each of the jurisdictions in which they operate. The provision for income taxes differs from the amount computed by applying the statutory income tax rate to the net losses before income taxes. The combined Canadian federal and provincial statutory rates as at December 31, 2009, 2008 and 2007 were 29.0%, 29.5% and 32.12%, respectively. The sources and tax effects for the differences were as follows:

	Year ended December 31, 2009	2008	2007
Tax benefit computed at the combined Canadian federal and provincial statutory income tax rates	$ (13,217)	$ (11,158)	$ (10,739)
Foreign net losses affected at lower income tax rates	106	4,562	1,456
Effect of change in foreign exchange rates	(2,858)	3,006	(2,878)
Expiry of tax loss carry-forwards	911	2,875	2,440
Tax credit carry-forward	(350)		
Compensation not deductible	1,456	753	844
Financing costs not deductible		695	
Net currency exchange losses not deductible	1,501	402	
Change in prior year estimate of tax loss carry-forwards	3,941	(59)	422
Realized derivative (gains)/losses not taxable/deductible	334	(422)	
Effect of change in effective income tax rates on future tax assets	(4,453)	(331)	6,109
Other permanent differences	32	(127)	991
	(12,597)	196	(1,355)
Change in valuation allowance	4,754	458	1,355
Provision for (recovery of) income taxes	$ (7,843)	$ 654	$

Significant components of the Company s future net income tax assets and liabilities were as follows:

	As at December 31, 2009 Future Income Tax Assets	2009 Future Income Tax Liabilities	2008 Future Income Tax Assets	2008 Future Income Tax Liabilities
Oil and gas properties and investments	$ 471	$ (1,124)	$ 4,285	$ (1,582)
Intangibles		(30,354)		(37,089)
Tax loss carry-forwards	37,583		29,602	
Tax credit carry-forward	350			
Valuation allowance	(29,570)		(24,816)	
	$ 8,834	$ (31,478)	$ 9,071	$ (38,671)

The tax loss carry-forwards in Canada are Cdn.$72.0 million, in China $37.2 million and in the U.S. $34.3 million. Tax loss carry-forwards in Ecuador are nominal. The tax loss carry-forwards in Canada expire between 2010 and 2029 and in the U.S. between 2015 and 2029. In China, the tax loss carry-forwards have no expiration period. A loss of approximately Cdn.$55.3 million from the disposition of Russian operations in 2000, being the aggregate investment, not including accounting write-downs, less proceeds received on settlement is a capital loss for Canadian income tax purposes, available for carry-forward against future Canadian capital gains indefinitely and is not included in the future income tax assets above.

The amount of current income tax payable at December 31, 2009 associated with income taxes for China equaled $0.2 million and the amount associated with income taxes for the U.S. equaled $0.3 million.

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 revised its 2008 current tax payable in China to $1.6 million from the $0.6 million that was recorded in 2008. The $1.6 million tax payable was subsequently paid in May 2009.

Prior to the Company selling its U.S. operating segment in July 2009, as further described in Note 19, the Company had future tax assets arising from net operating losses carry-forwards generated by this business segment. These future income tax assets were partially offset by certain future income tax liabilities in the U.S. and by a valuation allowance. As at June 30, 2009, as a result of the sale of the business segment, the Company was no longer able to offset these tax assets and liabilities but was required to present these future income tax assets as assets from discontinued operations and a future income tax liability both in the amount of $29.6 million in the accompanying balance sheet. The future income tax assets classified as Assets from discontinued operations were ultimately included in the $23.4 million loss on disposition as described in Note 19. Revisions were made to the future income tax liability during the third quarter of 2009 based on revised projections of taxable income and utilization of net operating loss carryforwards. As at December 31, 2009, the Company s future income tax liability is $22.6 million in the accompanying balance sheet, $20.0 million for the U.S. tax jurisdiction and $2.6 million related to the assets acquired in Mongolia (see Note 18).

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15. NET LOSS PER SHARE

Had the Company generated net earnings during the years presented, the earnings per share calculations for the years presented would have included the following weighted average items:

	Year ended December 31,		
	2008	2007	2006
	(thousands of shares)		
Stock options	289	1,374	2,433
Purchase warrants	409		
Convertible debt	13,166	6,943	
	13,864	8,317	2,433

Additionally, the earnings per share calculations would have included the following weighted average items had the exercise prices exceeded the average market prices of the common shares:

	Year ended December 31,		
	2008	2007	2006
	(thousands of shares)		
Stock options	10,908	9,944	8,616
Purchase warrants	16,444	16,399	28,898
	27,352	26,343	37,514

16. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information for each of the years ended December 31 was as follows:

	Year Ended December 31,		
	2009	2008	2007
Cash paid during the period for			
Income taxes	$ 1,876	$ 5	$ 6
Interest	$ 2,122	$ 1,120	$ 238
Investing and Financing activities, non-cash			
Acquisition of business/assets *(see note 18)*			
Shares issued	$ 6,899	$	$
Warrants issued	622		
Debt issued		52,052	
	$ 7,521	$ 52,052	$
Conversion of debt to shares			
Extinguishment of debt	$	$ 4,737	$
Extinguishment of interest		125	
	$	$ 4,862	$

Shares issued for bonuses and services	$	207	$	490	$	793
Stock based compensation capitalized	$		$	175	$	

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	Year Ended December 31, 2009	2008	2007
Changes in non-cash working capital items			
Operating Activities			
Accounts receivable	$ (1,253)	$ 3,509	$ (1,281)
Note receivable	(225)		
Prepaid and other current assets	(175)	(48)	69
Accounts payable and accrued liabilities	1,314	1,905	852
Income tax payable	(120)	650	
	(459)	6,016	(360)
Investing Activities			
Accounts receivable	(140)	7	(250)
Prepaid and other current assets	41	(70)	86
Accounts payable and accrued liabilities	163	(972)	(1,119)
	64	(1,035)	(1,283)
Financing Activities			
Accounts payable and accrued liabilities	(26)	26	
	$ (421)	$ 5,007	$ (1,643)

Cash and cash equivalents at December 31, 2009, and 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.

17. RELATED PARTY TRANSACTIONS

The Company has entered into agreements with a number of entities which are related or controlled through common directors or shareholders. These entities provide access to an aircraft, the services of administrative and technical personnel, and office space or facilities in Vancouver, London and Singapore. The Company is billed on a cost recovery basis in most cases. For the year ended December 31, 2009 the costs incurred in the normal course of business with respect to the above arrangements amounted to $3.8 million ($3.0 million for 2008 and $3.3 million for 2007), and have been measured at their exchange amount and are recorded in general and administrative and business and technology expense in the statement of operations. As at December 31, 2009 amounts included in accounts payable and accrued liabilities on the balance sheet under these arrangements were $0.1 million ($0.1 million at December 31, 2008).

18. ACQUISTION AND PROJECT RELATED AGREEMENTS

Mongolia

In November 2009, the Company completed the acquisition of PanAsian Petroleum Inc. (**PPI**) which provides it with the exclusive right to explore, develop and produce oil or gas within Block XVI in Mongolia s Nyalga Basin. This transaction with PPI resulted in the Company issuing 2,683,291 common shares in exchange for all of the issued and outstanding common shares of PPI. In addition, existing purchase warrants in PPI were converted to 735,449 Ivanhoe purchase warrants that entitle the holders to purchase Ivanhoe s common shares at Cdn.$4.05 per share with an expiry in February 2011.

The consideration for this acquisition and net assets acquired are summarized as follows:

Purchase Consideration:

2,683,291 shares of Ivanhoe at Cdn.$2.70 per share[(1)]	$	6,899
735,449 warrants to purchase Ivanhoe shares[(2)]		622
	$	7,521
Net Assets Acquired:		
Cash	$	29
Non-cash working capital, net		(606)
Oil and gas properties unproved		10,742
Future income tax liability		(2,644)
	$	7,521

(1) The Cdn.$2.70 was the closing share price on the TSX on November 26, 2009, the date of acquisition.

(2) See Note 8.

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Canada

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. The total purchase price was Cdn.$90.0 million, of which an initial payment of Cdn.$22.5 million was made on closing. In addition to this initial payment the Company issued a promissory note to Talisman in the principal amount of Cdn.$12.5 million bearing interest at a rate per year equal to the prime rate plus 2% which matured and was paid on December 31, 2008 and a second promissory note to Talisman in the principal amount of Cdn.$40.0 million bearing interest at a rate per annum equal to the prime rate plus 2%, maturing in July 2011 and convertible (as to the outstanding principal amount), at Talisman s option, into a maximum of 12,779,552 common shares of the Company at Cdn.$3.13 per common share.

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 December 31, 2008 as the chance of occurrence can not be determined at this time.

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

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

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

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

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

Ecuador

In October 2008, Ivanhoe Energy Ecuador Inc. (**IE Ecuador**) entered into a contract with Empresa Estatal de Petroleos del Ecuador, Petroecuador (**Petroecuador**), the state oil company of Ecuador, and its affiliate, Empresa Estatal de Exploracion y Produccion de Petroleos del Ecuador, Petroproduccion (**Petroproduccion**) to explore and develop an exploration block in Ecuador that includes the Pungarayacu heavy-oil field, utilizing the Company s HTL^{TM} technology. IE Ecuador is a wholly-owned subsidiary of Ivanhoe Energy Latin America Inc. (**IE Latin America**), a wholly-owned subsidiary of the Company.

IE Ecuador will lead the development of the project. The contract is guaranteed by its parent company IE Latin America, which will obtain or provide funding and financing for IE Ecuador s operations under the contract. The contract s 30-year term may be extended by mutual agreement. To recover its investments, costs and expenses, and to provide for a profit, IE Ecuador will receive from Petroproduccion a payment of US$37.00 per barrel of oil produced and delivered to Petroproduccion. The payment will be indexed (adjusted) quarterly for inflation, starting from the contract date, using the weighted average of a basket of three US Government-published producer price indices relating to steel products, refinery products and upstream oil and gas equipment.

19. DISCONTINUED OPERATIONS

In June of 2009, management commenced a process to sell all of the Company s United States oil and gas exploration and production operations. On July 17, 2009, the Company completed the sale of its wholly owned subsidiary Ivanhoe Energy (USA) Inc. for a purchase price of $39.2 million. The purchaser acquired all of the Company s oil and gas exploration and production operations in California and Texas and additional exploration acreage in California. An escrow deposit in the amount of $2.0 million, which has been set aside from the sales proceeds, will be available to the purchaser for a period of one year to satisfy any indemnification obligations of the Company. The Company used approximately $5.2 million of the sales proceeds to repay an outstanding loan to a third party financial institution holding a security interest in the subsidiary company s assets.

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The operating results for this discontinued operation for the periods noted were as follows:

	Year Ended December 31,		
	2009	2008	2007
Revenue			
Oil and gas revenue	$ 5,455	$ 18,120	$ 12,270
Gain (loss) on derivative instruments	189	278	(5,594)
Interest income	8	98	152
	5,652	18,496	6,828
Expenses			
Operating costs	2,132	5,137	4,319
General and administrative	139	2,413	1,972
Depletion and depreciation	3,772	6,143	5,884
Interest expense and financing costs	173	520	427
	6,216	14,213	12,602
Income (Loss) before disposition	(564)	4,283	(5,774)
Loss on disposition (net of tax of $29.6 million for 2009, nil for 2008 and 2007)	(23,357)		
Net Income (Loss) from discontinued operations	$ (23,921)	$ 4,283	$ (5,774)

The carrying amounts of the major classes of assets and liabilities for this discontinued operation were as follows:

	December 31, 2008
Assets	
Current Assets:	
Cash and cash equivalents	$ 788
Accounts receivable	1,067
Prepaid and other current assets	172
Derivative instruments	700
	2,727
Oil and gas properties and equipment, net	32,577
Future income tax assets	29,600
Long term assets	467
	$ 65,371

Liabilities		
Current Liabilities:		
Accounts payable and accrued liabilities	$	874
Debt current portion		5,200
Derivative instruments		
		6,074
Asset retirement obligations		1,810
	$	7,884

In conjunction with this asset disposition and the Company s focus on Calgary, Alberta, as a key management center supporting business units within the Ivanhoe Energy group of companies the Company decided to close its support office in Bakersfield. Total costs associated with this closure, including severance and retention payments, are expected to be $0.4 million with nil accrued as of December 31, 2009 and included in the accompanying operations.

20. SUBSEQUENT EVENT

In January 2010, the Company completed a Cdn.$125.0 million private placement (the **Private Placement**) consisting of 41,666,667 special warrants (the **Special Warrants**) at Cdn.$3.00. Each Special Warrant was converted into one common share of the Company and one quarter of a share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred on February 10, 2010. Each whole share purchase warrant entitles the holder to acquire one common share of the Company at an exercise price of Cdn.$3.16 on or before January 26, 2011. The net proceeds from the Private Placement were approximately Cdn.$120.2 million after deducting fees and commissions of Cdn.$4.3 million and the expenses of the Private Placement of approximately Cdn.$0.5 million.

Under the terms of the Private Placement, an additional 8,333,333 Special Warrants issuable at Cdn.$3.00 per Special Warrant were subject to an option, which was exercised in February 2010. The net proceeds realized by the Company from the issue of the Special Warrants under option totaled approximately Cdn.$24.3 million after deducting fees and commissions payable of Cdn.$0.63 million and the expenses of approximately Cdn.$0.1 million. Each Special Warrant under option was converted into one common share and one quarter of a share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred on March 12, 2010.

In January 2010, the Company s wholly-owned subsidiaries, Sunwing Holding Corporation (**Holdings**) and Sunwing Energy Ltd. (**Sunwing**), entered into an agreement with a third party (the **Optionee**) whereby Sunwing granted to the Optionee a contingent option exercisable until January 2012 (the **Contingent Option**) to make an equity investment in Sunwing. Upon exercise of the Contingent Option, the Optionee would acquire an equity interest in Sunwing of approximately 15% at a price of Cdn.$25 million. Unless accelerated upon the occurrence of certain events (including a sale or change of control of Sunwing or an initial public offering of Sunwing securities), the Contingent Option only becomes exercisable in January 2011. If, prior to the Contingent Option having become exercisable, the Optionee exercises any share purchase warrants it holds to acquire common shares of the Company, the Contingent Option will immediately terminate.

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21. ADDITIONAL DISCLOSURES REQUIRED UNDER U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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:

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 December 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	$ 21,512	$		$ 21,512	$ 38,477	$		$ 38,477
Accounts receivable	5,021			5,021	3,802			3,802
Note receivable	225			225				
Prepaid and other current assets	771			771	637			637
Restricted cash	2,850			2,850	850			850
Derivative instruments					1,459			1,459
Assets of discontinued operations					2,727			2,727
Total Current Assets	30,379			30,379	47,952			47,952
Oil and gas properties and development costs, net	158,392	(38,500)	(i)	139,346	143,974	(38,500)	(i)	114,385
		20,315	(ii)			9,929	(ii)	
			(iii)			(1,018)	(iii)	
		(861)	(iv)					
Intangible assets technology	92,153			92,153	92,153			92,153
Long term assets	839			839	152	451	(v)	603
Assets of discontinued operations					62,644	(24,890)	(xii)	37,754
Total Assets	$ 281,763	$ (19,046)		$ 262,717	$ 346,875	$ (54,028)		$ 292,847

Liabilities and Shareholders Equity								
Current Liabilities:								
Accounts payable and accrued liabilities	$ 10,779	$		$ 10,779	$ 9,219	$		$ 9,219
Income tax payable	530			530	650			650
Debt current portion					412			412
Derivative instruments		8,249	(viii)	8,249		1,121	(viii)	1,121
Asset retirement obligation current portion	753			753				
Liabilities of discontinued operations current portion					6,074			6,074
Total Current Liabilities	12,062	8,249		20,311	16,355	1,121		17,476
Long term debt	36,934	1,225	(iv)	38,005	37,855	2,086	(iv)	40,392
		(154)	(iv)			451	(v)	
Asset retirement obligations	195			195	1,928			1,928
Long term obligation	1,900			1,900	1,900			1,900
Future income tax liability	22,643			22,643	29,600			29,600
Liabilities of discontinued operations					1,810			1,810
Total Liabilities	73,734	9,320		83,054	89,448	3,658		93,106
Shareholders Equity:								
Share capital	422,322	74,455	(vi)	510,784	413,857	74,455	(vi)	502,372
		(551)	(vii)			(498)	(vii)	
		1,358	(ix)			1,358	(ix)	
		13,200	(viii)			13,200	(viii)	
Purchase warrants	19,427	(19,427)	(viii)		18,805	(18,805)	(viii)	
Contributed surplus	20,029	(3,197)	(vii)	13,885	16,862	(3,250)	(vii)	10,665
		(2,947)	(viii)			(2,947)	(viii)	
Convertible note	2,086	(2,086)	(iv)		2,086	(2,086)	(iv)	

Accumulated deficit	(255,835)	(89,171)		(345,006)	(194,183)	(119,113)	(313,296)
Total Shareholders Equity	208,029	(28,366)		179,663	257,427	(57,686)	199,741
Total Liabilities and Shareholders Equity	$ 281,763	$ (19,046)		$ 262,717	$ 346,875	$ (54,028)	$ 292,847

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Oil and Gas Properties and Development Costs

(i) There are certain differences between the full cost method of accounting for oil and gas properties as applied in Canada and as applied in the U.S. The principal difference is in the method of performing ceiling test evaluations under the full cost method of accounting rules. In the ceiling test evaluation for U.S. GAAP purposes, the Company limits, on a country by country basis, the capitalized costs of oil and gas properties, net of accumulated depletion, depreciation and amortization and deferred income taxes, to (a) The present value of estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of ten percent and assuming continuation of existing economic conditions; plus (b) the cost of properties not being amortized (e.g. major development projects) and (c) the lower of cost or fair value of unproven 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 unamortized capitalized costs within a cost center exceed this limit, the excess is charged as a provision for impairment in the statement of operations. Amounts thus required to be written off shall not be reinstated for any subsequent increase in the cost center ceiling. 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 year ended December 31, 2009 no impairment provision was required and no impairment provision was required under Canadian GAAP.

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

(iii) As more fully described under Development Costs in Note 2, under Canadian GAAP, the Company capitalizes certain development costs incurred for HTL™ and GTL projects subsequent to executing a MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the project s products. If no definitive agreement is reached, then the project s capitalized costs, which are deemed to have no future value, are written down and charged to the results of operations with a corresponding reduction in HTL™ and GTL development costs. Under U.S. GAAP, feasibility, marketing and related costs incurred prior to executing an HTL™ or GTL definitive agreement are considered to be research and development and are expensed as incurred.

(iv) As described in Note 5, under Canadian GAAP the Company was required to bifurcate the value of the Convertible Debt, 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 $1.2 million and the accreted discount that was capitalized in the amount of $0.9 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 $0.2 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 Foreign Exchange Loss line item in the U.S. GAAP reconciliation of the statement of operations below.

Deferred Financing Costs

(v) As more fully described under Financial Assets and Liabilities in Note 2, for Canadian GAAP the Company accounts for deferred financing costs, or transaction costs, as a reduction from the related liability and accounted for using the effective interest method. For U.S. GAAP purposes, these costs are classified as other assets and amortized over the expected term of the financial liability.

Shareholders Equity

(vi) 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.

(vii) 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 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 FASB s Accounting Standards Codification Manual (**ASC**) Topic 718 Stock Compensation (formerly Statement of Financial Accounting Standards (**SFAS**) No. 123R) which supersedes APB No. 25, Accounting for Stock Issued to Employees . The Company elected to implement this statement on a modified prospective basis 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 subsequent to January 1, 2006.

(viii) The Company accounts for purchase warrants as equity under Canadian GAAP. The accounting treatment of warrants under U.S. GAAP reflects the application of ASC Topic 815 Derivatives and Hedging (formerly SFAS No. 133). Under ASC Topic 815,, 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.

(ix) Under U.S. GAAP, the aggregate value attributed to the acquisition of 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.

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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:

	Year Ended December 31, 2009			
	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP
Revenue				
Oil revenue	$ 24,968	$		$ 24,968
Loss on derivative instruments	(1,335)	(6,506)	(viii)	(7,841)
Interest income	25			25
Total Revenue	23,658	(6,506)		17,152
Expenses				
Operating costs	10,191			10,191
General and administrative	21,693			21,693
Business and technology development	9,501	150	(x)	9,651
Depletion and depreciation	19,868	(10,574)	(xi)	9,294
Foreign exchange loss	5,220	(154)	(iv)	5,066
Interest expense and financing costs	856			856
Provision for impairment of intangible asset and development costs	1,903	(980)	(x)	923
Total Expenses	69,232	(11,558)		57,674
Loss from continuing operations before income taxes	(45,574)	5,052		(40,522)
(Provision for) recovery of income taxes				
Current	(1,757)			(1,757)
Future	9,600			9,600
	7,843			7,843
Net loss from continuing operations	(37,731)	5,052		(32,679)
Net income (loss) from discontinued operations (net of tax of $29.6 million)	(23,921)	24,890	(xii)	969
Net Loss and Comprehensive Loss	(61,652)	29,942		(31,710)
Net income (loss) per share				
Net Loss from continuing operations, basic and diluted	**$ (0.13)**	**$ 0.01**		**$ (0.12)**
	(0.09)	**0.10**		**0.01**

Net Income (loss) from discontinued operations, basic and diluted						
Net Loss per share, basic and diluted	**$**	**(0.22)**	**$**	**0.11**	**$**	**(0.11)**
Weighted Average Number of shares (in thousands)						
Basic and Diluted		279,722				279,722

	Year Ended December 31, 2008			
	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP
Revenue				
Oil revenue	$ 48,370	$		$ 48,370
Gain on derivative instruments	1,688	4,665	(viii)	6,353
Interest income	612			612
Total Revenue	50,669	4,665		55,335
Expenses				
Operating costs	21,515			21,515
General and administrative	14,252			14,252
Business and technology development	6,453			6,453
Depletion and depreciation	25,761	(2,820)	(xi)	22,941
Foreign exchange loss	1,527			1,527
Interest expense and financing costs	1,309			1,309
Provision for impairment of intangible asset and development costs	15,054	(4,640)	(x)	10,414
Write off of deferred financing costs	2,621			2,621
Provision for impairment of oil and gas properties		21,560	(ix)	21,560
Total Expenses	88,492	14,100		102,592
Loss from continuing operations before income taxes	(37,822)	(9,435)		(47,257)
Current recovery of income taxes	(654)			(654)
Net loss from continuing operations	(38,476)	(9,435)		(47,911)
Net income (loss) from discontinued operations	4,283	(19,423)	(xii)	(15,140)
Net Loss and Comprehensive Loss	(34,193)	(28,858)		(63,051)
Net income (loss) per share				
Net Loss from continuing operations, basic and diluted	$ **(0.15)**	$ **(0.04)**		$ **(0.19)**
Net Income (loss) from discontinued operations, basic and diluted	**0.02**	**(0.07)**		**(0.05)**
Net Loss per share, basic and diluted	$ **(0.13)**	$ **(0.11)**		$ **(0.24)**

Weighted Average Number of shares (in thousands)		
Basic and Diluted	258,815	258,815

	Year Ended December 31, 2007						
		Canadian GAAP		Increase (Decrease)	Notes		U.S. GAAP
Revenue							
Oil revenue	$	31,365	$			$	31,365
Loss on derivative instruments		(4,993)		592	(iii)		(4,401)
Interest income		317					317
Total Revenue		26,689		592			27,281
Expenses							
Operating costs		13,000					13,000
General and administrative		9,803					9,803
Business and technology development		9,625					9,625
Depletion and depreciation		20,640		(3,470)	(ix)		17,170
Foreign exchange loss		301					301
Interest expense and financing costs		623					623
Provision for impairment of intangible asset and development costs				(6,011)	(x)		(6,011)
Provision for impairment of oil and gas properties		6,130		(280)	(ix)		5,850
Total Expenses		60,122		(9,761)			50,361
Net loss from continuing operations		(33,433)		10,353			(23,080)
Net income (loss) from discontinued operations		(5,774)		1,462			(4,312)
Net Loss and Comprehensive Loss		(39,207)		11,815			(27,392)
Net income (loss) per share							
Net Loss from continuing operations, basic and diluted	**$**	**(0.14)**	**$**	**0.04**		**$**	**(0.10)**
Net Income (loss) from discontinued operations, basic and diluted		**(0.02)**		**0.01**			**(0.01)**
Net Loss per share, basic and diluted	**$**	**(0.16)**	**$**	**0.05**		**$**	**(0.11)**
Weighted Average Number of shares (in thousands)							
Basic and Diluted		242,362					242,362

Development Costs

(x) As more fully described under Oil and Gas Properties and Development Costs in this note, for Canadian GAAP, feasibility, marketing and related costs incurred prior to executing a HTL™ or GTL definitive agreement are capitalized and are subsequently written down upon determination that a project s future value has been impaired. For U.S. GAAP, such costs are considered to be research and development and are expensed as incurred.

As more fully described under Note 3, the Company and INPEX have signed an agreement to jointly pursue the opportunity to develop a heavy oil field in Iraq that Ivanhoe believes is a suitable candidate for its patented HTL™ heavy oil upgrading technology. In the second quarter of 2007, the Company received a $9.0 million payment related to this agreement which was credited to the carrying value of its Iraq and CDF HTL™ Investments related to this project for Canadian GAAP purposes. The prior costs for Iraq projects had previously been expensed for U.S. GAAP purposes therefore that portion of the proceeds, $6.3 million, was credited to the statement of operations for U.S. GAAP purposes. For the year ended December 31, 2009 the Company recorded nil (nil in 2008 and $6.3 million in 2007) as a reduction to net loss for U.S. GAAP when compared to Canadian GAAP due to the recovery of prior costs expensed for U.S. GAAP and capitalized for Canadian GAAP.

As more fully described under Note 3, the Company wrote off $5.1 million in GTL development costs under Canadian GAAP. These costs had already been expensed under U.S. GAAP in previous periods and therefore this transaction reduced the net loss for U.S. GAAP purposes in 2008.

Depletion and Depreciation

(xi) 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 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 losses for the years ended December 31, 2009, 2008 and 2007.

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Discontinued Operations

(xii) As at December 31, 2008, the $24.9 million adjustment related to discontinued operations included a $1.4 million increase that is attributed to the acquisition of royalty rights during 2000 and 1999 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, Additionally, there was a $3.1 million increase due to depletion differences as more fully described in note (ii). These increases were offset by $29.4 million decrease due to impairment differences as more fully described in note (i).

These accumulated balance sheet adjustments were charged off as part of the gain/loss calculation at the time of sale and flow through the statement of operations for the year ended December 31, 2009 in the Net Loss from Discontinued Operations line item.

Consolidated Statements of Cash Flows

As a result of the expensing of HTL™ and GTL development costs as required under U.S. GAAP and the recovery of such costs, the statement of cash flows as reported would result in cash (deficit) surplus from operating activities of $(12.4 million), $16.6 million and $11.5 million for the years ended December 31, 2009, 2008 and 2007. Additionally, capital investments reported under investing activities would be $26.2 million, $20.7 million and $28.3 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Additional U.S. GAAP Disclosures

Oil and Gas Properties and Development Costs

The categories of costs included in Oil and Gas Properties and Development Costs , including the U.S. GAAP adjustments discussed in this note were as follows:

	As at December 31, 2009					
	Canada	Ecuador	Asia	Corporate	Business and Technology Development	Total
Property acquisition costs	$ 77,093	$ 852	$ 42,298	$	$	$ 120,243
Capitalized Interest	3,049					3,049
Exploration costs	6,437	2,988	32,831			42,256
Development costs			87,100			87,100
Production facilities		2,483				2,483
HTL™ facilities	6,991				10,868	17,859
Support equipment and general property	24	601	427	968	22	2,042
	93,594	6,924	162,656	968	10,890	275,032
Accumulated depletion and depreciation	(8)	(53)	(79,521)	(650)	(404)	(80,636)
Provision for impairment			(55,050)			(55,050)
	$ 93,586	$ 6,871	$ 28,085	$ 318	$ 10,486	$ 139,346

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	As at December 31, 2008					
	Canada	Ecuador	China	Corporate	Business and Technology Development	Total
Property acquisition costs	$ 75,732	$ 863	$ 31,137	$	$	$ 107,732
Capitalized Interest	1,672					1,672
Exploration costs	3,686	591	31,575			35,852
Development costs			83,315			83,315
HTL™ facilities					19,590	19,590
Support equipment and general property	20	90	412	13	406	941
	81,110	1,544	146,439	13	19,996	249,102
Accumulated depletion and depreciation	(6)		(72,030)	(6)	(7,628)	(79,670)
Provision for impairment			(55,050)			(55,050)
	$ 81,104	$ 1,544	$ 19,359	$ 7	$ 12,368	$ 114,382

As at December 31, 2009, the costs of unproved properties included in oil and gas properties, which have been excluded from the depletion and ceiling test calculations, were as follows:

		Incurred in			
	Total	2009	2008	2007	Prior to 2007
Property Acquisition	$ 89,206	$ 11,920	$ 77,187	$	$ 99
Exploration	25,530	17,655	6,325	129	1,421
	$ 114,736	$ 29,575	$ 83,512	$ 129	$ 1,520

The following is a summary of unproved oil and gas properties by prospect as at December 31, 2009:

		Incurred in			
	Total	2009	2008	2007	Prior to 2007
Canada					
Tamarack	$ 93,570	$ 12,480	$ 81,090	$	$
Ecuador					
Block 20	6,755	5,301	1,454		
Asia					
Zitong Block	3,249	632	968	129	1,520
Nyalga Block	11,162	11,162			

	14,411	11,794	968	129	1,520
	$ 114,736	$ 29,575	$ 83,512	$ 129	$ 1,520

With regard to the Tamarack Project in Canada, the Company plans to continue on the path for submitting a regulatory application, for the first phase of development, in the 3rd quarter of 2010.

With regard to Block 20 in Ecuador, the Company began drilling the first well in the appraisal phase at the end of 2009 and will be evaluating the results through the end of the first quarter of 2010. Additional wells are planned for the first and second quarter of 2010.

With regard to the Zitong Block prospect, drilling at two locations is planned to commence in the second quarter of 2010 with expected completed drilling, completion and evaluation of the prospects finalized in late 2010, which would satisfy the Phase II exploration.

With regard to the Nyalga Block prospect, the Company plans to initiate a seismic program in the first quarter of 2010 and complete a drilling and testing program by the end of 2012, which would satisfy the exploration phase.

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Accounts Payable and Accrued Liabilities

The following was the breakdown of accounts payable and accrued liabilities:

	As at December 31, 2009	2008
Trade payables	$ 3,767	$ 4,659
Accrued general and administrative expenses	784	1,112
Accrued operating expenses	515	394
Accrued capital expenditures	2,820	1,896
Accrued salaries and related expenses	2,123	148
Accrued interest	770	1,010
	$ 10,779	$ 9,219

Accounting Standards Codification 820 Fair Value Measurements and Disclosures (**ASC 820**) 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: Input values based on unadjusted quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2: Input values based on other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.

Level 3: Input values are unobservable inputs for the asset or liability.

As required by ASC 820 10 35 37, 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 December 31, 2009.

	As at December 31, 2009			
	Level 1	Level 2	Level 3	Total
Derivative instruments liabilities	$ 7,582	$	$ 667	$ 8,249

The fair value measurement of derivative instruments liabilities related to its purchase warrants denominated in Cdn.$ that are traded on the TSX are considered Level 1, while the fair value measurement of derivative instruments liabilities related to its purchase warrants denominated in Cdn.$ that are not traded on the TSX are considered Level 3.

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

In June 2009, the FASB issued guidance now codified as ASC Topic 105, Generally Accepted Accounting Principles, as the single source of authoritative nongovernmental U.S. GAAP. ASC Topic 105 does not change current U.S. GAAP, but is intended to simplify user access to all authoritative U.S. GAAP by providing all authoritative literature related to a particular topic in one place. All existing accounting standard documents will be superseded and all other accounting literature not included in the FASB Codification will be considered non authoritative. These provisions of ASC Topic 105 are effective for interim and annual periods ending after September 15, 2009 and, accordingly, are effective for our current fiscal reporting period. The adoption of this pronouncement did not have an impact on the Company s financial position or results of operations, but did impact our financial reporting process by eliminating all references to pre codification standards. On the effective date of this Statement, the Codification superseded all then existing non SEC accounting and reporting standards, and all other non grandfathered non SEC accounting literature not included in the Codification became non authoritative.

As a result of the Company s implementation of this codification during 2009, previous references to new accounting standards and literature are no longer applicable. In these annual financial statements, the Company has provided reference to both new and old guidance to assist in understanding the impacts of recently adopted accounting literature, particularly for guidance adopted since the beginning of the current fiscal year but prior to the ASC.

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Also in June 2009, the FASB issued guidance for Amendments to FAS 46R in ASC Topic 810 (formerly SFAS No. 167) of the Codification, which improves financial reporting by enterprises involved with variable interest entities. The amendments replace the quantitative based risks and rewards calculation for determining which enterprise, if any, has a controlling financial interest in a variable interest entity with an approach focused on identifying which entity has the power to direct the activities of a variable interest entity that most significantly impact the entity s economic performance and: (1) the obligation to absorb losses of the entity; or, (2) the right to receive benefits from the entity. The amendments are effective as of the beginning of the first annual reporting period that begins after November 15, 2009, and shall be applied prospectively. The Company is currently reviewing the potential impact, if any, this guidance will have on the consolidated financial statements upon adoption.

Also in June 2009, the FASB issued guidance for Accounting for Transfers of Financial Assets, an Amendment to FAS 140 in ASC Topic 860 (formerly SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities a replacement of FASB Statement No. 125,* as amended by SFAS No. 166, *Accounting for Transfers of Financial Assets An Amendment of FASB Statement No. 140*) of the Codification, which is effective for fiscal years beginning after November 15, 2009, which amends prior principles to require more disclosure about transfers of financial assets and the continuing exposure, retained by the transferor, to the risks related to transferred financial assets, including securitization transactions. It eliminates the concept of a qualifying special purpose entity, changes the requirements for derecognizing financial assets, and requires additional disclosures. It also enhances information reported to users of financial statements by providing greater transparency about transfers of financial assets and an entity s continuing involvement in transferred financial assets. The Company is currently reviewing the potential impact, if any, this guidance will have on the Company s consolidated financial statements upon adoption.

In May 2009, the FASB issued guidance in the ASC Topic 855 Subsequent Events (formerly SFAS No. 165) of the Codification, which establishes the accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. The guidance was effective for interim or annual periods ending after June 15, 2009. The adoption of this guidance did not have a material impact on the Company s consolidated financial statements. In February 2010, the issued Accounting Standards Update No. 2010 09 Subsequent Events (Topic 855) Amendments to Certain Recognition and Disclosure Requirements which provides amendments to Subtopic 855 10 to alleviate potential conflicts between Subtopic 855 10 and the SEC s requirements with regard to subsequent event disclosures. An entity that is an SEC filer is required to evaluate subsequent events through the date that the financial statements are issued and is not required to disclose the date through which subsequent events have evaluated.

In April 2009, the FASB issued guidance in the ASC Topic 820 Fair Value Measurements and Disclosures (formerly FASB Staff Position (**FSP**) FAS 157 4) of the Codification on determining fair value when the volume and level of activity for an asset or liability have significantly decreased and identifying transactions that are not orderly. The guidance emphasizes that even if there has been a significant decrease in the volume and level of activity, the objective of a fair value measurement remains the same. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction (that is, not a forced liquidation or distressed sale) between market participants. The guidance provides a number of factors to consider when evaluating whether there has been a significant decrease in the volume and level of activity for an asset or liability in relation to normal market activity. In addition, when transactions or quoted prices are not considered orderly, adjustments to those prices based on the weight of available information may be needed to determine the appropriate fair value. The guidance was effective for interim or annual reporting periods ending after June 15, 2009, and shall be applied prospectively. The implementation of this guidance did not have a material impact on the Company s consolidated financial statements.

In April 2009, FASB issued guidance in the ASC Topic 825 Financial Instruments (formerly FSP FAS 107 1 and APB 28 1) of the Codification on interim disclosures about fair value of financial instruments. The guidance requires disclosures about the fair value of financial instruments for both interim reporting periods, as well as annual reporting periods. The guidance was effective for all interim and annual reporting periods ending after June 15, 2009 and shall be applied prospectively. The implementation of this guidance did not have a material impact on the Company s consolidated financial statements as at December 31, 2009, other than the additional disclosure in Note 12.

In March 2008, FASB issued guidance in the ASC Topic 815 Derivatives and Hedging (formerly SFAS No. 161) of the Codification on improved financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand the effects on an entity s financial position, financial performance and cash flows. The guidance was effective beginning January 1, 2009. Management has complied with the disclosure requirements of this recent statement see additional disclosures under Commodity Price Risks under Note 12 to these financial statements.

In February 2008, FASB issued guidance in the Effective Date of FASB Statement No. 157 ASC Topic 820 (formerly FSP FAS 157 2) of the Codification, which amended 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 this Topic, which was effective January 1, 2009, did not have a material impact on the Company s consolidated financial statements.

In December 2007, the FASB issued guidance in ASC Topic 805 Business Combinations (formerly 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 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 guidance in the ASC Topic 810 Consolidation (formerly SFAS No. 160) of the Codification on the accounting for non controlling (minority) interests in consolidated financial statements. This guidance clarifies the classification of non controlling interests in consolidated statements of financial position and the accounting for and reporting of transactions between the reporting entity and holders of such non controlling interests. This guidance was effective as of the beginning of an entity s first fiscal year that began on or after December 15, 2008 and was required to be adopted prospectively, except for the reclassification of non controlling interests to equity and the recasting of net income (loss) attributable to both the controlling and non controlling interests, which were required to be adopted retrospectively. The Company adopted this guidance effective January 1, 2009, and did not have a material impact on the consolidated financial statements.

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 became effective for disclosures in our Annual Report on Form 10 K for the year ended December 31, 2009. The implementation of this Rule, did not have a material impact on the Company s consolidated financial statements.

In August 2009, the FASB issued Accounting Standards Update (**ASU**) 2009 05 Fair Value Measurements and Disclosures (Topic 820) Measuring Liabilities at Fair Value (**ASU 09 05**), which became effective the first reporting period (including interim periods) beginning after issuance. ASU 09 05 requires entities to measure the fair value of liabilities using one or more of several prescribed valuation techniques within the ASU when quoted prices in an active market for the identical liability are not available. The ASU also clarifies that: entities are not required to include separate inputs or adjustments to other inputs relating to the existence of restrictions that prevent the transfer of liabilities when estimating their fair value; and quoted prices in active markets for identical liabilities at the measurement date and the quoted prices for identical liabilities traded as assets in active markets when adjustments to the quoted prices of assets are required are Level 1 fair value measurements. The adoption of this standard did not have a material impact on the Company s financial statements.

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QUARTERLY FINANCIAL DATA IN ACCORDANCE WITH CANADIAN AND U.S. GAAP (UNAUDITED)

	2009				2008			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
Total revenue								
Canadian GAAP	$ 4,999	$ 7,991	$ 4,844	$ 5,824	$ 19,525	$ 26,159	$ (3,249)	$ 8,235
U.S. GAAP	$ 2,263	$ 6,826	$ 4,280	$ 3,783	$ 24,920	$ 40,800	$ (15,453)	$ 5,068
Net income (loss) from continuing operations:								
Canadian GAAP	$ (11,915)	$ (2,795)	$ (11,444)	$ (11,577)	$ (16,321)	$ 4,822	$ (18,547)	$ (8,430)
U.S. GAAP	$ (12,385)	$ (1,151)	$ (8,985)	$ (10,158)	$ (27,188)	$ 20,206	$ (30,201)	$ (10,728)
Net income (loss) from discontinued operations: (net of tax):								
Canadian GAAP	$	$ (23,290)	$ 66	$ (697)	$ 2,341	$ 5,240	$ (3,184)	$ (114)
U.S. GAAP	$ 41	$ (689)	$ 1,151	$ 466	$ (18,212)	$ 5,618	$ (2,780)	$ 234
Net income (loss) per share continuing operations								
Canadian GAAP	$ (0.04)	$ (0.01)	$ (0.04)	$ (0.04)	$ (0.06)	$ 0.02	$ (0.08)	$ (0.03)
U.S. GAAP	$ (0.04)	$ (0.00)	$ (0.03)	$ (0.04)	$ (0.11)	$ 0.08	$ (0.12)	$ (0.04)
Net income (loss) per share discontinued operations								
Canadian GAAP	$ 0.00	$ (0.09)	$ 0.00	$ (0.00)	0.01	0.02	$ (0.01)	$ (0.00)
U.S. GAAP	$ 0.00	$ (0.00)	$ 0.00	$ 0.01	(0.06)	0.02	$ (0.01)	$ 0.00

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.

SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES (UNAUDITED)
(all tabular amounts are expressed in thousands of U.S. Dollars, except reserves and depletion rate amounts)

The following information about the Company s oil and gas producing activities is presented in accordance with Accounting Standards Codification 932 Extractive Activities Oil and Gas (section 235 55) formerly U.S. SFAS No. 69, Disclosures About Oil and Gas Producing Activities .

On December 31, 2008, the SEC issued final rules relating to reserve definitions and related disclosure requirements. The rules are effective for estimates and disclosures made in annual reports on Form 10 K for fiscal years ended on or after December 31, 2009, including those in this report. The impact of the new rules on our reserves estimates also require us to modify our reserves disclosures this year to transition our reserves estimates from the old rules to the new rules. We have chosen to report our transition to the new rules in a manner that we believe best illustrates the impact of the changes on our reserves estimates and allows us to clearly present how our reserves estimates changed during 2009 as a result of our operational activities separate from the adoption of the new rules. The unaudited supplemental information on oil and gas exploration and production activities for 2009 has been presented in accordance with the new reserve estimation and disclosure rules, which may not be applied retrospectively. The 2007 and 2006 data are presented in accordance with FASB oil and gas disclosure requirements effective during those periods.

Oil and Gas Reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.
Proved developed oil and gas reserves are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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Estimates of oil and gas reserves are subject to uncertainty and will change as additional information regarding the producing fields and technology becomes available and as future economic conditions change.

Reserves presented in this section represent the Company s share of reserves, excluding royalty interests of others. The reserves were based on the estimates by the independent petroleum engineering firm of GLJ Petroleum Consultants Ltd.

The changes in the Company s net proved oil reserves for the three year period ended December 31, 2009 were as follows:

	Oil (MBbl)
	China
Net proved reserves, December 31, 2006	1,785
Revisions of previous estimates	(22)
Production	(483)
Net proved reserves, December 31, 2007	1,280
Revisions of previous estimates	242(1)
Production	(490)
Net proved reserves, December 31, 2008	1,032
Revisions of previous estimates	535(2)
Production	(466)
Net proved reserves, December 31, 2009	1,101

(1) The oil reserve revision is due to better performance of the Dagang property in relation to the 2007 Reserve Report.

(2) The oil reserve revision is due to improved production and fracture performance of the Dagang property in relation to what was estimated in the 2008 Reserve Report.

Net proved developed reserves as at:

December 31, 2007	1,071
December 31, 2008	862
December 31, 2009	885

During 2009 the Company performed 6 fracture stimulations for approximately $3.7 million including capitalized overhead. This resulted in re classing a portion of our proved undeveloped reserves into proved developed reserves.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

For the year ended December 31, 2009, future net cash flows were computed using prices used in estimating the Company s proved oil reserves (12 month historical average), and current costs, and statutory tax rates (adjusted for tax deductions) that relate to existing proved oil reserves. For the years ended December 31, 2008 and 2007, future net cash flows were computed using year end prices, year end costs, and statutory tax rates. The following standardized measure of discounted future net cash flows from proved oil reserves was computed using prices of $58.00, $41.57 and $92.90 per barrel of oil in 2009, 2008 and 2007, respectively. A discount rate of 10% was applied in determining the standardized measure of discounted future net cash flows.

The Company does not believe that this information reflects the fair market value of its oil and gas properties. Actual future net cash flows will differ from the presented estimated future net cash flows in that:

- future production from proved reserves will differ from estimated production;
- future production may also include production from probable and possible reserves;
- future, rather than average annual, prices and costs will apply; and
- existing economic, operating and regulatory conditions are subject to change.

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The standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years were as follows:

	2009 China
Future cash inflows	$ 63,862
Future development and restoration costs	3,307
Future production costs	36,825
Future income taxes	593
Future net cash flows	23,137
10% annual discount	4,589
Standardized measure	$ 18,548

	2008 China
Future cash inflows	$ 42,906
Future development and restoration costs	3,310
Future production costs	22,934
Future net cash flows	16,662
10% annual discount	2,576
Standardized measure	$ 14,086

	2007 China
Future cash inflows	$ 118,911
Future development and restoration costs	5,190
Future production costs	52,446
Future income taxes	1,010
Future net cash flows	60,265
10% annual discount	10,674
Standardized measure	$ 49,591

Note: The Company is using current costs in the preparation of the information shown in the tables above and to determine proved reserves. However, future production costs may not be easily comparable to historical production costs. The two main causes for this difficulty in analyzing of future production costs when compared to historical spending are summarized as follows:

1. In March 2006, the Ministry of Finance of the Peoples Republic of China (**PRC**) issued the Administrative Measures on Collection of Windfall Gain Levy on Oil Exploitation Business (the **Windfall Levy Measures**). According to the Windfall Levy Measures, effective as of March 26, 2006, enterprises exploiting and selling crude oil in the PRC are subject to a windfall gain levy (the **Windfall Levy**) if the monthly weighted average price of crude oil is above $40 per barrel. The Windfall Levy is imposed at progressive rates from 20% to 40% on the portion of the weighted average sales price exceeding $40 per

barrel. As a result, the cost associated with the Windfall Levy is not related to production volumes but instead is related to the commodity price. As an example, as oil prices increased during 2008, the amount of the Windfall Levy also increased significantly, resulting in $13.46 per barrel (**bbl**) increase in 2008 when compared to 2007. The Windfall Levy accounted for $21.14 per bbl cost of the total $43.92 per bbl operating costs in our China operations, or in absolute terms $10.4 million of the total $21.5 million. This compared to only $4.00 per bbl or $1.9 million in absolute terms incurred during 2009.

2. Effective January 1, 2009 the Dagang field reached Commercial Production status as defined by the Production Sharing Contract with our partner CNPC. 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. Effective September 1, 2009 the project reached cost recovery and the working interests changed to 51% CNPC and 49% for the Company. In our 2008 independent reserve report that was used to prepare the standardized measure disclosures above, the 49/51% reversion was estimated based on total costs yet to recover.

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Changes in standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years were as follows:

	2009 China
Sale of oil and gas, net of production costs	$ (14,777)
Net changes in prices and production costs	6,396
Net change in future development costs	(3,536)
Development costs incurred during the period that reduced future development costs	3,712
Revisions of previous quantity estimates	11,106
Accretion of discount	1,409
Net change in income taxes	(593)
Changes in production rates (timing) and other	745
Increase	4,462
Standardized measure, beginning of year	14,086
Standardized measure, end of year	$ 18,548

	2008 China
Sale of oil and gas, net of production costs	$ (26,855)
Net changes in prices and production costs	(21,620)
Net change in future development costs	(2,708)
Development costs incurred during the period that reduced future development costs	4,720
Revisions of previous quantity estimates	3,739
Accretion of discount	4,959
Net change in income taxes	925
Changes in production rates (timing) and other	1,335
Decrease	(35,505)
Standardized measure, beginning of year	49,591
Standardized measure, end of year	$ 14,086

	2007 China
Sale of oil and gas, net of production costs	$ (18,365)
Net changes in prices and production costs	16,322
Net change in future development costs	(3,545)
Development costs incurred during the period that reduced future development costs	10,188
Revisions of previous quantity estimates	(898)
Accretion of discount	4,279
Net change in income taxes	(925)
Changes in production rates (timing) and other	(257)
Increase	6,799
Standardized measure, beginning of year	42,792

Standardized measure, end of year	$	49,591

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Costs incurred in oil and gas property acquisition, exploration, and development activities for the Company s Oil and Gas Properties were as follows:

	For the year ended December 31,		
	2009	2008	2007
Canada			
Property acquisition			
Unproved	$ 1,361	$ 75,732	$
Exploration	11,119	5,357	
	12,480	81,089	
Ecuador			
Property acquisition			
Unproved		863	
Exploration	5,301	591	
	5,301	1,454	
Asia			
Property acquisition			
Unproved	11,161		
Exploration	1,253	1,956	11,611
Development	3,785	6,420	11,881
	16,199	8,376	23,492
Total	$ 33,980	$ 90,919	$ 23,492

The U.S. GAAP depletion rates, calculated on a per Boe of net production basis, were as follows:

China	
Year ended December 31, 2009	$ 16.06
Year ended December 31, 2008	$ 41.61
Year ended December 31, 2007	$ 32.73

The results of operations from producing activities for the years ended December 31 were as follows:

	2009	2008	2007
Oil and gas revenue	$ 24,968	$ 48,370	$ 31,365
Operating costs	10,191	21,515	13,000
Depletion	7,479	20,385	15,832
Provision for impairment		21,560	5,850
Results of operations from producing activities	$ 7,298	$ (15,090)	$ (3,317)

ITEM 9.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. ***CONTROLS AND PROCEDURES***

The Company s management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Exchange Act Rules 13a 15(e) and 15d 15(e)) as of December 31, 2009. Based upon this evaluation, management concluded that these controls and procedures were (1) designed to ensure that information required to be disclosed in the Company s reports under the Exchange Act is accumulated and communicated to the Company s Chief Executive Officer and Chief Financial Officer to allow timely decisions regarding required disclosure and (2) effective in accomplishing those objectives, 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. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company s principal executive and principal financial officers and effected by the Company s board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. The Company s management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2009. In making this assessment, the Company s management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* Based on our assessment, management has concluded that, as of December 31, 2009, the Company s internal control over financial reporting was effective based on those criteria. Management has reviewed the results of its assessment with the Audit Committee of the Board of Directors. Deloitte & Touche LLP, the Company s independent registered Chartered Accountants that audited the financial statements included in Item 8 of this Form 10-K, has also audited the effectiveness of the Company s internal control over financial reporting as of December 31, 2009, as stated in their report which immediately follows.

/s/ Robert M. Friedland	/s/ Gerald D. Schiefelbein
Robert M. Friedland	Gerald D. Schiefelbein
Chief Executive Officer	Chief Financial Officer

March 12, 2010

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of

Ivanhoe Energy Inc.:

We have audited the internal control over financial reporting of Ivanhoe Energy Inc. and subsidiaries (the Company) as of December 31, 2009, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2009, and our report dated March 12, 2010 expressed an unqualified opinion on those financial statements.

(signed) Deloitte & Touche LLP

Independent Registered Chartered Accountants

Calgary, Canada

March 12, 2010

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in the Company s internal control over financial reporting that occurred during the three months ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

ITEM 9B. ***OTHER INFORMATION***

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The following table provides the names of all of our directors and executive officers and their ages, positions with the Company and terms of office. Each director is elected for a one year term or until his successor has been duly elected or appointed. Officers serve at the pleasure of the Board of Directors.

Name and Municipality of Residence	Age	Position with the Registrant
A. ROBERT ABBOUD Barrington Hills, Illinois	80	Co-Chairman and Independent Lead Director (since May 2006)
ROBERT M. FRIEDLAND Singapore	59	Executive Co Chairman, President and Chief Executive Officer (since May 2008) Director (since February 1995)
HOWARD R. BALLOCH Beijing, China	58	Director (since January 2002)
ROBERT G. GRAHAM Ottawa, Ontario	56	Director (since April 2005)
ROBERT A. PIRRAGLIA Wellington, Florida	60	Director (since April 2005)
BRIAN F. DOWNEY, C.M.A. Lake in the Hills, Illinois	68	Director (since July 2005)
PETER G. MEREDITH, C.A. Vancouver, British Columbia	66	Director (since December 2007)
GERALD D. SCHIEFELBEIN Sycamore, Illinois	52	Chief Financial Officer (since November 2009)
DAVID A. DYCK Calgary, Alberta	49	Executive Vice President, Capital Markets (since January 2010)
IAN BARNETT Toronto, Ontario	55	Executive Vice President, Corporate Development (since March 2007)
MICHAEL A. SILVERMAN Houston, Texas	57	Executive Vice President, Technology and Chief Technology Officer (since September 2007)
EDWIN J. VEITH Frazier Park, California	51	Executive Vice President, Upstream (since September 2007)
K. C. PATRICK CHUA Hong Kong, China	54	Executive Vice President (since June 1999)
	61	Executive Vice President (since June 1999)

GERALD G. MOENCH
Lethbridge, Alberta

All of our directors were elected at our last annual general meeting of shareholders (**AGM**) held on April 15, 2009. The term of office of each director concludes at our next AGM, unless the director s office is earlier vacated in accordance with our by laws. There are no family relationships among any of our directors, officers or key employees.

Under the terms of our acquisition of Ensyn, we granted to Ensyn the right to designate two individuals for appointment to our Board of Directors and agreed to use reasonable best efforts to nominate Ensyn s designees for re election to our Board of Directors annually for at least five years. Ensyn s designees, Dr. Robert G. Graham and Mr. Robert A. Pirraglia, were originally appointed to the Board of Directors on April 15, 2005.

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Robert Abboud Mr. Abboud has been Co Chairman and Independent Lead Director of the Company since May 2006 and serves as a member of the Company s Audit, Nominating and Corporate Governance, Compensation and Benefits and Executive Committees. Mr. Abboud has been President and CEO of A. Robert Abboud and Company, a private investment company, since 1984, and has had a 46 year career in oil and gas, banking and foreign affairs. He was previously President and Chief Operating Officer of Occidental Petroleum Corporation, Chairman and CEO of First Chicago Corporation and The First National Bank of Chicago, Chairman and CEO of First City Bancorporation of Texas, Chairman of ACB International, Ltd., a joint venture that included the Bank of China and a subsidiary of the Chinese Ministry of Foreign Relations and Trade. Mr. Abboud has served as a member of the Board of Directors of AMOCO and as Audit Committee Chairman for AAR Corporation, Alberto Culver Company, Hartmarx Corporation, ICN Pharmaceuticals Inc. and Inland Steel Industries. Mr. Abboud holds a Bachelor of Arts (Cum Laude) from Harvard College, a J.D. from Harvard Law School and a Master of Business Administration from Harvard Business School, and is a member of the Illinois and Massachusetts Bar Associations, as well as the Federal Bar and American Bar Associations. Mr. Abboud was selected to serve on our Board due to his extensive experience at the senior executive and board level in the oil and gas industry and in international finance, and for the financial acumen, strategic insight, acute business judgment and international business experience he brings to the Company.

Robert Friedland Mr. Friedland has been Executive Co Chairman, President and Chief Executive Officer of the Company since May 2008. A co founder of the Company, Mr. Friedland has been a director since February 1995, and was Deputy Chairman of the Company from June 1999 to May 2008. Mr. Friedland has been the Chair of the Company s Executive Committee since its formation in October 2008. Mr. Friedland has also been Executive Chairman of Ivanhoe Mines Ltd., a Canadian public company with extensive operating, development and exploration interests in the Asia Pacific region since 1994, and is Chairman (since 1991) and President (since 1988) of Ivanhoe Capital Corporation, a private company based in Singapore that specializes in providing venture capital and project financing for international business enterprises, predominantly in the fields of energy and minerals. He has also been Chairman since 2000, and was President from 2003-2008, of Ivanhoe Nickel & Platinum Ltd., and has been Chairman of Potash One Inc., a Canadian public company, since May 2009. Mr. Friedland brings many valuable attributes to our Board, including his extensive experience in international corporate finance and as a senior executive and director of several internationally focused natural resource companies and his proven track record in overseeing the exploration for, and discovery of, major resource deposits in Canada, Mongolia and elsewhere.

Howard Balloch Mr. Balloch has been a director of the Company since January 2002. Mr. Balloch is the Chair of both the Nominating and Corporate Governance and Compensation and Benefits Committees, and a member of the Audit and Executive Committees. Mr. Balloch has been the President of The Balloch Group, an investment advisory firm he founded, since 2001. From 2001 to 2006, Mr. Balloch served as the President and Chief Executive Officer of the Canada China Business Council. A veteran Canadian diplomat, Mr. Balloch served as Canada s ambassador to the People s Republic of China, Mongolia and the Democratic People s Republic of Korea from 1996 to 2001, after a 20 year career in the Government of Canada s Department of Foreign Affairs and International Trade. Mr. Balloch holds a Bachelor of Arts (Honours) degree in Political Science and Economics and a Master of Arts in International Relations from McGill University, and completed Ph.D. studies at the University of Toronto and at Fondation Nationale de Sciences Politiques, Paris. Mr. Balloch was selected to serve as a director on our Board based on his experience as a Canadian diplomat and as an international businessman, his extensive knowledge of foreign affairs and the political and regulatory environment in many of the key regions in which the Company operates, including China, and his knowledge and experience in matters of public company governance.

Dr. Robert Graham Dr. Graham has been a director of the Company since April 2005 and served as the Company s Chief Technology Officer from April 2007 to September 2007. Dr. Graham co founded Ensyn Group, Inc. (**Ensyn**) and served on the board and in various senior executive roles with Ensyn until it was acquired by the Company in 2005. Since then, he has served as Chairman (since June 2007) and Chief Executive Officer (since July 2008), and President and Chief Executive Officer (from April 2005 to June 2007) of Ensyn Corporation. Dr. Graham has been working on the commercial development of the RTP biomass refining and petroleum upgrading technologies since the early 1980 s. This work culminated in the development of commercial RTP applications in the wood industry in the late 1980 s and the establishment of Ensyn Renewables Inc. to capitalize on commercial projects for this business. In

1997, Dr. Graham initiated the application of this commercial RTP technology in the petroleum industry. Dr. Graham holds Bachelor of Science and Bachelor of Science Honours degrees from Carlton University, and a Master of Engineering and Ph.D. in Chemical Engineering from the University of Western Ontario. Dr. Graham brings unique skill, expertise and experience to our Board as the inventor of our HTL technology and as a scientist and businessman with extensive experience in the technology industry.

Robert Pirraglia Mr. Pirraglia has been a director of the Company since April 2005 and acted as the Chair of the Business Development Committee from August 2007 until May 2008. He is currently a member of the Compensation and Benefits Committee and the Nominating and the Corporate Governance Committee. Mr. Pirraglia is an engineer and attorney with more than 25 years of experience in the development of energy projects and projects employing innovative technologies. He served on the board of Ensyn starting in 1996, and was also Chief Operating Officer of Ensyn from September 1998 to April 2005. He is currently Executive Vice President of Ensyn Corporation (since October 2007) and was Chief Operating Officer and Vice President of Ensyn Corporation from April 2005 to October 2007. He is also a director of Pirraglia Associates, Inc. and RRP Development Holdings, LLC. In addition to being a founder and manager of several energy and waste processing companies, Mr. Pirraglia has provided management and business consulting services to various U.S., Canadian and European companies. Mr. Pirraglia holds a Bachelor of Electrical Engineering degree from New York University and a J.D. from Fordham University School of Law. Mr. Pirraglia brings significant legal, technical and project management experience and expertise to our Board as well as governance experience acting as a public company director.

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Brian Downey Mr. Downey joined the Board of Directors in July 2005 and was appointed Chairman of the Audit Committee at that time. Mr. Downey also serves as a member of the Compensation and Benefits Committee and the Nominating and the Corporate Governance Committee. Mr. Downey has been President of Downey & Associates Management Inc. since July 1986, and Financial Advisor to Lending Solutions, Inc., a full service loan call centre located in the U.S. whose clients are primarily U.S. and Canadian financial institutions, since January 2002. From 1995 to 2002 he was a principal and served as CEO of Lending Solutions, Inc., and from 1986 to 1995 he served as President and CEO of Credit Union Central of Canada, the national trade association and national liquidity facility for all credit unions in Canada. Mr. Downey has a Certified Management Accountant (CMA) designation from the University of Manitoba and is a Member of the Society of Management Accountants of Ontario. Mr. Downey was selected to serve as a director on our Board due to his extensive experience and expertise in financial and accounting matters. Mr. Downey is the Company s audit committee financial expert within the meaning of the Securities Exchange Act of 1934.

Peter Meredith Mr. Meredith joined the Board of Directors in December 2007 and serves as a member of the Executive Committee. He previously served as a director from 1996 to 1999 and as the Company s Chief Financial Officer from June 1999 to January 2000. Mr. Meredith has been Deputy Chairman of Ivanhoe Mines Ltd. since May 2006 and was Chief Financial Officer of Ivanhoe Mines from May 2004 to May 2006 and from June 1999 to November 2001. He is also presently Chairman (since October, 2009) and was previously Chief Executive Officer (June 2007 to October 2009) of SouthGobi Energy Resources Ltd, and served as Chief Financial Officer of Ivanhoe Capital Corporation from 1996 to March 2009. Prior to joining the Company Mr. Meredith spent 31 years with Deloitte & Touche LLP, Chartered Accountants, where he retired as a partner in 1996. He was a member of its Canadian board of directors from 1991 to 1996. Mr. Meredith is a Chartered Accountant and is a member of the Institute of Chartered Accountants of British Columbia, the Institute of Chartered Accountants of Ontario and the Ordre des Comptables Agrees du Quebec. He is also a Certified Management Accountant (CMA) and is a member of the Certified Management Accountants Society of British Columbia. Mr. Meredith was selected to serve as a director on our Board due to his extensive experience at the senior executive and board level with international resource companies and his financial accounting, reporting and corporate finance expertise, and the depth of his knowledge of the Company s operations and of the political and regulatory requirements of the regions in which the Company operates derived from his involvement in leadership roles with the Company and other resource companies operating in similar regions since 1996.

Gerald Schiefelbein Mr. Schiefelbein has been the Chief Financial Officer of the Company since November 2009. Prior to his appointment as Chief Financial Officer, Mr. Schiefelbein served as Chief Financial Officer, Oil Americas BP p.l.c. (September 2007 to February 2009), Controller, Oil Americas BP p.l.c. (February 2006 to September 2007) and Controller, Other Business and Corporate (January 2005 to February 2006) for BP p.l.c., one of the world s largest energy companies.

Gordon Lancaster Mr. Lancaster served as Chief Financial Officer of the Company from January 2004 to November 2009. Prior to joining the Company, Mr. Lancaster served as Vice President Finance and Chief Financial Officer of Xantrex Technology Inc. (July 2003 to December 2003) and as Vice President Finance and Chief Financial Officer of Power Measurement, Inc. (August 2000 to June 2003).

David Dyck Mr. Dyck has been the Executive Vice President, Capital Markets of the Company since January 2010. He has also been President and Chief Executive Officer of our subsidiary Ivanhoe Energy Canada Inc. since October 2009. Prior to his appointment with Ivanhoe Energy Canada, Mr. Dyck served as President and Chief Executive Officer of LeaRidge Capital Inc. (January 2008 to October 2009) and as Senior Vice President Finance and Chief Financial Officer of Western Oil Sands Inc. (April 2000 to October 2007).

Ian Barnett Mr. Barnett has been the Executive Vice President, Corporate Development of the Company since March 2007. From November 2005 to March 2007 he was Vice President, Finance of the Company and from January, 2005 to November 2005 he was a consultant to the Company. Mr. Barnett is a director of Ensyn Corporation. He is also co founder and has been a director of Heptagon Investments Ltd. since 1991, and was a director and a consultant with Ensyn from 1999.

Michael Silverman Mr. Silverman has been the Executive Vice President, Technology and Chief technology Officer of the Company since September, 2007. From May 2007 to September 2007 he was Vice President, Technology of the Company. Prior to joining the Company, Mr. Silverman served as Vice President, Petrochemicals (May 2004 to May 2007) and Director, Technology Center (May 2000 to May 2004) for KBR, Inc.

Edwin Veith Mr. Veith has been Executive Vice President, Upstream of the Company since September 2007. Mr. Veith has also been Vice President, HTL Technology of Ivanhoe Energy (USA) Inc. since November 2005. From June 2001 to November 2005 he was Chief Reservoir Engineer of Ivanhoe Energy (USA) Inc.

K.C. Patrick Chua Mr. Chua has been Executive Vice President of the Company since June, 1999 and Chairman of the Company s subsidiary Sunwing Energy Ltd. since April 2004. From March 2000 to April 2004 he was President of Sunwing.

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Gerald Moench Mr. Moench has been Executive Vice President of the Company since June, 1999 and President of the Company s subsidiary Sunwing since April, 2004.

As required under the *Business Corporations Act* (Yukon), our Board of Directors has an Audit Committee. We also have a Compensation and Benefits Committee, and a Nominating and Corporate Governance Committee and an Executive Committee. The members of the Audit Committee are Messrs. Brian F. Downey, Howard R. Balloch and A. Robert Abboud. Mr. Downey, one of our current independent directors, has been determined by the Board of Directors to be an Audit Committee financial expert. We believe that Mr. Downey s prior experience working as a Certified Management Accountant and significant financial and business experience at the executive levels of management qualifies him to be an Audit Committee financial expert. The current members of the Compensation and Benefits Committee are Messrs. Howard R. Balloch (Chair), Robert A. Pirraglia, A. Robert Abboud and Brian F. Downey. The current members of the Nominating and Corporate Governance Committee are Messrs. Howard R. Balloch (Chair), Robert A. Pirraglia, Brian F. Downey and A. Robert Abboud. The current members of the Executive Committee are Messrs. Robert M. Friedland, A. Robert Abboud, Howard R. Balloch and Peter G. Meredith.

Management is responsible for our financial reporting process including our system of internal controls over financial reporting and for the preparation of consolidated financial statements in accordance with generally accepted accounting principles in Canada. Our independent registered chartered accountants are responsible for auditing those financial statements. The members of the Audit Committee are not our employees, and are not professional accountants or auditors. The Audit Committee s primary purpose is to assist the Board of Directors in fulfilling its oversight responsibilities by reviewing the financial information provided to shareholders and others, and the systems of internal controls which management has established to preserve our assets and the audit process. It is not the Audit Committee s duty or responsibility to conduct auditing or accounting reviews or procedures or to determine that our financial statements are complete and accurate and in accordance with generally accepted accounting principles in Canada. In giving its recommendation to the Board of Directors, the Audit Committee has relied on management s representations that the financial statements have been prepared with integrity and objectivity and in conformity with generally accepted accounting principles in Canada and on the opinion of the independent registered chartered accountants included in their report on our financial statements.

Other Public Company Directorships

The following is information respecting directorships held by our directors over the last five years at public and registered investment companies.

Messrs. Howard R. Balloch, Peter G. Meredith and Robert M. Friedland are all directors of Ivanhoe Mines Ltd. Mr. Balloch is also a director of Methanex Corporation and Tiens Biotech Group USA Inc. and was previously a director of Cast Energy Corp. Messrs. Friedland and Meredith are both directors of Ivanhoe Australia Limited, and Mr. Friedland is also a director of Potash One Inc., a Canadian public company. Mr. Meredith is also a director of Entrée Gold Inc., SouthGobi Energy Resources Ltd. and Great Canadian Gaming Corporation, and was previously a director of Jinshan Gold Mines Inc. and Olympus Pacific Minerals Inc.

Code of Business Conduct and Ethics

We have a Code of Business Conduct and Ethics applicable to all employees, consultants, officers and directors regardless of their position in our organization, at all times and everywhere we do business. The Code of Business Conduct and Ethics provides that our employees, consultants, officers and directors will uphold our commitment to a culture of honesty, integrity and accountability and that we require the highest standards of professional and ethical conduct from our employees, consultants, officers and directors. A copy of our Code of Business Conduct and Ethics, as amended, may be obtained, without charge, by request to Ivanhoe Energy Inc., Suite 654-999 Canada Place, Vancouver, British Columbia, Canada V6C 3E1, Attention: Corporate Secretary or by phone to 604-688-8323.

ITEM 11. ***EXECUTIVE COMPENSATION***

We are a foreign private issuer that voluntarily files its annual reports on Form 10 K. As permitted by Item 402(a)(1) of Regulation S K, we follow the disclosure requirements applicable in Canada with respect to executive compensation (Form 51 102F6 of the Canadian Securities Administrators), which we believe address the requirements of, and require more detailed information than, Items 6.B and 6.E.2 of Form 20 F.

STATEMENT OF EXECUTIVE COMPENSATION

In accordance with the requirements of applicable securities legislation in Canada, the following executive compensation disclosure is provided in respect of each person who served as the Company s Chief Executive Officer or Chief Financial Officer during the 2009 fiscal year, and each of the Company s three most highly compensated executive officers whose annual aggregate compensation for the 2009 fiscal year exceeded Cdn.$150,000 (collectively, the Named Executive Officers).

COMPENSATION DISCUSSION AND ANALYSIS

Compensation and Benefits Committee, Philosophy and Goals

The Company s executive compensation program is administered by the Compensation and Benefits Committee (the Compensation Committee). The members of the Compensation Committee are all independent, non management directors. Following review and approval by the Compensation Committee, decisions relating to executive compensation are reported to, and approved by, the full Board of Directors.

In determining the nature and quantum of compensation for the Company s executive officers the Company is seeking to achieve the following objectives, in approximately an equal level of importance:

- to provide a strong incentive to management to contribute to the achievement of the Company s short term and long term corporate goals;
- to ensure that the interests of the Company s executive officers and the interests of the Company s shareholders are aligned;
- to enable us to attract, retain and motivate executive officers of the highest calibre in light of the strong competition in the Company s industry for qualified personnel;
- to recognize that the successful implementation of the Company s corporate strategy cannot necessarily be measured, at this stage of its development, only with reference to quantitative measurement criteria of corporate or individual performance; and
- to provide fair, transparent, and defensible compensation

Recent Developments Relating to Executive Compensation.

Effective November 15, 2009, Mr. Gerald Schiefelbein was appointed Chief Financial Officer of the Company to succeed Mr. Gordon Lancaster following his retirement. Effective October 1, 2009, Mr. David Dyck was appointed President and Chief Executive Officer of Ivanhoe Energy Canada Inc. Mr. Dyck was also appointed Executive Vice President, Capital Markets, of the Company on January 26, 2010.

How We Make Compensation Decisions

The Compensation Committee oversees and sets the general guidelines and principles for the implementation of the Company s executive compensation policies, assesses the individual performance of the Company s executive officers and makes recommendations to the Board of Directors. Based on these recommendations, the Board of Directors makes decisions concerning the nature and scope of the compensation to be paid to the Company s executive officers. The Compensation Committee bases its recommendations to the Board on its compensation philosophy and on individual and corporate performance.

The Compensation Committee annually reviews, and recommends to the Board, the cash compensation, any performance bonus and overall compensation package for each of the Corporation s executive officers.

Decisions for base salary adjustments are usually made during the first quarter of a new fiscal year. Although specific individual targets were not set for executives for the 2009 year, in the normal course, targets for performance bonuses for the next fiscal year are set prior to the beginning of the next fiscal year, and decisions on actual bonuses, are made at some point during the first quarter following the end of the fiscal year. Incentive awards may be made at any time during the year, but are ordinarily made during the first quarter following the end of the fiscal year. In the ordinary course, management presents its compensation recommendations for consideration by the Compensation Committee.

The Compensation Committee may seek compensation advice where appropriate from consultants, although the Compensation Committee did not engage outside consultants for 2009. In 2007, the Company adopted a compensation program based on a series of quantitative and qualitative compensation parameters for the Company s executive officers and the Company s non executive management personnel. This program was based on a 2005 report prepared by an external consultant and an internal review of the Company s compensation policies and practices. The compensation program was designed to provide incentives to work for, and stay with, the Company, to drive strong Company performance, and to differentially reward skills more critical to the Company s business plans. During the fourth quarter of 2008 and the first quarter of 2009, the Company s financial position was relatively weak. Accordingly, virtually all executive compensation decisions during that time were based on the Company s ability to pay and the principles upon which the 2007 compensation program were based were largely subordinated to this overriding consideration. In addition, no performance targets or objectives were adopted upon which to base executive compensation decisions for the 2009 fiscal year.

The Company s financial position improved during the second quarter of 2009 through the first quarter of 2010. Since no performance targets or objectives were adopted upon which to base executive compensation decisions for the 2009 fiscal year, the Compensation Committee based its decisions for purposes of establishing 2010 base salaries and bonuses for the 2009 fiscal year on available industry data and the role played by senior management in corporate performance and achievements during 2009.

Based on the significant changes to the Company s executive management team during the second half of 2009, the Compensation Committee decided to adopt a new compensation program for 2009 and subsequent years and has instructed senior management to make a series of executive compensation proposals to the Compensation Committee for its consideration by the second quarter of 2010.

Elements of Total Compensation

The compensation that the Company pays to its executive officers generally consists of base salary, annual performance bonuses (in cash, fully paid common shares, or a combination thereof) and equity incentives. The Company s compensation policy reflects a belief that an element of total compensation for the Company s executive officers should be at risk in the form of common shares or incentive stock options, so as to create a strong incentive to build shareholder value. In setting compensation levels, the Compensation Committee takes into account an executive s past performance, future expectations for performance and also considers both the cumulative compensation being granted to executives as well as internal comparisons amongst the Company s executives. At this stage of the Company s development, the Company also considers the available cash resources of the Company.

The following summarizes the primary purpose of each compensation element and its emphasis:

- Base salary paid in cash as a fixed amount of compensation for performing day to day responsibilities.
- Performance Bonus Annual bonus awards, paid in common shares or cash, or both, earned for achieving strategic corporate, business unit or individual goals.
- Incentive Awards Equity incentives, in the form of stock options, granted to align compensation with achievement of the Company s goals, creation of shareholder value, and retention of executives over a longer period.

In making compensation decisions in respect of these elements, the Compensation Committee considers both the cumulative compensation being granted to executives as well as internal comparisons amongst the Company s executives.

Peer Comparator Group

The original salary ranges for the Company were established in 2005 with reference to a number of Canadian and United States based oil and gas companies with international operations and similar market capitalizations; North America based energy focused technology companies with somewhat comparable market capitalizations, and United States based junior oil and gas companies. The comparator group established in 2005 is no longer considered relevant and a new comparator group is being established as part of the process of establishing a new executive compensation program for 2010 and subsequent years. For purposes of establishing 2010 base salaries and bonuses for the 2009 fiscal year, the Compensation Committee relied upon externally generated compensation data in respect of the Canadian oil and gas industry, primarily in the category of exploration and production companies.

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Base Salary

The base salaries of the Company s executive officers are determined at the commencement of employment as an executive officer by the terms of the executive officer s employment contract. The base salary is determined by a subjective assessment of each individual s performance, experience and other factors the Company believes to be relevant, including prevailing industry demand for personnel having comparable skills and performing similar duties, the compensation the individual could reasonably expect to receive from a competitor and the Company s ability to pay. In the past, the Company has considered recommendations from outside compensation consultants and used compensation data obtained from publicly available sources.

Under the Company s 2007 compensation program, salary levels have historically been assessed using a pay grade system that is consistent with industry practice. Each of the Company s employees, including the Company s executive officers, is placed in a pay grade based upon his or her knowledge, skills and relevant experience and credentials. Annual salary increases are made based on performance and relative position within a pay grade. Performance will be assessed and rated based on agreed objectives and behaviors. A simple three tiered rating system is used for salaries, with top performers rewarded the highest, regular performers rewarded consistent with average industry trends and bottom performers receiving little or no salary increases. The Compensation Committee also considers retention risks, succession requirements and compensation changes in the market in determining salaries. The Compensation Committee does not anticipate that this approach will materially change when a new compensation program is adopted during 2010.

Annual Bonus

Under the 2007 compensation program, the intent of awarding an annual bonus has been to provide competitive near term compensation. The program calls for the same pay grade system used to establish base salary to be used for determining the target and maximum bonus that is achievable by an employee.

Bonus award levels for executive officers and senior non executive management personnel are to be based on a targeted percentage of base salary and determined with regard to job specific criteria in addition to overall corporate performance, which is assessed relative to new project development and the achievement of business plan and technology development goals. Other goals in respect of overall corporate performance include production targets, investor and corporate communications, staffing and business development. An individual executive s bonus is to be assessed by allocating a lesser or greater percentage of the executive s target bonus to business targets within his or her sphere of influence.

The composition of annual bonus awards is usually a combination of the Company s common shares and cash. In order to preserve cash, bonus awards consist predominantly of common shares with a significantly smaller cash component to facilitate the recipient s ability to pay applicable income taxes.

Under the existing compensation program, for executive officers, potential bonus amounts were expected to range from 40% of salary (target) and 60% of salary (maximum) for the Company s Chief Financial Officer and 25% 30% of salary (target) and 37.5% 45% of salary (maximum) for other executive officers. In the ordinary course, 90% of the targeted bonus amount is earned through the achievement of measurable defined corporate objectives, including share price, net income, net operating cash flow and net production, as well as other specific corporate and individual goals, and 10% of the targeted bonus is based on discretionary factors. However, for the 2009 year, specific performance targets for individual executives were not set for executives, who were evaluated subjectively in terms of their contribution during 2009 to overall corporate objections and the corporate business plan.

Incentive Compensation

The relationship of corporate performance to executive compensation under the Company s executive compensation program is created, in part, through equity compensation mechanisms. Incentive stock options, which vest and become exercisable through the passage of time, link the bulk of the Company s equity based executive compensation to shareholder return, measured by increases in the market price of the Company s common shares. All outstanding stock options that have been granted under the Company s Equity Incentive Plan were granted at prices not less than 100% of the fair market value of the Company s common shares on the dates such options were granted.

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The Company continues to believe that stock based incentives encourage and reward effective management that results in long term corporate financial success, as measured by stock appreciation. Stock based incentives awarded to the Company s executive officers have been traditionally based upon the Compensation Committee s subjective evaluation of each executive officer s ability to influence the Company s long term growth and to reward outstanding individual performance and contributions to the Company s business. Other factors influencing the Company s recommendations respecting the nature and scope of the equity compensation and equity incentives to be awarded to the Company s executive officers in a given year have included: awards made in previous years and, particularly in the case of equity incentives, the number of incentive stock options that remain outstanding and exercisable from grants in previous years and the exercise price and the remaining exercise term of those outstanding stock options.

The intent of the Company s incentive compensation under the compensation program has been to provide retention incentives to employees and prospective employees that are superior to incentive compensation offered by our competition. Under the program, the Company has used the same pay grade system for outlining the target and maximum incentive compensation that is achievable for an executive or employee. For executives and higher pay grade employees, annual incentive compensation awards will be provided based on specific performance criteria, value to the Company in terms of skills, knowledge and experience, completion of specific projects as well as subjective criteria. Incentive compensation awards for executives and upper pay grade employees are expected to include stock options and may in the future include other securities such as restricted shares.

Option exercise periods and vesting schedules for options granted to executive officers are determined, on a case by case basis, by the Compensation Committee and the Board. Although the Company has traditionally taken an approach to vesting that is based on the passage of time, the Company has, in appropriate circumstances, granted options with vesting schedules based on the achievement of specified corporate objectives.

2009 EXECUTIVE COMPENSATION DECISIONS

Salary Compensation

Robert Friedland, Executive Co Chairman, President and Chief Executive Officer, has voluntarily waived a cash salary from the Company.

The base salaries of Messrs. Schiefelbein and Dyck, who were hired during 2009, were set by the terms of their respective employment contracts which are described under Termination and Change of Control Benefits and were based on competitive market factors, level of experience and scope of responsibility.

The overall approach taken by the Compensation Committee in establishing base salaries for its executives during the 2010 fiscal year was to simply increase base salaries for all of the Company s executives by 4.2%, which represented the average increase in base salaries for executives of Canadian exploration and production companies reported as part of the externally generated compensation data in respect of the Canadian oil and gas industry upon which the Compensation Committee relied.

Bonus Compensation

In March 2010, the Compensation Committee decided to create a bonus pool having an aggregate value of approximately $1.4 million from which bonus for the entire Company will be drawn, including individual bonus awards to its executive officers, including the Named Executive Officers (the 2009 Bonus Pool). The quantum of the 2009 Bonus Pool represents approximately 18.7% of the aggregate base salaries paid by the Company to its executive officers and other senior management staff during the 2009 fiscal year and is consistent with average aggregate bonus awards, as a percentage of base salary, that the Compensation Committee understands that Canadian exploration and production companies have paid or intend to pay based on the externally generated compensation data in respect of the Canadian oil and gas industry upon which the Compensation Committee relied. The Compensation Committee has also allocated an additional $250,000 for payment of additional bonuses to executives perceived by the Compensation Committee as having achieved extraordinary performance.

The Compensation Committee has requested that the Company s Chief Executive Officer, who does not accept any salary or bonus, make recommendations to the Compensation Committee as to the allocation of the 2009 Bonus Pool among the Company s other executive officers. The Compensation Committee will take these recommendations into account in making bonus awards from the 2009 Bonus Pool to individual executives and senior management staff. Since specific quantitative and qualitative performance targets were not established in advance, the Compensation

Committee, in differentiating awards made to individual executives and senior management staff, will also take into account their relative contributions to corporate performance and achievements during 2009, including the following:

- the $150 million equity financing transaction completed early in the first quarter of 2010;
- the sale of the Company s U.S. operations and assets;

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- the consolidation of the Company s management and operating structure and the closure of redundant offices;
- the progress made during the 2009 fiscal year in advancing the Company s core projects having regard to the Company s limited financial resources; and
- the increase in the Company s market capitalization through share price appreciation.

Incentive Compensation

In connection with Mr. Schiefelbein s appointment as Chief Financial Officer in November 2009, he was granted stock options to purchase 200,000 common shares exercisable for a term of seven years. In connection with Mr. Dyck s appointment as President and Chief Executive Officer of Ivanhoe Energy Canada Inc. in October 2009, he was granted stock options to purchase 500,000 common shares exercisable for a term of seven years.

In respect of the 2009 year, awards of stock options to certain executive officers were made on a subjective discretionary basis as part of an annual review, taking into account performance and internal comparisons of executive officer s stock option positions, and for retention considerations. In September 2009, each of Messrs Barnett, Chua, Moench and Silverman received options to purchase 150,000 common shares with a five year term, vesting as to 20%, immediately and then at the end of each of the first through fifth year of the term and exercisable at $2.22.

Other Compensation

The Company does not provide its executive officers with a pension plan and the share purchase plan of the Company has not been activated. In 2009, the Company paid Mr. Silverman US$22,000 for the purpose of contributing to the 401(k) retirement plan of the recipient. In 2009 the Company paid life insurance premiums and long term disability premiums on behalf of each Named Executive Officer except for Mr. Friedland. The aggregate other compensation received by each Named Executive Officer is disclosed in the Summary Compensation Table.

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Performance Graph

The following graph and table compares the cumulative shareholder return on a Cdn.$100 investment in our common shares to a similar investment in companies comprising the S&P/TSX Composite Index, including dividend reinvestment, for the period from December 31, 2004 to December 31, 2009.

	As at December 31, (Cdn.$)					
	2004	**2005**	**2006**	**2007**	**2008**	**2009**
Ivanhoe Energy Inc.	$ 100	$ 25	$ 32	$ 32	$ 12	$ 61
S&P/TSX Composite Index	$ 100	$ 124	$ 146	$ 160	$ 107	$ 145

The information provided in this Performance Graph shall not be deemed soliciting material or filed with the Securities and Exchange Commission or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 (**Exchange Act**), other than as provided in Item 201 to Regulation S K under the Exchange Act, or subject to the liabilities of Section 18 of the Exchange Act and shall not be deemed incorporated by reference into any filing under the Securities Act of 1933 or the Exchange Act except to the extent the Company specifically requests that it be treated as soliciting material or specifically incorporates it by reference.

The trend in overall compensation paid to the Company s executive officers over the past five years has not tracked the performance of the market price of the Company s common shares, or the S&P/TSX Composite Index, particularly since 2007. Market price targets of the Company s common shares have, however, been included as a component of the Company s annual bonus incentives.

Option Based Awards

Please see the section Incentive Compensation in the Compensation Discussion and Analysis for a discussion of the Company s approach to option based awards.

In 2009 the Company issued option based awards under its Equity Incentive Plan to executive officers as described under the heading 2009 Executive Compensation Decisions .

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SUMMARY COMPENSATION TABLE

SUMMARY COMPENSATION TABLE (U.S.$)

Name and principal position	Year	Salary ($)	Share-based awards ($)	Option-based awards ($)(4)	Non-equity incentive plan compensation ($) Annual incentive plans	Non-equity incentive plan compensation ($) Long-term incentive plans	Pension value(2) ($)	All other compensation ($)	Total compensation ($)
Friedland, Robert Executive Co-Chairman, President & CEO	2009								(1)
	2008								
Lancaster, Gordon CFO	2009	250,942(3)(5)						4,745(5)	255,687
	2008	259,552(3)	29,965(10)	50,550	69,626(12)			1,972(13)	411,665
Schiefelbein, Jerry CFO	2009	61,750		392,889					454,639
	2008								
Barnett, Ian Executive VP, Corp Development	2009	223,129(3)		361,820				4,253(6)	589,202
	2008	223,113(3)	29,965(10)		69,626(12)			3,648(7)	326,352
Silverman, Michael Executive Vice President, Technology & Chief Technology Officer	2009	272,250		228,623				32,071(8)	532,944
	2008	261,938	29,965(10)		73,866 12)			32,945(9)	398,714
Dyck, David Executive Vice President, Capital Markets	2009	83,030(3)		982,223				6,825(11)	1,072,078
	2008								

NOTES:

(1) Mr. Friedland is also a director of the Company. Pursuant to the Company s policies regarding

management directors, Mr. Friedland does not receive compensation from the Company for acting as a director, and no portion of the Total Compensation disclosed in the summary compensation table was received by Mr. Friedland as compensation for acting as a director.

(2) The Company does not presently have a long-term incentive plan for any of its executive officers, including its Named Executive Officers.

(3) Amounts were paid to Mr. Lancaster, Mr. Barnett and Mr. Dyck in Canadian currency. Salaries have been converted to US currency based on the noon buying price for Canadian currency of the Bank of Canada and Federal Reserve Bank of New York on the date of each pay period during 2009 and 2008 respectively.

(4) The Company used the Black-Scholes option-pricing model for determining the fair value of stock options issued at the grant date. The

practice of the Company is to grant all option based awards in Canadian currency, then convert the grant date fair value amount to U.S. currency for reporting the value of the grants in the Company s financial statements. For 2009 the conversion rate is the noon buying price for Canadian currency of the bank of Canada on the date the grant was made on October 15, 2009 which was .9706 for each of Messrs. Schiefelbein and Dyck, and .9422 for options granted to each of Messrs. Barnett and Silverman on September 17, 2009. For 2008 the conversion rate is the noon buying price for Canadian currency of the Federal Reserve Bank of New York noon rate on March 11, 2008 which was .9953 for options granted to Mr. Lancaster.

(5) Includes: $4,745 paid for life insurance, long term disability, medical and dental insurance.

(6) Includes: $4,253 paid for life insurance, long term disability,

medical and dental insurance.

(7) Includes: $3,648 paid for life insurance, long term disability, medical and dental insurance.

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(8) Includes: $22,000 paid as a contribution to Mr. Silverman s 401(k) retirement plan; and $10,071 paid for life insurance and long term disability premium.

(9) Includes: $20,496 paid as a contribution to Mr. Silverman s 401(k) retirement plan; and $12,449 paid for life insurance and long term disability premiums.

(10) The grant date fair value is determined by the closing trading price for the Company s common shares on the day the Company delivered a treasury order for the share based award to the Company s transfer agent. The share based awards granted to the Named Executive Officers and listed in the Summary Compensation Table were based on the closing price for the Company s

common shares on August 5, 2008. The grant date fair value was US$2.26.

(11) Includes: $5,250 paid for contribution to Mr. Dyck s Canadian savings plan; $1,575 paid for life insurance, long term disability, medical and dental insurance and parking.

(12) Includes US$73,866 for Mr. Silverman and Cdn.$73,866 for Messrs. Lancaster and Barnett (converted to US$69,626 at the US Federal Reserve noon rate on August 15, 2008: 0.9426), that was paid on August 15, 2008, as an advance on bonuses payable for the year ending 2008, which are normally determined and paid in mid-2009.

(13) Includes: $1,972 paid for life insurance, long term disability, medical and dental insurance.

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INCENTIVE PLAN AWARDS

Outstanding share-based awards and option-based awards

	Option-based Awards				Share-based Awards	
Name	**Number of securities underlying unexercised options (#)**	**Option exercise price ($)**	**Option expiration date**	**Value of unexercised in-the-money options (US$)(1)**	**Number of shares or units of shares that have not vested (#)**	**Market or payout value of share-based awards that have not vested (US$)**
Friedland, Robert Executive Co-Chairman, President & CEO	2,500,000(2)	Cdn$1.61	March 5, 2013	**$ 3,224,813**		
Lancaster, Gordon CFO	50,000(3)	Cdn$1.68	March 11, 2013	**$ 64,496**		
Schiefelbein, Gerald CFO	200,000(7)	Cdn$2.51	Oct. 1, 2016	**$ 85,995**		
Barnett, Ian	150,000(8)	Cdn$2.22	Sept. 17, 2014			
Executive Vice President,	226,000	US$1.92	Oct. 4, 2012			
Corporate Development	150,000(4)	US$2.06	March 15, 2012			
	124,481	US$2.41	July 20, 2010	**$ 499,017**		
Silverman, Michael	150,000(8)	Cdn$2.22	Sept. 17, 2014			
Executive Vice President,	270,000(10)	US$1.92	Oct. 4, 2012			
Technology and Chief	150,000(5)	US$1.92	Sept. 19, 2012			
Technology Officer	80,000(6)	US$2.06	May 28, 2012	**$ 564,861**		

Dyck, David Executive Vice President, Capital Markets	500,000(9)	Cdn$2.51	Oct. 15, 2016	$	**214,988**

NOTES:

(1) The Value of unexercised in-the-money options is calculated on the basis of the difference between the closing price of the common shares on the TSX on December 31, 2009 and the Exercise Price of the total unexercised options on the TSX and NASDAQ. The value of options granted in Canadian currency was converted to US currency based on the noon buying price for Canadian currency of the Bank of Canada as of December 31, 2009.

(2) This option grant vests 20% on March 5, 2008, and 20% on each of the four anniversaries thereafter, and will be fully vested on March 5, 2012.

(3) This option grant vests 20% on March 11, 2008, and 20% on each of the four anniversaries thereafter, and will be fully vested on March 11, 2012.

(4) This option grant vested 33 1/3% on March 15, 2008, and 33 1/3% on each of the two anniversaries

thereafter and will be fully vested on March 15, 2010.

(5) This option grant vests 20% on September 19, 2007, and 20% on each of the four anniversaries thereafter, and will be fully vested on September 19, 2011.

(6) This option grant vests 25% on May 28, 2008, and 25% on each of the three anniversaries thereafter, and will be fully vested on May 28, 2011.

(7) This option grant vests 25% on October 1, 2010, and 25% on each of the three anniversaries thereafter, and will be fully vested on October 1, 2013.

(8) This option grant vests 20% on September 17, 2009, and 20% on each of the four

anniversaries thereafter, and will be fully vested on September 17, 2013.

(9) This option grant vests 25% on October 15, 2010, and 25% on each of the three anniversaries thereafter, and will be fully vested on October 15, 2013.

(10) This option grant vested 20% on October 4, 2007, and will continue to vest over the four years following October 4, 2007, upon the achievement of performance milestones.

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Incentive Plan Awards value vested or earned during 2009

Name	Option-based awards Value vested during the year (U.S.$)[1]	Share-based awards Value vested during the year (U.S.$)	Non-equity incentive plan compensation Value earned during the year (U.S.$)
Friedland, Robert Executive Co-Chairman, President & CEO	Nil		
Lancaster, Gordon CFO	Nil		
Schiefelbein, Gerald CFO	Nil		
Barnett, Ian Executive Vice President, Corporate Development	$ 96,214		
Silverman, Michael Executive Vice President, Technology and Chief Technology Officer	$ 113,566		