IVANHOE ENERGY INC
Form 10-K
March 16, 2011

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

Form 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2010
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)	(IRS Employer Identification No.)

654-999 Canada Place
Vancouver, BC, Canada V6C 3E1
(604) 688-8323
(Address and telephone number of the registrant s principal executive offices)
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
	The 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. þ Yes o 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.

Large accelerated filer o Accelerated filer þ Non-accelerated filer o 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, 2010, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $530,616,815, based on the Toronto Stock Exchange closing price on that date. At March 4, 2011, the registrant had 343,931,658 common shares outstanding.

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ABBREVIATIONS

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

bbl	=	barrel	mcf	=	thousand cubic feet
bbls/d	=	barrels per day	mcf/d	=	thousand cubic feet per day
boe	=	barrel of oil equivalent	mmcf	=	million cubic feet
boe/d	=	barrels of oil equivalent per day	mmcf/d	=	million cubic feet per day
mbbls	=	thousand barrels	mmbbls	=	million barrels
mbbls/d	=	thousand barrels per day	mmbls/d	=	million barrels per day
mboe	=	thousands of barrels of oil equivalent	mmbtu	=	million British thermal units
mboe/d	=	thousands of barrels of oil equivalent per day	tcf	=	trillion cubic feet

Oil equivalents compare quantities of oil with quantities of gas or express these different commodities in a common unit. A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6 mcf/1 bbl). Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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CURRENCY AND EXCHANGE RATES

Unless otherwise specified, all reference to dollars or to $ are to US dollars and all references to Cdn$ are to Canadian dollars. The noon-day exchange rates for Cdn$1.00, as reported by the Bank of Canada, were:

(US$)	2010	2009	2008	2007	2006
Closing	1.01	0.96	0.82	1.01	0.86
High	1.01	0.97	1.03	1.09	0.91
Low	0.93	0.77	0.77	0.84	0.85
Average Noon	0.93	0.88	0.94	0.93	0.88

On March 4, 2011, the noon-day exchange rate was US$0.97 for Cdn$1.00.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report, including those appearing in Items 1 and 2 Business and Properties and Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A), constitute 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 (the Exchange Act), and Section 27A of the United States Securities Act of 1933, as amended (the Act). 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 or HTL™ 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 oil and gas exploration properties from larger, better 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

The principal executive offices of Ivanhoe Energy Inc. (Ivanhoe, the Company, we, our, or us) are loca 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.

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Electronic copies of the Company s filings with the United States Securities and Exchange Commission (the SEC) and the Canadian Securities Administrators (the CSA) are available, free of charge, through our website (www.ivanhoeenergy.com) or, upon request, by contacting our investor relations department at (403) 817-1108. Alternatively, the SEC and the CSA each maintains a website (www.sec.gov and www.sedar.com) that contains our reports, proxy and information statements and other published information that have been filed or furnished 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.

PART I

ITEMS 1 AND 2: BUSINESS AND PROPERTIES

GENERAL

Ivanhoe 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. Core operations are in Canada, Ecuador, China and Mongolia, with business development opportunities worldwide. Ivanhoe is the listed parent company and is responsible for Canadian operations. Operations in Latin American are conducted through Ivanhoe Energy Latin America Inc., while activities in China and Southeast Asia are operated by Sunwing Energy Ltd. (Sunwing).

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. On June 24, 1999, Black Sea Energy Ltd. merged with Sunwing, and we changed our name to Ivanhoe.

In 2005, Ivanhoe completed a merger with Ensyn Group Inc. (Ensyn) acquiring the proprietary, patented heavy oil upgrading process called HTL . In July 2008, the Company acquired oil sand assets in the Athabasca region of Canada. Later in 2008, we signed a contract with the Ecuador state oil companies to explore and develop Ecuador s Pungarayacu heavy oil field in Block 20. In 2009, Ivanhoe sold its wholly owned subsidiary, Ivanhoe Energy (USA) Inc., disposing of all our oil and gas exploration and production operations in the United States (US). We also acquired a production-sharing contract for the Nyalga Block XVI in Mongolia in 2009, through a merger with PanAsian Petroleum Inc., a privately-owned corporation.

CORPORATE STRATEGY

Ivanhoe continues to pursue its core strategies, which are:

- Utilize long-standing knowledge and relationships in the Far East to pursue conventional oil and gas production and exploration opportunities;
- Seek out heavy oil development projects globally that have operational needs that can benefit from our proprietary HTL™ technology; and
- Bias new country entry and business development to projects that, because of their remote setting, geo-political status or operational needs, have been overlooked by the broader industry, subsequently expanding efforts in the new locations to more conventional oil and gas industry activities.

Pursuing Natural Gas in China

Ivanhoe s wholly-owned subsidiary, Sunwing, has been conducting operations in China since the mid-1990s. In particular, Sunwing is focused on a key natural gas exploration project (the Zitong Block) in Sichuan Province of China. Sichuan is the oldest and one of the most productive gas producing regions of China. Sinopec and PetroChina have made significant gas discoveries in blocks adjacent to Sunwing s Zitong Block.

The Sichuan Basin, located in central China approximately 930 miles southwest of Beijing, is the country s largest gas-producing region, currently producing more than 800 mmcf/d and estimated by Chinese officials to contain a natural gas resource potential of 260 tcf. There is a strong and growing local market for natural gas, with approximately 120 million people living within the basin and with well-developed grid connections to adjacent industrial and population areas.

Natural gas sales are regulated in China and current prices are approximately $5.00/mcf at the wellhead. As part of China s commitment to develop cleaner sources of energy, demand for natural gas is projected to continue to grow in the country and Sunwing s goal is to tap into this burgeoning market.

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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 low cost replacement reserves. This has resulted in volatility in oil markets and marked shifts in the demand and supply landscape. Ivanhoe believes 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 types of oil play an important role in our 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 become increasingly more common.

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. Nevertheless, remaining challenges for profitable exploitation include: i) the requirement for steam and electricity to help extract heavy oil; ii) the need for diluent to move the oil once it is at the surface; iii) the heavy versus light oil price differentials that the producer is faced with when the product gets to market; and iv) conventional upgrading technologies are 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

With the application of the HTL process, Ivanhoe seeks to address the key heavy oil development challenges and can do so at a relatively small minimum economic scale.

Ivanhoe s HTL upgrading is a partial upgrading process that is designed to operate in facilities as small as 10,000 to 30,000 bbls/d. 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 bbls/d. The HTL process 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, with processing times 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. HTL has the added advantage of converting the by-products 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:

- virtual elimination of external energy requirements for steam generation and/or power for upstream operations;
- elimination of the need for diluent or blend oils for transport;
- capture of the majority of the heavy versus light oil value differential; and
- 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 Ivanhoe will have to establish its unique value proposition.

Implementation Strategy

Ivanhoe is an oil and gas company with a unique technology which addresses several major problems confronting the oil and gas industry today and the Company believes it has a competitive advantage because of its patented upgrading process. In addition, because Ivanhoe has experienced thermal recovery teams, the Company is in a position to add value and leverage its technology advantage by working with partners on stranded heavy oil resources around the world.

The Company s continuing strategy is as follows:

- **Advance its two key heavy oil projects in Canada and Ecuador.** Continue to deploy personnel and financial resources in support of the Company s goal to become a significant heavy oil producer.
- **Advance the HTL process.** Additional development work will continue to advance the HTL process through the commercial application of HTL upgrading in Canada, Ecuador and beyond.
- **Advance its natural gas project in the Zitong Block in Sichuan Province, China**. Through its wholly-owned subsidiary, Sunwing Energy, proceed with additional planning and operational analysis to develop an appraisal program leading to a full development plan for the Zitong block.
- **Enhance the Company s financial position to support its major projects.** Implementation of large projects requires significant capital outlays. The Company is working on various financing initiatives and establishing the relationships required for future development activities.
- **Build internal capabilities.** The Company continues to seek to build its internal leadership and technical capabilities through the addition of key personnel associated with each major project.
- **Continue to deploy the personnel and the financial resources to capture additional opportunities for development projects utilizing the Company s HTL process**. Commercialization of the Company s upgrading process requires close alignment with partners, suppliers, host governments and financiers.

PROPERTY DESCRIPTIONS

Our oil and gas operations are broken down into three geographic areas: Canada, Ecuador and Asia. The Business and Technology Development area captures costs incurred in the pursuit of projects throughout the world as well as expenses incurred to develop, enhance and identify improvements in the application of the HTL technology. Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 11 to the consolidated financial statements and in the MD&A in this Annual Report.

Integrated Oil and Gas Properties

Canada

Tamarack, acquired in 2008, is a 6,880 acre block located approximately 10 miles northeast of Fort McMurray, Alberta, Canada. Ivanhoe holds a 100% working interest in the property, subject only to a 20% back-in right held by Talisman Energy Canada (Talisman), which expires in mid-2011.

Our independent reserve evaluator, GLJ Petroleum Consultants Ltd. (GLJ), has assigned total 3P reserves of 220 mmbbls of bitumen to Tamarack. It is anticipated that the resources will be developed utilizing steam assisted gravity drainage (SAGD) technology. The Company expects that 12 well pads and approximately 160 SAGD well pairs will be required to fully develop and produce the targeted resource base.

In March 2010, a 28 well winter delineation program was completed, which provided information necessary for regulatory filings. In November 2010, Ivanhoe filed a comprehensive Environmental Impact Assessment with the Government of Alberta. In support of the application, Basic Engineering and Design and Front End Engineering and Design were completed to generate a Class III (+25/-20%) capital cost estimate. Subject to regulatory approvals from the Alberta Energy Resources Conservation Board and Alberta Environment, construction at Tamarack could commence in mid-2012, with commissioning and start-up of the production facilities expected in the fourth quarter of 2013.

Ecuador

In October 2008, Ivanhoe Energy Ecuador Inc., an indirect wholly owned subsidiary, signed a 30 year contract with the Ecuador state oil companies Petroecuador and Petroproduccion. The contract gives us the right to explore and develop the Pungarayacu heavy oil field in Block 20, an area of 426 square miles, approximately 125 miles southeast of Quito, Ecuador s capital. We anticipate using HTL technology, as well as providing advanced oilfield technology, expertise and capital to develop, produce and upgrade heavy oil from the Pungarayacu field. The Company may also explore for lighter oil in the contract area and use any light oil discoveries to blend with the heavy oil for delivery to Petroproduccion.

In 2010, the IP-5b well was successfully drilled, cored and logged to a total depth of 1,080 feet. The well was perforated in the Hollin oil sands and steam was successfully injected into the reservoir resulting in production of heated heavy oil. The Company s IP-15 well, drilled in 2010, encountered certain cementing and completion problems during steam injection operations and testing at the well was suspended without recovering oil. Ivanhoe sees significant variability between the two well locations, supporting the view that geological faulting is prevalent in Block 20 due to the close proximity of the Andes, directly to the west of the block. We plan to commence a seismic program following testing operations at IP-5b to increase understanding of the geological faulting and to help determine locations for our next appraisal wells.

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Conventional Oil and Gas Properties

Asia

China

Zitong

In November 2002, we entered into a 30 year production sharing contract with China National Petroleum Corporation (CNPC) for the Zitong block, which covers an area of approximately 658,000 gross acres after contractual relinquishments in the Sichuan basin. The parties will jointly participate in the development and production of any commercially viable deposits, with production rights limited to the later of 2032 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 for $4.0 million.

In Phase I of the contract, Ivanhoe reprocessed 1,649 miles of existing 2D seismic data and acquired 705 miles of new 2D seismic data. Two wells were drilled and although both wells encountered expected reservoirs and gas was tested on the second well, neither well demonstrated commercially viable flow rates and both wells were suspended.

In Phase II, two wells were drilled in 2010 at the Zitong block, both resulting in gas discoveries. The Yixin-2 well was tested in December 2010 with gas flowing from the Xu-4 Formation. Following initial flow and pressure tests, the well was shut-in for pressure build-up. The Zitong-1 well reached total depth in December 2010 and was tested in January 2011, with gas flowing from the Xu-4 Formation. The well was subsequently shut-in to record reservoir pressure build-up and allow testing of the shallower, Xu-5 formation.

Following the drilling of the Zitong-1 and Yixin-2 wells, areas excluding those identified for development and future production were to be relinquished. In January 2011, Ivanhoe received notice that the exploration period has been extended for an additional six months.

Dagang

Ivanhoe s oil production originates in the Kongnan oilfield in Dagang, Hebei Province, China (the Dagang field). We have a 30 year production sharing contract with CNPC, covering an area of 10,255 gross acres. From 2001 to 2007, we drilled 44 wells and commercial production commenced on January 1, 2009. The project reached cost recovery in September 2009 and our working interest decreased to 49%. Operations in the Dagang field will revert to CNPC at the end of the 20 year production phase of the contract or earlier if the field is abandoned.

In 2010, quotas restricted production to 70,000 gross tonnes or 1,400 bbls/d gross. Actual production in 2010 averaged 750 bbls/d net. Production quotas in 2011 are set at 80,000 gross tonnes or approximately 1,600 bbls/d gross.

Mongolia

Through a merger with PanAsian Petroleum Inc. in November 2009, we acquired a production sharing contract for the Nyalga Block XVI in the Khenti and Tov provinces in Mongolia. The block covers an area of approximately 3.1 million gross acres, after a 25% relinquishment in 2010. The five year exploration period is divided into three consecutive phases, consisting of two years (Phase I), one year (Phase II) and two years (Phase III), with the ability to nominate a two year extension following Phase I or Phase II.

During the initial seismic program, approximately 16% of the block in the Delgerkhaan area was declared by the Mongolian government to be a historical site and operations in this area were suspended. A letter from the Mineral Resources and Petroleum Authority of Mongolia (MRPAM) stated that the obligations under year one of Phase I would be extended for one year from the time the Company is allowed to re-enter the suspended area. To date, access has not been granted and discussions with MRPAM are ongoing. As a result, the government has adjusted the dates in which the project year begins. Phase II is now considered to have commenced on July 20, 2010.

From late 2009 through the first quarter of 2010, the Company acquired an additional 465 kilometres of 2-D seismic across Block XVI, for a total of 925 kilometres of 2-D seismic data over the Kherulen sub-basin. In 2010, preparations commenced for a five well drilling program and a seismic acquisition program. The first exploratory location has been identified and we expect to initiate drilling operations in Mongolia in the first half of 2011.

RESERVES, PRODUCTION AND RELATED INFORMATION

In addition to the information provided below, please refer to the Supplementary Disclosures About Oil and Gas Production Activities (Unaudited) set forth in Item 8 in this Annual Report for certain details regarding the Company s oil and gas proved reserves, the estimation process and production by country. We have not filed with nor included in reports to any other US federal authority or agency, any estimates of total proved oil reserves since the beginning of the last fiscal year.

The following table presents estimated proved, probable and possible oil reserves as of December 31, 2010:

Summary of Oil and Gas Reserves Using Average 2010 Prices[(1)]

	Canada	**China**		
(mbbl)	**Tamarack**	**Dagang**	**Other**	**Total**
Proved				
Developed		1,186	79	1,265
Undeveloped		473		473
Total proved		1,659	79	1,738
Probable				
Developed		322		322
Undeveloped	175,684	470		176,154
Possible				
Developed				
Undeveloped	43,809			43,809

(1) Reserves are the Company s total gross reserves before royalty deductions.

Canada

Probable and Possible Reserves

In 2010, probable and possible reserves increased from nil in 2009 to 219,493 mbbls as a result of completing a 28 well delineation drilling program on the Tamarack lands, further technical evaluation and the submission of Ivanhoe s regulatory application to the Government of Alberta in November 2010. Further reserve development is subject to regulatory approval and availability of financing.

Possible reserves are within the Tamarack project application area, but have a lower degree of certainty compared to our probable reserves due to lower quality reservoir characteristics or decreased certainty based on the level of reservoir delineation.

Basis of Reserves Estimates

Probable and possible reserves will be developed using a SAGD thermal recovery process, which has been successfully demonstrated in similar projects in the Athabasca Oil Sands region. Recovery estimates for Tamarack are based on applying appropriate recovery factors to original oil-in-place estimates developed through detailed reservoir characterization. The reservoir characterization is based on information gathered during historical field delineation programs. Recovery factors applied to the oil-in-place estimates are the result of simulation and analytical models, incorporating the actual performance of existing analog projects.

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China

Proved Reserves

Proved reserves at December 31, 2010, were 1,738 mbbls compared to 1,101 mbbls at December 31, 2009, an increase of 58% after 2010 production. Proved reserves increased due to in-field performance improvements from continued water injections, a partial natural water drive and our ongoing hydraulic fracture stimulation program in the Dagang field. Drilling activity in late December 2010 was successful and, in combination with geological review and reservoir mapping, supported additional future drilling locations. Proved reserves also benefitted from a pool extension due to the addition of re-activated wells in the periphery of the reservoir.

The transfer of reserves from proved undeveloped to the proved category was immaterial in 2010.

Probable Reserves

At December 31, 2010, probable reserves in China were 792 mbbls, an increase of 137% over the 334 mbbls reported at December 31, 2009. Additional probable reserves were assigned based on production improvements and increased recovery factors discussed under proved reserves.

Basis of Reserve Estimates

Reserve estimates were calculated using recovery forecasts based on historical production, supported by volumetric estimates using geological parameters. Recoveries rarely exceed 15% of the volumetrically calculated original oil-in-place per well spacing, which is judged acceptable for a water flood in a light oil reservoir. Improvements in production history and production declines are used for a review of producing reserves. With further mapping and geological reviews, proved and probable undeveloped reserves may then be assigned to future drilling and well optimizations.

Internal Control Over Reserve Estimation

Management is responsible for the estimates of oil and gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the US and the standards of the Canadian Oil and Gas Evaluation Handbook modified to reflect SEC requirements. Our reserve estimates and disclosures may differ from other Canadian issuers who follow National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities (NI 51-101). Significant differences between SEC and Canadian reserve estimates and disclosures are described in the Special Note to Canadian Investors on page 10.

The process of estimating reserves requires complex judgments and decision making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and make various assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepared our estimates. However, 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.

Reserve estimates are categorized by the level of confidence that they will be economically recoverable. Proved 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 in future years from known reservoirs under existing economic conditions, operating methods and government regulations. The term reasonable certainty implies a high degree of confidence that the quantities of oil and gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, the technologies used in the estimation process have been demonstrated to yield results with consistency and repeatability.

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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. Therefore, probable reserves have a higher degree of uncertainty than proved reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. Although possible reserve locations are found by stepping out from proved reserve locations, estimates of probable and possible reserves are, by their nature, more speculative than estimates of proved reserves and, accordingly, are subject to substantially greater risk of being realized.

Our reserve estimates were prepared by GLJ and reviewed by our in-house Senior Engineering Advisor (SEA). Our SEA is a professional engineer, with over 25 years of experience in the oil industry focused on heavy oil recovery techniques. His past experience includes international positions responsible for thermal horizontal and vertical well development projects using state-of-the-art reservoir management techniques and advanced 3D reservoir visualization methods to integrate complex data sets. He has experience supervising project expansions and investigating new development scenarios using reservoir simulation and advanced economic modeling.

All reserve information in this Annual Report is based on estimates prepared by GLJ. The technical personnel responsible for preparing the reserve estimates at GLJ meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas by the Society of Petroleum Engineers. GLJ is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

Our Board of Directors reviews the current reserve estimates and related disclosures as presented by the independent qualified reserves evaluators in their reserve report. 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 regulatory securities disclosures are prepared based on SEC disclosure requirements. In 2003, certain Canadian securities regulatory authorities adopted NI 51-101 which prescribes standards that Canadian companies are required to follow in the preparation and disclosure of reserves and related information.

In 2010, we re-applied for, and received, exemptions from certain 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 US 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 reserve quantities disclosed in this Annual Report represent net reserves calculated on an average, first-day-of-the-month price during the 12 month period preceding the end of the year for 2010, 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 US, 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 and NI 51-101 requirements may be material.

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Production, Sales Prices and Production Costs

	2010	2009	2008
Oil production (bbls/d)	**788**	1,276	1,339
Average sales price ($/bbl)	**75.52**	53.60	98.73
Average operating costs (1) ($/bbl)	**33.05**	21.88	43.92

(1) Average operating costs per unit of production, based on net interest after royalties, represent lifting costs, including a windfall gain levy. According to the Administrative Measures on Collection of Windfall Gain Levy on Oil Exploitation Business, enterprises exploiting and selling oil in China are subject to a windfall gain levy (the Windfall Levy) if the monthly weighted average price of oil is above $40.00/bbl. Excludes depletion and depreciation, income taxes, interest, selling and general administrative expenses.

Ivanhoe s oil production originates in Asia, specifically the Dagang and Daqing fields in China. The majority of our production comes from Dagang and is sold to the national petroleum company.

Producing Oil Wells

The company does not have any producing gas wells. Producing oil wells are reported below.

	2010		2009		2008	
	Gross(1)	**Net(2)**	Gross(1)	Net(2)	Gross(1)	Net(2)
Asia	**44.0**	**21.6**	44.0	21.6(3)	44.0	36.1

(1) Gross wells are the total number of wells in which a working interest is owned.

(2) Net wells are the sum of fractional working interests owned in gross wells.

(3) Our working interest in net wells was reduced from 82% to 49% as stipulated by the governing production sharing contracts upon the Company completing the recovery of its development investments in September 2009.

Drilling Activity

At December 31, 2010, we were actively drilling the Zitong-1 and Yixin-2 wells in our Zitong project and one well in our Dagang field. No wells were completed in 2010. The Company did not drill any exploration or development wells in 2009 or 2008.

Acreage

	Developed Acres		Undeveloped Acres(1)	
	Gross	**Net**	**Gross**	**Net**
Canada			7,520	7,520
Ecuador			272,639	272,639
Asia China(2)	1,525	747	664,314	595,338
Asia Mongolia			3,107,907	3,107,907

(1) Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves.

(2) 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.

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

We signed a specific services contract with affiliated entities of the State of Ecuador in October 2008 that allows us to develop Block 20 for a term of 30 years, extendable by mutual agreement of the parties, for two additional periods of five years each, depending on the interests of the State and in conformity with local laws.

Acreage in the Dagang field will return to CNPC in 2027. Following the completion of Phase II of the Zitong Contract, the remaining acreage must be relinquished to CNPC except for areas identified for development and future production, which will be relinquished upon termination of the production sharing contract in 2032.

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Acreage in Mongolia is subject to periodic relinquishments up to the end of the exploration period and the remaining acreage designated for appraisal and development will expire 20 years after the final commercial discovery on the Nyalga block.

BUSINESS AND TECHNOLOGY DEVELOPMENT

The Company s Business and Technology Development segment captures HTL activities as well as costs associated with the pursuit of new business development opportunities.

Technology Development

In April 2005, Ivanhoe acquired Ensyn and thereby obtained an exclusive, irrevocable license to the HTL process for all applications other than biomass. We have since continued to expand patent coverage to protect innovations to the HTL technology and to significantly extend Ivanhoe s portfolio of HTL intellectual property. Ivanhoe is the assignee of three granted US patents and currently has three US patent applications pending. In other countries, 47 patents are pending. In addition, Ivanhoe owns exclusive, irrevocable licenses to 21 global patents as well as proprietary technological knowledge for the rapid thermal processing process of petroleum.

Ivanhoe operates a feedstock test facility (FTF) at the Southwest Research Institute in San Antonio, Texas. The FTF is a small 10-15 bbls/d, highly flexible state-of-the-art facility which will permit analysis of crude oil in small volumes.

In 2010, the FTF was used to support basic and front-end engineering for a commercial-scale HTL plant for the Tamarack project in Canada. Also, the unit was used to support conceptual design for several projects, including Pungarayacu in Ecuador. As we continue to advance our technology, the FTF will serve an integral role in supporting the Company s commercial operations.

The FTF replaced the Commercial Demonstration Facility (CDF), constructed in 2004. The CDF was decommissioned in 2010 and all future testing will be conducted at the FTF.

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.

In 2010, HTL™ heavy oil and selected conventional oil opportunities were pursued in North and South America, the Middle East and North Africa.

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 gas companies and other individual producers and operators, many of which have substantially greater financial and human resources and more developed and extensive infrastructure. Our larger competitors, by reason of their size and relative financial strength, can more easily access capital markets 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, adversely affecting our competitive position. Our competitors may be able to pay more for producing oil and gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly. 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. We have submitted the Regulatory Application/Environmental Impact Assessment for the Tamarack project to the Government of Alberta. The regulatory process is expected to take approximately 18 to 24 months. 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.

China, Mongolia 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.

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 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 in the US, 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, 2010, we had 211 employees actively engaged in the business. None of our employees are unionized.

ITEM 1A: RISK FACTORS

Our operations are exposed to various risks, some of which are common to others in the oil and gas industry and some of which are unique to our operations. Certain risks set out below constitute forward-looking statements and readers should refer to the Special Note Regarding Forward-Looking Statements set out on page 3 of this Annual Report.

Our ability to continue as a going concern may be adversely affected by inadequate funding

We have a history of operating losses and cash flow from operating activities will not be sufficient to meet our current obligations and fund future capital projects. Historically, we have relied upon equity capital as our principal source of funding. Continuation of the Company is dependent upon our ability to obtain additional capital to preserve our interests in current projects and to meet obligations associated with future projects. We may seek financing 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. There is no assurance that we will be able to obtain such financing on favorable terms, if at all, and any future equity issuances may be dilutive to investors. Obtaining financing may be hampered by 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. Without access to financing, we may not be able to continue as a going concern.

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We may not be able to fund our substantial capital requirements

Our business is capital intensive and the advancement of our exploration projects in China and Mongolia, development projects in Canada and Ecuador and HTL initiatives require significant funding. Since cash flows from existing operations are insufficient to fund future capital expenditures, we intend to finance future capital projects with 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 or from the sale of existing assets. There is no assurance that we will be able to obtain such financing on favorable terms, if at all, and any future equity issuances may be dilutive to investors. Obtaining financing in the future may be hampered by 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 adequate funding when needed, we may have to delay or forego 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.

We have fixed and contingent payment obligations to Talisman

As a result of acquiring our Athabasca heavy oil leases from Talisman in 2008, we have fixed and contingent payment obligations to Talisman. These obligations include a Cdn$40.0 million convertible promissory note (the Convertible Note) that, unless converted into Ivanhoe common shares, is due in July 2011, and a contingent payment of up to Cdn$15.0 million that will become due and payable if and when the requisite government and other approvals to develop the northern border of one of the Athabasca heavy oil leases are obtained. 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, if at all, and any future equity issuances may be dilutive to investors. Obtaining financing in the future may be hampered by 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. Failure to obtain such additional financing could put us in default of our obligations to Talisman, 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 common shares we own in our subsidiaries. In the case of such default, Talisman could foreclose on the secured assets, including the leases.

The volatility of oil prices may affect our financial results

Our revenues, operating results, profitability and future growth are highly dependent on the price of 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.

Oil prices may fluctuate widely in response to relatively minor changes in supply and demand, 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 (OPEC) 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; and 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.

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

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 in Item 7, MD&A, of this Annual Report.

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. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment, the assumptions used regarding prices for oil and gas, production volumes, required levels of operating and capital expenditures and quantities of recoverable oil reserves. 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 oil and gas prices after the date of the estimate may result in revisions to our reserve estimates. Revisions to prior estimates may be material.

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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 acceptable level of economic return. We may misinterpret geological or engineering data, which may result in material losses from 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 production costs.

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

We operate in a highly competitive environment and compete with oil and gas companies and other individual producers and operators, many of which have longer operating histories and substantially greater financial and other resources. Many of these companies not only explore for and produce oil and gas, but also carry on refining operations and market petroleum and other products on a worldwide basis. We also compete with companies in other industries supplying energy, fuel and other needs to consumers. Our larger competitors, by reason of their size and relative financial strength, can more easily access capital markets 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 and handle longer periods of reduced oil and gas prices more easily. Our competitors may be able to pay more for productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects.

We compete with other companies to recruit and retain the limited number of individuals who possess the requisite skills and experience 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 employees with the abilities and expertise we require will be available.

Changes to laws, regulations and government policies in the jurisdictions in which we operate could adversely affect our ability to develop our projects

Our projects in Canada, Ecuador, China and Mongolia are subject to various international, federal, state, provincial, territorial and local laws and regulations relating to the exploration for and the development, production, upgrading, marketing, pricing, taxation and transportation of heavy oil, bitumen and related products and other matters, including environmental protection.

The exercise of discretion by governmental authorities under existing legislation and regulations, the amendment of existing legislation and regulations or the implementation of new legislation or regulations, affecting the oil and gas industry could materially increase the cost of developing and operating our projects and could have a material adverse impact on our business. There can be no assurance that laws, regulations and government policies relevant to our 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 our projects and increase 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 government 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 denied. There is no assurance that 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 our projects.

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

Our operations are governed by various international, federal, state, provincial, territorial and local laws and regulations. Oil, gas, oil sands and heavy oil extraction, upgrading and transportation operations are subject to extensive regulation. 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 in 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.

The costs of complying with environmental laws and regulations in the future may harm our business. Furthermore, future changes in environmental laws and regulations may 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 or our ability to develop or operate our projects in a manner consistent with our current expectations. No assurance can be given that environmental laws will not limit project development or materially increase the cost of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or prospects.

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

Our operations are subject to many risks inherent in the oil and gas industry, including 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, any of which could cause us to experience material losses.

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.

Under environmental 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, if environmental damage occurs.

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

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. Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels for the production of steam 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 SAGD 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 may not successfully commercialize our HTL technology

Success in commercializing our HTL technology in the oil and gas industry depends on our ability to economically design, construct and operate commercial-scale plants and a variety of other factors, many of which are outside our control. To date, commercial-scale HTL plants have only been constructed in the bio-mass industry.

Technological advances could render our HTL technology 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 progress. It is possible that those advances could cause our HTL technology to become uncompetitive or obsolete.

Alternate sources of energy could lower the demand for our HTL technology

Alternative sources of energy are continually under development. If reliance upon petroleum based fuels decreases, the demand for our HTL upgraded product may decline. It is possible that technological advances in engine design and performance could reduce the use of petroleum based fuels, which would also lower the demand for our HTL upgraded product.

Efforts to commercialize our HTL technology may give rise to claims of infringement upon the patents or other 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 other rights of others in this technology until after we have made a substantial investment in the development and commercialization of projects utilizing the technology. Third parties may claim that the technology infringes upon past, present or future patented technologies. Legal actions could be brought against us and our licensors 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.

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

While discussing potential business relationships with third parties, we may disclose confidential information on operating results or proprietary intellectual property. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to our business that such a breach of confidentiality may cause.

Certain projects are at a very early stage of development

Our projects are at varying stages of development. We have submitted the Regulatory Application/Environmental Impact Assessment for the Tamarack project to the Government of Alberta. The regulatory process is expected to take approximately 18 to 24 months; however, there is no assurance that the process will be completed on a timely basis and construction of the Tamarack Project could be significantly delayed. The Government of Alberta may not approve the project as proposed, or it may place certain conditions upon the approval, which could significantly impair the economics of the project. Our Zitong project in China and projects in Ecuador and Mongolia are at a very early stage of development; no reserves have yet been established and no detailed feasibility or engineering studies have yet been produced.

There can be no assurances that 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.

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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 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, if at all.

Aboriginal peoples have claimed aboriginal title and rights to large areas of land in western Canada where oil and 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 material adverse effect on our business.

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 will comply with the dispute resolution provisions or otherwise voluntarily submit to arbitration.

Government policy in Ecuador may change to discourage foreign investment or requirements not 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.

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.

Our principal shareholder may significantly influence our business

As at the date of this Annual Report, our largest shareholder, Robert M. Friedland, owned approximately 15.22% 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.

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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 that these individuals will remain with us in the future. An unexpected partial or total loss of their services would harm our business.

Information 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 the availability and cost of capital; the 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; personnel; success or failure of activities in similar areas; changes in estimates of project completion costs; and our ability to attract other industry partners to acquire a portion of the working interest to reduce costs and exposure to risks.

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. Our plans regarding our projects might change.

ITEM 1B: UNRESOLVED STAFF COMMENTS

None.

ITEM 3: LEGAL PROCEEDINGS

The Company is a defendant in a lawsuit filed on November 20, 2008, in the United States District Court for the District of Colorado by Jack J. Grynberg and three affiliated companies. The suit alleged bribery and other misconduct and challenged the propriety of a contract awarded to the Company s wholly-owned subsidiary Ivanhoe Energy Ecuador Inc. to develop Ecuador s Pungarayacu heavy oil field. The plaintiff s claims were for unspecified damages or ownership of the Company s interest in the Pungarayacu field. The Company and related defendants filed motions to dismiss the lawsuit for lack of jurisdiction. The Court granted the motion and dismissed the case without prejudice. The Court granted Mr. Robert Friedland s request to sanction plaintiffs and plaintiffs counsel for their conduct related to bringing the suit by awarding Mr. Friedland fees and costs. The Ivanhoe corporate defendants, including the Company, have been awarded their costs in defending the suit and have requested an award of attorneys fees.

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. On July 15, 2010, the Court denied the plaintiffs motion to vacate the judgment. The request for attorneys fees remains pending before the Court. On August 13, 2010, the plaintiffs filed a notice of appeal challenging the district court s judgment and some of its orders. The appeal is currently pending in the United States Court of Appeals for the Tenth Circuit. Briefing on the appeal is complete; the plaintiffs have filed an opening and reply brief and the Company and related defendants have filed a response brief. The Court has not announced whether it will hold oral argument on the appeal before it is decided. 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.

On December 30, 2010, the Company received a demand for arbitration from GAR Energy and Associates, Inc. (GAR Energy) and Gonzalo A. Ruiz and Janis S. Ruiz as successors in interest to and assignees of GAR Energy. The demand alleges breach of contract, fraud and other misconduct arising from a consulting agreement and various collateral agreements between GAR Energy and the Company relating to the Pungarayacu heavy oil field. The claimants seek actual damages of $250,000, a portion of the Company s interest in the Pungarayacu field and other miscellaneous relief. The dispute is still in its early stages and arbitration proceedings, including discovery, have not yet commenced. The likelihood of loss or gain resulting from this dispute, and the estimated amount of ultimate loss or gain, are not determinable or reasonably estimable at this time.

PART II

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

Our common shares trade on the Toronto Stock Exchange (the TSX) and The NASDAQ Capital Market (NASDAQ) under the symbols IE and IVAN respectively. The trading range of our common shares is as follows:

	TSX (Cdn$)		NASDAQ (US$)	
	High	**Low**	**High**	**Low**
2010				
Q1	3.90	2.90	3.79	2.75
Q2	3.36	1.97	3.37	1.87
Q3	2.19	1.59	2.08	1.50
Q4	2.89	2.15	2.88	2.10
2009				
Q1	1.53	0.57	1.22	0.45
Q2	2.16	1.38	1.85	1.10
Q3	2.98	1.31	2.81	1.13
Q4	3.25	2.20	3.12	2.02

On December 31, 2010, the closing prices of our common shares were Cdn$2.72 on the TSX and $2.72 on NASDAQ. As at December 31, 2010, a total of 334,365,482 of our common shares were issued and outstanding and held by 203 holders of record with an estimated 22,700 additional shareholders whose common 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.

EXEMPTIONS FROM CERTAIN NASDAQ MARKETPLACE RULES

As a Canadian issuer listed on 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 Exchange Act; and (iv) we must provide a brief description of any significant differences between our corporate governance practices and those followed by US 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 independent directors hold meetings from time to time, as and when considered necessary or desirable by the independent lead director or by any other independent 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 reside outside the US and a substantial portion of their assets and our assets are located outside the US. As a result, it may be difficult to effect service of process within the US upon the directors, controlling shareholders, officers and representatives of experts who are not residents of the US or to enforce against them judgments obtained in the courts of the US based upon the civil liability provisions of the federal securities laws or other laws of the US. 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 US, in original actions or in actions for enforcement of judgments of US courts, of liabilities based solely upon civil liability provisions of the US 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.

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) 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 (a Cultural Business). 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 2011 is Cdn$312 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 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$312 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 common 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 shareholders as dividends in respect of the common shares held at a time when the beneficial owner is 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-US 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 US resident that is entitled to the benefits of the Convention is generally 15%. However, if the beneficial owner of such dividends is a US 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 US for the purpose of the Convention, the withholding tax on dividends may be reduced to 0%.

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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.

PERFORMANCE GRAPH

See table under Executive Compensation set forth in Item 11 in this Annual Report.

SALES OF UNREGISTERED SECURITIES

All securities we issued during the years ended December 31, 2010 and 2009, which were not registered under the Act, have been detailed in previously filed Form 10-Qs and Form 8-Ks.

ITEM 6. SELECTED FINANCIAL DATA

FIVE YEAR SUMMARY OF SELECTED FINANCIAL DATA

The financial data presented below has been revised to account for the sale of all of the Company s US oil and gas exploration and production operations in 2009 as discontinued operations on a retroactive basis in accordance with generally accepted accounting principles (GAAP) in Canada. See Note 18 to the consolidated financial statements under Item 8 in this Annual Report.

($000s, except per share amounts)	**2010**	**2009**	**2008**	**2007**	**2006**
Results of Operations					
Revenues	21,928	23,658	50,670	26,689	36,320
Net loss from continuing operations	(29,110)	(37,731)	(38,476)	(33,433)	(25,677)
Net loss from continuing operations per share basic and diluted	(0.09)	(0.13)	(0.15)	(0.14)	(0.11)
Financial Position					
Total assets	409,585	281,763	346,875	266,516	278,144
Debt	39,832				
Long term debt		36,934	37,855	9,812	2,737
Asset retirement obligations	744	195	1,928	739	484
Long term obligation	1,900	1,900	1,900	1,900	1,900

RECONCILIATION TO US GAAP

Our consolidated financial statements have been prepared in accordance with GAAP in Canada, which differ in certain respects from those principles that we would have followed had our consolidated financial statements been prepared in accordance with GAAP in the US. The differences between Canadian and US GAAP, which affect our consolidated financial statements, are described in detail in Note 20 to our consolidated financial statements in this Annual Report. Had we followed US GAAP, certain selected financial information would have been reported as follows:

($000s, except per share amounts)	**2010**	**2009**	**2008**	**2007**	**2006**
Results of Operations					
Revenues	36,945	17,152	55,335	27,281	35,628
Net loss from continuing operations	(10,271)	(32,679)	(47,911)	(23,080)	(35,477)
Net loss from continuing operations per share basic and diluted	(0.03)	(0.12)	(0.19)	(0.10)	(0.15)

Financial Position					
Total assets	393,675	262,717	292,847	251,627	252,893
Debt	40,217				
Long term debt		38,005	40,392	10,412	2,737
Asset retirement obligations	744	195	1,928	739	484
Long term obligation	1,900	1,900	1,900	1,900	1,900

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

The following MD&A should be read in conjunction with the consolidated financial statements for the year ended December 31, 2010. The consolidated financial statements have been prepared in accordance with GAAP in Canada. The impact of significant differences between Canadian and US GAAP on the consolidated financial statements is disclosed in Note 20 to the consolidated financial statements. The date of this discussion is March 4, 2010. Unless otherwise noted, tabular amounts are in thousands of US dollars. Oil and gas volumes and reserves and related measures are presented on a working interest, before royalties basis.

EXECUTIVE OVERVIEW OF 2010 RESULTS

Production decreased in 2010 compared to 2009 as Ivanhoe s working interest at Dagang, China was reduced to 49% upon the Company recovering its development costs in 2009. Although realized prices in 2010 were higher than in the past year, overall oil revenue declined due to lower production volumes. Lower revenue in combination with higher general and administrative costs resulted in additional cash flow used in operating activities in 2010 compared to 2009.

The net loss from continuing operations in 2010 improved over the prior year as the result of non-cash items. Lower depletion expense and an unrealized foreign exchange gain compensated for the decrease in revenue, the elimination of a future income tax recovery and higher stock-based compensation costs.

Capital expenditures totaled $86.3 million in 2010. A 28 well winter delineation program was completed in March 2010 at Tamarack. With the information gathered from the drilling program, Ivanhoe filed a comprehensive Environmental Impact Assessment with the Government of Alberta in November 2010. In support of the application, Basic Engineering and Design and Front End Engineering and Design were completed to generate a Class III (+25/-20%) capital cost estimate.

Two wells were drilled in the Pungarayacu field on Block 20 in Ecuador. The IP-5b well was drilled, perforated in the Hollin oil sands and steam was successfully injected into the reservoir resulting in production of heated heavy oil. The Company s initial well, IP-15, encountered cementing and completion problems during steam injection operations and testing at the well was suspended without recovering oil.

Gas was discovered at the Zitong-1 and Yixin-2 wells drilled in the Zitong Block in China. Following initial flow and pressure tests, both wells have been shut-in for pressure build-up. In Dagang, one well was drilling at year end and five fracture stimulations were performed during 2010. In the Nyalga basin of Mongolia, additional 2D seismic was acquired and preparations were made for a further 2D seismic program and a drilling program.

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HIGHLIGHTS

($000, except as stated)	2010	2009	2008
Average production (bbls/d)	**788**	1,276	1,339
Realized oil prices ($/bbl)	**75.52**	53.60	98.73
Oil revenue	**21,720**	24,968	48,370
Cash flow provided by (used in) operating activities	**(17,764)**	(12,290)	17,053
Net loss (continuing operations[(1)])	**(29,110)**	(37,731)	(38,476)
Net loss per share basic and diluted (continuing operations[(1)])	**(0.09)**	(0.13)	(0.15)
Working capital (continuing operations[(1)])	**16,485**	18,317	31,597
Capital expenditures (continuing operations[(1)])	**86,285**	26,373	21,063

(1) In July 2009, the Company disposed of its US operations and used the proceeds for its ongoing projects. To properly reflect this sale in the Company s 2010 consolidated financial statements, the results of the US operations have been separately identified in comparative disclosures as Discontinued Operations.

CHANGE IN NET LOSS

The following quantifies year-over-year changes in the components of net loss realized in the years ended December 31, 2010, 2009 and 2008.

	2010	*Change*	2009	*Change*	2008
Cash items					
Oil revenues	21,720		24,968		48,370
Production volumes		*(9,515)*		*(2,384)*	
Oil prices		*6,267*		*(21,018)*	
Operating costs	(9,503)	*688*	(10,191)	*11,324*	(21,515)
General and administrative, less stock-based compensation	(20,565)	*(2,563)*	(18,002)	*(6,198)*	(11,804)
Business and technology development, less stock-based compensation	(10,215)	*(872)*	(9,343)	*(3,458)*	(5,885)
Realized foreign exchange gain (loss)	(198)	*(87)*	(111)	*(346)*	235
Realized gain (loss) on derivatives		*(124)*	124	*4,554*	(4,430)
Net interest	184	*485*	(301)	*283*	(584)
Current income tax expense	(126)	*1,631*	(1,757)	*(1,103)*	(654)
Total cash changes	(18,703)	*(4,090)*	(14,613)	*(18,346)*	3,733
Non-cash items					
Unrealized gain (loss) on derivatives		*1,459*	(1,459)	*(7,577)*	6,118
Unrealized foreign exchange gain (loss)	3,523	*8,632*	(5,109)	*(3,347)*	(1,762)
Depletion and depreciation	(8,960)	*10,908*	(19,868)	*5,893*	(25,761)
Stock-based compensation	(6,095)	*(2,246)*	(3,849)	*(833)*	(3,016)

Provision for impairment of intangible asset and development costs		*1,903*	(1,903)	*13,151*	(15,054)
Write off of deferred financing costs				*2,621*	(2,621)
Future income tax recovery	1,125	*(8,475)*	9,600	*9,600*	
Discontinued operations (net of tax)		*23,921*	(23,921)	*(28,204)*	4,283
Other		*530*	(530)	*(417)*	(113)
Total non-cash changes	(10,407)	*36,632*	(47,039)	*(9,113)*	(37,926)
Net loss	(29,110)	*32,542*	(61,652)	*(27,459)*	(34,193)

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RESULTS OF OPERATIONS

Revenue

	2010	2009	2008
Production			
Asia (net bbls)			
Dagang	**273,868**	452,573	471,817
Daqing	**13,751**	13,231	18,096
Total production	**287,619**	465,804	489,913
Average daily production (bbls/d)	**788**	1,276	1,339
Pricing			
Average realized oil price ($/bbl)	**75.52**	53.60	98.73
West Texas Intermediate (WTI) ($/bbl)	**79.39**	61.80	99.65

2010 vs 2009

Oil revenue in 2010 was lower than in 2009 as a result of lower production volumes, despite higher realized prices in the current year. Production in 2010 decreased primarily as a result of Ivanhoe s working interest in the Dagang field decreasing to 49% in September 2009. The Company received a 2010 production quota of 70,000 gross tonnes or approximately 680 bbls/d net. The Company took advantage of this quota situation and performed certain maintenance workovers that normally would have been delayed. Production quotas in 2011 are set at 80,000 gross tonnes or approximately 1,600 bbls/d gross.

Dagang production is sold at the three month rolling average price of Cinta crude, which historically averages $3.00/bbl less than West Texas Intermediate (WTI). Following the increase in Cinta crude prices in 2010, our realized oil prices rose compared to 2009.

2009 vs 2008

Due to the combination of lower production and realized prices, oil revenue was lower in 2009 than in 2008. Production in 2009 decreased from 2008 due to normal field declines which were partially offset by productivity increases from adding new perforations, fracture stimulations and water flood response. In addition, Ivanhoe s working interest in the Dagang field decreased from 82% to 49% in September 2009 upon the Company recovering its development investments.

Realized oil prices decreased 46% per barrel in 2009 compared to the prior year, consistent with the decline in Cinta crude.

Netbacks

($/bbl)	**2010**	**2009**	**2008**
Oil revenue[(1)]	**75.52**	53.60	98.73
Less operating costs			
Field operating	**(19.96)**	(17.13)	(21.70)
Windfall Levy	**(11.59)**	(4.00)	(21.14)
Engineering and support costs	**(1.50)**	(0.75)	(1.08)
Net operating revenue[(1)]	**42.47**	31.72	54.81
Depletion	**(29.87)**	(38.70)	(47.22)
Net revenue (loss) from operations[(1)]	**12.60**	(6.98)	7.59

(1)

Oil revenue per barrel, net operating revenue per barrel and net revenue (loss) from operations per barrel do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Please refer to the Non-GAAP Financial Measures at the end of this MD&A for more details.

Operating Costs

2010 vs 2009

Operating costs on a per barrel basis rose in 2010, primarily as the result of an increase in the Windfall Levy administered in China due to higher realized oil prices in 2010 than in 2009. The Windfall Levy is imposed at progressive rates from 20% to 40% on the portion of the monthly weighted average sales price exceeding $40.00/bbl. Higher field costs in 2010 also contributed to the increase in operating costs per barrel. Additional electrical and instrumentation costs were incurred in Dagang as we installed variable frequency drives on certain producing wells to assist in reducing future maintenance and power costs. Additional transportation, oil treatment and processing expenses were also incurred, as well as higher local office costs due to increased field activity.

2009 vs 2008

Operating costs on a per barrel basis, as well as in total, decreased in 2009 from the prior year due to lower field costs as well as a reduction in the Windfall Levy. Field operating costs in 2009 declined from 2008 as the result of decreased road and lease maintenance and workover costs, offset by higher oil treatment costs. Once key milestones in the Production Sharing Contract with CNPC were reached in September 2009, we incurred a smaller proportionate share of costs in 2009 and a decline in overall working interest. Had the Company paid a smaller proportionate share of costs in 2008 and the overall working interest had also been lower, field operating costs would have been $0.68/bbl lower in 2008. The Windfall Levy expense decreased in 2009 from the prior year since oil prices realized by the Company were lower in 2009.

General and Administrative

2010 vs 2009

General and administrative expenses (G&A) rose in 2010, primarily as a result of higher staff and office costs incurred with the Company s growing commitments to its projects around the world. Staff and office costs increased $5.0 million in 2010 across all operating segments and corporate costs, such as stock exchange filing fees and non-cash stock-based compensation, increased by $1.8 million, which were offset by a decrease of $2.1 million in contract labour.

2009 vs 2008

In 2009, G&A rose in comparison to the prior period primarily as the result of higher costs in the corporate area and Ecuador. Corporate G&A rose $5.5 million in 2009 over 2008 due to incurring additional legal fees (see Item 3 to Part I of this Annual Report), corporate aircraft costs and personnel costs previously allocated to our US segment. These increases were partially offset by lower salary and benefit costs in 2009 due to the resignation of an executive in 2008, severance paid in 2008 and reallocating certain executive salaries to the Business and Technology Development segment. G&A for Ecuador were $1.6 million higher in 2009 as costs incurred prior to signing the contract to explore and develop Block 20 were minimal. G&A in China increased $0.8 million for 2009 over 2008 since a lower amount of G&A was allocated to capital projects in 2009. These increases were offset by a $0.5 million decrease in G&A incurred in Canada due to capitalizing costs related to the Tamarack property.

Business and Technology Development

2010 vs 2009

Business and technology development costs were higher in 2010 than in 2009. In 2010, the FTF was used to support basic and front-end engineering for a commercial-scale HTL plant for the Tamarack project in Canada and to support conceptual design for several projects, including Pungarayacu in Ecuador. Costs were also incurred in 2010 in connection with pursuing HTL™ heavy oil and selected conventional oil opportunities in North and South America, the Middle East and North Africa.

2009 vs 2008

Business and technology development expenses increased in 2009 over 2008, as a result of the startup of the FTF, opening an office in Houston, the pursuit of financing initiatives in 2009, as well as the reallocation of certain executive salaries to the Business and Technology Development segment in late 2008.

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Depletion and Depreciation

2010 vs 2009

Depletion and depreciation expense decreased in 2010 compared to 2009 due to lower depletion in Asia and reduced depreciation in the Business and Technology Development segment. Depletion in Asia was lower due to the combination of reduced production and higher proved reserves in China. We stopped depreciating the CDF at the end of 2009 when it was retired, lowering our depreciation expense in 2010.

2009 vs 2008

Ivanhoe s depletion and depreciation expense in 2009 was lower than in 2008. Depletion in Asia decreased in 2009 as a result of an increase in proved reserves at our Dagang project in China as well as lower production in the current year. Additionally, our depreciation expense in the Business and Technology Development segment decreased in 2009 in comparison to the prior year as the depreciation expense associated with the FTF was lower than the depreciation expense incurred on the CDF.

Foreign Exchange

2010 vs 2009

The Company incurred a net foreign exchange gain in 2010 in comparison to a net foreign exchange loss in the prior year. In 2010, the Canadian dollar continued to strengthen relative to the US dollar resulting in a foreign exchange gain on the Cdn$150.0 million proceeds raised in our private placement in the first quarter of 2010, partially offset by a foreign exchange loss on our Canadian dollar debt.

2009 vs 2008

We incurred a foreign exchange loss primarily due to the translation of our Canadian dollar debt in 2009 and 2008. The loss was greater in 2009 than in 2008 due to the Canadian dollar strengthening relative to the US dollar.

Interest

2010 vs 2009

In the first quarter of 2010, the Company raised Cdn$150.0 million through a private placement. The short term investment of these funds earned interest income. Interest expense in 2010 was lower than in 2009 from the repayment of loan obligations associated with the Company s China and US operations during the course of 2009.

2009 vs 2008

Interest expense in 2009 was lower in comparison to 2008 due to the repayment of debt. In 2008, we repaid a Cdn$12.5 million promissory note and $3.0 million against our bank loan for Asian operations.

Impairment

When the FTF was completed in 2009, we commenced the abandonment process for the CDF. The $0.9 million net asset value of the CDF was impaired. Additionally, $0.8 million of development costs related to the pursuit of projects in the Middle East were impaired in 2009.

In 2008, we impaired costs associated with our GTL project due to the lack of a definitive agreement and appropriate financing. Development costs of $5.1 million and intangible license costs of $10.0 million were written off.

The Company incurred costs associated with the pursuit of corporate financing initiatives by Sunwing. In the fourth quarter of 2008, this financing initiative was postponed indefinitely and therefore the associated costs were written down to nil.

Derivatives

In 2007, we entered into a costless collar derivative as required by the Company s lenders to minimize variability in our cash flow. This derivative had a ceiling of $84.50/bbl and a floor of $55.00/bbl using the WTI as the index traded on the NYMEX. In December 2009, the Company repaid the outstanding loan balance and this derivative was subsequently cancelled.

The derivative instrument resulted in a loss to the Company in 2009, compared to a gain in 2008, due to movements in WTI. WTI 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, recovering in the last half of the year.

Income Taxes

The Company s income tax recovery was lower in 2010 than in 2009 due to a decrease in future taxes in the current year. Future taxes were significantly higher in 2009 due to the sale of the Company s US oil and gas operations.

In 2009, current income taxes included a provision for taxes in Asia and a net adjustment of $1.0 million related to 2008 from changes in the minimum depreciation and amortization periods for oil and gas companies by the Chinese State Tax Administration Bureau. The future tax recovery in 2009 was driven by the sale of our US operating segment.

In 2008, current taxes were payable on Asian operations.

Discontinued Operations

In 2009, Ivanhoe sold its wholly owned subsidiary, Ivanhoe Energy (USA) Inc., disposing of all our oil and gas exploration and production operations in the US. The US operations have been accounted for as discontinued operations on a retroactive basis in accordance with Canadian GAAP and the results for 2009 and 2008 have been amended accordingly.

The operating results for the discontinued operations were as follows:

	2009	2008
Revenue		
Oil and gas	5,455	18,120
Gain on derivative instruments	189	278
Interest	8	98
	5,652	18,496
Expenses		
Operating	2,132	5,137
General and administrative	139	2,413
Depletion and depreciation	3,772	6,143
Interest and financing	173	520
	6,216	14,213
Income (loss) before disposition	(564)	4,283
Loss on disposition (net of tax of $29.6 million for 2009, nil for 2008)	(23,357)	
Net income (loss) from discontinued operations	(23,921)	4,283

LIQUIDITY AND CAPITAL RESOURCES

Contractual Obligations and Commitments

The following information about our contractual obligations and other commitments summarizes certain liquidity and capital resource requirements. The information presented in the table below does not include planned, but not legally committed, capital expenditures or obligations that are discretionary and/or being performed under contracts which are cancelable with a 30 day notification period. Previous exploration commitments in Zitong and Nyalga have been fulfilled and therefore are not included below.

	Total	2011	2012	2013	2014	After 2014

Debt	39,832	39,832				
Interest	2,042	2,042				
Asset retirement obligations[1]	1,939		332			1,607
Long term obligation	1,900					1,900
Leases	2,989	1,769	885	335		
Total	48,702	43,643	1,217	335		3,507

(1) Represents undiscounted asset retirement obligations after inflation. The discounted value ($0.7 million) of these estimated obligations is provided for in the consolidated financial statements.

Debt

As described in Note 5 to the consolidated financial statements, the Company issued a Cdn$40.0 million convertible promissory note maturing in July 2011. The outstanding principal amount is convertible, at Talisman s option, into a maximum of 12,779,552 Ivanhoe common shares at Cdn$3.13 per common share. Interest at the prime rate plus 2% is calculated daily and payable semi-annually. The estimated interest payments on the convertible promissory note are included in the above table.

Asset Retirement Obligations

The Company is required to remedy the effect of our activities on the environment at our operating sites by dismantling and removing production facilities and remediating any damage caused. At December 31, 2010, we estimated the total undiscounted, inflated cost to settle our asset retirement obligations in Canada, Ecuador and the FTF in the US was $1.9 million. These costs are expected to be incurred between 2013 and 2038. Ivanhoe does not make such a provision for asset retirement costs in connection with its oil and gas operations in China as dry holes are abandoned as occurred and the Company is under no obligation to contribute to the future costs to restore well sites or abandon the field.

Long Term Obligation

As part of its 2005 merger with Ensyn, the Company assumed an obligation to pay $1.9 million in the event that proceeds from the sale of units incorporating the HTL technology for petroleum applications reach a total of $100.0 million.

Operating Leases

We have long term operating leases for office space, which expire between January 2011 and September 2013.

Other

From time to time, Ivanhoe 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, common shares, stock options or some combination thereof. These fees are not considered to be material.

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 Ivanhoe 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 indemnities are immaterial.

In the normal course of business, we are subject to legal proceedings being brought against us. While the final outcome of these proceedings is uncertain, we believe that these proceedings, in the aggregate, are not reasonably likely to have a material effect on our financial position or results of operations.

Sources and Uses of Cash

The following table sets forth a summary of our cash flows from operating, investing and financing activities, as reported in the consolidated statements of cash flows.

	2010	**2009**	**2008**
Net cash provided by (used in) operating activities	**(17,764)**	(12,290)	17,053
Net cash provided by (used in) investing activities	**(79,860)**	6,396	(49,321)
Net cash provided by (used in) financing activities	**138,286**	(11,875)	70,751

Operating Activities

2010 vs 2009

Operating activities in 2010 used more cash than in 2009 primarily as a result of lower oil revenue and higher G&A costs, partially offset by current tax savings. 2009 operating activities benefitted from net cash from discontinued operations. An increase in accounts payable, partially offset by changes in accounts receivable and income taxes, represented working capital cash in flows from operating activities in 2010 compared to an overall working capital outflow in 2009.

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2009 vs 2008

Operating activities in 2009 resulted in a use of cash due to significantly lower revenue in 2009, in contrast to 2008 activities which generated cash inflows.

Investing Activities

2010 vs 2009

Net cash used for investing activities was higher in 2010 than in 2009 due to a more extensive capital program. Payables related to capital expenditures were higher at December 31, 2010, than the prior year, creating a source of working capital. In 2009, $35.3 million cash was generated from the sale of our US operating segment.

2009 vs 2008

In 2009, investing activities resulted in a net cash inflow due to the sale of the US operating segment. In comparison, $22.3 million was paid to acquire the Tamarack leases in 2008, and when combined with other capital expenditures, created a net cash outflow in 2008.

Financing Activities

2010 vs 2009

In 2010, financing activities raised $135.7 million of cash with the private placement of 50 million special warrants in February and March 2010 at a price of Cdn$3.00 per special warrant. Additional cash was raised through the exercise of stock options. The repayment of debt in 2009 resulted in a net cash outflow from financing activities.

2009 vs 2008

Financing activities in 2009 resulted in a net cash outflow due to the final debt repayment of long term notes and the repayment of a note associated with discontinued operations. In 2008, financing activities resulted in a net cash inflow due to a private placement in the third quarter and the receipt of cash from a Cdn$5.0 million loan.

Capital Structure

As at December 31,	**2010**	**2009**
Cash and cash equivalents	**67,817**	21,512
Debt	**39,832**	
Long term debt		36,934
Shareholders equity	**324,109**	208,029

Ivanhoe intends to use its cash and cash equivalent balance to fulfill its commitments and partially fund operations in 2011. Cash flow from operating activities may be insufficient to meet operating requirements in the next 12 months and additional sources of funding, either at a parent company level or at a project level, will be required to grow the Company s major projects and fully develop its oil and gas properties. Historically, Ivanhoe has used external sources of funding, such as public and private equity and debt markets. There is no assurance that we will be able to obtain additional financing on favorable terms, if at all, and any future equity issuances may be dilutive to our current investors. If we cannot secure additional financing, we may have to delay our capital programs and forfeit or dilute our rights in existing oil and gas property interests.

CRITICAL ACCOUNTING PRINCIPLES AND ESTIMATES

Our significant accounting policies may be found in Note 2 to the consolidated financial statements. Some of these policies involve critical accounting estimates because they require us to make particularly subjective or complex judgments about matters that are inherently uncertain and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions. The following section discusses our critical accounting estimates and assumptions and how they affect the amounts reported in our consolidated financial statements.

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Oil and Gas Reserves

The process of estimating quantities of reserves is inherently uncertain and complex. It requires significant judgment 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 becomes available and as economic conditions impacting oil and gas prices and costs change. Such revisions could be upwards or downwards. For details on our reserve estimation process, refer to the section titled Reserves, Production and Related Information in Items 1 and 2 of this Annual Report. Reserve estimates have a material impact on depletion and the Company s impairment evaluations, which in turn have a material impact on the results of operations.

Total proved reserves estimates are used to determine rates that are applied to each barrel of production in calculating our depletion expense. In 2010, depletion expense of $9.0 million was recorded. If our proved reserves estimates changed by 10%, our depletion and depreciation expense would have changed by approximately $0.6 million, assuming all other variables remained constant.

Impairment

Oil and Gas Properties and Development Costs

We periodically evaluate our oil and gas properties and development costs for impairment. Among other things, an impairment of these assets may be triggered by falling oil and gas prices, a significant negative revision to our reserve estimates, the inability to use our HTL technology in certain projects, changes in capital costs or the inability to raise sufficient financial resources to further develop the property. If one of these occurs, we assess if the undiscounted future net cash flows from proved reserves at future commodity prices plus the cost of undeveloped properties is less than the carrying value of the capitalized costs. If an impairment is found to exist, the impaired properties are written down to their fair value. The fair value of the assets is calculated based on future net cash flows from proved plus probable reserves, discounted at a risk-free interest rate using future commodity prices, plus the cost of undeveloped properties.

Cash flow estimates for our impairment assessments require assumptions about future prices and costs, reserves, discount rates and potential benefits from the application of our HTL technology. Given the significant assumptions required and the likelihood that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate.

It is difficult to determine and assess how a decrease in proved reserves could impact our impairment tests. The relationship between our reserve estimates and the estimated undiscounted cash flows and the nature of the property-by-property impairment test is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

Intangible Assets

Intangible assets consist of an exclusive, irrevocable license to deploy HTL technology our proprietary, patented heavy oil upgrading process. We periodically review the intangible assets for impairment or if an adverse event or change occurs. Indicators of adverse events could include HTL patent expiries, advancements of new technologies or the inability to successfully commercialize the HTL technology. To determine if the intangible assets are impaired, we assess if the undiscounted future cash flows are in excess of the carrying value. If not, the assets are reduced to their fair value based on expected discounted future cash flows.

We believe that the intangible asset impairment is a critical accounting estimate because it requires management to make assumptions about competitive technological developments, the successful commercialization of our HTL technology and future cash flows from the HTL technology. We cannot predict if an event that triggers impairment will occur, when it will occur or how it will affect the asset amounts we have reported. Although we believe our estimates are reasonable and consistent with current conditions, internal planning and expected future operations, such estimates are subject to significant uncertainties and judgments.

Future Income Taxes

We operate in a specialized industry and in several tax jurisdictions. As a result, our income is subject to various rates of taxation. The breadth of the Company s operations and the global complexity of tax regulations require assessments of uncertainties and judgments in estimating the taxes we will ultimately pay. The final taxes paid are dependent upon many factors, including negotiations with taxing authorities in various jurisdictions, uncertain tax positions and resolution of disputes arising from federal, provincial, state and local tax audits. The resolution of these uncertainties and the associated final taxes may result in adjustments to our tax assets and tax liabilities.

We estimate future income taxes based upon temporary differences between the assets and liabilities that we report in our consolidated financial statements and the tax basis of our assets and liabilities as determined under applicable tax laws. We record a valuation allowance against our future income tax assets when we believe, based on all available evidence, that it is not more likely than not that all of our future income tax assets recognized will be realized. The amount of the future income tax asset recognized and considered realizable could, however, be reduced if projected income is not achieved.

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Convertible note liability

In connection with the acquisition of the Tamarack leases in July 2008 from Talisman, we issued a Convertible Note. The Convertible Note is a compound financial instrument, containing a debt instrument as well as an embedded conversion feature classified as equity. The residual basis method was used to value the instrument which means the fair value of the liability component was calculated and the remaining value was assigned to the equity component. Management estimated the value of the liability component to be Cdn$37.9 million by discounting the expected interest and principal payments. The remaining value of Cdn$2.1 million was allocated to the equity component. If the interest rate used to discount the liability decreased by 1%, the amount of the Convertible Note originally recorded as a liability would increase by $1.0 million and the equity component would have been $1.0 million lower. Since the accretion of the liability component over the three year maturity period is capitalized on the balance sheet, there would not have been an impact on our operating results. Increasing the interest rate by 1% would have had the opposite, but equal, impact on our consolidated financial statements.

NEW ACCOUNTING PRONOUNCEMENTS

Transition to International Financial Reporting Standards

Effective January 1, 2011, we adopted International Financial Reporting Standards (IFRS) as our basis for accounting. Most adjustments required on transition to IFRS were made retrospectively against opening retained earnings as of the date of the first comparative balance sheet. Transitional adjustments relating to those standards where comparative figures are not required to be restated will only be made as of the first day of the year of adoption.

As a foreign private issuer in the US, we will be permitted to file with the SEC consolidated financial statements prepared under IFRS without a reconciliation to US GAAP. The impact of this change is that we will no longer prepare a reconciliation of our results to US GAAP. It is possible that some of our accounting policies under IFRS could be different from US GAAP.

First-time Adoption of International Financial Reporting Standards

First-Time Adoption of International Financial Reporting Standards (IFRS 1) provides companies adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions to the general requirement for full retrospective application of IFRS where retrospective restatement would either be onerous or would not provide more useful information. As a result of relying upon the exemptions described below, there was no material impact in these areas at the date of transition to IFRS.

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Area of IFRS	Summary of Exemption Available
Property, plant and equipment	Companies may elect to report property, plant and equipment from oil and gas operations on the opening balance sheet on the transition date at a deemed cost, instead of the actual cost, as though IFRS had been adopted retroactively. The deemed cost of an item may be either its fair value at the date of transition to IFRS or an amount reported under Canadian GAAP. The exemption can be applied on an asset-by-asset basis. Ivanhoe elected to report property, plant and equipment from oil and gas operations in its opening balance sheet on the transition date at the deemed cost previously calculated under Canadian GAAP.
Decommissioning liabilities	In accounting for changes in decommissioning liabilities, IFRS requires changes in such obligations to be added to, or deducted from, the cost of the asset to which they relate. The adjusted depreciable amount of the asset is then depreciated prospectively over its remaining useful life. Rather than recalculating the effect of all such changes throughout the life of the obligation, companies may elect to measure the liability and the related depreciation effects at the date of transition to IFRS. Ivanhoe elected to measure only those decommissioning liabilities outstanding from our FTF on the date of transition to IFRS**.**
Stock-based compensation	Companies may elect not to apply IFRS 2, Share-Based Payment, to stock options granted on or before November 7, 2002, or which vested before the date of transition to IFRS. Ivanhoe elected to utilize this exemption for the all stock options awarded after November 7, 2002, that vested before January 1, 2010.
Business combinations	Companies may elect to either restate all past business combinations in accordance with IFRS 3, Business Combinations, or to apply an elective exemption from applying IFRS 3 to past business combinations Ivanhoe has elected to utilize this exemption such that transactions entered into prior to the transition date will not be restated.

Expected Areas of Significance

IFRS will have a significant impact on the Company s ongoing accounting in the areas described below, in addition to the impact of transition policy choices made under IFRS 1.

Accounting Policy Area	Impact of Policy Adoption
Exploration and evaluation assets	The Company followed the full cost method of accounting for its oil and gas operations under Canadian (Cdn) GAAP, whereby all costs related to the exploration for, and development of, oil and gas reserves were capitalized and periodically evaluated for impairment. Under IFRS, exploration costs will initially be capitalized as exploration and evaluation (E&E) assets until it can be determined if sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are found, E&E assets will be reclassified to oil and gas properties and development costs and, if not, E&E assets will be expensed on the consolidated income statement. Costs incurred in connection with our projects in Canada,

Ecuador, Mongolia and exploration projects in China will be reclassified as E&E assets, while producing assets in China will continue to be classified as oil and gas properties and development costs on the consolidated balance sheet.

Impairments	Cdn GAAP generally used a two-step approach to impairment testing: first comparing asset carrying values with undiscounted future cash flows to determine whether impairment exists and then measuring any impairment by comparing asset carrying values with fair values calculated using discounted cash flows. International Accounting Standard 36, Impairment of Assets, uses a one-step approach for both testing and measuring of impairment, with asset carrying values compared directly with the higher of fair value less costs to sell and value in use (which uses discounted future cash flows). This may potentially result in more write downs where carrying values of assets were previously supported under Cdn GAAP on an undiscounted cash flow basis, but could not be supported on a discounted cash flow basis. IFRS also requires the reversal of any previous impairment losses where circumstances have changed such that impairments have been reduced. Cdn GAAP prohibits the reversal of impairment losses. IFRS will result in greater variability in our operating results and asset carrying values.
Capitalized G&A	G&A directly related to exploration and development activities were capitalized as oil and gas properties and development costs under Cdn GAAP. The threshold to capitalize G&A is higher under IFRS; therefore, we expect to capitalize less G&A in the future and G&A on the consolidated income statement will be higher as a result.
Financial instruments	Under Cdn GAAP, the equity component of the Company s Convertible Note and the common share purchase warrants were classified as shareholders equity. In accordance with IAS 32, Financial Instruments: Presentation, financial instruments with an exercise price denominated in a currency other than our functional currency are accounted for as derivatives. Since our Convertible Note and common share purchase warrants are denominated in Cdn dollars and our functional currency is US dollars, these items were reclassified from shareholders equity to liabilities under IFRS. Additionally, IFRS requires derivative instruments to be recorded at fair value with changes in their fair value recognized in the income statement. This will create variability in our results of operations and the carrying value of liabilities.
Stock-based compensation	Stock options were accounted for using the fair value method under Canadian GAAP. The fair value was determined using the Black Scholes option pricing model and recorded as compensation expense on a straight-line basis over the period that the stock options vested. Under IFRS 2, Share-Based Payment, compensation expense will be charged to earnings on a graded vesting basis. This will accelerate the compensation expense recognized on the consolidated income statement in comparison to Cdn GAAP.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations.

ITEM 7A: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed in varying degrees to normal market risks inherent in the oil and gas industry, including commodity price risk, foreign currency exchange rate risk, credit risk and liquidity risk. We recognize these risks and manage our operations to minimize our exposures to the extent practicable.

COMMODITY PRICE RISK

Commodity price risk related to oil prices is one of Ivanhoe s most significant market risk exposures. The Company s operating results and financial condition are influenced by the prices we receive for our oil production. Oil prices may fluctuate widely in response to a variety of factors including global and domestic economic conditions, weather conditions, political stability, transportation facilities, the price and availability of alternative fuels and government regulations.

Based on our estimated 2011 production, a US$1.00/bbl change in the price of oil would increase or decrease net income and cash flows from operations for 2011 by US$0.82/bbl. In the past, we have used derivatives to minimize variability in our cash flow from operations when required to do so by loan covenants. However, no hedging contracts were in place in 2010 nor do we anticipate using hedging contracts in 2011 to manage our commodity price risk.

FOREIGN CURRENCY EXCHANGE RATE RISK

Ivanhoe is exposed to foreign currency exchange rate risk as a result of incurring capital expenditures and operating costs in currencies other than the US dollar. A substantial portion of our activities are transacted in or referenced to US dollars, including oil sales in Asia, capital spending in Ecuador and ongoing FTF operations. A portion of our transactions are in other currencies, such as Dagang operating costs paid in Chinese renminbi, Tamarack exploration activities funded in Cdn dollars and the 2010 common share issuance in Cdn dollars. The Company did not enter into any foreign currency derivatives in 2010, nor do we anticipate using foreign currency derivatives in 2011. To help reduce the Company s exposure to foreign currency exchange rate risk, it seeks to hold assets and liabilities denominated in the same currency when appropriate.

The following table shows the Company s exposure to foreign currency exchange rate risk on its net loss and comprehensive loss, assuming reasonably possible changes in the relevant foreign currency. This analysis assumes all other variables remain constant.

(Increase) Decrease in Net Loss and Comprehensive Loss	**10% Increase or Weakening**	**10% Decrease or Strengthening**
Chinese renminbi	1,438	(1,758)
Canadian dollar	(2,089)	167

CREDIT RISK

Ivanhoe is exposed to credit risk with respect to its cash and cash equivalents, accounts receivable, note receivable, restricted cash and long term receivables. The Company s maximum exposure to credit risk at December 31, 2010, is represented by the carrying amount of these non-derivative financial assets. Most of the Company s credit exposures are with counterparties in the energy industry and are therefore exposed to normal industry credit risks. Ivanhoe manages its credit risk by only entering into sales contracts with established entities.

The Company believes its exposure to credit risk related to cash and cash equivalents, as well as restricted cash, is minimal due to the quality of the financial institutions where the funds are held and the nature of the deposit instruments.

Currently, all of the Company s oil production is sold to one national oil corporation. As a result, 85% of the outstanding accounts receivable balance at December 31, 2010 (December 31, 2009 94%) is due from a national oil corporation. Long term value-added tax receivable from Ecuador will be recoverable upon commencement of commercial operations. Ivanhoe considers the risk of default on these items to be low due to the Company s ongoing operations in China and Ecuador.

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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. Since cash flows from existing operations are insufficient to fund future capital expenditures, we intend to finance future capital projects with 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 or from the sale of existing assets. There is no assurance that we will be able to obtain such financing on favorable terms, if at all.

NON-GAAP FINANCIAL MEASURES

Oil revenue per barrel is calculated by dividing oil revenue by the Company s total production for the respective periods presented. Net operating revenue per barrel is calculated by dividing oil revenue less operating costs by total production for the respective periods presented. Net revenue (loss) from operations per barrel is calculated by subtracting depletion from net operating revenue and dividing by total production for the respective periods presented. The Company believes oil revenue per barrel, net operating revenue per barrel and net revenue (loss) from operations per barrel are important to investors to evaluate operating results and the Company s ability to generate cash. Each of the components used in these calculations can be reconciled directly to the consolidated statement of loss and comprehensive loss. The calculations of oil revenue per barrel, net operating revenue per barrel and net revenue (loss) from operations per barrel may differ from similar calculations of other companies in the oil and gas industry, thereby limiting its usefulness as a comparative measure.

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ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

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

We have audited the accompanying consolidated financial statements of Ivanhoe Energy Inc. and subsidiaries, which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of loss and comprehensive loss, shareholders equity and cash flows for each of the years in the three-year period ended December 31, 2010 and the notes to the consolidated financial statements.

Management s Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor s Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ivanhoe Energy Inc. and subsidiaries as at December 31, 2010 and 2009 and the results of their operations and cash flows for each of the years in the three-year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

Emphasis of Matter

Without qualifying our opinion, we draw attention to Note 2 in the financial statements which indicates that the Company had an accumulated deficit of $284.9 million and working capital of $16.5 million at December 31, 2010 and cash flow used in operating activities of $17.8 million and a net loss of $29.1 million during the year ended December 31, 2010. These conditions, along with other matters as set forth in Note 2, indicate the existence of a material uncertainty that may cast significant doubt about the Company s ability to continue as a going concern.

Other Matter

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, 2010, 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 4, 2011 expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Canada

March 4, 2011

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IVANHOE ENERGY INC.
Consolidated Balance Sheets
December 31, 2010 and 2009

(US$000s, except share amounts)	**2010**	**2009**
Assets		
Current Assets		
Cash and cash equivalents *(Note 15)*	**67,817**	21,512
Accounts receivable	**6,359**	5,021
Note receivable	**264**	225
Prepaid and other current assets	**2,859**	771
Restricted cash *(Note 18)*	**500**	2,850
	77,799	30,379
Oil and gas properties and development costs, net *(Note 3)*	**237,200**	158,392
Intangible assets *(Note 4)*	**92,153**	92,153
Long term receivables *(Note 12)*	**2,433**	839
	409,585	281,763
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities *(Note 12)*	**21,482**	10,779
Debt *(Note 5)*	**39,832**	
Income tax payable *(Note 14)*		530
Asset retirement obligations *(Note 6)*		753
	61,314	12,062
Long term debt *(Note 5)*		36,934
Asset retirement obligations *(Note 6)*	**744**	195
Long term obligation *(Note 7)*	**1,900**	1,900
Future income tax liability *(Note 14)*	**21,518**	22,643
	85,476	73,734
Commitments and contingencies *(Note 7)*		
Going concern and basis of presentation *(Note 2)*		
Shareholders Equity		
Share capital, issued 334,365,482 common shares	**550,562**	422,322
December 31, 2009 282,558,593 common shares		
Purchase warrants *(Note 8)*	**33,423**	19,427
Contributed surplus	**22,983**	20,029
Convertible note *(Note 5)*	**2,086**	2,086

Accumulated deficit	**(284,945)**	(255,835)
	324,109	208,029
	409,585	281,763

(See accompanying Notes to the Consolidated Financial Statements)

Approved on behalf of the Board:

(signed) Robert M. Friedland
Director

(signed) Brian F. Downey
Director

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IVANHOE ENERGY INC.
Consolidated Statements of Loss and Comprehensive Loss
Three Years Ended December 31, 2010

(US$000s, except per share amounts)	**2010**	**2009**	**2008**
Revenue			
Oil	**21,720**	24,968	48,370
Gain (loss) on derivative instruments		(1,335)	1,688
Interest	**208**	25	612
	21,928	23,658	50,670
Expenses			
Operating	**9,503**	10,191	21,515
General and administrative	**26,260**	21,693	14,252
Business and technology development	**10,615**	9,501	6,453
Depletion and depreciation	**8,960**	19,868	25,761
Foreign exchange (gain) loss	**(3,325)**	5,220	1,527
Interest and financing	**24**	856	1,309
Impairment of intangible asset and development costs *(Note 3)*		1,903	15,054
Impairment of deferred financing costs *(Note 13)*			2,621
	52,037	69,232	88,492
Loss from continuing operations before income taxes	**(30,109)**	(45,574)	(37,822)
(Provision for) recovery of income taxes *(Note 14)*			
Current	**(126)**	(1,757)	(654)
Future	**1,125**	9,600	
	999	7,843	(654)
Net loss continuing operations	**(29,110)**	(37,731)	(38,476)
Net (loss) income discontinued operations (net of tax of $29.6 million for 2009, nil for 2008) *(Note 18)*		(23,921)	4,283
Net loss and comprehensive loss	**(29,110)**	(61,652)	(34,193)
Net loss per common share			
Net loss continuing operations, basic and diluted	**(0.09)**	(0.13)	(0.15)
Net (loss) income discontinued operations, basic and diluted		(0.09)	0.02
Net loss per common share, basic and diluted	**(0.09)**	(0.22)	(0.13)
Weighted average number of common shares			

Basic and diluted (000s)	**327,442**	279,722	258,815

(See accompanying Notes to the Consolidated Financial Statements)

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IVANHOE ENERGY INC.
Consolidated Statements of Shareholders Equity
Three Years Ended December 31, 2010

(US$000s)	2010	2009	2008
Common shares, beginning of year	**422,322**	413,857	324,262
Shares issued for cash, net of share issue costs *(Note 8)*	**121,697**		82,451
Shares issued for services	**799**	207	
Shares issued for acquisition of a business, net of share issue costs *(Note 17)*		6,874	
Exercise of stock options	**5,735**	1,384	1,792
Exercise of purchase warrants	**9**		
Exercise of convertible debt			4,862
Shares issued for employee bonuses			490
End of year	**550,562**	422,322	413,857
Purchase warrants, beginning of year *(Note 8)*	**19,427**	18,805	23,078
Issuance of special warrants on private placement	**13,999**		
Warrants issued for acquisition of a business		622	
Exercise of purchase warrants	**(3)**		
Expiry of purchase warrants			(4,273)
End of year	**33,423**	19,427	18,805
Contributed surplus, beginning of year	**20,029**	16,862	9,937
Stock-based compensation expense	**6,894**	3,659	3,239
Exercise of stock options	**(3,940)**	(492)	(587)
Expiry of purchase warrants			4,273
End of year	**22,983**	20,029	16,862
Convertible note, beginning of year	**2,086**	2,086	
Issuance of convertible note			2,086
End of year	**2,086**	2,086	2,086
Accumulated deficit, beginning of year	**(255,835)**	(194,183)	(159,990)
Net loss and comprehensive loss	**(29,110)**	(61,652)	(34,193)
End of year	**(284,945)**	(255,835)	(194,183)

(See accompanying Notes to the Consolidated Financial Statements)

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IVANHOE ENERGY INC.
Consolidated Statements of Cash Flows
Three Years Ended December 31, 2010

(US$000s)	**2010**	2009	2008
Operating Activities			
Net loss	**(29,110)**	(61,652)	(34,193)
Net loss (income) from discontinued operations		23,921	(4,283)
Items not requiring use of cash			
Depletion and depreciation	**8,960**	19,868	25,761
Provision for impairment		1,903	15,054
Stock-based compensation *(Note 9)*	**6,095**	3,849	3,016
Unrealized loss (gain) on derivative instruments		1,459	(6,118)
Impairment of deferred financing costs *(Note 13)*			2,621
Unrealized foreign exchange (gain) loss	**(3,523)**	5,109	1,762
Future income tax recovery	**(1,125)**	(9,600)	
Provision for uncollectible accounts		174	625
Other	**(14)**	553	519
Abandonment costs settled *(Note 6)*	**(179)**	(118)	
Changes in non-cash working capital items	**1,132**	(459)	6,016
Net cash (used in) provided by operating activities continuing operations	**(17,764)**	(14,993)	10,780
Net cash provided by operating activities discontinued operations		2,703	6,273
Net cash (used in) provided by operating activities	**(17,764)**	(12,290)	17,053
Investing Activities			
Capital investments	**(86,285)**	(26,373)	(21,063)
Acquisition of oil and gas assets			(22,308)
Settlement of advances			200
Decrease (increase) in restricted cash	**2,350**	(2,000)	(850)
Long term receivables	**(1,558)**	(587)	73
Changes in non-cash working capital items	**5,633**	64	(1,035)
Net cash used in investing activities continuing operations	**(79,860)**	(28,896)	(44,983)
Net cash provided by (used in) investing activities discontinued operations		35,292	(4,338)
Net cash (used in) provided by investing activities	**(79,860)**	6,396	(49,321)
Financing Activities			
Shares and warrants issued on private placements, net of share issue costs	**135,696**		82,451
Share issue costs on acquisition		(26)	
Proceeds from exercise of options and warrants	**2,600**	893	1,205
Proceeds from debt obligations, net of financing costs			4,790

Payments of debt obligations		(7,416)	(15,750)
Payments of deferred financing costs			(2,621)
Other		(100)	(50)
Changes in non-cash working capital items	**(10)**	(26)	26
Net cash provided by (used in) financing activities continuing operations	**138,286**	(6,675)	70,051
Net cash provided by (used in) financing activities discontinued operations		(5,200)	700
Net cash provided by (used in) financing activities	**138,286**	(11,875)	70,751
Foreign exchange gain (loss) on cash and cash equivalents held in a foreign currency	**5,643**	16	(10,574)
Increase (decrease) in cash and cash equivalents, for the year	**46,305**	(17,753)	27,909
Cash and cash equivalents, beginning of year	**21,512**	39,265	11,356
Cash and cash equivalents, end of year	**67,817**	21,512	39,265
Cash and cash equivalents, end of year continuing operations	**67,817**	21,512	38,477
Cash and cash equivalents, end of year discontinued operations			788

(See accompanying Notes to the Consolidated Financial Statements)

IVANHOE ENERGY INC.
Notes to the Consolidated Financial Statements
(all tabular amounts are expressed US$000s, except share and per share amounts)

1. NATURE OF OPERATIONS

Ivanhoe Energy Inc. (the Company or Ivanhoe), 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 plans to utilize advanced technologies designed to significantly improve recovery of heavy oil resources, including its HTL technology. 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 carried out in Canada, Ecuador, China and Mongolia.

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 US GAAP on the consolidated financial statements is disclosed in Note 20.

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.

Going Concern and Basis of Presentation

These consolidated financial statements have been prepared in accordance with GAAP applicable to a going concern, which assumes that Ivanhoe will be able to meet its obligations and continue operations for at least its next fiscal year. Realization values may be substantially different from carrying values as shown and these consolidated financial statements do not give effect to adjustments that may be necessary to the carrying values and classification of assets and liabilities should the Company be unable to continue as a going concern. Such adjustments could be material.

At December 31, 2010, Ivanhoe had an accumulated deficit of $284.9 million and working capital of $16.5 million. In 2010, cash used in operating activities was $17.8 million and the Company expects to incur further losses in the development of its business. Continuing as a going concern is dependent upon attaining future profitable operations to repay liabilities arising in the normal course of operations and accessing additional capital to develop the Company s properties (refer to Notes 5 and 7). Ivanhoe intends to finance its future funding requirements through 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. There is no assurance that Ivanhoe will be able to obtain such financing on favorable terms, if at all. Without access to additional financing in 2011, there is significant doubt that the Company will be able to continue as a going concern.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company, its subsidiaries and any variable interest entities. Any reference to the Company or Ivanhoe throughout these consolidated financial statements refers to Ivanhoe, its subsidiaries, and any variable interest entities. All inter-entity transactions have been eliminated. Ivanhoe conducts some of its oil production activities through jointly controlled operations and the consolidated financial statements reflect only Ivanhoe s proportionate interest in such activities.

Foreign Currency Translation

The Company s functional currency is the US dollar. All of Ivanhoe s operations are considered integrated and are translated into US dollars using the temporal method. Under this method, monetary assets and liabilities are translated at the exchange rate in effect at the balance sheet date. Non-monetary assets and liabilities, as well as operating transactions, are translated at the exchange rate prevailing at the time of the transaction. Translation exchange gains and losses are reflected in the results of operations.

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Cash and Cash Equivalents

Cash and cash equivalents include short term investments, such as money market deposits or similar type instruments, with an original maturity of 90 days or less when purchased.

Full Cost Accounting for Oil and Gas Operations

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 could include lease and royalty interest acquisitions, geological and geophysical expenses, carrying charges for unproved properties, costs of drilling both successful and unsuccessful wells, gathering and production facilities and equipment, major renovations, financing, asset retirement costs and administrative costs related to capital projects.

Proceeds from the sale of oil and gas properties are applied against capitalized costs, without any gain or loss being realized, unless such sale would significantly alter the rate of depletion and depreciation, in which case a gain or loss would be recognized.

Capitalized Interest

The Company capitalizes interest on major development projects until construction is complete. Capitalized interest cannot exceed the actual interest incurred.

Depletion and Depreciation

Provision for depletion of oil and gas assets is calculated using the unit-of-production method, based on proved reserves net of royalties as evaluated by independent petroleum engineers. The cost basis used for the depletion provision is the capitalized costs of oil and gas assets, including undeveloped property, plus the estimated future development costs of proved undeveloped reserves.

Furniture and equipment are depreciated on a straight line basis over the estimated useful life of the respective assets, at rates ranging from three to five years. The Feedstock Testing Facility (FTF) is being depreciated over its expected economic life of 20 years.

Impairment

The Company annually evaluates the carrying values of its oil and gas properties and development costs whenever events or conditions occur that indicate that the carrying values may not be recoverable from future cash flows. If the carrying values exceed the sum of estimated undiscounted future cash flows expected from proved reserves, the asset is impaired. The impairment charge is measured by assigning a fair value to the asset equal to its estimated discounted future net cash flows expected from proved plus probable reserves and the excess carrying value is expensed in the results of operations. The cost of unproved properties is excluded from the impairment test described above and subject to a separate impairment test. If impaired, the carrying value of the unproved properties is included in the petroleum and gas depletable base.

Cash flow estimates require assumptions about future commodity prices, ultimate recoverability of oil and gas reserves, operating costs and other factors. Actual results can differ materially from these estimates.

Intangible Assets

Intangible assets are recognized and measured at cost. Intangible assets with finite lives are amortized over their estimated useful life. 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 discounted future cash flows, the excess is expensed to the results of operations.

Asset Retirement Costs

The Company provides for future asset retirement obligations on its resource properties and facilities based on estimates established by current legislation and industry practices. The asset retirement obligation is initially measured at fair value and capitalized to the asset as an asset retirement cost that is depreciated over the life of the related asset. The obligation is accreted through interest expense until it is settled.

The fair value of the obligation is estimated by discounting expected future cash outflows to settle the asset retirement obligation using a credit-adjusted risk-free interest rate. Ivanhoe recognizes revisions to either the timing or the amount of the original estimate of undiscounted cash outflows as increases or decreases to the asset retirement obligation. Actual retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligations and the actual retirement costs incurred is recorded as a gain or loss in the settlement period.

Oil and Gas Revenue

Sales of oil and 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 its share of operating costs and both its share and the government s share of capital costs. The Company recovers the government s share of the capital costs from future revenues over the life of the production sharing contract.

Income or Loss Per Common Share

Basic net income per common share is computed by dividing net income by the weighted average number of common shares outstanding during the period. Diluted net income per common share amounts are calculated based on net income divided by dilutive common shares. Dilutive common shares are arrived at by adding weighted average common shares to common shares issuable on conversion of options, using the treasury stock method. The treasury stock method assumes that proceeds received from the exercise of in-the-money options is used to repurchase common shares at the average market price. Dilution from the convertible debt is considered using the if converted method.

Income Taxes

Ivanhoe follows the liability method of accounting for future income taxes. Under the liability method, income tax assets and liabilities are recorded to reflect the expected future tax consequences of 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 if the future benefit of income tax assets, including unused tax losses, is not more likely than not to be ultimately realized. The effect of a change in tax rate on future income tax assets and liabilities is recognized in net income in the period in which the change is substantively enacted.

Stock-based Compensation

Options to purchase common shares are granted to directors, officers, employees and consultants at current market prices. The fair value of the options at the time of grant is recognized as a compensation expense in the results of operations over the vesting period of the option, with a corresponding increase to contributed surplus. Upon the exercise of the stock options, consideration paid together with the amount previously recognized in contributed surplus, is recorded as an increase in share capital. In the event that vested options expire unexercised, the previously recognized compensation expense associated with such stock options is not reversed. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures.

Financial Assets and Liabilities

Financial assets and financial liabilities are measured at fair value on initial recognition. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading, loans and receivables, or other financial liabilities.

Financial assets and liabilities designated as held-for-trading are subsequently measured at fair value with changes in those fair values charged immediately to earnings. Ivanhoe classifies all derivative contracts as held-for trading. Cash and cash equivalents and restricted cash are classified as held-for-trading. Transaction costs are expensed as incurred.

Loans and receivables and other financial liabilities are subsequently measured at amortized cost using the effective interest method. Ivanhoe classifies accounts receivable and the note receivable as loans and receivables, and accounts payable, debt and the long term obligation as other financial liabilities. Transaction costs for other long term financial liabilities are deducted from the related liability and accounted for using the effective interest rate method.

Fair value measurements are classified according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 Quoted prices are available in active markets. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Pricing inputs are other than quoted prices in an active market included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the market place.

Level 3 Valuation at this level are those with inputs for the asset or liability that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

3. OIL AND GAS PROPERTIES AND DEVELOPMENT COSTS

As at December 31, 2010	**Oil and Gas**				**Business and Technology**	
	Integrated		**Conventional**			
	Canada	**Ecuador**	**Asia**	**Corporate**	**Development**	**Total**
Oil and gas properties						
Proved			159,551			159,551
Unproved	125,435	26,249	39,126			190,810
	125,435	26,249	198,677			350,361
Accumulated depletion			(108,334)			(108,334)
Accumulated provision for impairment			(16,550)			(16,550)
	125,435	26,249	73,793			225,477
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					11,426	11,426
Accumulated depreciation and impairment					(921)	(921)
					10,505	10,505
Furniture and equipment	27	436	592	1,361	58	2,474
Accumulated depreciation	(17)	(101)	(229)	(894)	(15)	(1,256)
	10	335	363	467	43	1,218

125,445	26,584	74,156	467	10,548	237,200

As at December 31, 2009	**Oil and Gas**				**Business and Technology**	
	Integrated		**Conventional**			
	Canada	**Ecuador**	**Asia**	**Corporate**	**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

Costs associated with unproved oil and gas properties that were not subject to depletion amounted to $190.8 million at December 31, 2010 (December 31, 2009 $115.6 million). Costs subject to depletion included future capital expenditures of $7.3 million at December 31, 2010 (December 31, 2009 $3.3 million) relating to the development of proved undeveloped reserves, as estimated by the Company s independent reserve engineers.

In 2010, $7.0 million (2009 $4.1 million; 2008 $1.0 million) in general and administrative expenses related directly to exploration and development activities and interest of $2.5 million (2009 $2.2 million; 2008 $3.8 million) were capitalized.

The Company performed a ceiling test calculation at December 31, 2010, 2009 and 2008 to assess the recoverable value of its oil and gas properties. The present value of future net revenue from the Company s proved reserves exceeded the carrying value of the Company s oil and gas properties in 2010, 2009 and 2008, resulting in no impairment in each of those years. 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, 2010:

($/bbl)	
2011	88.00
2012	89.00
2013	90.00
2014	92.00
2015	95.17
2016	97.55
2017	100.26
2018	102.74
2019	105.45
2020	107.56
Thereafter	2% per year

In 2009, Ivanhoe impaired $0.8 million of development costs associated with its HTL projects in Iraq and Libya. Gas-to-Liquids technology (GTL) development costs of $5.1 million and intangible GTL assets of $10.0 million were impaired in 2008.

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When the Company s FTF was placed into service, the Commercial Demonstration Facility was abandoned and the carrying value of $0.9 million was written down to nil in 2009.

4. INTANGIBLE ASSETS

The Company s intangible assets consist of an exclusive, irrevocable license to deploy HTL technology, a master license permitting Ivanhoe to use the Syntroleum Process and the exclusive right to deploy the Rapid Thermal Processing process in all applications other than biomass. The carrying value of the HTL technology as at December 31, 2010 and 2009 was $92.2 million. This asset was not amortized and its carrying value was not impaired for the years ended December 31, 2010, 2009 and 2008.

5. DEBT

As at December 31,	2010	2009
Convertible note	**40,217**	38,005
Unamortized discount	**(385)**	(1,071)
	39,832	36,934

In connection with the acquisition of the Tamarack leases in July 2008 from Talisman Energy Canada (Talisman) (refer to Note 17), the Company issued a Cdn$40.0 million convertible promissory note (the Convertible Note) which matures in July 2011. Interest at the prime rate plus 2% is calculated daily and is payable semi-annually. The outstanding principal amount is convertible, at Talisman s option, into a maximum of 12,779,552 Ivanhoe common shares at Cdn$3.13 per common share. The interest rate on the Convertible Note at December 31, 2010 was 5.00% (December 31, 2009 4.25%).

The Convertible Note is a compound financial instrument, containing a debt instrument as well as an embedded conversion feature classified as equity. The residual basis method was used to value the instrument. The fair value of the liability component was determined and the remaining value was assigned to the bifurcated equity component. The value of the liability was determined by discounting the expected interest and principal payments and was calculated at Cdn$37.9 million with the remaining value of Cdn$2.1 million allocated to the equity component. The liability component is accreted over the three year maturity period up to the Cdn$40.0 million principal amount using the effective interest rate method.

The Company s obligations under the Convertible Note 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.

Interest expense included in the statement of operations was nil in 2010 (2009 $0.8 million; 2008 $1.2 million). In 2010, $2.5 million (2009 $2.2 million; 2008 $3.8 million) in interest was capitalized to oil and gas properties and development costs in the consolidated balance sheet.

6. ASSET RETIREMENT OBLIGATIONS

At December 31, 2010, the Company s total estimated undiscounted inflated costs to settle its asset retirement obligations were approximately $1.9 million (December 31, 2009 $0.9 million). These costs are expected to be incurred between 2013 and 2038 and have been discounted using an inflation rate specific to the country in which the costs will be incurred (2% to 4%) and a weighted average credit-adjusted risk-free rate of 5.2% (December 31, 2009 5.3%).

As at December 31,	2010	2009
Asset retirement obligations, beginning of year	**948**	1,928
Liabilities incurred	**479**	185
Liabilities settled	**(179)**	(118)
Accretion expense	**23**	79
Revisions in estimated cash flows	**(527)**	(1,126)

	744	948
Less current portion		(753)
Asset retirement obligations, end of year	**744**	195

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7. COMMITMENTS AND CONTINGENCIES

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 that proceeds from the sale of units incorporating the HTL technology for petroleum applications reach a total of $100.0 million.

Income Taxes

The Company has an uncertain tax position in China related to when it is entitled to take tax deductions on capitalized development costs that are amortized over six years on a straight line basis. 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 expense of $0.9 million.

The Company has an uncertain tax position related to the calculation of a gain on the consideration received from two farm-out transactions. To the extent that the calculation of the gain is interpreted differently and the amounts are subject to withholding tax, there would be an additional current tax expense of approximately $0.7 million.

No amounts have been recorded in the consolidated 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.

Lease Commitments

In 2010, the Company expended $2.6 million (2009 $1.2 million; 2008 $1.1 million) on operating leases relating to the rental of office space, which expire between January 2011 and September 2013. As at December 31, 2010, future net minimum payments for operating leases were the following:

2011	1,769
2012	885
2013	335
	2,989

Other

The Company may be required to make a Cdn$15.0 million cash payment to Talisman upon receiving government and other approvals necessary to develop the northern border of one of the Tamarack leases (refer to Note 17).

Occasionally, Ivanhoe 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 these agreements, the consultant may receive cash, common shares, stock options or some combination thereof.

From time to time, Ivanhoe is involved in litigation or has claims brought against it in the normal course of business. Management is currently not aware of any claims that would materially affect the reported financial position or results of operations.

8. SHAREHOLDERS EQUITY

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.

(000s)	**2010**	**2009**	**2008**
Common shares, beginning of year	**282,559**	279,381	244,874
Shares issued for cash	**50,000**		29,334
Shares issued for services	**280**	81	
Shares issued for acquisition of a business *(Note 17)*		2,683	
Exercise of stock options	**1,525**	414	2,666
Exercise of purchase warrants	**2**		
Exercise of convertible debt			2,291
Shares issued for employee bonuses			216
End of year	**334,366**	282,559	279,381

The following reflects the changes in the Company s common share purchase warrants for the three year period ended December 31, 2010.

(000s)	**2010**	**2009**	**2008**
Purchase warrants, beginning of year	**12,135**	11,400	26,496
Private placements	**12,500**		29,334
Issued on acquisition		735	
Exercised	**(2)**		(29,334)
Expired			(15,096)
End of year	**24,633**	12,135	11,400

Year of Issue	**Price per Special Warrant**		**Outstanding(1) (000s)**	**Value ($US000s)**	**Expiry Date**	**Exercise Price per Share**		**Cash Value on Exercise ($US000s)**
2006	US$	2.23	11,398	18,802	May 2011	Cdn$	2.93(2)	33,577
2009		N/A	735	622	Feb 2011	Cdn$	4.05	2,993
2010	Cdn$	3.00	10,417	11,419	Feb 2011	Cdn$	3.16	33,095
2010	Cdn$	3.00	2,083	2,580	Feb 2011	Cdn$	3.16	6,619
			24,633	33,423				76,284

(1) One common share is issuable for each purchase warrant upon exercise.

(2) 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.

In January 2010, the Company completed a Cdn$125.0 million private placement (the Private Placement) consisting of 41,666,667 special warrants (Special Warrants) at Cdn$3.00. Each Special Warrant was converted into one common share of the Company and one-quarter of a common share purchase warrant. Each whole common 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 February 25, 2011 (refer to Note 19). The net proceeds from the Private Placement were approximately Cdn$120.2 million after deducting fees and commissions of Cdn$4.3 million and 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 were exercised in February 2010 for Cdn$25.0 million. The net proceeds realized by the Company from the issue of the Special Warrants were Cdn$23.8 million, after deducting fees and commissions payable of Cdn$1.1 million and expenses of Cdn$0.1 million. Each Special Warrant was converted into one common share and one-quarter of a common share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred on March 12, 2010.

The Company calculated the value of the common share purchase warrants using the Black Scholes option pricing model which included assumptions related to risk-free interest rates, volatility factors, and the expected life of the warrant. The value of the 10.4 million and 2.1 million purchase warrants issued in 2010 were calculated using a risk-free interest rate of 0.7% and 0.9% respectively, a volatility factor of 78.9% and 71.6% respectively and an expected life of one year.

In January 2010, one of the Company s subsidiaries signed an agreement that granted a private investor an option to acquire a 20% interest in the subsidiary for Cdn$25.0 million. The option is valid for one year and does not become exercisable until the first quarter of 2011. The option was determined to have a nominal value at the grant date.

In 2009, 0.7 million purchase warrants were issued in exchange for outstanding warrants of a company that Ivanhoe acquired (refer to Note 17).

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 were approximately Cdn$83.4 million after deducting the agents commission of Cdn$4.0 million and expenses 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.

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 a conversion price of Cdn$2.24 per share.

As the Company incurred a net loss for the years ended December 31, 2010, 2009 and 2008, the following potentially dilutive securities had an anti-dilutive effect on basic earnings per share:

(000s of common shares)	**2010**	**2009**	**2008**
Stock options	**16,927**	15,013	11,913
Purchase warrants	**24,633**	12,135	11,400
Convertible debt	**12,780**	12,780	12,780
	54,340	39,928	36,093

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 common shares under a share purchase plan for eligible employees. The total number of common shares that may be issued under this plan cannot exceed 7% of the Company s issued and outstanding common shares which, at December 31, 2010, was 23.4 million (December 31, 2009 29.3 million). The maximum common share issuances under this plan was changed from a fixed number of common shares to a percentage of outstanding common shares in the second quarter of 2010.

Stock options are issued at the weighted average trading price for the five days immediately preceding the award and are conditional on continuing employment. Expiration and vesting periods are set at the discretion of the Board of Directors, but typically vest over three to four years and expire five to ten years from the date of issue. In 2007, the Company granted stock option awards that vest upon meeting various departmental and company-wide goals. At December 31, 2010, there were approximately 479,000 unvested options outstanding.

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

	2010		2009		2008	
	Number of Stock Options (000s)	**Weighted Average Exercise Price (Cdn$)**	Number of Stock Options (000s)	Weighted Average Exercise Price (Cdn$)	Number of Stock Options (000s)	Weighted Average Exercise Price (Cdn$)
Outstanding, beginning of year	**15,013**	**2.27**	11,913	2.32	12,945	2.37
Granted	**6,041**	**2.56**	4,188	2.17	3,832	1.79
Exercised	**(2,743)**	**2.28**	(413)	2.46	(3,067)	0.90
Expired	**(635)**	**2.60**	(114)	2.44	(580)	5.78
Forfeited	**(749)**	**2.64**	(561)	2.41	(1,217)	3.05
Outstanding, end of year	**16,927**	**2.24**	15,013	2.27	11,913	2.32
Exercisable, end of year	**7,324**	**2.19**	7,101	2.48	5,062	2.61

The following table summarizes information respecting stock options outstanding and exercisable as at December 31, 2010:

	Outstanding			Exercisable		
Range of Exercise Prices (Cdn$)	**Outstanding (000s)**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price (Cdn$)**	**Exercisable (000s)**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price (Cdn$)**
1.51 to 2.06	6,289	2.7	1.74	3,723	2.3	1.73
2.15 to 2.71	7,788	4.9	2.34	2,079	2.7	2.41
2.77 to 3.41	2,850	3.8	3.08	1,522	1.6	2.98
	16,927	3.9	2.24	7,324	2.3	2.19

The fair value of each option award is estimated on the date of grant using the Black Scholes option pricing formula. Service condition options are 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:

	2010	2009	2008
Expected life (in years)	**6.0**	4.6	4.0
Volatility	**75.2%**	81.1%	63.5%
Dividend yield	**0.0%**	0.0%	0.0%
Risk-free rate	**2.6%**	2.6%	3.1%

The weighted average grant date fair value of stock options granted in 2010 was Cdn$1.73 (2009 Cdn$1.62; 2008 Cdn$0.90).

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The Company s stock-based compensation related to option awards, share bonus awards and common shares issued for services were classified as follows in the consolidated statement of loss:

	2010	**2009**	**2008**
General and administrative			
Option awards	**5,695**	3,484	2,241
Share bonus awards			207
Shares issued for services		207	
	5,695	3,691	2,448
Business and technology development			
Option awards	**400**	158	432
Share bonus awards			136
	400	158	568
Discontinued operations			
Option awards		17	391
Share bonus awards			147
		17	538
	6,095	3,866	3,554

Additionally, in 2010, $0.8 million (2009 nil; 2008 $0.2 million) of stock-based compensation was capitalized to oil and gas properties and development costs.

10. RETIREMENT PLAN

In 2001, the Company adopted a defined contribution retirement or thrift plan (401(k) Plan) to assist US employees in providing for retirement or other future financial needs. Employees contributions (up to the maximum allowed by US tax laws) were matched 100% by the Company in 2010. In 2010, the Company s matching contributions to the 401(k) Plan were $0.4 million (2009 $0.4 million; 2008 $0.5 million).

11. SEGMENT INFORMATION

The Company subdivides its operations into four areas: Oil and Gas Integrated, Oil and Gas Conventional, Business and Technology Development and Corporate. Accounting policies for segments are the same as those described in Significant Accounting Policies (refer to Note 2).

Oil and Gas Integrated

Projects in this segment have two primary components: conventional exploration and production activities supported by enhanced oil recovery techniques, such as steam assisted gravity drainage and deployment of the HTL technology. The Company has two projects currently reported in this segment: a heavy oil project in Canada and a heavy oil project in Ecuador.

Oil and Gas Conventional

Projects in this segment consist of conventional oil and gas exploration and production activities without enhanced oil recovery techniques or the use of HTL technology. The Company has two conventional projects in Asia, located in China and Mongolia. Prior to July 2009, the Company conducted conventional exploration, development and production activities primarily in the US (refer to Note 18).

Business and Technology Development

The Company s Business and Technology Development segment captures HTL activities as well as costs associated with the pursuit of new business development opportunities.

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Corporate

The Corporate area tracks costs associated with the board of directors, executive officers, corporate debt, financings and other corporate activities.

	2010						
	Oil and Gas				Business and Technology Development	Corporate(2)	Total
	Integrated		Conventional				
	Canada	Ecuador	Asia	US(1)			
Revenue							
Oil(3)			21,720				21,720
Interest			6			202	208
			21,726			202	21,928
Expenses							
Operating			9,503				9,503
General and administrative	1,802	2,707	3,619			18,132	26,260
Business and technology development	187	43			10,385		10,615
Depletion and depreciation	9	47	8,697		(36)	243	8,960
Foreign exchange	(15)		(62)			(3,248)	(3,325)
Interest and financing	6	7			11		24
	1,989	2,804	21,757		10,360	15,127	52,037
Loss continuing operations before income taxes	(1,989)	(2,804)	(31)		(10,360)	(14,925)	(30,109)
(Provision for) recovery of income taxes							
Current			(111)			(15)	(126)
Future			(73)		1,198		1,125
			(184)		1,198	(15)	999
Net loss continuing operations	(1,989)	(2,804)	(215)		(9,162)	(14,940)	(29,110)
Net loss discontinued operations							

Net loss and comprehensive loss	(1,989)	(2,804)	(215)	(9,162)	(14,940)	(29,110)
Capital investments	29,987	18,727	36,613	567	391	86,285
Identifiable assets as at December 31, 2010	125,569	28,916	91,189	102,810	61,101	409,585

(1) The Company sold its US operations in the third quarter of 2009.

(2) Corporate activities undertaken on behalf of a segment are allocated to that segment at cost.

(3) All revenues in Asia are generated from the sale of production to one customer.

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	2009						
	Oil and Gas				Business and Technology Development	Corporate[2]	Total
	Integrated		Conventional				
	Canada	Ecuador	Asia	US[1]			
Revenue							
Oil[3]			24,968				24,968
Loss on derivative instruments			(1,335)				(1,335)
Interest			6			19	25
			23,639			19	23,658
Expenses							
Operating			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	(8)		71		2	5,155	5,220
Interest and financing			770		79	7	856
Provision for impairment of intangible asset and development costs					1,903		1,903
	1,685	2,322	31,842		12,558	20,825	69,232
Loss 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
Net loss continuing operations	(1,685)	(2,322)	(9,602)		(2,958)	(21,164)	(37,731)

Net loss discontinued operations (net of tax of $29.6 million)				(23,921)			(23,921)
Net loss and comprehensive 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

(1) The Company sold its US operations in the third quarter of 2009.

(2) Corporate activities undertaken on behalf of a segment are allocated to that segment at cost.

(3) All revenues in Asia are generated from the sale of production to one customer.

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	2008						
	Oil and Gas				Business and Technology		
	Integrated		Conventional				
	Canada	Ecuador	Asia	US(1)	Development	Corporate(2)	Total
Revenue							
Oil(3)			48,370				48,370
Gain on derivative instruments			1,688				1,688
Interest			50			562	612
			50,108			562	50,670
Expenses							
Operating			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	26		278			1,223	1,527
Interest expense and financing			821		76	412	1,309
Provision 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 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 continuing operations	(1,845)	(658)	(879)		(24,014)	(11,080)	(38,476)
Net income discontinued operations				4,283			4,283
Net (loss) income and comprehensive (loss) income	(1,845)	(658)	(879)	4,283	(24,014)	(11,080)	(34,193)
Capital investments	6,484	1,369	8,378		4,832		21,063
	81,126	1,766	64,901	65,371	105,587	28,124	346,875

Identifiable assets as at December 31, 2008

(1) The Company sold its US operations in the third quarter of 2009.

(2) Corporate activities undertaken on behalf of a segment are allocated to that segment at cost.

(3) All revenues in Asia are generated from the sale of production to one customer.

12. FINANCIAL INSTRUMENTS

The Company s financial instruments are comprised of cash and cash equivalents, accounts receivable, note receivable, restricted cash, long term receivables, accounts payable and accrued liabilities, debt and a long term obligation.

The Company s cash and restricted cash are transacted in active markets and have been classified using Level 1 inputs. Carrying amounts of financial instruments approximate their fair value except for debt. The Company calculated the fair value of its debt to be $40.2 million as at December 31, 2010.

Financial Risk Factors

In the normal course of operations, the Company is exposed to market risks resulting from movements in commodity prices, foreign currency exchange rates and interest rates, which may result in fluctuations in the fair value or future cash flows of its financial instruments.

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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. 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.

In 2007, the Company entered into a costless collar derivative to minimize variability in its cash flow from the sale of up to 18,000 bbls/month of the Company s production from its Dagang field in China over a three year period. This derivative had a ceiling price of $84.50 /bbl and a floor price of $55.00 /bbl using the WTI as the index traded on the NYMEX. The contracts related to this derivative 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.

Results of these derivative transactions for the three years ended December 31, 2010, are:

	2010	2009	2008
Realized gains (losses) on derivative transactions		124	(4,430)
Unrealized gains (losses) on derivative transactions		(1,459)	6,118
		(1,335)	1,688

Foreign Currency Exchange Rate Risk

Ivanhoe is exposed to foreign currency exchange rate risk as a result of incurring capital expenditures and operating costs in currencies other than the US dollar. A substantial portion of the Company s activities are transacted in or referenced to US dollars, including oil sales in Asia, capital spending in Ecuador and ongoing FTF operations. A portion of transactions are in other currencies, such as Dagang operating costs paid in Chinese renminbi, Tamarack exploration activities funded in Canadian dollars and the 2010 common share issuance in Canadian dollars. The Company did not enter into any foreign currency derivatives in 2010, nor do we anticipate using foreign currency derivatives in 2011. To help reduce the Company s exposure to foreign currency exchange rate risk, the Company seeks to hold assets and liabilities denominated in the same currency when appropriate.

The following table shows the Company s exposure to foreign currency exchange rate risk on its net loss and comprehensive loss, assuming reasonably possible changes in the relevant foreign currency. This analysis assumes all other variables remain constant.

(Increase) Decrease in Net Loss and Comprehensive Loss	Change From a 10% Increase or Weakening	Change From a 10% Decrease or Strengthening
Chinese renminbi	1,438	(1,758)
Canadian dollar	(2,089)	167

Interest Rate Risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate as a result of changes in market interest rates. Interest rate risk arises from interest-bearing borrowings which have a variable interest rate. The Company s net loss and accumulated deficit would not have changed with a change in interest rates in 2010 as the Company s debt consists of the Convertible Note issued for the acquisition of the Tamarack leases for which interest is capitalized.

Credit Risk

Ivanhoe is exposed to credit risk with respect to its cash and cash equivalents, accounts receivable, note receivable, restricted cash and long term receivables. The Company s maximum exposure to credit risk at December 31, 2010, is represented by the carrying amount of these non-derivative financial assets. Most of the Company s credit exposures are with counterparties in the energy industry and are therefore exposed to normal industry credit risks. Ivanhoe manages its credit risk by entering into sales contracts only with established entities.

The Company believes its exposure to credit risk related to cash and cash equivalents, as well as restricted cash, is minimal due to the quality of the financial institutions where the funds are held and the nature of the deposit instruments.

Currently, all of the Company s oil production is sold to one national oil corporation. As a result, 85% of the outstanding accounts receivable balance at December 31, 2010 (December 31, 2009 94%) is due from a national oil corporation. Long term receivables are composed of value-added tax receivable amounts from Ecuador and will be recoverable upon commencement of commercial operations. Ivanhoe considers the risk of default on these items to be low due to the Company s ongoing operations in China and Ecuador.

In 2008, the Company recorded an allowance associated with an advance balance for the outstanding amount of $0.7 million.

As at December 31,	**2010**	**2009**
Accounts receivable current	**6,329**	5,004
Accounts receivable over 90 days	**30**	17
	6,359	5,021

Liquidity Risk

Liquidity risk is the risk that suitable sources of funding for the Company s business activities may not be available. Since cash flows from existing operations are insufficient to fund future capital expenditures, we intend to finance future capital projects with 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 or from the sale of existing assets. There is no assurance that we will be able to obtain such financing on favorable terms, if at all.

As at December 31, 2010	**Less than 1 year**
Accounts payable and accrued liabilities	21,482
Long term debt and interest	41,275

13. CAPITAL MANAGEMENT

The Company s main source of funds has historically 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. There have been no significant changes in Management s objectives, policies and processes to manage capital from the previous year.

The Company defines capital as total shareholders equity plus cash and cash equivalents and debt.

As at December 31,	**2010**	**2009**
Cash and cash equivalents	**67,817**	21,512
Debt	**39,832**	
Long term debt		36,934
Shareholders equity	**324,109**	208,029

The Company s management reviews the capital structure on a regular basis to maintain an 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.

As at December 31, 2010, the Company is not subject to any financial covenants.

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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 rates to the net losses before income taxes. The combined Canadian federal and provincial statutory rates as at December 31, 2010, 2009 and 2008 were 28.0%, 29.0% and 29.5%, respectively. The sources and tax effects for the differences were as follows:

	2010	2009	2008
Loss from continuing operations before income taxes	**(30,109)**	(45,574)	(37,822)
Combined Canadian federal and provincial statutory rates	**28.0%**	29.0%	29.5%
Tax benefit	**(8,431)**	(13,217)	(11,158)
Foreign net (gains) losses affected at lower income tax rates	**(396)**	106	4,562
Effect of change in foreign exchange rates	**(2,309)**	(2,858)	3,006
Expiry of tax loss carry-forwards	**982**	911	2,875
Tax credit carry-forward		(350)	
Compensation not deductible	**1,310**	1,456	753
Financing costs not deductible			695
Net currency exchange (gains) losses not deductible	**(900)**	1,501	402
Change in prior year estimate of tax loss carry-forwards	**(918)**	3,941	(59)
Realized derivative (gains) losses not taxable/deductible		334	(422)
Effect of change in effective income tax rates on future tax assets	**1,096**	(4,453)	(331)
Other differences	**425**	32	(127)
	(9,141)	(12,597)	196
Change in valuation allowance	**8,142**	4,754	458
Provision for (recovery of) income taxes	**(999)**	(7,843)	654

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

As at December 31,	**2010**		**2009**	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Oil and gas properties and investments	**266**	**(8,569)**	471	(1,124)
Intangibles		**(30,493)**		(30,354)
Tax loss carry-forwards	**54,990**		37,583	
Tax credit carry-forward			350	
Valuation allowance	**(37,712)**		(29,570)	
	17,544	**(39,062)**	8,834	(31,478)

The consolidated loss carry-forward amounts and the year of expiry as at December 31, 2010, are shown in the table below. In China, the loss carry-forwards have no expiration period. A loss of approximately Cdn$55.3 million from the disposition of Russian operations in 2000, is a capital loss for Canadian income tax purposes, and is available for carry-forward against future Canadian capital gains indefinitely and is not included in the future income tax assets above.

Year of Expiry	
2011	505
2012	2,327
2014	5,243
2015	6,803
2018	2,093
2019	1,079
2020 2025	5,508
2026 2030	116,123
No expiry	63,994
	203,675

There are no current income taxes payable at December 31, 2010 (December 31, 2009 $0.2 million related to China, $0.3 million related to the US).

Prior to the Company selling its US operating segment in July 2009, the Company had future tax assets arising from net operating loss carry-forwards generated by this business segment. These future income tax assets were partially offset by certain future income tax liabilities in the US 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 consolidated balance sheet. The future income tax assets classified as assets from discontinued operations were included in the $23.4 million loss on disposition. 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 carry-forwards.

As at December 31, 2010, the Company s future income tax liability is $21.5 million in the accompanying consolidated balance sheet, composed of $18.8 million in the US tax jurisdiction and $2.7 million related to Mongolia.

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. 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 June 2009.

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15. SUPPLEMENTAL CASH FLOW INFORMATION

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

	2010	2009	2008
Cash paid during the year for			
Income taxes	**656**	1,876	5
Interest	**1,610**	2,122	1,120
Investing and financing activities, non-cash			
Acquisition of business/assets			
Shares issued		6,899	
Warrants issued		622	
Debt issued			52,052
		7,521	52,052
Conversion of debt to common shares			
Extinguishment of debt			4,737
Extinguishment of interest			125
			4,862
Shares issued for bonuses and services	**799**	207	490
Stock-based compensation capitalized			175

	2010	2009	2008
Changes in non-cash working capital items			
Operating activities			
Accounts receivable	**(551)**	(1,253)	3,509
Note receivable	**(39)**	(225)	
Prepaid and other current assets	**176**	(175)	(48)
Accounts payable and accrued liabilities	**2,076**	1,314	1,905
Income tax payable	**(530)**	(120)	650
	1,132	(459)	6,016
Investing activities			
Accounts receivable	**(775)**	(140)	7
Prepaid and other current assets	**(2,264)**	41	(70)
Accounts payable and accrued liabilities	**8,672**	163	(972)
	5,633	64	(1,035)

Financing activities			
Accounts payable and accrued liabilities	**(10)**	(26)	26
	6,755	(421)	5,007

Cash and cash equivalents are composed of the following:

As at December 31,	**2010**	**2009**
Bank accounts	**10,147**	21,512
Term deposit	**57,670**	
	67,817	21,512

16. 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 various international locations. The Company is billed on a cost recovery basis in most cases. In 2010, the costs incurred in the normal course of business with respect to the above arrangements amounted to $3.3 million (2009 $3.8 million; 2008 $3.0 million). These transactions 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, 2010, amounts included in accounts payable and accrued liabilities on the consolidated balance sheet under these arrangements were $0.2 million (December 31, 2009 $0.1 million).

17. ACQUISITION 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 and expire in February 2011.

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

Purchase consideration	
2,683,291 common shares[(1)]	6,899
735,449 warrants to purchase Ivanhoe common shares *(Note 8)*	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 closing share price on the Toronto Stock Exchange on the date of acquisition, November 26, 2009, was Cdn$2.70.

Canada

In July 2008, the Company acquired from Talisman two leases located in the Athabasca oil sands region in the Province of Alberta, Canada. The amount paid was Cdn$75.0 million of which Cdn$22.5 million was paid on closing and two promissory notes were issued to Talisman. The principal amount of the first note was Cdn$12.5 million with an interest rate of prime plus 2%. The first note matured and was repaid on December 31, 2008. The second promissory note was Cdn$40.0 million, with an interest rate of prime plus 2%. The second note matures in July 2011 and the outstanding principal amount is convertible at Talisman s option into a maximum of 12,779,552 Ivanhoe common shares at Cdn$3.13 per common share.

The Company may be required to make a Cdn$15.0 million cash payment to Talisman upon receiving government and other approvals necessary to develop the northern border of one of the Tamarack leases.

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. If the Back-in Right is exercised, the cost to Talisman would be 20% of 200% of Ivanhoe s acquisition cost and certain expenses incurred since acquisition in respect of the relevant lease.

Until July 11, 2011, Talisman also 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, Petro (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 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/bbl of oil produced and delivered to Petroproduccion. The payment will be adjusted quarterly, on a weighted average basis, for movement in a basket of three US Government published producer price indices relating to steel products, refinery products and upstream oil and gas equipment.

18. DISCONTINUED OPERATIONS

In 2009, management commenced a process to sell all of the Company s US 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 the Company s oil and gas exploration and production operations in California and Texas and additional exploration acreage in California.

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 Ivanhoe Energy (USA) Inc. s assets. The Company applied the balance of the sales proceeds in the ongoing development of its heavy oil projects in Canada and Ecuador and for general corporate purposes.

An escrow deposit of $2.0 million was set aside from the sale proceeds and made available to the purchaser for a period of one year to satisfy any indemnification obligations of the Company. In July 2010, the purchaser notified the Company of a claim against the entire escrow deposit for alleged breaches of certain covenants in the purchase and sale agreement in respect of tax matters. While the Company believed there was no basis for the claim, in the fourth quarter of 2010, Ivanhoe agreed to pay the purchaser $250,000 of the escrow deposit to avoid a lengthy legal dispute and the remaining $1.75 million was returned to Ivanhoe.

In conjunction with the disposition of the US assets and the Company s focus on heavy oil opportunities, the Company closed its support office in Bakersfield, California and transferred its accounting operations to Calgary, Alberta. This transition was completed by the end of the second quarter of 2010. Total costs associated with this closure, including severance and retention payments, were approximately $0.6 million.

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

	2010	2009	2008
Revenue			
Oil and gas		5,455	18,120
Gain on derivative instruments		189	278
Interest		8	98
		5,652	18,496
Expenses			
Operating		2,132	5,137
General and administrative		139	2,413
Depletion and depreciation		3,772	6,143
Interest and financing		173	520
		6,216	14,213
Income (loss) before disposition		(564)	4,283
Loss on disposition (net of tax of $29.6 million for 2009, nil for 2008)		(23,357)	

Net income (loss) from discontinued operations	(23,921)	4,283

19. SUBSEQUENT EVENTS

On January 24, 2011, the Company announced its application to extend the expiry date of 12,410,000 unlisted outstanding common share purchase warrants had been approved by the Toronto Stock Exchange. The extension excluded 90,000 warrants held by an insider. These warrants were scheduled to expire on January 26, 2011 and instead expired on February 25, 2011. The Company received proceeds of $27.2 million from the exercise of 8,616,665 out of the 12,320,000 common share purchase warrants. These proceeds will be used for general corporate purposes.

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20. ADDITIONAL DISCLOSURES REQUIRED UNDER US 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 US GAAP except for certain matters, the details of which are as follows:

Consolidated Balance Sheets

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

As at December 31,		**2010**				**2009**		
	Canadian GAAP	***Increase (Decrease)***	***Notes***	**US GAAP**	**Canadian GAAP**	***Increase (Decrease)***	***Notes***	**US GAAP**
Assets								
Current assets								
Cash and cash equivalents	67,817			67,817	21,512			21,512
Accounts receivable	6,359			6,359	5,021			5,021
Note receivable	264			264	225			225
Prepaid and other current assets	2,859			2,859	771			771
Restricted cash	500			500	2,850			2,850
Total current assets	77,799			77,799	30,379			30,379
Oil and gas properties and development costs, net	237,200	*(38,500)*	*(i)*	221,290	158,392	*(38,500)*	*(i)*	139,346
		24,172	*(ii)*			*20,315*	*(ii)*	
		(1,582)	*(iii)*			*(861)*	*(iii)*	
Intangible assets	92,153			92,153	92,153			92,153
Long term receivables	2,433			2,433	839			839
Total assets	409,585	*(15,910)*		393,675	281,763	*(19,046)*		262,717
Liabilities and shareholders equity								
Current Liabilities								
Accounts payable and accrued liabilities	21,482			21,482	10,779			10,779
Debt	39,832	*504*	*(iii)*	40,217				
		(119)	*(iii)*			-		
Income tax payable					530			530
Derivative instruments		*7,228*	*(vi)*	7,228		*8,249*	*(vi)*	8,249
Asset retirement obligation					753			753
Total current liabilities	61,314	*7,613*		68,927	12,062	*8,249*		20,311
Long term debt					36,934	*1,225*	*(iii)*	38,005
						(154)	*(iii)*	

Asset retirement obligations	744			744	195			195
Long term obligation	1,900			1,900	1,900			1,900
Future income tax liability	21,518			21,518	22,643			22,643
Total liabilities	85,476	*7,613*		93,089	73,734	*9,320*		83,054
Shareholders equity								
Share capital	550,562	*74,455*	*(iv)*	638,420	422,322	*74,455*	*(iv)*	510,784
		(1,155)	*(v)*			*(551)*	*(v)*	
		1,358	*(vii)*			*1,358*	*(vii)*	
		13,200	*(vi)*			*13,200*	*(vi)*	
Purchase warrants	33,423	*(33,423)*	*(vi)*		19,427	*(19,427)*	*(vi)*	
Contributed surplus	22,983	*(2,593)*	*(v)*	17,443	20,029	*(3,197)*	*(v)*	13,885
		(2,947)	*(vi)*			*(2,947)*	*(vi)*	
Convertible note	2,086	*(2,086)*	*(iii)*		2,086	*(2,086)*	*(iii)*	
Accumulated deficit	(284,945)	*(70,332)*		(355,277)	(255,835)	*(89,171)*		(345,006)
Total shareholders equity	324,109	*(23,523)*		300,586	208,029	*(28,366)*		179,663
Total liabilities and shareholders equity	409,585	*(15,910)*		393,675	281,763	*(19,046)*		262,717

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 US. The principal difference is in the method of performing ceiling test evaluations. In the ceiling test evaluation for US 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 a 12 month average oil price to reserves 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 10% 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 unproved properties included in the costs being amortized less (d) income tax effects related to the difference between the book and tax basis of the properties referred to in (b) and (c) above. If capitalized costs exceed this limit, the excess is charged as a provision for impairment. Unproved properties and major development projects are assessed on a quarterly basis for possible impairments or reductions in value. If a reduction in value has occurred, the impairment is transferred to the carrying value of proved oil and gas properties. The Company performed the ceiling test in accordance with US GAAP and determined that for the year ended December 31, 2010, no impairment provision was required. The cumulative differences in the amount of impairment provisions between US and Canadian GAAP were $38.5 million at December 31, 2010, and December 31, 2009.

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

(iii) Under Canadian GAAP, the Company was required to bifurcate the value of the Convertible Note, allocating a portion to debt and a portion to equity. Under US GAAP, convertible debt securities are classified as debt in their entirety. Under Canadian GAAP, this discount accretion was capitalized. To reconcile to US GAAP the entire $2.1 million recorded in equity is reversed as well as the unamortized discount of $0.4 million and the accreted discount that was capitalized in the amount of $1.6 million. In addition, because the convertible note is not denominated in US currency the re-measurement of the different carrying value for US GAAP results in an increase to net income. The foreign exchange gain of $0.1 million is shown as a separate amount in the US GAAP reconciliation of the Company s balance sheet shown above and is adjusted to the foreign exchange expense line item in the US GAAP reconciliation of the statement of operations below.

Shareholders Equity

(iv) 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 US GAAP, a reduction of the accumulated deficit such as this is not recognized except in the case of a quasi reorganization.

(v) 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 US 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 US 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 US GAAP subsequent to January 1, 2006.

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(vi) The Company accounts for purchase warrants as equity under Canadian GAAP. The accounting treatment of warrants under US 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 US 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 US 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.

(vii) Under US 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 US GAAP in the value ascribed to the common shares issued, primarily resulting from differences in the recognition of effective dates of the transactions.

Consolidated Statements of Loss and Comprehensive Loss

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

	2010			
	Canadian GAAP	**Increase (Decrease)**	**Notes**	**US GAAP**
Revenue				
Oil	21,720			21,720
Gain on derivative instruments		15,017	*(vi)*	15,017
Interest	208			208
	21,928	15,017		36,945
Expenses				
Operating	9,503			9,503
General and administrative	26,260			26,260
Business and technology development	10,615			10,615
Depletion and depreciation	8,960	(3,857)	*(ix)*	5,103
Foreign exchange	(3,325)	35	*(iii)*	(3,290)
Interest and financing	24			24
	52,037	(3,822)		48,215
Loss from continuing operations before income taxes	(30,109)	18,839		(11,270)
(Provision for) recovery of income taxes				
Current	(126)			(126)
Future	1,125			1,125
	999			999

Net loss continuing operations	(29,110)	18,839	(10,271)
Net loss discontinued operations			
Net loss and comprehensive loss	(29,110)	18,839	(10,271)
Net loss per share			
Net loss continuing operations, basic and diluted	(0.09)	0.06	(0.03)
Net loss discontinued operations, basic and diluted			
Net loss per share, basic and diluted	(0.09)	0.06	(0.03)
Weighted average number of common shares			
Basic and diluted (000s)	327,442		327,442

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	2009			
	Canadian GAAP	**Increase (Decrease)**	**Notes**	**US GAAP**
Revenue				
Oil	24,968			24,968
Loss on derivative instruments	(1,335)	(6,506)	*(vi)*	(7,841)
Interest	25			25
	23,658	(6,506)		17,152
Expenses				
Operating	10,191			10,191
General and administrative	21,693			21,693
Business and technology development	9,501	150	*(viii)*	9,651
Depletion and depreciation	19,868	(10,574)	*(ix)*	9,294
Foreign exchange	5,220	(154)	*(iii)*	5,066
Interest and financing	856			856
Provision for impairment of intangible asset and development	1,903	(980)	*(viii)*	923
	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 continuing operations	(37,731)	5,052		(32,679)
Net income (loss) discontinued operations (net of tax of $29.6 million)	(23,921)	24,890	*(x)*	969
Net loss and comprehensive loss	(61,652)	29,942		(31,710)
Net income (loss) per share				
Net loss continuing operations, basic and diluted	(0.13)	0.01		(0.12)
Net income (loss) discontinued operations, basic and diluted	(0.09)	0.10		0.01
Net loss per share, basic and diluted	(0.22)	0.11		(0.11)

Weighted average number of common shares		
Basic and diluted (000s)	279,722	279,722

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	2008			
	Canadian GAAP	Increase (Decrease)	Notes	US GAAP
Revenue				
Oil	48,370			48,370
Gain on derivative instruments	1,688	4,665	*(vi)*	6,353
Interest	612			612
	50,670	4,665		55,335
Expenses				
Operating	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)	*(ix)*	22,941
Foreign exchange	1,527			1,527
Interest and financing	1,309			1,309
Provision for impairment of intangible asset and development	15,054	(4,640)	(viii)	10,414
Write off of deferred financing	2,621			2,621
Provision for impairment of oil and gas properties		21,560	(ix)	21,560
	88,492	14,100		102,592
Loss from continuing operations before income taxes	(37,822)	(9,435)		(47,257)
Current provision for income taxes	(654)			(654)
Net loss continuing operations	(38,476)	(9,435)		(47,911)
Net income (loss) discontinued operations	4,283	(19,423)	(x)	(15,140)
Net loss and comprehensive loss	(34,193)	(28,858)		(63,051)
Net income (loss) per share				
Net loss 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 common shares Basic and diluted (000s)	258,815			258,815

Development Costs

(viii) 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. The Company wrote off $5.1 million in GTL development costs under Canadian GAAP. These costs had already been expensed under US GAAP in previous periods and therefore this transaction reduced the net loss for US GAAP purposes in 2008.

Depletion and Depreciation

(ix) As discussed under Oil and Gas Properties and Development Costs in this note, there is a difference between US and Canadian GAAP in performing the ceiling test evaluation under the full cost method. Application of the ceiling test evaluation under US GAAP has resulted in an accumulated net increase in impairment provisions on the Company s US and China oil and gas properties. This net increase in US GAAP impairment provisions has resulted in lower depletion rates for US GAAP purposes and a reduction in the net losses for the years ended December 31, 2010, 2009 and 2008.

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Discontinued Operations

(x) As at December 31, 2009, 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 US GAAP in the value ascribed to the common 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. These increases were offset by $29.4 million decrease due to impairment differences. 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 US GAAP and the recovery of such costs, the statement of cash flow under US GAAP would result in a net use of cash from operating activities of $17.8 million, $12.4 million and cash provided from operating activities of $16.6 million for the year ended December 31, 2010, 2009 and 2008, respectively. Additionally, capital investments reported under investing activities would be $86.3 million, $26.2 million and $20.7 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Additional US GAAP Disclosures

Oil and Gas Properties and Development Costs

The categories of costs included in Oil and Gas Properties and Development Costs , including the US GAAP adjustments were as follows:

As at December 31, 2010	Canada	Ecuador	Asia	Corporate	Business and Technology Development	Total
Property acquisition	77,742	2,089	31,137			110,968
Capitalized interest	4,936					4,936
Exploration	30,085	19,763	75,091			124,939
Development			91,885			91,885
Production facilities		4,397				4,397
HTL facilities	11,089				11,426	22,515
Support equipment and general property	27	436	1,157	1,361	58	3,039
	123,879	26,685	199,270	1,361	11,484	362,679
Accumulated depletion and depreciation	(17)	(101)	(84,391)	(894)	(936)	(86,339)
Provision for impairment			(55,050)			(55,050)
	123,862	26,584	59,829	467	10,548	221,290

As at December 31, 2009	Canada	Ecuador	Asia	Corporate	Business and Technology Development	Total
Property acquisition	77,093	852	42,298			120,243
Capitalized interest	3,049					3,049
Exploration	6,437	2,988	32,831			42,256
Development			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

As at December 31, 2010, the costs of unproved properties included in oil and gas properties and development costs, which have been excluded from the depletion and ceiling test calculations, were incurred as follows:

	Total	**2010**	**2009**	**2008**	**Prior to 2008**
Property acquisition	90,992	1,786	11,920	77,187	99
Exploration	98,235	72,705	17,655	6,325	1,550
	189,227	74,491	29,575	83,512	1,649

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As at December 31, 2010, the costs of unproved oil and gas by prospect were incurred as follows:

	Total	2010	2009	2008	Prior to 2008
Canada					
Tamarack	123,852	30,282	12,480	81,090	
Ecuador					
Block 20	26,249	19,494	5,301	1,454	
Asia					
Zitong Block	23,652	20,403	632	968	1,649
Nyalga Block	15,474	4,312	11,162		
	39,126	24,715	11,794	968	1,649
	189,227	74,491	29,575	83,512	1,649

Accounts Payable and Accrued Liabilities

The following was the breakdown of accounts payable and accrued liabilities as at December 31, 2010:

Trade payables	8,922	3,767
Accrued liabilities	12,560	7,012
	21,482	10,779

Stock-based Compensation

The aggregate intrinsic value of total options outstanding as well as options exercisable as at December 31, 2010 was $8.1 million and $3.8 million respectively. The total intrinsic value of options exercised during the year ended December 31, 2010 was $2.3 million (2009 $3.0 million; 2008 $5.4 million), and the cash received from exercise of options during the year ended December 31, 2010 was $2.6 million (2009 $0.9 million; 2008 $0.2 million).

A summary of the Company s unvested options as at December 31, 2010, and changes during the year then ended, is presented below:

	Number of Stock Options (000s)	Weighted-Average Grant Date Fair Value (Cdn$)
Outstanding, beginning of year	7,912	1.21
Granted	6,040	1.73
Vested	(3,060)	1.53
Cancelled and forfeited	(748)	1.77
Outstanding, end of year	10,144	1.55

Unvested options outstanding as at December 31, 2010, by type:

Based on fulfilling service conditions	9,665
Based on fulfilling performance conditions	479

10,144

As at December 31, 2010, there was $10.0 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 3.0 years. The total fair value of options vested during the year ended December 31, 2010 was $4.7 million (2009 $2.2 million; 2008 $3.0 million).

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Impact of New and Pending US GAAP Accounting Standards

There were no changes in accounting standards in 2010 that affected or are expected to affect the Company. As a foreign private issuer in the US, Ivanhoe is permitted to file with the SEC consolidated financial statements prepared under IFRS beginning in 2011 without a reconciliation to US GAAP. The impact of this change is that the Company will no longer prepare a reconciliation of its results to US GAAP. It is possible that some of the Company s accounting policies under IFRS could be different from US GAAP.

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SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES
(Unaudited)
(all tabular amounts are expressed in US$000s, 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 US SFAS No. 69, Disclosures About Oil and Gas Producing Activities .

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.

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 in China for the three-year period ended December 31, 2010, were as follows:

(mbbls)	
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
Revisions of previous estimates	925(3)
Production	(288)
Net proved reserves, December 31, 2010	1,738

(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.

(3) The reserve revision in 2010 is mainly related to lower estimated decline rates on the Dagang property based on production to date.

Net proved producing reserves in China as at December 31, were as follows:

(mbbls)	
2008	862
2009	885

2010	1,265

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

For the year ended December 31, 2010 and 2009, future net cash flows were computed using 12 month historical average prices in estimating the Company s proved oil reserves, current costs, and statutory tax rates adjusted for tax deductions, that relate to existing proved oil reserves. For the year ended December 31, 2008, 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 $76.35, $58.00 and $41.57 /bbl of oil in 2010, 2009 and 2008, 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 for China as at December 31 in each of the three most recently completed financial years were as follows:

	2010
Future cash inflows	132,745
Future development and restoration costs	(7,209)
Future production costs	(58,790)
Future income taxes	(12,238)
Future net cash flows	54,508
10% annual discount	(14,861)
Standardized measure	39,647

	2009
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
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

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 of difficulty in analyzing 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 oil in the PRC are subject to a windfall gain levy (the Windfall Levy) if the monthly weighted average price of oil is above $40.00/bbl. The Windfall Levy is imposed at progressive rates from 20% to 40% on the portion of the weighted average sales price exceeding $40.00/bbl. 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 a $13.46 per bbl increase in 2008 when compared to 2007. The Windfall Levy accounted for

$21.14/bbl cost of the total $43.92/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/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 from China as at December 31 in each of the three most recently completed financial years were as follows:

	2010
Sale of oil and gas, net of production costs	(12,216)
Net changes in prices and production costs	15,878
Net change in future development costs	(8,082)
Development costs incurred during the period that reduced future development costs	4,924
Revisions of previous quantity estimates	31,578
Accretion of discount	1,855
Net change in income taxes	(11,645)
Changes in production rates (timing) and other	(1,193)
Increase	21,099
Standardized measure, beginning of year	18,548
Standardized measure, end of year	39,647

	2009
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
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

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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:

	2010	2009	2008
Canada			
Property acquisition			
Unproved	**649**	1,361	75,732
Exploration	**29,634**	11,119	5,357
	30,283	12,480	81,089
Ecuador			
Property acquisition			
Unproved	**1,237**		863
Exploration	**18,257**	5,301	591
	19,494	5,301	1,454
Asia			
Property acquisition			
Unproved		11,161	
Exploration	**31,326**	1,253	1,956
Development	**5,057**	3,785	6,420
	36,383	16,199	8,376
Total	**86,160**	33,980	90,919

The US GAAP depletion rates, on a net production basis, were as follows:

China ($/bbl)	
2010	16.45
2009	16.06
2008	41.61

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

	2010	**2009**	**2008**
Oil revenue	**21,720**	24,968	48,370
Operating	**(9,503)**	(10,191)	(21,515)
Depletion	**(8,590)**	(7,479)	(20,385)
Provision for impairment			(21,560)
Results of operations from producing activities	**3,627**	7,298	(15,090)

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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, 2010. 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 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 consolidated financial statements for external purposes in accordance with Canadian 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 consolidated financial statements in accordance with Canadian 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 consolidated 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, 2010. 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, 2010, 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, 2010, as stated in their report which immediately follows.

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

March 4, 2011

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, 2010, 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, 2010, 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 Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2010 of the Company and our report dated March 4, 2011 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Canada
March 4, 2011

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CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in the Company s internal control over financial reporting that occurred during the 12 months ended December 31, 2010, that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART III

ITEM 10: DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Each director is elected for a one-year term or until his successor has been duly elected or appointed. All of our directors were elected at our last annual general meeting of shareholders (AGM) held on April 28, 2010. 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.

Name	Age	Positions Held	Ivanhoe Director Since
A. Robert Abboud	81	Co-Chairman and Independent Lead Director	2006
Robert M. Friedland	60	Executive Co-Chairman	1995
Howard R. Balloch	59	Director	2002
Carlos A. Cabrera	59	Director	2010
Brian F. Downey	69	Director	2005
Robert G. Graham	57	Director	2005
Peter G. Meredith	67	Director	2007
Alexander A. Molyneux	36	Director	2010
Robert A. Pirraglia	61	Director	2005

Officers serve at the pleasure of the Board of Directors.

Name	Age	Current Position	Executive Officer Since
Robert M. Friedland	60	Chief Executive Officer	2008
David A. Dyck	50	President and Chief Operating Officer	2010
Gerald D. Schiefelbein	53	Chief Financial Officer	2009
Ian Barnett	56	Executive Vice President, Corporate Development	2007
K. C. Patrick Chua	55	Executive Vice President	1999
David R. Martin	80	President, Chief Executive Officer & Co-Chairman of Ivanhoe Energy Latin America Inc. Co-Chairman of Ivanhoe Energy Ecuador Inc.	2008
Gerald G. Moench	61	Executive Vice President	1999
Michael A. Silverman	58	Executive Vice President, Technology and Chief Technology Officer	2007
Edwin J. Veith	52	Executive Vice President, Upstream	2007

A. 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 and Executive Committees. Mr. Abboud has been President and Chief Executive Officer 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 Chief Executive Officer of First Chicago Corporation and The First National Bank of Chicago, Chairman and Chief Executive Officer 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 M. FRIEDLAND

Mr. Friedland has been Executive Co-Chairman 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, Deputy Chairman of the Company from June 1999 to May 2008 and President of the Company from May 2008 to May 2010. 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 was appointed as Chief Executive Officer in October 2010. Mr. Friedland 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 was Chairman of Potash One Inc., a Canadian public company, from May 2009 to January 2011. 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 R. 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 is a member of the Executive Committee. He is Chairman of Canaccord Genuity Asia, following the acquisition by Canaccord Financial Inc. of The Balloch Group, the investment advisory firm he founded in 2001. A veteran Canadian diplomat, Mr. Balloch began serving as Canada s ambassador to the People s Republic of China, Mongolia and the Democratic People s Republic of Korea in 1996 after a 20-year career in the Government of Canada s Department of Foreign Affairs and International Trade and Privy Council Office. Mr. Balloch is Vice Chairman of the Canada China Business Council, having served as its President between 2001 and 2006. 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.

CARLOS A. CABRERA

Mr. Cabrera has been a director of the Company since May 2010 and serves as a member of the Audit, Nominating and Corporate Governance and Compensation and Benefits Committees. Mr. Cabrera is the former Chairman, President and Chief Executive Officer of UOP LLC, a Honeywell company. He is the President and Chief Executive Officer of the National Institute of Low Carbon and Clean Energy (NICE) based in Beijing, China. Mr. Cabrera also serves as a Distinguished Associate to the World Energy Consultancy Firm FACTS. Mr. Cabrera serves on the Global Advisory Board of the University of Chicago Booth School of Business. During Mr. Cabrera s 35 years in the refining and petrochemicals industry, he has been granted seven U.S. patents, authored numerous publications and frequently serves on industry panels as a recognized business and technical leader. He has a Bachelor of Science degree in chemical engineering from the University of Kentucky and a Master s degree in business administration from the University of Chicago. Mr. Cabrera brings to the Board extensive experience in petroleum refining, gas processing and petrochemical production as well as international business development and senior executive management experience.

BRIAN F. 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 Corporate Governance Committee. Mr. Downey has been President of Downey & Associates Management Inc., a real estate holding company, since July 1986, and Financial Advisor to Lending Solutions, Inc., a full-service loan call centre located in the US whose clients are primarily US 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 Chief Executive Officer 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.

DR. ROBERT G. 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 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.

PETER G. 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 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. 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.

ALEXANDER A. MOLYNEUX

Mr. Molyneux is President and Chief Executive Officer of Canadian-based SouthGobi Resources Ltd. (TSX:SGQ, HK:1878). SouthGobi is focused on exploration and development of its Permian-age coal deposits in Mongolia s South Gobi region to supply a wide range of coal products to markets in Mongolia and China. SouthGobi s largest shareholder is Ivanhoe Mines Ltd. Before joining SouthGobi in 2009, Mr. Molyneux was Head of Metals and Mining Investment Banking for Citigroup where he established a leading metals and mining investment banking business in Asia. During a distinguished career at Citigroup and UBS, he advised on coal-related public offerings, mergers and acquisitions, bond and debt offerings totalling several billion dollars. Mr. Molyneux holds a Bachelor s degree in Economics from Monash University in Australia. Mr. Molyneux was selected to serve as a director on our Board based on his comprehensive background in the areas of international capital markets, corporate finance and investment banking in Asia and elsewhere and his experience in doing business in the natural resource sector in China and Mongolia.

ROBERT A. 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 Group, Inc. starting in 1996, and was also Chief Operating Officer of Ensyn Group, Inc. from September 1998 to April 2005. He is currently Executive Vice President of Ensyn

Corporation and was the Chief Operating Officer and Vice President of the Company 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 US, 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.

DAVID A. DYCK

Mr. Dyck was appointed President and Chief Operating Officer of the Company in May 2010 and continues to serve as President and Chief Executive Officer of Ivanhoe Energy Canada Inc. Mr. Dyck was the Executive Vice President, Capital Markets from October 2009 to May 2010. 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).

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GERALD D. 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 Businesses and Corporate (September 2003 to February 2006) for BP p.l.c., one of the world s largest energy companies.

IAN BARNETT

Mr. Barnett has been the Executive Vice President, Corporate Development of the Company since March 2007. From January 2005 to November 2005, Mr. Barnett was a consultant to the Company and was Vice President, Finance from November 2005 to March 2007. Mr. Barnett is a member of the Board of Ensyn Corporation and has been a director (since 1996) and consultant (1999-2007) to various companies in the Ensyn group of companies. He is also co-founder and has been a director of Heptagon Investments Ltd. since 1991.

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 Energy Ltd.

DAVID R. MARTIN

Mr. Martin is the President, Chief Executive Officer and Co-Chairman of Ivanhoe Energy Latin America Inc. and Co-Chairman of Ivanhoe Energy Ecuador Inc., the Company s wholly owned subsidiaries. He was the Chairman of the Company from August 1998 to May 2006 at which time he was appointed as Executive Co-Chairman, serving in the position until May 2008.

Mr. Martin has over 50 years of international experience in the oil and gas industry, having spent 26 years in senior management positions with Occidental Petroleum Corporation. Part of the founding team at Occidental Petroleum, Mr. Martin was President and Chief Executive Officer of Occidental Oil & Gas Corporation from 1983 to 1996. He was also Executive Vice-President and a director of Occidental Petroleum Corporation and a director of Canadian Occidental Petroleum.

GERALD G. MOENCH

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

MICHAEL A. 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 J. 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. from November 2005 until June 2009. From June 2001 to November 2005, he was Chief Reservoir Engineer of Ivanhoe Energy (USA) Inc.

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 Canaccord Financial Inc. and was previously a director of East Energy Corp. and Tiens Biotech Group USA Inc. Messrs. Friedland and Meredith are both directors of Ivanhoe Australia Limited. Mr. Friedland was a director of Potash One Inc., a Canadian public company. Mr. Meredith is also a director of Entrée Gold Inc., SouthGobi Resources Ltd. and Great Canadian Gaming Corporation, and was previously a director of Jinshan Gold Mines Inc. (renamed China Gold International) and Olympus Pacific Minerals Inc. Mr. Molyneux is a director of SouthGobi Resources Ltd. Mr. Cabrera is also a director of GEVO, Inc.

BOARD COMMITTEES

As required under the Business Corporations Act (Yukon) and under section 3(a)(58)(A) of the Exchange Act, our Board of Directors has a separately designated standing Audit Committee. The members of the Audit Committee are Messrs. Brian F. Downey (Chair), A. Robert Abboud and Carlos A. Cabrera. 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.

We also have a Compensation and Benefits Committee, a Nominating and Corporate Governance Committee and an Executive Committee. The current members of the Compensation and Benefits Committee are Messrs. Howard R. Balloch (Chair), Robert A. Pirraglia, Carlos A. Cabrera 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, Carlos A. Cabrera and A. Robert Abboud. The current members of the Executive Committee are Messrs. Robert M. Friedland (Chair), A. Robert Abboud, Howard R. Balloch and Peter G. Meredith.

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 51-102 F6 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.

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 (Compensation Committee). The members of the Compensation Committee are all independent directors. Following review and approval by the Compensation Committee, decisions relating to executive compensation are reported to, and approved by, the 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 Ivanhoe s short-term and long-term corporate goals;
- to ensure that the interests of Ivanhoe s executive officers and the interests of the Company s shareholders are aligned;
- to ensure that Ivanhoe is able to attract, retain and motivate executive officers of the highest caliber in light of the strong competition in the oil and gas industry for qualified personnel;
- to recognize that the successful implementation of Ivanhoe 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 Related to Executive Compensation

Effective May 18, 2010, David A. Dyck was promoted to the position of President and Chief Operating Officer of Ivanhoe. On September 3, 2010, Greg Phaneuf was appointed Senior Vice President, Corporate Development of Ivanhoe and Ian Barnett provided notice that effective March 31, 2011, he will resign from his position as Executive Vice President, Corporate Development of the Company to pursue other business interests.

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 Ivanhoe s compensation philosophy and on individual and corporate performance.

The Compensation Committee annually reviews, and recommends to the Board, the cash compensation, any annual performance bonus, long term incentive grants 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 the new fiscal year. Although specific individual targets were not set for executives for the 2010 year, in the normal course of business, targets for performance bonuses for the fiscal year are set at the beginning of the 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 are ordinarily made during the first quarter following the end of the fiscal year. In the normal course of business, management presents its compensation recommendations for consideration by the Compensation Committee.

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The Compensation Committee may seek compensation advice where appropriate from external consultants, and based on significant changes to the Company s executive management team in 2009, the Compensation Committee instructed senior management to make a series of executive compensation proposals to the Compensation Committee. Subsequently, in the second quarter of 2010 the Compensation Committee engaged the services of the consulting firm Mercer Canada Ltd. to undertake a comprehensive review of executive compensation for named executive positions and other senior management positions. For 2011 and beyond, the Company will be implementing a new compensation program based on the results of the Mercer study and incorporating specific performance targets and objectives. Certain aspects of this new program were applied in 2010 to decisions relating to long term incentive awards in October 2010.

Since no performance targets or objectives were adopted upon which to base executive compensation decisions for the 2010 fiscal year, the Compensation Committee based its decisions for the purposes of establishing 2010 base salaries and bonuses awarded in 2010 in respect of the 2009 fiscal year on available industry data and a subjective review of the role played by senior management in corporate performance and achievements.

Elements of Total Compensation

The compensation package that the Company provides to its executive officers generally consists of base salary, annual performance bonuses 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 and in the form of common shares or incentive stock options so as to create a strong link 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 and external equity 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 the day to day responsibilities of the job.

Performance bonus annual award, paid in cash and earned for the achievement of near term critical strategic corporate and project goals.

Long Term Incentive awards annual equity award, in the form of a combination of stock options and restricted share units, granted to align the interests of the executive with longer term Company goals, the creation of shareholder value and the retention of key executives.

Peer Comparator Group

A new comparator group was established in 2010 as part of the process of establishing a new executive compensation program. The comparator group includes oil and gas companies with international operations, oil sands operations and similar market capitalization. The comparator group was composed of Pacific Rubiales Energy Corporation, Black Pearl Resources Inc., Niko Resources Ltd., Connacher Oil & Gas Ltd., Athabasca Oil Sands Corporation, OPTI Canada Inc., Petrobank Energy & Resources Ltd., TransGlobe Energy Corporation, Bankers Petroleum Ltd., Ithaca Energy Inc., Gran Tierra Energy Inc., Calvalley Petroleum Inc., Paramount Resources Ltd., Pan Orient Energy Corporation, UTS Energy Corporation, Southern Pacific Resources Corporation, Transatlantic Petroleum Ltd. and Oilsands Quest Inc.

However, for purposes of establishing 2010 base salaries and bonuses for the 2010 fiscal year in respect of the 2009 fiscal year, the Compensation Committee relied on data from the comparator group and externally generated survey data from the energy sector, primarily in the category of exploration and production companies.

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.
Under the Company s compensation program and onward, salary levels are to be 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 position, knowledge, skills, relevant experience and credentials. Annual salary increases are made based on performance and the relative position within a pay grade. The Compensation Committee also considers retention risks, succession requirements and compensation changes in the market in determining salary changes.

Cash Performance Bonus

The annual bonus program is intended to align the performance of the Company s employees with the near term critical goals defined in the annual business plan. The program calls on the same pay grade system used to establish base salary to be used for determining the bonus targets for each employee.

Prior to adoption of the Company s new compensation plan under the existing plan potential bonus amounts in the ordinary course 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. However, for the 2010 year, specific performance targets were not set and individual executives were evaluated subjectively in terms of their contribution to overall corporate objectives and execution of the corporate business plan.

Under the new compensation plan for 2011 and onwards, cash bonuses are awarded to the Company s executive officers and senior non-executive management according to the performance of the Company and the success in meeting, or exceeding, the annual established corporate and project targets. For executive officers, potential bonus awards can range from 55% to 75% of base salary multiplied by a weighted achievement factor ranging from 0% to 200%.

Long Term Incentive Plan

Equity based compensation is granted to the Company s executive officers and management. This long term incentive portion of salary is meant to retain key employees over the long term and to focus the efforts of those individuals on shareholder return and the longer broader goals of the organization. To remain competitive within the industry and to provide parity with compensation levels within the Comparator Peer Group, equity grants are used to enhance the overall total compensation package.

Equity based compensation is determined as a percentage of base pay and may have a combination of stock option grants and restricted share units, the combination of which is determined by the pay grade level. The higher the grade level the higher the weighting towards at risk stock option grants.

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. In addition, the Board of Directors has traditionally taken an approach to vesting that is based on the passage of time and option exercise periods and vesting schedules for options granted to executive officers are determined by the Compensation Committee and the Board of Directors.

Under the new compensation plan, equity grants are awarded to the Company s executive officers and senior non-executive management according to performance and the success in meeting or exceeding the annual established corporate and project targets. For executive officers, potential value of equity grants can range from 160% to 225% of base salary multiplied by a weighted achievement factor ranging from 0% to 200%. For the 2010 year, specific performance targets were not set and individual executives were evaluated subjectively in terms of their contribution to overall corporate objectives and execution of the corporate business plan.

The new compensation plan for 2011 will result in the establishment of a Restricted Share Unit Plan to provide a form of equity compensation that is less dilutive than produced by a plan based on options. The amounts awarded through the Restricted Share Unit Plan will be shares purchased on the TSX through a Trustee. Restricted Share Units are subject to the vesting provisions of the plan. Should the employee voluntarily leave the employment of the Company any unvested Restricted Share Units are forfeited by the employee under the terms of the plan.

2010 EXECUTIVE COMPENSATION DECISIONS

Salary Compensation

Robert Friedland, Executive Co-Chairman and Chief Executive Officer, has voluntarily waived a cash salary from Ivanhoe to help conserve the Company s cash.

Pending finalization and adoption of the Company s new compensation plan, the Company determined to increase base salaries for executive officer s by 4.2%, which percentage was established with reference to 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 to the Canadian oil and gas industry upon which the Compensation Committee relied. Exceptions to this include significant changes in roles and responsibilities during the year.

Bonus Compensation

As specific performance targets were not set for individual executives, bonuses awarded in 2010 in respect of the 2009 fiscal year were awarded based on subject criteria in terms of the individual executive s contribution to overall corporate objectives and execution of the corporate business plan. In March 2010, the Compensation Committee created a bonus pool having an aggregate value of approximately $1.4 million from which bonuses for the entire Company would be drawn, representing approximately 18.7% of aggregate base salaries paid by the Company to its executive officers and other senior management staff during the prior fiscal year. This percentage was established with reference to the Compensation Committee s understanding of what Canadian exploration and production companies paid based on externally generated compensation data in respect of the Canadian oil and gas industry and upon which the Compensation Committee relied. The Compensation Committee also allocated an additional $250,000 for payment of additional bonuses to executives perceived by the Compensation Committee as having achieved extraordinary performance. The final allocation was made with input from the Company s Chief Executive Officer, who did not accept any salary or bonus.

Incentive Compensation

For the 2010 year, specific performance targets were not set and individual executives were evaluated subjectively in terms of their contribution to overall corporate objectives and execution of the corporate business plan. The Compensation Committee also considered overall compensation factors, the need to retain valuable employees and the practices of comparator companies.

In April 2010, at the recommendation of the Compensation Committee, the Company granted options to purchase 250,000 common shares to David R. Martin, President, CEO and Co-Chairman of Ivanhoe Energy Latin America Inc., in recognition of his considerable efforts made on behalf of the Company to advance its projects and business interests in Latin America.

In October, 2010, at the recommendation of the Compensation Committee, the Company granted options to purchase 1,000,000 common shares to Robert M. Friedland, Executive Co-Chairman and Chief Executive Officer, in recognition of the considerable efforts made on behalf of the Company to advance its projects and business interests without receiving an annual salary. In October 2010, the Company further granted options to purchase 200,000 common shares to David A. Dyck, President and Chief Operating Officer, and 130,000 shares to each of David M. Martin, President, CEO and Co-Chairman of Ivanhoe Energy Latin America Inc., Edwin J. Veith, Executive Vice-President, Upstream, and Gerald Schiefelbein, Chief Financial Officer.

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 2010, the Company paid Mr. Veith US$22,000 for the purpose of contributing to his 401(k) retirement plan and $28,570 as an expatriate housing allowance.

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Performance Graph

The following graph shows the change in a Cdn$100 investment in Ivanhoe common shares over the past five years, compared to the S&P/TSX Composite Index, the S&P/TSX Oil & Gas Exploration & Production and the S&P/TSX Energy Sector Index. Our common shares were added to the S&P/TSX Composite Index on March 22, 2010.

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 2010, the Company issued option-based awards under its Equity Incentive Plan to executive officers as described under the heading 2010 Executive Compensation Decisions.

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SUMMARY COMPENSATION TABLE

The following table sets forth all compensation earned by the individuals who served as our Chief Executive Officer, our Chief Financial Officer and by each of our other three most highly compensated executive officers as of the end of 2010 (the Named Executive Officers or NEOs). Our NEOs may change from year to year due to fluctuations in our executive officers annual compensation.

Name and Principal Position	Year	Salary[1] ($)	Share-Based Awards ($)	Option-Based Awards[2] ($)	Non-Equity Incentive Plan Compensation Annual Incentive Awards[3] ($)	Pension Value ($)	All Other Compensation ($)	Total Compensation ($)
Robert M. Friedland[4]	2010			1,497,797				1,497,797
Executive Co-Chairman & CEO	2009							
	2008			1,977,888				1,977,888
David A. Dyck	2010	374,297		299,559				673,856
President & COO	2009(5)	82,842		982,223	42,424			1,107,489
	2008							
Gerald D. Schiefelbein	2010	264,523		194,714				459,237
CFO	2009(6)	61,750		392,889	29,874			484,513
	2008							
David R. Martin	2010	296,971		194,714		22,000		513,685
President, CEO & Co-Chairman,	2009	285,000		537,100[7]	134,942	19,645		976,687
Ivanhoe Energy Latin America Inc.	2008	285,000	29,965[8]			21,354		336,319
Edwin J. Veith	2010	263,627		194,714		22,000	31,914(9)	512,255
Executive VP, Upstream	2009	253,000		228,623	128,936	21,083		631,642
	2008	239,250	29,965(8)			19,958		289,173

(1) Amounts paid in Canadian dollars to Messrs. Dyck and Schiefelbein were converted to US currency based on the monthly average exchange rate during the pay periods.

(2) Estimated fair value on date of grant calculated using the Black Scholes option pricing model. Key assumptions are outlined in Note 9 to the consolidated financial statements. The value of stock options with a Canadian dollar exercise price was converted to US dollars using the Bank of Canada exchange rate on date of grant.

(3) A cash bonus was paid in 2010 in connection with the NEOs performance in 2009. The bonus was not previously disclosed as the amounts had not been finalized by the filing date of our 2009 10K report.

(4) 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.

(5) Mr. Dyck joined the Corporation effective October 21, 2009, and was employed for approximately two months during 2009.

(6) Mr. Schiefelbein joined the Corporation effective October 1, 2009, and was employed for three months during 2009.

(7) Stock options were awarded to Mr. Martin in 2010 in connection with 2009 events. The options were not previously disclosed as they had not been finalized by the filing date of our 2009 10K report.

(8) Estimated fair value calculated as the closing trading price for the Company s common shares on August 5, 2008, when a treasury order for the award was delivered to the Company s transfer agent, multiplied by the number of common shares awarded.

(9) Includes $28,570 paid as an expatriate housing allowance. Ivanhoe reimburses Mr. Veith for the difference between the actual Canadian income taxes paid by him and the US income taxes that would have been paid if Mr. Veith had remained in the US. This amount has not yet been determined for 2010.

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INCENTIVE PLAN AWARDS

To value stock options awarded to our NEOs, we used the Black Scholes option pricing model. The actual value realized on exercises may be higher or lower depending on our common share price at the time of exercise.

Outstanding option-based awards at December 31, 2010

Name	Number Of Securities Underlying Unexercised Options (#)	Option Exercise Price ($)	Option Expiration Date	Total Value of Unexercised in-the-Money Options(1) (US$)
Robert M. Friedland	1,000,000	Cdn$2.28	Oct 28, 2017	3,232,456
	2,500,000	Cdn$1.61	Mar 5, 2013	
David A. Dyck	200,000	Cdn$2.28	Oct 28, 2017	194,048
	500,000	Cdn$2.51	Oct 15, 2016	
Gerald D. Schiefelbein	130,000	Cdn$2.28	Oct 28, 2017	99,739
	200,000	Cdn$2.51	Oct 1, 2016	
David R. Martin	130,000	Cdn$2.28	Oct 28, 2017	57,511
	250,000	Cdn$3.26	Apr 29, 2017	
Edwin J. Veith	130,000	Cdn$2.28	Oct 28, 2017	274,928
	150,000	Cdn$2.22	Sep 17, 2014	
	158,000	US $1.92	Oct 4, 2012	
	250,000	US $2.70	Jun 2, 2011	
	70,734	US $2.57	Apr 18, 2011	
	22,000	US $3.06	Mar 8, 2011	

(1) Calculated as the difference between the December 31, 2010, closing market price of our common shares and the exercise price of the options, multiplied by the number of unexercised options. The value of options with a US dollar exercise price is calculated using the NASDAQ closing price of $2.72 per common share. The value of options with a Canadian dollar exercise price is calculated using the TSX closing price of Cdn$2.72 per common share and converted to US dollars using the December 31, 2010, Bank of Canada closing rate. Where the exercise price exceeds the market value per common share, the value is zero.

Incentive plan awards value vested in 2010

Name	Option-Based Awards Value Vested During the Year[1] (US$)
Robert M. Friedland	960,699
David A. Dyck	nil
Gerald D. Schiefelbein	nil
David R. Martin	nil
Edwin J. Veith	11,132

(1) Calculated as the difference between the closing market price of our common shares on the vesting date and the exercise price of the options, multiplied by the number of options vesting in the current year. The value of options with a Canadian dollar exercise price were converted to US dollars using the Bank of Canada closing rate on the vesting date. Where the exercise price exceeds the market price per common share, the value is nil.

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PENSION PLAN

Employees of Ivanhoe Energy Holdings Inc. (the Employees) may participate in Ivanhoe s 401(k) (the Plan). The Plan is a defined contribution plan that includes Employee and Company contributions. Employees may contribute up to the maximum amount established by the Internal Revenue Code and the Company may elect to make annual discretionary matching and profit sharing contributions. Employee contributions vest immediately and Company contributions vest after two years of service. Investment decisions are made by the Employee from a variety of investment options.

The following table represents the value of accumulated pension assets within the Plan for Messrs. Martin and Veith. There were no above-market or preferential earnings provisions.

Name	Accumulated Value at January 1, 2010 ($)	Compensatory ($)	Non-compensatory ($)	Accumulated Value at December 31, 2010 ($)
David R. Martin	342,031	22,000	27,559	391,590
Edwin J. Veith	282,345	22,000	48,613	352,958

TERMINATION AND CHANGE OF CONTROL BENEFITS

The Company has written contracts of employment with Messrs. Dyck and Schiefelbein. In the case of termination for cause or voluntary resignation, the employment contracts do not result in incremental payments, payables or benefits, and therefore have been excluded from the following discussion. Perquisites and other personal benefits totalling less than $50,000 have also been omitted.

Estimated incremental payments are based on the individual s annual salary as at December 31, 2010. Any amounts payable in Canadian dollars have been translated to US dollars using the December 31, 2010, Bank of Canada closing rate. Unexercised stock options were valued using the December 31, 2010, closing market price of our common shares and stock options with a Canadian dollar exercise price were converted to US dollars using the December 31, 2010, Bank of Canada closing rate.

David A. Dyck

Mr. Dyck s employment contract provides that:

(a) in the case of termination without cause or termination upon disability, the Company must pay twelve months wages in a lump sum, cause all of the unvested stock options that would vest in the succeeding twelve months to vest immediately and generally remain exercisable for six months;

(b) in the case of termination of the employment contract by the Company within twelve months of a change of control, the Company must pay twelve months wages in a lump sum and cause all stock options to vest immediately and generally remain exercisable for six months; and

(c) Mr. Dyck is bound by a confidentiality clause that is effective for three years after the termination of active employment.

The estimated incremental payments to Mr. Dyck in the above scenarios are (a) a lump sum of US$366,673 and accelerated vesting of stock options valued at US$167,655; and (b) a lump sum of US$366,673 and accelerated vesting of stock options valued at US$167,655.

Gerald D. Schiefelbein

Mr. Schiefelbein s employment contract provides that:

(a) in the case of termination without cause or termination upon disability, the Company must pay twelve months wages in a lump sum, cause all of the unvested stock options that would vest in the succeeding twelve months to vest immediately and generally remain exercisable for six months;

(b)

in the case of termination of the employment contract by the Company within twelve months of a change of control, the Company must pay twelve months wages in a lump sum and cause all of the unvested stock options to vest immediately and remain generally exercisable for six months;

(c) in the case that Mr. Schiefelbein does not continue to have all the necessary work permits to be employed in Canada and is unable to fulfill the role of CFO due to legal or regulatory requirements, the Company must pay six months wages in a lump sum, vested stock options will remain generally exercisable for six months from the date that employment terminates, all unvested stock options will terminate immediately;

(d) Mr. Schiefelbein is bound by a non-competition clause effective until the later of twelve months after the termination of active employment or the date he no longer receives compensation of any kind under the employment contract;

(e) Mr. Schiefelbein is bound by a non-solicitation clause effective for twelve months after the termination of active employment; and

(f) Mr. Schiefelbein is bound by a confidentiality clause that is effective for three years after the termination of active employment.

The estimated incremental payments to Mr. Schiefelbein in the above scenarios are (a) a lump sum of US$272,399 and accelerated vesting of stock options valued at US$89,182; (b) a lump sum of US$272,399 and accelerated vesting of stock options valued at US$89,182; and (c) a lump sum of US$136,200.

DIRECTOR COMPENSATION

Each non-management director other than Mr. Abboud, the Lead Director, and Mr. Cabrera, receives US$40,000 per annum for acting as a director of the Company. Mr. Abboud, as Co-Chairman and Lead Director, and Mr. Cabrera, as Co-Chairman and Lead Director of the Company s wholly owned subsidiaries, Ivanhoe Energy Latin America Inc. and Ivanhoe Energy Ecuador Inc., receive US$80,000 per annum. Mr. Balloch receives an additional $10,000 for his duties as Chairman of the Nominating and Corporate Governance and Compensation and Benefits Committees. Effective August 1, 2010, Mr. Downey receives an additional $10,000 for his duties as Chairman of the Audit Committee. In addition, directors receive $1,000 for each board meeting and committee meeting attended in person or by conference telephone.

NON-MANAGEMENT DIRECTOR COMPENSATION TABLE

The following compensation was earned by non-management directors in 2010.

Name	Fees Earned ($)	Option-Based Awards (1)(US$)	Total ($)
A. Robert Abboud	100,000	107,420	207,420
Howard R. Balloch	69,000	107,420	176,420
Carlos A. Cabrera	53,667	408,504	462,171
Brian F. Downey	71,542	107,420	178,962
Robert G. Graham	49,000	107,420	156,420
Peter G. Meredith	49,000	107,420	156,420
Alexander A. Molyneux	27,000	154,291	181,291
Robert A. Pirraglia	60,000	107,420	167,420

(1) Estimated fair value of stock options on date of grant calculated using the Black Scholes option pricing model. Key assumptions are outlined in Note 9 to the consolidated financial statements. The value of stock options with a Canadian dollar exercise price was converted to US dollars using the Bank of Canada exchange rate on date of grant.

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Outstanding option-based awards at December 31, 2010

Name	Number of Securities Underlying Unexercised Options (#)	Option Exercise Price ($)	Option Expiration Date	Total Value of Unexercised in-the-Money Options[(1)] (US$)
A. Robert Abboud	50,000	Cdn$3.26	Apr 29, 2017	1,500
	50,000	US $2.69	May 29, 2013	
	480,000	US $2.85	May 15, 2011	
Howard R. Balloch	50,000	Cdn$3.26	Apr 29, 2017	84,959
	50,000	Cdn$1.51	Apr 29, 2016	
	50,000	Cdn$2.66	May 29, 2013	
	50,000	Cdn$2.30	May 3, 2012	
	50,000	Cdn$3.12	May 4, 2011	
Carlos A. Cabrera	200,000	Cdn$2.00	Jul 28, 2017	153,831
	100,000	Cdn$2.63	May 18, 2017	
Brian F. Downey	50,000	Cdn$3.26	Apr 29, 2017	95,328
	50,000	Cdn$1.51	Apr 29, 2016	
	50,000	US $2.69	May 29, 2013	
	50,000	US $2.06	May 3, 2012	
	20,000	US $2.80	May 4, 2011	
Robert G. Graham	50,000	Cdn$3.26	Apr 29, 2017	150,312
	50,000	Cdn$1.51	Apr 29, 2016	
	50,000	Cdn$2.66	May 29, 2013	
	200,000	Cdn$2.29	Mar 8, 2012	

	50,000	Cdn$3.12	May 4, 2011	
Peter G. Meredith	50,000	Cdn$3.26	Apr 29, 2017	349,387
	50,000	Cdn$1.51	Apr 29, 2016	
	50,000	Cdn$2.66	May 29, 2013	
	100,000	Cdn$1.68	Mar 11, 2013	
	150,000	Cdn$1.52	Dec 19, 2012	
Alexander A. Molyneux	100,000	Cdn$2.63	May 18, 2017	49,266
	80,000	Cdn$2.22	Sep 17, 2014	
Robert A. Pirraglia	50,000	Cdn$3.26	Apr 29, 2017	95,328
	50,000	Cdn$1.51	Apr 29, 2016	
	50,000	US $2.69	May 29, 2013	
	50,000	US $2.06	May 3, 2012	
	50,000	US $2.80	May 4, 2011	

(1) Calculated as the difference between the December 31, 2010, closing market price of our common shares and the exercise price of the options, multiplied by the number of unexercised options. The value of options with a US dollar exercise price is calculated using the NASDAQ closing price of $2.72 per common share. The value of options with a Canadian dollar exercise price is calculated using the TSX closing price of Cdn$2.72 per common share and converted to US dollars using the December 31, 2010, Bank of Canada closing rate. Where the exercise price exceeds the market value per common share, the value is nil.

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Incentive plan awards value vested in 2010

Name	Option-Based Awards Value Vested During the Year[(1)] (US$)
A. Robert Abboud	172,568
Howard R. Balloch	82,554
Carlos A. Cabrera	nil
Brian F. Downey	84,654
Robert G. Graham	102,951
Peter G. Meredith	150,849
Alexander A. Molyneux	nil
Robert A. Pirraglia	84,654

(1) Calculated as the difference between the closing market price of our common shares on the vesting date and the exercise price of the options, multiplied by the number of options vesting in the current year. The value of options with a Canadian dollar exercise price were converted to US dollars using the Bank of Canada closing rate on the vesting date. Where the exercise price exceeds the market price per common share, the value is nil.

ITEM 12: SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Ivanhoe s common shares are the only class of voting securities. Based on information known to the Company, the following table shows each person or group who beneficially owns (pursuant to SEC Regulations) more than 5% of our voting securities as at March 4, 2011.

Name and Address of Beneficial Owner	Number of Shares Beneficially Owned[(1)]	Percentage of Class
Robert M. Friedland 150 Beach Road #25-03 The Gateway West Singapore 189720	53,411,725(2)	15.22
Directors and Executive Officers as a group (17 persons)	64,173,532(2)(3)	18.29
Caisse de dépôt et placement du Québec 1000 place Jean-Paul-Riopelle Montreal, Quebec, H2Z 2B3	19,442,822	5.54
FMR LLC 82 Devonshire Street Boston, Massachusetts USA 02109	19,025,800	5.42

(1) Beneficial ownership is determined in accordance with the rules of the SEC and generally includes voting or investment power with respect to securities. Unissued common shares subject to options, warrants or other convertible securities currently exercisable or convertible, or exercisable or convertible within 60 days, are deemed outstanding for the purpose of computing the beneficial ownership of common shares of the person

holding such convertible security but are not deemed outstanding for computing the beneficial ownership of common shares of any other person.

(2) Includes 48,794,620 common shares and 2,200,000 common shares issuable upon the exercise of common share purchase warrants held indirectly through Newstar Securities SRL, Premier Mines SRL and Evershine SRL, companies controlled by Mr. Friedland. Also includes 2,000,000 common shares issuable upon the exercise of stock options and 417,105 common shares held directly by Mr. Friedland.

(3) Includes 4,697,734 unissued common shares issuable to directors and senior officers upon exercise of incentive stock options and 2,210,500 common shares issuable upon the exercise of common share purchase warrants.

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Security Ownership of Management

The following table sets forth the beneficial ownership, pursuant to SEC Regulations, as at March 4, 2011, of our common shares by each of our directors, our executive officers and by all of our directors and executive officers as a group:

Name of Beneficial Owner	Amount And Nature of Beneficial Ownership[(1)] (a)	Percentage of Class (b)	Incentive Stock Options Included in (a) (c)
A. Robert Abboud	834,624	0.24	100,000
Robert M. Friedland	53,411,725(2)	15.22	2,000,000
Howard R. Balloch	300,000	0.09	250,000
Carlos A. Cabrera		0.00	
Brian F. Downey	224,707	0.06	100,000
Robert G. Graham	4,896,726	1.40	400,000
Peter G. Meredith	398,000(3)	0.11	350,000
Alexander A. Molyneux	32,000	0.01	32,000
Robert A. Pirraglia	515,929	0.15	200,000
David A. Dyck	485,000	0.14	125,000
Gerald D. Schiefelbein	50,000	0.01	50,000
Ian Barnett	19,020	0.01	
Patrick Chua	202,318	0.06	148,000
David Martin	1,814,213	0.52	125,000
Gerald Moench	290,151	0.08	200,000
Michael A. Silverman	127,259	0.04	114,000
Edwin J. Veith	571,860	0.16	503,734
All directors and executive officers as a group (17 persons)	64,173,532	18.29	4,697,734

(1) Beneficial ownership is determined in accordance with the rules of the SEC and generally includes voting or investment power with respect to securities. Unissued common shares subject to options, warrants or other convertible securities currently exercisable or convertible, or exercisable or convertible within 60 days, are deemed outstanding for the purpose of computing the beneficial ownership of common shares of the person holding such convertible security but are not deemed outstanding for computing the beneficial ownership of common shares of any other person.

(2) Includes 48,794,620 common shares and 2,200,000 common shares issuable upon the exercise of common share purchase warrants which are held indirectly through Newstar Securities SRL, Premier Mines SRL and Evershine SRL, companies controlled by Mr. Friedland. 417,105 common shares are held directly by Mr. Friedland.

(3) Includes 10,500 common shares issuable upon the exercise of common share purchase warrants.

Securities Authorized for Issuance under Equity Compensation Plans

All of the incentive stock options and equity compensation awards the Company granted in 2010 were made under the Company s Equity Incentive Plan. The Equity Incentive Plan is the only equity compensation plan the Company has in effect and is intended to further align the interests of the Company s directors and management with the Company s long term performance and the long term interests of the Company s shareholders. The Company s shareholders have approved the Equity Incentive Plan and all amendments thereto. The following information is as at December 31, 2010:

Plan category	**Number of Securities to be Issued Upon Exercise of Outstanding Options**	**Weighted-Average Exercise Price of Outstanding Options (Cdn$)**	**Number of Securities to be Remaining Available for Future Issuance Under Equity Compensation Plans**
Equity compensation plans approved by Security holders	16,877,275	2.24	4,589,957
Equity compensation plans not approved by Security holders[(1)]	50,000	2.15	
Total	16,927,275	2.24	4,589,957

(1) 50,000 stock options were granted as employment inducements and therefore were not granted under the Company s stock option plan.

ITEM 13: CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

RELATED TRANSACTIONS

Ivanhoe is party to cost sharing agreements with other companies, some of which are wholly or partially owned by Mr. Friedland. Through these agreements, we share office space, furnishings, equipment, air travel and communications facilities in various international locations. We also share the costs of employing administrative and non-executive management personnel at these offices. In 2010, our share of these costs was $2.0 million.

In 2008, we agreed, as part of our cost sharing arrangements and in connection with Mr. Friedland s position as Chief Executive Officer, to share the costs of operating an aircraft owned by a private company of which Mr. Friedland is the sole shareholder. Ivanhoe paid $1.2 million towards aircraft operating costs in 2010.

A director of the Company, Dr. Robert Graham, was engaged to provide services through his private consulting company. In 2010, the Company paid $52,000 to his firm.

Our Board of Directors recognizes that related party transactions present a heightened risk of conflicts of interest and therefore has a written policy that is part of our Code of Business Conduct and Ethics. This policy prohibits activities that could give rise to conflicts of interest, unless they are specifically approved by the Board of Directors. Directors and officers are obligated to inform us of any related party transactions and any proposed related party transactions. In addition, we present a summary of related party transactions to the Audit Committee on a quarterly basis for its review and approval.

DIRECTOR INDEPENDENCE

We undertook a review of the independence of our directors and, using the definitions and independence standards for directors established under NASDAQ and Canadian Securities Administrators National Instrument 58-101, Disclosure of Corporate Governance Practices. As a result of this review, we determined that each of Messrs. Abboud, Balloch, Downey, Cabrera and Pirraglia is considered to be an independent director.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

In considering the nature of the services provided by Deloitte & Touche LLP (Deloitte), the Audit Committee determined that such services are compatible with the provision of independent audit services. The Audit Committee discussed these services with Deloitte and our management to determine that they were permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants. In accordance with our policy, all of the services outlined below were pre-approved by our Audit Committee.

(Cdn$000s)	**2010**	**2009**
Audit fees	551	791
Audit related fees	93	119
Tax fees	223	274
Other fees	242	86
	1,111	1,270

Audit fees in 2010 and 2009 include services related to the audit of our annual consolidated financial statements and the review of our interim consolidated financial statements. Fees were also incurred in 2010 and 2009 for the audit of internal controls related to requirements under the United States Sarbanes-Oxley Act of 2002 and similar Canadian regulatory compliance.

Audit related fees include services performed to translate the annual and quarterly consolidated financial statements into French as well as the reimbursement of the pro-rata share of annual fees charged to each audit firm by the Canadian Public Accountability Board.

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Tax services performed by Deloitte, outside of normal audit procedures, consisted of tax compliance and tax planning and advice. Tax compliance services consisted of Federal, state and local income tax return assistance, preparation of expatriate tax returns and assistance with tax return filings in certain foreign jurisdictions. Tax planning and advice was rendered in connection with the structuring of intercompany transactions as well as proposed mergers, acquisitions and disposals. In 2009, additional tax assistance was provided in connection with the disposition of our US operations.

Other non-audit fees in 2010 relate to services provided in connection with a common share prospectus and support for our transition to IFRS on January 1, 2011. Both 2010 and 2009 include fees for a subscription to an accounting research tool and human capital salary information.

AUDIT COMMITTEE PRE-APPROVAL POLICY

The Audit Committee has adopted a pre-approval policy for services that may be provided by the Company s auditors. A description of the services expected to be performed by Deloitte in the following fiscal year is presented to the Audit Committee for approval. If services that were not pre-approved are required, approval may be granted by the Chairman of the Audit Committee. However, the Chairman must inform the Audit Committee, at the next regularly scheduled meeting, of any services that were pre-approved by him. Additionally, the Audit Committee generally requests a range of fees associated with each proposed service. On a quarterly basis, the Audit Committee reviews the status of services and fees incurred year-to-date against the original estimates and the forecast of remaining services and fees.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

We refer you to the consolidated financial statements and Supplementary Data in Item 8 of this Annual Report where these documents are listed. The following exhibits are filed as part of this Annual Report:

		Incorporated by Reference		
Exhibit Number	**Description of Document**	**Form**	**Filing Date/ Period End Date**	**Exhibit Number (if different)**
3.1	Articles of Ivanhoe Energy Inc. as amended to May 3, 2007	10-K	March 17, 2008	
3.2	Bylaws of Ivanhoe Energy Inc. as amended May 15, 2001 and further amended March 8, 2007	10-K	March 17, 2008	
10.1	Petroleum Contract for Kongnan Block, Dagang Oilfield of the People s Republic of China dated September 8, 1997 between China National Petroleum Corporation and Pan-China Resources Ltd., as amended June 11, 1999	20-F	February 28, 2000	3.15
10.2	Petroleum Contract dated September 19, 2002 between China National Petroleum Corporation and Pan-China Resources Ltd. for Zitong Block, Sichuan Basin of the People s Republic of China	10-K	March 19, 2003	10.12
10.3	Employees and Directors Equity Incentive Plan as amended April 28, 2010	S-8	August 20, 2010	
10.4	Amended and Restated License Agreement dated December 8, 1997 between Ensyn Technologies Inc. and Ensyn Group, Inc. and as amended on February 12, 1999	10-K	March 15, 2006	10.12
10.5	Indemnification Agreements entered into during the first quarter of 2008 between Ivanhoe Energy Inc. and its executive officers and directors	10-K	March 17, 2008	10.16
10.6	Employment Agreement, dated May 2, 2007 between Ivanhoe Energy Inc. and Michael Silverman	10-K	March 17, 2008	10.17
10.7	Asset Transfer Agreement dated July 11, 2008 between Ivanhoe Energy Inc. and Talisman Energy Canada	10-Q	August 11, 2008	10.1

10.8	Back-In Agreement dated July 11, 2008 between Ivanhoe Energy Inc. and Talisman Energy Canada	10-Q	August 11, 2008	10.2
10.9	Cdn$40 million Promissory Note in favour of Talisman Energy Canada due July 11, 2011 and convertible at the option of Talisman Energy Canada into 12,779,552 common shares at Cdn $3.13 per share	10-Q	November 11, 2008	10.2
10.10	Fixed and Floating Charge Debenture of Ivanhoe Energy Inc. in favour of Talisman Energy Canada dated July 11, 2008 in the principal sum of Cdn$67.5 million	10-Q	November 11, 2008	10.3
10.11	Pledge Agreement dated July 11, 2008 between Ivanhoe Energy Inc. and Talisman Energy Canada	10-Q	November 11, 2008	10.4
10.12	English translation of Specific Services Contract dated October 8, 2008 between Ivanhoe Energy Ecuador Inc., Empresa Estatal de Petroleos del Ecuador, Petroecuador and Empresa Estatal de Exploracion y Produccion de Petroleos del Ecuador, Petroproduccion	10-K	March 16, 2009	10.24
10.13	English translation of Contract Modification to the Specific Services Contract dated February 13, 2009 between Ivanhoe Energy Ecuador Inc., Empresa Estatal de Petroleos del Ecuador, Petroecuador and Empresa Estatal de Exploracion y Produccion de Petroleos del Ecuador, Petroproduccion	10-K	March 16, 2009	10.25
10.14	Stock Purchase Agreement dated June 16, 2009 among Ivanhoe Energy Holdings Inc., Ivanhoe Energy Inc., Seneca South Midway LLC and Seneca Resources Corporation	10-Q	November 9, 2009	10.1

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			Incorporated by Reference	
Exhibit Number	Description of Document	Form	Filing Date/ Period End Date	Exhibit Number (if different)
10.15	Employment Agreement dated October 1, 2009 between Ivanhoe Energy Inc. and Gerald D. Schiefelbein	8-K	November 17, 2009	10.1
10.16	Employment Agreement dated October 1, 2009 between Ivanhoe Energy Inc. and David A. Dyck	8-K	May 24, 2010	10.1
10.17	Amended and Restated Employees and Directors Equity Incentive Plan dated April 28, 2010	S-8	August 20, 2010	5.1
10.18	Employment Agreement dated March 15, 2007 between Ivanhoe Energy Inc. and Ian Barnett			
10.19	Employment Agreement dated September 1, 2010 between Ivanhoe Energy Inc. and Ian Barnett			
10.20	Indemnification Agreement dated May 18, 2010 between Ivanhoe Energy Inc. and Carlos A. Cabrera			
10.21	Indemnification Agreement dated May 18, 2010 between Ivanhoe Energy Inc. and Alexander A. Molyneux			
20.1	Submission of Matters to a Vote of Security Holders	8-K	July 29, 2010	
21.1	Subsidiaries of Ivanhoe Energy Inc.			
23.1	Consent of GLJ Petroleum Consultants Ltd., Petroleum Engineers			
23.2	Consent of Deloitte & Touche LLP			
31.1	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			
31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the			

	Sarbanes-Oxley Act of 2002
32.1	Certification by the Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	GLJ Petroleum Consultants Ltd., Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor as of December 31, 2010

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 16, 2011.

IVANHOE ENERGY INC.

By: /s/ Robert M. Friedland

Robert M. Friedland
Executive Co-Chairman
Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 16, 2011.

/s/ Robert M. Friedland

Robert M. Friedland
Executive Co-Chairman

Chief Executive Officer
(Principal Executive Officer)

/s/ Gerald D. Schiefelbein

Gerald D. Schiefelbein

Chief Financial Officer
(Principal Financial and Accounting Officer)

/s/ A. Robert Abboud

A. Robert Abboud
Co-Chairman and Independent Lead Director

/s/ Howard R. Balloch

Howard R. Balloch, Director

/s/ Carlos A. Cabrera

Carlos A. Cabrera, Director

/s/ Brian F. Downey

Brian F. Downey, Director

/s/ Robert G. Graham

Robert G. Graham, Director

/s/ Peter G. Meredith

Peter G. Meredith, Director

/s/ Alexander A. Molyneux

Alexander A. Molyneux, Director

/s/ Robert A. Pirraglia

Robert A. Pirraglia, Director

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